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Decarbonisation of the EU’s natural gas market

2026 Monitoring Report

23 June 2026

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Highlights: Decarbonisation of the gas market

20%

EU greenhouse gas emissions attributable to the EU gas sector

Today EU gas consumption amounts to 340 bcm (~3645 TWh) per year and methane contributes significantly to global warming.

85%

share of EU's attributable CH_4 emissions from gas and oil supply chains originating outside the EU

Methane emissions from gas and oil supply chains serving the EU far exceed emissions within EU territory.

5%

annual growth in EU biomethane production

EU reached a production of 4.3 bcm in 2024 with more than 1500 biomethane production plants across EU Member States.

12%

reduction in EU industrial final energy consumption between 2021 and 2023

Half of this reduction corresponds to natural gas.

40%

lower average electricity day-ahead prices in low-carbon power systems vs. carbon-intensive ones

8 Member States exhibit a low carbon intensity factor in their electricity mixes.

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Decarbonising gas market to support EU climate neutrality

Gas demand services

- Gas for electricity production (Covered)
- Industrial gas use (Covered)
- Heating sector (Outside of scope)

Decarbonisation instruments

- Biomethane (Covered)
- Hydrogen (Partially covered)
- Electrification (Partially covered)
- Carbon capture, utilisation and storage (Partially covered)
- Methane emissions abatement (Covered)

Covered | Partially covered | Outside of scope

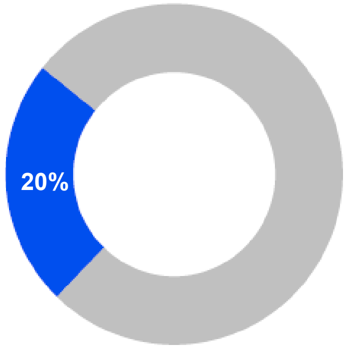
Scope of the report

- This report explores the main challenges and trade-offs in decarbonising the EU gas market.
- The report is structured around four dilemmas and an overarching trilemma[1], exploring how sustainability, security of supply, and competitiveness/affordability[2] can be balanced throughout the energy transition.
- The analysis focuses on selected demand services and decarbonisation instruments[3], while electrification and other pathways are considered only to a limited extent and not assessed comprehensively. Network tariff impacts arising from declining gas demand are outside the scope of this report.

Fossil gas still remains the most cost-competitive option under current carbon pricing

- The EU aims to achieve climate neutrality[4] by 2050 through initiatives such as the Fit-for-55 package and the REPowerEU plan.
- While fossil gas still remains the most cost-competitive option under current carbon pricing, decarbonising the gas market[5] will rely on increased electrification, supported by biomethane and emerging technologies (e.g. hydrogen, carbon capture, utilisation, and storage).
- In 2024, the EU gas sector accounted for around 20% of EU greenhouse gas emissions. Methane emissions from gas and oil supply chains serving the EU exceeded those generated within EU territory.

EU greenhouse gas emissions attributable to the EU gas sector



[1] See slide 18. [2] In this report, sustainability is understood as the reduction of emissions and the greening of the economy while progressing the energy transition sensibly. Security of supply refers to the reliability and diversification of gas supplies in an uncertain geopolitical environment. Competitiveness and affordability refer to the development of an integrated market that promotes competition and innovation while ensuring affordable energy prices. [3] Including biomethane, hydrogen, and methane emissions reduction across the gas value chain. [4] Climate neutrality by 2050 means achieving net zero GHG emissions for EU Member States as a whole, mainly by cutting emissions, investing in clean technologies, and protecting the environment. [5] Different strategies are possible (see slide 9).

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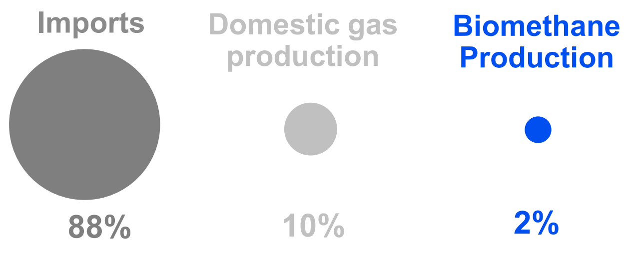
Biomethane has potential; natural gas ensures flexibility

Share of gas imports, domestic gas production and biomethane production, 2024 (%)



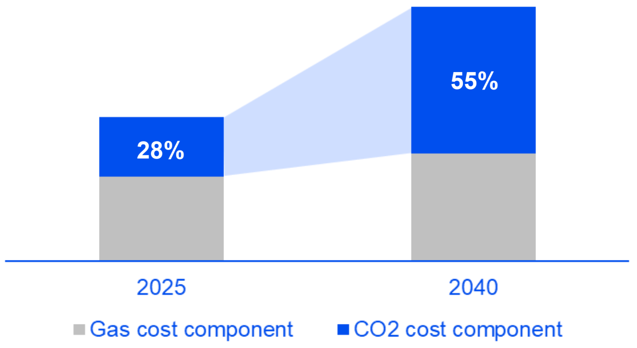
Biomethane is the most viable renewable gas in the near-term, but scaling up requires targeted policy action

- The Commission's target of 35 bcm of biomethane[1] by 2030 contrasts with actual production of just 4.3 bcm in 2024, or about 2% of gas injected into EU networks, despite the technology being mature.
- Its expansion is constrained by high costs, limited feedstock mobilisation and cross-border tradability issues, requiring careful assessment of land use constraints and competing biomass uses.
- While competitiveness depends on carbon and sustainability certificate prices and policy support, EU's biomethane production could significantly enhance energy security by reducing both import dependence and geopolitical risks.

Fossil natural gas remains pivotal to cover the electricity system flexibility needs

- Gas-fired power plants continue to set referential values for wholesale electricity prices[2], particularly during peak hours with limited renewable availability.
- Decarbonisation progress is uneven across Member States, with systems relying more on low-carbon generation experiencing electricity prices about 40% lower than more carbon-intensive ones.
- Rapid solar PV growth is increasing system flexibility needs currently met partly by gas. However, rising carbon prices and insufficient deployment of clean flexibility options[3] could raise electricity prices in certain hours[4].

Production costs of gas power plants – 2025 vs 2040



[1] Currently, 35 bcm refers to both biomethane and biogas. See The Oxford Institute for Energy Studies, January 2026. [2] Gas-fired power plants were in-the-money in ~40% of hours in 2025 while accounting for 15% of total EU power generation. [3] For instance, demand response and batteries. Note that batteries are already growing significantly. [4] Biomethane remains a lower-carbon option but still less competitive alternative to natural gas.

Gas/carbon prices drive competitiveness; methane cuts lag

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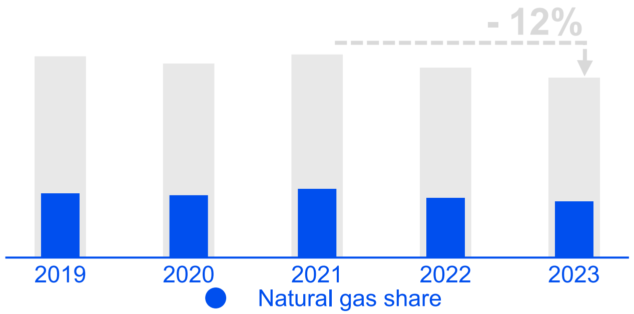
EU final energy consumption in industry, 2019-2023



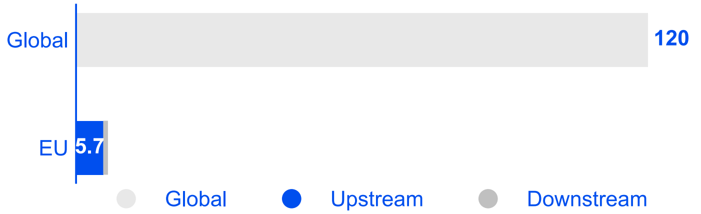
EU industry competitiveness hinges on gas and carbon prices

- In 2023, natural gas accounted for one third of EU final energy consumption in industry, while overall industrial energy use fell by roughly 12% compared to 2021 levels.
- Industrial gas consumption[1] in 2024 increased 5% year-on-year but still about 17% below pre-crisis levels.
- Future demand will depend on sector-specific decarbonisation pathways, gas and carbon price dynamics, and policy tools[2]. Engaging with industry stakeholders is key to assess economic impacts.

Methane abatement is cost-effective but hindered by regulatory uncertainty

- Around 85% of methane emissions from EU oil and gas supply are embedded in imports, while the EU accounts for about 6% of global energy-related methane emissions.
- The EU Methane Regulation introduces phased requirements for importers[3], but implementation is constrained by supply-chain complexity, delayed national penalty frameworks, and the need to manage security of supply concerns.
- Although most domestic and global methane abatement potential is cost-effective, it remains underexploited[4].

Global energy-related methane emissions and EU methane emissions associated with oil and natural gas consumption, 2024 (Mt of methane)



[1] Key gas-intensive sectors such as chemicals, iron & steel, and glass represent around 40% of EU final energy demand in industry. [2] Such as the carbon border adjustment mechanism, which will shape competitiveness and emissions alignment across EU and non-EU producers. [3] Focused on transparency and monitoring. [4] Due to fragmented responsibilities, weak enforcement, and limited transparency across supply chains.

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Coordinated planning and regulatory alignment are essential

Qualitative assessment[2] leaning towards certain decarbonisation instruments

	Avoided emissions	System-wide costs as decarbonisation progresses	Energy independence
Green hydrogen	Favourable	Partly unfavourable	Partly favourable
Biomethane	Partly favourable	Neutral	Partly favourable
Carbon capture, utilisation and storage	Partly favourable	Neutral	Unfavourable
Unabated natural gas	Unfavourable	Unfavourable	Unfavourable

Favourable · Partly favourable · Neutral · Partly unfavourable · Unfavourable

Disclaimer 1: these considerations represent a certain temporal snapshot in the mid-term and are subject to changes in the future.
Disclaimer 2: electrification is assumed to be a baseline condition across all assessed hypothetical pathways.

European climate and energy policies need to reconcile climate, security of supply and competitiveness

- Various technological options are available for decarbonising the EU gas market, including electrification, biomethane, carbon capture, utilisation and storage, and hydrogen. Each involves trade-offs between costs, emissions reductions and energy independence.
- Inaction deploying new technologies may lead to costly outcomes[1]. Coordinated infrastructure planning and regulatory alignment will be essential to integrate gas, electricity and hydrogen systems efficiently and address potential mismatches.

[1] Maintaining a strong dependence on unabated natural gas risks generating high system-wide costs as carbon prices are expected to rise, limited decarbonisation gains, and continued import dependence.
[2] See slides 84 and 85 for a description of the rationale behind this qualitative assessment.

Guiding actions: Decarbonisation of the gas market

Unlock EU's biomethane potential

Address remaining regulatory and technical barriers to biomethane scale-up, including feedstock mobilisation and obstacles to biomethane cross-border trade.

Promote low-carbon gas supply options to cover electricity system needs

Reducing the influence of fossil-based natural gas on electricity price formation will require significant deployment of low-carbon gas supply options, such as biomethane, as well as clean flexibility solutions, including batteries and demand response.

Harmonise tradability of certificates for biomethane

Regulatory certainty, clearer rules when issuing guarantees of origin and proof of sustainability certificates as well as the completion of the EU database, are key to achieving this objective.

Reduce regulatory and contractual uncertainty in methane emissions regulation

Provide early clarity on key methodologies and acceptable compliance approaches to avoid inefficient contract renegotiations, risk premiums and over-compliance that could drive up costs for consumers. Dialogue and cooperation with end industrial consumers should be promoted.

Make carbon pricing work for climate and EU industry

Set fair and predictable carbon prices to reduce EU industrial emissions, alongside a Carbon Border Adjustment Mechanism to safeguard EU industry competitiveness. Do so while actively engaging with stakeholders to assess impacts.

Strengthen cross-sector coordination

Coordinated infrastructure planning and regulatory alignment to resolve possible discrepancies will enable efficient integration of the gas, electricity and hydrogen sectors along the energy transition.

Note: These guiding actions are intended for policymakers.

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Decarbonisation targets in the EU

Sector targets, current status and key considerations ahead

Targets, current status and considerations ahead

How to achieve gas system decarbonisation?

- Gas system decarbonisation (or gas decarbonisation) can be defined as all actions aimed at reducing or eliminating greenhouse gas emissions associated with the production, processing, transportation and utilisation of natural gas.
- Two strategies can be implemented to decarbonise the gas market: (i) displacing natural gas and (ii) reducing its carbon footprint.
- Gas displacement strategies involve:
  - Energy efficiency: Reducing gas consumption.
  - Green electrification: Switching to renewables to replace gas-based heating and other applications with electric alternatives.
- Reducing carbon footprint strategies comprise:
  - Carbon capture, utilisation and storage.
  - Addressing methane leaks.
- Renewable and low-carbon gases, such as biomethane or hydrogen produced from renewable energy sources, are key to reduce carbon molecules and/or displace these molecules.

Balancing sustainability, supply security and competitiveness/affordability involve inherent trade-offs

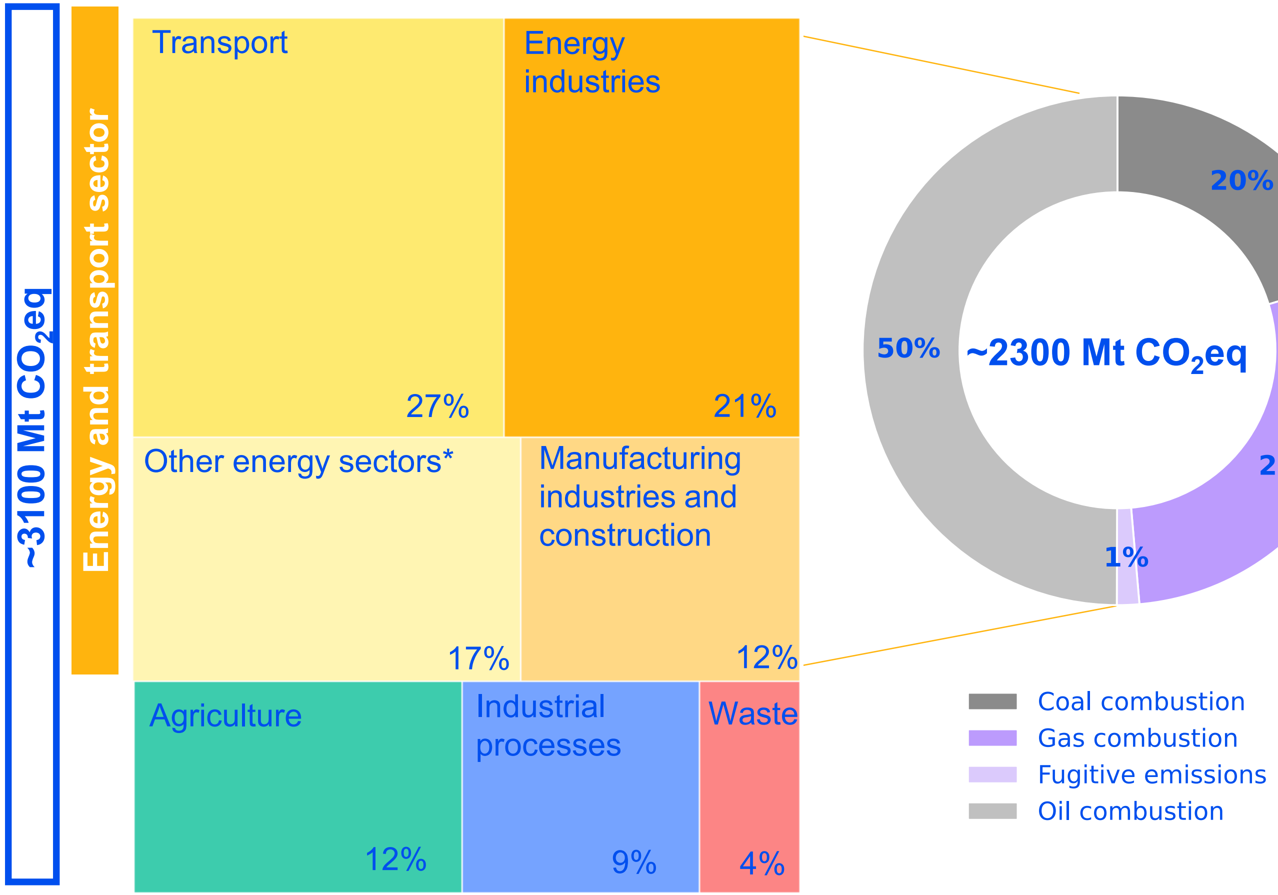
- The EU gas sector accounts for ~20% of EU greenhouse gas emissions. While EU downstream methane emissions are relatively low, methane emissions linked to EU gas and oil supply chains represents ~6% of global energy-related methane emissions.
- Reducing gas consumption is central to EU decarbonisation efforts and supported by several legislative initiatives. This includes the REPowerEU plan, which sets ambitious targets for lowering gas demand by 2030.
- Progress towards some policy targets has been uneven, putting gas demand reduction at risk and potentially affecting the achievement of intermediate 2040 targets and climate neutrality by 2050.
- Decarbonisation of the gas market will rely on a mix of mature and emerging technologies, including biomethane, hydrogen, and carbon capture and storage solutions.

Note: A non-exhaustive list of the legal and policy framework supporting the decarbonisation of the EU's energy system can be found in Annex A.

Emissions in the EU gas sector accounted for 20% in 2024

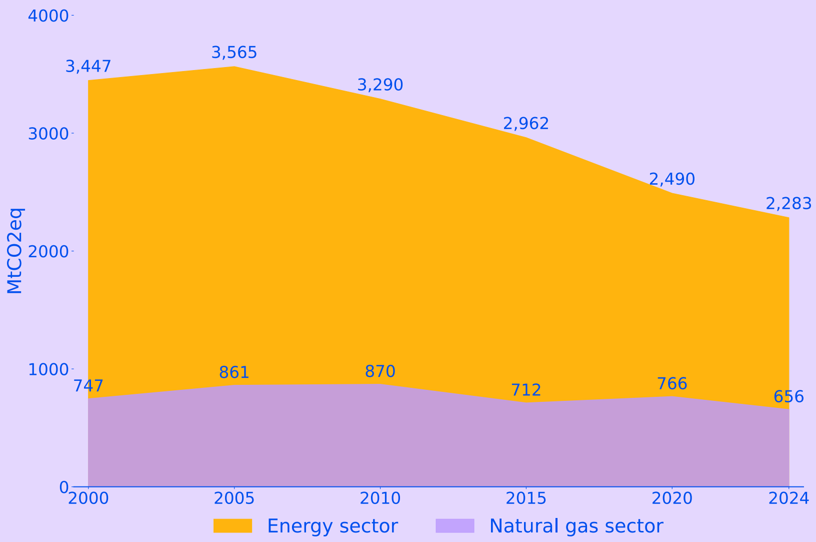
75% of the total emissions in 2024 in the EU stems from the energy and transport sector, of which 30% derives from the EU's gas sector

Total greenhouse gas emissions in the EU by sector and breakdown of emissions in the energy and transport sectors, 2024 (Mt CO_2eq)



Most greenhouse gas emissions from the energy sector come from the burning of fossil fuels. Although the combustion of natural gas produces considerably lower emissions than coal or oil, it still contributes substantially to overall emissions.

Evolution of greenhouse gas emissions in the EU energy/transport and gas sectors, 2000-2024 (Mt CO_2eq)



Fugitive emissions and those associated with routine venting and flaring, mean that upstream gas production contributes significantly to climate change even before combustion.

Source: ACER based on EEA and IEA.

Note: left chart does not include negative emissions from the Land Use, Land-use Change, and Forestry (LULUCF) sector, which in 2024 accounted for -8% of total emissions in the EU. This chart is based on the Common Reporting Tables, which are standardized formats to report greenhouse gas emissions under the Paris Agreement's Enhanced Transparency Framework.

* Other energy sectors in the chart above refers to *other sectors* (1.A.4), *others* (1.A.5), *fugitive emissions* (1.B), and *CO2 transport and storage* (1.C).

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Methane's role in energy-sector emissions

Methane is a powerful driver of near-term global warming

The energy sector is a major source of global anthropogenic methane emissions (around one third of the total).

Energy-related methane emissions remain high at around **120 Mt per year globally**, driven by continued fossil fuel production and limited mitigation. Natural gas operations emitted around 35 Mt of methane in 2024.

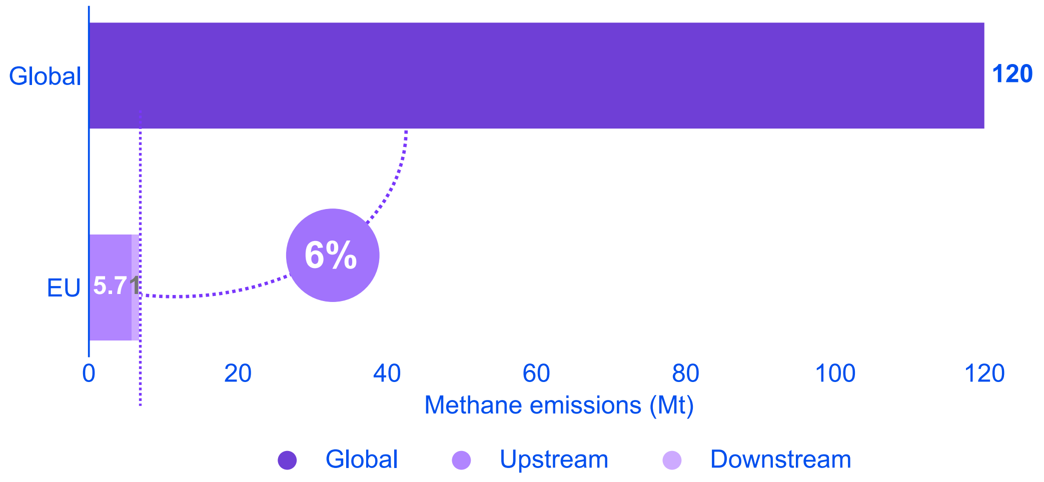
In the EU, emissions associated with oil and gas consumption were around 6.7 Mt of methane (~6% of global energy-related methane emissions). Reducing methane emissions offers one of the fastest, most cost-effective ways to reduce climate footprint of energy use.

Methane emissions are uneven, episodic and under-detected. Reliable monitoring, reporting and verification (MRV) is essential to identify leaks and to avoid relying on misleading averages*. Targeting super-emitters globally should be a key policy priority.

Do you know that ...

- Methane is the second most important greenhouse gas contributor to climate change.
- It is responsible for around 30% of the increase in global temperatures since the Industrial Revolution.
- Its global warming potential is roughly 80 times higher than CO_2 over a 20-year timeframe, but over a 100-year timeframe, effect dilutes to 28 times, as the CH_4 molecule has a 12-year average lifetime in the atmosphere.

Global energy-related methane emissions and EU methane emissions associated with oil and natural gas consumption, 2024 (Mt of methane)



Source: ACER based on IEA Methane Tracker 2025.
* Methane emissions estimates vary widely across sources. For instance, the IEA estimates that actual methane emissions from the energy sector are around 50% higher than those reported in official inventories, based on satellite and other top-down measurements.

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Regulatory targets needed to reach climate neutrality

Greenhouse gas emissions reduction	**55%** by 2030 compared to 1990 levels **90%** by 2040 **Net zero** by 2050	*European Climate Law* 6/2021
	62% by 2030 compared to 2005 levels for ETS sectors	*EU ETS Directive* 5/2003
Energy consumption	No more than **763 Mtoe** in final energy consumption by 2030*	*Energy Efficiency Directive* 9/2023
	30% decrease in fossil gas consumption by 2030	*Fit-for-55 Package* 7/2021
Renewable energy**	**42.5%** (targeting 45%) renewable sources share by 2030 **1.6%** annual increase in industry by 2030	*Renewable Energy Directive III* 10/2023
	42% share of RFNBO in industry by 2030 **1%** RFNBO in transport by 2030	*Renewable Energy Directive III* 10/2023
	35 bcm per year of biomethane (and biogas) production by 2030	*REPowerEU* 5/2022

Source: ACER based on EU policy and legislation, including the European Climate Law, EU ETS Directive, Energy Efficiency Directive, RED, the Fit-for-55 Package and REPowerEU Plan.
Note: ETS stands for emissions trading system. RFNBO stands for renewable fuels of non-biological origin, namely liquid and gaseous fuels the energy content of which is derived from renewable sources other than biomass. * 885.5 Mtoe in 2024. ** Other targets do not impact directly the decarbonisation of the gas market (e.g. RFNBO targets in maritime and aviation sectors).

REPowerEU's gas reduction ambitions at risk

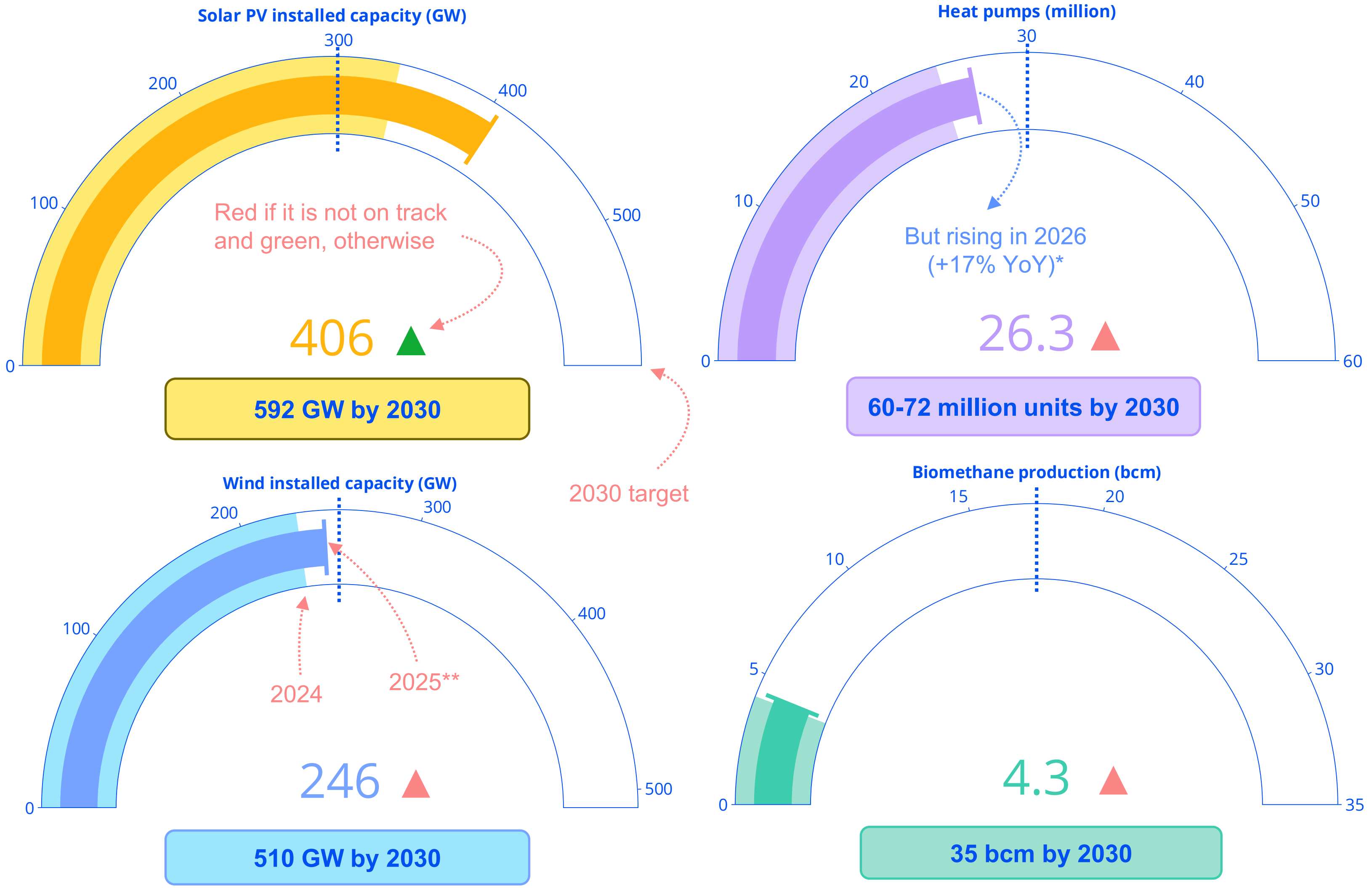
Investments accelerate in solar while wind expansion shows signs of slowing

Solar PV is the only REPowerEU plan's target currently on track, requiring just an 8% annual growth rate to reach approximately 600 GW by 2030.

Wind installed capacity and heat pump installations lag and would need annual growth of 16-18% to meet their goals.

Renewable hydrogen (almost negligible) is far off the 2030 target (20 Mt). Two of the most ambitious targets, for renewable hydrogen and biomethane, appear unlikely to be achieved by 2030.

In February 2025, the Commission adopted the Clean Industrial Deal and the Affordable Energy Action Plan. These initiatives aim to strengthen EU competitiveness and accelerate energy system decarbonisation.



Source: ACER based on data from European Commission, In focus: Solar energy, Wind Europe, EHPA, EBA and Shell. Note: targets for solar photovoltaics (PV) and heat pumps are set in REPowerEU Plan, while targets for wind are set in the European Wind Power Action Plan, which includes a target of 111 GW for offshore wind. * Residential heat pump sales increased 17% across 11 European countries in Q1 2026, following a sharp rise in gas and oil prices after Iran closed the Strait of Hormuz in March. ** All data is from 2025 with exception of biomethane where data was only available until 2024.

Gas consumption reduction has stalled …

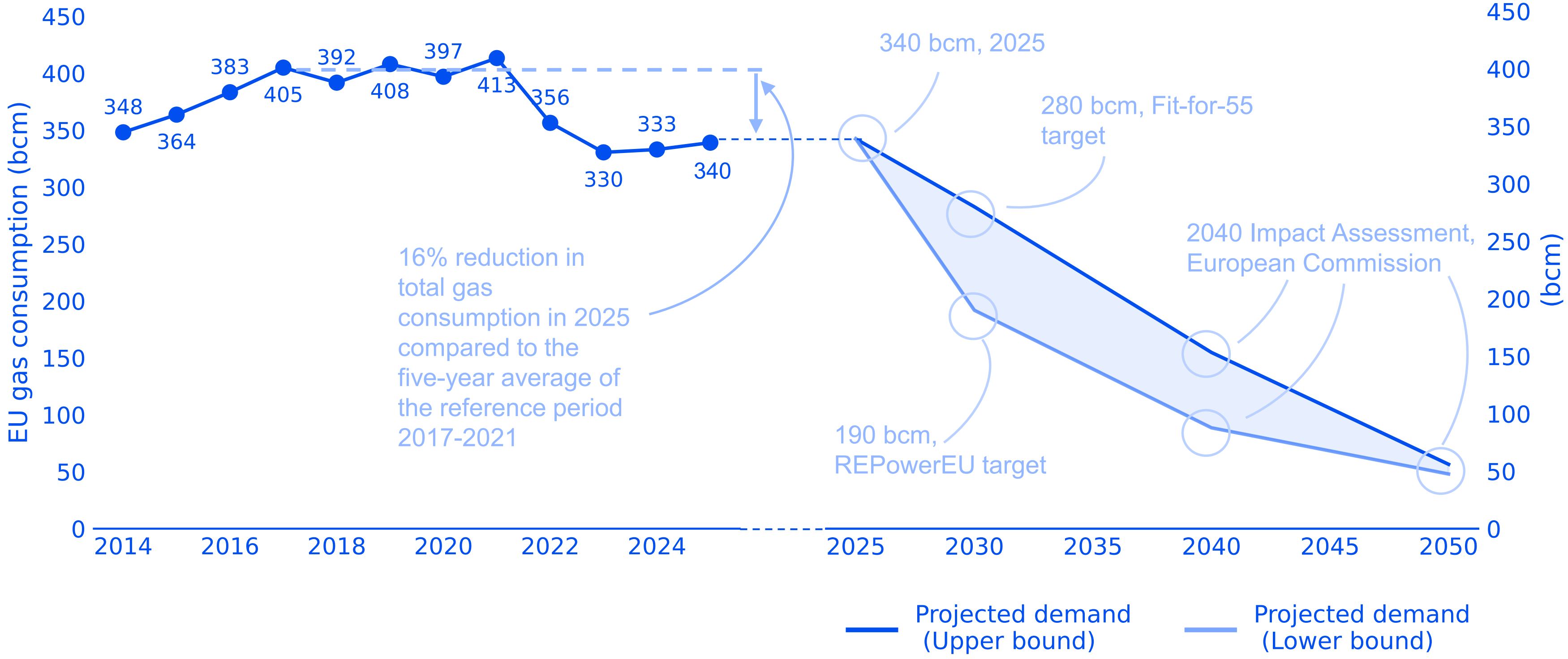
… putting EU decarbonisation objectives at risk

In 2025, EU gas consumption increased to 340 bcm, around 2% year on year, but remained 16% below the 2017–2021 five-year average. The sharp decline in gas demand since 2021 has been driven by electrification, energy efficiency improvements, and the gradual deployment of renewable gases, with elements of gas demand destruction. This trend signals a structural shift, with natural gas moving from a backbone energy source toward a supporting flexibility role.

In the absence of stronger decarbonisation efforts, the gas consumption reductions envisaged under the Fit-for-55 package are at risk—let alone the more ambitious, non-binding targets set out in the REPowerEU plan.

Moreover, declining gas demand, and consequently capacity bookings, may drive higher network tariffs. This topic is out of the scope of this report.

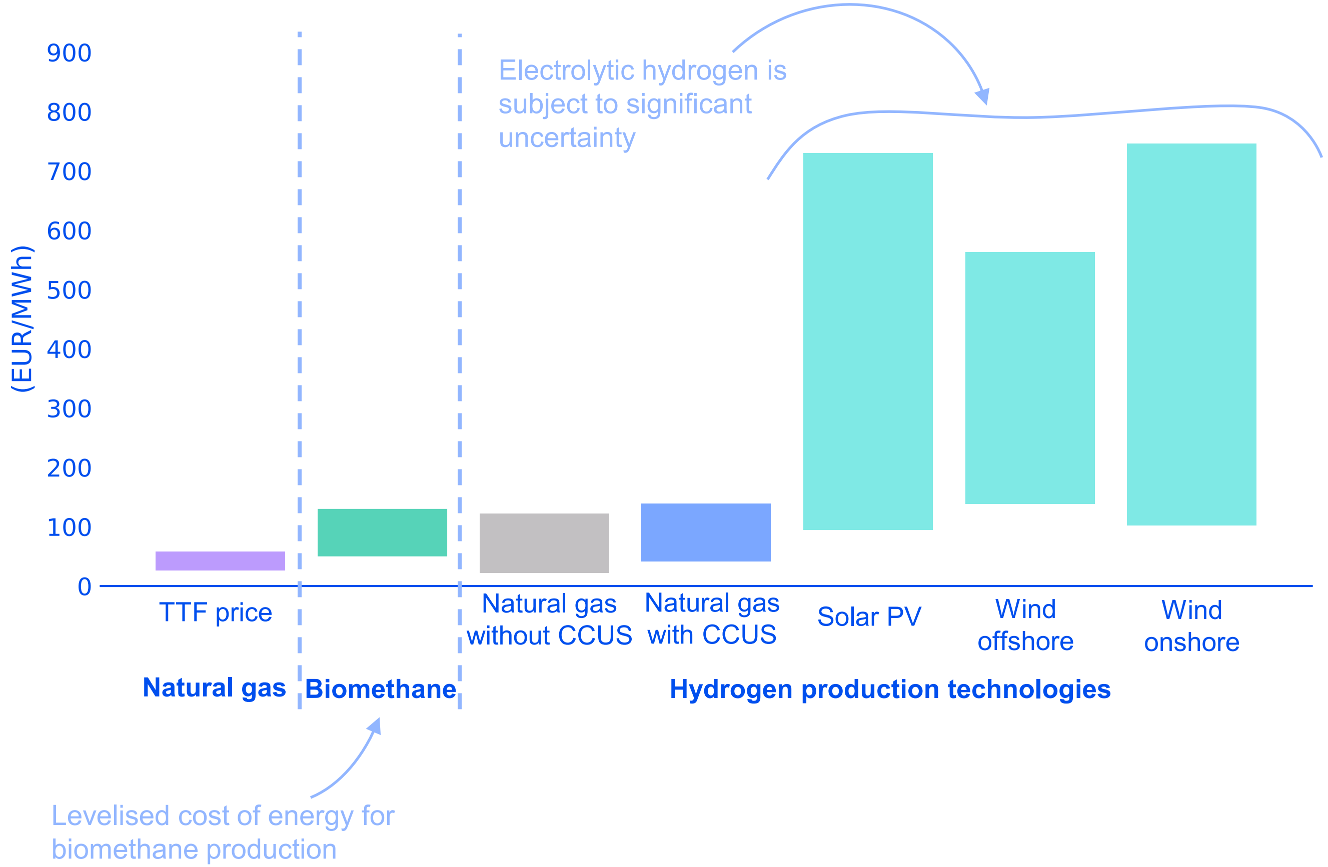
Historical gas consumption in the EU, 2014-2025 (bcm) and projected gas consumption under various decarbonisation scenarios, 2026-2050 (bcm)



Source: ACER calculations based on Eurostat, EC's impact assessment for the 2040 climate target. See the ACER Monitoring report on LNG market developments, 2025 and Annex B.
Note: Fit-for-55 implies a 32% reduction in natural gas demand compared to 2019, while the most ambitious REPowerEU scenario (without considering the gas savings related to renewable hydrogen targets) projects gas demand 32% below the Fit-for-55 level.

Decarbonisation needs established and emerging options

Current gas prices in 2025 and estimated levelised cost of energy for biomethane and hydrogen by technology (EUR/MWh)



The cost gap between fossil-based and renewable-based hydrogen increased

- The decarbonisation of the EU gas market will rely on a mix of mature and emerging technologies.
- While fossil natural gas remains the most cost-competitive option under current carbon prices, biomethane is the most mature low-carbon alternative and could become competitive* under stricter carbon constraints.
- CCUS applied to hydrogen production from natural gas is widely seen as a transitional solution, whereas renewable hydrogen remains costly and uncertain.
- In the near term, hydrogen is unlikely to replace natural gas at scale and is expected to play a role primarily in hard-to-abate sectors over the medium to long term.

Source: ACER based on IEA, ICIS, and Haya Energy.
Note: In the plot CCUS stands for carbon capture, utilisation and storage. * The competitiveness of biomethane is examined in dilemma 1. A broader assessment of emerging technologies for decarbonising the EU gas market is developed in the rest of this report, with particular focus on the trilemma analysis.

The EU ETS strengthens the Union's decarbonisation

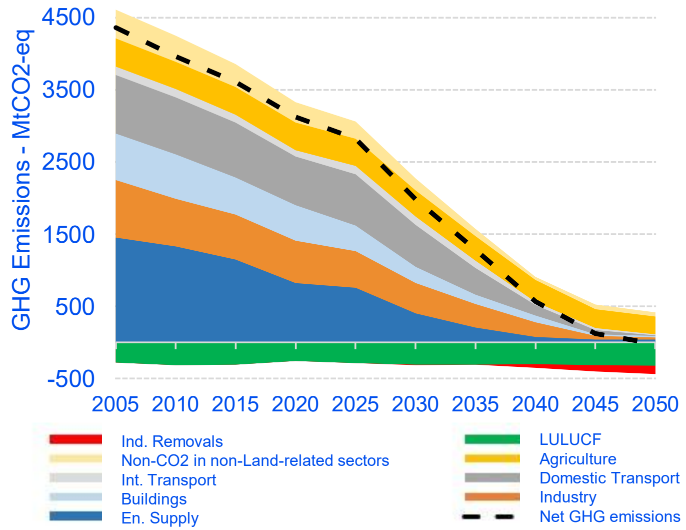
The EU Emissions Trading System (ETS) is the central carbon pricing framework in the Union

Spot day-ahead carbon price of EU general allowances (EUR/tCO_2)

Source: ACER based on EEX, European Commission, the EU ETS Directive, RED, ETS2.
Note: energy-intensive industries comprise sectors such as steel, cement, lime, aluminium, chemicals, ceramics, glass, pulp and paper. The ETS applies in Northern Ireland for electricity generation.
As highlighted by BusinessEurope study (page 65), most countries do not apply carbon pricing, while the EU faces the highest CO_2 costs among market-based systems, especially since 2020.

Balancing security, competitiveness, and climate ambition

Greenhouse gas emissions – 2015-2050 (Mt CO_2eq)



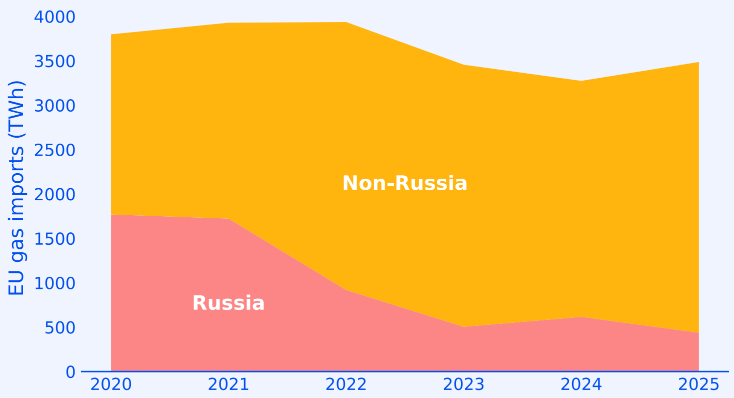
Sustainability

The 2040 climate target reinforces the EU's commitment to climate neutrality by 2050, a legally binding goal at the core of the European Green Deal. The political will is to reduce the EU's net greenhouse gas emissions by 90% by 2040, relative to 1990. At the same time, the EU risks missing some 2030 targets.

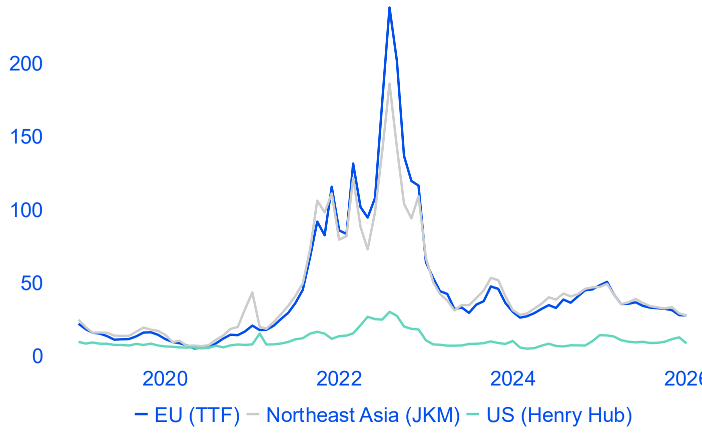
Security of supply

Security of supply has become a key priority following Russia's invasion of Ukraine. Ensuring the reliable availability of gas remains central to discussions on the future of the EU gas market during the energy transition.

EU gas supply imports – 2020-2025 (TWh)



Gas prices in EU, US, and Asia (EUR/MWh)



Competitiveness/affordability

Transforming the gas market to reduce greenhouse gas emissions while ensuring security of supply comes at a cost. Concerns have been raised about competitiveness disadvantages due to high gas prices.

Sources: EC's impact assessment for the 2040 climate target, ENTSOG, ICIS, Henry Hub - EIA and TTF/JKM - S&P Global.
Note: A broader discussion on security of supply can be found in ACER's report on security of EU electricity supply.

Challenges in decarbonising the EU gas market

Energy sector trilemma* and the role of gas market decarbonisation

Dilemma 1
Can renewable gases (biomethane or low-carbon hydrogen) reconcile the EU's objective of reducing gas import dependency with the need to maintain affordable energy prices?

Dilemma 2
Will the rising cost of natural gas contribute to persistently high electricity prices during the energy transition?

Dilemma 3
Can EU decarbonise its gas sector without further affecting industrial competitiveness?

Dilemma 4
How to tackle methane emissions (low-cost potential – rising implementation risks)?

Trilemma
What are cost-effective pathways for decarbonising the gas market, considering technological readiness, emissions impact, and energy independence?

* The dilemmas are positioned along axes connecting two challenges, to illustrate the key trade-offs involved. In this report, sustainability is understood as the reduction of emissions and the greening of the economy while progressing the energy transition sensibly. Security of supply refers to the reliability and diversification of gas supplies in an uncertain geopolitical environment. Competitiveness and affordability refer to the development of an integrated market that promotes competition and innovation while ensuring affordable energy prices.

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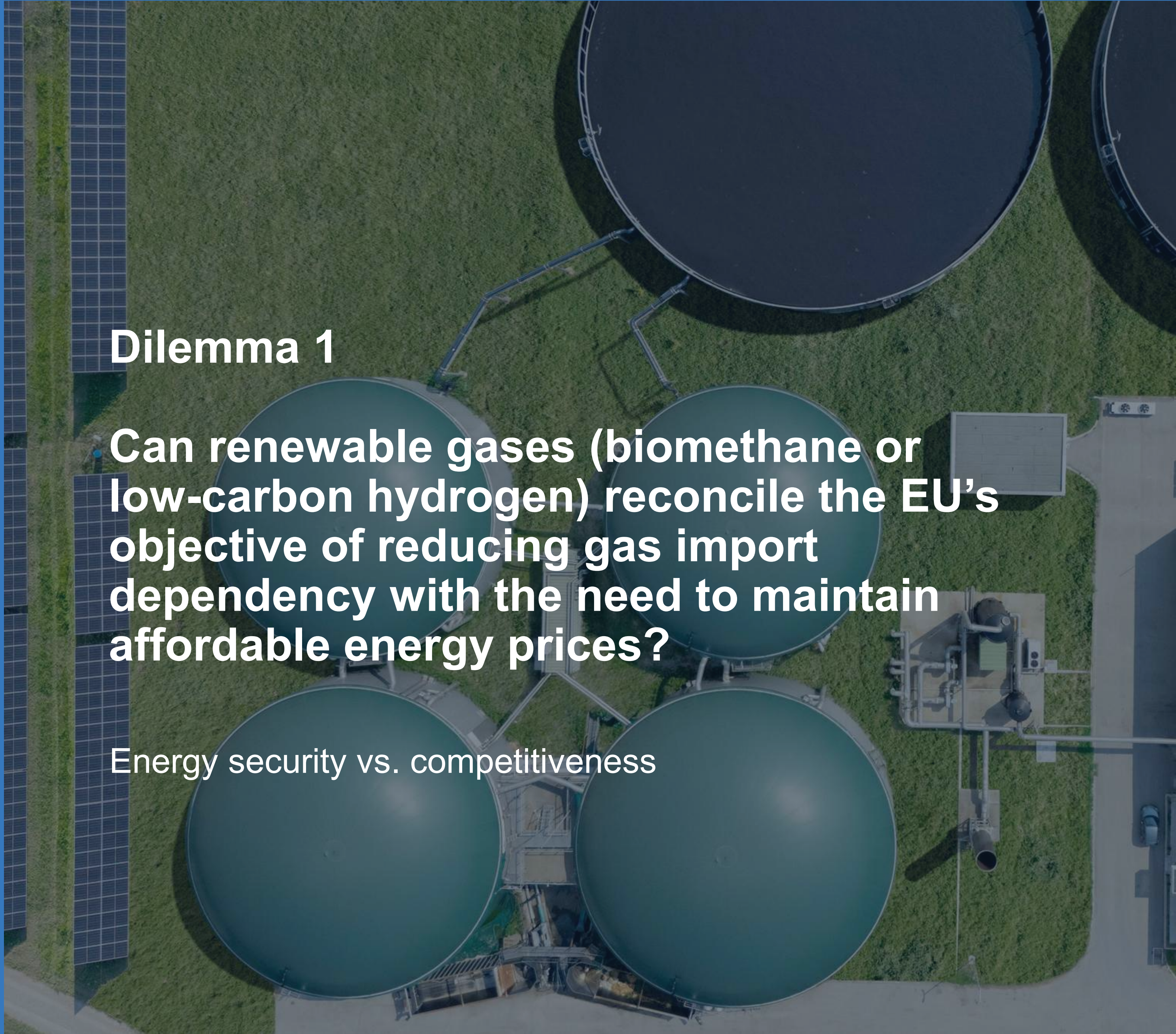
The EU’s recent energy crisis has reinforced the strategic importance of reducing dependence on imported natural gas. Security of supply has become a central objective of EU energy policy. Together with the decarbonisation, there is a renewed interest in domestically produced alternatives to fossil gas.

However, the large-scale deployment of biomethane raises questions about cost and competitiveness. Production costs remain higher than those of conventional natural gas. In addition, scaling up renewable gas supply may have implications for energy prices, public support mechanisms, and industrial competitiveness. This trade-off between security of supply and affordability lies at the core of the current debate on the role of renewable gases in the EU’s natural gas market.



Dilemma 1

Can renewable gases (biomethane or low-carbon hydrogen) reconcile the EU’s objective of reducing gas import dependency with the need to maintain affordable energy prices?

Energy security vs. competitiveness

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Where others see waste, we see energy

Biomethane is a mature and scalable renewable gas

- Biomethane production technologies are well established. Anaerobic digestion and biogas upgrading are widely deployed, offering a pragmatic and near-term pathway to decarbonise the gas market.
- EU biomethane production reached 4.3 bcm* in 2024, but this still represents only a small share of total gas supply despite significant potential.
- Production progresses unevenly across Member States, reflecting differences in support schemes, regulatory frameworks and feedstock mobilisation.
- Upgrading existing biogas to biomethane could significantly increase supply. If 90% of current biogas were upgraded, EU biomethane production could increase roughly threefold.

Biomethane can support both decarbonisation and energy security through domestic production

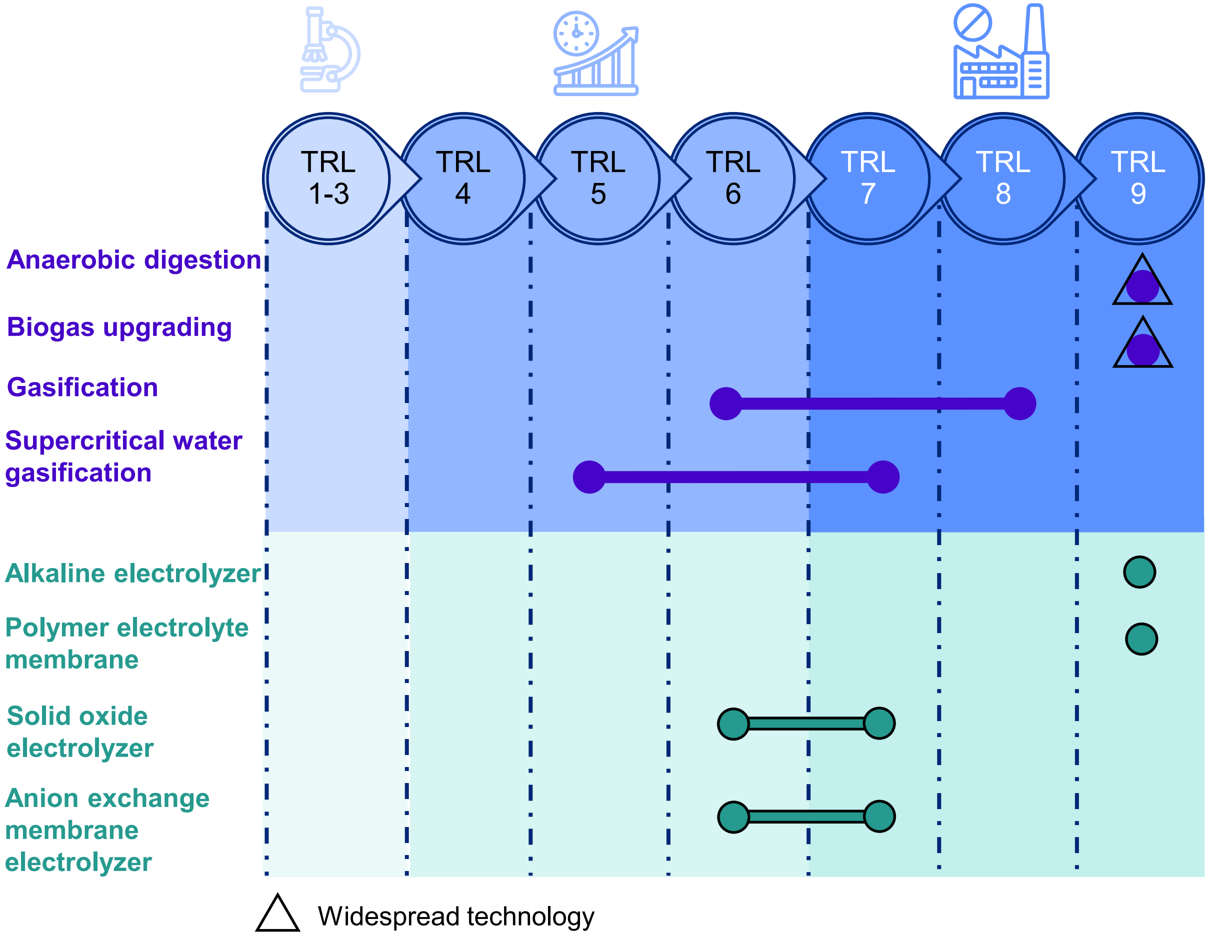
- Expanding domestic biomethane production can strengthen EU energy resilience, reducing dependence on external suppliers while supporting decarbonisation of gas consumption.

Further deployment depends on supportive market frameworks and cost competitiveness

- Biomethane certificates help track renewable and sustainable gas in integrated systems and can improve the economic viability of biomethane by providing additional revenue streams.
- Biomethane competitiveness depends on carbon prices and the value of these certificates.
- Higher carbon prices and low prices for its “green” label can improve uptake, but it may reduce producer’s profitability and constrain supply.

* Source: EBA.

Biomethane & hydrogen complementary in decarbonisation



Technology Readiness Levels (TRLs) provide a **common framework to a technology's maturity**, from basic research (TRL 1) to full commercial deployment (TRL 9).

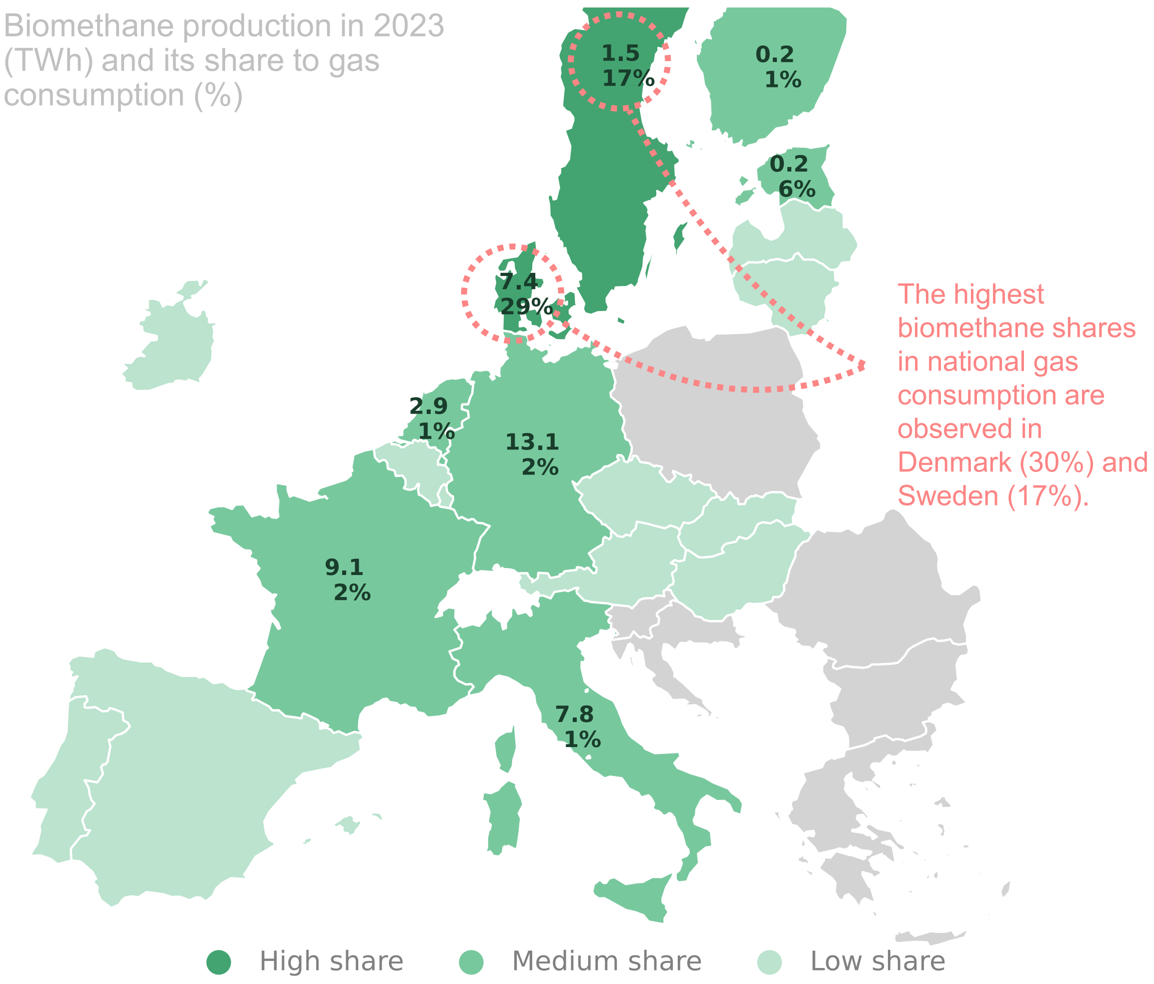
Biomethane has received uneven political attention

The Renewable Energy Directive (RED III) includes binding targets for renewable fuels of non-biological origin, such as hydrogen, in hard-to-electrify sectors (transport and industry). By 2030, RFNBOs must cover at least 42% of all hydrogen used in industry, increasing to 60% in 2035. Also, the Hydrogen and decarbonised gas market package adopted in 2024 supports the development of a dedicated hydrogen infrastructure and an efficient hydrogen market.

Despite these political actions, its large-scale deployment in the EU still lags compared to biomethane. Infrastructure, storage, and end-use technologies are not yet ready for full commercial deployment, let alone keeping security of supply. While green hydrogen will contribute to decarbonisation, biomethane offers a faster and more pragmatic path. Anaerobic digestion and biogas upgrading are well-established technologies for producing renewable gas.

Source: ACER based on Rabobank, Yunfei Li et al. 2024, and ETP Clean Energy Technology Guide.

Biomethane rollout varies widely across EU Member States



More than 1500 biomethane production plants operational in EU

Biomethane stands out as the most mature renewable gas option, enabling seamless integration into existing gas infrastructure. Yet, the trade-off between investing in local supply and sourcing cheaper imports raises questions of feasibility and long-term sustainability.

As of mid-2025, the EU has around 1,500 biomethane production plants, with France and Germany hosting the largest numbers (approximately 760 and 260 plants, respectively)*.

EU biomethane production reached 4.3 bcm per year in 2024, representing a year-on-year increase of around 5%. Production is already established in several Member States, creating a base for rapid scale-up.

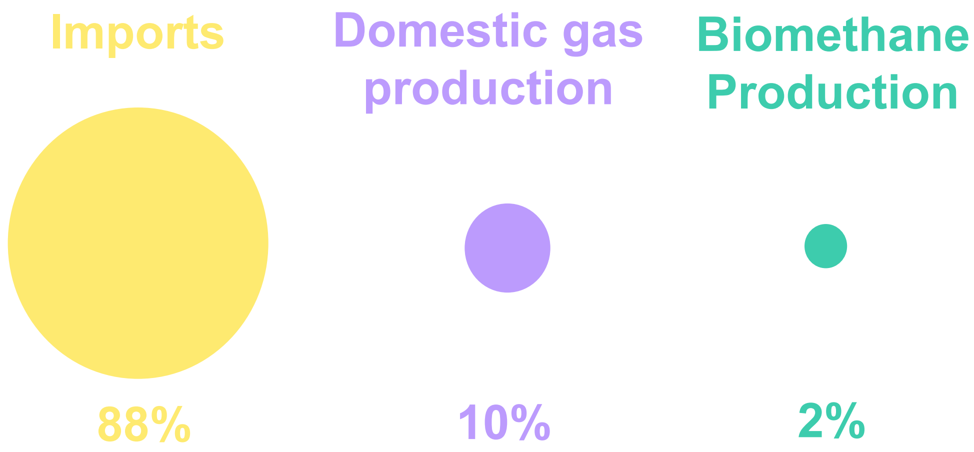
While production volumes are highest in Germany, France, and Italy, Denmark stands out for the significant role biomethane plays in its gas mix, covering nearly one-third of national gas consumption in 2023. Together with Sweden, Denmark demonstrates how biomethane can contribute substantially to security of gas supply by reducing reliance on imported and conventional gas.

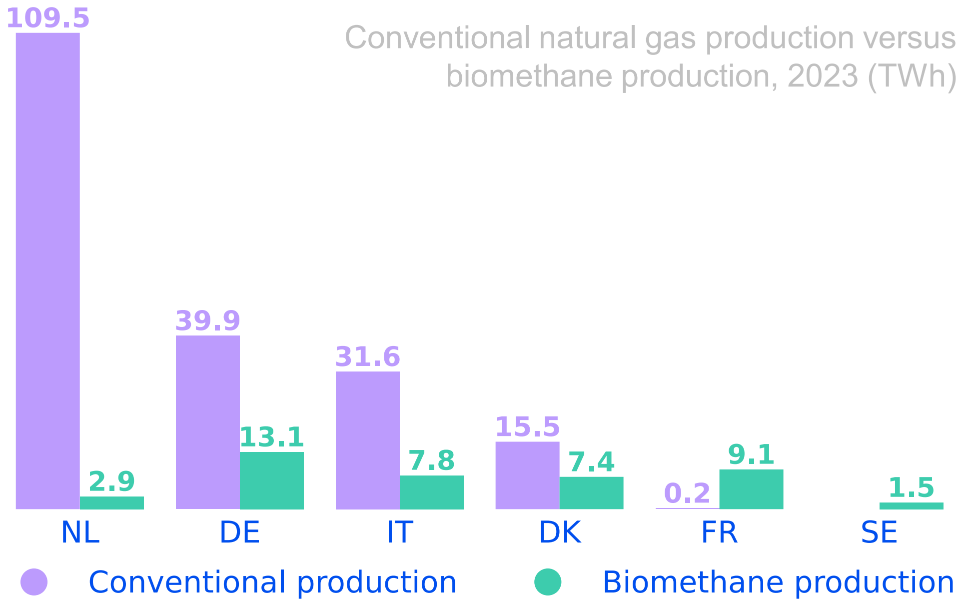
Source: ACER based on GIE, EBA, and Eurostat. High share: >10%, medium share: between 1 and 10%, low share: < 1%.
* Biomethane production plants come from the European biomethane map 2025. By the end of 2025, the number of units in service in France reached 803.

Biomethane share is still small

Limited share of biomethane from total gas supply

Share of natural gas imports, domestic gas production and biomethane production, 2024 (%)





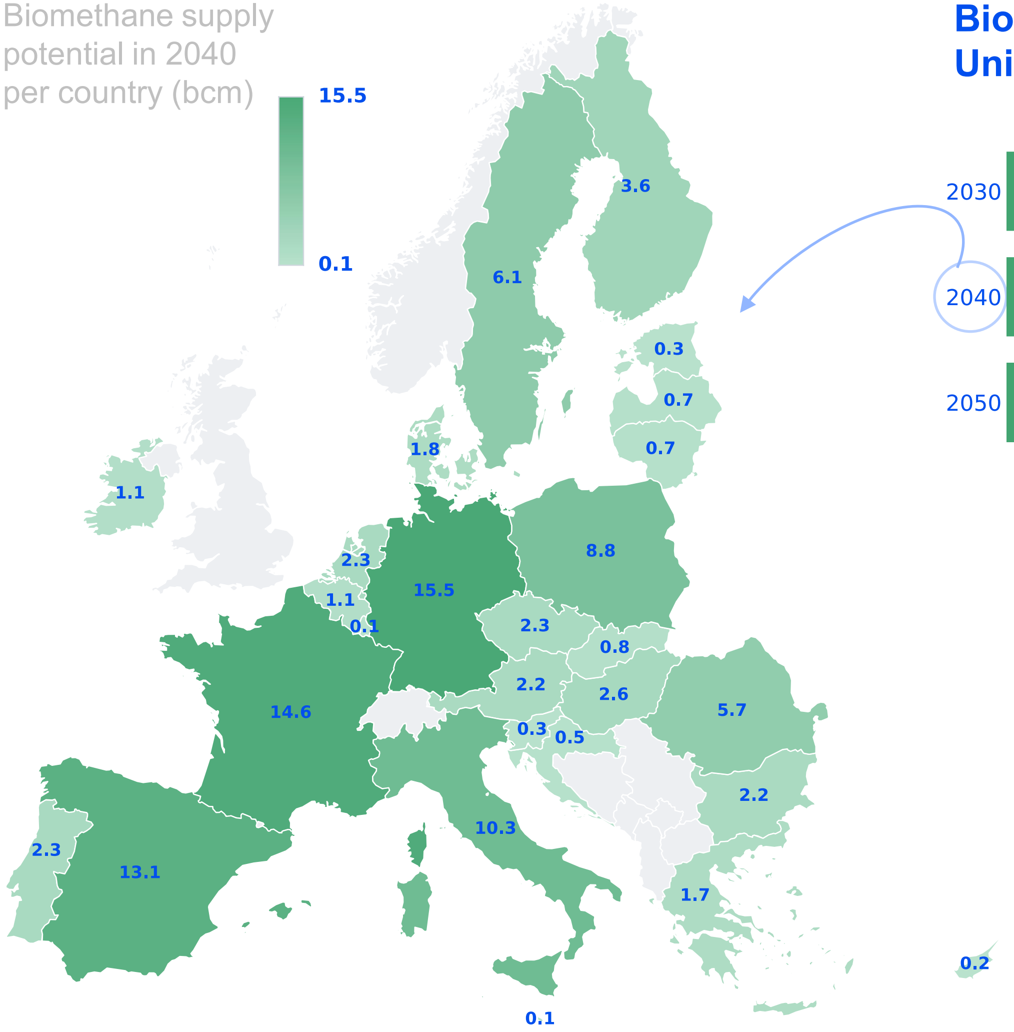
There are disparities across countries when compared to their conventional domestic gas production. Countries with strong domestic natural gas production, usually those with a high gas consumption, have a relatively small biomethane share. Biomethane represented a significant share of gas consumption in some countries with limited domestic gas production and relatively low overall gas demand, reaching around 30% in Denmark and 17% in Sweden in 2023.

At EU level, domestically-produced biomethane accounts for only a **small share of total EU gas supply**, despite its significant potential to contribute to decarbonisation and energy security.

Source: ACER based on EBA and Eurostat.
Note: on the left plot, percentages are computed with respect to total gas injected to the grid. On the right plot, only countries with a biomethane production above 0.5 TWh are shown (year 2023).

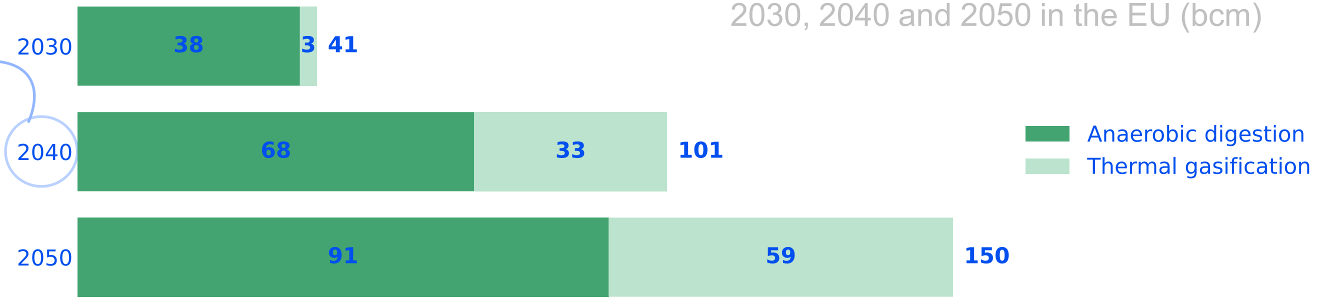
Biomethane as a key driver of EU clean energy objectives

Biomethane supply potential in 2040 per country (bcm)



Biomethane production across the EU is expected to rise to achieve the Union's net-zero goal by 2050

Biomethane supply potentials per technology in 2030, 2040 and 2050 in the EU (bcm)



The European Biomethane Association provides sustainable supply estimates of 150 bcm in 2050 based on the efficient use of available feedstock. However, other sources (e.g. Agora) estimate an upper bound around 62.5 bcm of biomethane potential by 2045 due to economical and technical constraints, significantly lower than EBA's projection.

For **anaerobic digestion**, key feedstock sources include sequential cropping, animal manure, agricultural residues and industrial wastewater. The highest supply potential for this pathway is projected in Germany, France, Italy, Spain and Poland.

Thermal gasification will continue to rely mainly on wood waste, forestry residues and municipal solid waste, with wood waste and forestry residues becoming more prominent over time. The highest supply potential is expected in Sweden, Germany, Spain, France, Italy, and Finland.

Source: ACER based on EBA's estimations, Gas for Climate, and Agora Agriculture (2024): Agriculture, forestry and food in a climate neutral EU. The land use sectors.
Note: Biomass extraction often comes with biodiversity and land use constraints, entailing trade-offs with the LULUCF sector. See EEA report on The European Biomass Puzzle.

Biogas to biomethane: A realistic decarbonisation pathway

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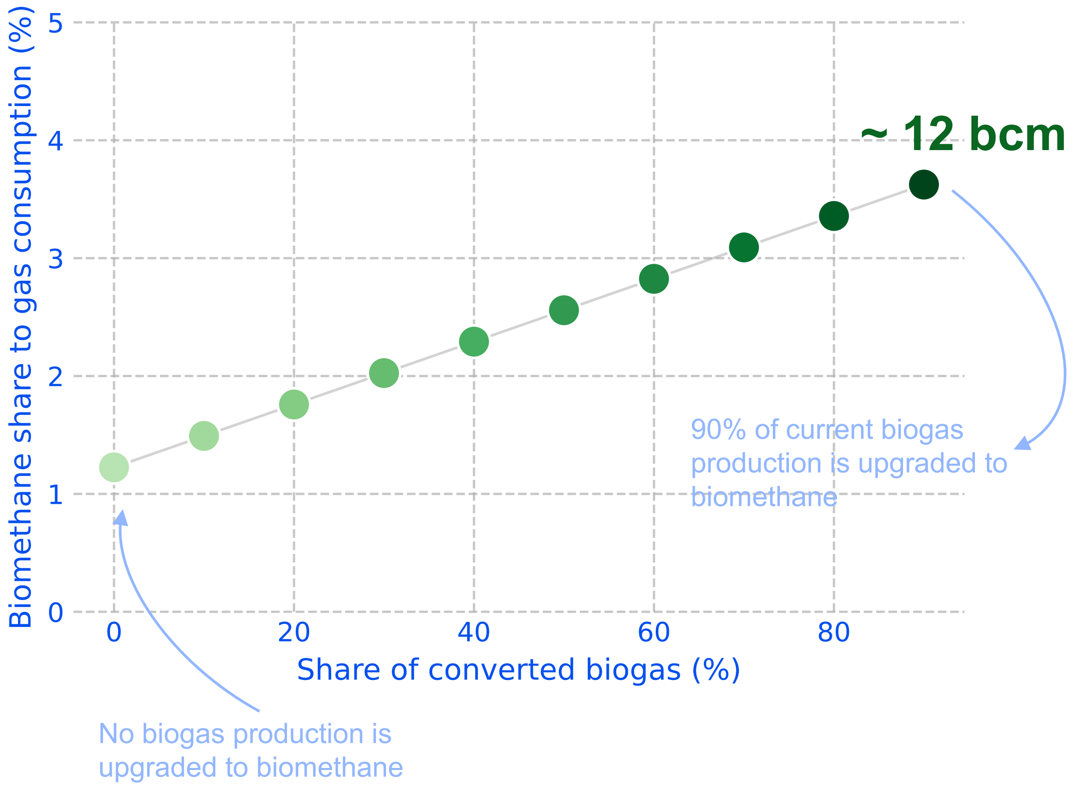
Threefold increase in biomethane production if 90% of biogas were upgraded to biomethane

The REPowerEU Roadmap of May 2025 towards ending Russian energy imports, updated the actions to be taken on both biogas and its upgraded version, biomethane. Biogas production already provides a tangible contribution to the EU's renewable energy mix, leveraging local resources such as agricultural residues, organic waste and manure.

With over **157 TWh (~14 bcm) of biogas produced annually** across the EU, the sector represents a well-established foundation for renewable gas development. This production supported by mature technologies and a wide network of small- and medium-scale plants, makes biogas a starting point for scaling up biomethane.

Today, biomethane production amounts to around 1% of EU gas consumption. Upgrading biogas to biomethane enables direct injection into the gas grid and use in the same applications as natural gas, from heating to transport and industry. In Europe, **biogas upgrading is the main biomethane pathway** and upgrading costs represent only a small fraction of total production costs**. If 90% of current biogas were upgraded to biomethane, almost 4% of EU gas consumption would be covered by biomethane.

Share of biomethane production to gas consumption if X% of current biogas production were upgraded* (%)



Source: ACER based on EBA and IEA.
* We assume 1 m^3 of biogas is assumed to yield ~60% biomethane after upgrading. Note that 0% conversion rate means that current biomethane production is used for computing the share.
** The costs of upgrading biogas to biomethane at a medium-to-large facility using a membrane separation system are around 3 USD/GJ (around 15% of the average production costs).

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How to certify biomethane as renewable and sustainable

Certificates track renewable gas in mixed systems, ensuring that double counting is avoided and confirming the origin and sustainability of gas to consumers

When signing a renewable-gas contract, operators can claim lower CO_2 emissions, even if the used biomethane comes from the mixed grid, because the certificate guarantees its renewable origin. There are two standard types of certificates set out in RED.

Guarantees of Origin (GOs)	Proof of Sustainability (PoS)
• Electronic documents disclosing to end consumers the **renewable share** of an energy source. • Issued by national registries for each MWh equivalent of energy produced. • Traded via the **book and claim principle**: GOs are transferred independently from physical product. Because they are traded on a different market than the physical gas, GOs have monetary value. • Used mainly in **voluntary markets** as green labels, strengthening the business case for renewable gas producers. • Once used, GOs must be retired in the national registry to avoid **double counting**.	• Certificates proving compliance with **sustainability and GHG emissions savings criteria** in RED. • Issued by certified producers meeting the requirements of certification bodies within an EU approved scheme. • Traded via the **mass balancing principle**: PoS keeps track of the certified renewable share so that the sustainability claims remains administratively attached to the quantity supplied. • Used in **compliance markets** to fulfil EU sustainability and energy obligations. • **Double counting** is avoided through mass balancing.
At the EU level, **there is not a harmonised biomethane market in Europe**, making the transfer of GOs and PoS difficult across Member States. The Union Database (UDB), launched in 2024, covers gas supply chains and, at a later stage, will link GOs and PoS for consignments that have both certificates.	

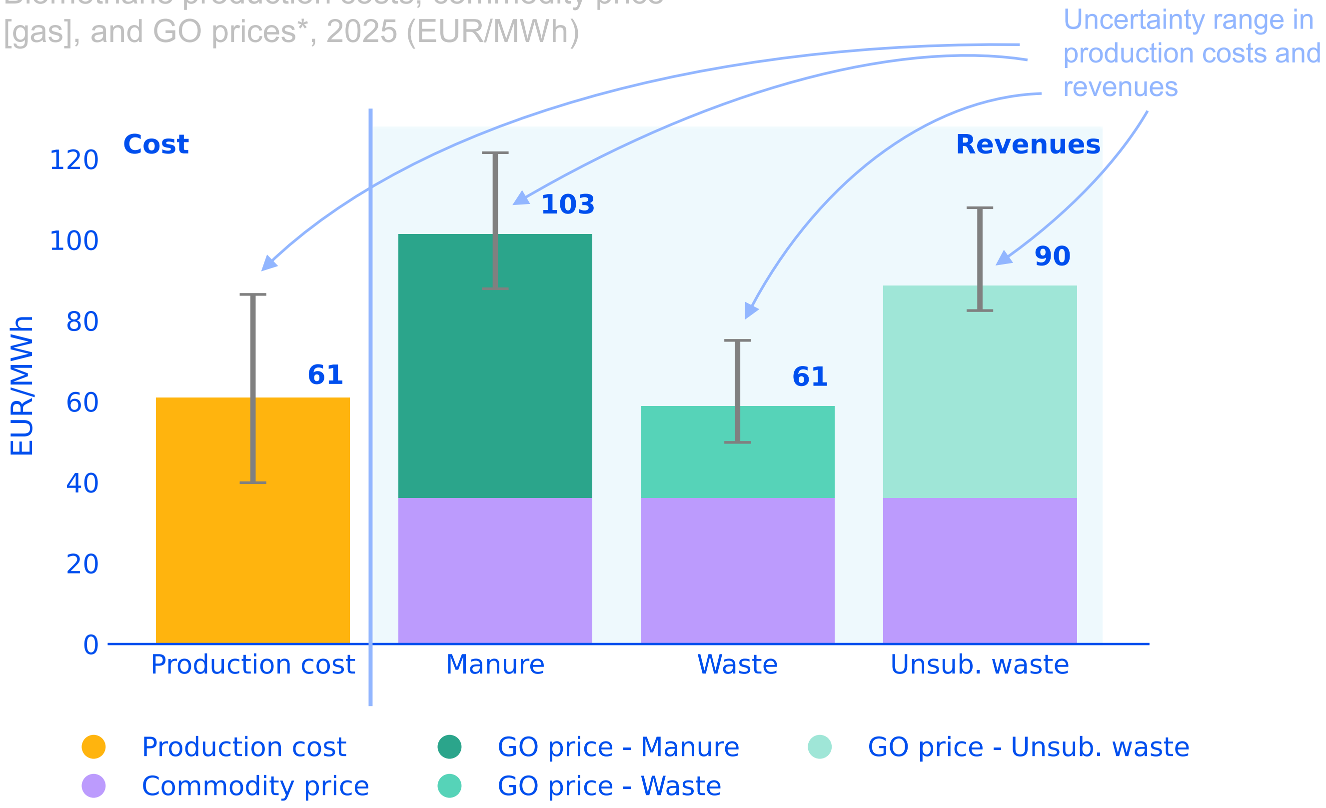
Operators must produce both GOs and PoS to prove the renewable and sustainable origin of biomethane under the EU ETS. If both certifications are produced, emissions stemming from biomethane are **zero-rated** and operators can lower the purchase of EU ETS allowances. The biomethane certificates will be integrated into the UDB, which will track biomethane molecules using mass balancing supported by PoS.

Source: ACER based on RED III, Commission Implementing Regulation (EU) 2018/2066 and S&P Global. Note: according to the Commission Implementing Regulation 2018/2066, which specifies GHG emissions monitoring and reporting requirements within the EU ETS, PoS must be produced to demonstrate compliance with sustainability criteria by using a mass balance, thereby ensuring that producer and consumer are connected to the same grid, while GOs ensure that double counting of the same biomethane quantity is avoided.

Producer-side competitiveness

Guarantees of origin (GO) offset biomethane production costs, but largely depend on feedstock

Biomethane production costs, commodity price [gas], and GO prices*, 2025 (EUR/MWh)



Biomethane producers and consumers face different market dynamics, which this analysis assesses from both perspectives to capture a balanced view of competitiveness.

Biomethane production **cost ranges depend widely on plant size, technology, and feedstock**. Large biodigesters can decrease costs by one third on average compared to smaller ones. Crop residues and animal manure are the largest sources of feedstock and the cheapest ones in the EU. Thermal gasification of woody biomass is considered less competitive nowadays. Scaling up production may require subsidies, stable policy frameworks, and investment certainty.

Despite biomethane's advantages, production costs remain higher than commodity gas prices. **GOs can offset a significant share of these costs for producers**, although GOs depend strongly on feedstock type, support schemes and end-use markets. Biomethane is valued differently across end-use markets depending on their corresponding willingness to pay, certificate framework or supply-demand dynamics. Cross-border traded volumes of biomethane certificates represent just 5% of total biomethane production in the EU. Additional revenue can be generated by monetising biogenic CO_2 and the digestate.

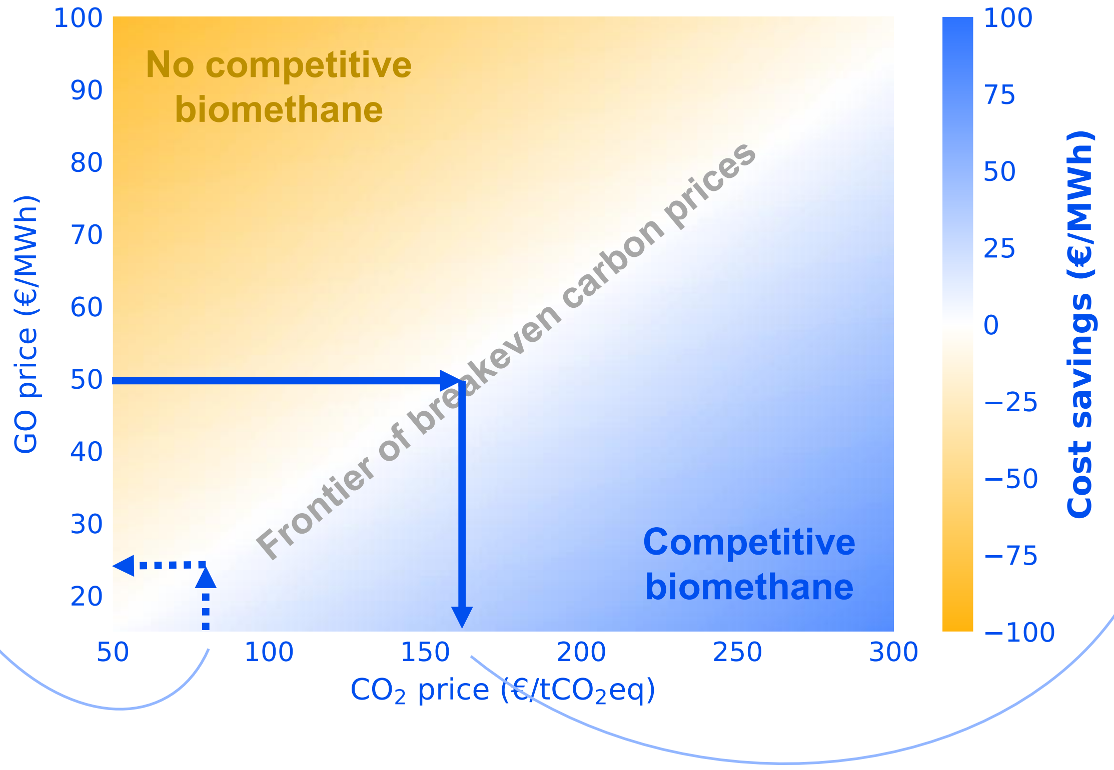
Source: ACER based on S&P Global, ICIS, EEX, IEA, and The Oxford Institute for Energy Studies, January 2026.
Note: Biomethane production costs include CAPEX, OPEX, and feedstock. Commodity price refers to gas day-ahead TTF price. GO prices for manure- and waste-derived biomethane are taken from 2025 markets in DK, NL, and DE. Subsidies are excluded from the stacking of revenues. See consideration (1) of Annex C. * GO prices refer to the price of GO and proof of sustainability certificates.

Consumer-side competitiveness

Biomethane's guarantees of origin (GO)* prices relative to carbon prices are key to its competitiveness

The figure below compares the potential **cost savings from using biomethane** for an industry consuming natural gas. In compliance with the EU's Emissions Trading System (ETS), when consuming natural gas, the industry faces additional costs linked to carbon pricing. Resorting to biomethane could be a choice for that industry: while biomethane has a higher price than natural gas, the industry would obtain guarantees of origin that would displace its emissions and hence offset ETS emission rights. The relative position between GOs and ETS prices is hence crucial for taking the choice.

Cost savings of an industry fully compliant with ETS including carbon prices for natural gas and GO prices for biomethane (EUR/MWh)



2025 average carbon price reached 72 EUR/tCO_2eq. For this carbon price, biomethane would not need financial support if GO prices were lower than 23 EUR/MWh.

For instance, biomethane with a GO price around 50 EUR/MWh would become competitive if the carbon price were higher than 160 EUR/tCO_2eq.

Source: ACER based on S&P Global, ICIS, and EEX.
Note: See consideration (2) in Annex C.
* Guarantees of origin prices refer to the price of guarantees of origin and proof of sustainability certificates.

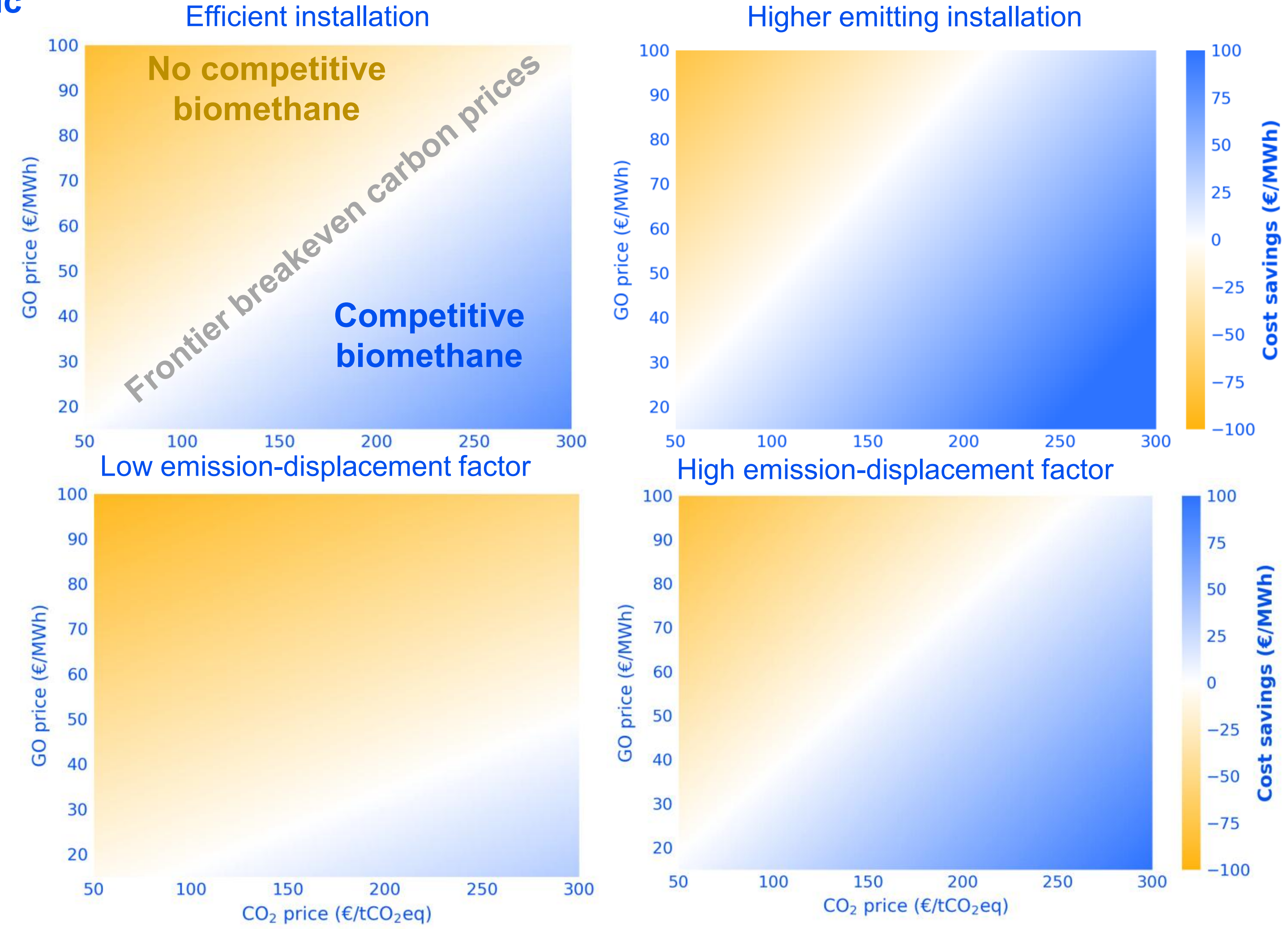
Biomethane is competitive earlier in high-emitting industries

Biomethane competitiveness is industry-specific

Assuming full compliance with the EU's ETS, the figure compares the **cost savings from using biomethane** for:

- an efficient installation versus a higher-emitting one, and
- industries with low versus high emission displacement factors of natural gas.

Illustrative examples of cost savings of industries fully compliant with ETS including carbon prices for natural gas and GO prices for biomethane (EUR/MWh)



Biomethane is more competitive in higher-emitting installations and in industries with a high emissions-displacement factor, where fuel-related emissions represent a large share of total process emissions. In such cases, switching from fossil natural gas to renewable natural gas can deliver greater cost savings, even at relatively low carbon prices (depending on the GO value).

From the consumer perspective, low GO prices and high CO_2 prices improve biomethane competitiveness. However, persistently low GO prices may reduce producer's profitability, potentially constraining supply.

Source: ACER based on S&P Global, ICIS, and EEX.
Note: See consideration (2) in Annex C.

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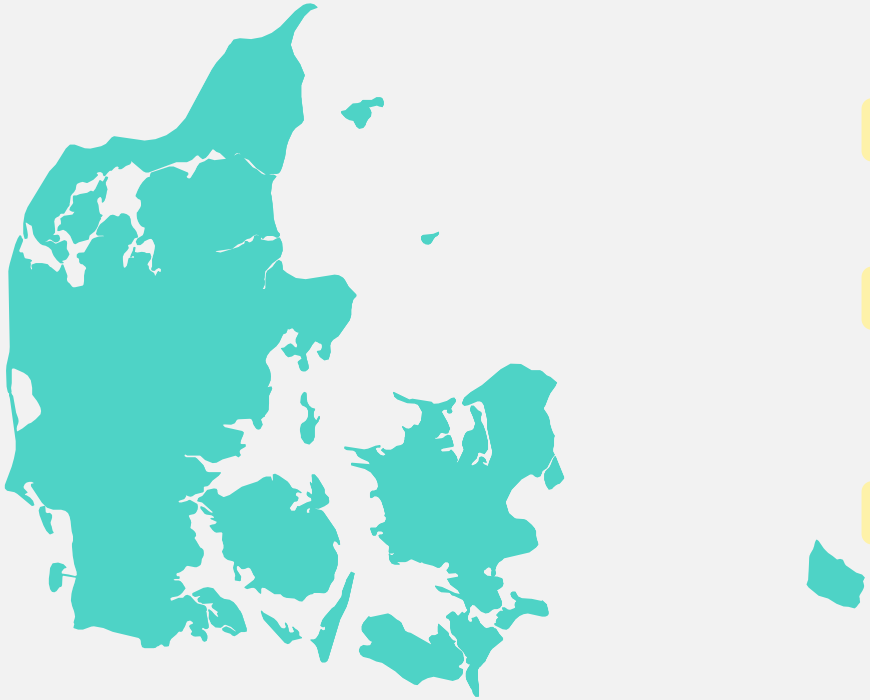
Case study – Denmark's biomethane success story

12% — Biomethane production to peak demand

70% — Annual biomethane potential by 2030

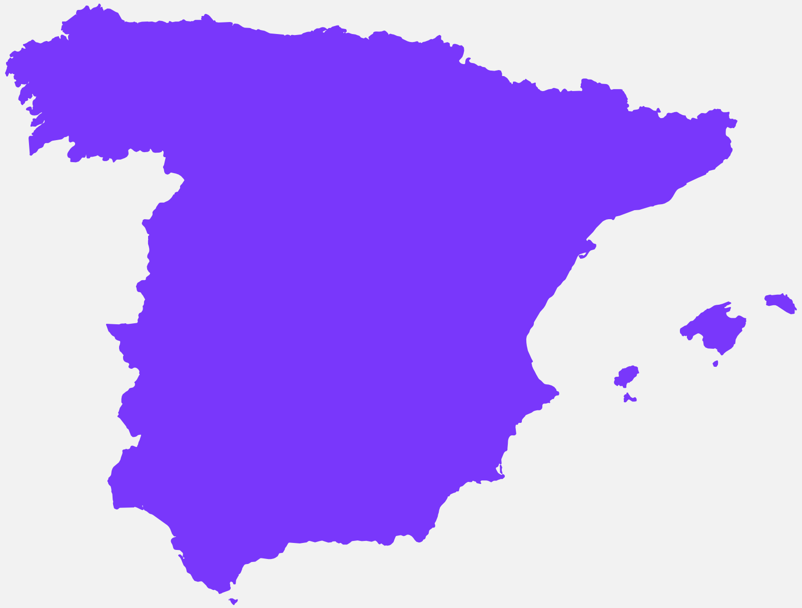


Biomethane status	58 biomethane plants. An average production of 7.4 TWh/year (30% of 2024 gas consumption and 12% compared to peak demand).
Biomethane potential	+10.3 TWh/year by 2030 (circa 70% of its 2024 gas demand).
Expected investments	Planned investments higher than 3 billion EUR.
Regulatory aspects	An efficient model with strong gas grid integration, though growth has slowed since 2020 following adjustments to feed-in tariffs and the end of the subsidy scheme for new biogas plants.
Ambition	100% of domestic consumption covered by green gases by 2030.

Source: ACER based on diverse sources, EBA, ICIS, S&P Global and Danish NRA input.
Note: Danish peak gas demand was 168.2 GWh/d in post-crisis years 2023-2024.

Case study – Spain, a nascent market with huge potential

Biomethane production to peak demand	0.1%
Annual biomethane potential by 2050	50%



Biomethane status	22 operational plants by October 2025 with a capacity around 1.1 TWh/year (negligible share of 2024 gas consumption and 0.1% compared to peak demand).
Biomethane potential	Target of 20 TWh/y for biogas by 2030, according to National Energy Plan. Third largest max. potential in the EU: 163 TWh/year (approx. 50% of 2024 gas consumption).
Expected investments	Around 300 new biomethane plants under project or construction with 20-24 TWh/y of capacity (4.5 billion EUR of investments).
Regulatory aspects	There are incentives for production, but not for consumption yet. Guarantees of origin in place since 2023; connection rules with the gas system in place since 2024. Distribution network third-party access tariffs for biomethane injection have been always 0 €/kWh/d.
Barriers	High transport costs, difficulties connecting rural plants to gas networks, digestate management, and public acceptance.

Source: ACER based on diverse sources, Sedigas, EBA, ICIS and Spanish NRA input.
Note: Spanish peak gas demand was 1670.1 GWh/d in post-crisis years 2023-2024.

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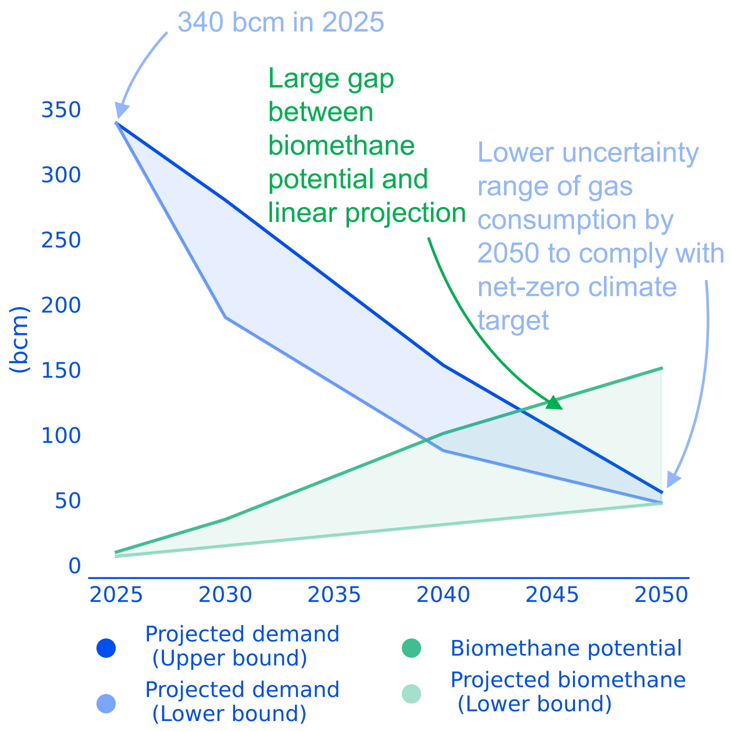
Biomethane reduces import dependence and geopolitical risk

Gas demand expected to decrease during the energy transition

Gas consumption vs biomethane production potential, 2025-2050 (bcm)



Biomethane integration reduces the dependency with external gas suppliers

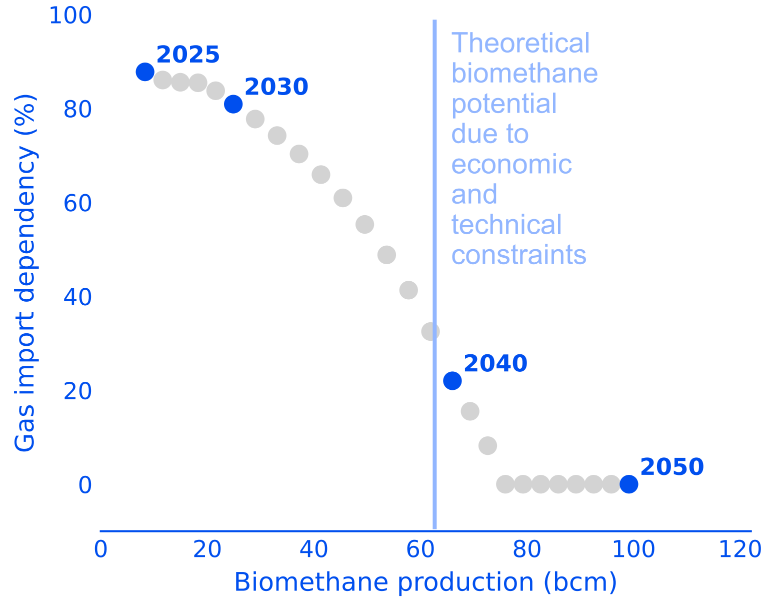
Gas consumption is expected to decrease during the energy transition according to the decarbonisation scenarios of the European Commission. The goal of these scenarios is to reach climate neutrality by 2050.

Increasing domestically-produced biomethane can help mitigate dependence on external suppliers and shields the EU from geopolitical risks. Domestic renewable production enhances resilience by localising energy value chains.

Moreover, fostering regional production can create a diversified supply base across Member States, ensuring reliability during crises and contributing to EU energy sovereignty.

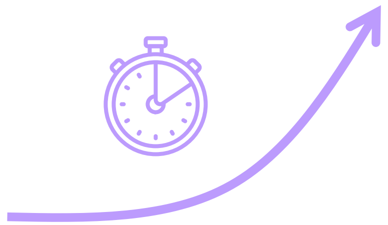
Import dependency improves when increasing biomethane production

Gas import dependency (%) vs biomethane production (bcm), 2025-2050



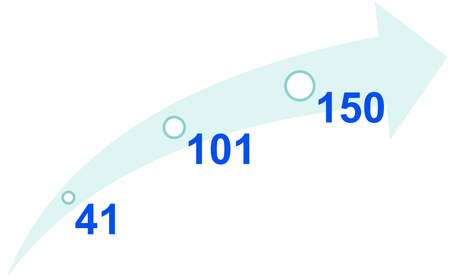
Source: ACER based on data from 2040 climate target's impact assessment of the European Commission, SolarPower Europe, Wind Europe, EHPA, EBA, Shell, and Agora.
Note: for left plot see Annex B. On the right plot, import dependency is computed as the share of biomethane and conventional gas production with respect to total gas consumption. Each point represents a year until 2050 based on averages.

Challenges to fully capturing biomethane's benefits



Slow ramp up

- Feedstock mobilisation
- Regulatory constraints



Scalability

- Cross-border trading barriers
- Different pace across Member States

Investment needs

- Network reinforcement to accommodate reverse flows
- Connection costs

Biomethane offers strategic security of supply benefits

The biomethane landscape in the EU is heterogeneous across Member States. Boosting its use presents scalability challenges, slow ramp up due to feedstock mobilisation and regulatory constraints, as well as investment needs to accommodate large-scale injection of biomethane in the transmission grid. Currently, 54% of the biomethane plants are connected to the gas distribution system of the EU, while only 18% are connected to the transmission system.

The growing role of biomethane in Europe's gas mix introduces important *security-of-supply considerations and operational challenges:*

- **Decentralisation of supply**: Scaling up biomethane reduces dependence on a few large import or storage hubs, enhancing resilience but shifting complexity to distribution gas networks.
- **Grid and tariff adaptation**: to a large extent, distribution grids must accommodate more injection points, which may require adjustments to balancing mechanisms, tariff structures, and capacity charges to ensure fairness and efficiency.
- **Limited flexibility**: most biomethane plants rely on steady utilisation to recover investment costs, so without storage, their ability to provide seasonal flexibility is constrained.

Source: ACER based on Outlook for biogas and biomethane, IEA.

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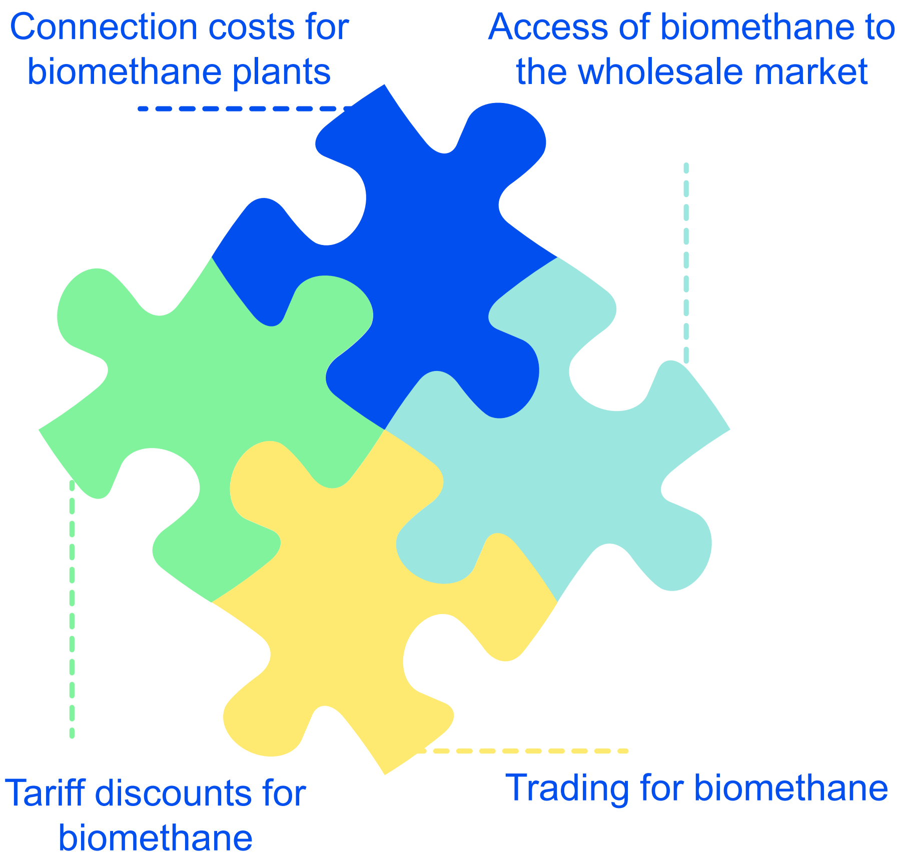
EU set common principles; national implementation diverges



Connection costs for biomethane plants

Cost-sharing models are applied in most Member States.

Access of biomethane to the wholesale market

Multiple workable models exist to integrate distribution-level biomethane into the wholesale market.

Tariff discounts for biomethane

Fragmented application of tariff discounts across Member States, subject to different stages of biomethane sector development and alternative support schemes.

Trading for biomethane

Different types of gas certification schemes exist (Guarantees of Origin or Proof of Sustainability).

Prioritising biomethane aligns with EU goals of security, sustainability, and sovereignty.

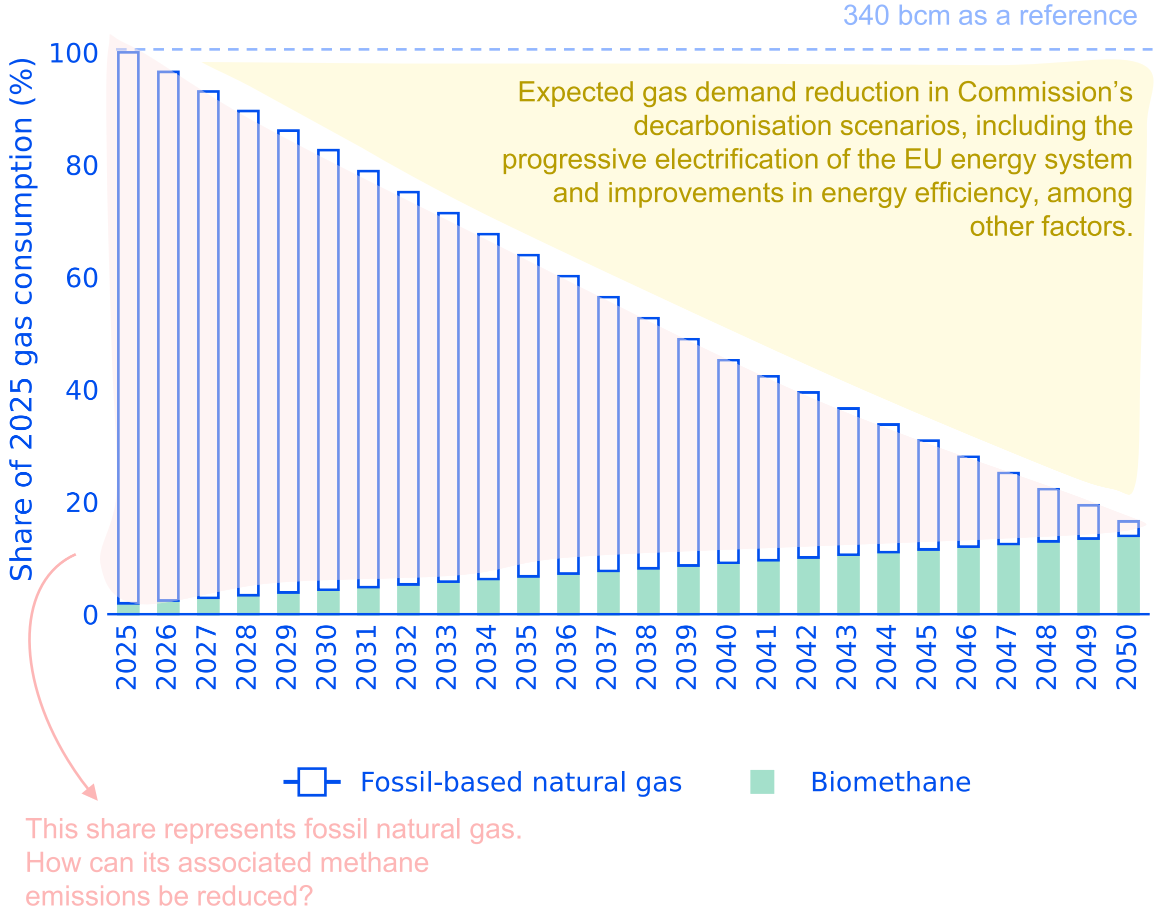
Policy support is essential to unlock biomethane's potential. A clear strategy could combine incentives for domestic production with safeguards that ensure imports do not undermine Europe's energy resilience.

Source: More information can be found in CEER document: Regulators' reflections on enabling the injection and access to the wholesale market of biomethane.

Beyond biomethane, what other solutions are available?

To fully decarbonise the gas sector by 2050, decarbonised supply options and demand must be addressed in an integrated way

Renewable and fossil-based natural gas share of 2025 gas consumption, 2025-2050 (%)



Looking forward to the next 25 years, two key uncertainties remain for the full decarbonisation of the gas market:

- Whether the supply capacities of the different decarbonisation pathways are sufficient to replace natural gas; and
- If the ambitious EU demand reduction plans do not materialise, how the share of natural gas not replaced by decarbonised gases can be effectively decarbonised.

Source: ACER's analysis is based on the average natural gas consumption trajectory envisaged in the European Commission's decarbonisation scenarios, together with a lower-bound estimate for biomethane production. It should be emphasised, however, that these assumptions and projections do not constitute an official ACER position regarding any specific decarbonisation pathway.

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Highlights & good practices: Security vs. competitiveness?

5%

annual growth in EU biomethane production

EU reached a production of 4.3 bcm in 2024 with more than 1500 biomethane production plants across EU Member States

12 bcm

of biomethane could be unlocked by upgrading biogas to biomethane

Upgrading costs represent only a small fraction of total production costs

50%

or more of gas consumption may be supplied by domestic gas production by 2040

This would entail using 60 bcm of biomethane if gas demand followed Commission's decarbonisation scenarios

01 Unlock EU's biomethane potential

The EU has mature biomethane production technologies to unlock domestic biomethane potential. Solving scalability challenges, slow ramp up due to feedstock mobilisation, cross-border trading barriers and regulatory constraints, remain essential.

02 Harmonise tradability of certificates for biomethane

Regulatory certainty and harmonised rules on guarantees of origin and sustainability certification are key to developing an internal biomethane market that boosts biomethane competitiveness, attracts investment and supports sustainable biomethane production.

03 Ensure well-functioning carbon pricing mechanisms

High carbon prices make biomethane more competitive in higher emitting industries. Next to compliance certificates, ensuring well-functioning carbon pricing mechanisms is of high importance to balance decarbonisation and competitiveness.

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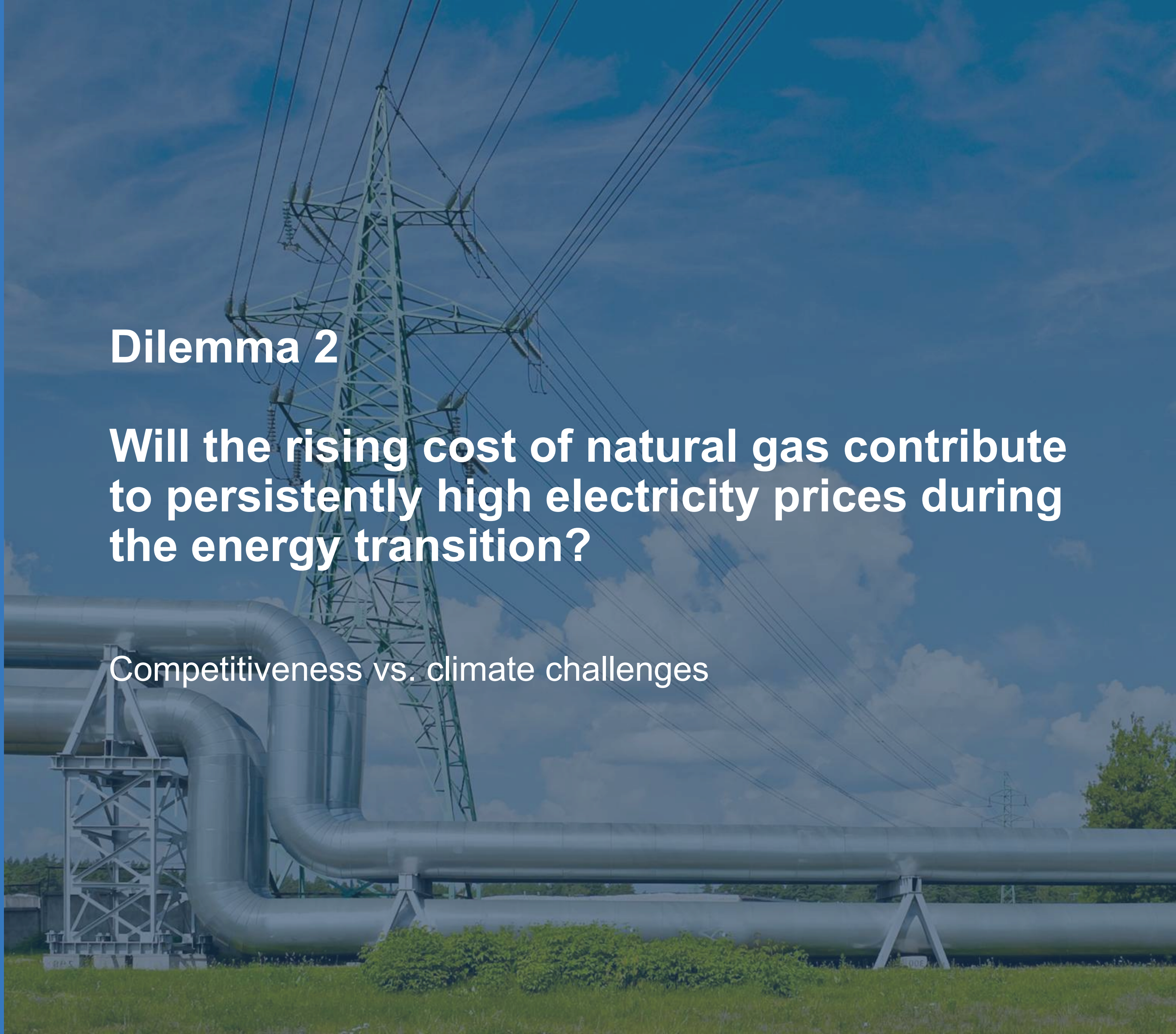
This dilemma questions whether gas-fired generation will continue to play a relevant role in setting wholesale electricity prices as the EU decarbonises both its gas and power systems. It sits at the intersection of climate objectives and competitiveness (meaning affordability of electricity for industry and households).

Increasing costs applied to conventional gas (via carbon prices or investments in methane abatement) will raise the short-run marginal cost of gas plants, while decarbonised gas options are also anticipated to result in higher nominal energy costs than conventional gas today.

The key question is how rapidly renewable resources, storage, and demand-side flexibility will erode the role of gas-fired generation in price formation, and whether increasing natural gas costs will continue to be reflected in electricity prices during the transition.



Dilemma 2

Will the rising cost of natural gas contribute to persistently high electricity prices during the energy transition?

Competitiveness vs. climate challenges

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Gas in power markets: Lower dependence, lasting influence

The gas–electricity price link has weakened but still affects electricity prices in certain periods

- Decarbonisation progress varies across EU power systems, creating differences between low-carbon and carbon-intensive electricity markets that affect prices, affordability and competitiveness.
- The rapid expansion of renewable generation has increased flexibility needs in the electricity system. These needs can be addressed in three different ways:
    - Fossil flexibility from gas-fired power plants.
    - Low-carbon flexibility when gas-fired power plants use biomethane.
    - Non-fossil flexibility* from storage and demand-side response.
- Despite the growing role of renewables, gas and electricity markets remain interconnected, as gas-fired power plants continue to provide flexible generation to balance variable renewable output, particularly solar.

Each flexibility solution comes with its own challenges

- Gas-fired power plants provide fossil-based flexibility during the transition. However, rising carbon prices may gradually increase their costs and, without faster deployment of renewables and clean flexibility solutions, may contribute to higher electricity prices.
- Biomethane can provide low-carbon flexibility, reducing exposure to carbon costs. However, its competitiveness remains uncertain due to the price of compliance certificates.
- Storage and demand response, are becoming competitive in renewable-dominated power systems, but deployment is still limited.

Coordinated decarbonisation of gas and electricity markets will be key to preserving affordability and competitiveness

- Integrating renewables and clean flexibility solutions will require modernising electricity grids, expanding cross-border capacity and improving the use of existing infrastructure.

* This is the target option which needs to be unlocked, especially demand-side response. ACER monitors the market to identify barriers to unlocking flexibility. See ACER 2025 report on no-regret actions to stimulate flexibility.

Uneven decarbonisation progress across EU power systems

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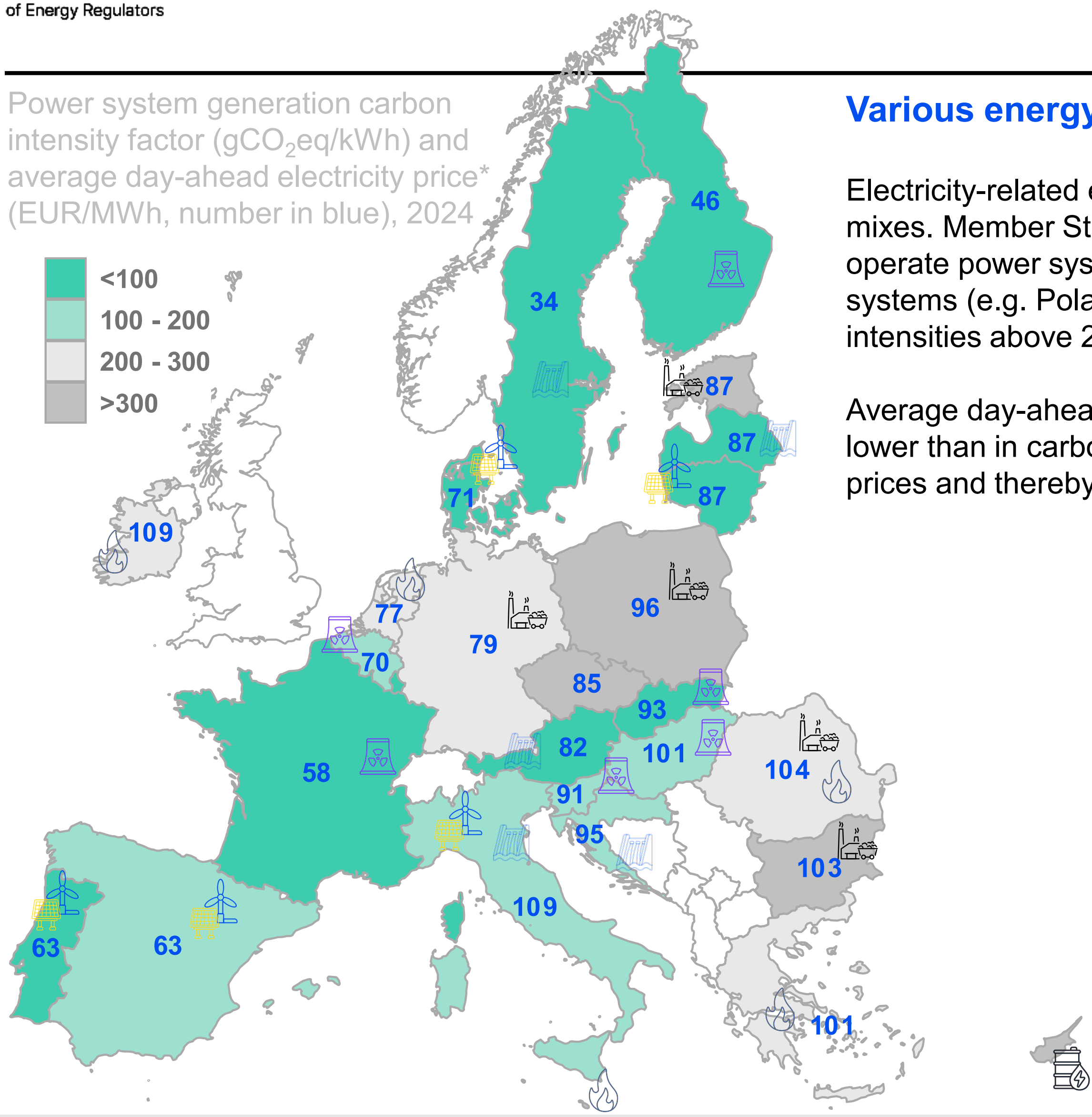
Power system generation carbon intensity factor (gCO_2eq/kWh) and average day-ahead electricity price* (EUR/MWh, number in blue), 2024

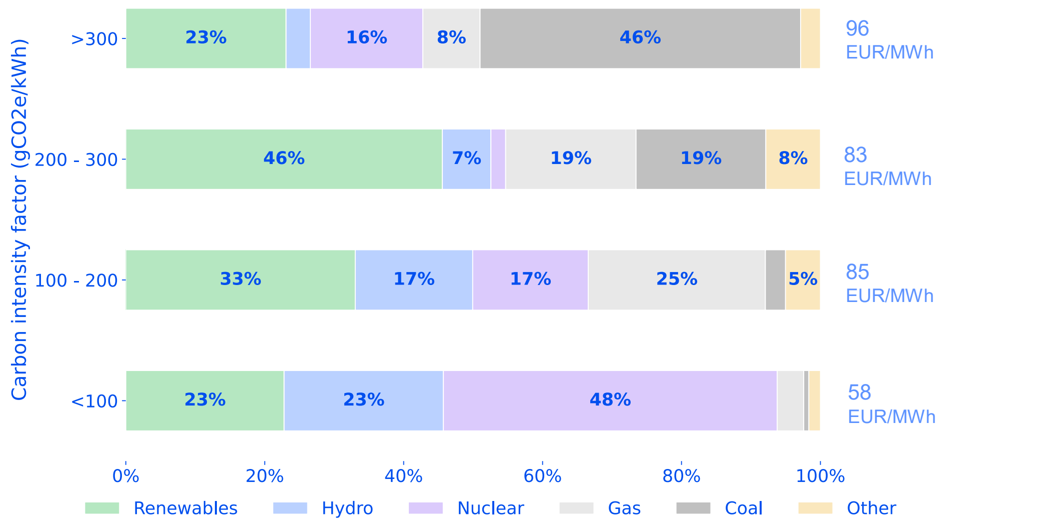


Various energy transition pathways observed across EU Member States

Electricity-related emissions across EU countries vary widely, reflecting differences in generation mixes. Member States with high shares of renewables and nuclear (e.g. Denmark, France), operate power systems with emissions below 100 gCO_2/kWh. In contrast, fossil-dominated systems (e.g. Poland or Germany), still rely heavily on coal and gas, resulting in emission intensities above 200 or even 300 gCO_2/kWh.

Average day-ahead electricity prices in Member States with low-carbon power mixes are 40% lower than in carbon intensive ones**. Reducing reliance on fossil fuels further can help decrease prices and thereby increase affordability and competitiveness.

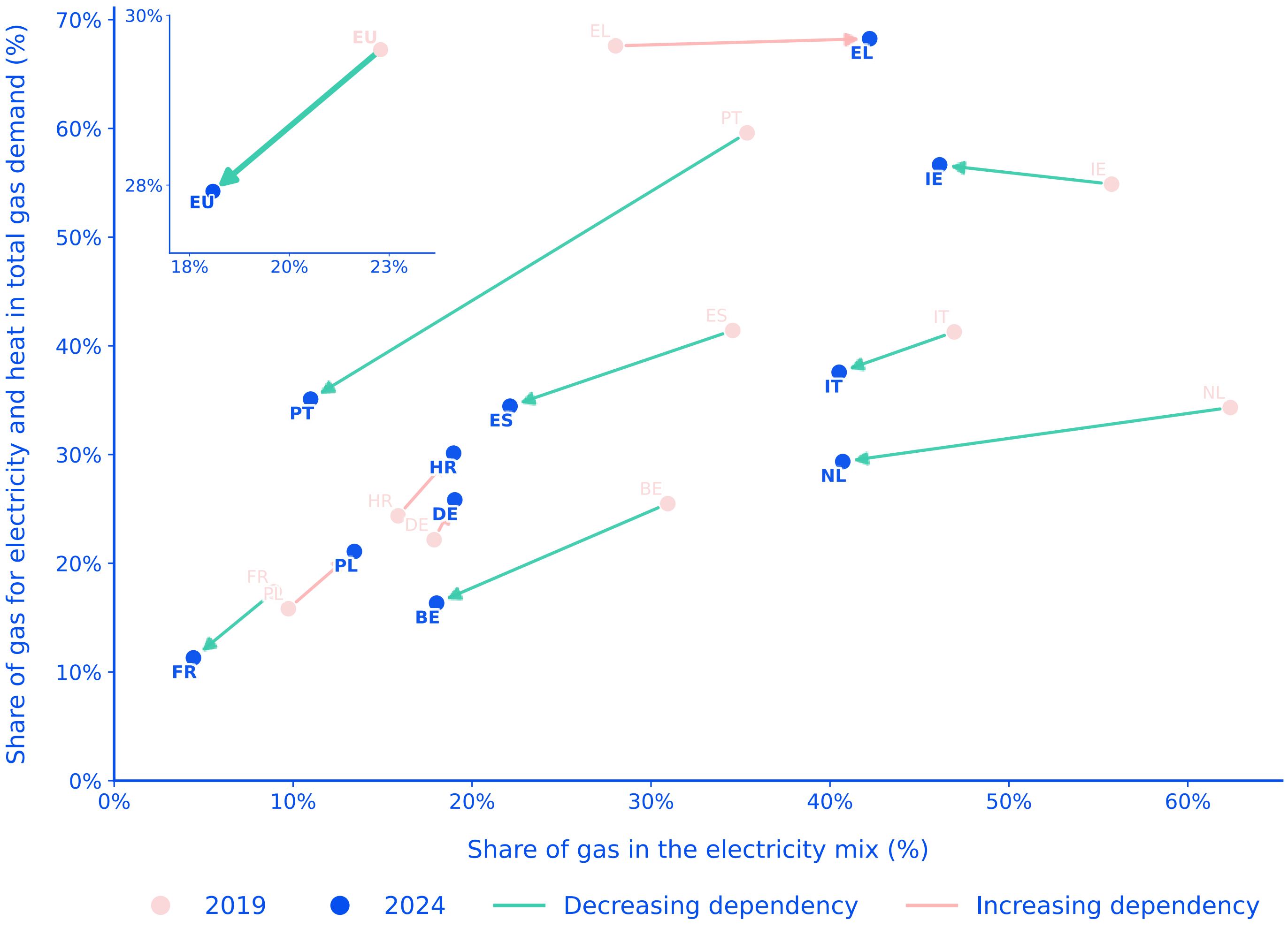
Share of production type, based on carbon intensity factor, 2024 (%)



Source: ACER based on EEA and ENTSO-E transparency platform. The CO_2 emission intensity is calculated as the ratio of CO_2 emissions from electricity generation and gross electricity generation. Icons represent the relative production group most detrimental for the current emission interval where the country is sorted. * For countries with more than one bidding zone price shown is an arithmetic average. ** Other aspects such as interconnection capacity or cost recovery (including waste in the case of nuclear power plants) need to be considered when comparing prices.

Gas-electricity interaction has diminished in recent years …

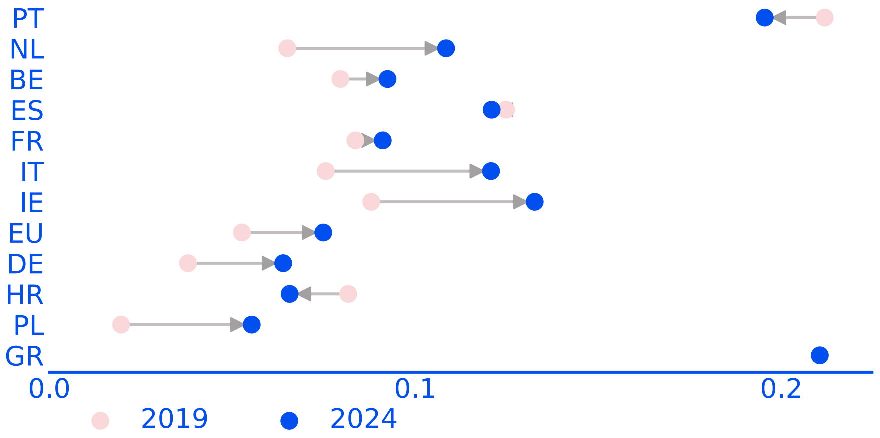
Gas for power dependency for selected EU countries, 2019 and 2024



… but some countries have increased their dependency on the gas sector to phase out coal

Gas and electricity markets in Europe are linked, as gas power plants provide flexibility needed to balance variable net electricity demand. Most countries and the EU overall, have reduced their dependence on gas and, consequently, the interaction between gas and electricity prices. However, some countries show an increased dependency due to the coal phase out. Others show increased volatility of gas use for power despite less overall dependency.

Volatility indicator calculated as the daily variation of gas demand for electricity over total gas demand, 2019 and 2024



Source: ACER based on Eurostat and ENTSO-E.

Increased renewables impacts operation of gas power plants

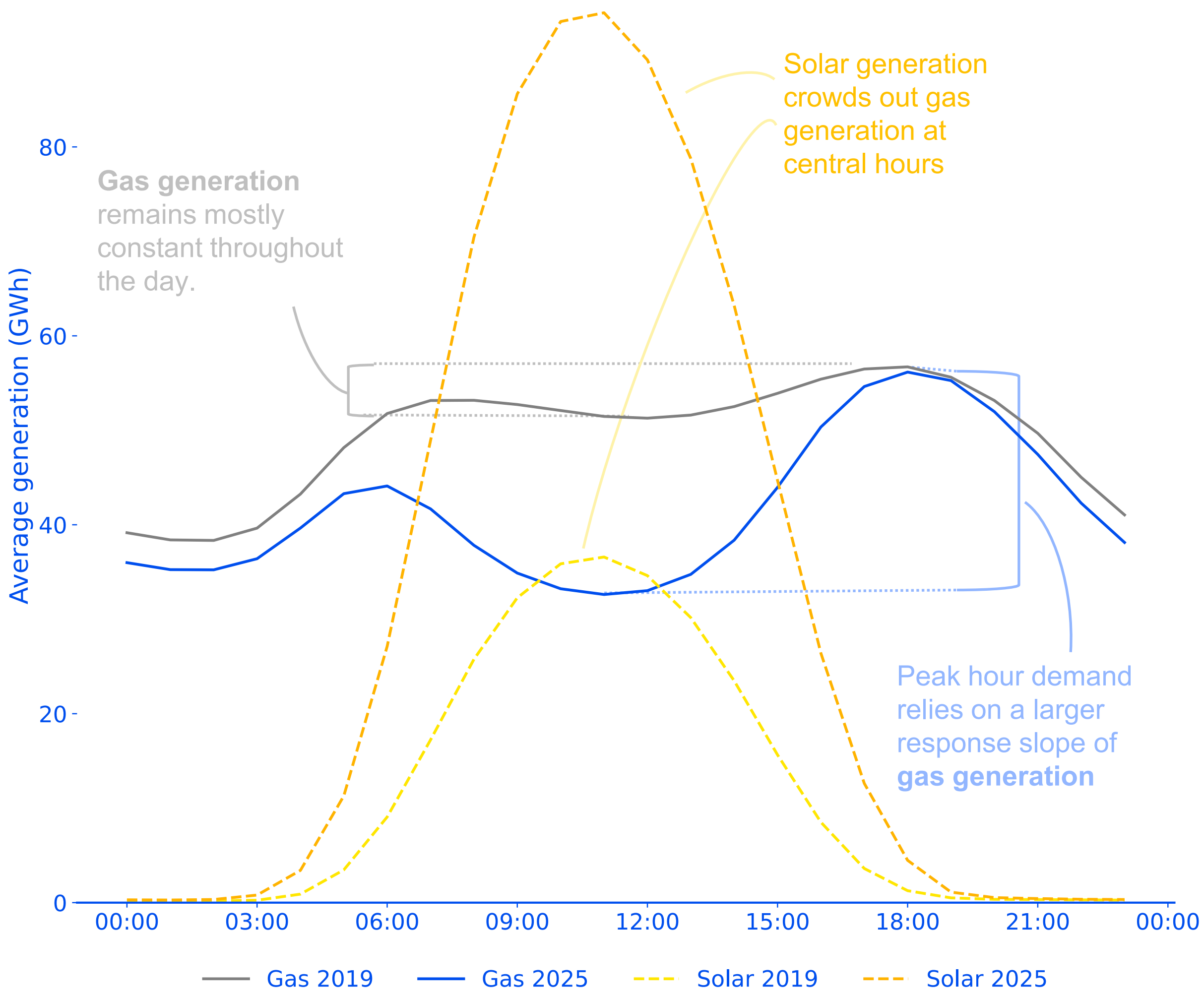
Gas-fired generation profiles are increasingly exhibiting a duck-curve pattern

Despite being flexible, the operation of gas-fired power plants is constrained by their physical characteristics (e.g. ramps). This inter-temporal coupling may be reflected in their generation offer.

While increasing solar output reduces morning reliance on dispatchable generation, it triggers steep evening ramps as the sun sets and electricity demand spike. This sudden need for flexibility forces sidelined power plants to rapidly restart, with expected impacts on market outcomes.

Explore ACER's key developments in EU electricity and gas markets for further information!

Average hourly gas and solar generation profiles, 2019 and 2025 (GWh)



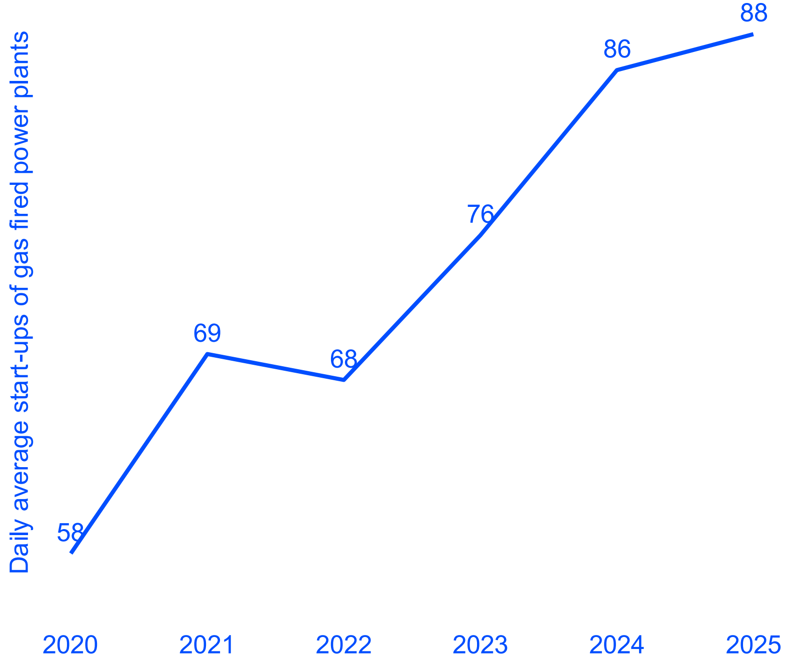
Source: ACER calculations based on ENTSO-E transparency platform performed for Member States where generation unit level data is available for gas-fired power plants - analyses excludes Estonia, Croatia, Ireland, Malta and Cyprus. Slovakia is also excluded from the analysis due to generation data quality issues.

Gas-fired generation is adapting to new system needs

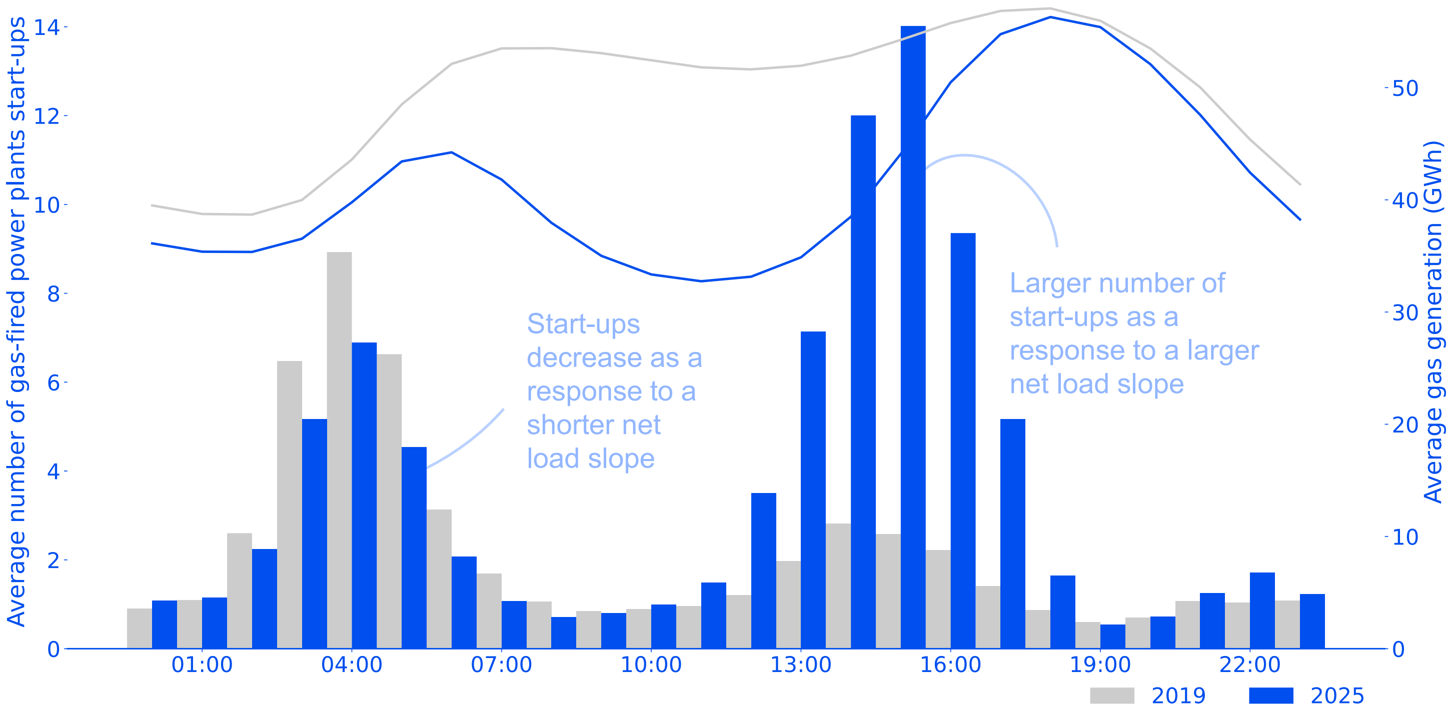
Start-ups in gas-fired power plants are increasing on central hours and decreasing in early hours

Fewer start-ups occurred during early hours with shorter gas generation ramps, while steeper ramps in central hours were associated with increased start-up activity. The second effect, being larger than the first, leads to an overall increase of start-ups. This trend has been increasing in the last years. As a result, start-up costs are expected to represent a bigger share of overall generation costs, thus impacting electricity prices.

Annual daily average of gas-fired generation units' start-ups, EU-27*, 2019-2025



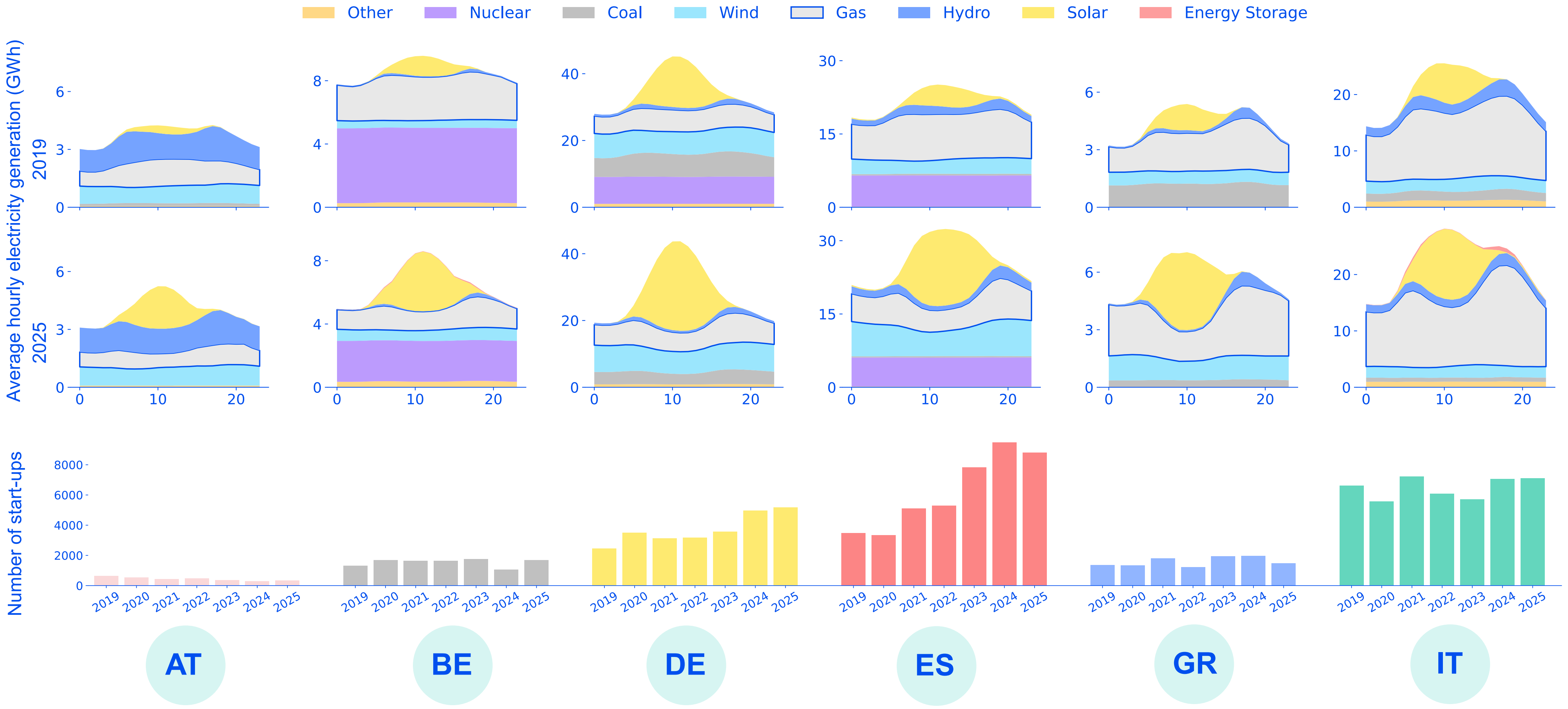
Average hourly generation profile (GWh) and number of start-ups of gas-fired generation units, 2019 and 2025



Source: ACER calculations based on ENTSO-E transparency platform.
* This is performed for Member States where generation unit level data is available for gas-fired power plants - analyses excludes Estonia, Croatia, Ireland, Malta and Cyprus. Slovakia is also excluded from the analysis due to generation data quality issues. See Annex D for further details.

Electricity mix drives operation of gas-fired power plants

Various flexibilities and operation choices drive different outcomes for start-ups of gas-fired power plants



Spain and Germany saw their number of start-ups increase considerably between 2019 and 2025, around 100 and 120% respectively, as solar is crowding out gas in central hours. The increase of solar generation in Greece and Italy has not produced the same impact, due to differing operation strategies and electricity mixes. Other countries like Austria have other flexibility options, such as hydro.

Source: ACER calculations based on ENTSO-E transparency platform.

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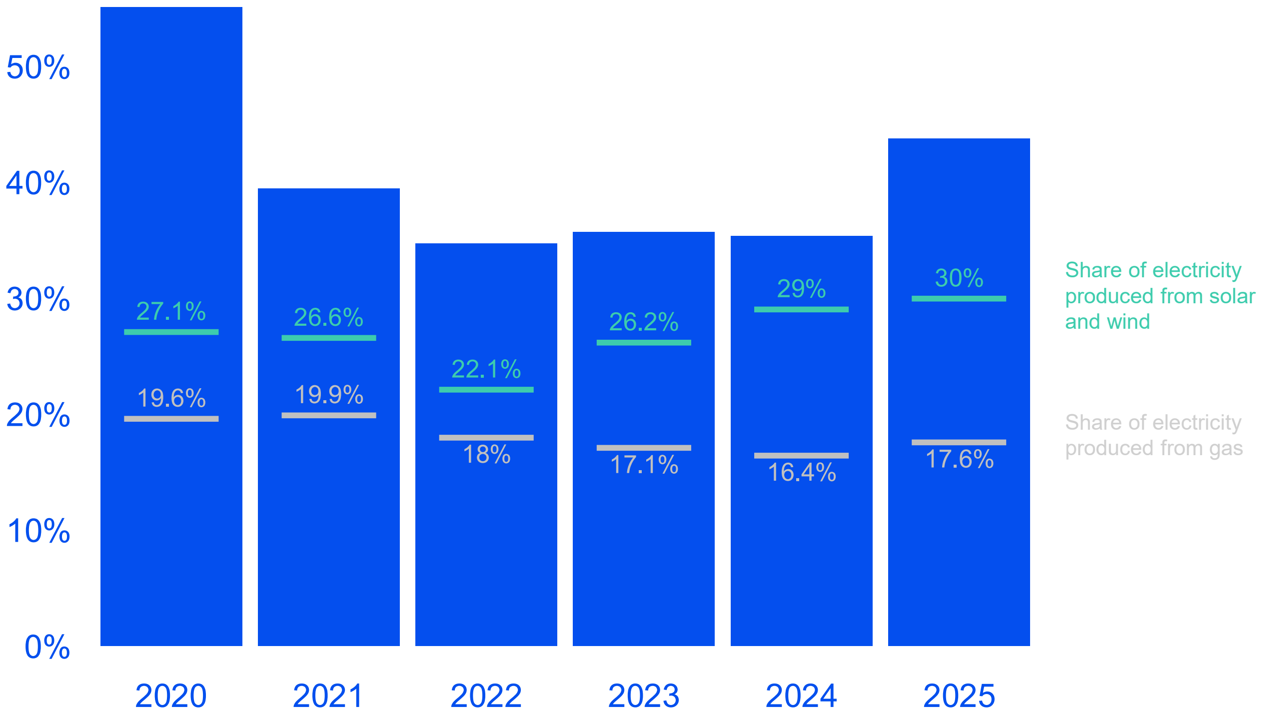
Gas-electricity linkages persist in 2025

2022-2023 energy crisis changed the role of gas in the electricity market

Percentage of hours when electricity day-ahead prices were equal or above the baseline costs of producing electricity from gas (blue bars) and gas-produced electricity as a share of the total electricity production (in grey) on average, EU-27/EEA (Norway), 2020-2025*

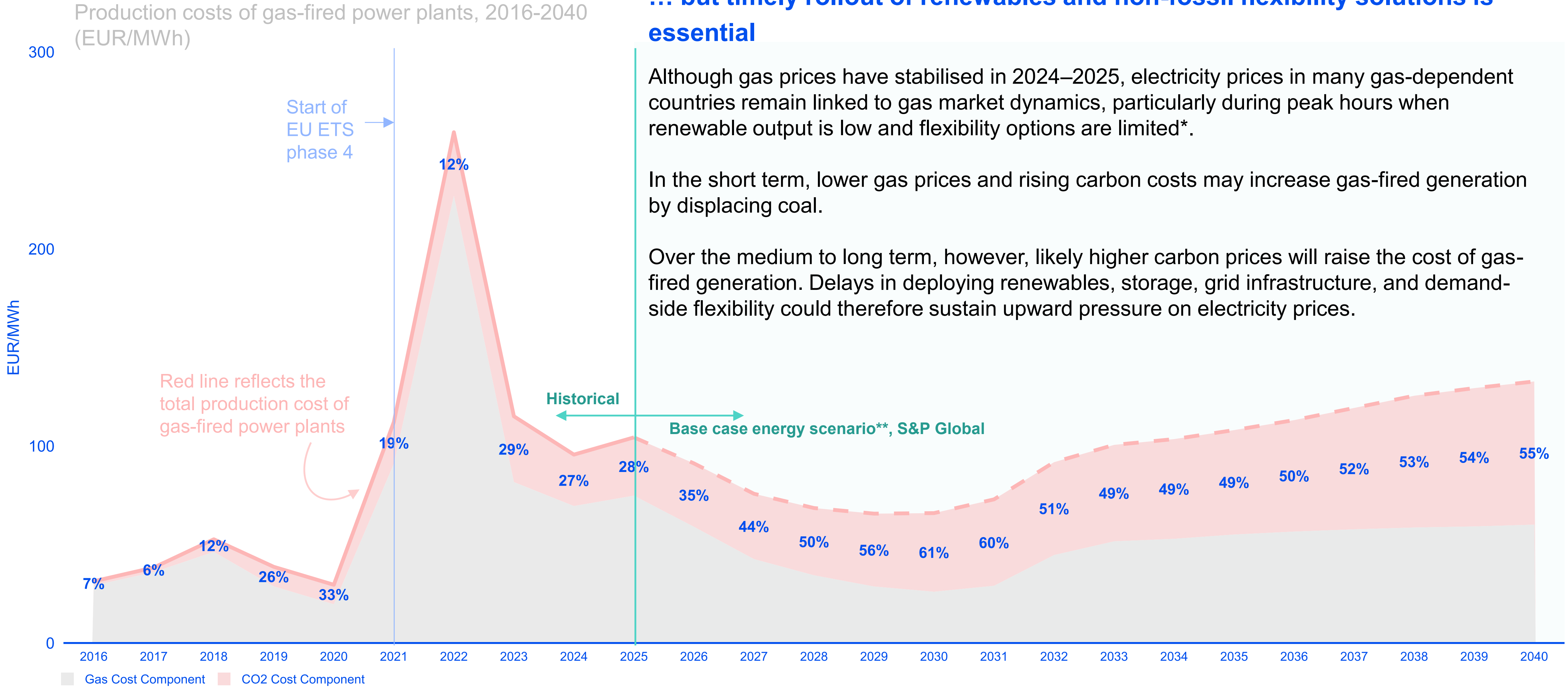


Historically, gas-fired power plants have disproportionately dictated EU electricity prices. In 2020, gas set the price 55% of the time despite making up only 20% of the energy mix. The 2022-2023 crisis proved this reliance causes severe price volatility, hurting consumers, industrial competitiveness, and decarbonisation efforts.

By 2024, efforts to reduce this reliance show gas generation dropped by ~4%, and its price-setting frequency fell below 40%. However, weather conditions in 2025 have slightly reversed this progress due to limited renewable output, temporarily increasing gas reliance once again.

Source: ACER based on ENTSO-E Transparency Platform and ICIS.
* Gas-in-the-money refers to periods when gas-fired generation is economically profitable, i.e. when electricity prices are high enough to cover variable generation costs. For example, if gas is in-the-money 41% of the time, this means that in 41% of hours electricity prices were equal to or above the cost of producing electricity from gas-fired power plants, making gas generation economically viable in those hours. Further explanations can be found in consideration (2) of Annex D.

Carbon pricing is a lever for electricity decarbonisation …



… but timely rollout of renewables and non-fossil flexibility solutions is essential

Although gas prices have stabilised in 2024–2025, electricity prices in many gas-dependent countries remain linked to gas market dynamics, particularly during peak hours when renewable output is low and flexibility options are limited*.

In the short term, lower gas prices and rising carbon costs may increase gas-fired generation by displacing coal.

Over the medium to long term, however, likely higher carbon prices will raise the cost of gas-fired generation. Delays in deploying renewables, storage, grid infrastructure, and demand-side flexibility could therefore sustain upward pressure on electricity prices.

Source: ACER calculations based on S&P Global and ICIS.
Note: The plot reflects the evolution of gas production costs for the base case energy scenario of S&P Global. ACER does not model this energy scenario, and this may be subject to change.
* See Key developments in EU electricity and gas markets . ** See consideration (3) of Annex D.

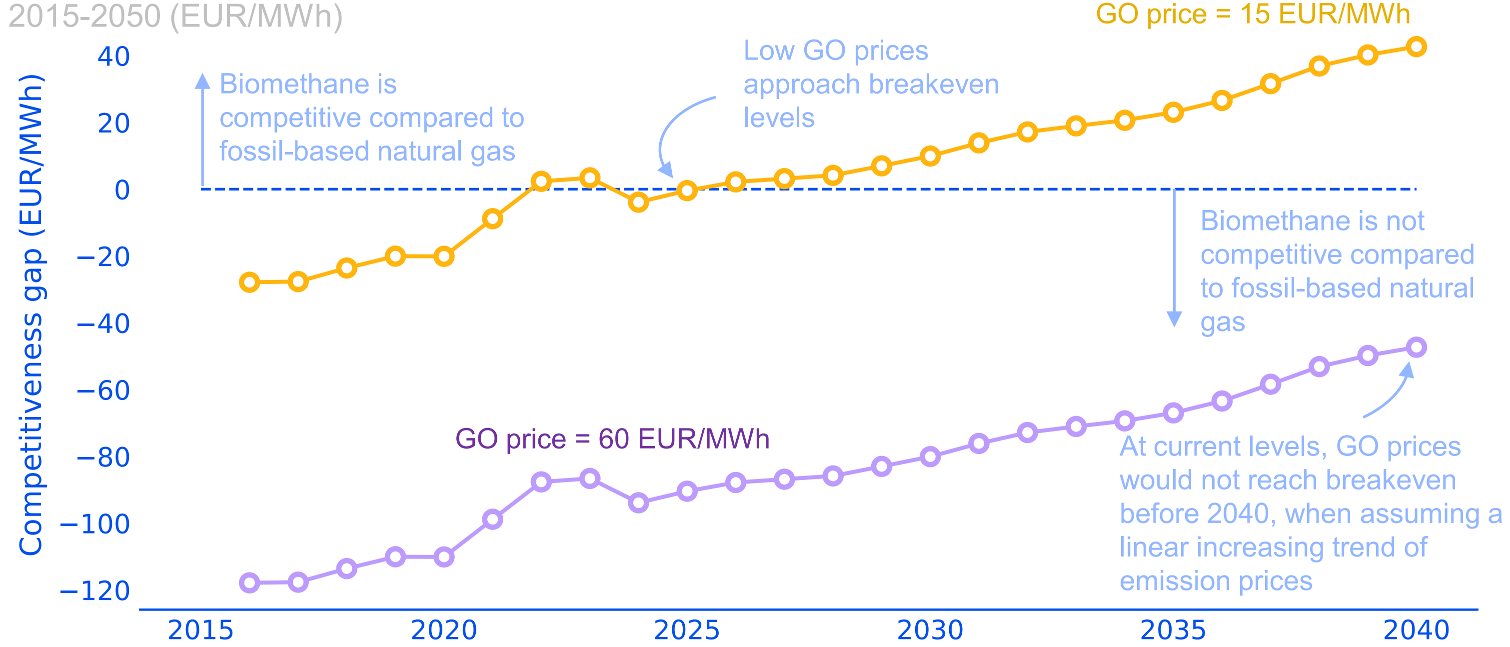
Biomethane may boost decarbonisation and competitiveness

Key indicator	Competitiveness gap
What is it?	The difference between the costs of using fossil-based natural gas and those of using biomethane
Key drivers	ETS price, GO price, carbon intensity factor and efficiency

Biomethane will reduce associated emissions when producing gas for electricity production …

Gas-fired generation is expected to continue providing flexibility during the energy transition. As carbon prices rise, biomethane could be an alternative, as it is not exposed to them. However, its renewable value is reflected in guarantees of origin and sustainability certificate prices.

Competitiveness gap for a gas-fired power plant, 2015-2050 (EUR/MWh)



… but will this be enough to make it competitive?

Low guarantees of origin prices may be at break-even levels for gas-fired power generation using biomethane compared to fossil natural gas. However, those prices highly depend on the end-use market, feedstock, and whether a support scheme was used.

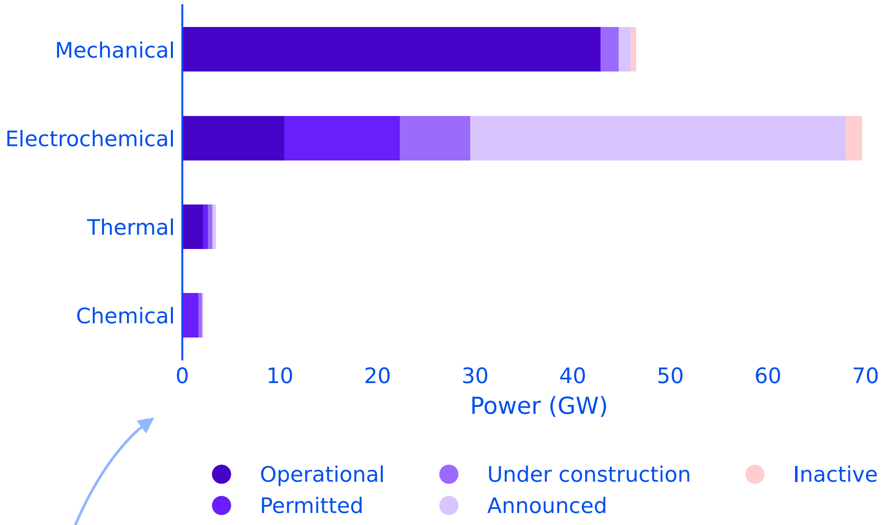
Biomethane competitiveness will impact on whether electricity affordability can be preserved.

Source: ACER based on S&P Global.

Note: Competitiveness gap is the difference between the costs of using fossil-based natural gas and those of using biomethane. The plot uses the evolution of carbon costs for the base case energy scenario of S&P Global assuming a carbon intensity factor of 0.4. A 50% efficiency is also assumed for the gas-fired power plant.

Flexibility in the power system as a way forward

Storage power by technology* and status in the EU, 2025 (GW)

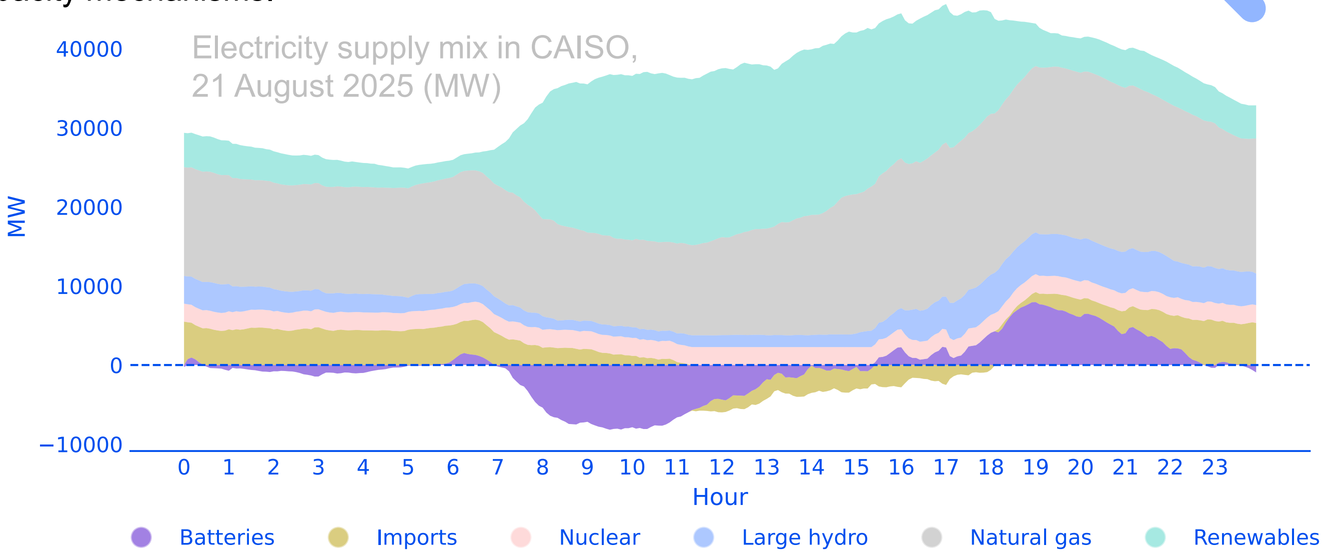


Electrochemical and chemical energy storage is still in early stages in the EU. Grid-scale batteries represent around 10 GW of rated power capacity in the EU (~**2.4% of 2025 EU peak demand**).

Other technologies are becoming competitive in renewable-dominated power systems

Growth in renewables and batteries progressively decouple electricity prices from gas price dynamics. Increased availability of clean flexibility and grid reinforcements allow these resources to contribute more frequently to price formation during peak hours, diminishing the role of gas power plants as the marginal flexibility provider. This will lower wholesale electricity prices for consumers. At the same time, gas power plants would benefit from their participation in capacity mechanisms.

ACER will publish an EU-wide assessment of flexibility needs by July 2027, including cross-border recommendations and identified resource gaps.



CAISO offers a forward-looking view of how storage can help address system flexibility needs. Its rated power capacity is around 17 GW (**~40% of 2025 peak demand** as of July 2025)**.

Source: ACER based on JRC and CAISO. JRC published an overview of energy storage deployment in Europe in 2025.
* Mechanical storage refers mainly to pumped-storage hydropower and compressed-air energy storage, electrochemical to batteries, and chemical to P2X technologies. ** Peak demand in August 2025 was 44.5 GW.

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Highlights and good practices: Gas-electricity linkage

40%

lower average day-ahead electricity prices in low-carbon power systems vs. carbon-intensive ones

8 Member States exhibit a low carbon intensity factor in their electricity mixes

40%

is the share of hours in which gas was in-the-money in 2025

Gas-fired electricity generation share was 18% in 2025

15

EUR/MWh guarantee of origin* needed to make biomethane viable

Low guarantees of origin prices are at breakeven levels for gas plants compared to fossil natural gas

01 Electrify through renewables

Decarbonising the energy system requires the large-scale deployment of renewable electricity, and the electrification of end uses. In the natural gas market, biomethane is currently the most mature option for decarbonising gas, though its competitiveness depends on compliance certificate prices.

02 Promote low-carbon gas supply options to cover electricity system needs

Reducing the influence of fossil-based natural gas on electricity price formation will require significant deployment of low-carbon gas supply options, such as biomethane, as well as non-fossil flexibility solutions, including batteries and demand response.

03 Coordinate grid management with efficient use of existing infrastructure

Deploying non-fossil flexibility solutions requires coordinated grid expansion with a more efficient use of existing infrastructure. In this context, the Grids Package can support both electricity affordability and energy independence.

* Guarantee of origin plus proof of sustainability.

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The EU faces the challenge of decarbonising its energy-intensive industry without further affecting its global competitiveness.

If decarbonised energy supply options become less price-competitive, these objectives will be difficult to reconcile.

While electrification supported by rapid growth of renewable sources is expected to expand significantly, its application in hard-to-abate industrial sectors (e.g., chemicals, cement, steel, glass) is technically feasible but remains costly and highly grid-intensive in the near term.

Dilemma 3

Can EU decarbonise its gas sector without further affecting industrial competitiveness?

Competitiveness vs. climate challenges

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Industrial gas demand under pressure

EU industry remains a major consumer of natural gas, but demand has structurally declined since the energy crisis

- In 2023, natural gas represented almost one third of industrial final energy consumption, while overall final energy consumption in industry declined by around 12% compared to 2021.
- Chemicals, iron and steel, and glass sectors represent about 40% of industrial final energy demand by natural gas.
- Industry accounts for roughly one third of EU gas demand. Industrial gas demand partially recovered in 2024, increasing by around 5% year-on-year, but it remains around 17% below pre-crisis levels (2017–2021 average).

Competitiveness will shape the pace of industrial gas demand reduction

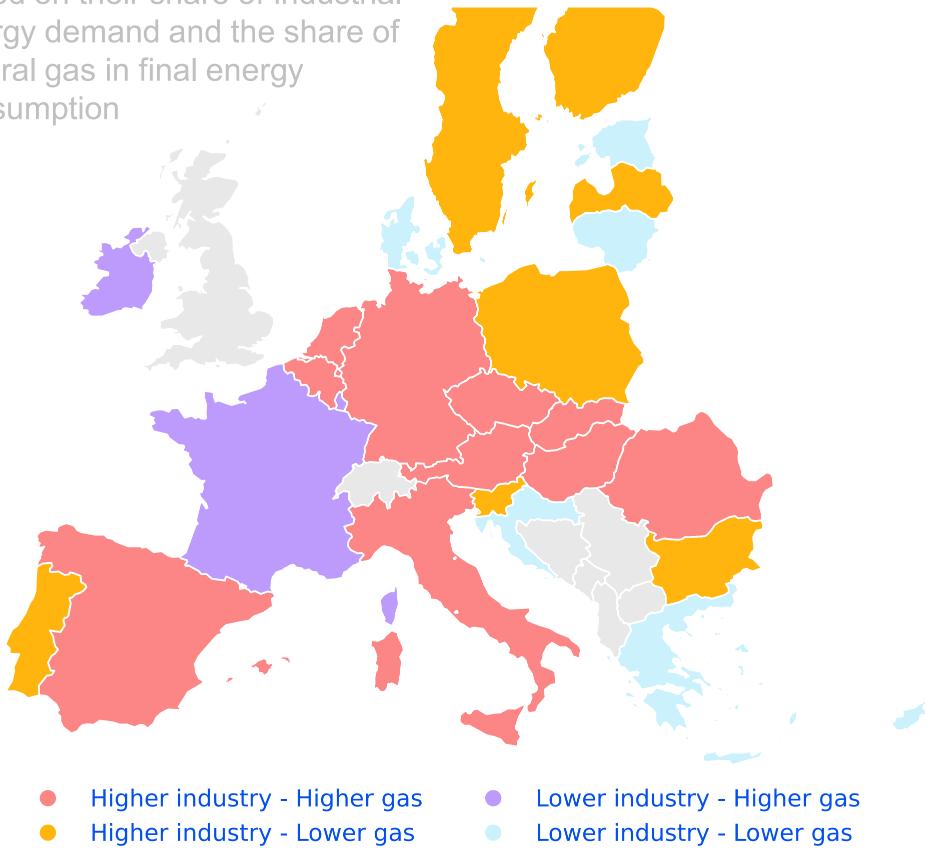
- Industrial sectors face uneven exposure to decarbonisation and energy price pressures.
- Decarbonisation pathways differ across sectors, depending on their ability to electrify, switch to renewable gases, deploy carbon capture, utilisation and storage solutions or improve efficiency.
- EU climate policies such as the Carbon Border Adjustment Mechanism aim to prevent carbon leakage* while maintaining a level playing field for EU industry during the transition.
- Global competitiveness will be a key driver of future gas demand. Relative gas prices, carbon costs and trade exposure may influence industrial activity and investment decisions.

* The term ‘carbon leakage’ refers to the transfer of CO_2 emissions from one country to another when, due to strict climate policies, companies relocate their production to countries with weaker emission constraints. This can contribute to an increase in global greenhouse gas emissions.

Decarbonisation is challenging for all countries …

… but it poses greater risks to industrial competitiveness where both industrial importance and gas dependence are high

Classification* of Member States based on their share of industrial energy demand and the share of natural gas in final energy consumption



Countries' exposure to the energy transition depends on two key factors: how their economies rely on industry and how dependent they are on natural gas.

This creates four distinct groups, each with different challenges:

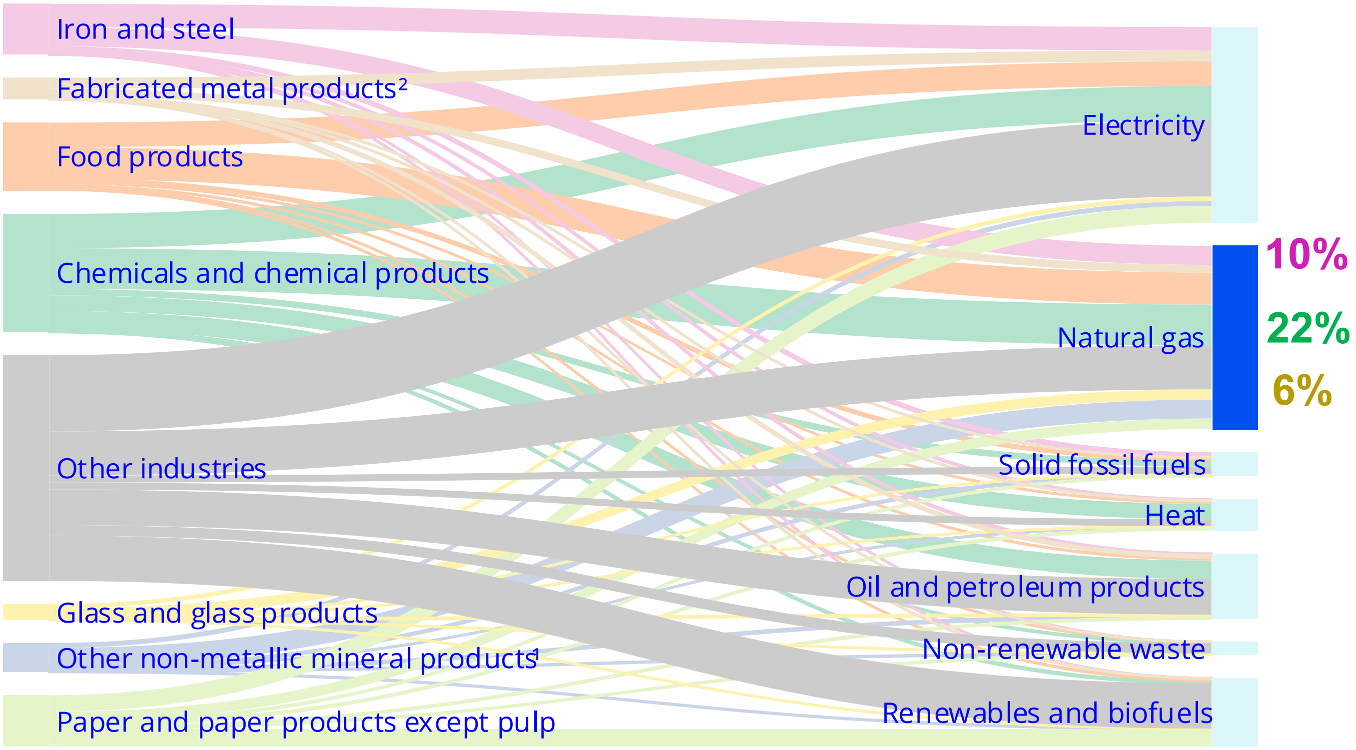
- **Lower industry – lower gas.** Countries with lower industrial energy demand share and lower gas dependence may face the easiest transition. Their energy needs can be met through electrification, efficiency gains or renewable heat with little disruption.
- **Lower industry – Higher gas**. These countries rely heavily on natural gas, often for heating or electricity, but are less exposed to industrial decarbonisation. Their main challenge is fuel switching, i.e. replacing gas with alternatives like heat pumps, biomass or green hydrogen where feasible.
- **Higher industry – Lower gas**. Higher industrial energy demand share but gas dependence is lower. The hurdle is decarbonising industrial processes (e.g., high-temperature heat, chemical reactions require new technologies like hydrogen or carbon capture and storage).
- **Higher industry – Higher gas**. They face a dual challenge: replacing gas and overhauling industrial processes. Without strong support (e.g., CBAM, innovation funding), they risk competitiveness losses during the transition.

Source: ACER based on Eurostat.
* Countries were classified using two key metrics: the share of industrial energy demand in final energy consumption (threshold: 20%); and share of natural gas use in final energy consumption (threshold: 15%).

Which industries use natural gas most?

40% of EU industrial gas use comes from chemicals, iron and steel, and glass

Final energy consumption per industry NACE 2 activities and energy product, 2023



¹ except glass, glass products, cement, lime and plaster.
² except machinery and equipment.

The largest consumer of industrial final energy consumption by natural gas, is the chemical and petrochemical sector (22%) followed by the sector of food products (18%) and iron and steel (10%). In terms of subsectors, Eurostat data show **chemicals, steel, cement, and glass as the largest users**, responsible for most process-heat-related emissions. The gas-dependent glass industry accounts for ~6% of total EU industrial gas consumption.

Certain industrial sectors compete globally in commoditised markets and are more exposed to prices. For instance, chemicals and refining predominantly rely on spot gas purchases and thus they are more vulnerable to price fluctuations and global competition*.

In addition, there is an uneven exposure of industrial sectors to the energy transition. The sectors emitting higher level of emissions are more prone to be affected by emissions-related regulations impacting its global competitiveness.

Source: ACER based on Eurostat, code nrg_d_indq_n and Implementing Regulation (EU) 2021/447.
Note: NACE 2 is a statistical classification of economic activities in the European Union. Note that the disaggregated industrial final energy consumption by natural gas amounts to 720 TWh.
* European Industrial Gas Demand Tracker, October 2025, S&P Global.

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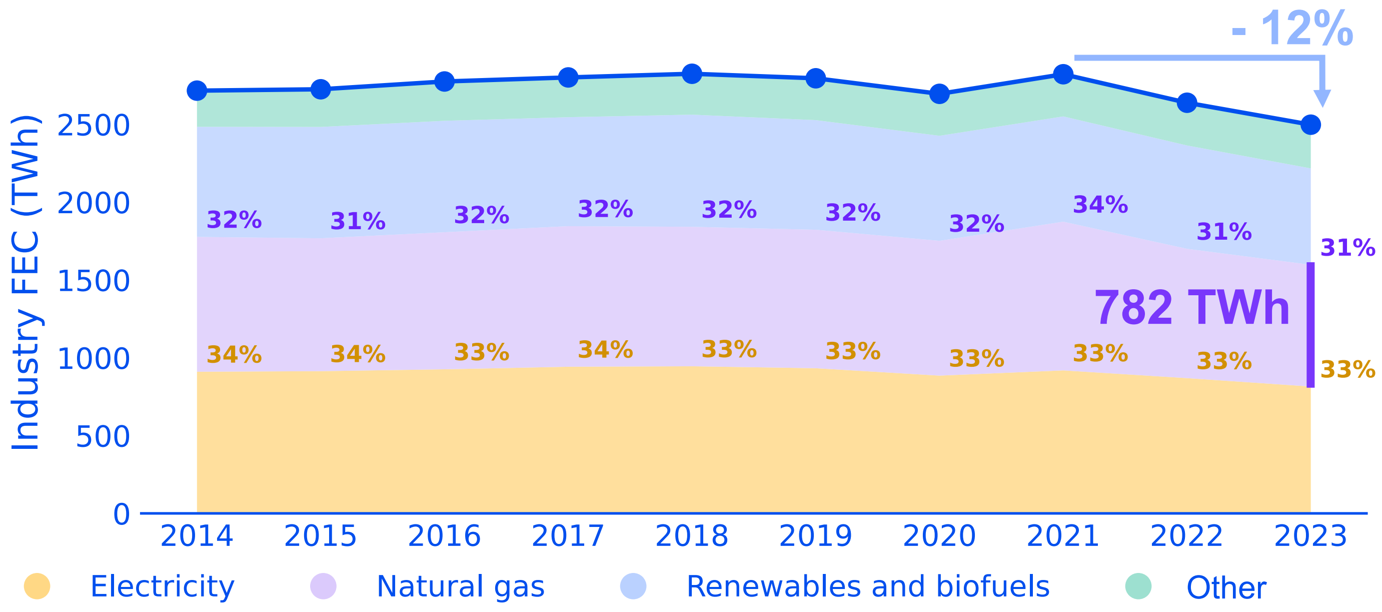
Around one third of industrial energy use comes from gas

Industrial energy use declined 12% after the energy crisis

EU industry final energy consumption (FEC) per energy product, 2014-2023 (TWh)



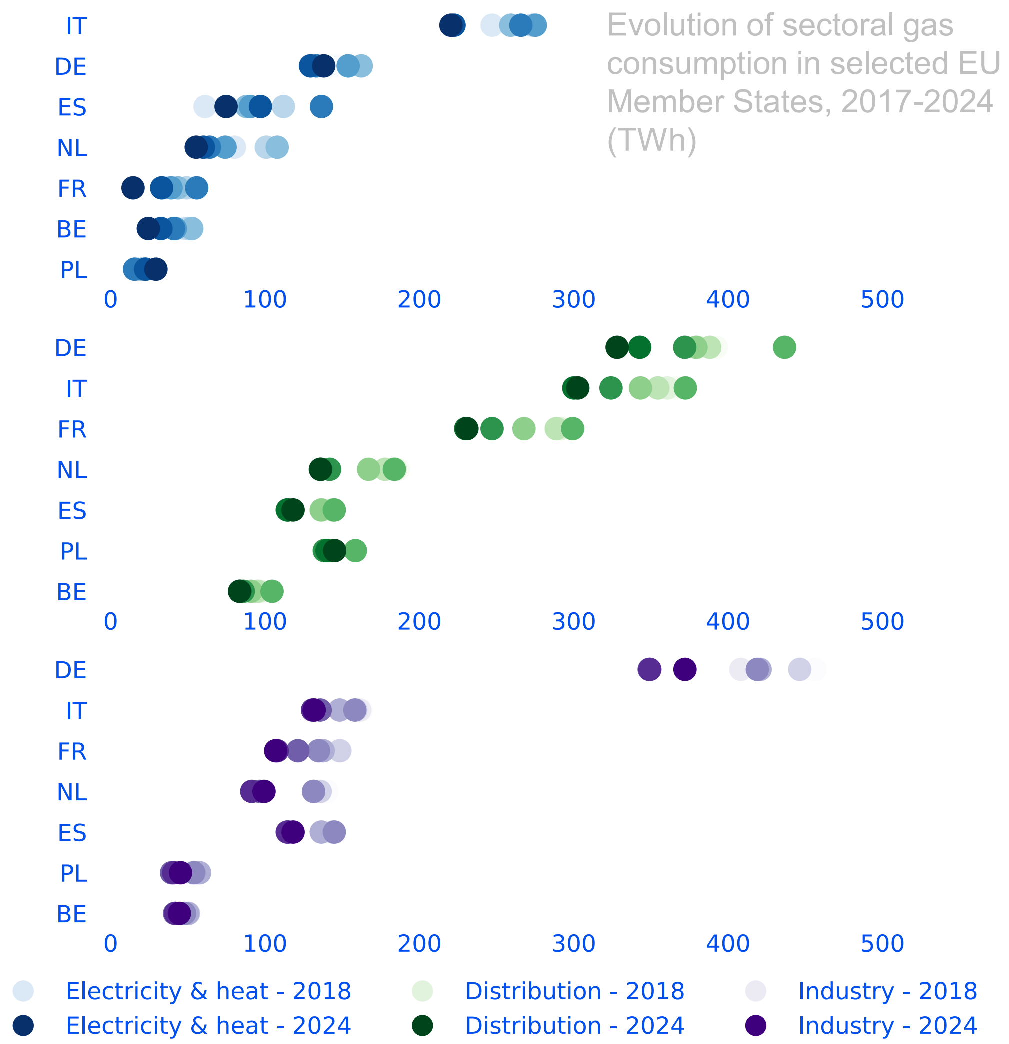
In 2023, natural gas accounted for almost one third of final energy consumption in the EU's industry sector. Compared to 2021, there was a reduction of 12% in final energy consumption in industry. Half of this reduction corresponds to natural gas and one third to electricity consumption, while there was a 4% increase in consumption from renewables and biofuels.

The reduction may indicate a degree of demand destruction, especially since electrification did not take place. However, several contributing factors might explain this trend, including inflation and industries finding greater competitiveness abroad due to less stringent decarbonisation strategies.

The resilience of industries to higher gas costs will depend on their ability to electrify, switch to renewable gas, or improve efficiency. There are distinct price responsiveness of industrial consumers which may affect purchasing strategies among industrial sectors. Some sectors with a greater exposure to the global market are more impacted by EU wider economic developments and regulations on emissions such as the carbon border adjustment mechanism. In some sectors, prices may cause temporary demand drops while in others it can materialise in a permanent shutdown of the industry. **Policymakers should tailor transition measures to sector-specific realities rather than apply uniform decarbonisation trajectories**.

Source: ACER based on Eurostat, code nrg_bal_s.
Note: *Other* encompasses oil and petroleum products, heat, solid fossil fuels, non-renewable waste, manufactured gases, peat and peat products, oil shale and oil sands, and nuclear heat.

EU gas demand for the industry sector: A partial recovery



Industrial gas demand remains below pre-crisis levels, despite recovering ~5% in 2024

Industry accounts for one third of EU gas demand, but its share varies widely across Member States. While 2024 shows signs of recovery, with increases ranging from 3% in Spain and 10% in Poland year-on-year (5% at EU level), consumption remains below pre-crisis levels (17% lower than 2017-2021 average).

The transition is moving at two speeds:

- Gas for electricity generation and households/commerce are decarbonising rapidly, driven by cost-competitive alternatives.
- Industry decarbonisation will follow a more conservative path to balance climate goals with global competitiveness.

Future industrial demand hinges on two key factors:

- **Gas and carbon price dynamics**. Low EU gas prices and slow decarbonisation might sustain, or lift, industrial use. High prices risk accelerating demand destruction.
- **Policy tools**. Instruments like the carbon border adjustment mechanism will shape competitiveness by aligning carbon costs for EU and non-EU producers.

Source: ACER based on Eurostat, ENaGaD and S&P Global.

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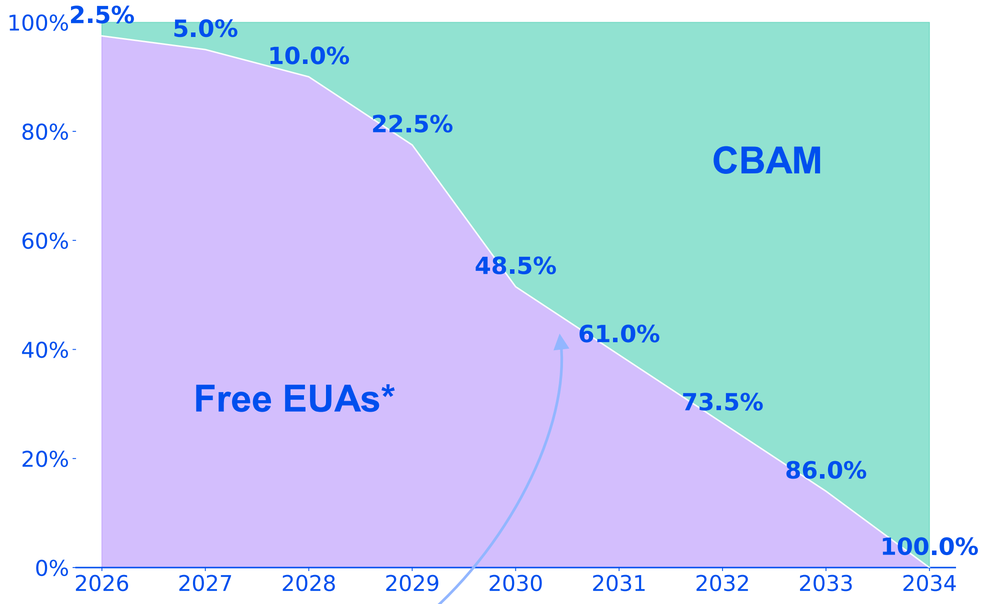
Ensuring competitiveness of EU energy-intensive industries

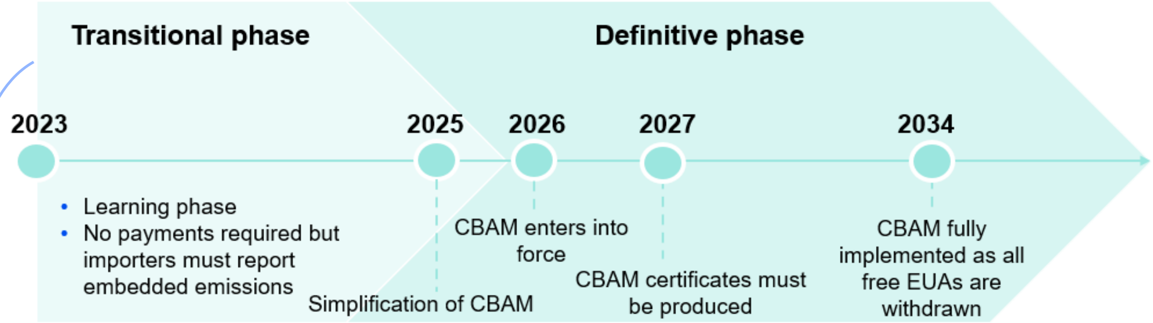
CBAM reduces free carbon permits for specific goods

CBAM applies a carbon price to imported goods comparable to that faced by EU producers. Non-EU producers must purchase a CBAM certificate**. The mechanism is designed to limit carbon leakage while preserving the effectiveness of the EU ETS.

Phasing-out of free allocation and phasing-in of CBAM timeline



CBAM factor determines the share of embedded emissions that must be covered with CBAM certificates each year



List of covered goods in sectors receiving free allocation under ETS

Transitional phase	De minimis exception	Possible inclusion
Cement Electricity Fertilisers Iron and steel Aluminium Hydrogen	Cement Fertilisers Iron and steel Aluminium	Oil refining All metals Pulp and paper Glass and ceramics Aviation Maritime Lime Chemicals Further downstream

Since 2026, companies importing less than 50 tonnes of goods subject to CBAM annually will be exempt from CBAM obligations

Source: ACER based on CBAM Regulation and Regulation simplifying and strengthening CBAM, EU Commission Guidance Document and CRU.
*EUA stands for European Union Allowance, which is the official carbon permit used within the EU ETS. If non-EU producers can show that they have already paid a price for the carbon used in the production of the imported good in a third country, the corresponding cost is fully deducted. ** A CBAM certificate corresponding to one tonne of embedded emissions from the previous year in the imported goods and priced according to the average EUA auction price.

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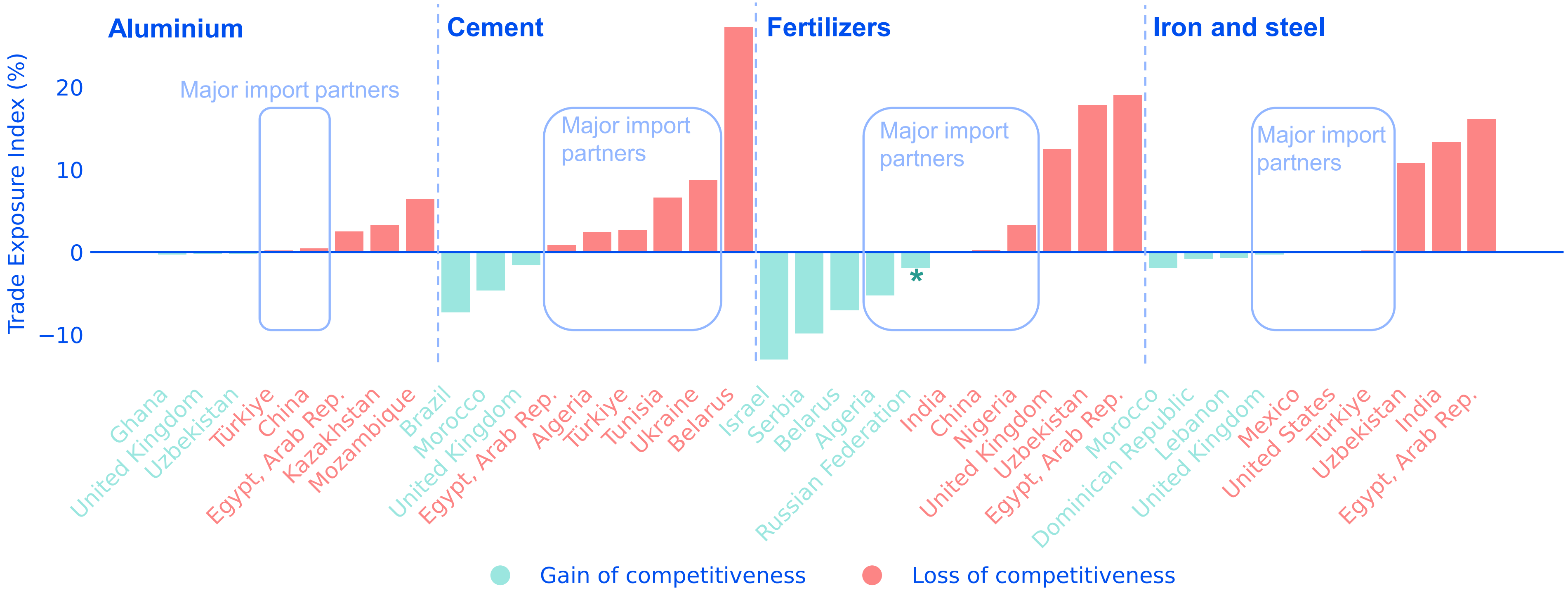
CBAM's levelling of the playing field may reconfigure trade

Most major import partners will be less competitive than the average EU producer in the internal market

Trade exposure index for selected countries and the CBAM sectors (%)



Key indicator

Trade exposure index

What is it?

Value of the excess carbon payments as a share of total sectoral exports.

Meaning

Red: high exposure to CBAM (potential loss of competitiveness relative to average EU producer)

Green: Low exposure to CBAM (potential gain of competitiveness relative to average EU producer)

The scope of the carbon border adjustment mechanism (CBAM) remains narrow, covering just 3% of EU imports from non-EU countries. Within the EU, CBAM sectors represent 7% of manufacturing output and 0.6% of employment, with embedded emissions in 2022 accounting for 0.31% of global greenhouse gas emissions (generating ~€14.7 billion annually).

While CBAM links sustainability and trade, aiming to equalise carbon costs borne by EU and foreign producers, it risks reshaping trade flows and affecting key partners' competitiveness. However, CBAM does not address the competitiveness disadvantage of EU producers exporting goods from higher production costs tied to phasing out free allowances and stricter emissions caps.

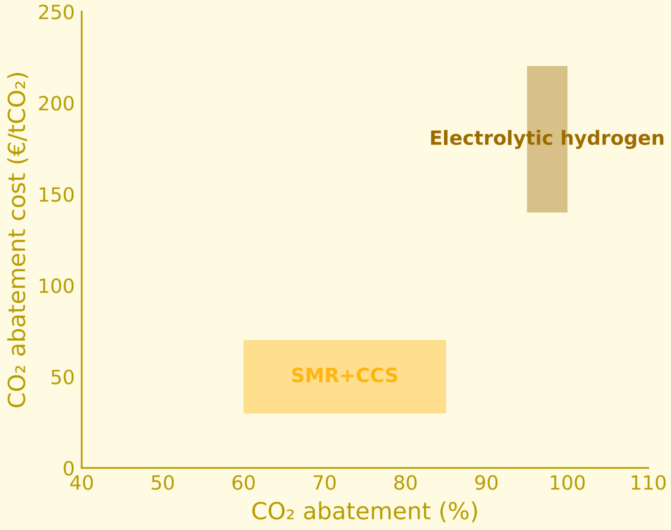
Source: ACER based on World Bank Group and OECD policy brief: What to expect from the EU Carbon Border Adjustment Mechanism?, 2025.

* On 23 July 2025, the EU increased tariff duties on Russian imports of agricultural products and fertilizers, subject to an additional customs duty of 50%. Further information.

Case study: Ammonia
One of the most natural-gas-intensive chemicals

Carbon capture and storage (CCS) provides potential for decarbonising the ammonia production sector, while electrolytic hydrogen production costs remain a barrier for decarbonisation

Carbon dioxide abatement potential and costs for the most technologically feasible decarbonisation routes*

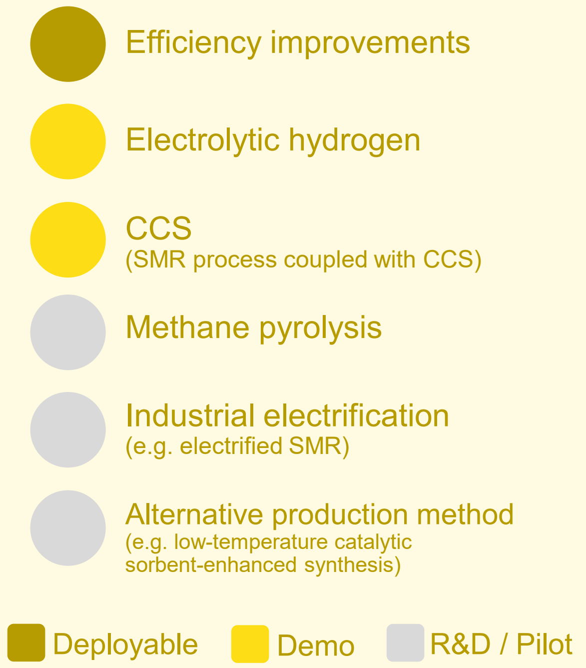


Ammonia production is representative of the chemical industry and relies on natural gas for both hydrogen feedstock and process energy. it is essential to nitrogen-fertiliser manufacturing in the EU.

70% of the ammonia global production comes from conventional steam methane reforming (SMR) processes, while the remaining production is primarily from coal gasification. The SMR emits directly around 1.5-2.0 tCO_2/t_{NH3}, making it one of the most carbon-intensive industrial processes. Retrofitting SMR with CCS is an attractive decarbonisation option for existing European ammonia production plants, with CO_2 abatement levels around 60-85% and moderate abatement costs.

Transitioning to electrolytic hydrogen or hydrogen produced via reforming with CCS could reduce emissions, but current production costs are higher than those of fossil-based routes. Process efficiency measures can contribute further to decarbonisation, but their carbon-abatement potential is generally estimated to reach up to 25%.**

Stage of development of decarbonisation levers

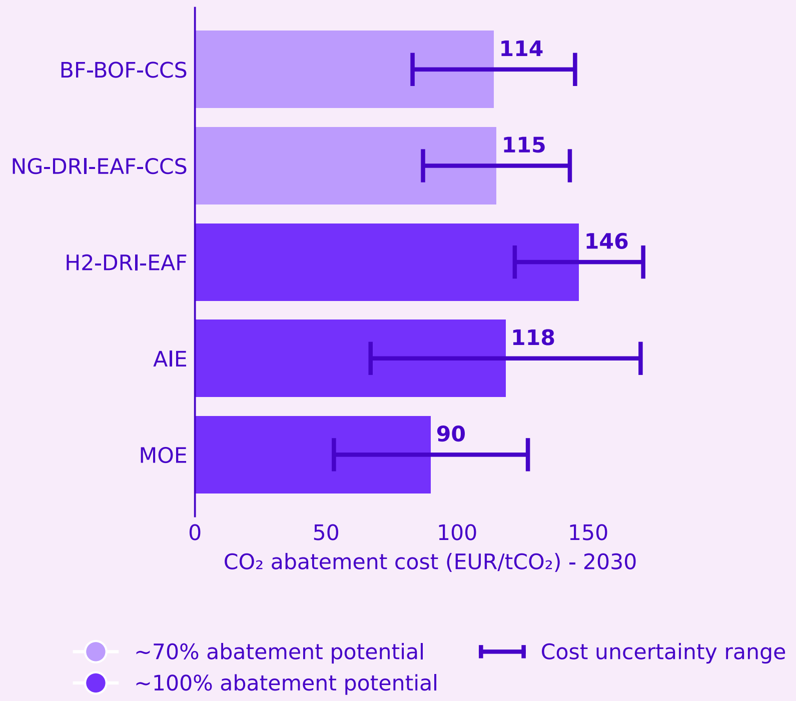


Source: ACER based on JRC energy-intensive industry factsheets.
*SMR stands for steam methane reforming. SMR is a process that produces hydrogen and carbon monoxide by reacting hydrocarbons, typically natural gas, with steam. CCS stands for carbon capture and storage. R&D for research and development. For SMR+CCS, costs include transport and storage. ** Other decarbonisation technologies are emerging but still need development before full commercialisation.

Case study: Iron and steel
Competing pathways between gas and hydrogen

Decarbonising the EU steel industry will involve a significant increase in fossil-free electricity demand by 2030

Carbon dioxide abatement potential (%) and costs (EUR/tCO_2) for selected production technologies*



The EU iron and steel sector is responsible for ~130 million tonnes of steel (7% globally). It is one of the most emissions-intensive industries in the EU, relying heavily on **carbon-dependent processes**.

Two primary steelmaking routes: (i) blast furnace-basic oxygen furnace (1.81 tCO_2eq/t_{steel}) using coal, and (ii) scrap-based electric arc furnace (0.24 tCO_2eq/t_{steel}). The latter emits 87% less CO_2 than the former per tonne of steel produced. The industry faces pressure to transition toward cleaner methods.

A key debate centres on replacing coal with alternative reducing agents:

- **Natural gas** offers a transition solution in direct reduced iron-based steelmaking, especially when paired with carbon capture and storage.
- **Renewable hydrogen**, while capable of nearly eliminating process emissions, remains costly and energy-intensive, requiring a substantial renewable electricity expansion.

The EU must balance short-term feasibility (gas + CCS) against long-term sustainability (hydrogen), all while maintaining industrial competitiveness in a global market.

Source: ACER based on JRC energy-intensive industry factsheets and Agora industry.
* Acronyms for production technologies are: blast furnace-basic oxygen furnace (BF-BOF), scrap-based electric arc furnace (EAF), carbon capture and storage (CCS), hydrogen-based direct reduction (H2-DRI-EAF), alkaline iron electrolysis (AIE), molten oxide electrolysis (MOE).

Case study: Glass industry
Electric melting, critical for decarbonising the glass industry

Process optimisation
Fuel switch
Electrification
Circularity
CCUS

Stage of development of decarbonisation levers

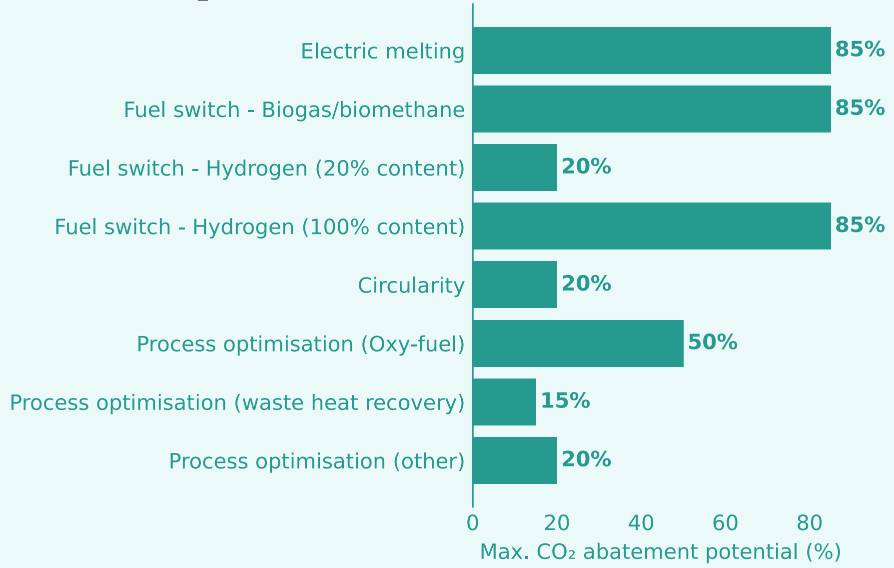
Deployable   Demo   R&D / Pilot

First, process optimisation strategies, fuel switching to biogas, and electrification in small furnaces

The flat glass sector is one of the highest temperature industrial processes, relying on continuous high-temperature furnaces where gas provides stable heat and product quality.

Process optimisation strategies could be implemented first. They could vary by glass type and plant scale and comes with a low CO_2 abatement potential. Fuel switching to biogas/biomethane along with electric melting in small furnaces are decarbonisation strategies more feasible for the glass industry with high CO_2 abatement potential.

Maximum CO_2 abatement potential (%)



Electrification is a key decarbonisation lever but its implementation for large furnaces still needs to upscale. Partial electrification through hybrid or full electric melting offers emission reductions but requires major capital upgrades and reliable low-cost electricity.

For the flat glass industry, the average electricity price in 2023 was around 150 EUR/MWh. Fossil-based hydrogen was estimated at ~180 EUR/MWh, while renewable hydrogen exceeded 300 EUR/MWh in the same period. As a result, decarbonising the sector remains economically uncompetitive without carbon pricing mechanisms such as the EU Emissions Trading System.

Although the glass industry is not included in the first phase of the CBAM, it is a potential sector to be covered by such mechanism due to its high risk of carbon leakage*.

Source: ACER based on JRC energy-intensive industry factsheets.
* The term ‘carbon leakage’ refers to the transfer of CO_2 emissions from one country to another when, due to strict climate policies, companies relocate their production to countries with weaker emission constraints. This can contribute to an increase in global greenhouse gas emissions.

Highlights and good practices: Industry decarbonisation

12%

reduction in EU final energy consumption in industry between 2021 and 2023

Half of this reduction corresponds to natural gas.

3

industrial sectors cover ~40% of industrial final energy consumption by natural gas

These sectors are chemicals, iron and steel, and glass.

5%

increase in industrial gas consumption in 2024

However, natural gas demand for the industrial sector remains well below pre-crisis levels.

01 Make carbon pricing work for climate and EU industry

Ensuring fair and predictable carbon prices through the EU emissions trading system and carbon border adjustment mechanism to reduce emissions while keeping EU industries competitive.

02 Boost clean technologies for climate goals

Meeting EU climate goals requires faster progress in electrification, hydrogen, and carbon capture, utilisation and storage. Strengthening innovation in industrial processes and ensuring a rapid deployment to achieve emission reductions in a cost-effective and reliable manner.

03 Strengthen cross-sector coordination

Coordinated infrastructure planning and regulatory alignment to resolve possible discrepancies will enable efficient integration of the gas, electricity and hydrogen sectors along the energy transition.

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Methane emissions from natural gas are a major, fast-acting driver of climate change. They may limit the climate benefits of using gas as a bridging technology compared to other fossil fuels.

Many methane abatement options are technically feasible at low cost. However, most emissions tied to EU's gas use originate outside its borders, remain poorly tracked, and lie beyond direct regulatory control.

The EU Methane Regulation tackles this challenge, including through stricter EU import requirements.

The key challenge is reducing methane emissions quickly while avoiding excessive contractual burdens, cost shifts, or risks to security of supply and diversification.

Dilemma 4

How to tackle methane emissions (low-cost potential – rising implementation risks)?

Competitiveness vs. climate challenges

Methane emissions abatement faces regulatory uncertainty

Methane emissions mitigation is a global challenge

- Methane is more than 28 times as potent as carbon dioxide over a 100-year timeframe and 80 times over a 20-year timeframe.*
- Methane emissions from gas and oil supply chains serving the EU far exceed emissions within EU territory. The former reached 5.7 Mt CH_4 in 2024 compared with about 1 Mt within the EU.
- Methane mitigation in the gas sector is therefore a global challenge, particularly for importing regions such as the EU.
- The Methane Regulation introduces gradual requirements for EU gas importers, starting with transparency and monitoring.

The main hurdle is regulatory uncertainty, not compliant gas supply availability

- Available evidence suggests supply availability should not be a binding constraint, with large volumes of low-methane-emission gas potentially available in global gas markets.
- Two main challenges can be identified:
    - Balancing ambition and implementation is key to credible methane emission reductions.
    - Delayed national penalty frameworks are creating legal uncertainty for methane regulation compliance.

Effective EU methane emission cuts at home can boost credibility of EU requirements on gas imports

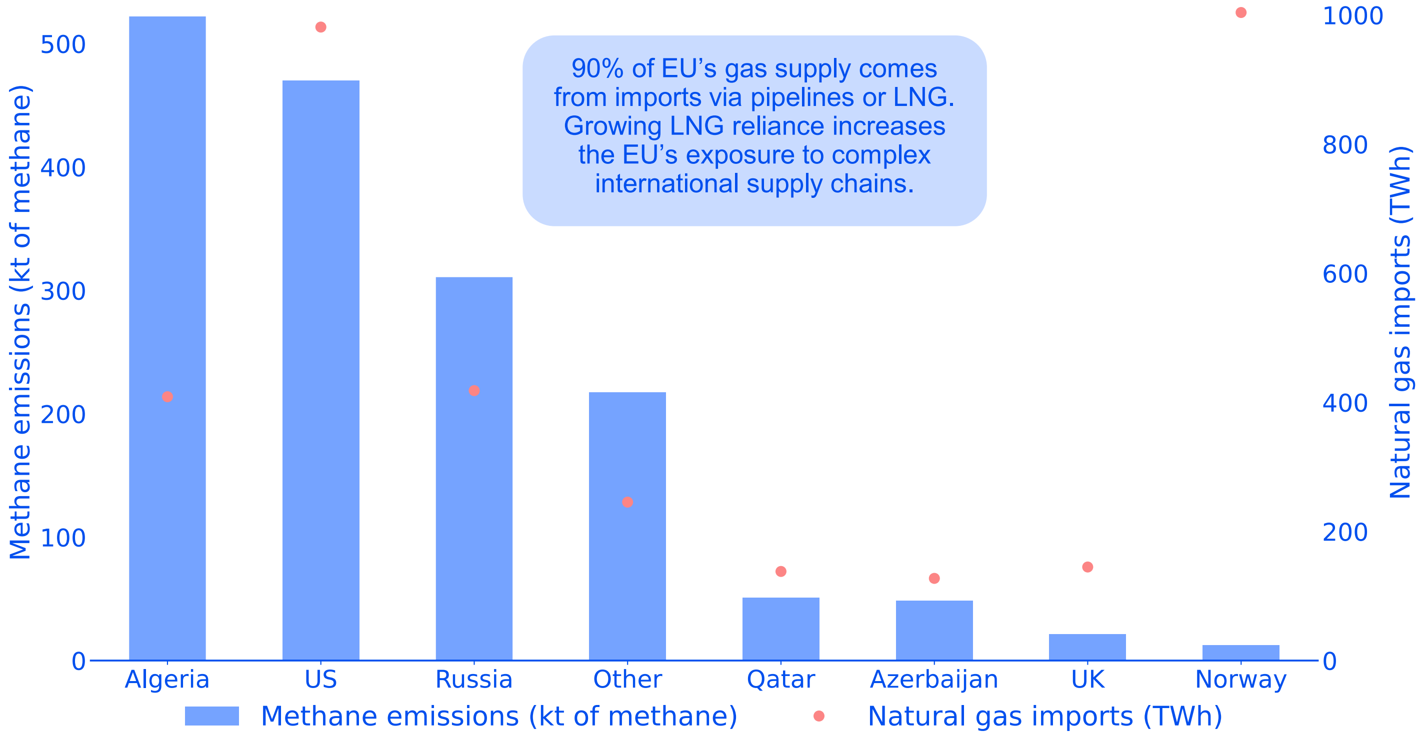
- 75% of domestic abatement potential assessed as profitable.
- Cost-effective emissions reductions are achievable.

* The methane molecule has a 12-year average lifetime in the atmosphere.

EU's gas climate footprint stems mostly from imports

Reducing methane emissions across global gas supply chains requires coordinated action

Volume-weighted methane emissions of EU natural gas imports by supply origin (kt CH_4 – left axis) and natural gas imports in the EU by supply origin (TWh – right axis), 2025



- Downstream operations* resulted in 13 Mt of methane emissions in 2024 globally. In the EU, they account for ~75% of methane emissions from domestic oil and gas supply chains, while representing only ~8% of global downstream methane emissions.
- Most methane emissions from the EU's gas use comes from imports**. EU methane inventories capture only a fraction of the methane linked to EU gas consumption.
- EU's methane mitigation must therefore be addressed as a global decarbonisation challenge.

Source: ACER based on Kayrros Methane Watch, ENTSOG, and ICIS.
* Downstream operations from oil and gas are mainly due to transmission, distribution and storage.
** In 2024, upstream methane emissions associated with oil and gas supply chains serving the EU were almost six times higher than domestic emissions (~6 Mt vs 1 Mt) for oil and gas sector.

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Methane intensity: Wide gaps by producer & supply chain

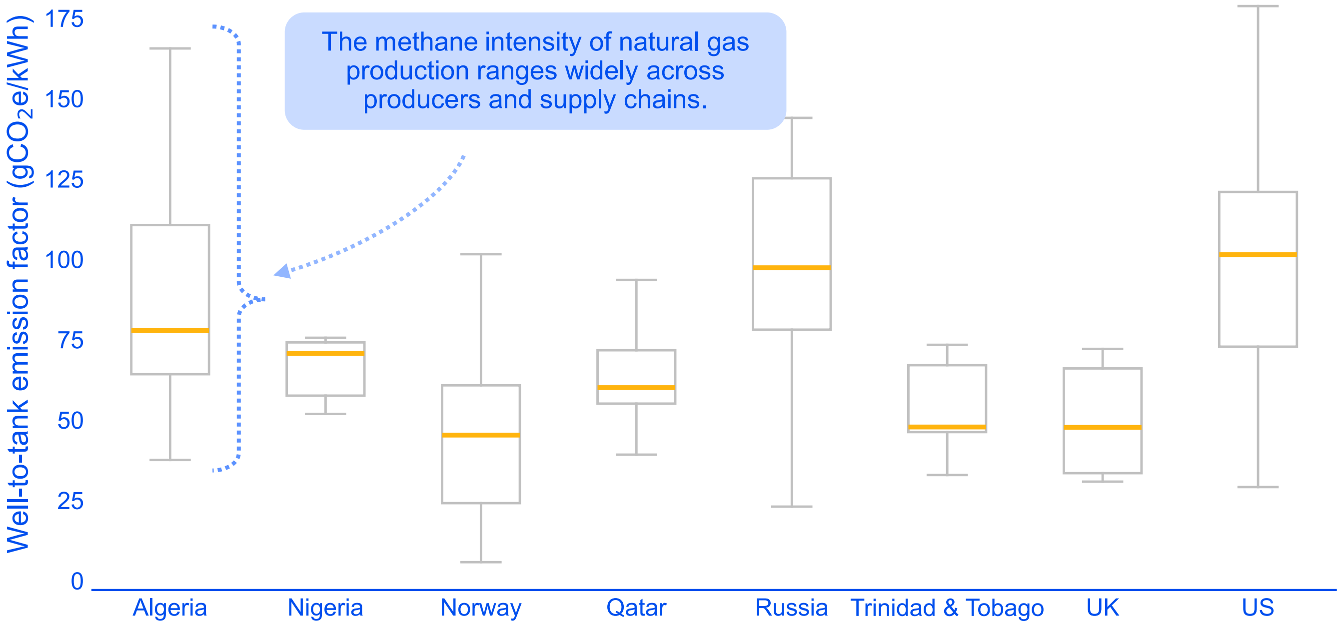
Supply-chain decisions shape the overall environmental footprint of delivered gas to the EU

Satellite observations and reconciled IEA estimates show higher methane emissions than the reported ones in some producing regions and LNG basins.

Variability in methane emission factors is not only observed across producing regions, but also within individual supply systems*.

Differences in production standards, gas gathering, processing, long-distance transport and LNG handling mean that two gas cargoes delivered to Europe can have very different methane footprints, even if their CO_2 combustion emissions are identical. As a result, simplified compliance approaches would be more suitable in the short to medium term (see page 69).

Well-to-tank carbon intensity** (gCO_2e/kWh) for selected LNG producing countries

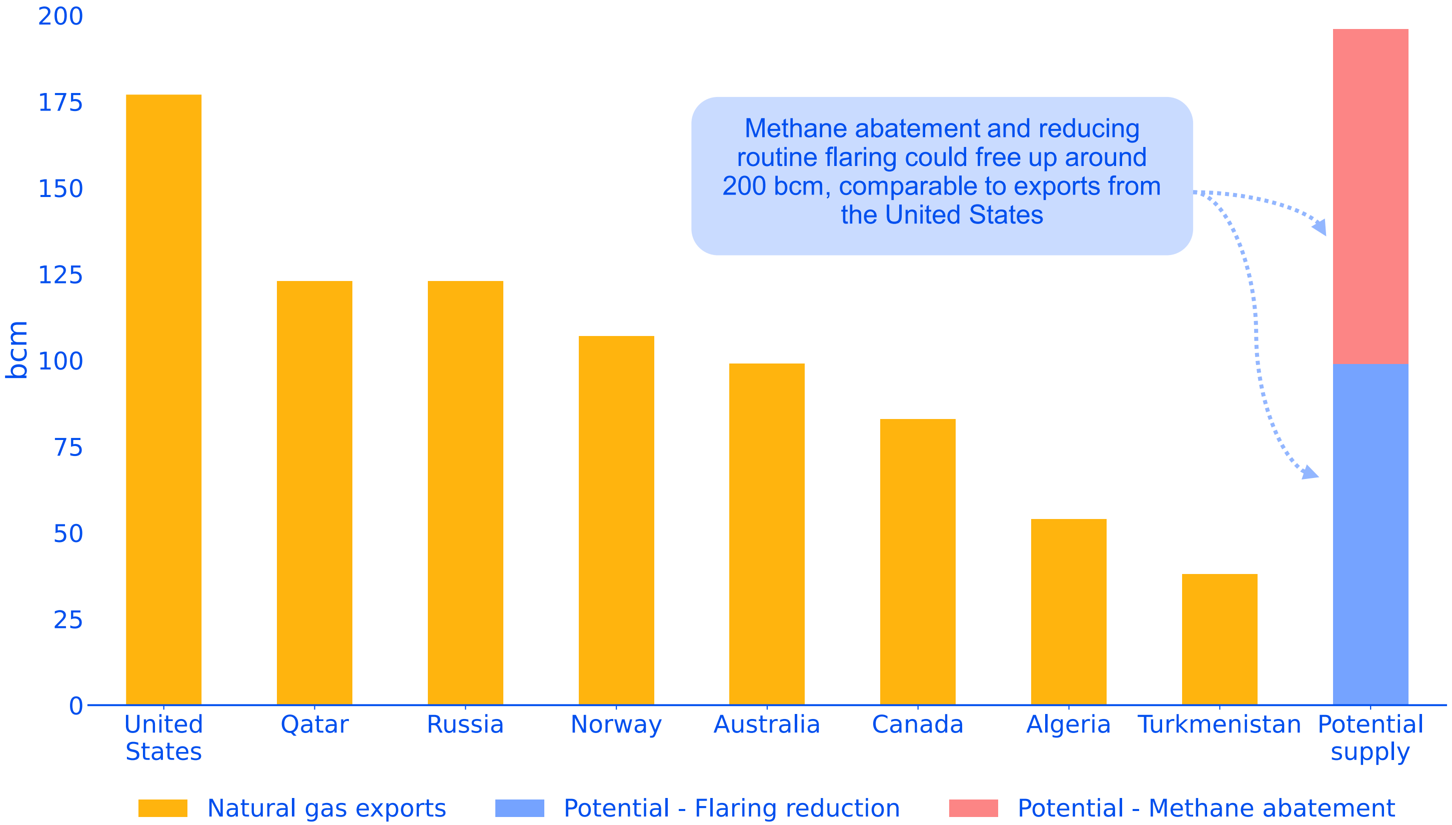


Source: ACER adaptation based on EERA (2024); other souces: IEA Methane Tracker 2025; ACS Sustainable Chemistry & Engineering (2024). Kayrros (2026);
* A recent peer-reviewed study of gas pathways supplying two major LNG export terminals identified 138 distinct gas pathways, with life-cycle GHG intensities differing by a factor of nearly six.
** Estimates accounting for the total emissions for CO_2, CH_4, and N_2O (where available) from the fifth IPCC assessment report and weighted for 100-year GWP timescale.

Methane emissions abatement could unlock gas supply

Much of methane emissions abatement potential is low-cost or net-positive

Natural gas exports and potential natural gas supply from reducing routine flaring and methane abatement, 2024 (bcm)



- 70% of global fossil fuel methane emissions could be avoided at a low cost, assuming captured gas is valued at 2024 market prices*.
- Methane emissions abatement is often not incentivised, as:
  - ✓ emissions are diffuse and episodic,
  - ✓ responsibilities are fragmented across supply chains,
  - ✓ benefits from recovered gas may accrue actors other than those paying for abatement,
  - ✓ transparency is limited and enforcement historically weak.
- Measures like major infrastructure replacement, retrofitting ageing gathering systems, or eliminating flaring in remote or low-pressure fields, carry higher costs and may require stronger regulatory signals or coordination.

Source: ACER adaptation based on IEA Methane Tracker 2025.

* Examples include leak detection and repair, replacement of high-emitting pneumatic devices, improved compressor sealing, and operational changes to reduce venting and routine flaring — many of which generate direct value through recovered gas.

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Timeline for the EU methane emissions regulation

The EU Methane Emissions Regulation: From domestic control to import requirements

5 May 2025
Article 27 & Annex IX reporting by importers (due annually on 31 May thereafter)

1 January 2027
MRV equivalency requirement takes effect for supply contracts concluded after 4 August 2024*

5 August 2028
Importers must report on the methane intensity of their gas supplies (due annually thereafter)

5 August 2030
Maximum methane intensity rule takes effect

It introduces obligations for importers gradually, starting with transparency and monitoring, reporting and verification and including flexibilities during the transition period.

More demanding requirements (methane intensity reporting and eventual maximum intensity thresholds) apply later to allow suppliers, markets and verification systems to adapt.

5 August 2025
Member States set rules on penalties

5 February 2026
Methane transparency database and rapid reaction mechanism

5 August 2026
Global methane monitoring tool and performance profiles

5 August 2027
Agreement on methane intensity methodology

5 August 2029
Commission assesses potential maximum methane intensity values

Key dates for gas importers and suppliers (blue boxes)

Key dates for EU and Member States (green boxes)

Source: ACER based on Cahill, Ben (2026), Jonathan Stern presentation at EEMDL Oct 2024.
Note: timeline is not exhaustive, other reporting obligations apply. * For supply contracts concluded before this date, “importers shall undertake all reasonable efforts” to ensure that MRV requirements are met, including via amendment of those supply contracts.

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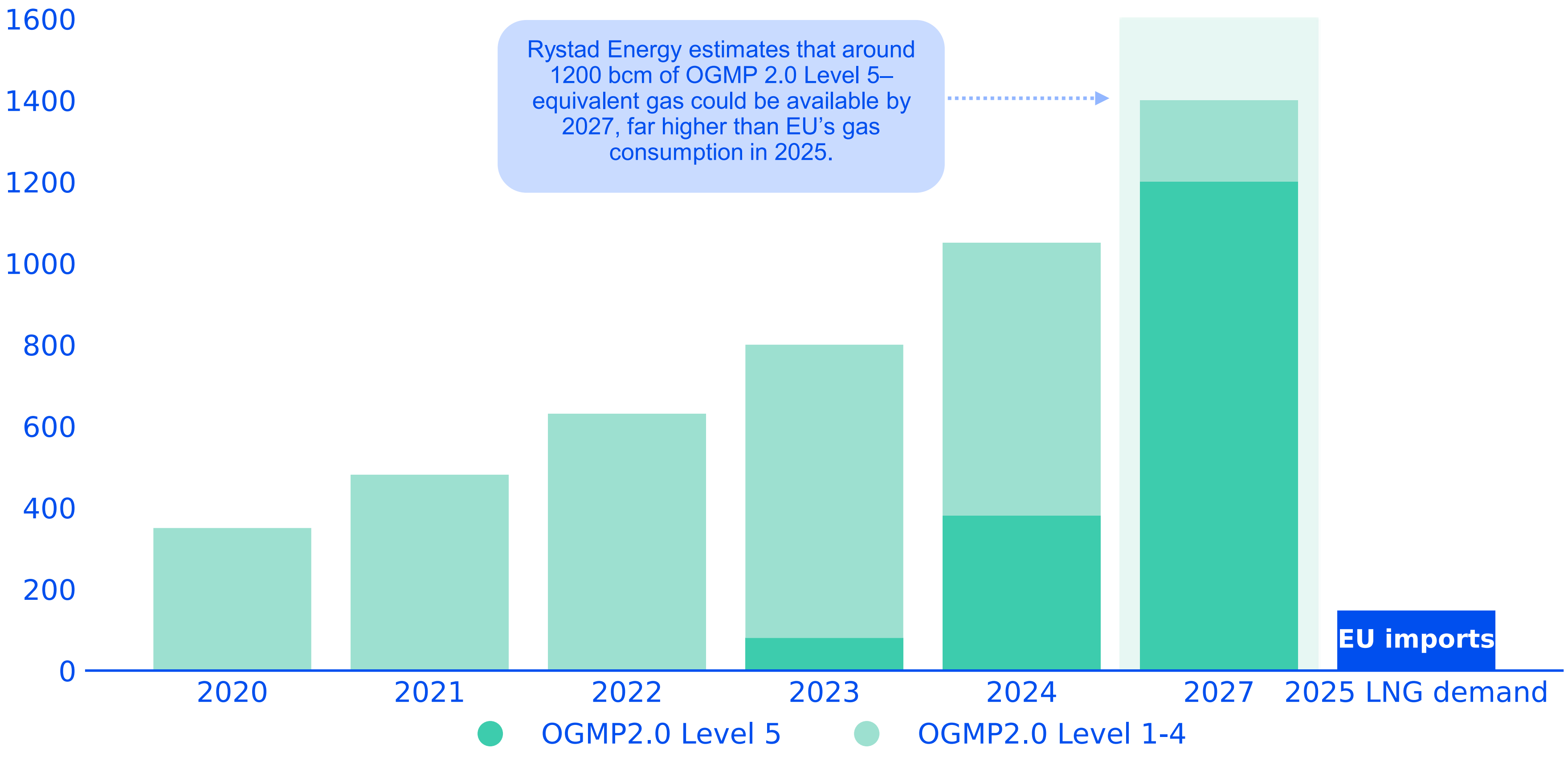
Growing compliant gas supply is expected …

By 2027, the EU's 2025 LNG demand could be met with gas measured to the highest industry standards*

Projected 2027 OGMP2.0 Level 5 gas volumes and EU's LNG demand, 2020-2027 (bcm)



- Available evidence suggests that supply availability should not be a binding constraint.
- To date, there is also no evidence that the Methane Regulation has resulted in material adverse effects on gas supply or overall market functioning.

Source: ACER adaptation based on Rystad Energy.

* This refers to standard OGMP 2.0 Level 5–equivalent gas, which is the most accurate way companies report methane emissions from oil & gas operations under the Oil and Gas Methane Partnership 2.0 (OGMP 2.0) framework run by the United Nations Environment Programme (UNEP). They represent real, measured amount of methane emitted from oil & gas facilities, reported with the highest accuracy.

… but growing implementation uncertainty

Two main challenges remain ahead for implementing the Methane Regulation

- Delays and unresolved implementation details are increasingly shaping market perceptions and risk assessments. At EU and national level, key implementing methodologies and rules are still under development*.
- Most Member States have yet to adopt national penalties, despite statutory deadlines having passed, leaving enforcement expectations unclear. Against this backdrop, implementation risk is less about physical supply availability and more about regulatory uncertainty.

Challenge 1: ambition vs implementation

This challenge is about balancing environmental ambition with practical implementation.

Stronger traceability improves integrity but increases complexity, requiring phased implementation aligned with supply-chain realities.

Challenge 2: regulatory uncertainty on penalties

Designing methane penalties that effectively support methane emissions reductions while remaining proportionate is a key challenge.

Greater coordination through EU-level guidance may help ensure consistent implementation across Member States.

* A future Delegated Act includes MRV equivalence criteria, accepted compliance pathways along international supply chains, and the methane intensity calculation methodology.

Challenge 1: Ambition vs. implementation

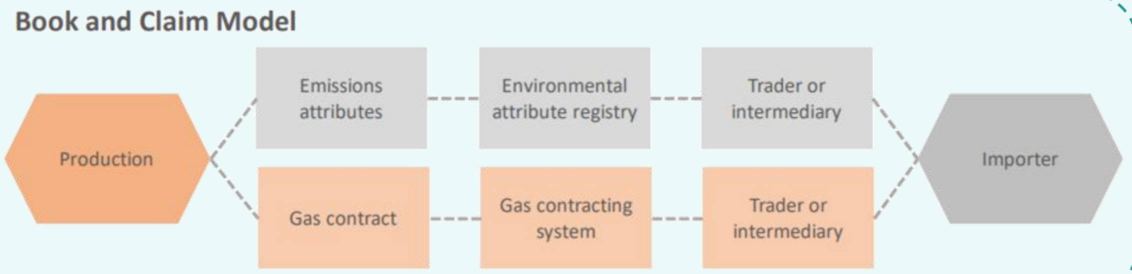
Compliance solutions range from national book-and-claim approaches to full trace-and-claim systems

The EU Methane Emissions Regulation requires information on producer-level methane emissions, but it does not prescribe a single compliance pathway for demonstrating Monitoring, Reporting, and Verification equivalence in complex international supply chains.

Progressive implementation, calibrated to supply-chain realities, may therefore be required, with trace-and-claim as the long-term reference model.

Book-and-claim models separates environmental attributes from physical gas flows.

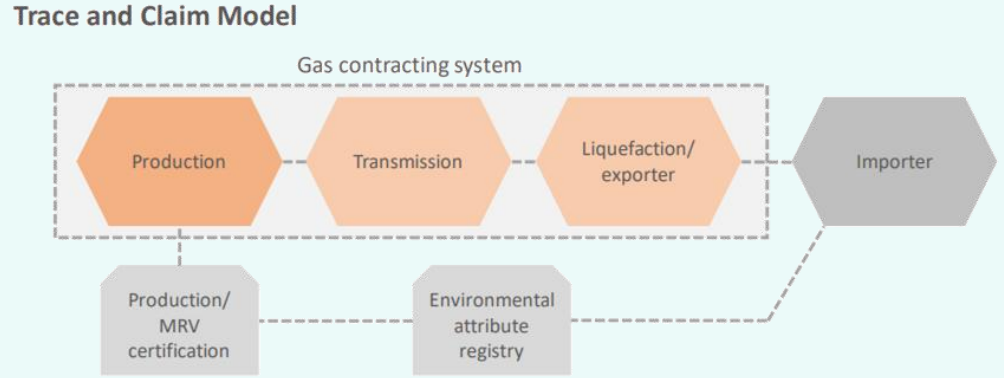
This approach avoids the need to track molecules, simplifying trade in complex supply chains.



Trace-and-claim models* link gas volumes to their source, tracking emissions back to production.

This approach works for point-to-point supply chains (e.g. Qatar to Europe) because traceability is technically achievable.

It struggles in highly interconnected systems, like the United States.



Alternative emissions tracing models**

Source: Adapted from Context Labs. Gas contracting system encompasses physical pathway or contractual commitments for the commodity between producers and counterparties such as exporters, traders, and importers. A previous version of this paper included a slightly different figure for trace and claim.

Source: ACER based on Cahill, Ben (2026). The flowcharts have been adapted from Context Labs.
* Their feasibility depends strongly on supply chain structure and complexity.
** Gas contracting system encompasses physical pathway or contractual commitments for the commodity between producers and counterparties such as exporters, traders, and importers.

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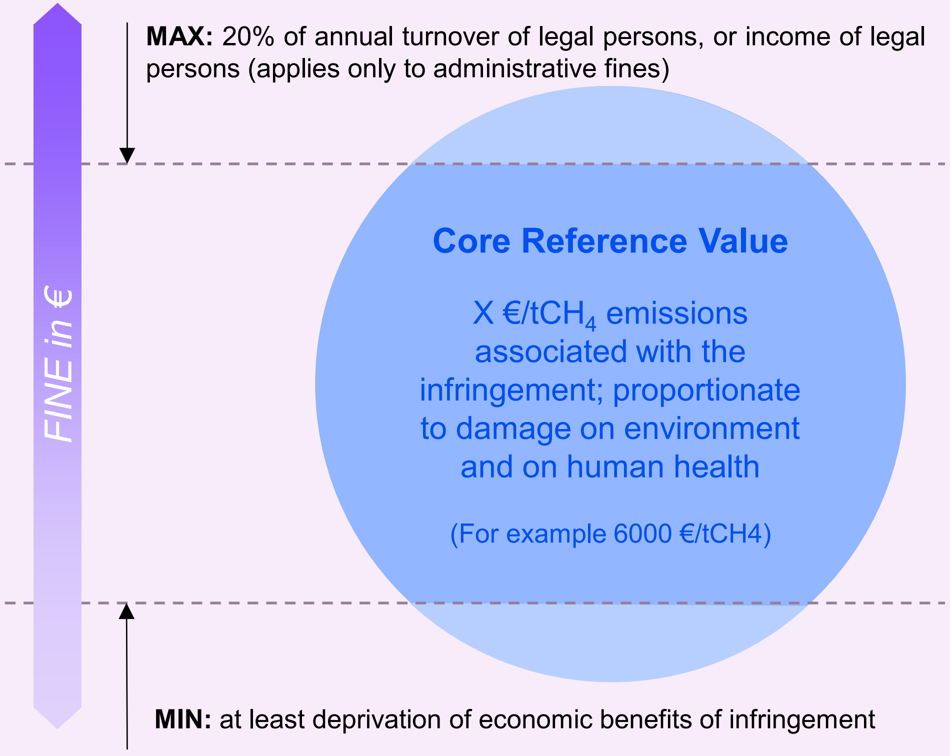
Challenge 2: Regulatory uncertainty on penalties

Low penalties may deter mitigation strategies

Translating article 33 of methane regulation into monetary fines



Public focus on maximum penalties has raised disproportionate liability concerns.

Low penalties could fail to incentivise methane emissions reductions

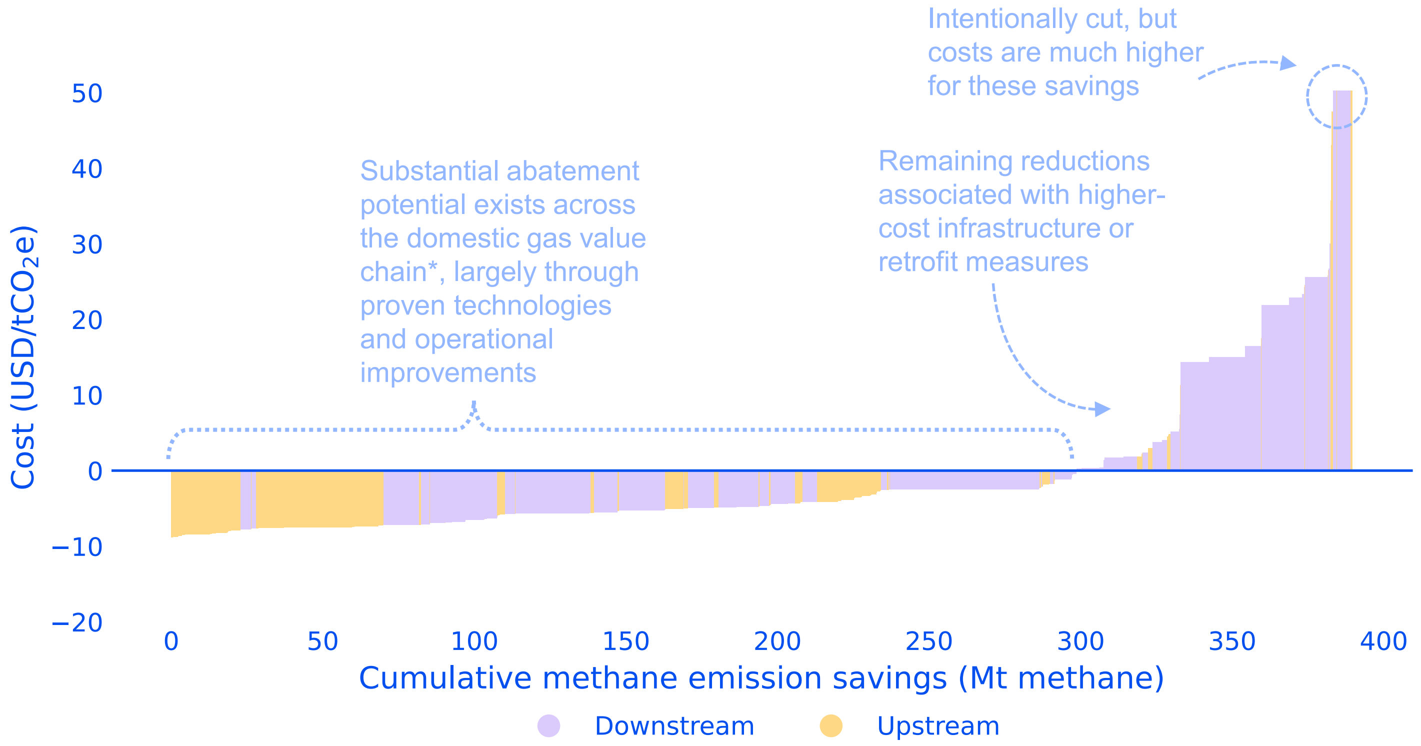
- Member States must enforce penalties that are effective, proportionate, and dissuasive, weighing mitigating and aggravating factors.
- Maximum penalties may apply only to intentional, repeated, and unremedied violations, rather than good-faith efforts to comply in a complex and evolving regulatory framework.
- Progress remain limited: **few Member States have adopted detailed penalty regimes**, and some have yet to formally designate competent authorities.
- Uneven implementation increases legal uncertainty and complicates consistent application of the Regulation across the EU.

Source: ACER adaptation based on Ecologic Institute (2024), Ecologic Institute (2025).
Note: While not yet sanctioned, as in May 2026 the possibility of the European Commission allowing polluters to avoid penalties under looming methane emissions rules until 2029 is under review.

Credibility starts at home

75% of domestic emissions abatement potential assessed as profitable

Methane abatement cost curve of the natural gas segment of the European Union, 2025



- Proving the EU can cut methane cost-effectively at home is critical to justify demands on foreign suppliers and maintain policy legitimacy.
- For regulated downstream entities*, compliance costs can be recovered through tariffs. Such costs must remain efficient and proportionate, to avoid undue cost increases for consumers as gas network utilisation declines.
- Domestic methane emission cuts must demonstrate both **technical and economic viability**, so that domestic implementation strengthens the credibility of importer requirements.

Source: Based on data from International Energy Agency (2024) Methane Tracker Database - IEA; as modified by ACER.
Note: ACER supports national regulators by developing benchmarks/indicators for methane-related implementation costs, helping ensure consistent, proportionate and credible domestic delivery.
* Including production, processing, transmission and distribution.

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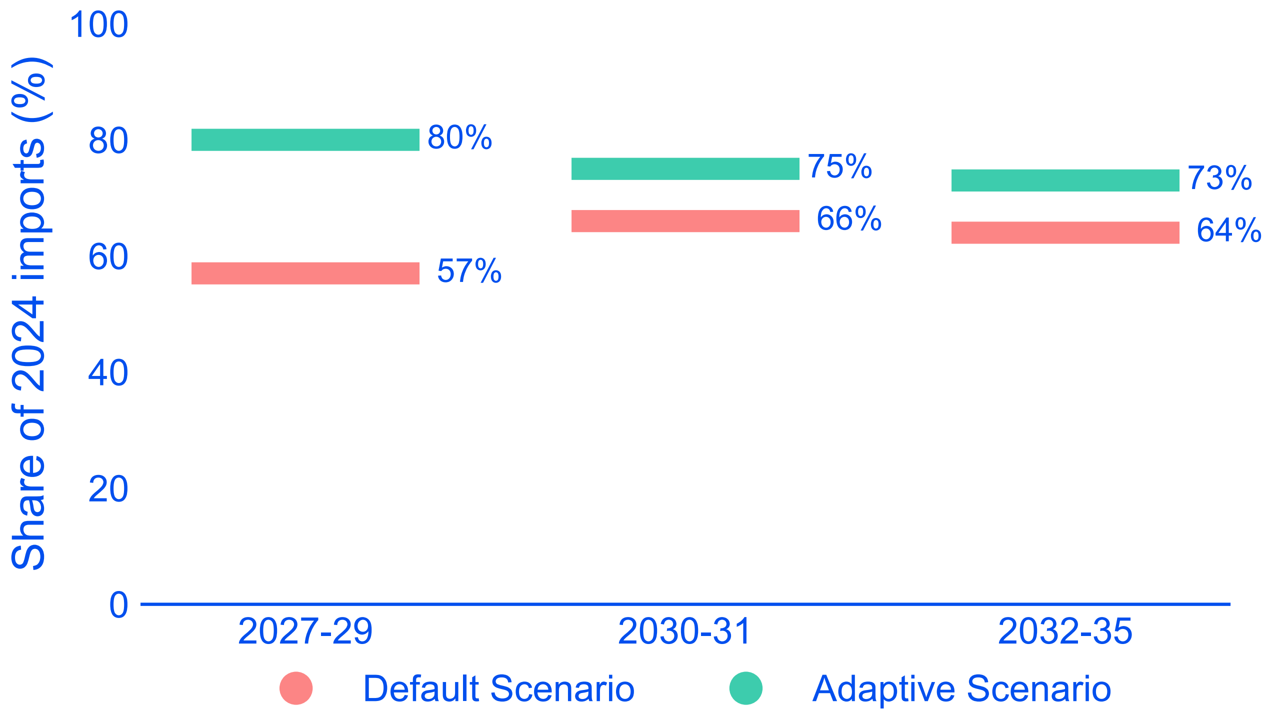
Methane Regulation: Implications for EU security of supply

While global compliant gas supply with the methane emissions regulation is projected to increase by 2027, the industry highlights potential security-of-supply concerns …

Methane-emissions-regulation compliant EU gas/LNG imports** (%)



… but these will depend on how implementation rules are designed, particularly whether certain flexibilities are retained

- An industry-led study* conducted a scenario-based analysis to assess the potential impact of the EU Methane Emissions Regulation on natural gas/LNG and crude oil supply and costs.
- This study warns about implications for security of supply, pricing and competitiveness of EU businesses.
- Implementing the methane regulation could constrain the EU’s ability to import natural gas, but Article 33 of the regulation requires Member States to weigh clearly aggravating and mitigating factors.
- Similar level playing field across the national implementations would be key to preserve market integration.

Source: ACER based on the results from this industry-lead study: Wood Mackenzie study.
* Wood Mackenzie study ** These figures result from the modelling of alternative policy enforcement scenarios. Default scenario: regulation is enforced as it was adopted in 2024. Adaptive scenario: modifications introduced to regulation allowing for greater flexibility in granting country-level MRV equivalence, prioritising security of supply.

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Highlights & good practices: Tackling methane emissions

6%

of global energy-related methane emissions are associated with EU oil and gas consumption

6.7 Mt methane linked to oil & gas supplied to the EU, out of 120 Mt of energy-related methane emissions globally (2024).

85%

share of EU's attributable CH_4 emissions from gas and oil supply chains originating outside the EU

Most methane linked to EU oil and gas use is effectively imported.

75%

of abatable gas methane emissions are profitable to mitigate

Cost-effective emissions reductions are achievable.

01 Reduce regulatory and contractual uncertainty to limit costs

Provide early clarity on key methodologies and acceptable compliance approaches to avoid inefficient contract renegotiations, risk premiums and over-compliance that could drive up costs for consumers. Dialogue and cooperation with end industrial consumers should be promoted.

02 Enable pragmatic compliance pathways while preserving ambition

Communicate compliance approaches across the EU in the short to medium term, while maintaining a clear trajectory toward higher integrity and granularity as tracing and verification systems mature, while safeguarding the integrity of the internal gas market.

03 Start with EU actions, to reinforce external credibility

Deliver methane emissions reductions effectively and cost-efficiently within the EU gas system to set a global example and do it in a way to support broader market confidence.

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A fundamental dilemma in gas decarbonisation is whether to prioritise investment in carbon capture utilisation and storage (CCUS), as a transitional enabler, or to invest directly in renewable-based solutions (green hydrogen and biomethane).

CCUS can speed up the deployment of blue hydrogen, even create negative emissions when used with biomethane, and offer decarbonisation pathways for hard-to-abate sectors.

Investing in renewable alternatives avoids carbon lock-in, supports long-term sustainability, and aligns with climate neutrality targets.

A balanced approach to decarbonisation can mix targeted electrification, low-carbon gases, CCUS, and efficiency/demand response, while preserving power generation capacity and gas storage to cover seasonal and unexpected events.

Trilemma

What are cost-effective pathways for decarbonising the gas market, considering technological readiness, emissions impact, and energy independence?

Strategic transition question

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Cost-effective gas decarbonisation strengthens EU resilience

Decarbonising the gas market requires a portfolio approach, not a single solution

- The EU energy transition requires sustained investments in low-carbon solutions, while safeguarding EU industrial competitiveness.
- Scaling up domestic renewable production will reduce the EU's external energy dependence and become resilient against an uncertain geopolitical landscape.
- Accelerated investments in decarbonisation technologies will help define the most cost-effective way of achieving climate neutrality by 2050.
- Four decarbonisation solutions for the gas market are analysed in this section: electrification, biomethane, carbon capture, utilisation and storage, and hydrogen. Each has its own benefits and drawbacks.

Gas decarbonisation must balance costs, emissions cuts, and security of supply

- Electrification has increased by only 4 percentage points over the past 25 years, progressing slower than EU targets for 2030.
- Biomethane can support decarbonisation and energy independence, with abatement potential of 10–40% depending on feedstock, though supply is limited.
- Carbon capture and storage abatement costs range from 50–300 EUR/tCO_2 and may act as a bridging solution but require significant infrastructure investment.
- Renewable hydrogen remains uncompetitive versus alternatives like biomethane. Costs and infrastructure are key constraints.
- A balanced portfolio of decarbonisation solutions rather than reliance on a single technology, will be needed to reconcile the three pillars: greening the economy, ensuring market competitiveness* and keeping security of supply.

* Progressing towards an integrated market enabling competition and scaling innovation, while keeping prices affordable.

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Policy/investment decisions shape decarbonisation speed

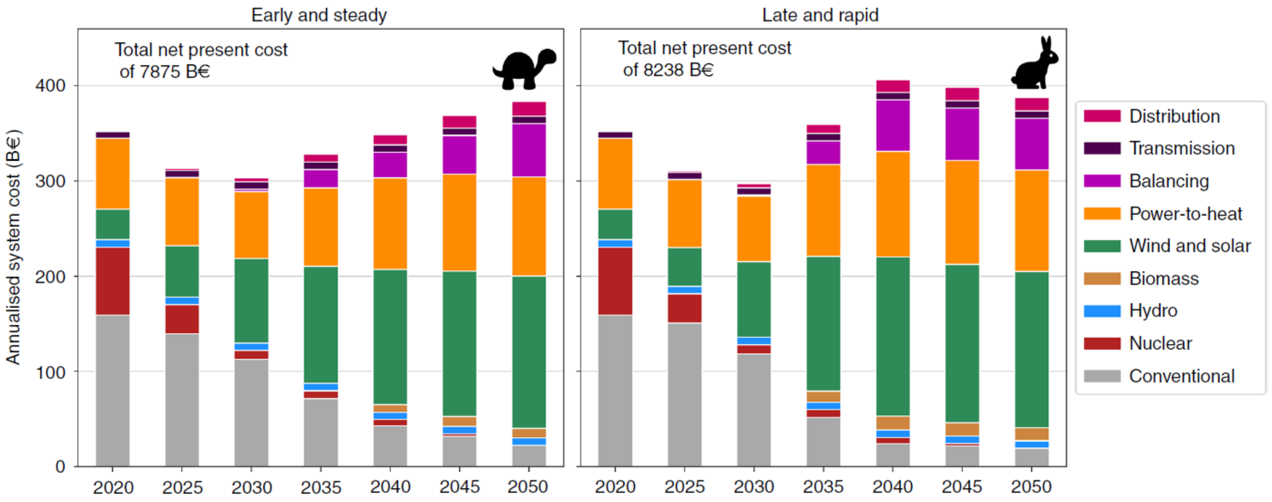
Policy choices will determine whether decarbonisation follows an earlier, steadier path or a later, rapid one

The pace of the transition towards a decarbonised system will shape both total system-wide costs (i.e., investment and operation costs) and the emission trajectories to reach climate neutrality by 2050. Policy and investment choices will be decisive to set that trajectory in the gas market. Ambitious targets require alignment with supportive regulatory framework (e.g., favourable carbon pricing, ample public funding) to accelerate the uptake of low-carbon technologies, while uncertainty or policy fragmentation can slow down investments and in turn raise costs. At the same time, further technology maturity and learning curves can also help reduce costs.

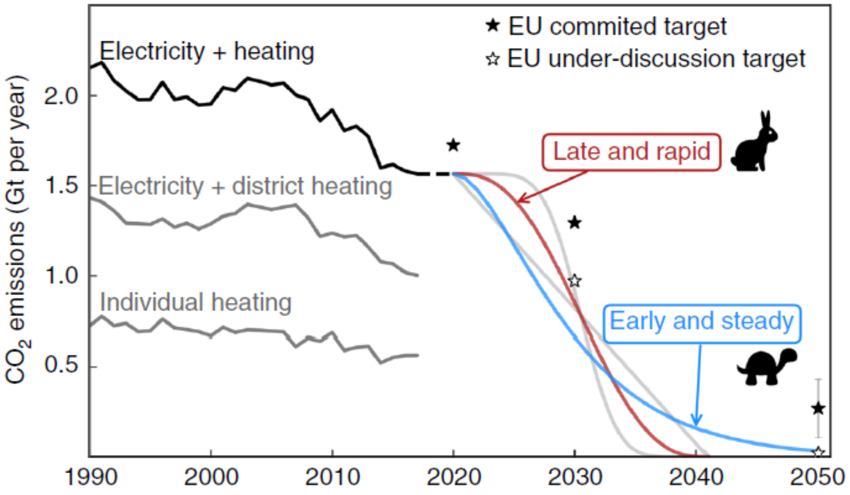
Decarbonisation trajectories depend on early or late investments. As shown in the below modelling for the European electricity/heating system decarbonisation, early investments could lead to steady emissions reductions, while a late response could reach climate neutrality fast but arguably at a higher cost.

Illustrative example for a sector-coupled model of the European energy system

Annualised system cost for the European electricity and heating system (Billion EUR)*



CO_2 emissions (Gt per year)*



Source: Early decarbonisation of the European energy system pays off, Nature Communications, 2020.
* Original figure from the scientific paper. As specified in the paper "Conventional includes costs associated with coal, lignite and gas power plants producing electricity as well as costs for fossil-fuelled boilers and CHP units. Power-to-heat includes costs associated with heat pumps and heat resistors. Balancing includes costs of electric batteries, H_2 storage and methanation."

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Gas decarbonisation pathways are multiple: what is right?

Gas decarbonisation is a portfolio challenge, not a single-solution choice

Various decarbonisation instruments are available for decarbonising the gas market. Each involves trade-offs between costs, emissions reductions and system impacts. These options may pursue conflicting outcomes in terms of economic efficiency, climate effectiveness, energy transition speed and energy independence.

Different combinations give rise to multiple transition pathways for the decarbonisation of the gas market.

In slide 84, three hypothetical pathways leaning towards certain decarbonisation instruments, namely green hydrogen, biomethane or carbon capture and storage, are compared against a baseline representing "inaction", where natural gas use remains unabated.

Electrification

- \+ Directly displaces natural gas
- \- Investments in power system expansion and renewable electricity sources are essential

Hydrogen

H_2

- \+ Potential low-carbon vector for hard-to-abate sectors
- \- Nascent market, high costs, potential import dependency

Biomethane

- \+ Contribute to security of supply
- \- Constrained by feedstock mobilisation, production costs, and scalability issues

Carbon, capture, utilisation and storage

CO_2

- \+ Mitigate emissions while allowing continued operation of gas-based assets
- \- High capital costs, lack of CO_2 transport and storage infrastructure, capture efficiency

Displacing natural gas

Reducing carbon footprint

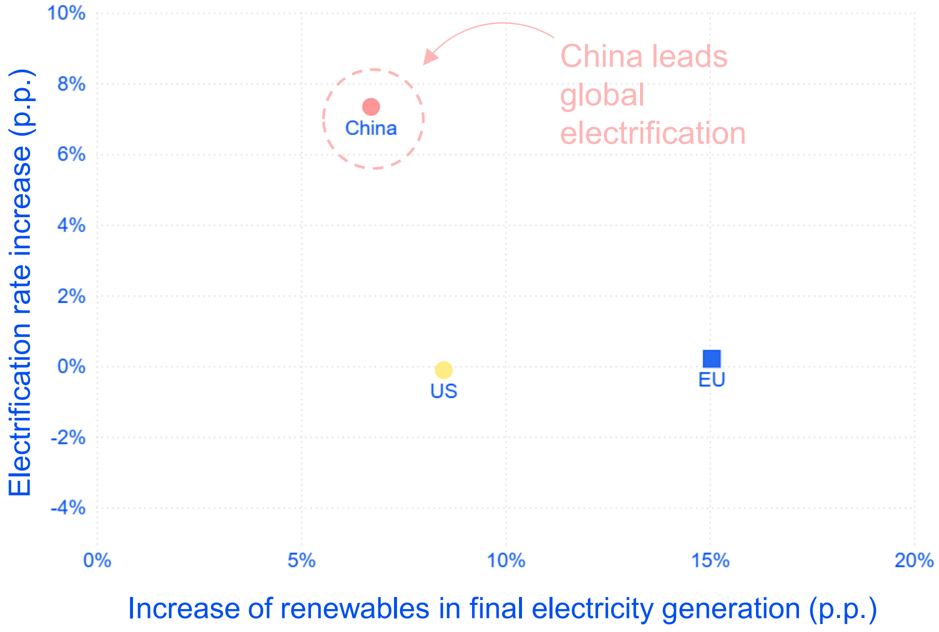
EU electricity mix is shifting rapidly toward renewables …

… but China leads the pace of electrification worldwide

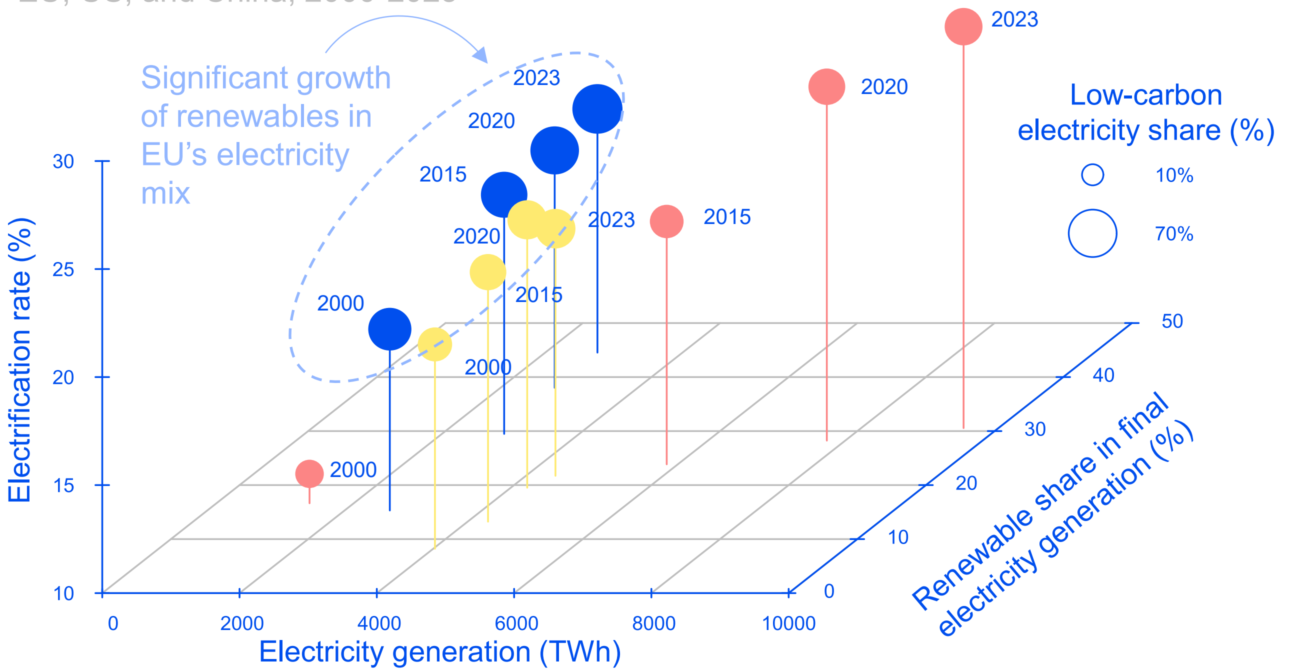
Electrifying heating, industry, and transport can significantly reduce EU carbon emissions. However, the scale of electrification depends on both renewable generation availability and adequate grid development, essential to ensure system resilience and cost efficiency. This will require major infrastructure investments and greater system flexibility.

China leads global electrification and renewable capacity expansion*. In contrast, stagnant energy demand in the US and EU has contributed to slower electrification over the last decade. Despite this, the EU keeps the global lead in both the share and relative growth of low-carbon sources** in its electricity mix.

Increase in electrification rate (percentage points – p.p.) and in renewables in final electricity generation (p.p.)
EU, US, and China, 2023 vs 2015



Electrification rate (%), electricity generation (TWh), renewable share in final electricity generation (%), and share of low-carbon electricity in final electricity generation (%)
EU, US, and China, 2000-2023



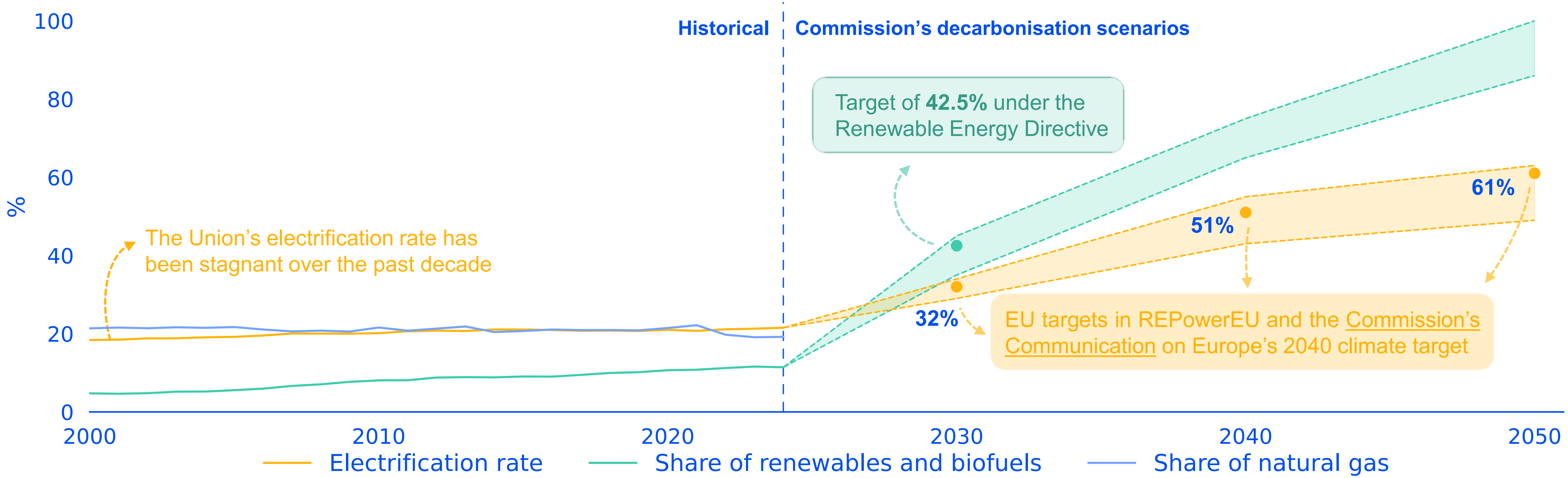
Source: ACER based on Eurostat and IEA. Note: European values are calculated based on Eurostat while China and US were calculated based on IEA World Energy Balances. * This is driven by strong policy choices and investment, supported by rising energy demand, high air pollution levels, limited domestic fossil fuel resources, and emerging trade opportunities. ** Low-carbon sources (or electricity) refers to the sum of both nuclear and renewable electricity generation.

Electrification: Displacing fossil gas consumption

Electrification rate of the EU slightly increased, gas use decreased and renewables increased steadily in past years

Despite significant progress in renewable energy and biofuel adoption, the overall electrification rate of the EU economy has grown slowly, rising from 18% in 2000 to roughly 22% in 2024. Meeting the bloc's ambitious 2030 climate goals now requires an unprecedented acceleration. Specifically, the share of electricity in final consumption must grow by 1.7% year-on-year. This required pace is three times faster than the highest consecutive-year growth the EU has achieved at any point this century. To put the scale of this challenge into perspective, even China - despite its rapidly surging energy demand and large electricity supply expansion - has only managed to achieve a 1.5% annual jump once, between 2016 and 2017.

Share of electricity, natural gas and renewables/biofuels of the final energy and non-energy consumption in EU, 2000-2024 (historical) and 2025-2050 (scenarios)

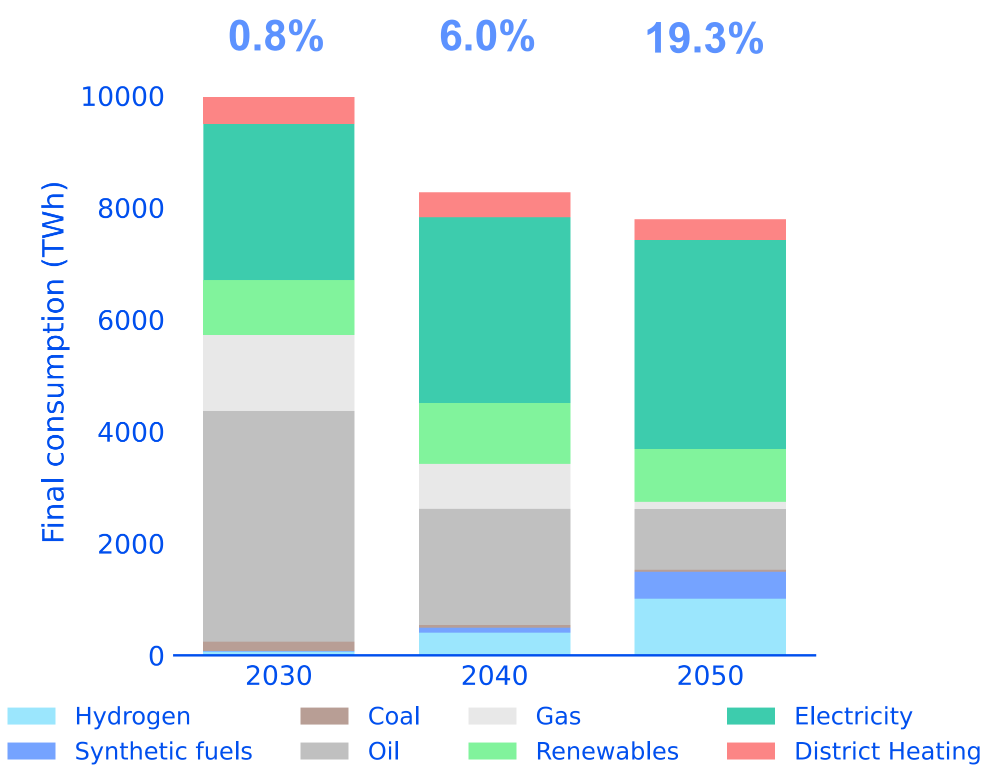


Source: ACER based on Eurostat and EC's 2040 impact assessment.
Note: The electrification rate is the share of electricity in final energy and non-energy consumption, and it measures the extent to which the energy sector relies on electricity rather than direct fossil fuel combustion. If linked to grid decarbonisation, electrification can deliver significant emissions reductions. Electrification will be further analysed in future ACER's reports.

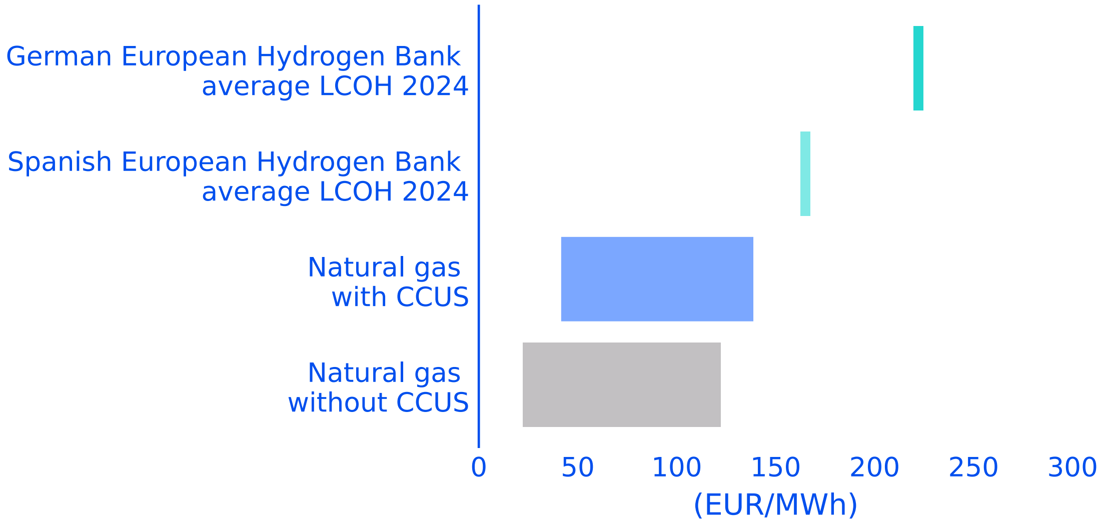
Hydrogen, an enabler of a decarbonised energy system …

… but it struggles with costs, competes with other technologies, and requires infrastructure for large-scale deployment

Final energy and non-energy consumption (TWh) and share of hydrogen and synthetic fuels (%), EU-27, 2030, 2040 and 2050



Comparison of cost estimates for hydrogen by technology, 2024 (EUR/MWh)



- According to Commission's impact assessment for the 2040 climate target, hydrogen and synthetic fuels are expected to play a targeted role in the European energy system, mainly in selected industrial applications, parts of transport, and other hard-to-abate sectors, rather than as a broad substitute for natural gas.*
- However, at an average German levelised cost of hydrogen of around 222 EUR/MWh, renewable hydrogen remains uncompetitive versus alternatives such as biomethane, with demand largely policy-driven. Its deployment is constrained by limited infrastructure, weak market formation and uncertain long-term demand due to industrial competitiveness pressures and potential technological substitution, including direct electrification.

Sources: EC's impact assessment for the 2040 climate target (Scenario S2), European hydrogen markets based on IEA, and second round of European Hydrogen Bank auctions.
* Hydrogen can also support the wider energy system. By linking electricity and gas systems, electrolysers can in the future help absorb low-carbon electricity, facilitate sector coupling, and support long duration energy storage. When produced domestically, electrolytic hydrogen can strengthen Europe's energy resilience.

Biomethane boosts decarbonisation and independence …

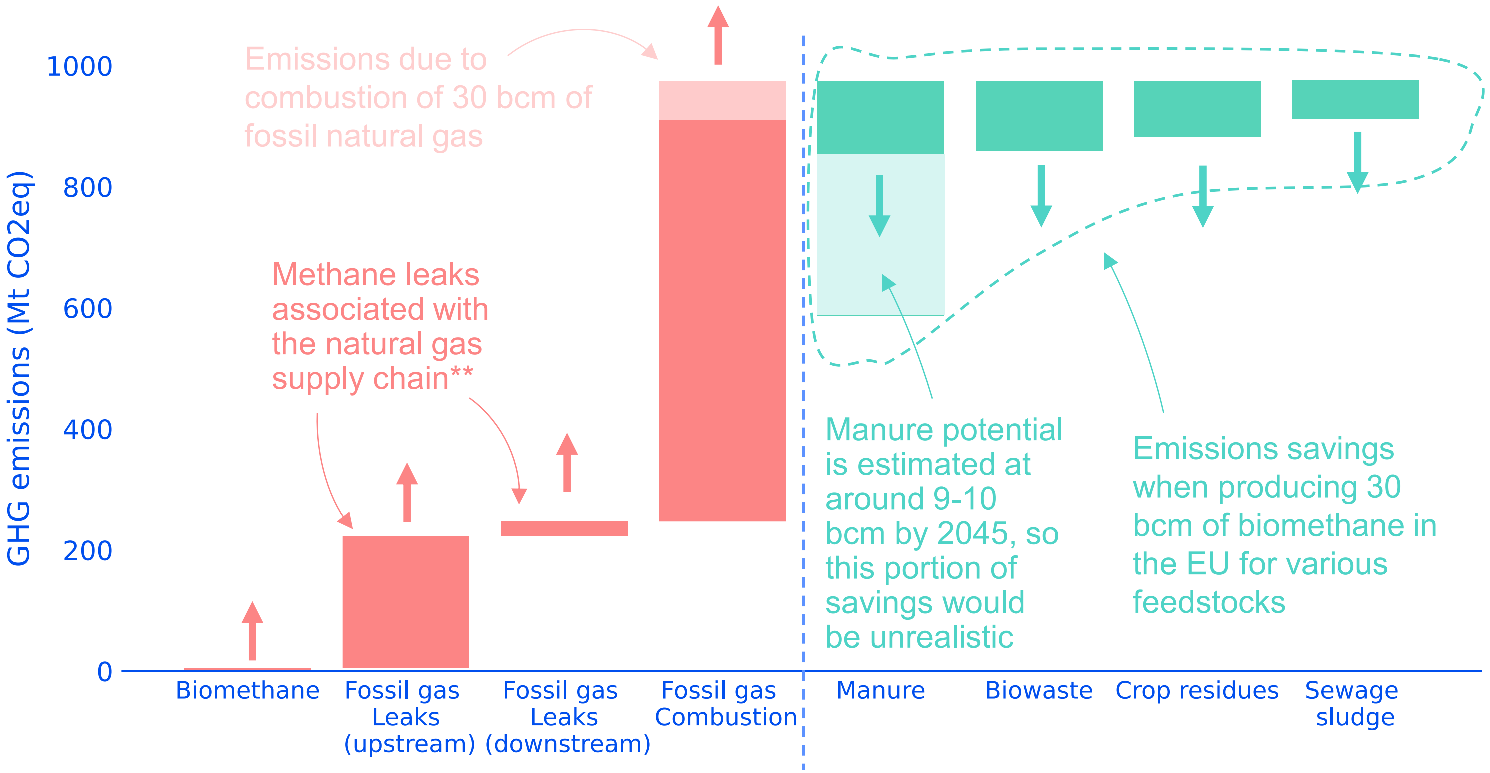
… but constrained supply potential and cost remain key barriers

Biomethane can replace conventional natural gas, while using existing infrastructure. Biomethane carbon footprint is significantly lower than that of conventional gas, and when produced from manure or waste, it can even deliver negative emissions*. Potential GHG emission reduction vary widely depending on feedstock, ranging from ~10% when using sewage sludge to ~40% with manure.

At the same time, biomethane can bolster energy security by reducing import dependency while supporting rural economies and promoting circularity.

However, the potential supply of biomethane in the EU is constrained by feedstock mobilisation and slow ramp-up. Production costs are currently higher than fossil gas and widespread deployment requires supportive policy frameworks, harmonised certification systems and investment in upgrading and grid injection infrastructure.

Greenhouse gas emissions related to the use of fossil and renewable natural gas in the EU, 2025 (Mt CO2eq)



Source: ACER based on 2006 IPCC Guidelines for National Greenhouse Gas Inventories, The International Council on Clean Transportation, Marconi and Rosa, 2023, Agora.
Note: The IPCC Default CO2 Emission Factor for Combustion for natural gas (56.1 kg CO_2/GJ) is used and perfect combustion has been assumed.
* Biogenic CO_2 emissions from the combustion of biomethane are generally considered carbon neutral and are not accounted for in the quantification of GHG emissions from a climate perspective.
** Natural gas leak rate from the fossil natural gas supply chain is assumed equal to 3.55%. It has been assumed a global warming potential 28 times greater than CO_2 over a 100-year timescale

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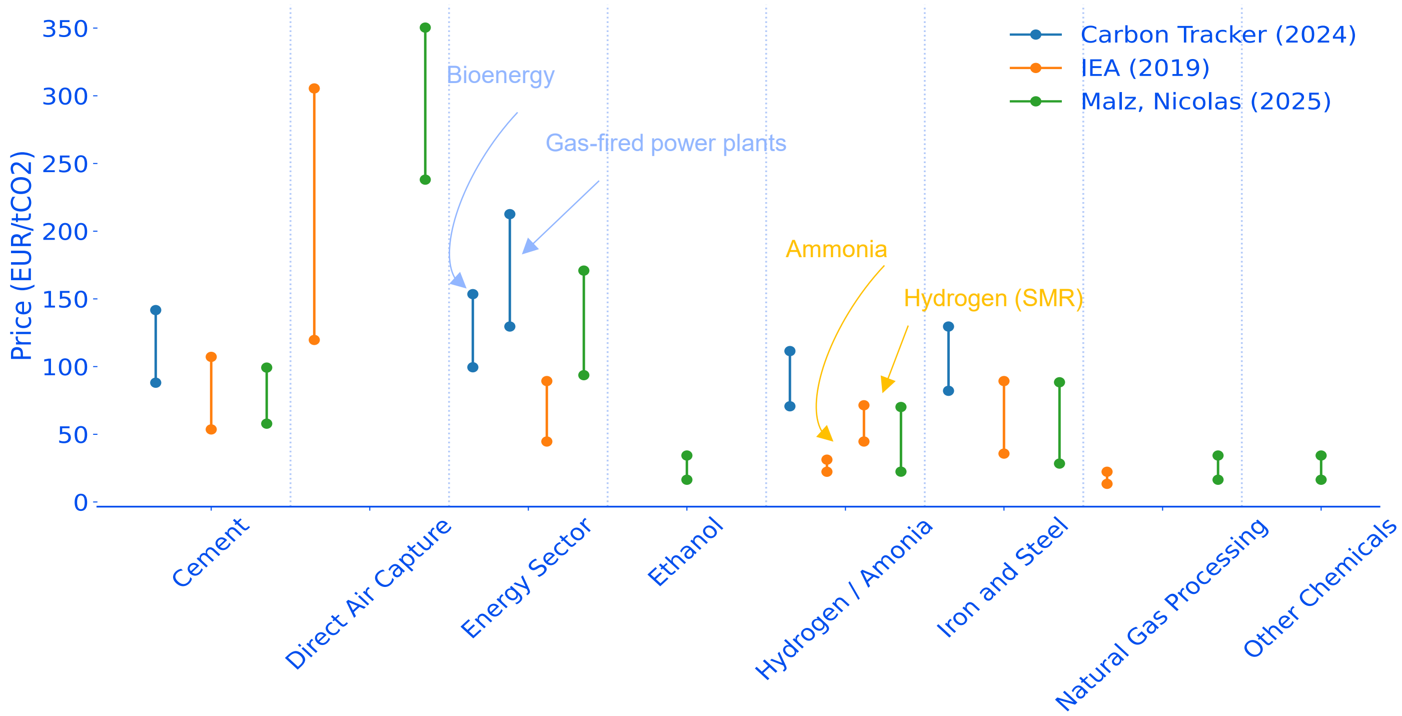
Carbon capture and storage reduces emissions …

… but high cost and infrastructure availability are challenges

Levelised cost of carbon capture for various subsectors across various sources (EUR/tCO_2)

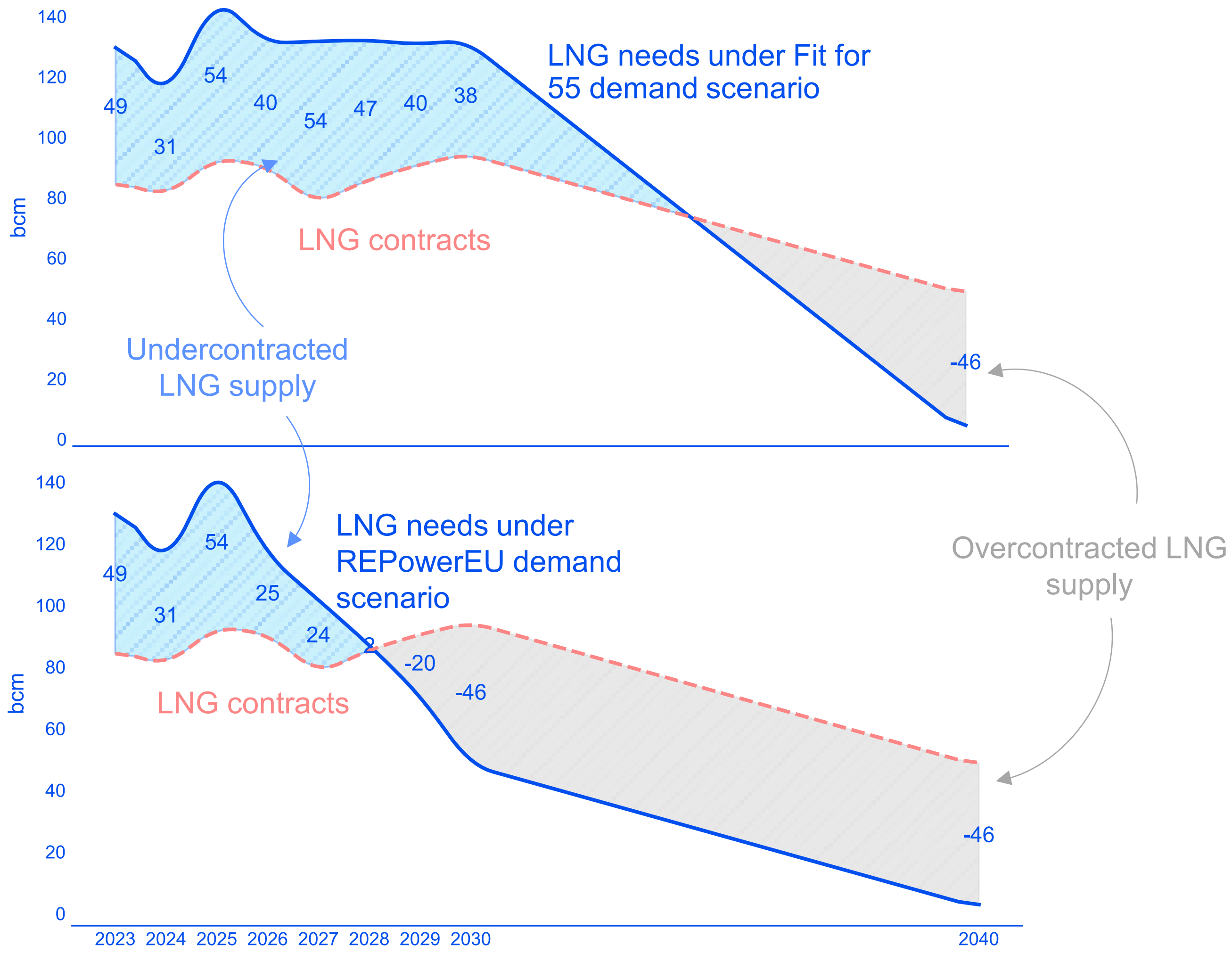


- Carbon capture and storage captures CO_2 from gas-fired power plants and industrial facilities for underground storage or reuse.
- This technology significantly reduces emissions from hard-to-electrify sectors (gas-fired power plants or high-temperature industrial heat). However, capture potential varies by industry: 90% for cement, 75% for chemicals, and 60% for metals.
- Despite its potential, it faces major barriers. Agora Industry estimates total costs—including capture, transport, and storage—at roughly 50–300 EUR/t CO_2. Beyond high capital and operational expenses, underdeveloped infrastructure, regulatory hurdles and public acceptance issues limit deployment.
- Its competitiveness depends heavily on carbon pricing or incentives that value avoided emissions.

Source: ACER based on Clean Air Task Force, Malz, Oei, and Herpich 2025, IEA, and Carbon Tracker Initiative.

Decarbonised gas scope and timing depend on contracts

EU LNG contractual position by 2030* and 2040** (bcm)



LNG can act as a flexible bridge fuel in the decarbonisation transition

- LNG is expected to serve as a flexible source during the energy transition, while pipeline imports and domestic production remain broadly stable.
- Uncontracted LNG volumes remain around one third of total EU LNG demand and peak in 2025, driven by the phase-out of Russian gas regulation.
- By 2030, new contracted volumes are insufficient to materially reduce exposure to the spot market. Closing the remaining gap will depend primarily on accelerated decarbonisation to lower gas demand and reduce import requirements.
- LNG contractual position will determine to some extent the timing and scope of the gas market decarbonisation.

Source: ACER based on data from REPowerEU, contracts data from ICIS LNG Edge and S&P Global, EC's impact assessment for the 2040 climate target, and Strategic Perspectives.
* LNG contractual assessment has been performed in 2026 ACER's monitoring report on LNG developments, and more information can be found in the report.
** 2040 gas consumption has been assumed as the average across the scenarios presented in the EC's impact assessment for the 2040 climate target.

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Qualitative assessment favouring decarbonisation tools

	Avoided emissions	System-wide costs as decarbonisation progresses	Energy independence
Green hydrogen	Green hydrogen significantly reduces emissions when produced from renewable electricity. Large-scale deployment depends on sufficient renewable generation and grid expansion.	Green hydrogen currently remains one of the costliest decarbonisation pathways, although costs may decline over time with technological learning and scale.	Green hydrogen reduces reliance on imported fossil fuels, but does not eliminate import dependence, as large-scale renewable hydrogen imports remain an integral part of EU energy policy under REPowerEU plan.
Biomethane	Biomethane contributes to emissions reductions, but its potential is limited and constrained by land-use considerations.	Biomethane will remain cost-competitive in a context of higher carbon prices without requiring additional infrastructure, although scalability remains uncertain.	Biomethane production reduces import dependence while making use of existing infrastructure and local agricultural or waste resources. But a residual unabated natural gas volume will remain, keeping external energy dependence.
Carbon capture, utilisation and storage	CCUS substantially reduces emissions from natural gas use, but overall performance depends on capture rates, methane leakage, and availability of transport and storage infrastructure.	CCUS may lower costs if carbon price is sufficiently large. But deployment requires significant infrastructure investments and long-term regulatory certainty.	CCUS pathways do not eliminate the EU's reliance on imported natural gas and therefore preserve a substantial degree of external energy dependence.
Unabated natural gas	Continued unabated natural gas use will result in the highest direct and methane-related emissions.	As climate policies tighten and carbon prices increase, continued reliance on unabated natural gas is likely to become increasingly costly.	Despite declining natural gas consumption, the EU will remain significantly dependent on external suppliers and vulnerable to geopolitical risks.

Favourable · Partly favourable · Neutral · Partly unfavourable · Unfavourable

Disclaimer 1: these considerations represent a certain temporal snapshot in the mid-term and are subject to changes in the future.
Disclaimer 2: electrification is assumed to be a baseline condition across all proposed pathways.

Note: this slide presents hypothetical pathways leaning towards certain decarbonisation instruments, namely green hydrogen, biomethane, or carbon capture, utilisation and storage. Unabated natural gas represents “inaction”, a baseline without any decarbonisation instrument. This analysis is qualitative in nature and reflects a specific mid-term temporal snapshot. The results are therefore indicative and subject to change under evolving conditions. The overarching policy objective remains the achievement of climate neutrality in the EU energy system by 2050.

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Concluding remarks

- The report examines a handful of **challenges for decarbonising the gas market** through a series of state-of-the-art dilemmas structured around three core pillars: sustainability, security of supply and competitiveness/affordability.
- It presents the “trilemma” problem by comparing the advantages and disadvantages of three hypothetical pathways leaning towards certain decarbonisation instruments against a baseline of doing nothing.
- The baseline (no decarbonisation instrument) serves as a **strong policy warning that the most expensive outcome is not necessarily associated with the deployment of new technologies, but rather with inaction**. Inaction also maintains significant energy dependence.
- No decarbonisation pathway significantly outperforms the other. This underlines the importance of approaching the energy transition through a diversified portfolio of solutions rather than relying on a single technology pathway.* However, the pathways vary in how quickly they can be scaled and in the timing of their emissions reduction impacts.
- At the same time, the energy transition calls for large-scale deployment of renewable energy technologies such as wind turbines, solar panels, and batteries.
- These technologies require critical raw materials, thus shifting Europe’s dependency from fossil fuel imports toward imports of critical raw materials and technologies, broadening the traditional concept of security of supply into one of secure and sustainable supply of critical raw materials.**
- The decarbonisation of the gas sector will largely depend on the evolution and implementation of several regulatory frameworks, including the revision of the EU ETS planned for mid 2026, the progressive implementation of the Carbon Border Adjustment Mechanism, and the further development of the Methane Emissions Regulation, which still requires the adoption of several implementing or delegated acts.***
- Finally, stronger coordination across sectors, energy carriers, and policy instruments is deemed necessary, with the strength of such coordination requiring closer assessment. Effective planning must reconcile the three core pillars of the energy trilemma (competitiveness, affordability, and sustainability) while ensuring that regulatory frameworks provide long-term certainty for investment and innovation.

* Biomethane, hydrogen, renewables, energy efficiency measures, and CCUS should be seen as complementary components of a broader energy transition strategy aimed at balancing the trilemma’s goals objectives. ** ECA report on Critical raw materials for the energy transition – Not a rock-solid policy. *** While CBAM aims to protect European industries from carbon leakage, concerns remain regarding the exclusion of indirect emissions and downstream sectors, as well as its potential inflationary effects and uncertain effectiveness in fully achieving its objectives. The EU ETS, despite being one of the most ambitious carbon pricing systems worldwide, may affect the global competitiveness of European industries if international carbon price disparities persist.

See ACER Monitoring reports

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Annex A - Robust policy framework for decarbonising the EU

- 5/2003: EU ETS Directive
- 4/2009: Renewable Energy Directive (RED)
- 5/2018: LULUCF Regulation
- 12/2019: European Green Deal
- 10/2020: Methane Strategy
- 7/2021: Fit-for-55 Package
- 6/2021: European Climate Law
- 5/2022: REPowerEU
- 5/2022: TEN-E Directive
- 4/2023: Effort Sharing Regulation
- 5/2023: CBAM Regulation
- 9/2023: Energy Efficiency Directive
- 9-10/2023: ReFuelEU Aviation + Maritime
- 10/2023: RED III
- 6/2024: Methane Regulation
- 4/2024: Energy Performance of Buildings Directive
- 6/2024: Hydrogen and Decarbonised Gas Package
- 2/2025: Clean Industrial Deal

EC's strategies (light blue: European Green Deal, Methane Strategy, Fit-for-55 Package, REPowerEU, Clean Industrial Deal) — **EC's regulations and directives** (darker blue: all other entries)

Note: This non-exhaustive list includes the legal and policy framework supporting the decarbonisation of the EU's energy system.

Annex B - Gas demand/biomethane projections

Two **decarbonisation scenarios** have been assumed, namely the European Commission's Fit For 55 (FF55) package and the ambitious REPowerEU plan to project the gas consumption by 2030.

The FF55 scenario projects a drop of 32% in natural gas consumption in 2030 relative to 2019 figures and the most ambitious REPowerEU target (without considering the gas savings related to renewable hydrogen targets), estimates gas demand 32% lower than the projected FF55 demand.

In 2040 and 2050, we assume the upper and lower estimates of the gas consumption of the decarbonisation scenarios considered in the impact assessment report to establish the 2040 climate target and eventually reach climate neutrality by 2050.

On the demand side, a linear decline is assumed to meet the demand targets in 2030.

On the supply side, domestic gas production is assumed to remain stable until 2027, when more liquefaction capacity comes online, after which a decreasing trend is projected until 2030. Then, fossil-based domestic production is assumed increasing until 2040 due to the rise in production in Romania, followed by a decreasing trend until 2050.

On biomethane production, two scenarios have been assumed:

- Supply potential scenario based on values from the European Biomethane Association, and
- Production estimated according to the National Energy and Climate Plans (NECPs) by 2030, which amounts to 14.5 bcm. A linear trend is then used to estimate the biomethane production in 2040 and 2050 based on NECPs.

Annex C - Analytical notes on biomethane competitiveness

(1) Biomethane production costs are provided in USD/GJ in the IEA report. To convert it to EUR/MWh, the European Central Bank's exchange rates are used for 2024 (1 USD equivalent to 0.9239 EUR on average).

(2) We assume that the buyer is an industry compliance with ETS with a carbon intensity of 421 kg CO_2eq/MWh and whose share of emissions associated with the use of natural gas is 75% [A] for the efficient installation. These values are (621, 75%), (421, 40%), (421, 90%) for the higher emitter installation, industry with low emission displacement, and industry with high emission displacement, in that order.

The cost of buying fossil-based natural gas for this industry is made up of two components: the commodity price and its carbon price. This can be written mathematically as:

$$c_{ng} = \lambda + p \cdot e_f$$

where λ is the commodity price, p is the carbon price in EUR/tCO_2eq, and e_f is the emission intensity factor in tCO_2eq/MWh.

The cost of buying biomethane for an industry fully reliant on the ETS is made up of three components: the commodity price, the guarantees of origin (including proof of sustainability) certificate price, and the carbon price for the remaining emissions. This can be represented as:

$$c_{bm} = \lambda + g + p \cdot (1 - m) \cdot e_f$$

where g is the guarantees of origin price, and m is the share of emissions associated with the use of natural gas.

Therefore, the cost savings of using biomethane Δ can be computed as the difference between c_{ng} and c_{bm}.

The guarantees of origin prices for manure- and unsubsidised-waste-derived biomethane are averaged across the Danish and Dutch markets in 2023-2025, while waste-derived biomethane guarantees of origin prices are taken from markets in Denmark, the Netherlands, and Germany in the same period 2023-2025.

[A] Flat glass in climate-neutral Europe 2050: Triggering a virtuous cycle of decarbonisation

Annex D - Considerations on dilemma 2

(1) Quantifying start-ups of gas-fired generating units

Data quality aspects

The analysis uses hourly ENTSO-E generation-unit-level data to assess the start-up behaviour of gas-fired power plants. The dataset presents several limitations:

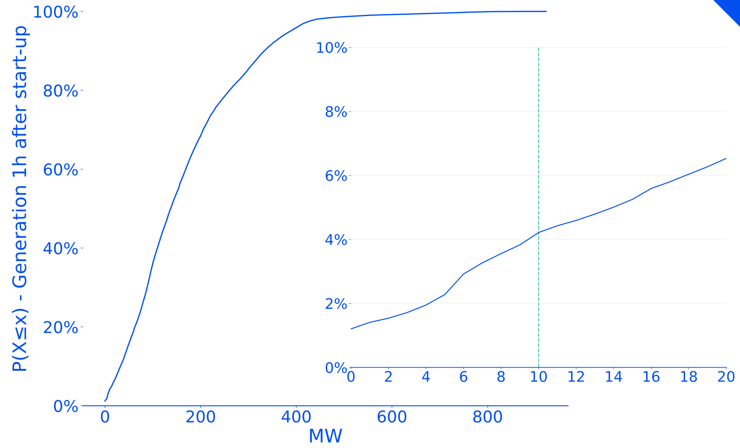
- It does not distinguish between different technologies, such as open-cycle gas turbines and combined-cycle gas turbines, although units below 50 MW are already excluded.
- Some data quality issues were identified. In certain cases, generation never falls fully to zero, remaining close to zero for extended periods and potentially reflecting idling behaviour. In others, generation fluctuates erratically at very low output levels (e.g. between 0–4 MW across consecutive hours), which may reflect misfires or measurement inconsistencies.

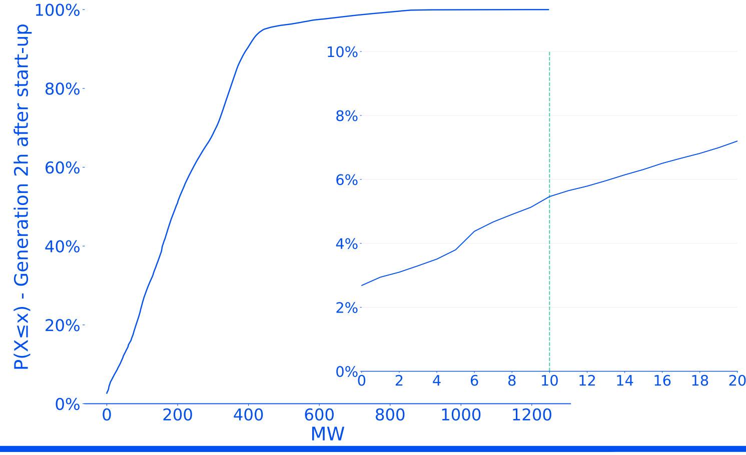
Start-up counting methodology

To address these limitations, a simplified methodology was developed. A start-up is identified when a unit's generation rises above a 5 MW threshold after being below 5 MW in the previous hour. This threshold helps filter out erratic low-output behaviour while still capturing gradual ramp-ups.

Some uncertainty nevertheless remains due to potential idling behaviour, misfires, and other data quality issues. To assess the robustness of the threshold, cumulative distribution functions of generation one and two hours after start-up were analysed (see figures). In 95% of cases, generation exceeded 10 MW within one to two hours after the start-up event, suggesting that the 5 MW threshold is reasonably well calibrated.

Cumulative distribution functions of generation one (top) and two (bottom) hours after start-up





Source: ACER based on ENTSO-E.

Annex D - Considerations on dilemma 2

(2) The calculation of the **gas in-the-money** considers whether at least one bidding zone recorded a day-ahead price equal to or above the gas-based generation cost. Note also that gas prices were taken from the most liquid national markets (AT, BE, CZ, DE, ES, FR, HU, IT, NL, PL) where available. For other EU Member States without sufficiently liquid gas hubs, the TTF price was used as a reference benchmark.

(3) The main **storyline behind S&P Global base energy scenario** is the following:

By 2060, the world has made significant albeit incomplete progress in shifting from fossil fuels while balancing global energy needs. Despite the instability of the 2020s, sustained efforts have cut greenhouse gas emissions and reduced fossil fuel dependence, though the transition remains a work in progress.

The key aspects of global gas demand to understand the scenario for the interested reader are:

- In the short to medium term (2020s–early 2030s), gas dominates over coal, driven by rising power demand (electrification, artificial intelligence/data centres) and LNG supply surges, keeping prices competitive. Developed markets (except Europe) rely on gas for baseload power; while Europe cuts demand due to energy security policies. EMDEs (Emerging Markets & Developing Economies) adopt gas to build power infrastructure, aided by ample LNG supply.

- From 2030s onward, there is a slowing growth as OECD nations and China shifts to renewables and storage, reducing gas in power and end-use sectors. US gas demand peaks in 2030 and then declines; while European gas use falls by more than 25% over 2030–40. China’s demand growth slows (transport demand falls; power sector peaks in 2037). Gas demand in EMDEs continues to grow strongly. Global gas consumption peaks at 5.8 trillion cubic feet by 2040 (4% rise from 2030), offsetting OECD declines.