S&P Global
Commodity Insights

European Gas Long-Term Forecast Quarterly Update

December, 2025

European gas: Exploring the risks

Short-term: downside price drivers strengthening

- Demand up an estimated 0.6% year-on-year in 2025, with a reversal of a multi-year decline in power sector gas consumption driving the small increase. Structural growth prospects outside in the near term are limited.
- Total gas supplies to the EU27 plus UK averaged 1010 MMcm/d during the second half of 2025, up 5.7% year on year. LNG sendout rose 93 MMcm/d (32%) year on year, offset by lower Russian supply (down 37 MMcm/d) and other pipeline supply decreasing by a net 2 MMcm/d.
- Storage expected to reach 35.7% by Mar. 31, 2026. Continuing growth in LNG supply will improve storage fill by the same time in 2027, which we expect to be 47.7%.
- Strong global liquefaction utilization rates and weak demand outside of Europe remain the key downside risk drivers for European prices, and are outweighing the bullish risk stemming from current low stock fill levels relative to the five year average.
- We expect winter 2025/26 outturn prices to average €30.19/MW. The average summer 2026 price at TTF in our current forecast is €23.3/MWh

Long-term: Optimising gas use in the energy transition

- Gas demand in the modelled European region is projected to decline to 348 Bcm by 2035, 2.6% below 2025 levels, with minor potential upside from low gas prices.
- The shift of focus in European energy policy towards affordability and security considerations has strengthened through 2025. Challenges in electrifying heat in multiple sectors, and in sustaining sufficient renewable electricity generation capacity build to displace both coal and gas in the next decade are supportive of a 'higher for longer' gas demand outlook.
- A liquefaction capacity FID boom in 2025 has significantly increased the project pipeline and the likelihood of an extended period of LNG overcapacity into the 2030s.
- European prices are expected to be pushed down by strong growth in LNG supply in this period. Global prices will be set by the balance between demand response outside Europe and supply-side response from the global LNG fleet. This balance is unlikely to be reached smoothly, implying significant price volatility in the process.
- TTF prices are expected to average €11.37/MWh ($3.9/MMBtu) in 2030 (in real 2024 terms), when the premium over Henry Hub in summer declines to $1.0/MMBtu. Prices average €26.8/MWh ($9.2/MMBtu) in 2035 rising to €33.9/MWh ($11.3/MMBtu) by 2050.

The state of the market

	NBP		TTF		HH	CIF ARA coal	EU carbon	Brent oil
Real 2024	**ppth**	**$/MMBtu**	**€/MWh**	**$/MMBtu**	**$/MMBtu**	**$/mt**	**€/tCO2e**	**$/bbl**
2020	29.0	3.8	10.9	3.7	2.4	59.6	29.3	49.4
2021-25	125.3	15.7	59.2	18.6	3.9	157.3	74.7	84.3
2026-30	45.4	6.3	18.3	6.3	3.8	98.3	90.2	60.5
2031-35	48.6	7.4	21.5	7.4	4.3	100.5	122.3	71.5
2036-40	65.4	9.5	28.0	9.6	4.7	99.6	162.9	72.4
2041-45	70.1	10.3	30.4	10.3	5.3	96.7	197.2	70.1
2046-50	74.8	11.0	32.9	11.0	6.0	92.8	205.1	67.9

Updated: December 31, 2025

European day-ahead gas prices have declined 24% since the mid-year high point in June, falling from an average of €36.3/MWh that month to €27.7/MWh so far in December amid growing LNG availability, weak demand in Europe and more flexible EU storage targets reducing the demand related to storage injections. There was little to no impact on prices coming from what would in other circumstances have been bullish geopolitical developments.

For instance, in late October, Presidents Donald Trump and Xi Jinping agreed to lift several tariffs on imports between their countries, signaling improving trade activity. This did nothing to prevent TTF prices from falling as weak demand and rising LNG imports continued to dominate price formation. Similarly, in October, Russian attacks on Ukrainian gas production infrastructure have increased Ukraine's import needs for this winter but while tightening CEE markets, have not prevented the LNG-exposed TTF month-ahead prices falling from an average of €31.88/MWh in October to €30.69/MWh in November. Weak demand for the time of year in December maintained the bearish momentum this month, with TTF month-ahead prices averaging €27.53/MWh to date.

The TTF DA-MA spread averaged narrowed throughout the third quarter from -€0.5 to -€0.3/MWh before flipping to a €0.11/MWh premium in October driven by early cold spells that effectively curtailed the storage fill season—very different to October 2024 which averaged -€0.4/MWh.

During November, amid a very mild start to the month, TTF DA-MA switched to -€0.38/MWh discount, but since late November the spread has averaged a low positive value—partly reflecting a need to withdraw storage to balance the market, but also partly reflecting weak month-ahead pricing as the risk premium has been eroded out of the peak winter months of this winter.

About 24.1 Bcm was injected into storage in our modelled European region in the third quarter, 5.8 Bcm more than for the same quarter last year. However, this failed to close the year-on-year gap in stock levels. EU stocks only grew from 59% to 82% fill throughout the quarter, compared to a rise from 78% to 94% fill last year. Given the early stalling of injections in October, by Nov. 18 EU stocks were still stuck at about 82% full versus 90% the year before. The TTF price weakness prevalent through winter so far has come despite European fill levels peaking about 12 Bcm below last year's level. Based on our December short-term forecast, we expect European storage fill to drop to 35.7% at the end of this winter and 47.7% at the end of next winter, compared to a five-year end of winter average of 43% for the period W20 through W24.

Global liquefaction utilization rates hit peak winter levels at the end of October and through November, two months earlier than the same peak achieved in winter 2024, though these have eased slightly in December to return to the five-year average utilization in the final week of the year. This has come amid relative weakness in demand across global markets, further reinforcing the state of comfort in the market. The global gas balance has remained relatively loose, with the JKM-DES NWE premium shrinking from $1/MMBtu in July to $0.6/MMBtu (€2.0/MWh) in October, which was the lowest level since the peak European demand months in the previous winter. After a brief surge to over $1.50/MMBtu in late November and early December, driven by European prices falling more rapidly than JKM, the JKM-DES NWE premium has settled back to about $1.0/MMBtu amid a trend of increasing cargoes heading to Asian markets while European demand through December has been reduced by warmer than average weather conditions.

In Italy, the Italian Council of ministers was set to discuss a proposed decree by end October aiming to equalise the spread between the PSV and TTF hubs to lower energy bills for Italian consumers and enhance the competitiveness of Italian industry. We would expect any direct removal of the Italian hub price premium over northwest Europe to significantly impact the regional balance, weakening the incentive for Italian imports, notwithstanding any bureaucratic impact on entities seeking to trade gas in Italy. Given that Germany trades as a persistent premium to TTF, and delivers marginal gas flows into Italy via Switzerland, and that CEE is generally a similar or greater premium to PSV, such an intervention could have profound effects on gas flows and price dynamics across the central and eastern European regions.

The most significant recent development in the long-running Russia-Ukraine conflict has been continued large-scale attacks on Ukrainian production infrastructure since October. After the initial largest attack, Naftogaz indicated that 30% higher imports from the EU than previously expected this winter are likely. Using this figure as a benchmark, we increased our forecast for Ukrainian imports from the EU in W-25 to 2.95 Bcm. Some later reports from Naftogaz, however, suggested a requirement of up to 4.4 Bcm during this winter (1.5 Bcm higher than our current assumption).

The major risk here is that if Russian attacks were to continue and successfully damage more production infrastructure, the higher 4.4 Bcm import need becomes a more likely outcome. For the 4.4 Bcm requirement to materialize, an attack on Ukrainian infrastructure comparable to the one seen in October would need to occur. If this scenario materializes, CEE premiums are expected to rise to pull more volumes from the west. Bottlenecks around the Germany-Czechia route due to limited commercial capacity would likely result in even higher CEE premiums over Germany, potentially resulting in greater imports from Italy. The increased demand will likely be balanced through higher storage withdrawals out of both eastern and western European regions, potentially eroding the current W26-S26 premium.

A Ukraine-Russia ceasefire this year has proven unworkable, with any immediate change in the situation in early 2026 unlikely. As such, the EU has proceeded with plans to phase out Russian gas by approving two pieces of legislation in October. First, the 19th sanctions package against Russia banning Russian LNG short-term contracts from the end of April 2026 and long-term contracts from the start of 2027. Second, EU energy ministers agreed to ban all RU gas supplies by the end of 2027 as part of the

RePowerEU package, this ban is expected to become law by the end of this year. It remains uncertain whether the main holders of long-term Russian LNG contracts, France's TotalEnergies and Spain's Naturgy, will be able to declare force majeure or divert the cargoes. They may be able to divert them, possibly to Turkey as TotalEnergies has recently signed a deal with Botas.

European gas demand struggling to recover

Gas demand in Europe weakened slightly in the second half of 2025, with total demand in the seven largest western European gas markets (BE, FR, DE, IT, NL, ES, UK) for July through December 25 down 0.7% year on year. This partially offset the slight year-on-year increase in the first half of the year, although it looks likely that 2025 as a whole will record a 0.6% year on year increase in demand, with cold weather spells in February and October key contributors to that.

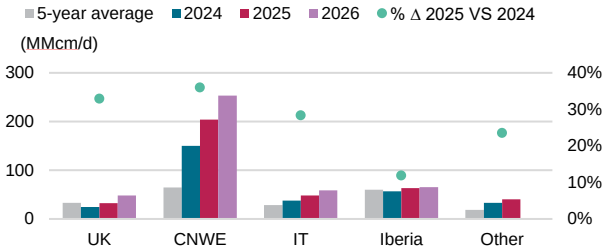
LDC demand in NWE in the third quarter was roughly in line with the previous year before rising 6% year on year in October, which was one of the coldest Octobers in the past decade. However, mostly mild conditions since late November have kept demand on a downward trajectory year-on-year. LDC demand in the top seven markets was down 4.0% year-on-year in the second half of 2025. We forecast LDC demand in NWE to drop 0.6% year on year in 2025, before rising 2% year on year in 2026 and dropping 1% in 2027.

Industrial demand in the top seven markets fell an estimated 4.8% year on year in the second half of 2025 amid continued poor economic activity. At the end of this year, we expect to see incentive for ammonia producers to consume more gas and produce ammonia domestically rather than importing it due to high prices for imported ammonia and outages in Trinidad and Tobago.

The continued weak industrial demand through 2025 led us to revise down our forecast for industrial demand in NWE to drop nearly 4% year on year in 2025. We expect it to rise 5.5% year on year in 2026 and 4.7% in 2027 but to stay 11-15% below the 2017-21 average.

Gas demand in the power sector was up 7.3% year-on-year in the second half of 2025 in the top seven markets, with a major contribution to the rise coming from the cold, low hydro October period which resulted in a 25% year-on-year boost in demand in that month alone. Gas prices falling coupled with rising EU ETS prices and stable coal prices have improved the competitiveness of gas plant vs coal plant through the second half of 2025, which means that gas burn has also gained at the expense of some coal and lignite generation. The power sector reversed a declining trend that had been in place since 2022, recording an estimated 12.5% increase year-on-year for the full year to date.

Average annual LNG sendout by region



Other includes Lithuania, Croatia, Poland, and Greece.
Data compiled: Nov. 5, 2025.
Source: S&P Global Energy.

LNG supply more than offsets pipeline decline

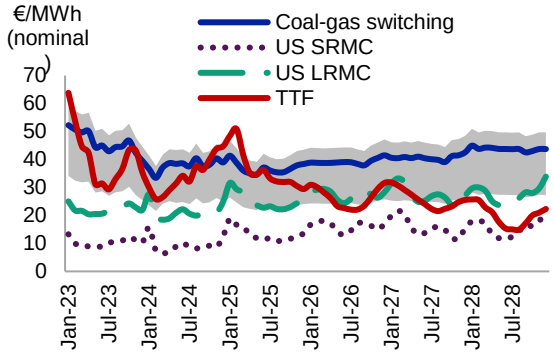
Combined supplies to Europe averaged 1010 MMcm/d in the second half of 2025, up 5.7% year on year. Within this figure is a 43% (37 MMcm/d) drop in Russian pipeline imports and a 7% (6 MMcm/d) drop in Algerian pipeline imports year-on-year, offset partially by a very minor 0.6% (2 MMcm/d) increase from Norway and 1.1% (2 MMcm/d) increase in domestic production.

The increase was only possible because of a surge in LNG sendout, which increases 32% (93 MMcm/d) year-on-year, driven by muted demand in Asia, growing global LNG capacity and significantly higher than normal liquefaction utilization rates.

LNG sendout in Europe rose above the 400 MMcm/d mark during September, and in November recorded a new monthly high for the year of 448 MMcm/d (and second only to the 468 MMcm/d recorded in April 2023). Among European LNG importers, CNWE stands out as this region and Germany in particular has an additional demand to meet in the form of stronger imports from CEE countries to replace lost Ukrainian transit flows of Russian gas and Ukraine's growing import needs.

We expect higher LNG supply to Europe to drive a 7% year-on-year rise in 2026 in our short-term modelled region of Europe, followed by a 2.4% year-on-year drop in 2027.

European gas prices and anchors



Data compiled December 31, 2025.
Source: S&P Global Energy
LRMC = long-rung marginal costs; SRMC = short-run marginal costs

We expect the first quarter 2026 TTF price to average €29.5/MWh, down €9.5/MWh since the September outlook. The decrease is largely due to increases in our supply side assumptions for LNG, which improved end-of-

winter stock level expectations. However, prices have fallen despite weakening stock levels, so our November and December editions also too into account a price model recalibration. The price response to stock build was adjusted to align with the persistent bearishness in the TTF as prices continued to soften despite European storage levels remaining below both our initial expectations and year-on-year levels.

A loosening global LNG balance is expected to accelerate European storage fill through 2026, and push **summer 2026 TTF prices down to an average of €23.3/MWh, below the coal-gas switching range**.

The long-term gas demand outlook

The full annual update to the European Planning Case energy balance has now been completed and a summary of the regional gas demand and supply figures are presented in this report. The key high-level data sets and narrative for this update can be referenced in the recently published *European Long-Term Energy Demand Balance — Planning Case, December 2025*.

The premise underpinning the update was described in the previous quarterly update. An industrial base weakened by persistently high energy costs and a subdued global economy is also facing competition from global trade partners that are increasingly reliant on protectionist measures to support their own industries.

Election results in European states in 2025 have shown voters prioritizing economic concerns such as growth, job and the cost of living. Successful candidates have generally been centre-right or further-right populist candidates, or coalitions with a strong representation from the economic right.

As a result, the cost of the energy transition in Europe has become a central political issue. Public willingness to bear the full extent of these costs, and the constrained capacity of governments to subsidize more comprehensive transition investments are reflected in this outlook. The key implications for the European gas market outlook are as follows:

- **There has been a paradigm shift in European energy policy.** The era of unified European energy consensus has ended, with energy affordability and industrial competitiveness now taking priority over climate objectives. Member states are asserting greater control over energy decisions, leading to amendments in existing legislation and mounting pressure on the ambitious 2040 greenhouse gas reduction targets.

- **European gas demand will not fall as fast as flexibility.** European gas demand is projected to decline relatively gradually, falling 33% by 2050 as political realities reshape consumption patterns. With limited growth potential from pipeline sources and reduced price-sensitive flexibility in both demand and supply, European markets will increasingly be subject to global price benchmarks and volatility dynamics.

Final gas consumption sectors—industry and buildings primarily—are largely unchanged from the September update. The assumptions and full energy balance changes are detailed in the report *European Long-Term Energy Demand Balance — Planning Case, December 2025*.

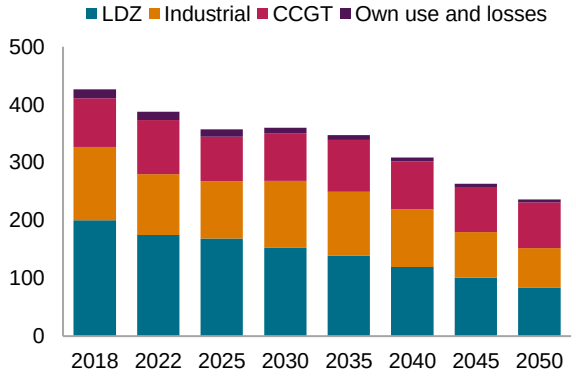
In buildings, lower traction for boiler ban policies, a revised ambition for the ETS 2 and simple economics result in more existing buildings to continue their reliance on gas-based heating. If low wholesale gas prices in the next decade can translate into materially lower retail gas prices—not expected in our base case but there is potential if other costs on gas bills are paid via other means—there is scope for the behavioral change that has manifested in Europe since the price shock of 2022 to run boilers more carefully to be partially reversed.

We expect that LDC demand in the modelled region[1] falls from an estimated 169 Bcm in 2025 to 153 Bcm in 2030, and 84 Bcm by 2050.

In the industrial sector, total energy consumption is reduced as industrial output continues to struggle. Less electrification—proportion of energy consumption electrified is down 3% in 2050 vs the December 2024 Planning Case energy balance—and lower demand for low carbon hydrogen uptake support natural gas demand.

We expect that industrial gas demand in the modelled region falls from an estimated 99 in 2025 to 115 Bcm in 2030, and 68 Bcm by 2050.

Total gas demand in Europe by sectors, Bcm/y



Data compiled December 31, 2025.
Source: S&P Global Energy

The key change that has taken place since the September 2025 report is in the outlook for the power sector, which has undergone its regular full annual update

[1] Modelled region here comprises UK, France, Belgium, Netherlands, Germany, Denmark, Sweden, Luxembourg, Switzerland, Poland, Czech Republic, Slovakia, Hungary, Austria, Portugal, Spain

taking into account full European energy balances on the demand side and updated supply-side considerations.

Various factors have been adjusted, which have a mix of positive and negative outcomes for gas demand in the power sector. A reduction in the rate of power demand growth has been modelled—power demand rises on average by 2.4% a year to 2050 in our new Planning Case resulting in a final power demand in 2050 that is 16% lower than in our previous Planning Case. While a slower rate of increase, 2.4% per year growth still represents a significant change compared with growth in the past decade—since reaching a peak in 2008, European power demand has declined by 0.5% per year.

Renewable additions have also been slowed in the short-term owing to rising cost concerns and underwhelming power demand in the here and now. The lower gas prices for longer we expect effectively increase the cost of new renewables relative to gas-fired capacity—particularly existing gas plant but also makes new gas-fired capacity investments less risky. We expect the renewables share in generation rises from 52% to 77% by 2050.

Supportive long-term policy signals have emerged this year around nuclear. We have increased our nuclear capacity outlook, notably revising down expected nuclear retirements as many operators increasingly simultaneously push for both lifetime extension of existing units and newbuild nuclear.

We continue to foresee a need for newbuild gas capacity in order to offset politically or economically motivated coal retirements and to provide peaking capacity to offset variable renewable output. The average rate of gas newbuild over 2029[2]-50 is 3.3 GW per year, comparable to the rate in the last decade. This results in installed fossil fuel generation capacity stopping its declining trend since 2010, plateauing between 2030 and 2050.

However, while CCGTs might be considered to be the least cost-disadvantaged generation type in a low gas price environment, it should be noted that the investment costs of new CCGT capacity has doubled since 2020. As a result, capacity and/or flexibility renumeration schemes will remain critical for existing and new gas plant to offset wholesale prices that fail to meet their costs.

Gas newbuild will also face increasing competition from batteries to provide peaking capacity, with low-carbon gas options likely to be much higher cost. We have downgraded our view for gas with CCS and hydrogen-fuelled generation units as a result. Cost is not the only aspect—once zero-emissions generation reaches 90% of the generation mix, incentives to further decarbonise the remaining 10% are low.

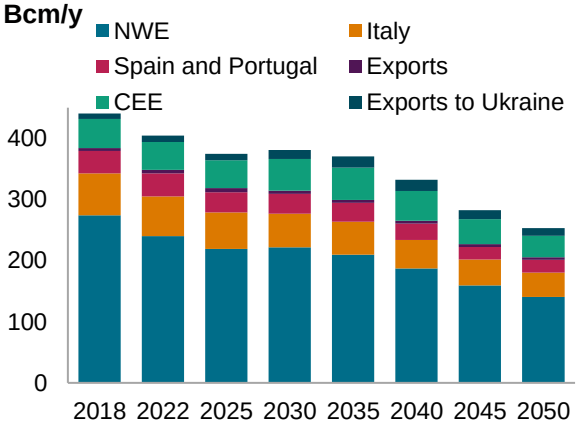
We have upgraded our expectations of battery growth in the long-term, given the significant newbuild across many business model cases being observed, as well as the domination of batteries in several recent long-term capacity auctions. Battery storage grows very strongly to 2050, driven by need for peaking capacity (competing with gas), rising renewable-driven price volatility, and increasing need for new grid equipment to help integrate renewables. It is likely that continued success for batteries will depend on the capacity derating factor ascribed to battery systems in future capacity auctions. Battery systems are expected to increase in both large-scale and smaller distribution scale situations.

The net effect of this changed power system is one where natural gas-fired generation increases from 2025 until the late 2030s as total non-renewable thermal generation plateaus and coal capacity is retired, while power demand rebounds and wind and solar additions slow-down. Gas generation then declines in the long-term as the rate of clean technology additions increases again, only dipping below the 2014 recent low point in the mid-2040s.

The challenge of trying to maintain decarbonization momentum in Europe while addressing more immediate pressures of energy costs, energy security, national security and voter requirements is being solved in favour of the latter concerns, for the immediate future at least.

Along with an expected next decade of low global gas prices, annual gas demand in Europe staying relatively stable for the next decade is now looking much more likely. We expect gas demand in the EU27 plus United Kingdom to decline by around 17 Bcm by 2035, a CAGR of just -0.4%. This compares with a CAGR of -1.5% in the last decade and -2.7% in the period 2035-2045.

Total gas demand in Europe by regions, Bcm/y



Data compiled December 31, 2025.

Notes: NWE = UK, France, Belgium, Netherlands, Germany, Denmark, Sweden, Luxembourg and Switzerland
CEE = Poland, Czech Republic, Slovakia, Hungary, Austria; Exports to other European countries including Ireland, Portugal, Croatia, Lithuania
Source: S&P Global Energy

With political activity in the last quarter focussed more on sanctions packages and trade law (see the State of the Market section of this report), progress on agreeing a binding 2040 climate target slowed, with concerns that a 90% ambition might be watered down. As recently as September it was still not clear that a target would be agreed on in 2025. However, a legally binding target of 90%

[2] 2029 corresponds to the earliest data for a new asset to come online

net greenhouse gas emission by 2040 (compared to 1990 levels) was finally provisionally agreed by both the European Parliament and European Council in December.

It should be noted that while the 90% headline figure remains, several flexibilities have also been introduced.

This includes the introduction of a review mechanism, a delay to the EU ETS2, increased flexibility regarding domestic carbon sinks and an increase in the cap for international carbon credits.

The revision mechanism would allow for regular assessment of progress and enable adjustments to policy based on the latest scientific evidence, technological advancements, and concerns regarding the EU's competitiveness. The potential for enabling countries to relax the targets for 2035 and 2040 is clear.

The agreement includes the postponing of the EU ETS2 by one year, from 2027 to 2028. This is in response to concerns that the new price on emissions from heating and transport fuels, previously scheduled to take effect in 2027, may lead to higher fuel bills. The European Commission has also proposed measures to mitigate price volatility, including a market reserve and temporary price ceiling. The delay to the start of the scheme buys more time for other amendments to be discussed and implemented.

Finally, the agreement allows the share of carbon credits from outside Europe that can be utilized to help achieve the 2040 climate goals to be up to 5% of 1990 EU net emissions from 2036, with a potential pilot phase for 2031-35 to support the development of a 'high integrity international credit market'. The EU has indicated that it would establish criteria to verify the origin, timing and quality of these credits.

Because of these flexibilities, the agreement of the 90% target does not invalidate the premise underpinning the Planning Case as presented here. The economic and political challenges facing energy transition in Europe remain significant, and the flexibility options inherent in the 2040 target leave plenty of room for manoeuvre for future policy makers.

There also remains a divergence of opinion amongst EU Member States. Full support for a 90% emissions reduction target by 2040 had been limited to the Nordics, Austria, the Netherlands, Iberia, Ireland and Balkan EU states. Another group comprising central and eastern European states, Romania and Bulgaria were opposed to such a target on financial grounds, while the remaining countries in the EU, including some of the bloc's biggest economies were also seeking wriggle room in how to reach this target—we would consider it likely that at least some Member States take advantage of the flexibilities available to them in the future.

The long-term supply outlook

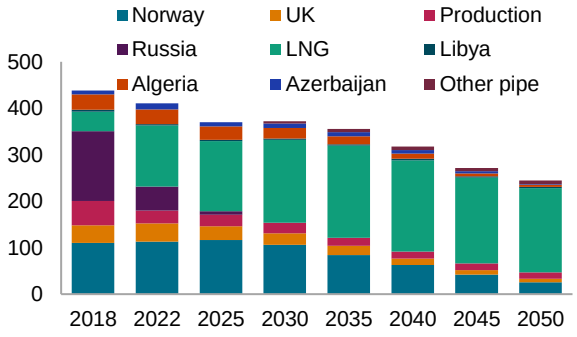
While European policy makers are keen to espouse their commitment to security and diversification of gas supply, the stark fundamentals are that the EU27 plus UK region only produces about 18% of its gas now, compared to 30% a decade ago. Furthermore, since the collapse in Russian pipeline supplies since 2021, just over half of these imports are from directly connected pipeline sources, compared to 85% in 2015. Given the likelihood that indigenous production will continue to decline faster than gas demand, the reliance on globally traded LNG to make up the difference is likely to increase—we expect LNG to form about 80% of imports to EU27 plus UK by 2050.

Indigenous production in the EU27 is expected to increase by 9.5 Bcm (28%) by 2030 compared to 2024 levels, driven by Romanian production ramping up (7.7 Bcm contribution) and Cypriot production starting (7.8 Bcm), offset by 5.9 Bcm of decline in other EU markets. Outside the EU, UK and Norwegian production decline by 8.4 Bcm and 10.5 Bcm respectively over the same period, offset by an expected 9.2 Bcm gain in Turkish offshore production.

We continue to assume the Neptun Deep offshore project in Romania will ramp up in 2027, which has a new significance given the impending intended phaseout of Russian pipeline gas supply into central Europe by 2028. Hungary in particular will be short pipeline gas, and neighbouring Romania will be a critical source of competitively priced gas in the region when it comes onstream. The first Deep Dive article in this report discusses the options and implications for Hungary and Slovakia.

We have increased our outlook for biomethane production slightly to reach 9.9 Bcm by 2030 and 20.8 Bcm by 2050 in the EU27 plus UK region—an increase of 1.6 Bcm and 3.0 Bcm respectively compared to the previous outlook. The second Deep Dive in this report discusses this in more detail.

Total gas supply in NWE, CEE, Italy, Spain, Portugal by sources, Bcm/y



Data compiled December 31, 2025.

Notes: NWE = UK, France, Belgium, Netherlands, Germany, Denmark, Sweden, Luxembourg and Switzerland
CEE = Poland, Czech Republic, Slovakia, Hungary, Austria
Biomethane is part of the total gas supply
Source: S&P Global Energy.

The Norwegian export outlook has not changed materially, showing only minor revisions in the very near term in line with our prevailing short-term outlook. Despite continual investment in new technology and easy-to-connect fields, the outlook is for a plateau in production for a few years before an accelerating decline from the mid-2030s. We expect Norwegian pipeline gas exports to

Europe to drop from 113 Bcm in 2024 to 106 Bcm by 2030 and 26 Bcm by 2050.

We have adjusted our outlook for Algerian pipeline exports to take into account an outlook for higher domestic consumption of gas in the Algerian power sector in the long term. As a result, Algerian pipeline exports were revised down in the 2030s by an average of 2.6 Bcm per year, impacting primarily the Italian gas market.

One risk that has come to light very recently is around Azerbaijan, with the Energy Minister downgrading expected gas production in the period to 2029 compared to last year's projection. Details on the reasons for the downgrade are scarce but supposedly include a later development of Absheron phase two (fully planned for exports) as well as delays in ACG deep gas developments led by BP, but we have revised our Azerbaijan gas balance accordingly. The result is reduced pipeline exports of gas to Turkey and the EU.

This decrease more than offsets the increase that was implemented in our June 2025 update, which had been driven by investments in boosting output from the Azeri-Chirag-Gunashli (ACG) deep gas project and later in the outlook a second development phase at Absheron.

LNG supply surge limits appetite for large-scale contracts

2025 marks a turning point in the global LNG market cycle. LNG supply has increased by 7% as new capacity has comes online, bringing the market back into balance after three tight years. The strong buildout will continue, with enough liquefaction already under construction today to increase global supply capacity by nearly 50% by 2030. This large increase in LNG supply is expected to be enough to loosen the global LNG market, causing spot prices to drop and potentially leading to a period of market surplus between 2029 and 2031.

During the second half of this year, however, the outlook for LNG supply has increased. In addition to the 164 MMtpa of capacity already under construction before the start of 2025, liquefaction projects with total capacity 84 MMtpa have taken FID this year. We expect to see a further 4 MMtpa to take FID before the end of the year, which will add 88 MMtpa of capacity that is expected to be online before the end of 2031.

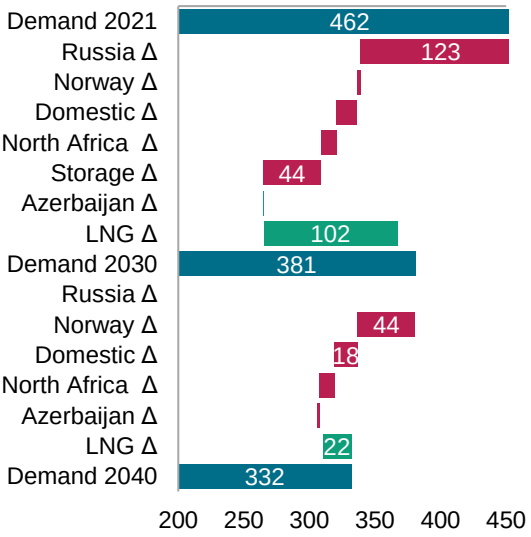
Further upside risk to our US supply forecast comes from commercial progress at proposed projects and potential capacity uprates — which require relatively little, if any, new construction and could move relatively quickly through the regulatory approvals process.

Russian LNG continues to deliver cargoes despite sanctions and the closure of the Northern Sea Route to all but Arc-class LNG carriers, although the rate of delivery has slowed since the onset of winter. The Arctic LNG 2 facility has been delivered cargoes to Beihai terminal in China since August 28 . The EU confirmed a ban on all imports of Russian LNG starting in 2027 as part of its 19th sanctions package, which was fully approved by EU member states on Oct. 23. Subsequently in December the EU Parliament approved a more sweeping legislative ban on all Russian LNG from Jan. 1, 2027—in line with the sanctions—and all Russian pipeline gas by Nov. 1, 2027. The deal still requires backing from the European Council, which is expected to vote in early 2026.

A multitude of European import contracts were signed in the second half of 2025—more details are included in the Tracking Update section. Most stem from Turkey, however—Turkish state-owned company BOTAŞ has been by far the leading end-market destination of firm LNG contracts signed between August and December 2025, driven by a spree of ten signings totalling 7.7 MMtpa in September. All of the signings came with portfolio players, with the majority (4.3 MMtpa) of the new contracts being less than five years in duration, primarily for three-year terms. The majority of deliveries are scheduled for the winter season, aligning with peak domestic demand driven by heating needs and higher electricity consumption, and follow unexpected spike in domestic gas use in Q1 2025, when colder-than-expected weather drove LNG imports to a quarterly record. In addition to lowering its expected winter reliance on spot LNG, BOTAŞ has also likely been motivated by maximizing leverage amid renegotiations of 22 Bcm/a in pipeline contracts with Gazprom, which were to expire at end-2025 before a one-year extension was signed in December. In early December BOTAŞ extended the original 2-year deals to 10-year deals totaling just under 1 MMtpa with Eni and SEFE starting from 2028, followed at the end of the month by an up to 9-year 0.5 MMtpa sale and purchase agreement with Woodside to start in 2030, firming up an heads of agreement signed by the two parties in September 2025.

However, such contracts are the exception rather than the rule. Portfolio buyers have continued to outpace both all individual producer countries as a source of new SPAs and all individual import markets as a buyer of new SPAs and equity entitlements. Contracts signed by portfolio buyers overwhelmingly consisted of US volumes over August-November 2025. With the exception of a single 1 MMtpa contract signed by Naturgy with CP2 LNG for delivery to Spain, all of the 15 MMtpa in US LNG contract signings are destined for portfolios without fixed destination, with implications for future cargo optimization and price formation.

2021 v 2030 v 2040 European gas balance changes, Bcm/y



Data compiled December 31, 2025.
Source: S&P Global Energy

Price and volatility

The global LNG market movements described above are set to be the dominant driver of a low-price regime over the coming years in Europe. The key determinant of price in this period will be demand response, and there is a strong likelihood that global LNG demand will not be able to grow at a fast enough pace to match the oncoming supply onslaught.

The resulting imbalance between LNG supply and demand are driving questions around which tranches of demand response might set price, and how LNG producers might respond to multi-year periods where there is spare productive capacity.

In thinking about demand response, a clear distinction can be drawn between European gas markets and those elsewhere.

Europe has low and declining short-term price responsive elasticity of demand in industry and power generation (from coal-gas switching). Furthermore, because of the additional cost of the EU ETS, gas becomes the defacto low-cost fuel in Europe at much higher gas prices than it would in other gas importing regions of the world.

European pipeline supply is either from mature, inflexible fields or from new developments where there are high sunk costs, very low operating costs and cashflow to be maintained. The one major exception is the large and flexible Troll field in Norway—but the price at which Troll turns down economically is much lower than the lowest price US LNG could be profitably sold into Europe. Long-term Russian pipeline supply contracts used to have significant volume flexibility that could be triggered by changes to prevailing market prices—but these have all largely gone and those remaining are not flexible. In effect, there is no elasticity of pipeline supply in Europe.

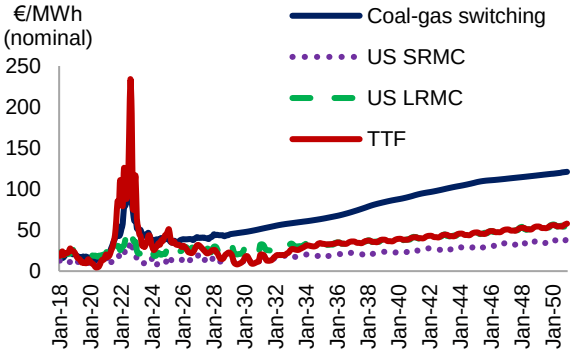
European storage will increasingly become the only short-term price responsive balancing item on the continent– but is not of a scale sufficient to balance the global gas market.

Asian LNG import markets offer substantial scope for price-responsive demand increases—however much of this hinges on very low JKM prices (under $6/MMBtu) which in practise are more likely to trigger supply-side responses.

Regas capacity in Europe will be a critical component of European and Global flexibility, contributing to meeting European demand volatility and seasonal demand swing and the global LNG market's need to place cargoes. Given that there is no transparent market value of regas capacity beyond the relevant DES LNG – Hub price spread, which is a simplistic guide to the value that regasification capacity and flexibility can offer, regasification capacity has scope to contribute to price volatility via inefficient allocation.

There is also a risk of spare regas capacity being removed in future—FSRUs in particular offer high throughput, at a price, but are temporary in nature and can be moved on to more profitable locations outside of Europe at fairly short notice.

European gas prices and anchors



Data compiled December 31, 2025.
Source: S&P Global Energy
LRMC = long-rung marginal costs; SRMC = short-run marginal costs

The lack of demand and supply flexibility in Europe mean that European underground gas storage will be a major buffer for LNG delivery volatility. European hub prices represent a complex equilibrium across two dimensions—one spatial as European buyers compete with other global regions, and the other being time as storage assets optimize within year and LNG traders react to relative geographic spreads at different points on the forward curve.

As a result, the hard-to-predict responses of non-European demand and non-European storage—which is currently of limited scale and accessibility to the global LNG market but this may change given time—to price will define key price benchmarks in Europe. The value of European gas assets and also, critically, power assets, will thus be determined by these 'drivers outside the system'.

In periods where supply growth in the global market exceeds demand growth in Europe to the extent that Europe

cannot flex enough by itself to absorb it (such as in 2029-30), European gas prices will fall to a level where either demand-side responses in the global gas market or supply-side responses from marginal LNG producers balance the market.

The degree of both short-term demand response and more medium-term investment responses to an extended period of lower-than-average prices are very hard to quantify and subject to significant uncertainty. There is the potential for global gas prices to surge quickly over a short space of time should a significant demand response occur.

This risk creates a headache for Asian buyers looking to sign up to long term LNG import contracts. Hub-indexed contracts linked to a global benchmark, whether that index is TTF, JKM or some other relevant benchmark, inherently contain that price risk. Henry Hub offers a different price risk profile, but given the US market is also losing demand flexibility, increasing absolute demand and demand volatility, it too is at risk of major price spikes. The perception that oil-indexed contracts offer a security of price and volatility that can make demand-side investments more tenable is growing, and such contracts are likely to help play a role in growing future demand as much as periods of low spot pricing.

The **TTF long term price forecast for 2030-40 is €23.45/MWh ($8.07/MMBtu), in real 2024 currency terms**.

Tracking update: Long-term European gas outlooks

European supply contract activity increases

ASSESSMENT: European interest in longer term contracts has intensified. Last quarter notable agreements include Equinor's decade-long supply to Czechia's Prazska plynarenska and Venture Global's breakthrough 20-year contracts with Spain's Naturgy and Greece's Atlantic-See LNG Trade.

Turkey's BOTAŞ continued actively signing new firm LNG deal with Woodside and extending gas supply contract with Russia.

Central European diversification intensified, with Hungary's MVM signing dual 10-year agreements with Shell Energy and Engie, additionally a new deal with SOCAR and LNG supply deal with Chevron, while CEZ extended Algerian supplies. Ukraine's emergency winter imports through Greek DEPA and Polish Orlen highlight acute supply security concerns following infrastructure attacks.

ITEM: In late November Equinor signed a 10-year gas supply deal with Prague's Prazska plynarenska, running until October 2035. Deliveries have already commenced, covering Prague and other Czech regions. Specific volumes and contract terms remain confidential.

ITEM: In mid-November Venture Global LNG signed a 20-year supply agreement with Spain's Naturgy for 1 MMtpa starting 2030. This marks Spain's first long-term US LNG contract since 2018.

ITEM: Naturgy signed an MoU with Oman LNG exploring long-term supplies of up to 1 MMtpa for 10 years from 2030. The agreement includes potential joint investment in an LNG carrier with Asyad and cooperation on European regasification terminals. Naturgy has been buying from Oman's Qalhat plant since 2005. Naturgy has an existing 1.7 MMtpa import contract with Oman LNG which expires in 2026.

ITEM: In mid-November Venture Global LNG signed Greece's first long-term US LNG supply agreement with Atlantic-See LNG Trade, a joint venture of Greek companies Aktor and DEPA. The 20-year deal starting 2030 covers minimum 0.5 MMtpa with expansion potential. Venture Global previously invested in 25% capacity at Greece's Alexandroupolis FSRU terminal.

ITEM In October CEZ extended its gas supply contract with Algerian Sonatrach, securing over 2% of Czech gas demand. In 2024, Czech gas consumption reached 6.77 Bcm. The move diversifies supplies away from Russia post-Ukraine war, with gas imported via Tunisia and Italy.

ITEM: Adnoc signed a 15-year LNG sales agreement with Shell to supply up to 1 MMtpa from its Ruwais terminal. This marks Adnoc's first long-term LNG deal with Shell and its eighth overall offtake agreement for the Ruwais project. The agreement converts a previous heads of agreement and supports Adnoc's strategy to double UAE's LNG production capacity to 15 MMtpa.

ITEM: Shell Energy Europe signed a 10-year agreement with Hungary's MVM CEEnergy to supply 0.2 Bcm/year of gas starting January 2026, marking Hungary's longest-term deal with a Western partner. The gas will be delivered via Czech and German pipelines. This strategic move aims to diversify Hungary's energy sources, traditionally reliant on Russian gas.

ITEM: In early October Hungary's MVM signed a 10-year LNG supply deal with Engie, securing 4 Bcm of LNG starting 2028 (0.4 Bcm/y). The agreement is indexed to US Henry Hub prices and offers more flexibility than the existing contract with Shell which restricts deliveries to Croatia's Krk LNG terminal. The Engie contract offers increased trading flexibility by enabling cargo delivery across multiple terminals. This arrangement allows MVM to strategically manage its LNG shipments and potentially optimize economic opportunities in different European markets.

ITEM: In December Azerbaijan's Socar signed a new gas supply deal with Hungary's MVM ONEnergy for 0.8 Bcm over 2 year from Jan. 1, 2026, building on their June 2023 agreement.

ITEM: Chevron signed a 5-year agreement with MVM to supply 2 Bcm (four LNG cargoes annually) starting Oct. 1, 2027, worth approximately $600 million, supporting Hungary's diversification from Russian energy supplies.

ITEM: Ukraine signed a gas import agreement with Greece for this winter with supplies to be delivered from December 2025 till March 2026. Volumes were not disclosed. The deal between Greek DEPA Commercial and Ukraine's Naftogaz will transport US LNG through the "Vertical Corridor" via Bulgaria, Romania, and Moldova.

ITEM: In late November Ukraine's DTEK imported its first FOB US LNG cargo via Lithuania's Klaipeda terminal, totaling 100 million cubic meters of natural gas for Ukraine, Baltic countries, Poland, and Eastern Europe. Following Russian attacks on energy infrastructure, DTEK estimates Ukraine needs approximately 4 Bcm of gas imports this winter. The company is negotiating additional US LNG shipments through its D.Trading arm to enhance regional energy security.

ITEM: Naftogaz and Poland's Orlen signed an agreement for 0.3 Bcm of US LNG supply to Ukraine. Orlen plans to supply Ukraine with 0.1 Bcm monthly. This year, Orlen has delivered 0.43 Bcm to Ukraine through four spot contracts with Naftogaz, importing US LNG via Polish and Lithuanian terminals. Norway has committed nearly $100 million in support for storage refill in Ukraine, additionally Naftogaz obtained a €500 million revolving loan

from the European Bank for Reconstruction and Development for gas purchases. As of August 19, Ukraine's gas stocks reached 10.4 Bcm, with 4.6 Bcm as cushion gas.

ITEM: In December Chevron's Aphrodite gas field offshore Cyprus entered FEED phase following Cyprus's February approval of the amended development plan. The $4 billion project, partnered with Shell and NewMed Energy, targets final investment decision in 2027 and first gas production in 2031. The development includes a floating production unit with 8.3 Bcm/y capacity and pipeline connection to Egyptian facilities for gas export.

ITEM: In December Turkey's BOTAS extended Russian gas contracts with Gazprom for one year till the end of 2026. Agreements cover 16 Bcm/y via Blue Stream (oil-linked contract)) and 5.75 Bcm/y via TurkStream (European hub-linked contract) through state-owned Botas, plus private importer contracts. Russia supplied 21.4 Bcm in 2024, increasing 14% to 16 Bcm in the first 9 months of 2025, making it Turkey's largest gas supplier.

According to Reuters, Minister Bayraktar stated that Turkey is facilitating the release of $2 billion in Russian funds frozen at J.P. Morgan, with these assets potentially financing the completion of the Akkuyu nuclear facility being built by Rosatom on Turkey's southern coastline.

Additionally in late December Australia's Woodside Energy finalized gas supply deal Botas for 0.5 MMt/y of LNG starting in 2030 for up to nine years.

ITEM: In late December Serbia extended its Russian gas import deal by three months to end-March 2026. The existing arrangement delivers 2.2 Bcm/y at oil-indexed prices, making it cheaper than European hub pricing. Serbia has 22.6 MMcm/d available from Russia, Hungary, and Azerbaijan, creating a surplus above maximum consumption of 17 MMcm/d. Serbia also serves as key transit for Russian gas to Hungary and Slovakia.

Mixed progress in low-carbon gases

ASSESSMENT: Hydrogen production is under pressure, with enhanced policies and funding likely required to sustain many planned projects. Regulatory delays and high costs had stalled or canceled more projects in Germany, Spain. Despite these obstacles, examples of investments taking place are still evident in Belgium, Germany, the Netherlands.
Meanwhile, the EU's approved 90% emissions reduction target by 2040, allowing 5% carbon credits, provides regulatory framework supporting hydrogen's role in decarbonization strategies, balancing climate ambition with industrial competitiveness across member states.

ITEM: The EU approved a 90% emissions reduction target for 2040, allowing up to 5% carbon credits for emissions offsetting. Ministers agreed on a 66.25%-72.5% emissions reduction range for 2035. The compromise reflects tensions between climate ambition and industrial competitiveness, with actual domestic cuts targeted at 85%. International carbon credits will be introduced through a pilot phase starting in 2031, subject to impact assessments. EU climate commissioner Wopke Hoekstra described the agreement as a "good compromise," balancing environmental goals with economic considerations. These targets are part of the EU's long-term climate strategy—the European Green Deal—which also calls for the EU to cut its GHG emissions by at least 55% by 2030 compared with 1990 and reach net-zero emissions by 2050.

ITEM: The European Commission adopted a methodology for low-carbon hydrogen production, requiring a 70% greenhouse gas emissions savings compared to unabated fossil fuels. This allows hydrogen to be produced through various methods, including natural gas with carbon capture. A public consultation on nuclear energy's role in hydrogen production is planned for next year. The proposals will be reviewed by the European Parliament and Council within two months.

ITEM: US company Plug Power delivered 44.5 tonnes of hydrogen for Germany's H2CAST pilot project, demonstrating hydrogen storage in salt caverns. The joint project between Gasunie and Storag Etzel plans 90 tonnes total injection. Plug secured a second mandate for additional 35 tonnes, sourcing from Hy2Gen ATLANTIS electrolyser in Werlte where it is the exclusive green hydrogen offtaker.

ITEM: Air Liquide commissioned the world's first industrial-scale ammonia cracking pilot facility in Belgium's Port of Antwerp-Bruges, converting 30 tonnes of ammonia to hydrogen daily. The technology addresses hydrogen transportation challenges. The company is scaling up through the ENHANCE initiative, supported by a €110 million EU grant for large-scale development.

ITEM: In late November Denmark inaugurated the HySynergy plant in Fredericia, one of Europe's first large-scale electrolysis facilities producing certified green hydrogen. The milestone included Denmark's first green hydrogen export to Germany. Everfuel and Crossbridge Energy collaborated on the project, with Crossbridge using 35 tonnes daily. Everfuel plans 2GW electrolysis capacity by 2035.

Energy security pushing decarbonisation from top of agenda

ASSESSMENT: The European gas market faces intensifying regulatory and geopolitical pressures as the EU accelerates its Russian energy phase-out timeline. The 19th sanctions package advances Russian LNG bans to end of 2026, while RePowerEU regulation, expected to become law at the beginning of 2026, will ban all Russian pipe imports by 2028. Qatar's threats to suspend deliveries over environmental regulations compound supply security concerns, despite being the EU's third-largest LNG supplier. Meanwhile, regulatory modifications provide some relief—

CBAM exemptions for 90% of importers and reduced corporate sustainability reporting obligations signal pragmatic adjustments.

ITEM: In late September the EU Parliament approved major Carbon Border Adjustment Mechanism (CBAM) changes, exempting 90% of importers from compliance rules. The reform, passed with 617 votes in favor, introduces a 50-Mt annual threshold for exemption. CBAM certificate purchases are delayed until February 2027, giving businesses more adaptation time. The mechanism targets imports of iron, steel, aluminum, cement, hydrogen, and fertilizers, aiming to level the playing field for EU companies. Despite the simplifications, the revised CBAM will still cover 99% of total CO2 emissions, maintaining the EU's environmental ambitions while improving industrial competitiveness.

ITEM: In November the European Parliament voted in favor of modifying sustainability regulations, reducing corporate reporting obligations. The revised proposal removes the 5% global turnover penalty cap for Corporate Sustainability Due Diligence Directive (CSDDD), allowing member states to determine penalties. Reporting will now apply only to larger companies: those with over 1,750 employees and €450 million annual turnover for CSRD, and over 5,000 employees and €1.5 billion turnover for CSDDD. The Parliament and Council will negotiate a final text by year-end, simplifying regulations amid criticism from LNG exporters like the US and Qatar.

ITEM: Qatar's Energy Minister Saad Al-Kaabi warned of potential LNG supply suspension to EU over strict environmental regulations, calling net-zero targets "unrealistic." Qatar became EU's third-largest LNG supplier in Q1 2025, behind US and Russia. The country is expanding its North Field project to boost LNG output by 2027. Suspension could force EU reliance on US/African producers.

ITEM: In late October EU energy ministers agreed to ban all Russian gas supplies by end-2027 under RePowerEU regulation, expected to become law in Q4 2025. Flows from the TurkStream pipeline are expected to decline from 16.2 Bcm/year in 2025 to 4.5 Bcm/year in 2028. The remaining volumes will be flowing to buyers in the non-EU markets of Serbia, Bosnia, North Macedonia, and the Transnistria part of Moldova This decrease in pipeline deliveries will be offset by increased LNG imports to Greece and Croatia plus additional pipeline gas from Romania and Turkish re-exports.

ITEM: In late October the EU formally approved its 19th sanctions package against Russia, accelerating the phaseout of Russian LNG by one year while leaving existing pipeline gas flows unaffected. Still, pipeline supplies from the country are expected to be prohibited by the end of 2027, as EU energy ministers agreed to the ban under the RePowerEU regulation, which is set to become law in Q4 2025. Under the latest sanctions package, all LNG cargoes linked to short-term or spot contracts will be banned from entering EU terminals by April 25, 2026, reducing Russian LNG inflows from the 19.8 MMcm/d expected in 2025 to about 6.6 MMcm/d in 2026. Besides the short-term and spot-linked volumes, long-term contracts, totaling 32 MMcm/d, will remain in effect until the end of 2026. From January 1, 2027, onward, the EU will therefore need to replace the full 52 MMcm/d of Russian LNG, which will likely come from US liquefaction projects.

With the loss of access to the European market in the coming years, Yamal LNG will need to considerably expand its shipping fleet to reach more distant markets in the Middle East and Pacific basins. Additionally, logistical constraints in the Arctic and Red Sea regions further complicate these new trade routes. Our analysis indicates that if Yamal LNG owners and contract holders rely solely on the existing fleet, in 2027 exports could decline by 42–52% from current levels, depending on the availability of the Suez Canal. In practice, it is plausible that project owners seek to expand the fleet ahead of the upcoming ban, albeit at a higher cost. In our base case, we project a middle-ground outcome, with Yamal LNG’s production reaching around 56 MMcm/d in the first year of the full ban, down from the expected 72 MMcm/d in 2025 and 78 MMcm/d in 2024.

ITEM: Slovakia to decide on appeal against EC proposed ban on Russian gas. Slovakia's Prime Minister Robert Fico announced November 19 that upcoming government meetings will decide whether to follow Hungary in appealing the European Commission's proposal to ban Russian gas and oil imports by 2028. Fico cited "significant damage" from halting Russian supplies, noting Slovakia has a Gazprom contract until 2034. The decision depends on EC fulfilling commitments made by President Ursula von der Leyen regarding price cushioning and arbitration support.

ITEM: In early December the European Parliament and EU Council have agreed on legislation to phase out Russian gas imports, representing a definitive closure of the EU's gas relationship with Russia rather than a temporary disruption. Pipeline imports of Russian gas under short-term contracts concluded before June 17, 2025 would be banned from June 17, 2026. Pipeline gas imports under long-term contracts would be banned from September 30, 2027, if “member states are on track to fulfil the storage filling targets” and “at the latest” on November 1, 2027, according to a European Commission statement. The EU wants to move beyond the immediate crisis response to establish a structured, legally binding framework that prevents or at least makes extremely difficult any future return to large-scale Russian gas imports. The agreement incorporates substantial additional financial penalties for non-compliance (potentially for Hungary and Slovakia), but also emergency provisions for supply crises. Although some "leakage" through Turkey may occur, this represents the EU's strategic pivot away from Russian energy dependence as a permanent geopolitical and economic reality rather than a temporary wartime measure. The earlier phaseout of

Russian pipeline gas from the CEE balance will result in the removal of 22.8 MMcm/d of pipe supply from the Hungarian and Slovak balances, which will require stronger storage withdrawals in CEE and additional imports from Austria and Czechia, both of which will need to increase their pull from Germany in Q4-2027.

ITEM: Russian attacks in October reduced Ukraine's domestic production by 1 Bcm this winter, resulting in a lower storage level at the beginning of the heating season as well as 30% higher imports from CEE. Ukraine's storage level as of 29th December stood at 11.95 Bcm (including 4.6 Bcm cushion gas), about 0.95 Bcm higher than at the same time a year ago.
Naftogaz has indicated that 30% higher Ukrainian imports from the EU this winter than they previously expected are likely. Some later reports have suggested a much higher volume of required imports – 4.4 Bcm till the end of March – double the volumes we forecasted before the strikes. Possible further damage to the still-recovering Ukrainian gas production facilities heading deeper into the winter, where security of supply becomes most critical within CEE, could see a significant widening in spreads between CEE and Western hubs as additional flows from the likes of Germany and Italy via Austria and Slovakia will be needed to support exports into Ukraine.

ITEM: In October, the Italian Council of Ministers was set to discuss a proposed decree aiming to equalize the spread between the PSV and TTF hubs to lower energy bills for Italian consumers and enhance the competitiveness of Italian industry.

European capacity constraints easing but tariff implications are not widely discussed.

ASSESSMENT: Europe continues to increase its gas import options and reduce interconnection constraints and costs. Central and Eastern Europe accelerates gas infrastructure expansion ahead of 2028 Russian gas phase-out. Hungary-Slovakia increased interconnection capacity 25%.

Regional LNG capacity strengthens: Croatia's Krk terminal expanded to 6.1 Bcm/y, Greece's Alexandroupolis resumed operations supporting EU's Vertical Corridor initiative, and Germany's Mukran secured long-term BASF-Equinor commitments.

ITEM: Slovakia's state-owned gas company SPP expects to import most future gas via Germany and Czech Republic rather than Poland, according to Trading Director Michal Lalik. German gas prices are cheaper due to diverse LNG and Norwegian supplies, while Polish transport costs are "twice as high." Current German-Czech route capacity is 9.5 Bcm/year, insufficient for Czech needs (8 Bcm) plus Slovak requirements (5 Bcm). Capacity improvements at German compressor stations are planned for 2026-2028, ahead of the EU's 2028 Russian gas ban.

ITEM: BASF and Equinor secured long-term regasification capacity at Deutsche ReGas's FSRU-based LNG terminal in Mukran, Germany. The terminal features the 145,000-cbm FSRU Neptune. Deutsche ReGas plans to add a second FSRU. The FSRU Neptune is 50% owned by Hoegh Evi and sub-chartered by Deutsche ReGas from TotalEnergies, who also holds capacity rights at the Mukran facility along with trader MET.

ITEM: In late October Greece's Gastrade received its first LNG cargo at Alexandroupolis FSRU since January 2025, supplied by TotalEnergies for Bulgaria's Bulgargaz. The 174,000-cbm vessel Qogir delivered cargo from Cameron LNG terminal in Louisiana. Gastrade expects seven cargoes total—five by March 2026, two in summer. After technical issues in January, operations resumed with capacity gradually increased to 136.2 GWh/day by October 21. The terminal's capacity is 5.5 Bcm/y.

ITEM: In November LNG Croatia commissioned a new regasification module at its Krk island FSRU terminal, completed November 7. The module adds 250,000 cbm/hour capacity, boosting total terminal capacity from 3.9 to 6.1 Bcm annually.

ITEM: In late December Poland's Gaz-System launched consultation until Jan 28, 2026, for a binding open season for a second 4.5 Bcm/year FSRU at Gdansk Bay. The first 6.1 Bcm/year FSRU is due online in 2028. September's non-binding study showed "significant interest" in additional capacity. A previous 2023 binding open season for the same project failed due to insufficient interest.

Deep Dives

Deep Dive: European biomethane production outlook

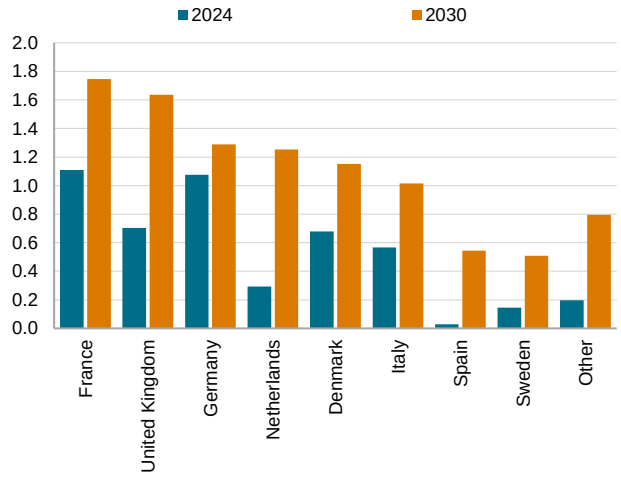
- Biomethane production in the EU27 plus UK grew by 10% year on year to 4.8 Bcm in 2024. The top six producers—France, Germany, UK, Denmark, Italy and Netherlands—account for 91% of production.
- We expect total biomethane production in EU27 plus UK to grow at a compound annual growth rate (CAGR) of 13% through to 2030 to reach 9.9 Bcm. This is significantly below the 35 Bcm/y REPower EU ambition. Biomethane development is a function of funding availability, infrastructure and demand-side policies, and the existing production base has proven to be higher cost than anticipated when the REPower EU documents were drafted.
- By 2050, we expect 20 Bcm of production across Europe. Five of the current top six producers remain there—France, Germany, Italy, Netherlands, UK—with Denmark being replaced by Spain.
- The top six producers in 2050 are expected to have grown three-fold to 11.4 Bcm vs 2024. Other markets are expected to increase by 5.2 Bcm in aggregate—producing over fourteen times more biomethane than they did in 2024.

Biomethane is a low-carbon alternative to fossil fuel gas and given that it also offers a means by which countries can reduce their gas import exposure while also promoting local industry, is expected to remain a key component in Europe's energy transition ambitions. In 2024, biomethane production in the EU27 plus UK grew by 10% year on year to 4.8 Bcm and is expected to have accelerated this year to reach 5.7 Bcm. This accelerated growth is driven by continued policy support, increasing private investment and technological advancements. With a total of 1,614 operational biomethane plants in EU28 with a cumulative annual production capacity of 7 Bcm, and 1,664 when including BioLNG, Europe continues to cement its strategy in supporting renewable gas via a framework of EU-level policies and commitments, supplements by a patchwork of national policy.

Mature markets with established funding and policy frameworks

Our outlook for biomethane production in the EU27 plus United Kingdom region is for France, Germany, the Netherlands, Denmark, Italy, Spain, Sweden, and the United Kingdom to be the eight largest biomethane producers in the region by 2030, producing 9.1 Bcm per year and accounting for 92% of production.

Top 6 biomethane producers (Bcm per year)



As of Dec. 24, 2025.
Source: S&P Global Energy.

In 2024, France overtook Germany to lead European biomethane production with an annual volume of 1.1 Bcm, supported by long-term fixed feed-in tariffs, Guarantees of Origin registries, and multi-year offtake agreements with industrial buyers such as ENGIE, Arkema, and Sanofi which provide security of demand. Registry reforms in 2023 further facilitated trading and contract structuring, reinforcing medium-term growth signals.

Germany is the longest-established European biogas market and accounted for 22% of EU biomethane production in 2024, building on a substantial biogas base established under EEG feed-in tariffs introduced in 2000 and expanded in 2004. Originally focused on biogas production for combined heat and power (CHP) electricity generation, the widespread adoption of upscaling technologies to produce biomethane increased after the 2015 update and further accelerated following the 2017 EEG amendment, which replaced fixed tariffs with competitive tenders. Supporting measures such as the Gas Grid Access Ordinance helped ensure grid injection.

The EEG Biomass Package (February 2025), in conjunction with Germany's transport fuel quota system, introduced flexibility bonuses that reward producers for operational adaptability, such as the ability to switch between gas grid injection, direct use in transportation, or supply to heating networks, depending on market demand. These measures also allow plants to optimise output during periods of high electricity or gas prices, or to adjust production volumes to balance local grid capacity, effectively creating a more market-responsive revenue structure, marking a turning point for large-scale deployment, reflective of Germany's maturity in the biomethane production.

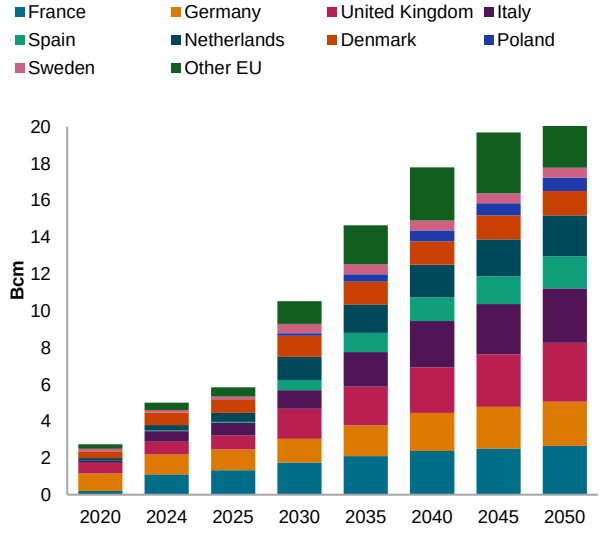
The UK biomethane market is the third largest in Europe and has a well-established policy framework. The Green Gas support scheme (GGSS) and Renewable Heat Incentive (RHI) provided revenue certainty for heat and grid-injected biomethane. These policies fostered rapid early deployment and high installed capacity—the next phase of

growth till 2030 will be driven by an extension of GGSS out to 2028. The GGSS provides fixed guaranteed premium, paying producers for biomethane grid injection covering 15 years. We project growth in the UK at 17% from 2025-2030 driven by continued deployment under GGSS followed by a slow down to 3% 2030-2050 as capacities reach maturity.

Denmark continues to produce biomethane in large volumes relative to the size of its total gas market—however ultimately we assume total gas consumption and infrastructure will act as a natural limit to how much further biomethane production could grow. Denmark will have to optimise high pressure fossil gas production from the North Sea and imports from Norway for high pressure consumers such as power generators and heavy industry, along with low pressure production from biomethane which can meet low pressure gas consumption. In 2022, the Danish government reaffirmed its ambition to reach 100% share of renewable gas in the national gas grid by 2030. As production draws near to the 2030 target, Denmark is transitioning from a broad fixed feed-in-tariff system to a tender-based one. Under this model, developers bid for a premium, the lowest bids win part of the allocated budget of €1.7 billion. The tenders are extended to 2029, with successful projects receiving fixed 20-year support.

The Netherlands and Sweden, producing an estimated 0.29 and 0.15 Bcm respectively in 2024, have developed more market-oriented or demand-driven frameworks. The Netherlands combined feed-in premiums with a forthcoming green gas blending obligation, which is expected to accelerate production from 2026 onward. Sweden relies on tax incentives and renewable fuel obligations rather than fixed tariffs, resulting in steadier, incremental growth. These frameworks reward efficiency and cost-effectiveness but require robust demand signals to accelerate market expansion.

Planning Case biomethane production: EU 27 plus UK



Data compiled December. 23, 2025.
Source: S&P Global Energy.
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Rapid growth markets with emerging production infrastructure

Austria, Belgium, Italy, Spain and Finland have had low annual biomethane production historically but have strong future potential growth.

Austria's policy landscape shifted in 2025 by the introduction of the Renewable Gases Act, ostensibly positioning the country for future growth. The Act provides a legal framework to ensure a share of green gas in its gas supply mix, although parliamentary approvals are still pending. The extension of feed-in premiums for existing biogas plant operators gives time for conversion to biomethane ahead of quota regime if the Renewable Gases Act is enacted. Production volumes remain moderate compared to the leading European biomethane producers, but infrastructure investments and formalized quotas are expected to expedite faster expansion. We expect Austrian annual biomethane production to be 0.39 Bcm by 2040 and 0.48 Bcm by 2050.

Belgium has limited current biomethane production. In 2025, Green Logix commissioned the first direct biomethane injection into the Fluxys high-pressure transmission network from its Lommel plant, supporting high-pressure grid integration, marking new infrastructure capabilities.

Spain is an emerging market, poised for rapid growth driven by public and private investments and policy. The number of operational facilities has increased from 2 in 2020 to 14 in 2024. In 2025, Naturgy and Hispania Silva plan to build 20-30 new plants with a total installed capacity of 2.5 TWh (0.181 Bcm) by 2030. In terms public support, Spain is actively developing its regulatory and support framework. A key regulation, known as Circular 2/2025, came into effect in July 2025, simplifying biomethane grid connection procedures, boosting investors' confidence, and aligning Spain more closely with EU directives (RED III). We forecast that biomethane production in Spain will increase twelvefold from its current volume by 2030, starting with smaller capacities, then growing rapidly by 66%, before slowing to 27%, reaching 0.54 Bcm and 0.51 Bcm respectively.

The Italian biomethane market is in a growth phase—by 2024, Italy was producing 0.57 Bcm of biomethane, quadrupling the 2019 level. The Biomethane Decree of September 2022, which provided access to capital grants and 15-year incentive tariffs under the National Recovery and Resilience Plan (NRRP), building on earlier 2018 measures for transport fuel use. These long-term incentives have supported production growth, and in 2025, Snam secured €264 million in EIB funding to construct 240 km of pipelines, enabling the transportation of up to 12,000 GWh/year (~1.13 Bcm) of biomethane and reinforcing the integration of new plants into the national gas network. Italian biomethane production is expected to grow by the most in absolute terms to 2050, rising 2.4 Bcm—bested only by the UK with 2.5 Bcm of additional production.

Early stage / potential growth markets

Poland, Hungary, Ireland, Norway, and Switzerland are in early stages of biomethane development.

Poland is emerging as a high-growth potential market. Over the last two years, the country has seen a series of policy shifts which in combination with its large agriculture sector providing feedstock are expected to boost its biomethane production. In 2025, the key regulatory frameworks needed in Poland for Biomethane production were formalised, including a legal definition of biomethane, grid access preferences, and a feed-in premium (FIP) support scheme that took effect on July 2025 for eligible producers. Poland's first commercial biomethane plant (Strzelin) became operational in 2025, Additionally, a draft auction-based support scheme for biomethane plants above 1 MW has been proposed and is expected to take effect in the near term. Poland is leading growth in Eastern Europe, with an expected rise in biomethane production of 84% between 2025 and 2030.

Ireland currently only has two biomethane facilities injecting into the gas grid. The advantage in Ireland are the private investors and local stakeholders aiming to process agricultural residues and organic byproducts. In 2024, the Irish government published its first National Biomethane Strategy, which aims to deliver 5.7 TWh of biomethane by 2030. The Renewable Heat Obligation (RHO) and Renewable Transport Fuel Obligation (RTFO) are envisaged to help create demand for renewable gases. Hungary, Norway, and Switzerland are also on an upward trend, with incremental plant additions and pilot projects gradually expanding volumes.

Other markets such as Romania, Portugal, Latvia, and Lithuania have limited or non-existing production. Latvia and Lithuania stand out with commercial biomethane production in the former starting this year. In July 2025, Latvia established its first biomethane injection point into its national gas grid. In November 2025, Latvia approved a new support scheme worth €21.5 million, funded by the European Regional Development Fund and the state budget, to stimulate biomethane production and the acquisition of biomethane transport vehicles.

Overall, these emerging biomethane markets are gradually scaling, but with lower aggregate volumes with the current European leaders. There is potential for medium-term development, depending on the evolution of the policy and economic framework producers are operating in.

We forecast biomethane production in the EU27 plus United Kingdom to reach 9.9 Bcm by 2030.

Europe's biomethane sector is entering a critical phase with challenges particularly around grid integration and cost recovery for new projects. Mature markets such as France and Germany are growing more slowly, reflecting the transition to market-based support and the need for substantial follow-on investment to achieve further growth. The biomethane production CAGR between 2024 and 2030 in France is expected to be 7.8% before slowing to 2.1% in the period 2030 to 2050. In Germany, the CAGR for both periods is 3.1% reflecting a relatively slow but steady continued growth.

We forecast biomethane production to reach 8.3 Bcm by 2030 in the EU27, 27 Bcm below the REPowerEU ambition. In September 2022, the European Commission estimated that €37 billion would be required to build 35 Bcm of biomethane by 2030. However, it is now apparent that this figure underestimated the cost to meet the 2030 target.

Supply-side funding and infrastructure are not the only hurdles to growth—insufficient or delayed demand signals, such as the absence of binding blending mandates, weak transport quotas, or limited certificate markets can also constrain growth rates. Currently, the only countries with formal mandatory injection or quota systems include Austria, the Netherlands, Ireland, France (through transport fuel quotas), Denmark (renewable gas quota), and Portugal.

Ongoing collaboration among governments, industry, and investors is required to maximise biomethane potential. The nature of funding and policy is expected to evolve as time passes, which will be required to bring laggard markets up the development curve and to exploit harder-to-process or more costly feedstocks in the more mature markets.

Prior to 2030, funding is expected to come primarily from National Energy and Climate Plan (NECP) instrument roll-outs and REPowerEU pre-finance, national subsidies and incentive tariffs, and private investment capital, which will support expansion of existing plants, early grid connections (e.g., Poland), and policy clarifications such as blending mandates. Closer to 2030, full implementation of EU renewable energy directives, additional funding streams (such as Cohesion Fund and RRF disbursements) along with sector-specific quotas and certificates are expected to contribute.

Post-2030, development of renewable gas markets involving cross-border biomethane certificate trading and deep decarbonisation frameworks are expected to keep biomethane positioned as a mainstream decarbonisation solution for Europe, though not at a scale sufficient to fully decarbonise those gas consuming sectors still reliant on methane as a fuel.

Deep Dive: Gas supply options for Hungary and Slovakia 2027-30

- The European Parliament and EU Council agreed in early December on legislation to ban all Russian gas imports from September 30, 2027. Hungary's MVM and Slovakia's SPP are both about 80% dependent on Russian gas supply in 2025, and most impacted by such a ban.
- Hungary and Slovakia are likely receiving significant informal discounts on Russian gas, but this politically-dependent arrangement becomes unsustainable as expected low gas prices in the late 2020s-early 2030s (TTF averaging €15.3/MWh in 2028-2030) will eliminate Russia's incentive to continue deferred payment schemes, undermining the primary economic argument for maintaining Russian contracts.
- Hungary and Slovakia face a number of challenges post-2027 and likely higher prices relative to TTF. If Hungary has restricted access to the Serbia pipeline, it must expand expensive interconnections with Croatia and Romania, to make it one of EU's highest-priced markets. Slovakia will be heavily dependent on German gas via Czechia, exposed to capacity bottlenecks, indirect LNG access and high tariffs.

In early December the European Parliament and EU Council agreed on legislation to phase out Russian gas imports, representing a definitive closure of the EU's gas relationship with Russia rather than a temporary disruption. Pipeline gas imports under long-term contracts would be banned from September 30, 2027, if "member states are on track to fulfil the storage filling targets" and "at the latest" on November 1, 2027, according to a European Commission statement. The agreement incorporates substantial additional financial penalties for non-compliance (potentially for Hungary and Slovakia), but also emergency provisions for supply crises.

Hungary's MVM and Slovakia's SPP have not received any exemption from this phaseout. They will continue to fight to get an exemption or prolongation of the deadline in order to continue to receive their long-term contract volumes of 7.5 Bcm/y in aggregate—4.5 Bcm per year to Hungary and the remainder to Slovakia until expiry in the mid-2030s.

Meanwhile, both Hungary and Slovakia have undertaken some efforts to diversify its gas supply, yet these are small scale and will not allow both countries to easily switch away from Russian pipeline gas supply as early as 2028.

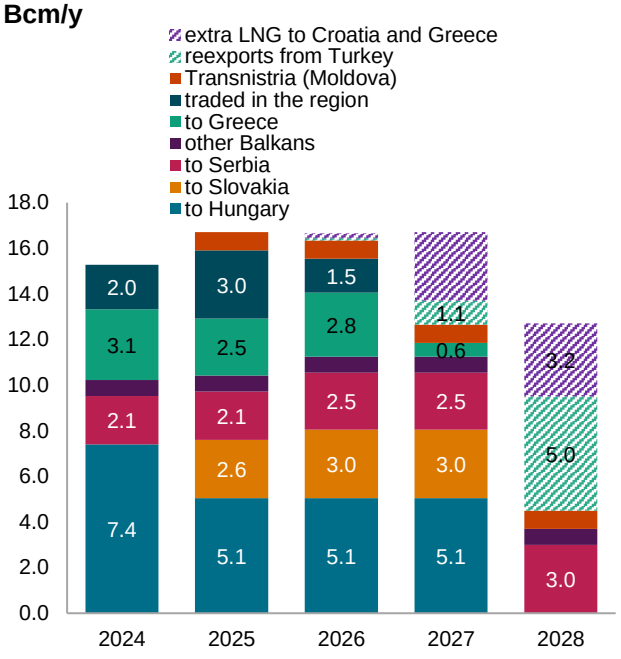
Russian gas supply to EU is currently flowing via the only remaining active route, TurkStream

Following the discontinuation of Russian gas transit via Ukraine from the beginning of 2025 Russian pipeline gas flow to Europe is only limited to one route – TurkStream. The TurkStream pipeline is currently delivering approximately 44 MMcm/d of gas across the Bulgarian border daily — roughly 16.2 Bcm/a — which is about 6% above its notional design capacity. Of this:

- 10.1 Bcm/a is being delivered to supply five long-term contracts with EU buyers: (a 4.5 Bcm/y to Hungarian MVM, a 2.5-3 Bcm/y to Slovakia SPP, a 2 Bcm/y to Greek DEPA, a 0.6 Bcm/y to Greek Metlen Energy & Metals and 0.2 Bcm/y to Greek PPC).
- An additional 3 Bcm/a is being delivered from TurkStream into the EU on a short-term or spot basis.
- Approximately 3.6 Bcm/a is flowing to buyers in the non-EU markets of Serbia, Bosnia, North Macedonia and Transnistria part of Moldova.

Russian gas pipeline flow via TurkStream will be gradually declining in line with the expiration of the DEPA and PPC contract expirations at the end of 2026 and 2027 respectively. Additionally, Gazprom will be prohibited to sign new short-term deals with EU buyers from mid-2026 and the volume of traded gas in the region will decline in 2026 and disappear by 2027.

TurkStream volumes distribution in 2024-28, Bcm/y



As of Dec. 30, 2025.
Source: S&P Global Energy.

The declining supply from Russia will have to be replaced by a combination of higher supply via different routes. Firstly, lower Russian pipe volumes in the Greek market will be substituted by more inflows of LNG to Greece. Secondly, Hungary would be highly reliant on imports from Romania and Croatia. Hungary will still need to meet its peak demand from either Austria (gas sources from Germany and Italy) or potentially even from Slovakia which in its turn will highly depend on gas from Germany via Czechia. Finally, Turkey has been strengthening its position as a gas re-exporter in the region, aided by record LNG import contracts and increased production with the goal to

become a southeastern European gas hub, leveraging regional pipeline integration.

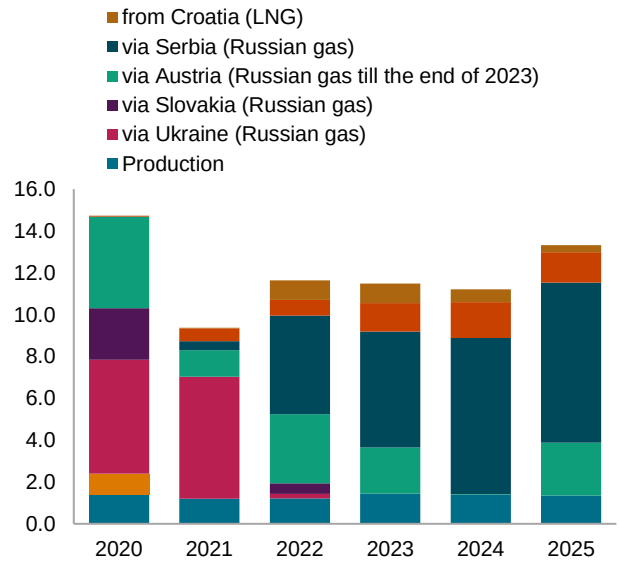
The importance of Russian gas supply in Hungarian and Slovakia gas balances

Hungary and Slovakia remain the last countries in the EU that are critically dependent on Russian pipeline gas supply. Hungary and Slovakia are caught between external pressures from other member states and EU institutions to wean themselves off Russian pipeline gas, and the domestic inflationary risks of rising gas prices if Russian supply were to be replaced.

Both Hungary and Slovakia have managed to somewhat lower dependence on Russian piped gas supply since 2020 as they moved from 100% dependence in 2020 to about 80% dependence in 2025.

In 2025, Hungary's domestic gas demand is projected to reach 8.5 Bcm, marking a 20% decrease from 2021 levels. Russian pipeline supply will fulfill 78% of these needs, equivalent to 6.57 Bcm. The foundation of Hungary's current Russian gas supply is a 15-year contract signed between the state-owned energy group MVM and Russia's Gazprom in September 2021. This agreement ensures the delivery of 4.5 Bcm/y of Russian gas, with the entire volume supplied via the TurkStream pipeline since 2023, followed by transit through Bulgaria and Serbia. Additionally, approximately 2.07 Bcm/y of Russian gas is provided through a mix of seasonal and short-term contracts.

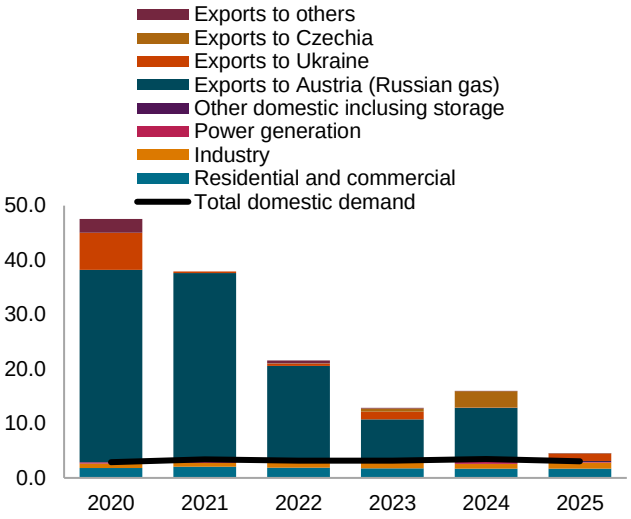
Hungary: imports, production, Bcm/y



As of Dec. 31, 2025.
Source: S&P Global Energy.

In 2025, Slovakia's gas consumption, defined as offtakes from the transmission system, is anticipated to be 3.1 Bcm, representing a 10% reduction from 2021 levels. Slovakia's state-owned utility SPP holds a long-term contract with Gazprom, due to expire at the end of 2034, which initially supplied 3.5 Bcm annually via Ukraine. The halt of Russian gas transit through Ukraine on January 1, 2025, significantly altered gas flow and pricing dynamics in Slovakia and the broader Central and Eastern Europe (CEE) region. With the Ukraine corridor closed, Slovakia and Austria were the most immediately affected EU member states. To maintain supply under its long-term contract with Gazprom, Slovakia's SPP began receiving Russian gas rerouted through the TurkStream pipeline, traveling via Bulgaria, Serbia, into Hungary, and then across the Hungary-Slovakia interconnector. The capacity of this interconnector has recently been increased to a firm 4.38 Bcm/y from the previous 3.5 Bcm/y.

Slovakia: demand and exports, Bcm/y



As of Dec. 31, 2025.
Source: S&P Global Energy.

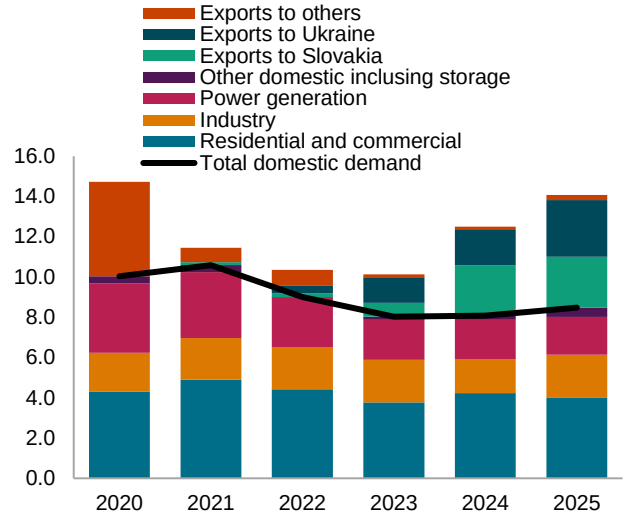
Over the past five years, both Hungary and Slovakia have increased their reliance on non-Russian gas supplies. Notably, Hungary has intensified its contracting efforts, securing four new supply agreements in the last quarter of 2025. Currently, Hungary holds the following contracts:

- Engie LNG to MVM Hungary: 10 years, totalling 4 Bcm (0.6 Bcm per year) starting from 2028.
- Shell LNG to MVM: 10 years, totalling 2 Bcm (0.2 Bcm per year) beginning in 2026.
- Chevron LNG to MVM: 5 years, totalling 2 Bcm (0.4 Bcm per year) commencing in 2026.
- SOCAR pipeline gas: 2 years, totalling 0.8 Bcm (0.4 Bcm per year) starting in 2026.

Despite these contracts, without Russian gas Hungary will face an uncontracted supply gap of approximately 8 Bcm per year between 2028-2030.

As the importance of TurkStream for Russian pipeline gas supply has grown since 2025, Hungary's role as a regional transit country has expanded, becoming a key transit geography for Slovakia and Ukraine. However, Russian supply was not enough to cover extra exports, thus additionally, Hungary has increased gas imports from Romania, Austria, and Croatia in 2025, totaling 4.3 Bcm, which accounted for 32% of total flows through Hungary.

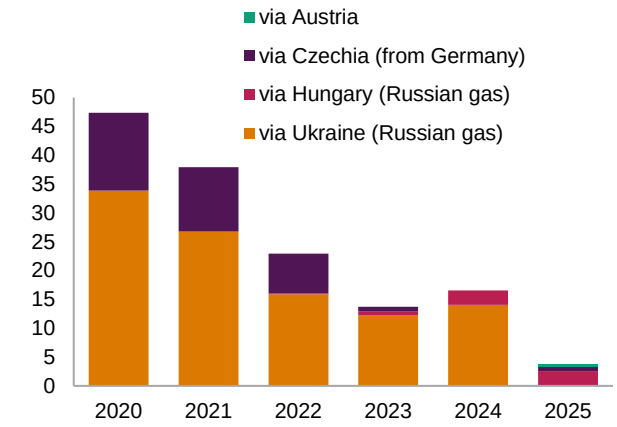
Hungary: demand and exports, Bcm/y



As of Dec. 31, 2025.
Source: S&P Global Energy.

Slovakia's SPP has also been exploring alternatives to Russian gas supply. SPP concluded a series of short-term gas deals for 2023 and 2024 with five international companies—BP, ExxonMobil, Shell, ENI, and RWE. In late 2024, SPP signed a short-term pilot contract to purchase gas from SOCAR. Slovakia initiated discussions in July 2025 regarding the potential use of Croatia's Krk LNG terminal. However, unlike MVM, SPP has not yet secured any new medium or long-term supply agreements, even for small volumes.

Slovakia: imports, production, Bcm/y



As of Dec. 31, 2025.
Source: S&P Global Energy.

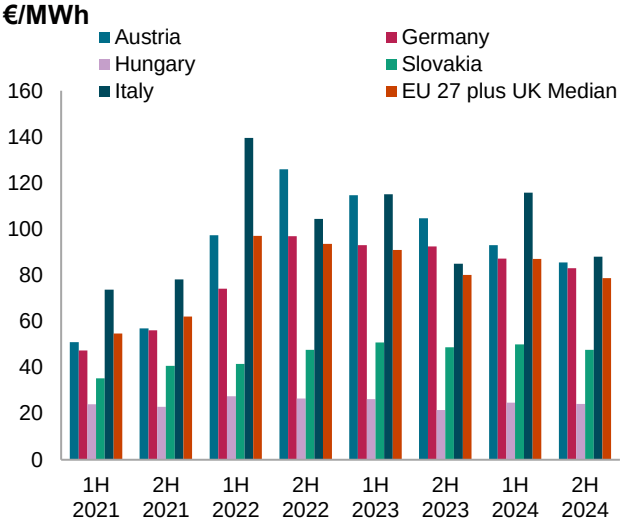
In contrast to Hungary, Slovakia's historic role as a major transit state has significantly diminished due to the cessation of Russian gas flows via Ukraine. This decline has been particularly challenging for Slovakian TSO Eustream, with transit volumes dropping from 47.4 Bcm in 2020 to less than 4 Bcm in 2025. Although Slovakia continues to export to Ukraine in 2025, it remains a marginal import route for Ukraine. In 2025, Slovakia received 2.5 Bcm of Russian gas from Hungary and imported an additional 1.3 Bcm, primarily from Czechia and some from Austria, to balance its needs.

Eurostat customs data for the cost of Russian gas imports by Hungary and Slovakia over the past three years reveals two things:

- Imports appear to be largely hub-linked with several months delay, and average 6-10% *higher* compared to the prevailing TTF price.
- Russian gas supply was, on average, 10-15% cheaper than other alternatives for Hungary and Slovakia in 2025.

However, anecdotal evidence suggests Hungary and Slovakia have likely received an informal discount since at least 2022, potentially in the form of deferred payments for gas. In October 2022, MVM and Gazprom agreed to defer payments for gas purchases exceeding a certain threshold. It is plausible that SPP reached a similar undisclosed agreement.

Gas prices for households in selected countries, €/MWh



As of Dec. 30, 2025.
Source: S&P Global Energy.

What is also clear is that both Hungary and Slovakia are able to sustain much lower household gas tariffs than other EU markets. While not evidence of a wholesale supply discount—discounted retail tariffs can be created in multiple ways—these tariffs do indicate the domestic pressure that could result from a loss of Russian pipeline gas.

The residential sector is substantial in both countries: 4 Bcm in Hungary and 1.7 Bcm in Slovakia, accounting for 47% and 55% of their respective total domestic markets in 2025. Hungary and Slovakia have notably low residential gas prices compared to the rest of the EU, despite unprecedented market price levels since 2021, as shown in the chart above. From 2022 to 2024, residential gas prices averaged only €25.15/MWh in Hungary and €47.75/MWh in Slovakia, representing just a 4% and 29% increase from 2020 prices, respectively. In contrast, the average residential price in the rest of the EU soared to €88/MWh during the same period, nearly a 100% increase from 2020.

The informal nature of this discount, heavily reliant on political regimes and loyalty to Russia in both Hungary and Slovakia, is arguably the greatest vulnerability in the argument for maintaining long-term Russian pipeline contracts, especially amid a full EU ban on purchasing Russian gas.

Declining gas prices may limit the attractiveness of Russian gas supply in 2027-30

There are strong arguments both for and against the prospect of Hungary and Slovakia continuing to import Russian pipeline gas on the basis of their long-term contracts:

Arguments against continuing Russian flows

- **EU Regulation Implementation:** Under the REPowerEU roadmap, the EU is enforcing a trade policy regulation requiring a qualified majority vote, preventing Hungary and Slovakia from blocking it. This creates binding obligations for all member states to end imports under existing long-term contracts by January 1, 2028.
- **Force Majeure Protection:** The European Commission frames the new EU law as a "force majeure" event, allowing European importers to end contracts with Gazprom without penalties, as the termination is mandated by EU law, not a commercial breach.
- **Collective EU Commitment:** The roadmap demonstrates strong EU political solidarity for energy diversification, suggesting that any attempts by Hungary and Slovakia to bypass the regulation will encounter collective resistance from other member states.

Arguments for continuing Russian flows:

- **Legal Challenge Strategy:** Hungary intends to challenge the EU at the European Court of Justice, claiming the regulation improperly uses qualified majority voting for trade policy as an energy sanction, violating EU law and national sovereignty over energy security.
- **Resistance Tactics:** Hungary and Slovakia might continue pipeline imports during extended ECJ proceedings or resist implementation due to high domestic costs, forcing the EU into lengthy enforcement processes while gas flows persist.
- **Multi-Energy Complexity:** The regulation, covering all Russian energy imports, poses challenges as Hungarian and Slovakian refineries rely on Russian Urals crude and nuclear technology, necessitating costly adjustments, though gas-specific flexibility may remain.
- **Gazprom Arbitration Risk:** Hungary and Slovakia risk arbitration from Gazprom over long-term contracts into the mid-2030s, as EU force majeure defences lack clear protection guarantees for member states.

Arguably one of the strongest arguments to keep Russian long-term gas supply contracts for Hungary and Slovakia has been the presumed purchase mechanisms for Russian gas that have allowed both states to shield their vulnerable consumers from price spikes.

However, in the late 2020s and early 2030s the global LNG market movements described in the long-term section of this report are set to be the dominant driver of a low-price regime over the coming years in Europe. We expect TTF price to average only €15.3/MWh in 2028-2030. Given that price discounts in MVM and SPP contracts are not specifically built-in it may be very unlikely that Russia will continue to lower a threshold value and keep deferring payments.

Hungary and Slovakia gas supply options and its key limitations

The network of pipelines connecting Hungary and Slovakia to their neighbors is the bedrock of their supply diversification strategy. Recent years have seen significant investment in enhancing bidirectional flows, moving away from the legacy predominant east-to-west model. As of 2025, the interconnection landscape provides a range of options, though not without limitations. Key projects like the Poland-Slovakia interconnector and capacity upgrades on the Hungary-Slovakia and Hungary-Romania borders have been recent critical developments. Additionally, the Vertical Corridor, a strategic initiative to connect Greece to Central Eastern Europe and Ukraine via Bulgaria, Romania, represents the most significant future enhancement for the region's south-to-north supply axis. (See map at the end of this report)

Since both countries are landlocked, access to LNG is indirect and relies on capacity at regional terminals and the pipeline infrastructure to deliver it inland. For Hungary and Slovakia, key import points are in Croatia, Poland, Greece, and Turkey.

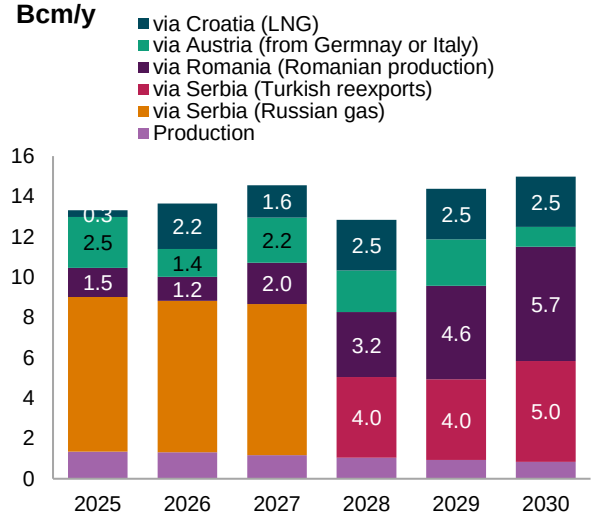
For Hungary, the key limitations are currently present on the borders with Croatia and Romania. For both Slovakia and Hungary current capacity limitation on the Germany and Czechia border is critical for bringing extra LNG supply from northwest European markets.

We have developed two alternative cases of Hungary and Slovakia gas supply in 2025-2030 in the case of Russian gas phase out from the 4th quarter of 2027.

In **option one** key additional supply comes from Romania, Croatia, and also Turkey. The Romanian route requires capacity expansion beyond already planned expansion and also depends on the timings of gas production ramping up from the Romanian Black Sea—we currently expect Romanian spare gas will be exported towards Hungary from late 2027. In Croatia, capacity is slowly being increased: the Krk FSRU is now available at a new increased capacity of 6.1 Bcm per year this winter, but the pipeline capacity to move gas into Hungary still requires work to be completed. Even then, the planned expansion

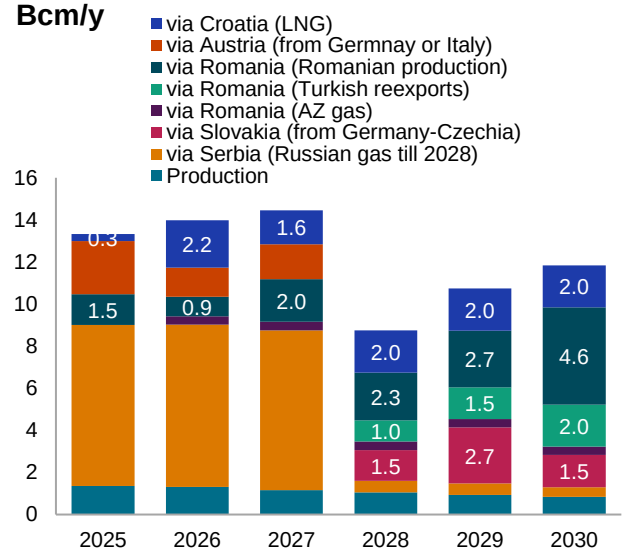
will bring total capacity between Croatia to Hungary to just 1.5 Bcm/y. Hungary will still need to meet its peak demand from either Austria (gas sources from Germany and Italy) or potentially even from Slovakia which in its turn will highly depend on gas from Germany via Czechia.

Hungary option #1: Sources of supply, Bcm/y



As of Dec. 31, 2025.
Source: S&P Global Energy.

Hungary option #2: Sources of supply, Bcm/y

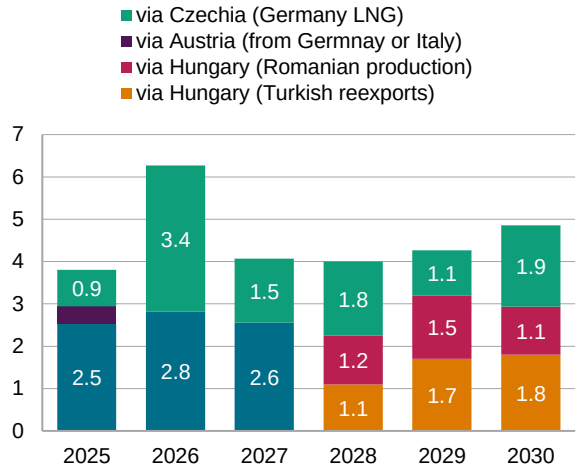


As of Dec. 31, 2025.
Source: S&P Global Energy.

A key concern is that some volumes might need to flow through Bulgaria and Serbia using the pipeline that crosses Serbia, which is owned and operated by Gastrans d.o.o. Novi Sad—an independent TSO but 51% Gazprom owned (the other 49% belongs to Srbijagas). Even with a full phase-out of Russian gas to EU members, Gastrans will need to continue operating this pipeline for supplies to the Balkans. It is unclear what will happen to the capacity in the pipeline that Gazprom currently has rights to. In option one, we assume that Turkish BOTAS will be able to obtain capacity in the Gastrans pipeline. For Gazprom this could make sense as a least-worst alternative option in a full phase out situation, as they will be able to sell more gas directly to Turkey to partially offset the lost sales in the EU.

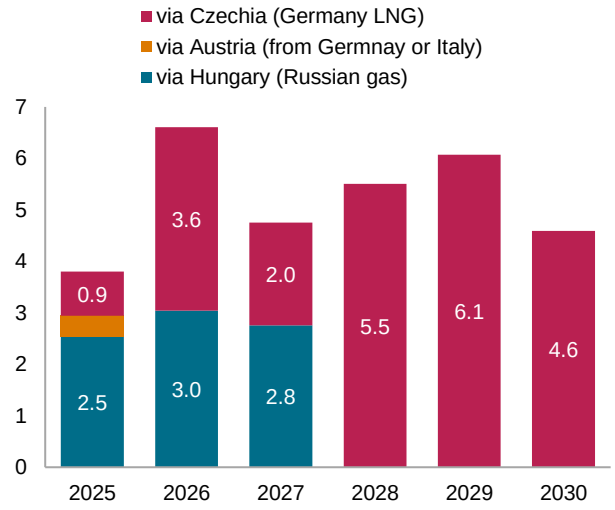
While Turkey has been strengthening its position as a gas re-exporter in the region, aided by record LNG import contracts and increased production with the goal to become a southeastern European gas hub, leveraging regional pipeline integration. (Turkish delight: Flurry of new LNG contracts, but more pipeline deals required to underpin surging demand and Turkey advancing its gas re-export goals but faces regional competition)

Slovakia option #1: Sources of supply, Bcm/y



As of Dec. 31, 2025.
Source: S&P Global Energy.

Slovakia option #2: Sources of supply, Bcm/y



As of Dec. 31, 2025.
Source: S&P Global Commodity Insights.

In an alternative scenario which is represented by **option two,** we assume capacity access on Gastrans is restricted. This could seriously compromise Hungary's supply security due to regional infrastructure constraints. In this instance Hungary would need to significantly expand its connections with Croatia and also with Romania well

beyond what is planned. Additionally, importing more from Austria will be challenging since any extra volumes to Austria for further reexports would need to come via Italy as connections with Germany are already maximized. Hungarian prices as a result of that might be one of the highest in the region together with Slovakian prices. Both markets are also therefore exposed to whatever market interventions Italy is currently discussing should get implemented.

Slovakia is less likely to face a physical gas shortage, but it will remain a super-premium market, with energy costs expected to be among the highest in the EU. In the case of full phase out of Russian volumes Slovakia's supply balance relies heavily on volumes from Czechia (sources from Germany), which means it will continue to see solid price premiums. Marginal supply again would flow through Austria, presenting the same challenge as with Hungary, where these flows come from Italy.

Southeastern Europe key gas infrastructure

Sources: S&P Global Market Intelligence, S&P Global Energy midstream content (EDIN); Data compiled November 21, 2025.

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- Future Energy Outlooks Quarterly Tracking Report

Contributors

EMEA Gas Analytics

Alun Davies
Anna Galtsova
Elizabeth Kunle

European Gas Long-Term Forecast

For inquiries related to the gas market, please contact our team: eurogasanalytics@spglobal.com.