



Delivering on the Promise of
Gas-Electric Coordination

Reliable Energy: Delivering on the Promise of Gas-Electric Coordination

**A Report of the National Petroleum Council
Committee on Gas-Electric Coordination**

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Preface

I. NATIONAL PETROLEUM COUNCIL

The National Petroleum Council (NPC) is an organization whose sole purpose is to provide advice to the federal government. After successful cooperation during World War II, President Harry Truman requested this federally chartered and privately funded advisory group to be established by the Secretary of the Interior to represent the oil and natural gas industry's views to the federal government by advising, informing, and recommending policy options. Today, the NPC is chartered by the Secretary of Energy under the Federal Advisory Committee Act of 1972, and the views represented are broader than those of the oil and natural gas industry.

NPC members, about 200 in number, are appointed by the Energy Secretary to assure well-balanced representation from all segments of the oil and natural gas industry, from all sections of the country, and from large and small companies. Members are also appointed from outside the oil and natural gas industry, representing related interests such as large consumers, states, Native Americans, and academic, financial, research, and public interest organizations and institutions. The NPC promotes informed dialogue on issues involving energy, security, the economy, and the environment of an ever-changing world.

II. STUDY REQUEST

On June 30, 2025, Secretary of Energy Chris Wright requested that the NPC undertake a *Future Energy Systems* study to provide advice on ensuring the availability of affordable, reliable, and secure energy for American consumers and allies. In his letter, the Secretary emphasized the need to address immediate priority topics—permitting and gas-electric coordination—in support of the administration's directives on energy reliability, infrastructure, and national security. The request specifically called for the delivery of this short-term study on the misalignment between the electric power and natural gas markets, and the risks this misalignment poses to the reliability of the interconnected systems. A separate short-term study is also being completed on streamlining the permitting of oil and gas infrastructure.

III. STUDY SCOPE

The Secretary asked the NPC to examine how rising natural gas and electricity demand, along with shifting load patterns, are straining natural gas pipelines in key regions of the United States. The study is also tasked with assessing the impacts of these strains on energy reliability and with providing actionable strategies to address the market misalignment. This work is to complement ongoing industry and government efforts while focusing on the reliability risks viewed through the lens of natural gas infrastructure operations and capabilities. Specifically, the study will:

- Examine the structural differences between the markets that limit incentives for long-term natural gas infrastructure investment.

- Assess how pipeline operational volatility and shifting load patterns affect gas-electric reliability.
- Review the current state of gas-electric coordination initiatives and identify remaining gaps.
- Develop policy and market recommendations to correct the misalignment and ensure long-term energy reliability and affordability.

The study places emphasis on regions identified by the North American Electric Reliability Corporation (NERC) as having elevated risks to resource adequacy, including PJM and NPCC-NE, which lie mostly within PADD I, while drawing conclusions relevant to the national energy system as a whole. The study committee notes that some areas of the nation, like the territory of Puerto Rico, have significant gas-electric coordination issues but were outside the scope of this study. Additionally, coastal shipping was determined to be out of scope for this report. Finally, while various hybrid and multi-fuel configurations exist, dual-fuel generation is not addressed within the scope of this report.

IV. STUDY GROUP ORGANIZATION

The study was directed by a study committee composed of senior leaders from the natural gas and electric power industries, along with representatives from government, academia, and public interest organizations. The coordinating subcommittee oversaw the development of scope areas, supported by task groups focused on specific technical and policy issues. This structure is designed to ensure that a broad range of expertise and perspectives are incorporated into the analysis, deliberations, and recommendations of the NPC (Figure P-1).

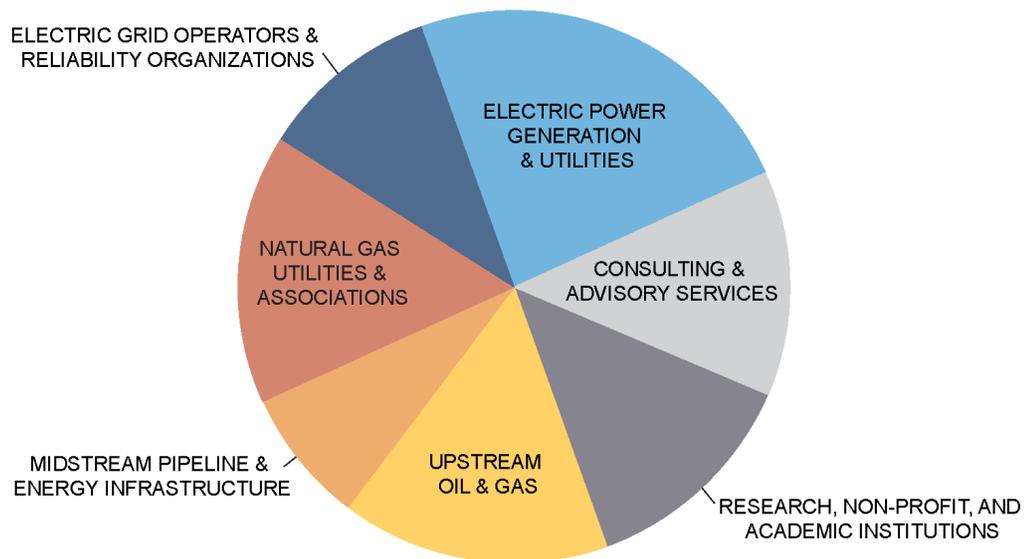


Figure P-1. Organization representation by sector on the Study Committee, Coordinating Subcommittee, and Task Groups

Participants in this study contributed in a variety of ways, ranging from work in all study areas, to involvement in a specific topic, to reviewing proposed materials. Involvement in these activities should not be construed as a participant's or their organization's endorsement or agreement with all the statements, findings, and recommendations in this report. Additionally, while U.S. government participants provided significant assistance in the identification and compilation of data and other information, they did not take positions on the study's recommendations.

V. REPORT STRUCTURE

The report is organized into four detailed chapters:

1. Examination of the misalignment between the electric power and natural gas markets.
2. Increasing variable demand on natural gas pipelines and threats to reliability.
3. Current state of gas-electric coordination.
4. Recommendations for healthy alignment between the natural gas and electric sectors.

Executive Summary

I. INTRODUCTION

The reliability of the United States energy system increasingly depends on effective coordination between the natural gas and electric sectors. Natural gas is a proven, reliable fuel for electricity generation, and gas-fired electricity generation plays a central role in providing reliable baseload power, balancing intermittent energy resources like wind and solar. Development of flexible, fast-ramping gas-fired electricity generation is needed for enhanced grid reliability today and in the future. Since natural gas became the dominant fuel for U.S. electricity generation in 2016 (Figure ES-1), the interdependence between the gas and electric systems has deepened—but so have the risks of misalignment. The two systems function under fundamentally different commercial, regulatory, and operational frameworks. The gas industry is built around long-term contracts and steady demand, while the electric sector depends on real-time market dispatch and hourly price signals. These structural differences create persistent mismatches in timing and incentives, particularly during periods of high demand or extreme weather, when generators may struggle to secure fuel precisely when it is needed most. Fragmented jurisdiction further complicates coordinated planning and accountability efforts. Overcoming these challenges requires aligning market design, operational and commercial practices, and regulatory frameworks to ensure that both sectors can operate with shared situational awareness, adequate infrastructure, and consistent incentives for reliability. Without such integration, each system remains vulnerable to disruptions in the other, undermining overall energy security.

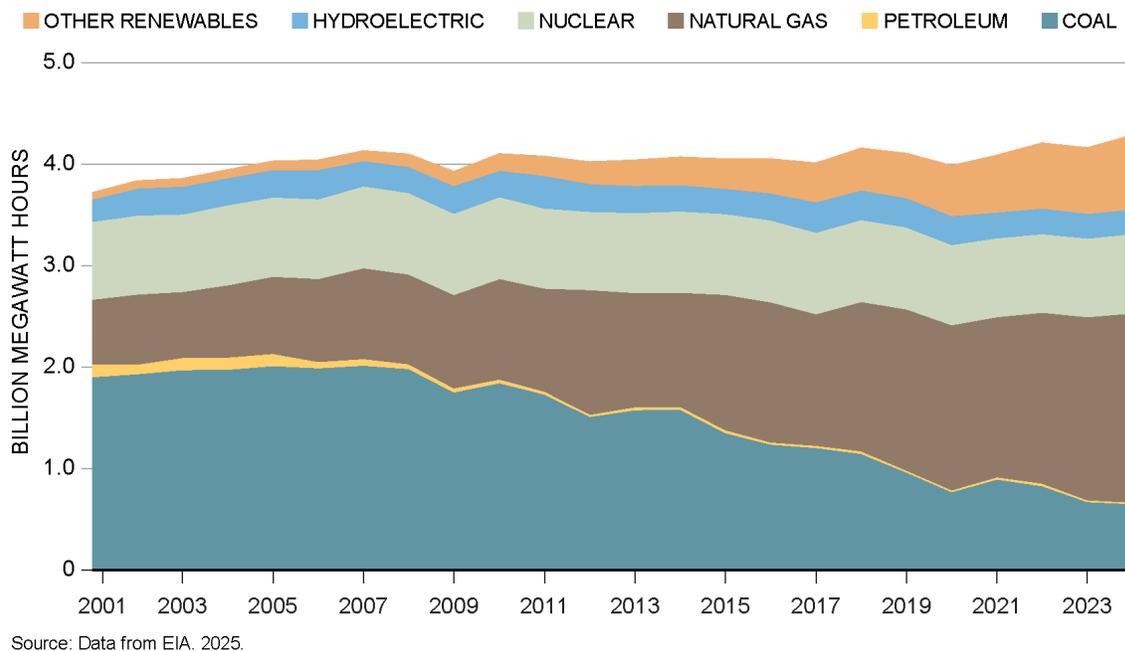


Figure ES-1. Net Annual U.S. Electricity Generation for All Sectors by Source (2001-2024)

On June 30, 2025, Secretary of Energy Chris Wright requested the National Petroleum Council (NPC) conduct a comprehensive *Future Energy Systems* study to evaluate how the United States can maintain affordable, reliable, and secure energy while undergoing rapid transitions in demand, infrastructure, and policy. As part of this broader effort, the NPC was asked to prepare two initial priority deliverables focused specifically on the coordination between natural gas and electric power systems and permitting oil and natural gas infrastructure. This report examines the near-term risks arising from the misalignment of gas and power sectors and outlines pathways to safeguard reliability while keeping pace with growing natural gas demand in the electricity sector.

The North American Electric Reliability Corporation (NERC) has noted that roughly half of the United States is facing an elevated risk of electricity supply shortfalls over the next decade¹ due to accelerating demand, retirement of dispatchable resources, and lagging firm capacity additions such as expanding pipelines. Both the Mid-Atlantic and Northeast regions have been identified as facing increasing risks—and extreme weather events over the past five years have borne out these risks. Insights from these regions anchor the analysis, but the findings and recommendations are intended to apply across the country, in both regulated and deregulated sectors.

NPC’s charge is rooted in a growing recognition that natural gas and electric power have become deeply interdependent. Pipelines, once designed primarily to serve steady ratable loads from local distribution companies (LDCs), now support a power sector that increasingly relies on gas-fired generation for both baseload and fast-ramping capacity.

The challenges are not entirely new. The gas and electric industries have examined integration since the early 1990s, beginning with efforts to reconcile operational and scheduling differences. Yet these steps were incremental as they did not resolve underlying economic and structural misalignments of the two markets. Additionally, many recommendations were only partially implemented (as noted in Chapter 3). Events such as Winter Storm Uri in 2021, Winter Storm Elliott in 2022, and even periods of growing operational volatility on pipelines in the absence of major storms demonstrate that without market reforms, operational and scheduling adjustments alone are insufficient to fully resolve reliability challenges.

Strengthening gas-electric coordination is not merely a technical exercise. It is now a public-facing reliability issue. The growing dependence of the electric grid on natural gas—and of gas infrastructure on electric power—means that disruptions in one system can now cascade into the other. Without such coordination and integration, each system remains vulnerable to disruptions in the other, undermining the resilience of the nation’s evolving grid.

This challenge also represents a strategic opportunity: by improving coordination between the natural gas and electric systems, the United States can establish a benchmark for reliability and resilience, leveraging abundant North American natural gas resources to strengthen the grid. Enhanced alignment between natural gas and electric systems will maximize

¹ NERC. “2024 Long-Term Reliability Assessment.” December 2024.
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

flexibility, reinforce infrastructure planning, and ensure performance under stress—positioning the U.S. to lead in the development of innovative technology and energy solutions built on a foundation of reliability. Seizing this opportunity will reinforce U.S. energy leadership and provide a model for reliability and security that others can follow.

This report 1) assesses how rising natural gas and electricity demand and shifting load patterns are straining U.S. pipeline infrastructure, 2) evaluates the reliability risks these strains pose, and 3) recommends actionable strategies to reduce misalignment between the gas and electric industries. These findings and recommendations are summarized below, with specific implementation actions associated with each recommendation discussed in detail in Chapter 4. NPC notes that many of the recommendations are interrelated and interdependent. By emphasizing natural gas infrastructure operations and capabilities, the study complements ongoing government and industry initiatives on gas-electric coordination.

II. HISTORICAL AND REGULATORY FOUNDATIONS

The natural gas and electric sectors in the United States have evolved under distinct regulatory and commercial frameworks that continue to shape their interactions today.

Historically, natural gas production and pricing were tightly regulated at the wellhead under the Natural Gas Act of 1938, with federal oversight extending through the mid-1980s. Following gradual deregulation, gas now trades at market-based prices, while interstate pipelines remain subject to Federal Energy Regulatory Commission (FERC) regulation. Because pipeline expansion depends on securing firm, long-term transportation contracts to underpin financing, the gas industry’s investment and operational model remains rooted in long-term, ratable service agreements designed for predictable consumption patterns. This means that there is little to no incentive for building pipeline capacity beyond contracted firm demand.

Electricity markets followed a different trajectory. For much of the 20th century, power generation, transmission, and distribution were vertically integrated under state-regulated monopolies.² Beginning in the 1990s, federal and state reforms introduced wholesale competition and nonutility ownership of generation, giving rise to independent system operators (ISOs) and regional transmission organizations (RTOs) that now manage roughly two-thirds of U.S. electricity load.³ These organized markets—originally designed to ensure nondiscriminatory dispatch of generation resources—offer real time, daily and forward markets⁴ in generation,

² National Bureau of Economic Research. “The U.S. Electricity Industry after 20 Years of Restructuring.” April 2015. https://www.nber.org/system/files/working_papers/w21113/w21113.pdf.

³ FERC. “Energy Primer: A Handbook for Energy Market Basics.” April 2020. https://www.ferc.gov/sites/default/files/2020-06/energy-primer-2020_0.pdf.

⁴ In organized electricity markets, the *daily* (or *day-ahead*) market schedules generation and demand for each hour of the next operating day, producing financially binding schedules and prices based on forecasted conditions. The *real-time* market balances supply and demand continuously during the operating day, settling deviations from day-ahead schedules at prices reflecting actual system conditions. *Forward* markets extend this structure over longer horizons—weeks, months, or years ahead—allowing participants to hedge price risk and secure supply through bilateral or centrally cleared contracts.

other services, and, in many cases, reliability functions. These include procurement of adequate future supplies based on a variety of different mechanisms, depending on the jurisdiction. The coexistence of regulated and deregulated regions has created a patchwork of market designs and incentive structures across the country.

In regulated markets, vertically integrated utilities ensure reliability through long-term contracts, integrated resource plans (IRPs),⁵ and cost-recovery mechanisms that allow prudent investments to be recovered from utility ratepayers, under a premise of long-term planning for resource adequacy and reliability assurance. By contrast, in deregulated markets, independent generators depend on short-term market revenues and hourly price signals, often without clear incentives or financial mechanisms to secure firm gas supply. As such, their gas procurements rely less on long-term delivery contracts and more on a variety of shorter-term commodity procurements and lower priority transportation arrangements. When the gas and electric systems are both under stress, these arrangements are the first to be curtailed. The growing variable conditions on pipelines, which are caused by inherently variable demand profiles of the electric power sector, can also endanger LDCs that serve homes and businesses. When pipeline pressures drop too low, residential and commercial gas service can be interrupted, and restoring service is a slow, labor-intensive, and costly process compared to restoring electricity.

III. CONSTRAINED INFRASTRUCTURE

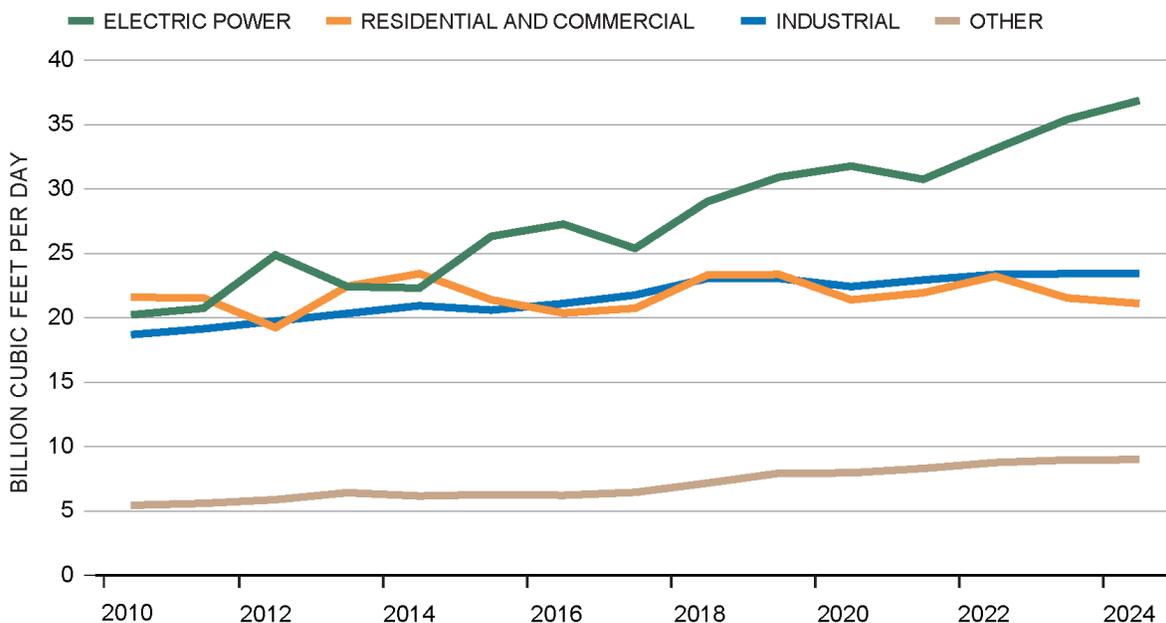
The U.S. natural gas pipeline network was engineered for predictable, ratable flows rather than the increasingly variable demands of an electricity market with a changing generation portfolio and unexpectedly rapid growth in demand. Historically, pipelines primarily served LDCs and large industrial customers (Figure ES-2) whose consumption patterns were relatively stable and forecastable. Under this model, firm transportation contracts—long-term agreements guaranteeing delivery rights—dominated, with LDCs holding most pipeline capacity (Figure ES-3) and associated storage rights to meet heating and industrial loads. Day-to-day operational flexibility was maintained through modest use of linepack (the gas stored under pressure within the pipeline system) and limited operational storage,⁶ sufficient to handle routine morning and evening demand ramps.

Over the past decade or so, the U.S. natural gas user mix has shifted dramatically as electric power generation has surpassed LDCs to become the largest gas consumer (Figure ES-2 and ES-3). This transformation has been driven by the retirement of coal plants, the widespread deployment of efficient natural gas combined cycle technology, and abundant, low-cost gas from the shale revolution. As a result, gas demand has become far more variable and dynamic, with power generators—especially in deregulated markets—often relying on secondary or

⁵ Integrated Resource Plans (IRPs) are long-term planning documents developed by utilities and approved by state regulators that assess future electricity demand and identify the mix of generation, transmission, and demand-side resources needed to meet reliability, cost, and policy objectives over a multi-year horizon.

⁶ “Operational storage” refers to short-term storage—typically pipeline-connected facilities used to manage daily pressure and flow variations—distinct from long-term, high-deliverability storage such as underground salt caverns or depleted reservoirs designed for seasonal balancing.

interruptible pipeline capacity,⁷ which amplifies intraday and seasonal fluctuations. The rapid expansion of wind and solar resources, which together account for more than 60% of new U.S. generation capacity since 2010⁸, has made gas-fired units essential for grid balancing, requiring flexible fuel supply and rapid ramping capability. At the same time, electrification of heating and transportation is shifting peak electricity demand from summer to winter, heightening competition for constrained pipeline capacity precisely when both heating and power generation needs are greatest. Electricity-driven gas demand introduces sharp and often unpredictable fluctuations that pipelines were not designed to accommodate.



Note: other = natural gas consumed as transportation fuel, as lease and plant fuel, and in pipeline and distribution use.
 Source: Data from EIA. 2025.

Figure ES-2. U.S. Annual Natural Gas Consumption by Sector (2010-2024)

⁷ “Secondary” or “interruptible” capacity refers to transportation rights that are not guaranteed and may be curtailed when firm (priority) shippers fully utilize the pipeline. These services offer flexibility and lower cost but carry higher risk of interruption during peak demand (see Chapter 2, I. A.)

⁸ EIA. “Electric Power Annual.” October 16, 2025. <https://www.eia.gov/electricity/annual/>.

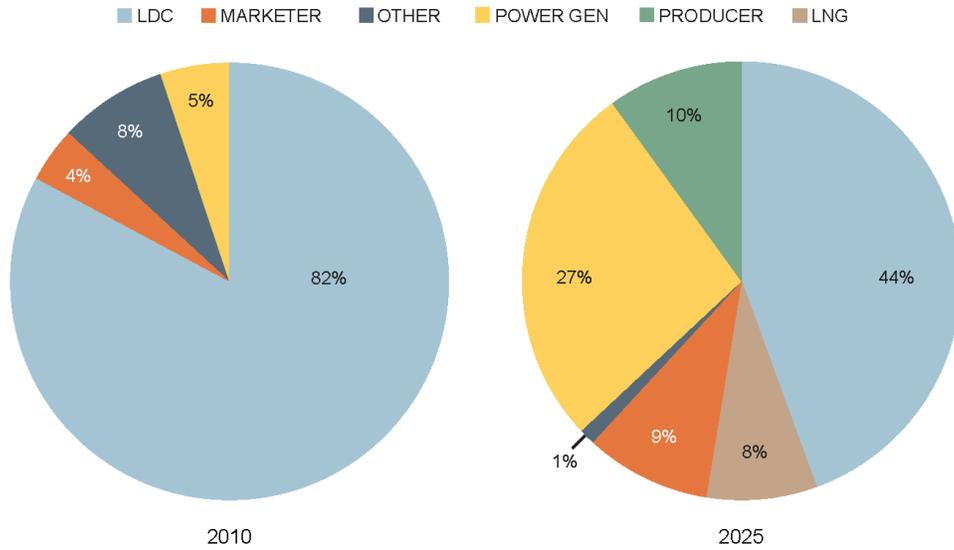
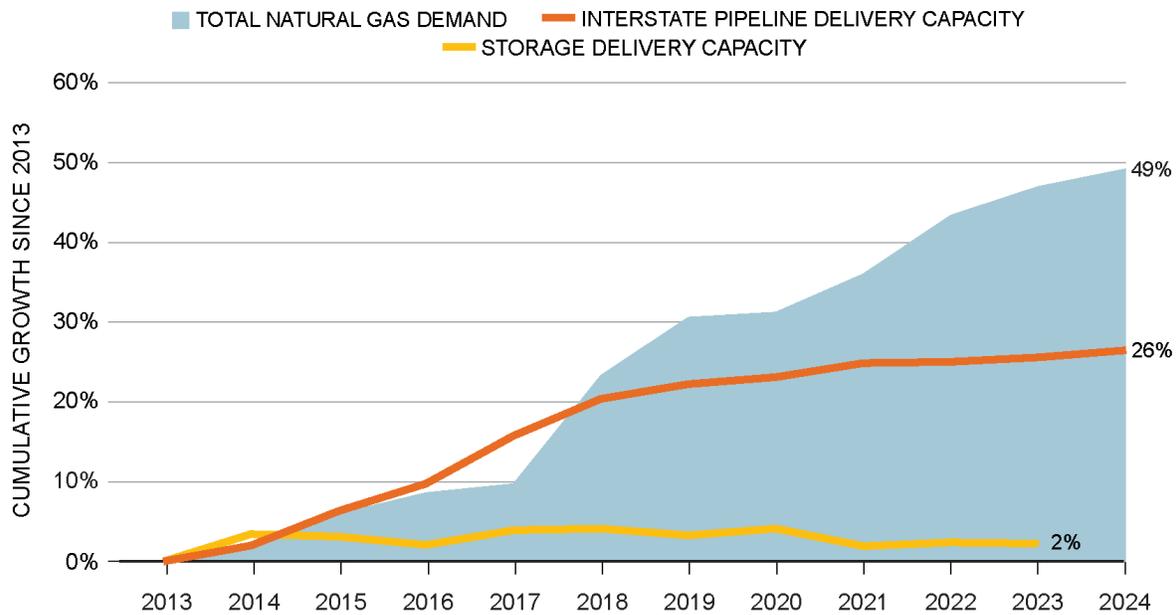


Figure ES-3. Share of Firm Transportation Capacity on Transco Pipeline in 2010 and 2025

Pipeline operators have implemented a number of innovative solutions to accommodate these changing patterns. While some pipeline expansion has occurred over the past decade, most of this work has involved reversing flow directions and adding compressors rather than building new long-distance lines. These investments have increased volume deliverability overall, meeting aggregate demand growth for gas in general, but have led to fewer flexibilities in the system for existing users, particularly from the electric sector who have come to rely on them.

As a result, the pipeline system’s ability to adjust to increased variability demands by electric sector participants has not significantly improved nor kept pace with those evolving needs. Storing excess gas along or within pipeline systems for unexpected peaks is an option. However, the power sector users who would benefit from such additions are not yet contracting to build these facilities (Figure ES-4). Most new storage capacity has been built near liquefied natural gas export terminals to support export operations, rather than in regions where gas-fired power generation requires flexibility to manage variable loads.



Note: 2023 is the most current data for storage delivery capacity.
 Source: Data from EIA. 2025.

Figure ES-4. Storage Delivery Capacity Compared to Pipeline Delivery Capacity and Gas Demand

FINDING: Electricity market signals prioritize short-term economic efficiencies, while natural gas infrastructure depends on long-term, firm commitments. Inadequate compensation in electricity markets often leaves generators with little incentive to secure the gas and transportation services needed to support their increasingly variable operations and peak reliability needs.

FINDING: Pipelines were built for predictable, ratable flows, but customers now require increasingly variable intraday services to meet growing demand and balance the grid as wind and solar generation expand.

FINDING: Recent pipeline expansions—implemented mainly through flow reversals and added compression rather than new pipelines—highlight the need to address challenges between pipeline capabilities and increasingly variable demand.

RECOMMENDATION: The NPC recommends Congress and the Executive Branch take immediate legislative and administrative action to reform permitting to unlock fit-for-purpose⁹ infrastructure investment¹⁰.

⁹ Fit-for-purpose infrastructure refers to infrastructure that is appropriately scaled and designed to meet specific functions, for example intraday variable and peak day needs.

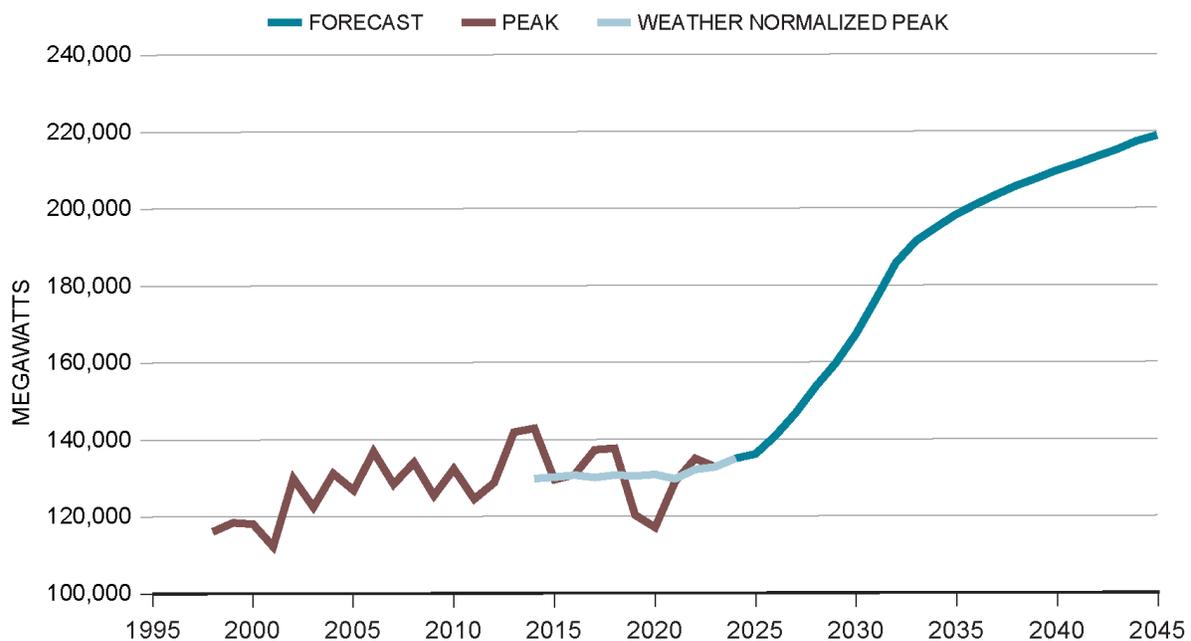
¹⁰ See companion study on Permitting Reform (NPC, 2025).

RECOMMENDATION: The NPC recommends the natural gas and electric industries take urgent action to construct new fit-for-purpose energy infrastructure across the energy value chain, consistent with changing energy consumption patterns.

RECOMMENDATION: The NPC recommends the natural gas and electric industries, in coordination with policymakers, prioritize actions to enhance and expand existing energy infrastructure where feasible, to manage rapidly changing flow patterns and growing demand.

IV. MAJOR COORDINATION CHALLENGES

To date, most of the gas-electric coordination debate and the studies and organized efforts to address gas-electric coordination have centered on the few days each year when the system is pushed to its limits by extreme weather. That focus risks overlooking the broader trajectory of the system. Over the next five to ten years, the rapid increase in demand for electric power, the increasing penetration of intermittent energy resources, and the emergence of a winter electricity demand peak (Figure ES-5) will drive additional absolute demand, more variation in flow patterns, and sharper peaks that extend beyond rare stress events. Preparing the system for this evolving demand profile will be just as important as addressing emergency coordination during extreme conditions.



Source: PJM. 2025.

Figure ES-5. Winter Peak Forecast in the PJM Interconnection LLC

A healthy alignment between the natural gas and electric power sectors is defined by shared priorities in reliability, resiliency, and accountability. Both industries must plan for peak demand, coordinate outages, and recover quickly from disruptions, recognizing reliability as a joint responsibility that protects consumers from cascading failures. Effective alignment also acknowledges the physical limits of gas production, transport, and storage—particularly the just-in-time nature of fuel delivery—and ensures that markets and policies set realistic expectations. Robust and flexible infrastructure, clear lines of accountability, and transparent coordination—underpinned by fully understood and complementary definitions of firm service across gas and electric sectors—are essential to sustaining reliability. Finally, alignment depends on market and policy frameworks that encourage long-term investment, operational flexibility, and commercial innovation. These characteristics together form the benchmark for assessing current gaps and guiding future reforms.

The gas-electric coordination challenges can be organized into four major categories. Key findings and recommendations are presented below for each category.

A. Operational Inefficiencies and Misalignments

The operational interface between the natural gas and electric power sectors is defined by different timelines, practices, and expectations. Gas flows on a fixed daily schedule, while electricity is dispatched on a rolling basis, often changing by the hour. Thus, these sectors physically move electrons and molecules across two different operating timelines. These structural differences contribute to generators making fuel commitments without certainty, and constrain their abilities to adjust to real-time shifting conditions. Various frameworks for communication exist between utility-based and competitive markets due to regulatory oversight and market integrity considerations, with a need for more coordination of planned maintenance to mitigate the risk of simultaneous outages. Electric reliability entities have made explicit measurable weatherization progress through new readiness standards and cold-weather preparedness programs through NERC. Comparable measures for the natural gas system remain voluntary, market driven, and fragmented across states; but progress has been implicitly demonstrated based on improved performance during the January 2024 Arctic Storms.

FINDING: *Operational improvements for electric and gas systems have been widely discussed in previous reports and forums and partially implemented. The electric sector has demonstrated more formalized progress, such as through NERC-led initiatives, while the gas sector's advancements have been primarily market driven.*

RECOMMENDATION: The NPC recommends the National Association of Regulatory Utility Commissioners convene a Natural Gas Readiness Forum working group¹¹ to broaden stakeholder dialogue and document leading management practices across all interconnected sectors of the energy value chain.

¹¹ The Natural Gas Readiness Forum is currently coordinated by the American Gas Association.

B. Power Market Design—Economic Inefficiencies and Fuel Assurance Misalignments

At a market design level, the incentives that guide gas and electric sectors diverge. Electricity markets in competitive regions are optimized for short-term efficiency and cost minimization, while natural gas infrastructure requires firm, long-term commitments to support financing and construction. This mismatch undermines fuel assurance for power generators who often rely on an interruptible supply of gas due to cost considerations. Unlike electricity markets, which account for reserve margins to ensure reliability, natural gas markets do not provide comparable incentives for building capacity beyond contracted demand. As a result, the system lacks buffers to absorb shocks, leaving both sectors vulnerable during peak-demand and extreme weather events.

FINDING: *Current market structures fail to incentivize generators to secure either long-term gas transportation or highly flexible premium products, heightening reliability risks.*

FINDING: *Electric and gas utilities plan for and rely on reserve margins to ensure reliability. Notwithstanding these planned utility margins, gas transportation infrastructure does not incorporate additional capacity because it is built to firm contractual needs. Therefore, there is no extra capacity on the existing pipeline system to serve the growing needs of the electric sector.*

RECOMMENDATION: The NPC recommends appropriate entities (e.g., RTOs/ISOs, federal and state authorities) ensure adequate risk-based compensation for gas-fired power generators to obtain sufficient fuel and operate reliably when called upon and to be prepared to perform during stress periods.

RECOMMENDATION: The NPC recommends FERC require RTO/ISOs to conduct comprehensive long-term planning that integrates resource adequacy and fuel assurance considerations, in cooperation with affected states.

C. Commercial – Gas Services Design and Power Sector Fuel Assurance Misalignments

Commercial practices in natural gas markets were not designed for today's power sector demands. Pipelines historically served LDCs with predictable, steady loads. Now, gas-fired generators impose sharp and unpredictable swings in demand, particularly as they balance the variability of intermittent energy resources. Yet flexible pipeline services are often inaccessible to generators, and storage development has been stagnant despite growing variability. These factors compromise the reliability of the secondary market, on which independent generators heavily depend, and expose local distribution companies to heightened risk.

FINDING: *The emergence of a winter electricity peak that coincides with local distribution companies' design-day needs has reduced the secondary market's ability to supply independent power producers, limiting their capacity to meet electricity demand with existing infrastructure.*

FINDING: *Enhanced pipeline services to complement variable demand are not new, but like traditional firm transportation capacity, are typically only subscribed to by local distribution companies or vertically integrated utilities. Organized electricity markets do not appear to be adequately compensating generators to contract for such services, and additional compensation mechanisms may be required to make enhanced or flexible services commercially viable for generators.*

FINDING: *If solutions designed to accommodate variable demand are not developed to alleviate pipeline constraints, operational flexibility—such as the ability of shippers to utilize to nonfirm or secondary delivery points—will likely become increasingly restricted, particularly in the Mid-Atlantic and Northeast regions.*

RECOMMENDATION: The NPC recommends policymakers and market operators/participants work to address changing hourly gas flow patterns by developing alternative tariff structures¹² that enable enhanced gas service offerings and more flexible contracting arrangements between gas suppliers and electric generators.

D. Fragmented Governance, Planning, and Reliability Coordination

The governance of the gas-electric interface is fragmented across multiple regulatory and operational entities. While FERC and NERC oversee parts of the system, neither has comprehensive authority to enforce alignment between the two sectors. Previous initiatives have improved communication but left deeper market misalignments unresolved. The absence of a clear accountability framework has meant that many recommendations have been implemented inconsistently, if at all. Past extreme weather events, such as Winter Storm Uri in 2021 and Winter Storm Elliott in 2022, have demonstrated how these gaps in planning and oversight translate directly into widespread consumer impacts. The NPC does not believe the creation of new oversight roles is necessary but instead submits that governance and oversight structures must be transparent for stakeholders to effectively engage.

FINDING: *Clear and distinct regulatory accountability plays a critical role in advancing implementation of recommendations, largely because of authority scope.*

RECOMMENDATION: The NPC recommends FERC (or RTO/ISOs) endorse or issue an accountability framework to address the risk created by the lack of direct market commitments certain generation owners have to end-use customers.

RECOMMENDATION: The NPC recommends the Federal and State Issues Collaborative publish a framework that clearly identifies and defines the roles and responsibilities for reliability, resource adequacy, and fuel assurance.

¹² “Tariff structures” refer to the rate designs, service categories, and terms established in pipeline or utility tariffs that define how customers pay for and access transportation, storage, or related services. These structures determine pricing, priority of service, and the flexibility available to different classes of users.

RECOMMENDATION: The NPC recommends FERC enhance the Common Metrics report (FERC-922) released biennially and include an interim progress report with a focus on fuel assurance, resource adequacy, and other critical reliability metrics on a state-by-state basis.

V. THE WAY FORWARD

This NPC analysis underscores a widening structural misalignment between natural gas and electricity markets that poses increasing risks to system reliability. The alignment of these two sectors could once be characterized as a technical challenge, but with the growing need for gas-fired dispatchable resources to keep pace with demand, immediate and meaningful action is required. This report finds that the natural gas and electric systems both face reliability risks today. Neither industry—nor their customers—can afford to wait. Strengthening the system before the next crisis, not after it, is the mark of prudent risk management.

Achieving true gas-electric coordination will require more than operational adjustments. It demands structural alignment of incentives, planning processes, and accountability frameworks. Regulators, market operators, pipelines, and utilities must work toward shared reliability objectives supported by consistent standards, transparent information exchange, and clear cost-recovery mechanisms that value firm fuel assurance. Healthy alignment will depend on balancing market efficiency with reliability obligations and recognizing that neither sector can achieve resilience in isolation. Similarly, each of the recommendations presented in this study cannot effectively stand alone. They are interdependent and must be executed concurrently to provide the transformational change the U.S. energy system needs.

Coordinated action today can bridge the divide between the gas and power sectors. The recommendations developed in this study provide a roadmap for building a more reliable, resilient, and affordable energy future for the nation.

Chapter 1: Examination of the Misalignment Between the Electric Power and Natural Gas Markets

VI. INTRODUCTION

Ensuring reliability in today’s energy system depends on the coordinated operation and long-term planning of two sectors with very different regulatory foundations: natural gas and electricity. Each has evolved under its own statutory and regulatory framework, producing distinct approaches to investment, planning, and operations. These frameworks made sense in their own context, but as the two systems have become increasingly interdependent, their structures, incentives, and operational needs are becoming harder to keep aligned to support reliability.

The natural gas supply chain starts with production at the wellhead. For many decades, federal policy regulated wellhead prices. A landmark Supreme Court case, *Phillips Petroleum Co. v. Wisconsin* (1954),¹³ extended Natural Gas Act¹⁴ (1938) authority to cover wellhead sales in interstate commerce. Over time, however, price controls created distortions and discouraged new production. The Natural Gas Policy Act of 1978¹⁵ began the shift toward deregulation by phasing out controls for new production and for certain categories of “high-cost” gas, such as supplies from deep formations, tight sands, or shale, while retaining ceilings for older conventional production. This process concluded with the Natural Gas Wellhead Decontrol Act of 1989,¹⁶ which removed all remaining federal controls effective January 1, 1993. Since then, natural gas producers have operated under market pricing at the wellhead. Thus, production is not subject to prescriptive mandates on reliability or performance obligations—unlike pipelines or utilities—but instead relies on competitive markets and economic incentives to ensure adequacy at this stage of the chain.

Interstate pipelines, by contrast, remain regulated under the 1938 Natural Gas Act. The Federal Energy Regulatory Commission (FERC) requires a showing of “public convenience and necessity” for new projects, typically demonstrated by long-term firm contracts.¹⁷ Beginning in

¹³ *Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672 (1954).

¹⁴ Natural Gas Act of 1938, Pub. L. No. 75-688, 52 Stat. 821 (1938).

¹⁵ Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350 (1978).

¹⁶ Natural Gas Wellhead Decontrol Act of 1989, Pub. L. No. 101-60, 103 Stat. 157 (1989).

¹⁷ Long-term (10–20 year) transportation and/or supply agreements that intend to guarantee delivery of natural gas under virtually all conditions, including peak demand periods, unless interrupted for force majeure.

the 1980s, a series of orders reshaped the pipeline business model: FERC Order 436¹⁸ introduced voluntary open access (1985); FERC Order 500¹⁹ allowed contract conversions (1987); FERC Order 636 mandated full unbundling²⁰ and created the capacity release market²¹ (1992); and FERC Order 587²² standardized practices and introduced electronic bulletin boards (1996 onward). These reforms transformed pipelines into contract carriers²³ providing open access under transparent tariffs,²⁴ while maintaining long-term contracting as the basis for financing new infrastructure. The pipeline system, therefore, remains structured around long-term commitments and capacity planning intended to ensure adequacy and design-day²⁵ reliability.

Electricity regulation has followed a more fragmented path (see Table 1-1). The electric industry was first structured under the Public Utility Holding Company Act of 1935 (PUHCA),²⁶ which curtailed sprawling utility holding companies and reinforced state oversight of vertically integrated utilities.²⁷ For decades, this bundled model of generation, transmission, and distribution under cost-of-service regulation remained dominant. The Public Utility Regulatory

¹⁸ Established the framework for nondiscriminatory transportation service by interstate natural gas pipelines, allowing producers, marketers, and end users to contract directly for pipeline capacity.

¹⁹ Previously bundled sales contracts could be separated into separate commodity and transportation agreements, allowing shippers to contract directly for pipeline capacity.

²⁰ FERC required pipelines separate (unbundle) their sales and transportation agreements and offer transportation on an open-access basis separated from commodity purchases.

²¹ This mechanism allows firm shippers such as LDCs to offer their unused pipeline capacity to other parties on a secondary basis while retaining recall rights as needed. This improves system utilization and can defray the expense of firm capacity for the firm shipper.

²² Online platforms required by FERC where pipelines post available capacity, scheduling information, and tariff details to ensure transparency and nondiscriminatory access.

²³ Pipelines that transport gas under individually negotiated contracts with shippers. Rates and terms are negotiated within regulator-approved limits, with a published “nonrecourse” tariff rate serving as the ceiling available to any shipper that cannot secure, or prefers not to use, a negotiated contract.

²⁴ Publicly filed, regulator-approved schedules of rates and service terms that pipelines must honor on a nondiscriminatory basis.

²⁵ The “design day” is the coldest or highest-demand day for which a natural gas system is engineered to meet all firm load without curtailment, based on statistically extreme weather conditions. Utilities and regulators establish these metrics serves as a planning metric to determine the maximum daily throughput required to satisfy firm contractual obligations under peak conditions. For system planning, the design day is defined as the coldest day expected once in 30 years—measured as 65°F minus the forecast average daily temperature.

²⁶ Enacted to regulate and simplify complex utility holding company structures, limits operations to geographically integrated systems under Securities and Exchange Commission oversight to prevent abusive financial practices.

²⁷ There are also electric utilities held by public entities, including federal power administrations, state and municipal entities, and rural electric cooperatives. These are also subject to regulatory oversight by various bodies and may operate as vertically integrated utilities or participants in competitive markets.

Policies Act of 1978 (PURPA)²⁸ introduced a foothold for competition by requiring utilities to purchase power from qualifying facilities, often small cogeneration or renewable plants, at avoided cost.²⁹ The Energy Policy Act of 1992³⁰ further opened the sector by easing entry for independent power producers (IPPs) and directing FERC to enable open access to wholesale transmission—reforms that paved the way for competitive regional markets in the 1990s.

In many regions, vertically integrated utilities continue to plan and build long-lived generation and transmission assets to ensure reliability, recovering costs through state-approved retail rates. Elsewhere, organized wholesale markets³¹ (Independent System Operators (ISO)/Regional Transmission Organizations (RTOs)³² emerged in the late 1990s and early 2000s under FERC’s Federal Power Act authority,³³ following FERC Orders 888³⁴ and 2000³⁵ on transmission access and regional market design. The reliability mechanisms in markets vary: Some rely on forward capacity auctions³⁶ (PJM Interconnection, the Independent System Operator-New England (ISO-NE), New York Independent System Operator (NYISO)); others on

²⁸ To promote energy conservation and domestic renewable generation, PURPA required utilities to purchase power from qualifying facilities (QFs) at no more than their avoided cost.

²⁹ “Avoided cost” represents the marginal cost the utility avoids by purchasing power externally rather than building or operating additional capacity itself. Avoided costs can include energy costs (fuel and variable O&M), capacity costs (the cost of new generation or procurement to meet peak demand), and sometimes transmission or distribution costs that would have been incurred absent the purchase.

³⁰ Section 721 amended the Federal Power Act to give FERC the authority to order non-discriminatory transmission access for wholesale electricity transactions, provided it was in the public interest and did not impair reliability.

³¹ Organized power and natural gas markets have transparent prices, standardized products, and a market operator. While they are competitive, they are still subject to FERC oversight to ensure fairness, transparency, and reliability.

³² “ISO/RTO means an independent transmission system operator or regional transmission organization approved by the FERC or the Public Utility Commission of Texas.” NERC. “Definitions Used in the Rules of Procedure, Appendix 2 to the Rules of Procedure.” June 27, 2024. https://www.nerc.com/AboutNERC/RulesOfProcedure/Appendix%20%20eff%2020240627_signed.pdf.

³³ FPA Sections 211 and 212.

³⁴ Required public utilities to provide open, nondiscriminatory access to their transmission systems under a single pro forma tariff, unbundling transmission from generation and establishing the foundation for competitive wholesale electricity markets.

³⁵ Encouraged utilities to voluntarily form RTOs to promote efficient grid management, regional planning, and independent operation of the transmission system.

³⁶ Capacity auctions/markets secure resources—typically three years ahead—to ensure availability during peak demand over a set interval (annual, seasonal, or monthly) in exchange for a capacity payment. Successful bidders receive this revenue stream to complement energy and ancillary services revenues.

mandated reserve margins³⁷ (Southwest Power Pool (SPP) and the California Independent System Operator (CAISO)); and some, like the Electric Reliability Council of Texas (ERCOT), rely primarily on energy-only constructs.³⁸ This diversity reflects regional policy choices and resource mixes, but across the board, organized markets emphasize short-term efficiency signals rather than long-term contracts to convey long-term investment signals.

While FERC’s early regional transmission initiatives were intended primarily to ensure nondiscriminatory access to electric transmission and foster efficient dispatch of generation, the scope of organized markets has steadily expanded. Over time, RTOs and ISOs evolved from independent transmission operators into central reliability coordinators that administer not only energy dispatch, but also capacity markets, operating reserves, and outage coordination.³⁹ In practice, these functions have come to define *resource adequacy* for the regions they serve—an area of responsibility that the Federal Power Act leaves to the states. The transition occurred incrementally, often without an express delegation by the states or a formal reassignment of authority recognized by FERC. As a result, many state commissions may find themselves dependent on RTO-administered constructs to meet obligations they never intended to relinquish.

As these market and regulatory structures evolved, each sector and its segments developed their own conventions for defining reliability and deliverability. One such term—“firm” service or capacity—is frequently used in the energy industry but carries distinct meanings that can obscure, rather than clarify, reliability obligations and risk if not carefully understood.

At the marketed production level, where the upstream system meets the pipeline system, firm is reflected through financial and operational deliverability obligations.⁴⁰ Once gas enters the interstate pipeline system, firm represents a contractual right to priority transportation or storage service, guaranteeing access to capacity but not necessarily to the fuel itself. In the power sector, it signifies a performance commitment—capacity or generation expected to deliver under all conditions, often backed by accreditation or penalties for nonperformance. Thus, the meaning

³⁷ Reserve margins are planning requirements, typically set by state regulators or regional authorities, that obligate load-serving entities to secure generation or demand-side resources above forecast peak demand (e.g., 12%–15%) to ensure reliability. Unlike forward capacity markets, these obligations are generally met through bilateral contracts or utility resource plans rather than centralized auctions.

³⁸ Energy-only markets are wholesale electricity market designs where electricity and ancillary services revenues are expected to be sufficient to ensure reliability because prices would rise high enough during scarcity periods to incentivize investment.

³⁹ Lenhart, Stephanie and Dalten Fox. “Participatory Democracy in Dynamic Contexts. A Review of Regional Transmission Organization Governance in the United States.” January 2022. *Energy Research & Social Science*. <https://doi.org/10.1016/j.erss.2021.102345>.

⁴⁰ These are defined in the North American Energy Standards Board (NAESB) Base Contract for the Sale and Purchase of Natural Gas, which was standardized by industry and is the preferred physical natural gas transaction contract. Producers demonstrate reliability via proved developed producing (PDP) reserves and enter long-term supply or offtake contracts—often with take-or-pay or deliver-or-pay provisions—that provide economic assurance rather than physical certainty. These agreements ensure compensation or continuity even if volumes cannot be delivered and, together with redundant production capacity, serve as the functional equivalent of firm commitments at the production stage.

and obligation of firmness in one segment does not automatically extend across others, and effective reliability planning requires recognizing where firm is a performance guarantee versus a scheduling or contractual right. Therefore, the segments within their respective markets and regulatory structures offer distinct but complementary forms of assurance—supply diversity and operational reliability in the upstream, contractual firmness in the midstream, and performance obligations in the power sector—working together to maintain continuity from wellhead to burner tip.

The differing regulatory models depended upon to support reliable supplies to the gas and electric industries are perhaps most visible in how institutions plan for and secure natural gas delivery. Local gas distribution companies (LDCs) have long shouldered statutory obligations to serve customers reliably under all conditions, especially on peak-demand days. To fulfill these obligations, they develop detailed fuel procurement and capacity plans and sign long-term firm contracts for pipeline transportation and storage. These entitlements intend to ensure deliverability during periods of system stress, like severe storms, while the capacity release program allows LDCs and other firm shippers to temporarily release unused rights to others. Releasing unused gas and transportation rights adds liquidity to the secondary market while preserving firm shippers' call-back authority⁴¹ when reliability requires it. The consequences of an interruption in gas service are particularly severe: Restoring delivery requires relighting pilot lights one by one across thousands of premises. Such episodes are rare, but they would likely last far longer than even widespread outages on the power system. For this reason, LDCs design their systems and fuel adequacy plans with caution and a low tolerance for risk, as the public safety and recovery challenges associated with a gas outage are larger from those of an electric outage, even as electricity is increasingly relied upon for heating.

Vertically integrated electric utilities have traditionally been able to contract in a similar fashion to LDCs. Their cost-of-service regulatory model allows long-term agreements for fuel and transportation to be incorporated into rate base,⁴² ensuring recovery through retail rates. This structure aligns financial incentives with long-term system adequacy, paralleling the approach taken by LDCs in the gas sector.

By contrast, restructured wholesale electricity markets have developed around a very different paradigm. RTOs and ISOs emphasize short-term optimization, relying on transparent dispatch price signals and, in some cases, forward capacity auctions that extend only one to three years into the future. In states that have adopted retail choice and unbundled generation from utilities, merchant generators often operate without long-term offtake agreements and on thin margins, leaving little incentive to secure firm gas transportation or storage and long-term fuel. This stands in contrast to vertically integrated frameworks, where utilities typically retain long-term planning and fuel procurement obligations. Regardless of whether an RTO region includes restructured or vertically integrated utilities, all generators that provide balancing energy—such

⁴¹ Call-back authority is the contractual right of the original firm shipper to take back some or all of the released capacity during the term of a release, usually if the shipper needs it to meet its own obligations. The type and length of notice of capacity recall would be specified in the pipeline's tariff.

⁴² Rate base is the value of a regulated utility's long-lived assets—such as plants, pipelines, transmission lines, and related infrastructure—that regulators allow the utility to recover over time through customer rates, along with an authorized return on that investment.

as gas-fired units—operate solely in response to market prices, without regional coordination to ensure the availability of the fuel and infrastructure needed to support reliable operation. This misalignment between short-term market incentives and the long-term commitments required by gas infrastructure has become a central challenge to ensuring electric adequacy and resilience. Recognizing this condition is essential to designing governance mechanisms—such as regional state committees—that can reestablish an accountability framework for state participation in reliability and fuel assurance planning. States in RTOs can develop collaborative agreements to resolve challenges (although they can encounter unexpected complications).⁴³

Natural gas generation has grown dramatically since 2000, rising from about 16% of total U.S. electricity generation to roughly 43% by 2024.⁴⁴ Its share increased steadily through the 2010s as gas displaced coal as one of the options states relied on to meet pollution control requirements. Natural gas units emit fewer conventional pollutants and greenhouse gases (GHGs) than coal plants, and require lower upfront capital investment than coal or nuclear plants. They can also be operated more flexibly, complementing the expansion of renewable resources, though gas-fired plant growth has moderated in recent years as wind and solar capacity expanded. That operational flexibility also provides critical value in managing risk and uncertainty in daily power system operations and continues to make gas-fired generation an essential balancing resource in a grid with increasing variable renewable output.

The growth in gas-fired generation has also been supported by a mutually beneficial arrangement facilitated through the capacity release market. LDCs and large industrial customers underpinned pipeline expansions with long-term contracts to meet their design-day needs, while IPPs and other generators accessed unused capacity through secondary release and interruptible transport. This arrangement worked efficiently when gas demand and electric demand were seasonally complementary—lower summer gas usage by LDCs freed capacity to serve higher air conditioning loads from gas-fired generation. Over time, however, that seasonal balance has eroded. Increasing winter electricity demand now coincides with peak LDC heating loads, tightening available capacity just when both sectors most need it. With pipeline infrastructure expansion having slowed and electricity demand projected to grow year-round, the same constraints that are now most acute in winter could begin to surface in summer as well.

As use of intermittent resources has increased, electricity markets have further evolved to integrate large amounts of wind and solar (see Chapter 2, Section II.B). As the generation mix has diversified, power markets have evolved from steady, block-based trading toward more granular, flexible dispatch to accommodate variable renewable output. Gas-fired generators cycle and ramp to balance these fluctuations, operating less like steady baseload units and more as

⁴³ In 2015, Enbridge’s proposed \$3B Access Northeast project would have brought 0.9 Bcf/d of capacity to power generators in New England. It would have been financially supported by local electric distribution companies (EDCs, nongeneration owning utilities) in Connecticut, Rhode Island, Massachusetts, Maine, and New Hampshire as the firm shipper counterparties with the pipeline. Enbridge cancelled Access Northeast in 2016 after a judicial ruling found that Massachusetts EDCs were prohibited by state law from recovering natural gas transportation contracts in their rates.

⁴⁴ EIA. “Electricity Data Browser: Net Generation by Energy Source” (monthly and annual series). Updated August 2025. <https://www.eia.gov/electricity/data/browser/>.

dynamic resources responding to changing system conditions.⁴⁵ While electric storage technologies are growing rapidly, they still represent a small share of capacity, with higher costs and limited operational durations. As a result, gas-fired units have become the default balancing resource, called upon to operate more flexibly and at greater frequency. They also help manage the growth of behind-the-meter resources that appear to bulk system operators only as reductions in load. While power plants can adapt operationally, this shift has strained the natural gas delivery system, which was designed and financed to serve firm, predictable gas delivery obligations rather than to accommodate the growing volume of variable and short-notice demands of wholesale power markets. After several years of flat growth, electricity demand is growing (potentially exponentially) as industrial companies reshore operations to the United States and data centers are constructed to support the expansion of the artificial intelligence industry, and the resources that provide power continue to diversify.

Policy and regulatory objectives add another layer of complexity to natural gas infrastructure investment and deployment. In some jurisdictions, explicit targets to reduce or eliminate gas consumption create uncertainty that shortens asset life expectations and increases financing costs. Even when market participants see the need for new infrastructure, weak commercial signals, political resistance, permitting process uncertainty,⁴⁶ and subsequent litigation risk have posed a variety of hurdles. These include sponsors electing to shelve projects prior to completing permitting, or incurring additional costs, experiencing delays, and/or canceling projects even after permits are secured.

Producers and marketers may elect to become long-term shippers in circumstances where gas demand appears clear, but the electric sector participants are unable to contract long term and know if they are likely to recover sufficient returns to offset the risk. For example, since the COVID-19 pandemic, planned electric resources—notably utility-scale renewable projects—faced supply chain delays and financing challenges. Crowded interconnection queues further complicated new intermittent resources coming to market as planned, reducing the supply anticipated to come on line in upcoming years. Others have faced canceled or reconsidered permits. In the meantime, older, less economic conventionally fueled plants continued to retire, reducing available resources.⁴⁷

⁴⁵ “Cycle and ramp” refer to changes in a generator’s output level—cycling means starting up and shutting down more frequently, while ramping refers to increasing or decreasing output.

⁴⁶ In parallel with this subcomponent of the Future Energy Systems study, Secretary Wright requested the NPC to reevaluate and update the permitting section of the NPC’s 2019 *Dynamic Delivery* study report with practical recommendations based on current legislation and regulations that can provide meaningful input to support the effective redesign of government systems and siting of new energy infrastructure.

⁴⁷ Over the last several months, the DOE has issued emergency orders under the Federal Power Act that have allowed several coal-fired power plants previously scheduled for retirement to continue operating to preserve electric sector reliability.

The consequences of these headwinds were evident in Winter Storm Uri (2021)⁴⁸ and Winter Storm Elliott (2022).⁴⁹ During Uri, extreme cold weather led power plants to freeze, causing the need for ERCOT to order rotating outages of electricity to customers, which included natural gas wellheads and gas gathering and processing facilities⁵⁰; Similarly, during Elliott, freezing, fuel, and mechanical electrical issues led to reliability issues and system operators narrowly avoided catastrophic gas service loss.⁵¹ While natural gas fueled substantial production of power, there were examples of fuel shortages due to these events that contributed to shortfalls. These revealed significant disconnects and a need to address how infrastructure is planned, financed, and valued across sectors.

Taken together, these developments highlight a growing structural misalignment between the natural gas and electric sectors. Gas infrastructure is built on long-term contracts and redundancy, while electricity markets rely on short-term signals and optimization. Each system is rational within its own framework, but their interaction now exposes reliability risks that neither sector can resolve alone. The severe consequences of losing gas service make these challenges especially acute for LDCs and their customers, while the power sector increasingly depends on gas for balancing energy that enables operating reliability because gas is the marginal generation resource.⁵²

⁴⁸ During Winter Storm Uri, spot natural gas prices at key hubs rose from ~\$2/MMBtu to ~\$3/MMBtu to more than \$300/MMBtu, in some cases over \$600/MMBtu—increases of several thousand percent in a matter of days (Enverus/ Texas Oil & Gas Association. “Winter Storm Uri: Impacts on Natural Gas and Electricity Markets.” <https://www.txoga.org/resources/enverus-winter-storm-uri-natural-gas-analysis-report/>. March 2021.) Wholesale electricity prices in ERCOT likewise escalated from ~\$30/MWh to the \$9,000/MWh cap, roughly a 300-fold jump (EIA. “The February 2021 Cold Weather Event in Texas and the Central United States.” https://www.nerc.com/pa/rm/ea/Documents/February_2021_Cold_Weather_Report.pdf. November 2021.) These extraordinary costs ultimately flowed through to utilities and consumers (Commodity Futures Trading Commission. “Staff Report on Lessons Learned from the 2021 Texas Winter Storm.” https://www.cftc.gov/media/6031/EEMAC060321_DMO_DCR/download.)

⁴⁹ During Winter Storm Elliott, New England natural gas prices increased from ~\$6/MMBtu to more than \$60/MMBtu (about a 10-fold rise), while wholesale electricity prices in PJM and MISO surged from typical winter levels of \$30/MWh–\$50/MWh to more than \$1,000/MWh in hours (a 20- to 30-fold increase) (FERC/NERC. “The South-Central United States Cold Weather Bulk Power System Event, December 2022.” <https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott>. November 2023; Potomac Economics. “2022 State of the Market Report for the PJM Interconnection.” https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf. May 2023; Grid Strategies. “Winter Storm Elliott: A Report of Power System and Market Impacts.” https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies_2023-Transmission-Congestion-Report.pdf. February 2023.)

⁵⁰ FERC, NERC and Regional Entity Staff. “The February 2021 Cold Weather Outages in Texas and the South Central United States.” November 16, 2021. <https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and>.

⁵¹ The FERC/NERC Joint Inquiry/Final Report on Winter Storm Elliott described in detail how gas pressures declined at Con Edison’s citygate in Manhattan, how the utility declared a “gas system emergency,” and how, had those pressures continued, service losses would likely have ensued.

⁵² The “marginal generation resource” refers to the resource that is dispatched last—or whose cost sets the market price—in meeting electricity demand. Natural gas-fired units often fill this role because gas-fired units can adjust output quickly to balance the system.

Gas Sector	Year	Electric Sector – Vertically Integrated	Electric Sector – Organized Markets
Natural Gas Act establishes FERC authority over interstate pipelines.	1938	Traditional cost-of-service regulation adopted to comply with the PUHCA of 1935; state-approved multiyear investments.	
Expansion tied to LDC and industrial demand; firm contracts support infrastructure.	1950	Vertically integrated utilities dominate.	
<i>Phillips Petroleum Co. v. Wisconsin</i> : Supreme Court holds wellhead sales in interstate commerce subject to NGA.	1954		
	1970	Clean Air Act passed by Congress setting emissions limitations on electric generation units leading to investments in pollution control technology or retirements for compliance.	
Natural Gas Policy Act: phased deregulation of wellhead prices for new/high-cost gas; older gas retained ceilings.	1978	PURPA introduces nonutility generation; promoted integrated resource planning (IRPs); opens the door to competition.	
FERC Order 436: voluntary open access on pipelines.	1985		
FERC Order 500: conversion of bundled contracts.	1987		
Natural Gas Wellhead Decontrol Act: complete deregulation of wellhead prices effective January 1, 1993.	1989		
	1990	Congress passed Clean Air Act Amendments establishing cap-and-trade programs for power plants pollution.	
FERC Order 636: mandatory unbundling, capacity release market.	1992	1992 Energy Policy Act created exempt wholesale electric generators free from PUHCA restrictions; expanded FERC's authority to order transmission access; directed states to use IRPs and demand side management.	
FERC Order 587 series: standardized practices (NAESB), electronic bulletin boards.	1996	Many regions remain vertically integrated (Southeast, much of West).	FERC Orders 888/889: transmission open access, ISOs/RTOs emerge.
<i>2005 Energy Policy Act</i> (EPAct05) required greater transparency in natural gas trading markets, expanded FERC enforcement, and enhanced FERC's authority over interstate underground natural gas storage.	2005	EPAct05 responds to the 2003 blackout; repeals PUHCA; North American Electric Reliability Council Standards (NERC) made mandatory for all bulk power systems; expanded loan guarantees and incentives for renewables, nuclear and clean coal. EPA promulgates the <i>Clean Air Interstate Rule</i> .	
Pipelines built only with long-term contracts (10–20 years); environmental advocates develop successful strategies challenging natural gas infrastructure.	2005–2025	Vertically integrated states continue long-term planning; decarbonization policies accelerate demand.	Capacity markets emerge; ERCOT develops energy-only market; renewables integration accelerates.

Source: ClearView Energy Partners. 2025.

Table 1-1. Timeline of Major Regulatory Decisions and Evolution of the Gas and Electric Sectors

I. MARKET DESIGN, CONTRACTING PRACTICES, AND CONTRASTING MODELS

This section outlines the differences between regulated and deregulated markets and how they influence the natural gas contracting behavior of gas generators. The analysis explores the structural distinctions between these market types, the role and function of capacity markets, and the incentives and challenges that shape decisions around gas procurement and infrastructure investment behaviors.

A. Market Structures: Regulated vs. Deregulated

Electricity markets vary significantly across the United States in terms of market structure and philosophy. Regulated markets, such as those in the Southeast, typically include vertically integrated utilities that own and control generation, transmission, and distribution assets. Deregulated markets, on the other hand, such as those in the Northeast and Midwest, are typically structured to separate the functions of generation, transmission, and distribution to promote greater competition among generators and empower consumer choice.

Utilities in regulated markets operate under pricing mechanisms regulated by state commissions, which approve tariffs that allow cost recovery for infrastructure and fuel investments. Although there can be exceptions, in most cases resource planning, including decisions about generation and fuel procurement, is conducted through integrated resource plans (IRPs), rather than through market-based procurement. This model provides utilities with long-term financial certainty when it comes to investments in infrastructure; however, the financial risk associated with these investments is borne by ratepayers.

In contrast, the goal of deregulated markets is to deliver electricity to the consumer at the lowest possible cost while maintaining system reliability and resource adequacy by allowing generators to compete. Additionally, consumers may also have the ability to choose their retail electricity provider in these markets. As a result, prices in these markets are driven by supply and demand dynamics. To avoid unnecessary overprocurement and underutilized or uneconomic assets, these markets rely on largely short-term economic signals by design to drive resource decisions (see “Rising Capacity Market Clearing Costs in PJM”). As a result, generators make investment decisions based on the availability of market revenue potential, including whether to secure firm gas supply, transportation, and storage rights. Generator behaviors are thus often focused on short-term investments, and must weigh the financial risks of performance penalties if their resources are unavailable. Varying market mechanisms exist within deregulated markets, with each having the intended objective to drive increased reliability and lower costs by encouraging a competitive generation resource mix. These market mechanisms include energy

markets,⁵³ reserve markets,⁵⁴ and capacity markets,⁵⁵ and IRPs that provide generators operating within these regional markets the opportunity to earn necessary revenues.

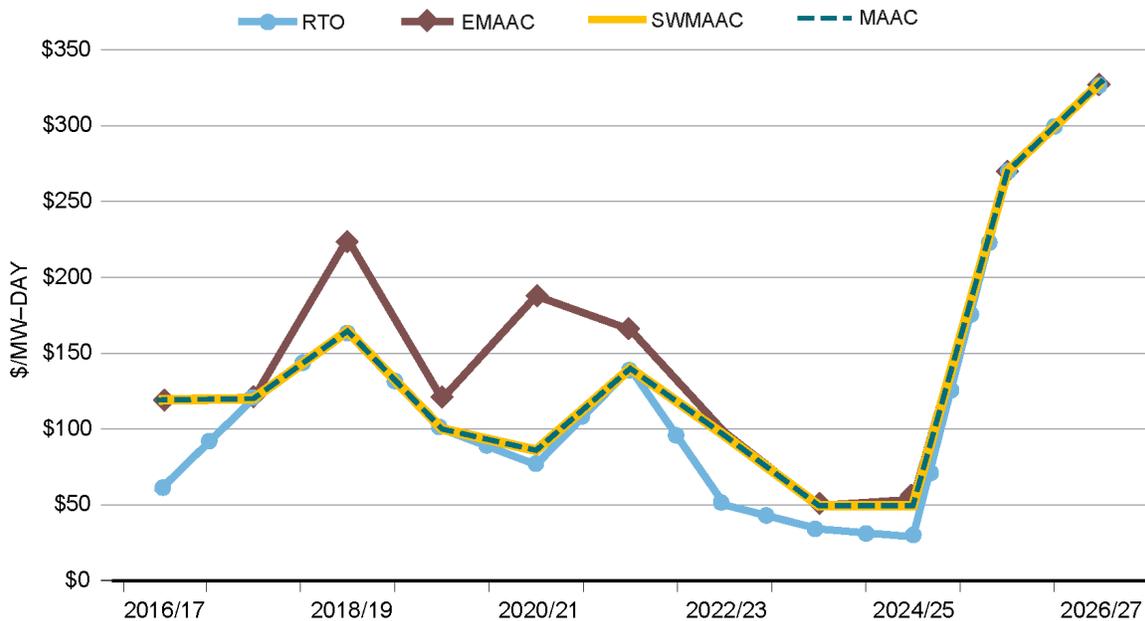
⁵³ Energy Markets: Energy markets typically comprise a Day-Ahead Market and a Real-Time Market focused on the current and next operating days. In a Day-Ahead market, generators submit bids to supply power for each hour of the next operating day. If these bids are cleared, the generator is paid the locational marginal price (LMP) for the amount of MWs cleared. During the operating day, the Real-Time Market provides a real-time price signal to adjust for any deviations from the day-ahead schedule. Generators are ultimately paid the LMP at their location when their MW are procured in real time.

⁵⁴ Reserve Markets: Reserve markets are market mechanisms that procure additional capacity above the expected load to protect the power system against uncertain loss of capacity or load forecasting errors. Generators can receive revenue for participating in reserve markets in which they can come online quickly to provide grid stability, frequency regulation, and voltage support.

⁵⁵ Capacity Markets: Capacity markets are mechanisms in deregulated markets used to ensure that sufficient resources will be available to meet future electricity demand at the lowest possible consumer cost. These markets are structured to procure commitments from generators to be available during future delivery periods, ranging from the next year to several years in advance. Capacity markets aim to ensure long-term reliability by allowing generators to clear MWs and secure future revenue for being available to provide power when needed. They work to incentivize new investment and prevent early retirements.

Rising Capacity Market Clearing Costs in PJM

As described in the introduction, natural gas-fired generation has continued to gain a larger share of the nationwide natural gas market in recent years. For example, the installed capacity from gas resources in PJM—the largest RTO/ISO in the United States—has more than doubled from approximately 40 GW in 2008 to nearly 90 GW today. However, natural gas infrastructure in the region has not expanded at a pace sufficient to support current or future capacity growth. Gas-fired generation resources continue to see reduced operating flexibility as pipeline operations are unable to support the growing demand and ramping nature of the generation (see Chapter 2). PJM’s recent base residual auction clearing prices provide a clear market signal to incentivize further investment in new and existing dispatchable generation resources (Figure 1-1). These price signals are expected to play a central role in guiding long-term resource and fuel procurement strategies in the competitive electricity markets. As more gas-fired resources are added to the system, more operational flexibility will be needed from the gas supply and delivery systems. This will require the development of incremental firm natural gas pipeline and storage capacity.



Source: PJM's 2026/2027 Base Residual Auction Report. 2025.

Figure 1-1. PJM Base Residual Auction Clearing Prices by Delivery Year for Major Locational Deliverability Areas

The forward nature of capacity market auctions is intended to provide time for generators to invest in new resources, upgrade existing facilities, or secure the necessary fuel arrangements to ensure availability in the identified delivery period. Capacity markets utilize various financial incentives and penalties to influence investment decisions. Generators whose bids are accepted in capacity auctions receive future payments for their commitment to be available, even if they are not ultimately dispatched to produce energy. Capacity markets also include performance-based incentives and penalties designed to ensure that committed resources are genuinely available when needed. Financial penalties may be imposed for nonperformance, while resources

may also face reduced capacity accreditation based on historical outages. Conversely, bonus payments are available for overperformance in certain markets, which are intended to incentivize resources to perform. Table 1-2 shows the variation in capacity market design across a selection of ISOs and RTOs (not listed are ERCOT, CAISO, and SPP).

While these markets provide the potential opportunity for future revenue, the lack of guaranteed cost recovery like that seen in regulated markets limits long-term investment behavior, which comes with the tradeoff of higher risk of unavailability. Recent analyses by FERC, the Energy Information Administration (EIA), and industry groups suggest that large interstate transmission pipeline projects typically require four to seven years to advance from initial development to in-service operation, depending on the scope of environmental review and permitting challenges.⁵⁶ By contrast, capacity market auctions held three years ahead of delivery seek to secure resources that depend on infrastructure that can take twice as long—or more—to bring online.

⁵⁶ FERC. “Environmental Review and Compliance Dashboard.” 2025; EIA. “Natural Gas Pipeline Projects Tracker.” 2024; INGAA Foundation “North American Midstream Infrastructure Through 2035” 2018. Updated 2023.

	PJM	ISO-NE	NYISO	MISO
Auction	Annual; Base Residual, up to three Incremental Auctions, and Bilateral Market	Annual; Forward capacity market	Monthly; Capability period, and spot	Seasonal (4); performed annually
Must-Offer Requirement	Mandatory	Mandatory	Mandatory	Voluntary
Minimum Offer Price Rule	Yes	Yes	Yes	No
Forward Period	3 years ahead	3 years ahead	Auction clears 1 month prior	Auction clears 2 months prior
Commitment Period	1 year	1 year	6 months	1 year, 4 seasons
Reliability Standard*	0.1 LOLE	0.1 LOLE	0.1 LOLE	0.1 LOLE
Most Recent Reserve Margin	18.6%	11.0% (15% without counting Hydro Quebec credit)	23.1%	7.9% (Summer); 14.9% (Fall); 18.4% (Winter); 25.3% (Spring)

Source: EPRI. 2025. “Wholesale Electricity Market Design in North America Reference Guide Volume I.”
Notes: Loss-of-Load Expectation (LOLE): Expressed in terms of days per year. It refers to the number of days in a year that are expected to have a single loss-of-load event (or multiple noncontiguous events) regardless of duration or magnitude.

Table 1-2. Capacity Market Design in U.S. Markets

B. Gas Contracting Behavior – Regulated Markets

In regulated markets, fuel procurement and system planning are integrated into long-term IRPs. These plans provide utilities with a framework for making investment decisions, including the execution of firm gas supply and transportation contracts. By dedicating capacity under firm arrangements, utilities help ensure reliability of supply on peak-demand days and reduce generator reliance on the secondary market for capacity. This, in turn, moderates pricing volatility in both power and natural gas markets by maintaining assured access to supply from liquid trading locations. The assurance of cost recovery (and regulator’s willingness to protect utility customers from year-to-year volatility) through regulated tariffs gives utilities the financial certainty to commit to long-term, often capital-intensive arrangements. Consequently, when there is a strong emphasis on fuel security, utilities generally favor firm contracts over interruptible ones to reduce the risk of unavailability and ensure they are serving their core customers.

This approach to reliability is not without challenges. As longer-term firm contracts to meet design-day needs are added to a utility’s portfolio under the approval of the state public utility commission, the capability of the system grows. However, this also means that for most of the year, a portion of the contracted capability is not being utilized to meet customer needs.

Although required by state regulators as a prudent investment, ratepayers would pay high costs for this high level of reliability. To address this inefficiency, the capacity release market evolved, allowing firm shippers—including LDCs and electric utilities—to temporarily release unused transportation rights to other market participants. These secondary sales help defray the fixed costs associated with holding firm capacity that may be underutilized outside of design-day conditions, while preserving the releasing shipper’s call-back authority when reliability requires it (see Chapter 2, Section I.).

C. Gas Contracting Behavior – Deregulated Markets

In deregulated markets, nonutility generators rely on comparatively short-term revenues from competitive energy and capacity markets to cover operations and investments. Unlike regulated utilities with long-term cost recovery, these generators face both market and operational risk over both short- and long-term horizons. As a result, generators tend to prefer shorter-term, flexible gas contracts that align with more visible near-term revenues and system needs. Additionally, how steadily or variably a power plant runs relative to its maximum possible output (the “load factor”) influences how it procures natural gas. High load factor plants, such as large natural gas combined cycle (NGCC) units operating in a baseload role, are more likely to secure firm gas delivery contracts because the more certain inherent load profile supports that practice. In contrast, lower load factor plants like smaller combustion turbines used for peaking, which are absolutely needed for reliability and the highest-demand days, typically tend to rely on the secondary gas market which, by virtue of its priority level, is less reliable. RTOs/ISOs continue to develop market designs intended to manage this dynamic to incent firm fuel delivery procurements to meet reliability requirements.

Generators in deregulated markets must also manage performance risk, particularly in the context of capacity market obligations. They must weigh the cost of firm gas transportation contracts (see “Illustrative Hypothetical: Peaker Service and Incremental Pipeline Investment”) against the risk of financial penalties for nonperformance or the opportunity to earn bonus payments for overperformance. However, there are many reasons why a generator might not obtain firm fuel arrangements. Some generators are located in regions with better access to gas supply and infrastructure, making secondary firm interruptible contracts a more viable option, even during high usage intervals. Others may simply choose to accept the risk of nonperformance on the relatively few days per year when firm delivery is critical, especially given the lower cost of interruptible service. Many generators in deregulated markets also rely on marketers and asset managers to manage their gas procurement needs, using short-term bundled supply and transportation arrangements that include a mix of firm and interruptible components. Some generators also maintain dual-fuel capability, allowing them to switch to backup fuels such as oil during periods of high gas demand. This flexibility enables them to reduce fuel procurement costs by relying on interruptible gas service for most of the year, while switching to their backup fuel during peak times.

Despite these strategies, generators in deregulated markets face several ongoing challenges. The evolving nature of capacity markets—driven in part by the increasing penetration of intermittent resources facilitated by some states’ resource adequacy and environmental policies—has led to frequent changes in market design and accreditation methods. These shifts create uncertainty and reduce the incentive for long-term gas contracting, particularly when state decarbonization policies articulate a preference for non-gas resources.

The lack of cost-recovery certainty also remains a key challenge in these markets, as generators often procure fuel and services based on forecasted needs but are later scheduled down due to changes in real-time demand. Furthermore, standard gas market commodity products, such as three-day or four-day weekend price strips, may require generators to procure more gas than is ultimately needed. This increases the risk of stranded costs if market design does not support the use of customized fuel products that exist in the natural gas market today. Similarly, market design may not support the acquisition of shaped service products that match the variable usage pattern of electric generation. Depending on market rules, these may be borne by the generation asset owners, or by customers through a mechanism called uplift.⁵⁷ Finally, gas-fired generation resources are seeing reduced operating flexibility as pipeline operations are unable to support the growing demand and ramping nature of the generation. This is examined in detail in Chapter 2; the impacts of this are shown in “Rising Capacity Market Clearing Costs in PJM”).

Illustrative Hypothetical: Peaker Service and Incremental Pipeline Investment

Here we present a simplified and idealized hypothetical to highlight how even modest incremental pipeline investments to provide incrementally firmer service to peaking generators present significant economic challenges under current market structures.

A fully subscribed interstate pipeline would like to offer a new service to four existing 350 MW natural gas peaking units on its system, each connected by its own lateral. We assume these units are simple-cycle turbines with a heat rate of 9,500 British thermal units per kilowatt-hour (Btu/kWh) to 10,000 Btu/kWh. At full output, each consumes roughly 3.2 million cubic feet (MMcf) to 3.4 MMcf) per hour of gas (≈ 77 MMcf–82 MMcf per day). Together, the four units require about 0.31 Bcf/d–0.32 Bcf/d if run simultaneously for 100 peak hours each year. We assume storage is available to stage gas into the system (a large assumption), and incremental compression is all that is needed to move this volume without disrupting existing firm shippers. To reflect limited generator appetite for long-term commitments, this example uses a five-year contract, rather than the 10 years–20 years common in pipeline development. The required service would resemble enhanced firm, nonratable or “no-notice” service as peakers require short bursts, instead of traditional firm contracts with ratable daily flows. Providing this shorter burst service is feasible if (1) compression and linepack maintain pressures for existing shippers, (2) nearby storage or fast-ratable supply can swing ~ 13 MMcf/h– ~ 15 MMcf/h, and (3) laterals/meters handle ~ 3.4 MMcf/hour each with rapid control. This example assumes all of the above exist.

We assume the underlying mainline is a 30- to 36-inch trunkline operating at 700 pounds per square inch gauge (psig) to 1,000 psig, typically supporting 1.5 billion cubic feet per day (Bcf/d) to 2.0 Bcf/d. The proposal would add two compressor units providing $\sim 6,000$ horsepower combined. We estimate capital costs at \$14 million–\$22 million, with permitting and construction taking two years, so service would not begin until year three.

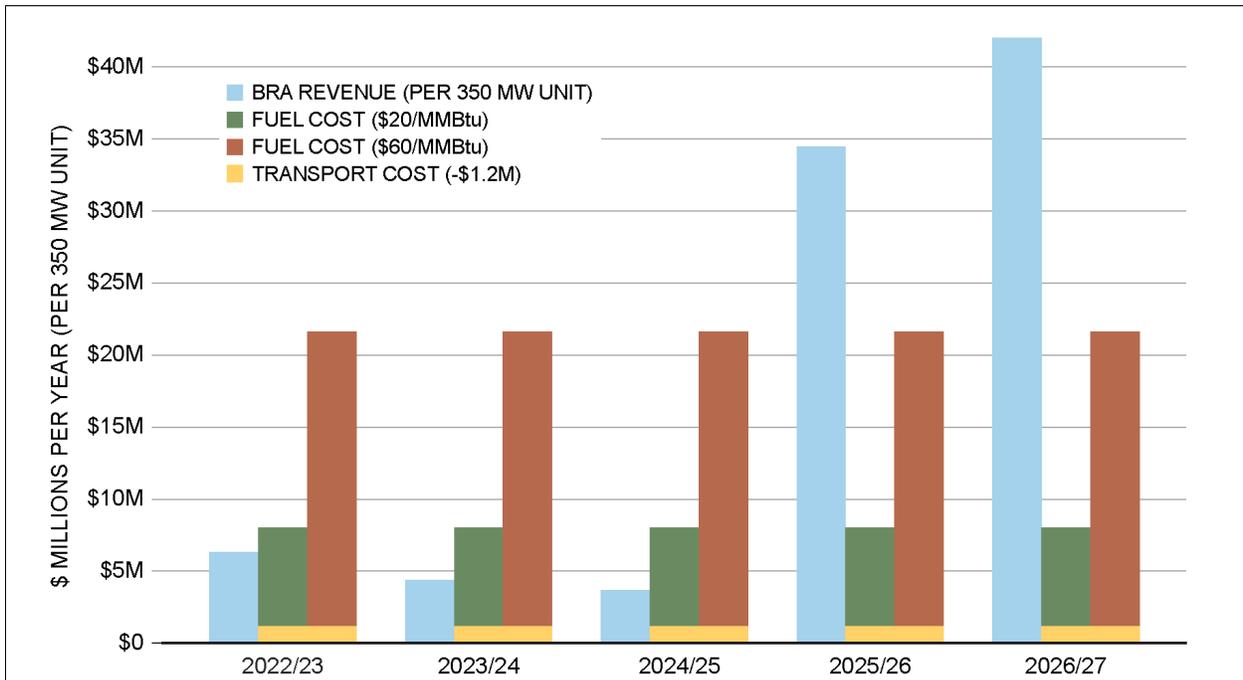
⁵⁷ Uplift is the spreading of costs to either generators or customers, so that the power system operator can cover expenses that energy market prices alone don’t address.

To recover this investment with a 12.5% return, the pipeline would require \$4.5 million/year – \$6.0 million/year, or \$1.1 million/year/generator – \$1.5million/year/generator. Spread across 100 hours of use, this equates to \$10,000–\$15,000 per generator-hour, or about \$3,100–\$4,300 per MW-year. These figures exclude routine operations and maintenance for the compressors and any offsetting revenues the peakers might earn in energy or ancillary markets. Fuel alone, at \$20–\$60 per million British thermal units (MMBtu),⁵⁸ would add \$7–\$21 million annually per unit for 100 hours of operation.

Whether such a commitment is rational depends on the generators' expectations of capacity market revenues. Capacity markets are intended to cover fixed costs not recovered through energy or ancillary services. In PJM, the base residual auction has produced volatile results: ~\$18,000/MW-yr in 2022/23, ~\$12,500 in 2023/24, ~\$10,500 in 2024/25, then a sharp increase to ~\$98,500 in 2025/26 and ~\$120,000 in 2026/27. For each 350 MW peaker, that translates to \$3.5 million–\$16 million per year in the low-price years and about \$42 million in the most recent auction (see Figure 1-2). At the higher clearing prices of the last two auctions, capacity revenues cover the transport obligation and fuel. But in earlier years, incremental transportation would have widened the gap between energy revenues and total costs.

Figure 1-2 shows PJM base residual auction revenues compared with costs. The figure illustrates that at low-capacity prices, high fuel costs make the operation uneconomic. But if capacity prices increase (like in 2025/26 and 2026/27), the unit can be viable. Note that capacity revenues are shown as total annual dollars for a 350 MW unit. Cost stacks include transport (~\$1.2 million/year for two compressors) and fuel (~\$7 million–\$21 million). Operation and maintenance for compression and offsetting energy/ancillary revenues are not included. In most years prior to 2025/26, capacity revenues fall short of covering these obligations; incremental transport only aggravates the problem.

⁵⁸ \$20–\$60/MMBtu represents a realistic stress-case range for short-duration peak operations under extreme cold-weather system conditions based on EIA daily hub price data.



Note: Analysis assumes 100 hours, ~3,400 MMBtu/h burn, ~\$1.2 million transport/year for two compressors.

Figure 1-2. PJM Base Residual Auction Revenues vs. Hypothetical Stacked Transport and Fuel Costs

One option to make the transaction more economic for the peaking units would be to allow recovery of costs through PJM’s tariff as a reliability payment, although this is not consistent with current design, and such “out-of-market” approaches are not necessarily supported by generators. Another variation is that a marketer could contract for the transportation and resell firm deliverability (likely bundled with commodity) to the generators, but this may increase costs since the marketer must cover its own risk. Other electricity market-based constructs could be developed to incentivize fuel procurements and provide the long-term price signals to bridge this gap.

This hypothetical shows how even a limited pipeline investment could pose a significant hurdle for IPPs to pursue under current conditions. Even if capacity can be created with two compressors instead of pipe, generators must weigh a medium-term fixed obligation against uncertain revenues. Physical realities—storage deliverability, hydraulics, siting, permitting—would complicate a real project further, but the core challenge remains the lack of sustained long-term price signals in restructured power markets.

D. Continued Challenges in Regulated and Deregulated Markets

Gas contracting behavior varies significantly between regulated and deregulated markets. In regulated markets, long-term planning and assured cost recovery promote the procurement of

firm gas arrangements, though this comes with the risk of inefficiencies and overbuilding. In deregulated markets, economic incentives and market risks drive more flexible and short-term contracting strategies, albeit at the expense of long-term fuel security and planning certainty. Despite the differences seen in investment behavior, similar challenges and inefficiencies continue to be seen in both regulated and deregulated markets due to the misalignment in gas and electric markets.

As the electric system continues to evolve, particularly with increasing intermittent penetration and policy-driven decarbonization efforts, better alignment between gas and electric market structures will be essential. Capacity market designs, day-ahead markets, and ancillary products must also continue to evolve to provide the right signals for resource investment and operational reliability—particularly variable services. Put another way, revenue visibility is required to underpin investment commitments from electric market participants for incremental infrastructure to meet new and increasingly varied need. The market design must also ensure that generators are not penalized for structural inefficiencies and political forces outside their control. Addressing these challenges is critical to ensuring that both regulated and deregulated systems can deliver reliable, affordable, and sustainable electricity to consumers and LDCs can efficiently and safely balance their systems to reliably service customers.

FINDING 1-1: Current market structures fail to incentivize generators to secure either long-term gas transportation or highly flexible premium products, heightening reliability risks.

FINDING 1-2: Electricity market signals prioritize short-term economic efficiencies, while natural gas infrastructure depends on long-term, firm commitments. Inadequate compensation in electricity markets often leaves generators with little incentive to secure the gas and transportation services needed to support their increasingly variable operations and peak reliability needs.

FINDING 1-3: Regulated and deregulated market types face risks from structural disconnects, highlighting the importance of integrated planning, market reforms, and investment signals to ensure long-term reliability.

II. GAS AND POWER RESERVE PHILOSOPHIES DIVERGE ACROSS REGULATED AND COMPETITIVE MARKETS

When electric utility organizations design and build their systems, they plan to ensure that they have enough supply or resource adequacy to meet their projected peak-day demand forecast. They are allowed to build an incremental amount of reserve capacity, consistent with system reliability mandates and the cost-recovery frameworks of utility models. This reserve capacity is intended to meet peak-day needs and provide a buffer or cushion for periods when load exceeds expectations, generation resources are unavailable due to unplanned outages, or intermittent resources are unavailable or running below their accredited capacity levels. Electric grid operators across the country maintain different percentages of this installed reserve margin

(IRM) depending on their characteristics and generation resource mix. In the PJM system, for example, the current planning period IRM is 20%.⁵⁹

In contrast, the natural gas interstate transmission expansion projects are exclusively market driven based on demonstrated customer demand per the FERC project approval process. During market outreach and open season processes⁶⁰, interstate natural gas pipeline and storage developers solicit customer requests for this incremental capacity. These shippers, usually referred to as anchor shippers, sign up for long-term (10 to 20 year) firm contracts. Once the open season has been completed and enough successful participants have committed to procuring adequate capacity to support the project, the natural gas pipeline will file the proposal with FERC. If the project is authorized by FERC, it is typically only authorized up to the subscribed amount of firm capacity in the open season. Due to the regulated cost-of-service model for the vast majority of the interstate natural gas transmission system, there is little to no incentive for these developers to take a speculative position with unsubscribed capacity. While pipelines and storage are typically built to serve firm contractual obligations, those obligations more often than not represent the peak-day requirements of the buyers. As such, when demand for gas is lower in nonpeak winter months, firm pipeline and storage capacity can be made available to nonfirm (interruptible) shippers through approved capacity release mechanisms. Via capacity release, firm capacity holders can release any of their contractual firm capacity into the market when they are not utilizing it. While the capacity release market is effective at making more efficient use of installed transportation and storage capacity, it is typically not very liquid during the coldest periods of the year when the primary holders—LDCs—need it to meet their peak-day requirements heating customers' homes and businesses.

A. Consequences of Divergent Reserve Capacity Planning Models

With the tremendous growth of gas-fired power generation over the past 15 to 20 years, the natural gas industry has had to try to adapt to a new and much different type of customer: a customer that does not operate on a uniform hourly ratable basis. As will be described in detail in Chapter 2, gas-fired generating resources are not only increasing in number, but also taking gas from interstate pipeline and the upstream natural gas sector in ways that the overall gas production and delivery systems were not originally designed. This operating paradigm shift demonstrates a need for more natural gas infrastructure. Most needed are underground gas storage and pipeline capacity to serve the power sector that requires greater levels of flexibility as more intermittent generating resources are introduced, which creates growing hourly and daily imbalance issues. Additional storage capacity, consistent with its role in bridging seasonal supply and demand patterns, also can play a crucial role in providing gas supply when gas production facilities are impacted by extreme weather events. Sufficient storage capacity does not exist

⁵⁹ PJM defines its Installed Reserve Margin (IRM)—the planning reserve margin required to meet reliability criteria—in its Manual 20: Resource Adequacy Analysis and Manual 20A: Reserve Requirement Study and ELCC Methodology, rather than in the PJM Open Access Transmission Tariff. See PJM Manual 20, Rev. 13. April 10, 2023 and PJM Manual 20A, current version available at <https://www.pjm.com/documents-and-notices/manuals>.

⁶⁰ Open season is a formal solicitation process in which a pipeline or storage operator invites potential shippers to commit to transportation or storage capacity before new infrastructure is built or expanded.

today. This is a problem that will intensify as power sector demand—marked by highly variable gas use—continues to grow.

Another area of divergence between the electric and gas industry is in long-term planning. From the perspective of electric grid infrastructure planning, ISOs/RTOs can analyze and identify system improvements needed for overall grid operations. An example of this is the PJM regional transmission enhancement plan (RTEP) process. The RTEP is a long-term (typically 15 year) forward look to identify necessary upgrades needed to minimize congestion and improve deliverability across multiple states and transmission owners. Additionally, it is important to point out that all areas of the U.S. electric grid, both regulated and competitive markets, are managed by the NERC-registered functional entities: reliability coordinators, balancing authorities, transmissions owners, etc. These entities must comply with NERC standards that help maintain reliable grid operations when it comes to real-time operations. The natural outcome of this is that electric system capacity planning models lead to the same real-time operating challenges.

An analogous planning approach does not exist in interstate natural gas system planning frameworks but appear consistent within gas LDC system planning. As previously noted, interstate gas system upgrades are typically tied to demand for incremental firm capacity, which is ultimately vetted by FERC to determine if it meets established requirements of the Natural Gas Act.⁶¹ For the gas LDC, system planning is based on design-day customer forecasts⁶² typically for a 5- to 10-year planning horizon, as prescribed by their regulator. The LDC runs the system design scenarios annually to determine infrastructure changes needed for their customer base.

FINDING 1-4: Electric and gas utilities plan for and rely on reserve margins to ensure reliability. Notwithstanding these planned utility margins, gas transportation infrastructure does not incorporate additional capacity because it is built to firm contractual needs. Therefore, there is no extra capacity on the existing pipeline system to serve the growing needs of the electric sector.

III. PRICING AND SCHEDULING IN THE GAS AND ELECTRIC INDUSTRIES

Even though power and gas markets trade physically and financially years in advance of their obligations, there is a significant misalignment between the two, predominantly in the cash

⁶¹ Under the Natural Gas Act, FERC determines whether a proposed interstate pipeline project serves the “public convenience and necessity” (15 U.S.C. § 717f(c)). FERC’s 1999 Certificate Policy Statement lays out a multistep analytical framework for FERC’s certificate review: first asking whether a project can proceed without subsidies from existing customers, then assessing efforts to minimize adverse impacts on existing shippers, pipelines, landowners, and communities, and finally—if residual harms remain—balancing those harms against public benefits. See “Certification of New Interstate Natural Gas Facilities, Statement of Policy.” 88 FERC ¶ 61,227 (Sept. 15, 1999) (the “1999 Certificate Policy Statement”), clarified, 90 FERC ¶ 61,128 (2000), further clarified, 92 FERC ¶ 61,094 (2000) (collectively “PL99-3”).

⁶² A design day customer forecast over a 5- to 10-year planning horizon is the utility’s projection of how much gas its customers would use on the coldest expected day, looking 5 to 10 years ahead, in order to plan reliable supply and infrastructure.

market.⁶³ ISOs are tasked with clearing power supply and demand on a daily basis and also meeting instantaneous demand needs through real-time optimization. Most of the supply/demand mix in the power industry is cleared on a next-day basis, allowing generators to align their fuel requirements in advance of their obligations. Each day, generators send a price signal for their willingness to generate power for the following day to each ISO by around 10 a.m. Central Clock Time (CCT). Generators can also update their offers in real time as gas liquidity and pricing changes intraday.

Gas markets also clear remaining supply and demand not already contracted on a term, monthly, and balance-of-the-month basis, on a daily basis in the physical spot market. The gas market and pipelines nominate the majority of their obligation on a next-day basis. Pipelines also allow for intraday nomination adjustments with varying additional flexibility with each pipeline having their own set of requirements depending on the breadth and depth of services while adhering to the standard North American Energy Standards Board (NAESB) nomination cycles.

A. Standard Power Day and Gas Day

The standard power day for trading and scheduling is different than the standard gas day, which causes misalignment. Electricity markets run on the regular calendar day, from midnight to midnight, while the natural gas day runs from 9 a.m. to 9 a.m. CCT. Several factors explain why these schedules remain out of sync, as discussed in Chapter 3.

B. Mismatch in When Next-Day Gas Products Trade and When Gas-Fired Generation Is Required

Next-day gas nominations are required to be scheduled by 1 p.m. CCT daily. Meanwhile, ISOs require gas-fired generation to enter their costs generally between 9 a.m. and 10 a.m. CCT. The 1 p.m. deadline for gas nominations allows the gas industry the flexibility to trade anywhere from 5 a.m. until 1 p.m. daily.

More often than not, gas trades before the ISO deadlines for next day offers. However, during extreme weather events, gas often will not trade until after the ISO's day-ahead deadline because prices tend to be more volatile until closer to the operating day. Under these occurrences, gas-fired electricity generators are estimating their cost to procure gas rather than entering a known gas cost. This can result in overprocurement or underprocurement of fuel, resulting in reliability concerns for the ISO. This mismatch can also result in generators pricing in the risk of procuring incremental fuel at an unknown price, which is reflected in the generator's initial offer cost.

C. Multiday Gas Trading Packages

ISOs are required to clear each calendar day individually on a next-day basis regardless of weekends, holidays, or whether it is the end of the month. This results in gas generators often receiving different commitment schedules from one day to the next.

⁶³ The cash market (or spot market) is where commodities are traded for near-term (typically current and/or next-day commodity requirements) delivery.

However, power users are not the only gas market participants. Gas is traded and scheduled seven days a week, but a majority of gas users can have their less variable needs met comfortably with three-day weekend “packages” (or four- and five-day holiday packages.) With all those needs met, power market participants with more variable needs driven by changing dispatch instructions face a marketplace with limited liquidity, and more limited supply options can command scarcity pricing.

While single-day and shaped products do exist, gas generators may have to procure the three- to five-day gas package regardless of varying unit commitment schedules from the ISOs across those days, in order to ensure gas availability. Gas-fired generation is then expected to reconcile and balance the daily nominations intraday, as the power markets move through the weekend/holiday package dates. This can result in power price distortion, uncertain fuel nominations due to limited liquidity, and higher daily pipeline imbalances. When pipelines issue operational flow orders, gas LDCs must also reconcile their daily gas nominations with actual customer demand. During multiday trading periods, they also have to purchase gas in advance while managing risk of daily load swings. Gas LDCs typically will use storage contracts for this daily balancing over weekends and holiday periods by adjusting injection and withdrawal quantities to stay within tolerance levels.

D. Nomination Changes After Intraday 3 Scheduling Cycle

ISOs adjust dispatch signals for gas-fired power plants every five minutes based on the real-time locational price at the generator’s location. Gas generators are expected to respond to this signal regardless of whether it is during the morning, evening, or middle of the night. This dispatchability is becoming even more important as renewable intermittent uncertainty becomes a larger component of ISOs’ daily supply. Many gas pipelines do not allow gas nomination changes after Intraday 3 (7 p.m. CCT). For power generators, limited fuel-scheduling flexibility can create large daily gas imbalances, potential pipeline pressure issues, and force plants either to run uneconomically or to sit idle even when they could operate if allowed to secure fuel. Due to design specifications, pipelines may be limited in their ability to achieve more flexibility. Tariffs and timelines may be set to safely operate their systems within those design specifications. Other operational constraints to more flexibility exist for pipelines that enforce Elapsed Pro Rata Scheduled Quantity. At each point in the gas day, limits exist on how much scheduled gas can be changed, since part of the day’s gas has already been delivered.

E. Long-term Outage Coordination Between the ISOs, the Public Transmission Operators, and the Pipeline Industry

There are currently three forms of planned maintenance events that can result in generation being unavailable to the ISOs: routine maintenance of the actual generator, routine maintenance of transmission lines, and scheduled maintenance on pipelines. Generators target maintenance during low-demand time periods like the spring or fall. This ensures the units are available during peak summer and winter conditions. The planned maintenance on the generation side is often known one to three years in advance. Electric transmission operators are also required to perform routine line work and upgrades throughout the year. Their planned routine maintenance is scheduled through the ISOs and generators are notified if any transmission maintenance is expected to restrict generators’ operation. Currently, generators attempt to overlap planned maintenance with any transmission work that is being performed, but that is the

only coordination that typically occurs. Pipelines coordinate maintenance operations during periods of anticipated low demand and collaborate with generators when feasible. However, because power generators typically do not hold significant firm mainline capacity, pipelines schedule outages in ways that minimize impacts to their firm shippers, such as LDCs. This issue is becoming increasingly challenging to manage as pipelines face year-round demand with fewer optimum periods for maintenance, increasing retirements of thermal dispatchable generation resources, and constraints from workforce and supply chain shortages.

FINDING 1-5: *Because the gas day runs from 9 a.m.–9 a.m. Central Clock Time and the power day runs from midnight-to-midnight local time, their schedules don't align. Generators must often secure gas before knowing if they will actually need it. When those forecasts miss the mark, generators can be left with unused fuel or unexpected costs, while system operators face greater uncertainty in planning reliable supply.*

FINDING 1-6: *Flexibility is limited by multiday gas trading packages, which is mitigated through storage solutions for gas utilities and may be a solution for generators to efficiently and reliably serve ISO hourly dispatch needs.*

FINDING 1-7: *Year-round reliance on pipeline infrastructure is creating challenges in aligning planned maintenance across pipelines, generators, and transmission operators with increased downtime risks and reliability impacts.*

IV. SUMMARY OF MISALIGNMENTS

The analysis in this chapter underscores a widening structural misalignment between natural gas and electricity markets that poses increasing risks to system reliability. Recent extreme weather events have already exposed these vulnerabilities, highlighting the urgency of reform. Maintaining reliable, affordable, and resilient energy delivery will require greater coordination between gas and power markets, stronger investment signals, improved planning processes, and expanded infrastructure capacity. Without these measures, reliability risks will intensify as intermittent generation sources continue to be connected to the grid as dispatchable thermal generation is retired.

FINDING 1-8: *Based on the analysis in this report, four interlocking categories of challenges that most clearly define the current coordination problem emerge:*

- *Operational Inefficiencies and Misalignments*
- *Market Design – Economic Inefficiencies and Fuel Assurance Misalignments*
- *Commercial – Gas Services Design and Fuel Assurance and Power Sector Misalignments*
- *Fragmented Governance, Planning, and Reliability Coordination*

These four categories of challenges are summarized below and will be referenced throughout the rest of the report. Chapter 2 will add more insight into the Commercial – Gas Services Design and Fuel Assurance and Power Sector Misalignments issues.

A. Operational Inefficiencies and Misalignments

As mentioned previously, gas and electricity systems operate on misaligned schedules: Power days begin at midnight in each time zone, while gas days start at 9:00 a.m. CCT, resulting in inefficiencies and potential risk impacts. Generators face further constraints because standard gas renomination windows occur only four times per day, limiting their ability to adjust to real-time conditions. Many generators rely on bundled fuel and transportation packages from marketers, but these packages present challenges regardless of timeline alignment, particularly since they can lack storage and prevent no-notice or park-and-lean procurement. Weekend and holiday trading practices that largely transact the same volume of gas for several consecutive days also limit flexibility for gas utilities and generators. Gas utilities balance their systems to achieve some flexibility using storage. However, generators that need to secure individual-day gas in advance are hindered by lack of flexibility, heightening financial exposure and liquidity risks. Limited pipeline flexibility and inadequate maintenance coordination add further stress. These operational and market rigidities are compounded by limited shared situational awareness between gas and electric systems, which complicates scheduling and coordination during periods of stress.

B. Power Market Design – Economic Inefficiencies and Fuel Assurance Misalignments

Thin liquidity during intraday, weekend, and other nonstandard trading hours combined with limited fuel risk mitigation in power market design hampers generators' ability to procure gas products and constrains further market development. Generators, especially low-dispatch units, often must secure fuel without dispatch certainty, increasing financial exposure and discouraging commitments to firm or variable products. Structural misalignments between gas and power markets add to the challenge: Across both regulated and deregulated electricity markets, capacity design and contracting practices shape fuel security outcomes. Regulated markets provide stability through firm contracting but risk economic inefficiency; deregulated markets emphasize short-term economic optimization, but are facing growing reliability challenges. Electricity markets favor short-term bidding, while gas transmission and storage favor long-term contracts. Baseload generators with predictable demand can more easily support firm transportation, but peaking and swing units, essential for ramping and balancing, struggle to justify such commitments, leaving pipeline services underdeveloped and underutilized by generators. As variable-load generators become more central to reliability, their need for flexible fuel options will grow, yet capacity and energy market designs do not always value firm fuel arrangements. Compensation mechanisms like uplift payments exist but are inconsistently applied and seldom aimed directly at ensuring fuel assurance. Similarly, divergent reserve philosophies (electricity and gas utility planning for reserves while gas transmission is built only to contracted demand with no additional capacity) further strain systems not designed for the variable loads that are becoming increasingly dominant.

C. Commercial – Gas Services Design and Power Sector Fuel Assurance Misalignments

Pipeline and storage services were originally designed for steady industrial loads and predictable seasonal heating patterns of LDCs, not the highly variable daily and hourly dispatch needs of power generators (as noted above). Long-term commitments required by transmission

and storage infrastructure are difficult for many generators to economically justify. Nonratable, hourly, or no-notice services that are critical for flexibility remain limited, costly, or unavailable during peak demand. Generators and pipelines require adequate storage, particularly when reliant on upstream gas systems particularly in regions where natural gas infrastructure may be negatively impacted by extreme weather. Storage becomes most critical in regions distant from winterized production, where morning and evening ramps can strain supply once nomination windows have closed. Meanwhile, storage capacity has not kept pace with the growing reliance on gas in electricity markets, and midstream flexibility is further constrained by physical limits on linepack, pressure management, and the prioritization of firm over interruptible service.

D. Fragmented Governance, Planning, and Reliability Coordination

Accountability for gas-electric reliability is fragmented across FERC, NERC, Department of Energy, state public utility commissions, RTOs/ISOs, NAESB, pipelines, and LDCs, with no single entity responsible. While notable progress has been made within individual jurisdictions, such as improvements in weatherization, forecasting, emergency planning, and system communications, coordination across sectors remains limited. Outage planning, seasonal assessments, and resource adequacy processes are rarely conducted jointly, and emergency communications vary by region, often lacking shared dashboards or tools. Differing legal and institutional frameworks further complicate market oversight, infrastructure planning, and fuel security expectations. FERC, NERC, and regional entities (responsible for reliable bulk electric system operations) have called for mandatory reliability standards instead of voluntary coordination.

The analysis in Chapter 2, Infrastructure for Reliability, builds on these findings on market misalignments by examining the physical systems, operational practices, and investment strategies needed to support a more reliable and resilient energy network.

Chapter 2: Increasing Variable Demand on Natural Gas Pipelines and Threats to Reliability

America's natural gas pipelines have long been fixtures in the nation's interconnected energy systems, reliably serving customers who distribute this clean and essential energy to homes and businesses. Until recently, the reliability of pipelines was largely without question. However, that has changed due to an evolving energy mix and a diversification of users of natural gas. What once was a relatively stable and steady demand for natural gas that would fluctuate seasonally has now become variable, not just seasonally, but within a day. The interstate pipelines were not designed for this type of variable demand, and as a result, reliability is a growing concern.

To address the rising reliability threat that stems from growing volatility on our natural gas pipeline infrastructure, it is critical that industries, regulators and policymakers come together and put meaningful solutions in place that will enable development of products tailored to changing market needs. In order to do so, it is important to understand the factors that have led to the situation. Accordingly, this chapter addresses four key questions:

- I. How Were Natural Gas Systems Historically Used?
- II. What Is Changing?
- III. What Is Not Changing?
- IV. Why Does This Matter?

The issues raised in this chapter apply across the country and thus should be acknowledged by stakeholders in all regions. However, in order to provide real examples that highlight the problems, this chapter will focus on the following three interstate natural gas pipelines:

- **Texas Eastern Transmission, LP** – Owned by Enbridge, Inc. (Enbridge), the Texas Eastern Transmission pipeline, commonly referred to as TETCO, is a pipeline network spanning approximately 8,500 miles, stretching from Texas and the Gulf Coast to markets in the Northeast. TETCO is a fully subscribed pipeline with a peak-day design capacity of 12.04 Bcf/d and approximately 74 Bcf of natural gas storage.
- **Algonquin Gas Transmission, LLC** – Also owned by Enbridge, the Algonquin Gas Transmission (Algonquin) pipeline is more than 1,000 miles long with a capacity of 3.09 Bcf/d, located in the Northeast. Algonquin is fully subscribed and is the largest transporter

of natural gas in New England, serving markets such as Boston and other major utilities in the region.

- **Transcontinental Gas Pipe Line Company, LLC** – Owned by The Williams Companies, Inc., the Transcontinental Gas Pipeline, known as Transco, is the nation’s largest interstate natural gas pipeline by volume. Like TETCO, it stretches from the Gulf Coast to the Northeast, serving markets in the Mid-Atlantic along the way. Transco is also fully subscribed and has a peak design capacity of approximately 20 Bcf/d and approximately 200 Bcf of natural gas storage.

I. HOW WERE NATURAL GAS SYSTEMS HISTORICALLY USED?

The historic utilization and operation of interstate natural gas pipelines—including business practices, the traditional mix of shippers, and commercial services—provides essential context for how recent changes have compromised pipeline reliability.

A. Business Practices

The regulatory framework and changes discussed in the introduction of Chapter 1 drove standardization in the operational business practices across the interstate pipelines, ultimately influencing how natural gas transportation is managed to ensure reliability for all customers holding firm transportation capacity. Before detailing the relevant business practices, a fundamental appreciation for how gas is delivered into and out of natural gas pipelines is important.

Natural gas can enter an interstate pipeline via several ways. It can enter directly from a production area once it has been gathered and processed, from a gas storage facility of any kind (types of storage are discussed later in this report), or most commonly, from an interconnection with another pipeline. Regardless of the initial entry source, the gas must enter a pipeline through a metering facility designated to constantly measure the rate at which gas is being received into the pipeline. This is commonly referred to as a “receipt meter.” Similarly, as gas is delivered out of a pipeline, it does so via a “delivery meter.” It is often the case that with interconnections with other pipelines or storage facilities, a meter can be bidirectional—it has the capability to receive or deliver gas in or out of the pipeline.

The measurement of gas in and out of pipelines is critical in ensuring that a pipeline remains in balance, which means that the rate of gas being received equals the rate of gas being delivered. Maintaining balance across a pipeline is one of the most fundamentally important aspects of pipeline operations, both for ensuring reliability and pipeline integrity. If more gas is being received into a pipeline than is being delivered out, its pressure will rise. Pipelines are designed to have a Maximum Allowable Operating Pressure (MAOP), and safety systems are engineered at pipeline facilities specifically to respond if pipeline pressures reach near MAOP levels. Keeping pressures below MAOP is key for protecting the structural integrity of pipelines and preventing incidents involving leaks or ruptures. On the opposite end, pipelines must keep pressures high enough to satisfy delivery commitments. If more gas is being delivered out of a pipeline than what is being received in, the pipeline pressure will drop. If pressure levels get too low, they may fall below a threshold at which deliveries cannot be sustained. Because of this, some pipeline customers negotiate specific minimum pressure requirements in their contracts.

While maintaining pipeline balance is fundamental, it is not without complexity. Any number of operational changes can occur upstream or downstream of a pipeline, causing receipts and deliveries to fluctuate. To give some context around this complexity, on the Transco pipeline alone, there are 1,854 active meters.

Because of the physical and commercial risks that can occur due to imbalances, the North American Energy Standards Board (NAESB) has put in place standard business practices that have been adopted by the pipeline industry and often incorporated by reference into federal regulations.

Examples of these practices, among others relevant to this report, include:

- **Nominations:** Nominations are requests submitted by shippers to a pipeline, indicating the quantity of gas to be transported on a specific contract from specific receipt and delivery points on a given gas day. Nominations can be made for firm or interruptible transportation, and pipelines must offer a minimum of the five nomination cycles shown in Table 2-1. NAESB’s standardized nominations deadlines allow gas to flow across regions more readily.

	Timely	Evening	Intraday 1	Intraday 2	Intraday 3
Nomination Deadline	1:00 PM	6:00 PM	10:00 AM	2:30 PM	7:00 PM
Confirmation Deadline	4:30 PM	8:30 PM	12:30 PM	5:00 PM	9:30 PM
Schedule Issued	5:00 PM	9:00 PM	1:00 PM	5:30 PM	10:00 PM
Start of Gas Flow	9:00 AM	9:00 AM	2:00 PM	6:00 PM	10:00 PM
Hours Remaining in Gas Day	24 hours	24 hours	19 hours	15 hours	11 hours

Table 2-1: Minimum Nomination and Scheduling Cycles for Gas Pipelines (times in central clock time)

- **Scheduling:** A process by which pipelines confirm and prioritize nominations based on available capacity and contractual rights.
- **Priority of Scheduling:** Scheduling priority is based on standards, dictated by each pipeline’s tariff, that interstate pipelines must follow to determine which shipper’s gas gets transported, according to contractual rights. It is especially important during periods of peak conditions and/or capacity constraints, as not all receipt and delivery points along a pipeline have the same level of scheduling priority, depending on the contract. Primary firm points associated with a firm transportation (FT) contract have the highest scheduling

priority, followed by secondary firm points, and finally, points scheduled under interruptible transportation (IT).

- **Primary firm points** are specifically listed in a FT service agreement as the official (primary) receipt and delivery points for the shipper's gas. These points provide the highest priority for FT service with guaranteed delivery outside of force majeure events. In other words, primary firm service is typically a point-to-point guarantee for specified volumes between contracted locations.
 - **Secondary firm points** are receipt or delivery locations not specifically listed as primary in an FT contract but that physically exist within the contracted FT path. Shippers may nominate gas for transport at secondary points, but confirmed scheduling is subject to available pipeline capacity after primary firm points have been accommodated. Service to secondary points is still firm if scheduled, but secondary nominations are subject to being restricted before primary points in the event of capacity constraints. The ability to nominate capacity to secondary points and from pools (an aggregation of points) rather than from primary point to primary point helped create market centers where gas began to trade and the spot market evolved.⁶⁴ This is further discussed in the Role of the Marketer section (I.H).
 - **IT has the lowest scheduling priority.** IT contracts allow nomination at any receipt and delivery points across a pipeline, but transport under an IT contract is only scheduled if capacity remains after a pipeline serves all FT obligations. IT service is flexible and typically only billed for volumes delivered, unlike FT contracts where capacity reservation charges are paid by a shipper whether the gas flows or not. Because of this, IT is typically used under opportunistic market conditions.
- **Priority Bumping:** Nominations of primary and secondary FT can “bump” previously scheduled IT nominations, if the firm nominations are made before the Intraday 3 cycle. This is an important consideration for areas where power generators do not hold FT capacity.
 - **Capacity Release:** Under FERC rules, any holder of FT capacity (the releasing shipper) is permitted to release all or part of its capacity on a temporary or permanent basis to another party (the replacement shipper). Accordingly, NAESB provides standard business practices for pipelines to facilitate capacity release from releasing shippers to replacement shippers. Replacement shippers of FT capacity receive the same scheduling priority as the releasing shipper, so long as transport of the released capacity is nominated in accordance with the receipt and delivery points identified in the FT contract. The secondary market created by the capacity release rules is widely used, either directly or indirectly, by independent power producers.
 - **Balancing and Imbalance Resolution:** Through their tariffs, pipelines have mechanisms to manage imbalances and incentivize shippers to remain in balance. These mechanisms include:

⁶⁴ The spot market is where gas is bought and sold for near-term delivery, usually within one or two days.

- **Operational Balancing Agreements (OBAs):** OBAs define balancing rules at interfacing pipeline systems. They are required to be established at all pipeline-to-pipeline interconnection points.
- **Operational Flow Orders (OFOs):** OFOs are directives from pipelines to shippers, requiring deliveries to be within pre-established tolerance levels, usually expressed as a percentage of total scheduled quantities. OFOs are typically issued when system balance is at risk, such as periods of high demand or constrained conditions occurring from maintenance or unplanned operational upsets. Financial penalties for noncompliance with OFOs vary depending on the pipeline, but are designed to be significant, to ensure that shippers remain within the OFO tolerance levels. Depending on the tariff, OFOs can be specific to certain receipt or delivery points, zones, or individual shippers. Alternatively, OFOs can be issued across an entire pipeline system. Typically, OFOs are issued to manage daily performance—meaning that compliance with an OFO is determined based on imbalance levels at the end of a gas day. While historically not as common, certain pipelines may have the ability to issue hourly OFOs, which require shippers to stay within tolerance levels on a per-hour basis.
- **Offsetting and Trading Imbalances:** FERC requires pipelines to let shippers offset imbalances across their contracts and trade imbalances with other shippers. These tools do not directly balance the pipeline in real time, but help shippers reduce their overall imbalance exposure.
- **Cash-Outs:** Cash-outs are financial settlements that resolve any gas imbalances at the end of a given period, usually each month. If a shipper’s actual gas usage does not match their nominations, the pipeline will either buy excess gas from the shipper (in the case of a shipper nominating more volume than used) or sell additional gas to the shipper (in the case of a shipper using more gas than they nominated). Cash-outs help maintain operational integrity of pipelines by creating financial incentives for shippers to accurately forecast and schedule their gas usage.

Each pipeline tariff has provisions detailing how imbalances will be resolved. These provisions commonly include cash-out mechanisms, in which the pipeline will buy or sell gas at a market or penalty price, or, specifically for OBAs, in-kind resolutions that can be employed where imbalances are physically made up over a period. FERC rules require revenues from cash-outs or OFO penalties be credited back to the pipeline shippers in accordance with the pipeline tariff.

B. Traditional Commercial Services

Interstate pipelines have developed and expanded to provide capacity for shippers subscribing to FT services. These FT contracts obligate a pipeline to provide firm service of a defined quantity of gas and specifically list a shipper’s primary receipt points and primary delivery points, together known as the “primary path.” FT shippers pay a reservation fee for primary path transportation, up to their maximum daily contract quantity, to be guaranteed available by the pipeline, outside of instances such as force majeure. The reservation fee is paid whether the gas is scheduled or not. Unlike FT contracts, IT contracts have no reservation fee, as the service is only paid for when used. Additionally, pipeline operators have no obligation to ensure capacity is available for IT service, as it is only available when capacity exists after all FT has been scheduled for a gas day. The differences in priorities and rights associated with these

services are important factors when considering future reliability on increasingly constrained pipelines. Table 2-2 summarizes the key differences.

	FT – Primary	FT – Secondary	IT
Receipt and Delivery Points	Reserved points of capacity, specified in contracts	All other points not specified in contracts, available to FT holders	No reserved points or routes
Priority of Service	Highest priority	Priority after primary firm	Lowest priority, only available if capacity remains
Reliability	Guaranteed, outside of force majeure	Firm after scheduling of primary	Can be interrupted anytime
Traditional Shippers	LDCs, utilities, major industrials	LDCs, utilities, major industrials	Marketers, merchant power generators
Fee Structure	Reservation and usage charges	Reservation and usage charges	Usage charges only

Table 2-2. Comparison of Interstate Pipeline Transportation Types

C. Enhanced Commercial Services

In addition to FT and IT services, interstate pipelines can offer packages of enhanced services, which are useful to support operational variability faced by shippers by allowing a shipper to balance supply and fluctuating demand within a gas day. These services are designed to provide a shipper with a higher degree of scheduling flexibility than what may be afforded in traditional FT. Each type of enhanced service will vary according to each pipeline tariff; however, they typically provide a shipper with no-notice and/or hourly balancing flexibility.

- **No-Notice Service:** A no-notice service allows a shipper to take volumes of gas above its scheduled nominations without prior notice. While each no-notice service will vary depending on the pipeline, especially in terms of the threshold amount of gas that can be taken over a predetermined period, typically the total volume taken for a gas day cannot exceed the total contract quantity. Additionally, if a no-notice service does not include hourly balancing, the total amount of gas delivered must still match the total scheduled amount by the end of the gas day, just like a standard FT contract.
- **Hourly Balancing:** While most gas services require end-of-day balancing, hourly balancing services require shippers align scheduled and actual gas flows each hour.

No-notice and hourly balancing can be critical pipeline services for a shipper that needs gas to be delivered nonuniformly, such as a LDCs needing to ramp up to follow its own customers' gas demands, or a gas-fired power generator that needs to follow electricity demand patterns. However, it is generally the case that the capacity of a pipeline alone is not enough to support such flexibility, and as a result, these types of services are often backed by gas storage infrastructure and corresponding services. Given the physical nature of production and

processing time, natural gas wells are poorly suited for variable production rates or meeting immediate shifts in demand. Gas is generally delivered into pipelines ratably (1/24 in every hour). As a result, a pipeline must either have excess gas in the system to provide for variable hourly flows, typically through linepack,⁶⁵ or have the ability to bring additional gas supplies into the system through storage.

D. Traditional Shipper Mix

As the regulatory framework and business practices were standardized across interstate pipelines through the 1990s, LDCs were the dominant holders of firm pipeline capacity, with other main shippers being municipal utilities and large industrial users. A 1997 paper published by the National Regulatory Research Institute focusing on LDC capacity turnback showed that nearly all FT rights were held by LDCs until the industry restructuring began in the 1990s.⁶⁶ Further, a 2019 paper published by the Interstate Natural Gas Association of America (INGAA) states that “In the past, natural gas LDCs were the traditional anchor sponsors for interstate natural gas pipeline projects, contracting for pipeline capacity to meet design-day load requirements.”⁶⁷ Even as recently as 2010, LDCs held 82% of the FT capacity on the Transco pipeline, as shown in Figure 2-1. LDCs would contract for FT capacity due to the reliability assurances needed to serve their baseload and peak needs. These contracts were typically for long-term services, up to 20 years.

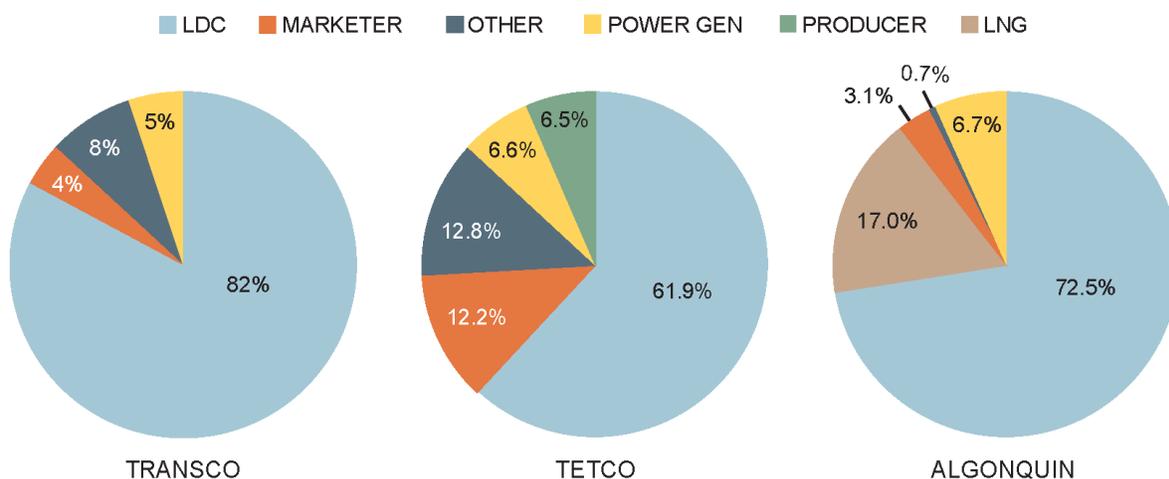


Figure 2-1. Share of FT Capacity on Transco, TETCO and Algonquin Pipelines in 2010

⁶⁵ Linepack is the volume of gas within a pipeline at any given moment, factored by pipe size and length, pressure, temperature and other properties. Simply put, when more gas is being injected (received) into the pipeline than what is being delivered out, linepack increases. On the other hand, when more gas is being delivered out of the pipeline than what is being received in, linepack decreases.

⁶⁶ National Regulatory Research Institute (NRRRI). “Pipeline Capacity Turnback: Problems and Options.” 1997. <https://pubs.naruc.org/pub/FA85FAF3-B040-A097-F64E-AAD1931ED8FB>.

⁶⁷ INGAA Foundation Inc., “The Role of Natural Gas in the Transition to a Lower-Carbon Economy.” 2019. Black & Veatch. <https://ingaa.org/stay-current/natural-gas-and-related-infrastructure-to-play-integral-role-in-u-s-transition-to-a-lower-carbon-economy/>.

E. Pipeline Designs

Traditionally, FT service came with an expectation that shippers take deliveries ratably, corresponding to how gas is scheduled from receipt points to delivery points. This means that a shipper is expected to take gas from nominated delivery points in equal amounts throughout the gas day. For example, if a shipper nominates 24,000 dekatherms (Dth) for one gas day, a typical FT service would require the shipper to take 1,000 Dth/h. Specific language regarding flow uniformity will vary across pipeline tariffs, but operating pipelines to near uniform flows is critical to ensure reliable service for all firm shippers. FERC acknowledges this in its Docket No. RM14-2-000, where it states that, “Except for special services, pipeline services are generally based on the assumption of uniform hourly flows over the Gas Day.”

Corresponding to the way gas was scheduled under FT contracts primarily held by LDCs, interstate natural gas pipelines were physically designed to provide ratable service. Generally, LDCs have been required by state regulators to demonstrate that they hold enough firm supply and transportation capacity to meet forecasted peak demand. Accordingly, interstate natural gas pipelines were designed to meet their own peak demands, which corresponded to the maximum contract capacity of all FT contracts. This is commonly referred to as a “peak day,” where nearly all the FT capacity is utilized, but still under a ratable delivery philosophy.

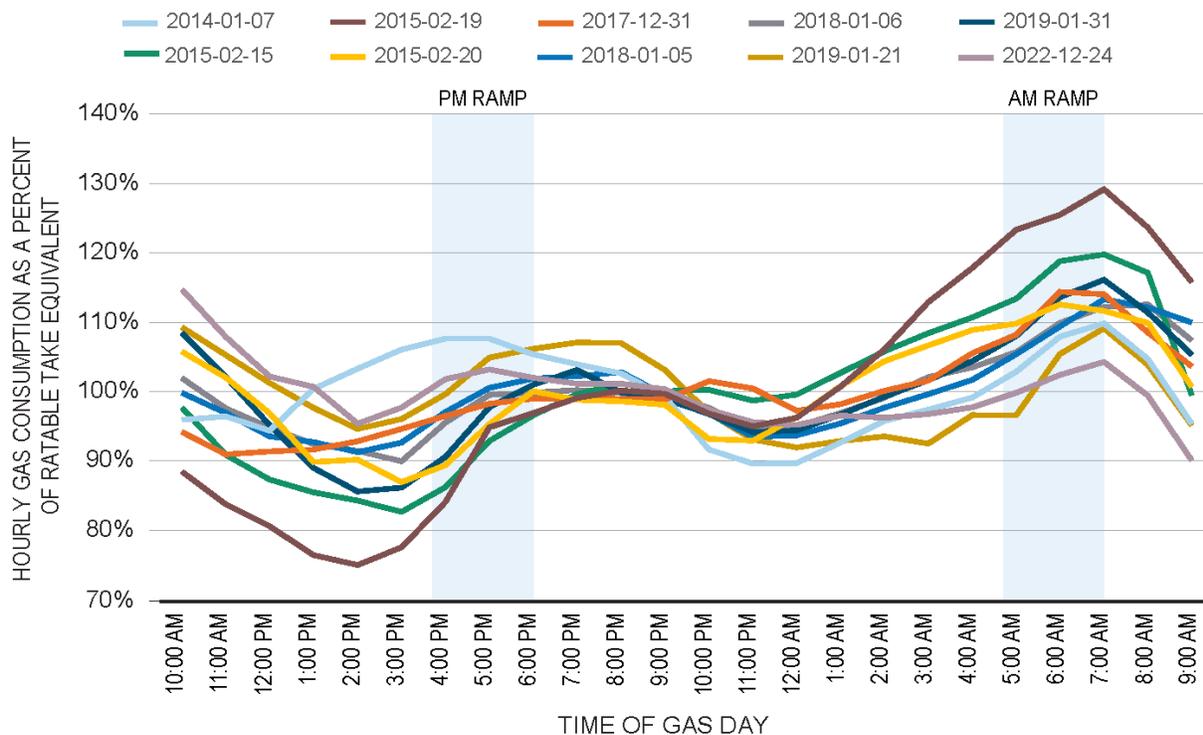
The fact that ratable design and operation of natural gas pipelines has largely mimicked the demand profiles of the LDC community is well summarized by the American Gas Foundation in its 2021 report “Building a Resilient Energy Future: How the Gas System Contributes to U.S. Energy System Resilience.”⁶⁸ The report states: “The gas system that serves the U.S. today was built to serve the residential, commercial, and industrial sectors, where the relative predictability of usage over the course of a day (ratable takes) and throughout the year for these customer segments enabled LDCs to design, construct, and operate the gas system with a high degree of confidence in how the gas system would be used to serve demand.”

F. Historical Load Patterns

While pipelines were designed under a basis of ratable services, operational realities are such that completely uniform delivery profiles throughout a day are not likely, and a pipeline is never truly balanced, where receipts into a pipeline exactly match deliveries out. Even when LDCs—known for relatively stable deliveries—held most pipeline capacity, intraday demand still fluctuated. However, this intraday variability was highly predictable and consistent, based on what is commonly referred to as the morning and evening ramps. Gas demand in the mornings would ramp up as people woke up and increased gas use for heating, hot water, and cooking. Morning ramps were also influenced by businesses increasing gas use for heating offices. Similarly, a second ramp would occur in the evenings as people returned home from work and used gas for heating, cooking, and hot water.

⁶⁸ American Gas Foundation. “Building a Resilient Energy Future: How the Gas System Contributes to the US Energy System Resilience.” January 2021. Prepared by Guidehouse. https://gasfoundation.org/wp-content/uploads/2021/01/Building-a-Resilient-Energy-Future-Full-Report_FINAL_1.13.21.pdf.

Data from New Jersey Natural Gas shows an aggregation of actual daily load profiles as an example of the predictable and consistent load patterns from LDCs. Even when focused on peak days, the minimum and maximum ramps only vary approximately $\pm 25\%$ from a daily average. This illustrates the fairly predictable and consistent ramps that would have historically been common when LDCs held most pipeline capacity (Figure 2-2).



Note: Lines depict actual data from top 10 firm sendouts for New Jersey Natural Gas (1994-2025).
Source: New Jersey Resources. 2025.

Figure 2-2. Daily Natural Gas Load Profiles for top 10 peak days for New Jersey Natural Gas

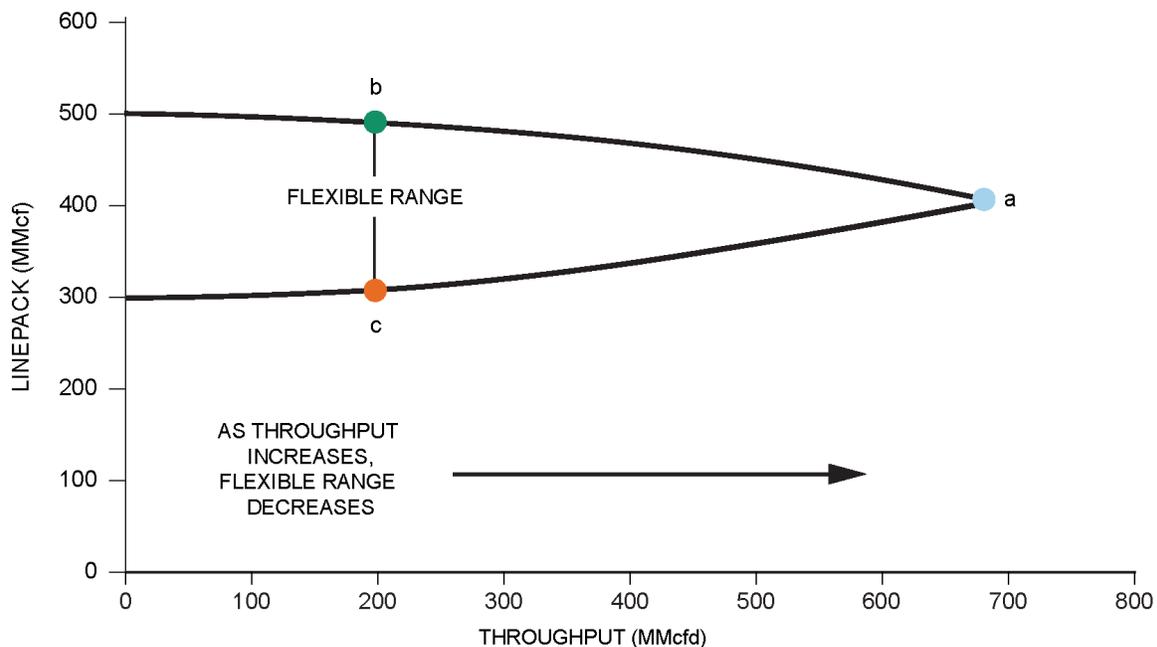
While intraday variability was common when LDCs were the primary shippers on interstate natural gas pipelines, the pipelines were generally balanced at the end of a gas day. Any imbalances were managed according to an individual pipeline tariff, but generally per the imbalance resolution mechanisms discussed in Section 1.1, such as offsetting/trading, or cash-outs.

G. Managing Variable Demand

To provide flexibility and follow the intraday variable loads brought by LDC evening and morning ramps, interstate pipelines used linepack and operational storage. Managing linepack at an appropriate level is a fundamentally critical aspect of gas pipeline operations, needed to protect the integrity of a pipeline and ensure delivery commitments to all firm shippers.

It is important to note that linepack is not a replacement for adequate storage, as it is only available for short-term, intraday, supply and demand balancing, under certain conditions. This

made linepack a useful tool in following the short-term, predictable, intraday variability of LDC loads into the early 2010s when LDCs were the predominant shippers on pipelines. During the evening and morning ramps, pipelines were unpacking, and when the LDC loads would lessen during the midday and overnight hours, pipelines would repack. Because linepack is just the volume of gas contained within a pipeline at a given moment, it cannot be used as a reserve product for periods of sustained deliveries more than what is scheduled. Further, because interstate natural gas pipelines are only designed to accommodate peak contractual capacity levels, the closer a pipeline is to operating at its design conditions, like during a severe cold-weather event, the less tolerance they will have to use linepack to absorb variations in actual deliveries being greater than scheduled deliveries. In other words, there is a difference between linepack and *usable* linepack, and usable linepack diminishes as demand increases. Figure 2-3 shows the decreasing flexibility of linepack with increasing pipeline utilization.



Source: Energy and Environmental Economics, Inc. 2014.

Figure 2-3. Illustrative Envelope of Allowable Linepack as a Function of Throughput

Figure 2-3 represents a theoretical pipeline with a design capacity of 675 million cubic feet per day (MMcf/d). When it is operating at its design capacity (point a), there is 404 MMcf of linepack. The 404 MMcf of linepack is what would be required to keep pressures at levels to meet minimum delivery obligations of its shippers holding firm capacity. In other words, that is not 404 MMcf of “extra gas” available to support deliveries beyond what is scheduled for FT capacity holders. When throughput decreases below the design capacity, the pipeline operator would have the ability to operate compressors at low discharge pressures (e.g., point c in Figure 2-3), decreasing linepack, or operate the compressors at higher pressures (e.g., point b), increasing linepack. The low- and high-end limitations of linepack during conditions of less-than-designed throughput would be minimum pressures needed to maintain commercial deliveries, or MAOP, respectively.

In addition to linepack, pipeline operators may use operational storage to manage intraday variability. This is storage that the pipelines own and operate for purposes of system balancing or pressure management during operational upsets. Operational storage is not contracted to third-party customers. Like linepack, operational storage is typically only available for short-term needs, as it is a relatively finite amount available to the pipeline owner. Under 18 CFR Part 284, FERC allows interstate pipelines to retain an amount of storage needed to provide reliable service, but such amounts must be approved by FERC and cannot unduly restrict customer access to otherwise marketable storage.

Similar to open access requirements for pipeline capacity, FERC Order No. 636 required interstate pipelines to maintain open access to storage capacity. And, just as LDCs were the primary holders of FT capacity, they were the majority holders of storage capacity on pipelines. According to a 1995 report, “While interstate pipelines own 61 percent of the U.S. working gas storage capability, they have contracted the vast majority of storage capacity to their customers, primarily local distribution companies (LDCs), retaining an average of 13 percent of the 61 percent of U.S. working gas capacity for operational needs and to provide no-notice service.”⁶⁹ Working gas can be thought of as the part of storage inventory available for commercial use. Figure 2-4 shows the percentages of customer types subscribed to storage services on the Transco and TETCO pipelines as of August 2025.

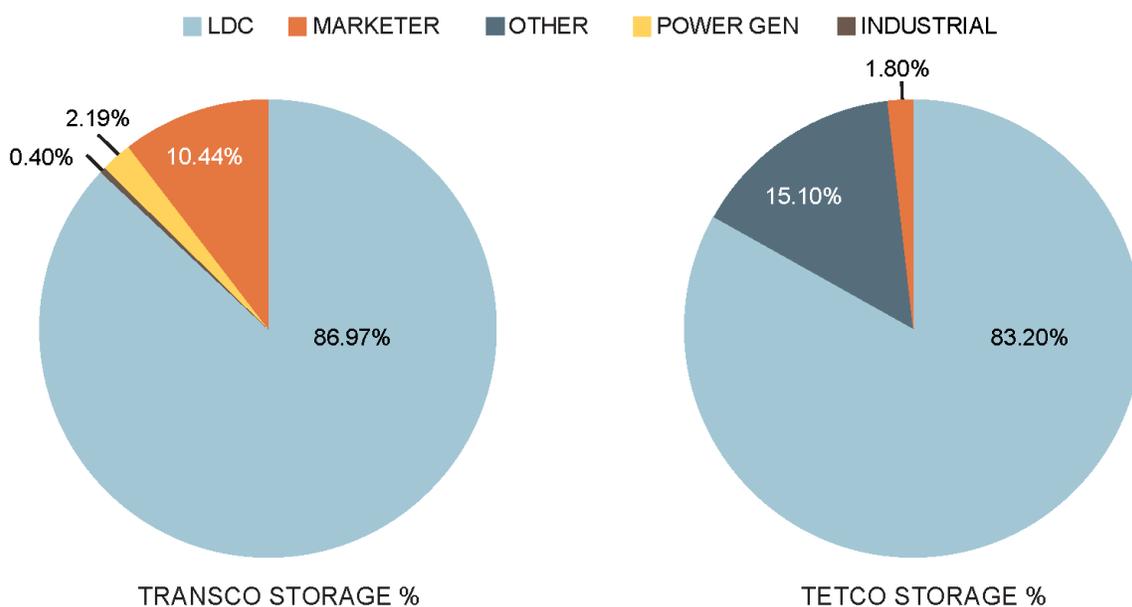


Figure 2-4. Mix of Storage Customers, by Type, on the Transco and TETCO Pipelines in August 2025

⁶⁹ INGAA Foundation Inc. 1995. “Profile of Underground Natural Gas Storage Facilities and Market Hubs.” Prepared by Foster Associates Inc. <https://ingaa.org/wp-content/uploads/2016/08/30077.pdf>.

Natural gas storage facilities can be broadly categorized into three main types, each possessing distinct features and contributing uniquely to managing variable demand: depleted underground hydrocarbon reservoirs, subterranean salt caverns, and aboveground liquefied natural gas (LNG) storage. The benefits of natural gas storage to customers needing to manage variable gas demand vary depending on type and location.

Depleted reservoir storage facilities are underground rock formations found in areas of the country historically associated with oil and gas production. As the production depleted, these formations were repurposed for natural gas storage. Accordingly, they are excellent for storing large quantities of gas, but their ability to move gas in and out of the formation is relatively slow and is a function of the porosity of the rock formation. As such, depleted hydrocarbon reservoir storage is best suited for seasonal demand fluctuations, not short-term cycling that supports intraday demand variability. Additionally, the limited regions where depleted reservoirs exist means storage cannot be injected directly into some market areas instantaneously. However, it remains an effective tool address longer-term supply interruptions or price spikes.

Salt caverns are developed by mining naturally occurring subterranean salt domes. Unlike depleted reservoir storage, there are no flow restrictions in the subsurface other than the well piping, and thus, salt cavern storage provides very fast cycling and deliverability, making it an ideal storage solution for peak-shaving and intraday load balancing. While a wide geographic distribution of underground salt cavern storage would be ideal to support the intraday gas demand variability becoming pronounced throughout the country, geology has limited any appreciable development of this storage type to the Gulf Coast region, where the salt domes are larger, shallower, and more accessible when compared to salt domes that exist in other parts of the country.

The final storage type of note is aboveground LNG storage. LNG operators use cryogenic processes to transform gaseous natural gas into a liquid. LNG occupies about 1/600th of the volume of natural gas in its gaseous state, which makes it ideal for global energy distribution, as evidenced by the tremendous buildout of large-scale LNG facilities in the U.S. Gulf Coast.

In addition to the large LNG export terminals, LNG storage can be developed at a smaller scale and used domestically for peaking needs or as an emergency backup to primary gas supply disruptions. Several LDCs have LNG storage strategically located behind their citygates to utilize during near-peak days, and to manage emergencies and to support transient operational conditions. For example, Consolidated Edison, Inc. (ConEd), one of the largest LDCs in the Northeast, declared a Gas System Emergency during Winter Storm Elliott after gas pressures declined to levels approaching those at which service could have been lost to all or parts of its system. To mitigate this risk and respond to the emergency, ConEd activated an LNG facility that it owns and operates. Doing so allowed ConEd to maintain pressures necessary to support its customer deliveries, until pressures on upstream pipelines recovered.

H. The Role of the Marketer

As described in the introduction, any holder of FT capacity is permitted under FERC rules to release all or part of its capacity on a temporary or permanent basis to another party. This business practice created a new, secondary market that helped marketers/intermediaries develop.

With FERC Order No. 637,⁷⁰ several measures were introduced to enable the secondary capacity market to compete better with pipelines and increase the flexibility of the gas market. For example, shippers gained the ability to segment capacity several times and still receive a high scheduling priority when operating within their primary path. Additionally, FERC Order No. 712⁷¹ enabled LDCs to move their gas supply needs to marketers/intermediaries who could maximize the value of that capacity and share the profits with LDCs, while serving other end users like IPPs. This allowed LDCs, with their peak winter needs, to defray some of their sunk capacity costs by releasing their summer capacity to marketers/intermediaries. In turn, marketers optimized released capacity by supplying gas-fired generation more cheaply, offering bundled services (e.g., gas supply, transportation, and storage), and supplying risk-managed products (e.g., fixed-priced bundles with physical balancing and capacity management) to hedge against market volatility or pipeline penalties.

Natural gas marketers act as intermediaries between gas sellers and consumers. Fundamentally, marketers add value to the system by driving competition and providing consumers with choice. Their role may include procurement, sales, transportation management, risk management, and customer service functions. More specifically, marketers enhance the reliability and cost effectiveness of the natural gas market by using a portfolio of assets to move natural gas from oversupplied regions to markets in need. Marketers can also enhance supply reliability by having multiple contractual arrangements with producers. They purchase term or spot supplies, either directly from market sellers or through an exchange. This enables marketers both to provide reliable, low-cost supply for their customers, and also to make a profit as they buy low-cost supplies and move them to higher-value markets for sale in the spot market.

Marketers generally do not own infrastructure but hold a portfolio of pipeline capacity to move supply throughout the country. They might acquire pipeline capacity directly from pipeline owners or from other shippers through the secondary capacity release market, or they might manage capacity held by others through Asset Management Agreements (AMAs).⁷² When purchasing transportation capacity directly from a pipeline owner, marketers review the secondary rights within the contracts to understand which points will receive scheduling priority. When capacity is acquired in the secondary capacity release market or through an AMA, that capacity typically has primary rights to the releasing customer's primary points listed within its contracts. If a marketer cannot change the primary point rights during the term of the release, marketers may have to nominate and schedule gas to flow to secondary points. Nominating to secondary points is generally reliable, except in circumstances where a pipeline must cut secondary point service when, for example, a pipeline is constrained by peak conditions or an operational problem and issues an OFO.

⁷⁰ DOE FERC. "Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services." *Federal Register*, Order No. 637 (February 9, 2000). <https://www.ferc.gov/enforcement-legal/legal/major-orders-regulations/order-no-637>.

⁷¹ DOE FERC. "Promotion of a More Efficient Capacity Release Market." *Federal Register*, Order No. 712 (June 19, 2008). <https://www.ferc.gov/sites/default/files/2020-06/OrderNo.712.pdf>.

⁷² Asset Management Agreements are contractual arrangements where an LDC or utility assigns control of its pipeline transportation and/or storage capacity to a third-party marketer.

In nonpeak periods, marketers have been highly successful at serving both existing customers and IPPs that may choose to rely on spot market purchases. As mentioned, marketers can draw on their portfolio of capacity acquired directly from pipelines, in the secondary market, or through AMAs. Having the flexibility to segment capacity and deliver to alternate/secondary points has been extremely useful for maximizing capacity usage to serve both contracting customers and IPPs. Finally, many pipelines generally have not enforced hourly balancing requirements during nonpeak periods when excess capacity is available, which has helped marketers serve the nonratable hourly flexibility required by IPPs.

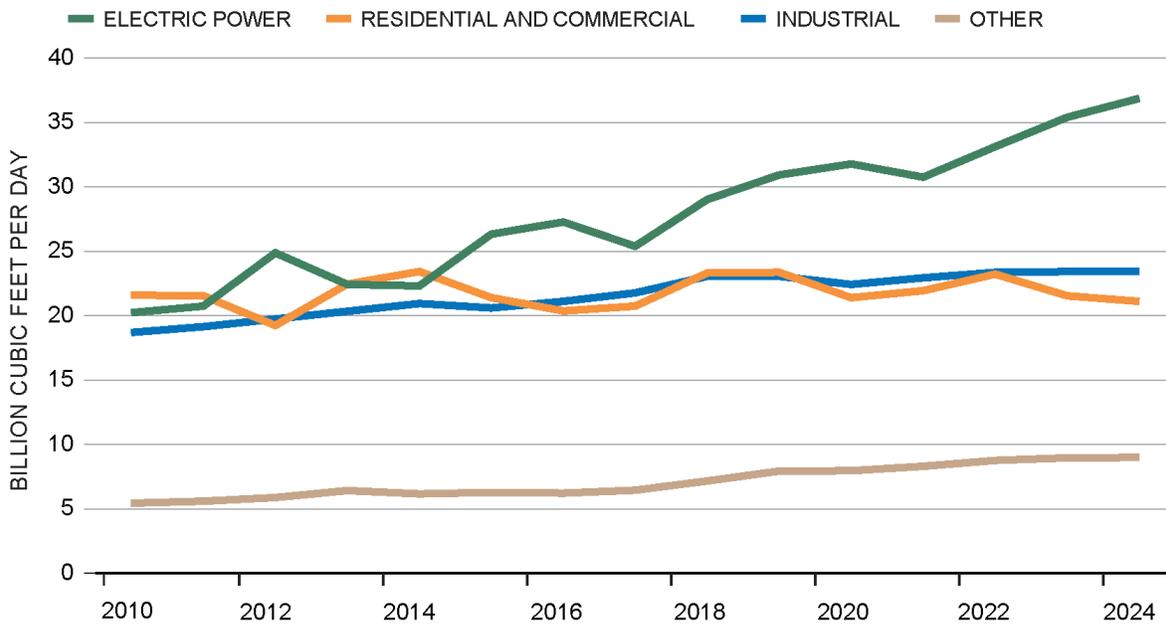
IPPs were able to rely on the secondary capacity market and spot commodity market to serve their gas needs for many years. And, for decades, interstate pipelines reliably operated against the daily rhythm of gas demand from the LDC customers holding FT capacity—the morning ramps, the evening peaks, the overnight lulls. However, it has become increasingly difficult for pipelines to manage intraday variability. To understand why, we need to look at what is changing.

II. WHAT IS CHANGING?

Since the mid-2010s, there have been major changes that have completely altered how our nation's natural gas systems operate. These changes have been driven by advances in technology associated with natural gas production and initiatives to reduce emissions from thermal generators and further incorporate intermittent resources into the energy mix.

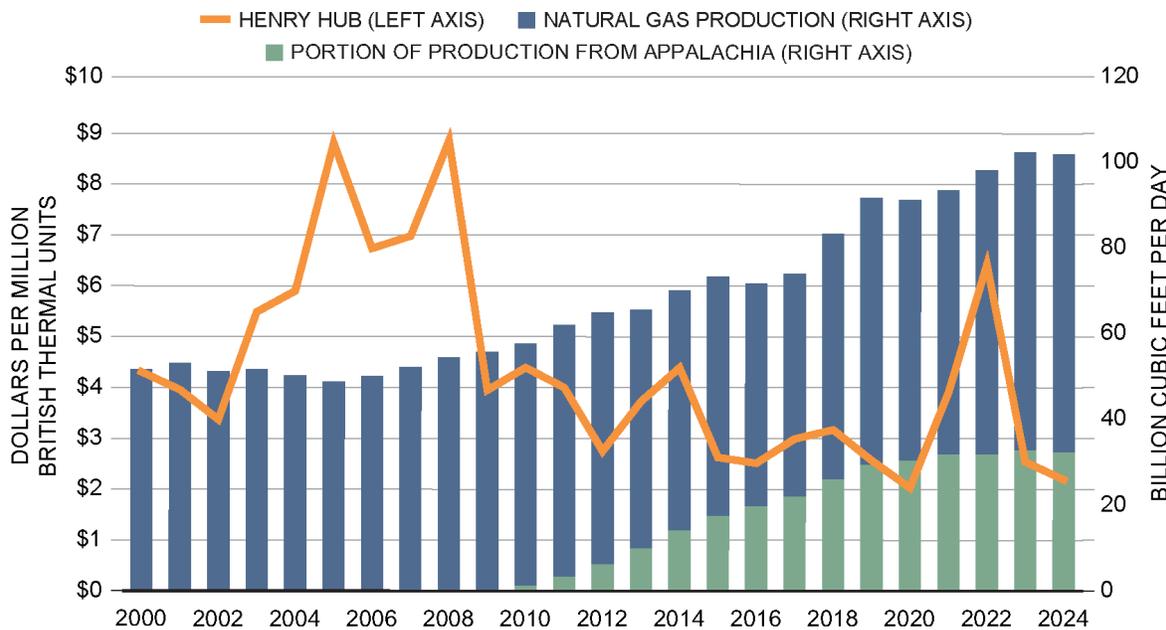
A. A New User Mix

Economic and climate policy tailwinds pushed the electric power sector to compete with LDCs as the nation's largest user of natural gas around the early 2010s, and electric power overtook LDCs in 2015 (Figure 2-5). The economic drivers of this shift were based on technological advancements in both the oil and gas and electric power sectors. Natural gas prices were driven down significantly due to advances in hydraulic fracturing and horizontal drilling, which together unleashed the shale gas revolution that remains prolific today. In the Appalachian region, natural gas production increased from essentially zero in 2009 to over 20 Bcf/d in 2016 (Figure 2-6). Tracking with the dramatic increase in natural gas production brought by the shale gas boom, gas prices at the Henry Hub dropped from nearly \$10/MMBtu in the early 2000s to steadily less than \$5/MMBtu in the mid-2010s (Figure 2-6).



Note: other = natural gas consumed as transportation fuel, as lease and plant fuel, and in pipeline and distribution use.
 Source: Data from EIA. 2025.

Figure 2-5. Natural Gas Consumption by Sector



Source: Data from EIA. 2025.

Figure 2-6. Annual U.S. Natural Gas Production and Natural Gas Prices at Henry Hub

These stable, low natural gas prices, along with emerging decarbonization and climate objectives, drove a surge in coal power plant retirements and coal-to-natural gas plant conversions in the 2010s. This occurred alongside several advancements made to improve efficiencies and economies of scale with the production of natural gas combined cycle power generating units (NGCC). NGCC units are highly efficient and, on average, produce approximately 58% less carbon dioxide emissions per MWh than coal-fired power plants. According to the EIA, more than 100 coal plants were replaced or converted to natural gas plants between 2011 and 2019 (Figure 2-7).⁷³ This being after 192 GW of natural-gas-fired electric generation capacity was added to the U.S. electric grid between 2000 and 2005 due to the advancements in NGCC technology—the fastest buildout of electric capacity in the country’s history.⁷⁴ By 2024, natural gas accounted for 43.5% of the fuel mix for electric generation (Figure 2-8); and the electric power sector has been the largest end user of natural gas in the United States since 2015 (Figure 2-5).⁷⁵

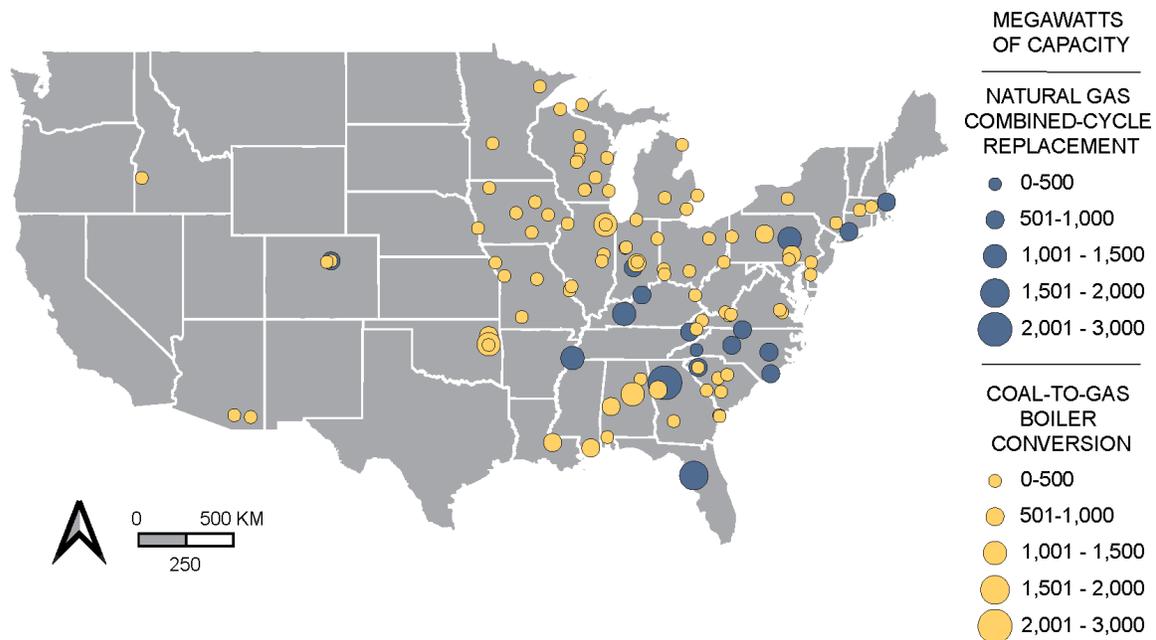
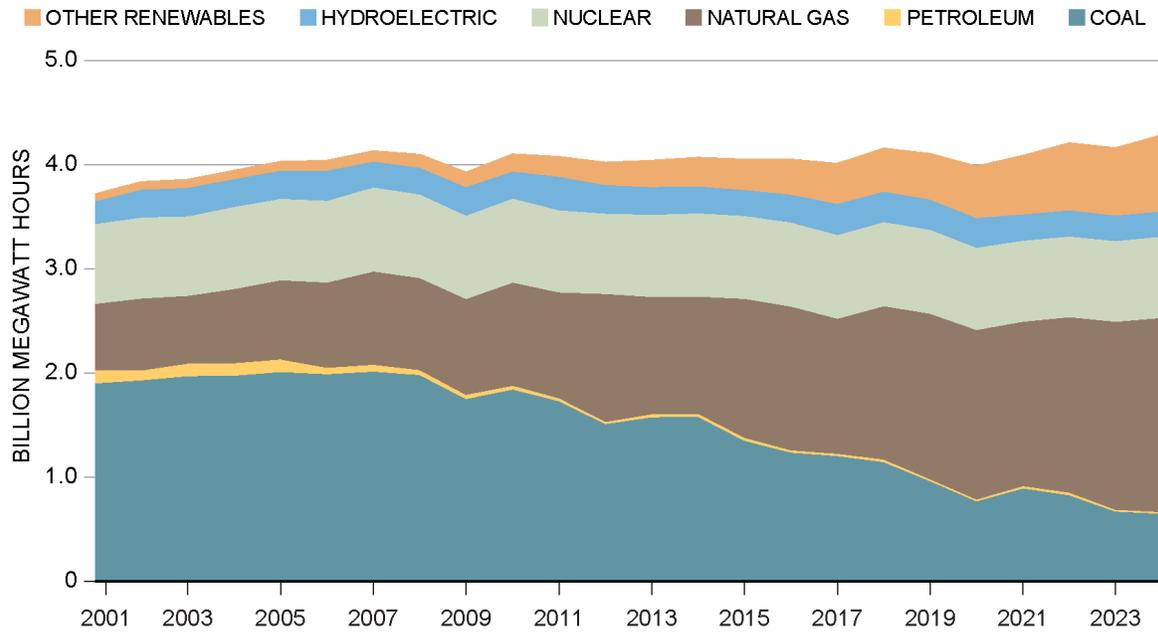


Figure 2-7. U.S. Coal-to-Natural Gas Plant Conversions by Type and Capacity (2011–2019)

⁷³ EIA. “More Than 100 Coal-Fired Plants Have Been Replaced or Converted to Natural Gas Since 2011.” August 5, 2020. <https://www.eia.gov/todayinenergy/detail.php?id=44636>.

⁷⁴ Headwaters Economics. “The Evolution of U.S. Electricity Generation Capacity.” April 22, 2020. <https://headwaterseconomics.org/economic-development/evolution-electricity-generation/>.

⁷⁵ EIA. Electricity Data Browser. n.d. <https://www.eia.gov/electricity/data/browser>.



Source: Data from EIA, 2025.

Figure 2-8. Net Annual U.S. Electricity Generation for All Sectors by Source, 2001–2024

With the massive buildout of gas-fired electric power generation, power generators became significant influencers of interstate pipeline commercial activity and operations, either directly or indirectly. Power generators influence pipeline operations directly if they are themselves shippers on a pipeline, and indirectly if they work through a marketer to secure gas supply and transportation capacity or if they are smaller facilities connected to LDC systems downstream of citygates. This shift is shown on the Transco pipeline where today, power generators and marketers hold 27% and 9% of all FT capacity, respectively. Currently, LDCs hold 44% of the Transco FT capacity, as shown in Figure 2-9, compared to 82% in 2010.

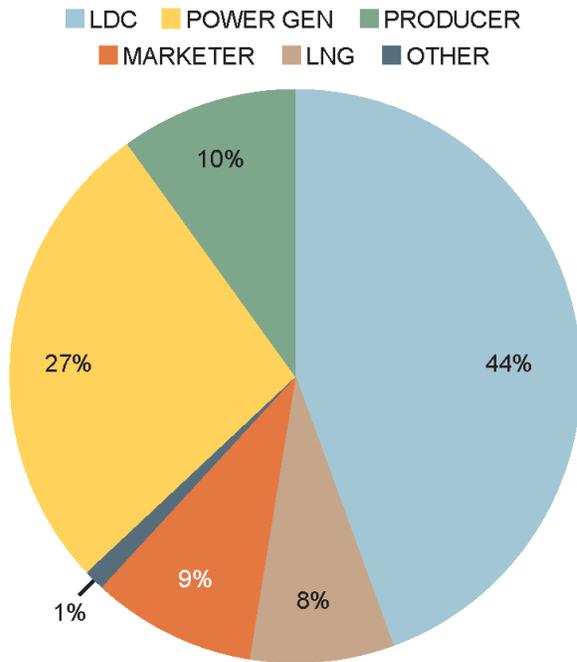


Figure 2-9. Share of FT Capacity by Customer Type on the Transco Pipeline in 2025

While the percentage of power generators subscribing to FT capacity on the Transco pipeline has increased substantially since 2010, that shift is minor compared to the increased utilization of gas-for-power demand overall. This again is because most of the utilization, especially in the deregulated electricity markets, comes from generators receiving their gas from marketers in the secondary markets, or through LDCs. This is especially pronounced on the TETCO and Algonquin systems, where the amount of power generators subscribing to FT capacity has actually decreased since 2010.

Intraday variability in gas demand has increased substantially with the expansion of natural-gas-fueled power generation, reflecting the inherent output fluctuations of both baseload and peaking units. According to the EIA, NGCC units represent about 40% of all baseload thermal capacity. The term baseload can lead to incorrect assumptions about how natural gas fuel is consumed, and it is important to note that baseload does not equal steady state. In addition to their efficiency ratings and low emissions, NGCC units have become the premier choice for new baseload power capacity because of their ability to ramp up or down quickly to balance fluctuations in the electric grid or on site for large energy users. Similarly, nearly all electric power peaking plants currently in service across the United States are fueled by natural gas. Peaking units are critical to maintaining reliability of the electric grid when power demand surges beyond the capacity of baseload units. This is often the case during days of excessive heat, for example, when people and businesses are running air conditioners to maintain comfort.

The problem with electric power now being the largest consumer of natural gas is that its inherent variable nature does not match the traditionally predictable loads on pipelines, their

contracts, and accordingly, their designs. Because balancing and reserve generators run unpredictably, their operations do not align well with traditional pipeline contracts or the storage arrangements needed to support flexible gas service.

Because baseload NGCC units and natural-gas-fired peaking units are specifically engineered and leveraged to respond to electric power demand fluctuations, their usage of natural gas is, by design, highly variable. This variability then, ripples through upstream natural gas infrastructure.

B. Penetration of Intermittent Energy Resources

While coal-to-gas conversions have increased the variability of natural gas demand, the overlapping growth of weather-dependent, intermittent renewable resources along with changing and extreme weather has amplified this effect even further. From 2010 to 2024, wind and solar accounted for more than 60% of new U.S. electric generation capacity. By 2024, they comprised about 22% of total installed capacity nationwide. Wind and solar resources are variable, meaning they cannot provide continuous, controllable power output, and the North American Electric Reliability Corporation (NERC) and EIA classify wind and solar as variable energy resources. Because wind and solar only produce electricity when weather conditions allow, their intermittency is directly reflected in their capacity factor values. Capacity factor is a measure of how much output a generator produces relative to its maximum nameplate capacity per year. Simply stated, it is a measure of how much electricity a resource produces versus what it is capable of producing within a year. A resource with a high-capacity factor is reflective of a unit that runs at high output most of the time. Conversely, a low-capacity factor is indicative of a resource that does not produce power relative to its nameplate capacity value. Wind and solar have lower capacity factors than gas. Table 2-3 shows the installed capacity relative to total capacity, along with capacity factors across the United States and specific to the PJM region.

Technology	U.S. Installed Capacity (GW)	U.S. % of Total Capacity	U.S. Avg. Capacity Factor	PJM Installed Capacity (GW)	PJM % of Total Capacity	PJM Avg. Capacity Factor
Solar (utility scale PV)	113.9	8.6%	24.5%	6.5	3.7%	17%
Wind	141.3	10.6%	35.6%	6.7	3.7%	32%
NGCC	291.6	22.0%	57%	54.3	30.5%	60%

Source: Data from EIA. 2025.

Table 2-3. Installed Capacity and Capacity Factors of Variable Energy Resources and Natural Gas Combined Cycle Power Generation

While the addition of wind and solar may support climate goals, their variable output raises important questions about impacts on overall grid reliability and challenges to natural gas

system stability. In its 2024 Long-Term Reliability Assessment,⁷⁶ NERC discussed these challenges to the bulk power system (BPS), describing natural gas units as providing essential reliability services (ERS):

"As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides."

"Natural-gas-fired generators are a vital BPS resource. They provide ERSs by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand. Natural gas pipeline capacity additions over the past seven years are trending downward, and some areas could experience insufficient pipeline capacity for electric generation during peak periods."

The intermittency of wind and solar reinforces the essential role of natural gas units as dispatchable resources, critical for energy balancing and ensuring the grid can quickly and reliably respond when renewable output declines.

In 2024, PJM published “Energy Transition in PJM: Flexibility for the Future,”⁷⁷ which provided an update to an installment of assessments on how the PJM grid needs to adapt to increasing penetration of intermittent resources and electrification trends. Within the report, PJM states:

"If the gas fleet of today remains as is, or decreases due to regulatory pressures, but additional storage resources do not get built, immense pressure will be placed on natural gas to supply the ramping needs for the system. Changes to market mechanisms must be evaluated to ensure that thermal resources are incentivized to meet evolving system needs."

C. An Emerging Electricity Winter Peak

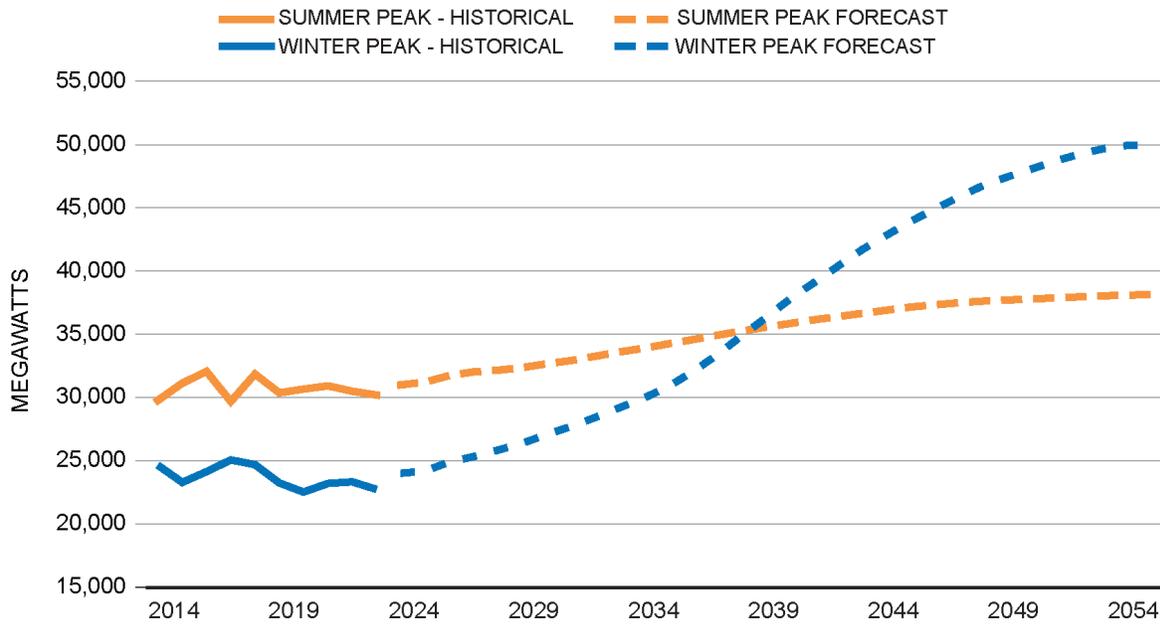
Traditionally, electricity demand in the United States has peaked in the summer months due to widespread air conditioning use by residential and commercial sectors. However, winter peak demand has surged in recent years due to factors such as electrification of heating, increased use of electric vehicles, and extreme cold events. For example, ISO New England (ISO-NE) projects that its seasonal peak electricity demand will shift from summer to winter by

⁷⁶ NERC. “2024 Long-Term Reliability Assessment.” December 2024, updated July 15, 2025. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

⁷⁷ PJM. “Energy Transition in PJM: Flexibility for the Future.” June 24, 2024. <https://www.pjm.com/-/media/DotCom/library/reports-notice/special-reports/2024/20240624-energy-transition-in-pjm-flexibility-for-the-future.pdf>.

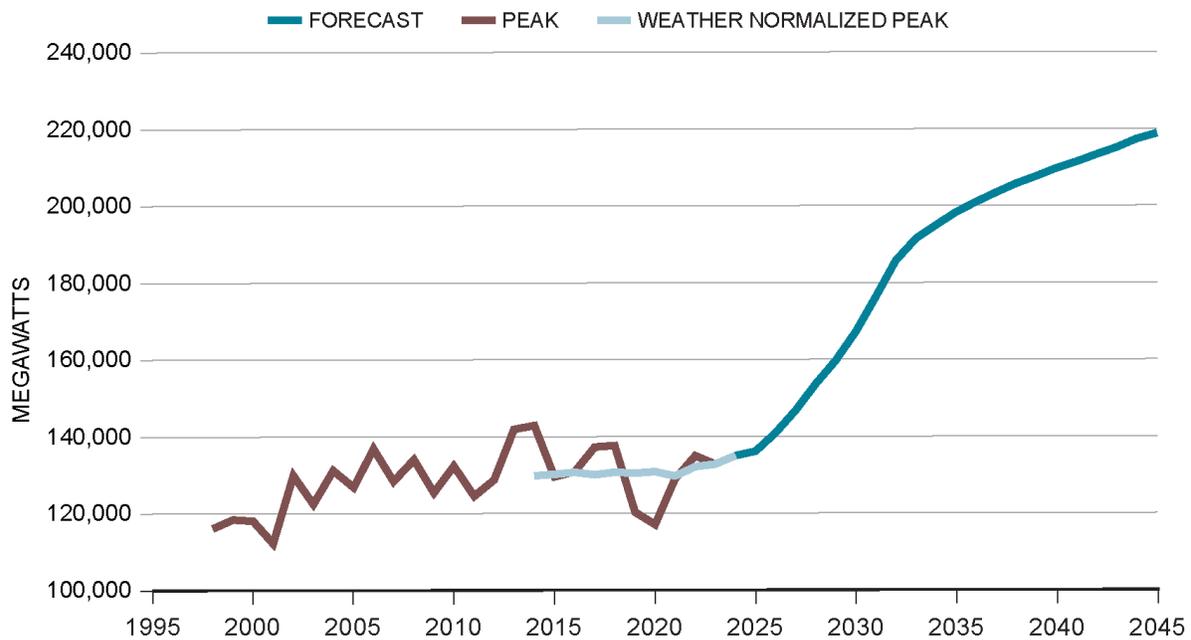
as early as 2035. Additionally, thermal power generating units are seeing a more pronounced demand in the winter because of the penetration of solar energy resources. This is because solar resources produce much less electricity in the winter versus the summer due to shorter daylight hours and a lower sun angle relative to the summer months. Similar to the ISO-NE projection, NYISO forecasts that peak demand for electricity in the winter in the New York Control Area will surpass peak summer demand in the 2030s (Figure 2-10).

Winter demand for electricity is growing fastest in regions with colder climates and more ambitious electrification policies. This is especially pronounced in the Northeast (ISO-NE), Mid-Atlantic (PJM), and Pacific Northwest (BPA, NWPP). Figure 2-11 shows the projected winter peak in the PJM region based on its 2025 forecast, compared to prior winter peaks.



Source: Data from New York ISO, 2024 Gold Book (history) and 2025 Gold Book (forecast). 2025.

Figure 2-10. Seasonal Peak Electricity Demand Comparison in New York Control Area



Source: PJM, 2025.

Figure 2-11. Winter Peak (WN) Forecast in PJM Region

As discussed in the Section I.H in this chapter, IPPs once successfully relied on the secondary market for gas supply and transport when the summer was the only peak season for gas-for-power demand. This worked because LDCs released more capacity in the summer than in the winter, creating a stable dynamic that optimized firm supply and transportation capacity held by the LDCs.

However, the emergence of winter electricity peaks that now rival summer demand undermine IPPs’ ability to rely on the secondary markets due to competition with LDC needs. Marketers have less capacity available through AMAs in winter because they must serve their own peak-season customers. Even when capacity is released, deliveries to IPPs often occur at secondary points, which have lower priorities and may be cut when a pipeline calls an OFO during constrained conditions.

It has also become increasingly difficult for marketers to meet IPPs’ nonratable, flexible flow needs—plants that may run only 8 to 12 hours a day and need quick ramping outside standard nomination cycles. If even available, a marketer may need to hold a greater amount (double or triple) of pipeline capacity to convert steady pipeline supply into variable deliveries, especially when hourly scheduling penalties apply during peaks. In addition, balancing services that once provided flexibility are now less available and often lower priority during winter, increasing the risk to marketers of imbalance penalties.

As discussed in other sections of this chapter, pipelines historically have been able to provide scheduling and balancing flexibility to marketers through the use of their linepack and operational storage to be able to serve the nonratable flow needs of IPPs. But this level of flexibility is becoming less available during peak periods. While marketers are incentivized to

serve spot market purchases, limited pipeline infrastructure makes it increasingly difficult to meet growing seasonal demand.

Changes such as the rapid growth of gas demand for electric power, penetration of intermittent energy resources, and the emergence of a winter electricity demand peak have contributed to ongoing changes in how natural gas units operate within the electric power systems. These changes have altogether altered the operational profiles of natural gas pipelines that were not designed for highly variable operations. Pipeline conditions have shifted from what once were relatively steady, to highly variable both seasonally and intraday. An example of how extreme variable conditions have become can be shown by looking at the Transco pipeline over the Martin Luther King Jr. (MLK) weekend of 2025.

Leading up to the MLK weekend, the Northeast and Mid-Atlantic regions experienced a dramatic drop in temperatures. Early in the week temperatures were relatively mild in these regions, but weather conditions changed rapidly, and accordingly, pipeline conditions rapidly changed as well.

Figure 2-12 shows scheduled deliveries (allocated, green line), actual hourly deliveries (orange line), and linepack levels (hashed black line) between January 15 and 25, 2025. As shown, scheduled deliveries were as low as ~15 Bcf/d on January 18, and as high as more than 19 Bcf/d from January 23 to 24, with scheduled deliveries incrementally stepping up during this period. These incremental increases in scheduled deliveries are manageable and expected in the normal course of operation; however, the actual hourly deliveries were extremely volatile, which is an altogether different challenge. As shown by the orange line, deliveries were higher than 21 Bcf/d in the overnight hours of January 19, dropped sharply to approximately 15 Bcf/d in the midmorning hours of January 20, before jumping back to 20.5 Bcf/d in the early hours of January 21. These extreme swings in deliveries persisted into the following week. While extreme hourly variations can create acute operational challenges, the bigger concern from an overall reliability standpoint is the linepack trend. Figure 2-12 shows that Transco's linepack was volatile during the large hourly delivery swings, but also steadily decreasing. This means that Transco's ability to provide sustained flexibility was also decreasing, unless there was strategically located storage. Furthermore, as Transco's linepack was decreasing, the pressure at all delivery meters, not just power generators, would have also been decreasing. This can be especially concerning for an LDC, as discussed further in Section IV.

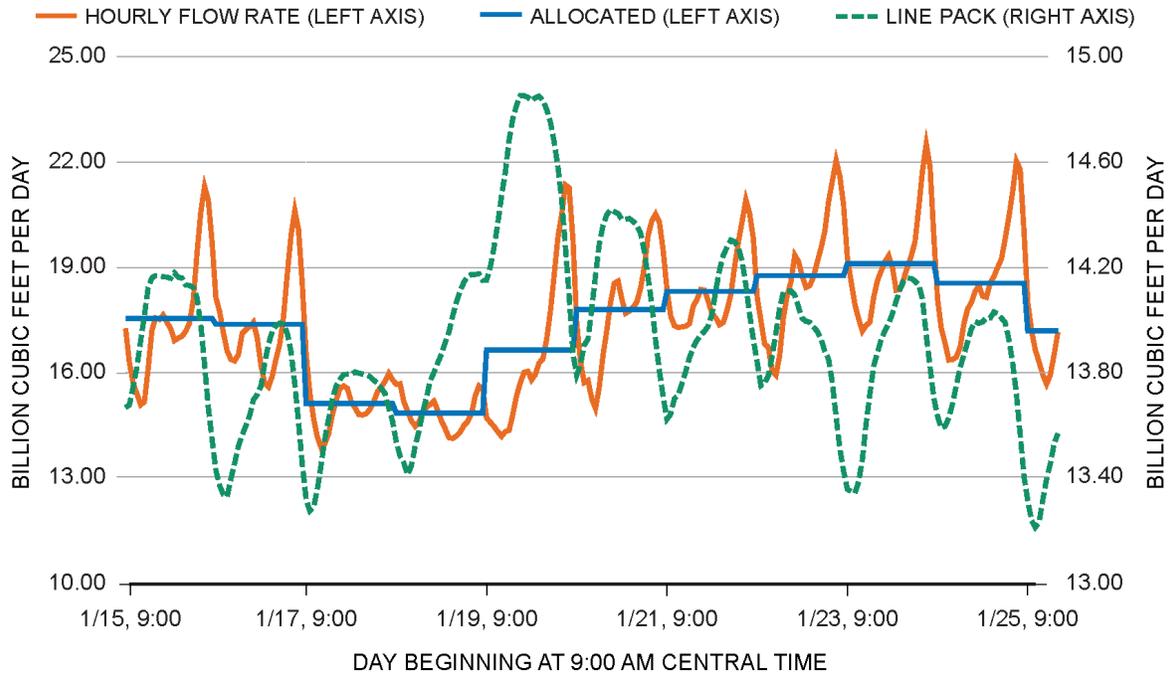


Figure 2-12. Operational Profile of the Transco Pipeline January 15–25, 2025

FINDING 2-1: Pipelines were built for predictable, ratable flows, but customers now require increasingly variable intraday services to meet growing demand and balance the grid as wind and solar generation expand.

FINDING 2-2: Power generators only subscribe to a small portion of pipeline capacity.

FINDING 2-3: The emergence of a winter electricity peak that coincides with local distribution companies' design-day needs has reduced the secondary market's ability to supply independent power producers, limiting their capacity to meet electricity demand with existing infrastructure.

FINDING 2-4: Enhanced pipeline services to complement variable demand are not new, but like traditional firm transportation capacity, are typically only subscribed to by local distribution companies or vertically integrated utilities. Organized electricity markets do not appear to be adequately compensating generators to contract for such services, and additional compensation mechanisms may be required to make enhanced or flexible services commercially viable for generators.

To understand why today's pipelines cannot continue to offer free flexibility to match intraday variability, we also need to understand what is not changing.

III. WHAT IS NOT CHANGING?

A. Pipe in the Ground – Capacity Without Construction

According to the EIA, approximately 44 Bcf/d of interstate natural gas capacity has been added in the United States since 2010.⁷⁸ That about equals the average natural gas consumption for power generation nationwide during peak summer months. It is also enough gas to heat around 160 million homes annually—more than double the total number of U.S. households that use natural gas.

With this level of expansion, one might reasonably assume that the ability of pipeline operators to support variable demand would be increasing, not decreasing. The reasons for this counterintuitive dynamic have to do with where the expansions have occurred, and how.

First, nearly half of this expansion capacity was driven by the growing LNG export industry on the Gulf Coast, which reshaped interstate pipeline flows. Instead of moving gas primarily from Gulf producing basins to markets in the Mid-Atlantic and Northeast, flows increasingly shifted toward the Gulf to meet LNG demand for exports. At the same time, production growth in shale basins such as the Permian (West Texas and eastern New Mexico), Haynesville (Northwest Louisiana and eastern Texas), and Marcellus (Appalachia) positioned these regions as key suppliers for LNG exports.

Second, much of the interstate pipeline capacity expansion since 2010 has come from flow reversals and added compression rather than new greenfield pipelines—a key factor limiting operators’ ability to handle variable demand. Flow reversal projects became common across interstate pipelines in the mid-2010s, driven largely by LNG export demand. These projects typically modified compressor stations so gas could flow opposite the original design—for example, enabling pipelines built to move gas northward toward prominent Northeastern markets to also move it southward. Often, additional compressors were installed to support the reversal.

With the wave of flow reversals, interstate pipelines expanded and shifted from largely unidirectional to bidirectional systems, moving gas from shale basins to new demand markets in the South. However, many of these expansion projects involved only flow reversal and compression, with little to no new greenfield pipe installed to support an expansion (see PJM-specific example in “PJM Infrastructure Challenges”). EIA data (Table 2-4) show that nearly half of interstate pipeline capacity growth between 2010 and 2024 came solely from these modifications.

⁷⁸ EIA. “U.S. Natural Gas Pipeline Projects.” October 31, 2025.
<https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx>.

Period	Reverse Flow/Compression Only	Greenfield Pipe
2010–2017	35%	65%
2018–2021	65%	35%
2022–2023	90%	10%
2024	85%	15%

Source: Data from the EIA. 2024.

Table 2-4. Interstate Natural Gas Pipeline Capacity Expansions Between 2010 and 2024

Returning to the linepack discussion: Because much of the recent capacity expansion came from flow reversals rather than new pipe in the ground, linepack has not kept pace with capacity growth. As a result, pipelines have become less flexible, despite gaining transportation capacity with minimal environmental impact. In short, the ratio of linepack to capacity has declined, reducing operators’ ability to balance intraday variability. This dynamic is true for both the TETCO and Transco pipelines, as shown in Figures 2-13 and 2-14, respectively, which illustrate how the maximum daily quantity (MDQ) has grown with expansion projects, compared to linepack. MDQ refers to the maximum volume of natural gas that shippers are contractually entitled to transport on a given day, based on FT contracts.

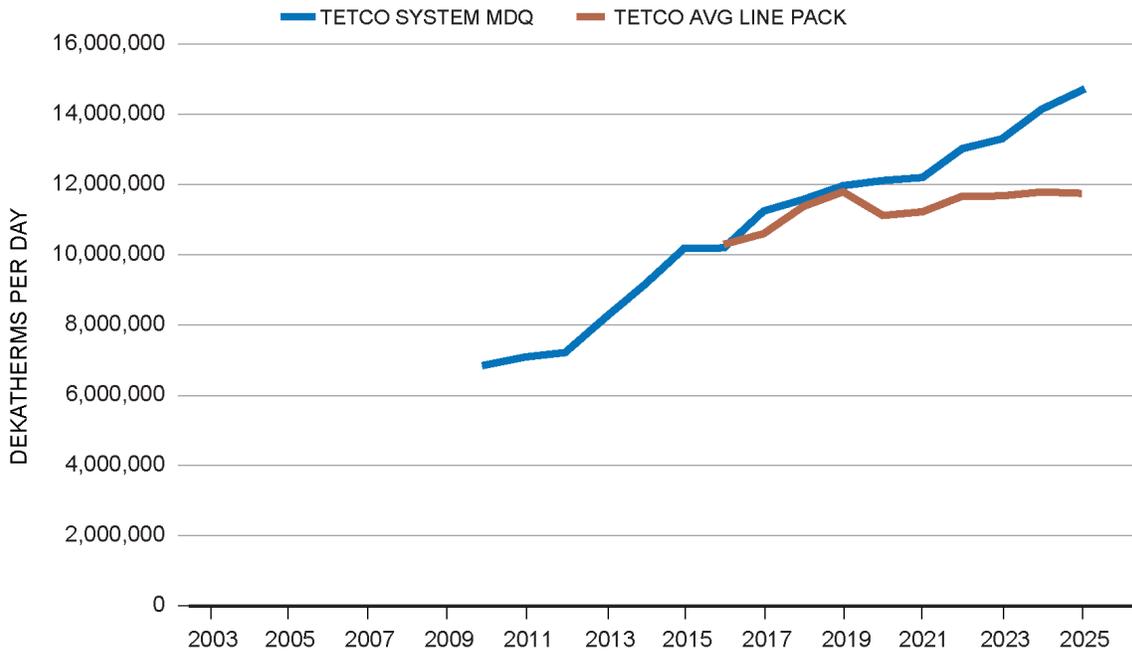


Figure 2-13. TETCO Pipeline Maximum Daily Quantity (MDQ) vs. Linepack

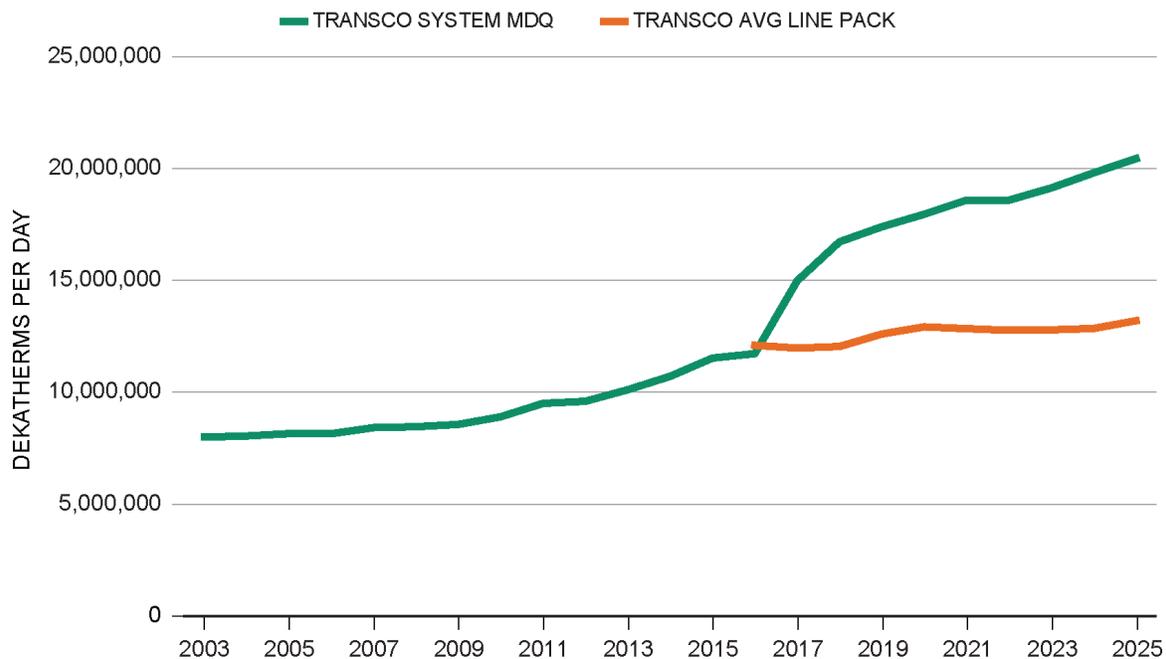


Figure 2-14. Transco Pipeline MDQ vs. Linepack

With linepack levels staying stagnant while capacity has increased, interstate pipelines can no longer manage variability with linepack alone. And, due to the fact that pipelines are only designed to meet delivery commitments to FT customers under peak conditions via ratable deliveries, FT alone will not be a viable solution to serve the electric power generation industry. Conditions are signaling a need for nontraditional (enhanced) transportation services, specifically tailored for those natural gas users with variable demand, and storage must be the backstop to such types of services. Unfortunately, another factor that is not changing is the diversity of shippers using flexible pipeline services.

PJM Infrastructure Challenges

PJM’s 2025 long-term (20-year) forecast shows a significant increase in demand, with the summer peak increasing by 3.1% per year and winter peak increasing by 3.8% per year. Much of this new demand is tied to the location of data centers, meaning growth will vary regionally.^a

On the supply side, PJM expects an acceleration of thermal resource retirements and a queue dominated by renewables (~94%) with only ~6% gas.^b PJM finds that near-term reliability through 2030–2035 will likely require some new gas capacity, depending on how quickly renewables resources and storage are connected to the grid.^c In some projections, gas plants run more in certain seasons to cover retirements, but overall gas use falls. These forecasts

lead to peaky, location-specific gas needs—which will require greater firm deliverability and storage withdrawal at winter/summer peaks—even if annual totals remain moderate.^d

The Appalachia Region—Marcellus and Utica shales in Pennsylvania, West Virginia, and Ohio—supplied about 31% of U.S. marketed natural gas in 2024 (~36 Bcf/d).^e Recent production growth has slowed, shown in the Figure 2-15, not for lack of resources, but because pipeline takeaway to demand centers has periodically been the binding constraint, especially during winter peaks when pipes run full and prices differences widen between producing areas and Mid-Atlantic load pockets.^{f, g, h}

In 2024, the U.S. added ~6,500 MMcf/d of new pipeline capacity in producing regions,ⁱ including projects that materially improved Appalachia-to-Mid-Atlantic deliverability for PJM:

- Mountain Valley Pipeline (~2,000 MMcf/d) began service in June 2024, carrying northern West Virginia gas to the Transco pipeline in Virginia—creating additional southbound and eastbound paths that can serve Virginia/Maryland/D.C. and PJM-adjacent demand.^j
- Transco’s Regional Energy Access (~829 MMcf/d) adds loops and compression to move northeastern Pennsylvania gas into New Jersey/Mid-Atlantic markets—supporting winter heating and power generation in PJM-served areas such as Public Service Electric & Gas, Jersey Central Power & Light, and Philadelphia/PPL zones.^{k, l}

Several smaller or phased projects improved local deliverability near PJM load pockets as well:

- Tennessee Gas Pipeline East 300 Upgrade (~115 MMcf/d) added compressor horsepower in PA/NJ (FERC docket CP20-493).^{m, n}
- Adelpia Gateway converted an oil line to gas service with capability up to ~850 MMcf/d into the greater Philadelphia area—relevant for Philadelphia/PPL load.^{o, p}

In summary, Mountain Valley Pipeline and Transco’s Regional Energy Access relieve prior takeaway bottlenecks by opening more capacity into Transco Zones 5 and 6 and related laterals. However, how quickly new pipeline proposals can commence construction remains to be seen.

Notes:

^a. PJM Interconnection. “2025 PJM Long-Term Load Forecast Report.” January 24, 2025. <https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf>.

^b. PJM Interconnection. “Energy Transition in PJM: Resource Retirements, Replacements & Risks.” February 24, 2023. <https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx>.

^c. PJM Interconnection. “Energy Transition in PJM: Resource Retirements, Replacements & Risks.” February 24, 2023. <https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx>.

^d. PJM Interconnection. “Energy Transition in PJM: Resource Retirements, Replacements & Risks.” February 24, 2023. <https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx>.

^e Ikonnikova, S., Smye, K., Browning, J., Dommissie, R., Gülen, G., Hamlin, S., Tinker, S. W., Male, F., McDaid, G., Vankov, E. “Report on Update and Enhancement of Shale Gas Outlooks.” 2018. DOE Technical Report, <http://doi.org/10.2172/1479289>.

^f EIA. “U.S. Natural Gas Production Remained Flat in 2024.” April 17, 2025. (States Appalachia produced 31% or 35.6 Bcf/d of U.S. marketed gas in 2024; growth constrained by takeaway.) <https://www.eia.gov/todayinenergy/detail.php?id=65025>.

^g EIA. “Rig Declines Limit Appalachia’s Marketed Natural Gas Production Growth.” March 10, 2025. <https://www.eia.gov/todayinenergy/detail.php?id=64664>.

^h EIA. “Drilling Productivity Report—Full Report (regional production data; Appalachia).” May 2024. <https://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf>.

ⁱ EIA. “Natural Gas Pipeline Project Completions Increase Takeaway Capacity in Producing Regions.” March 17, 2025. <https://www.eia.gov/todayinenergy/detail.php?id=64744>.

^j EIA. “Natural Gas Pipeline Project Completions Increase Takeaway Capacity in Producing Regions.” March 17, 2025. <https://www.eia.gov/todayinenergy/detail.php?id=64744>.

^k Reuters. “U.S. Reinstates Certificate for Williams’ Transco Pipeline’s Expansion Project.” January 27, 2025. <https://www.reuters.com/business/energy/us-reinstates-certificate-williams-transco-pipelines-expansion-project-2025-01-27/>.

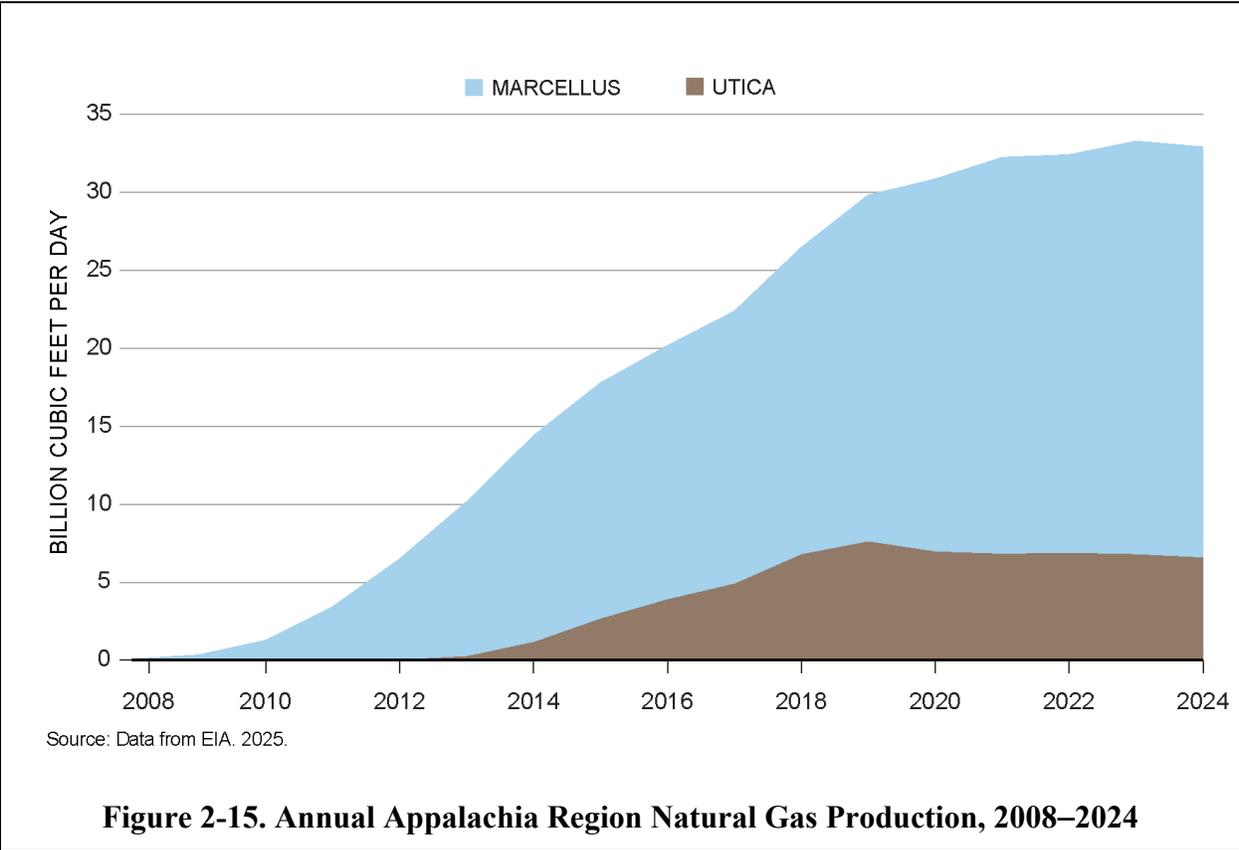
^l Williams (Transcontinental Gas Pipe Line). “FERC Reinstates Certificate for Transco’s Regional Energy Access Expansion.” News Release, January 27, 2025. <https://investor.williams.com/news-releases/news-release-details/ferc-reinstates-certificate-transcos-regional-energy-access>.

^m FERC. “Tennessee Gas Pipeline Company, L.L.C.; Notice of Availability of the Final Environmental Impact Statement (East 300 Upgrade Project, CP20-493-000).” *Federal Register*, Sept. 30, 2021. <https://www.federalregister.gov/documents/2021/09/30/2021-21265/tennessee-gas-pipeline-company-llc-notice-of-availability-of-the-final-environmental-impact>.

ⁿ Kinder Morgan—Tennessee Gas Pipeline. “East 300 Upgrade Project—Project Information/FAQs.” (Project capacity ~115 MMcf/d.) Accessed August 13, 2025. <https://www.federalregister.gov/documents/2021/07/09/2021-14625/tennessee-gas-pipeline-company-llc-notice-of-availability-of-the-draft-environmental-impact?>

^o New Jersey Resources (NJR) Midstream. “Our Midstream Investments—Adelphia Gateway (up to 0.85 Bcf/d).” Accessed August 13, 2025. <https://www.njresources.com/njrmidstream/index.aspx>.

^p Adelphia Gateway LLC. “Adelphia Gateway Project—System Overview.” Accessed August 13, 2025. <https://www.adelphiagateway.com/>.



B. The Mix of Enhanced Service Customers

As described in Section I.C, pipelines have a history of offering types of transportation services specifically established to provide flexibility to customers who have variable gas demands. Because enhanced services are not new market products, one might assume that the growth of natural gas demand for power generation sparked a corresponding growth of subscribers to enhanced pipeline transportation services. That is not the case, as demonstrated by Enbridge’s TETCO and Algonquin pipelines, both of which offer a no-notice transportation service. Table 2-5 shows that almost all no-notice service is, and has been, subscribed to by LDCs.

Pipeline	Year	Shipper Type			
		LDC	Marketer	Other	Power Plant
TETCO	2010	98.7%	0.5%	0.8%	0%
TETCO	2025	97.7%	1.6%	0.8%	0%
Algonquin	2010	100%	0%	0%	0%
Algonquin	2025	100%	0%	0%	0%

Table 2-5. Mix of Subscribers to Enhanced Services on TETCO and Algonquin Pipelines

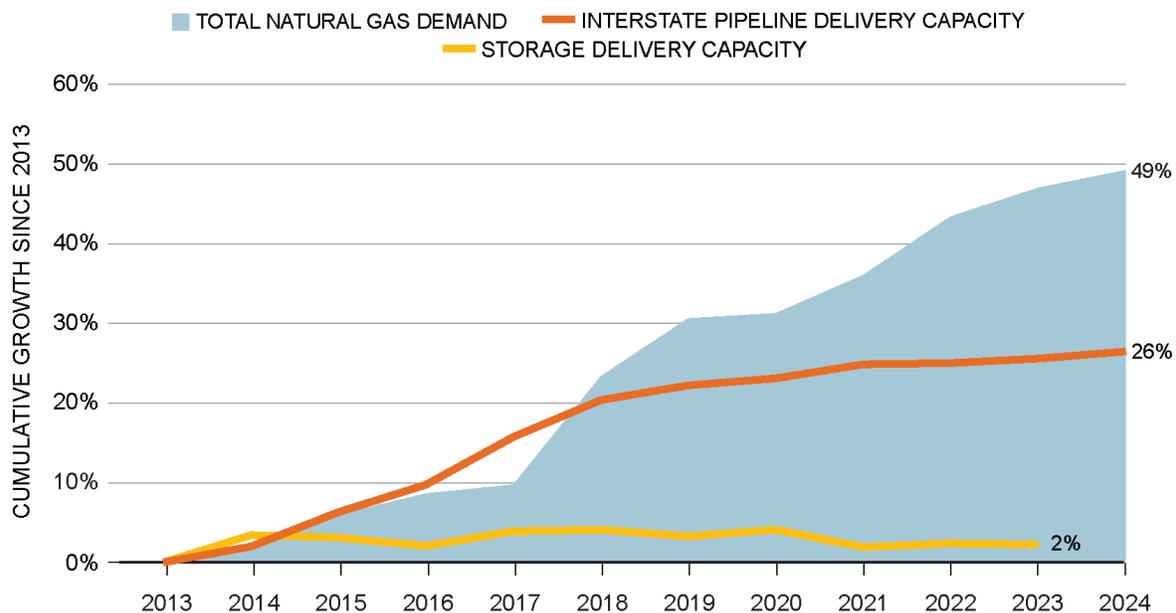
Unlike the TETCO and Algonquin pipelines, Transco does not have an enhanced service that specifically offers no-notice or hourly balancing as a premium to its traditional FT. Through its tariff, any holder of FT capacity on Transco can realize no-notice delivery (swing service) of volumes greater than scheduled quantities to Swing Service Delivery Points. A Swing Service Delivery Point is a gas delivery location where volumes can fluctuate within a contracted range, allowing the buyer—an LDC, municipality, industrial customer, or a power generator—to “swing” gas takes up or down based on changing demand. Swing service was historically offered by Transco to primarily support unexpected supply and demand fluctuations by LDCs, to afford some flexibility if conditions allowed.

It is important to highlight the “if conditions allowed” statement above, as Transco may limit or disallow swing service in its sole discretion, based on operating conditions. This is further discussed in Section IV.

Because linepack decreases as pipeline utilization increases, any new developments of enhanced services need to be accompanied by gas storage. Development of gas storage, however, is another factor that is not changing in a meaningful way.

C. Storage Development

Figure 2-16 shows that since 2013, natural gas storage delivery capacity has only grown by 2% as compared to natural gas demand and interstate pipeline capacity, which have grown in that time by more than 40% and 25%, respectively.



Note: 2023 is the most current data for storage delivery capacity.
Source: Data from EIA. 2025.

Figure 2-16 Storage Delivery Capacity Compared to Pipeline Delivery Capacity and Gas Demand

Most storage infrastructure predates 1990, with incremental development from 2000 to the early 2010s driven by seasonal price spreads and limited nationwide natural gas production during this period. Storing gas in off-peak seasons and withdrawing in winter helped meet LDC peak demand. For example, in 2005, Henry Hub spot prices in December were as much as nearly \$6/MMBtu higher than they were in March. But the shale boom that began in the mid-2010s sharply lowered natural gas prices and narrowed seasonal spreads. By 2015, the spring-to-winter spread had fallen to less than \$1/MMBtu, triggering a five-year average seasonal spread of only \$0.36/MMBtu.⁷⁹ Accordingly, the intrinsic value of gas storage dropped from the mid-2010s to the early 2020s. But that has subsequently changed again. Seasonal price spreads for natural gas have grown in recent years, with values regularly surpassing \$1.05/MMBtu. These widening spreads risk winter premiums and highlight the strategic value of gas storage in today's growing market.⁸⁰

Growth in LNG exports continues to drive storage demand as operators must effectively manage supply fluctuations and navigate operational uncertainties. For example, several new storage projects in the Gulf Coast region are being permitted or have been put in service in recent years as demand for storage has increased in that region, primarily from the growth in the LNG market. Simultaneously, utilities within vertically integrated electricity markets are leveraging gas storage to support grid reliability amid rising winter peak-day demand, fuel assurance risks, and intermittent resources. This is not the case, however, in all electricity markets.

Recent extreme weather, such as Winter Storm Uri in 2021 and Winter Storm Elliott in 2022, has pushed annualized short-term price volatility above 100%, suggesting natural gas storage as a possible hedge against market and operational risk.

Elevated spreads provide the price signal and increasingly volatile conditions on pipelines provide the operational signal to justify renewed capital investment in the expansion of storage infrastructure. However, new storage projects must be the right type and strategically located in order to serve customers needing flexibility (see discussion in Section I.G). Because most of the recent, minimal storage development has occurred near the Gulf Coast, it will not be sufficient to support the need for power resources that can quickly come online in response to operator dispatch signals in power system operations.

FINDING 2-5: Recent pipeline expansions—implemented mainly through flow reversals and added compression rather than new pipelines—highlight the need to address challenges between pipeline capabilities and increasingly variable demand.

FINDING 2-6: Traditional FT services will not solve the problem of increasing variable demand for gas by the electric power sector.

⁷⁹ EIA. “Natural Gas Summary.” October 31, 2025. https://www.eia.gov/dnav/ng/ng_sum_lsum_a_epg0_sac_mmc_f_m.htm.

⁸⁰ EIA. “Annual Energy Outlook 2023.” May 23, 2023. https://www.eia.gov/outlooks/aeo/IIF_LNG/.

FINDING 2-7: Enhanced pipeline services to complement variable demand are not new, but like traditional FT capacity, are typically only subscribed to by LDCs or vertically integrated utilities.

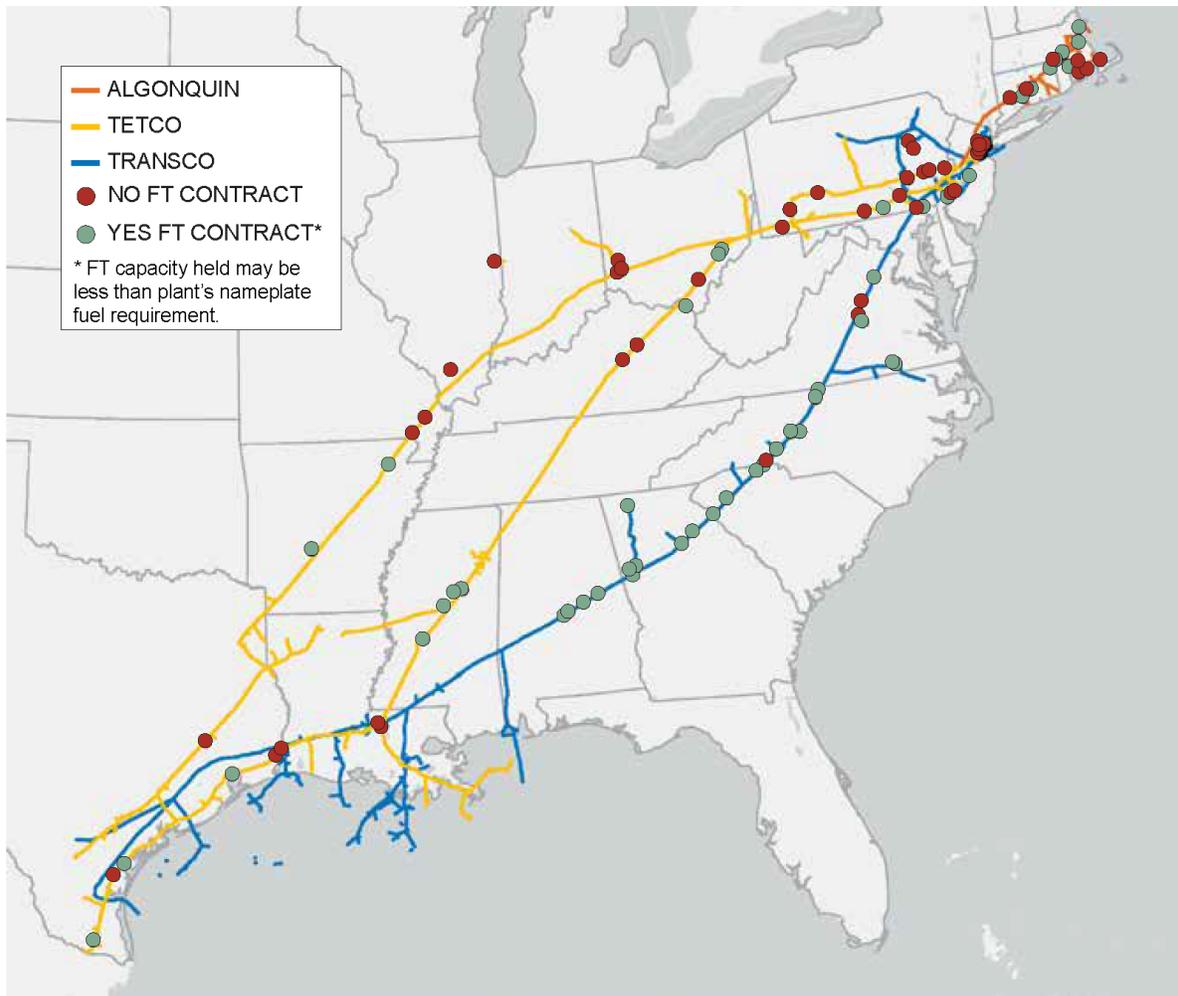
In summary, pipelines are increasingly required to accommodate variable gas demand—even as their flexibility has declined and storage capacity stagnated. The reasons why it matters are not just academic, but critical for supporting the increasing interdependence of our gas and electric power systems.

IV. WHY DOES THIS MATTER?

A. Protecting FT Holders and Threats to Independent Power Producers

Together, the Transco, TETCO, and Algonquin pipelines have more than 110 natural-gas-fired power generators directly connected to them. When accounting for the additional power generators relying on these pipelines indirectly through an LDC, these three pipelines clearly illustrate the vast scale of natural gas demand for power generation. Based on the number of power generators directly connected to these pipelines, one might assume that the natural gas and electric power markets must be highly aligned—where growing demand drives infrastructure investment and elicits a timely market response. Unfortunately, that is not the case.

On the Transco pipeline, approximately 80% of the directly connected power generators hold some degree of mainline FT capacity, but it should be noted that in many instances, the amount of FT capacity held is far less than the equivalent needed to satisfy a plant's nameplate. However, within the PJM region, for example, that number drops to approximately 50%. Outside the PJM region—in North Carolina, South Carolina, and Georgia—where the states allow integration of power generation and transmission bundled under a single utility, 96% of Transco's directly connected power generators hold FT capacity on the mainline. These regional differences are also pronounced across the TETCO and Algonquin pipeline systems, where approximately 30% of the directly connected power plants hold mainline FT capacity within the PJM, ISO-NE, and NYISO regions (Figure 2-17).



Note: All data presented in this map has been sourced from ESRI and Rextag. The basemap and state boundaries are ESRI data resources. The power plants and all pipeline data are Rextag data resources.
 Source: Data from Enbridge and Williams Companies. 2025.

Figure 2-17. Directly Connected Power Generators on Algonquin, TETCO, and Transco Pipelines

This matters because most gas-fired power generators in deregulated markets lack FT capacity and rely on secondary points within another shipper’s FT path. Pipelines are only designed to meet peak capacity at primary points, so under constrained conditions with declining flexibility, pipeline operators have few options to protect the integrity of the pipeline system and honor the contractual rights of customers who have subscribed to FT capacity. That leaves secondary users, such as many IPPs, at risk of curtailment as pipelines are forced to limit the flexibility of deliveries to secondary points. Since swing service is only available under optimal conditions on Transco, actions such as limiting no-notice activity to only primary firm points is a likely outcome if solutions are not implemented to relieve the stress on pipelines during high-demand periods. This presents a threat to the reliability of the bulk power system in deregulated electricity markets, where almost all the power plants connected to a pipeline are associated with secondary points. To appreciate the significance of the threat, look at pipeline utilization compared to contracted capacity. Figures 2-18 and 2-19 show that, over the past three years on

Enbridge's TETCO and Algonquin pipelines, power generators' winter peak loads were eight and six times greater, respectively, than their contracted mainline capacity. This disparity is even more stark in the summer peaks. As conditions on pipelines become more constrained, the ability of power generators to rely on gas being scheduled to secondary points will continue to wane.

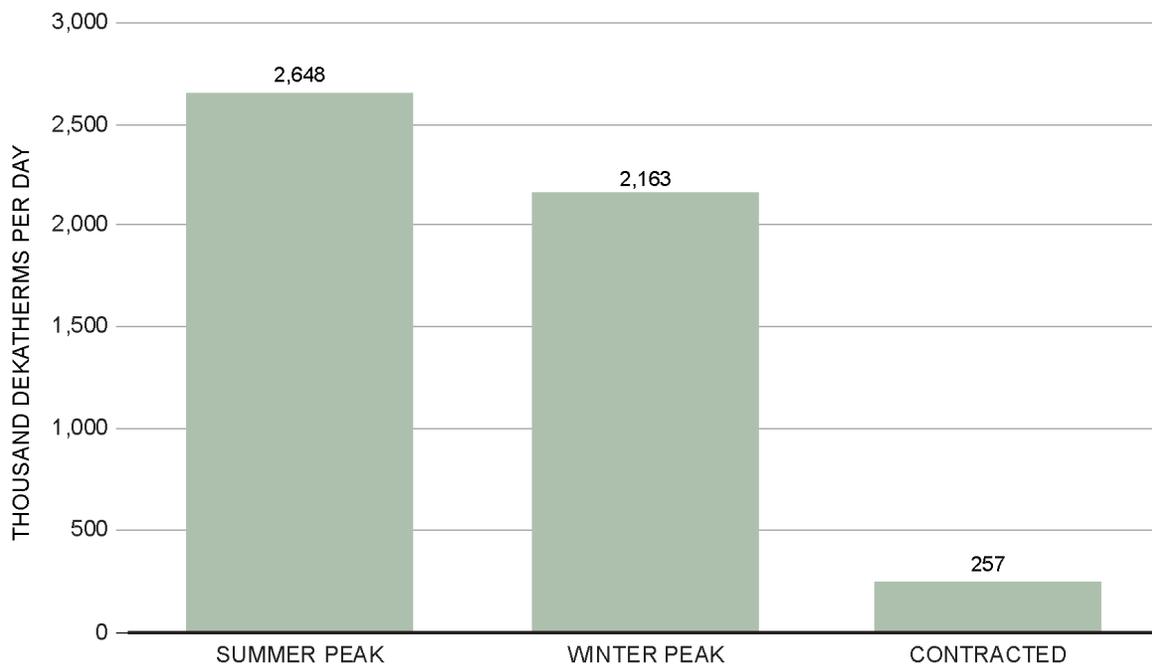


Figure 2-18. TETCO Peak Demand Over the Past Three Years vs. Firm Contracted Capacity

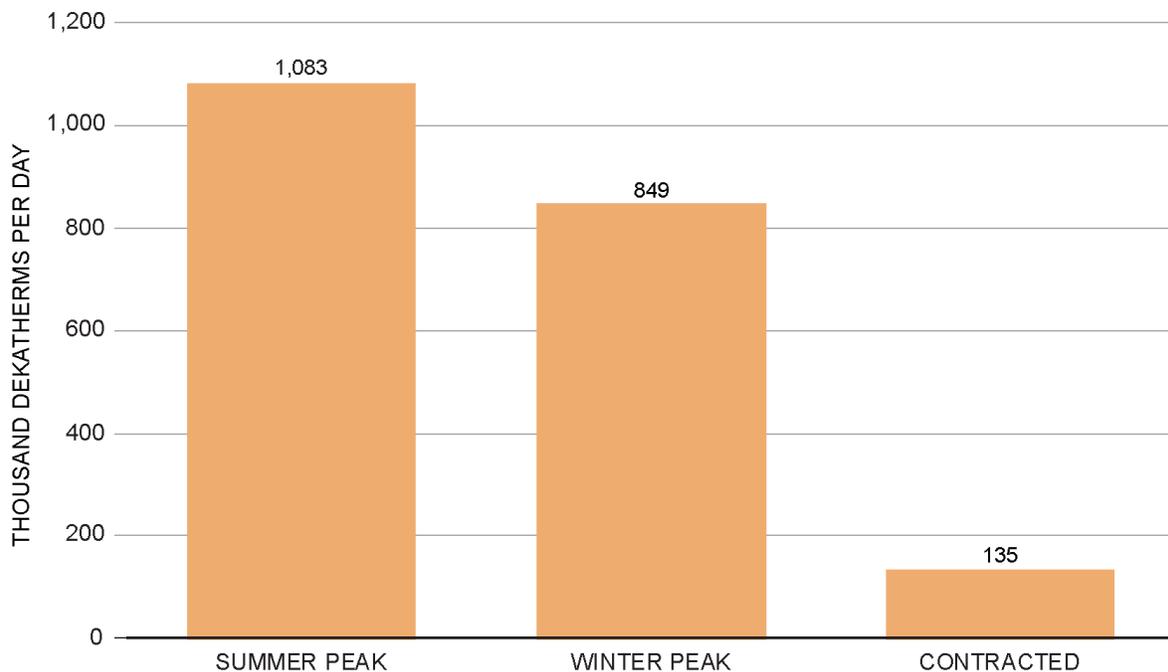


Figure 2-19. Algonquin Peak Demand Over the Past Three Years vs. Firm Contracted Capacity

In addition to an increasing likelihood of limiting flexibility, pipelines such as TETCO and Algonquin will likely need to begin reducing hourly flexibility under their no-notice services, during constrained conditions. In fact, due to some recent maintenance outages on Algonquin’s system, the pipeline has begun issuing hourly OFOs for the first time in recent history. These hourly OFOs are a prime example of a decrease in system flexibility when the system is at or near capacity. As a result, pipelines may require power generators to reduce unratable gas usage and consume gas more evenly—closer to 1/24th of their scheduled daily quantity each hour—to align with how the system was designed to operate. This means that customers like LDCs—who pay for flexibility—risk losing such flexibility when conditions on pipelines are strained by users without firm or enhanced services.

As peak demand continues to increase on pipelines like TETCO, Algonquin, and Transco, an alternative, do-nothing approach compromises reliability to more than just the electric power sector. If solutions are not implemented and conditions are left as is, volatility will continue to increase on pipelines, and the entire natural gas value chain is at risk of reliability impacts.

B. Threats to LDCs

As intraday deliveries become increasingly variable on pipelines, so too does their linepack. Since linepack levels directly correlate to delivery pressures at all delivery points, LDCs are directly impacted by fluctuations of interstate pipeline pressures. Small fluctuations in delivery pressures are part of the normal course of operations; however, the wildly variable loads

being driven by power generators (often occurring on near-peak design days) will inevitably impact LDC reliability if not mitigated.

An example and granular view of this problem is shown in Figure 2-20. This example shows the delivery profile versus scheduled quantities of a single power plant connected to the Transco pipeline in the PJM region, on June 23, 2025, which was a summer peak day on Transco. The power plant in this example does not hold FT on Transco, nor is it a primary, firm delivery point on any other party’s FT contract.

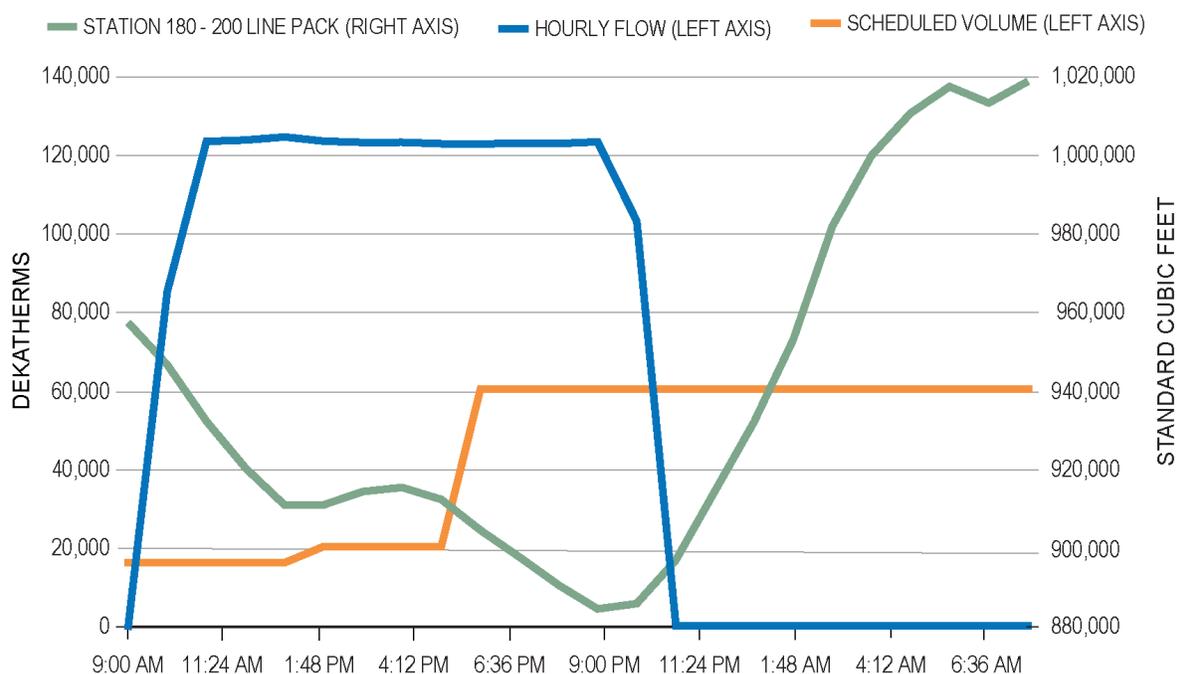


Figure 2-20. Transco Zone 5 Power Plant Delivery Profile vs. Scheduled Volume and Linepack on June 23, 2025

Figure 2-20 shows that over the first seven hours of the June 23 gas day, the power generator was taking between 500% and 700% of its scheduled volume on a per-day basis. The increase in scheduled volumes during the early evening hours reflect an intraday nomination change; however, even after increasing the scheduled quantity, the plant continued to take more than 100% of its scheduled quantity on a per-day basis, for an additional four to five hours, until it ceased flow altogether. The green line shows what was happening to Transco’s linepack in this area over the same time period. While it should be noted that the drop and rise in linepack was not solely a function of this one power plant’s delivery profile, it is representative of how pipeline pressure is immediately impacted by an IPP taking gas nonratably at a particular delivery point. The green line, therefore, represents the extreme variability in delivery pressures that would be realized at all delivery points in this area, including LDCs. As established in this report, highly variable conditions on a pipeline compromise the ability of a pipeline operator to meet scheduled gas deliveries to FT customers such as LDCs, and as a result, a pipeline may be required to credit back demand charges paid by the LDCs during an underperformance period.

However, the commercial costs to a pipeline of not fulfilling a contractual commitment to an LDC are minor compared to the physical risks faced by the LDCs when pipeline conditions are volatile. Low delivery pressures on interstate pipelines pose a serious risk to LDCs by undermining their ability to reliably serve end users. When pipeline pressures drop to below contract or design specifications, LDCs may be unable to receive their full scheduled gas volumes, putting residential, commercial, and critical infrastructure customers at risk of supply shortfalls or outright service interruptions, which can result in time-consuming and expensive processes to restore services.

An example of this is well documented within the joint FERC and NERC report issued upon their inquiry into the performance of the bulk power system during Winter Storm Elliott of 2022.⁸¹ The report includes a section titled “Reliability-Threatening Delivery Pressure Decreases at Major Natural Gas LDC Citygate,” and describes delivery pressures reaching such alarmingly low pressures at the ConEd citygate that it had to take emergency actions and activate its backup LNG facility in an attempt to preserve pressures at levels needed to avoid service outages to its customers. While freeze-offs of natural gas production impacted supply into interstate pipelines, the report acknowledged, “A likely contributing factor exacerbating pipelines’ integrity issues was that some generators may have flowed in excess amounts over their confirmed nominations.” The report goes on to discuss potential impacts if pipeline pressures did not recover, stating service to natural gas customers “would have taken months to restore, even with mutual assistance.”

Following an electric power outage, electric utilities can often restore thousands of customers within minutes or hours by reenergizing circuits once hazards are removed. However, natural gas service restoration by LDCs involves manual and sequential steps, such as shutting off and securing individual meters, making safety checks, and visiting each property to relight appliances once isolated meters are placed back into service. Depending on the scale of a natural gas outage, restoration costs realized by an LDC can be substantial, not to mention the additional hidden costs seen by their customers in the form of lost revenue for restaurants, manufacturers, and others. These costs are minimal in comparison to the human health and safety risks associated with an LDC outage leaving people without their primary heating source.

In the NERC 2024, “Long-Term Reliability Assessment,” NERC noted that the “North American Bulk Power System faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement,” and while “new solar PV, battery, and hybrid resources continue to flood interconnection queues ... completion rates are lagging behind the need for new generation. Additionally, NERC notes that “the performance of these replacement resources is more variable and weather dependent than the generators they are replacing.”⁸²

⁸¹ FERC. “FERC, NERC Release Final Report on Lessons from Winter Storm Elliott.” November 7, 2023. <https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott>.

⁸² NERC. “2024 Long-Term Reliability Assessment.” December 2024. Updated July 15, 2025. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

To address these and other concerns resulting from the increased interdependence of the markets, NERC is developing an Electricity-Natural Gas Strategy that will be incorporated into its Risk Framework and annual Work Plan Priorities. Specifically, the current strategy has identified four key reliability risks resulting from the growing interdependence: natural gas supply and transportation, electric and gas market harmonization, resource adequacy and capacity to support large intermittency in load and resources, and vulnerabilities in generator winterization. Specifically related to intermittency, it was noted that, “extreme cold can cause sharp increases in electricity demand during the morning and evening hours, requiring generation resources to ramp up quickly,” and “natural gas power plants that are ill-prepared for rapid ramping may fail to secure fuel in real-time conditions.”

Further exacerbating the issue is the projected load growth over the next several years. The EIA estimates that total power demand will increase by approximately 5% by 2030 as compared to 2025 levels. By 2030, it is estimated that peak summer and winter electricity demand will increase by 5.4% and 7.7%, respectively. The EIA estimates that total power demand will increase by approximately 50% by 2050⁸³.

In summary, natural gas has transitioned from an energy resource that historically supported relatively stable and predictable demands from the LDC sector to the most critical energy resource in balancing the highly variable electric power grid. The infrastructure that connects natural gas to this growing demand center—our nation’s interstate natural gas pipeline network—is not designed for these variable conditions, and reliability impacts will soon occur if not addressed. This is especially concerning in regions where the electric power markets do not incentivize power generators to subscribe to solutions that will enable tailored infrastructure development. By contrast, we do see instances where innovative solutions are being developed by the natural gas industry in support of power generation needs, in regions where vertically integrated utilities remain.

A recent example of this involves Enbridge’s East Tennessee Natural Gas, LLC (ETNG) pipeline. ETNG has obtained approval from FERC to construct and operate new pipeline and compression facilities to support a gas-fired power plant and provide FT service and enhanced FT service. The enhanced FT service will allow the shipper to utilize linepack created by the newly constructed facilities to balance supply and consumption both on an hourly and daily basis, customizing their daily demand profile and allowing for quick power generation ramping to meet demand. The linepack is essentially serving as storage for the customer’s balancing needs.

Demand for natural gas to fuel power generation is agnostic to whether the generation sits within a regulated or deregulated electric power market. However, with growing demand for natural gas, changes need to be made to better align the two industries in order for infrastructure solutions to be advanced. Policymakers, regulators, and industry participants have a responsibility to acknowledge and correct the situation.

FINDING 2-8: If solutions designed to accommodate variable demand are not developed to alleviate pipeline constraints, operational flexibility—such as the ability of

⁸³ EIA. “Annual Energy Outlook 2025”. https://www.eia.gov/outlooks/aeo/tables_ref.php

shippers to utilize to nonfirm or secondary delivery points—will likely become increasingly restricted, particularly in the Mid-Atlantic and Northeast regions.

FINDING 2-9: *Local distribution companies (LDCs) face challenges while managing increasingly volatile conditions on natural gas pipelines.*

FINDING 2-10: *Development of flexible, fast-ramping gas-fired generation is essential to enhance grid reliability. The North American Electric Reliability Corporation (NERC) now recognizes fuel security as a key reliability risk to the power system due to the ramping requirements of natural gas units.*

Chapter 3: Current State of Gas-Electric Coordination

I. PREVIOUS GAS-ELECTRIC COORDINATION EFFORTS

Effective gas-electric coordination has been frequently studied and debated by regulatory bodies, market participants, and researchers over the past two decades; nearly all of the studies include extensive feedback from a wide variety of energy system stakeholders. Prominent players include the North American Energy Standards Board (NAESB), Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), and Regional Transmission Organizations (RTOs)/Independent System Operators (ISOs). These studies often have precipitated, or been informed, by forums and workshops involving pipeline operators, electric generators, oil and gas producers, regulators, utilities, and market designers and resulted in numerous recommendations that have varying levels of implementation.

The gas and electric industries have examined integration since the early 1990s. What began as a technical concern at the boundary between two networks is morphing into a public-facing reliability issue. The growing dependence of the electric grid on natural gas—and of gas infrastructure on electric power—means disruptions in one system can now cascade into the other. Without prompt action, what was once a professional challenge risks becoming a national vulnerability.

In 2009, electric power exceeded all other sectors as the largest user of natural gas. By 2016, natural gas overtook coal as the leading fuel for electricity generation. Today, the power sector consumes more than 40% of U.S. natural gas, 40% more than any other segment. These increases were driven by rapid growth in natural gas production (up ~80% since 2010), which has pushed U.S. gas prices down, providing the nation a durable economic advantage over the rest of the world (European and Asian prices average ~4x higher and 7x more volatile). During the same interval natural gas storage has increased only about 10% and interstate pipeline capacity has barely budged, stressing the system.

This has also pushed the electricity and natural gas systems together. Electricity depends on gas for real-time generation, while gas depends on electricity to power compressor stations, control systems, and for storage operations. Once-distinct value chains now increasingly operate as a coupled network—without shared planning, synchronized markets, or unified oversight.

In recent years, several adverse weather events have severely tested both sectors.

- **Winter Storm Uri (2021)** frozen power generation and wells and compressors that cut gas supply as electric demand surged. Customers faced blackouts.
- **Winter Storm Elliott (2022)** frozen power generation, strained some pipelines in the Northeast and New York utilities narrowly avoided full system loss.
- **The 2024 Pacific Northwest outage** at Jackson Prairie storage showed how a single control-system failure can threaten both heating and generation.

These events exposed how physical stress, misaligned markets, and digital dependence can converge to turn local disturbances into larger regional reliability risks. The U.S. gas system remains operationally strong, but the assumption that pipeline reliability guarantees power reliability no longer holds.

As discussed in Chapters 1 and 2, **four interdependent locking categories of challenges** that most clearly define the current coordination problem emerge from a review of studies, reports, and forums:

- 1) Operational Inefficiencies and Misalignments
- 2) Power Market Design – Economic Inefficiencies and Fuel Assurance Misalignments
- 3) Commercial – Gas Services Design and Power Sector Fuel Assurance Misalignments
- 4) Fragmented Governance, Planning, and Reliability Coordination

Framing the issues identified in the literature across these four interdependent challenges provides context for how prior gas-electric coordination efforts have evolved and will help to inform how this study develops its recommendations. A view of the key issues under these four main challenges can be found in Table 3-1.

Issue/Challenge	Sample Recommendations from Prior Studies
1. Operational Inefficiencies and Misalignments	<ul style="list-style-type: none"> • Align the gas and power operational days. • Improve gas scheduling flexibility and opportunity. • Improve intraday, weekend, and holiday gas market liquidity. • Improve total system situational awareness and outage communication protocols between gas and electric operators. • Improve gas and electric system weatherization. • Improved electric system risk modeling and interconnect vulnerability assessments. • Change upstream force majeure practice.
2. Market Design – Economic Inefficiencies and Fuel Assurance Misalignments	<ul style="list-style-type: none"> • Ensure dispatch timelines support the opportunity to procure fuel. • Improve generator compensation incentives and frameworks to support infrastructure development. • Improve economic certainty and risk balance in power markets to facilitate advanced gas purchases, including additional reserve products. • Increase use of firm supply access to improve fuel assurance/resource adequacy.
3. Commercial – Gas Services Design and Fuel Assurance and Power Sector Misalignments	<ul style="list-style-type: none"> • Allow for adequate gas hedging opportunities for generators. • Generator and supplier dialogue about contracting capabilities and supply risks. • More rationalization and frequent use of capacity release and asset management arrangements. • More robust demand-response programs. • Establish secondary markets for intrastate transportation. • Develop more enhanced services to meet variable generation (e.g., hourly/nonratable, no-notice). • Look for ways to improve gas market liquidity.
4. Fragmented Governance, Planning, and Reliability Coordination	<ul style="list-style-type: none"> • Recommendation implementation is robust where a single regulatory authority has implementation accountability: • Bulk electric system (BES) operational performance standards. • Advancements in BES risk assessments. • Recommendation implementation frustrated where there is no clear oversight: • Implement joint system and outage planning. • Establish gas communication protocols. • Designate and protect critical infrastructure. • Enforceable gas system performance standards.

Table 3-1. Literature Identified Issues/Challenges and Mapped Sample Recommendations

A. Early Studies and Efforts (2006–2018)

Early literature and regulatory efforts primarily tackled operational challenges tied to rising reliance on gas-fired electricity generation: particularly scheduling misalignment between natural gas pipelines (gas day) and electricity markets (power day). The NAESB Gas-Electric Interdependency Committee (GEIC) in 2006⁸⁴ highlighted scheduling conflicts, inadequate outage communications, and insufficient intraday scheduling flexibility as challenges. The report also emphasized the need for clearly defined operational practices and recommended standardized scheduling protocols to better align natural gas and power market operations. The main focus prior to 2006 was on improving operational and transactional efficiency, while recognizing key differences between how electricity and natural gas markets functioned.

Subsequently, FERC Order No. 698 mandated standardized communication protocols for both the wholesale electric and wholesale natural gas industries, establishing initial operational baselines. FERC also held Section 206 proceedings that concluded in 2007 for the ISOs/RTOs “to examine if additional procedures are needed to determine whether their scheduling and compensation mechanisms need to be revised to ensure that gas-fired generators can obtain gas when the gas-fired generation is necessary for reliability.” During this proceeding, FERC found no reason to take action, declaring that existing conditions and practices were sufficient for system performance. However, this occurred in the early stages of gas-fired generation growth and may have been an opportunity to implement market design enhancements in anticipation of the emerging trend. These early FERC regulatory initiatives were critical in setting the operational baseline for future coordination efforts, although the scope was primarily limited to technical scheduling and operational communications. No major interdependency-related systemwide outages occurred during 2006–2010 that significantly impacted reliability. The lack of an emergency likely meant that practices were sufficient for system performance at the time, though it also meant there was less pressure to pursue deeper reforms until later events highlighted the risks more clearly.

However, the 2011 Southwest Cold-Weather Event—a severe three-day cold snap that struck the Southwest in early February 2011—brought greater visibility to these coordination gaps as prolonged subfreezing temperatures led to frozen equipment at power plants and natural gas production facilities, including electrified upstream and midstream outages due to blackouts. The event exposed vulnerabilities in both systems, with widespread generator outages, gas production losses due to freeze-offs, and impacts to about 4.4 million people across Arizona, New Mexico, and Texas. It marked an early warning of the operational risks that could emerge from tighter interdependence, particularly under extreme weather conditions.

In response to the 2011 Southwest Cold-Weather Event, FERC and NERC issued joint recommendations and held follow-up technical conferences. Building on these, FERC opened docket RM14-2 and related 206 proceedings (2012–2013) to address concerns with divergent interstate natural gas pipeline and wholesale electric utility day-ahead scheduling practices, as

⁸⁴ North American Energy Standards Board (NAESB). "Gas-Electric Interdependency Committee Final Report." 2006. <https://naesb.org/pdf2/geic020306w1.pdf>.

well as concerns regarding the efficient use of pipeline capacity by gas-fired generators and other shippers. The review focused on electric and gas operational days, generator dispatch timing, gas scheduling cycles, and multiparty contracting for interstate capacity. Minor adjustments in these areas (except for operational days), such as better synchronizing dispatch and nomination cycles under FERC Order 809, improved alignment.

The 2014 Polar Vortex marked another pivotal moment in gas-electric coordination. Severe cold weather led to widespread generator outages, fuel supply shortfalls, and soaring electricity prices, particularly in the Northeast and Mid-Atlantic regions. In its aftermath, NERC and PJM issued detailed reviews highlighting the commercial and operational vulnerabilities exposed by the event. These reports emphasized the risks of relying on interruptible gas supply, underscored the need for firm contracting and improved winterization, and recommended reforms to capacity market design to better account for fuel assurance. This body of work helped shift the policy conversation beyond operational fixes toward more fundamental questions of market incentives and infrastructure adequacy.⁸⁵

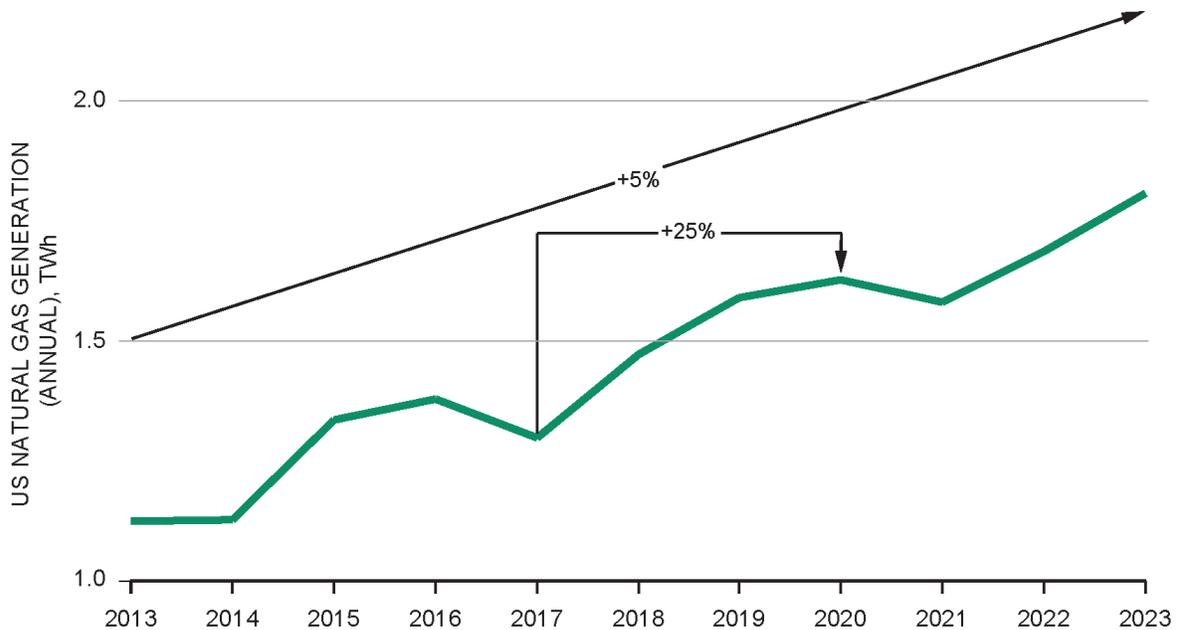
More recent reviews, including the 2023 NAESB Gas-Electric Harmonization Forum Report and the 2024 Joint RTO White Paper emphasize that, without regulatory clarity on cost recovery and explicit market incentives, generators (particularly the more variable and marginal portion of the generation stack) remain reluctant to commit to firm contracts, perpetuating fuel assurance risks.

B. Focus on Commercial and Organized Power Market Design Issues Since 2018

While literature from this period continued to identify operational improvements, it increasingly pointed to commercial gaps—particularly the lack of firm pipeline contracts and clear cost-recovery mechanisms—as the main barriers to gas-electric coordination.⁸⁶ These gaps limited the effective use of existing gas transportation systems in the near term and discouraged future infrastructure investment, both critical to reliability, as gas-fired generation continued its rapid development (Figure 3-1).

⁸⁵ NPC. "Dynamic Delivery: America's Evolving Oil and Natural Gas Transportation Infrastructure." 2019. <https://dynamicdelivery.npc.org/>.

⁸⁶ INGAA Foundation. "Gas-Electric Coordination and Natural Gas Pipeline Infrastructure Investment." 2019; "Dynamic Delivery." 2019; Peress, Jonathan. "Topic Paper on Gas/Electric Coordination and Natural Gas Pipeline Deployment." (Published by NPC). 2019. https://dynamicdelivery.npc.org/files/reports/Infra_Topic_Paper_3-3_FINAL.pdf.



Source: Data from EIA. 2024.

Figure 3-1. Gas Generation Boom from 2017 to 2020

These reports also underscored how the lack of clear incentives for generators to sign firm contracts or for pipelines to expand capacity impeded critical pipeline investments needed for reliability. ISO-led white papers further stressed the need for regulatory frameworks to encourage firm contracts,⁸⁷ yet concrete policy action remained limited due to regulatory uncertainty and gas-electric market design misalignments.⁸⁸

In the last several years (between 2019–2024), literature explicitly began focusing on the urgency of addressing market design while also highlighting major implementation barriers, including political complexity, regulatory uncertainty, and divergent stakeholder objectives. Notably, most analyses focus on organized RTO/ISO markets, while nonmarket (regulated) regions dominated by bilateral contracting remain overlooked, leaving a significant gap in understanding.⁸⁹ A key catalyst for the recent focus on market design in RTO/ISO regions (organized electricity markets) was the 2023 FERC/NERC inquiry into the December 2022 Winter Storm Elliott. This revealed systemic failures during extreme weather, particularly

⁸⁷ Such as Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024.

⁸⁸ Peress, Jonathan. "Topic Paper on Gas/Electric Coordination and Natural Gas Pipeline Deployment." (Published by NPC.) 2019. https://dynamicdelivery.npc.org/files/reports/Infra_Topic_Paper_3-3_FINAL.pdf; INGAA Foundation. "Gas-Electric Coordination and Natural Gas Pipeline Infrastructure Investment." 2019; Congressional Research Service (CRS). "Natural Gas Reliability: Issues for Congress." 2024.

⁸⁹ Peress, Jonathan. "Topic Paper on Gas/Electric Coordination and Natural Gas Pipeline Deployment." (Published by NPC.) 2019; Congressional Research Service (CRS). "Natural Gas Reliability: Issues for Congress." 2024.

incentives that discouraged power generators from securing firm pipeline capacity and firm fuel. The inquiry urged regulators and market operators to consider structural reforms to strengthen fuel assurance and reliability during peak-demand events.⁹⁰ In parallel, RTO-led efforts have drawn attention to capacity accreditation as a potential lever to address the relative lack of firm contracting since many organized markets do not account for a generator's ability to secure firm fuel, limiting the market value of actions that enhance reliability.⁹¹

Following the FERC/NERC inquiry, the 2023 NAESB Gas-Electric Harmonization (GEH) Forum Report highlighted the need for improved situational awareness across market participants and extensively discussed commercial and market design challenges, emphasizing the absence of market mechanisms to value firm fuel arrangements. Transactional frustrations and friction manifested in several recommendations but differences in market structure (competitive vs. designed) and regulatory oversight made balanced and nondisruptive implementation a challenge. The NAESB forum was unable to generate sufficient consensus for immediate implementation of any of the recommendations by the industry. This prompted the forum chairs to independently call for the formation of a natural gas reliability organization, similar in design to NERC, which was not an idea embraced by industry.

Reinforcing market design concerns around cost recovery and fuel assurance, the Congressional Research Service (CRS) emphasized in 2024 that current market structures fail to incentivize long-term midstream infrastructure investments. Such investments include new pipeline capacity, compression, and storage expansions, which are essential for ensuring reliable gas supply to power generators. The CRS report also noted the potential benefits of implementing structured incentives or reforms to address these systemic midstream infrastructure issues.⁹²

The literature's shift toward these elements reflects a key insight: Without substantial market design reforms that align infrastructure and contracting with the electric system's variable needs, incremental operational or commercial improvements cannot ensure gas-electric reliability. There is clear recognition that these improvements (such as scheduling reforms under FERC Orders 698/809, enhanced outage communication from FERC Order 787, and ISO-NE winter reliability pilot programs) are necessary for power generators to compete more effectively for natural gas services and products.

Notably, most of this emerging body of literature is concentrated on organized electricity markets (RTO/ISO regions), and generally omits non-market areas where bilateral arrangements

⁹⁰FERC and NERC. "Inquiry into Bulk Power System Operations During Winter Storm Elliott." October 2023. https://www.ferc.gov/sites/default/files/2023-11/24_Winter-Storm_Elliot_1107_1300.pdf.

⁹¹ Capacity accreditation refers to the process of determining how much of a resource's installed capacity can be relied upon to contribute to system adequacy. Accreditation adjusts a resource's nameplate capacity to reflect its expected availability and performance during peak or stressed system conditions. NERC defines it as "the process of quantifying the contribution of different resources to meeting resource adequacy needs, typically using methods such as Effective Load Carrying Capability (ELCC)." (*North American Electric Reliability Corporation, Report on Capacity Accreditation Practices*, September 2025, p. 3*).

⁹² CRS. "Natural Gas Reliability: Issues for Congress." 2024.

dominate. These regions represent a significant share of U.S. electricity markets (approximately 36% in 2024 Summer)⁹³ and are likely to face many of the same coordination risks but have received comparatively little analytical or policy attention. While there should be consistency in the overarching gas-electric coordination principles impacting system performance, these regions may require further analysis. This gap in the literature may present a challenge for developing holistic, national-level strategies and likely indicates some solutions will need to be regionally tailored.

NPC and CRS both stress that while coordination risks are similar across all regions in the United States, the mechanisms for addressing them differ.⁹⁴ RTO/ISO markets rely on centralized market rules, while nonmarket regions depend on state regulation, bilateral contracting, and integrated resource planning. NAESB, in 2023, also noted that recommendations focused on organized markets may not transfer directly. Expanding analysis to these regulated nonmarket regions is needed to build a comprehensive strategy that reflects both governance models.

The electrification of gas infrastructure and the associated risks of power outages is another risk identified in previous studies. As decarbonization pathways are evaluated for the gas supply chain, electrifying key services (such as compression and rigs) is often proposed as a greenhouse gas mitigation option.⁹⁵ While the literature shows that electrifying compressor stations can reduce Scope 1 emissions, electrification can also shift some emissions to Scope 2⁹⁶ and can add reliability risk.⁹⁷ In 2024, NPC recommended case-by-case deployment of electrification of key services with close coordination with power providers and further analysis of reliability trade-offs. Outside of decarbonization benefits, explicit treatment of black-start capability⁹⁸ for electrified gas infrastructure is largely absent in the literature. Electrified gas assets that depend on the grid during disturbances may require defined black-start or backup provisions, as restoration and resilience may be compromised.

⁹³ NERC. “2025 Summer Reliability Assessment.” May 2025.
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

⁹⁴ NPC. “Dynamic Delivery.” 2019; Peress, Jonathan. “Topic Paper on Gas/Electric Coordination and Natural Gas Pipeline Deployment.” (Published by NPC.) 2019.
https://dynamicdelivery.npc.org/files/reports/Infra_Topic_Paper_3-3_FINAL.pdf; CRS. “Natural Gas Reliability: Issues for Congress.” 2024.

⁹⁵ NPC. “Charting the Course: Reducing GHG Emissions from the U.S. Natural Gas Supply Chain — Volume I: Report Summary.” 2024. <https://chartingthecourse.npc.org/>.

⁹⁶ Per the EPA, Scope 1 emissions are direct greenhouse gas emissions from sources that an organization owns or controls. Scope 2 emissions are indirect greenhouse gas emissions from the generation of purchased electricity, steam, heat, or cooling consumed by the organization.

⁹⁷ NPC. “Charting the Course.” 2024.

⁹⁸ Black-start capability is the ability to start generators or other components of the electricity system on their own, without assistance from any part of the electricity system.

II. OPERATIONAL INEFFICIENCIES AND MISALIGNMENTS: A CLEAR NEED FOR BETTER OPERATIONAL COORDINATION

Operational coordination between the natural gas and electricity sectors has consistently been identified as foundational for ensuring reliability, particularly given the increasing dependency of electricity generation on natural gas fuel supplies. Several reports and regulatory efforts have been dedicated to improving operational alignment, focusing on three primary areas: scheduling synchronization, outage communication, and expanded scheduling flexibility. Despite broad industry consensus on these operational objectives, persistent implementation roadblocks have limited their overall effectiveness, highlighting the critical need for continued progress.⁹⁹

A. Alignment Between Gas Day and Power Day

The first and most fundamental operational challenge identified in the literature is the misalignment between the operating and scheduling timelines of natural gas pipelines, the gas day, and electricity systems, the power day (anywhere from 7 to 10 hours), which also has implications for how each market transacts.¹⁰⁰ The gas and electric systems operate on different daily schedules, creating a timing mismatch that forces generators to make fuel commitments before knowing whether their plants will be dispatched. This misalignment leads to inefficiency, higher costs, and reliability risks during extreme weather and weekends when flexibility is limited.

Gas local distribution company (LDC) contracting is based on design-day and customer load forecast.¹⁰¹ Gas LDCs contract to firm interstate pipeline transportation and storage assets to reliably serve their customers on design day. On nondesign days, the gas LDCs optimize their assets not needed to serve their customer load by making off-system sales or participating in the FERC-regulated capacity release market, which can be supply/capacity made available to gas-fired power generators.

Early investigations into gas-electric coordination, notably by the NAESB GEIC in 2006, emphasized how misaligned scheduling between the gas and power industries created uncertainty and inefficiency between the two markets and systems—especially during periods of system stress—when power plant dispatch decisions did not align with gas nomination cycles. In response, regulatory rules such as FERC's 2007 Order No. 698 established standardized communication protocols to improve coordination between pipelines and electric system operators. Building on this, FERC's 2015 Order No. 809 shifted the gas day 90 minutes later,

⁹⁹ NAESB. "Gas-Electric Harmonization Forum Report." 2023. <https://www.nysrc.org/wp-content/uploads/2023/08/11.1-Extract-from-NAESB-Gas-Electric-Harmonization-Report-7-28-2023-Attachmemt-11.1.pdf>; FERC Order 809, 2015; FERC Order 698, 2007.

¹⁰⁰ Power markets trade within the standard calendar day of midnight to midnight in local time zones (the "power day"). Gas markets trade from 9:00 a.m. Central Clock Time through 9:00 a.m. Central Clock Time the following day (the "gas day"). See Chapter 1 for more.

¹⁰¹ Design Day: The coldest expected day used by gas utilities to size firm pipeline and storage capacity needed to meet peak demand. Customer Load Forecast: An estimate of total gas demand used by utilities to plan supply, capacity, and storage to reliably serve customers.

added intraday nomination cycles for greater flexibility, and revised capacity release timelines to better align gas and power market schedules.¹⁰²

Following these changes, PJM moved its day-ahead commitment to 1:30 p.m. Eastern Clock Time to match the 2:00 p.m. gas nomination deadline, and physical gas market closing shifted from 11:30 a.m. to 1:00 p.m. Central Clock Time (CCT). The benefit of this change is that dispatch is known prior to the deadline for the gas Timely scheduling deadline. Despite these adjustments, misalignment persists: Gas operates on a 9:00 am–9:00 a.m. CCT schedule, while power runs midnight–midnight in each time zone.

Recent extreme weather events have also shown that gas-power scheduling, trading, and dispatch are not aligned. The 7- to 10-hour difference in operating day start times can require gas purchased for one day to serve two power days, complicating coordination and transactional efficiency. Winter Storm Elliott further exposed these gaps that are more pronounced during weekends and holidays, when flexibility is particularly restricted.¹⁰³ The storm underscored the need for improved scheduling coordination and broader adoption of standardized practices. While recent reforms have made partial progress, persistent vulnerabilities highlight the need for continued regulatory and industry-driven action to close these coordination gaps.

B. Situational Awareness of Operating Conditions and Outage Communication

The second major operational challenge highlighted in the literature concerns improving outage communications and information transparency among gas pipelines, power generators, and electric grid operators. Information on gas system outages, constraints, and operating conditions has historically not been shared in real time with power generators and grid operators. Without timely visibility, system operators cannot anticipate disruptions, leading to delayed responses and uncoordinated decisions that amplify reliability risks during stress events.

Standardized communication protocols during planned or unplanned outages are crucial for minimizing disruptions, especially if they occur during extreme weather conditions or during periods of high electricity and natural gas demand.¹⁰⁴ FERC's 2013 Order 787 was a foundational step in enabling such coordination: It allowed interstate pipelines and electric transmission operators to share nonpublic operational information (e.g., about system conditions, outages, or capacity constraints) with each other to promote reliability. For example, during Winter Storm Elliott, the ability for pipelines and grid operators to exchange outage and constraint information under Order 787 enabled faster redispatch and capacity reallocation, helping prevent broader service interruptions in several RTO regions.

Improved communication and data transparency since 2013 have partially facilitated better commercial decision-making, allowing generators to more effectively schedule gas

¹⁰² NAESB. "Gas-Electric Harmonization Forum Report." 2023.

¹⁰³ FERC and NERC. "Inquiry into Bulk Power System Operations During Winter Storm Elliott." 2023.

¹⁰⁴ NAESB. "Gas-Electric Harmonization Forum Report." 2023; FERC and NERC. "Inquiry into Bulk Power System Operations During Winter Storm Elliott." 2023.

nominations and pipelines to allocate capacity during disruptions. Industry-led initiatives such as the NAESB 2023 GEH Forum and NERC's 2023 Natural Gas and Electrical Operational Coordination Considerations Reliability Guideline have advocated robust real-time data-sharing frameworks that have incrementally improved operational visibility and coordination. For instance, industry and researcher collaborations have led to the development of tools like Argonne National Lab's NGInsight platform, which attempts to translate pipeline critical notices into actionable operational insights for electric grid operators. NGInsight was reviewed in NAESB forums but has stalled in further development, highlighting the need for sustained investment in data-sharing solutions. Better sharing of information among pipelines, generators, and grid operators helps markets function as intended during disruptions, ensuring gas flows to where it is needed most when guided by market signals.

While FERC Order 787 improved the legal and regulatory basis for information exchange between interstate pipelines and electric transmission operators, its practical application has varied across regions and events. During Winter Storm Elliott, for example, Order 787's information-sharing provisions allowed some operators to coordinate gas and power system constraints more effectively, improving response time and limiting the scale of interruptions. However, overall implementation remains uneven, and consistent, real-time communication practices have yet to be established. Thus, while enhancing outage communication and operational transparency has improved short-term coordination, deeper commercial and market design solutions are still needed to address systemic challenges, including the need for more physical infrastructure in supply-constrained regions.

C. Scheduling Flexibility in Both Gas and Power Markets

While FERC Order 809 improved scheduling flexibility, generators still face limited ability to adjust nominations on weekends, holidays, or under sudden load changes. This inflexibility leaves generators exposed to overbuying or underbuying gas, increasing both economic inefficiency and operational risk when market conditions change quickly.

Expanded scheduling flexibility has emerged as a critical priority for managing operational risk and improving reliability during real-time market shifts and weather-driven demand changes. FERC Order No. 809 advanced industry practice by shifting the Timely nomination cycle and adding an intraday scheduling window, giving generators and pipelines more flexibility to respond to daily fluctuations in power demand. However, these reforms remain insufficient, particularly on weekends and holidays or for intrastate pipelines, when procurement constraints, thin liquidity, and limited flexibility continue to challenge reliability.¹⁰⁵ Market forces require generators to buy multiday gas packages on Fridays, before actual power system needs are known. This creates two opposing risks: overbuying gas (and incurring financial losses if units are not dispatched) or underbuying gas (and facing shortages if units are called on). With little liquidity or incremental supply available, generators have limited ability to adjust to unexpected weather or real-time load changes, constraining system flexibility when it is needed most.

¹⁰⁵ NAESB. "Gas-Electric Harmonization Forum Report." 2023; Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024.

D. Weatherization and System Preparedness

A persistent operational challenge across both the gas and electric sectors is the lack of consistent, enforceable weatherization standards. Successive FERC and NERC investigations following major events such as the 2011 Southwest Cold-Weather Event, Winter Storm Uri in 2021, and Winter Storm Elliott in 2022, have documented recurring failures of generation, transmission, and fuel supply infrastructure during extreme weather. Electric reliability entities have made measurable progress through new readiness standards and cold-weather preparedness programs. Comparable measures for the natural gas system remain voluntary, market driven and fragmented across states, but progress has been implicitly demonstrated based on improved performance during the January 2024 Arctic Storms.

In the aftermath of Winter Storm Uri, the State of Texas implemented Senate Bill 3 (2021), directing the Railroad Commission of Texas to establish critical infrastructure designation rules and weatherization guidelines (that are enforceable for critical infrastructure). The Commission's Rule 3.66 and its associated guidance provide technical expectations for gas supply chain and pipeline operators. However, there is no comparable national requirement for upstream or interstate pipeline facilities, leaving preparedness levels dependent on individual operator practices and state oversight.

The literature notes that these inconsistencies create systemic risk: Gas supply interruptions during extreme cold directly affect power generation reliability, particularly in regions where gas-fired generation constitutes a large share of capacity. Despite incremental progress, much of the literature acknowledges the absence of federal authority over gas weatherization and variable state implementation continues to expose the energy system to weather-driven disruptions.

While operational coordination challenges persist, the literature highlights that meaningful progress has been made in several key areas. As discussed above, FERC Orders 787 and 809 established improved channels for information sharing and introduced intraday nomination cycles, enhancing scheduling flexibility and situational awareness between gas and power operators. Following recent winter events, NERC, FERC, and industry groups have advanced cold-weather preparedness and outage communication protocols, which have strengthened reliability on the electric side. These steps represent measurable improvement in operational communication and coordination, even as broader structural misalignments remain unresolved.

III. MARKET DESIGN – ECONOMIC INEFFICIENCIES AND FUEL ASSURANCE MISALIGNMENTS: CRITICAL CHALLENGES AND GAPS

Market design fundamentally shapes the long-term incentives for gas pipeline investment, the structure of pipeline services, and firm fuel contracting, all of which are essential

for electric reliability. Multiple analyses¹⁰⁶ conclude that U.S. wholesale electricity markets fail to adequately value or incentivize firm fuel arrangements. As a result, generators face cost-recovery uncertainty¹⁰⁷ and weak investment signals, discouraging long-term commitments to pipeline infrastructure and capacity. Without clear financial incentives or market products that recognize the value of fuel assurance, generators rely on interruptible, short-term gas contracts, leaving the system vulnerable during peak demand and extreme weather.

Market design coordination has emerged in recent literature as the most critical yet least developed aspect of gas-electric integration. While operational alignment and some practices like winterization standards and outage communication protocols (e.g., FERC Order 787) have improved, structural reforms remain limited. Market design fixes like incorporating fuel assurance into capacity accreditation and developing fuel-secure market products¹⁰⁸ aim to help, but progress has been slow and uneven. Despite its central role in enabling midstream infrastructure investment and firm contracting, market design has received limited sustained regulatory attention, creating a persistent policy gap that constrains long-term reliability and infrastructure development.¹⁰⁹ Studies starting in 2019¹¹⁰ have recommended incorporating fuel assurance into capacity accreditation, providing clear cost-recovery pathways for firm contracts, and developing specialized products such as uplift mechanisms and no-notice services to strengthen reliability.

On the natural gas side, studies similarly emphasize that clearer cost-recovery mechanisms and long-term contracting signals are needed to support pipeline and storage expansion. Reports from Peress, INGAA Foundation, and NAESB GEH Forum¹¹¹ identify potential reforms such as enhanced crediting for firm transportation in generator accreditation, indexed pricing structures for pipeline capacity, and regulatory guidance on cost pass-through—as possible levers to better align gas sector investment with power sector reliability needs.

¹⁰⁶ Peress, Jonathan. “Topic Paper on Gas/Electric Coordination and Natural Gas Pipeline Deployment.” 2019; INGAA Foundation. “Gas-Electric Coordination and Natural Gas Pipeline Infrastructure Investment.” 2019; CRS. “Natural Gas Reliability: Issues for Congress.” 2024.

¹⁰⁷ A cost recovery mechanism is a rule, tariff, or market product that ensures a power generator can recover the money it spends on investments or services for firm gas transportation, storage, or infrastructure capacity that improves reliability.

¹⁰⁸ Such as ISO-NE’s Pay-for-Performance; NAESB GEH Forum proposals; Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). “Strategies for Enhanced Gas-Electric Coordination.” 2024.

¹⁰⁹ NPC. “Dynamic Delivery.” 2019.

¹¹⁰ Such as Jonathan Peress’s “Topic Paper on Gas/Electric Coordination and Natural Gas Pipeline Deployment.” 2019; INGAA Foundation. “Gas-Electric Coordination and Natural Gas Pipeline Infrastructure Investment.” 2019; CRS. “Natural Gas Reliability: Issues for Congress.” 2024; NAESB. “Gas-Electric Harmonization Forum Report.” 2023.

¹¹¹ Peress, Jonathan. “Topic Paper on Gas/Electric Coordination and Natural Gas Pipeline Deployment.” 2019; INGAA Foundation. “Gas-Electric Coordination and Natural Gas Pipeline Infrastructure Investment.” 2019; NAESB. “Gas-Electric Harmonization Forum Report.” 2023.

A. Mechanisms for Cost Recovery for Generators

Clear cost-recovery mechanisms have emerged as a market design gap in need of policy attention due to the commercial and operational implications. Because cost-recovery pathways depend heavily on how electricity markets are structured, the issue is not only market design but also fundamentally tied to commercial structures, a theme explored further in Section IV.

Literature from INGAA and joint ISO/RTO studies repeatedly underscores the need for transparent, predictable mechanisms for cost recovery that allow generators to recover pipeline capacity costs across both organized markets and nonmarket regions. Such mechanisms could include uplift provisions or make-whole payments, capacity accreditation rules that credit fuel assurance, tariff riders that allow pass-through of firm transportation costs, or market-based compensation tools (such as reliability or reserve products) that explicitly value firm fuel supply. Without such mechanisms, generators lack economic incentives to commit to essential long-term infrastructure investments, perpetuating reliability gaps.¹¹²

ISO-NE's own fuel security analyses, along with FERC/NERC post-severe weather reviews, have consistently identified the lack of clear cost recovery for fuel assurance-related investments as a structural limitation driving a major reliability risk.¹¹³ The Northeast illustrates how weak investment signals in capacity markets and regulatory barriers to new pipelines leave generators without incentives to secure firm gas supply. With limited pipeline capacity and no large-scale storage, demand spikes in winter routinely strain the system, forcing reliance on oil and dual fuel as a stopgap rather than addressing long-term reliability needs.¹¹⁴

IV. COMMERCIAL – GAS SERVICES DESIGN AND POWER SECTOR FUEL ASSURANCE MISALIGNMENTS

The literature indicates gas and power industry stakeholders acknowledge the critical need for robust commercial solutions that facilitate transactions consistent with operational needs, including firm gas contracts for both transportation and storage service and commodity supply. Inadequate policy support and unclear or limited regulatory frameworks have significantly hindered meaningful investment and implementation of these commercial recommendations, discussed below.¹¹⁵

¹¹² FERC and NERC. "Inquiry into Bulk Power System Operations During Winter Storm Elliott." 2023; Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024.

¹¹³ ISO New England (ISO-NE). "Operational Fuel Security Analysis." 2018; FERC and NERC. "Inquiry into Bulk Power System Operations During Winter Storm Elliott." 2023.

¹¹⁴ Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024; NPC. "Dynamic Delivery." 2019.

¹¹⁵ Peress, Jonathan. "Topic Paper on Gas/Electric Coordination and Natural Gas Pipeline Deployment." 2019; INGAA Foundation. "Gas-Electric Coordination and Natural Gas Pipeline Infrastructure Investment." 2019; NAESB. "Gas-Electric Harmonization Forum Report." 2023.

An illustrative example of commercial constraints can be seen in ISO-NE, where limited pipelines and the absence of large-scale gas storage have left the system vulnerable to fuel shortfalls. For decades, New England has faced persistent constraints as demand has outpaced supply availability due to insufficient pipeline expansion, the absence of underground storage, and reliance on distant supply basins. A central driver for these constraints has been the lack of long-term firm contracting commitments from generators, which restricts deliverability and has undermined the business case for new infrastructure investment.¹¹⁶ Without those commercial signals, pipelines have had little incentive to expand capacity, leaving generators exposed during peak heating demand when residential customers are prioritized.

In response, many generators in ISO-NE have invested in dual-fuel capability, allowing them to switch to oil when gas supplies are scarce. While this provides a short-term hedge, it has effectively made New England an oil-peaking system during cold snaps—one with operational drawbacks. Oil units face limited on-site storage, challenges in replenishing fuel during storms, and emissions restrictions on run hours. These constraints mean that, although oil provides backup, it cannot ensure the same level of sustained operational readiness as firm gas supply or new infrastructure investment.

Another illustrative example of fuel assurance vulnerability is upstream weather-driven force majeure disruptions, which can sharply reduce gas supply before it ever reaches pipelines. During extreme cold, wellhead freeze-offs and related gathering or processing outages due to freeze related issues, road conditions, and loss of power have caused rapid production declines and pressure drops, cascading into pipeline operational flow orders and curtailments. Events such as the 2011 Southwest Cold-Weather Event, Winter Storm Uri (2021), and Winter Storm Elliott (2022) highlight how upstream supply disruptions can limit generators' ability to secure fuel.¹¹⁷ These events underscore a critical gap: Even perfect scheduling and data sharing cannot overcome upstream force majeure supply failures. Ensuring fuel assurance and resilience therefore requires explicitly accounting for exposure to freeze-off risks, while also recognizing the importance of mitigating arrangements such as firm transportation contracts, storage, and clear cost-recovery mechanisms for generators that hedge with firm capacity.

A. Firm Contracts Procurement for Generators

Literature repeatedly emphasizes firm pipeline contracts as essential for ensuring stable and reliable gas supply to electric power generators, particularly during peak electricity demand events. The NPC and INGAA Foundation reports highlighted that firm pipeline arrangements significantly reduce operational risks, thereby enhancing reliability and predictability of fuel supplies. Despite broad recognition of the need, firm gas contracting by generators remains uneven.

Analyses by the NPC and the INGAA Foundation, and more recent assessments such as the *Rethinking Report* highlight a core mismatch between the gas system's ratable flow model and the variable fuel demand of gas-fired generators. Recommendations across these studies

¹¹⁶ ISO New England (ISO-NE). "Operational Fuel Security Analysis." 2018.

¹¹⁷ NPC. "Dynamic Delivery." 2019; FERC and NERC. "Inquiry into Bulk Power System Operations During Winter Storm Elliott." 2023; CRS. "Natural Gas Reliability: Issues for Congress." 2024.

converge on the need for more flexible transportation products (e.g., nonratable and no-notice services), clearer cost-recovery pathways for firm contracting, and integration of fuel assurance into capacity accreditation. Together, these measures are intended to better align gas supply practices with the operational realities of modern power markets.

Though some pipelines offer enhanced and flexible delivery options such as nonratable or no-notice service,¹¹⁸ these are limited and often costly. During Winter Storm Elliott, the unavailability of a sufficient amount of these services was reported across several major interstate pipelines in the East, including Columbia Gas Transmission, Texas Eastern, and Transco, all of which imposed flow restrictions as linepack was depleted.¹¹⁹ These flexible options exist, but have seen limited contracting by generators due to their generally high cost and the lack of sufficient cost-recovery mechanisms in power markets. The financial implications for incenting flexible options are discussed in the market design section.

B. Flexible Gas Scheduling and Pricing Mechanisms

Several flexible mechanisms in the interstate natural gas market have been implemented to enhance responsiveness to real-time market conditions, including intraday nomination cycles. Intraday nominations allow generators to adjust gas purchases more frequently within the gas day, improving alignment with real-time dispatch, but require the appropriate services consistent with pipeline operational capabilities. Indexed pricing ties gas transport costs more closely to market conditions, creating potential incentives for generators to secure firm fuel when it is most needed. While both mechanisms have been discussed extensively, utilization in support of reliability has been limited, constrained by the lack of regulatory incentives and market-based frameworks.¹²⁰ To date, intraday flexibility has been partially implemented under FERC's 2015 Order 809, while indexed pricing remains largely at the proposal stage.¹²¹

More fundamentally, the majority of all gas transportation service (e.g., FT-1) continues to require ratable, uniform flow across the gas day—usage that diverges sharply from the variable consumption patterns of gas-fired generators.¹²² During ramps or contingency events, generators may require large, short-duration flows that exceed ratable delivery limits. In these scenarios, access to nonratable or no-notice services becomes essential for fuel assurance.¹²³ For

¹¹⁸ Nonratable, also known as hourly, allows shippers to take a day's worth of gas in a manner different than an equal amount for each of the 24 hours. No-notice is the ability for a shipper to take gas without notifying the pipeline until the action is taken, which contrasts with the preaction notice communicated by nominations.

¹¹⁹ FERC and NERC. "Inquiry into Bulk Power System Operations During Winter Storm Elliott." 2023.

¹²⁰ NAESB. "Gas-Electric Interdependency Committee Final Report." 2006; INGAA Foundation. "Gas-Electric Coordination and Natural Gas Pipeline Infrastructure Investment." 2019; NPC. "Dynamic Delivery." 2019.

¹²¹ NAESB. "Gas-Electric Harmonization Forum Report." 2023; FERC and NERC. "Inquiry into Bulk Power System Operations During Winter Storm Elliott." 2023.

¹²² INGAA Foundation. "Gas-Electric Coordination and Natural Gas Pipeline Infrastructure Investment." 2019; NPC. "Dynamic Delivery." 2019.

¹²³ NAESB. "Gas-Electric Harmonization Forum Report." 2023.

example, during Winter Storm Elliott in 2022, generators relying on interruptible service were unable to obtain gas quickly enough to meet steep electricity ramping needs, underscoring the importance of flexible, no-notice firm transportation products.¹²⁴

C. Further Market Reform Is Needed

Limited commercial progress, as evidenced by minimal offering and contracting of variable services due to a lack of buyer price signals, clearly illustrates the need for explicit market reforms to enable the meaningful implementation of firm gas contracting. Absent regulatory clarity and defined incentives, generators remain reliant on interruptible contracts, exposing the grid to fuel supply risks and operational vulnerabilities during periods of extreme demand.¹²⁵

Going forward, effective commercial progress will critically depend on generator gas contracting practices and firm fuel supply and delivery cost recovery, supported by market and regulatory changes in both the natural gas and power sectors. This need is underscored by the fact that electric power generation is now the largest single consumer class of natural gas in the United States.¹²⁶ The literature clearly indicates that resolving these commercial challenges requires structural regulatory reforms and targeted incentives to fully leverage operational improvements, strengthen gas-electric reliability, and support investment in physical infrastructure, including pipeline capacity, compression, and storage.¹²⁷

V. FRAGMENTED GOVERNANCE, PLANNING, AND RELIABILITY COORDINATION

A. Fragmented Oversight and Coordination Across Regulatory Entities

Coordination across the gas and electric systems requires collaboration among multiple entities, including FERC, NERC, DOE, RTOs/ISOs, state public utility commissions, and NAESB. Each plays an important and distinct role, but their jurisdictions and mandates are not always aligned.

As a result, implementing cross-sector reforms often requires multiparty agreement, which can be difficult to coordinate. In practice, well-supported recommendations may be stalled or limited in scope because no single entity has the authority—or obligation—to ensure their execution across the full value chain.

¹²⁴ FERC and NERC. "Inquiry into Bulk Power System Operations During Winter Storm Elliott." 2023.

¹²⁵ Peress, Jonathan. "Topic Paper on Gas/Electric Coordination and Natural Gas Pipeline Deployment." 2019; INGAA Foundation. "Gas-Electric Coordination and Natural Gas Pipeline Infrastructure Investment." 2019.

¹²⁶ NPC. "Dynamic Delivery." 2019; INGAA Foundation. "Gas-Electric Coordination and Natural Gas Pipeline Infrastructure Investment." 2019.

¹²⁷ NAESB. "Gas-Electric Harmonization Forum Report." 2023; FERC and NERC. "Inquiry into Bulk Power System Operations During Winter Storm Elliott." 2023.

Where jurisdiction is clear and authority is centralized, such as for the bulk electric system under NERC, recommendations with operational parameters have seen measurable progress. By contrast, areas governed by disparate or overlapping regulatory oversight lack a single entity with authority to enforce implementation, making cross-sector coordination complex and often impractical.

Outside of electricity supply, there has been less attention on risks to gas end uses, such as heating and cooking, during supply shortages. Major electrical blackouts have received more thorough post-event analysis in FERC/NERC inquiries, while comparable risks on the gas side remain underexplored.

This imbalance reflects differences in regulatory mandates: Electric reliability has clearer oversight, whereas gas system risks are more fragmented and less consistently integrated into planning and market design. Yet disruptions in one system often cascade into the other—gas shortages can undermine electric supply, while blackouts can disable gas compression and distribution. Addressing this full spectrum of risks is essential to ensure resilience not only for generators, but also for households, essential services, and industry.

B. Delayed Regulatory Response to Immediate Needs

Regulatory frameworks play a pivotal role in shaping commercial decisions and market behavior. Regulatory bodies directly influence incentives for firm pipeline contracts and infrastructure investments. Historically, regulatory actions have significantly shaped operational and commercial coordination; however, regulatory involvement in explicit market design has been comparatively limited, largely reactive, and insufficiently proactive.

Past studies emphasize the need for regulatory clarity to facilitate meaningful market design changes. Reports such as those from ICF in 2006 and the INGAA Foundation in 2019 underscore that regulators must explicitly value firm fuel arrangements through market structures to ensure reliability. NPC's 2019 Gas-Electric Coordination report provided detailed recommendations, such as incorporating fuel security explicitly into capacity accreditation, to realign market incentives with long-term infrastructure reliability. The report argued that regulatory inertia coupled with the complexities involved in long-term market reform have significantly impeded meaningful action.

This slow response is evident in the limited regulatory initiatives that explicitly address fuel assurance or infrastructure investment in gas markets. While entities such as NAESB and NERC have repeatedly highlighted market design challenges and recommended specific reforms, implementation has been predominantly theoretical and conceptual rather than actionable. For example, capacity accreditation reforms that consider fuel assurance remain in discussion but have not been widely adopted; proposals for nonratable or no-notice gas services have been raised but not implemented; and multiple forums have produced white papers and technical recommendations without binding rule changes.¹²⁸ Some ISOs and RTOs have introduced incremental measures through capacity market processes and pilot programs, such as ISO-NE's

¹²⁸ NAESB. "Gas-Electric Harmonization Forum Report." 2023; Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024.

winter reliability programs and PJM’s capacity performance construct, but these remain early stage and uneven across regions.

The Electric Reliability Council of Texas (ERCOT) offers a contrasting domestic example to a capacity-based approach. Unlike other U.S. RTOs, ERCOT does not operate a capacity market; instead, its energy-only design relies on scarcity pricing to incentivize resource adequacy. This has successfully attracted new gas-fired generation and supported investment in dispatchable capacity, but it does not explicitly value firm fuel assurance, leaving generators exposed to similar vulnerabilities seen in capacity markets. Recent reform debates in Texas, including proposals for a performance credit mechanism and firm fuel supply obligations for certain generators, illustrate recognition of the problem, but these mechanisms are still in development and their effectiveness remains uncertain.¹²⁹

C. Lessons from International Experiences: Europe and Australia

While the United States has struggled with market design deficiencies, established and integrated markets in Europe and Australia offer useful models of structured reforms. In Europe, wholesale gas markets are highly liquid and standardized, supported by strong cross-border interconnections and centralized market platforms that enable coordinated reforms. Power markets in both Europe and Australia feature explicit capacity and reliability mechanisms, along with centralized planning that incentivizes fuel assurance. In these regions, gas and electricity markets are both more centralized and more consistently utilized for cross-sector planning, making coordinated reforms more feasible. By contrast, the U.S. system is fragmented, with diverse regional structures and less standardized gas trading.

The UK has effectively used its electricity capacity market to incentivize firm gas contracts and infrastructure investment. Through structured auctions and targeted financial incentives, UK generators are compensated directly for reliable fuel supply commitments. In addition, the UK system interacts with the European Union’s Emissions Trading System (EU ETS), which complements capacity mechanisms by aligning market signals for both carbon reduction and infrastructure reliability. Together, these regulatory structures have improved long-term investment predictability, reducing operational vulnerabilities and enhancing fuel security.¹³⁰

Similarly, Australia’s National Electricity Market, managed proactively by the Australian Energy Market Operator (AEMO), explicitly incentivizes infrastructure investments through targeted market structures. AEMO employs clear reliability standards, explicit capacity accreditation, and financial incentives for generators to secure firm gas pipeline arrangements.

¹²⁹ Bates White Economic Consulting. *Fuel Security and Electric System Reliability: An Economic Assessment*. 2022; Electric Reliability Council of Texas (ERCOT), *Fuel Assurance and Resource Adequacy Review*. 2023.

¹³⁰ Office of Gas and Electricity Markets (Ofgem). “Capacity Market Annual Report.” 2023; European Commission. “Annual Report on the Operation of the EU Emissions Trading System (EU ETS).” 2023.

These structured market designs have successfully addressed infrastructure gaps, significantly enhancing reliability and fuel assurance.¹³¹

It should be noted that some of these reforms, particularly around reserve capacity and reliability obligations, have raised concerns about higher costs and potential market distortion in certain regions. Analyses by regulators such as Ofgem in the UK and AEMO in Australia indicate that while these measures have enhanced reliability, they have also resulted in measurable cost impacts for ratepayers, making the trade-offs between security and affordability an ongoing subject of evaluation.¹³²

While these international models are context specific, they underscore the importance of clearly defined market structures, explicit regulatory incentives, and proactive regulatory engagement, unlike in the United States, where regulatory responses have been reactive.

D. Existing Recommendations and Pathways to Improve Market Design

Studies from industry experts and regulatory bodies in the United States emphasize several pathways to explicitly improve market design coordination. NPC, NAESB GEH Forum, and CRS recommend that wholesale electricity markets explicitly incorporate fuel assurance into capacity market structures and accreditation frameworks.¹³³ Regulatory reforms should provide clear financial signals for generators committing to firm pipeline contracts, rewarding infrastructure investment and long-term fuel security commitments.

Beyond wholesale electricity markets, some state-level regulatory approaches on the natural gas side, often described as “load-justified investment,” allow infrastructure costs to be recovered when customers commit to multiyear or higher-volume consumption levels. For example, New York has required its LDCs to demonstrate firm customer load before approving new pipeline expansions, and Texas intrastate pipelines have similarly relied on anchor shipper commitments to justify investment. While these mechanisms vary across jurisdictions, they illustrate how demand commitments can support capital investment in gas infrastructure and may offer lessons for aligning fuel assurance incentives in power markets.

Additionally, explicit market products designed specifically to incentivize secure fuel arrangements have been proposed, such as fuel security products that provide capacity accreditation credit for firm fuel commitments, winter reliability programs with uplift payments, and no-notice gas transportation services tailored to generators.¹³⁴ Such specialized market mechanisms would clarify financial incentives and enhance market transparency. Regulatory

¹³¹ Australian Energy Market Operator (AEMO). "Reliability Outlook and Energy Supply Forecasts." 2023.

¹³² UK Office of Gas and Electricity Markets (Ofgem). "State of Industry Report." 2023; Australian Energy Market Operator (AEMO). Reliability and Emergency Reserve Trader (RERT) Report 2025.

¹³³ NPC. "Dynamic Delivery: America's Evolving Oil and Natural Gas Transportation Infrastructure." 2019; NAESB. "Gas-Electric Harmonization Forum Report." 2023; CRS. "Natural Gas Reliability: Issues for Congress." 2024.

¹³⁴ NAESB. "Gas-Electric Harmonization Forum Report." 2023; Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024.

bodies should implement transparent pricing mechanisms that accurately reflect reliability costs, thus enabling generators to justify infrastructure investments effectively.

Improving reliability across the gas-electric interface does not necessarily require the creation of a new, standalone oversight body, though one has been proposed that is akin to NERC but focused specifically on natural gas reliability to consolidate oversight and accelerate reform. Several recent studies have instead emphasized the need for stronger coordination among the existing entities that share responsibility for reliability and infrastructure (e.g., namely FERC, NERC, NAESB, state commissions, ISOs/RTOs, and pipeline operators). Enhanced collaboration among these stakeholders could enable clearer reliability standards for natural gas infrastructure, more consistent expectations for fuel assurance, and greater transparency in emergency response protocols. Regulatory mechanisms that support strategic generator dispatch ahead of high-demand periods could also strengthen system preparedness by incentivizing early firm fuel procurement and reducing the risk of last-minute shortfalls.

In terms of power market design, comprehensive regulatory reforms and structured market incentives represent the necessary pathway forward for enhancing long-term reliability and securing midstream infrastructure investment. Market design coordination remains underdeveloped in the United States, despite widespread conceptual acknowledgment. Explicit regulatory frameworks, structured incentives, and proactive market reforms are essential to resolve these fundamental gas-electric coordination gaps and to unlock interdependent market efficiencies. U.S. regulators and market participants may be able to learn some lessons from European and Australian markets on successful pathways to implement explicit market design changes.

Addressing these critical regulatory gaps in market design coordination will not only resolve persistent reliability vulnerabilities but also enable more efficient and transparent commercial decision-making across the natural gas and electricity sectors. Ultimately, robust market design coordination and proactive regulatory engagement are foundational for the sustained reliability and long-term infrastructure development necessary for a secure and resilient energy future.

VI. BARRIERS AND IMPLEMENTATION GAPS

Over the past two decades, stakeholders across the gas and electric sectors have developed a body of recommendations to improve coordination. Achieving consensus, navigating FERC approvals, and balancing stakeholder interests make structural change difficult, leaving fundamental problems intact. While meaningful progress has been made in certain areas with the implementation of various recommendations over the last 20 years, particularly around operational communication,¹³⁵ significant gaps remain, reflecting a combination of, commercial design limitations, and physical and regulatory constraints. This section summarizes six core barriers that continue to affect implementation, and the challenges each relates to.

¹³⁵ Such as through enhanced operational communication and scheduling flexibility following FERC Orders 787 and 809, and through recent cold-weather preparedness and coordination initiatives led by FERC, NERC, and industry.

A. Misaligned Commercial Models Between Gas and Electric Sectors

The most fundamental barrier is the underlying business model of the natural gas and electricity sectors. Incentive structures and operational timelines of the two industries are fundamentally different, having evolved based on the discrete characteristics of each market and not being designed to work together. Gas pipelines are structured around long-term, ratable service contracts with firm cost recovery. Power generators, especially peakers and variable-load units, in competitive markets require short-term, highly flexible service that does not align with those contractual norms. This clash is not incidental; it is structural. Pipelines optimize around steady industrial and LDC loads, while the modern power system increasingly depends on gas plants that must ramp up and down within hours.

Disparate economic drivers also inhibit alignment. Competitive producers and marketers are incentivized by price signals and short-term liquidity, pipelines by long-term contracts and cost-recovery frameworks, and utilities by reliability obligations under regulatory oversight. These diverging economic logics shape how each stakeholder evaluates proposed reforms and complicate systemwide solutions.

It is also important to recognize that gas is a slow-moving physical commodity, and the gas network lacks the level of automation and flow control found in the electric industry. Implementing automation across the gas system would be extremely costly and, in the interim, would require dispatching field technicians in the middle of the night to manually adjust flows—raising serious safety concerns. Additionally, shifting the gas scheduling team (and potentially supporting teams) to overnight operations would be highly disruptive.

Studies from NPC in 2019 and INGAA in 2019 consistently highlight the general gas and power market misalignments. Generators are reluctant to commit to long-term firm contracts that do not fit their operating profile, while pipelines lack incentives to innovate products that diverge from their traditional customer base. During the 2014 Polar Vortex, generators without firm contracts were unable to obtain supply and faced steep penalties, which translated directly into a reliability risk. The commercial misalignment leaves a systemic fuel assurance gap precisely when flexible generation is most needed.

B. Fragmented Oversight and Coordination Across Regulatory Entities

A core barrier is the fragmented governance of gas-electric reliability, where overlapping jurisdictions among federal, state, and industry bodies diffuse authority and accountability, leading to ad hoc coordination, uneven progress, and unresolved cross-sector issues.

The NAESB 2023 GEH Forum underscored this problem: Despite broad consensus on many recommendations, no single entity had the authority to enforce them. CRS in 2024 likewise stressed that fragmented governance explains why some operational fixes have advanced, but deeper commercial or market design reforms have stalled. Even well-supported proposals are left to voluntary action or regional discretion, which leads to uneven adoption. While decades of regulatory systems developing independently have widened the gap, the barrier is reinforced by stakeholders with opposing incentives and political positions.

C. Asynchronous Gas and Electric Market Schedules

Despite years of debate and marginal progress, the fundamental timing mismatch between gas and electricity markets has not been resolved. The most liquid gas trading periods, pipeline nomination deadlines, and next-day electricity bidding cycles remain out of sync, forcing generators to make binding fuel decisions before they know whether generators will be dispatched or waiting for a dispatch decision and locating fuel when liquidity is low.

The persistence of this timing mismatch reflects institutional inertia and conflicting interests rather than technical constraints. Gas markets and the vast majority of gas market participants benefit from the stability of the current trading and gas day structure, while power markets have been reluctant to accept the disruptions and cost shifts that reform would entail. Various reports and studies have identified this as a structural blind spot where reliability and operational efficiency are compromised by fuel and price uncertainty: Generators are locked into fuel commitments made in uncertainty or exposed to low liquidity, and system operators and pipelines are left managing the fallout. This is a design flaw that continues to expose the grid during periods of stress.

Various industry stakeholders, for example, have suggested that shifting the gas day to midnight-to-midnight hours could create operational challenges for LDCs, including balancing issues during off-peak hours, reduced market liquidity, higher staffing costs, and added system risks. Proponents argue, however, that alignment, whether performed by the gas or electric day timing changes, could improve nomination accuracy and better integrate gas-fired generation with power markets.

D. Limited Incentives for Reliability and Fuel Assurance

Operational misalignments make it harder for gas generators to meet the grid's flexibility needs. Pipelines typically require uniform hourly deliveries—about 1/24th of daily load—conflicting with the variable ramping of power generation. Deviations create linepack imbalances, raising or lowering pipeline pressure and requiring operator intervention to maintain reliability. These constraints limit generators' ability to respond efficiently and add costs, especially given the misalignment between the gas and electric day.

At present, wholesale electricity markets provide only limited recognition of the value of fuel assurance. Market rules prioritize short-term efficiency, meaning generators are compensated for delivering electricity but not for securing the fuel that underpins that delivery. This creates a structural gap: Securing firm gas contracts is often financially unattractive and relying on interruptible supply is cheaper and, in many cases, sufficient to remain competitive.

The consequence is that reliability is undervalued within existing market structures. Without explicit mechanisms to recognize fuel assurance, most generators rationally avoid incurring costs that cannot be recovered. This leaves the system with persistent exposure during periods of stress as short-term cost efficiency remains the dominant market signal.

E. Cost-Recovery Uncertainty Under Diverse Rate Structures

Another barrier is the absence of predictable cost recovery for firm fuel supply. Generators cannot reliably recover the costs of securing transportation or storage through

existing power market structures, leaving investment in fuel assurance financially unattractive. In many markets, there is no clear line of sight between what a generator spends to secure firm gas and what they can earn back through energy or capacity payments. That uncertainty is enough to discourage investment in firm arrangements.

Partial fixes such as uplift exist, but they are piecemeal and temporary and do not send sufficient signals for change. At a more fundamental level, the issue is not only economic, but political. No stakeholder group wants to pay more or lead a discussion on shifting costs, and debates over who should bear those costs often stall progress. Disagreements span across states and regions, with opposing desires and jurisdictional boundaries shaping different positions on fairness and responsibility. This dynamic reinforces the uncertainty: Without a durable, broadly accepted cost-recovery framework, fuel assurance remains commercially unattractive and difficult to resolve.

F. Limited Communication and Operational Integration

Gas and electric systems continue to operate largely in parallel, with limited alignment in planning and operations, although there are some differences across region types. Information-sharing protocols exist but are inconsistently applied, often voluntary, and vary widely across regions. Outage planning, seasonal assessments, and emergency coordination remain sector specific rather than integrated.

An entity's position within the regulatory spectrum strongly influences its view on appropriate solutions for communication, coordination, and commercial reform. Utilities with mandated reliability obligations often push for measures that competitive gas market participants perceive as excessive or inefficient. Even within ISOs, where stakeholder processes aim for consensus, alignment remains difficult as participants diverge over how to distribute risks, costs, and benefits. This divide was evident in the NAESB 2022–23 Forum, where broad conceptual agreement was insufficient to generate actionable momentum for implementation.

These silos become most problematic under stress. During extreme weather or sudden shifts in demand, system operators in both sectors often lack timely visibility into each other's constraints, forcing decisions based on incomplete information. That lack of shared situational awareness and communications increases operational risk and exposes both sectors to cascading disruptions. In short, despite growing interdependence, gas and electric planning and operational frameworks remain fundamentally divided. The result is a persistent structural vulnerability that is repeatedly exposed during major reliability events.

VII. IMPLEMENTATION PROGRESS TO DATE

Many of the barriers to gas-electric coordination span operational, commercial, institutional, and technical domains and persist across multiple parts of the system. While targeted efforts have been made to address specific challenges, implementation of widely discussed recommendations remains uneven. Efforts to improve gas-electric coordination must be evaluated within the broader spectrum of regulatory authority as incentives and obligations differ sharply across sectors: Competitive producers operate under minimal regulation, pipelines face moderate oversight, and utilities are highly regulated. This spectrum roughly mirrors the

energy value chain—from production to transportation, distribution, and end use—and influences both the feasibility of proposed actions and the degree of regulatory standardization that can be applied. Recommendations suited to one segment may be impractical in another with fundamentally different regulatory and economic structures. This distinction applies not only between the gas and electric sectors, but also between regulated and deregulated segments of the electricity sector.

Regional variations in market structure and roles also shape outcomes. Differences in wholesale market design, midstream gas ownership (producer or utility-controlled), risk allocation (merchant generators vs. vertically integrated utilities), and cost-recovery mechanisms all affect how coordination measures and recommendations should be tailored. These regional and structural differences underscore that effective solutions must be context specific rather than uniform across markets.

To provide a snapshot of where progress has occurred and where gaps remain, the following discussion summarizes the status of 16 of the most substantive or frequently cited recommendation areas and notes why some have not been successfully implemented.

1) Clarify and improve cost-recovery frameworks for firm gas contracting (tariffs/capacity credit)

Recommended/noted by: NPC (2019); Joint RTO White Paper (2024); NAESB GEH Forum Report (2023)

Status: Partially implemented.

Progress to date:

- ISO-NE has included limited uplift provisions for fuel costs, but these remain ad hoc and require manual requests.
- Broader RTO/ISO markets have not adopted standardized cost-recovery mechanisms.
- Stakeholder discussions continue, but no binding reforms are in place.

Why/why not fully implemented?

- No standardized tariff mechanism across markets to recover fixed pipeline charges for generators.¹³⁶
- Merchant generators face ongoing uncertainty on including firm transport costs in offers, dampening willingness to sign long-term contracts.¹³⁷
- Pipeline investments typically require long-term commitments; absent clear cost recovery, sponsors and offtakers continue to hesitate.¹³⁸

¹³⁶ Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024.

¹³⁷ NPC. "Dynamic Delivery." 2019; Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024.

¹³⁸ Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024.

- Ongoing stakeholder disagreement on who should bear costs slows consensus.¹³⁹

2) Establish a gas reliability authority for power support

Recommended/noted by: Stakeholders in NAESB GEH Forum Report (2023); NPC, 2019; Joint RTO White Paper, 2024

Status: Not yet implemented.

Progress to date:

- The idea has been raised in multiple stakeholder forums (e.g., NAESB GEH) but not adopted as a recommendation, limiting any actions or next steps as no agreement.
- Coordination continues through existing entities (FERC, NERC, DOE, NAESB, RTOs/ISOs, state regulators) without new jurisdiction.

Why/why not fully implemented?

- Fragmented jurisdiction across federal/state bodies and industries; unclear locus of authority.¹⁴⁰
- Likely requires legislative action; limited policy appetite to create a new entity across all jurisdictions.¹⁴¹
- No stakeholder consensus in prior forums; proposals remained “considerations,” not adopted recommendations.¹⁴²
- Concerns about duplication with existing roles in agencies and implementation complexity.¹⁴³

3) Designate critical gas infrastructure for electric reliability

Recommended/noted by: FERC/NERC Inquiry into Winter Storm Elliott (2023); NAESB GEH Forum Report (2023); Railroad Commission of Texas (2024)

Status: Partially implemented.

Progress to date:

- Texas SB3 established state-level designation of certain critical facilities.

¹³⁹ NAESB. "Gas-Electric Harmonization Forum Report." 2023; NPC. "Dynamic Delivery." 2019

¹⁴⁰ NAESB. "Gas-Electric Harmonization Forum Report." 2023; NPC. "Dynamic Delivery." 2019.

¹⁴¹ NAESB. "Gas-Electric Harmonization Forum Report." 2023; Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024.

¹⁴² NAESB. "Gas-Electric Harmonization Forum Report." 2023.

¹⁴³ Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024; NPC. "Dynamic Delivery." 2019.

- Implementation is ongoing at the state level (all lower-48 states), primarily in response to NERC standard EOP-011-4, with criteria varying by jurisdiction.
- No federal or multistate designation framework has been progressed.
- Progress remains partial, with inconsistent coverage and limited enforceability across regions.

Why/why not fully implemented?

- No national mandate analogous to NERC authority; designation varies by state.¹⁴⁴
- Interstate nature of gas networks complicates scope, prioritization, and enforcement.¹⁴⁵
- Misaligned curtailment priorities and coordination/scheduling barriers (e.g., weekend/holiday liquidity, gas day alignment) hinder consistent treatment.¹⁴⁶
- Absent clear, durable cost-recovery mechanisms for required upgrades, owners face weak investment signals.¹⁴⁷

4) Align gas and power operating days and shift day-ahead clearing before gas nominations

Recommended/noted by: NAESB (2006); NAESB GEH Forum Report (2023); Joint RTO White Paper (2024)

Status: Partially implemented.

Progress to date:

- FERC Order 809 shifted the gas scheduling cycle 90 minutes later and added intraday nomination windows.
- Some RTOs adjusted day-ahead timelines.
- A 7- to 10-hour gap remains between gas and power days.

Why/why not fully implemented?

- Inconsistent RTO adoption.
- Stakeholder resistance to further changes.

5) Add late-day and weekend nomination windows

¹⁴⁴ FERC and NERC. "Inquiry into Bulk Power System Operations During Winter Storm Elliott." 2023; CRS. "Natural Gas Reliability: Issues for Congress." 2024.

¹⁴⁵ Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024; NAESB. "Gas-Electric Harmonization Forum Report." 2023.

¹⁴⁶ Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024.

¹⁴⁷ Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024; NAESB. "Gas-Electric Harmonization Forum Report." 2023; Texas SB3 implementation experience.

Recommended/noted by: NAESB (2006); NPC (2019); NAESB GEH Forum (2023); Joint RTO White Paper (2024)

Status: Not yet implemented.

Progress to date:

- Intraday flexibility added under FERC Order 809, but no late-day or weekend nomination windows established.

Why/why not fully implemented?

- Thin liquidity on weekends/holidays.
- Counterparty reluctance.
- Pipelines unwilling to alter NAESB cycles without broad consensus.¹⁴⁸
- Requires variable services.

6) Require pipelines to publish real-time operational notices

Recommended/noted by: NAESB (2006); NAESB GEH Forum (2023); FERC Order 787 (2013)

Status: Partially implemented.

Progress to date:

- All interstate pipelines issue operational flow orders.
- Ad hoc dashboards in ISO-NE and PJM.
- FERC Order No. 787 allowed data sharing with transmission operators.

Why/why not fully implemented?

- Practices inconsistent across regions.
- No standardized platform.
- Limited incentives for real-time transparency.¹⁴⁹

7) Mandate joint planning meetings and shared emergency tools

Recommended/noted by: FERC/NERC Inquiry into Winter Storm Elliott (2023); (NAESB GEH Forum, 2023)

Status: Not yet implemented.

Progress to date:

¹⁴⁸ Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024.

¹⁴⁹ FERC and NERC. "Inquiry into Bulk Power System Operations During Winter Storm Elliott." 2023.

- Coordination occurs informally.
- Some regional pilot programs exist but are not institutionalized (e.g., ISO-NE piloted winter reliability programs (2013–2018.))

Why/why not fully implemented?

- RTOs cannot compel pipeline participation.
- Jurisdictional fragmentation.
- No federal mandate for joint planning.¹⁵⁰

8) Apply federal weatherization standards to gas infrastructure

Recommended/noted by: FERC/NERC (2011, 2021, 2023 event reports); Railroad Commission of Texas (2024)

Status: Partially implemented.

Progress to date:

- Texas mandated weatherization post-Uri for intrastate and upstream facilities designated as critical.
- Some regional initiatives.
- No national mandate to proceed.
- The market largely drives gas infrastructure weatherization.

Why/why not fully implemented?

- No federal authority over interstate pipelines and upstream system.
- Cost and enforcement concerns.
- Inconsistent state approaches for intrastate and upstream systems.¹⁵¹

9) Allow intraday bid changes to reflect fuel volatility

Recommended/noted by: NPC (2019); NAESB GEH Forum (2023)

Status: Partially implemented.

Progress to date:

- ISO-NE allows intraday bid adjustments and after-market updates.
- Other RTOs vary by region.

Why/why not fully implemented?

- Uptake is scant from inconsistent application across RTOs.

¹⁵⁰ NAESB. "Gas-Electric Harmonization Forum Report." 2023.

¹⁵¹ FERC and NERC. "Inquiry into Bulk Power System Operations During Winter Storm Elliott." 2023.

- Unclear cost recovery also discourages use.¹⁵²

10) Provide uplift/make-whole payments for fuel procurement risk

Recommended/noted by: Stakeholders in NAESB GEH Forum Report (2023); NPC, 2019; Joint RTO White Paper, 2024

Status: Partially implemented.

Progress to date:

- ISO-NE IEP program provides incremental compensation for fuel security.
- CAISO provides uplift under tariff rules.

Why/why not fully implemented?

- Not standardized; limited to pilot programs.

11) Develop short-term, nonratable transport for generators

Recommended/noted by: NPC (2019); Joint RTO White Paper (2024)

Status: Partially implemented.

Progress to date:

- Pipelines still prioritize daily firm service.
- No widespread offering of hourly or shaped contracts.

Why/why not fully implemented?

- Insufficient demand.
- Pipelines lack incentives.
- Products seen as high risk.
- Cost recovery uncertain in power markets.¹⁵³

12) Incorporate fuel assurance into capacity/procurement criteria

Recommended/noted by: Stakeholders in NAESB GEH Forum Report (2023); NPC, 2019; Joint RTO White Paper, 2024

Status: Not yet implemented.

Progress to date:

¹⁵²Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024.

¹⁵³ Joint RTO White Paper (PJM, ISO-NE, MISO, SPP). "Strategies for Enhanced Gas-Electric Coordination." 2024.

- ISOs have discussed capacity accreditation reforms.
- No binding integration of fuel assurance.

Why/why not fully implemented?

- Capacity market rules prioritize least-cost resources.
- Stakeholder disagreement.
- FERC approvals are pending.

13) Credit fuel-secure resources in capacity markets

Recommended/noted by: NPC (2019); Joint RTO White Paper (2024); NAESB GEH Forum, (2023).

Status: Not yet implemented.

Progress to date:

- Proposals for enhanced crediting exist but have not been mandated, so adoption is limited and inconsistent across RTOs.

Why/why not fully implemented?

- Stakeholder disagreement on fairness/cost.
- FERC reluctant to impose fuel-specific mechanisms.¹⁵⁴

14) Prioritize fuel-secure resources in real-time dispatch

Recommended/noted by: NAESB GEH Forum (2023)

Status: Not yet implemented.

Progress to date:

- Issue has been discussed at NAESB GEH Forum, but no recommendation advanced.
- ISOs/RTOs continue to apply fuel-neutral least-cost dispatch in real time.

Why/why not fully implemented?

- Only limited attention to the idea of fuel-specific dispatch in stakeholder discussions.
- Lack consensus support—**time dispatch must remain fuel-neutral** for legal and market.
- Proposals to provide differential compensation advantage fuel-secure resources (e.g., gas units with firm contracts) were not advanced and lacked consensus support.

15) Electric system physical and operational improvements

Recommended/noted by: FERC/NERC (2011, 2019, 2021, 2023 event reports); NERC 2014

¹⁵⁴ NAESB. "Gas-Electric Harmonization Forum Report." 2023.

Status: Fully implemented.

Progress to date:

- Improved cold-weather preparedness standards from NERC: *Cold Weather Reliability Standards* (EOP-011-2, IRO-010-4, TOP-003-5, and the upcoming EOP-012 series).
- Studies and simulations to improve system risk understanding.
- Updating forecasting processes and modeling.
- Ongoing NERC standards development.

Why/why not fully implemented?

- Fully implemented, but future improvements likely needed as performance is assessed.

16) Generator commercial gas arrangements

Recommended/noted by: NAESB GEIC (2006), FERC 206 Inquiry (2007), NPC (2011), NERC (2014), FERC/NERC Uri (2021), Reliability Alliance (2023)

Status: Partially implemented.

Progress to date:

- Acquisition of pipeline services and natural gas commodity aligned with operational needs.
- Inadequate market signals and compensation risk sensitivities.

VIII. FINDINGS

The following discussion on findings is synthesized from the published reports, regulatory inquiries, and industry forums reviewed in this literature assessment. They are intended to summarize the themes, barriers, and areas of progress reflected in that body of work. These findings do not render judgment on the appropriateness of specific recommendations, nor do they assess the desirability of implementation concepts. Instead, they reflect on how issues have been characterized across the literature and stakeholder engagement record, including both consensus views and areas of ongoing debate that will help to inform the recommendations from this NPC report.

The literature and industry engagement record are robust with studies and forums involving stakeholders across the gas and electric systems. Numerous issues have been discussed and assessed, many times, with varying degrees of implementation over the last 20 years.

Key barriers for adoption and implementation include attaining sufficient consensus across energy system stakeholders and disparate regulatory authority and economic drivers across the competitive/regulated spectrum, from the highly competitive/lightly regulated (producers) to the moderately competitive/moderately regulated (pipelines) to the highly regulated/lightly competitive (utilities) markets and entities.

A. Operational Inefficiencies and Misalignments

FINDING 3-1: *Operational improvements for electric and gas systems have been widely discussed in previous reports and forums and partially implemented. The electric sector has demonstrated more formalized progress, such as through NERC-led initiatives, while the gas sector's advancements have been primarily market driven.*

- Numerous studies and forums have produced recommendations on weatherization, situational awareness, and outage communication.
- Explicit progress has been greater in electric systems' winterization and reliability standards; implementation on the gas side remains market driven and implicitly understood based on recent improved performance.¹⁵⁵

B. Market Design – Economic Inefficiencies and Fuel Assurance Misalignments

FINDING 3-2: *Prior recommendations acknowledge the fundamental differences between gas and electric commercial models, highlighting the need for clearer price signals and greater transactional efficiency to improve cost recovery and deliverability certainty in support of fuel assurance, which will facilitate infrastructure development.*

- Market design and commercial arrangements (see Finding 3-3) have a very interdependent relationship. Literature shows an evolution from focusing on operational fixes to market and commercial issues, with a growing emphasis on capacity accreditation, cost recovery, and valuation of fuel assurance. These have emerged as significant issues with complex trade-offs, consensus alignment challenges (particularly around who bears costs), and multifaceted regulatory hurdles affecting implementation.
- Studies emphasize improving market design and behavior of organized power and gas markets to better align incentives and ensure more efficient cost recovery.
- Literature notes that vertically integrated market design has received comparatively little attention compared to organized market challenges.
- Persistent barriers include the complexity of balancing cost allocation across stakeholders, achieving consensus on reforms, and reconciling diverse regulatory regimes.

C. Commercial – Gas Services Design and Power Sector Fuel Assurance Misalignments

FINDING 3-3: *Commercial and contractual frameworks for gas supply and transportation have not evolved to support the more variable and time-sensitive operating needs of generators. This lack of market mechanisms and contracting*

¹⁵⁵ FERC and NERC. “System Performance Review of the January 2024 Arctic Storms.” April 25, 2024. https://www.ferc.gov/sites/default/files/2024-04/24_System%20Performance%20Review%20of%20the%20January%202024%20Arctic%20Storms_0425.pdf.

flexibility has, in turn, limited investment in the infrastructure and services needed to reliably meet those requirements.

- Recommendations are particularly beneficial for adequately pricing and mitigating fuel assurance risk broadly across the system.
- Generators that operate at the margin—starting and stopping as system conditions change—face the greatest challenge under current arrangements. Existing gas supply and transportation structures do not align well with their variable operating patterns.

D. Fragmented Governance, Planning, and Reliability Coordination

FINDING 3-4: Clear and distinct regulatory accountability plays a critical role in advancing implementation of recommendations, largely because of authority scope.

- Where regulatory accountability is strong and clearly defined, implementation of recommendations has progressed more consistently.
- Where accountability is diffuse or fragmented, outcomes depend more on market forces and commercial practices, producing uneven or less predictable performance.
- This disparity highlights how fragmented governance across gas and electric sectors has slowed adoption of reforms compared to areas with clear accountability.
- States retain exclusive responsibility for resource adequacy under the Federal Power Act, but that authority has been attenuated—not by deliberate delegation, but through the practical evolution of organized markets—necessitating renewed, coordinated state engagement in reliability and fuel assurance.

IX. CONCLUSION

To date, most of the gas-electric coordination debate and the studies and organized efforts to address gas-electric coordination have centered on the handful of days each year when the system is pushed to its limits by extreme weather. While that focus is understandable, it risks overlooking the broader trajectory of the system. Over the next five to 10 years, dynamic changes and growth in energy consumption will drive less steady demand patterns and sharper peaks, creating new challenges that extend beyond rare stress events. Preparing the system for this evolving demand profile will be just as important as addressing emergency coordination during extreme conditions.

Across the gas-electric interface, stakeholders have made valuable progress in identifying coordination challenges and advancing early-stage reforms—particularly in the operational domain. However, barriers persist, especially when commercial arrangements and market design features remain misaligned with system needs. Future efforts may benefit from a more integrated approach that combines technical improvements with institutional alignment and market reform. In particular, addressing cost-recovery challenges, enabling fuel assurance incentives, and clarifying governance responsibilities may be key to unlocking more durable and scalable solutions in the future.

Chapter 4: Recommendations for Healthy Alignment Between the Natural Gas and Electric Sectors

I. INTRODUCTION

The gas and electric industries in the United States both have a strong track record of reliability and adaptability. The gas industry has leveraged technologies such as fracking and horizontal drilling to become a global leader in production and exports. The electric industry has a long-standing history of providing reliable electricity across a vast and diverse geographic area and continues to evolve and integrate new energy resources onto the grid. However, immediate challenges exist as interdependence between the two sectors continues to grow. Unprecedented growth and changing demand patterns have exposed critical limits in both sectors. As noted in previous chapters, these challenges are no longer restricted to peak periods, but are rapidly becoming commonplace. Capacity that once provided flexibility in both the electric and gas markets has been absorbed by demand growth, and the physical limits of the integrated system have been reached in some regions. Many of these operational challenges have historically been managed out of public view and understood only by those directly involved in system operations. Today, as system conditions tighten, their effects are becoming more visible and increasingly relevant to all energy consumers in terms of reliability, resilience, and cost.

The recommendations in this report are intended as best practices and applicable across multiple regions, recognizing that regional differences exist. Growth-driven pressures, infrastructure design restrictions, distinct regulatory obligations, and operational differences have resulted in misalignments between the gas and electric sectors, causing unintentional but competing priorities that challenge coordination between these interdependent industries. As discussed in previous chapters, such friction can lead to real-time operational challenges and dampen market activity—both of which undermine short and long-term reliability and resiliency. The NPC’s recommendations aim to provide substantive, practical steps to reduce both operational and commercial friction and support both industries.

II. CHARACTERISTICS OF HEALTHY ALIGNMENT BETWEEN THE NATURAL GAS AND ELECTRIC SECTORS

To appreciate why these recommendations matter amid growing energy reliability risks, it is first necessary to understand the key characteristics of a healthy alignment and the indicators that reveal whether the gap between the two sectors is narrowing. The following section outlines

these characteristics and associated indicators. The 10 core characteristics of a healthy alignment include:

1. **Infrastructure Serves as the Foundation for Healthy Alignment:**

Energy markets rely on robust infrastructure. Gas pipelines, production wells, compressor stations, storage facilities, electric generators, transmission lines, energy storage, and distribution facilities are just some of the physical components of the infrastructure on which energy markets are built. Strains and limitations in infrastructure are often exposed in market operations. Likewise, infrastructure can expose constraints and flaws in market design. Therefore, healthy alignment most often exists when infrastructure is sufficient to allow customer demand to be met with supply at an affordable price. As the foundation for healthy alignment, adequately sized infrastructure supports reliability and resiliency and provides enough operational flexibility to absorb supply and demand shocks. Determining the size of the infrastructure requires robust long-term planning.

2. **Inherent Physical Limitations Between Natural Gas and Electric Sectors Are Acknowledged:**

Understanding the physical constraints of existing infrastructure—such as limited pipeline capacity and finite storage availability—is crucial for designing effective solutions and setting realistic expectations. Addressing these challenges requires honest recognition of the physical realities that govern each sector and the need for facilitation of new pipelines and storage. The inherent physical flow characteristics of the natural gas value chain can prevent natural gas markets from adjusting and delivering natural gas to electric generators as dynamically as electricity demand fluctuates. Historically, on-site fuel inventories and gas storage helped buffer these rapid shifts in demand, but these capabilities have become more limited as coal generation has decreased. A healthy market alignment acknowledges these challenges and sets reasonable expectations to ensure reliability.

3. **Reliability and Resilience Are Shared Priorities:** Cooperative support across the gas and power sectors exists to ensure performance at all times and includes:

- Preparation for peak periods.
- Planned outage coordination.
- Coordinated recovery plans for unplanned events.
- Proactive information sharing.

In a healthy market alignment, policymakers have established clear requirements not only for generation resource capacity, but also for assurance of fuel availability and deliverability. Cooperative cross-sector support helps ensure resources can reliably operate under critical system conditions, and market mechanisms are designed to explicitly value reliability services from both the natural gas and electric sectors.

4. **Accountability Requires Transparency:** Clear accountability helps identify responsibility for risk mitigation and improves management of uncertainties across complex markets and systems. Understanding roles and responsibilities in the gas and electric sectors encourages effective responses to supply chain disruptions and other market uncertainties while enabling faster recognition of potential risks and proactive

mitigation measures. Mechanisms promoting accountability should be well defined and visible for all stakeholders, including market participants and policymakers.

5. **Level of Service Expectations are Consistent:** Clear and consistent reliability expectations across the energy value chain help align performance standards among all stakeholders. Clarifying what “firm service” means at each stage—from production and transportation to generation and delivery—can promote a common understanding of where firmness represents a performance commitment, a scheduling right, or a contractual guarantee. In a well-functioning system, these distinct assurances work together to maintain continuity of service across every link in the energy value chain, from wellhead to burner tip.
6. **Commercial Solutions Enhance Alignment and Mitigate Risk:** In a healthy gas-electric market alignment, friction is often mitigated through commercial solutions—such as firm transportation release, capacity trading, or enhanced balancing agreements—that rarely require regulatory or legal intervention. Secondary markets can both improve reliability and deliver economic efficiency by allowing participants to reallocate capacity and manage risk in real time. Aligned markets also promote commercial innovation, encouraging participants to develop creative mechanisms that strengthen reliability under changing operating conditions. These solutions are most effective when all market participants share a common understanding of the essential value of reliable energy delivery to end-use customers.
7. **Market Design Provides Flexibility to Adapt to Changes in Supply and Demand:** A healthy market framework provides clear, actionable investment signals—through pricing, operational indicators, and forecasts—while supporting both short and long-term capital needs. At the same time, market designs should reflect capital market realities. A healthy framework supports operational flexibility, lowers risk, underpins appropriate cost recovery, and incorporates some method of robust long-term planning to help inform infrastructure development. When commercial and market structures function well, they create the adaptability needed to respond effectively to changing supply and demand conditions.
8. **Policy Environment is Constructive:** Healthy alignment is reinforced by a constructive policy environment. Certainty and durability in policy and permitting supports tailored infrastructure investments. (See separate NPC Permitting Reform study.) Additionally, constructive policy and governance fosters transparency, ensuring stakeholders clearly understand their respective responsibilities and obligations. (See above #4: Accountability Requires Transparency.)
9. **Participants Are Motivated to Reduce Misalignment and Friction:** Participants are motivated to participate in ongoing gas-electric reliability and coordination initiatives. Friction arises when alignment between sectors or market participants breaks down. It impairs market efficiency and often creates constraints (or misalignments) that can increase costs. In an effective and healthy market, particularly one grounded with as many competitive principles as possible, stakeholders and market participants are motivated to reduce friction, treating misalignment as a call to action rather than an inevitable obstacle.

10. **Costs of Alignment Are Clearly Identified:** A healthy alignment ensures that costs of both action and inaction are identified. Transparent accounting of costs ensures that trade-offs are openly understood and that resources are directed toward the most effective solutions. Likewise, opportunities for cost recovery must be clear. As such, a cost-benefit analysis is necessary for any evaluation to mitigate misalignments.

III. RISK OF NOT ADDRESSING CURRENT MISALIGNMENTS

Despite the strong track record of reliability of the natural gas and electric sectors, history offers several examples in which risks were not effectively mitigated. As has been well documented, Winter Storm Uri exposed millions of energy consumers to the risks of failure. Despite challenges faced during the storm, both sectors responded with tangible improvements in resilience through increased coordination, improved market signals, and better weatherization of infrastructure.

This study has highlighted the growing risks facing both sectors. The energy industry—and, more importantly, its customers—cannot afford to act only after failures occur. Proactive measures are essential for energy reliability. Though improved coordination and harmonization between the two sectors are crucial, these alone cannot fully address all current and future reliability risks. The rapidly changing resource mix, volatility in load profiles, and soaring energy demand clearly indicate the need for immediate and transformational action. Stakeholders, particularly traditional end-use energy customers, face tremendous risks. There is a cost to mitigating the current risk. However, there are also tangible consequences of delaying action or not acting at all.

Most end-use customers have an appropriate expectation that their lights will come on, and their pilot lights will stay lit. These customers expect, based on past experience, their energy providers to continue delivering reliable service. Customers may expect an occasional outage for a short period of time, but for the most part, their expectations for reliable service are high. For those operating in the natural gas and electric sectors, reliability is paramount, and each component of reliability must be examined and addressed to ensure reliability can be maintained. Each individual component comprising reliability is distinct and includes:

- **Operating Reliability:** The energy system's ability to consistently deliver electricity or natural gas to consumers without interruption. It involves both adequacy and resiliency during periods of stress, such as extreme weather.
- **Resiliency:** The ability of the energy system to prepare for, withstand, and recover from disruptions, such as natural disasters, cyberattacks, or other significant disturbances. Whereas reliability focuses on preventing outages, resiliency emphasizes the system's ability to bounce back quickly after disruptions.
- **Resource Adequacy:** A concept central to system planning functions that ensures there are sufficient resources, such as generation capacity, to meet expected future electricity demand. It involves forecasting demand and ensuring that enough resources are available to meet that demand, even during peak periods or when some resources are unavailable.

- **Energy Adequacy:** Having enough energy supply and delivery capacity available over a longer period, typically encompassing seasonal or annual needs. It ensures that the energy system can meet demand not just at peak times but also over sustained periods, considering factors like fuel supply and storage.
- **Fuel Assurance:** The certainty that fuel supplies (such as natural gas, coal, or oil) will be available when needed to generate electricity. Fuel assurance involves securing reliable fuel sources, maintaining adequate fuel inventories, and having contingency plans in place to address potential disruptions in fuel supply. This is particularly important for power plants that rely on fuel deliveries to operate because interruptions can directly impact their ability to generate electricity. Fuel assurance is a critical component of both resource adequacy and resiliency because it ensures that power plants have the necessary resources to meet demand and recover from disruptions. It is particularly relevant for natural gas-fired power plants, which may face supply constraints when faced with weather-related production interruptions, equipment outages, or reduced pipeline flexibility. During such periods, firm transportation commitments can leave little room for nonfirm users, constraining deliveries to generators when demand is highest.
- **Firm:** A commitment to be available and deliverable when needed. In the upstream portion of the natural gas supply chain, the term is rarely used because contracting provisions focus primarily on throughput and processing. However, “marketed production,” more relevant for this study, does use the term firm in financial and operational delivery obligations, which are typically outlined in base gas supply (North American Energy Standards Board) agreements. Unless otherwise agreed upon, these firm obligations are excused only in cases of force majeure, which ensures no payments for unsupplied gas will be made. In the context of natural gas transportation and storage entitlements, firm service signifies the highest priority and are subject to curtailment under limited circumstances such as force majeure and planned maintenance, with financial protections for shippers afforded under Federal Energy Regulatory Commission (FERC) policy. Importantly, firm applies only to capacity, not the fuel supply (marketed production) itself, which is covered under base gas supply agreements. In the power sector, firm capacity refers to an obligation to perform, ensuring generation or capacity delivery under all conditions. Depending on the segment of the energy value chain, and subject to the timing of nominations, firm can reflect a performance guarantee or reserved capacity. Reliability planning must account for these distinctions. The different sectors offer complementary assurance forms—supply diversity and operational reliability in the upstream, contractual firmness in the midstream, and performance obligations in the power sector—working together to ensure continuity from wellhead to burner tip.

When addressing the components of reliability, associated risks must also be considered. Additional risks that can ultimately impact the end user include:

- **Economic Risk:** The financial uncertainties and challenges that can affect energy markets, infrastructure investments, and operations. Economic risk includes factors such as fluctuating fuel prices, changes in policies, and the financial health of energy companies. It impacts the cost of energy production and the development of infrastructure and is closely tied to the affordability of energy for consumers. Addressing

economic risk requires careful planning, proactive risk management, and an adaptive response to changing market conditions.

- **Affordability:** The ability of consumers to access energy at reasonable and manageable costs. Affordability is influenced by factors such as energy prices, production costs, regulatory policies, and market dynamics. Ensuring affordability involves balancing the need for financial investment in infrastructure and new technologies while keeping energy prices stable and fair for consumers. Affordability is intertwined with other components like economic risk, resource adequacy, and fuel assurance. For instance, securing affordable fuel supplies and maintaining efficient operations can help keep energy prices in check. Addressing affordability requires careful planning and consideration of all elements in the energy value chain.
- **Commercial Risk:** The potential challenges and uncertainties that energy companies encounter in the marketplace. It includes risks related to competition, contractual obligations, changes in market demand, and shifts in consumer preferences. Commercial risk also encompasses the potential for financial losses due to market fluctuations, credit risks, and the failure of counterparties to fulfill contractual terms.
- **Regulatory Risk:** The uncertainties that arise from changes in the regulatory environment governing the energy sector. Regulatory risk can include shifts in standards, tariffs, market rules, and compliance obligations. Regulatory actions can affect the cost structure, investment decisions, and operational flexibility of energy companies. Changes in regulations can have wide-ranging implications, including impacting the feasibility of certain projects or technologies.

The energy system is complex and includes a diverse range of stakeholders, including policymakers, infrastructure owners, service providers, and end-use customers. Each component of the value chain offers a unique and valid perspective that can contribute to the healthy alignment between the natural gas and electric sectors. Aligning stakeholder priorities to ensure a safe, reliable, and affordable energy system is crucial for achieving the best outcomes for customers. However, a methodology for balancing the previously identified risks and components of reliability is critical in every well-designed energy market. Achieving healthy alignment includes acknowledging the stakeholders that ultimately bear the risks of not receiving reliable service and identifying the stakeholders in the best position to mitigate such risks.

The following recommendations aim to strengthen alignment between the natural gas and electric sectors by balancing reliability, risk, and cost. Building on the findings of the first three chapters of this report, they address key themes of infrastructure development, market design, integrated planning, and accountability—all directed toward ensuring reliable service to end-use customers. They do not address any relations the electric sector has with sectors other than gas.

Sustained alignment is essential as both sectors confront mounting reliability challenges. By fostering complementary assurance mechanisms—including supply diversity, upstream operational reliability, midstream contractual firmness, and performance obligations in electric markets—the energy system can strengthen its ability to sustain continuity from wellhead to burner tip. Yet, as these recommendations emphasize, even the most effective assurance mechanisms depend on pragmatic expansion of infrastructure to unlock their full value.

What was once a technical coordination challenge has become a strategic imperative: With growing reliance on gas-fired, dispatchable resources to meet demand, timely action is now required. The recommendations that follow are designed to be both actionable and impactful.

RECOMMENDATION #1: EMBRACE COMPREHENSIVE LONG-TERM PLANNING

The NPC recommends FERC require RTOs/ISOs to conduct comprehensive long-term planning that integrates resource adequacy and fuel assurance considerations, in cooperation with affected states.

1. Detailed Explanation

Current capacity market constructs, while addressing near-term needs, have not consistently provided an adequate substitute for long-term, integrated planning that supports state resource adequacy obligations under the Federal Power Act. A robust long-term planning process in cooperation with the states should evaluate the entire energy value chain, from the wellhead to the customer delivery point, and account for both intrastate and interstate pipeline systems where applicable. Such evaluations must consider the interplay of fuel supply, transportation, and electric generation resources across multistate regions, assessing firm fuel needs and load profile variations to ensure reliability under diverse conditions. “Long-term” should include at least a ten-year forward view so as to be able to capture development times and shifts in demand forecasts. To improve coordination and accountability, regulatory frameworks governing organized markets may need to be revisited and updated to better align state resource adequacy mandates with regional transmission organization/independent service operator (RTO/ISO) market structures. Establishing a clear, consistent approach to comprehensive long-term planning will enhance system resilience, fuel security, and cross-sector reliability.

2. Primary Findings

The findings that this recommendation will address include:

- **Finding 1-1:** Current market structures fail to incentivize generators to secure either long-term gas transportation or highly flexible premium products, heightening reliability risks.
- **Finding 1-2:** Electricity market signals prioritize short-term economic efficiencies, while natural gas infrastructure depends on long-term, firm commitments. Inadequate compensation in electricity markets often leaves generators with little incentive to secure the gas and transportation services needed to support their increasingly variable operations and peak reliability needs.
- **Finding 1-3:** Regulated and deregulated market types face risks from structural disconnects, highlighting the importance of integrated planning, market reforms, and investment signals to ensure long-term reliability.
- **Finding 1-4:** Electric and gas utilities plan for and rely on reserve margins to ensure reliability. Notwithstanding these planned utility margins, gas transportation infrastructure does not incorporate additional capacity because it is built to firm contractual needs. Therefore, there is no extra capacity on the existing pipeline system to serve the growing needs of the electric sector.
- **Finding 3-4:** Clear and distinct regulatory accountability plays a critical role in advancing implementation of recommendations, largely because of authority scope.

3. Benefits

Comprehensive long-term planning supports all markets by identifying risks and challenges that short-term signals alone might not detect. It enables consideration of all resource types and assesses the entire energy value chain, including the strengths and limitations of intermittent resources. By evaluating fuel assurance and natural gas generation together, long-term planning considers gas-electric interdependencies to optimize reliability and cost for customers. This approach also improves visibility of future cost impacts and allows all stakeholders to participate. Comprehensive long-term planning supports a healthy alignment between the natural gas and electric sectors in several areas, including:

- Prioritizing reliability and resiliency while also evaluating the associated costs.
- Recognizing physical limitations between the natural gas and electric sectors.
- Evaluating and planning for the impact of long lead-time and capital-intensive infrastructure projects.
- Supporting transparent accountability through the planning process as mechanisms promoting accountability should be well defined and visible for all stakeholders, including market participants and policymakers.
- Defining a consistent level of service expectations for customers and suppliers.
- Providing space to include commercial solutions in long-term plans.

4. Actions Required to Implement

- FERC should propose fuel assurance and resource adequacy criteria to be considered in required long-term planning roadmaps.
- Alternatively, RTO/ISOs could reform stakeholder processes to incorporate comprehensive planning, such as adopting regional state committees to reestablish a tariff-based framework for state participation in reliability and fuel assurance planning.
- Federal and state policymakers, along with RTO/ISOs must determine under which entity comprehensive planning will reside.
- Optional DOE action: DOE could invoke Section 403 of the Department of Energy Organization Act to initiate a review of long-term planning in organized markets.

5. Challenges to Implementation

- Implementing comprehensive long-term planning is difficult and will likely require a top-down approach from FERC such as rulemaking or show-cause proceedings to ensure coordinated state engagement in reliability and fuel assurance.
- A determination of where comprehensive long-term planning will reside in multistate regional markets is essential because states may have differing views and resource goals.
- A clear distinction of roles and responsibilities is essential to incorporating comprehensive long-term planning into RTO/ISO regions. Recommendations 8, 9, and 10 highlight the importance of transparent accountability and clarity of roles and responsibilities.

6. Impacted Stakeholders

- End-use energy customers: End-use customers should benefit most from the adoption of this recommendation because long-term planning helps mitigate risks associated with resource adequacy and fuel assurance while allowing for robust participation in the planning process by stakeholders.
- Federal and state policymakers: Clarification of roles and responsibilities related to the adoption of a comprehensive planning process within RTOs/ISOs will impact both federal and state policymakers. While it is likely FERC would have to approve any long-term planning implementation plans, state policymakers will have to be intimately involved in the actual planning process.
- RTO/ISO authorities: Adoption of comprehensive planning within the construct of an RTO/ISO market is a significant undertaking and will require cooperation between the RTO/ISOs and federal and state entities.

RECOMMENDATION #2: REFORM PERMITTING

The NPC recommends Congress and the Executive Branch take immediate legislative and administrative action to reform permitting to unlock fit-for-purpose¹⁵⁶ infrastructure investment.

1. Detailed Explanation

Infrastructure projects already require significant investment and therefore create substantial financial risk for investors. However, the uncertainty embedded in the current permitting process has a chilling effect on investment: higher costs, longer construction times, and a material increase in the risk of noncompletion. Business certainty and durable policies in permitting decisions are essential to mitigate current operational and energy adequacy risk for today's customers as well as respond to the rapidly increasing level of energy demand. While the process for obtaining permits should not compromise prudence, a path for expedited and durable outcomes at both the federal and state level must exist. (Note: Permitting reform is considered so vital, a separate study in the *Future Energy Systems* initiative is solely dedicated to permitting reform: See *Bottleneck to Breakthrough: A Permitting Blueprint to Build*.¹⁵⁷)

2. Primary Findings

The findings that this recommendation will address include:

- **Finding 2-8:** If solutions designed to accommodate variable demand are not developed to alleviate pipeline constraints, operational flexibility—such as the ability of shippers to utilize to nonfirm or secondary delivery points—will likely become increasingly restricted, particularly in the Mid-Atlantic and Northeast regions.
- **Finding 2-9:** Local distribution companies (LDCs) face challenges while managing increasingly volatile conditions on natural gas pipelines.
- **Finding 2-10:** Development of flexible, fast-ramping gas-fired generation is essential to enhance grid reliability. The North American Electric Reliability Corporation (NERC) now recognizes fuel security as a key reliability risk to the power system due to the ramping requirements of natural gas units.

3. Benefits

Permitting reform can reduce investment risk by providing regulatory certainty and durability; facilitate fit-for-purpose infrastructure to ease friction between the natural gas and electricity sectors; allow for demand growth and accommodation of large load customers; and lower operating costs and construction timelines, offering certainty for both investors and at-risk customers. Additionally, permitting reform supports the increased pace of flexible, fast-ramping

¹⁵⁶ Fit-for-purpose infrastructure refers to infrastructure that is appropriately scaled and designed to meet specific functions, for example intraday variable and peak day needs.

¹⁵⁷ NPC. "Bottleneck to Breakthrough: A Permitting Blueprint to Build." 2025. <https://permitting.npc.org/>.

gas-fired generation. Recognizing that infrastructure provides the foundation for a healthy alignment, permitting reform:

- Supports reliability and resiliency.
- Acknowledges the physical limitations between the natural gas and electric sectors.
- Supports transparent accountability.
- Reflects a constructive policy environment.

4. Actions Required to Implement

The NPC's report on Permitting Reform identifies targeted recommendations to improve permitting processes in the near term, as well as a broader vision for comprehensive permitting reform that maximizes reliance on standardized approaches in lieu of case-specific review. See the NPC (2025) report on Permitting Reform for more details.

5. Challenges to Implementation

Recognizing the complexity of permitting reform, the details associated with implementation challenges are discussed in the NPC (2025) permitting study.

6. Impacted Stakeholders

- End-use energy customers: Permitting reform will enable the expansion of fit-for-purpose infrastructure, increasing reliability for end-use customers.
- Infrastructure developers: Infrastructure developers will benefit from improved durability of permitting decisions, as well as potentially shortening development and construction timelines.
- Investment community: Lower project execution risk improves access to capital and reduces its cost, allowing infrastructure to be financed more affordably—and ultimately lowering costs to consumers.

RECOMMENDATION #3: CONSTRUCT NEW FIT-FOR-PURPOSE INFRASTRUCTURE

The NPC recommends that the natural gas and electric industries take urgent action to construct new fit-for-purpose energy infrastructure across the energy value chain, consistent with changing energy consumption patterns.

1. Detailed Explanation

The existing energy infrastructure system is under strain. Despite improvements in gas and electric sector alignment noted in Chapter 3, the ability for natural gas infrastructure to accommodate changing demand patterns is reaching its limit, elevating the risk of customer outages in certain regions. Large infrastructure projects generally have long lead times from approval to commercial operation, highlighting the importance of starting now. Fit-for-purpose investment across a spectrum of gas and electric infrastructure solutions—including greenfield pipeline projects, natural gas storage facilities, pipeline expansions, new peak-shaving assets, energy storage systems, and other related assets—is needed to accommodate variable load profiles and increasing demand. Infrastructure tailored to meet the specific needs of each region and support enhanced services is the surest method to ensure energy adequacy, operational reliability, and resource adequacy for current and future needs. Increasing capacity in the system also enhances liquidity by creating more commercial opportunities, such as allowing for new market products and contracting options.

2. Primary Findings

The findings that this recommendation will address include:

- **Finding 2-3:** The emergence of a winter electricity peak that coincides with local distribution companies' design-day needs has reduced the secondary market's ability to supply independent power producers, limiting their capacity to meet electricity demand with existing infrastructure.
- **Finding 2-8:** If solutions designed to accommodate variable demand are not developed to alleviate pipeline constraints, operational flexibility—such as the ability of shippers to utilize to nonfirm or secondary delivery points—will likely become increasingly restricted, particularly in the Mid-Atlantic and Northeast regions.
- **Finding 2-9:** Local distribution companies (LDCs) face challenges while managing increasingly volatile conditions on natural gas pipelines.
- **Finding 2-10:** Development of flexible, fast-ramping gas-fired generation is essential to enhance grid reliability. NERC now recognizes fuel security as a key reliability risk to the power system due to the ramping requirements of natural gas units.

3. Benefits

Constructing new fit-for-purpose infrastructure will accommodate changing demand profiles, support load growth from electrification and large loads, improve market liquidity, open new commercial opportunities, and enhance reliability and resiliency by mitigating customer outage risk. Recognizing that infrastructure provides the foundation for a healthy alignment, well-planned investment in new tailored infrastructure:

- Supports reliability and resiliency.
- Acknowledges the physical limitations between the natural gas and electric sectors.
- Clearly identifies the costs associated with alignment.
- Supports the development of flexible, fast-ramping gas-fired generation needed for future reliability.

4. Actions Required to Implement

- A thorough needs assessment and evaluation should be completed in order to choose suitable (fit-for-purpose) infrastructure balancing reliability and cost.
- A durable method of cost recovery should be identified to ensure project success. These cost recovery methods may require new or modified market mechanisms or regulatory action to properly incentivize infrastructure construction.
- Project developers must obtain durable permitting decisions (permitting reform).

5. Challenges to Implementation

- Permitting uncertainty.
- Lack of comprehensive planning.
- Durable path of cost recovery.
- Supply chain challenges.
- Potential opposition from nonindustry stakeholders.
- Lack of investor confidence in deliverability.
- Cost-benefit justification.

6. Impacted Stakeholders

- End-use energy customers: Customers will benefit from a more reliable and resilient energy system, though they may face costs related to infrastructure construction. A thorough cost-benefit analysis will be required.
- Federal and state policymakers: Policymakers will be responsible for making permitting decisions related to infrastructure, as well as ensuring appropriate involvement in resource decisions and cost-benefit evaluations.
- RTO/ISOs: RTO/ISOs should benefit from the enhanced reliability and increased secondary market activity resulting from the addition of new infrastructure and capacity to the system.

RECOMMENDATION #4: ENHANCE AND EXPAND EXISTING INFRASTRUCTURE

The NPC recommends the natural gas and electric industries, in coordination with policymakers, prioritize actions to enhance and expand existing energy infrastructure where feasible, to manage rapidly changing flow patterns and growing demand.

1. Detailed Explanation

Enhancing and optimizing existing infrastructure can often deliver faster reliability benefits than building entirely new facilities. As more regions face elevated outage risk, targeted upgrades or “bridge solutions” may be needed to maintain reliability until new infrastructure is permitted and constructed. The current anticipated long lead times for new projects make short-term investment in practical mitigation measures essential. Such measures could include utility-scale batteries, incremental natural gas storage capacity, additional compression or looping on existing pipelines, installation of backup generation or fuel systems, deferred generation retirements, and expanded demand-response programs. These near-term improvements can help stabilize system performance while comprehensive, fit-for-purpose investments are pursued over the longer horizon.

2. Primary Findings

The findings that this recommendation will address include:

- **Finding 2-3:** The emergence of a winter electricity peak that coincides with local distribution companies’ design-day needs has reduced the secondary market’s ability to supply independent power producers, limiting their capacity to meet electricity demand with existing infrastructure.
- **Finding 2-8:** If solutions designed to accommodate variable demand are not developed to alleviate pipeline constraints, operational flexibility—such as the ability of shippers to utilize to nonfirm or secondary delivery points—will likely become increasingly restricted, particularly in the Mid-Atlantic and Northeast regions.
- **Finding 2-9:** Local distribution companies (LDCs) face challenges while managing increasingly volatile conditions on natural gas pipelines.
- **Finding 2-10:** Development of flexible, fast-ramping gas-fired generation is essential to enhance grid reliability. NERC now recognizes fuel security as a key reliability risk to the power system due to the ramping requirements of natural gas units.

3. Benefits

Identifying opportunities to optimize and enhance existing infrastructure can provide a faster and more efficient path to addressing current reliability challenges and supporting ongoing domestic growth until new assets can be constructed. Targeted expansions, upgrades, and deployment of shorter-term solutions can increase system reliability and resilience, helping to mitigate the effects of shifting gas flow patterns, rising demand, and emerging reliability risks. Additionally, the challenges associated with building new infrastructure, such as permitting and supply chain constraints, may delay timely solutions to current risks. Recognizing that

infrastructure provides the foundation for a healthy alignment, timely investment in existing infrastructure:

- Supports reliability and resiliency.
- Acknowledges the physical differences between the natural gas and electric sectors.
- Clearly identifies the costs associated with alignment.

4. Actions Required to Implement

- A thorough needs assessment and evaluation should be completed in order to choose suitable (fit-for-purpose) infrastructure balancing reliability and cost.
- A durable method of cost recovery should be identified to ensure project success. These cost-recovery methods may require new or modified market mechanisms or regulatory action to properly incentivize infrastructure construction.
- Project developers must obtain durable permitting decisions (permitting reform).

5. Challenges to Implementation

- Permitting uncertainty.
- Lack of investor confidence in deliverability.
- Durable path of cost recovery.
- Supply chain constraints.
- Cost-benefit evaluation.

6. Impacted Stakeholders

- End-use energy customers: Appropriately selected fit-for-purpose infrastructure projects should increase near-term reliability and reduce outage risk but will still require a prudent cost-benefit analysis to determine the impact on the customer.
- Federal and state policymakers and officials: Policymakers at the federal and state level will be challenged to act quickly in order to support near term capital investments or other programs to support reliability.
- Infrastructure developers: Developers will be challenged to demonstrate an ability to move fast to mitigate current energy adequacy risks.

RECOMMENDATION #5: REFORM MARKET COMPENSATION MODELS

The NPC recommends appropriate entities (e.g., RTOs/ISOs, federal and state authorities) ensure adequate risk-based compensation for gas-fired power generators to obtain sufficient fuel and operate reliably when called upon and to be prepared to perform during stress periods.

1. Detailed Explanation

Electric reliability depends on generators being available when needed. Currently, generators in certain regions lack sufficient economic motivation to secure firm gas transportation capacity and supply to maximize fuel certainty. To minimize generator nonperformance and enhance reliability, compensation and accreditation structures should value readiness and fuel assurance and reduce unnecessary risk. In this context, “adequate risk-based compensation” may require updating electricity market payment structures so that revenues reasonably reflect the cost of maintaining fuel readiness, while still relying on generators to manage the operational and financial risks inherent to performance, preserving market discipline and supporting reliable operations.

2. Primary Findings

The findings that this recommendation will address include:

- **Finding 1-1:** Current market structures fail to incentivize generators to secure either long-term gas transportation or highly flexible premium products, heightening reliability risks.
- **Finding 2-8:** If solutions designed to accommodate variable demand are not developed to alleviate pipeline constraints, operational flexibility—such as the ability of shippers to utilize to nonfirm or secondary delivery points—will likely become increasingly restricted, particularly in the Mid-Atlantic and Northeast regions.
- **Finding 3-2:** Prior recommendations acknowledge the fundamental differences between gas and electric commercial models, highlighting the need for clearer price signals and greater transactional efficiency to improve cost recovery and deliverability certainty in support of fuel assurance, which will facilitate infrastructure development.

3. Benefits

This recommendation would reduce situations where individual economic decision-making leads to decreasing electric system reliability margin. Resolving this misalignment is essential to providing a reliable and resilient system while leveraging a market-driven approach. In situations where the system is stressed and all available energy supply is needed, compensating to ensure performance is prudent, particularly when end-use customers ultimately bear the nonperformance risk. This recommendation supports healthy alignment characteristics like reliability and resiliency, and a constructive policy environment. In addition:

- Commercial solutions enhance alignment.
- Market design provides flexibility.

- Participants are motivated to enhance alignment between the gas and electric sectors.
- Costs of alignment are clearly identified.

4. Actions Required to Implement

- States and/or RTOs/ISOs should proactively embed fuel assurance planning into their system planning process. These collaborative efforts can be modeled after successful transmission planning.
- Implementation will require Federal Power Act Section 205 or 206 filings.
- Optional DOE action: DOE could invoke Section 403 of the Department of Energy Organization Act to initiate a review of generator compensation in organized markets by appropriate authorities.

5. Challenges to Implementation

- In some regions, gas transmission capacity is so constrained that even if all interruptible gas-fired generators wanted firm capacity, it might be unavailable due to fully subscribed pipelines.
- Estimating the cost to end-use customers.
- Demonstrating the need and value of the increased cost to the consumer for improved reliability.
- Stakeholder processes may be complicated and lengthy, but will be necessary to forge durable policy.
- Achieving consistent energy policy positions across participating states within RTOs.

6. Impacted Stakeholders

- End-use customers: Customers may be impacted by potentially higher costs required to ensure reliability and mitigate energy adequacy risk. A cost-benefit analysis will be prudent to understand the impact to the customer.
- Power generators: Generators, especially independent power producers (IPPs), will be more likely to respond to market signals that are better matched with actual costs.
- Pipeline operators: Interstate and intrastate pipelines should respond to higher demand for pipeline capacity as generator compensation will be better aligned with risk and translate into contract commitments.

RECOMMENDATION #6: IMPLEMENT AN ACCOUNTABILITY FRAMEWORK

The NPC recommends FERC (or RTO/ISOs) endorse or issue an accountability framework to address the risk created by the lack of direct market commitments certain generation owners have to end-use customers.

1. Detailed Explanation

Because reliable electric service depends on continuous real-time balancing of supply and demand, electricity differs fundamentally from traditional traded commodities. These operational and reliability characteristics have led to distinct regulatory and market frameworks and warrant policy considerations that reflect the essential nature of electric service. Unlike other traded commodities such as soybeans and coffee, for which shortages drive up futures prices, the failure of an available generator to operate and deliver electricity can have an immediate human impact. Some generators continue to overly depend on spot trading platforms for natural gas, assuming these mechanisms will perform even under system stress. Experience shows this approach can leave both the generators and the system exposed, which suggests more proactive actions are necessary.

A prudent practice for all generators, including IPPs, is to maintain a plan for operation during stressed periods by including a portfolio of base gas supply contracts with credit terms already in place. Though contract terms and counterparty relationships should not be dictated, it is reasonable for physical market participants to have a plan established that includes a portfolio of base gas supply contracts or gas supply arrangement with a reputable third-party supplier. Notably, many gas-fired generation owners rely on third-party marketers or asset managers for fuel procurement who typically have diverse asset portfolios and strategies. However, in today's environment, especially during stress periods like severe cold-weather events, all generators, including IPPs, should have prudent measures in place to ensure readiness and responsiveness.

The NPC believes a proactive best practice for RTO/ISOs is the implementation of a robust capacity accreditation process that takes fuel assurance into consideration. Distinguishing between generating sources with firm storage rights or dual-fuel capabilities and those with lower levels of assurance allows the RTO/ISO to improve reliability planning. Generators able to demonstrate performance ability through current base supply contracts and/or other mitigation measures in place to ensure fuel reliability will receive a higher accreditation value than those who rely on less firm arrangements. The ability to identify and rely on firm delivery capability is prudent in any market, and this proactive approach may be more effective than nonperformance penalties alone.

2. Primary Findings

The findings that this recommendation will address include:

- **Finding 1-1:** Current market structures fail to incentivize generators to secure either long-term gas transportation or highly flexible premium products, heightening reliability risks.
- **Finding 3-1:** Operational improvements for electric and gas systems have been widely discussed in previous reports and forums and partially implemented. The electric sector

has demonstrated more formalized progress, such as through NERC-led initiatives, while the gas sector's advancements have been primarily market driven.

3. Benefits

Prudence in contracting practices allows for efficient and more reliable fuel purchases, minimizing disruptions and recognizing the unique nature of electricity. At a minimum, adhering to a "best-efforts" accountability framework:

- Supports reliability and resilience.
- Supports transparent accountability.
- Supports a consistent level of service expectations.
- Leverages commercial solutions, enhancing alignment, and mitigating risk.
- Reflects the belief that market participants are motivated to strengthen alignment while reducing misalignment and friction.

4. Actions Required to Implement

- FERC or the RTO/ISOs will need to initiate the development of best-efforts accountability framework. This can be accomplished through a technical conference or through a request to individual RTO/ISOs.
- Voluntary implementation by the RTO/ISOs.
- Acceptance by the stakeholder community, including IPPs in each RTO/ISO.

5. Challenges to Implementation

- Acceptance by market participants who would face a change in business practices.
- There is no "duty to serve" obligation for IPPs.
- In some regions, gas transmission capacity is so constrained that even if all interruptible gas-fired generators wanted firm capacity, it might be unavailable due to fully subscribed pipelines.

6. Impacted Stakeholders

- End-use energy customers: Customers should benefit from actions that support an IPP's prudent participation in the market, particularly during high stress conditions such as extreme winter weather events.
- IPPs: IPPs will be subjected to increased expectations but should benefit in the long-run by having more reliable gas supply agreements in place, allowing for more participation in the power market.
- RTO/ISOs: RTO/ISOs will benefit by having a more responsive natural gas generation fleet.

RECOMMENDATION #7: EXPAND PIPELINE SERVICE OFFERINGS

The NPC recommends policymakers and market operators/participants work to address changing hourly gas flow patterns by developing alternative tariff structures that enable enhanced gas service offerings and more flexible contracting arrangements between gas suppliers and electric generators.

1. Detailed Explanation

Even with recent improvements in gas-electric coordination, hourly flow profiles on natural gas pipelines continue to exhibit increasing variability, straining traditional operational practices. Unlike local distribution companies, electric generators often consume natural gas in less predictable, highly variable patterns, creating operational challenges for pipeline operators and increasing the likelihood that gas deliveries may need to be curtailed to maintain adequate pressure on the pipeline. In response, there are some operational and commercial actions that may help mitigate some of this friction, including:

- Developing market mechanisms to encourage generators to sign long-term firm gas transportation and storage contracts.
- Creating additional commercial gas supply offerings tailored for specific types of gas generation (combined cycle or combustion turbine) to better reflect the expected variability of their natural gas usage.
- Creating additional or complementary infrastructure that provides the platform to expand current gas supply offerings.
- Commitments to provide advance notice of operation to allow pipeline operators to prepare for large swings in offtake.

2. Primary Findings

The findings that this recommendation will address include:

- **Finding 2-1:** Pipelines were built for predictable, ratable flows, but customers now require increasingly variable intraday services to meet growing demand and balance the grid as wind and solar generation expand.
- **Finding 2-5:** Recent pipeline expansions—implemented mainly through flow reversals and added compression rather than new pipelines—highlight the need to address challenges between pipeline capabilities and increasingly variable demand.
- **Finding 3-3:** Commercial and contractual frameworks for gas supply and transportation have not evolved to support the more variable and time-sensitive operating needs of generators. This lack of market mechanisms and contracting flexibility has, in turn, limited investment in the infrastructure and services needed to reliably meet those requirements.

3. Benefits

Expanding service offerings can help reduce transactional friction in energy markets and improve cost recovery by aligning prices with the specific services provided. Increasing contractual commitments to firm transportation supply enables pipelines to provide more certainty in delivery capability and to better accommodate the services generators often desire. Tying product offerings to advance notice commitments also supports reliable pipeline performance. Enhancing service by tailoring commercial and contractual solutions enhances gas-electric alignment by:

- Prioritizing reliability and resiliency.
- Supporting a consistent level of service across the energy value chain.
- Leveraging commercial solutions to enhance alignment and mitigate risk.
- Demonstrating that market participants are motivated to reduce misalignment and friction.
- Underscoring the need for adequately sized infrastructure.
- Clearly identifying the cost of alignment.

4. Actions Required to Implement

- Market participants across the energy value chain should proactively initiate new products and determine demand for new offerings.
- RTO/ISOs will have to implement new business practices to accommodate new products and offerings.
- Policymakers will have to approve changes to tariffs as necessary.

5. Challenges to Implementation

- The cost of new services will likely be greater than current pipeline tariff rates, so cost/benefit evaluation will be required.
- Natural gas generators may need to identify and communicate desired services they historically were able to utilize indirectly as a result of the historic pipeline flexibility.
- The cost of new product offerings may indirectly impact pricing in RTO/ISOs. Market monitors in RTO/ISOs will likely need to weigh in on new proposals affecting generators in organized markets.
- Ultimately, pipeline service offerings will be limited by infrastructure constraints.

6. Impacted Stakeholders

- End-use customers: Customers should benefit from actions to better align electric demand and gas supply as it is supportive of reliability and resiliency. However, it will be important for end-use customers to understand the impact on cost.
- Gas-fired generators: Generators should benefit by obtaining access to new service offerings tailored for specific use cases.

- Pipeline operators: Operators should benefit from potentially more information regarding the expected performance and gas demands of its generation customers.

RECOMMENDATION #8: CLEARLY IDENTIFY ROLES AND RESPONSIBILITIES

The NPC recommends the Federal and State Issues Collaborative publish a framework that clearly identifies and defines the roles and responsibilities for reliability, resource adequacy, and fuel assurance.

1. Detailed Explanation

Transparency in an integrated energy system is essential for reducing market friction, enhancing accountability, and supporting effective risk mitigation. The range of governance models in the RTO/ISO markets is varied, and responsibilities, particularly concerning fuel assurance, are often unclear. Enhancing transparency is crucial for all stakeholders, especially end-use customers, who ultimately bear the risk of energy system failures. These customers need the ability to clearly identify and hold the appropriate authorities accountable for system performance and planning inadequacies. Chapter 3 of this report highlights fragmented governance, planning, and reliability coordination as key barriers to the adoption of previous gas-power alignment recommendations. To improve alignment between the gas and electric sectors and ultimately reduce risk for the customer, it is vital to maintain clear and distinct regulatory oversight and accountability. As the energy industry evolves to address the interdependency of these sectors and the convergence of risks in gas and electric markets, the associated governance and oversight structures must be transparent for stakeholders to effectively engage. This recommendation underscores the belief of the NPC that new oversight roles do not need to be created.

The Federal and State Issues Collaborative is uniquely positioned to clearly identify and publish the roles and responsibilities associated with electric reliability, fuel assurance, and planning. The Collaborative, which reflects a joint effort between FERC and the National Association of Regulatory Utility Commissioners (NARUC), was officially established by FERC in March 2024 to provide a venue for federal and state regulators to share perspectives, increase understanding, and, where appropriate, identify potential solutions regarding challenges and coordination on matters that impact specific state and federal regulatory jurisdiction. Potential topics include exploring where coordination is needed between state and federal regulators, such as in the following areas: electric reliability and resource adequacy, natural gas-electric coordination, wholesale and retail markets, new technologies and innovations, and infrastructure. The Collaborative is made up of all FERC commissioners plus 10 state commission representatives submitted by NARUC.

2. Primary Findings

The findings that this recommendation will address include:

- **Finding 3-1:** Operational improvements for electric and gas systems have been widely discussed in previous reports and forums and partially implemented. The electric sector has demonstrated more formalized progress, such as through NERC-led initiatives, while the gas sector's advancements have been primarily market driven.
- **Finding 3-4:** Clear and distinct regulatory accountability plays a critical role in advancing implementation of recommendations, largely because of authority scope.

3. Benefits

Clear accountability supports a well-aligned energy system that ensures real-time energy adequacy and resiliency, while also supporting long-term planning initiatives. Additionally, this recommendation utilizes existing cross-jurisdictional organizations and does not require the establishment of a new organization or increase in bureaucracy. Transparent accountability reduces market uncertainty and provides clarity in stakeholder decision-making, ultimately helping to reduce risk. This recommendation is a direct example of why transparent accountability is listed as a key characteristic of healthy alignment. This recommendation is supportive of most of the other healthy characteristics, including reliability and resiliency. In addition, the recommendation:

- Reflects a constructive policy environment.
- Acknowledges inherent physical limitations between natural gas and electric sectors.
- Reflects that participants are motivated to reduce misalignment and friction, allowing costs of alignment to be more clearly identified.

4. Actions Required to Implement

- FERC or NARUC will need to include the development of a roles and responsibilities framework as an agenda item for the Federal and State Issues Collaborative.
- The Collaborative will have to initiate regional meetings to discuss and establish a framework, which may need to be reconciled across different regions of the country. RTO/ISO and other subject matter representatives will likely be called upon to participate.
- The Collaborative should publish the framework identifying existing roles and responsibilities across the energy value chain.

5. Challenges to Implementation

- Because of the different structures across regions and markets, this effort will require a thorough evaluation of the roles and responsibilities across multiple regions and may vary at the state level.
- Because fuel assurance responsibility is not always explicitly defined in all regions and markets, some discussions and determinations may be challenging.
- This recommendation directly impacts gas-electric alignment, but is also essential to comprehensive planning, where roles and responsibilities may differ across regions.
- Action by the Collaborative will likely require convening regional meetings which are contemplated in the FERC order but will require additional time and coordination efforts.

6. Impacted Stakeholders

- End-use customers: Customers, who bear the most reliability risk, gain a more transparent view of entities' roles and responsibilities, improving their ability to hold the appropriate entities accountable.

- Federal and state policymakers: Policymakers can improve alignment with markets and other regulators because transparency brings a better understanding of roles and responsibilities.
- Market participants: Participants will benefit from understanding which entity is responsible for each role, enhancing accountability.

RECOMMENDATION #9: UTILIZE EXISTING ENTITIES TO IMPROVE LEADING PRACTICES

The NPC recommends the National Association of Regulatory Utility Commissioners (NARUC), convene a Natural Gas Readiness Forum working group to broaden stakeholder dialogue and *document* leading management practices across all interconnected sectors of the energy value chain.

1. Detailed Explanation

With elevated risk levels for supply shortfalls identified in several regions of the country, leading management practices should be documented to enhance transparency and coordination across the natural gas and electric value chains to improve fuel assurance, resilience, and reliability. The Natural Gas Readiness Forum (NGRF), established by NARUC and administered by the American Gas Association, is best positioned to convene diverse energy system stakeholders to document existing leading management practices. No new entity needs to be created. Despite its name, the NGRF includes representatives from both the natural gas and electric value chains (e.g., natural gas transportation, storage, and distribution operators; natural gas producers; electric utilities; federal and state regulators; state regulatory utility commissioners; RTOs; and federal and state officials.) Notably, NERC is also a participant in the forum. The multistate forum was established as an industry-led, voluntary effort aimed at improving the communication, preparation, and readiness of the energy sector. It is positioned to improve the energy value chain reliability via the promotion of collaboration and education across relevant stakeholders, which is critical to responding to the current national energy emergency, while still complying with applicable antitrust laws.

2. Primary Findings

The findings that this recommendation will address include:

- **Finding 3-1:** Operational improvements for electric and gas systems have been widely discussed in previous reports and forums and partially implemented. The electric sector has demonstrated more formalized progress, such as through NERC-led initiatives, while the gas sector's advancements have been primarily market driven.
- **Finding 3-4:** Clear and distinct regulatory accountability plays a critical role in advancing implementation of recommendations, largely because of authority scope.

3. Benefits

Utilizing existing entities and avoiding duplicative efforts is critical when reliability concerns are elevated and an energy emergency has been declared. The formation of the NGRF demonstrates that its participants are motivated to reduce misalignment and friction. Additionally:

- Discussion and documentation of industry-leading management practices, including performance criteria, guidance, processes, and protocols in a forum dedicated to

operational readiness across the entirety of the U.S. energy value chain is ultimately beneficial to all stakeholders because it is supportive of reliability.

- Recognizing that some progress has been made over the years, leveraging the NGRF allows for rapid action without having to convene another committee or organization.
- The compilation and sharing of Leading Management Practices across a diverse group of stakeholders encourages better understanding and adoption of practices, supporting several components of a healthy aligned market, including reliability and resilience, plus:
 - Acknowledging the inherent physical limitations between natural gas and electric sectors.
 - Supporting transparent accountability.
 - Creating a consistent level of service expectations.

4. Actions Required to Implement

- Direction or instruction by NARUC or the NGRF is needed to address this action item.
- The NGRF must include this specific topic in the agendas for its meetings.

5. Challenges to Implementation

- The NGRF has previously focused on winter reliability coordination. The original recommendation from NARUC establishing the NGRF may need to be revised and expanded, to the extent that new action items are outside the NGRF's original scope.
- A new communications effort to document leading management practices will require additional meetings.
- Segmented scope of authority over reliability standards on the energy value chain.
- Agreement across the diverse participants across the energy value chain.

6. Impacted Stakeholders

- End-use customers: Customers are the ultimate beneficiaries of improved collaboration and cooperation between the various entities in the energy value chain, as they are the ultimate beneficiaries of improved reliability and resiliency.
- Electric generators and electric utilities: Generators and utilities benefit from increased dialogue with other participants across the energy value chain, particularly nonelectric entities.
- Natural gas suppliers, pipelines, and LDCs: These groups benefit from increased dialogue with participants across the energy value chain, particularly electric utilities as practices and terminology differ across segments.
- RTO/ISOs: Increased dialogue with participants across the value chain improves understanding of how upstream and downstream participants perceive each other.
- Federal and state policymakers and officials: These groups benefit from close dialogue with other policymakers, but also with market participants across the value chain.

RECOMMENDATION #10: REFORM PERFORMANCE METRICS

The NPC recommends FERC enhance the Common Metrics report (FERC-922) released biennially and include an interim progress report with a focus on fuel assurance, resource adequacy, and other critical reliability metrics on a state-by-state basis.

1. Detailed Explanation

To increase transparency and accountability and to inform short- and long-term planning necessary to address the federally declared national energy emergency,¹⁵⁸ FERC should enhance and expand its Common Metrics report to include additional reliability and fuel assurance metrics.

The Common Metrics report was first established to develop standardized measures to track performance of RTO operations and markets, at the recommendation of the Government Accountability Office in 2008.¹⁵⁹ FERC released its first report on performance metrics (FERC-922) to Congress in April 2011.¹⁶⁰ In 2017,¹⁶¹ the Government Accountability Office found that FERC should take additional steps to improve the quality of the data collected and further document an approach to regularly identify, assess, and respond to risks that capacity markets face. In 2020, the Office of Management and Budget approved FERC's request to reinstate a revised version of the Common Metrics report.¹⁶² The current report provides a wealth of information and is accessible to the average reader.

The current Common Metrics report focuses on three areas: Administrative and Descriptive Metrics, Energy Market Metrics, and Capacity Market Metrics and is released every other year. The most recent edition (2023 Common Metrics) can be found here: <https://www.ferc.gov/media/2023-common-metrics>.

¹⁵⁸ The White House. "Executive Order No. 14156, Declaring a National Energy Emergency." January 20, 2025. <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

¹⁵⁹ U.S. Government Accountability Office. "Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance." GAO-08-987. September 26, 2008. <https://www.gao.gov/products/gao-08-987>.

¹⁶⁰ FERC. "Performance Metrics for Independent System Operators and Regional Transmission Organizations (FERC-922): A Report to Congress." April 2011. <https://www.ferc.gov/sites/default/files/2020-05/report-to-congress.pdf>.

¹⁶¹ U.S. Government Accountability Office. "Electricity Markets: Four Regions Use Capacity Markets to Help Ensure Adequate Resources, but FERC Has Not Fully Assessed Their Performance." GAO-18-131. December 2017. <https://www.gao.gov/assets/gao-18-131.pdf>.

¹⁶² On April 21, 2020, OMB approved the Federal Energy Regulatory Commission ... reinstatement and proposed changes to FERC-922 (Performance Metrics for ISOs and RTOs and Regions Outside ISOs and RTOs, OMB Control No. 1902-0262). <https://www.ferc.gov/industries-data/electric/electric-power-markets/rtoiso-performance-metrics>.

Similar to the type of data analysis reflected in the recent DOE Resource Adequacy Report, *Evaluating the Reliability and Security of the United States Electric Grid*, released in July 2025,¹⁶³ a robust data exchange is necessary to urgently address energy reliability and security concerns. FERC can leverage available information from entities such as the National Renewable Energy Laboratory (NREL), NERC, and the EIA to gather state and regional data for the development of an interim progress report. Transparency and accountability are important tools to guide states and regions as they take action and develop energy policies to inform short- and long-term planning necessary to close the current energy reliability gaps.

Though the NPC acknowledges the improvements to the current Common Metrics report, further adjustments are needed in light of the ongoing shift in load profiles and the rapid increase in demand discussed in previous chapters. The report should be expanded to incorporate additional reliability metrics for fuel assurance and resource adequacy to demonstrate adequate preparation. FERC should incorporate an appendix with additional data to increase transparency and better highlight and inform potential areas of mitigation for states.

Considering the current national energy emergency, the NPC recommends releasing a summary version of the report in the years when the full report is not released to better monitor resource adequacy and fuel assurance. Both the summary report and the full report should include the Capacity Market Metrics and fuel assurance metrics consistent with the following metrics:

- In-state generation mix.
- Peak demand.
- Energy load.
- In-state electric capacity supply, including level of fuel supply and delivery assurance.
- Outages and generator performance.
- Peak and off-peak imports vs. import transmission capacity.
- Generation additions and retirements.
- Gas system capacity.
- State policy directives (such as limits or targets informing generation mix) and regulatory/legislative mandates that impact system reliability.
- Committed generation gas procurement relative to forecast peak demand.
- Share of winter peak served by firm resources.
- Number of starts for gas generators per month.
- The number of hours per month generator is idle/offline.

¹⁶³ DOE. “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid.” July 2025. <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

2. Primary Findings

The findings that this recommendation will address include:

- **Finding 2-10:** Development of flexible, fast-ramping gas-fired generation is essential to enhance grid reliability. NERC now recognizes fuel security as a key reliability risk to the power system due to the ramping requirements of natural gas units.
- **Finding 3-4:** Clear and distinct regulatory accountability plays a critical role in advancing implementation of recommendations, largely because of authority scope.

3. Benefits

Customers and stakeholders should have a clear view of the reliability risks they face in order to hold policymakers and regulators accountable. Common metric comparisons at the state level can aid policymakers in balancing cost and reliability, inform federal and state policy, and enhance gas and electric system coordination and long-term planning. These comparisons can also identify reliability risk trends, resource adequacy and fuel assurance concerns, and provide insight into state reliability solutions. This recommendation addresses the transparent accountability characteristic. Adoption of this recommendation is consistent with these underlying principles relevant to supporting customers:

- Clear accountability helps identify responsibility for risks and improves management of uncertainties.
- Accountability mechanisms should be well defined and enforced for every stakeholder across the gas and electric value chain, including policymakers.
- Roles and responsibilities are publicly stated with clear pathways for oversight, performance monitoring, and corrective action when issues emerge.

4. Actions Required to Implement

- FERC may be required to seek Office of Management and Budget approval to make amendments to the current approved metrics.
- Stakeholder engagement and technical conferences¹⁶⁴ are needed to help inform metrics.
- Adoption of metrics and reporting process.
- Approval from the Office of Management and Budget is likely required for additional information collection.

5. Challenges to Implementation

- FERC action may be necessary as RTOs/ISOs may be reluctant or lack authority to require state reporting.

¹⁶⁴ A FERC technical conference is a public, staff-led meeting convened to gather information, exchange views, and build the record on complex or emerging issues within the Commission's jurisdiction. Technical conferences allow stakeholders—including industry participants, state regulators, and the public—to present data and perspectives that inform potential Commission actions as part of a formal record, but they do not by themselves establish binding rules or policy or adjudicate specific cases.

- Additional resources and costs required by RTOs/ISOs to support additional metric reporting.
- Political reactions by states.

6. Impacted Stakeholders

- End-use customers: Customers will benefit from common metrics that they can use to evaluate their providers and accountable entities.
- RTO/ISOs: RTO/ISOs will be subjected to additional evaluation of resource adequacy and fuel assurance.
- State policymakers: Policymakers may also be subjected to additional evaluations of resource adequacy and fuel assurance depending on the state relationship with the energy market.

Appendices

Appendix A:

Study Request Letter and Description of the NPC

Appendix B:

Study Group Rosters

Appendix A
Study Request Letter and
Description of the NPC



The Secretary of Energy

Washington, DC 20585

June 30, 2025

Mr. Alan Armstrong
Chair
National Petroleum Council
1625 K Street, NW
Washington, DC 20006-1656

Dear Mr. Armstrong:

Many of President Trump's directives, including Executive Order 14156, *Declaring a National Energy Emergency*, Executive Order 14154, *Unleashing American Energy*, and Executive Order 14213, *Establishing the National Energy Dominance Council*, underscore the critical role of domestic energy and natural resources in powering the Nation's economic prosperity and national security. Meeting future energy needs will require ingenuity, innovation, and market-based solutions.

Accordingly, I request that the National Petroleum Council (NPC) undertake a broad *Future Energy Systems* study with subcomponent deliverables designed to recognize and leverage the vast potential of domestic oil and natural gas resources and industry expertise to advance Administration goals for increasing the availability of affordable, reliable, and secure energy for American consumers and our allies. The scope of this study should be developed with key objectives, deliverables, and timelines mutually determined between the NPC and the Department. Please work with Deputy Assistant Secretary Ryan Peay from the Office of Fossil Energy and Carbon Management (FECM) to delineate the preliminary scope and subcomponent deliverables within the next 30 days.

For the initial deliverables within the *Future Energy Systems* study, I am requesting the NPC address two priority topics immediately, with reports delivered to me by December 2025. These topics are crucial to advancing the priorities outlined in President Trump's energy agenda and require prompt and focused attention:

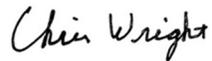
Oil and Natural Gas Infrastructure Permitting. Streamlining and expediting permitting is essential for all parts of the energy value chain and for building infrastructure to meet future energy needs. Re-evaluating and updating the permitting section of the NPC's 2019 Dynamic Delivery study report with practical recommendations based on current legislation and regulations can provide meaningful input to support the effective redesign of government systems and siting of new energy infrastructure. The advice of the NPC on this topic will be particularly helpful in concert with the work of the National Energy Dominance Council. Important also will be insights regarding factors that affect industry's ability to attract and retain private sector investment or rapidly deploy new technologies that increase safety, integrity, or operational efficiency.

Gas-Electric Coordination. A failure of natural gas infrastructure to keep pace with growing natural gas demand has created natural gas supply challenges and revealed new risks to the reliability of interconnected natural gas and electric power systems. A misalignment between the electric power and natural gas markets has exacerbated these risks resulting in inadequate access to natural gas and cost impacts to power consumers. The misalignment is rooted in fundamental market differences that influence decision making and the pace of infrastructure development made worse by legacy decarbonization mandates and the rapid growth of electricity demand. The NPC, working with both natural gas suppliers and electric power producers, can bring forward unique insights regarding the growth of natural gas demand in the United States and resolution of the misalignment of the natural gas and electric markets that if not addressed could threaten energy security, reliability, and affordability. This study should assess how rising natural gas and electricity demand and shifting load patterns are straining natural gas pipelines in key regions of the United States; examine what impact these strains can have on energy reliability; and recommend actionable strategies to address the misalignment between these two industries that can prevent or mitigate reliability impacts. The study will fill an important gap and complement ongoing gas-electric reliability and coordination initiatives involving industry and/or government by specifically focusing on the energy reliability risk viewed from the perspective of natural gas infrastructure operations and capabilities.

For the broad ***Future Energy Systems*** study, I request the NPC consider other additional subcomponents for which it can deliver high-value, actionable, and timely advice. Topics that may meet these criteria include energy security, infrastructure security, and analyses supporting U.S. energy trade and competitiveness globally.

I welcome continued dialogue with the NPC as we work together to shape a new era of American technology leadership and energy dominance. Please keep me advised of progress on the efforts addressed in this letter.

Sincerely,



Chris Wright
Secretary of Energy

cc: Ryan Lance
Vicki Hollub

NATIONAL PETROLEUM COUNCIL

**MEMBERSHIP
(196)**

December 3, 2025

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BACKGROUND INFORMATION ON THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters. Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council (NPC) on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new Department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy and the Executive Branch on any matter requested or approved by the Secretary, relating to oil and natural gas or the oil and gas industries. Matters that the Secretary would like to have considered by the Council are submitted in the form of a letter outlining the nature and scope of the study. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of reports of studies undertaken by the NPC at the request of the Secretary include:

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Appendix B

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STUDY PARTICIPATION

Participants in this study contributed in a variety of ways, ranging from work in all study areas, to involvement on a specific topic, to reviewing proposed materials. Involvement in these activities should not be construed as endorsement or agreement with all the statements, findings, and recommendations in this report. Additionally, while U.S. government participants provided significant assistance in the identification and compilation of data and other information, they did not take positions on the study's recommendations.

As a federally appointed and chartered advisory committee, the NPC is solely responsible for the final advice provided to the Secretary of Energy. However, the NPC believes that the broad and diverse participation has informed and enhanced the study and advice. The NPC is very appreciative of the commitment and contributions from all who participated in the process.

This appendix lists the individuals who served on this study's Coordinating Subcommittee and Task Groups, as a recognition of their contributions. In addition, the NPC wishes to acknowledge the numerous other individuals and organizations who participated in some aspects of the work effort. Their time, energy, and commitment significantly enhanced the study, and their contributions are greatly appreciated.

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Gas-Electric Coordination Task Group 2 – Chapter 2: Increasing variable demand on natural gas pipelines and threats to reliability

Gas-Electric Coordination Task Group 3 – Chapter 3: Current state of gas-electric coordination

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