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Why EU countries should avoid carbon capture for gas power plants

- *Decarbonising gas power plants with carbon capture and storage (CCS) is a high-risk strategy in the EU, given the unproven track record, high costs, long development timelines and infrastructure constraints.*
- *The EU's Industrial Carbon Management Strategy, introduced in February 2024, prioritises CCS deployment across hard-to-abate industrial sectors. But it does not explicitly exclude power generation, creating policy ambiguity around future CCS use for gas-fired power.*
- *The UK's sole under-construction gas power with CCS plant demonstrates the scale of subsidy requirements for first-of-a-kind projects. UK electricity consumers will pay for most of the £23 billion in subsidies supporting this project.*
- *Using hydrogen as a fuel to decarbonise gas power plants remains technically immature and materially more expensive than CCS. On a levelised cost of electricity basis, it can be 10 times more costly.*

Executive summary

Gas-fired power plays a material role in the EU electricity system, accounting for 13% of net generation in 2025. While EU countries have rapidly built out renewable energy, gas will remain a significant source of the bloc's power capacity and greenhouse gas emissions in the coming decades.

Despite this, there are currently few gas-fired power stations in the EU that officially plan to use or retrofit carbon capture and storage (CCS) technology. This reflects the lack of commercial-scale gas CCS plants anywhere in the world as well as the underperformance of CCS projects for other applications in terms of capture rates, cost and delivery timelines.

Most potential European gas CCS projects are in the UK, where CCS subsidy support and accompanying legislation are much further progressed. The UK has assigned £23 billion in subsidies for its sole under-construction gas power with CCS plant. CCS-equipped power stations would not go forward without such government subsidies.

Struggling to meet its 2050 net-zero obligations, the European Commission introduced an Industrial Carbon Management Strategy (ICMS) in February 2024. This aims to develop technologies and infrastructure for capturing, transporting, storing and using carbon dioxide to help the EU reach net zero. The ICMS was designed to target hard-to-abate sectors such as cement, lime and steel production, and initially sought to channel capture technologies toward these areas. But it does not explicitly exclude CCS for power generation.

Some EU Member States with high levels of gas generation are actively pursuing hydrogen strategies, planning to retrofit existing methane-based power generation facilities to use hydrogen blends or full hydrogen combustion. But the hydrogen market remains in its infancy. Using hydrogen as a fuel to decarbonise gas power plants is a materially more expensive option than adding CCS.

Taken together, these factors raise the risk that the EU, faced with ongoing dispatchable power requirements and the cost and immaturity of hydrogen markets, may increasingly seek to extend CCS use for gas power plants. Given the high cost, technical immaturity and general failure of CCS projects globally to date, this presents a high-risk and expensive option at the expense of cheaper, technically proven renewable energy solutions.

CCS: Background and historical context

Carbon capture and storage (CCS) refers to a suite of technologies that capture carbon from large sources, such as power generation facilities or industrial plants that use fossil fuels or biomass as fuel. Once captured, the carbon is compressed and transported by pipeline, ship or rail to be injected into deep geological formations. These are either depleted oil and gas reservoirs or saline aquifers, which trap the carbon dioxide (CO_2) for permanent storage.[1]

The economic justification for carbon capture, utilisation and storage (CCUS) has historically centred around supporting oil and gas operations. Carbon capture is used to support natural gas processing by removing CO_2 from gas with high concentrations of CO_2 relative to other gases, a requirement to market and sell the gas. The other application is to inject the CO_2 back into oil reservoirs to provide artificial lift to support increased oil production, referred to as enhanced oil recovery (EOR).

CCS applications have been in existence for many decades, primarily for EOR. The first facility was the Terrell Natural Gas Processing Plant in Texas, US, which opened in 1972 to capture and use CO_2 for EOR at a nearby oil field.[2] There are presently around 77 commercial facilities in operation globally, capturing a mere 64 million tonnes of CO_2 ($MtCO_2$) per annum combined,[3] of which 60% is used for natural gas processing and EOR.[4] As such, CCS use across other industrial applications remains in its infancy.

CCS for gas power generation: Technical and economic challenges

While CCS is frequently described as a mature technology, there are no operating commercial-scale gas power plants equipped with CCS anywhere in the world. Existing CCS projects predominantly capture emissions from coal-fired power generation or industrial processes where CO_2 concentrations are significantly higher. The US National Energy Technology Laboratory reports that flue gas from natural gas combined-cycle plants typically contains around 4% CO_2 by volume, compared with 12–15% for coal-fired plants, requiring significantly greater energy input and increasing capture costs.[5]

There have historically been few gas power with CCS pilot or demonstration projects worldwide. The most notable is the NET Power demonstration facility in Texas, US. Built in 2018, the 50-megawatt facility has run for over 1,600 hours and, according to NET, has successfully demonstrated the technology, despite not producing any excess electricity over that required to run the plant.[6]

Net Power is also constructing a larger-scale project of 300 megawatts in Texas,[7] which is expected to capture 820,000 tonnes of CO_2 per year.[8] Like most CCS projects to date, it is plagued by cost overruns and delays. Project costs have more than doubled from an initial estimate of USD750–900 million in 2022 to USD1.7–2 billion as of November 2025.[9] Start-up has been delayed from 2026 to no earlier than 2029.

The performance of pilot projects underlines the extent of the challenges that surround CCS and its use in attempting to decarbonise gas-fired power generation. CCS has never been deployed on new-build gas power within the EU, nor at scale on retrofits anywhere in the world. This is due to the technical and economic challenges of integrating CCS into existing or new facilities, which include:

- **No track record**: Europe has no successful CCS projects attached to gas-fired power plants. Previous efforts in the UK were cancelled because of high cost and poor performance.[10,11] At present, the technology readiness level for gas-fired CCS is seven out of 11, or the pre-commercial demonstration phase, according to the International Energy Agency.[12]

- **Costs**: IEEFA estimates that CCS costs for the power and heat sector in Europe are more than €150/tonne of CO_2, including €64/tonne for capture and €88/tonne for transport and storage.[13] This is around double the current EU Emissions Trading System price of €76.[14] Assuming the EU Emissions Trading System price remains at similar levels over the coming years, there is little economic incentive for infrastructure owners to apply CCS without subsidies or other forms of financial support.

- **Capture rates**: Even leading projects underperform. An IEEFA review of 13 operating CCS projects globally found that most captured below design levels of 90%, while some failed outright.[15] This highlights the continued technical challenges of CCS as a solution and the potential for further cost escalation per tonne.

- **Timelines**: CCS projects take 10–15 years to develop because of permitting, infrastructure and cross-border agreements. Delays at flagship European CCS projects such as Northern Lights in Norway and Porthos in the Netherlands illustrate the risks: Both are over budget and behind schedule.[16,17]

- **Infrastructure gaps**: The EU has no operational CO_2 pipeline network. There are potential transport projects linking to storage sites, albeit these projects remain at the early stages of planning. They still require legislative changes, project final investment decision and economic support before a lengthy construction process can begin. Until the EU ratifies international agreements, exporting CO_2 to potential storage sites in Norway or Denmark is uncertain. Without this, domestic offshore storage capacity will not be sufficient to support CCS at scale.

- **Storage**: Offshore sites are technically feasible but costly. Even leading sites, such as Sleipner and Snøhvit offshore in Norway, have experienced unexpected CO_2 migration and capacity problems.[18] There remain significant uncertainties about the long-term storage potential and safety of offshore sites.

EU Industrial Carbon Management Strategy

The EU's Industrial Carbon Management Strategy (ICMS) provides a framework to help scale up CCS and other related technologies to support carbon reduction across the bloc. The strategy will support the development of CO_2 storage and transport networks and associated regulation, prioritise capture across hard-to-abate sectors, and provide funding mechanisms to drive development and continued investment.

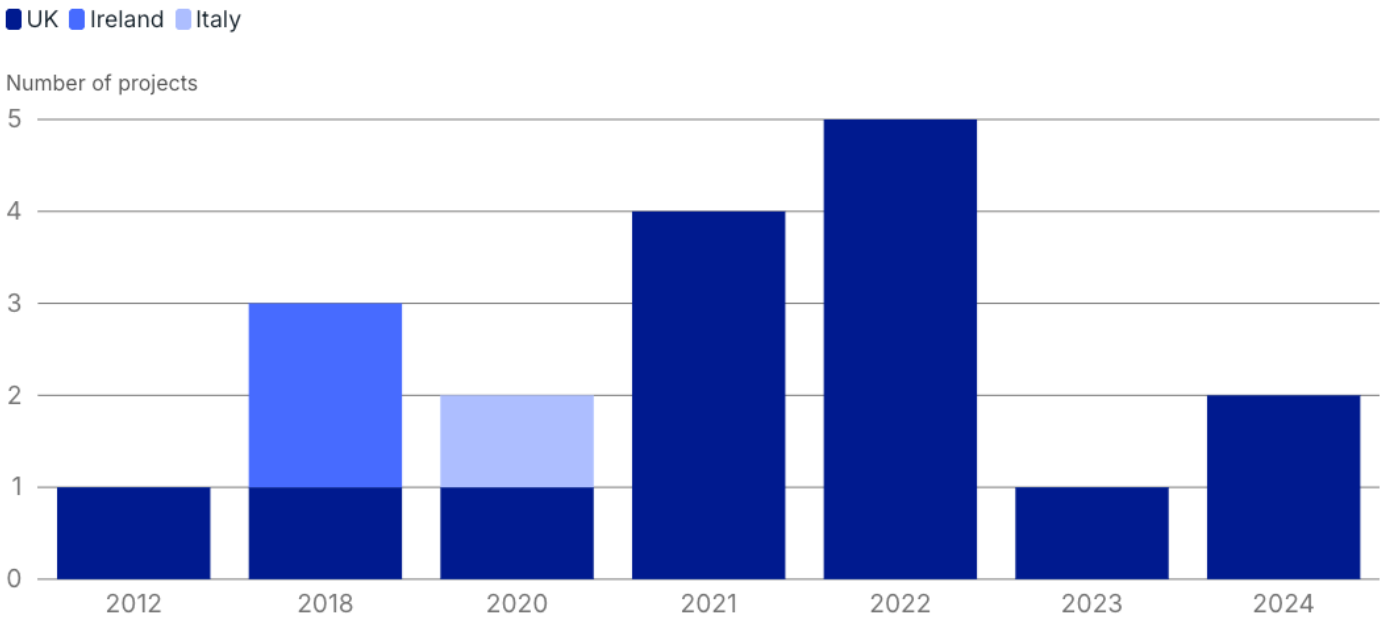
The ICMS set an initial capture target of 450MtCO_2 equivalent per annum by 2050, mainly to come from capture across fossil fuels, process and biogenic emissions, and direct air capture.[19] It remains unclear to what extent CCS will be used to decarbonise fossil fuel use, or on which facilities this will occur. But the ICMS recognises that it may be deployed on power installations in the future.

At present, the potential application and introduction of CCS in the EU is very much in its infancy. The ICMS highlights that there are many obstacles to overcome before CCS can gain traction. In addition to the technical and economic challenges, the region is behind countries such as the UK and Norway, as it lacks clear political guidance. This in turn means that investment, incentives, cross-border and infrastructure coordination, and regulation remain unclear and still need to be developed. Additionally, public perception and acceptance issues for the technology remain, which may further delay its implementation.

Gas power with CCS across Europe

As of March 2025, there were 18 planned gas power with CCS projects announced in Europe. These aim to retrofit carbon capture on existing gas-powered facilities or are proposed new builds that will have carbon capture simultaneously installed. Capture volumes have been announced for 14 of the projects, totalling 27MtCO_2, according to the International Energy Agency's CCUS Projects Database.[20] At the country level, the UK dominates proposed activity, accounting for 92% of the emissions capture and storage across 15 projects. Other active states include Ireland with two potential projects and Italy with one.

Figure 1: European gas power CSS project announcements



Source: International Energy Agency CCUS Projects Database.

Despite Europe's large portfolio of gas power CCS opportunities, only one project — in the UK — has reached final investment decision. The UK government announced in December 2024 that new-build gas-fired power plant Net Zero Teesside (NZT) would receive funding as the UK's first carbon capture project.[21] Forming part of the East Coast Cluster in northeast England, the facility is a joint venture owned by integrated oil and gas firms BP and Equinor. The plant will have a capacity of 724 megawatts and is expected to capture 2MtCO_2 per annum, with a start-up date planned for 2028.[22]

The construction of NZT is a global landmark in that it will be the first commercial-scale combined-cycle gas turbine (CCGT) and CCS power plant in the world once completed.[23] There are technology differences to the NET Power projects in the US, as NZT plans to use conventional CCGT power units combined with amine-based post-combustion capture. It remains unknown whether this approach will work at scale, as presently the technology readiness level is at seven out of 11, or the pre-commercial demonstration phase.[24]

The quantum of subsidy exposure for NZT is alarming. Some £13 billion has been allocated for transport and storage,[25,26] while the Dispatchable Power Agreement scheme awarded £10 billion.[27] Collectively £23 billion of subsidies have been assigned to support around 2MtCO_2 per annum of capture, transportation and storage for this single project. This is a worrying amount given that the UK's 2050 CCS target is 73MtCO_2.

These CCS subsidies are mostly supported under Contracts for Difference and Renewables Obligation schemes. These two mechanisms are collectively referred to as environmental levies. They are paid by consumers as additional payments on electricity bills to support the buildout of solar and wind electricity capacity, in addition to other low-carbon energy generation. Around 75% of the costs of CCS in the UK will be passed onto customers, according to a UK Public Accounts

Committee (PAC) report published in February 2025, which highlighted the impact on electricity consumers' bills amid high energy prices.[28,29]

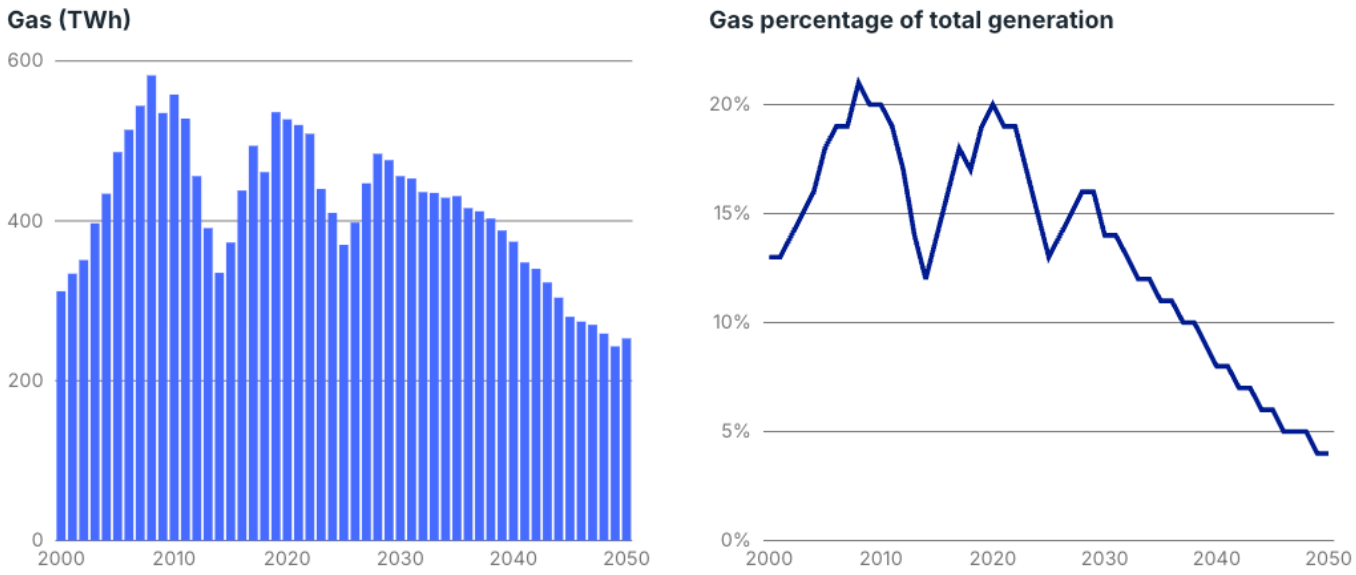
This PAC review of UK government CCS schemes noted several technical, commercial and timing risks associated with supporting CCS projects. It found that CCUS remains an unproven technology at scale, raising concerns about performance.

The PAC also flagged timing concerns, pointing to UK CCS failures in 2011 and 2016. It noted that the UK's 2030 CCS targets have been abandoned due to slow progress, and that projects are behind schedule, pushing back carbon reduction targets and threatening net-zero goals. The PAC warned that the UK government "needs to avoid over reliance on the programme at the expense of other routes to net zero, such as renewable energy".[30]

Gas power generation in the EU

Despite the increase in renewable and low-carbon power generation, fossil fuel plants still account for a quarter of EU electricity generation.[31] Natural gas-fired power is material, accounting for 13% of the bloc's net generation in 2025, at 370 terawatt-hours (TWh).[32] In the short term, S&P Global Commodity Insights expects that EU gas-powered generation will increase by 31% from the recent low in 2025 to 484 TWh by 2028, when it will account for 16% of the region's demand. This in part is driven by increased power requirements overall, the phase out of coal, low storage capacities across batteries and hydro, and more dispatchable power requirements to combat renewable power intermittency. But S&P expects that EU gas power generation will fall significantly over the coming decades. It forecasts a 48% decline between 2028 and 2050, when the technology will provide 4% of the bloc's electricity.[33]

Figure 2: EU gas power generation



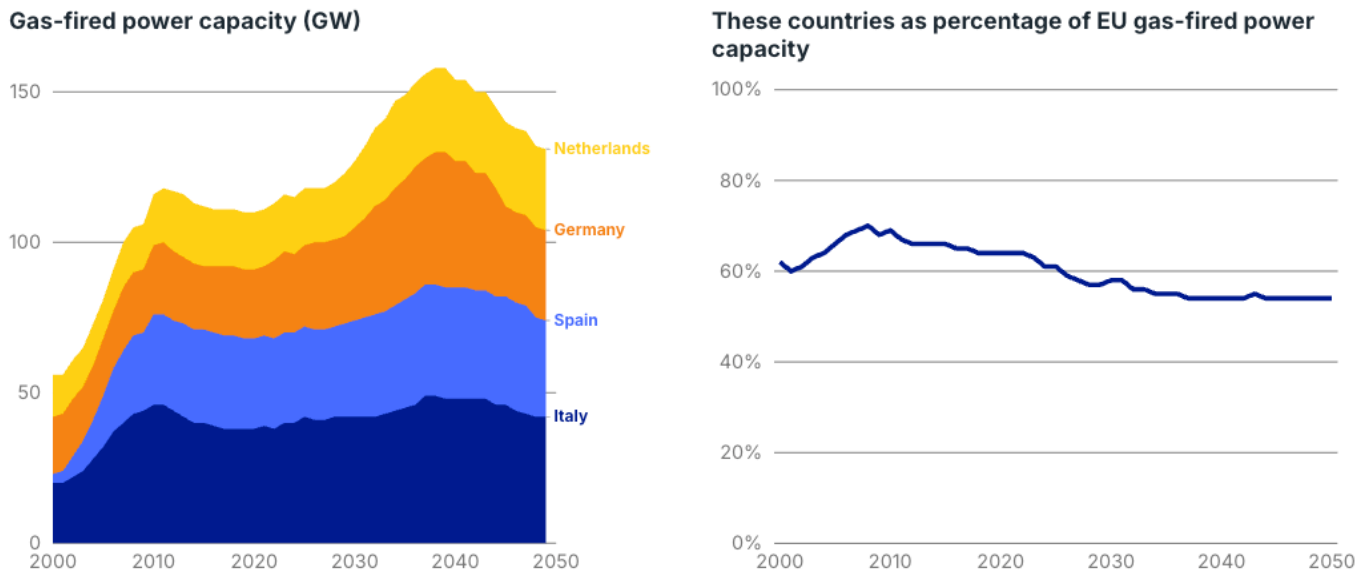
Source: S&P Global Commodity Insights.

Despite being championed as a lower-carbon alternative to coal or oil, gas power is a major contributor of greenhouse gases across the EU. Gas power generation accounted for 26% of the

bloc's energy-related emissions and 7% of its total emissions in 2023.[34] While EU gas power generation is forecast to reduce by 32% through to 2050, it remains material and could still be producing 135MtCO_2 equivalent per annum in 2050, the equivalent of the 2024 annual emissions of Ireland and Greece combined.[35]

Italy, Germany, Spain and the Netherlands account for 61% of the EU's 194 gigawatts (GW) of gas generation capacity. As demand for dispatchable power increases, EU gas generation capacity is expected to rise by 22% to 232GW by 2050. Of the four largest producers, Germany plans 10GW of additions, while the Netherlands aims for a 36% rise in capacity to 26GW. Italy has the largest existing capacity at 42GW, which is expected to remain stable out to 2050. The EU's buildout of gas generation capacity largely occurred between 2000 and 2010, and projects remain relatively new. Given that facilities can have a lifespan of 40–45 years if properly maintained,[36] much of the existing infrastructure will likely remain operational towards the middle of the century.

Figure 3: Germany, Italy, Spain and the Netherlands gas-fired power capacity



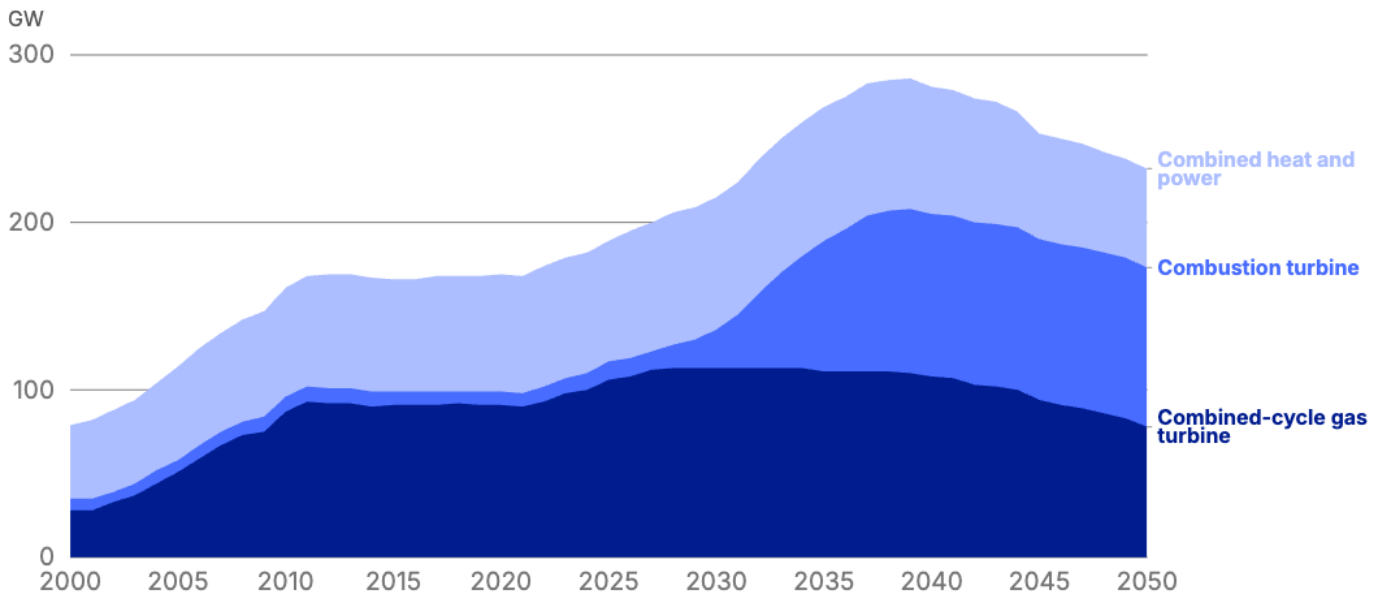
Source: S&P Commodity Insights.

There are three primary types of gas generation facilities that use gas turbines to produce power: CCGT, combustion turbine (CT) and combined heat and power (CHP). Around 94% of EU gas power capacity is currently CCGT and CHP. CCGT facilities recycle the produced heat to create additional power, while CHPs use the excess heat for industrial processes or district heating. This recycling of heat makes CCGT and CHP much more efficient, reaching between 60–80% efficiency.[37]

CT use is currently limited. They are often smaller facilities used for peaking power, grid support, industrial processes in chemical plants, refineries, remote oil and gas sites, and marine applications.[38] They also benefit from being able to start up and reach their generation capacity quickly, making them attractive for providing flexible electricity generation for short periods. As the EU scales up renewable power generation, it is expected that CT capacity will also increase to provide support for renewable intermittency. The EU's CT capacity is expected to increase from 11GW currently to

95GW in 2050. This is the primary driver of EU gas power increases over the coming decades. Despite this, the proportion of CCGT and CHP use will remain high, representing 59% of the EU's 232GW of gas-fired capacity in 2050.

Figure 4: EU gas power capacity by generation type



Source: S&P Commodity Insights.

Retrofitting or building new gas power stations with CCS is not suited to all types of facilities. CCGT facilities, which generally provide large-scale constant power generation, are likely more attractive for CCS use and post-combustion technology. CCGT projects' high operating utilisation means they have lower CO_2 capture costs than CHP or CT plants. While CCS can be used on CHP facilities, it requires low-pressure steam for the CCS reboiler, diverting the heat produced for district heating or industrial processes. CT or simple-cycle turbines would require additional capital expenditure (capex) to install a heat recovery system, adding further costs.

Hydrogen as an alternative to CCS retrofits

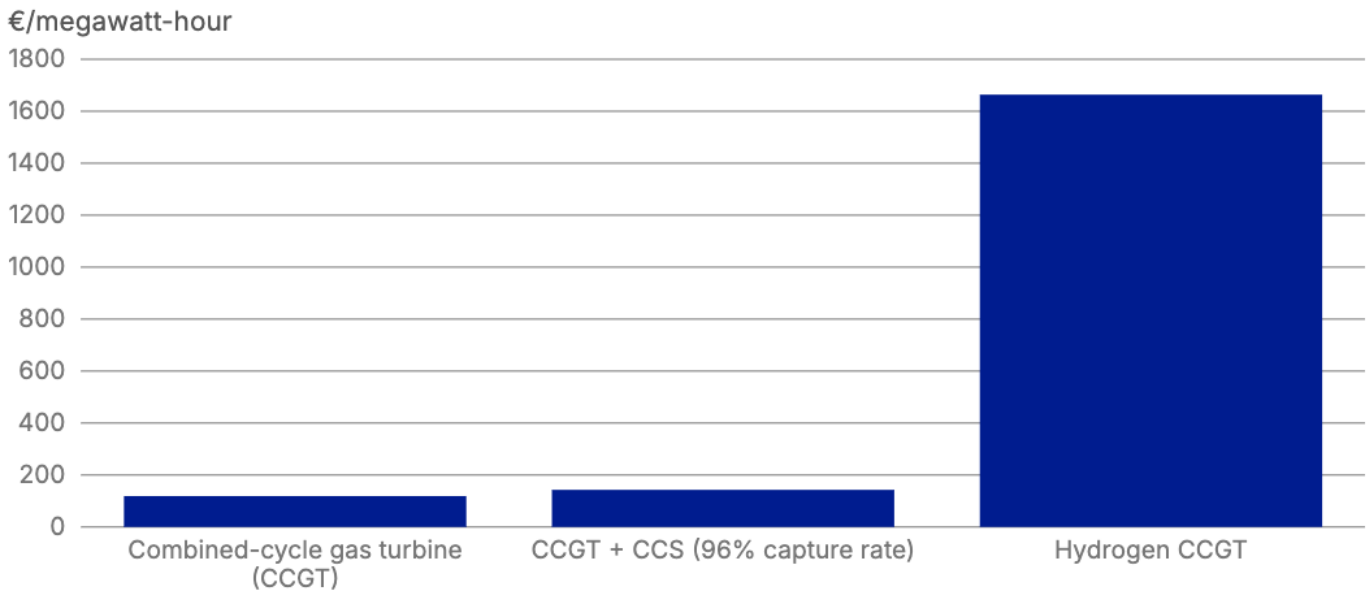
Fuelling gas-fired power station turbines with hydrogen is championed as a low-carbon alternative to CCS. There are many variants of hydrogen production, but two main types provide low-carbon solutions. Green hydrogen is produced through electrolysis using water and renewable energy to split the molecules. Blue hydrogen relies on natural gas with steam methane reforming, a carbon capture solution that allows for the carbon to be trapped and stored.

Using either green or blue hydrogen to power gas turbines eliminates combustion CO_2 at the point of use. They are thus, in theory, low-emissions approaches. While hydrogen could be used for power generation retrofits or installed on new facilities, the technology and infrastructure are in their infancy, and the costs associated with low-carbon hydrogen power generation are significantly higher than those for CCS. Furthermore, there are material safety risks associated with handling and combustion

of hydrogen, such as how it embrittles certain materials and the extreme pressures and temperatures needed to compress and liquify it.[39]

The EU remains keen to promote the increased use of renewable hydrogen to decarbonise energy-intensive industrial processes and the transport sector. The bloc aims for renewable hydrogen to account for 10% of its energy needs by 2050.[40] Despite this aspiration, progress in the EU has been slow as production and regulation costs remain high.[41] Hydrogen market growth is insufficient to meet EU and national targets, according to a 2025 report from the EU Agency for the Cooperation of Energy Regulators. [42] The report noted that green hydrogen costs are eight times those of hydrogen produced using fossil fuels, transportation rules have been delayed, and rising network tariffs and electricity costs are prohibitive.

Figure 5: Levelised cost of electricity of CCGT plants with CCS or hydrogen retrofits



Source: University of Mons paper.

An analysis by the University of Mons found that a conventional 663-megawatt CCGT gas-fired power plant requires a capex of €1,000 per kilowatt.[43] This increases to €1,250 per kilowatt for a hydrogen retrofit and €2,500 per kilowatt for 100% carbon capture. Despite having significantly higher capex than hydrogen retrofits, gas CCS benefits from comparatively lower operating costs, greater efficiency and lower fuel costs. As hydrogen fuel costs are over twice those of natural gas, the impact on the levelised cost of electricity (LCOE) is dramatic: The LCOE of a hydrogen-fuelled CCGT plant is ~€1,600 per megawatt-hour, more than 10 times that of CCGT with CCS.

Evolving legislation: Is Germany preparing to use CCS on gas power facilities?

Before November 2025, Germany's Carbon Dioxide Storage Act restricted CCS to pilot projects and gave states the right to opt out. This halted early projects in Schleswig-Holstein and Brandenburg. However, following an amendment by the federal government, a revised Carbon Dioxide Storage and Transport Act came into force in November 2025.[44] The revision now permits capture and storage on a larger scale, allowing for both onshore and offshore CO_2 storage and enabling

development of a national CO_2 pipeline network. The legislation also designates that investment in transport and storage infrastructure is in the overriding public interest. This status intends to simplify and accelerate the permitting process, leading to increased CCS use.

A core purpose of the legislative change is to open CCS use to combat emissions in hard-to-abate sectors, such as cement and lime production, basic chemicals and waste incineration. The law only excludes CCS for coal power plants, suggesting that gas-fired power generation may be applicable for future government support. Germany launched a €6 billion funding initiative for CCS projects in October 2025, which will see firms participate in competitive auctions for climate protection contracts in 2026.[45] The contracts will provide 15-year subsidies for projects that demonstrate the largest emissions reductions at the lowest public cost.[46]

As Germany seeks to increase its CCGT power generation capacity with an initial 10GW expansion, the pressure to reduce emissions from this infrastructure will rise in line with emissions reduction targets through to 2045. This hydrogen-ready capacity must decarbonise by 2045 at the latest,[47] despite hydrogen's high costs and safety questions. While using CCS may seem like a more attractive option, the reality is that the same technical and commercial risks and high-cost burden remain.

Conclusions

CCS applied to gas-fired power generation remains technologically immature, costly and slow to deploy. The absence of commercial-scale reference projects, persistent underperformance and substantial subsidy requirements undermine confidence in gas CCS as a scalable decarbonisation solution.

While the EU's ICMS appropriately prioritises hard-to-abate sectors, the strategy's ambiguity around CCS for power generation risks encouraging deployment of an unproven and subsidy-intensive technology. The UK experience illustrates the potential financial exposure of supporting CCS. And previous pilot projects across capture, transport and storage highlight the execution challenges.

In this context, expanding CCS to gas-fired power generation in the EU represents a high-risk strategy that should be approached with caution, particularly where it may divert resources from more cost-effective and mature decarbonisation pathways.

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