Gas Reserve Mechanisms and Flexibility Options

Enhancing gas supply security in a changing global market

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Abstract

Two major gas supply crises in the last five years have fundamentally challenged long-held assumptions about gas supply security and exposed deep vulnerabilities in an increasingly interconnected but geopolitically more complex global gas market. This evolving landscape, combined with reduced supply flexibility and growing weather sensitivity, calls for stronger gas supply security frameworks built on closer international cooperation, new reserve mechanisms and greater market flexibility.

This report focuses on gas reserve mechanisms and flexibility options that can strengthen gas system resilience against short-term supply disruptions. It identifies practical measures that gas-importing countries can implement over the next five years to reinforce supply security through a combination of physical reserve assets, flexible commercial arrangements and policy-based mechanisms, complementing longer-term efforts to diversify supply sources and enhance gas infrastructure.

The report also explores how governments can advance international cooperation by strengthening coordination and dialogue, increasing transparency, enhancing market flexibility and jointly exploring new voluntary reserve mechanisms. The IEA stands ready to support these efforts.

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Executive summary

Over the past five years, global gas markets have experienced two major energy crises that fundamentally challenged long-held assumptions about gas supply security and resilience. The 2022-2023 energy crisis following Russian Federation's full-scale invasion of Ukraine and the closure of the Strait of Hormuz during the 2026 Middle East conflict demonstrated that events previously considered extreme can materialise with significant consequences for import-dependent economies in both Europe and Asia.

The crises highlighted that well-functioning gas markets remain the first and most important line of defence against supply disruptions. Price signals, commercial incentives, and the international reallocation of liquefied natural gas (LNG) allowed supplies to move towards regions with the greatest need (and willingness to pay), helping to mitigate what could have been more severe and widespread physical shortages. Market flexibility therefore remains an essential component of gas security.

At the same time, recent experience also showed that market-based reallocation alone may not always be sufficient during periods of acute stress. When global gas supply is exceptionally tight, competition for available cargoes can trigger extreme price volatility, amplify economic impacts and, in some cases, fail to prevent physical shortages. These risks highlight the importance of maintaining physical reserves, emergency response arrangements, and coordinated policy measures that can help bridge the most acute phase of a crisis until markets rebalance.

Long-term supply security ultimately depends on adequate investment across the gas value chain, diversified supply sources, robust infrastructure, and appropriate contracting arrangements. These structural elements create the supply base upon which secure gas systems ultimately depend, but they are not the focus of this report. Instead, we focus on a complementary set of measures that importing countries – and, where appropriate, groups of importers and exporters – can implement in the medium term to strengthen resilience against short-term market shocks. Many of these measures build on existing infrastructure, commercial arrangements, and market structures, allowing resilience to be enhanced without requiring major new physical investments.

Making gas markets more resilient does, however, come at a cost. Maintaining strategic reserves, securing commercial flexibility, and preserving unused capacity all involve premiums that are ultimately borne by consumers, taxpayers, or market participants. Yet recent crises have demonstrated that the economic and social costs of being underprepared may be substantially higher than failing to invest in resilience measures. As with other forms of insurance, such investments involve upfront costs that can provide significant value when highly disruptive events occur. Understanding the costs, benefits, trade-offs, and potential unintended consequences of these measures is therefore essential to designing efficient and appropriate supply security frameworks.

There is no one-size-fits-all model for strengthening gas security; countries differ considerably in their resource endowment, infrastructure, geography, import dependence, market design, and regulatory frameworks. As such, the most appropriate mix of physical reserve mechanisms, commercial flexibility, and policy tools will vary according to national market conditions, risk profile, and security objectives. Many of the concepts presented in the report warrant further technical analysis, economic assessment, and international dialogue to better understand their costs, benefits, trade-offs, and implementation challenges. By identifying practical options to strengthen short- to medium-term resilience, this report aims to catalyse continued discussion and cooperation among governments, industry, and international organisations. Its main findings are summarised below.

- **The global gas market has become structurally and geopolitically more complex.**

  The global gas market has become structurally more complex since the 2022-2023 energy crisis. This growing complexity reflects increased geopolitical risks, trade fragmentation, and greater weather sensitivity of gas flows and demand. In addition, supply flexibility has been reduced because of decreased pipeline import optionality in Europe. As a result, future supply disruptions and price volatility remain significant risks, despite expectations of stronger LNG supply in the coming years. This increasingly complex environment calls for stronger gas supply security frameworks built on closer international cooperation, new reserve mechanisms, and greater market flexibility. The expected easing of market conditions later this decade may provide a valuable opportunity for governments to strengthen resilience, build strategic buffers, and deepen international cooperation before the next major disruption occurs.

- **Physical reserves are essential but are not sufficient.**

  Physical gas reserves remain a cornerstone of gas security, but existing storage assets alone cannot fully address future supply risks. While underground gas storage (UGS), LNG tanks, and floating storage assets offer opportunities to strengthen resilience, their effectiveness is constrained by geography, infrastructure, commercial incentives, and technical limitations. Developing new storage infrastructure requires significant investment and long lead times. Therefore, physical reserves need to be complemented by commercial flexibility enhancements and policy-based mechanisms to strengthen overall system resilience.

- **Commercial flexibility can be further strengthened.**

  Commercial flexibility is a critical complement to physical reserves because it enables available LNG to move more efficiently during market disruptions. Increasing contractual flexibility, encouraging commercial innovation, and facilitating greater use of LNG swaps could strengthen market flexibility, improve the allocation of available supply, enhance system resilience, and help moderate price volatility without requiring new physical infrastructure.

- **Policy-based reserve mechanisms should be tailored to national circumstances while offering significant scope for cross-border schemes and knowledge sharing.**

  Policy-based reserve mechanisms should be tailored to national circumstances rather than follow a single model. Options such as mandatory storage obligations, strategic reserves, and buffer LNG schemes each offer distinct advantages but also involve different costs, governance arrangements, and operational trade-offs. Beyond domestic policies, there is considerable scope to strengthen gas security through cross-border reserve arrangements, shared infrastructure, coordinated emergency planning, and greater knowledge sharing. Combining national measures with regional and international cooperation can improve resilience while making more efficient use of existing assets.

- **Closer international cooperation is essential for strengthening gas security.**

  International cooperation, as a complement to national measures, is essential to strengthening gas security in an increasingly interconnected but geopolitically complex market environment. While not directly applicable to gas, the International Energy Agency's (IEA) oil emergency response framework provides valuable lessons for developing voluntary gas reserve mechanisms. Governments can most effectively advance international cooperation in these areas by strengthening coordination and dialogue, increasing transparency, working together to enhance market flexibility, and jointly exploring new types of voluntary reserve mechanisms. The IEA stands ready to support further analysis, knowledge sharing, and international collaboration to strengthen gas security, including through its Working Party on Natural Gas and Sustainable Gases Security (GWP).

1. Introduction

Over the past five years, the global gas market has experienced two major energy crises. In 2022-2023, a sharp reduction in Russian pipeline gas supplies to Europe following Russian Federation (hereafter, "Russia")'s full-scale invasion of Ukraine triggered record high gas prices, an unprecedented reconfiguration of global LNG trade flows, intense competition for flexible cargoes, and significant demand destruction across gas-importing economies. While the acute phase of that gas supply shock has since eased – and the market is expected to transition toward a more comfortably supplied state in the second half of the decade – gas market risks and vulnerabilities remain significant. These vulnerabilities were laid bare in 2026 when LNG flows through the Strait of Hormuz were disrupted, including interruptions to LNG exports from the world's second largest LNG supplier, Qatar. The events of 2026 serve as a reminder that even in a more structurally balanced market environment, economies dependent on imported gas remain exposed to sudden supply disruptions and price volatility.

Governments in these countries have an extensive toolkit to address gas supply security risks, including diversifying supply sources and building long-term contract portfolios; supporting investments in supply capacity and infrastructure, including storage; maintaining adequate gas and LNG stocks; enhancing demand-side flexibility; addressing vulnerabilities related to chokepoints and bottlenecks; ensuring robust regulatory and market frameworks; and establishing plans to manage supply emergencies.

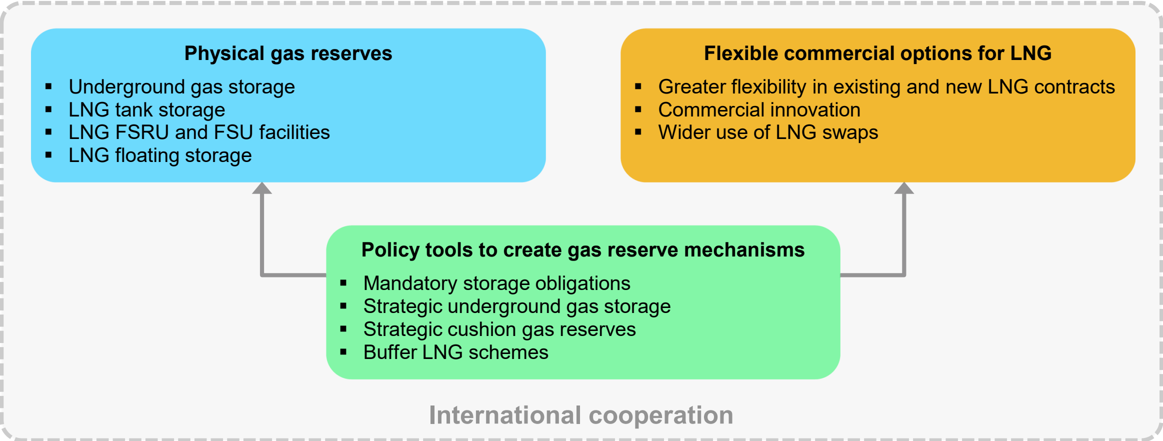
This report focuses on a relatively narrow subset of this toolkit, centred on reserve mechanisms and flexibility options, which governments can deploy in the short to medium term to enhance gas supply security.

Specifically, the report considers three areas for such mechanisms:

- Physical assets
- Flexible commercial arrangements
- Policy mechanisms

The 2022-2023 crisis also exposed the risks of uncoordinated international action and zero-sum dynamics during an emergency. The recent disruptions affecting LNG flows through the Strait of Hormuz further reinforced those risks, highlighting the importance of international coordination in managing supply shocks that can rapidly propagate through interconnected gas and LNG markets globally. As such, the international dimension, including potential areas for closer coordination and cooperation among like-minded importers and exporters across physical, commercial, and policy-based mechanisms, is also explored in detail in this report.

Figure 1.1 Overview of gas reserve mechanisms and flexibility options



A post-crisis market environment offers an opportune window to strengthen strategic buffers and policy frameworks for gas security globally. The rapid expansion of global LNG supply between now and 2030 – albeit with some delays due to the conflict in Iran – could significantly increase market liquidity, improve the affordability of gas, and shift the balance of power towards buyers in the second half of this decade. A period of looser market conditions, however, is unlikely to be permanent. The IEA's long-term scenarios indicate that global gas and LNG demand could continue to grow beyond 2030, while a prolonged period of lower prices could reduce the investment incentives for new LNG export capacity as well as upstream and midstream gas infrastructure. Given long project lead times, insufficient investment in the coming years could set the stage for renewed market tightness in the early to mid-2030s, particularly if demand turns out to be higher than expected.

The events of 2026 demonstrate that even during periods of improving supply availability, geopolitical disruptions affecting key LNG exporters or critical chokepoints can quickly tighten markets. Taking advantage of more favourable conditions expected in the late 2020s to build reserves, enhance resilience, strengthen international cooperation, and establish durable security mechanisms can therefore reduce future vulnerabilities and help avoid more costly interventions later.

2. A gas market in transition

2.1 Lessons from the 2022-2023 energy crisis

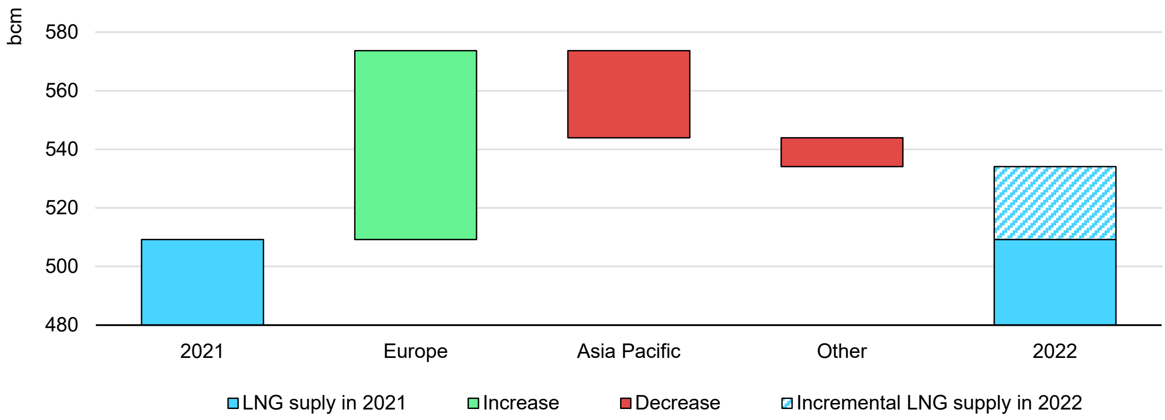
In 2022-2023, the global natural gas market experienced a major supply shock following Russia's full-scale invasion of Ukraine.[1] Early signs of market stress had already emerged in 2021, as the state-owned Russian gas supplier, Gazprom, halted spot market sales and refrained from filling its European storage facilities during the injection season, leading to a period of "artificial tightness". The crisis deepened significantly after the invasion, in 2022 and 2023. Between 2021 and 2023, Russian pipeline natural gas deliveries to Europe fell by around 125 bcm/yr (close to 75%), as importers struggled to secure alternative pipeline volumes at short notice.

As a result, European buyers turned to the LNG market to secure new supply, increasing LNG imports by more than 60% in 2022 (Figure 2.1). With global LNG supply unable to fill the sudden spike in demand, Europe drew LNG cargoes away from other markets to fill the sizeable supply gap, triggering a significant reconfiguration of global LNG trade. But LNG trade flexibility alone could not sufficiently rebalance the European market, even with UGS fully utilised and with relatively mild winter weather reducing heating demand. The remaining adjustment came through price-driven demand reductions, particularly in energy-intensive industrial sectors and economically vulnerable households and small businesses, at a substantial social and economic cost.

The crisis underscored a structurally and geopolitically more complex global gas market, revealing the need to strengthen international supply security frameworks. While a wave of new LNG supply in the second half of this decade is set to ease market conditions, this period of relative comfort may be temporary, or, in the event of renewed geopolitical disruption, even illusory, as demonstrated by the 2026 Middle East crisis. Policymakers should therefore look beyond the early 2030s, when market fundamentals could start tightening again, and use any periods of interim reprieve to accelerate the design and implementation of gas reserve mechanisms and other security instruments.

[1] For a more comprehensive analysis of the origins of the crisis and the resulting gas market lessons, please refer to the Gas Market Lessons from the 2022-2023 Energy Crisis report.

Figure 2.1 Year-on-year change in LNG imports by region, 2022 vs. 2021



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Source: IEA analysis based on data from ICIS LNG Edge.

The crisis also highlighted the risk of zero-sum dynamics taking hold during global crises, which can harm gas market participants worldwide. While competition for a commodity such as natural gas under normal market conditions supports the efficient allocation of resources, strengthened dialogue and coordination among like-minded LNG importers and exporters can help mitigate the most damaging effects of bidding wars under emergency conditions.

The close link between gas supply security and affordability was also revealed during this period, demonstrating that price shocks rendering gas unaffordable can deprive some end users of access to gas in ways that can resemble the effects of a physical supply disruption, particularly in energy-intensive industries and in developing countries. While governments can develop backstops to balance consumer protection and demand-side responses to tight market conditions, collective tools beyond the national level can play a complementary role to ensure future gas supply security and affordability.

2.2 The post-crisis gas market environment

In 2024 and 2025, the global gas market gradually rebalanced, albeit with some reversals along the way. In the second half of the decade, a wave of new LNG supply is set to bring about a transition from a relatively tight to a relatively well-supplied market. However, this temporary easing of market conditions should not lead to complacency. Disruption risks remain, as demonstrated by the war in Iran and the effective closure of the Strait of Hormuz starting on 28 February 2026, which hampered global energy flows, including of LNG supplies. The global gas market is expected to enter a period of greater supply abundance, but within a structurally more complex and volatile market framework shaped by longer-term trends that predate recent geopolitical disruptions. This complexity reflects the erosion of key flexibility mechanisms along the upstream, midstream, and downstream parts of the value chain that previously helped absorb shocks and stabilise prices during periods of market imbalance (see next section). As a result, the resilience of gas supply systems cannot be taken for granted, even under more favourable supply-demand conditions.

Reduced flexibility in Europe

At the centre of this structural shift lies Europe, which had served as the global gas market's balancing region of last resort since the 2010s. The loss of around 125 bcm/yr of Russian pipeline gas supply since 2021 has removed not only a major source of imports, but also a uniquely price-responsive form of supply flexibility. The remaining roughly 15 bcm/yr (equivalent to around 5% of the European Union's total gas supply) is set to be phased out by the end of 2027. This loss has been compounded by the phase-down of production at the Groningen gas field in the Netherlands and the effective exhaustion of swing capacity in Norway. At the same time, European gas storage is increasingly reserved for supply security rather than market-driven flexibility following the introduction of mandatory storage fill targets under the EU Gas Storage Regulation in 2022. In parallel, the phase-out of coal-fired generation is reducing the scope for gas-to-coal switching in the power sector, narrowing the adjustment options on the demand side as well, although the impact has been partly offset by the rapid expansion of renewable electricity generation, which has reduced the overall need for fuel switching.

Europe has significantly expanded its LNG import infrastructure, adding more than 50 bcm/yr of regasification capacity since the 2022-2023 energy crisis. However, this has only partially offset the loss of other sources of supply flexibility. Unlike indigenous production or flexible pipeline gas imports, additional LNG import capacity does not increase gas supply availability, it only enhances the region's ability to attract and absorb more LNG cargoes.

Geopolitical risks

Beyond Europe, the global gas market is becoming increasingly complex and less predictable. Geopolitical risks have intensified, as demonstrated by Russia's full-scale invasion of Ukraine, which severely disrupted global gas supplies, as well as an increase in the number of attacks and sabotage targeting energy infrastructure. These included an attack on the Nord Stream 1 and Nord Stream 2 pipelines in the Baltic Sea in September 2022, when explosions rendered the entire 55 bcm/yr Nord Stream 1 system and one of the two 27.5 bcm/yr sections of the completed (but uncommissioned) Nord Stream 2 project inoperable. In October 2023, the 2.6 bcm/yr Balticconnector gas pipeline linking Estonia and Finland was damaged by a ship dragging its anchor, and was shut down for approximately seven months, in what authorities treated as a suspected act of sabotage. Since Russia's full-scale invasion of Ukraine in 2022, Russian strikes have repeatedly targeted Ukraine's energy infrastructure, including upstream assets, gas pipelines, UGS sites, gas-fired power plants and combined heat and power units. In March 2025, the Sudzha gas metering station on the Russian side of the border – the only operational entry point for Russian gas into the Ukrainian transit corridor at the time – was also damaged in a targeted attack.

In the Middle East, Israel's conflict with Hamas prompted production suspensions and heightened security concerns at Israel's offshore gas fields due to rocket fire in late 2023, while the 12-day Israel-Iran conflict in June 2025 saw strikes on Iran's South Pars gas facilities and a gas processing plant. The start of the broader regional conflict in February 2026 further escalated risks to energy infrastructure across the Gulf, as military strikes targeted gas facilities in several countries. In Qatar, airstrikes on the Ras Laffan complex in March 2026 heavily damaged two LNG liquefaction trains with a combined capacity of 17 bcm/yr, requiring an estimated three to five years to repair. The Pearl gas-to-liquid plant was also struck, which will take at least one year to repair. In the United Arab Emirates, the Shah gas field, the largest sour gas field in the world, was struck in March, while the Habshan gas complex, which processes more than half of the country's domestic gas supply, sustained repeated attacks and extensive damage in March and April 2026. In Iran, airstrikes on gas processing plants and petrochemical facilities at the Assaluyeh industrial hub disrupted output from several production phases of the South Pars gas field and severely curtailed petrochemical activity.

Beyond direct attacks on gas infrastructure, the effective closure of the Strait of Hormuz blocked about 20% of global LNG trade for several months, while widespread oil production curtailments reduced associated gas production across the region, particularly in Iraq and Saudi Arabia. At the start of the conflict, Israel also suspended production at the offshore Leviathan and Karish fields as a precautionary measure, leading to a temporary disruption of pipeline gas exports to Egypt and Jordan. Both fields resumed operations in April 2026. These events demonstrate that armed conflict can disrupt natural gas supply not only through direct attacks on gas infrastructure, but also indirectly through impacts on oil production and downstream industrial facilities.

Geopolitical instability poses a risk not only to physical energy infrastructure but also to critical maritime trade routes. Since October 2023, regular attacks on commercial shipping in the Red Sea by Houthi rebels in Yemen have forced fleet operators to divert cargoes, including most LNG shipments, away from the Suez

Canal onto the much longer route around Africa. In March 2026, meanwhile, the Russian-flagged LNG carrier *Arctic Metagaz*, carrying a sanctioned LNG cargo, was heavily damaged in a drone strike in the Mediterranean, marking the first known targeted attack on an LNG carrier.

Greater interconnectivity

The growing interconnectivity among regional markets, driven by the expansion of flexibly traded LNG, has improved market flexibility and liquidity. At the same time, it has also heightened the risk of contagion, allowing price shocks and market imbalances to spread more rapidly and widely across regions.

During the 2022 gas crisis in Europe, extreme price spikes at European hubs spilled over not only into European power prices and industrial activity, but also into Asian LNG markets, pushing spot prices to record levels and pricing out several emerging buyers. In Pakistan, for example, some LNG suppliers cancelled contracted LNG cargoes to Pakistani buyers and diverted volumes toward higher-priced European markets, exacerbating gas shortages in the country. Similarly, Egypt introduced demand-rationing measures, including dimming streetlights and curbing gas use, to maximise LNG exports to Europe. Finally, the June 2025 Israel-Iran conflict triggered simultaneous price increases at both European and Asian benchmarks, highlighting how security risks in one region can have near-immediate global price impacts in an increasingly interconnected global market.

Trade fragmentation

While greater interconnectivity allows price signals to reverberate rapidly across regions, growing fragmentation in international trade is adding friction to global gas flows, reducing the overall efficiency of global gas market adjustment. This includes the expanded use of international sanctions, as well as restrictive trade policies and tariffs that increasingly affect – or explicitly target – natural gas and LNG flows. Economic sanctions often pursue clear geopolitical and security objectives, such as curtailing Russia's ability to finance and sustain its war against Ukraine. However, they also increase complexity in global gas trade and reduce flexibility in market adjustment. Since 2023, successive rounds of US sanctions have targeted Russian LNG export infrastructure, including Arctic LNG 2 and, since January 2025, the smaller Portovaya and Vysotsk LNG facilities on the Baltic Sea, severely constraining exports and shipping operations.

In parallel, the European Union has progressively tightened restrictions on Russian LNG. The 14th sanctions package, adopted in June 2024, prohibited LNG transshipment in EU ports to non-EU destinations. In May 2025, the European Commission's REPowerEU roadmap set out the objective of phasing out the remaining Russian energy imports, including both pipeline gas and LNG, by the end of 2027. Subsequent legal measures supported this objective, including the 19th sanctions package, adopted in October 2025, which introduced a phased ban on Russian LNG imports. That ban applies to imports under short-term contracts from April 2026 and to imports under long-term contracts from January 2027. The REPowerEU Gas Regulation, which entered into force in February 2026, established a legally binding phase-out of Russian pipeline gas and LNG imports by 1 November 2027. The European Union's 20th sanctions package, adopted in April 2026, introduced additional restrictions, including a prohibition on maintenance and other services for Russian LNG tankers and ice-breakers, and a ban on LNG terminal services to Russian entities.

Trade fragmentation has also intensified in the Asia Pacific region. Since February 2025, the People's Republic of China (hereafter, "China") has imposed retaliatory tariffs on US LNG – at one point reaching 125% before being reduced to 25%. Those measures led to a complete halt of direct LNG shipments from the United States to China between early 2025 and mid-2026, with contracted volumes redirected or resold into other markets instead.

The EU's Methane Regulation, although not designed as a trade measure, has been identified as a potential non-tariff barrier that may impact LNG trade flows in the medium term. The measure, which entered into force in 2024, seeks to reduce methane emissions across the gas value chain in line with the EU's broader climate and decarbonisation objectives. It requires more stringent monitoring, reporting, and verification on EU gas importers, which some stakeholders have suggested creates friction within the global LNG market.

Growing weather sensitivity

Finally, gas flows and gas demand are becoming increasingly weather-sensitive, reflecting their growing exposure to weather-related disruptions and the rising share of variable renewables in power systems. Severe drought conditions in 2024 forced the Panama Canal to impose water-level restrictions that reduced the number of LNG cargo transits by more than 80% compared with the five-year average. Earlier weather shocks also had lasting effects: severe cold spells in Northeast Asia and Texas in early 2021, followed by a long and cold spring season in Europe, caused short-term disruptions and drew down gas inventories, setting the stage for tight market conditions ahead of the 2022-2023 energy crisis. More recently, prolonged heatwaves across South and Southeast Asia in the second quarter of 2024 pushed electricity demand for cooling higher, supporting stronger LNG import demand for power generation and elevated regional prices. At the same time, greater reliance on variable renewables has increased short-term volatility in gas-fired generation, as well as in wholesale gas and power prices. In November and December 2024, for example, extended "*dunkelflaute*" episodes across northwestern Europe – characterised by simultaneously low wind speeds and low solar generation – occurred during a period of elevated power demand. This led to notable increases in gas-fired generation, highlighting the growing balancing role of gas in renewables-heavy energy systems.

Gas is also increasingly required when nuclear or hydro power are hampered by dry spells. During a 2022 heatwave in Europe, for example, a drought in France reduced river levels and elevated water temperatures, ultimately constraining nuclear output that had already been reduced due to maintenance outages. Similar heatwave-induced droughts forced hydropower generation to decline significantly across Europe during the same period. Such weather-related volatility is likely to increase the importance of gas as a balancing fuel during episodes of low renewable output, even in markets where overall gas demand is declining.

Taken together, the above developments indicate that in today's less predictable market environment, the deployment of new reserve mechanisms and flexibility options, along with stronger international cooperation, are critical to enhancing global gas supply security and system resilience.

3. Flexibility options along gas and LNG value chains

Flexibility exists throughout the gas value chain, from upstream production through midstream infrastructure and trade to end-use consumption, though not every segment of the supply chain is equally suitable, or available for governments to leverage in order to enhance system flexibility. We explore some of the key flexibility levers in the section below.

Production flexibility

Supply-side flexibility determines how much natural gas can be made available to the market, but it is generally limited to a small number of swing fields and is increasingly constrained in major LNG-importing regions, including Europe and Asia. Several factors have reduced pipeline-based flexibility in Europe, including the sharp decline in flexible pipeline gas supplies from Russia since 2022; the progressive phase-down of production at the Groningen field in the Netherlands, which was previously a major source of upstream flexibility; and the plateauing and expected decline of production from key North Sea fields, some of which also provide flexible output. In Asia, meanwhile, gas fields have demonstrated limited ability to adjust production in response to demand fluctuations, while production in South and Southeast Asia has been in long-term decline.

LNG liquefaction facilities also offer limited operational flexibility. Outside planned maintenance periods and unplanned outages, liquefaction plants typically operate close to capacity, leaving little scope for rapid supply increases. Over the 2021-2025 period, utilisation of available LNG export capacity averaged around 85% worldwide. In principle, future LNG projects could be developed with spare liquefaction capacity to provide additional supply flexibility, potentially backed by importers as a cost-effective alternative to storage investments closer to their home market. However, no major LNG project has been developed with this objective to date. As a result, supply-side flexibility across the global gas system remains limited. This represents one of the biggest bottlenecks in the LNG value chain. Moreover, it is typically outside the direct control of governments, as decisions on production and liquefaction utilisation reside with upstream producers and LNG exporters.

Demand flexibility

Demand-side flexibility allows gas consumption to be reduced temporarily through a number of measures, including fuel switching; market-based demand response; behavioural changes; or administrative restrictions. Governments can also influence demand flexibility through measures such as efficiency improvements, pricing reforms, conservation campaigns, and emergency response programmes. While demand response can be a key element of gas market flexibility, certain types of demand adjustments, particularly administrative restrictions, can be socially and economically costly and are typically reserved for emergencies.

Fuel-switching options are becoming more limited in markets that are phasing out coal, while administrative measures usually prioritise protecting households and critical services by curtailing industrial demand first. As such, downstream flexibility can play a role in responding to supply disruptions and enhancing system resilience, but some demand-side measures involve economic and social trade-offs or are primarily designed for crisis situations rather than to provide a durable source of system flexibility.

Midstream flexibility

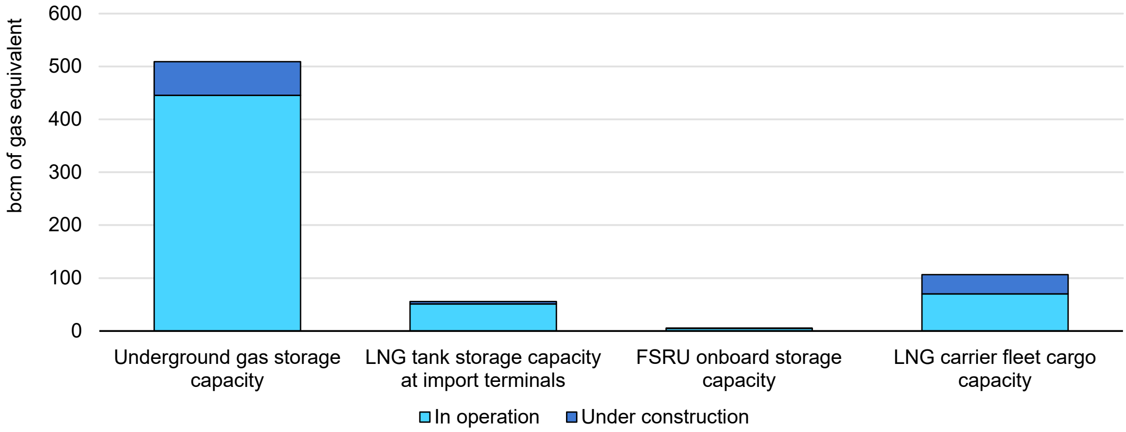
Midstream flexibility mechanisms enable the timely and efficient allocation of natural gas and LNG to market participants. Destination-free LNG cargoes and LNG reload infrastructure, for example, are key sources of locational flexibility within the midstream segment of the LNG value chain. Underground storage facilities provide critical seasonal flexibility, particularly in Europe, while short-term balancing can be supported by linepack management, fast-cycling salt cavern storage, floating LNG storage, and contractual flexibility. LNG tank storage at import terminals provides operational flexibility, helping to manage cargo arrivals, regasification schedules, send-out rates, and short-term market imbalances. For LNG-dependent import markets in Asia with limited underground storage, terminal tank capacity and large regasification capacity help to strengthen supply security by improving short-duration resilience. In markets with winter peak demand, such as Japan and Korea, LNG tanks also provide seasonal flexibility.

While opportunities to enhance flexibility exist across all segments of the gas value chain, the midstream segment offers a particularly broad set of physical, commercial, and policy levers that governments can use to strengthen system flexibility. As such, it is the primary focus of the analysis that follows.

4. Physical gas reserves

Physical gas reserves are an essential component of gas system resilience. This chapter examines the main forms of physical gas reserves that can enhance gas security and system flexibility: UGS, LNG tank storage, floating storage and regasification units (FSRUs) and floating storage units (FSUs), and LNG floating storage on conventional carriers.[2] Together, these tools form the core set of physical reserve options that can be deliberately expanded and strategically mobilised by governments as part of national or international reserve mechanisms and supply security frameworks.

Figure 4.1 Physical storage capacity in operation and under construction worldwide, end of 2024



Source: IEA analysis based on data from the International Group of Liquefied Natural Gas Importers (2025), Annual Report 2025; and CEDIGAZ (2026), UGS Dataset.

Other sources of physical flexibility exist in gas systems. One is linepack management (Box 1), which relies on pressure variations within high-pressure transmission pipelines to temporarily store and release gas. Linepack management is a critical operational flexibility tool, and plays a central role in intraday balancing, especially in highly meshed transmission systems such as those in Europe. However, linepack management falls primarily within the operational remit of gas transmission system operators (TSOs), who already

[2] FSUs are purpose-built vessels or LNG carriers that have been permanently converted into dedicated storage facilities and remain moored at a fixed location, typically as part of LNG import infrastructure. By contrast, LNG floating storage on conventional carriers refers to standard LNG carriers that temporarily hold cargoes on board without being converted into dedicated storage assets.

optimise linepack as part of normal system balancing and reliability management. As such, it is treated here as a background source of system flexibility rather than as a distinct reserve instrument for policy design and is not examined in detail. Nevertheless, experience sharing between European TSOs and their counterparts in Asia could help transfer best practices, as well as support more effective system balancing and better linepack utilisation during supply emergencies.

Box 4.1 Linepack management: The hidden flexibility embedded in gas transmission systems

Linepack refers to the quantity of gas stored within a transmission pipeline system. In practice, operators can increase or decrease the amount of gas physically held in the network by adjusting pressure within permitted technical and safety limits. This makes linepack the most immediate and continuously available source of flexibility in many pipeline gas systems.

Although linepack is not usually classified alongside dedicated storage infrastructure, it performs an essential balancing function. When demand rises unexpectedly over the course of a day, gas can temporarily be withdrawn from the transmission network through a controlled reduction in pressure. Conversely, when inflows exceed offtake, TSOs can rebuild linepack by increasing system pressure. In this way, the transmission network itself functions as a short-duration storage buffer.

The main benefit of linepack is its speed and operational responsiveness. Unlike underground storage or LNG-based flexibility tools, linepack can be adjusted almost instantaneously and does not require separate injection or withdrawal infrastructure beyond the normal operation of compressors, valves, and control systems. It is therefore especially important for managing intraday demand fluctuations and maintaining system balance between nominations and actual flows. In liberalised gas markets, linepack also helps absorb small imbalances created by shippers, supporting market-based balancing regimes and reducing the need for costlier balancing options.

The volume of gas that can be stored as linepack depends on pipeline diameter, network length, operating pressure, compressor configuration, and the permissible pressure range within the system. Highly meshed, high-pressure networks with large-diameter transmission lines can hold substantial quantities of gas in linepack terms. In the United Kingdom, for example, the transmission system operator reports average and maximum linepack swings during peak winter periods of around 15-20 mcm/d and 30-40 mcm/d, respectively (equivalent to roughly 5% to 15% of average winter demand) over the past five winters. However, these volumes cannot be withdrawn repeatedly without being replenished by upstream flows, storage withdrawals or imports. In this sense, linepack complements dedicated reserve infrastructure, instead of replacing it.

From a policy perspective, linepack is best understood as an embedded source of system flexibility rather than a substitute for seasonal or strategic stockholding. While it can address hourly or daily imbalances, it cannot address structural shortages, cover prolonged supply disruptions, or provide the multi-week or seasonal reserve capacity required for security planning.

Another option is peak-shaving LNG plants, which liquefy gas during off-peak periods and vaporise it during periods of peak demand. Peak-shaving plants have historically played a useful role in some local or regional gas systems (e.g. in Canada, China, and the United States). However, they are typically small in scale, often dedicated to specific local demand centres, and differ in both economics and system function from the large-scale reserve instruments considered in this chapter. For these reasons, they are not assessed further in this study.

The tools covered in this chapter also differ in the extent to which they can support reserve mechanisms, particularly those involving multiple countries or spanning regions. Under appropriate regulatory and commercial conditions, UGS and LNG tanks can provide dedicated reserve capacity and host stocks on behalf of other countries or market participants. By contrast, floating LNG assets tend to offer more limited reserve volumes but can provide valuable rapid-response capability, particularly where permanent infrastructure is lacking or where emergency import access is required at short notice. LNG floating storage occupies a still narrower niche: although costly and generally unsuitable for long-duration reserve building, it can provide temporary buffering capacity during periods of extreme market dislocation or infrastructure bottlenecks.

These different tools illustrate that there is no single model for developing and maintaining physical gas reserves. The following sections assess the key characteristics of the main physical reserve tools, with a particular focus on their suitability for strategic use.

Table 4.1 Overview of physical gas reserve and LNG flexibility options

	Underground gas storage			LNG tank storage	FSRUs and FSUs	LNG floating storage
	Depleted fields	Aquifers	Salt caverns			
Description	Former gas reservoirs repurposed for storage in porous rock formations.	Water-bearing formations converted into gas storage reservoirs.	Artificial caverns in salt formations created by solution mining.	Cryogenic tanks storing LNG at -162°C at LNG import terminals.	Floating units used to import LNG; FSRUs include regasification, FSUs require onshore regasification.	Conventional LNG carriers used for offshore LNG storage.
Primary purpose	Seasonal storage and large-scale system balancing.	Seasonal storage where depleted fields are unavailable.	Short-term balancing and peak demand management.	Operational buffer with partial seasonal role in LNG-dependent markets.	Fast-track LNG import infrastructure for regular and emergency access to LNG.	Commercial optimisation during market dislocations.
Advantages	• Proven geology reduces risk. • Large available capacity. • Large potential working gas capacity.	• Broad geographic availability of aquifers, including where no depleted fields exist. • Large potential working gas capacity.	• High withdrawal and injection rates. • Lower cushion gas requirement (~20%).	• Typically located near demand centres. • High deliverability to the gas grid.	• Fast-track deployment (< 1 year) possible with existing infrastructure and government support. • Redeployable assets. • High send-out rates (about 5 bcm/yr).	• Highly flexible and mobile. • No fixed infrastructure required for storage. • Can utilise ageing vessels nearing retirement.
Limitations	• Low cycling capability. • Long lead time (five to seven years). • High cushion gas requirement (about 50%).	• Greater geological uncertainty. • Possible environmental issues. • High cushion gas requirement (about 50% or more).	• Small working gas capacity. • Limited suitable geology.	• High unit cost vs. underground storage. • Long construction time (up to five years). • Limited volumetric capacity.	• Limited storage capacity (0.1 bcm per unit). • Limited vessel availability. • Not suitable for long-term storage.	• Limited storage capacity (0.1 bcm per unit). • Operational complexity. • Technical constraints (e.g. cargo ageing and boil-off). • Not suitable for long-term storage.
Estimated cost	USD 0.5 million – USD 1.0 billion per bcm of working gas capacity (excluding cushion gas).			USD 150 million – USD 250 million per 180 000 m³ storage tank (about 0.1 bcm of gas equivalent).	• Newbuild FSRU: USD 300 million – USD 420 million. • Conversion: USD 200 million. • Charter rate: USD 100 000 - USD 200 000 per day (USD 35 million - USD 70 million per year). • Onshore infrastructure: USD <100 million to several hundred million.	• Newbuild LNG carrier: USD 250 million. • Cost of old LNG carrier at scrap value: USD 15 million - USD 20 million. • Additional cost of converting an old LNG carrier to an FSU more suitable for storage: USD 14 million - USD 20 million.

Note: Working gas is the volume of gas in underground storage that can be regularly injected and withdrawn during normal operations. Cushion gas is the volume of gas permanently held in a UGS reservoir to maintain pressure and ensure deliverability; it is not withdrawn during normal operations but may be recoverable under specific circumstances, including as part of the closure and decommissioning of a storage facility.

4.1 Underground gas storage

UGS is a key source of gas system flexibility, both regionally and globally, helping to balance seasonal demand variability with more stable gas production profiles throughout the year. On shorter timescales, UGS facilities can also provide daily flexibility through their withdrawal capacity and proximity to demand centres, making them one of the fastest midstream flexibility levers available to mitigate demand swings and price volatility.

Globally, UGS facilities are predominantly developed from depleted fields (accounting for more than 80% of operational capacity), followed by aquifers (about 10%), and salt caverns (less than 10%).[3] Depleted fields offer the advantage of being proven gas-bearing formations, providing greater certainty regarding their technical suitability for conversion into UGS facilities. Where depleted fields are not available, aquifers can provide an alternative, although more rigorous testing is typically required to confirm permeability and storage performance, and higher cushion gas requirements generally make aquifers a more costly option. Both depleted fields and aquifers are typically used for seasonal balancing and tend to have relatively low cycling capability.

Salt caverns, by contrast, are better suited to managing short-term demand fluctuations due to their high injection and withdrawal rates, allowing for multiple cycles per year. The working gas capacity of salt caverns is generally smaller than that of depleted fields or aquifers and they account for less than 10% of working gas capacity globally, but they provide roughly 25% of global deliverability, reflecting their superior cycling capability relative to other types of UGS facilities.

While UGS facilities act as a key lever of supply-side flexibility in the global gas market, they are capital-intensive, requiring subsurface analysis, above ground infrastructure, and the purchase of cushion gas for the facility to be operational. Recently completed UGS facilities had reported capex of between USD 500 million and USD 1 billion per bcm of working gas capacity, excluding cushion gas. Furthermore, UGS facilities have relatively long lead times, often requiring five to ten years to develop, depending on local conditions and the type of facility. As such, the maximum UGS capacity that will be available to the market in 2030 is already broadly known today and defined by existing capacity and investments that have already been committed. Developing new UGS capacity can therefore fit into long-term energy system planning but will have little impact on short-term market dynamics.

Global distribution of UGS capacity

Underground gas storage capacity, totalling about 445 bcm globally at the end of 2024, is unevenly distributed across the world. Regions with mature gas markets

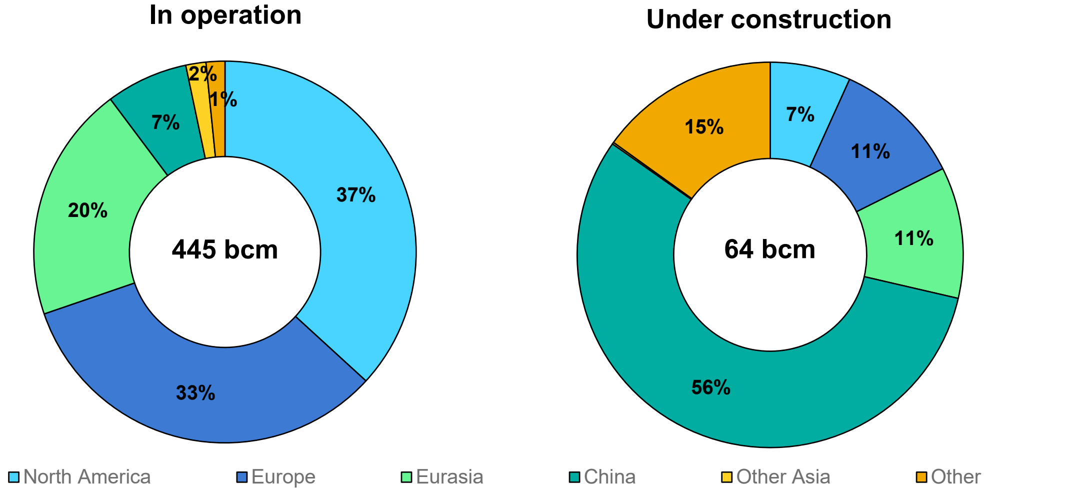
[3] CEDIGAZ (2025), Underground Gas Storage in the World - 2025 Status.

and highly seasonal gas demand patterns account for the largest operational capacity: North America has about 37% of operation capacity, Europe has about 33%, and Eurasia has about 20%. Asia holds only about 9% of global UGS capacity, although the region, led by China, has increased its UGS capacity in recent years.

The United States and Russia are the two largest individual UGS markets, with about 135 bcm and 75 bcm of storage capacity, respectively. In Russia, UGS capacity in operation accounted for about 14% of domestic demand in 2024, down one percentage point from 2010. In the United States, however, this share declined from about 18% to 14% over the same period, as growth in capacity additions remained below growth in demand. (Taking into account feedgas requirements for LNG exports further reduces this ratio). However, both countries are also major gas producers and net exporters, setting them apart from Europe and Asia, the world’s two largest LNG importing poles. While Europe and Asia rely on LNG as a key element of gas supply, their available UGS capacities differ markedly: Europe has around 150 bcm of UGS capacity (of which about 105 bcm is located in the European Union), whereas the Asia Pacific region has only about 38 bcm, including about 31 bcm in China.

The prospects for UGS capacity growth are predominantly in Asia. Out of the approximately 64 bcm of UGS capacity that were under construction globally by the end of 2024, China alone accounted for more than half (around 36 bcm). The remaining share was spread between relatively mature gas markets across Europe, Eurasia, North America, and the Middle East. In terms of geology, most of the total capacity under construction was being developed in depleted fields (around 80%), with the rest mostly accounted for by salt caverns.

Figure 4.2 Distribution of UGS capacity in operation and under construction, by region, 2024



Source: IEA analysis based on CEDIGAZ (2026), UGS Dataset.

Europe

Sizeable UGS capacity has long been a central feature of the European gas market, having been developed in response to highly seasonal gas demand patterns across the continent well before market liberalisation. It has subsequently become integrated into the unique regulatory structure of a large, liquid, and liberalised gas market, particularly in the European Union (and members of the Energy Community). EU rules on third-party access (TPA) to gas infrastructure, including storage facilities, ensure that UGS is used to its full potential in market balancing.

Over the past decade, capacity additions, mainly concentrated in Czechia, Italy, Poland, and Türkiye, have been limited relative to the total capacity in operation. Capacity additions were partly offset by closures, primarily in Germany, Ireland, and the United Kingdom (although the Rough facility in the UK, which closed in 2017, was subsequently reopened in 2022 with reduced capacity). Between 2016 and 2023, overall working gas capacity in the European Union increased by only around 1 bcm, or 1%, on a net basis, while in the broader European region, including Türkiye, Ukraine, and the United Kingdom, it grew by around 5 bcm, or 4%. More facilities could be closed in the coming years, driven by the phase-out of low-calorific gas (L-gas) originally supplied from the Groningen field in the Netherlands, which will reduce the need for dedicated L-gas storage sites, as well as by limited commercial interest in small, ageing, and slow-cycling facilities in mature markets, particularly in Germany.

Still, with close to 7 bcm of new UGS capacity under construction as of the end of 2024 (mostly concentrated in southern and southeastern Europe, with notable additions in Bulgaria, Italy, Romania, and Türkiye), total European storage capacity is expected to remain relatively stable in the medium term.

The potential repurposing of existing UGS sites for hydrogen storage has also gained attention, as the European Union and the United Kingdom seek to support the development of a hydrogen economy. However, the ongoing reassessment of hydrogen demand and deployment timelines in view of high costs suggests that large-scale conversion of UGS assets remains a long-term possibility rather than an imminent prospect.

Asia Pacifc

Compared with the leading UGS regions, Asia Pacific relies much less on underground storage to balance its gas market. The region's legacy gas markets, including in Japan and Korea, have limited suitable geological formations for large-scale underground storage facilities. In South and Southeast Asia, where gas – and especially LNG – demand is projected to grow rapidly in the medium term, limited pipeline infrastructure and the absence of strong seasonal heating demand have also constrained opportunities for UGS development. Nevertheless, depleted gas fields in the region could provide suitable geological formations for future storage projects as gas use and LNG import dependence grow over time.

UGS capacity in the Asia Pacific region is overwhelmingly concentrated in China, which more than quadrupled its storage capacity between 2015 and 2024 to reach an estimated 31 bcm, largely in depleted field formations. A comparable volume of additional capacity is currently under construction, alongside further early-stage expansion plans, driven by storage mandates introduced in 2018 and an implementation plan issued in 2021 to help boost the pace of UGS capacity additions. As residential and commercial gas demand grows in China, alongside rising domestic production and increasing pipeline and LNG imports, underground storage is increasingly important for balancing seasonal demand and enhancing supply security, especially during peak winter months. Outside of China, UGS capacity in Asia Pacific remains limited to Australia, New Zealand, and a handful of small-scale facilities in Japan.

Third-party access to underground storage facilities

The effective use and integration of UGS into market balancing also depends on the regulatory framework that storage operators must adhere to. In this respect, TPA rules have become essential to extracting the full flexibility and market benefits from UGS infrastructure. In practice, these rules require storage operators to offer available capacity to eligible third parties on transparent and non-discriminatory terms.

In the European Union, third-party access to UGS infrastructure was introduced under the Third Energy Package in 2009 and became mandatory in the following years as member states transposed the relevant gas market directives into national law. The package established an obligation for member states to implement a TPA regime, while providing a choice between two models: regulated third-party access and negotiated TPA.[4] Under regulated TPA, national regulators set cost-reflective storage tariffs, which are periodically revised and adjusted. Under negotiated TPA, storage operators are free to negotiate access terms and prices with individual users. In both models, the fundamental principles underpinning third-party access – namely transparency, non-discrimination, and effective market competition – still apply, although facility-level exemptions can be granted under strictly defined conditions.

In the United States, the principle of open access was established in the 1990s through a series of Federal Energy Regulatory Commission orders that introduced

[4] Derogations to third-party access exist under certain criteria, but represent the exception as opposed to the rule.

unbundling requirements for pipeline and storage assets owned by companies engaged in interstate operations. Interstate storage operators have since been required to offer available capacities to third parties on a non-discriminatory basis. Over time, open access has also been extended to storage infrastructure owned by intra-state operators, broadening the role of these facilities in market balancing and optimisation. While this evolution was not driven by a single regulatory mandate at the state level, the strengthening of federal safety and oversight standards across all storage facilities encouraged state regulators to adopt more robust regulatory oversight and open access principles at the state level as well.[5]

In China, gas market reforms began later than in Europe and North America, and efforts to introduce third-party access have taken place in stages. Initial trial measures on fair and open access to oil and gas infrastructure were introduced in 2014. A more decisive step came with the creation of the China Oil and Gas Piping Network Corporation (PipeChina) in 2019. The transfer of ownership of key pipeline assets from the country's three national oil companies to the newly established independent state-owned midstream operator represented a significant move toward unbundling and created the institutional basis for wider application of TPA principles. While effective implementation and enforcement of TPA rules remain uneven, China's regulatory commitment to unbundling and to open access demonstrates the importance of third-party access in unlocking the broader market and system benefits of UGS facilities.

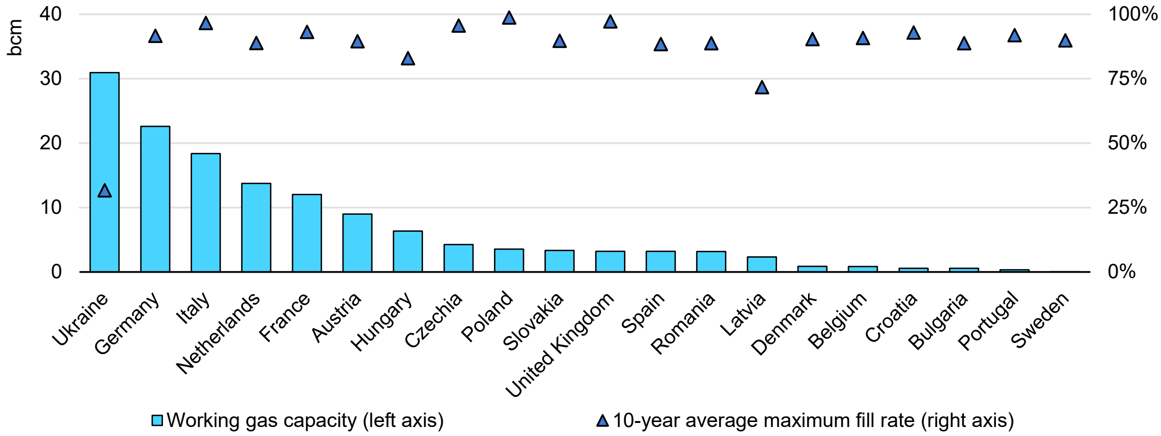
Transparent, non-discriminatory third-party access to storage capacity is not only critical to integrating UGS into competitive gas markets at the national and regional level, but also determines the extent to which storage infrastructure can be mobilised as part of international cooperation frameworks and cross-border gas reserve mechanisms.

Underused storage capacity in Europe

European UGS facilities are typically operated close to capacity. Over the past decade, the maximum combined EU storage fill level averaged more than 90% ahead of the winter heating season, and it reached at least 95% in five of those years. Since 2022, these high storage levels have been supported by the European Union's Gas Storage Regulation, which required member states to ensure that UGS facilities on their territory were filled to at least 80% of capacity by 1 November 2022, and then 90% in subsequent years. The regulation has been extended through 2027, with the 90% target maintained, while introducing additional flexibility around the filling trajectory and timing of compliance.

[5] US Department of Transportation, *Protecting Our Infrastructure of Pipelines Enhancing Safety (PIPES) Act of 2016*.

Figure 4.3 European UGS capacity and average maximum utilisation by country, 2024



Note: Ukrainian fill rate corresponds to four-year average maximum in 2022-2025, in line with data availability; Swedish fill rate corresponds to five-year average maximum in 2021-2025, in line with data availability.

Source: IEA analysis based on CEDIGAZ (2026), UGS Dataset; Gas Infrastructure Europe (2026), AGSI+ Database.

Ukraine, however, remains a notable outlier in Europe, with a vast but heavily underutilised UGS system. With 31 bcm of working gas storage capacity, Ukraine had the world's third-largest UGS capacity at the end of 2024, behind the United States and Russia, although China and Canada were only slightly behind and China has since been on track to move into third place. Ukraine's extensive infrastructure reflects the country's higher domestic gas demand during and after the Soviet era, as well as its former role as a major transit corridor for Russian pipeline gas deliveries to the European Union. As a result, Ukraine's UGS capacity significantly exceeds current domestic requirements.

Between 2022 and 2025, maximum storage fill levels in Ukraine averaged only around 32%. Out of a total working gas capacity of 31 bcm, this implies an annual average of around 21 bcm of unused UGS capacity. Around 25 bcm of the country's total capacity is in western Ukraine, with an additional 2 bcm in central Ukraine, under firm Ukrainian control. Approximately 4 bcm is located closer to eastern entry points for Russian gas, including facilities in partly or fully occupied territory.

Ukraine has undertaken regulatory reforms that have made the country's storage facilities more attractive for European market participants. In 2020, Ukraine harmonised elements of its regulatory framework with EU rules and significantly reduced the cost of storing gas for EU-based traders, including by cutting transport tariffs and allowing temporarily stored gas to be exempt from customs duties. These reforms enabled European companies to use Ukraine's UGS facilities as overflow capacity and store up to 10 bcm of gas in Ukraine during a market oversupply period in 2020, when EU storage sites filled rapidly ahead of the winter.

Current rules allow duty-free warehousing of gas in Ukrainian storage for up to three years, potentially enabling multi-year stockbuilding when market conditions are favourable.

In the summer of 2023, EU storage facilities were once again near capacity well ahead of the winter heating season and market conditions, in principle, would have allowed for that oversupply to be stored in Ukrainian facilities. In April of that year, Ukraine's state-owned gas storage operator, Ukrtransgaz, was certified as a European storage operator, paving the way for it to hold strategic gas reserves for EU member states, which received strong support from Ukrainian authorities and industry. But heightened security risks, including potential infrastructure damage and the loss of control over facilities, due to the war with Russia significantly reduced commercial appetite for utilising Ukrainian storage capacity. As a result, foreign-held inventories reached less than 3 bcm at their peak in 2023 and were negligible in 2024 and 2025.

In October 2025, Ukraine's state-owned oil and gas company Naftogaz proposed that part of the country's spare UGS capacity could be used to develop an EU-wide strategic natural gas reserve. While Ukraine's underutilised and geographically well-positioned storage capacity could potentially provide a valuable flexibility asset for Europe – and indirectly benefit Asian LNG importers as well – such a mechanism would require a clear governance framework, public-sector involvement in financing, and robust arrangements to manage security and political risks. In practice, it would likely only be feasible after the end of the war.

4.2 LNG tank storage

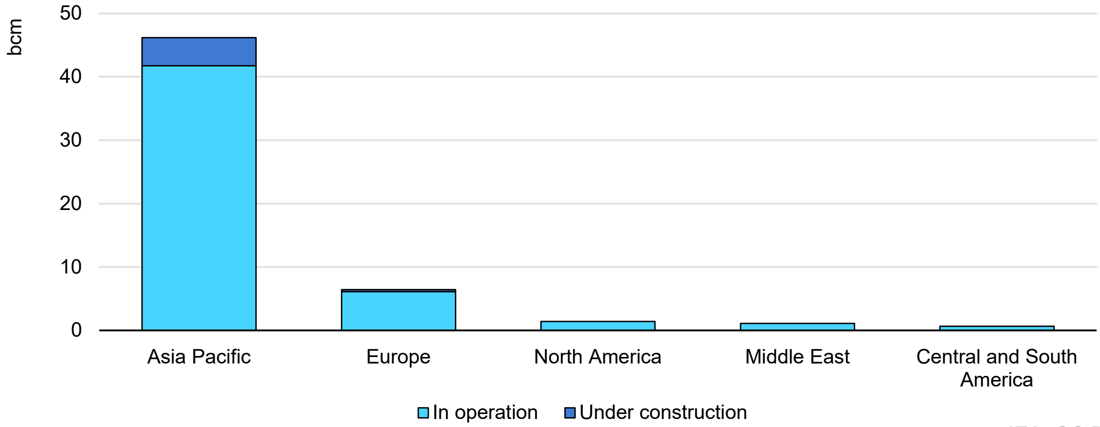
LNG storage tanks provide an additional pathway for storing natural gas in physical form, although their use for long-term storage remains relatively limited. By cooling natural gas to around -162°C, its volume is reduced by a factor of roughly 600, allowing large quantities of gas to be stored in liquid form in insulated cryogenic tanks at LNG terminals. While LNG tank storage is primarily designed to smooth operational flows at regasification facilities, it also constitutes an important, albeit relatively limited, form of physical gas reserves in the global gas system.

Most onshore LNG import terminals are equipped with storage tanks that allow operators to decouple the timing of LNG cargo arrivals from the regasification send-out to the pipeline network. These tanks provide short-term buffering capacity that can accommodate fluctuations in shipping schedules, variations in daily demand, and temporary operational disruptions. In systems with limited UGS, particularly in Japan and Korea, LNG tanks can also play a broader role in balancing seasonal demand or providing a strategic buffer against supply disruptions.

In volumetric terms, LNG tank storage represents the second-largest form of gas storage globally after UGS. At the end of 2024, the total working capacity of LNG storage tanks located at onshore regasification terminals was roughly 50 bcm of natural gas equivalent worldwide. This is only a fraction of global UGS capacity – which was around 445 bcm in 2024 – reflecting the fact that LNG tanks are primarily designed for operational flexibility rather than long-term stockholding. However, when combined with the high mobility of LNG cargo delivery, they can nonetheless function as a physical buffer in the global gas-LNG system.

The distribution of LNG storage capacity broadly mirrors the geography of LNG import infrastructure. More than 80% (42 bcm) of global onshore LNG storage capacity is in Asia, where LNG plays a central role in gas supply. Globally, an additional 5 bcm of LNG storage capacity was under construction at the end of 2024, with approximately 95% of these additions located in Asia.[6]

Figure 4.4 Onshore LNG tank storage capacity at regasification terminals by region, end of 2024



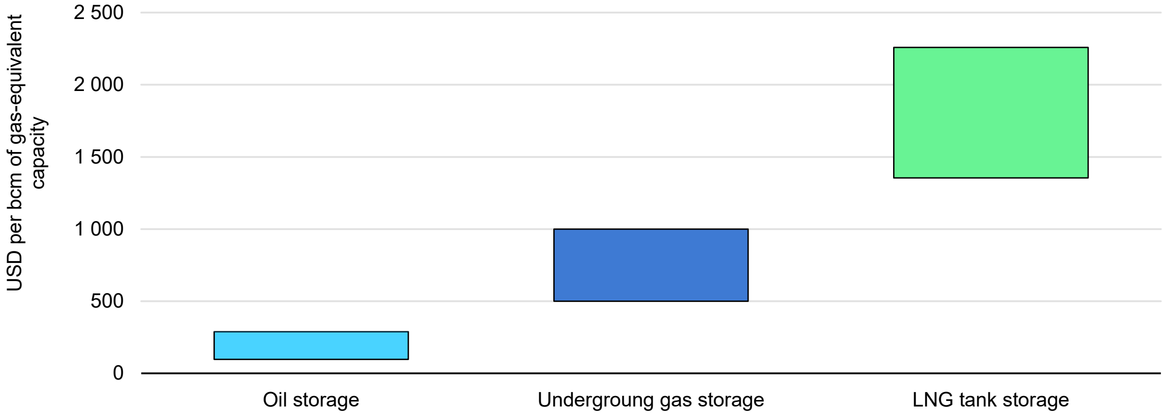
Source: IEA analysis based on data from the International Group of Liquefied Natural Gas Importers (2025), Annual Report 2025.

LNG storage tanks are relatively complex structures compared with tanks used for oil or oil product storage and, unlike UGS, require purpose-built containment structures rather than relying primarily on existing geological formations. LNG tanks are designed to safely contain LNG at cryogenic temperatures and typically use single-containment, double-containment, or full-containment designs, depending on safety requirements and site conditions. Modern tanks are usually full-containment structures, consisting of a stainless steel or nickel steel inner tank surrounded by a reinforced concrete outer shell and thermal insulation to minimise LNG boil-off. Due to this complexity, LNG storage tanks are relatively expensive.

[6] Liquefaction terminals also contain LNG storage tanks. However, the aggregate storage capacity at liquefaction plants – estimated at around 10 bcm of gas equivalent – is much smaller than at regasification terminals, and these tanks are designed primarily to smooth export operations rather than to provide reserve capacity for importing markets. As such, they are excluded from the scope of this study.

Based on recent project data, a standard 180 000 m³ LNG tank typically costs between USD 150 million and USD 250 million, depending on site conditions, engineering specifications, and local construction costs. On an energy-equivalent basis, this corresponds to a unit cost that is at least five to ten times higher than that of oil storage and two to four times higher than that of UGS.

Figure 4.5 Cost of physical storage



IEA. CC BY 4.0.

Tank sizes vary across terminals, but most modern onshore LNG tanks have capacities in the range of 160 000 to 200 000 m³ of LNG (equivalent to roughly 0.10 to 0.12 bcm of natural gas). Onshore regasification terminals in Europe typically operate two to four storage tanks, while large-scale facilities in northeast Asia, where LNG tanks can also serve seasonal roles, may have many more. As a result, total storage capacity at individual LNG terminals generally ranges between 0.2 and 0.5 bcm of natural gas equivalent, depending on terminal size and configuration.

The role of LNG tank storage varies significantly across regions, reflecting differences in gas market structure, infrastructure availability, and demand patterns.

Asia Pacific relies more heavily on LNG tank storage than any other region. China, Japan, and Korea – the world's three largest holders of LNG tank storage capacity – together account for nearly 90% of Asia's capacity and 70% of the global total.

China has the largest LNG tank storage capacity in the world, with over 15 bcm of total capacity at the end of 2024. This reflects the rapid expansion of the country's LNG import infrastructure in recent years (in anticipation of rapid growth in LNG demand), as well as China's extensive truck-based LNG distribution networks, which benefit from additional storage capacity at import terminals to support inland deliveries.

In Japan and Korea, LNG tanks serve not only as operational buffers but also as a partial substitute for seasonal gas storage. Both countries lack large-scale underground storage formations, and inventories accumulated in LNG tanks ahead of the winter heating season contribute to supply security during periods of peak demand. With around 12 bcm of LNG tank capacity distributed across roughly 190 tanks at 37 import terminals, Japan has the world's second-largest LNG storage system after China. Korea ranks third globally, with around 9 bcm of storage capacity, more than the entire LNG tank storage capacity of Europe. Other Asian importing countries also rely on LNG tanks as their primary storage buffer due to the absence of underground storage infrastructure, although their capacities are considerably smaller. Much of the remaining LNG tank capacity in Asia is concentrated in India (1.9 bcm), Chinese Taipei (1 bcm), Thailand (0.7 bcm), and Singapore (0.5 bcm).

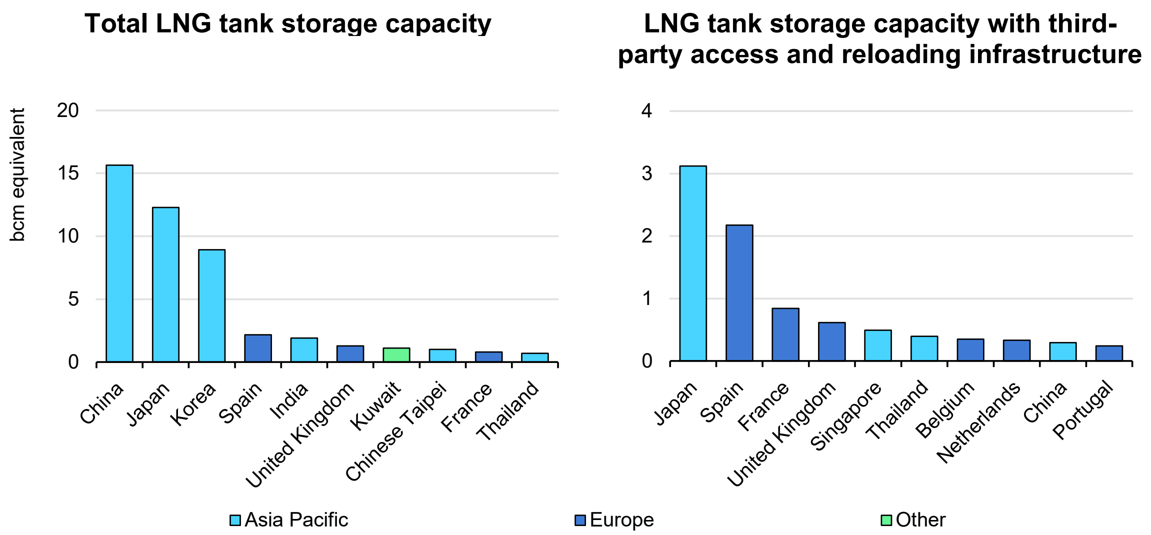
In Europe, LNG tank storage plays a more limited role in overall gas system flexibility because the region already possesses extensive underground storage infrastructure. LNG tanks at European regasification terminals, which have around 6 bcm of total capacity, are therefore used primarily for operational balancing. Nevertheless, certain markets stand out. Spain has 2.2 bcm of LNG tank capacity, while the United Kingdom has 1.3 bcm of LNG tank capacity, relatively large when compared with their LNG demand. The reason for the comparatively larger storage capacities is because their underground storage capacity is limited. In the case of the United Kingdom, the infrastructure also supports gas security in northwest Europe through pipeline interconnections with continental Europe. Together, Spain and the United Kingdom account for around 56% of Europe's total LNG tank storage capacity but only about 20% of LNG demand on the continent, reflecting their extensive, and at times underutilised, LNG import infrastructure.

In some cases, underutilised LNG storage tanks are used by third parties for commercial optimisation, reloading operations, or regional trading activities. For example, Indonesia's Arun LNG complex has four LNG storage tanks that were originally built to support LNG exports. They became partially idle after the terminal was converted into an import facility in 2015, and in 2021, TotalEnergies signed an agreement with the terminal owner to use two of Arun's four LNG storage tanks for trading and portfolio optimisation in the Asian LNG market, leveraging the terminal's reloading infrastructure. Similarly, Spain's El Musel LNG terminal, which was completed in 2012 but was mothballed for a decade due to unfavourable market conditions, was restarted in 2023 as an LNG storage and reloading hub. By leveraging its available tank capacity, the facility now receives and reloads cargoes for redistribution to other European markets.

Under certain conditions, underutilised LNG tank capacity could also be mobilised as part of broader gas reserve arrangements. For example, countries with LNG storage capacity that exceeds domestic operational needs could host LNG inventories on behalf of other importing markets. Under such models, LNG inventories could be rotated commercially during normal market conditions while remaining available for emergency supply in the event of supply disruptions. Similar arrangements exist in oil markets, where IEA member countries can meet part of their minimum oil stockholding obligations through stocks held in another country, typically under bilateral government agreements. These arrangements can take the form of either direct ownership of stocks held abroad or ticketing arrangements, under which the ticket seller agrees to hold oil on behalf of the buyer in return for an agreed fee (see Section 7.1).

However, such arrangements would require sufficient reloading infrastructure to allow LNG to be re-exported to other destinations when needed, as well as third-party access to the LNG terminals hosting the relevant storage capacity. Of the approximately 50 bcm of onshore LNG tank capacity in operation at the end of 2024, only 14 bcm was located at terminals equipped with reloading infrastructure. Of this, less than 10 bcm was at terminals that also offer third-party access. Most of this capacity, 49%, is in Europe, led by Spain with around 2.2 bcm of capacity that combines reloading infrastructure and third-party access. Asia accounts for more than 80% of global LNG tank capacity, but only 47% of that capacity has both reloading infrastructure and third-party access, and Japan is the only country with a significant LNG tank capacity (more than 3 bcm) that combines these features. Asia's remaining such capacity is in Singapore (0.5 bcm), Thailand (0.4 bcm), China (0.3 bcm), and Indonesia (0.2 bcm). LNG tank capacity with comparable features is negligible in the Americas and non-existent in the Middle East and Africa.

Figure 4.6 Top 10 countries by onshore LNG tank storage capacity, end of 2024



IEA. CC BY 4.0.

Source: IEA analysis based on data from International Group of Liquefied Natural Gas Importers (2025), Annual Report 2025.

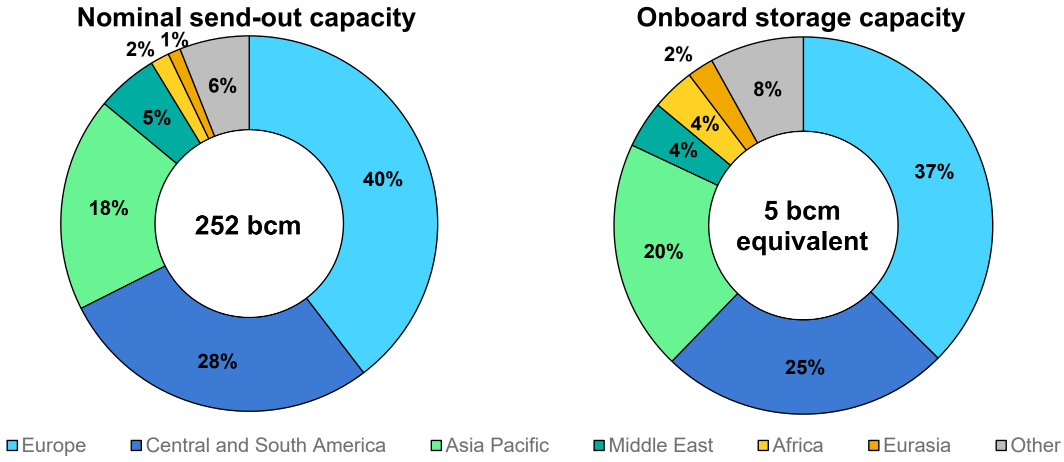
To facilitate such arrangements, governments in importing countries could encourage the development of reloading infrastructure and third-party access at a larger number of LNG terminals, particularly in Asia. Expanding these capabilities would allow a greater share of existing, and at times underutilised, LNG tank infrastructure to support supply security and enhance the strategic value of LNG storage assets without requiring major new investment. However, the relatively high capital cost of new LNG tanks and their limited volumetric capacity compared with underground storage mean that their role as large-scale strategic reserves is likely to remain secondary. Instead, LNG tanks are more likely to serve as supplementary reserve assets, complementing UGS and other flexibility mechanisms in the global gas system.

4.3 LNG FSRU and FSU facilities

Floating storage and regasification units have emerged over the past two decades as a flexible alternative to conventional onshore LNG import terminals, particularly for countries seeking rapid access to LNG imports without the long lead times and relatively high capital costs associated with onshore facilities. FSRUs are either purpose-built vessels or converted LNG carriers equipped with onboard regasification systems. LNG is stored in the vessel's cryogenic tanks and vaporised on board before being sent out via high-pressure pipelines to the onshore transmission grid.

At the end of 2024, the global FSRU fleet comprised 52 operational vessels, with another four units under construction. Most modern FSRUs have storage capacities of around 150 000 to 170 000 cubic metres of LNG, less than the storage capacity typically found at large onshore regasification terminals, which often feature two or more tanks of 160 000 to 200 000 cubic metres. The total LNG storage capacity of the FSRU fleet is approximately 7.7 million cubic metres of LNG, equivalent to around 5 bcm of natural gas in gaseous form. This is modest relative to UGS capacity, which was around 445 bcm globally, or even to cumulative onshore LNG tank capacity, which was around 50 bcm, at the end of 2024. Therefore, in volumetric terms, FSRUs do not represent a major storage resource on a global scale. Instead, the technology's main advantage lies in rapid deployment and operational flexibility.

Figure 4.7 Distribution of FSRU capacity by region, end of 2024



IEA. CC BY 4.0.

Source: IEA analysis based on data from International Gorup of Liquefied Natural Gas Importers (2025), Annual Report 2025.

While conventional onshore LNG import terminals typically require four to five years to build, FSRU-based terminals can be developed on significantly shorter timescales. Where suitable port infrastructure, berthing facilities, and nearby transmission grid connections already exist, and an FSRU vessel can be chartered from the existing fleet, an import terminal can be brought online within 12 months or less. Recent examples of such accelerated deployment completed in less than a year include Germany's Wilhelmshaven terminal, Italy's Piombino LNG terminal, and the Netherlands' Eemshaven terminal, all of which were completed during the 2022-2023 energy crisis. Earlier examples include Egypt's FSRU in Ain Sokhna in 2015, the country's first, which was completed in less than a year to address acute domestic gas shortages.

Where port and pipeline infrastructure must be constructed from scratch or no suitable FSRU vessel is readily available, total project lead times are longer, typically around three to three-and-a-half years. Newly built FSRUs generally require 30 to 36 months to construct and are mainly built in Korean shipyards, although a limited number have also been built in China. Conversion of an existing LNG carrier into an FSRU – a process carried out primarily in Singaporean shipyards – usually takes 18 to 24 months. Shore-side infrastructure can be built concurrently in order to accelerate the process, including mooring and berthing facilities, high-pressure gas pipelines connecting to the transmission network, metering stations, gas treatment facilities, emergency shutdown systems, and, in some cases, dredging works and breakwater reinforcement.

FSRU projects typically require lower upfront capital investment than conventional onshore regasification terminals. As of 2025, the cost of a newly built FSRU vessel was in the range of USD 300 million to USD 420 million, while the total cost of converting an existing LNG carrier into an FSRU, including the cost of acquiring the vessel but excluding the jetty and marine infrastructure, was reported at around USD 200 million. The cost of associated onshore and marine infrastructure varies widely depending on site conditions. For projects with well-developed port and pipeline infrastructure, additional investment can be less than USD 100 million, whereas greenfield developments requiring extensive marine works and new transmission connections can be several times higher.

Unlike onshore regasification terminals, FSRU vessels can be, and often are, chartered from specialised fleet operators for fixed periods, with charter rates ranging between USD 100 000 and USD 300 000 per day in recent years, depending on market conditions, vessel specifications, and contract terms. This structure allows importers to convert what would otherwise be large upfront capital expenditure into operating expenditure (amounting to between USD 35 million and USD 70 million per year at prevailing charter rates). By contrast, a conventional onshore LNG import terminal with storage tanks and regasification facilities typically requires total capital investment in the range of USD 500 million to more than USD 1 billion.

FSRUs can also be redeployed when no longer needed, reducing the risk of long-term infrastructure lock-in compared with permanent onshore terminals. This flexibility was recently demonstrated at France's Le Havre terminal, for example, where an FSRU-based facility was commissioned in 2023 to reinforce the country's gas safety net. However, as the acute phase of the 2022-2023 energy crisis passed and utilisation remained limited from 2024 onward, the terminal's operator decided to demobilise the FSRU vessel following a 2025 court ruling that confirmed that the facility was no longer needed and concurrently revoked the terminal's authorisation. The vessel is currently operating as a conventional LNG carrier, and the terminal was dismantled in early 2026. Similar redeployments have been observed in several other markets in recent years, particularly where floating units were installed as emergency or transitional solutions.

Although FSRUs have higher per-unit operating costs than permanent onshore infrastructure and offer less storage capacity, they have nonetheless been routinely deployed as backup or peak-supply facilities. In Brazil, for example, they were deployed to supply gas-fired power plants during periods of low hydro availability, and in the United Arab Emirates they are used to support power generation during the peak summer months.

In other cases, floating terminals have been backed by public policy objectives related to energy security. Lithuania's FSRU terminal, which began operations in 2014, was initially developed, and publicly funded, as a strategic diversification tool before it started to receive regular deliveries from 2016. More recently, Ireland has advanced plans for a state-backed FSRU as part of its emergency gas supply framework (see Section 6.4), and New Zealand is considering the development of a new LNG import terminal that includes FSRU-based designs to mitigate dry-year power risks. In such publicly supported schemes, the vessel is often state-owned or secured under long-term arrangements, and the cost of the project is justified not purely on commercial throughput considerations, but as insurance against potentially far more costly economic disruptions in the event of a supply shortfall. FSRUs are not inherently suited to seasonal or strategic storage. Due to their limited tank capacity, their primary value lies in providing LNG import and regasification capability at relatively high send-out rates, typically around 15 mcm/d or roughly 5 bcm/yr, rather than in providing extended reserve capacity.

Another key constraint on wider FSRU deployment is the limited availability of vessels in the near term. Of the more than 50 units in operation today, the vast majority are tied to medium- or long-term charters, leaving only a small number of ships potentially available for near-term redeployment. At the same time, the order book for newly built FSRUs remains limited, with only a handful of vessels under construction. As a result, global floating regasification capacity cannot be expanded rapidly beyond the existing fleet without new investment commitments. Conversion of conventional LNG carriers into FSRUs remains technically feasible and has historically played an important role in expanding floating regasification capacity. However, conversion projects face several constraints, including the age and technical suitability of candidate vessels, as well as limited shipyard capacity, particularly in specialised yards, mainly in Singapore, that can install regasification modules.

FSUs represent a similar but distinct configuration compared with FSRUs. In an FSU-based import terminal, the vessel provides LNG storage only, while regasification equipment and the associated high-pressure send-out systems are located onshore, at a jetty or on a separate offshore installation. Examples of this model include the Hidd terminal in Bahrain, the Melaka terminal in Malaysia, and the Delimara terminal in Malta. Converting an LNG carrier into an FSU is technically less complex and less costly than conversion into an FSRU, as no onboard regasification modules are required, and conversion costs typically range between USD 14 million and USD 20 million, in addition to the vessel's residual value (see Section 4.4). At the same time, FSU-based projects require more substantial shore-side investment in vaporisers, pumping systems, and utilities, which can offset part of the speed and cost advantages relative to FSRUs. Moreover, because regasification infrastructure is fixed onshore, the risk of stranded assets may be higher if the facility is no longer required. As with FSRUs, expansion of the FSU fleet through LNG carrier conversion is subject to constraints related to vessel availability, shipyard capacity, and regulatory approvals. The number of operational FSUs remains limited at around 10 vessels globally, representing only a fraction of the already small FSRU fleet.

While FSRUs and FSUs have significantly lowered the barriers to entry into the LNG market, their role as physical reserve assets is inherently limited. Although FSRUs offer relatively high send-out capacity, which in some cases is comparable to the peak withdrawal rates of underground storage facilities, their onboard storage capacity is modest and generally sufficient for only several days to a few weeks of operation at full send-out rates. From a system flexibility perspective, an FSRU can resemble a fast-cycling storage asset if LNG cargoes are delivered and regasified on a near continuous basis. However, unlike UGS, which can accumulate volumes over extended periods and release them during peak demand, floating terminals provide only limited buffering capacity and are relatively expensive on a per-unit storage basis. Their systemic value therefore lies less in stockholding and more in securing access to global LNG supply, diversifying import channels, and providing rapid-response capacity in times of disruption. As such, they are complements to, rather than substitutes for, large-scale seasonal or strategic storage infrastructure.

4.4 LNG floating storage on vessels

Floating storage – the use of vessels to hold energy commodities offshore or at anchor – is a widely used flexibility mechanism in oil markets but has historically played a much more limited role in the LNG market. LNG held “on water” is typically associated with commercial optimisation (for example, in anticipation of higher prices ahead of peak winter months), short periods of excess LNG supply, or terminal congestion, rather than deliberate stockpiling. Unlike FSUs, which are permanently moored assets integrated into LNG import infrastructure, floating storage in this context refers to conventional LNG carriers temporarily retaining cargoes while awaiting delivery.

Floating storage as a temporary market-balancing mechanism

LNG floating storage faces several technical and economic challenges that distinguish it from oil storage.

- **High vessel costs:** LNG carriers (LNGCs) are highly specialised, capital-intensive assets. Even in weak shipping markets, chartering LNG vessels for storage bears a significant cost.[7]

[7] The average construction cost of a standard 174 000 cubic metre LNGC was around USD 250 million in 2024, more than twice the cost of a very large crude carrier (VLCC), despite the latter being capable of transporting roughly three times as much fuel on an energy-equivalent basis. Daily spot charter rates for standard-size steam-turbine and tri-fuel diesel electric LNG carriers averaged around USD 23 000 and USD 43 000 in 2024, respectively, around 2.5 to 5 times higher than the average rate of a VLCC on an energy-equivalent basis.

- **Gas boil-off:** LNG naturally evaporates over time. While modern vessels can reliquefy boil-off or consume it as fuel, prolonged storage increases either commodity losses or operational complexity.[8]
- **Cargo quality changes:** Extended storage can alter the composition of LNG through the so-called ageing (or weathering) process, whereby lighter chemical components in the gas boil off first, potentially resulting in off-spec cargoes. The extent of ageing varies across LNG sources, and tolerance for such deviations varies across terminals and among buyers.
- **Operational and regulatory constraints:** LNG vessels used for floating storage require continuous crewing and power supply, must comply with strict safety and regulatory requirements, and may face limits on anchorage duration.

These constraints mean that LNG floating storage is best suited to short-term buffering rather than long-term strategic reserves. While traders and portfolio players routinely use floating storage to delay deliveries from shoulder seasons into peak demand periods, particularly when contango is present,[9] it is rarely used as a reserve mechanism for energy security purposes.

The cost of LNG floating storage – estimated as the shadow price of LNG carriers held idle at sea – is generally high and varies widely over time. The cost of LNG floating storage consists of two main components: vessel-related costs, including time charter or spot charter rates, and the opportunity cost of LNG lost through boil-off.[10]

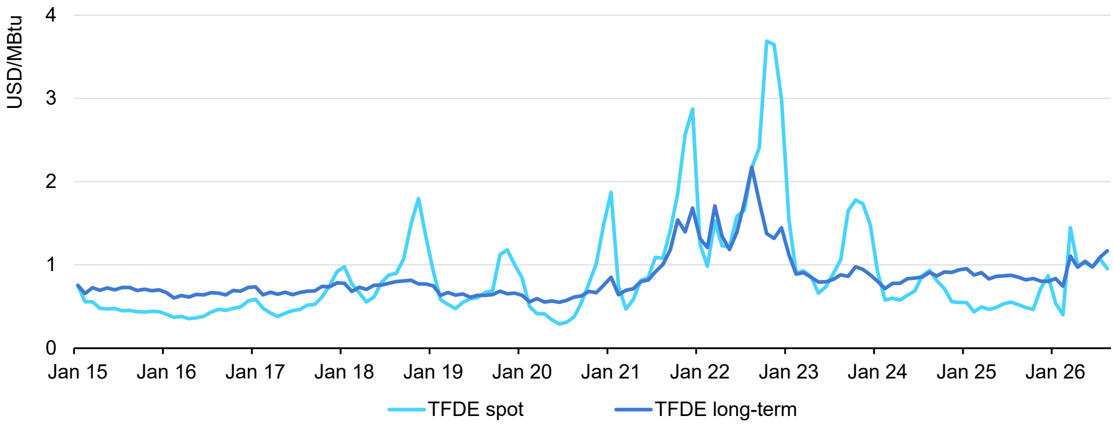
Vessel-related costs depend chiefly on prevailing charter rates. These tend to fluctuate widely on the spot market, although most LNG is transported under long-term charter contracts, typically at rates of around USD 70 000 to USD 90 000 per day. During balanced market conditions, such as in 2024-2025, monthly average spot LNG carrier charter rates ranged from USD 10 000 to USD 70 000 per day for standard tri-fuel diesel electric (TFDE) vessels. By contrast, during the tight shipping markets in 2021-2023, spot charter rates fluctuated between USD 30 000 and more than USD 300 000 per day on a monthly basis, averaging around three times higher than in 2024-2025.

[8] Boil-off rates vary significantly by vessel design and type. The ageing fleet of steam-turbine LNG carriers have daily boil-off rates of around 0.15% of total cargo, while the most advanced ME-GI vessels equipped with full reliquefaction systems have boil-off rates of only 0.035% to 0.075% per day, around two to four times lower than those of steam turbine vessels.
[9] Contango refers to a market structure in which futures prices are higher than the current spot price, creating an incentive to store gas or LNG and sell later. This price structure typically reflects expectations of tighter future supply, seasonal demand patterns, or storage-related constraints.
[10] In addition to charter rates and the cost of boil-off gas, additional charges, such as fuel, insurance, and potential demurrage or terminal-related fees may apply, although these vary on a case-by-case basis.

The opportunity cost of boil-off gas depends on prevailing spot LNG prices, which have fluctuated over a similarly wide range since 2020, from around USD 2 to more than USD 50 per million British thermal unit (MBtu) on a monthly average basis.

Taken together, these two cost components suggest that the monthly cost of LNG floating storage rarely falls below USD 0.5 per MBtu and can at times reach or exceed USD 3 per MBtu, as was the case in late 2021 and late 2022. Over the 2021-2025 period, floating storage costs averaged more than USD 1 per MBtu per month. Estimated costs are somewhat less volatile when based on long-term charter rates, but the five-year average remains broadly similar, at just over USD 1 per MBtu per month. On a commercial basis, these costs are only sustainable for brief periods, when contango is sufficiently wide or the alternatives to floating storage are even costlier.

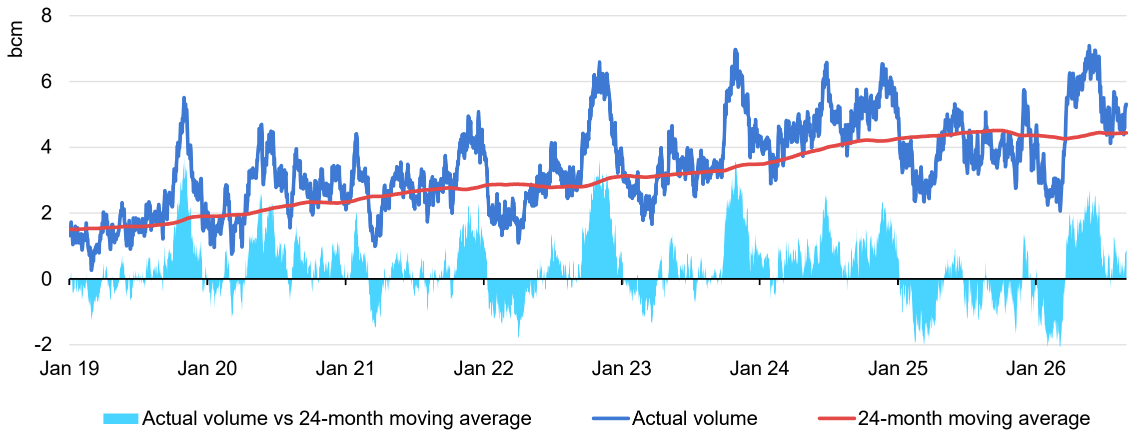
Figure 4.8 Estimated monthly cost of LNG floating storage



Source: IEA analysis based on data from ICIS LNG Edge.

The volumetric “reserve” capacity that LNG floating storage can provide is relatively limited, and any estimate of this volume is necessarily imprecise. Indicators tracking LNG cargoes remaining at sea for more than 20 days provide a useful proxy for floating storage and delayed deliveries, although these cargoes are typically slow steaming towards their destination rather than remaining stationary offshore. Under normal conditions, there is a structural baseline of LNG volumes on water associated with long transit times and logistical delays, rather than deliberate storage. This baseline volume is estimated to have increased from around 2 bcm in 2020 to around 4 bcm by 2025, reflecting the overall growth in LNG flows, longer average shipping distances, and increasingly complex trade patterns.

Figure 4.9 LNG on water for more than 20 days



Source: IEA analysis based on data from Bloomberg.

Additional LNG volumes on top of this baseline, at least part of which can be classified as floating storage, fluctuate widely over time. However, these incremental volumes reached or exceeded 3 bcm on very few occasions during periods of severe market dislocation, including in 2019, 2022, and 2023, when European storage sites reached near-full capacity ahead of the withdrawal season, as well as during the 2020 Covid-19 crisis, when a combination of terminal closures, falling LNG demand, and deliberate efforts by at least one major supplier, Qatar, to avoid production curtailments led to a prolonged period of elevated LNG volumes parked on water.

These episodes demonstrate that floating storage can expand rapidly when conditions align, but such expansions have historically been temporary and market-driven, rather than the result of deliberate reserve building.

However, there is at least one recent case in which LNG floating storage was used for an extended period for energy security purposes. As a complement to Singapore's Standby LNG Facility (see Section 6.4), Singapore LNG Corporation, the designated manager of the Standby LNG Facility (SLF) at the time, chartered an LNG carrier alongside an FSRU for floating LNG storage. These vessels remained largely in Singapore waters for approximately 12 months, between March 2022 and March 2023, and 8 months, between August 2022 and April 2023, providing an additional buffer during a period of heightened global market stress.

Repurposing LNG carriers for strategic floating storage

The current LNG carrier fleet offers potential for more strategic uses of floating storage capacity. At the end of 2025, the active fleet of conventional LNG carriers comprised roughly 800 vessels, excluding small-scale carriers, bunkering vessels, FSRUs, and FSUs. Of these, around 200 vessels were ageing steam turbine-driven LNG carriers, with a median age approaching 20 years. This segment of the fleet is highly fuel-inefficient, increasingly challenged by existing and forthcoming environmental regulations, and therefore faces accelerated retirement and demolition in the foreseeable future.

Over the past five years, an average of eight steam turbine LNG carriers per year have been laid up (i.e. withdrawn from active service but maintained in operational condition) and an average of five vessels per year have been scrapped, often from the pool of previously laid-up ships. The pace of retirements could accelerate further as a wave of modern LNG carriers enters service to support the next phase of LNG liquefaction capacity expansion in the second half of the decade. Among the remaining active steam turbine fleet, around 50 vessels appear to be inactive (i.e. not currently under contract or routinely delivering cargoes), making them the most immediate candidates for retirement. The remainder are committed under existing charters, but only around 65 vessels could plausibly extend beyond 2030, leaving the rest highly vulnerable to removal from the fleet. A similar fate may also await a handful of older vessels propelled by dual-fuel diesel electric (DFDE) engines that exceed 20 years of age.

In some cases, these older vessels slated for demolition could provide emergency storage capacity instead. Governments could, for example, purchase or charter ageing LNG carriers at close to scrap value and convert such vessels into FSUs or incentivise shipowners to delay demolition and maintain selected vessel in operational condition for future emergencies.

The market value of an ageing LNG carrier is close to scrap value, typically in the range of USD 15 million to USD 20 million, while conversion to an FSU would cost another USD 14 million to USD 20 million, depending on the technical specification.[11] A converted FSU is still four to five times cheaper than constructing a new onshore LNG storage tank of similar capacity, which is estimated to cost between USD 150 million to USD 200 million.

The full cohort of LNG carriers at risk of retirement worldwide represents around 25 bcm of potential storage capacity, in natural gas equivalent terms. In practice, however, only a fraction of this capacity is likely to be suitable for strategic floating storage in the near term, due to existing charter commitments, operational constraints (such as high boil-off rates in the case of LNG carriers), high maintenance requirements, and compatibility issues with modern terminal infrastructure.

[11] On this basis, the implied breakeven charter rates for ageing LNG carriers and converted FSUs are around USD 10 000 to USD 15 000 per day and USD 20 000 to USD 30 000 per day, respectively, assuming a 9% required rate of return and a five-year payback period.

5. Flexible commercial options for LNG

Flexible commercial arrangements are a second, critical pillar for building security buffers against unexpected supply disruptions and episodes of extreme price volatility. These include more flexible traditional LNG contracts, commercial innovation such as seasonal and call option-type LNG contracts, joint procurement and portfolio optimisation arrangements, and physical LNG swaps that allow cargoes to be redirected more quickly during supply disruptions. Such commercial flexibility complements rather than replaces physical reserve assets. While physical storage provides the gas inventory needed to withstand supply disruptions, contractual flexibility improves the allocation of available gas across markets and over time. By strengthening the ability of markets to adjust quickly to supply and demand shocks, greater flexibility can help dampen price swings and reduce the risk of physical shortages, while spreading the burden of adjustment more evenly across importing markets and regions. But such flexibility is not free, and the cost of having more options is reflected in commercial arrangements.

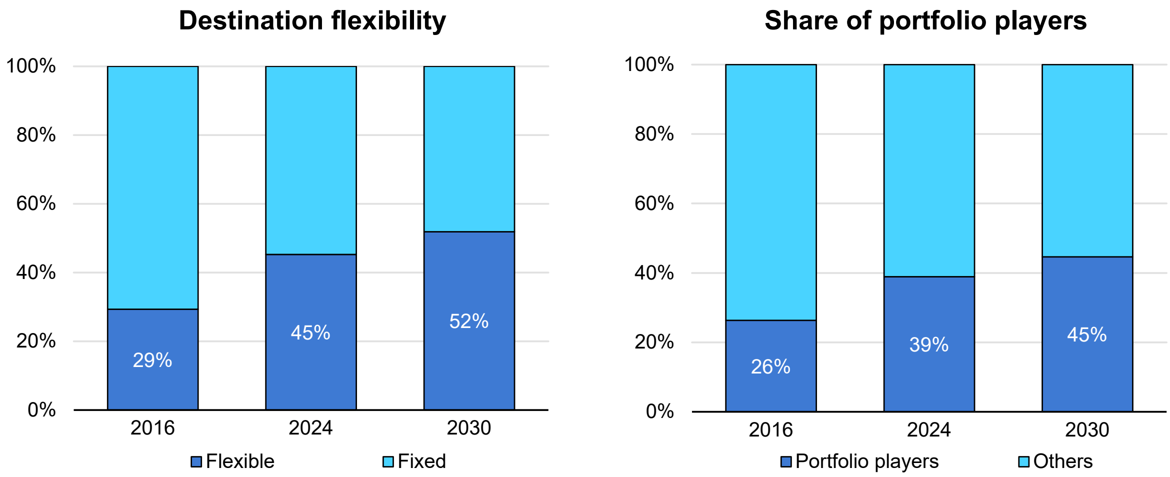
This chapter focuses on the global LNG market, which provides the primary mechanism linking the world’s main net importing regions, and allows gas flows to respond to shifting market signals across basins. While developments in pipeline gas trade can influence LNG flows indirectly, pipeline gas remains inherently constrained by fixed infrastructure and geography, meaning it is limited in its ability to deliver significant global rebalancing during periods of market stress. Moreover, in Europe, the flexibility of pipeline gas contracts was substantially expanded in the 2010s – through the renegotiation of legacy contracts that resulted in changes that mainly benefitted buyers – leaving relatively limited scope for further gains. In most Asian economies, by contrast, pipeline gas plays little or no role in the supply mix, apart from China, where buyer leverage is already reflected in contractual terms and, at times, in actual buyer behaviour. Against this backdrop, LNG stands out as the segment of gas trade where additional commercial flexibility can still deliver further improvements in market resilience in both Europe and Asia and therefore remains the focus of the analysis.

Since the early days of LNG trade in the 1960s, it has evolved from a rigid, point-to-point business model, characterised by inflexible long-term agreements with fixed volumes, fixed destinations, and limited scope for periodic adjustment. Today, it is a more flexible and increasingly global commodity market. This transition gained momentum in the early 2000s, driven by the liberalisation of gas markets, the emergence of LNG portfolio players, and the availability of more flexible sources of LNG supply, for example, in Trinidad and Tobago and Equatorial Guinea.

Over the past decade, the pace of change has accelerated markedly, driven in particular by the rise of destination-flexible LNG exports from the United States and by the widening range of companies acting as portfolio players. Previously dominated by traditional oil majors that pioneered the model, this group of portfolio players now includes trading houses, major utilities, state-controlled exporters, and independent project developers.

Between 2016 – the year of the first publication of the IEA's *Global Gas Security Review* tracking LNG contracts – and 2024, the share of destination-flexible LNG contracts increased from 29% to 45% of total contracted volumes, largely driven by the expansion of LNG exports from the United States. This share is set to rise further and could reach around 52% by 2030, reflecting both the gradual expiry of destination-fixed legacy contracts and the continued growth of destination-flexible US LNG supply. In parallel, the share of LNG procurement contracts held by portfolio players has also expanded significantly, rising from 26% of total contracted volumes in 2016 to around 39% by 2024. Based on existing contracts, this share is expected to increase further to around 45% by 2030, potentially enabling greater flexibility, pricing diversity, and supply optionality for LNG importers over the medium term.

Figure 5.1 The evolution of key LNG contract characteristics, 2016-2030



Source: IEA analysis based on data from IEA (2025), Gas 2025,

Despite this progress, important sources of contractual inflexibility remain in the existing LNG contract portfolio, notably in relation to:

- **Destination restrictions**, which limit buyers' ability to redirect cargoes in response to changing market conditions and price signals, thereby constraining cross-regional arbitrage and market efficiency.

- **Volume-related provisions**, including minimum take-or-pay (TOP) volumes, upward and downward quantity tolerances (UQT and DQT) and make-up clauses, which can restrict buyers' ability to adjust contracted volumes in line with short-term demand fluctuations.
- **Profit sharing and seller consent requirements**, which can weaken incentives to resell LNG by reducing the economic upside of diversions or by introducing administrative and information-sharing burdens, thereby limiting the effective use of contractual flexibility in practice.

5.1 Existing LNG contracts

Long-term contracts remain a defining feature of global LNG trade and are likely to continue playing a central role, as they underpin investment in new liquefaction capacity by providing revenue certainty and supporting project financing. As of 2025, around 60% of global LNG trade was conducted under long-term agreements, defined as contracts with a duration of 10 years or longer.

The evolution of LNG contract flexibility

Until the 2010s, LNG trade was still largely structured around rigid point-to-point arrangements; long-term contracts typically included provisions that limited buyers' flexibility, especially in relation to destination and TOP volumes. Such contractual structures were particularly prevalent in Asia, where more than 70% of total LNG imports in 2025 were supplied under long-term contracts and where buyers historically prioritised security of supply and stable delivery arrangements. This was reinforced by the bilateral nature of LNG procurement and the long-standing commercial relationships between buyers and sellers, which shaped contracting practices over several decades.

Over the course of the last 25 years, competition authorities in key importing regions have taken steps, with varying degrees of stringency, to remove or soften restrictive non-price provisions in LNG contracts to promote greater competition and market flexibility. These efforts have focused mainly on destination restrictions, profit-sharing mechanisms, and seller consent requirements, which had been widely used in earlier contracts to limit cross-regional arbitrage and preserve market segmentation. Progress differs by region, but overall contractual flexibility has improved while there is less tolerance for clauses that constrain diversions and resale.

In the European Union, the phasing out of destination restrictions has been closely linked to market liberalisation and the enforcement of EU competition policy, notably under Articles 101 and 102 of the Treaty of the Functioning of the European Union and its predecessor treaties. Early enforcement action included proceedings against Norwegian gas suppliers, which led to a commitment in 2002 by Statoil and Norsk Hydro to refrain from introducing territorial restrictions, including destination clauses, in their gas supply contracts. This was followed by a series of antitrust investigations targeting territorial and resale restrictions in long-term gas and LNG contracts, including the 2002 settlement with Nigeria LNG (focused on LNG), the 2003 settlement involving Eni and Gazprom (focused on pipeline gas), and the 2007 Sonatrach decision, which required the deletion of territorial restrictions and limited the use of profit-sharing mechanisms to delivered ex ship (DES) contracts, where ownership and risk are transferred at the delivery point (covering both pipeline gas and LNG).

More recently, the European Commission's 2015 antitrust investigation into Russia's Gazprom (primarily focused on pipeline gas contracts) resulted in a commitment decision in 2018, under which Gazprom made legally binding commitments to address the Commission's competition concerns. That decision required Gazprom to remove contractual barriers to the free flow of gas, including destination restrictions, in Central and Eastern Europe. By contrast, the Commission's proceedings against Qatar Petroleum, launched in 2018 and focused on LNG destination restrictions, were closed in 2022 after the Commission concluded that the evidence did not confirm its initial concerns. Although these cases targeted specific suppliers, and often focused primarily on pipeline gas contracts, the underlying principles have shaped expectations for gas and LNG contracting practices more broadly among market participants. As such, after more than two decades of enforcement, destination clauses have been progressively eliminated in European gas supply contracts and are now generally considered incompatible with EU competition law. The Commission's approach has also significantly narrowed the scope for profit-sharing mechanisms.

Elsewhere, the Japan Fair Trade Commission (JFTC) published the results of a sector inquiry in 2017 assessing destination clauses and other restrictive provisions in long-term LNG contracts. The JFTC concluded that destination restrictions and profit-sharing requirements in so-called free-on-board (FOB) contracts are highly likely to raise concerns under Japan's Antimonopoly Act, as they can limit competition by preventing resale and reducing market liquidity. For DES contracts, the JFTC took a more nuanced view. They determined that destination restrictions, profit-sharing, and seller consent requirements may be justifiable given the seller's responsibility for arranging shipping and delivery. But they also emphasised that such clauses could still raise competition concerns if they go beyond what is necessary for operational purposes or effectively prevent redirection and resale in practice. The JFTC noted as well that overly strict and unilateral application of TOP provisions may violate the Antimonopoly Act where suppliers have already recovered their initial investment. While non-binding, the JFTC report prompted market participants to review their contracting practices, including existing legacy contracts. Although there are no publicly known cases of the JFTC investigating specific LNG sales contracts, the report's findings nonetheless sent a clear signal to market participants to phase out problematic clauses from their contract portfolios (see Box 2 for details).

Box 5.1 Japan's 2017 JFTC survey on LNG contracts

The Japan Fair Trade Commission published its *Survey on LNG Trades* in June 2017, based on information from LNG market participants concerning the use of destination clauses and other resale provisions in long-term LNG contracts. The assessment ultimately determined that the assumption that flexible contracts incur higher prices was not necessarily correct, as outlined in our overview below.

The JFTC's central competition concern was that destination restrictions and profit-sharing clauses can have foreclosure effects, eliminating opportunities for LNG buyers to enter the market as suppliers through resale and reducing trading opportunities overall, thereby limiting market liquidity. The JFTC assessed that such clauses, if lacking necessity and rationality, could violate Japan's Antimonopoly Act.

The investigation highlighted the view that LNG reloading (i.e. unloading a cargo at the designated destination and immediately reloading the same LNG for re-export to the desired destination) is not an effective alternative to diversion and resale rights, as it imposes additional costs and is subject to infrastructure constraints.

The JFTC differentiated its assessment based on delivery terms. For FOB contracts, where ownership and risk are transferred to the buyer at the loading point, the JFTC found that destination restrictions and profit-sharing clauses generally lack necessity and rationality, and therefore likely to violate antitrust laws. This reflects the principle that buyers bearing shipping and market risk should be able to optimise the placement of the cargo after the transfer of ownership.

For DES contracts, the JFTC recognised a certain degree of necessity and rationality for destination restrictions and profit-sharing clauses, given that ownership and risk remain with the seller until unloading and that such provisions may help recover costs associated with destination changes. However, it also emphasised that such clauses could still raise competition concerns where diversion requests are unduly denied or where sellers attach restrictive conditions to diversion consent, effectively limiting resale. The JFTC noted that profit-sharing mechanisms could be problematic if they are based on gross rather than net profits, or if key parameters such as the calculation method and distribution ratio are not clearly defined in advance, as this may discourage resale and restrict market participation. The JFTC also raised concerns about requirements to disclose detailed information on resale destinations and profit breakdowns in profit-sharing arrangements.

The investigation also considered other standard contract features. For example, the report recognised the role of TOP arrangements in recovering initial investment in new LNG projects. But it also noted that overly strict TOP terms imposed unilaterally on buyers could constitute a potential abuse of market power and violate antitrust laws, particularly where suppliers have already recovered their initial investment.

It is often argued that flexibility comes at a price, and that relaxing overly restrictive provisions in existing contracts would lead to higher contract prices. However, the JFTC's systematic analysis found no evidence that long-term contracts containing more restrictive provisions on destination clauses, profit-sharing arrangements, or TOP obligations were associated with lower contract prices than contracts with more flexible terms.

While the JFTC's report is understood to be non-binding, it has nonetheless sent a clear policy signal that Japanese buyers should avoid anti-competitive clauses in new or renewed LNG contracts and should review restrictive provisions in existing LNG SPAs.

It remains to be seen to what extent the JFTC could enforce a ruling if it determined that a particular LNG sales contract violates antitrust laws. However, even without issuing rulings on specific contracts, the JFTC's continued expression of its views in reports can significantly influence market practices by strengthening the negotiating position of buyers and encouraging more balanced contract terms.

LNG contracts remain confidential, and detailed information such as on price-related terms is rarely disclosed. Nevertheless, the limited available evidence suggests that some restrictive practices persist in existing legacy contracts. In Japan, the Japan Organization for Metals and Energy Security (JOGMEC), which is tasked with monitoring LNG contract terms, found that destination restrictions – either through the specification of destination ports or through profit-sharing requirements on diverted cargoes – still applied to 40% of contracted volumes under long-term LNG contracts in 2024. This represents a notable reduction from 57% in 2020, when the first survey was published, but the remaining share appears relatively high considering the JFTC's stated preference against such clauses. Most, if not all, of these restrictions are likely concentrated in DES contracts, where such provisions may be justifiable. However, there is no available information to assess whether their application is necessary and reasonable in the remaining legacy contracts in Japan.

The Korea Fair Trade Commission has also examined destination restrictions in LNG contracts, including the possibility of investigating resale limitations, signalling to market participants the undesirability and potential scrutiny of such restrictions. However, no formal investigation has been reported to date.

Remaining flexibility constraints in legacy LNG contracts

The above assessments point to the need for a careful and differentiated approach to addressing remaining inflexibilities in legacy LNG contracts. Where destination restrictions, profit-sharing clauses, and seller consent requirements persist in FOB contracts, they are increasingly difficult to justify on operational grounds. Such provisions may be challenged under existing competition rules in liberalised gas markets, addressed through arbitration, or renegotiated through standard price review mechanisms or other contract reopener clauses included in most LNG sales purchase agreements (SPAs).

Legacy DES contracts present a more complex challenge for flexibility enhancements. Fixed destinations (or a limited list of permitted delivery points within the target market) were historically acceptable for many traditional Asian buyers. In the past, limited market liberalisation in Asian gas markets meant that buyers often had predictable domestic supply obligations, faced limited competition, and had little or no global trading capability. As a result, their trading needs remained relatively modest, and they were therefore generally willing – albeit reluctantly – to accept fixed destination clauses.

While these conditions have weakened or disappeared in most LNG importing countries, and restrictive destination and profit-sharing clauses have likely been largely phased out of FOB contracts, many legacy DES contracts still reflect earlier market realities and have not been uniformly challenged or renegotiated. However, even where DES contracts remain commercially preferred, rigid destination provisions have become increasingly outdated. In many cases, they could be amended within existing legacy contracts, justified by evolving market conditions and, where relevant, the guidance of competition authorities. Where destination terms are narrowly limited to a single terminal or a small number of ports within the destination market, the list of permitted delivery points could be expanded if agreed by the seller, for example to all terminals within the importing country or, where applicable, to a broader regional market (such as the JKTC market in Asia encompassing Japan, Korea, Chinese Taipei, and China). In DES contracts, seller consent for diversions is often unavoidable given the seller's responsibility for shipping and delivery logistics, but procedures can be streamlined, for example through time-bound response requirements and deemed consent provisions, under which diversion requests are automatically approved if the seller does not respond within a specified period.

Profit-sharing mechanisms may be more defensible in DES contracts where diversions impose additional operational costs on the seller. In principle, well-designed profit-sharing clauses can support efficient cargo diversions and lead to commercially efficient outcomes. In practice, however, there are few examples of profit sharing being used to recover the seller's additional operating costs.

Replacing profit-sharing formulas with a transparent fixed diversion fee could, in theory, preserve cost recovery while reducing administrative burdens, limiting the need for disclosure of commercially sensitive information and avoiding disputes linked to complex and often ambiguous calculation methodologies. It could also provide incentives to actively consider and implement resales, thereby supporting a more efficient allocation of LNG across markets. However, fixed diversion fees can be similarly difficult to establish in practice and are not widely used today in LNG markets.

TOP provisions, including minimum TOP volumes and DQT terms, are standard features of long-term LNG contracts. Compared with destination-related clauses, they are typically more difficult for sellers to revise. This is particularly true where contracts underpin project-financed liquefaction facilities, as lenders may restrict amendments that weaken revenue certainty. Buyers also have a more limited basis to challenge such provisions, given their established role in supporting investment in LNG supply. The JFTC noted in its 2017 report that sellers who have fully recovered their initial investment may violate antitrust laws if they impose overly strict TOP obligations on buyers. In practice, negotiations to increase volumetric flexibility are possible, but they often require buyers to compensate sellers for revising previously agreed volume commitments, for example through upward price adjustments, higher contracted volumes, or an extension of contract duration. For contracts approaching expiry, particularly those linked to older legacy plants, offering a contract extension in exchange for more flexible terms, including on TOP and DQT provisions, can provide a viable pathway to phase in greater flexibility. In cases where buyers place a high value on additional volume flexibility within an existing contract, the introduction of a fixed cancellation fee could also be considered, although this may turn out to be a costly option for buyers.

Another potential area of concern relates to possible imbalances in cargo cancellation penalties between buyers and sellers. Evidence from recent market developments suggests that such asymmetries can exist in practice. During Pakistan's energy crisis in 2022, for example, several contracted LNG cargoes were cancelled by suppliers, reportedly subject to penalties as low as 30% of the cargo value in cases of "failure to deliver", while buyers are typically required to pay 100% of the contract price in the event of their "failure to take" contracted volumes outside the standard downward quantity tolerance ranges. Such asymmetric provisions may create incentives for sellers to cancel deliveries and divert cargoes when spot market prices substantially exceed contract prices. In principle, contractual arrangements that value undelivered cargoes at prevailing market prices rather than fixed contractual penalties could help mitigate such incentives, although designing appropriate mechanisms is more complex in LNG markets given the potential divergence between spot LNG prices and contract pricing formulas. To the extent that such imbalances persist in existing legacy contracts, they may raise concerns about fairness and, if they result from an abuse of market power, warrant the attention of competition authorities.

Balancing flexibility and contractual stability

Revising existing contracts can also have broader implications for buyer-seller relations, investment incentives and, ultimately, supply security. In most cases, existing LNG contracts are private commercial arrangements, limiting the scope for direct government intervention beyond the application of competition law and established legal frameworks. Therefore, buyers' desire for greater flexibility needs to be carefully balanced against these broader considerations, ensuring that stable contractual relationships are maintained and that any revisions remain consistent with established legal frameworks and norms. Nevertheless, nearly 10 years after the landmark 2017 JFTC report, the continued presence of restrictive and potentially competition-distorting provisions in legacy LNG contracts warrants renewed scrutiny and more systematic monitoring across LNG importing countries, not only in Japan.

5.2 New LNG contracts

Signing new LNG contracts creates opportunities for buyers to incorporate flexibility-enhancing provisions. This can help optimise LNG trade flows under normal market conditions, while improving the ability of LNG volumes to respond quickly in periods of market stress.

At least four factors are creating new opportunities to secure more flexible LNG contracts going forward, which we will explore in depth in this section:

- Growing volumes of destination-flexible LNG supply from the United States.
- The expiry of legacy contracts.
- The depreciation of legacy LNG projects.
- Increasing volumes of unsold LNG held by portfolio players.

Growing LNG supply from the United States

The rapid ramp-up of LNG exports from the United States since 2016 has marked a major shift in global LNG market flexibility. US LNG contracts generally do not include destination or resale restrictions, allowing cargoes to be redirected freely in response to market signals. In addition, US LNG offtakers retain the ability to cancel cargoes with relatively short notice, providing far greater downward volume flexibility than is typically available in other long-term LNG contracts. Both the destination and downward volume flexibility of US LNG have been clearly demonstrated in recent years. During the 2022-2023 energy crisis, for example, US LNG played the single largest role in bridging Europe's supply-demand gap, with more than 40 bcm of US-sourced LNG redirected to the European market in 2022, mainly from Asia. The downward volume flexibility of US LNG was also evident during the COVID-19 crisis in 2020, when around 170 US LNG cargoes were cancelled and US liquefaction utilisation rates fell sharply, at one point dropping to around 30% at the height of the demand shock in mid-2020.

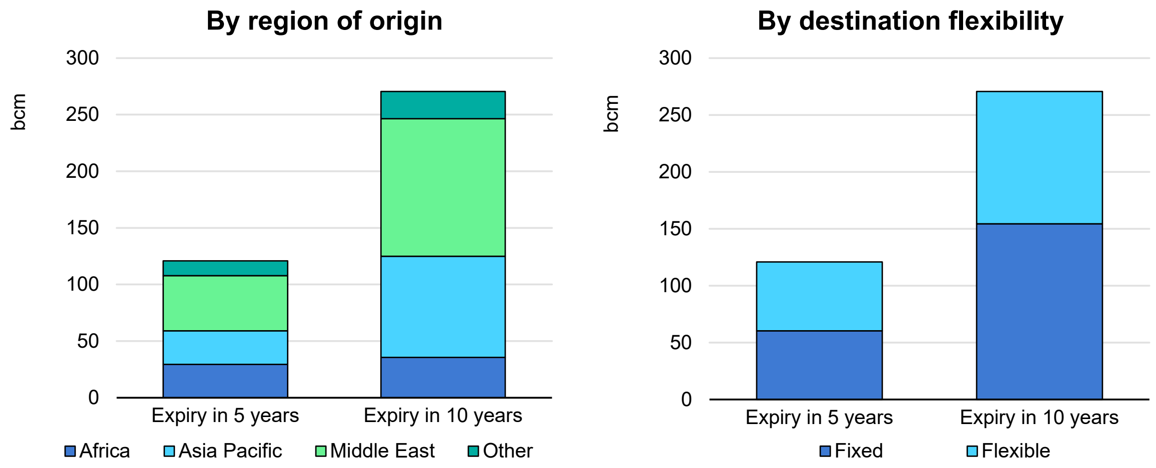
Looking ahead, US liquefaction capacity is projected to increase substantially, from around 150 bcm at the end of 2025 to nearly 300 bcm by 2030, based on projects that have already reached a final investment decision. A further increase to over 350 bcm is expected in the early 2030s, once all projects currently under construction become fully operational. While most operational capacity is contracted to long-term offtakers, about 40% (more than 50 bcm) of the capacity currently under construction remains uncontracted, creating further scope for new long-term agreements on flexible terms. However, project developers often retain a share of volumes for spot and short-term sales, allowing them to capture the potential upside from market volatility. As a result, while a large share of future US liquefaction capacity is expected to be contracted under long-term SPAs, it is unlikely that all volumes will be committed on a long-term basis.

Expiring legacy contracts

Global LNG supply has expanded significantly over the past several decades. With close to 600 bcm of LNG traded in 2025, the market, historically underpinned largely by long-term contracts, has reached a scale at which a sizeable volume of LNG tied to legacy contracts expires each year.

According to the IEA's in-house database, LNG contracts covering around 120 bcm of primary LNG supply (sourced directly from production projects rather than supplier portfolios) are set to expire over the next five years, rising to more than 270 bcm over the next decade. The largest share of expiring volumes is linked to projects in the Middle East, followed by Asia Pacific, where LNG SPAs have historically been less flexible. As a result, close to 60% of expiring contract volumes are destination-fixed DES agreements, although detailed flexibility-related provisions, such as diversion rights, profit-sharing arrangements, and seller consent requirements, are typically not publicly disclosed.

Figure 5.2 Expiration of LNG contracts in effect in 2025



Expiring legacy contracts create a sizeable opportunity for buyers and sellers to recontract LNG on more flexible terms. In many cases, the underlying liquefaction projects will have largely or fully recovered their capital investments and repaid their debt, and thus can offer shorter contract durations, lower prices, and enhanced flexibility, at least to the extent that feed gas supply can be sustained. Offering to extend existing contracts with ageing legacy plants in exchange for greater flexibility can represent a strong negotiating lever for buyers. In practice, however, contract negotiations are typically approached holistically, and flexibility provisions may sometimes be traded away in favour of lower pricing or other prioritised contract attributes. On the other hand, if sellers refuse the buyer's preference for FOB delivery and insist on DES terms during SPA negotiations or renegotiations, such practices would warrant careful scrutiny by competition authorities, as it could amount to imposing destination restrictions in disguised form, especially if the seller holds a dominant position in the relevant market.

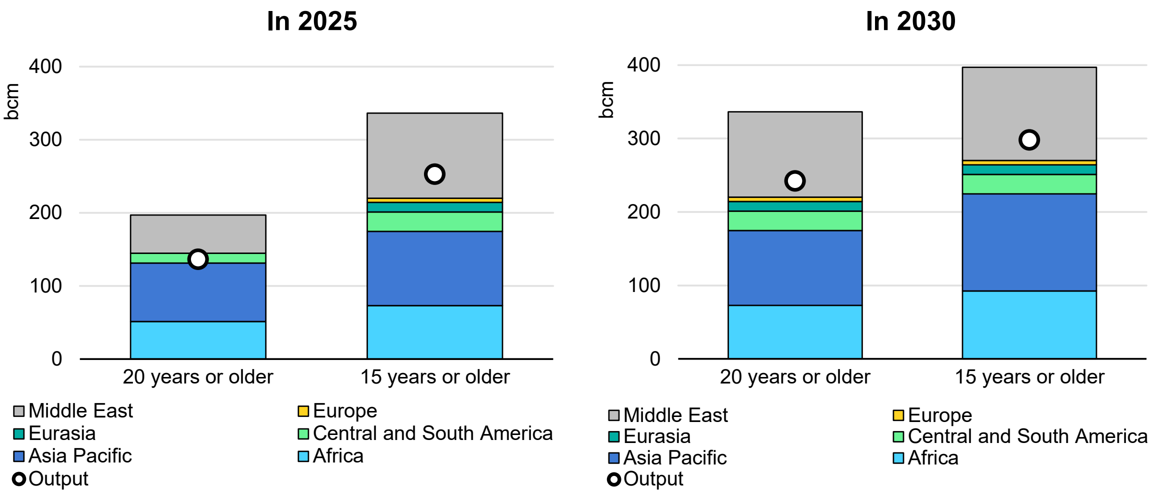
Depreciated legacy plants

LNG liquefaction projects are highly capital-intensive assets, typically developed based on long-term SPAs that underpin investment decisions and facilitate access to financing. Historically, many initiatives have relied on project finance structures, with lenders requiring stable and predictable cash flows to support debt service. This has contributed to the widespread use of long-term LNG contracts with TOP provisions requiring relatively rigid volume commitments and offering limited flexibility, effectively allocating project and price risk to developers while placing volume risk largely on buyers. Contract durations have often been aligned with financing tenors, which typically range from around 15 to 20 years, reflecting the time needed to repay debt and recover upfront capital expenditure.

Once a liquefaction plant has repaid its debt and recovered its initial investment – typically after 15 to 20 years of operation – the commercial rationale for strict contractual rigidities diminishes. At this stage, sellers may have greater scope to offer shorter contract durations and more flexible volume and destination terms to gain competitive advantage, particularly where the plant continues to benefit from established infrastructure and relatively low operating costs. However, pricing and contractual outcomes remain influenced by prevailing market conditions, and there is no guarantee that such flexibility will materialise in practice. A recent survey of Japan's long-term LNG contract portfolio by JOGMEC indicates, for example, that TOP clauses still apply to more than 90% of Japan's contracted LNG volumes, according to data from the 2025 fiscal year. This remains true even though around half of global LNG export capacity – and more than 50% of the capacity in countries supplying LNG to Japan in 2025 – appears to be largely depreciated.

In 2025, around 335 bcm (49%) of global liquefaction nameplate capacity and an estimated 250 bcm (43%) of actual LNG output came from plants that were at least 15 years old. The corresponding figures for plants older than 20 years were approximately 200 bcm (29%) of nameplate capacity and 135 bcm (23%) of supply. The contribution of ageing liquefaction assets is expected to increase in the coming years. By 2030, liquefaction capacity and projected output from plants older than 15 years are set to reach nearly 400 bcm and 300 bcm, respectively, while the figures for plants older than 20 years rise to more than 330 bcm and 240 bcm. The largest shares of legacy export capacity in 2025 were in the Middle East and Asia Pacific, which together accounted for around two-thirds of liquefaction capacity aged 15 years or more, overlapping with regions where a significant volume of legacy contracts is also set to expire.

Figure 5.3 LNG liquefaction capacity and output from legacy plants, 2025 and 2030



Source: IEA analysis based on data from ICIS LNG Edge.

This growing pool of mature and largely depreciated assets is likely to play an increasingly important role in shaping contracting dynamics, offering buyers opportunities to negotiate new supply contracts on more flexible terms, particularly with respect to TOP provisions, but also pricing, contract duration and other non-price terms, provided that upstream gas availability and plant reliability can be maintained.

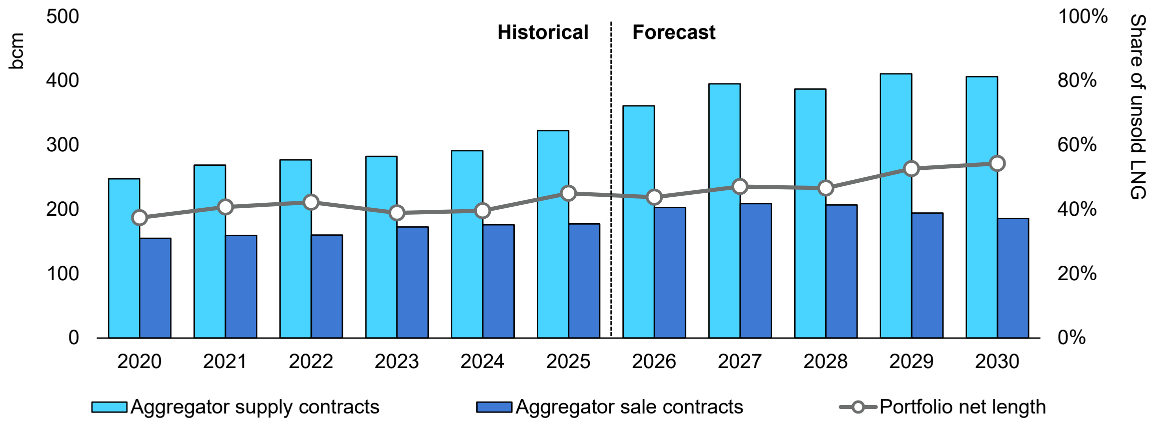
Unsold portfolio volumes

Portfolio players, also known as aggregators, are intermediaries that build diversified LNG supply portfolios by holding equity positions in, or contracting volumes from, multiple liquefaction projects and reselling them to end users through a combination of long-, medium-, and short-term contracts and spot market transactions. Unlike traditional sellers tied to a single production project, portfolio players can offer buyers a broader range of contractual options, including flexible delivery points, shorter contract durations, and the ability to adjust volumes. This can be particularly valuable for buyers seeking to diversify supply sources, manage demand uncertainty, and reduce exposure to regional supply disruptions. Portfolio suppliers have therefore played an increasingly important role in enhancing the operational flexibility of global LNG trade.

At the same time, portfolio players' commercial incentives do not always align with those of LNG importing countries and companies. Trading margins typically benefit from price volatility, and flexibility is often priced explicitly into contract terms. The growing role of portfolio suppliers is reflected in their rising share of global contracting activity, with procurement volumes increasing from around 26% of total LNG contracts in 2016 to around 39% by 2024. This share is projected to rise further to around 45% by 2030, assuming no additional contracts are signed.

The net long position of portfolio players – reflecting contracted supply volumes not covered by term sales commitments to end users – has also widened in recent years, from around 90 bcm in 2020 to more than 115 bcm in 2024. That has resulted in a growing pool of unsold LNG held within their portfolios. Based on existing contracts, this net long position is set to increase to around 220 bcm by 2030, representing around 54% of total volumes in aggregator portfolios.

Figure 5.4 Contractual position of LNG portfolio players, 2020-2030



Note: This graph represents LNG contract volumes signed by the end of 2025.
Source: IEA analysis based on data from IEA (2025), Gas 2025,

As the next wave of liquefaction capacity comes online and market conditions are expected to loosen, portfolio players may become more willing to market these uncommitted volumes on more favourable terms. This could create additional opportunities for buyers to secure LNG supply with enhanced flexibility, particularly through shorter-duration, destination-flexible contracts with greater volume optionality.

Taken together, these factors – some of which overlap, notably contract expirations and the growing share of depreciated liquefaction capacity – create a sizeable pool of volumes that could be recontracted on more flexible terms. This provides a strong basis for buyers to secure greater flexibility in LNG contracts on an individual basis, particularly as market conditions loosen and competition among suppliers intensifies.

There is also scope for buyers to secure greater flexibility collectively through deeper cooperation, within the bounds of applicable competition law. Such initiatives could support the development of minimum flexibility standards that participating buyers would voluntarily incorporate into their new LNG contracts.

In practice, these standards could include the elimination of destination and resale restrictions, seller consent requirements, and profit-sharing clauses from FOB contracts. For DES contracts, collective standards could limit destination restrictions to broad regional boundaries, avoid any resale restrictions, and establish standardised and time-bound seller consent procedures, with profit-sharing mechanisms replaced by transparent diversion fees (although such fee-based mechanisms are not widely known to be used in practice today). In the case of supply from mature and depreciated liquefaction plants, buyers could commit to seek wide DQT ranges or more extensive cancellation rights in exchange for relatively modest fees reflecting the lower capital recovery requirements of the underlying asset.

However, collective approaches to contract flexibility face practical, commercial, and legal constraints. Monitoring and enforcement are complicated by the confidentiality of LNG SPAs, limiting transparency over the extent to which buyers adhere to agreed standards. Quantifying the share of supply sourced from depreciated legacy plants is also challenging, particularly for contracts signed with portfolio players. In addition, any coordination among buyers would need to be carefully assessed in light of applicable competition law, particularly where it involves coordination among companies that may compete in downstream gas markets. Further analysis would therefore be needed before such collective approaches could be implemented effectively.

5.3 Commercial innovation

Beyond strengthening flexibility provisions in existing and new LNG contracts, market participants can also pursue commercial innovation. Scaling up the use of non-traditional contractual structures, such as seasonal LNG contracts, contracts with cancellation rights, or LNG options contracts, can complement traditional LNG SPAs and spot market procurement and provide flexibility in a more targeted way. Buyers can also enhance flexibility and resilience through joint LNG procurement and trading arrangements, whereby companies pool purchasing power, share portfolios or jointly optimise LNG marketing and logistics across different regional markets.

The case for exploring more innovative approaches to LNG contracting has strengthened in recent years. On the buyer side, LNG demand is becoming more uncertain and variable, shaped by weather sensitivity, geopolitical developments, market volatility, and policy uncertainty. Buyers in Europe and Asia are increasingly seeking to preserve security of supply without being locked into rigid long-term commitments that may become misaligned with future demand trends or regulatory constraints. At the same time, extreme price volatility since 2021 has reinforced the value of instruments that can limit exposure to spot market disruptions while avoiding excessive TOP liabilities.

On the seller side, the current wave of liquefaction capacity growth is expected to loosen market conditions in the second half of this decade. In parallel, portfolio players are holding a large and growing share of LNG volumes that are not committed to end users. These suppliers may face increasing pressure to monetise uncommitted volumes and reduce their exposure to downside price risk in a well-supplied market. This creates a stronger incentive to offer commercial structures that provide buyers with greater volumetric flexibility (in exchange for an explicit premium), while offering sellers relatively stable revenues amid a potential softening of spot LNG prices.

Seasonal LNG contracts

Unlike traditional LNG SPAs, which commit buyers to relatively stable year-round deliveries with limited volume flexibility, seasonal LNG contracts are typically structured to cover only periods of predictable peak demand, with deliveries concentrated in a defined seasonal window, such as the peak winter months.

Such seasonal contracts could be particularly relevant for buyers with strongly seasonal gas consumption profiles and limited storage capacity, allowing them to secure incremental winter supply directly rather than relying on storage withdrawals or spot LNG procurement.

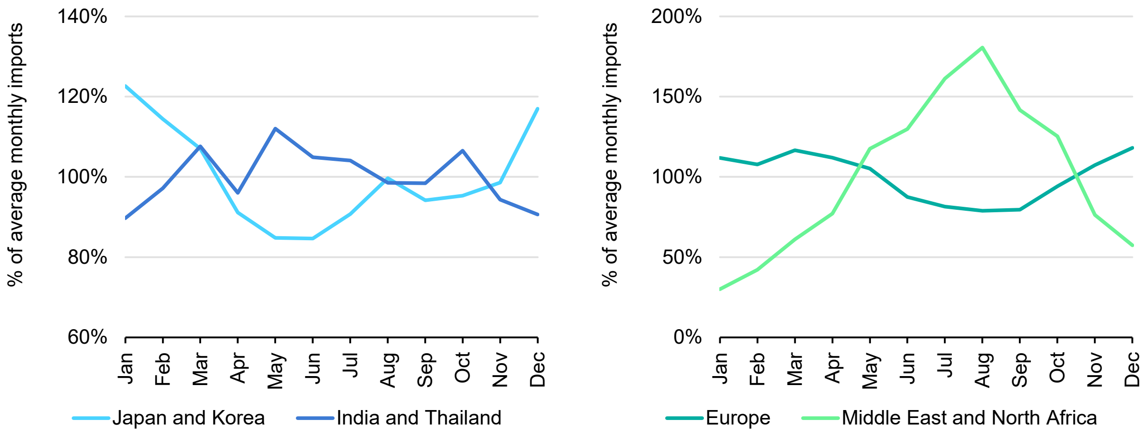
The pricing of seasonal LNG contracts would likely require a premium over prevailing forward prices at the time of signing, reflecting the convenience benefit for buyers of avoiding storage costs ahead of the peak demand season, and the additional marketing challenge for sellers of having to place their LNG elsewhere during the remainder of the year. As a result, suppliers with extensive portfolio flexibility and access to a diversified customer base are likely to be the best positioned counterparties to offer and scale seasonal LNG contracting.

Seasonal contracts have begun to emerge in the LNG market, although they remain relatively limited. Recent examples include a five-year seasonal contract between the Australian firm Woodside and Japan’s JERA, under which JERA will receive three LNG cargoes per year within the December-February delivery window starting in 2027. JERA also signed a 10-year LNG supply agreement with India’s Torrent Power covering four LNG cargoes per year during India’s peak summer months, also starting in 2027. While the number of seasonal contracts signed to date remains small, these deals suggest a preference for medium-term arrangements (ranging from five to ten years), although both shorter- and longer-duration structures could also emerge depending on market conditions and buyer requirements.

Seasonal contracting could become more relevant across key importing regions. In Europe, LNG demand has become increasingly seasonal as the region relies more heavily on LNG to balance winter consumption peaks. Even with substantial underground storage capacity, the region typically requires incremental LNG imports in winter to complement storage withdrawals. Northeast Asia, including northern China, Japan, and Korea, can also experience demand spikes during the peak winter months. However, overall gas demand seasonality in northeast Asia is less pronounced than in Europe, and, as such, seasonal requirements are smaller. In South and Southeast Asia, seasonal arrangements may gain importance as LNG demand rises in power systems that are sensitive to summer cooling loads and hydropower variability.

In principle, seasonal LNG contracts could also help facilitate intra-regional and inter-regional balancing, particularly where seasonal demand patterns differ across geographies (Figure 5.5). Such complementary seasonal demand profiles could be leveraged between northeast Asia, with peak demand during the Northern Hemisphere winter, and South and Southeast Asia, the Middle East, or even Australia and New Zealand (once they develop LNG import infrastructure), where peak requirements typically occur during the Northern Hemisphere summer. JERA's recent complementary seasonal LNG contracts with Woodside and Torrent Power illustrate how such structures can leverage differing seasonal demand profiles across markets, in this case between Japan and India.

Figure 5.5 Monthly LNG imports relative to the annual average in geographies with complementary seasonal demand profiles, 2020-2025 average



Source: IEA analysis based on data from ICIS LNG Edge.

LNG contracts with extended cancellation rights

The volumetric flexibility embedded in traditional LNG SPAs is constrained by minimum TOP obligations and limited to UQT and DQT tolerances, often subject to make-up provisions in subsequent periods. Cancelling contracted cargoes beyond these narrow limits typically does not make economic sense, as buyers would still be required to pay for most or all of the contracted volume even if it is not lifted.

US LNG offtake contracts introduced a commercial model in which a larger share of total costs is variable, thus making cargo cancellations economically feasible in a wider set of market conditions. Under the prevailing tolling-type agreements currently in place, buyers of US LNG pay a fixed liquefaction fee (typically USD 2 to USD 3.5 per MBtu over long contract durations (typically 15 to 25 years). Conversely, the costs of feedgas, liquefaction fuel (typically around 15% of the Henry Hub price benchmark), and, in some cases, shipping remain variable. This structure effectively gives buyers the ability to cancel cargoes when market conditions do not support exports. In practice, the widespread difference between Henry Hub prices and prices in key importing markets in Europe and Asia following the shale revolution meant that most US LNG contracts were signed with an expectation of continuous lifting. However, when price spreads narrow or turn negative, buyers can cancel cargoes while remaining liable only for fixed tolling or liquefaction fees, thereby limiting their downside exposure. This mechanism played an important role during the demand shock triggered by the Covid-19 pandemic, when more than 170 US LNG cargoes were cancelled between April 2020 and November 2020.

Outside the United States, however, cancellation rights beyond standard contractual tolerances have historically been limited, reflecting the greater difficulty of incorporating such flexibility into traditional integrated LNG projects. One notable exception was a short-term agreement between Greece's DEPA and TotalEnergies in 2022, under which the buyer (DEPA) retained the right to cancel scheduled cargoes in exchange for a fixed fee. The contract required the delivery of two LNG cargoes per month between November 2022 and March 2023, but local reports indicate that DEPA exercised its cancellation right for at least two cargoes in February 2023, reportedly paying approximately EUR 10 million per cancelled cargo (around USD 3 per MBtu).

These examples illustrate the potential for broader use of LNG contracts with extended cancellation rights. In such structures, buyers commit to a base volume but retain the ability to cancel cargoes in exchange for a predefined fee, typically with an expectation of regular lifting under normal market conditions. Compared with traditional SPAs, this approach provides unlimited downward flexibility while preserving a degree of revenue certainty for sellers. Such arrangements could be extended to a wider range of LNG contracts, particularly those involving portfolio players with diversified supply sources and marketing outlets. For sellers, cancellation fees can provide a stable revenue stream while reducing exposure to unsold volumes. For buyers, these structures offer a middle ground between rigid long-term commitments and fully flexible spot procurement, improving their ability to respond to demand uncertainty and short-term market developments.

Call option-type LNG contracts

Another promising innovation is the wider use of call option-style LNG contracts, which provide buyers with the right – but not the obligation – to receive LNG cargoes on predefined terms. These contracts function in many ways like insurance policies: buyers pay a fixed upfront premium to secure access to supply but may never need to exercise that right. Such structures allow buyers to secure access to supply capacity while limiting volume risk. In exchange, buyers pay an upfront option premium, similar to an insurance premium, for the right to request deliveries during a defined period. Cargoes are then expected to be lifted only when needed – potentially only in rare or extreme market circumstances. This premium compensates the seller for reserving volumes and bearing the risk that the buyer may not exercise the option, requiring the LNG to be marketed and sold elsewhere.

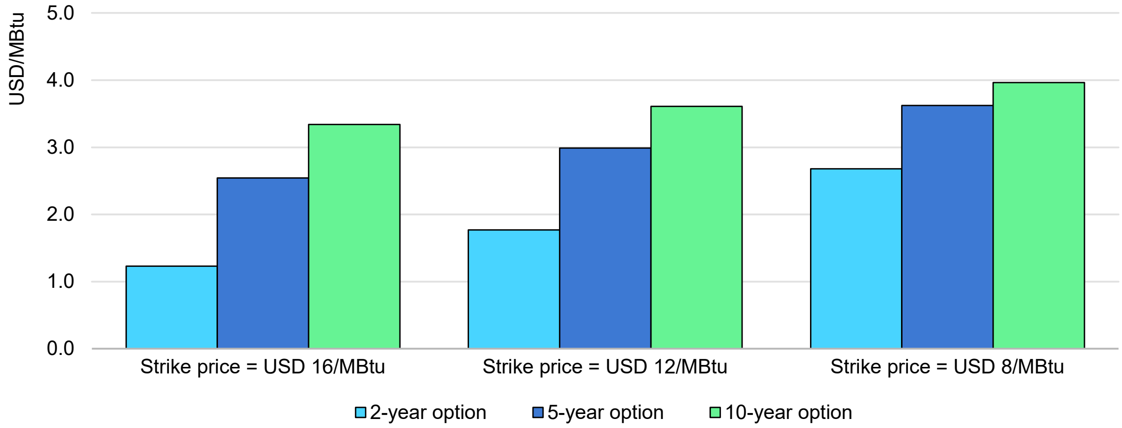
Call option-type LNG contracts can be particularly valuable where buyers face highly uncertain gas and LNG demand, for example due to decarbonisation policies or unpredictable pipeline gas supplies. They are also useful where importers require an insurance-like mechanism against heightened supply security risks, allowing them to secure access to LNG volumes without committing to firm offtake obligations.

From the seller's perspective, options contracts could provide a stabilising revenue stream through option premiums, particularly in a well-supplied market environment where spot price volatility may not consistently generate attractive trading margins. For portfolio players holding significant uncommitted volumes, monetising optionality may be preferable to carrying full exposure to downside price cycles.

However, these contracts also come with implementation challenges. Sellers must manage the operational complexity of reserving cargo availability while optimising their broader portfolios. Meanwhile, buyers need robust trading and risk-management capabilities to evaluate whether the option premium offers value relative to alternative strategies such as storage, hedging instruments, or spot market procurement.

The price of a call option, namely the option premium paid by buyers, depends on several variables, including contract duration, strike price, and the volatility of the underlying commodity. Higher volatility, longer contract durations, and lower strike prices generally increase the value of the option and therefore the premium that buyers must pay. Illustrative calculations suggest that such contracts could be relatively expensive, particularly when buyers seek to secure comparatively low strike prices or long contracts during periods of elevated market volatility. In practice, economically viable structures are more likely to involve higher strike prices and shorter contract durations, with the option intended to be exercised only in relatively rare circumstances, reinforcing its role as insurance rather than a routine supply source.

Figure 5.6 Illustrative cost of LNG call options at different strike prices and contract durations



Note: Option premia are calculated using the Black-76 framework, treating the LNG procurement contract as a call option on a forward gas price. The underlying forward price is assumed to be USD 8/MBtu, and the risk-free rate is set at 3.5%. Volatility is derived from historical market data using daily European and Asian month-ahead gas price series over the 2016-2025 period. Annual volatility is first calculated separately for each calendar year as the standard deviation of daily log returns, annualised using the actual number of trading days in each year. The reported volatility is the simple average of these annual values.

This relatively high cost, particularly under conditions of elevated volatility, long contract durations, and low strike prices may partly explain the limited use of explicit call option-style LNG contracts in transactions to date. Where such instruments are intended to serve broader supply security objectives, their deployment is likely to require some form of public support. In such cases, governments can help facilitate or incentivise their use, for example by mandating or supporting designated entities to include LNG call options in their portfolios to meet gas supply security requirements.

Beyond bilateral arrangements, call option-style LNG contracts could be developed further as a tool for collective action and coordinated emergency response. In principle, LNG options could be pooled across multiple buyers or even across multiple importing countries, creating a shared flexibility buffer that can be activated during supply emergencies.

The absence of a single, well-defined and flexible asset base, as is the case with strategic oil stocks under the IEA framework, has historically been a barrier to coordinated gas security mechanisms. A diversified portfolio of pooled LNG call options, with full destination flexibility, could in principle help address this and function as a collectively managed "virtual" emergency reserve. However, such a mechanism would raise numerous implementation and governance challenges, including around activation triggers, cost-sharing arrangements, enforcement mechanisms, allocation rules, and the simultaneous exercise of options by multiple participants during widespread supply disruptions, all of which require further study.

If a period of abundant supply in the late 2020s were to materialise, it could create more favourable conditions for the development of such instruments, as sellers may be more willing to monetise optionality to secure additional revenue streams. At the same time, buyers and governments in import-dependent countries may view the associated premiums more favourably relative to alternative supply security measures, such as building strategic underground gas reserves or deploying FSRU-based import infrastructure, which can also entail significant costs.

Joint LNG procurement and trading

An additional option for commercial innovation is collaborative LNG procurement and portfolio optimisation arrangements between buyers (Asian and European ones in particular). Such arrangements can help participants better manage demand uncertainty, price risks, and portfolio flexibility by allowing companies operating in different markets to combine their procurement strategies, share contractual volumes, or jointly optimise LNG trading and marketing activities. Given the right incentives, they could also enhance supply security by prioritising deliveries to their respective domestic markets in the event of supply emergencies.

One example of joint procurement across regions is between Tokyo Gas and the United Kingdom’s Centrica, who together secured long-term LNG supply from Mozambique LNG. The project is only expected to start production in 2029, following a suspension of construction between 2021 and January 2026 due to security concerns in northern Mozambique. Under the agreement, Tokyo Gas and Centrica would jointly purchase LNG volumes from Mozambique LNG, enabling them to leverage their respective positions in the Asian and European gas markets. This structure allows the partners to optimise the destination of cargoes depending on regional market conditions, redirecting LNG between Europe and Asia where commercial opportunities or supply needs are greatest. Such arrangements can help buyers diversify supply sources and respond more effectively to supply disruptions affecting only one region.

Collaboration opportunities are not limited to procurement. A notable example is the LNG optimisation and trading joint venture established between JERA and France’s EDF Trading. The partnership combines JERA’s substantial LNG procurement portfolio and access to regasification infrastructure in Asia with EDF Trading’s global trading capabilities and market presence in Europe and the Atlantic basin. Through such structures, partners can jointly manage cargo scheduling, optimise shipping, and regasification capacity, and market LNG volumes across multiple regions. By pooling portfolios and trading capabilities, these partnerships can improve operational efficiency, expand market access and help smooth supply-demand imbalances across regional markets.

There may be further scope to expand such cooperative structures. Cross-regional partnerships between buyers in Europe and Asia could facilitate more efficient global balancing of LNG flows, particularly during periods of market stress when demand surges in one region can rapidly tighten supply elsewhere. Joint procurement arrangements could also enable smaller buyers or emerging LNG importers to participate in larger projects by aggregating demand, while joint trading platforms could help participants optimise increasingly complex LNG portfolios as destination flexibility becomes more widespread.

However, these structures may face practical constraints. Aligning commercial interests between partners can be challenging, particularly when participants operate in markets with different regulatory environments, demand profiles, or risk tolerances. Governance arrangements must clearly define decision-making processes, profit-sharing mechanisms, and the allocation of cargoes during periods of market stress. Competition policy considerations and concerns about market concentration may also limit the extent to which buyers can formally coordinate procurement strategies in certain jurisdictions.

Despite these challenges, joint procurement and trading partnerships illustrate how LNG buyers can adapt their commercial strategies to an increasingly flexible and globally interconnected market. By combining purchasing power, portfolio diversity and trading expertise, such collaborations can enhance both supply security and commercial optimisation for participating companies. Governments in like-minded importing countries could support these arrangements by encouraging partnerships that allow portfolio optimisation under normal market conditions while providing incentives to prioritise supply security during crises.

As noted, commercial innovation is not a substitute for conventional long-term contracts, which will remain essential for financing new liquefaction capacity. However, the expansion of seasonal contracts, portfolio contracts with cancellation rights, and call option-style contracts could help buyers strengthen supply security and meet seasonal balancing requirements without increasing their exposure to rigid TOP obligations. Deeper cooperation between buyers through joint procurement and portfolio optimisation arrangements could further enhance flexibility by allowing participants to pool volumes, share infrastructure access, and coordinate trading strategies across regions. Over the medium term, the growing role of portfolio players, the expiry of legacy contracts, and the prospect of looser market conditions could create a favourable environment for such innovations to scale. If widely adopted, these approaches could form a third layer of LNG procurement between traditional LNG SPAs and spot market purchases, supporting both supply security and market efficiency in key importing regions.

5.4 LNG swaps

Agreements between two or more parties to exchange cargoes or delivery obligations, knows as physical LNG swaps, can enhance market flexibility and support more coordinated reserve or balancing mechanisms. Although swaps are primarily used to compensate for missing deliveries or economic optimisation, they can improve system efficiency, reduce shipping costs, and enable faster cross-basin rebalancing when regional supply-demand conditions shift abruptly. During periods of market stress, they can redirect volumes to the most affected markets more rapidly than negotiating new spot purchases or arranging reloading.

The main challenge for physical LNG swaps lies in aligning two counterparties' cargo specifications, shipping and terminal schedules, contractual terms, and credit arrangements within a narrow timeframe. This complexity is often compounded by residual contractual rigidities, including destination restrictions, seller consent requirements, and profit-sharing clauses. These remain prevalent in parts of the legacy contract portfolio, especially in DES contracts (see Section 5.1). Their gradual removal from existing and future LNG SPAs could therefore facilitate more diversions as well as a broader use of LNG swap arrangements over time.

Technical and operational parameters, including schedules, ship-shore compatibility, and LNG quality, must also be closely aligned or otherwise accommodated through operational adjustments.

Documentation, compliance, and financial requirements are similarly complex, including potential amendments to bills of lading, reissuance of certificates, amendments to letters of credit, as well as customs treatment and sanctions screening requirements applicable to cargo origin, vessels, and counterparties. Streamlining these processes could facilitate the execution of physical LNG swap transactions in the future.

Some of these technical and administrative constraints could be eased, especially during periods of market stress or supply emergencies, on a temporary basis. Options for pre-established, standardised emergency frameworks include expedited nomination and terminal access procedures; shorter notice periods; simplified documentation requirements; accelerated customs and regulatory approvals; temporary widening of quality tolerances (within safe operational limits); and streamlined authorisation for ship-to-ship operations where relevant and properly regulated.

Market transparency around potential swap opportunities remains limited and largely confined to bilateral contacts. This could be improved through "matchmaking" platforms enabling the exchange of non-binding expressions of interest, particularly as the number of spot LNG cargoes available for swap transactions at any given time increases. Such platforms could focus on standardised and non-sensitive parameters, including delivery windows, volume ranges, destination regions, basic quality specifications, and the existence of seller consent requirements, without requiring disclosure of detailed contractual terms. The objective of these platforms would not only be to allocate cargoes, but also to reduce the time and transaction costs associated with identifying feasible counterparts for potential swap transactions.

Finally, easing the contractual and operational constraints that currently limit swap transactions could also create scope for more advanced policy mechanisms, including arrangements that enable the exchange of LNG cargoes for LNG or gas held in storage in a third country. Such structures could support coordinated action among partner countries during supply disruptions. Some of these potential mechanisms, and their implications for energy security and market functioning, are discussed further in Section 6.

6. Policy tools to create gas reserve mechanisms

This chapter discusses four main types of policy instruments that governments use or may consider using to strengthen gas supply security through reserve mechanisms (see Table 2). Mandatory storage obligations require gas storage facilities to reach minimum fill levels by specific dates, typically ahead of the winter withdrawal season, to ensure sufficient inventories. Strategic underground gas reserves designate a portion of storage capacity or volumes for use only in emergencies, rather than for commercial balancing. Strategic cushion gas reserves refer to the potential use of part of the cushion gas in existing underground storage facilities as an emergency backstop under exceptional circumstances. Finally, various buffer LNG schemes provide contingency supply mechanisms by securing access to LNG cargoes or LNG import infrastructure that can be mobilised during periods of severe market tightness or supply disruption.

These instruments differ in their objectives, costs, and implications for market functioning. The choice among them depends on the structural characteristics of national gas systems. Countries with large underground storage systems and liquid gas markets may prioritise measures that influence storage filling behaviour, while LNG-dependent economies with limited storage capacity may rely on import-based contingency mechanisms. This chapter provides an overview of the main features of each policy tool, including their advantages, limitations, and typical use cases.

Table 6.1. Overview of policy tools for gas reserve mechanisms

	Mandatory storage obligations	Strategic underground gas reserves	Strategic cushion gas reserves	Buffer LNG schemes
Core concept	Regulatory requirement to reach minimum gas storage fill levels by specified dates (e.g. ahead of the heating season), often supported by intermediate targets to guide the filling trajectory.	Ringfencing of UGS capacity or volumes for emergency use only, with release subject to predefined conditions and government authorisation, and typically supported by public funding.	Designating a portion of cushion gas in underground storage facilities as a publicly backed emergency reserve, with withdrawal permitted only under predefined emergency conditions.	Publicly backed contingency mechanisms that secure access to LNG cargoes or import capacity during emergencies, through contractual arrangements, dedicated infrastructure, or a combination of both.
Pros	▪ Ensures adequate inventories ahead of the winter season. ▪ Utilises existing commercial storage capacity.	▪ Provides a guaranteed physical buffer in emergencies. ▪ Can support storage economics where existing UGS sites are converted to strategic use.	▪ Immediately available emergency buffer within existing UGS facilities. ▪ Cost-effective compared with building new strategic storage as no additional infrastructure or gas procurement is required. ▪ No impact on market functioning and commercial storage operations under normal conditions.	▪ Flexible and scalable emergency supply option. ▪ Can be implemented cost-effectively through contractual arrangements or existing infrastructure. ▪ Can support security of supply without distorting market functioning under normal conditions.
Cons	▪ May distort market price signals and exacerbate price spikes during the storage fill period. ▪ Risk of crowding out commercial market activity.	▪ High capex and long lead times if new facilities are developed from scratch. ▪ Reduces storage available for commercial balancing when existing capacity is ringfenced. ▪ Limited track record of use during actual emergencies.	▪ Reduced deliverability and risk of permanent reservoir damage if cushion gas is withdrawn. ▪ Feasible volumes and withdrawal rates are site-specific and require detailed studies.	▪ Relies on LNG availability in tight global markets. ▪ High commercial and governance complexity. ▪ Limited track record of effectiveness in actual emergencies.
Use cases	Markets with high reliance on storage for seasonal balancing, large storage capacity, and insufficient market incentives to ensure adequate refilling ahead of peak demand periods.	Countries with surplus storage capacity and/or weak commercial storage economics.	UGS facilities at risk of closure where preserving storage assets provides system value and supports resilience.	Economies with high reliance on LNG imports and limited storage capacity.
Examples	European Union.	Ten countries within the European Union.	Under study in the Netherlands.	Japan's SBL scheme; Singapore's SLF.

6.1 Mandatory storage obligations

Gas storage facilities generally operate on a commercial basis, with capacity holders weighing the opportunities to buy gas to store and sell later at a higher price. However, injection and withdrawal decisions can also be shaped by policy mechanisms, including through mandatory storage obligations.

Mandatory storage obligations are set by governments (or, in the European Union, through EU-level regulation) and typically require that a minimum storage fill level or volume be reached by a specified date, often ahead of a period of expected high withdrawals, such as the winter heating season in the Northern Hemisphere. By requiring higher inventories than might be achieved under purely commercial incentives, such obligations aim to strengthen supply security, limit the potential impact of geopolitical actions by state-owned suppliers, and ensure that storage facilities can effectively perform their balancing function.

Complementary intermediate targets can be set to achieve a desired filling trajectory. In some cases, indicative minimum levels for the end of the withdrawal season have also been implemented, although these present the drawback of potentially constraining the optimal use of storage withdrawals when they are the most needed. Mandatory storage obligations differ from strategic gas storage arrangements in that they do not seek to reserve a specific volume for release only in predefined emergency situations. Rather than restricting withdrawals, their objective is to maximise the utilisation and system value of available storage capacity.

The rationale for mandatory storage obligations lies in the risk that storage facilities may not be adequately filled on a purely commercial basis when seasonal spreads are tight. In such circumstances, market incentives alone may not result in storage levels needed to provide sufficient security ahead of the peak winter season. While storage injections are generally incentivised when forward prices exceed spot prices (i.e. when summer-winter spreads are positive), seasonal spreads may be insufficient to cover both direct and opportunity costs of storing gas. Low inventory levels, in turn, reduce the balancing potential of underground storage, contributing to tighter market conditions and higher price volatility. Paradoxically, expectations of adequate future supply can weaken incentives to fill storage ahead of the withdrawal season by compressing seasonal price spreads. The expected wave of new LNG supply in the remainder of the decade, for example, could structurally narrow seasonal spreads in Europe, weakening the market signal for storage injections.

In 2021, UGS levels in the European Union were below the five-year average at the end of the winter. Nevertheless, injections during the subsequent filling season remained about 17% below the five-year average, reflecting relatively benign market expectations for the year ahead. Storage levels reached only about 77% ahead of the 2021/22 winter, compared with a five-year average peak above 90%. This occurred as artificial market tightness was building, driven by Gazprom's limited injections into its European storage facilities and Russia's decision to reduce short-term and spot gas sales to Europe. As a result, the continent entered the 2022 crisis period less well prepared to face an unexpected supply shock.[12]

Case study: The European Union's Gas Storage Regulation

In 2022, the European Union sought to strengthen system resilience by maximising the use of its underground storage facilities, following a period characterised by sharply reduced injections into Gazprom-controlled gas storage sites in Europe, declining Russian pipeline gas deliveries to the continent, and below-average EU gas storage levels.

The European Union's Gas Storage Regulation was adopted in June 2022 in response to these events. The measure introduced a binding requirement for member states with UGS to reach an 80% fill level by 1 November in 2022 and 90% in subsequent years, complemented by intermediate targets to support the filling trajectory during the injection season.[13] The regulation was adopted at the EU level, and allowed member states to choose the measures most appropriate for their national systems, which resulted in a range of approaches to achieving the target. These included administrative tools (e.g. stockholding obligations on specific entities and "filling of last resort" mechanisms), as well as market-based measures (e.g. filling subsidies).[14] Approaches varied in their effectiveness, efficiency, and cost.[15] Despite these differences, all member states with UGS met the 1 November storage target in both 2022 and 2023, with only one (Denmark) missing the target in 2024. The regulation was set to expire at the end of 2025, but an amendment has extended it, and the 90% storage target, through the end of 2027, while providing greater flexibility over the timing of storage filling.

Some observers have expressed concern that mandatory storage targets distort market price signals and put upward pressure on the cost of refilling storage, which remains the subject of ongoing debate. In response to stakeholder feedback, the revised EU framework approved in September 2025 allows member states to

[12] For more on this, see Europe and the world need to draw the right lessons from today's natural gas crisis by IEA Executive Director Fatih Birol.
[13] Member states without UGS on their territory must store the equivalent of 15% of their national consumption in facilities in other member states.
[14] "Filling of last resort" refers to the appointment of an entity that is charged with filling storage as a last resort if market signals are insufficient to incentivise sufficient storage injections.
[15] For more on this, see Study on the impact of the measures included in the EU and National Gas Storage Regulations from VIS Consultants.

deviate from filling targets under unfavourable market conditions, providing additional flexibility to reflect changing market fundamentals and price signals.

In 2025, the European Commission announced plans for an impact assessment of the EU's broader energy security framework, indicating that the future of storage rules beyond 2027 could be addressed with a more permanent regulatory structure. While discussions are at an early stage, a key issue is likely to be whether storage obligations should be integrated into a broader EU-level supply security or resilience framework. The extension to 2027 suggests that any longer-term arrangement would likely allow for a degree of flexibility in meeting targets. It also suggests that alternative benchmarks may be set, based on domestic consumption levels and the availability of alternative supply options, rather than the total storage capacity in a member state.

Given the ongoing conversation about the potential market-distorting and price-increasing effects of mandatory storage obligations, there is growing interest among EU member states and market participants in using strategic gas reserves as an alternative or complement to mandatory storage obligations (see next section).

Case study: Korea's mandatory LNG reserve policy

Unlike countries in the European Union, Korea does not have UGS facilities. Instead, the country uses LNG storage tanks at its seven LNG import terminals for short-term storage (those seven facilities have a total storage capacity of about 9 bcm). Korea has a mandatory LNG reserve policy requiring minimum inventories to be met at facilities run by the state-owned Korea Gas Corporation (KOGAS), which run five of the terminals, representing around 6.5 bcm of LNG tank storage capacity.

The country's minimum storage rules were introduced in 2016 with the establishment of the Urban Gas Business Act (which was later amended, notably in 2021) and spells out two requirements for KOGAS-operated facilities. The first is mandatory inventory volumes, which calls for KOGAS to maintain emergency LNG stocks equivalent to at least nine days of average demand, up from seven days, following the 2021 policy update. The second requirement is to maintain preventive reserves, defined as LNG tank storage capacity equivalent to at least 30 days of average demand. Based on Korean gas demand of about 60 bcm in 2025, this corresponds to mandatory inventory volumes of approximately 1.5 bcm and preventive reserve capacity of around 5 bcm.

6.2 Strategic underground gas storage

Strategic underground gas storage refers to the regulatory ringfencing of UGS capacity or working gas volumes for use only in emergencies, rather than for commercial purposes. Strategic reserves should provide emergency capacity beyond commercially operated storage; they should not simply replace commercial inventories. This additionality can help address gaps in firm supply availability during periods of severe system stress, including for gas-fired power generation.

Strategic gas reserve volumes are generally held by a state entity or entrusted by state authorities to a gas market participant and typically represent only a portion of the available UGS capacity in a market. The cost of purchasing and maintaining strategic reserves is typically funded directly from state budgets or recovered from end users via network charges. The release of strategic storage volumes typically requires government authorisation and is triggered by predefined emergency market conditions.

As such, strategic gas reserves shift UGS capacity away from commercially driven operational signals (such as pricing) towards security of supply driven signals, trading a degree of supply flexibility to create an emergency buffer for extreme market conditions. Given the fundamentally different functions of commercial and strategic storage, it is important to maintain clear operational and regulatory distinctions between the two. Preserving differentiated signals for commercial and strategic storage can help avoid distorting market incentives while ensuring strategic reserves remain available for emergencies.

While much of the discussion around strategic underground gas storage focuses on the volume of gas that can be stored, responding to immediate supply shocks in the market rests on the ability to deliver gas as quickly as possible. Therefore, beyond working gas capacity, maximum withdrawal rates and the proximity of storage facilities to demand centres are also key considerations in the development of strategic underground gas reserves.

While some countries, particularly in Asia, may choose to develop new strategic storage facilities, others, especially in Europe, mostly rely on existing assets for strategic storage. Designating all or part of the capacity at existing but underutilised storage sites as strategic capacity can improve deliverability by maintaining higher storage fill levels, which support higher withdrawal rates. It can also improve the commercial viability of underground gas storage in markets such as the European Union, where narrow seasonal spreads often undermine storage revenues. However, some storage sites may be underutilised precisely because lower deliverability or less favourable locations limit their contribution to supply security. By contrast, the most suitable sites, particularly high-deliverability salt cavern facilities, are often already in strong demand for commercial use. Therefore, while supporting commercially challenged storage sites may be an additional benefit of strategic storage, security-of-supply considerations should remain the primary consideration in site selection to ensure that strategic reserves provide effective emergency buffer during actual emergencies.

Case study: Strategic gas reserves in EU member states

Strategic gas reserves played a role in the gas security of at least six EU member states even before the 2022-2023 energy crisis. The use of such reserves has expanded further since 2022, with four of those six member states amending their existing frameworks, largely in response to the 2022 EU Gas Storage Regulation. An additional four member states introduced new strategic reserves after 2022 (Table 3). In total, an estimated 12 bcm of gas was held as strategic reserves across the European Union in 2025, representing around 3.5% of annual gas consumption and 12% of working gas storage capacity (Table 4).

Table 6.2. Evolution of strategic gas reserve policies in selected EU member states

Country	Existing measure not amended	Existing measure amended since 2022	New measure introduced since 2022
Austria			x
Bulgaria	x		
Czechia			x
Estonia			x
Germany			x
Hungary		x	
Italy	x		
Latvia		x	
Poland		x	
Spain		x	

Source: IEA analysis based on data from European Union Agency for the Cooperation of Energy Regulators (2023), ACER publishes a consultancy study on the impact of EU and national gas storage regulations.

The financial mechanisms used to recover the costs of establishing and maintaining strategic gas reserves within the EU vary across countries. In some cases, costs are passed directly to final consumers, either through supplier prices (Spain) or specific emergency levies (Hungary). In others (Austria, Czechia, and Latvia), they are funded from state budgets. Cost recovery can also be embedded in regulated charges, such as transmission tariffs (Bulgaria), neutrality charges applied at system exit points (Germany),[16] or storage and transmission tariffs

[16] Germany's gas storage neutrality charge, which was introduced in 2022 to finance the cost of mandatory storage filling with a levy on network users at system exit points, was abolished on 1 January 2026 and replaced by direct financing from the federal budget.

(Bulgaria and Italy). Where a single entity such as a transmission system operator or state agency is responsible for stockholding, which is the case in most EU countries with strategic gas reserves, these mechanisms typically ensure full cost recovery. By contrast, in Spain, where obligations are placed on market participants, cost recovery depends on individual supplier pricing strategies and may be less certain. Penalties for non-compliance are applied in Germany, Hungary, and Spain.

Table 6.3. Strategic gas reserves in selected EU member states

Country	Strategic reserve	Description
Austria	1.9 bcm	In 2022, a government-funded strategic gas reserve was established under the management of Austrian Strategic Gas Storage Management GmbH, a subsidiary of the Austrian Gas Grid Management. The reserve is distributed across multiple storage sites with contracted withdrawal capacities, cannot be used for commercial purposes, and can be released by order of the energy minister with parliamentary consent; the framework is valid until 1 April 2027.
Bulgaria	0.1 bcm	Bulgartransgaz is required to maintain a strategic gas reserve of up to 70 mcm in the Chiren UGS facility to ensure security of supply upon order by the Minister of Energy; costs are recovered through transmission tariffs.
Czechia	0.2 bcm	In 2022, the Administration of State Material Reserves established a 2.4 TWh (approximately 0.2 bcm) state-owned strategic gas reserve. Gas can only be released from the facility with explicit government approval, and costs for procurement and maintenance are covered by the state budget.
Estonia	0.1 bcm	State-owned strategic gas stocks are managed by the Estonian Stockpiling Agency and stored in Latvia’s Inčukalns UGS facility. The reserves can be released by the government or the Minister of Economic Affairs and Infrastructure; costs are recovered through a stockpiling fee collected from gas consumers.
Germany	0.0 bcm	A market-based framework for strategic gas reserves was introduced in 2022, with Trading Hub Europe mandated to procure Strategic Storage-Based Options (SSBOs) from market participants. In exchange for a fee, providers must keep 20% of contracted volumes in storage for emergency call-off; release is authorised by the economy ministry in coordination with the regulator, BNetzA. Costs are recovered via a neutrality charge levied on network users; two auctions in 2022 secured 84 TWh of SSBOs, including 17 TWh (1.6 bcm) of call-off volumes, but these options have since expired with no subsequent auctions.
Hungary	1.9 bcm	The Hungarian Hydrocarbon Stockpiling Association maintains two types of strategic gas reserves: security stocks (around 1.2 bcm) and special stocks (around 0.7 bcm). Volumes are set annually and releases are authorised by the Minister of Energy; costs are covered by a stockpiling fee paid by gas consumers (excluding households).
Italy	4.6 bcm	The strategic storage operator (Stogit, a subsidiary of Snam) is required to maintain strategic gas reserves in underground storage. Stock levels are set annually by the Ministry of Environment and Energy Security, costs are recovered through regulated tariffs, and stocks can only be released in emergencies with ministerial approval.
Latvia	0.2 bcm	State-owned strategic gas security reserves (1.8 TWh) are held by Latvenergo in the Inčukalns UGS facility; stocks cannot be sold and can only be released by decision of the Cabinet of Ministers, which reassesses volumes every two years. Procurement and transit costs are covered by the state budget, while storage tariffs are recovered through transmission tariffs at the national exit point.
Poland	1.3 bcm	Gas importers must maintain mandatory emergency stocks equivalent to 30 days of average net imports. Stocks may be held domestically or abroad (with

Country	Strategic reserve	Description
		firm cross-border capacity) and must be deliverable to the Polish system within 50 days; release is authorised by the Minister of Energy and implemented by the transmission system operator.
Spain	1.7 bcm	Suppliers and large consumers must maintain security stocks equivalent to around 20 days of prior-year consumption (10 days of strategic reserves and 10 days of system operating stocks), with additional user-level operational stocks varying seasonally. The government authorises the release of strategic stocks, while the Ministry for the Ecological Transition and the Demographic Challenge oversees system operating stocks.

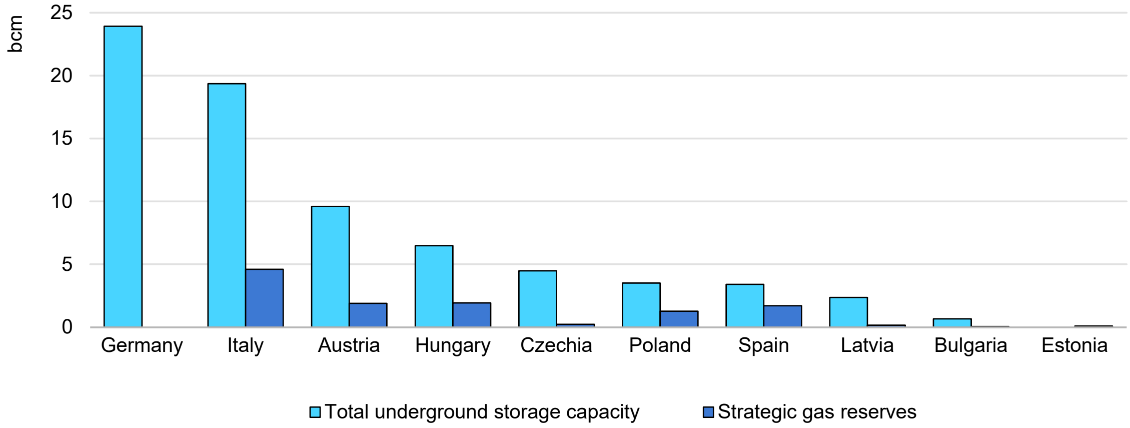
Note: Strategic reserve volume reflects current size or latest available data. Germany has a legal and framework in place to procure gas for strategic storage, but currently no gas volume is stored under the scheme.

As outlined above, several EU member states maintain strategic gas reserves while also complying with mandatory storage obligations under the EU's Gas Storage Regulation. But the two measures have potentially competing objectives, which could complicate gas storage priorities in certain countries. Strategic reserves create an emergency buffer by reducing the storage capacity available for commercial use. By contrast, mandatory EU storage obligations aim to maximise the potential for commercial withdrawals, and therefore the flexibility value of storage during the withdrawal season, even if this limits commercial flexibility during the injection season.

While these measures are not inherently incompatible, their objectives may compete when storage capacity is constrained and strategic reserve requirements are high. In 2025, for example, strategic reserves accounted for about 50% of UGS capacity in Spain, 37% in Poland, 30% in Hungary, 24% in Italy, and 20% in Austria (Figure 6.1). However, LNG storage (in Spain), the option to store gas abroad (as in the case of Poland), and a market-based approach in Germany (where stocks are procured only when needed) provide some additional flexibility for the use of domestic storage capacity.

Additional EU member states are exploring the creation of new strategic gas reserves. Germany, which has the legal framework in place but held no physical stocks in its strategic reserve as of 2026, is considering the establishment of a permanent publicly funded 24 TWh (2.2 bcm) emergency reserve, which would repurpose around 10% of the country's commercial UGS capacity for strategic use. The Netherlands also plans to establish a 5 TWh (0.5 bcm) strategic reserve at the Alkmaar UGS facility, by the winter of 2026/27 and it is exploring options to expand strategic storage beyond this initial target.

Figure 6.1 Underground storage capacity and strategic gas reserves in selected EU member states



Note: Underground storage capacity as of 31 December 2025. Size of strategic gas reserves based on latest available information. Estonia's strategic gas reserve is stored in Latvia.
Source: IEA analysis based on data from Gas Infrastructure Europe (2026), AGSI+ Database.

While strategic gas reserves have so far been implemented only at the member-state level, they could feasibly be combined and operated at the EU level, backed by member states on a proportional basis. In 2025, Ukraine's state-owned oil and gas company, Naftogaz, proposed using Ukraine's spare UGS capacity (estimated at more than 10 bcm) to establish EU-level strategic gas reserves. To date, no concrete progress has been made towards mutualising strategic storage at the supranational level. However, such a mechanism could offer the advantage of centralising the non-market function of underground gas storage, while allowing commercial storage to continue to respond to market signals.

Case study: India's plan to build strategic gas reserves

Strategic gas reserves are not commonly deployed outside of Europe. As a possible exception to this, India's Petroleum and Natural Gas Regulatory Board proposed developing strategic UGS in depleted fields in 2023, following the extreme price volatility during the 2022-2023 crisis and the resulting demand curtailments in key sectors. The unpredictable market dynamics that played out during the crisis helped strategic storage gain importance as a potential lever in reducing exposure to price and supply shocks.

Despite early interest, the proposal and a plan for a feasibility study intended to evaluate costs, potential locations, timeliness, and business models, appears to have been shelved in 2025, notably linked to cost considerations. Instead, India has prioritised the expansion of LNG storage at regasification terminals as a less capital-intensive and better distributed potential alternative, which is considered more suitable for India's market context.

6.3 Strategic cushion gas reserves

Cushion gas refers to the volume of natural gas that must remain permanently in a UGS facility, in addition to the commercial (or working) gas volume, to maintain sufficient reservoir pressure and ensure reliable deliverability. The required volume of cushion gas varies by storage type, typically accounting for around 30% of total capacity in salt caverns, about 50% in aquifers, and 50% to 60% in depleted gas fields.

Under normal operating conditions, cushion gas is not intended to be withdrawn, as doing so can impair storage performance, reduce withdrawal rates, and in some cases, compromise reservoir integrity. However, in the context of heightened gas supply security concerns following the 2022-2023 energy crisis, cushion gas has been discussed as a potential emergency backstop.

The concept of strategic cushion gas reserves refers to the designation of a portion of cushion gas in existing UGS facilities as a publicly backed reserve that could be withdrawn in clearly defined emergency situations.

The potential appeal of cushion gas lies in its immediate availability and, in most cases, its proximity (via existing UGS sites) to major demand centres. Designating existing cushion gas volumes as a strategic reserve can be a cost-effective alternative to building dedicated strategic (working) gas reserves, as it does not require additional infrastructure investment or natural gas procurement. Compared with mandatory storage obligations, the risk of market distortion is also more limited, as strategic cushion gas reserves have no impact on supply-demand dynamics under normal market conditions.

However, withdrawing cushion gas from operational UGS facilities during emergencies could pose significant technical, economic, and governance challenges, though feasible withdrawal amounts vary by facility and site-specific cushion gas requirements and would necessitate case-by-case assessment. Reducing reservoir pressure below design thresholds can lower deliverability rates and degrade storage performance precisely when flexibility is most needed. In some cases, excessive pressure declines may cause irreversible damage to storage facilities by increasing water ingress or compromising reservoir integrity. From an economic perspective, replenishing cushion gas and restoring normal storage operations can be costly and time-consuming, potentially requiring multiple injection seasons and gas procurement at elevated prices if adverse market conditions persist. Strategic cushion gas reserves would also require clearly defined legal and regulatory frameworks and compensation schemes. Storage operators are typically bound by contractual obligations to maintain minimum technical parameters, and without such safeguards, the designation of cushion gas as a strategic reserve could undermine the commercial viability of privately owned storage assets, potentially leading to storage closures.

Historically, storage operators and regulators have largely treated cushion gas as off-limits. Documented cases of cushion gas withdrawal from commercial UGS facilities are limited and have generally occurred only after the cessation of storage operations at ageing sites. Examples include the closure of the Rough storage facility in the United Kingdom (with 3.3 bcm of working gas capacity and 5.2 bcm of recoverable cushion gas at the time) and the Southwest Kinsale gas storage facility in Ireland (with 0.23 bcm of working gas and approximately 0.4 bcm of cushion gas), both of which ceased operations in 2017.

In 2022, the Rough facility reopened with a reduced working gas capacity of 1.5 bcm. By 2025, however, its operator again signalled the potential closure of the site in the absence of government support for modernisation, citing financial losses and poor operational performance. This experience illustrates both the technical feasibility and the economic and operational challenges associated with restoring UGS capacity once the cushion gas has been removed.

The potential use of cushion gas as a strategic reserve has recently been examined in greater detail in the Netherlands, providing one of the most developed examples of how such a mechanism could be implemented in practice, which we examine below.

Case Study: Assessing the Potential Role of Strategic Cushion Gas Reserves in the Netherlands

The Dutch case illustrates both the potential benefits and the practical challenges associated with strategic cushion gas reserves. A 2025 industry-commissioned study examined the potential use of cushion gas for strategic storage as an alternative to permanently closing Norg, the country's largest underground gas storage facility, and immediately extracting its recoverable cushion gas. The Norg facility has a working gas capacity of about 6 bcm of L-gas and contains a further 17 bcm of low-calorific cushion gas, of which around 15 bcm is estimated to be recoverable over time. The study estimated that approximately 10 bcm can be withdrawn within a single year without modifications to existing surface infrastructure, and around 6 bcm could be recovered within six months or less.

The study concluded that designating part of Norg's cushion gas as a strategic reserve could represent a cost-effective alternative to conventional strategic storage options, while preserving the operational value of a large and flexible storage site and avoiding the premature loss of a strategic asset. According to the study, implementation would require a pre-authorised emergency production plan that could be rapidly activated in emergency situations under the authority of the responsible minister.

At the same time, the study highlighted several important limitations and risks. It recognised that the strategic use of cushion gas would require public support, as private storage operators cannot be expected to bear the costs and risks of maintaining a strategic reserve on a voluntary basis. The analysis also noted that changes in reservoir pressure could increase induced seismicity risks around the Norg storage site, which would need to be carefully managed and monitored. (Norg is located near the Groningen gas field, where production was phased out between 2018 and 2023 due to increased induced seismicity).

In addition, the study underlined challenges related to gas quality, as Norg is designed for low-calorific L-gas storage, limiting its compatibility with the wider northwest European market, which is increasingly dominated by high-calorific H-gas. Nevertheless, the Norg facility continues to provide crucial flexibility for the shrinking L-gas market in parts of the Netherlands and, until the planned phase out of L-gas exports by 2030, also in parts of neighbouring France and Germany.

The concept of strategic cushion gas reserves could be applicable beyond the Netherlands, and the absence of induced seismicity risks and L-gas compatibility issues in most other parts of Europe could lower implementation barriers in other jurisdictions. However, given the risk of permanent damage to existing storage capacity that cushion gas withdrawals may cause, and the need for public support to cover the associated costs and risks, the feasibility of strategic cushion gas reserves is likely limited to underground storage sites that are facing permanent closure.

Based on recent announcements by storage operators, European UGS facilities representing at least 9 bcm of working gas capacity are at risk of closure. Of this total, two facilities in Germany, with a combined working gas capacity of 1.5 bcm, have already filed for decommissioning by 2027. The estimated cushion gas volume across the broader set of at-risk facilities in Europe is in the range of 20 bcm, representing a potentially significant strategic reserve largely concentrated in northwestern Europe.

Designating the cushion gas in underground storage facilities that are no longer commercially viable as strategic reserves – and providing appropriate compensation to their operators – could help extend the operational life of uneconomic assets that nonetheless retain supply security value. However, the feasibility and cost-effectiveness of this approach relative to other options would require detailed, case-by-case assessment. In particular, the deliverability of cushion gas from ageing reservoirs under reduced pressure requires further study, as storage facilities facing the highest risk of closure often exhibit operational challenges, including slow cycle times, reservoir quality issues, and other site-specific technical limitations.

6.4 Buffer LNG schemes

In the wake of the 2022-2023 global energy crisis, a handful of countries implemented various “buffer LNG schemes”. Among the most prominent examples are those adopted by Japan, Singapore, and Ireland.

These schemes aim to provide governments with a credible, publicly backed option to secure additional gas supply during periods of acute market stress, when commercial procurement alone is insufficient or prohibitively expensive. They are explicitly framed as contingency mechanisms, intended to ensure that LNG can be made available to priority end users during supply disruptions or episodes of extreme market tightness, thereby reducing the risk of physical shortages, involuntary demand curtailment, or wider economic disruption. All three schemes involve public financial backing, whether through state ownership of assets, public funding of capacity, or government-mandated arrangements with private operators, and are designed to operate alongside existing commercial LNG procurement and gas market structures, rather than replace them.

Despite these similarities, the schemes differ markedly in key elements of their design. Japan’s Strategic Buffer LNG (SBL) scheme, for example, relies primarily on contractual and commercial arrangements. Singapore’s Standby LNG Facility (SLF) is more tightly integrated into the country’s power-sector emergency framework, and physical LNG volumes are held on standby to safeguard electricity supply in a highly gas-dependent power system. Ireland’s Strategic Gas Emergency Reserve (SGER) relies on the development of a state-backed FSRU-based import and storage capacity, which can be refilled as needed, reflecting Ireland’s limited gas infrastructure and heavy reliance on a single import route.

Case study: Japan’s Strategic Buffer LNG scheme

Japan is the world’s second-largest LNG importer after China and is almost entirely dependent on LNG imports to meet its natural gas demand. Natural gas plays an important role in Japan’s energy system, accounting for roughly 20% of primary energy supply and about 30% of electricity generation. Domestic gas production, at less than 2 bcm, accounts for only around 2% of total gas supply, and Japan has no cross-border gas pipeline connections or large-scale underground gas storage facilities.[17] As a result, gas supply security in Japan is fundamentally tied to the availability of LNG cargoes (more than 80% of which are sourced under long-term contracts), as well as to around 300 bcm of regasification capacity (more than three times current demand). LNG tank storage capacity also

[17] The combined working gas capacity of Japan’s two small-scale underground storage sites is around 0.13 bcm, according to CEDIGAZ.

plays a significant role, offering the equivalent to about 12 bcm of natural gas, or around 13% of total demand, across Japan's 37 operational LNG import terminals.

Historically, Japan has attached great importance to gas and LNG supply security, reflecting its near-total import dependence and limited infrastructure flexibility. This has translated into a multi-layered strategy combining long-term LNG contracts, portfolio diversification, and equity participation in upstream gas and LNG liquefaction projects. Public institutions, including the Japan Bank for International Cooperation, JOGMEC, and Nippon Export and Investment Insurance, have provided financing and risk mitigation for overseas LNG investments. At the same time, Japanese utilities and trading houses have built globally diversified LNG portfolios to reduce exposure to individual suppliers and trade routes. This security-oriented approach was further reinforced following the Fukushima Daiichi nuclear accident in 2011, which led to a sharp increase in gas-fired power generation and LNG imports.

A renewed focus on LNG security emerged in the aftermath of a brief LNG supply crunch in early 2021, when a combination of unusually cold weather, LNG shipping bottlenecks, and constrained supply pushed utilities close to physical shortages. Those constraints forced some power generators to curtail output, exposing vulnerabilities in Japan's LNG procurement and inventory management practices. The episode highlighted the risks of relying solely on commercial optimisation for gas supply security and prompted a comprehensive review by the Ministry of Economy, Trade and Industry (METI), resulting in closer monitoring of LNG stocks, the introduction of new LNG procurement guidelines, and industry consultations to enhance cooperation during emergencies.

Japan weathered the 2022-2023 global energy crisis relatively well compared with other importing regions, thanks to a diversified LNG portfolio that includes a mix of oil-indexed, Henry Hub-linked, and hybrid LNG contracts, as well as limited reliance on spot market procurement and short-term volumes. As a result, Japan's average LNG import price remained just below USD 15 per MBtu in 2022 at the height of the crisis, compared with around USD 34 per MBtu for the Asian spot LNG benchmark (JKM) and approximately USD 40 per MBtu for the European benchmark (TTF). The crisis nevertheless heightened concerns about extreme spot LNG price volatility, spillover effects from Europe into Asia, and geopolitical risks surrounding Russian LNG supplies from Sakhalin LNG, which accounts for about 9% of Japan's LNG imports.

Against this backdrop, the Japanese government moved to further reinforce its LNG supply security toolkit, culminating in the introduction of the SBL scheme under the Economic Security Promotion Act in 2022, which designated LNG as a critical product requiring stable supply. METI launched the SBL ahead of the 2023/24 winter season, and it was implemented in late 2023.

The SBL framework is an innovative contractual reserve mechanism that provides emergency LNG supply flexibility at a lower cost than physical storage. Under the scheme, METI designates private LNG importing companies with strong procurement capabilities as certified supply providers, requiring them to secure additional LNG volumes beyond their normal commercial needs. Japanese energy company JERA was designated as the first, and, to date, only, SBL operator in November 2023. During the initial phase of the scheme (through January 2026), JERA was required to procure at least one additional LNG cargo per month during the winter season from December to February, with contractual provisions ensuring that LNG could be delivered to Japan within 18 days in the event of an emergency. From January 2026, as the scheme shifted to year-round operation, the minimum SBL volume of one cargo per month was extended throughout the year, increasing the annual volume to around 1.2 bcm/yr, compared with about 0.3 bcm/yr under the initial phase.

The SBL is designed as a contractual and financial buffer, rather than a permanent physical stockpile of LNG. Under normal conditions, buffer LNG cargoes can be traded or resold to domestic or overseas buyers, but they remain subject to government direction if supply risks materialise. Activation of the SBL is discretionary and anticipatory: METI may instruct the release or redirection of buffer LNG when it judges that supply-demand conditions pose a material risk to energy security, including during periods of tight winter balances or heightened geopolitical uncertainty. As of May 2026, the SBL has not been formally activated to address a domestic supply emergency.

Allocation decisions are coordinated between public authorities and private stakeholders. Any losses incurred from buffer LNG redirections or resales are compensated through a public fund managed by JOGMEC, while any profits earned from buffer LNG transactions are returned to the fund. This structure is intended to ensure that private operators are willing to maintain buffer volumes without bearing disproportionate commercial risk, effectively sharing tail-risk exposure more broadly while preserving market-based procurement and trading practices.

Japan’s SBL scheme represents a hybrid model that combines public risk-sharing with private-sector procurement and trading. While distinct from infrastructure-based reserves such as Ireland’s SGER or power-sector-focused mechanisms like Singapore’s SLF, the SBL illustrates how contractual buffers can complement physical capacity and long-term contracting in strengthening energy security during periods of extreme stress.

Unlike the other buffer LNG schemes discussed in this chapter, Japan’s SBL has the potential to be scaled up over time. One possible pathway would be to open the scheme to participation by regional partners in East and Southeast Asia, allowing them to access buffer LNG in exchange for contributing to the cost of the mechanism.

Case study: Singapore's Strategic LNG Facility

Singapore produces no natural gas domestically and is therefore entirely dependent on imports to meet its gas demand, which was around 12 bcm in 2024. Natural gas plays a central role in the country's energy mix, accounting for about one-third of primary energy supply, and gas remains the dominant fuel for electricity generation. Singapore imports gas through a combination of LNG shipments and pipeline gas from neighbouring Indonesia and Malaysia. Net LNG imports exceeded 8 bcm in 2024 and approached 9 bcm in 2025, more than doubling since 2018, while pipeline gas imports declined by approximately 30% over the same period.

The power generation sector dominates Singapore's gas demand, accounting for more than 85% of total gas use, with most of the remainder consumed by industry. Residential and commercial sector use accounts for a much smaller share of gas use. Within the power sector, gas-fired generation is overwhelmingly dominant, accounting for almost 95% of electricity output in 2024, underlining the strong linkage between gas supply security and electricity security in Singapore's energy system.

A cold spell in northeast Asia in January 2021 sent shockwaves across LNG-importing markets in Asia and triggered a brief but exceptionally sharp price spike. In response, the Asian spot LNG benchmark JKM rose temporarily above USD 30 per MBtu, the highest level on record at the time. Although Singapore was spared severe physical shortages, the episode underscored the vulnerabilities associated with global LNG market volatility, long supply chains, and reliance on a limited set of supply sources. Market conditions progressively tightened throughout the rest of the year, while Indonesia's announcement that pipeline gas supplies could end by 2023 (subsequently extended to 2028) added further uncertainty and exacerbated the price increases sparked by the cold spell. The episode ultimately prompted Singapore to seek backup options to enhance gas supply resilience, particularly for power generation companies that depend on an uninterrupted supply of gas. In response, Singapore's Energy Market Authority (EMA) proposed and implemented the SLF in 2021 as a preemptive energy security measure to ensure that gas for power generation remains available during supply disruptions or adverse market conditions. The SLF was framed not as a price-stabilisation tool, but as an instrument to enhance the reliability of gas and electricity supply, allowing power generators to access additional LNG supplies when needed and for the regulator to coordinate such access in an emergency.

In October 2021, the EMA appointed Singapore LNG Corporation (SLNG) as the manager of the SLF. In this role, SLNG was responsible for procuring, managing, and facilitating the drawdown and replenishment of LNG supplies made available to licensed power generation companies. SLNG's mandate also included coordination with generation companies and the gas transporter, PowerGas Limited, a subsidiary of Singapore Power, to ensure that gas can be sent out and delivered as instructed by the EMA in the event of a supply shortfall.

Based on publicly available information, there have been no confirmed instances to date in which power generation companies needed to use the SLF to address fuel shortages. To support the system, an FSRU and an LNG carrier were deployed as floating storage in Singapore in 2022, but this interim arrangement ended in early 2023.

In May 2025, Singapore's government established the state-owned Singapore GasCo Pte Ltd. (GasCo) to centralise the procurement of natural gas for the country's power generators and strengthen gas supply security and price stability. On 1 April 2026, GasCo assumed the role of SLF manager from SLNG and has since maintained physical buffer LNG stocks in Singapore's existing LNG storage tanks, complementing other energy stockpiles such as crude oil and diesel fuel. To increase storage and send-out capacity, SLNG has committed to developing a separate FSRU-based terminal, the second LNG import terminal in Singapore. The terminal located at Jurong Port has a nameplate capacity of 5 million tonnes per annum (around 7 bcm/yr) and is expected to start operations by 2030.

Although originally conceived as a temporary measure, the operational framework of the SLF is now expected to remain in place as a permanent feature of Singapore's energy market until further notice by the EMA, reflecting the country's ongoing commitment to maintaining buffer LNG capability.

Like Japan's and Ireland's buffer LNG schemes, Singapore's Standby LNG Facility is a publicly backed mechanism to safeguard LNG supply during emergencies. However, unlike Japan's SBL, which relies primarily on contractual arrangements, and Ireland's SGER, which is anchored in state-owned physical import infrastructure, Singapore's SLF is more tightly integrated into the power sector and leverages existing LNG terminal capacity and market-based procurement procedures to achieve its objectives.

Case study: Ireland's Strategic Gas Emergency Reserve

Ireland's energy system is heavily dependent on natural gas, which accounted for about one-third of the primary energy mix and around half of the country's electricity mix in 2024, with gas-fired generation supplying up to 80% of Ireland's electricity during periods of peak demand. Despite this significant role, Ireland's domestic gas production is relatively limited, at around 1 bcm in 2024, accounting for roughly 20% of the country's total gas consumption of about 5 bcm. Following the closure of the Kinsale Head gas field in 2020, the Corrib field off Ireland's northern coast remains the country's only source of domestic gas production. Output from this field has been in decline since 2017 due to depletion, with further declines expected in the coming years.

Consequently, around 80% of Ireland's natural gas supply is imported from the United Kingdom via two subsea interconnector pipelines that both originate at the same exit point in Moffat, Scotland. Ireland is among only a handful of EU member states without any underground gas storage infrastructure, following the closure of the Southwest Kinsale gas storage facility in 2017. This combination of high import dependence and the absence of storage means that Ireland does not meet the European Union's N-1 infrastructure standard, which requires member states to be able to satisfy total gas demand on a day of exceptionally high demand (defined as a 1-in-20-year event) even after the loss of the single largest piece of gas infrastructure.

Ireland has set out ambitious targets to decarbonise its energy system in line with EU objectives. The government's Climate Action Plan calls for a 51% reduction in greenhouse gas emissions by 2030 relative to 2018 levels, and climate neutrality by 2050. Those goals will require a diminishing role for fossil fuels, including natural gas, over the coming decades. According to a 2022 demand projection by Gas Networks Ireland, the country's gas transmission system operator, annual gas consumption could fall by nearly 25% between 2024 and 2030 in the "best estimate" demand scenario, driven by the expansion of renewable generation, improvements in energy efficiency, and the electrification of heat and transport.

Given the expectation of diminishing natural gas use over time, supply security solutions with long lead times (for example, UGS investments or onshore LNG import terminals) are not relevant to the Irish context and are therefore difficult to justify under the current policy framework. Over the last decade, Ireland has considered commercial FSRU initiatives, including the Shannon FSRU and Cork FSRU projects, to supplement pipeline imports and enhance supply flexibility without locking in infrastructure. However, none of these initiatives have materialised on a commercial basis.

The 2022-2023 energy crisis highlighted Ireland's structural vulnerability to gas supply security risks and prompted the government to launch a comprehensive review as part of the Energy Security in Ireland to 2030 plan, which was approved in November 2023. Among the plan's 28 action items, one called for the development of an SGER to protect against major supply disruptions and bring Ireland into compliance with the EU's N-1 infrastructure standard.

Following detailed studies by Gas Networks Ireland, the government determined that the best option for a strategic reserve would be a state-owned FSRU facility. The FSRU will be capable of receiving LNG shipments, storing them on board, and regasifying the LNG for injection into Ireland's gas network during an emergency. To avoid gas losses due to boil-off, the scheme envisages a minimum continuous send-out of gas from the FSRU into the Irish gas grid, with the facility refilled up to six times per year to replenish the injected volumes.

In March 2025, the government formally approved the development of the state-led SGER, to be owned and operated by Gas Networks Ireland on behalf of the government and run as a non-commercial, emergency-only facility. The SGER infrastructure will centre on an FSRU moored at a deep-water jetty, complemented by an onshore reception facility and a new connection to the national gas network. After evaluating multiple potential sites, Cahiracon along the Shannon Estuary was selected as the preferred location due to its favourable deep-water access, proximity to existing infrastructure, and technical suitability.

The FSRU will act as a standby source of natural gas, activated only in the event of a significant disruption to Ireland's conventional pipeline imports. In such a scenario, LNG would be supplied to the FSRU by ship, regasified, and delivered into the domestic network to help maintain gas supply for heating, electricity generation, and industrial uses while pipeline routes are restored. The policy documents emphasise the temporary nature of the SGER. Once Ireland's energy system has sufficiently diversified and the risk of a major gas supply disruption have diminished, the FSRU could be decommissioned or repurposed, with the onshore infrastructure adapted for other uses, including the handling of low-emissions gases.

As of mid-2026, legislative and regulatory frameworks are being updated to support the development of the project. Those frameworks include amendments to Gas Networks Ireland's statutory functions to enable it to manage the reserve, as well as provisions for cost recovery and regulatory oversight. At the time of writing, no FSRU vessel has been secured, and the timeline for the start of operations is uncertain, although reports indicate that inquiries for available FSRUs for Ireland's SGER were made at the end of 2025.

Ireland's SGER differs from other buffer LNG schemes, for example Japan's and Singapore's, in several respects. Most notably, Japan and Singapore already possess LNG import infrastructure and regasification capacity, whereas Ireland currently has no LNG import terminals. Unlike Japan's approach, which relies largely on contractual arrangements with designated private operators to procure and redirect LNG, Ireland's reserve is state-owned, state-operated, and tied to dedicated physical import and regasification infrastructure. Similarly, the SGER is not designed to safeguard a particular downstream sector (such as power generation in Singapore), but rather to provide system-wide gas supply continuity across the national economy in the event of a major supply disruption. But like the schemes in Japan and Singapore, Ireland's SGER is framed as an emergency-only mechanism and is backed by public funding, reflecting a shared emphasis on resilience to severe market shocks or supply curtailments.

Prospective cross-regional buffer LNG schemes

In the future, mixed UGS-LNG buffer schemes could be developed on a cross-regional basis, particularly between Europe and Asia, by leveraging UGS capacity in storage-rich markets to enhance security of supply for LNG-dependent importers. Under such arrangements, LNG-importing countries without sufficient domestic storage capacity (or countries that rely primarily on more costly LNG tank storage) could hold gas inventories in UGS facilities located in partner countries, particularly in Europe. Such arrangements could be carried out under predefined commercial and regulatory frameworks. In normal market conditions, these volumes could be commercially managed, while remaining contractually earmarked for emergency use.

In the event of a supply disruption, a cross-regional scheme could rely on pre-agreed swap-type mechanisms, whereby LNG suppliers or portfolio players with market coverage in the storage-hosting country deliver LNG cargoes to the importing country in exchange for the release of equivalent gas volumes from storage. Price differentials could be settled in advance, or according to predefined contractual formulas.

Such arrangements would allow LNG importers to build strategic buffers in the form of stored gas rather than LNG, thereby reducing storage costs while maintaining access to physical supply during crises. At the same time, host countries could benefit from higher storage utilisation rates and improved market liquidity. However, the commercial viability of such schemes would depend on public support from LNG-dependent importers to cover the cost of procuring and storing gas, as well as on robust contractual design and effective risk-sharing mechanisms among participants. A key constraint is the limited pool of counterparties capable of both maintaining a strong market presence in European gas markets and reliably delivering LNG cargoes to Asian buyers, which may restrict scalability and operational feasibility.

7. Options to increase international cooperation

Close international cooperation can complement national-level preparedness and is essential to strengthen gas security in a market environment that is increasingly interconnected but geopolitically fragile. The IEA oil emergency response framework provides the most advanced example of collective action in energy security, combining a coordinated asset base, well-defined governance arrangements and tested stock release mechanisms. While fundamental differences between oil and gas markets limit the direct applicability of this model, its underlying principles offer valuable lessons for the development of voluntary gas reserve mechanisms among like-minded importing and exporting countries.

This chapter outlines a range of options to enhance international cooperation on gas reserves and market flexibility. The recommendations cover measures to strengthen coordination and dialogue, increase transparency, enhance market flexibility, and explore new reserve mechanisms. Taken together, they provide an extensive set of options for governments to build strategic buffers, enhance resilience, and support more coordinated and effective responses to gas supply disruptions.

7.1 Lessons from the IEA oil emergency response framework

The oil emergency response mechanism under the IEA's founding treaty, the Agreement on an International Energy Programme, is the most formalised system for the collective management of global energy supply emergencies. Introduced in 1974 following the 1973 oil crisis, the framework was designed to mitigate major oil supply disruptions through a combination of mandatory stockholding obligations, coordinated response mechanisms, and well-established governance arrangements.

The IEA oil emergency response system requires member countries to hold oil stocks equivalent to at least 90 days of net imports. Many countries hold stocks specifically for emergency purposes, which can be held directly by governments, by agencies (acting either on behalf of governments or industry), or by obligated industry participants fulfilling minimum stockholding requirements set by their respective governments. Emergency oil stocks may be held domestically or abroad under bilateral agreements between governments, which guarantee access during emergencies. Emergency oil stocks can take the form of directly held inventories or so-called "ticketing" arrangements, under which the seller agrees to hold a specified volume of oil on behalf of the buyer in exchange for an agreed fee, and in some cases, the right to buy the stocks under specific circumstances.

The IEA framework allows countries to meet their stockholding obligations using either crude oil or refined petroleum products, depending on national circumstances. Countries with large refining sectors tend to hold a higher share of crude oil, which provides greater flexibility during crises. By contrast, countries with limited domestic refining capacity, or those relying heavily on imports of refined products, typically maintain a larger share of their reserves in the form of petroleum products.

In the event of a significant supply disruption, the IEA can coordinate a collective response with member states, focused on the release of oil stocks. The roles and processes underpinning a stockdraw are well defined and well established. In the case of an actual or potential disruption, the IEA Secretariat first assesses the potential market impact and the need for a coordinated response. The decision to initiate a collective action can be made in a matter of days, following an assessment of the scale of the disruption and prevailing market conditions, as well as consultations with member governments and industry experts (through the IEA's Industry Advisory Board).

Following this consultation, and in the absence of objections from member countries to the proposed joint action, the IEA executive director issues an activation notice accompanied by a press release. Member country shares of the collective action are calculated based on a proxy for their share of total IEA oil consumption, known as Base Period Final Consumption. Member countries are requested confirm the details of their intended contribution to a collective action within 24-48 hours after the activation notice.

Coordinated oil stock releases may be complemented by demand restraint, surge production, and/or fuel-switching measures. These emergency response procedures are regularly tested and evaluated through formal exercises and peer reviews.

The IEA emergency response system was designed to address sudden, short-term oil supply disruptions, but it is not intended as a tool for price intervention or long-term supply management.

Since its creation, the IEA has undertaken six collective actions: in 1991 in the lead-up to the Gulf War; in 2005 following hurricanes Katrina and Rita; in 2011 during the Libyan civil war; in 2022 on two separate occasions during the Russian invasion of Ukraine and the ensuing energy crisis, and in March 2026 during the conflict in the Middle East.

The oil supply emergency framework offers important lessons for gas security, even if its direct transferability to natural gas and LNG is fundamentally constrained by structural differences between oil and gas markets. Oil is a globally fungible commodity that is relatively easy and cost-effective to store in large volumes for extended periods. By contrast, gas storage is more complex, capital-intensive, and geographically constrained. Underground gas storage depends on suitable geological formations, while LNG storage requires specialised cryogenic infrastructure with significantly higher unit costs. As a result, replicating a universal stockholding obligation comparable to the IEA's 90-day oil requirement is neither technically nor economically feasible for most gas-importing countries.

Differences in market structure further limit direct transferability. Oil markets are highly liquid and globally integrated, with well-developed spot trading and relatively flexible logistics. Although the expansion of LNG trade has increased the interconnectivity of gas markets, natural gas remains more regionally segmented and infrastructure dependent. Supply-side flexibility is also more limited in gas systems. While oil markets can often draw on spare production capacity in some exporting countries, gas production and LNG liquefaction typically operate close to the available maximum capacity, leaving little scope for rapid supply increases. The fungibility of oil also differs fundamentally from that of natural gas. A barrel of crude oil or refined petroleum product released into the market, regardless of location, tends to have a broadly similar impact on global balances and prices. By contrast, the impact of additional gas supply is far more location-specific: releasing a given volume of gas in one region does not automatically alleviate tightness elsewhere, particularly where interconnection capacity or LNG import infrastructure is limited.

Despite these limitations, several core principles that underpin the oil emergency response framework are highly relevant for gas security.

- **Multilateral institutional framework and governance arrangements.** One of the key strengths of the oil system lies in its pre-established, rules-based coordination mechanisms. Clearly defined procedures help enhance predictability, reduce uncertainty and enable rapid collective action during crises. The institutional architecture developed under the IEA oil emergency response mechanism, including formal decision-making processes and structured engagement with industry, provides a useful model for strengthening coordination in gas markets, where comparable frameworks remain less developed.
- **Single, well-defined asset base for collective action.** In the case of oil, emergency stocks held under the 90-day stockholding requirement provide a broad and relatively uniform foundation for coordinated response measures. By contrast, gas markets currently lack an equivalent shared asset base for collective action. Potential alternatives, such as jointly managed strategic gas

storage, portfolios of gas or LNG stocks held abroad, or pooled LNG call-option arrangements, could, in principle, serve a similar function. However, these instruments are more complex to implement, depend on specific infrastructure conditions and availability, and are unlikely to reach the scale, uniformity, or accessibility of oil stocks.

- **Reliance on private actors for public policy implementation.** The oil emergency response system combines public policy frameworks with implementation by private industry, including stockholding, logistics, and distribution. This hybrid model is also relevant for gas, where most infrastructure, storage, and trading activities are owned and operated by private entities. Effective gas security frameworks therefore require close coordination between governments and market participants to ensure policy objectives are aligned with operational realities.
- **Interchangeability of multiple types of reserves.** The oil system allows countries to meet their stockholding obligations using either crude oil or refined petroleum products, as well as through a combination of physical barrels and paper tickets, depending on national circumstances and infrastructure constraints. Gas reserve mechanisms could draw lessons from this approach and explore how – and to what extent – different forms of reserves, such as gas held in underground storage and LNG stored in tanks, or physical volumes and call option-based "paper" instruments, can be integrated into a broader reserve base to support collective action.
- **Cross-border storage and ticketing arrangements.** Oil-style ticketing systems, under which one party holds stocks on behalf of another in exchange for a fee, could be adapted to gas in certain contexts. This may be particularly relevant for accessing underutilised physical storage assets, including underground storage capacity, for example, in Ukraine, or for LNG storage facilities with reloading capabilities, for example in Spain. Such arrangements could help optimise the use of existing infrastructure and provide additional flexibility without requiring domestic storage capacity.
- **Regular emergency reviews, exercises, and trainings.** Under the IEA oil emergency framework, regular reviews, exercises, and training sessions are conducted to test procedures, identify bottlenecks, and strengthen preparedness across member countries. Comparable practices remain less developed in gas markets, where crisis response mechanisms are often less formalised or limited to the regional level. Similar reviews, joint exercises and training programmes – potentially complemented by scenario analysis and the sharing of best practices – could also be adopted in voluntary gas reserve mechanisms.

7.2 Recommendations

Summary

The recommendations presented in the report focus on four areas where governments can advance international cooperation on gas reserves and market flexibility.

1. Cooperation and dialogue

- Deepen cooperation through existing platforms, including through the IEA.
- Establish other consultative forums and industry advisory bodies.
- Conduct regular emergency exercises.
- Undertake joint studies on reserve mechanisms.
- Facilitate the exchange of best practices.

2. Transparency

- Establish a framework for information sharing on reserve mechanisms and policies impacting gas security.
- Strengthen data transparency via standardised and timely reporting.
- Enhance LNG contract transparency within legal and confidentiality limits.

3. Deepening market flexibility

- Support the development of LNG reloading infrastructure and third-party access.
- Establish a working group on LNG swaps.
- Facilitate the relaxation of restrictive clauses in legacy LNG contracts.
- Encourage flexibility in new LNG contracts.

4. Developing voluntary gas reserve mechanisms

- Assess the feasibility of a joint strategic gas reserve in Ukraine.
- Enable cross-border stockholding arrangements.
- Study options for strategic floating storage using existing LNG vessels.
- Evaluate the use of cushion gas as strategic reserve.
- Explore the development of cross-regional buffer LNG schemes.
- Assess the feasibility of pooling LNG call options into a jointly managed security buffer.

The recommendations presented below focus on four areas where governments can most effectively advance international cooperation on gas reserves and market flexibility: coordination and dialogue, transparency, deepening market flexibility, and the development of voluntary gas reserve mechanisms. They are intended to strengthen system resilience in the short to medium term, rather than address longer-term questions of supply adequacy or investment across the gas value chain. These recommendations are not the end point of the discussion, but rather a starting point for further work. Several of the concepts outlined in this chapter would benefit from additional analysis and targeted follow-up studies, including on the feasibility and governance of joint strategic gas reserves, pooled LNG call options, cross-regional buffer schemes, cross-border stockholding arrangements, and mechanisms to facilitate LNG swaps. The IEA stands ready to provide such a platform for deeper international cooperation, knowledge sharing, and analysis on these and other emerging gas security issues.

Coordination and dialogue

Deepen cooperation through existing platforms, including the IEA's Natural Gas and Sustainable Gases Security Working Party (GWP).

Existing multilateral platforms such as the IEA's GWP provide a ready-made institutional foundation for strengthening coordination among gas-importing and exporting countries.[18] Expanding their role could help move beyond information exchange towards more structured coordination on reserve mechanisms, emergency response frameworks, and market developments. Deepened cooperation could focus on regular engagement at both technical and policy levels, enabling countries to align expectations on global gas market dynamics and share forward-looking assessments of supply security risks. Over time, such platforms could evolve into coordination hubs that facilitate collective responses among like-minded importers and exporters during supply disruptions on a voluntary basis.

Establish additional consultative forums, such as industry advisory bodies, to strengthen public-private dialogue on policies related to market flexibility and gas reserve mechanisms.

Given that much of the flexibility in gas and LNG markets is controlled by private companies, including producers, portfolio players, utilities, and traders, effective gas reserve mechanisms require close engagement with industry. Dedicated consultative forums and industry advisory boards can help bridge the gap between public policy objectives and commercial realities, ensuring that reserve

[18] The GWP was established in 2025 as a dedicated platform to support its members in addressing gas supply security challenges. It aims to strengthen the resilience of natural gas systems through enhanced market monitoring, improved data and information sharing, and closer coordination among member countries and other key stakeholders.

mechanisms and flexibility measures can be implemented and do not interfere with the functioning of liberalised energy markets. Such forums could also provide early feedback on regulatory proposals, identify unintended consequences, and support the development of novel commercial solutions, such as buffer LNG schemes or new types of contractual arrangements. Drawing on industry expertise is particularly important in areas where operational constraints are complex and significant, such as LNG shipping, trading, contracting, and storage operations.

Conduct regular emergency exercises to simulate gas supply disruptions and test existing and proposed reserve tools and policy mechanisms.

Under the IEA oil emergency response framework, emergency exercises and security reviews are conducted regularly to reinforce decision-making processes and strengthen coordination among member countries. Comparable exercises are less common in gas markets and, where they exist, are often limited to the national or regional level. Expanding the use of joint exercises in gas systems could therefore help strengthen emergency preparedness and inform the development of voluntary gas reserve mechanisms. Simulations could cover a range of disruption scenarios, including major LNG supply outages, infrastructure failures, geopolitical shocks, and extreme weather events. By involving public authorities and, where appropriate, private stakeholders, such exercises can help test operational readiness, clarify decision-making processes, and identify bottlenecks in activating reserve mechanisms. Drawing on practices from established oil emergency frameworks, regular exercises can also support the refinement of coordination procedures and contribute to more timely, predictable, and effective responses during actual emergencies.

Undertake joint studies to assess the cost of various reserve mechanisms, evaluate the feasibility of innovative technical and commercial concepts, and explore governance models for shared strategic gas stocks.

The diversity and complexity of potential reserve mechanisms – from strategic underground storage and cushion gas reserves to contractual instruments and buffer LNG schemes – require a strong analytical foundation. Joint studies can help quantify the costs, benefits, and trade-offs of different approaches across regions with varying infrastructure and market structures, taking into account the high capital intensity and long lead times associated with many physical storage options. Collaborative research can also explore emerging concepts, such as pooled LNG call options, cross-border storage arrangements, buffer LNG schemes, and floating LNG storage, which lack extensive real-world experience. It can also support the development of governance frameworks for shared reserves, partly drawing on experience from more established oil emergency management frameworks.

Facilitate the exchange of best practices among like-minded importers and exporters on emergency response frameworks, strategic gas reserves, LNG contracting, and operational practices.

Experience sharing is a low-cost, high-impact tool for strengthening gas reserve mechanisms and overall system resilience. Countries have adopted diverse approaches to managing their natural gas systems, including storage, LNG contracting, and emergency response plans. The systematic exchange of experiences can accelerate the adoption of effective policy tools by enabling countries to learn from each other's successes and challenges. For example, experience from Europe's mandatory storage obligations and strategic gas reserves, Japan's SBL scheme, and Singapore's Standby LNG Facility offers valuable lessons for other import-dependent economies. In addition to policy and regulatory design, operational practices, such as linepack management and LNG terminal operations, could also benefit from greater cross-border knowledge sharing through structured exchanges, including workshops and technical cooperation programmes.

Transparency

Establish a framework for regular information sharing with partner governments on current and planned gas reserve mechanisms and policy developments related to market flexibility.

Greater transparency and regular information sharing on existing and planned gas reserve mechanisms and policy measures related to market flexibility can reduce uncertainty, improve coordination, and help governments anticipate each other's actions, particularly during periods of market stress. Enhanced visibility over national strategies, storage policies and contingency measures, while ensuring that commercially sensitive information is appropriately protected, would reduce the risk of unintended market distortions and help identify opportunities for cooperation.

Strengthen data transparency through standardised and timely reporting of gas and LNG stocks, the operational status of LNG tanks, and reloading capabilities at LNG import terminals.

Reliable and timely data is essential for well-functioning gas reserve mechanisms and effective emergency response. However, the availability, quality, and timeliness of reporting – particularly on gas storage levels, LNG inventories, and infrastructure availability in importing countries – remain uneven across regions. Improved transparency and more standardised reporting frameworks, potentially coordinated through international organisations, could enhance comparability and support coordination during crises. Greater data availability among participating governments, while ensuring that confidentiality is appropriately safeguarded, would also provide timely insights into system tightness and available flexibility levers, enabling more effective responses to supply disruptions.

Enhance transparency of LNG contracts by regularly reporting aggregated, non-confidential information on key LNG contract terms relevant to market flexibility.

While LNG contracts are confidential and specific terms are commercially sensitive, publishing aggregated information on destination restrictions, profit-sharing clauses, seller consent requirements, volume flexibility, and cancellation rights can help policymakers assess system resilience and identify structural constraints without compromising commercial confidentiality. Existing efforts, such as monitoring by JOGMEC, demonstrate the value of such approaches. Improved transparency could also support more informed decision-making by market participants, reduce information asymmetries, and facilitate the adoption of more flexible contracting practices over time by highlighting trends and enabling the benchmarking of contract structures across markets.

Deepening market flexibility

Support the development of LNG reload infrastructure and third-party access to underutilised LNG import terminals, particularly in Asia, to improve overall market flexibility, facilitate cross-border stockholding, and improve the utilisation of existing LNG storage assets.

Expanding reloading capabilities and ensuring effective third-party access to underutilised LNG terminals, where needed, would allow stored LNG volumes to be redirected across regions, improving the system's ability to respond to supply disruptions. This would also enable LNG inventories to be held on behalf of other countries and mobilised when needed, similar to cross-border stockholding arrangements in oil markets. Given that only a limited share of global LNG storage capacity currently combines reloading capability with third-party access (especially in Asia), targeted investments and regulatory reforms could unlock significant additional flexibility. While LNG tanks are unlikely to serve as large-scale strategic reserves, improved reloading infrastructure and third-party access could enhance their role as complementary buffer assets within the global gas security architecture.

Establish a working group on LNG swaps to identify measures to streamline and facilitate swap transactions, including through the development of "matchmaking" platforms.

Physical LNG swaps can enhance market flexibility and enable faster reallocation of supply during disruptions, but their use remains constrained by operational, contractual, and administrative complexities. A dedicated working group comprising policymakers and industry experts could identify practical solutions to reduce these barriers, including streamlining documentation, aligning procedures, and improving coordination among market participants. Priorities could include the development of pre-established emergency frameworks with expedited procedures, simplified documentation, accelerated regulatory approvals and, where appropriate, temporary widening of quality tolerances during supply emergencies. In parallel, “matchmaking” platforms could facilitate the exchange of non-binding expressions of interest and enable faster identification of compatible counterparties. Such measures could lower transaction costs and support more effective use of swaps, including during supply disruptions.

Facilitate the removal or relaxation of restrictive clauses in legacy LNG contracts, including through public-private dialogue and consultation among importers and exporters.

Legacy LNG contracts may still contain provisions that can significantly limit flexibility, including destination restrictions, profit-sharing clauses, seller consent requirements, and rigid volume commitments. Where these continue to persist and no longer reflect the preferences of the contracting parties, they can be addressed directly by market participants through renegotiation via price review and reopener clauses or arbitration. Governments can support this process through enhanced market monitoring, competition policy enforcement, and structured dialogue with industry. While preserving contract sanctity and maintaining incentives for long-term investment remain essential, targeted and coordinated efforts could gradually reduce these rigidities and improve market flexibility, especially during periods of market stress.

Encourage the development of minimum flexibility standards in LNG contracts, potentially through coordinated buyer initiatives or platforms.

Establishing common expectations for LNG contract flexibility, particularly with respect to destination flexibility, profit-sharing, seller consent, and volume flexibility, can help shift market norms over time. While formal standardisation may be difficult, voluntary alignment among buyers, potentially through coordinated platforms, could create collective leverage to promote more flexible terms in new LNG contracts. Such measures could improve market efficiency and resilience, but implementation would face commercial and legal constraints and would need to comply with applicable competition law. They could also have unintended effects on market structure and competition, including by favouring larger portfolio players with greater access to diversified supply and shipping capacity over smaller suppliers, and would therefore require careful analysis and further study.

Options to create voluntary gas reserve mechanisms

Assess the feasibility of establishing a joint strategic gas reserve in Ukraine, including governance frameworks, financing, and risk mitigation mechanisms, subject to improved security conditions.

Ukraine's large and underutilised underground gas storage capacity offers a potential opportunity to develop a shared strategic gas reserve for Europe and possibly for a broader group of LNG-importing countries. With around 10-15 bcm of available capacity, such a mechanism could provide a sizeable and flexible reserve that can be called upon in emergency situations. However, its cost and feasibility remain uncertain and require careful assessment. Key challenges include the joint reserve's governance framework, including ownership of stocks, access rights, and release conditions; the allocation of financial responsibilities, including funding for gas procurement and risk-sharing arrangements; and the management of security risks related to infrastructure. In addition, the extent to which a Ukraine-based joint reserve could support markets beyond Central and Eastern Europe, especially more distant LNG-dependent regions in Asia, would depend on the availability of cross-border capacities, cost-effective transit tariffs, and well-functioning LNG trade and swaps. While the ongoing war in Ukraine limits the feasibility of such a mechanism in the near term, a jointly managed reserve in Ukraine could, in a post-conflict environment, become a key element of regional and potentially inter-regional gas security architecture if supported by robust institutional arrangements and public-sector backing.

Enable or expand cross-border stockholding arrangements, allowing countries to store gas and LNG inventories in third countries under bilateral agreements or ticketing mechanisms, while ensuring access in emergencies.

Cross-border stockholding can increase the efficiency and utilisation of existing storage infrastructure and provide additional flexibility for countries with limited domestic storage capacity. Similar arrangements are already widely used in oil markets, where countries can meet part of their strategic stockholding obligations under the IEA's oil emergency response mechanism by holding stocks abroad under bilateral government agreements or through so-called ticketing mechanisms. Comparable approaches also exist within the European Union under the EU Gas Storage Regulation. Building on such models and extending their application more broadly, particularly to countries without existing cross-border storage arrangements, would require tailored regulatory and commercial frameworks, given the more complex and infrastructure-dependent nature of gas storage. Key requirements include clearly defined and enforceable access rights during emergencies, sufficient LNG reloading infrastructure to enable the re-export of stored volumes, and robust contractual arrangements to ensure that stored gas or LNG can be mobilised and redirected efficiently, potentially through pre-arranged swap mechanisms. If these challenges can be overcome, and such arrangements can be demonstrated to be cost-effective, cross-border stockholding could meaningfully enhance supply security, particularly for LNG-dependent economies in Asia.

Develop strategic floating storage options by retaining ageing LNG carriers, including through public support, conversion to FSUs, or incentives to delay scrappage to preserve emergency storage capacity.

The ageing segment of the current LNG carrier fleet represents a potential source of flexible, short-term storage capacity in markets that already have access to LNG import infrastructure. Retaining selected vessels for strategic use (either as converted FSUs or as conventional LNG carriers deployed for floating storage) could provide a relatively low-cost buffering option in the short term, complementing existing reserve mechanisms without requiring large capital investments. Public support would likely be needed to incentivise shipowners to delay scrappage or convert vessels for storage purposes. Due to operational and technical constraints, including boil-off, maintenance requirements, and high operating costs, floating LNG storage is not suitable for long-term reserves. However, where the necessary import infrastructure is already in place, it can potentially provide short-term buffering capacity during acute market disruptions, when the rapid deployment of substitute volumes is critical.

Evaluate the use of cushion gas as a strategic reserve, including appropriate compensation mechanisms for storage operators and technical feasibility assessments.

Cushion gas in underground storage facilities represents a potentially significant but complex source of emergency supply. Its use as a strategic reserve could provide additional flexibility without requiring new infrastructure investment. However, tapping into cushion gas requires careful technical assessment to avoid damaging storage facilities, reducing deliverability and undermining long-term system flexibility. The most relevant use cases are likely to be sites at risk of permanent closure, where designating cushion gas as a strategic reserve could help preserve the supply security value of these assets that might otherwise be lost. Public support and compensation mechanisms would be essential to ensure that storage operators are not adversely affected and to maintain incentives for continued operation. At the same time, such measures would need to be carefully designed to avoid unintended consequences. The feasibility and cost-effectiveness of this approach relative to alternative reserve options would require a detailed, case-by-case assessment. While not a universal solution, cushion gas could provide a valuable emergency backstop in specific circumstances, particularly for underutilised sites facing closure.

Explore cross-regional buffer schemes, based on underground storage and LNG swap mechanisms, enabling LNG importers to store gas abroad and access LNG in emergencies through pre-arranged exchanges.

Cross-regional buffer schemes could combine the cost advantages of underground gas storage with the flexibility of LNG supply. By storing gas in regions with abundant storage capacity, particularly in Europe, and accessing it in the form of LNG through swap arrangements during emergencies, LNG-importing countries with limited or high-cost domestic storage could build strategic buffers at lower cost. Such arrangements could complement commercial portfolio flexibility by underpinning swap mechanisms with dedicated physical gas reserves that are available during supply emergencies. In the event of a disruption, such schemes would rely on pre-arranged swaps, whereby LNG suppliers or portfolio players deliver cargoes to the importing country in exchange for the release of equivalent gas volumes from storage in the host nation. This would allow importers to access physical supply without storing LNG domestically, while host countries could benefit from higher storage utilisation and improved market liquidity. Implementation would require robust coordination and well-defined frameworks, including clear governance structures, reliable counterparties with global market reach, and effective risk- and cost-sharing mechanisms, supported where necessary by public funding. While potentially promising and scalable, the feasibility and cost-effectiveness of such schemes would need to be carefully evaluated, and delivery times would need to remain sufficiently short to provide an effective response to supply disruptions in emergency situations.

Assess the feasibility of pooling LNG call options across participating buyers or countries, to create jointly managed flexibility buffers for emergency response, with clear allocation rules, activation triggers, and governance frameworks.

Pooling LNG call options could create a shared “insurance mechanism” against supply disruptions, allowing participating countries to secure access to additional LNG volumes without committing to firm offtake obligations. In contrast to physical reserves, such a mechanism would provide flexibility without requiring large upfront investments in storage infrastructure, making it particularly attractive for LNG-importing countries with limited domestic storage capacity. By aggregating demand for optionality, participating countries could also benefit from portfolio diversification across suppliers and delivery points, while sharing the cost of maintaining access to a potentially sizeable emergency supply buffer that could be drawn upon during localised supply disruptions. However, the cost, operational complexity and governance challenges of such pooled instruments remain underexplored and warrant further detailed analysis. Key questions include which countries or groups of countries would be most likely to participate and bear the associated costs, how transparent and credible activation triggers could be defined, how delivery volumes would be allocated among participants during emergencies, how the cost of option premiums and exercised cargoes would be shared, and how the risk of multiple participants seeking to exercise their options simultaneously during major supply disruptions could be managed. In addition, implementation would require coordination with LNG suppliers and portfolio players capable of offering such optionality at scale, as well as alignment with competition policy frameworks.

Abbreviations and acronyms

Bcm	Billion cubic metres
DES	Delivered ex ship
DFDE	Dual-fuel diesel electric
DQT	Downward quantity tolerance
EMA	Energy Market Authority (Singapore)
EU	European Union
EUR	Euro
FOB	Free-on-board
FSRU	Floating storage and regasification unit
FSU	Floating storage unit
GasCo	Singapore GasCo Pte Ltd.
GWP	Working Party on Natural Gas and Sustainable Gases Security (IEA)
IEA	International Energy Agency
JFTC	Japan Fair Trade Commission
JKM	Japan-Korea Marker (Asian LNG price benchmark)
JOGMEC	Japan Organization for Metals and Energy Security
KOGAS	Korea Gas Corporation
L-gas	Low-calorific gas
LNG	Liquefied natural gas
LNGC	LNG carrier
MBtu	Million British thermal units
Mcm	Million cubic metres
METI	Ministry of Economy, Trade and Industry (Japan)
PipeChina	China Oil and Gas Piping Network Corporation
SBL	Strategic Buffer LNG (Japan)
SGER	Strategic Gas Emergency Reserve (Ireland)
SLF	Standby LNG Facility (Singapore)
SLNG	Singapore LNG Corporation
SPA	Sales purchase agreement
SSBO	Strategic storage-based option
TFDE	Tri-fuel diesel electric
TPA	Third-party access
TSO	Transmission system operator

TTF	Title Transfer Facility (European gas price benchmark)
TOP	Take-or-pay
TWh	Terawatt-hour
UGS	Underground gas storage
UQT	Upward quantity tolerance
USD	United States dollar
VLCC:	Very large crude carrier

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