ACER

European Union Agency for the Cooperation of Energy Regulators

Analysis of the European LNG market developments

2025 Monitoring Report

22 May 2025

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of Energy Regulators

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Table of contents

Executive summary **4**

1. Global LNG market dynamics **8**

1.1. LNG production 8

1.2. LNG demand 13

1.2.1. European LNG demand 14

1.2.2. Drivers and outlook of LNG demand in the European Union 19

2. LNG trade **31**

2.1. Contractual positions 35

2.1.1. EU contractual LNG position 35

2.1.2. LNG contracted and spot purchases in 2024 top 5 LNG Importers 39

2.1.3. Contractual position of portfolio players 42

2.2. ACER's LNG price assessment 43

2.2.1. Overview of key insights 44

3. The role of import LNG terminals **51**

3.1. Present role of EU LNG import infrastructure 51

3.1.1. Utilisation of EU LNG terminals 52

3.1.2. Versatility of LNG terminals 54

3.2. Future role of LNG import terminals 59

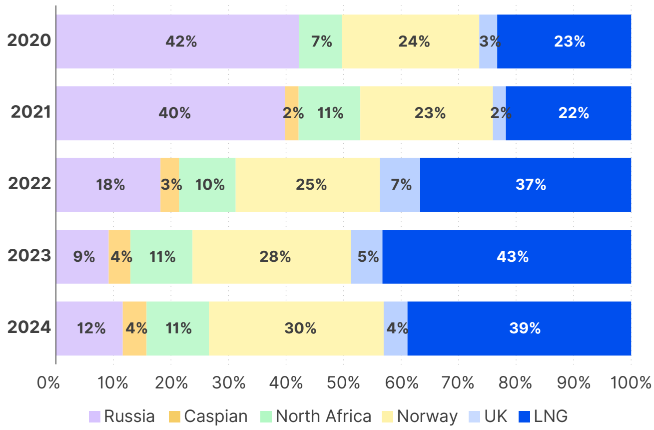
3.2.1. Overview of decarbonised gases for LNG import 59

Annex I: **64**

List of figures **66**

Executive summary

Gas supply to the EU by route, 2020-2024 (%)

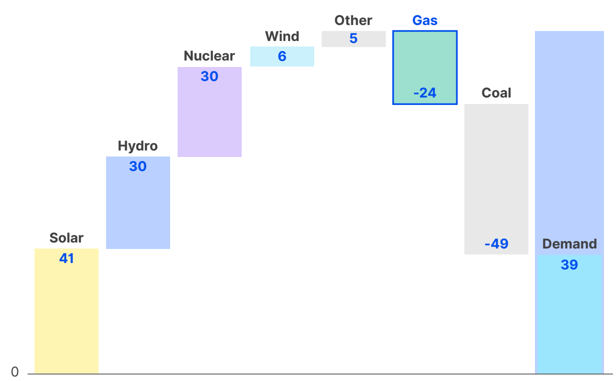


The importance of liquified natural gas (LNG) in the European gas supply mix has been increasing over this decade. The Russian invasion of Ukraine in 2022 accelerated EU's efforts to phase out Russian fossil fuels, leading to a surge in LNG imports as a more flexible and geographically diversified supply source. As a result, LNG's share of the EU's total gas supply nearly doubled – from 23% in 2020 to around 40% in 2024.

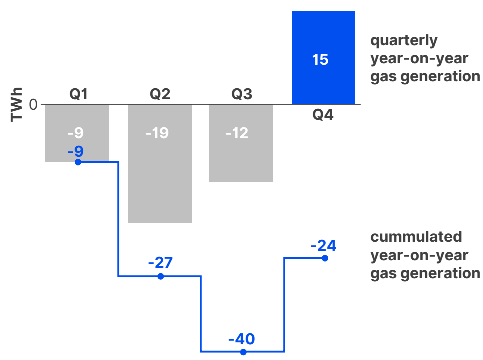
Gas in the power sector – flexibility enabler supporting the energy transition

In 2024, gas consumption in the EU was relatively evenly spread across sectors: the residential and commercial segment and consumption for industrial uses represent more than one third each, while gas for both electricity generation and cogeneration covers the rest. Each sector faces unique decarbonisation challenges. Gas-fired power generation plays an important role in providing flexibility. Renewables have reduced the overall demand for gas (and coal), while also shaping gas generation when is needed to balance the system.

Year-on-year changes for the main generation technologies, EU-27/EEA(Norway), 2024 (TWh)



Year-on-year changes for generation, EU-27/EEA(Norway), 2024 (TWh)



In 2024, gas-fired power generation remained below historical averages for most of the year but increased sharply in the final quarter to meet seasonal demand and compensate for low renewables output. Demand-side response, utility-scale battery storage and enhanced cross-border electricity flows via interconnectors are improving the short-term flexibility of the electricity system. However, gas-fired generation, and, by extension LNG, will remain key to meeting its medium- to long-term flexibility needs.

Under the European Commission's REPowerEU roadmap (May 2025), Europe must complete its shift away from Russian fossil fuels (including gas from both pipeline and LNG) by the end of 2027. At the same time, it must accelerate the transition to a decarbonised energy system. In this context, LNG from non-Russian sources is expected to play an increasingly important role as a flexible and geographically diversified supply source.

Both a higher reliance on LNG supply and uncertainty about gas demand lead to an inevitable trade-off: ensuring a reliable LNG supply under more stable pricing through sufficient contracted volumes, while maintaining the flexibility necessary to avoid overcontracting in a changing market environment.

Despite a 17% drop last year (22 bcm), the EU has remained the world's largest LNG importer since 2022, ahead of China and Japan. While new liquefaction projects and long-term contracts are coming online, ACER projects that the EU's reliance on spot LNG volumes will remain significant throughout this decade.

Insufficient progress on decarbonisation could lead to deeper EU reliance on spot LNG

Europe's high reliance on spot LNG is likely to persist through 2030 if progress towards REPowerEU targets falls short.

EU LNG demand outlook: 90 bcm of LNG demand is the uncertainty range between Fit-for-55 and REPowerEU decarbonisation scenarios. The legally binding Fit for 55 package (July 2021) sets a 30% reduction in EU gas demand by 2030 compared to 2019 – equivalent to over 120 bcm. The REPowerEU plan (May 2022), while non-binding, has more ambitious goals for renewables and energy efficiency, aiming for a total gas demand reduction of around 210 bcm by 2030 compared also to the 2019 baseline.

Delivering on decarbonisation: Without stronger decarbonisation efforts beyond Fit for 55, the EU could face up to 30 bcm in additional LNG demand by 2030 compared to 2024 levels. Meeting this via the spot LNG market might be costlier than medium- or long-term contracting and would heighten the EU's exposure to spot price volatility.

REPowerEU targets under pressure: While solar photovoltaic (PV) is on a strong trajectory to meet its targets, wind, biomethane and renewable hydrogen are falling behind.

LNG terminals drive resilience and transition

The value of LNG import terminals extends beyond their utilisation rates. Their additional strength lies in the strategic flexibility and resilience they offer across different timeframes, seasons and supply-demand shifts. As critical infrastructure, LNG terminals ensure backup during winter demand peaks, support the refilling of underground storage, diversify supply sources and serve landlocked regions. Consequently, they also facilitate EU market integration.

Looking ahead, as Europe advances towards decarbonisation, LNG terminals should be prepared to handle future low-carbon fuels, such as synthetic methane, bio-LNG, hydrogen, ammonia and methanol.

LNG terminals provide access to landlocked countries, such as Austria via Italy and Bulgaria through Greece, further strengthening security of supply.

Bringing transparency to the EU LNG spot market

ACER engages in LNG price monitoring and oversight to enhance market transparency. Since January 2023, it publishes reliable data on actual EU spot LNG trades. This helps market participants make informed decisions, supports fair competition and strengthens price signals across the EU gas market.

In 2024, ACER assessed over 550 spot LNG trades in the EU, totalling 45.5 bcm. The Dutch Title Transfer Facility (TTF) hub remains the leading benchmark for pipeline gas prices and provides an index for 73% of EU LNG spot trades. 55% of the monitored LNG trades were concluded at a price below 35 EUR/MWh.

In 2024, the EU purchased 30 bcm of LNG on the spot market, more than any other major importer and over twice as much as China or India. This high reliance on spot LNG increases the EU's exposure to price volatility. While price swings have eased since the 2022 spike, volatility remained high in 2024.

Since 2023, ACER's daily spot LNG prices have ranged between 20 and 55 EUR/MWh. These trends have reignited calls to reduce the EU's exposure to the spot LNG market.

Recommendations: A dual strategy to reduce exposure to the spot LNG market

To manage the uncertainty surrounding future gas demand under the EU's 2030 decarbonisation targets and to mitigate associated volume and price volatility risks, the EU should pursue a dual strategy: **accelerate the decarbonisation of its energy system while securing additional LNG volumes through flexible contractual arrangements**. This balanced approach reinforces energy security while staying aligned with the EU's decarbonisation goals. The strategy can be implemented through the following steps:

1. Accelerate decarbonisation to reduce structural gas demand

Faster deployment of renewables, greater electrification and improved energy efficiency will reduce overall gas consumption, lowering Europe's reliance on both spot and contracted LNG (and gas overall). This demand-side decarbonisation not only enhances energy resilience but also ensures alignment with the EU's decarbonistation objectives. Strengthened monitoring and transparency of decarbonisation progress are essential to identify underperforming technologies early and enable corrective actions to support their development.

2. Secure additional LNG supply under flexible contract terms

While gas demand is projected to decline over the medium-term, securing additional contracted LNG volumes would significatly reduce short-term exposure to price volatility. To prevent carbon lock-in and ensure consistency with the EU's climate objectives, new LNG contracts should include destination flexibility clauses for long-term agreements or be structured as short- to medium-term contracts.

Market players should consider the following actions:

- **Prioritise the renewal or expansion of expiring contracts through 2030**, targeting up to 20 bcm via short- to medium-term agreements (1 to 5 years).
- **Engage with portfolio suppliers** to secure mid-term (3 to 5 year) contracts. Portfolio players managing 15-20 bcm/year of uncommitted supply can offer diversified and adaptive solutions in a changing market.
- **Explore spare capacity at liquefaction facilities not bound by long-term contracts** as an alternative option.

3. Strengthen transparency and coordination across stakeholders

Enhanced coordination between Member States and the European Commission is essential to enable efficient data sharing and to ensure the timely monitoring and reporting of decarbonisation progress. ACER, the national regulatory authorities (NRAs) and the European Network of Transmission System Operators for Gas (ENTSOG) shall also support this process. This will:

- Reduce uncertainty surrounding future gas demand pathways, enabling better-informed LNG procurement decisions.
- Help identify lagging technologies early, allowing policymakers to intervene with targeted support or policy adjustments.

1. Global LNG market dynamics

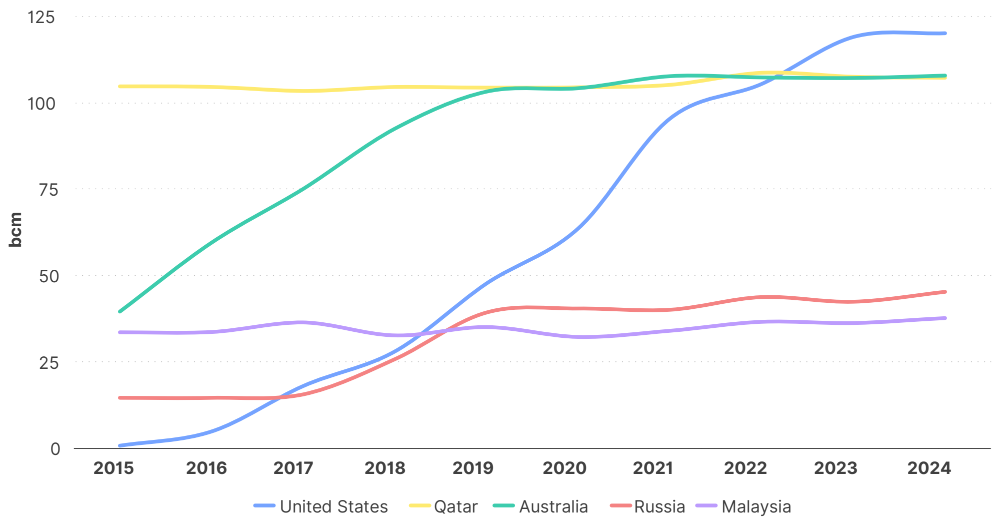
1 This first chapter provides an overview of recent LNG market dynamics, with a focus on production and demand trends. The chapter also analyses how global LNG developments affect the European gas market. In addition, it explores the sectoral breakdown of the EU's natural gas consumption and progress toward REPowerEU objectives, which are crucial for completing the shift away from Russian gas and LNG supply by 2027.

1.1. LNG production

2 The increase in global LNG production in 2024 was quite moderate with 3 million tonnes, equivalent to 4 billion cubic meters (bcm), representing an annual growth of less than 1%. By the end of 2024 total LNG output reached 412 million tonnes, equivalent to 561 bcm. LNG production is broadly distributed between the Atlantic and Pacific basins. The United States remains the world's largest producer, leading the Atlantic basin followed by Russia and some countries in South America and West Africa. In the Pacific basin, Qatar and Australia lead LNG production, with Malaysia contributing with a significantly lower share.

3 As illustrated in Figure 1, the United States has emerged as the world's largest LNG producer over the past decade, accounting for approximately 30% of global production. Over the last five years, US LNG production has doubled, reaching 120 million tonnes, and is expected to maintain its leading position in the coming years. Australia and Qatar follow closely, each producing around 110 million tonnes; however, their production levels have remained stagnant over the past five years. Collectively, these three countries contribute to more than 80% of global LNG production. Russia, the fourth-largest LNG producer reaching 33 million tonnes, recorded the highest annual increase, two million tonnes more than the previous year. Finally, Malaysia ranks fifth among the top LNG producers, with approximately 28 Mt.

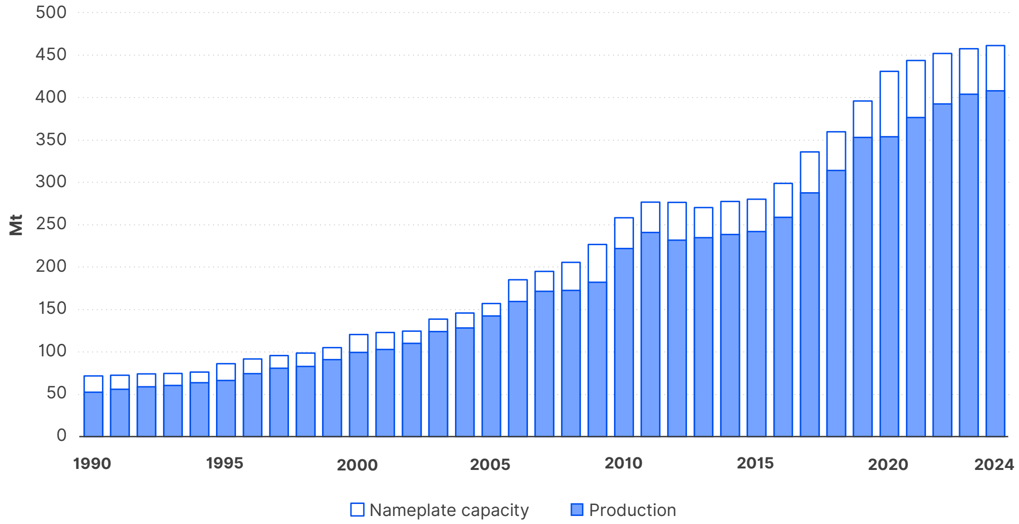
Figure 1: Top 5 largest LNG producers (bcm) - 2015 – 2024



Source: ACER based on data from ICIS LNG Edge.

4 Over the past decade, global LNG production expanded by 70. However, growth has slowed in the last five years, with only a 15% increase during that period. This expansion is driven by several factors such as rising global energy demand and the shift toward natural gas as a cleaner alternative to coal. Also, technological progress in production and transport have supported LNG production growth. More flexible and interconnected global supply chains, along with an improved market liberalisation and enhanced trade dynamics, have further boosted LNG global production in the last decade.

Figure 2: Historical evolution of LNG production and nameplate capacity (Mt) - 1990 – 2024



Source: ACER based on data from ICIS LNG Edge and S&P Global.

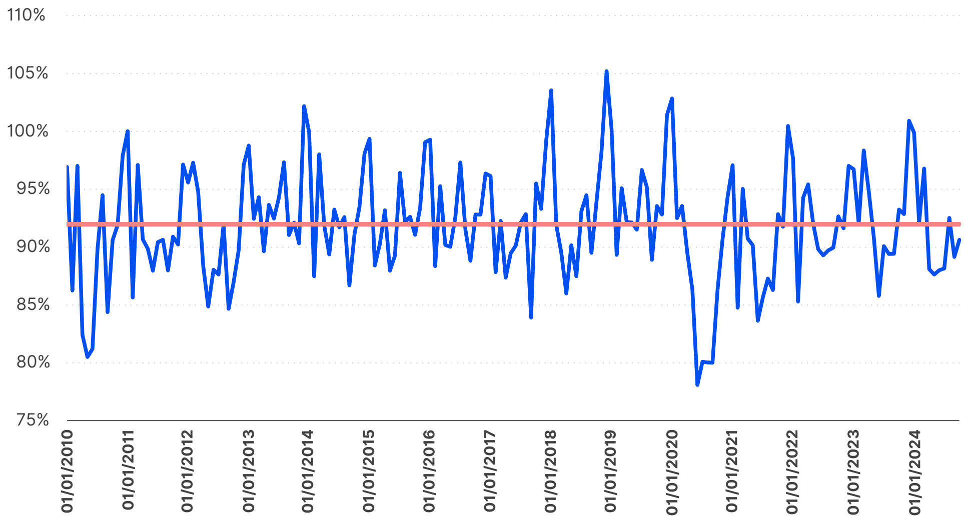
Production outages and other factors of unavailability

5 LNG output at liquefaction plants is often reduced due to regular maintenance activities[1]. Additional constraints, such as feedgas shortages, security concerns, severe weather events, and technical issues, can further impact production infrastructure availability. In recent years, the global liquefaction capacity utilisation rate has averaged 92% (see Figure 3). Despite regular and planned maintenance, unexpected disruptions significantly affected Freeport in the U.S. and Ichthys in Australia, causing capacity equivalent at least one liquefaction train at each facility to remain offline for approximately one-third of 2024. Precisely, the two liquefaction projects were conducting debottlenecking[2] processes to enlarge production capacity.

1 The average downtime for a liquefaction plant attributed to planned maintenance is estimated at around 5%, equivalent to approximately 20 days per year. Maintenance is typically scheduled during the shoulder season. Routine light maintenance is conducted over a 10-day period annually, while major maintenance occurs every two or three years, with potential durations extending up to one month.

2 Debottleneck implies removing production bottlenecks by upgrading pipelines, compressors, or gas treatment units typically during maintenance shutdowns and can potentially increase LNG production by around 10%.

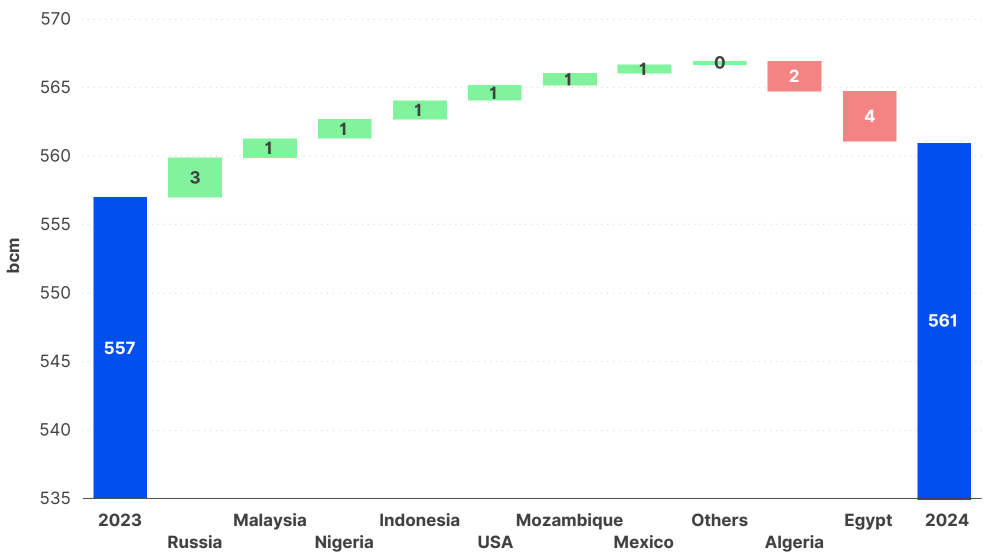
Figure 3: Global LNG export infrastructure utilisation (%) - 2010 – 2024



Source: ACER based on data from S&P Global.

6 Figure 4 illustrates the variations in global LNG output throughout 2024. The most significant shift was the increase in Russian LNG production driven by the strong performance of the Yamal liquefaction plant, which added 3 million tonnes year-on-year. Similarly, improved operational availability in Malaysia, Nigeria, and Indonesia contributed an additional 3 million tonnes collectively. In contrast, LNG production declined in Egypt and Algeria, primarily due to persistent feedgas shortages and rising domestic energy demand. Egypt was forced to import LNG for domestic consumption after Israel suspended gas pipeline exports amid the ongoing conflict in Gaza. Nigeria's output remained constrained by continuing regional security challenges, particularly pipeline theft and sabotage. Meanwhile, Atlantic LNG in Trinidad and Tobago, Peru LNG, and Algeria's Arzew and Skikda facilities faced declining feedgas availability, further limiting production.

Figure 4: Global LNG production variations in 2024 compared to 2023 (bcm)



Source: ACER based on data from ICIS LNG Edge.

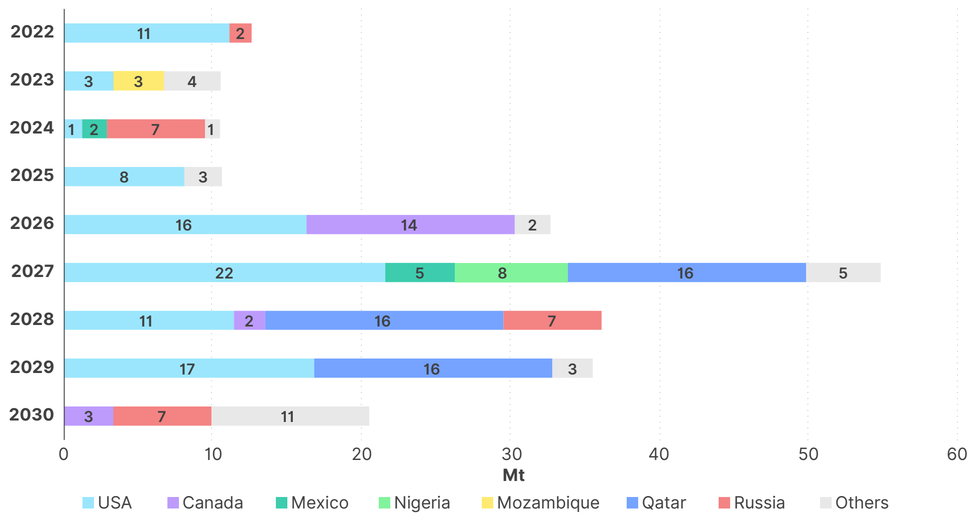
Expansion of the LNG production infrastructure

7 Global LNG production capacity currently stands at 462.5 Mt and is projected to increase by approximately 50% over the course of this decade, underscoring LNG's expanding role in the global gas trade. The most significant capacity additions are expected in 2027 and 2028. However, the extent to which this new capacity will be available to the spot market remains limited, as the majority of LNG volumes are committed under long-term contracts. Typically, between 85% and 95% of a project's output is pre-sold, leaving only 5% to 15% available for spot transactions. The only notable exception is Qatar's North Field projects which only have around half of the capacity under long-term contracts.

8 The balance between long-term contracted and uncontracted volumes is shaped by several factors, with the debt-to-equity ratio being the most influential. Other relevant considerations include the level of government involvement, particularly where liquefaction assets are controlled by National Oil Companies (NOCs), as well as the role of Export Credit Agencies (ECAs) in providing financial backing. Long-term contracting remains the foundation of project bankability in the LNG sector, as it offers lenders revenue certainty and mitigates exposure to price and demand volatility. Chapter 2 will analyse how these upcoming additions to global LNG production capacity translate into contractual arrangements and assess the share of secured volumes allocated to the European Union.

9 The growth in global LNG production will primarily stem from new liquefaction plants being developed in the United States and Qatar, which together account for two-thirds of the upcoming liquefaction capacity. Russia could also partly contribute to this rise with around 10% of the total capacity by 2030, as shown in Figure 5.

Figure 5: New capacity developments in global LNG liquefaction (Mt) - 2022 - 2030



Source: ACER estimations based on data from S&P Global.

10 In 2024, several projects across multiple regions reached key milestones, either through new commissioning or by debottlenecking existing infrastructure, adding 10.5 million tonnes (14 bcm) of liquefaction capacity.

11 The largest single contributor to capacity growth in 2024 was Arctic LNG 2 Train 1 in Russia. Despite challenges related to international sanctions, limited financing, and restricted access to technology, the first train of the project became operational with 6.6 million tonnes of new capacity. However, international sanctions have effectively blocked access to the LNG volumes produced at Arctic LNG 2.

12 In Mexico, Fast LNG Altamira 1 project, a floating liquefaction unit, added 1.7 million tonnes of new capacity. In Central Africa, Congo FLNG 1 project added 0.6 million tonnes. In Australia, modest gains of around 0.4 million tonnes were achieved through the debottlenecking of Ichthys LNG Trains 1 and 2. Meanwhile, in the United States, a debottlenecking process across the three trains of Freeport LNG added 1.2 million tonnes of new capacity.

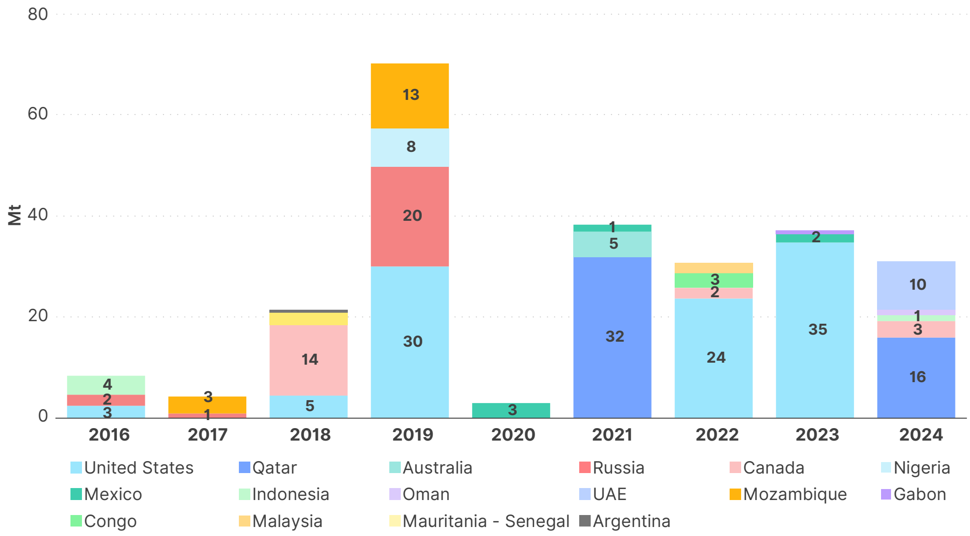
13 In 2025, a similar level of capacity growth is anticipated, with over three-quarters expected to come from the United States, primarily from the Plaquemines and Corpus Christi Stage 3 projects. The remaining addition comes from the Greater Tortue project, located in Senegal-Mauritania which delivered its first LNG cargo in April 2025.

14 Final Investment Decisions (FIDs) announced in 2024 totalled around 16 million tonnes (approximately 22 bcm), driven by projects in the Middle East, Ruwais LNG Trains 1–2 (United Arab Emirates) and Marsa LNG Train 1 (Oman), as well as the floating LNG projects Cedar FLNG 1 (Canada) and Kasuri FLNG (Indonesia). These projects are included in the capacity projections shown in Figure 5, based on their expected timelines from FID to commissioning which typically ranges from 4 to 6 years.

15 No FIDs were announced in the United States, reflecting a slowdown following the recent pause on permitting and export licensing. In contrast, FIDs announced in 2023 from U.S. liquefaction projects totalled 38 million tonnes, including Phase 2 of Plaquemines LNG, Port Arthur LNG Phase 1, and Rio Grande LNG.

16 On 20 January 2025, the American President signed a series of executive orders aimed at bolstering oil and gas development, including LNG. A key directive, titled 'Unleashing American Energy,' instructs the Department of Energy (DOE) to expedite the review and approval process for LNG export license applications. This policy shift is expected to accelerate approvals for approximately 54 million tonnes of pre-FID liquefaction capacity in the United States and Mexico that has already secured authorization from the Federal Energy Regulatory Commission (FERC). The directive focuses on non–Free Trade Agreement (non-FTA) export licenses, which are essential for accessing global LNG markets not covered by existing U.S. FTAs. Securing these licenses is a critical step in enabling project financing. If implemented effectively, this initiative could increase LNG export capacity from 2030 onward, particularly as the timeline from FID to commercial operation in North America has lengthened, with many projects now requiring over five years to come online.

Figure 6: Evolution of financial investment decisions at liquefaction plants per country – Mt



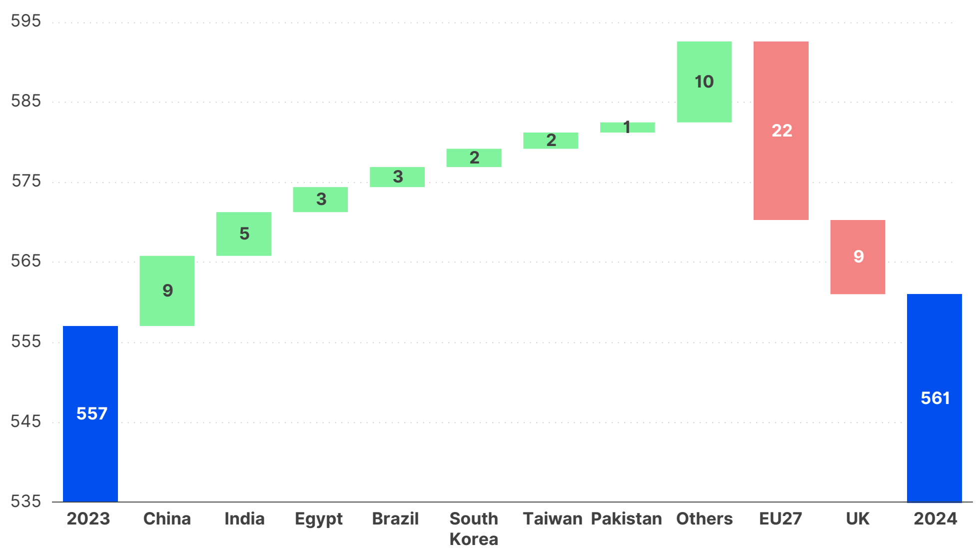
Source: ACER based on data from S&P Global.

1.2. LNG demand

17 The global LNG consumption rose marginally by 4 bcm in 2024, reaching 561 bcm. China led this demand growth in 2024 increasing by 9 bcm from 2023. In contrast, the EU experienced a reduction of 22 bcm, while the UK's LNG consumption fell by 9 bcm.

18 These trends highlight the growing LNG demand in Asia. By the end of winter 2023–2024, EU underground gas storages (UGSs) reached an all-time high for the end of a heating season, standing at 60% of total capacity. This combined with a reduced gas consumption, led to reduced LNG imports in 2024. Despite the decline of LNG imports in the EU, several factors point to a likely increase in 2025. These include the halt of Russian gas via Ukraine due to expiration of the five-year transit deal, lower-than-expected underground gas storage levels in winter 2024-2025, and regulatory storage obligations due by end of 2025.

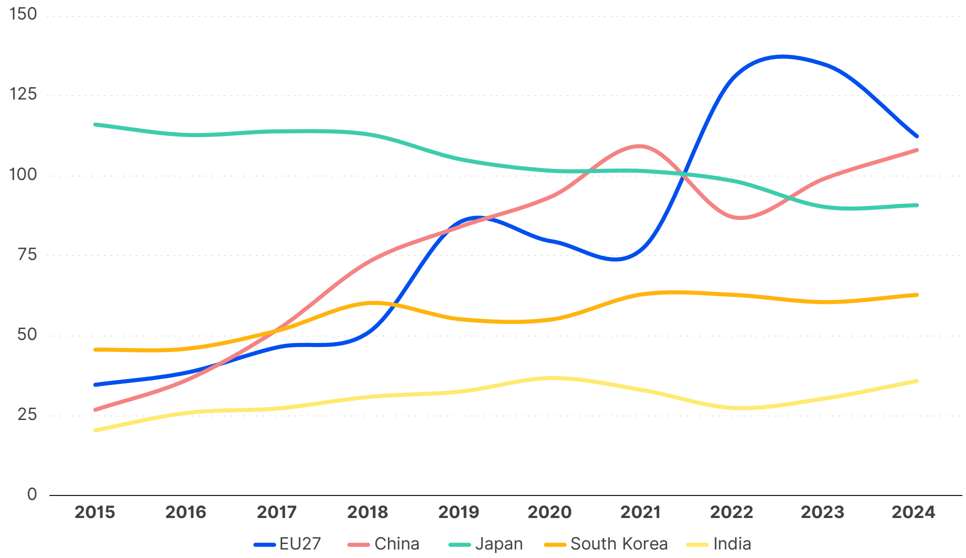
Figure 7: LNG demand variations in 2024 compared to 2023 – bcm



Source: ACER based on data from ICIS LNG Edge.

19 In 2023, EU LNG imports declined to a level matching China's LNG consumption (see Figure 8). Meanwhile, China's LNG imports rose by 9%, reaching around 108 bcm in 2024. This increase was driven by rising domestic gas demand across all end-use sectors. India was the fifth-largest LNG importer in 2024, experiencing an 18% increase in LNG imports due to growing energy needs and rapid economic expansion. In contrast, LNG demand in Japan and South Korea has remained unchanged from 2023 levels.

Figure 8: Top 5 largest LNG importers (bcm) - 2015 – 2024

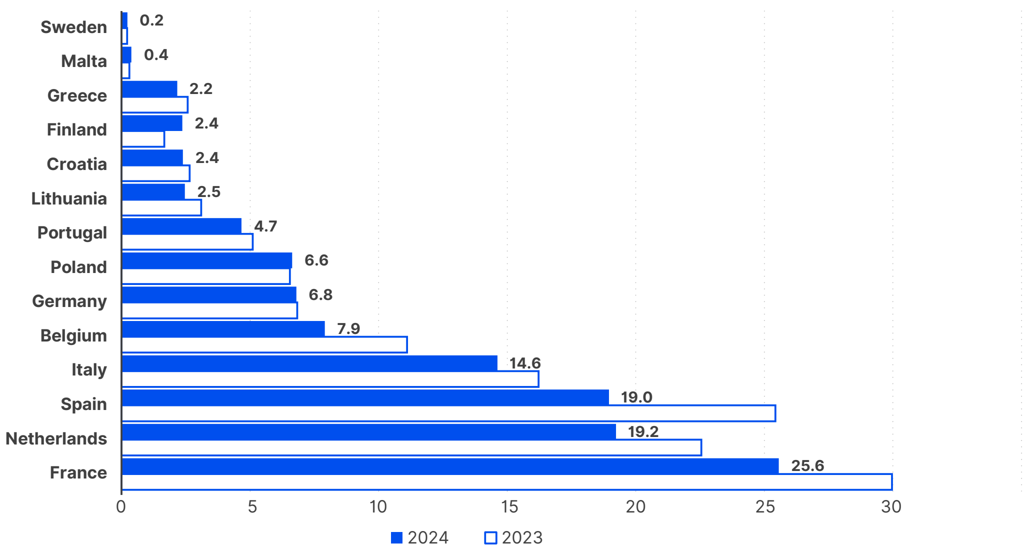


Source: ACER based on data from ICIS LNG Edge.

1.2.1. European LNG demand

20 Figure 9 illustrates the changes in LNG imports across EU countries in 2024 compared to the previous year, highlighting an overall decline of 17% in EU LNG imports, from 134 bcm to 112 bcm. The most significant reductions were observed in Spain, France, and the Netherlands, the EU's three largest LNG importers.

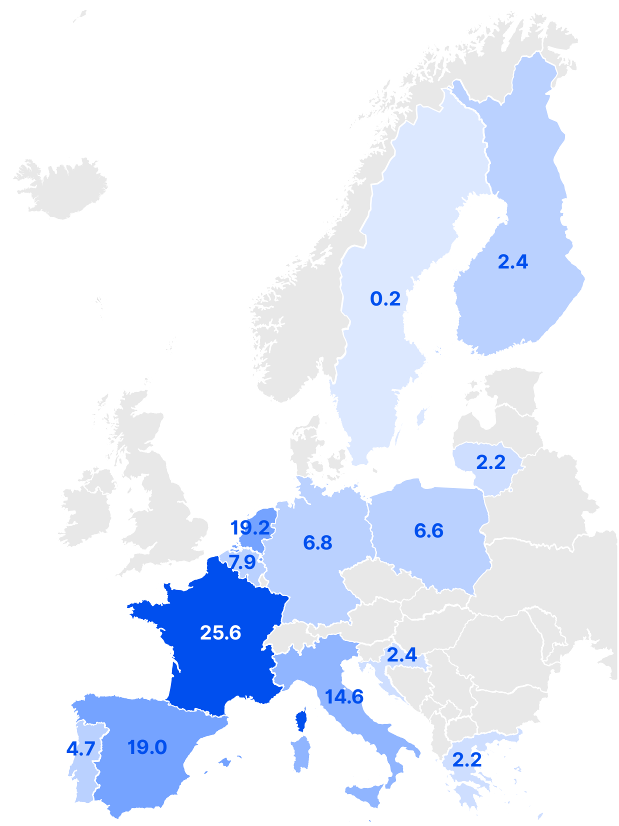
Figure 9: LNG demand variation year on year by EU Member State (bcm) - 2023 – 2024



Source: ACER based on data from ICIS LNG Edge.

21 Spain recorded the largest drop, with imports falling by nearly 8 bcm, followed by France with a reduction of over 4 bcm, and the Netherlands with a decrease of 3 bcm. Italy and Belgium also showed declining trends, as did Portugal, Lithuania, and Greece, though to a lesser extent. In contrast, imports in Germany, Poland, Croatia, Sweden, and Malta remained largely stable.

Figure 10: EU LNG imports by country in 2024, (bcm)

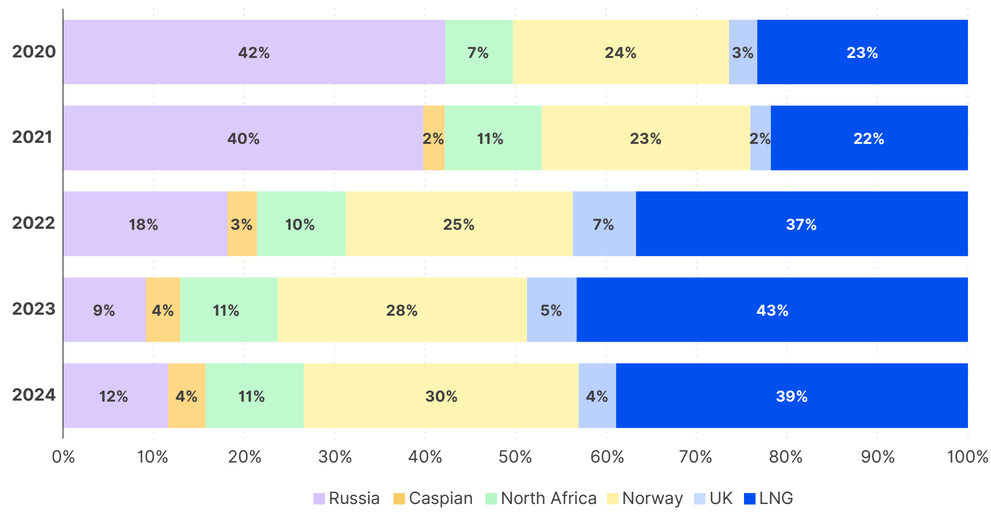


Source: ACER based on data from ICIS LNG Edge.

22 EU Member States imported 112 bcm of LNG in 2024. The figure represents around 40% of the total gas imports in the EU. As in 2023, France is the largest EU LNG importer with 26 bcm in 2024, surpassing Netherlands and Spain with 19 bcm each. Italy, Belgium, and Germany follow as largest LNG importing countries. The share of LNG in gas consumption differs among national markets. Based on the share of LNG in the country's gas consumption, the various roles of LNG terminal facilities are analysed in Chapter 3.

23 The decline in gas production in the EU is ongoing after the closure of the Dutch Groningen field. However, domestic biogas and biomethane production are expected to rise in line with the REPowerEU plan, which calls for a total production of 35 bcm by 2030. Biomethane production will partly compensate the steady drop in conventional gas production helping to reduce the dependence on external suppliers.

Figure 11: Evolution of gas deliveries into the EU by supply route - 2020 - 2024



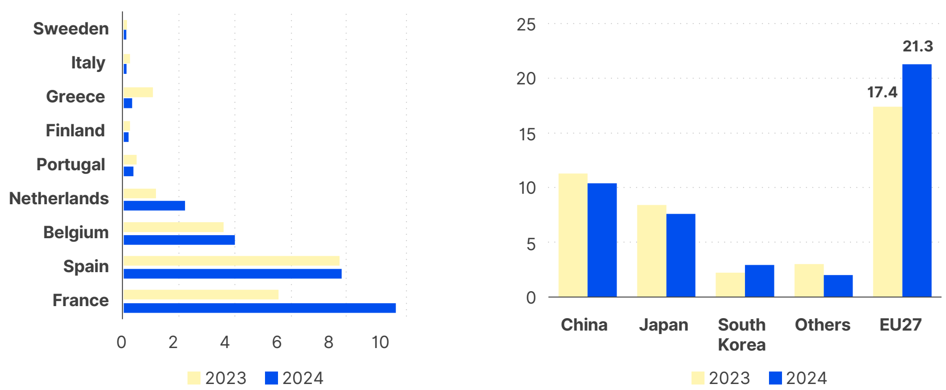
Source: ACER based on data from ENTSOG TP and ALSI GIE.

24 Figure 11 illustrates the shift in EU gas supply from 2020 to 2024, marked by a sharp decline in Russian gas from 42% to 12% and a rise in diversification. LNG nearly doubled its share (23% to 39%), becoming the EU's main source, while Norway's contribution rose from 24% to 30%. North Africa remained stable, and the Caspian region and UK showed minor changes. The most notable change occurred between 2021 and 2022, as Russia's share fell sharply, offset by increased LNG and Norwegian imports. By 2024, LNG and Norway accounted for over two-thirds of EU gas supply, highlighting a shift toward more secure and diverse sources.

Russian LNG imports to the European Union

25 The EU remains the largest importer of Russian gas today. In 2024, EU Member States imported 3.9 bcm more Russian LNG than in 2023 (see Figure 12). This increase was largely absorbed by France, which is now the EU's top importer of Russian LNG, followed by Spain and Belgium. Together, these three Member States accounted for 85% of the 21.3 bcm imported from Russia in 2024. While most of these volumes were consumed domestically, a significant share went to neighbouring markets[3]. However, the exact quantity of Russian LNG ultimately reaching other countries remains difficult to determine.

Figure 12: Russian LNG imports into the EU and global LNG exports - 2024 vs. 2023, (bcm)



Source: ACER based on data from ICIS LNG Edge.

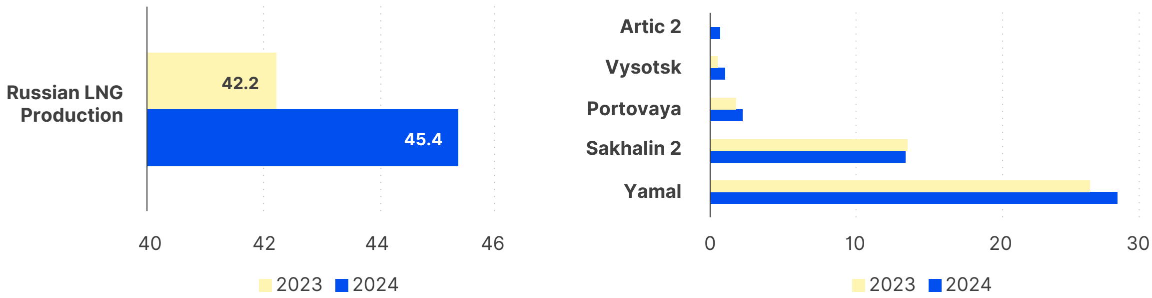
26 Most Russian LNG imported to the EU originates from the Yamal liquefaction plant. The Yamal plant provided 19.4 bcm out of a total of 21.3 bcm of Russian LNG imported into the EU in 2024. The remainder 1.9 bcm was sourced from the smaller Portovaya, Vysotsk, and Kaliningrad liquefaction plants. The Arctic 2 liquefaction plant has produced approximately 0.7 bcm since the beginning of 2024, but it halted operations in October/November 2024 due to significant challenges in finding buyers. Arctic 2 cargoes were successfully tracked, and the volumes from Arctic 2 did not physically reach the EU. However, some volumes committed under long-term contracts from Arctic 2 might have been replaced by surplus production from Yamal LNG.

3 A recent report by several German research centres titled 2024, a bumper year for Russian LNG exports to the EU – abetted by Germany, reveals that the German company SEFE GmbH purchased 58 LNG cargoes in 2024, totalling 5,7 bcm. This represents a six-and-a-half-fold increase compared to 2023. All shipments were delivered to the Dunkirk terminal in France, with significant volumes likely transported to Germany through the Belgian pipeline system. Out of the 8.4 bcm of Russian LNG unloaded in France in 2024, 5.5 bcm were unloaded in Dunkirk. Dunkirk is connected to the French and Belgian systems and the unloaded volumes were (roughly) evenly shared between these two systems.

27 Member States such as Estonia, Lithuania, Sweden or Germany[4] have already implemented national bans to import Russian LNG at their terminals. Furthermore, in June 2024, the EU adopted its 14th sanctions package against Russia, which introduced measures that ban transshipment of Russian LNG through EU ports to non-EU countries.

28 On 10 January 2025, the US imposed new sanctions on the Russian oil and gas sectors. Until then, the Biden administration had solely targeted new Russian LNG plants (Arctic LNG 2). However, this time, the US sanctioned two operational liquefaction plants: Gazprom's Portovaya LNG and Novatek's Vysotsk, which collectively exported 3.1 bcm of LNG in 2024, mainly to Europe and Turkey. The sanctions also targeted specific LNG vessels. Nonetheless, major facilities, such as the 23.6-bcm Yamal LNG and the 14.1-bcm Sakhalin II LNG terminals were not included.

Figure 13: Russian total LNG production per liquefaction plant – 2024 vs. 2023, (bcm)



Source: ACER based on data from ICIS LNG Edge.

REPowerEU roadmap to phase out Russian energy imports

29 On 6 May 2025, the European Commission presented the REPowerEU roadmap outlining the gradual phase-out of Russian oil, gas, and nuclear energy from EU markets. This strategy is part of the broader energy transition and includes several key actions related to gas and LNG:

- **Transparency and monitoring**: To enhance transparency and traceability of Russian gas imports, the European Commission will introduce a new legislative proposal. Under this framework, companies will be required to report contract details to both national authorities and the Commission. Additionally, authorities will coordinate efforts and share import data across customs authorities. Similar transparency requirements will be extended to all gas imports as part of the 2026 revision of the EU energy security architecture.

- **National phase-out plans**: Member States will be mandated to submit national plans outlining how they intend to phase out Russian gas, with initial submissions encouraged by the end of 2025. These plans must provide details on existing gas contracts, including take-or-pay clauses, and set out clear milestones along with infrastructure and diversification strategies. The implementation and alignment of these plans will be supported through coordination mechanisms, such as the Gas Coordination Group and regional platforms.

4 The German government has banned the state-owned company Deutsche Energy Terminal GmbH from importing Russian LNG, operating at Wilhelmshaven 1 & 2, Stade and Brunsbüttel terminals. That restriction may not apply to Deutsche Regas GmbH, a privately owned company.

- **Stepwise ban on Russian gas imports**: A legislative proposal will introduce a two-step ban on Russian gas imports. The first step, to be implemented by the end of 2025, will prohibit new contracts and spot & short-term volumes. The second step, scheduled for the end of 2027, will extend the ban to cover imports under existing long-term contracts. The feasibility of this timeline is supported by recent investments in LNG infrastructure, new domestic gas production, and increased interconnection capacity within the EU.

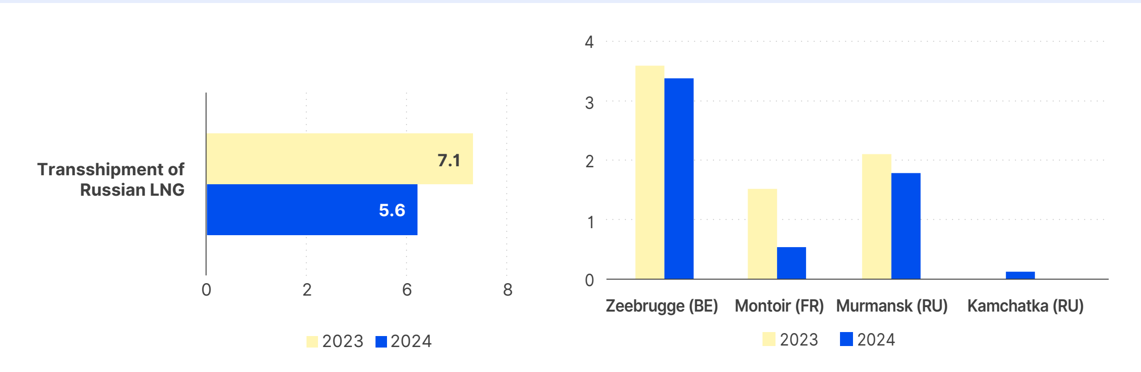
- **Diversification and Infrastructure optimisation**: The AggregateEU joint purchasing platform will be expanded to include renewable gases, such as biomethane. In parallel, infrastructure in Central and South-East Europe will be optimised through initiatives led by CESEC. The EU will also intensify its energy diplomacy to diversify supply sources. Further support for electrification, biomethane, and clean hydrogen will be delivered through the REPowerEU framework, including the establishment of a biogas network.

Russian LNG Transhipment (BOX)

The EU adopted in June 24 its 14th sanction package against Russia. This package introduced measures that ban transshipment of Russian LNG through EU ports to non-EU was immediately effective for new transshipments. It became effective for existing ones as of 26 March 2025, after a transition period of 9 months. Moreover, these sanctions prohibit imports of Russian LNG via terminals not connected to the EU natural gas system (e.g., Sweden and Finland), and forbid the provision of goods, technology, or services to support the completion of Russian LNG projects. The sanctions also extend to banning EU Member States from offering technical assistance, brokerage services, or financial support related to these transshipment activities.

The analysis of LNG transhipments[5] of Russian origin reveals that the actual volumes transhipped at EU ports decreased year-on-year by 1.5 bcm in 2024 relative to 2023 (see Figure 14). If these transhipped volumes had remained and consumed in the EU, they would have resulted in the rise of direct LNG imports into EU markets.

Figure 14: Transhipment of Russian LNG and operations' location - 2024 vs. 2023, (bcm)



Source: ICIS LNG Edge.

5 LNG transhipments refer to the transference of LNG from ship-to-ship, typically at a port or designated offshore facility. This is often done to optimize shipping logistics, reduce costs, or adapt to changes in trade routes and demand patterns

Table 1: Transhipment of Russian LNG and its destination market - 2024 vs. 2023 (volume and number of operations)

Russian LNG Transhimpment destination	2024 bcm	2023 bcm	Delta bcm	2023 #	2024 #
China	3.05	4.43	-1.38	32	48
India	0.29	0.65	-0.37	3	7
Italy	0	0.19	-0.19	0	1
Japan	0	0.08	-0.08	0	1
Kuwait	0.2	0.1	0.1	1	1
Singapore	0	0.09	-0.09	0	1
Spain	0.77	0.57	0.2	8	6
Taiwan	0.36	0.47	-0.11	4	5
Turkey	0.2	0.51	-0.31	2	6
Belgium	0.1	0	0.1	1	0
South Korea	0.45	0	0.45	5	0
Unknown	0.24	0	0.24		

Source: ICIS LNG Edge.

1.2.2. Drivers and outlook of LNG demand in the European Union

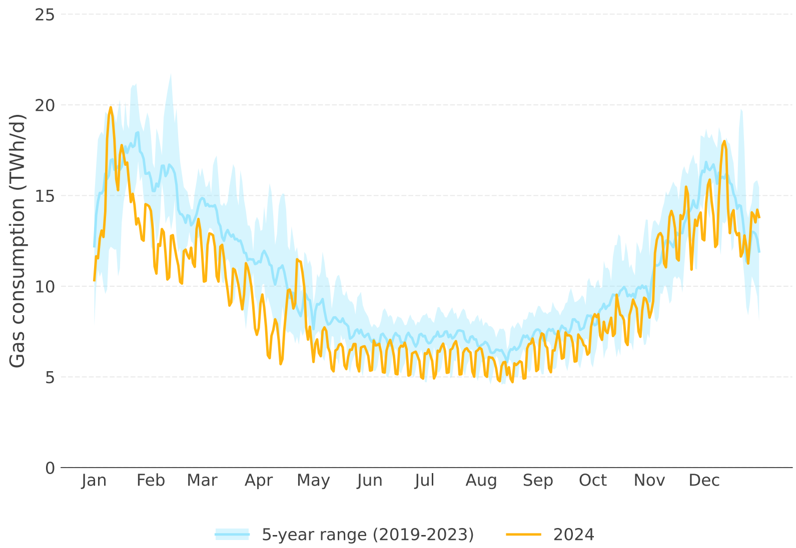
30 The growth of LNG imports in Europe must be understood in the broader context of Europe's natural gas supply and demand. Although LNG imports have increased in the last years due to the reduction of reliance on Russian gas piped supply, gas consumption has steadily decreased as a response to the energy crisis and discouraging high prices. Gas demand reduction is also driven by the ongoing shift toward electrification and decarbonisation of the EU's energy system, which are key priority areas in Draghi report[6] about a competitiveness strategy for Europe.

31 In this context, LNG is playing an increasing role as flexible and geographically diversified supply source in meeting natural gas demand in the EU. In 2024, gas demand rose by 0.6% year-on-year, reaching 3556 TWh (approximately 333 bcm). Despite this increase, gas consumption remains 12% below the 2019-2023 average and 17% lower than 2017-2021 pre-crisis levels. This 17% decline in demand was evenly distributed across industrial, electricity, and residential & commercial sectors.

6 The Draghi report on EU competitiveness.

32 As shown in Figure 15, gas demand exceeded the five-year average during certain periods of January and April 2024, and more notably during the last quarter of the year. This increase was driven by gas-fired power generation. In Q4 2024, overall gas demand was 9% higher than Q4-2022 and 17.6% higher than in Q4 2023.

Figure 15: Daily gas consumption in the European Union in 2024 compared to 2019-2023 – (TWh/d)



Source: ACER based on JRC's ENaGaD.

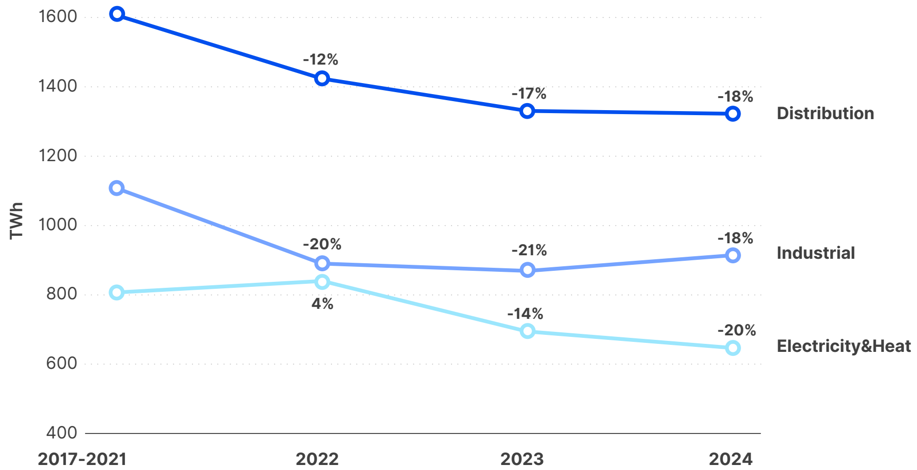
Note: Slovakia is missing in the EU aggregate.

33 Although gas demand for power generation rose in Q4 2024, annual gas demand in 2024 in the electricity sector declined by 7% compared to 2023 (Figure 16). Industrial gas demand increased by 5% in 2024 compared to 2023. Heating demand from residential & commercial segment remained stable but continued to fall short of the 2017-2021 average. Looking ahead, further reductions in gas demand are expected due to sustained energy efficiency, government-led savings initiatives, and the continued electrification of the heating sector.

34 In 2024, the power sector recorded the largest relative decline in gas demand. Gas-fired generation fell by 24 TWh (see Figure 17) offset by increased output from solar, hydro and nuclear. Compared to previous year solar generation rose by 41 TWh, hydro by 30 TWh and nuclear by an additional 30 TWh[7].

7 See expanded considerations in ACER report on key developments in European electricity and gas markets, 2025.

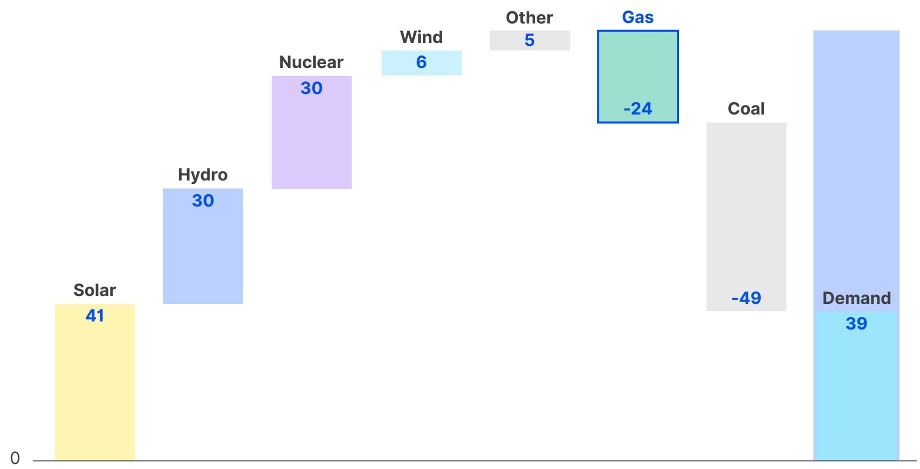
Figure 16: EU gas consumption evolution per sector, 2017-2024 (TWh)



Source: ACER based on JRC's ENaGaD and Eurostat.

Note: Estimated sectoral breakdown. The sectoral breakdown is based on 12 countries (BE, DE, EL, ES, FR, HR, HU, IE, IT, LU, NL, PT) which covered 83% of the 2024 EU gas consumption.

Figure 17: Year-on-year change for main electricity generation technologies in 2024



Source: ACER Key developments in European electricity and gas markets – 2025 Monitoring Report.

Note: ACER calculations based on ENTSO-E data. Note: Hydro does not include hydro-pumped storage. Hydro-pumped storage, biomass and other generation sources were accounted for separately, with other generation sources for which the aggregated variation in generation for 2024 was zero.

35 Figure 18 illustrates changes in electricity generation by technology compared to the five-year average. Wind and solar power continue to play a key role in advancing the energy transition by reducing reliance on fossil fuels such as gas and coal. However, the variability of solar and wind output makes the electricity system reliant on gas-fired power plants as flexible resource to quickly respond to residual demand variations. Such behaviour is evident in the complementary relationship between wind and gas-fired generation, particularly during Dunkelflaute episodes (periods of low wind and solar output) such as those observed in January and November 2024. In the case of coal-fired generation, 2024 output remained below the five-year average while both nuclear and hydropower rebounded, maintaining higher-than-average output for most of the year.

Figure 18: EU electricity generation from main sources in the period 2019-2024

Source: ACER based on ENTSOe.

Role of LNG in Europe by 2030

36 The European Commission has established two intermediate climate targets to achieve climate neutrality by 2050, as set out in the European Climate Law[8]. The EU's 2030 climate target aims to reduce greenhouse gas emissions by at least 55% compared to 1990 levels, under the legally binding 'Fit-for-55' (FF55) package. In February 2024, the European Commission presented its assessment for a 2040 climate target, proposing a reduction of at least 90% in net greenhouse gas emissions relative to 1990. While meeting the 2030 climate targets is not an end, it represents a critical milestone in keeping the EU on track to achieve its more ambitious 2040 climate objective.

37 Achieving the 2030 and 2040 EU climate targets will require a significant reduction in natural gas demand. The scale of this decline will depend on several factors, including progress in electrification, improvements in energy efficiency, energy prices, the implementation of gas-saving measures, and most importantly, the deployment of renewable and low-carbon technologies.

38 Launched in May 2022 in response to the energy market disruptions caused by Russia's invasion of Ukraine, the REPowerEU plan aims to rapidly phase out imports of Russian fossil fuels. It focuses on three key pillars: promoting energy savings, diversifying energy supply sources, and accelerating the deployment of renewable energy.

39 REPowerEU envisages an ambitious gas demand reduction of almost 50% compared to FF55 proposal by 2030. REPowerEU plan has led to a better winter preparedness by storing gas beyond the target of 90% of storage capacity by 1 November in the years 2022-2024 and reducing the EU gas import dependency (pipeline and LNG) on Russia, from 45% in 2021 to 15% in 2023 and 18% in 2024[9].

8 See European Climate Law, which writes into Law the objectives set out in the European Green Deal to become climate-neutral by 2050.

9 REPowerEU - 2 years on.

40 On 26 February 2025, the Commission adopted the Clean Industrial Deal[10] and the Affordable Energy Action plan[11] to enhance the EU competitiveness and boost the decarbonisation of the energy system. Affordable energy is essential for the transition to a low-carbon economy. In line with the REPowerEU plan, the initiatives emphasise accelerating the roll-out of clean energy and electrification, completing the internal energy market, and reducing the dependence on imported fossil fuels. Regarding natural gas markets, the plan calls for more flexible storage filling trajectories, led to the creation of a Gas Market Task Force to scrutinise the EU natural gas market to ensure well-functioning gas markets, and the aggregation of LNG demand to secure long-term contracts.

Tracking progress on REPowerEU targets

41 Solar photovoltaic (PV) deployment stands out as the only area currently on track to meet its 2030 target. The sector has shown strong and consistent growth, driven by supporting policies, declining costs, and investor confidence.

42 The development of heat pumps, while not yet fully aligned with the 2030 goals, is showing promising progress. The gap, though notable, is not as significant when compared to other technologies such as wind power and biomethane. Both sectors would require substantial acceleration to meet goals set out under REPowerEU compared to current annual growth rates.

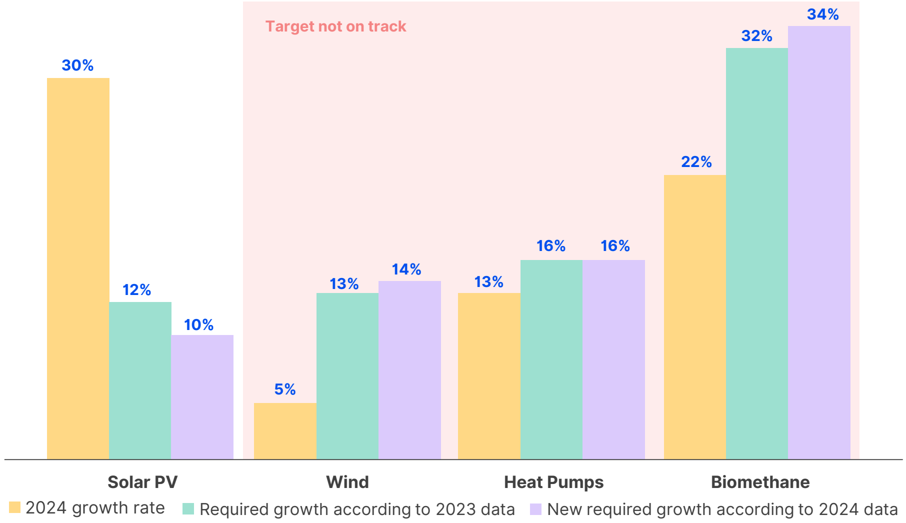
43 Renewable hydrogen faces several structural and technical barriers, including high production costs, limited infrastructure, and insufficient demand signals, all of which contribute to the widening gap between ambition and actual progress. At the current pace, the deployment of renewable hydrogen remains significantly below the level required to meet the 2030 targets.

44 Figure 19 compares the 2024 growth rates of key REPowerEU targets with the growth rates needed to meet the 2030 goals, based on 2023 data. The analysis covers solar PV and wind installed capacity, the number of heat pump units, biomethane production, and renewable hydrogen consumption. Among these, only solar PV is currently on track, requiring a steady annual growth rate of 10% to reach 592 GW by 2030. In contrast, all other targets need to grow faster than they did in 2023 to stay aligned with REPowerEU milestones.

10 The Clean Industrial Deal: A joint roadmap for competitiveness and decarbonisation. Brussels, 26 February 2025, COM(2025) 85 final.

11 Action Plan for Affordable Energy: Unlocking the true value of our Energy Union to secure affordable, efficient and clean energy for all Europeans. Brussels, 26 February 2025, COM(2025) 79 final.

Figure 19: Annual growth rates for various REPowerEU targets



Source: ACER based on data from European Commission, SolarPower Europe, Wind Europe, EHPA, EBA.

Note: The assessed REPowerEU targets are the solar PV and wind installed capacities, the number of heat pump units, the biomethane production, and the renewable hydrogen consumption. Note that the current growth rate is calculated as the difference between 2024 and 2023 values. The required growth rate is derived from the 2030 targets relative to 2023 levels, while the minimum growth rate reflects the necessary pace from 2024 onwards to meet the same targets.

45 REPowerEU set ambitious 2030 targets for the wind and solar PV installed capacities equal to 510 GW and 592 GW, respectively. In 2024, the solar PV capacity is 338 GW[12], on track to meet its target by 2030, while the wind installed capacity increased by 4.5% relative to 2023, reaching 231 GW in 2024[13] (which is not on track to meet its 2030 objective).

46 The roll-out of heat pumps and energy efficiency measures can save up to 37 bcm of gas consumption additional to the FF55 measures. The REPowerEU objective is to install at least 10 million additional heat pumps by 2027. According to the Commission's impact assessment for its 2040 climate target, nearly 60 million heat pump units should be installed in 2030. 21.5 million heat pumps had been installed in the EU by 2023, with 3 million heat pump units installed in 2022 alone[14]. The heat pump annual sales decreased by 7% in 2024. If this level of annual sales does not increase, the EU will not be on track to meet the target on heat pumps[15].

47 For renewable hydrogen, the REPowerEU target is to supply 20 million tonnes by 2030. 10 million tonnes to be produced within the EU, 6 million tonnes imported from third countries and 4 million tonnes supplied in the form of ammonia or other derivative chemical substances. This 20 million tonnes are intended to replace 25-50 bcm of natural gas[16]. A 2024 assessment of the European Court of Auditors found that the EU is not on track to meet this goal[17].

12 SolarPower Europe.

13 Wind Europe.

14 European Commission, Joint Research Centre, Toleikyte, A., Lecomte, E., Volt, J., Lyons, L., Roca Reina, J.C., Georgakaki, A., Letout, S., Mountraki, A., Wegener, M., Schmitz, A., Clean Energy Technology Observatory: Heat Pumps in the European Union - 2024 Status Report on Technology Development, Trends, Value Chains and Markets, Publications Office of the European Union, Luxembourg, 2024, https://data.europa.eu/doi/10.2760/7205477, JRC139377.

15 European Heat Pump Market and Statistics Report 2024.

16 RePowerEU: Can Renewable Gas help reduce Russian gas imports by 2030? The Oxford Institute for Energy Studies, July 2022.

17 The EU's industrial policy on renewable hydrogen. European Court of Auditors, 2024.

Some obstacles include technological challenges, lack of a detailed implementation plan, misalignment between Member States' objectives and EU targets and uncertainty regarding how the EU regulation framework will impact the cost competitiveness of renewable hydrogen.

48 The REPowerEU plan sets a biomethane production target of 35 bcm by 2030, an increase of approximately 20 bcm over the target outlined in the Fit for 55 package. The European Biogas Association (EBA) estimates that biomethane production potential could reach 41 bcm by 2030. As of 2024, EU biomethane production capacity stood at 6.4 bcm. Reaching the 2030 target an will require a faster deployment with stronger policy support to improve market viability, streamline permitting, upgrade gas grid infrastructure and improve cross-border certification systems.

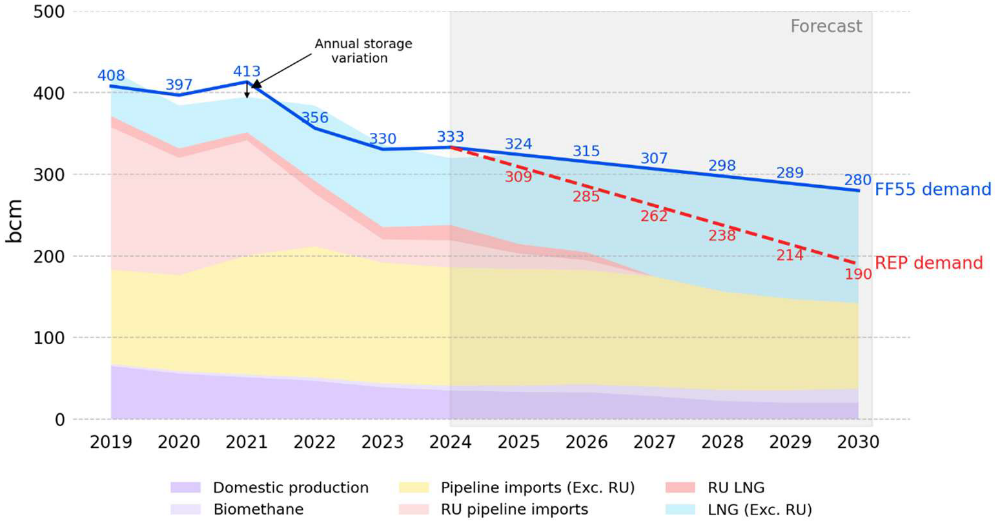
49 This report factors in the European Commission's FF55[18] and the even more ambitious REPowerEU demand scenarios as referential benchmarks to project EU gas demand. On that basis, we conduct an analysis of the EU's LNG import needs up to 2030. Figure 20 offers a simplified overview of the potential balance between EU gas sourcing options to meet the EU gas demand through 2030. Two scenarios of gas demand are considered. The FF55 scenario, in which there is a drop by 32% in natural gas consumption in 2030 relative to 2019 figures, and the most ambitious REPowerEU (REP) target (without considering the gas savings related to renewable hydrogen targets), which is 32% lower than the projected FF55 demand.

50 In line with REPowerEU and its roadmap to end Russian energy imports, all Russian gas, both LNG and pipeline, is phased out by 2027. This scenario assumes that non-Russian pipeline imports remain relatively stable, while LNG provides the flexibility needed to balance EU gas demand[19].

18 We rely on the published scenario MIX-CP, which is one of the three policy scenarios for analysing the impact of the legislation proposed under the European Green Deal. The suitability of this scenario may have changed as the energy landscape and the national policies have been evolving in the last years.

19 The supply-demand balance through 2030, under two demand scenarios, is based on high-level assumptions rather than in-depth modelling. On the demand side, we assume a linear decline to meet the corresponding demand targets in 2030. On the supply side, domestic gas production is assumed to remain stable until 2027, when more liquefaction capacity comes online, after which a decreasing trend in indigenous production is projected. A similar approach has been applied to pipeline imports into the EU. The biomethane production target of 17 bcm by 2030 is a conservative estimate that could be surpassed should access to biomethane production get more support in accessing the grid and get closer to the 35 bcm foreseen by REPowerEU.

Figure 20: EU gas supply under Fit-for-55 and REPowerEU demand scenarios by 2030 (bcm)



Source: ACER based on data from ICIS, S&P Global, ENTSOG, AGSI GIE, Eurostat, and REPowerEU.

Note: The demand evolution from 2025 to 2030 reflects a linear decrease in alignment with the target set for 2030. The potential gas demand reduction described in REPowerEU linked to the 20 Mt goal for renewable hydrogen by 2030 is not factored in the assessed scenario.

51 Under the REPowerEU scenario[20], LNG imports are gradually declining. This is because the plan foresees an ambitious reduction of natural gas consumption to around 190 bcm provided most of the proposed targets are met.

52 Under the FF55 scenario, LNG imports could stabilise at levels similar to those observed in 2022-2024 in the next two years. However, LNG imports may still rise from 2027 onwards due to higher relative demand. In both demand scenarios, the expansion of the global liquefaction capacity could alleviate price pressures. The analysis may vary across EU regions; in this respect though, the strong integration of the European gas system is expected to mitigate potential pressures.

53 A linear decline in natural gas consumption has been assumed for both scenarios. However, the pace of the energy transition through this decade may vary, potentially at a slower pace in the earlier years, and possibly accelerating later on. This trajectory will depend on the implementation of national energy policies, decarbonisation goals, the financing and permitting of renewable energy projects, and security of supply considerations.

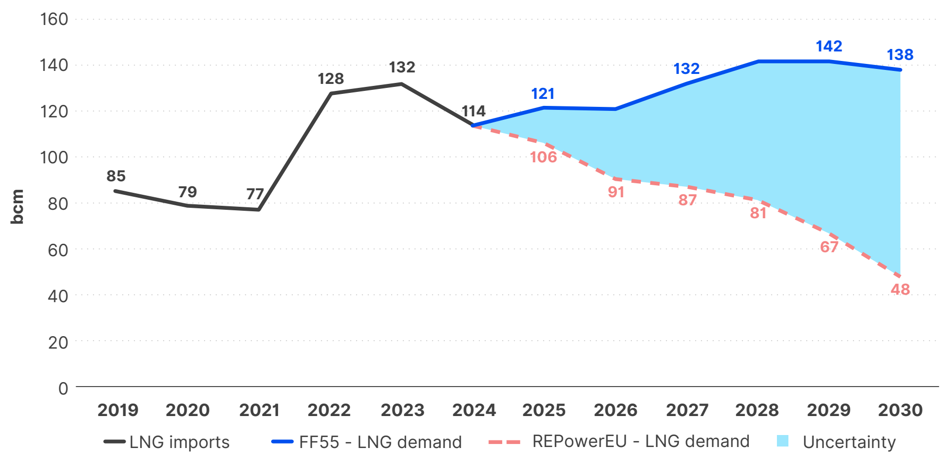
54 By 2030, the LNG imports required to bridge the supply gap in the EU are projected to range from 48 bcm under the REPowerEU scenario to 138 bcm in the FF55 scenario, see Figure 21. The midpoint trajectory supports to understand why it is important to maintain the flexibility in LNG contractual arrangements. Such flexibility will effectively accommodate the decreasing yet uncertain trajectory of EU demand.

20 Note that the potential gas demand reduction described in REPowerEU linked to the 20 Mt goal for renewable hydrogen by 2030 is not factored in the assessed scenario.

55 Security of supply comes with cost considerations against which benefits are weighed. Short-term flexibility benefits should be complemented with long-term contracts, which offer price stability and supply reliability. It is essential to ensure sufficient flexibility in long-term contracts as those contractual flexibilities will allow to manage a potential over-contracted position in the future. From the perspective of producers, these agreements play a critical role in securing investments in LNG production infrastructure and are also aligned with the practice of booking long-term capacity at regasification plants. From the buyers' perspective, the short-term and spot market purchases are more flexible but come with higher costs and higher price volatility risks.

56 Using simplified assumptions, Figure 20 assesses the future role of LNG in meeting the EU gas demand. These include fluctuations in price, global competition for LNG resources, the progression of legacy supply contracts in the EU, and the availability of alternative pipeline supplies. As opposed to simplified assumptions, a modelling exercise would require considering potential phase-in of hydrogen infrastructure and how this relates to the gas system adequacy.

Figure 21: LNG imports under Fit-for-55 and REPowerEU scenarios (bcm) in 2025-2030



Source: ACER based on data from ICIS, S&P Global, ENTSOG, AGSI GIE, Eurostat, and REPowerEU.

57 The projected gap in future LNG demand between the Fit for 55 and REPowerEU scenarios could be as large as 90 bcm. A key distinction between the two lies in their legal status: Fit for 55, launched in July 2021, is legally binding, while REPowerEU, introduced in May 2022, is not. Nonetheless, REPowerEU reflects a higher level of ambition, aiming to accelerate the energy transition by mobilising additional funding and aligning various EU programmes, as outlined in Table 2.

58 Even if some targets are met a bit later than 2030, gas demand is still expected to follow a trajectory closer to the REPowerEU scenario than the Fit-for-55 baseline. This is mainly due to the progress already achieved and the anticipated rollout of clean energy technologies, supported by EU programmes and funding mechanisms outlined in Table 2. These efforts are pushing gas demand reductions further toward REPowerEU goals and beyond the original Fit-for-55 objective.

59 A growing number of industry stakeholders have raised concerns about the REPowerEU targets, arguing that they may be overly ambitious. These concerns suggest that the actual pace of development across some clean energy technologies is likely to fall short of the 2030 objectives set by the European Union.

60 Monitoring decarbonisation progress is essential to understand how different technologies are advancing toward the EU's decarbonisation targets. Improved tracking efforts would allow policymakers to anticipate delays and respond with targeted support or policy adjustments to keep progress on track. Currently, data on decarbonisation is fragmented across Member States, regulators, and EU institutions. Improving coordination and effective exchange of data would strengthen monitoring of decarbonisation progress by reducing uncertainty while enabling faster response when technologies fall behind target trajectories.

Table 2: EU funds and programs supporting the achievement of REPowerEU targets

Programme/Fund	Contribution to REPower EU	Estimated Funding for REPowerEU
Recovery and Resilience Facility (RRF)[21]	Main vehicle for REPowerEU; supports renewables, efficiency, grid investments, and energy independence	€270 billion (grants + loans); €20 billion in new grants for REPowerEU chapters
Connecting Europe Facility (CEF) – Energy[22]	Funds cross-border energy infrastructure: LNG terminals, electricity interconnectors, hydrogen networks	Approx. €5.8 billion (2021–2027) for energy
Innovation Fund[23]	Financed by the EU ETS; supports large-scale clean tech projects: hydrogen, CCS, renewables, storage	Up to €38 billion (2020–2030) depending on carbon prices
Modernisation Fund[24]	Helps lower-income Member States supporting investment in renewable energy, energy efficiency, energy storage and energy networks	€48 billion (2021–2030), funded through ETS revenues
InvestEU[25]	Helps accelerating lending, blending and advisory products for renewables, energy efficiency and electricity networks.	€372 billion in total investment mobilised; includes green transition window
Cohesion Policy Funds (ERDF & Cohesion Fund)[26, 27]	Supports energy transition in less developed regions, renewables, smart grids	€100+ billion (2021–2027) across all priorities
Horizon Europe[28]	Funds R&D in clean energy, hydrogen, energy system integration	€95.5 billion (2021–2027) total; energy transition is a major pillar

21 https://commission.europa.eu/strategy-and-policy/priorities-2019-2024/european-green-deal/repowereu-affordable-secure-and-sustainable-energy-europe_en#how-repowereu-is-funded.

22 https://cinea.ec.europa.eu/programmes/connecting-europe-facility/energy-infrastructure-connecting-europe-facility-0_en.

23 https://research-and-innovation.ec.europa.eu/research-area/energy_en.

24 https://climate.ec.europa.eu/eu-action/eu-funding-climate-action/modernisation-fund_en.

25 https://investeu.europa.eu/index_en?prefLang=el.

26 https://ec.europa.eu/regional_policy/funding/cohesion-fund_en.

27 https://commission.europa.eu/funding-tenders/find-funding/eu-funding-programmes/european-regional-development-fund-erdf_en.

28 https://research-and-innovation.ec.europa.eu/funding/funding-opportunities/funding-programmes-and-open-calls/horizon-europe_en.

The Fit for 55 package and global climate measures: Implications for LNG shipping (BOX)

Beyond the methane requirements for importers under the EU Methane Regulation, additional EU and global climate policies are reshaping the LNG shipping supply chain. The extension of the EU Emissions Trading System (EU ETS) to maritime transport and the new FuelEU Maritime Regulation introduce direct compliance obligations and price signals. Meanwhile, international negotiations at the International Maritime Organization (IMO) could soon align global shipping with these regional efforts. Together, these measures are set to reshape the cost structure, compliance strategies, and fuel choices for LNG carriers serving the EU market.

EU ETS extension to maritime transport

Since January 2024, the EU ETS applies to CO_2 emissions from large ships (over 5,000 gross tonnage), including LNG carriers. Coverage will expand in 2026 to include methane and nitrous oxide. Operators must surrender allowances for 40% of CO_2 emissions in 2024, rising to full coverage from 2026. However, only 50% of emissions from EU–non-EU voyages are covered, partially limiting the overall cost impact. ETS allowance prices have fluctuated between €60 and €100 per tonne of CO_2 in recent years, with market expectations pointing towards rising prices over the coming decades as emissions caps tighten and market maturity increases.

FuelEU Maritime and LNG Fuel Standards

Effective January 2025, FuelEU Maritime sets greenhouse gas intensity limits for ship fuels. Targets become progressively stricter, from 2% in 2025 to 80% in 2050. The regulation applies to ships over 5,000 gross tonnage, covering 100% of energy use on intra-EU voyages and 50% on international routes.

LNG-fuelled ships initially benefit from favourable default values and compliance flexibility under FuelEU Maritime. Most LNG carriers are expected to generate surplus credits in the early years, which can be banked or pooled. However, this advantage is expected to erode after 2030 as targets tighten and methane slip factors are tightened[29].

Developments at IMO

In 2023, the IMO adopted a revised greenhouse gas strategy, aiming for net-zero emissions from international shipping by around 2050. Interim targets include at least 20% reductions by 2030 and 70% by 2040, relative to 2008.

At its Marine Environment Protection Committee (MEPC) 83 meeting in 2025, IMO member states reached political agreement on a global greenhouse gas pricing mechanism and fuel standard, expected to enter into force by 2028. The package combines a hybrid levy and credit trading system, with revenues supporting clean fuel deployment and just transition efforts. Although final pricing levels are not yet defined, early estimates suggest the IMO mechanism could raise significant revenues and progressively increase cost pressures on fossil-fuelled vessels through the 2030s. If confirmed, these measures would apply globally, reinforcing EU initiatives and covering emissions from international voyages not fully addressed by EU law.

29 See the DNV white paper [FuelEU Maritime – Requirements, compliance strategies, and commercial impacts].

Potential implications for LNG transport by sea

In the near term, the EU ETS and FuelEU Maritime will increase compliance costs for LNG shipping, but the overall impact on delivered LNG prices is expected to remain limited. Partial coverage of international voyages and flexibility mechanisms, such as allowance trading, credit pooling, and bioLNG blending, will help mitigate early effects.

However, this modest short-term impact masks a progressive tightening of obligations. As FuelEU Maritime targets rise after 2030 and methane slip factors are revised, compliance costs for LNG carriers are set to grow, especially on long-haul routes. Initial assessments of the IMO agreement suggest a similar trajectory for LNG-fuelled ships possibly face a rising penalty, particularly from 2033 onward[30].

These growing costs will also increase contractual complexity. Although modest relative to LNG cargo values, they could become significant compared to the margins of shipping operators. Ship owners, as the obligated entities, will seek to pass through costs to charterers or importers. This will require clear contractual arrangements to ensure cost recovery and compliance with the changed rules.

Taken together, these measures point to rising LNG shipping costs over the coming decade, with increasing implications for the price, contractual structuring, and competitiveness of LNG deliveries to Europe. LNG carriers will also face greater pressure to differentiate through lower emissions and verified performance.

Table 3: Regulatory coverage across the LNG supply chain (with LCA Approach)

Supply Chain Segment	EU Methane Regulation	EU ETS (Maritime)	FuelEU Maritime
Upstream production	◑ Indirectly regulated via importer MRV disclosure	✕ Not covered (TTW only)	◑ Indirectly regulated via life-cycle approach (WtW)
Liquefaction & export	◑ Indirectly covered via importer MRV disclosure	✕ Not covered (TTW only)	◑ Indirectly regulated via life-cycle approach (WtW)
LNG shipping	✕ Not regulated	✔ CO_2 (2024), CH_4 & N_2O (2026) — TTW only	✔ GHG intensity limits on fuel used — WtW
LNG import terminals	✔ Directly regulated (MRV, LDAR, flaring restrictions)	✕ Not regulated	✕ Not regulated
LNG importers	✔ Reporting & contract compliance obligations	✕ Not regulated	✕ Not regulated

Note:

TTW = Tank-to-Wake, referring to emissions produced onboard the ship during fuel combustion. WtW = Well-to-Wake, a full life-cycle approach that includes both upstream (fuel production, processing, and transport) and onboard emissions.

LCA = life cycle assessment

FuelEU Maritime applies to ships ≥5,000 GT calling at EU ports and covers 100% of energy used during intra-EU voyages and port stays, and 50% of energy used on international voyages.

The EU ETS applies to ships ≥5,000 GT and covers 100% of emissions from intra-EU voyages, 50% from voyages between EU and non-EU ports, and 100% of emissions during port stays at EU ports.

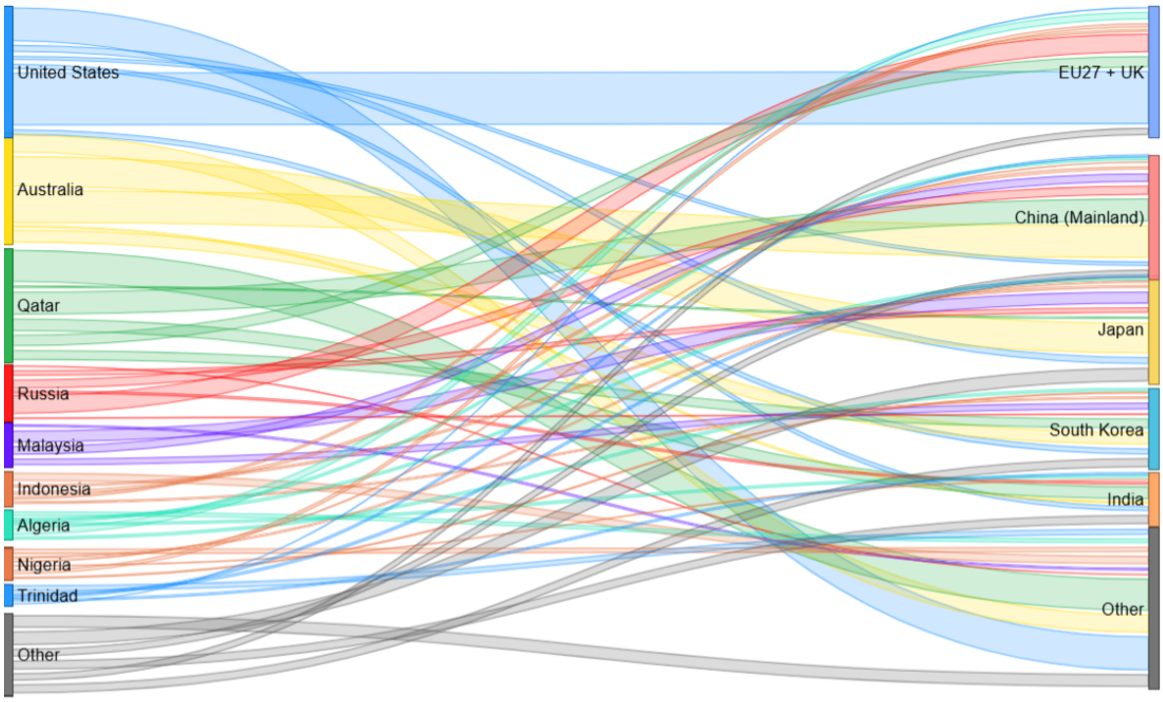
30 Readout of the IMO MEPC 83 by the UCL Shipping and Oceans Research Group.

2. LNG trade

61 This chapter provides a comprehensive overview of LNG trade, with a particular focus on the structure and evolution of contractual arrangements and pricing mechanisms. It examines the balance between long-term contracted positions and reliance on the spot market across key regions, with special emphasis on Europe. The analysis highlights the role of uncommitted volumes held by portfolio players, along with spare capacity made available by expiring legacy contracts, as an alternative supply buffer, complementing new liquefaction capacity being developed, in meeting future demand and enhancing market flexibility. Finally, the chapter offers key insights from ACER's LNG Daily Price Assessment, shedding light on spot LNG prices, regional price differentials, and the increasing role of market-based indices in shaping LNG spot trade.

62 In 2024, global LNG trade continued to expand, connecting 20 producing countries to 51 importing markets reflecting an increasingly interconnected and diversified LNG trade landscape. Figure 22 illustrates LNG trade showing the volume and direction of LNG flows where line thickness represents traded volumes between exporters (on the left) and importers (on the right).

Figure 22: Sankey diagram of bilateral global LNG trade in 2024 (Mt)



Source: ACER based on data from ICIS LNG Edge.

63 The United States stands out as the single largest exporter serving the EU27 + UK region. Russia, while facing sanction-related constraints, remained the second largest supplier to the EU which continues diversifying its energy sourcing, pursuing its strategic goal of reducing reliance on Russian fossil fuels. Qatar, one of the world's traditional top LNG exporters, currently ranks as the third-largest supplier to the European market. It is expected to return to the second position as soon as new long-term contracts come into effect when additional liquefaction capacity, currently under construction, enters commercial operation.

64 Other important suppliers to Europe's LNG mix include Algeria, Nigeria, and Trinidad & Tobago. While their export volumes are significantly smaller compared to the top three (United States, Russia, and Qatar), they continue to play a valuable role in supporting the region's energy security and supply diversification efforts.

65 Qatar keeps supplying considerable volumes to Southeast Asia, including major flows to India, China, and Japan. Australia also plays a critical role, with significant export volumes to Japan, China, and South Korea. This longstanding trading relationship is supported by geographic proximity and long-term supply contracts, particularly with Japan and South Korea. Other key exporters serving Asian markets, although with smaller volumes, are Malaysia and Indonesia.

66 Established LNG flow patterns have traditionally been underpinned by long-term commitments between exporters and importers, infrastructure investments, and geopolitical alignment shaping the global LNG market for decades. However, the recent rise in trade-related taxation and protectionist policies introduces a new layer of uncertainty that could prompt a structural shift in global LNG flows. Such reconfiguration of LNG flows could have an impact on price dynamics, shipping routes, contract structures, and even investment decisions.

Possible effects of US trade tariffs on LNG trade (BOX)

Earlier this year the United States (US) announced, initiated and imposed several new tariffs to different countries and products:

- On 31 January, the US Administration threatened 100% tariffs on BRICS member countries provided that they replace the US dollar as a reserve currency.
- On 4 February, the US introduced 25% tariffs on all imported products from Mexico and Canada (limiting the tariff on Canadian energy resources to 10%). On the same day, 10% tariffs on all Chinese imports were also introduced, which were later raised to 20% on March 4th.
- On 13 February, a US presidential memorandum was signed to develop the 'Fair and Reciprocal' Plan aimed at addressing trade deficits by setting tariffs that match those imposed by other countries.
- On 26 February the US announced 25% tariffs on imports from the EU.
- On 7 March, the US threatened Russia with tariffs, among other measures, until a final settlement agreement on peace is reached with Ukraine.
- On 12 March, the US imposed 25% tariff on all imports of steel and aluminium.
- On 13 March, the US threatened, following EU's countermeasures announcement, a 200% tariff on alcoholic beverages from the EU.
- On 24 March, the US announced 25% tariffs on any country that buys oil and gas from Venezuela.

- On 2 April, the US announced a 10% universal tariff, plus additional reciprocal higher tariffs for trading partners with which the US has a trade deficit that vary according to the specific trade balance. For the EU these announced tariffs were 20%.

- On 9 April, the US announced a 90-day pause on reciprocal tariffs for all countries with the exception of China. In addition, the US announced the increase to 125% of tariffs on Chinese goods in the framework of the reciprocal tariffs in reaction to China's retaliation.

- On 16 May, the US agreed to cut the extra tariffs it imposed on Chinese imports to 30% from 145% for next three months, while China committed to cutting duties on US imports to 10% from 125%.

Countermeasures

Canada has responded with a 25% tariff on US imported goods and recently imposed an additional and reciprocal 25% tariff on steel and aluminium products, as well as on additional imported US goods for a total of $29.8 billion. Moreover, the Canadian government is considering a second round of tariffs and is seeking views on imposing tariffs on additional import goods of a value of $125 billion from the United States[31].

China reciprocated, on 10 February, with tariffs of 10-15% on a list of different US products (including a 15% tariff on US LNG) complemented later with 10-15% tariffs on additional import goods (including agricultural products)[32]. On 10 and 12 April China further retaliated against additional tariffs imposed by the US early April, increasing tariffs on US goods to 125%.

On 12 March, following the US Steel and Aluminium tariffs, the European Commission announced, the reimposition of the suspended 2018 and 2020 rebalancing measures (automatically reinstated once their suspension expires on 31 March) and targeting US imported goods ranging from boats to bourbon to motorbikes. Additionally, the European Commission will adopt a new package of additional measures applying to EUR 18 billion of US imports expected to enter into force mid-April, following a public consultation with Member States and stakeholders. The target products proposed include a mixture of industrial and agricultural products[33].

Moreover, on 13 April, after the US announcement on universal tariffs the European Commission announced to be ready to negotiate with the US to remove 'any remaining barriers to transatlantic trade', but also stated being ready to respond and preparing for further countermeasures to protect EU interests and businesses if negotiations fail[34].

31 Canada's response to US tariffs on Canadian goods.

32 Announcement of the State Council Tariff Commission on imposing additional tariffs on some imported goods originating from the United States.

33 Memo on EU countermeasures on US tariffs.

34 Statement by President von der Leyen on the announcement of universal tariffs by the US.

On the EU side, the president of the European Commission, Ursula von der Leyen, suggested[35] last year that the EU could consider buying more LNG to further reduce EU's imports of Russian gas. The European Commission has also announced that it is considering developing a policy to support investment in export infrastructure in LNG producing countries[36]. Any development in this area could also have an impact on further adjustment of global LNG flows.

Possible effects of US tariffs on international LNG trade

Between 2021 and 2023 Chinese importers signed various long-term LNG contracts and US LNG imports are expected to rise in the coming years if all expected projects are implemented. The recent round of tariffs could redirect US LNG supplies toward European gas markets.

Table 4: Contracts between US LNG projects and Chinese companies

Date	Seller	Buyer	Quantity (mtpa)	Start	Duration (years)
Existing LNG projects and projects under construction					
Feb.18	Cheniere	PetroChina	1.2	2018	25
Oct.21	Cheniere Energy	ENN	0.9	Jul.22	~13
Nov.21	Cheniere Energy	Sinochem	0.9-1.8	Jul.22	17.5
Nov.21	Cheniere Energy	Foran Energy Group	0.3	2023	20
Nov.21	Venture Global LNG	Sinopec	4.0*	Plaquemines LNG	20
Nov.21	Venture Global LNG	UNIPEC	1	Mar.23	3
Dec.21	Venture Global LNG	CNOOC	2	Plaquemines LNG	20
Dec.21	Venture Global LNG	CNOOC	0.5	Mar.23	3
Apr.22	NextDecade	ENN	1.5	Rio Grande LNG	20
Jul.22	NextDecade	China Gas	1	Rio Grande LNG (T2)	20
Jul.22	NextDecade	Guangdong Energy	1-1.5**	Rio Grande LNG (T2)	20
Jul.22	Cheniere Energy	PetroChina	1.8	Corpus Christi Stage 3	25
Feb.23	Venture Global	China Gas Holdings	1	Plaquemines LNG	20
			17.1-18.5		

35 Stated during the questions and answers part of the press conference following the informal meeting of heads of state or government on November 8th 2024 in Budapest.

36 Action Plan for Affordable Energy.

Date	Seller	Buyer	Quantity (mtpa)	Start	Duration (years)
Planned LNG projects					
Mar.22	ET LNG	ENN NG	1.8	Lake Charles LNG	20
Mar.22	ET LNG	ENN Energy	0.9	Lake Charles LNG	20
Jun.22	ET LNG	China Gas	0.7	Lake Charles LNG	25
Feb.23	Venture Global	China Gas Holdings	1	CP2***	20
Jun.23	Cheniere	ENN	1.8	SPL Expansion Project****	20
Nov.23	Cheniere	Foran	0.9	SPL Expansion Project	20
			7.1		

**The contract with Sinopec consists of two contracts of 2.8 and 1.2 million tonns, respectively, but they are often aggregated and reported with a total of 4 million tonns.*

*** Right to buy an additional 0.5 million tonns.*

****CP2:.*

*****SPL: Sabine Pass Liquefaction.*

In 2018 and 2019, when the US first imposed tariffs on Chinese goods, China responded with a range of tariffs on different US imports, including a 10% tariff on LNG, which was later increased to 25%. The US LNG exports to China fall to zero from March 2019 to April 2020.

While tensions could make Chinese companies cautious about signing new long-term contracts, the flexibility of US LNG destination gives Chinese US LNG importers the opportunity to minimize the impact of the Chinese tariffs on US LNG imports by redirecting American contracted LNG cargoes to other markets, like Europe.

Therefore, US tariffs and countermeasures imposed by the affected countries could lead to a range of adjustments in global LNG markets flows. The overall impact would be determined by the evolution of the scope, nature and duration of the tariffs, the reactions from other international partners and the ability of US LNG importers to adapt to a changing environment.

2.1. Contractual positions

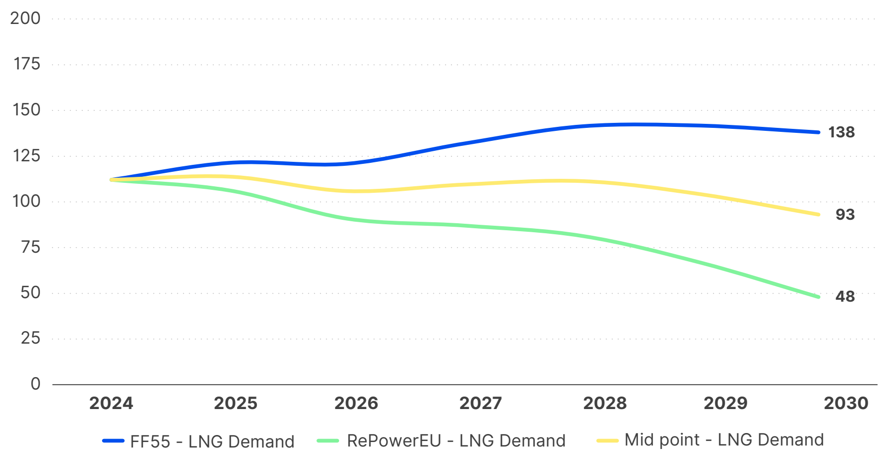
2.1.1. EU contractual LNG position

67 As Europe undergoes a structural transformation of its energy mix, the role of LNG has become increasingly important as a flexible source of supply in ensuring both energy security and supply diversification. Building on the demand and supply outlook through 2030 outlined in Section 1.2.1, this section examines the EU's LNG contracting landscape, with a focus on the balance between long-term contractual commitments and exposure to the short-term and spot markets. The analysis aims to quantify the share of expected LNG demand already secured through existing agreements under each demand scenario, and to identify the remaining volumes that will need to be sourced on the spot market.

68 To carry out this analysis, ACER conducted a comprehensive assessment of the contractual positions held by buyers importing LNG into the EU. While it is important to recognise that the available data on some individual contracts may be limited or subject to uncertainty, the results and conclusions derived from this assessment are considered robust. Moreover, the findings are broadly consistent with observable trends in the LNG industry, reinforcing the validity of the analytical approach.

69 The assessment begins by analysing the contracted volumes already secured for the European market under long-term, mid-term and short-term LNG supply agreements. This involves mapping the existing contracts expected to remain in force throughout this decade. The analysis assumes that these contracts will expire as originally scheduled, without renewals or extensions beyond their original end date. Based on this foundation, the analyses then evaluate the uncontracted volumes of LNG by comparing projected EU's LNG import needs under each decarbonisation demand scenario Fit for 55 and REPowerEU with the secured contracted supply. The resulting supply gap represents the volumes that would need to be sourced from the spot market.

Figure 23: LNG import requirements under decarbonisation scenarios (bcm)



Source: ACER based on Fit for 55 and REPower EU policies.

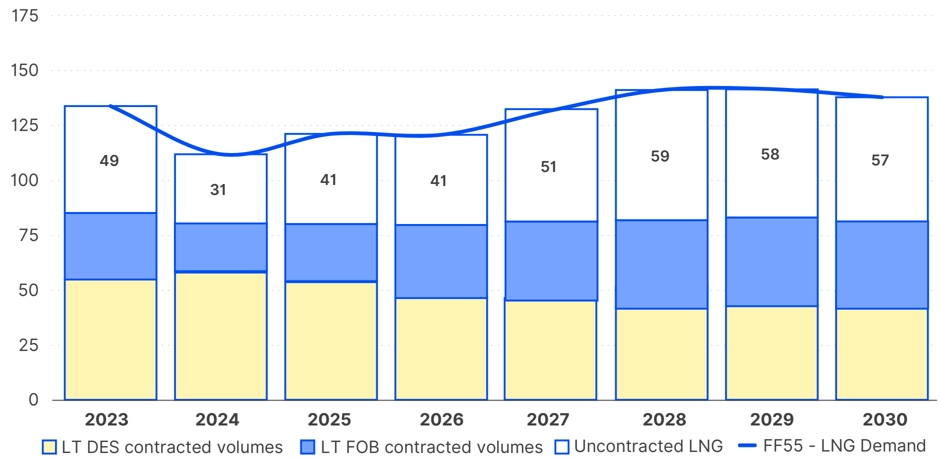
70 Figure 23 illustrates projected LNG import needs in Europe from 2025 to 2030 under two decarbonisation scenarios:

- Fit for 55 (FF55) – represented by the dark blue line, shows the highest projected LNG import demand, rising steadily from about 120 bcm in 2024 to approximately 138 bcm by 2030.
- REPowerEU – shown in green, presents the lowest LNG demand trajectory, starting similarly around 120 bcm in 2024 but declining sharply to around 50 bcm by 2030.

71 There is a significant uncertainty between the two demand scenarios, ranging from close to 50 bcm to around 140 bcm of LNG needs by 2030, with a divergence of over 90 bcm in projected LNG needs. To address this, ACER has introduced a mid-point LNG demand trajectory, depicted by the yellow dotted line in Figure 23. This reference line represents the average of the two scenarios and serves as a benchmark for analytical purposes. The mid-point trajectory starts in 114 bcm in 2025 and shows a gradual decline, reaching 93 bcm by 2030 offering a balanced view between the two decarbonisation scenarios. Such difference in potential LNG demand underscores the need for flexible LNG supply strategies, as actual future requirements could vary substantially depending on the decarbonisation ambition and pace of implementation.

72 Uncontracted volumes are represented as the difference between projected LNG demand and supply already secured through long-term, mid-term and short-term contracts. As illustrated in Figure 24, uncontracted LNG volumes remain a substantial component of Europe's future supply needs under the Fit-for-55 gas demand scenario. From 2028 to 2030, the volume of uncontracted LNG would remain close to 60 bcm, representing nearly half of the total projected LNG demand. This high dependence on spot volumes poses a significant risk to price volatility events particularly during periods of global market tightness or geopolitical tensions. The findings reinforce the importance of securing new contracted LNG volumes to mitigate price volatility risks, particularly in the absence of further decarbonisation efforts beyond the legally binding Fit For 55 goals.

Figure 24: Uncontracted LNG volumes under Fit-for-55 demand scenario by 2030 (bcm)



Source: ACER based on data from Fit-for-55 scenario and contract data from ICSI LNG Edge and S&P Global.

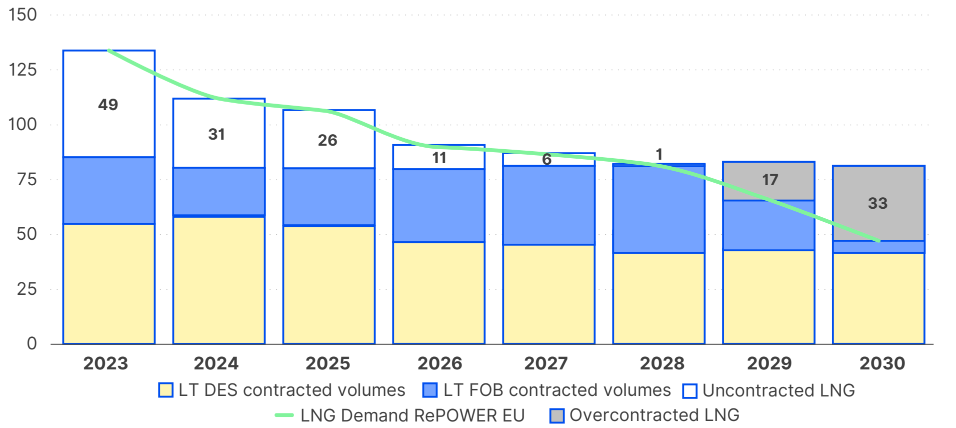
Note: Under Free on Board (FOB) terms, LNG buyers arrange shipping and freely decide on destination of the LNG cargo while under Delivery Ex-Ship (DES) terms, sellers handle shipping and the destination is fixed.

73 In 2024, this gap narrowed to 31 bcm, primarily due to lower overall demand. However, the gap widens progressively over the second half of the decade, reaching close to 60 bcm by 2028–2030. This trend reflects a growing uncontracted position and signals an increasing reliance on spot and short-term markets unless new long-term contracts are signed. The trend underscores the increasing exposure to the LNG spot market and therefore to price volatility and supply risk if additional contracts are not secured to cover the rising demand.

74 As illustrated in Figure 25, the REPowerEU gas demand scenario projects a sharp and continuous decline in LNG needs across Europe from 2025 to 2030, driven by accelerated energy transition policies and reduced reliance on fossil fuels. However, by 2026, the combination of declining demand and long-term contracted volumes results in a narrowing gap, with uncontracted needs dropping to just 11 bcm.

75 From 2028 onward, the supply landscape changes as existing long-term contracts begin to exceed projected demand. By 2030, if realised, this results in an over-contracted position of 33 bcm across Europe. While the surplus may provide a degree of supply security, it also raises strategic concerns regarding contractual flexibility. Particularly in those long-term contracts bound by take-or-pay provisions, which could expose buyers to substantial financial liabilities in the absence of flexible destination. This highlights the need for flexible contractual arrangements in alignment with the EU's evolving demand trajectory to be able to mitigate the risk of over-contracted volumes.

Figure 25: EU LNG contractual position under REPowerEU demand scenario by 2030 (bcm)

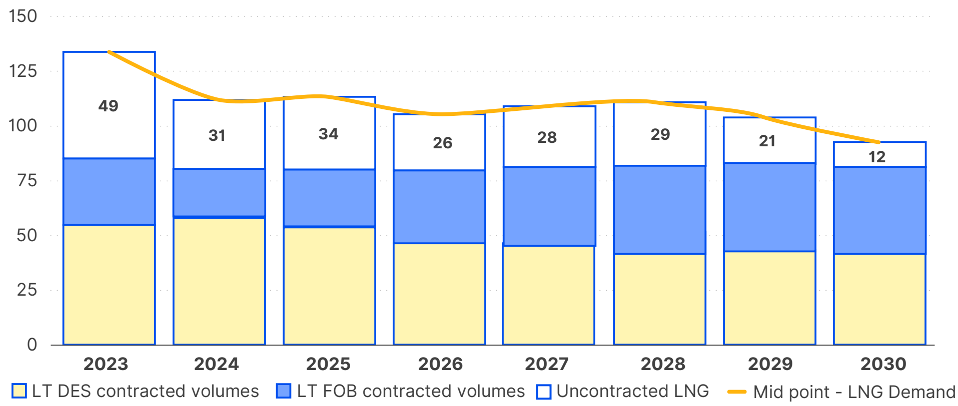


Source: ACER based on data from REPowerEU and contracts data from ICIS LNG Edge and S&P Global.

Note: Under Free on Board (FOB) terms, LNG buyers arrange shipping and freely decide on destination of the LNG cargo while under Delivery Ex-Ship (DES) terms, sellers handle shipping and the destination is fixed.

76 Figure 26 illustrates the evolution of Europe's LNG contractual landscape under the mid-point gas demand trajectory. This trajectory represents a moderate reduction in gas demand, positioned equally distant to the two decarbonisation scenarios. The resulting LNG supply gap is much more manageable compared to Fit for 55 and entitles a much more moderated risk exposure to price volatility of the spot LNG market.

Figure 26: EU LNG contractual position under Mid-point trajectory by 2030 (bcm)



Source: ACER based on data from REPowerEU and Fit for 55.

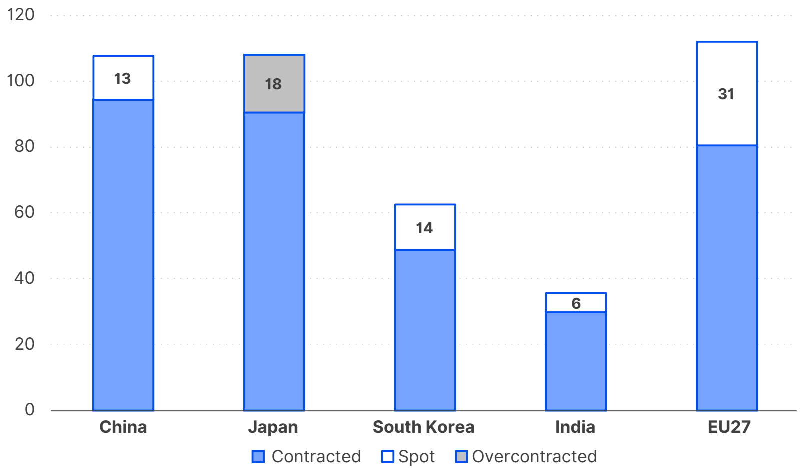
Note: Under Free on Board (FOB) terms, LNG buyers arrange shipping and freely decide on destination of the LNG cargo while under Delivery Ex-Ship (DES) terms, sellers handle shipping and the destination is fixed.

77 The uncontracted share steadily declines. By 2025, uncontracted LNG volumes fall to 34 bcm, and further down to 12 bcm by 2030. This reduction is largely driven by a combination of factors: stable long-term Delivery ex-ship (DES) and Free on board (FOB) contracted volumes and a gradual decrease in overall demand. The narrowing gap between contracted supply and demand indicates an improving balance and a reduced reliance on short-term procurement strategies. It also reflects the long-term commitments made by European buyers in response to recent energy security concerns, particularly following the energy crisis triggered by the war in Ukraine.

78 The contractual balance improves with uncontracted volumes remaining part of the mix present throughout the decade. This highlights the need for flexible and responsive procurement strategies. Also under the mid-point scenario, the region is not fully covered by contracted volumes, suggesting that a portion of LNG needs will continue to be met through the spot market or new contracting activity. This has important implications for portfolio players, who will play a key role in bridging the gap between uncontracted demand and available supply through their ability to manage commercial risk and offer flexible delivery options.

2.1.2. LNG contracted and spot purchases in 2024 top 5 LNG Importers

Figure 27: Reliance on spot purchases of top 5 LNG importers in 2024 (bcm)



Source: ACER based on data from ICIS LNG Edge and S&P Global.

79 Among the major LNG importers in 2024, China, South Korea, and India maintained a close alignment between their import requirements and long-term contracted LNG volumes, resulting in limited reliance on spot purchases. In the case of China, approximately 90% of its total LNG imports, 94 bcm out of 108 bcm, were secured through long-term contracts, with just 13 bcm sourced from the spot market highlighting a low level of exposure to the spot market. Similarly, South Korea imported 63 bcm of LNG in 2024, of which 14 bcm, about 22%, came from spot purchases. While slightly higher than China's relative spot share, South Korea's relies heavily on long-term supply commitments with limited use of the spot market to meet short-term needs or demand fluctuations. India, despite being the smallest among the top five LNG importers with 36 bcm of LNG imports in 2024, only sourced 6 bcm from the spot market showing a moderately low exposure to the spot market which in relative terms is of around 15%.

80 In contrast, Japan's did not rely on the spot market for additional imports during 2024. In fact the import level fell short of existing contractual obligations, resulting in an over-contracted surplus of 18 bcm. This reflects Japan's long-standing risk-averse approach shaped by experiences such as the Fukushima disaster, which prompted a greater emphasis on security of supply and price stability through long-term contracts and equity investments in liquefaction plants.

81 The European Union stands out with the highest reliance on the spot LNG market among the top five global importers, with nearly 30% of its 2024 LNG imports sourced through spot purchases. Out of a total of 111 bcm of LNG imported, 31 bcm came from the spot market. This

significant dependence reflects the EU's ongoing strategy to diversify away from Russian pipeline gas and transition toward a more flexible and diversified LNG supply. The EU's reliance on the spot market increases its exposure to price volatility and possibly also supply risks, particularly during periods of global market tightness and/or geopolitical tension.

82 Beyond the snapshot of spot market reliance in 2024 among the top five LNG importers, it is equally important to examine the contractual outlook for the remainder of the decade. This outlook offers insight into the evolving reliance on spot market of these key players. As illustrated in Figure 28, the trajectory of long-term contracted volumes varies significantly across Asian countries.

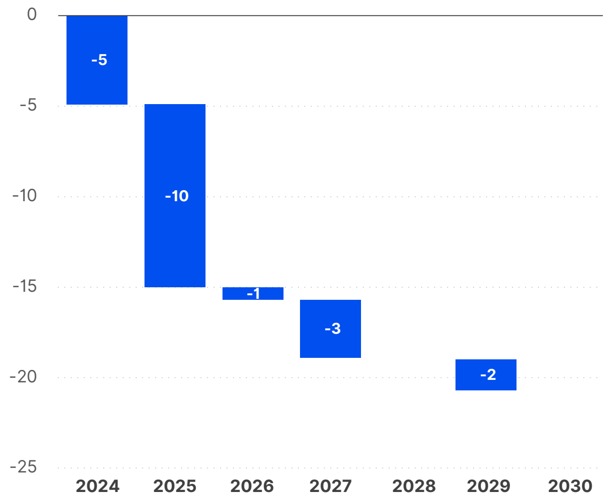
Figure 28: LNG contracted position of China, Japan, South Korean and India by 2030 (bcm)

Source: ACER based on data from ICIS LNG Edge and S&P Global.

83 China stands out with a robust and growing contractual baseline. From a contracted volume of 94 bcm in 2024, China is expected to increase its long-term commitments by an additional 42 bcm by the end of the decade. This upward trend underscores China's strategic objective to secure long-term supply amid rising domestic demand and to reduce its vulnerability to spot market volatility. In India, the outlook for long-term contracts also shows a moderate upward trend in alignment with gradually growing LNG demand albeit at a slower pace than China.

84 In contrast, both Japan and South Korea are expected to see a decline in their long-term contracted LNG volumes by 2030. South Korea's contracted baseline is projected to fall by approximately 10 bcm, while Japan's will decline even more sharply, with a reduction of around 20 bcm, effectively halving its current contractual commitments.

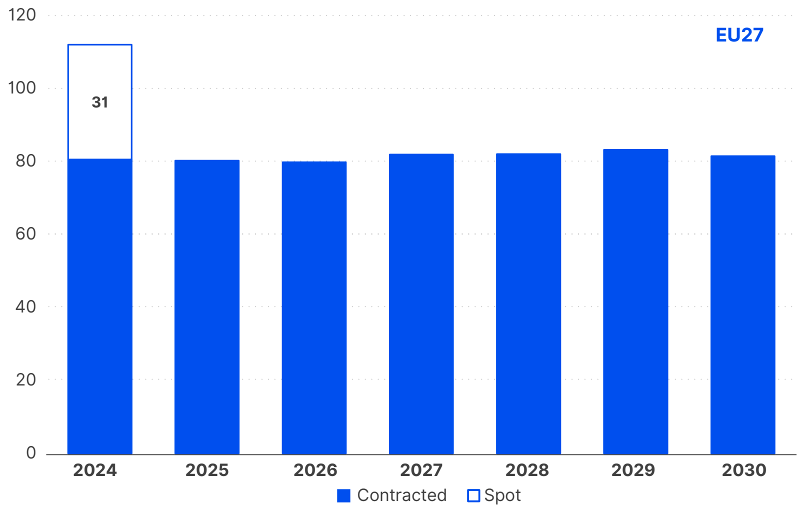
Figure 29: Expiring LNG contracted volumes for EU destination 2024 - 2030 (bcm)



Source: ACER based on data from ICIS LNG Edge and S&P Global.

85 For the European Union (EU27), the long-term outlook appears relatively stable, as shown in Figure 30. Assuming that expiring long-term and medium-term LNG agreements destined for the European market are neither extended nor renewed, more than 20 bcm of contracted volumes are expected to expire between 2024 and 2030 (see Figure 29). Most of these expiring volumes originate from Qatar, Algeria, and Nigeria, with Qatar alone accounting for nearly half of the total. Nevertheless, new long-term agreements are set to replace expiring ones, resulting in a relatively small net increase and roughly flat trajectory. The EU's contracted baseline remains around 80 bcm from 2024 through 2030, indicating limited net contractual baseline growth despite the significant growth in liquefaction capacity.

Figure 30: LNG contracted position for EU destination 2024 - 2030 (bcm)



Source: ACER based on data from ICIS LNG Edge and S&P Global.

2.1.3. Contractual position of portfolio players

86 Unlike the traditional point-to-point arrangements between buyers (importers) and sellers (exporters) that have defined the LNG business for decades, portfolio players[37], also known as aggregators, operate across multiple segments of the LNG value chain. Portfolio players source LNG from a diverse range of suppliers and sources, often under long-term contracts, and resell it fully or broken down into smaller contracts (in volume or duration). LNG portfolio sales are conducted through mid-term, short-term, or spot trades to a wide range of customers, including utilities, smaller-scale importers, and buyers in emerging markets. Portfolio players typically own and manage infrastructure such as LNG carriers, storage facilities, and regasification terminals, providing the operational flexibility needed to optimise logistics and respond effectively to changing market dynamics.

87 Portfolio players play a critical intermediary role in the global LNG trade by assuming the commercial risk of managing large volumes of uncommitted LNG. This is especially relevant in periods of sustained oversupply but also, when predicting future demand, is increasingly complex due to decarbonisation goals.

88 Portfolio players do not only offer financial and technical assurance but are also better equipped to manage volume risk, leveraging their deep expertise in downstream gas markets. Therefore, enabling player of smaller size to become a new entrant in the LNG business. However, growing LNG demand in emerging markets has introduced buyers with weaker credit ratings making client creditworthiness a source of concern for portfolio players.

89 Sponsors of liquefaction projects that enter into long-term supply agreements with portfolio players often grant destination flexibility in exchange for reduced exposure to volume and credit risks. This risk transfer mechanism has made portfolio players essential to project financing, particularly when producers face difficulties in securing long-term contracts directly with end-users. In return for absorbing risk during market gluts, portfolio players are well positioned to capture ample rewards during periods of supply tightness.

90 Some portfolio players arbitrate prices between regions (e.g., Asia, Europe, and the Americas) to maximise profitability. They engage in LNG trading and financial hedging to mitigate price volatility and manage market risks. They have various business models and strategies as well as different degrees of diversification of supply sources and exposure to Henry Hub, TTF, and Brent.

91 Figure 31 illustrates the evolution of portfolio players' LNG commitments, both purchase and sales contracts, between 2024 and 2030. Throughout this period, purchase commitments consistently exceed sales, suggesting that portfolio players maintain a certain degree of flexibility ranging between approximately 15 to 20 bcm annually. Portfolio players can provide this supply buffer to the global LNG market through either spot sales or short- to medium-term arrangements.

37 Examples of LNG Portfolio Players: Major Oil & Gas integrated energy companies (e.g., Shell, BP, TotalEnergies, ENI), large commodity traders (e.g., Glencore, Trafigura, Gunvor, Vitol), utilities and large buyers (e.g., Naturgy).

Figure 31: Total committed LNG volumes by portfolio players 2024 - 2030 (bcm)

Source: ACER based on data from ICIS LNG Edge and S&P Global.

2.2. ACER's LNG price assessment

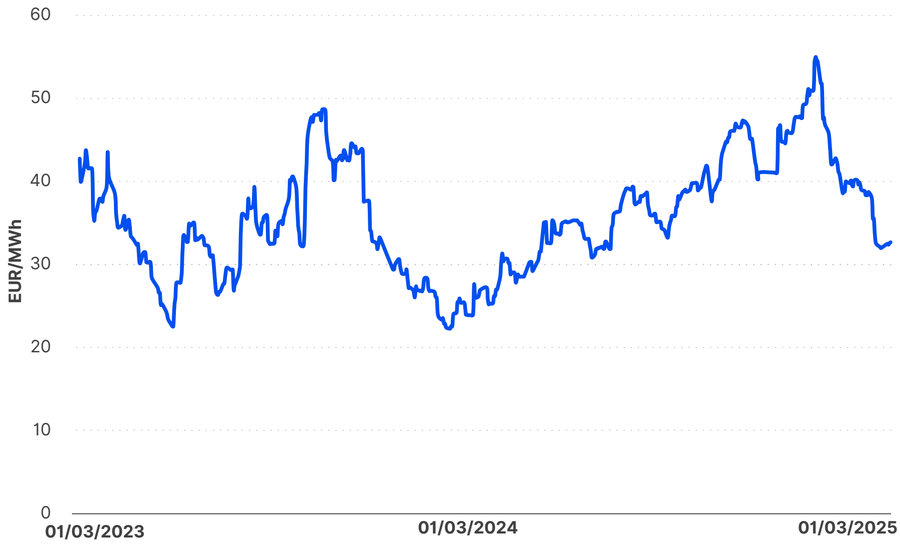
92 In December 2022, Council Regulation (EU) 2022/2576 tasked ACER with the responsibility of producing and publishing a daily LNG price assessment, which would subsequently evolve into a daily LNG price benchmark, commencing in January 2023. The primary goal was to identify the prevailing level at which LNG transactions occurred, to enhance EU LNG price transparency and to better understand the reasons behind the ample price differentials between LNG transactions and the gas prices within EU Virtual Trading Points (VTPs).

93 The Regulation granted ACER with the necessary powers to gather data for establishing the LNG benchmark. In pursuit of this, ACER developed reporting guidance and a data reporting tool to collect real-time information on LNG transactions. Concurrently, ACER, assisted by various LNG market experts, developed a methodology clarifying how the reported data is utilised to produce the daily referential price.

94 ACER collects information on spot-type concluded transactions, bids, and offers, as well as data about individual transactions executed under portfolio-type contracts. The latter relates to long-term gas delivery contracts for larger volumes and comprises several transactions within the same overarching contract. The reported transactions must have the EU as destination. The methodology establishes the data hierarchy, and the calculation steps employed in the assessment process for the publication of daily spot LNG prices (see Figure 32). Essentially, ACER's LNG price assessment consists of a time[38] and volume weighted average price of spot DES transaction prices reported for the purchase or sale of LNG with delivery in the European Union. For the sake of transparency, ACER presents in this section key insights related to the data reported to ACER for the calculation of the LNG price benchmark.

38 A rolling window of up to ten working days is used to identify, aggregate and analyse the LNG market data used in each daily LNG price assessment.

Figure 32: ACER EU daily spot LNG price assessment



Source: ACER LNG Price Assessment.

2.2.1. Overview of key insights

95 Spot LNG trades for cargoes delivered to Europe in 2024 amounted to approximately 45.5 bcm. Spot traded volumes comprised of over 550 reported transactions out of which 93% belonged to DES shipping mode and the remaining 7% to FOB transactions involving 67 companies including buyers and sellers. This represents a slight decline compared to the 47 bcm of spot trades reported in 2023. More notably, uncontracted LNG volumes, defined as cargoes not tied to long-term agreements, fell significantly from 49 bcm in 2023 to 31 bcm in 2024, reflecting a sharp contraction of 18 bcm year-on-year. This decrease in uncontracted volumes closely mirrors the overall 22 bcm reduction in total EU LNG imports over the same period. When comparing the volume of spot trades to the size of the uncontracted LNG market in the EU, the resulting churn rate, defined as the ratio of traded volumes to physically available supply, reaches 1.5. This indicates that each uncontracted molecule of LNG was, on average, traded 1.5 times before reaching its final destination.

96 There is a relatively low level of concentration in the EU spot LNG market. The combined spot sales of the three largest sellers (C3) accounted for around 25% of total spot market volumes. Furthermore, the top ten sellers reach approximately 50% of total spot volumes. The presence of numerous active participants contributes to greater liquidity, reinforcing the LNG role as a flexible and responsive mechanism within the broader EU gas system. On the buyer side, 50% of the traded volumes was bought by seven market participants which were involved in more than 280 transactions. The C3 indicator, representing the market share of the three largest buyers, accounted for 30% of the traded volumes.

97 As described in Table 5, the structure of spot sales in the EU spot LNG market is characterised by a diverse mix of sellers where trading companies accounted for the largest share in 2024, representing 33.6% of total volumes. LNG producers follow, contributing 25.1% of spot sales. These include both independent liquefaction project operators and integrated upstream companies directly marketing uncontracted volumes or excess supply into the European spot market. Oil and gas companies, many of which manage integrated LNG portfolios, combine upstream production with downstream marketing and trading. In 2023, they accounted for 23.8% of EU spot LNG sales. Utilities, traditionally focused on long-term supply contracts

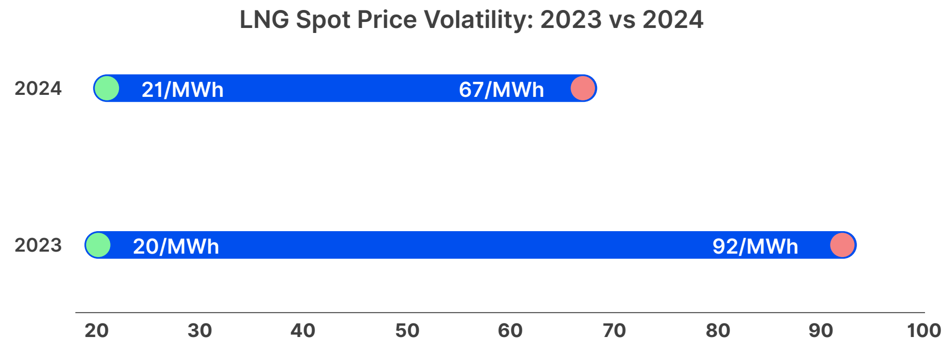
serving its respective downstream markets, make up 18.3% of spot sales. The "Others" category represented a marginal 0.2% of the market, comprising smaller independent market participants or new entrants.

Table 5: Market shares by type of market participant in the EU LNG spot market - 2024

Spot sales in the EU LNG market in 2024	%
Trading companies	33.6 %
LNG Producers	25.1 %
Oil & Gas companies	23.8 %
Utilities	18.3 %
Others	0.2 %

Source: ACER LNG Price Assessment.

Figure 33: Price range of the EU spot LNG transactions within the year 2023-2024



Source: ACER LNG Price Assessment.

98 According to the reported data, 16 bcm of LNG, representing 35% of total traded volumes, were transacted at prices below 30 EUR/MWh, highlighting a significant share of competitively priced cargoes. This indicates that market participants were able to secure 16 bcm of LNG at prices up to 30 EUR/MWh. Most probably the prices of transactions concluded under this threshold correspond to periods of lower demand, milder weather, or increased supply availability occurred during 2024.

99 As the price threshold increases, a larger share of total traded volumes is captured. At 35 EUR/MWh, the cumulative traded volume reaches 25 bcm, or 55% of total spot LNG trades. This indicates that more than half of all spot LNG volumes were transacted at or below this level, pointing to a broader stabilization of prices and improved affordability for buyers. When the threshold is extended to 40 EUR/MWh, 34 bcm, or three-quarters of all spot LNG volumes, fall within this range.

100 At the upper threshold of 45 EUR/MWh, the volume of LNG traded reached 39 bcm, covering 86% of total spot market transactions. In other words, only 6.5 bcm of LNG were priced above 45 EUR/MWh.

Table 6: Cumulative spot LNG volume traded under selected price thresholds - 2024

Selected price thresholds EUR/MWh	Volume traded bcm	%
30	16	35%
35	25	55%
40	34	75%
45	39	86%

Source: ACER based on information from ACER's LNG Price Assessment & Benchmark.

101 The TTF is the Europe's most liquid natural gas benchmark, remained the dominant price index in the EU LNG spot market in 2024, serving as the reference for 73% of spot traded volumes. In contrast, other regional hubs such as the PVB (Spain), ZTP (Belgium), PEG (France), and PSV (Italy) played only a marginal role in LNG spot price indexation. Each of these Virtual Balancing Points accounted for just 1–2% of total indexed volumes, reflecting their more limited liquidity and regional scope compared to the TTF's broader market influence.

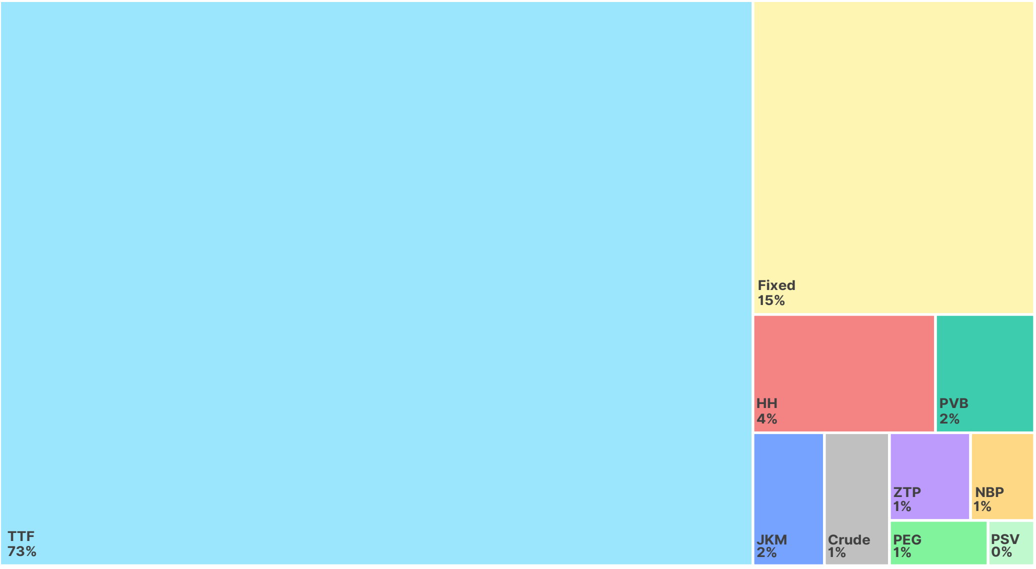
102 The second most common pricing mechanism was fixed-price indexation, accounting for 15% of spot LNG trades. These deals were priced at a set value agreed upon at the time of the transaction, independent of any market index. Fixed-price arrangements are often used for opportunistic buying or short-term optimisation when market conditions are stable or predictable.

103 Henry Hub, the U.S. natural gas benchmark, was the price index in 4% of spot traded volumes. Although less influential in Europe than TTF, Henry Hub remained relevant for cargoes originating from the United States.

104 Japan Korea Marker (JKM), the leading LNG benchmark in Asia, was used in 2% of spot trades, highlighting limited but growing linkages between the European and Asian spot markets.

105 TTF continues to serve as the primary indexation term for European LNG spot trade, reflecting its deep liquidity and wide acceptance as a benchmark for gas in Europe. The presence of a wide array of other indices, albeit in smaller shares, highlights a diverse and competitive spot market. This allows for tailored pricing strategies based on supply origin, delivery location, and buyer-seller preferences. For long-term contracts, Henry Hub is the predominant index, accounting for over half of the volumes destined for the EU, followed by Brent indexation, which represents more than one-third of the contracted European LNG volumes by 2030.

Figure 34: Breakdown of price indexation for spot trade in Europe 2024 - %



Source: ACER based on information from ACER's LNG Price Assessment & Benchmark

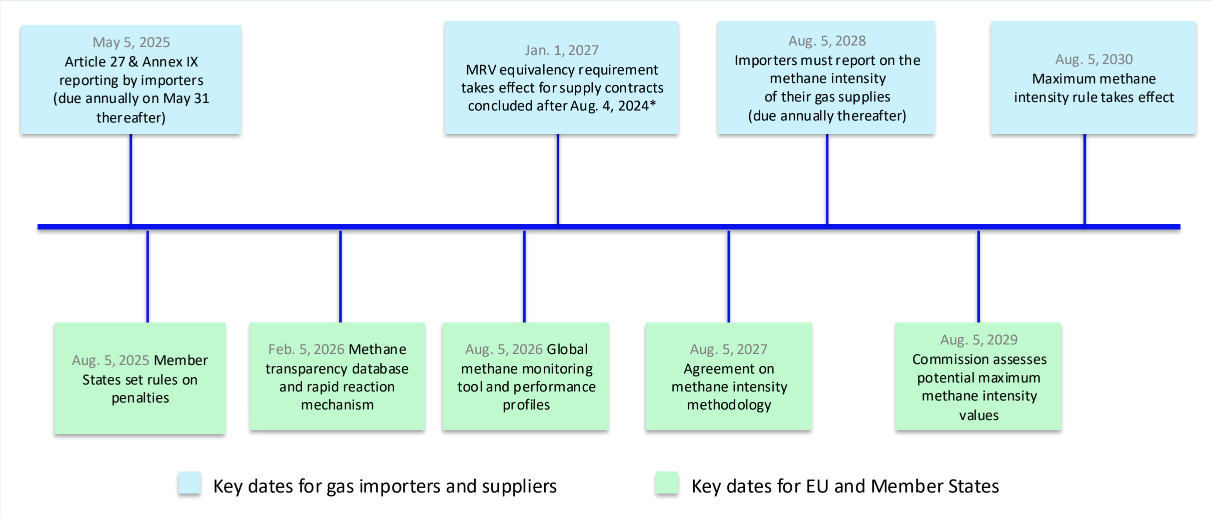
Disclaimer: The analysis uses the data reported by reporting parties to TERMINAL[39]. The TERMINAL data may not be complete, fully accurate and/or reported in a timely manner. ACER thus reserves the right to update the figures and outcomes of the analysis in the event of newly identified data quality issues.

39 TERMINAL is a dedicated data collection system developed by ACER for the publication of the LNG price assessment and benchmark.

The EU Methane Regulation and its potential impact on LNG imports (BOX)

The Regulation[40] introduces wide-ranging requirements for operators in the oil, gas, and coal sectors within the EU, including LNG import terminals. Importantly, it also applies to methane emissions from fossil fuels produced outside the EU but imported into its market.

Figure 35: Timeline for EU methane regulation



Source: EC, Jonathan Stern presentation at EEMDL Oct2024.

*Note: timeline is not exhaustive, other reporting obligations apply. * For supply contracts concluded before this date, "importers shall undertake all reasonable efforts" to ensure that MRV requirements are met, including via amendment of those supply contracts"*

Key obligations for LNG importers

The Regulation sets out a phased series of obligations for LNG importers aimed at reducing methane emissions associated with imported natural gas. These obligations become progressively more stringent, with key dates in 2025, 2027, 2028, and 2030.

- From 5 May 2025: Importers must begin submitting annual reports to the designated EU competent authority. Reports must include information on the exporter and producer, and the measures taken to monitor, report, and reduce methane emissions along the supply chain.

- By 2026: The European Commission will establish a public methane transparency database based on submitted data. The database will enable comparisons of emissions performance between different producers and importers.

- From 1 January 2027: All LNG supply contracts signed or renewed after 4 August 2024 must comply with monitoring, reporting, and verification (MRV) standards equivalent to EU requirements. These include both site-level and source-level monitoring, data reconciliation, and third-party verification. **For contracts signed before this date, importers must make "all reasonable efforts" to align with EU-equivalent MRV standards, which may include renegotiating contract terms**.

40 On 4 August 2024, the EU Methane Regulation (Regulation (EU) 2024/1787) entered into force, following its publication in the Official Journal of the European Union on 15 July 2024.

- From 5 August 2028: Importers must report the methane intensity of imported LNG for contracts signed or renewed after 4 August 2024. The European Commission will define the required calculation methodology in a Delegated Act due by 5 August 2027. For older contracts, the “reasonable efforts” obligation continues to apply.

- From 5 August 2030: **All new or renewed LNG contracts must comply with maximum methane intensity values (MMIV), to be defined in the same Delegated Act**.

To support implementation, the European Commission is preparing non-binding model contract clauses covering MRV obligations. These are intended to help importers and suppliers incorporate methane-related requirements into new or amended contracts. While no formal deadline is set, the Commission is prioritizing their development and will consult with stakeholders during the process[41].

Penalties for non-compliance, to be set by Member States by 5 August 2025, must be “effective, proportionate and dissuasive.” These may include fines of up to 20% of annual turnover or commercial restrictions. In parallel, **the EU aims to conclude cooperation agreements with key exporting countries to facilitate implementation. LNG imports from countries with methane frameworks deemed equivalent may be exempt from some requirements**.

Implementation challenges and open questions

Despite its entry into force, several important details of the Regulation remain unclear:

- **Equivalence of MRV systems and recognition of national frameworks**: The European Commission has yet to clarify how it will assess whether MRV systems used by non-EU producers meet EU standards. This includes both the technical assessment of company-level MRV practices and the recognition of national methane frameworks, which could exempt imports from some obligations.

- **Accepted tracking approaches**: The Regulation does not yet specify which tracking methods, such as mass balance, book-and-claim, or trace-and-claim, will be accepted for demonstrating compliance[42].

- **Third-party verification**: It remains uncertain which entities will be accredited to conduct independent verification, how accreditation will be managed, and whether sufficient qualified firms are available.

- **Methane intensity methodology**: The methodology for calculating methane intensity along the LNG supply chain will only be defined in a Delegated Act by August 2027. Until then, importers do not know how methane intensity will be calculated or reported.

- **Timing of model clauses**: Although model clauses are in development, the lack of a fixed timeline could delay their availability, affecting contract negotiations for existing supply agreements.

41 See the Questions and answers on importer requirements of EU Methane Regulation (EU) 2024/1787.

42 See University of Texas (2025): Three Big Questions on the EU Methane Regulation.

- **National-level implementation**: Many Member States have yet to appoint competent authorities or specify penalties for non-compliance. National decisions, due by August 2025, will be critical to provide enforcement clarity across the EU.

Clarifying these issues will be essential to ensure consistent implementation and reduce uncertainty for LNG importers. This is especially important given the complexity of many global LNG supply chains, where exporters may lack full control over upstream and midstream emissions, as is often the case in supply routes from the United States or Nigeria.

Risks and opportunities for LNG importers

The Methane Regulation introduces a new layer of compliance risk and contractual complexity for LNG importers.

In the short term, the most immediate challenge lies in managing existing contracts. For agreements signed before August 2024, importers must demonstrate “reasonable efforts” to align with EU rules, potentially requiring renegotiations. From 2027 onward, importers must ensure new or renewed contracts meet EU-equivalent MRV standards. From 2028, methane intensity reporting will be required, and by 2030, compliance with binding intensity limits will become mandatory.

These escalating requirements are likely to increase financial and operational burdens along the LNG supply chain. While the capital investments needed to deploy advanced methane monitoring and mitigation technologies will generally fall to producers, the associated costs may be passed through to importers via higher contract prices. How these costs will be distributed among producers, traders, importers, and EU consumers remains uncertain. Non-compliance, meanwhile, could result in significant penalties and reputational risks, further heightening the risk exposure for importers.

The Regulation could also complicate LNG contract negotiations, especially if producers or traders are unwilling to assume the necessary obligations. Some global suppliers, particularly from countries with less stringent methane rules, may choose to prioritize other, less regulated markets. This could lead to reduced supply options for the EU and increased costs for compliant LNG, potentially presenting short-term risks for Europe’s energy security.

At the same time, the Regulation creates strategic opportunities. Importers that proactively align with the requirements may benefit from market differentiation, preferred access to environmentally conscious buyers, and improved long-term competitiveness. The Regulation is also likely to accelerate innovation in methane measurement and reporting technologies, support global standardization, and enhance supply chain transparency.

3. The role of import LNG terminals

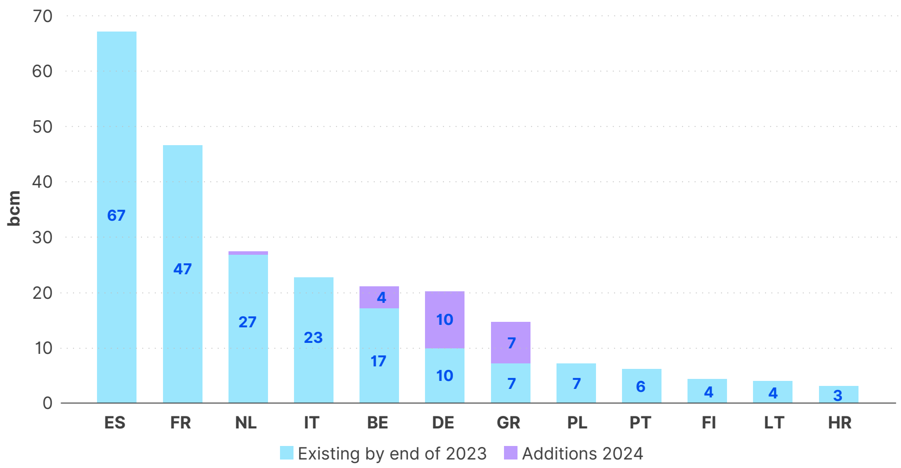
106 The third chapter of this report describes the importance of the LNG import terminals in the European Union beyond the metrics of utilisation rates. It explores how these terminals currently contribute to underpin security of supply. It also highlights their strategic role in facilitating the integration of renewable and low-carbon gases in the near future.

3.1. Present role of EU LNG import infrastructure

107 By January 2025, the EU's LNG regasification capacity had reached 243 bcm, an increase of around 68 bcm since August 2022. This rapid expansion has alleviated LNG supply and pipeline congestion across much of Europe, enhanced system flexibility, and helped ease the price pressures experienced in 2022 and 2023. The increase stems from the deployment of Floating Storage and Regasification Units (FSRUs) and the expansion of existing LNG import terminals. Approximately 75% of the added capacity between 2022 and 2024 came from FSRUs, while the remaining 25% resulted from terminal expansions.

108 FSRUs offer several advantages over land-based regasification plants, including faster planning, construction, and deployment timelines. They also provide flexible redeployment options, reduce dependency on land availability, and generally require lower upfront capital investment. However, they tend to have higher operational costs and are typically limited in scale by the size of the vessels, making them more suitable for mid-sized projects.

Figure 36: Overview of existing EU LNG capacity per Member State and yearly additions by 2024 (bcm)



Source: ACER based on data from GIE ALSI.

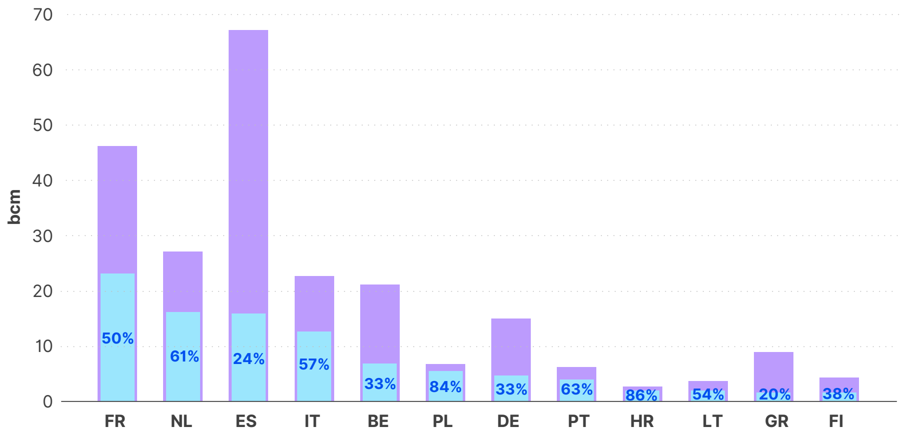
Note: A uniform conversion factor of 11.620 TWh/bcm has been used to convert energy units into volumetric units.

109 As shown in Figure 36, the EU added approximately 21 bcm or a 9% increase to its total LNG regasification capacity of 2023 by the end of 2024. In Germany, the FSRU-based LNG import terminal Neptune was relocated from Lubmin to Mukran, while two new terminals, FSRU Energos Power (also in Mukran) and Alexandroupolis in Greece, commenced operations in 2024. Additionally, Belgium expanded the Zeebrugge LNG terminal by 4 bcm/year at the start of 2024, with a further 2 bcm/year increase scheduled for early 2025. As of now, the EU's total LNG regasification capacity stands at approximately 7,740 GWh/day (around 260 bcm/year), equivalent to 70% of the EU's five-year average annual gas consumption.

3.1.1. Utilisation of EU LNG terminals

110 The utilisation rates of EU LNG terminals surged in 2022–2023, underscoring their crucial role in safeguarding security of supply through seasonal balancing and strategic flexibility. In 2024, as shown in Figure 37, however, utilisation rates declined due to high storage stocks at the end of the 2023/24 heating season, reducing the need for summer refilling. This decline in terminal activity, observed in most countries except during the last quarter, when colder temperatures and increased consumption led to a temporary rebound in utilisation, has broader commercial and market implications beyond security of supply.

Figure 37: Regasification capacity and utilisation rate of LNG terminals by EU country – 2024 (bcm)



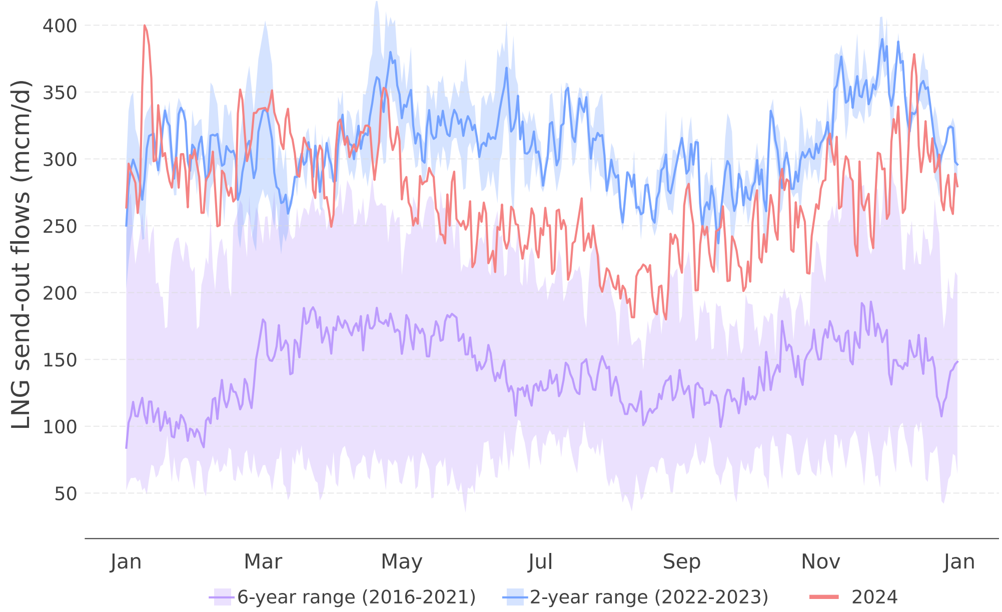
Source: ACER based on data from ALSI GIE.

Note: A uniform conversion factor of 11.620 TWh/bcm has been used to convert energy units into volumetric units.

111 Lower terminal utilisation directly affects the revenues of terminal operators, who typically earn income through regasification tariffs, slot bookings, and ancillary services. Underutilisation may challenge the financial viability of recent investments or delay returns on newly built or expanded facilities. It also reduces the attractiveness of long-term capacity bookings, especially if shippers perceive limited arbitrage opportunities or weak domestic demand. Conversely, during high utilisation periods, terminals can generate substantial revenue through congestion pricing, flexibility services (e.g., temporary storage, send-out scheduling), and re-exports, creating commercial value beyond simple gas delivery.

112 It is important to note, however, that the low utilisation of LNG terminals in 2024 was a consequence of extraordinarily high storage levels at the end of the 2023/24 heating season. This significantly reduced the need for additional LNG imports during the summer refilling period, thereby lowering utilisation terminal relative to 2022 and 2023, as can be seen in Figure 38.

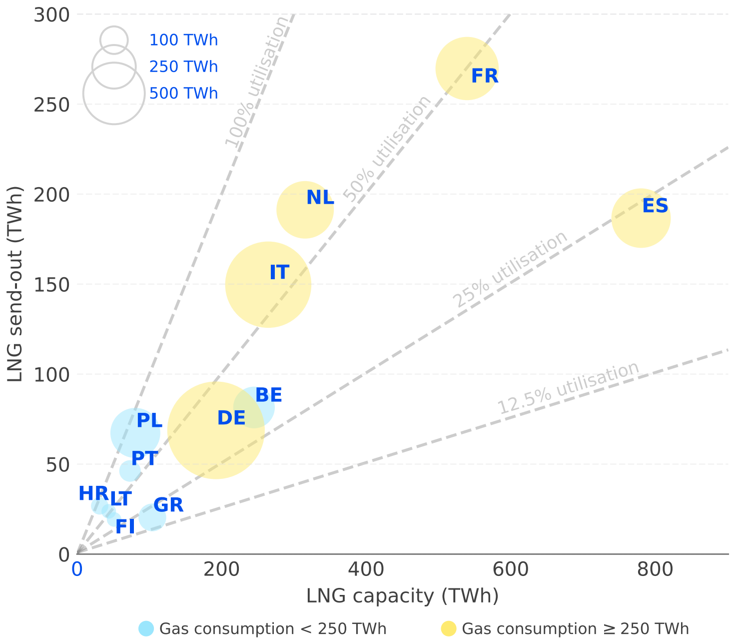
Figure 38: Daily evolution of LNG send-out flows in the EU (mcm/d)



Source: ACER based on data from ALSI GIE.

Note: A uniform conversion factor of 11.620 TWh/bcm has been used to convert energy units into volumetric units.

Figure 39: LNG terminal utilisation compared to gas demand by country - 2024



Source: ACER based on data from ALSI GIE and Eurostat.

Note: The size of the circles represents annual gas consumption while the grey, dashed lines indicate annual utilisation rates.

113 Figure 39 illustrates the relationship between LNG regasification capacity (x-axis) and LNG send-out flow in 2024 (y-axis), with the size of each bubble representing country's annual gas consumption. The five largest gas-consuming Member States are highlighted in yellow, together accounting for approximately 70% of the EU's total gas demand in 2024. Dashed grey lines indicate benchmark utilisation rates (e.g., 100%, 50%, 25%). Utilisation rates vary significantly across Member States and offer limited insight without a detailed, country-specific analysis. Each country presents a distinct context, differing in terminal size, national

gas demand, and the availability of alternative supply routes, which means LNG import terminals serve various roles throughout the EU. As such, utilisation figures alone, which simply indicate how close actual send-out is to designed capacity, do not capture the full picture. Any decisions regarding capacity expansions must therefore be evaluated on a case-by-case basis, supported by thorough cost–benefit analyses that consider national energy needs, system flexibility, and strategic value.

3.1.2. Versatility of LNG terminals

114 The various roles that LNG facilities can play in the current gas market paradigm can be categorised as follows:

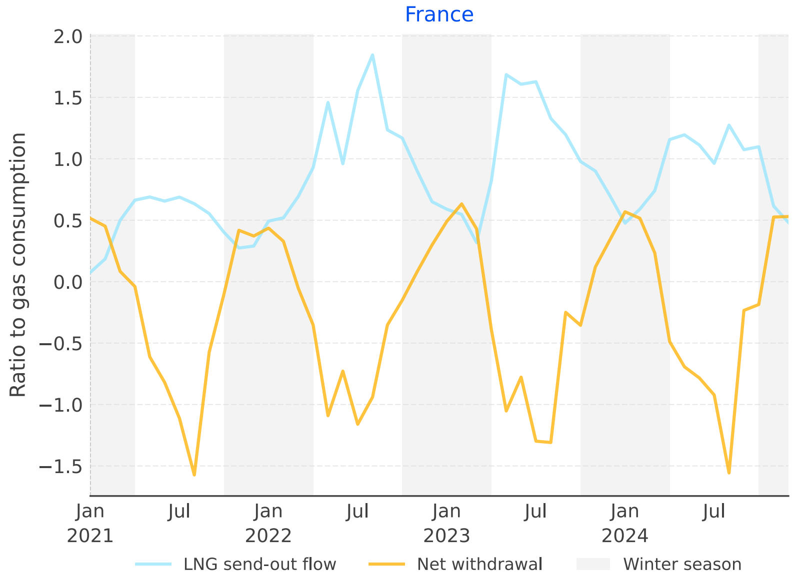
- **Seasonal support**: complementing UGS facilities to manage seasonal demand fluctuations (e.g., France, the Netherlands, Italy).
- **Primary supply**: serving as the main source where storage is limited or absent particularly relevant to meet daily peak demand (e.g., Spain, Baltics).
- **Pipeline complement**: complementing baseload pipeline supply (e.g., Belgium, France).
- **Market integration**: enhancing interconnectivity within the EU gas market.
- **Supply diversification** (e.g., Germany, Poland, South-South-East).

115 These roles are not mutually exclusive and frequently overlap. Security of supply is a common thread across all. Importantly, they offer system-wide value beyond simple utilisation metrics. Looking forward, their role is also expected to evolve in support of decarbonisation pathways, facilitating imports of low-carbon gases such as e-methane, hydrogen, or ammonia.

116 The following paragraphs examine selected examples to illustrate the various roles of LNG terminals. These examples are based on the ratio to gas consumption, which is computed as the amount of LNG send-out flow or net withdrawal divided by the country's gas consumption on a monthly basis. On net withdrawals, a positive ratio indicates deliveries whereas a negative ratio corresponds to injections. This ratio reflects the relative contribution of LNG and storage net withdrawals to meeting gas consumption over time.

117 **Seasonal Support**: LNG terminals complement UGS to manage seasonal demand fluctuations (e.g., France, Netherlands, Italy). A complementary relationship between LNG terminals and UGS is evident in many EU countries, including France, Croatia, Italy, the Netherlands, and Poland. Figure 40 illustrates this pattern in France, showing monthly LNG send-out and UGS withdrawals as a share of gas consumption. Since 2022, LNG has played an increasingly important role in keeping storages filled during the heating season, supported by falling overall gas demand. In 2024, French LNG terminals operated at a 50% utilisation rate, while LNG send-out covered 77% of national gas consumption. During the summer, when send-out volumes exceed consumption, surplus gas is either injected into storage or exported to neighbouring countries.

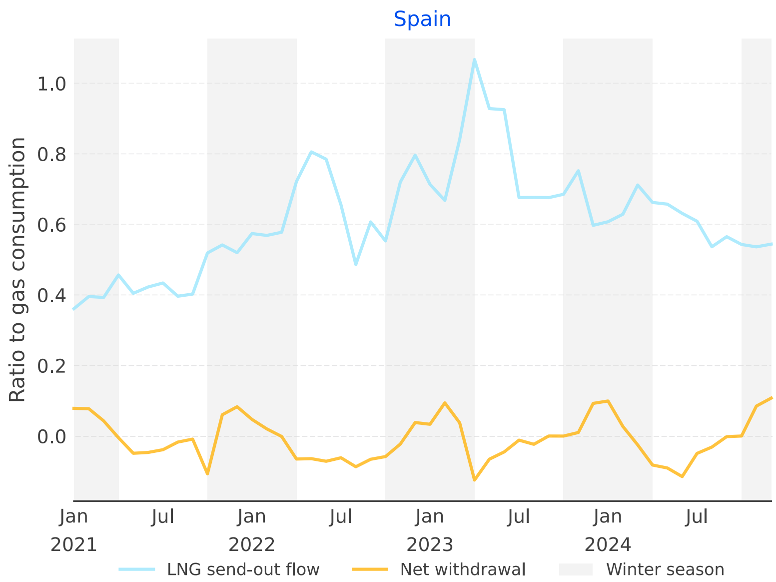
Figure 40: Ratio of LNG send-out and net withdrawal to gas consumption in France – 2021-2024



Source: ACER based on data from ALSI GIE, AGSI GIE, and Eurostat.

118 **Primary supply**: LNG terminals serve as a main supply source in countries with insufficient entry capacity to meet daily peak demand (e.g., Spain, Baltics). Spain has the largest LNG regasification capacity among EU Member States but recorded the lowest utilisation rate in 2024. Understanding the role of LNG terminals in Spain requires a broader perspective than annual utilisation rates. Spain's LNG infrastructure serves a critical function as a primary supply source to ensure security of supply during winter peak demand days. On such days, the combined capacity of all other supply sources, namely indigenous production, storage withdrawals, pipeline imports from Algeria, and cross-border flows from Portugal and France, are insufficient to meet national demand.

Figure 41: Ratio of LNG send-out and net withdrawal to gas consumption in Spain – 2021-2024

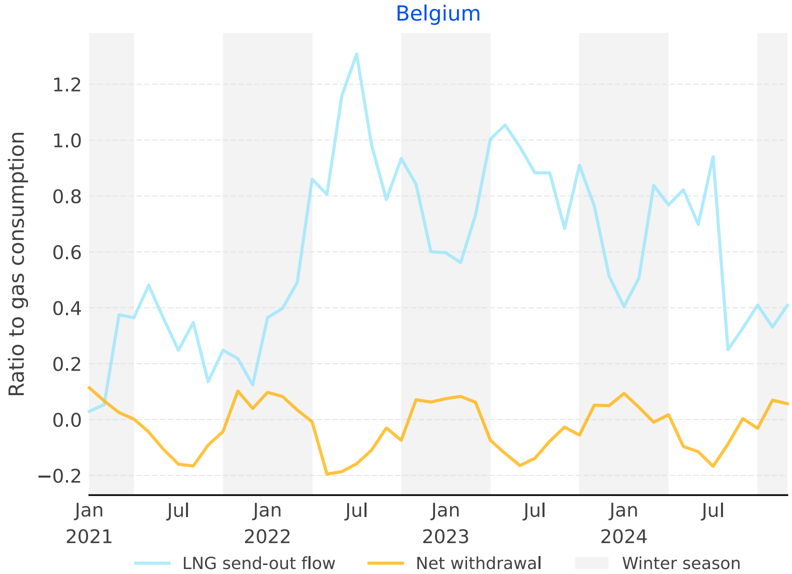


Source: ACER based on data from ALSI GIE, AGSI GIE, and Eurostat.

119 (The LNG supply is mainly driven by the gas consumption for electricity production due to the strong interdependence between their natural gas and electricity systems. The gas for electricity production constituted 22% of the total gas consumption in 2024[43], and approximately 30% in 2023. The gas-fired generation represented 20% of the total electricity produced while the renewable generation accounted for 57% of Spain's electricity mix in 2024.

120 **Pipeline complement**: LNG terminals can supplement baseload pipeline supply, especially where pipeline flexibility is constrained. Countries like France, Belgium, Croatia, and Netherlands, rely heavily on LNG to support pipeline imports, particularly since 2022, when gas flow patterns shifted away from the traditional east–west axis to more complex west–east and north–south directions. This role becomes even more prominent during the summer injection season, when LNG is essential for refilling UGS to agreed targets, in line with obligations under Regulation (EU) 2022/1032 on gas storage.

Figure 42: Ratio of LNG send-out and net withdrawal to gas consumption in Belgium – 2021-2024



Source: ACER based on data from ALSI GIE, AGSI GIE, and Eurostat.

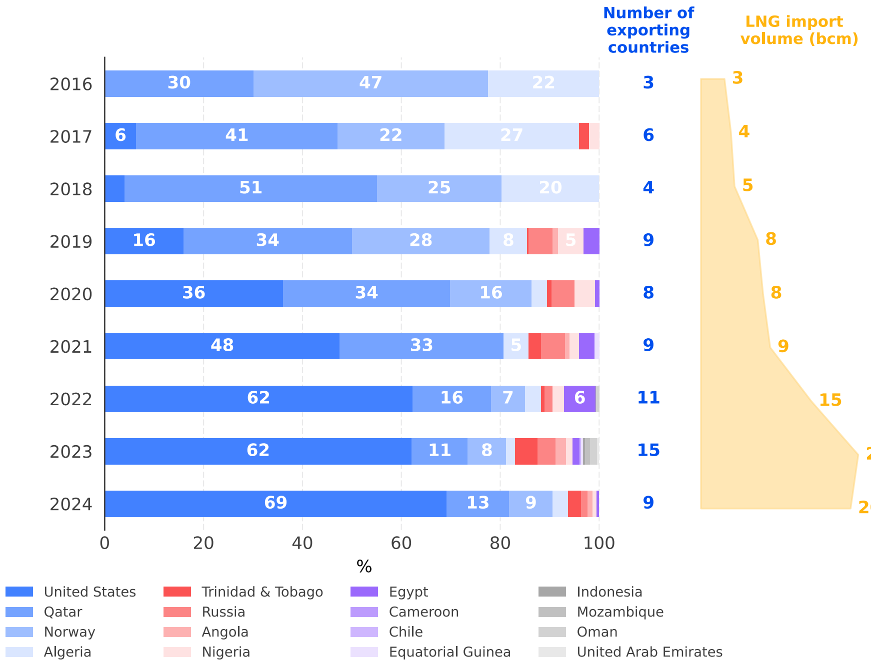
121 Supply diversification. LNG import terminals allow access to a broader range of global suppliers, reducing reliance on pipeline gas from a limited number of sources. For example, the Eastern and Southeastern European countries have strengthened their supply diversification through the capacity expansion in Krk LNG terminal in Croatia, and the ongoing LNG infrastructure developments in Greece.

122 Figure 43 illustrates how supply diversification in Central and Southeastern European countries[44] has evolved from 2016 to 2024. LNG import volume increased significantly from 3 bcm in 2016 to 20 bcm in 2023 and 2024, enhancing security of supply through diversification. The number of LNG exporting countries also grew from three in 2016 to more than ten in post-crisis years. However, dependence on a single exporting country has increased, with the United States supplying around two-thirds of total LNG imports in 2024. Unlike other exporting countries that have a single supplier, the United States has a diverse range of market players exporting LNG.

43 Eurostat, dataset nrg_cb_gasm with codes IC_CAL_MG and TI_EHG_MAP.

44 Central and Southeastern European countries with LNG terminals include Germany, Poland, Lithuania, Croatia, and Greece.

Figure 43: Breakdown of LNG import sources in Central and Southeastern EU countries



Source: ACER based on data from ICIS LNG Edge.

Note: Central and Southeastern European countries with LNG terminals include Germany, Poland, Lithuania, Croatia, and Greece.

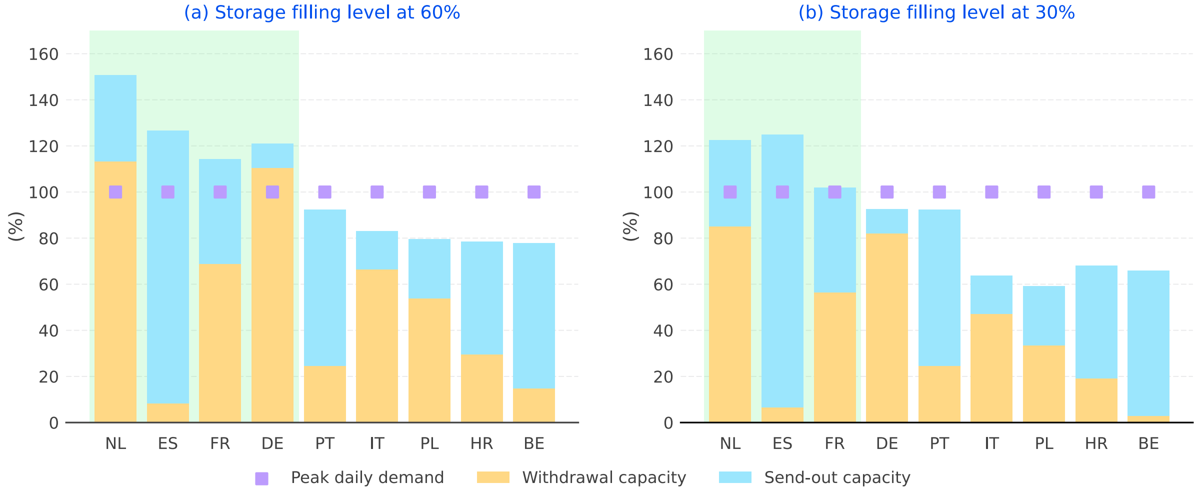
123 **Market integration**: Increasing reliance on LNG not only supports security of supply but also contributes to the broader goal of improving gas market integration in Europe. The convergence of hub prices has improved since the all-time high gas price of the 2022 energy crisis, but integration across all EU markets has not yet returned to pre-crisis levels[45]. Price formation is driven by multiple factors beyond LNG supply expansion, including shifting demand-supply dynamics and newly congested intra-EU pipeline routes[46]. LNG terminals benefit landlocked countries too (e.g., Bulgaria via Greece, Austria via Italy), enhance interconnectivity and support price convergence across EU gas hubs.

124 **Security of supply**: The security of supply provided by LNG import terminals can be better assessed by comparing a country's peak daily gas demand with its LNG regasification and underground storage withdrawal capacities, as illustrated in Figure 44. This figure depicts this comparison, showing how these supply sources stack up against the highest daily gas demand observed between 2015 and 2024 in countries that have both storage and LNG infrastructure. It is important to acknowledge that pipeline supply and domestic production also play a significant role in meeting peak gas demand, although they have been intentionally excluded from this analysis.

45 Key developments in European gas markets – Q3 2024. 2024 Market Monitoring Report. ACER, 22 October 2024.

46 Congestion in the EU gas markets: have we reached a new normal? 11th ACER report on congestion in the EU gas markets. ACER, 30 May 2024.

Figure 44: Daily peak demand compared to current LNG send-out and storage withdrawal capacity



Source: ACER based on data from ALSI GIE, AGSI GIE, ENTSOG, and JRC's ENaGaD.

125 Peak gas demand occurs often in the first quarter of the year when gas storage facilities may be close to depletion. The storages are characterised by their deliverability curve relating the maximum withdrawal capacity with the volume of gas stored. The lower the gas in storage, the lower the gas that can be extracted. Two different situations are assumed, i.e. gas storages are filled at 60% in Figure 43.(a) and at 30% in Figure 43.(b). These countries can be categorised into two groups based on their ability to meet daily peak gas demand.

126 Germany and the Netherlands have sufficient underground gas storage withdrawal capacity to handle daily peak demand. However, as storage levels decrease over the winter, so does their ability to withdraw gas at the same rate. In such situations, LNG terminals can serve as a backup supply source, ensuring security of supply, particularly towards the end of winter when storage levels are lower. In Spain and France, LNG terminals play a critical role in meeting peak daily demand, as their underground storage facilities alone are insufficient to cover these peaks. LNG supply is, therefore, essential to balancing their gas system.

127 Portugal, Italy, Poland, Croatia, and Belgium should rely on a combination of pipeline imports and LNG supply to meet daily peak demand. Neither storage withdrawal capacity nor LNG regasification alone is enough, making both supply sources necessary for system adequacy. This is even more stressed if the daily peak demand occurs when storages are close to depletion. Needless to say, gas market integration helps provide the necessary security of supply to meet demand even under these extreme demand conditions.

3.2. Future role of LNG import terminals

128 The plans to decarbonise the European gas sector focus on increasing the production of domestic low-carbon resources, and notably biomethane and renewable hydrogen[47]. However, imports of biomethane, hydrogen and hydrogen derivatives are expected to play a key complementary role[48]. Those imports will arrive either via pipelines or shipments, each linked to different markets and subject to their own economic dynamics. Overall, pipeline imports face fewer uncertainties (particularly for hydrocarbons, which are easier and cheaper to transport than hydrogen), while the question is whether shipping chains and infrastructure can scale up sufficiently to supply a significant share of the EU's decarbonised gas needs within the next decade.

129 This section discusses the current state and challenges to leverage existing European LNG terminals for importing decarbonised gas forms in the coming years.

3.2.1. Overview of decarbonised gases for LNG import

130 The section provides an overview of the different renewable and decarbonised gases (and overall energy carriers) that could be imported through LNG receiving infrastructure in Europe. It should be noted that this section refers to the reuse of existing LNG terminals to import such gases. In case the terminal was used for hydrogen transport, then it would be designated as a hydrogen terminal.

131 The prospective gases for the decarbonisation of the LNG supply chain can be categorised into two groups depending on the type of energy carrier. **Biomethane-based fuels** still use the molecule of methane, while **hydrogen and its derivatives** adopt alternative molecules to be imported into LNG terminals. In turn, these groups can be further divided resulting into six different renewable and decarbonised gases.

Biomethane-based fuels:

1. **Bio-LNG** is biomethane (CH_4) in liquid form. Biomethane is derived from organic waste (e.g., agricultural residues, sewage, or landfill gas), produced from anaerobic digestion processed or from the gasification of biomass. A key advantage of bio-LNG is that biomethane can be liquefied like conventional natural gas, allowing for seamless integration into the existing supply chains - including the import infrastructure - and enabling blending with conventional LNG.

2. **Synthetic LNG**, also called E-LNG, is produced from renewable hydrogen, i.e. hydrogen obtained from the electrolysis of water, using renewable electricity. This renewable hydrogen then reacts with captured CO_2 to form methane. The resulting methane can then be liquified to produce E-LNG and be transported in conventional LNG carriers and received in conventional LNG terminals

47 ACER published in November 2024 its first hydrogen Market Monitoring Report, discussing its slow market uptake so far and revising the feasibility and challenges to meet targets of hydrogen. The report sheds light on the main regulatory challenges at EU and national level. The report addresses issues such as the repurposing of gas networks and the need for greater coordination by hydrogen, natural gas and electricity network operators.

48 Decarbonised gases imports have been discussed in 1.2.1 tracking progress on REPowerEU targets. Ammonia imports or other derivative chemical substances are targeted to be 4 Mt by 2030.

Hydrogen and its derivatives

3. **Liquified hydrogen** is hydrogen stored at cryogenic temperatures (-253°C) and low pressures. While it offers a high energy density by mass, the process of liquefying hydrogen is extremely energy intensive. Furthermore, its transport over long distances presents technological challenges, particularly due to boil-off losses.

4. **Ammonia (NH_3)** is a hydrogen derivative mostly used for fertilizers' production. It is primarily obtained from steam methane reforming of conventional natural gas, followed by nitrogen fixation. Ammonia is associated however with significant CO_2 emissions. These emissions can be mitigated with carbon capture, utilisation, and storage (CCUS) technologies, leading to blue ammonia. Renewable ammonia (or green ammonia) can be also produced using renewable hydrogen, combined with nitrogen, making it a low-carbon alternative.

   Unlike liquefied hydrogen, ammonia can be transported as a liquid at -33°C and 10 bar in specialised carriers, is safer, has a higher heating value per unit of volume, and a lower boil-off rate. It can also be decomposed (cracked) back into hydrogen through catalytic cracking. This process reduces shipping costs compared to direct hydrogen shipment. Therefore, ammonia becomes a suitable energy carrier for decarbonising a hard-to-abate sector such as the maritime transport sector.

5. **Methanol**, another hydrogen derivative, is mostly used as a chemical feedstock, while it can also be used directly as a fuel or blended with gasoline. Conventional methanol is obtained from the steam methane reforming of natural gas, resulting in substantial carbon emissions, though again these can be mitigated with CCUS technologies. Renewable methanol (e-methanol) is produced from renewable hydrogen reacting with captured CO_2, making it also a low-carbon alternative. Methanol can also be derived from biomass (bio-methanol). Unlike ammonia or LNG, methanol remains liquid at ambient temperature, what simplifies its handling. Methanol can be shipped in dedicated chemical tankers or LNG-type carriers.

6. **Liquid organic hydrogen carriers (LOHC)** are compounds that can absorb and release hydrogen through chemical reactions. Their advantage is that they can be transported as liquid and use existing oil infrastructure, including ships and terminals, while requiring moderate energy for reconversion. Yet, these developments are still in development and have a lower content of hydrogen by mass.

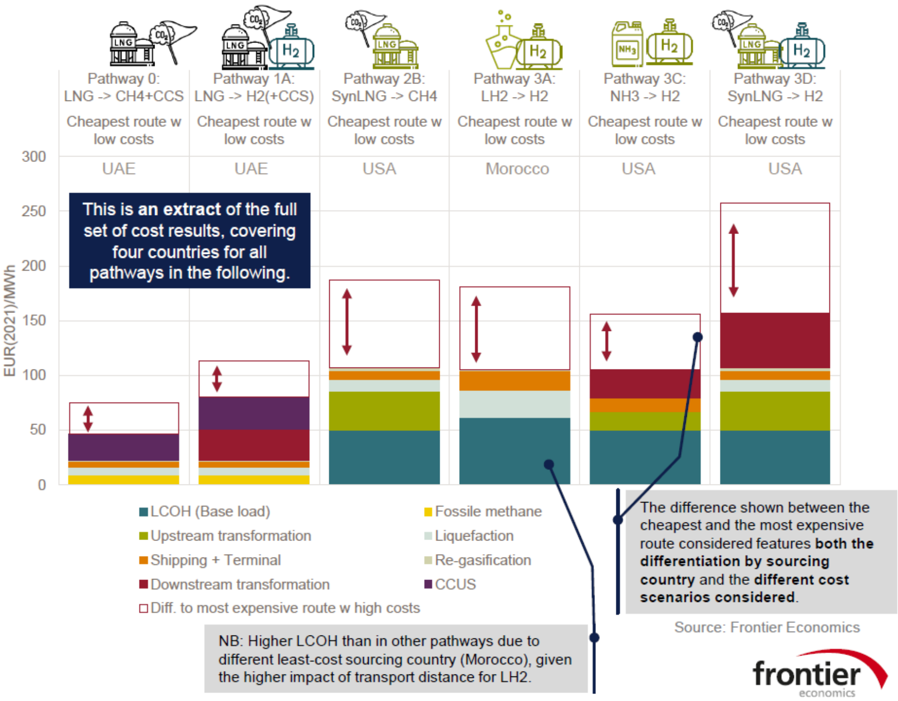
132 Biomethane-based fuels could be easily integrated into current LNG supply chains; however, their adoption depends on various environmental and regulatory aspects. While transportation of liquid hydrogen could still be challenging, hydrogen derivatives, such as ammonia or methanol, present various advantages. First, they are easier to ship than liquified hydrogen. And second, they can be either consumed directly for end-use processes, or they can serve as an energy carrier to produce hydrogen once again.

Decarbonised LNG imports: Status and challenges

133 The European industry faces two primary challenges to import decarbonised gases by sea: the high production and shipping costs of these gases, due to their costlier supply chains, and the suitability/readiness of existing import terminals. Figure 45 offers an overview of the production and transport costs of various decarbonised gas forms and energy carriers, highlighting their higher relative costs compared to conventional natural gas. The assessment leverages the findings from a consultancy report commissioned by Gas Infrastructure Europe.

134 Currently, as Figure 45 shows, all these alternative gases result in higher final costs relative to natural gas, limiting their widespread adoption from an economic perspective. Therefore, their extensive uptake will chiefly hinge on their contribution in achieving decarbonisation goals and regulatory targets.

Figure 45: Overview of decarbonised and renewable gas options for LNG imports



Source: Frontier economics study commissioned for GLE. Unlocking the potential of import terminals to a sustainable energy landscape.

135 Hydrogen derivatives, such as ammonia and methanol, are today well established in industrial applications, although primarily in their non-decarbonised forms. Ammonia and methanol are globally traded chemical feedstocks, with European ammonia consumption reaching 98 TWh in 2024, of which 21 TWh were imported. EU methanol consumption stood at 33-44 TWh, with 80-86% imported.

136 Both hydrogen derivatives are expected to contribute to the development of the renewable hydrogen economy. Ammonia is gaining traction as an energy carrier for hydrogen storage and overseas ship transport[49]. This is because ammonia supply and transport chains are better established than those of hydrogen. The key challenge is that ammonia's (targeted) renewable form requires also significant electricity input – as it is derived from green hydrogen –, what still leads to higher costs. However, its benefit in comparison to hydrogen stays in its lower transport costs, that could outpace liquified hydrogen imports even if ammonia is returned into hydrogen via cracking. Moreover, technically, and further than its use as feedstock (and as discussed, a promising hydrogen carrier), ammonia is emerging as a direct fuel for power generation and shipping. Its broader further adoption will depend on improvements in production efficiency, cost reductions, and supportive policies.

49 A recent FSR study, Are pipelines and ships an 'either or' decision for Europe's hydrogen economy? Planning import lines for hydrogen and derivatives compares the rationale and cost of both options. While project specific, shipping starts to hold an advantage over pipeline transport for ammonia at distances various hundreds of km and around few 2,000-3,500 km for hydrogen.

Terminals suitability and emerging projects

137 Adapting existing EU LNG terminals, or even developing new facilities, would enable the import of decarbonised gases from overseas. Shipping imports may offer advantages relative to domestic production or pipeline imports when they are cost-competitive, while also enhancing flexibility and supply diversification options. For example, today, certain regions such as the United States and Middle East present significantly lower renewable hydrogen production costs relative to Europe. As a result, even after accounting for higher marine transport costs, those gases could remain economically viable if adequate import infrastructure is available.

138 European LNG infrastructure operators are promoting projects to ensure that LNG terminals can handle large-scale imports of decarbonised gases. They also aim at synchronising the development of the production capacities in export countries with the pace of European import infrastructure. However, the viability of these maritime supply chains will depend on cost efficiency, technological readiness, and supportive policy frameworks, with further advances overall still needed. Ultimately, as various decarbonised gas options can have comparable costs depending on project specifics, the choice of energy carrier will also be driven by the specific projects' competitiveness and the predominant end-use applications at the different markets.

139 At present, most European terminals are currently equipped to import synthetic methane and biomethane, including blended forms with LNG, making them a more accessible option compared to hydrogen. However, the infrastructure required for importing other decarbonised gases in liquefied form is still in its early stages. The primary concern is the suitability of the storage tank material, and it represents the largest cost factor (~50%). Further research is needed, particularly on material compatibility with liquid H_2 and NH_3. Moreover, as GLE report[50] states, due to differences in physical properties of hydrogen gas forms relative to natural gas, many components, such as pumps, compressors, control and metering systems, safety systems, and possibly piping, will need to be replaced. However, some components may no longer be necessary if the imported carrier is used or transported directly without regasification. This is particularly relevant for ammonia, as well as methanol and LOHCs, where regasification is not required.

140 No European terminal is ready to import liquefied hydrogen at present day. In fact, given its high costs and technical complexities, liquified hydrogen trade via ship is limited to a few pilot projects. For instance, a hydrogen tanker was commissioned in Japan in 2022 for deliveries from Australia.

141 Ammonia is already imported through various European ports. Interestingly, existing LNG infrastructure can be adapted for ammonia imports. Converting an existing LNG import terminal to an ammonia-ready terminal is feasible, but costs and investment profiles depend on factors like terminal characteristics and location[51]. Some estimates suggest repurposing an LNG terminal to become ready to import ammonia costs roughly 20% of the LNG terminal's CAPEX. Hybrid terminal uses are also expected, with the same terminal can import multiple carriers if more than one storage tank is used. This adaptation would leverage current ample LNG import capacity amid declining conventional gas imports and the rise of the hydrogen economy. It is worth emphasising that transporting ammonia as a hydrogen carrier at higher volumes presents some safety and sustainability challenges due to its toxicity.

50 Study commissioned by Gas LNG Europe (GLE): Securing & Greening Energy for Europe: The Role of Terminal Operators, Presented by DNV & Frontier Economics, March 2024.

51 E.g., some onshore terminals have higher available capacity, while Floating Storage Regasification Units (FSRUs) can be relocated, allowing infrastructure modifications for hydrogen and derivative imports.

142 As for the sector prospects, gradually more ambitious plans exist to import hydrogen, synthetic methane, and ammonia via terminals. The feasibility of scaling up those projects will depend on infrastructure readiness and cost dynamics. Among these, ammonia seems the most stable option. Ambitious plans aim to expand ammonia import capacity to approximately 62 TWh (54 TWh hydrogen equivalent, including cracking losses).

143 Several pilot and investment projects are progressing For instance, there are various initiatives for import of other gases besides natural gas in the LNG Gate terminal of the Port of Rotterdam in the Netherlands, which includes green ammonia and the building of a hydrogen terminal. Some of these projects have been designated as European Projects of Common Interest, underscoring their strategic importance.

144 Finally, the terminals with multiple tanks could have a pivotal role in the energy transition. One or more tanks can be repurposed for various commodities while other tanks can still import LNG. This versatility of LNG terminals allows for keeping security of supply in the European natural gas system while allowing flexibility for the development of other energy import pathways. Although technically feasible, adapting safety barriers and design of the LNG storage tank would be necessary.

Considerations about investment requirements and revenue recovery models

145 While a number of terminal developments are advancing, uncertainties in the sector, and particularly, its higher costs, require a measured and evidence-based approach in assessing the future role of new LNG terminals to import decarbonised gases. This consideration is especially relevant given the possibility that hydrogen and its derivatives may be produced at a pace that does not align with the development of corresponding import infrastructure.

146 To support an efficient and smooth transition, it is advisable that LNG system operators and national regulatory authorities should engage stakeholders in demand assessments before approving investments. The Hydrogen and Decarbonised Gas Market Regulation already establishes that LNG and storage system operators should evaluate market demand for renewable and low-carbon gas investments, including hydrogen and ammonia, every two years. Operators must report their findings to regulatory authorities to guide infrastructure planning. Governments can also play a crucial role in securing industrial demand, while efforts should also be made to keep administrative costs manageable in order to support overall project viability.

147 Ultimately, the successful transition of LNG terminals to new energy carriers will depend on the development of downstream gas markets and the competitiveness of emerging technologies. Industrial demand must align with regional transition plans to ensure coordinated progress. As such, a key consideration is ensuring access to industrial clusters that will consume these alternative fuels. The expansion of hydrogen infrastructure is still in its early stages and may take time to develop. Therefore, the terminal projects should be targeting nearby clusters. In that sense, the sector calls for greater regulatory clarity. A forthcoming study by CEER, due in Q4 2025, will further expand on the feasibility of some of these new initiatives and the regulatory provisions that could apply to them.

Annex I:

Table 7: Transhipment of Russian LNG and their location - 2024 vs. 2023, (bcm)

Transhipment location of Russian LNG (bcm)	2024	2023	ΔDelta
Zeebrugge (BE)	3.3	3.5	-0.2
Montoir (FR)	0.5	1.5	-1
Murmansk (RU)	1.7	2.0	-0.3
Kamchatka (RU)	0.1	0	0.1
Total transhipment	**5.6**	**7.1**	**-1.5**

Source: ICIS LNG Edge.

Table 8: Russian LNG transhipment destination - 2024 vs. 2023, (bcm)

Russian LNG Transhipment destination	2024 (bcm)	2023 (bcm)	ΔDelta (bcm)	2024 #	2023 #
China	3.05	4.43	-1.38	32	48
India	0.29	0.65	-0.37	3	7
Italy	0.00	0.19	-0.19	0	1
Japan	0.00	0.08	-0.08	0	1
Kuwait	0.20	0.10	0.10	1	1
Singapore	0.00	0.09	-0.09	0	1
Spain	0.77	0.57	0.20	8	6
Taiwan	0.36	0.47	-0.11	4	5
Turkey	0.20	0.51	-0.31	2	6
Belgium	3.05	4.43	-1.38	1	0
South Korea	0.29	0.65	-0.37	5	0
Uknown	0.00	0.19	-0.19	-	-

Source: ICIS LNG Edge.

Table 9: Fit for 55 LNG compliance timeline

Date	Event	Relevant Regulation	Who is Affected
1 Jan 2024	EU ETS begins pricing CO_2 emissions (40% of verified emissions)	EU ETS (Art. 3g)	LNG ship operators
1 Jan 2025	GHG intensity limit of -2% takes effect	FuelEU Maritime (Art. 4)	LNG ship operators
5 May 2025	First annual MRV disclosure by importers	EU Methane Regulation (Art. 27 & Annex IX)	LNG importers
5 Aug 2025	Member States must define penalty frameworks	EU Methane Regulation (Art. 31)	EU Member State authorities
By Aug 2025	LNG terminals implement MRV, LDAR & flaring rules	EU Methane Regulation (Arts. 4–14)	LNG terminal operators
1 Jan 2026	EU ETS expands: CO_2 at 100%, CH_4 and N_2O included	EU ETS (Art. 3g)	LNG ship operators
5 Feb 2026	Methane transparency database & rapid reaction mechanism due	EU Methane Regulation (Art. 30)	European Commission
5 Aug 2026	Global monitoring tool & performance profiles due	EU Methane Regulation (Art. 30)	European Commission
1 Jan 2027	MRV compliance for new/revised contracts post Aug 2024	EU Methane Regulation (Art. 28)	LNG importers & suppliers
5 Aug 2027	Commission defines methane intensity methodology	EU Methane Regulation (Art. 29)	European Commission
5 Aug 2028	Importers begin reporting methane intensity	EU Methane Regulation (Art. 29)	LNG importers
1 Jan 2030	GHG intensity target -6% applies to shipping fuels	FuelEU Maritime (Art. 4)	LNG ship operators
5 Aug 2030	Max methane intensity limits apply for new/renewed contracts	EU Methane Regulation (Art. 29)	LNG importers & suppliers

Source: EU Methane Regulation (Regulation (EU) 2024/1787); EU ETS Directive (Directive 2003/87/EC (as amended); FuelEU Maritime Regulation (Regulation (EU) 2023/1805).

List of figures

Figure 1: Top 5 largest LNG producers (bcm) - 2015 – 2024 8
Figure 2: Historical evolution of LNG production and nameplate capacity (Mt) - 1990 – 2024 9
Figure 3: Global LNG export infrastructure utilisation (%) - 2010 – 2024 10
Figure 4: Global LNG production variations in 2024 compared to 2023 (bcm) 10
Figure 5: New capacity developments in global LNG liquefaction (Mt) - 2022 - 2030 11
Figure 6: Evolution of financial investment decisions at liquefaction plants per country – Mt 13
Figure 7: LNG demand variations in 2024 compared to 2023 – bcm 13
Figure 8: Top 5 largest LNG importers (bcm) - 2015 – 2024 14
Figure 9: LNG demand variation year on year by EU Member State (bcm) - 2023 – 2024 14
Figure 10: EU LNG imports by country in 2024, (bcm) 15
Figure 11: Evolution of gas deliveries into the EU by supply route - 2020 - 2024 15
Figure 12: Russian LNG imports into the EU and global LNG exports - 2024 vs. 2023, (bcm) 16
Figure 13: Russian total LNG production per liquefaction plant – 2024 vs. 2023, (bcm) 17
Figure 14: Transhipment of Russian LNG and operations' location - 2024 vs. 2023, (bcm) 18
Figure 15: Daily gas consumption in the European Union in 2024 compared to 2019-2023 – (TWh/d) 20
Figure 16: EU gas consumption evolution per sector, 2017-2024 (TWh) 21
Figure 17: Year-on-year change for main electricity generation technologies in 2024 21
Figure 18: EU electricity generation from main sources in the period 2019-2024 22
Figure 19: Annual growth rates for various REPowerEU targets 24
Figure 20: EU gas supply under Fit-for-55 and REPowerEU demand scenarios by 2030 (bcm) 26
Figure 21: LNG imports under Fit-for-55 and REPowerEU scenarios (bcm) in 2025-2030 27
Figure 22: Sankey diagram of bilateral global LNG trade in 2024 (Mt) 31
Figure 23: LNG import requirements under decarbonisation scenarios (bcm) 36
Figure 24: Uncontracted LNG volumes under Fit-for-55 demand scenario by 2030 (bcm) 37
Figure 25: EU LNG contractual position under REPowerEU demand scenario by 2030 (bcm) 38
Figure 26: EU LNG contractual position under Mid-point trajectory by 2030 (bcm) 38
Figure 27: Reliance on spot purchases of top 5 LNG importers in 2024 (bcm) 39
Figure 28: LNG contracted position of China, Japan, South Korean and India by 2030 (bcm) 40
Figure 29: Expiring LNG contracted volumes for EU destination 2024 - 2030 (bcm) 41
Figure 30: LNG contracted position for EU destination 2024 - 2030 (bcm) 41
Figure 31: Total committed LNG volumes by portfolio players 2024 - 2030 (bcm) 43
Figure 32: ACER EU daily spot LNG price assessment 44
Figure 33: Price range of the EU spot LNG transactions within the year 2023-2024 45
Figure 34: Breakdown of price indexation for spot trade in Europe 2024 - % 47
Figure 35: Timeline for EU methane regulation 48
Figure 36: Overview of existing EU LNG capacity per Member State and yearly additions by 2024 (bcm) 51
Figure 37: Regasification capacity and utilisation rate of LNG terminals by EU country – 2024 (bcm) 52
Figure 38: Daily evolution of LNG send-out flows in the EU (mcm/d) 53
Figure 39: LNG terminal utilisation compared to gas demand by country - 2024 53
Figure 40: Ratio of LNG send-out and net withdrawal to gas consumption in France – 2021-2024 55
Figure 41: Ratio of LNG send-out and net withdrawal to gas consumption in Spain – 2021-2024 55
Figure 42: Ratio of LNG send-out and net withdrawal to gas consumption in Belgium – 2021-2024 56
Figure 43: Breakdown of LNG import sources in Central and Southeastern EU countries 57
Figure 44: Daily peak demand compared to current LNG send-out and storage withdrawal capacity 58
Figure 45: Overview of decarbonised and renewable gas options for LNG imports 61