

Q3
2026



Energy Economic Horizons

A QUARTERLY PUBLICATION OF THE
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AUTHORS

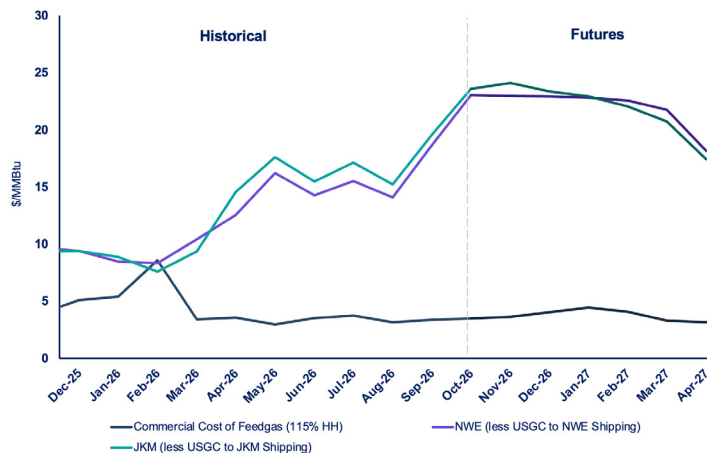
Tim Boersma
Director
tboersma@thinkbrg.com
+31 64 322 94 48

Drake Hernandez
Director
dhernandez@thinkbrg.com
+1 617 337 4498

Prabhat Agrawal
Associate Director
pagrawal@thinkbrg.com
+65 6022 2111

Economic Horizons for LNG and Gas-Fired Generation

US LNG COMMERCIAL MARGINS



Notes

Commercial cost of feedgas: 115% HH (Source: S&P).

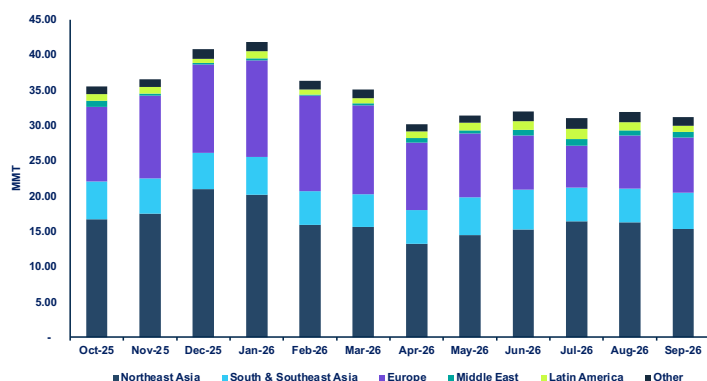
NWE (less USGC to NWE shipping): Platts NWE *minus* BRG calculated shipping costs (Sabine Pass to Zeebrugge).

JKM (less USGC to JKM shipping): Platts JKM *minus* BRG calculated shipping costs (Sabine Pass to Futtsu).

Insights

- As the Iran war continues:
 - > LNG prices in Europe and Asia continue to rise, approaching levels not seen since early 2023.
 - > Futures markets for LNG indicate uncertainty; futures will remain flat through end of year before dipping in spring 2027.
 - > Henry Hub (HH) prices remain steady at normal levels.
 - > Future curves through end of 2026 indicate LNG trading margins of around \$16.50/MMBtu and \$17.20/MMBtu for NWE and JKM markets, respectively, primarily driven by consistent elevated margins in Europe and Asia, while HH remains at normal levels.

GLOBAL LNG IMPORTS



Notes

Regional data aggregated based on individual cargo deliveries (Source: Kpler).

Insights

- Over the trailing twelve months:
 - > Global monthly imports averaged 34.5 MMT.
 - > Northeast Asia—predominantly Japan, Korea, and China—accounted for 48% on average of global imports.
 - > Global imports of LNG in Q3 2026 were down 7.4 MMT (-7.2%) compared to Q3 2025, primarily driven by price and supply constraints due to ongoing war in Iran.

CCUS Moves from Policy Ambition to Project Delivery

Carbon capture, utilization, and storage (CCUS) has entered an execution phase. Governments have set targets, incentives are more established, and developers are advancing a broader range of projects.

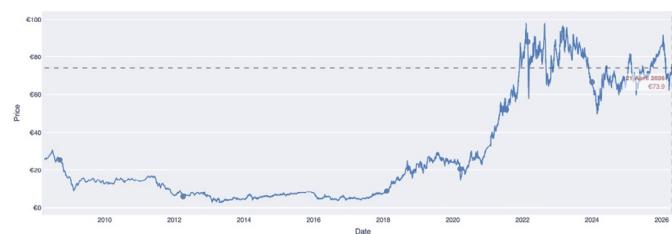
The next question: how many projects can secure the permits, customers, infrastructure, and financing needed to operate at scale? The answer will differ by region and the economic role that captured carbon dioxide (CO₂) plays in each project.

Europe: A Stronger Framework with Execution Still Ahead

Europe's early carbon capture efforts, launched in December 2005, showed the difficulty of moving from demonstration funding to commercial deployment. These efforts demonstrated that subsidies alone could not help companies absorb risks along the supply chain.

The policy environment has since changed. Early demonstration programs did not produce the commercial fleet originally envisioned, in part because projects lacked a reliable revenue basis. Carbon pricing, the European Union (EU) Green Deal, and the Industrial Carbon Management Strategy have given CCUS a more defined place in industrial decarbonization. The European Emissions Trading Scheme (ETS) price (Figure 1), which reflects the effective price of CO₂ in the European market, is structurally higher following the COVID-19 pandemic than in the past (for reasons including the Market Stability Reserve, tougher climate targets, and increased demand for emissions allowances because of the economic rebound).

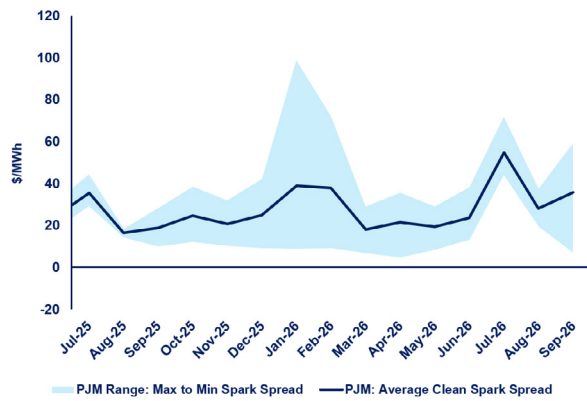
FIGURE 1. EUROPEAN ETS PRICE HISTORY (€/TONNE)



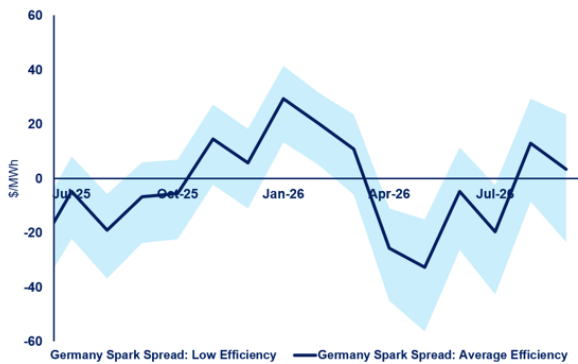
Government-established targets have further increased CCUS prospects within the EU. The EU's Net-Zero Industry Act establishes a target of 50 million tonnes per annum (Mtpa) of CO₂ injection capacity by 2030, including obligations for certain oil and gas producers. This is a capacity target, not a projection of the volume that will be captured or injected in that year. Reaching it will depend on identifying suitable storage formations, completing permitting, and building links to industrial emitters. Cross-border networks introduce another layer of coordination among national authorities, transport providers, and customers.

CLEAN SPARK SPREADS¹ FOR CCGT PLANTS

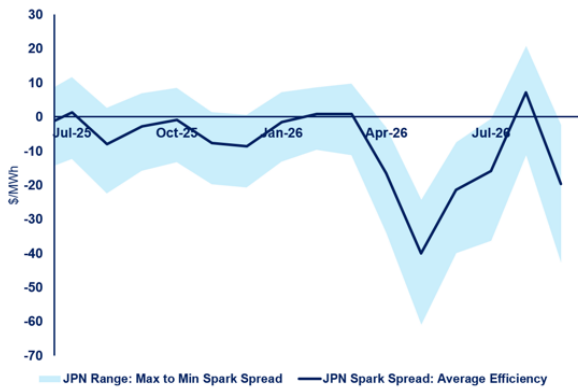
PJM



GERMANY



JAPAN



Notes

¹ Clean spark spreads = electricity prices – natural gas costs – traded carbon prices. Ranges in clean spark spread prices are based on variation in market prices and plant efficiencies.

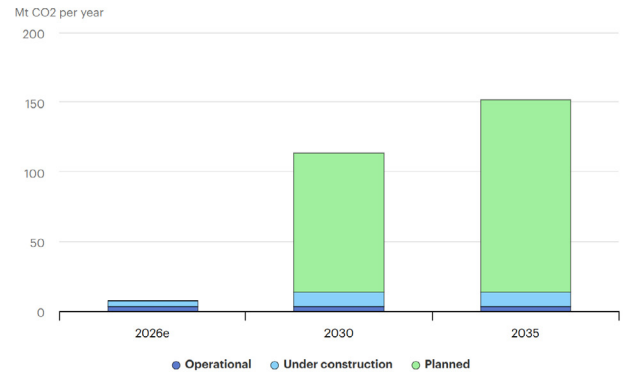
Market data from S&P and Platts.

Emissions prices from a specified carbon tax (Japan), RGGI (PJM), and ICAP or Trading Economics (Germany).

Insights

- Over the trailing twelve months, clean spark spreads:
 - Remained positive in the US PJM region.
 - Turned positive going into the start of 2026; returned to negative on price spikes due to the war in Iran; then returned and stayed positive from August 2026 onward.
 - Hovered around 0 going into the start of 2026 in Japan before dropping sharply due to the war in Iran; rebounded back to positive in August 2026, then dropped sharply again in September.
- Since the conflict in Iran began:
 - The PJM region has continued to be insulated due to the US natural gas market being relatively unimpacted by the price spikes.
 - Markets in Europe and Asia faced initial spikes in fuel costs leading to sharp drops in spark spreads before quickly rebounding in Q3 2026.
 - Since our last quarterly release, EU Emissions Trading System (ETS) prices increased at around 8% from Q2 to Q3 2026.

FIGURE 2. INDICATIVE EUROPEAN CCUS PROJECT CAPACITY BY STATUS (2026E–2035)



Economics are equally important. A carbon price can strengthen the case for capture but may not cover the full cost of building a shared transport and storage system. Projects need sufficient committed volumes to support the infrastructure, while prospective customers need confidence that storage will be available when their capture plants start. Larger hubs may spread costs across emitters and can require more complex sequencing and risk allocation. Reducing a project's scale in response to uncertainty may ease immediate financing needs but weaken its unit economics.

Ultimately, the market is moving beyond the question of whether CCUS belongs in Europe's policy toolkit. Key indicators for CCUS development in the EU include storage sites reaching permission and construction, binding capacity commitments, and industrial facilities connecting to operating networks. The pace of these steps will determine how quickly the policy framework translates into measured emissions reductions.

United States: Strong Incentives, Interdependent Investments

US Internal Revenue Code Section 45Q provides a meaningful potential revenue stream for qualifying projects. Subject to applicable requirements, credit values can reach \$85 per metric tonne for point-source capture and \$180 per tonne for direct air capture. Those amounts help projects underwrite investment, but the credit is earned only when relevant conditions are met. Further, capture equipment, CO₂ transport, and storage must come together as an operating chain.

For geologic storage, securing a Class VI permit (designed to protect underground sources of drinking water) is a central development milestone. A final Class VI permit allows construction of a proposed injection well; however, the permit does not provide authorization to inject CO₂ underground on its own. Developers must complete the well and required testing before a regulator can authorize injection. The US Environmental Protection Agency (EPA) has historically issued Class VI permits but recently has begun to grant certain states

primacy over the permit issuance process (Table 1). Whether the EPA or a state with primacy administers the permit, applicants still must submit a robust application Class VI permit package that includes site characterization, monitoring plans, and statements of financial assurance.

TABLE 1. STATES WITH APPROVED CLASS VI PRIMACY	
State	Final Rule Effective Date
North Dakota	4/24/2018
Wyoming	10/9/2020
Louisiana	2/5/2024
West Virginia	3/28/2025
Arizona	10/15/2025
Texas	12/15/2025

A growing permit pipeline does not immediately translate into stored volumes of CO₂. Permitting can span years, and construction and pre-operational tests follow a final permit. Storage developers need to commit capital before they have certainty about the timing and volume of CO₂ deliveries. Emitters and pipeline operators face the corresponding risk that storage will not be ready when capture equipment is commissioned.

Contracts managing the commercial relationships across the CO₂ supply chain must address construction timing, minimum volumes, credit eligibility, operating interruptions, and longer-term obligations. The allocation of these risks can be consequential, as the headline value of the tax credit generally provides a set amount of value that must be shared across parties in the supply chain.

Local considerations also shape the pace of development. Projects may face public questions about subsurface performance, transport safety, or long-term stewardship. Regulatory changes and community responses can alter schedules even after substantial planning.

There has been movement in the US market, with CCUS projects continuing to be commercialized, but development of the broader supply chain is required for CCUS to play a material role in the US market. We are monitoring further issuance of Class VI permits, development of sequestration facilities, and how these projects are driving broader development across the supply chain.

Asia-Pacific: Distinct Routes to a Storage Market

Asia-Pacific is best understood as several connected markets rather than one regional market. Japan, South Korea, and Singapore are seeing developing demand for CO₂ storage, including cross-border options. China has a growing operating base with substantial use of CO₂ for enhanced oil recovery. Australia and parts of Southeast Asia have projects linked to natural gas development alongside ambitions to serve third-party emitters. India has a large industrial opportunity, though its operating CCUS base remains comparatively small.

Japan has advanced its legal framework and selected projects intended to support a domestic industry. South Korea is developing a domestic prospect and considering storage abroad, while Singapore’s limited domestic geology makes cross-border options particularly important. These steps create a basis for demand, but targets and selected projects do not equal sanctioned capacity. Exploration, investment decisions, shipping arrangements, and customer contracts around the world remain important tests of the emerging model. The Tomakomai project in Japan illustrates the transition from appraisal to a possible investment decision.

China presents a different picture of scale. Reported 2025 nameplate capture capacity was approximately 8 to 9 Mtpa, while CO₂ actually injected that year was about 3.85 million tonnes. Much of the commercial activity is tied to enhanced oil recovery, which gives captured CO₂ an immediate use. Simultaneously, projects involving saline storage, coal-to-liquids production, and cement show that activity extends beyond the upstream model. The difference between capture capacity and injected volumes remains important when comparing China’s progress with other markets.

Several operating or advanced projects in Australia and Southeast Asia begin with high-CO₂ gas reservoirs. Because gas cannot be marketed without separating some CO₂, capture and reinjection can be integrated into the economics of upstream development. Gorgon and Moomba in Australia provide operating experience, including lessons on performance and carbon crediting. Kasawari in Malaysia, Tangguh in Indonesia, and Arthit in Thailand show how similar considerations are shaping new investments. Such projects can build experience in subsurface monitoring and regulation, although their economics do not automatically transfer to stand-alone industrial storage services.

A second business model would connect industrial emitters in one country to storage sites in another. Japan, South Korea, and Singapore have plans that collectively suggest roughly 13 to 19 Mtpa of prospective import demand around 2030. That range represents ambitions and planning assumptions, not binding commitments or a forecast of shipped volumes. Australia, Malaysia, and Indonesia are exploring their potential as hosts. Turning that potential into a service will require approved storage capacity, export and import arrangements, transport infrastructure, and commercial terms acceptable to both sides.

Cross-border projects must also decide who bears leakage risk, how injected CO₂ is monitored and credited, and when responsibility passes after closure. The international framework for exporting CO₂ for offshore storage requires workable arrangements between the jurisdictions involved; memoranda of understanding alone may not settle those requirements. Storage tariffs and the treatment of commingled streams will influence pricing. For customers, certainty about the recognition of emissions reductions likely matters as much as physical access to a storage site. Carbon prices may be insufficient to support all early projects, making targeted support and long-term contracts relevant. Japan's planned cost-gap support could provide an early indication of the funding needed to bridge that difference. Proposed hubs such as Duyong offshore Malaysia will be most informative when prospective customer interest becomes binding offtake and an investment decision.

The Next Phase

The sector has moved beyond a single debate about the merits of CCUS. Its prospects now depend on the fit between technology, geology, policy, and commercial structure in each market. European storage networks need to connect permitted capacity with industrial demand. US projects need to progress from final permits to sustained injection across a coordinated value chain. In Asia-Pacific, upstream-linked projects may continue to lead near-term delivery, while cross-border services work toward bankable contracts and an allocation of long-term risk.

Over the next eighteen months, the clearest signals will be operational: European sites coming online, US wells receiving injection authorization, and commercial agreements being executed to use the infrastructure. Watch progress at Tomakomai and Kasawari and binding offtake supporting a Duyong investment decision. Japan's first cost-gap auction may also help clarify price expectations.

These milestones will not produce a uniform regional verdict. They should, however, make it easier to distinguish projects that can deliver measurable storage from those still establishing their commercial foundations.

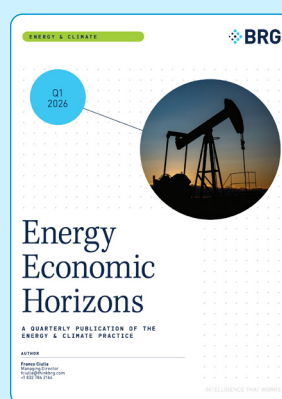
Previous Issues



Q2 2026

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Q1 2026

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Christopher Goncalves

Managing Director and Chair of BRG's Energy & Climate practice
cgoncalves@thinkbrg.com
+1 202 480 2703

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