

The Replacement Challenge: Why US Gas Supply Sits Inside a Tightening Price Corridor



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Executive Summary

In 2025, the United States produced 1,108 bcm of natural gas and exported a record 113 Mt of LNG, the first time any country has crossed the 100 Mt annual threshold. As both the world's largest gas producer and largest LNG exporter, the economics governing US supply set the marginal cost of new LNG entering global markets and, by extension, shaped the competitive order across the entire gas value chain. Major energy outlooks have revised the US production trajectory upward over the long-term, yet beneath that revised growth lies a structural challenge the headline numbers obscure: sustaining the trajectory requires an unprecedented replacement of declining unconventional resources at the very moment lower-cost international supply intensifies competition for LNG market share. Three strategic findings stand out:

- First, future production is a replacement story, not a net expansion story. Existing unconventional fields, the backbone of US production today, are declining at approximately 10% per year. Sustaining the revised production trajectory will require roughly 1,000 bcm of entirely new unconventional supply by 2050, equivalent to nearly a quarter of current global gas production. Sustaining this trajectory would require Henry Hub (HH) prices at structurally higher levels than those seen during the shale era, around USD 4.50/MMBtu on a full-cycle basis to develop secondary acreage.
- Second, US gas supply operates within a narrow economic corridor constrained from three directions. The lower bound is set by the rising breakeven cost of marginal replacement acreage. The upper bound is set by the delivered-cost competition of lower-cost international producers expanding capacity. A third axis runs through oil prices, with nearly one-third of US gas production coming from oil-directed basins. The corridor is wide today, supported by elevated TTF and JKM prices following the 2026 disruption to Gulf LNG and oil flows, which simultaneously holds the oil floor in place. Through the late 2020s and into the 2030s, the corridor is expected to narrow as new African and Middle Eastern supply compresses the spread against international benchmarks, while US domestic demand from data centres and AI infrastructure pushes Henry Hub higher. A softer oil-price environment would narrow the corridor from a third direction rather than two.
- Third, the implications for global gas markets are structural, though their near-term timing is mediated by an elevated geopolitical premium. The disruption to Gulf shipping in early 2026 has lifted both oil and international gas prices, temporarily underwriting US LNG economics and supporting the Permian associated-gas growth that anchors the US supply floor. This security-driven support is unlikely to persist long-term. While existing US LNG capacity is largely protected by long-term contracts, the US could gradually cede ground as the marginal source of new global supply. Portfolio traders and buyers renewing offtake agreements in the 2030s will face a vastly different market with more options, placing new US investment decisions under competitive pressure from lower-cost global alternatives.

Introduction

North America is the world's largest gas-producing region, anchored by the United States (US) as the single largest producer and LNG exporter globally. The US production trajectory and the pace at which new LNG capacity is sanctioned shape future global gas markets. In 2025, the US produced 1,108 bcm of natural gas (25% of global gas production) and exported a record 113 Mt of LNG — the first time any country has surpassed the 100 Mt annual threshold (GECF Annual Gas Market Report 2026). Its LNG export capacity is set to nearly double from approximately 123 Mtpa in 2025 to 230 Mtpa by 2030 based on already-sanctioned projects alone (Wood Mackenzie, 2025).

As the global LNG market expands, the US is increasingly emerging as the marginal LNG producer in international markets, shaping global LNG balances and conditioning the competitive position of every other LNG-exporting nation. How the US gas supply evolves over the next decades is therefore a question of global, not regional, importance.

In every major energy outlook, from international agencies through leading consultancies to the GECF, US gas production is projected to continue growing over the long term, peaking in some outlooks the mid-to-late 2030s before entering gradual decline. Beneath this growth trajectory, however, lies a significant structural bottleneck. The US gas supply is dominated by unconventional resources that decline at roughly 10% annually and sustaining high levels of gas production over the long term will require very large volumes of entirely new unconventional supply to come online. This replacement effort cannot be delivered at the low Henry Hub price levels of around USD 2-3/MMBtu that prevailed through much of the 2010s, and the materially higher prices it now requires sit uncomfortably close to the levels that would erode the competitiveness of US LNG exports against lower-cost suppliers.

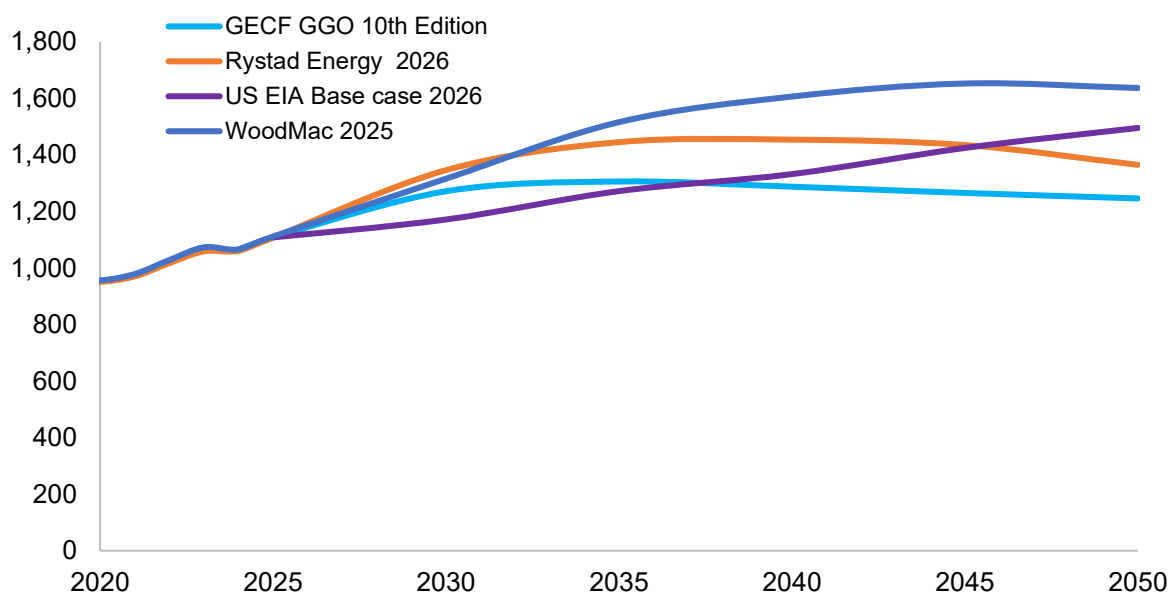
This commentary examines four dimensions of the projected US gas supply trajectory and the structural challenges it carries. First, the long-term growth in US gas production and factors supporting the trajectory across several outlooks. Second, the replacement challenge posed by the fast-depleting unconventional resources that have anchored US production over the past decade. Third, the dual dependence of US gas supply on both oil and gas prices, arising from the growing share of associated gas in the production mix. Fourth, the long-term implications for global gas markets, and the moderating role of current geopolitical premia in determining where US LNG retains, and where it cedes, the marginal investment ground. A central thread runs through all four: US gas supply faces a narrow economic corridor. Henry Hub must rise enough to remunerate the development of higher-cost replacement acreage, but cannot rise so far that delivered US LNG loses ground to lower-cost producers.

1. Foundations of the long-term supply expansion

The growth in US gas production expected through the next two decades is shared across the major energy outlooks (Figure 1). The GECF Global Gas Outlook 2055 (10th Edition) projects US production rising to 1,272 bcm by 2030 and peaking at 1,306 bcm in 2035, before easing

modestly through 2050. Other major outlook providers — Wood Mackenzie, Rystad Energy, and the US Energy Information Administration — concur on substantial growth through the next decade and a half, with long-term views by 2050 ranging from approximately 1,250 to over 1,600 bcm. The wider divergence over this long-term horizon reflects differing views on the pace of decline in maturing unconventional basins and the speed at which higher-cost replacement acreage is unlocked. The central conclusion, however, is shared: the US is set for substantial gas-supply expansion from current levels.

Figure 1 US natural gas production projections across energy outlooks (bcm)



Source: GECF Secretariat based on data from GECF Global Gas Outlook 2055 (10th Edition), Wood Mackenzie (2025), Rystad Energy (2026), and US EIA Annual Energy Outlook (2026)

Four factors underpin this projected growth, each working through its effect on the investment outlook for new upstream development.

- First, domestic demand in the US itself is providing commercial certainty. The GECF Global Gas Outlook projects power-sector gas consumption to grow more rapidly than historical trends, with electricity demand accelerating to 1.3% per annum through 2055, compared with just 0.4% per year over the two decades to 2024. The shift is concentrated in commercial computing: the US Energy Information Administration's (EIA) expects data-centre and AI-related loads to rise from around 8% of commercial electricity consumption in 2024 to about 20% by 2050, reshaping load profiles and lifting peak demand. These facilities require round-the-clock, dispatchable power that variable renewables cannot fully provide, reinforcing the role of combined-cycle and fast-ramping gas turbines as firm capacity. Wood Mackenzie estimates US gas-fired generation will grow from about 350 bcm in 2025 to more than 470 bcm by the early 2040s, a 35% increase in burn from one sector alone. The strength of this demand pull is reflected in price expectations with the EIA 2026 Annual Energy Outlook projects

HH in the USD 5–6/MMBtu range through the early 2030s, a level historically unusual for sustained periods. Stronger and more predictable demand improves the price outlook and the investment case for new upstream development, supporting higher production projections.

- Second, accelerated LNG export sanctioning is unlocking long-cycle upstream capital. The removal of the US regulatory pause on non-FTA approvals catalysed a rapid normalisation of project advancement. In 2025, seven US LNG projects representing 62 Mtpa of export capacity reached FID (GECF, 2025), bringing US non-speculative liquefaction capacity (sanctioned, under construction, and proposed pre-FID) to around 270 Mtpa by 2040 (Wood Mackenzie, 2025). The long-term offtake contracts underpinning these projects provide firm price visibility and predictable revenue streams that enable upstream operators to commit to multi-year development programmes. What matters for upstream investment is the contracting behaviour underpinning these sanctions. The long-term offtake contracts underpinning these projects provide firm price visibility and predictable revenue streams that enable upstream operators to commit to multi-year development programmes.
- Third, technical performance has exceeded expectations. The adoption of extended laterals in the Permian has, according to Rystad Energy, limited productivity degradation per foot while delivering cost reductions, with type-curve upgrades more than offsetting the decline in rig activity. Additionally, rig productivity increased across all basins, in the Permian for example rig productivity increased by 20% compared to 2020 level according to Wood Mackenzie. Additionally, some operators reported 10–15% supply improvement from scaled AI deployment in completion optimization, well placement, and real-time drilling decisions in the Marcellus (Snyder, 2026). These gains are part of a broader innovation cycle now underway across US unconventional. McKinsey & Company identifies 27 emerging technologies and oilfield practices – spanning four-mile laterals, AI-driven completions, advanced proppants, and remote operating centres – with the cumulative potential to reduce breakeven by 17-32%, over the next five to ten years (McKinsey & Company, 2026).
- Fourth, easing infrastructure and permitting constraints are enabling supply to reach demand centres. Production growth in the lowest-cost US basins, particularly the Permian and Appalachia, has historically been capped by takeaway bottlenecks rather than by resource availability. In the Permian, the commissioning of Gulf Coast Express, Permian Highway, Matterhorn, and Blackcomb, together with Hugh Brinson and the planned Permian-to-REX expansion, lifts total basin evacuation capacity to roughly 300 bcm by 2027 (Wood Mackenzie, 2025).

By relaxing the midstream constraint on the supply response, these developments allow the investment signals from stronger demand, LNG sanctioning, and operator-level efficiency gains to translate into produced gas volumes to markets.

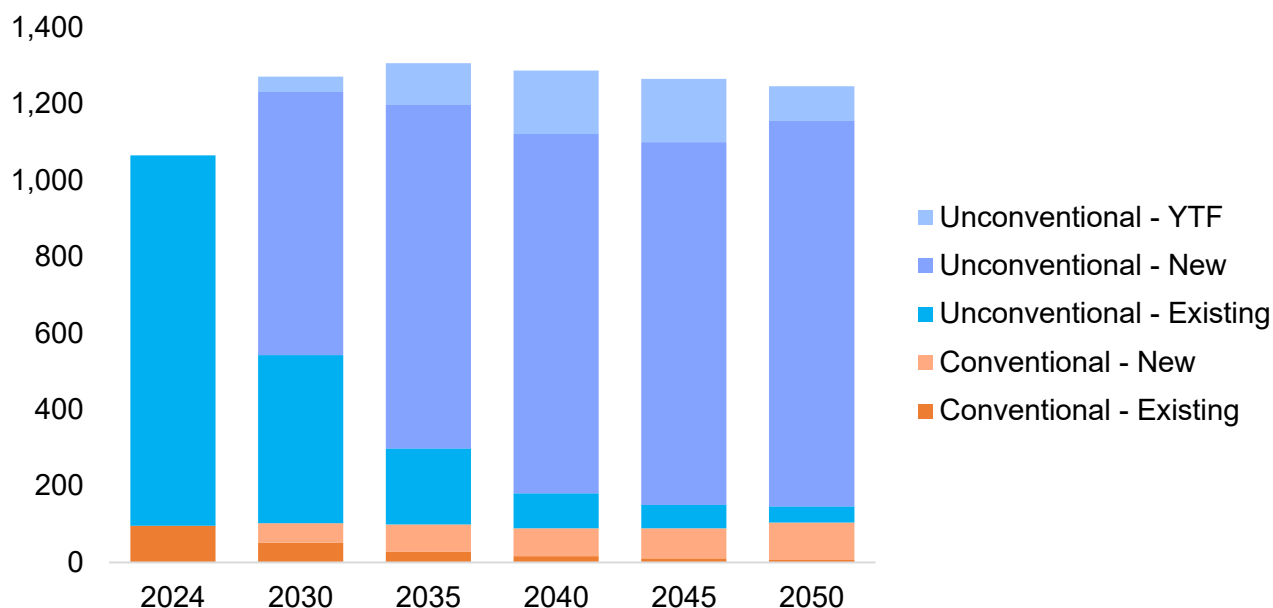
2. The replacement challenge

The headline growth in the US gas supply conceals a heavy replacement burden. Unconventional resources account for 91% of gas production, declining at 10–11% per year - meaning the country must keep drilling at a substantial pace simply to keep production flat. Sustaining long-term market volumes requires entirely new unconventional production to scale continuously, growing to approximately 1,000 bcm per year by 2050. Supplying gas on this scale is fundamentally a replacement operation, offsetting legacy wells that are running down faster than headline production figures suggest.

The replacement burden becomes binding in the second half of the 2030s. By that point, North America's major unconventional basins are forecast to have reached peak production, after which new projects, those not operational in the base year of 2024, become the principal driver of all production. Ultimately, the sheer scale of this replacement effort will constrain net growth, causing total US production to peak near 1,306 bcm by 2035 before gradually easing to 1,240 bcm by 2050 (GECF, 2026) (Figure 2). What looks like a flat or gently declining headline number therefore conceals a rapid replacement underneath: existing assets declining, new projects scaling up to fill the gap. However, filling this gap will be complicated by rapid industry consolidation, which has concentrated remaining inventory among disciplined operators unwilling to develop marginal acreage without higher price incentives (Kimmeridge, 2025).

The challenge is not just how fast wells decline, but what kind of acreage will replace them. Outside the Permian and Appalachia, most major basins already hold fewer than four years of Tier 1 inventory at current rig counts (McKinsey & Company, 2026). Independent inventory analysis points in the same direction, with high-return drilling locations estimated at approximately 6–8 years in the Permian sub-basins, 6 years in the Marcellus, and less than 3 years in the Haynesville core at current pace (Kimmeridge, 2025). The transition to lower-quality acreage is therefore not a 2030s phenomenon; for most basins, it is already underway. As operators move to secondary acreage, well productivity typically falls 20–30% according to Rystad Energy while drilling and completion costs rise due to more complex geology. Independent operator data points in the same direction: Dallas Fed survey respondents report 15–20% lower reserves in secondary zones (Snyder, 2026). These shifts lift the economic threshold for new development materially above the prices that defined the early shale era, which the following section discusses.

Figure 2 Natural gas production outlook of the United States by project type, 2024-2050 (bcm)



Source: GECF Global Gas Model 2025

3. The dual impact of oil and gas prices

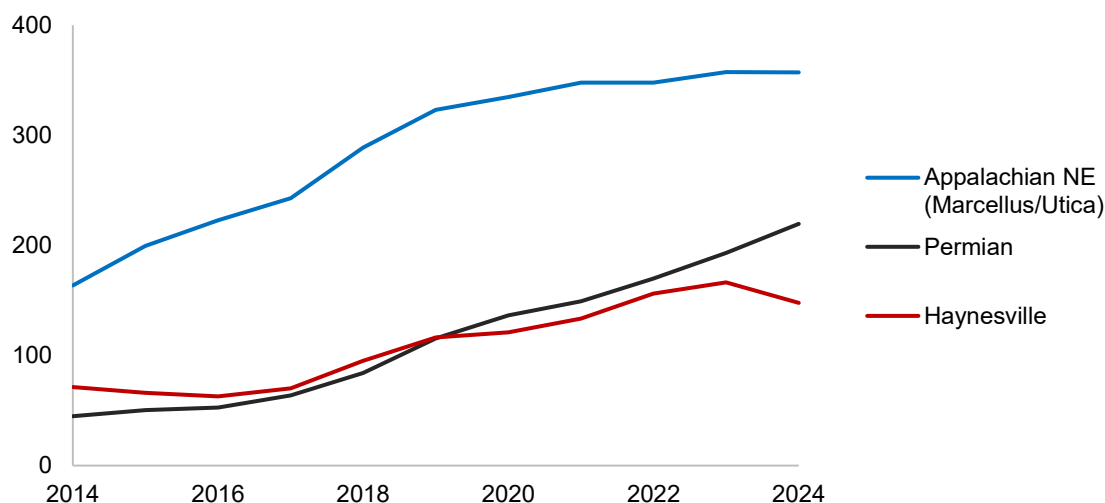
3.1 The associated gas dimension: oil price as a determinant of gas supply

Over the past decade, gas production growth in the US was driven by low-cost associated gas. In 2014, gas production from oil-directed basins, mainly the Permian, but also the Eagle Ford, Williston, and Denver-Julesburg, accounted for approximately 25% of total US gas production. By 2024, that share had risen to 38%. Figure 2 highlights this growth trend by basin, showing the sustained rise of associated gas from the Permian compared to non-associated gas from Appalachia and the Haynesville. This divergence means that nearly 40% of US gas production is now linked to oil-directed drilling, making crude oil prices a major determinant of gas supply dynamics. Associated gas is set to play a key role in the future of US gas production with more than 110 bcm of gas pipeline expansion has been committed out of the basin (Snyder, 2026).

The mechanism driving this associated gas boom is well maturation, rather than new gas-directed drilling. As reservoir pressure declines, the gas-oil ratio rises, and existing wells contribute growing volumes of gas even when new drilling slows. Associated gas therefore provides a partial supply floor for the US market, although that floor is not unlimited.

A downside risk of relying increasingly on associated gas is its dependence on oil prices. Based on breakeven analyses from Rystad Energy, sustained WTI prices below approximately USD 60/bbl mark a meaningful threshold for the cheap-gas component of US supply, slowing oil-directed drilling and weakening the associated gas growth trajectory. Analysis from Wood Mackenzie suggests that if WTI were to fall to and remain at USD 50/bbl over a multi-year horizon, roughly 100-120 bcm of associated gas production could be lost.

Figure 3 Gas production in the major US basins from 2014 to 2024 (bcm)



Source: GECF Secretariat based on data from the Rystad Energy

3.2 The non-associated gas dimension: a rising price floor

The major non-associated gas basins, Appalachian Northeast (Marcellus/Utica) and Haynesville, remain substantial contributors to US supply, together accounting for approximately 47% of total production in 2024. However, their growth trajectories have shifted markedly, as detailed in Table 1.

In the Appalachian Northeast, the growth narrative has encountered a physical ceiling. Despite holding vast undeveloped resources, production in the Marcellus and Utica shales has plateaued near 357 bcm, constrained primarily by limited pipeline takeaway capacity to Gulf Coast demand centres acting as the primary break. The basin added 159 bcm of incremental supply between 2014 and 2019, but only 34 bcm between 2019 and 2024, a sharp deceleration that infrastructure expansion has not yet reversed.

Table 1 Gas production in the major US basins (bcm)

Basin	Gas production		Incremental production	
	2014	2024	2014-2019	2019-2024
Appalachian (Marcellus/Utica)	164	357	159	34
Permian	45	220	71	104
Haynesville	71	148	45	32

Source: GECF Secretariat based on data from the Rystad Energy

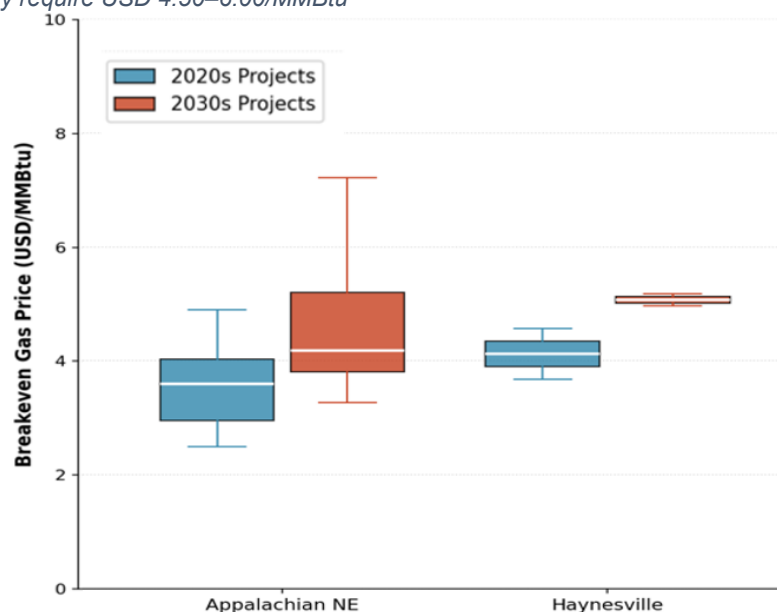
An emerging dynamic may ease this bottleneck without requiring unlikely long-haul pipelines to the Gulf Coast. Rather than moving gas to demand, the market is bringing demand to the gas. Data centres are increasingly clustering in Appalachia to draw directly on local production, supported by advancing short-haul pipeline expansions, including Mountain Valley Pipeline and its south-east extensions. If this localized demand continues, the Marcellus basin could

play a larger role in medium-term supply without requiring significantly higher HH-equivalent prices (Snyder, 2026). This dynamic does not, however, alleviate the broader replacement challenge; it shifts a share of Marcellus volumes from feedgas for Gulf Coast LNG to behind-the-meter power supply.

The Haynesville plays a different role. It is the principal price-responsive basin in the US market and acts as the main marginal source of non-associated supply. Production expanded rapidly when HH averaged USD 6.4/MMBtu in 2022, but momentum proved reversible: as prices fell to USD 2.2/MMBtu in 2024, activity moderated sharply, confirming the basin's role as a marginal supplier that adjusts production relative to specific economic thresholds.

While operating costs of around USD 1.50/MMBtu allow existing wells to keep producing through downturns, Rystad Energy data indicates that sustaining new development requires HH above USD 4.50/MMBtu to incentivise the secondary acreage that the replacement effort needs at scale. Figure 3 shows breakeven costs for projects starting up in the 2020s versus the 2030s. Across all major basins, costs are rising as operators exhaust core inventory and move into less productive acreage. While 2020s projects in the Permian and Appalachian basins remain largely below USD 3.50/MMBtu, 2030s developments increasingly require USD 4.50–6.00/MMBtu to be economic, implying sustained upward pressure on HH prices.

Figure 4 Breakeven gas prices for projects starting up in the 2020s are largely below USD 4/MMBtu; 2030s projects increasingly require USD 4.50–6.00/MMBtu



Source: GECF Secretariat based on data from the Rystad Energy

3.3 The price corridor: lower bound, upper bound

The replacement challenge therefore creates a constraint that runs in both directions. HH must rise sufficiently to unlock the secondary dry-gas inventory required through the 2030s, but it cannot rise too far without eroding the spread against TTF and JKM that underwrites US LNG competitiveness in the global LNG market.

The US gas industry therefore operates within a narrow economic corridor. The lower bound is dictated by the rising breakeven costs of its marginal supply basins. The upper bound is constrained by the delivered-cost competition of other producers, including Qatar, the UAE, Mozambique, and Nigeria.

The corridor is, however, not defined by HH alone. As established in Section 3.1, nearly 40% of US gas production now comes from oil-directed basins. The economic viability of that supply depends on WTI rather than HH, which means oil prices act as a third axis of the corridor. Sustained WTI above approximately USD 60/bbl keeps associated gas flowing and partially insulates HH from upward pressure. Below that threshold, the cheap-gas floor erodes and the replacement burden shifts onto non-associated basins.

Today's elevated TTF and JKM, sustained by the disruption to Gulf LNG flows in early 2026 alongside tight European balances, keep that upper bound comfortably high. The same disruption is keeping WTI elevated, which simultaneously sustains associated gas growth and holds the cheap-gas floor in place. But by the 2030s, as new African LNG comes online alongside competitive Middle Eastern expansion, oversupply is likely to compress the TTF–HH spread. Simultaneously, AI and data-centre demand within the US could push HH higher still. The corridor narrows from both ends. If a softer oil-price environment accompanies that gas-side rebalancing, the corridor narrows from three directions rather than two.

4. Long-term implications for global gas markets

The narrow corridor identified in Section 3 does not remain confined to North America. As HH adjusts to the replacement challenge and international benchmarks respond to new supply, the consequences propagate directly into global gas markets through the LNG channel. The path to the 2030s is likely to unfold in two distinct phases, with very different implications for US supply, investment, and contract economics.

4.1 Near term: geopolitical premium that buys time

The current elevated risk premium in oil and gas markets, driven by the disruption to Gulf shipping and the closure of the Strait of Hormuz in early 2026, has lifted WTI and Brent above levels that supply-and-demand fundamentals would otherwise support, while simultaneously removing approximately 20% of global LNG supply from the market. This environment is supportive of the US replacement challenge outlined in Section 2. The geopolitical premium is doing two things at once: lifting WTI above the level that sustains Permian associated-gas growth, and keeping international benchmarks high enough to underwrite US LNG economics. In the near term, the crisis is buying the US upstream sector time to sanction the new unconventional volumes that the decline curve requires. The question is what happens when the premium fades and African and Middle Eastern volumes arrive - does the corridor close from both ends?

4.2 From the early 2030s: the corridor narrows

This environment is unlikely to persist through the outlook horizon. Three structural shifts are set to converge by the early 2030s.

- First, the scale of the incoming supply wave is substantial and largely already committed. Qatar's North Field expansion is the largest single contributor, raising capacity from 77 to approximately 142 Mtpa, with first new trains originally scheduled for 2026–2027 and full capacity by 2030. The UAE's Ruwais LNG (9.6 Mtpa) is expected online in 2028. The timing of these expansions, and the pace at which existing affected capacity returns to full operation, will depend on the resolution of the current disruption and the restoration of normal Gulf shipping conditions. A return of Middle East volumes through 2028–2029, even at moderately delayed timelines, would mark a meaningful shift in global LNG balances.
- Second, new supply is coming from Africa. The GECF Global Gas Outlook 2055 identifies Africa as the fastest-growing producing region through 2055. Mozambique LNG is expected to deliver first production by 2030. Nigeria's NLNG Train 7 is expected online by 2027, raising liquefaction capacity from 22 to 30 Mtpa, with further FLNG projects advancing. Tanzania and Senegal-Mauritania add further optionality.
- Third, demand-side pressure builds inside the US itself. AI and data-centre loads will push power-sector gas consumption higher than projected even a year ago, tightening the domestic balance precisely as international competition intensifies. With HH already projected by EIA to remain in the USD 5–6/MMBtu range through the early 2030s, this domestic demand pressure could push the spread against international benchmarks beyond what greenfield US LNG projects can absorb.

The combined effect is a corridor that narrows from both ends. African and Middle Eastern volumes pull TTF and JKM lower; US domestic demand and rising secondary-acreage costs push HH structurally higher.

4.3 Implications for US investment, contracts, and competitiveness

The narrowing corridor expresses itself through three distinct channels.

- Operational cargoes continue to flow. Over 300 Mtpa of non-speculative North American LNG capacity will be in place or under construction by 2040, operating under long-term take-or-pay arrangements. These volumes are largely insulated from short-term price movements and will continue lifting across most market conditions.
- New FIDs become harder to underwrite. A structurally higher HH combined with a narrower TTF and JKM spread erodes the economic space for greenfield US projects against the delivered cost of low-cost international suppliers. Brownfield expansions at existing US terminals, which benefit from lower capital intensity and contracted offtake, are likely to proceed. Pure greenfield developments without equity offtake or contracted volumes face a far more demanding test.

- Contract renewals could be repriced. The first long-term US LNG sales contracts signed during the early shale-export era begin to expire in the 2030s. When buyers and portfolio traders, come to renew their offtake agreement, the negotiation will take place in a very different market than the one in which the original deals were struck. Buyers will have more options to choose from, and lower-cost producers will be well placed to win contract volumes that the US would find harder to defend on price alone.

5. Conclusion

The replacement challenge facing North American gas supply is real, and its implications extend well beyond the region. As the price corridor tightens through the 2030s, US producers will need HH high enough to develop higher-cost acreage, but not so high that LNG exports lose their competitive edge. Existing US LNG capacity will continue to operate, supported by long-term contracts; but new projects and contract renewals will face a tougher test against lower-cost producers in the Middle East and well-positioned projects in Africa. For global gas markets, the result is a more contested competitive landscape.

A reasonable counterargument is that innovation and material conventional frontier discoveries could rescue the economics. If the technologies described in Section 1 scale up, drilling costs fall, more unconventional acreage becomes profitable, and pressure on Henry Hub eases. New conventional frontier discoveries could also raise the long-term reserve ceiling in the outer years. This is possible; however, it does not change the conclusion. Even the most optimistic projections of cheaper drilling assume a much lower Henry Hub than the EIA now expects, and they leave out the demand surge from AI and data centres. Equally, frontier gas discoveries do not automatically translate into low-cost reserve replacement. In many cases, they require additional infrastructure, long-cycle project execution, export routes, liquefaction capacity, and sustained capital commitments before they can be converted into commercial reserves. Alaska illustrates the point clearly: gas potential exists, but meaningful additions depend on the delivery of major infrastructure, while high drilling and development costs limit its ability to lower the marginal cost of US supply. More broadly, conventional gas discoveries have declined sharply, frontier basins remain selective and risk-weighted, and their expected contribution is meaningful but insufficient to offset the scale of the US unconventional replacement burden. Therefore, material frontier discoveries should be treated as upside optionality, not as a base-case solution to the tightening US gas price corridor, unless they are confirmed, sanctioned, connected to markets, and capable of delivering gas at a competitive marginal cost.

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