Natural Gas Supply Security in Korea

Insights from the 2022 Gas Supply Shock

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Abstract

This report was commissioned by the Korea Energy Economics Institute (KEEI) and carried out jointly by the International Energy Agency (IEA) and the KEEI. The objective of the study was to provide high-level policy recommendations on natural gas security of supply in Korea, particularly within the context of the global gas supply shock that emerged in 2022. The report covers an analysis of the natural gas supply shock in question, a detailed review of the Korean natural gas market and recommendations applicable to the Korean market.

Acknowledgements, contributors and credits

The report was jointly prepared by the International Energy Agency (IEA) and the Korea Energy Economics Institute (KEEI), with the objective of providing high-level policy recommendations on natural gas security of supply in Korea.

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Reducing Europe's reliance on Russian natural gas and the impact on the global liquefied natural gas market

2022 gas supply shock

The Russian invasion of Ukraine on 24 February 2022, the resulting war and the cut in Russian pipeline natural gas supply to Europe together represent the single greatest disruptor of global energy security in recent history. These elements intervened in a period already expected to be characterised by progressive liquefied natural gas (LNG) market tightening, driven by post-Covid-19 demand recovery in both Europe and Asia, and by limited liquefaction capacity additions in the first half of the 2020s. The resulting supply shock to natural gas markets brought about an energy crisis that has been felt on a global scale, well beyond the borders of Europe.

The end of gas interdependence between Europe and Russia

The onset of the war in Ukraine raised immediate concerns in Europe about overreliance on the Russian Federation (hereafter, "Russia") as a source of natural gas supply. Accordingly, European Union (EU) policy initiatives set out the objective of reducing reliance on Russian gas at an accelerated timeline. In its Versailles Declaration of March 2022, the European Union made a commitment to phase out Russian fossil fuel imports "as soon as possible". This declaration was reinforced by the publication in May 2022 of the European Commission's REPowerEU package, detailing measures and investments required to reduce fossil fuel dependence on Russia to zero by 2027.

Following these announcements, a number of EU member states quickly reduced or ceased their imports of Russian gas, while others announced their intention not to renew long-term supply contracts with Gazprom, the Russian majority state-owned energy company, that were set to lapse in 2022. Other member states announced their aim to phase out imports of Russian gas in the coming years, in certain cases before the 2027 target in the REPowerEU package.

Simultaneously, Gazprom abruptly cut supplies to several EU countries as early as April 2022 following buyers' refusal to adhere to a rouble payment requirement that had been introduced unilaterally by Russia, thus effectively pre-empting the phase-out of Russian gas in those countries. In September 2022, unexplained explosions on the Nord Stream pipelines rendered three of the four Nord Stream strings inoperative, thus further diminishing the possibilities for physical Russian gas pipeline supplies to Europe.

While the unprecedented Russian gas supply disruptions led to sudden and at times extreme price increases in both gas and electricity in Europe and prompted demand reductions across the continent, Europe navigated the crisis without supply interruptions, thanks to new LNG supplies, policy initiatives and a well-integrated energy market.

Russian gas deliveries to Europe

Prior to the war in Ukraine, Russia was by far Europe's largest gas supply source, meeting just over 50% of the region's yearly gas imports (pipeline and LNG imports) in recent years after constant growth over the past decade. Over this period, the convergence of two key factors led to the sustained predominance of Russian gas in the European supply mix. Broadly stable EU demand and a fall in domestic production by two-thirds since 2010 – linked to ageing gas fields in the United Kingdom, the phasing out of Groningen production in the Netherlands and the plateauing of Norwegian output – increased Europe's import dependency, paving the way for growing Russian imports to fill the gap.

The reversal in the trend of the growing weight of Russian gas in Europe began prior to the start of the war in Ukraine, as Russian gas deliveries to Europe started declining ahead of the 2021/22 heating season. Over Q4 2021, Russian pipeline exports to Europe fell by close to 25% year on year, reflecting lower transit flows to both the European Union and Türkiye. Gazprom embarked on a strategy of reducing its exposure to short-term sales to the European Union despite spare supply capacity being available, with no day-ahead auctions carried out on the company's electronic sales platform over this period. Lower direct sales to European hubs and Gazprom's failure to fill its gas storage sites in Europe further contributed to an environment of "artificial scarcity" in the European market.

Russia's gas supply reductions to Europe accelerated further in 2022 following the decision to impose a rouble payment system on European buyers on existing contracts. EU member states largely contested the move by Russia, leading to unilateral cuts in supply to several EU countries and curtailed deliveries to Gazprom subsidiaries in Europe after they were placed under Russian sanctions.

Russian punitive measures also targeted specific pipeline export routes, effectively reducing the number of viable natural gas infrastructure links between Russia and Europe. Following a range of Russian sanctions imposed on European companies in May 2022, Gazprom announced that it would cease using the Yamal-Europe pipeline, a key historical export route through Poland. From mid-

June 2022, Gazprom gradually reduced gas deliveries via Nord Stream to just 20% of the pipeline's capacity and had completely stopped gas flowing via this route by the beginning of September, leaving only three pipeline systems operational by then (the Ukrainian transit route, Blue Stream and TurkStream). The subsequent acts of sabotage on the Nord Stream and Nord Stream 2 pipelines at the end of September acted as an extra squeeze on Europe, further decoupling the European and Russian natural gas markets.

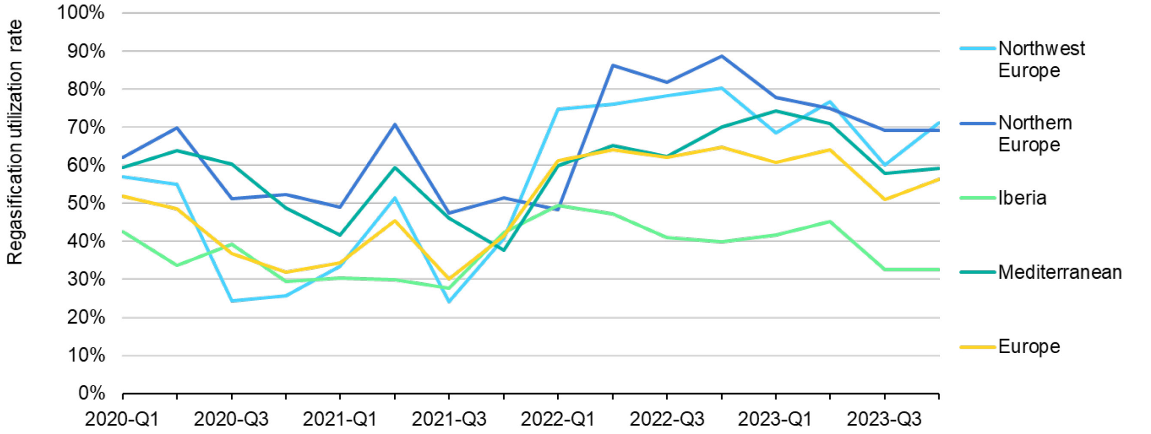
Russian piped gas exports to OECD Europe fell by an estimated 50% (83 bcm) year on year in 2022 to their lowest level since the mid-1980s, with deliveries to Türkiye declining by 18% year on year and supply to the European Union falling by more than half. As a result, Russian deliveries to several European offtakers fell below their minimum contractual commitments throughout the year, adding to structural uncertainty in the market and driving acute price pressure throughout 2022.

In contrast to the drastic fall in Russian pipeline deliveries to Europe, Europe's increased appetite for LNG led to an increase in imports of Russian LNG. As pipeline imports of Russian gas dropped, total European LNG imports grew by approximately 60% year on year to reach nearly 170 bcm in 2022, an increase which was balanced by a steep decline in LNG deliveries to other markets, particularly in Asia. As a result, LNG effectively became a baseload supply in Europe, meeting over one-third of the region's gas demand over the 2022/23 winter period. In this context, Europe attracted a growing amount of Atlantic Basin LNG cargoes in 2022, importing nearly 90% of US LNG exports (up from less than 45% in 2021). European imports of Russian LNG also grew by over 30% from 2021 levels.

Other supplies to Europe

The exceptional increase in European LNG imports to replace Russian pipeline volumes also highlighted existing limits on the availability of incremental pipeline imports from longstanding alternative gas suppliers to Europe. Spare capacity at existing LNG regasification plants allowed for a swift increase in LNG cargo arrivals in Europe throughout 2022, while quick implementation of debottlenecking works at some of those facilities and the rapid installation of floating storage and regasification units (FSRUs) added further import capacity in time for the 2022/23 heating season. However, spare capacity in alternative pipeline import routes was far lower, leaving less room for incremental flows in response to falling Russian deliveries.

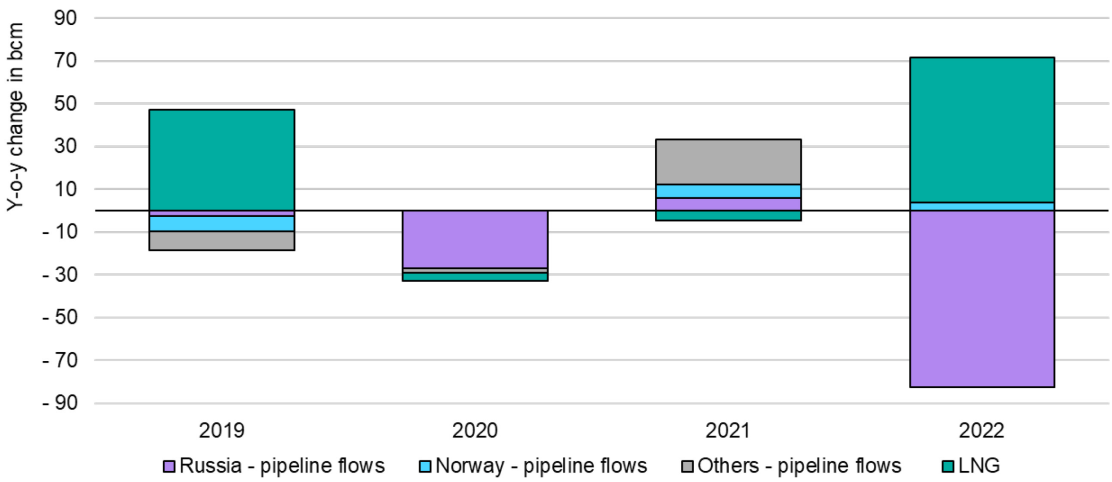
Average quarterly regasification utilisation rates, 2020-2023



Note: Northwest Europe includes Belgium, France and the Netherlands. Northern Europe includes Germany, Lithuania and Poland. Iberia includes Portugal and Spain. Mediterranean includes Croatia, Greece and Italy.
Source: IEA analysis based on GIE (2023), ALSI.

Pipeline flows from Norway rose by 3% (or 4 bcm) in 2022, with deliveries increasingly directed towards the European Union (up by 9%) at the expense of the United Kingdom (down by 14%). Gas supply from Azerbaijan surged by 40% (or 3 bcm) year on year as the Trans Adriatic Pipeline operated at its full nameplate capacity of 10 bcm. Overall flows from North Africa fell by 10% (4 bcm) as a result of lower Libyan flows, fluctuating Algerian production and the closure of the Maghreb-Europe pipeline, one of the two pipeline entry points for Algerian gas. In total, growth in non-Russian pipeline gas supply to Europe was marginal compared to the 66-bcm increase in LNG imports.

Year-on-year change in European natural gas imports and deliveries from Norway, 2019-2022



Source: IEA analysis based on ICIS (2023), ICIS LNG Edge, and ENTSOG (2023), Transparency Platform.

Price impact: TTF and JKM

As Russian gas deliveries to Europe tumbled and global gas market tensions worsened through 2022, natural gas price movements highlighted the various stages of tightening market fundamentals, reaching successive record highs in both Europe and Asia.

In late 2021, a number of factors drove growing market pressure in Europe, including strong gas demand recovery after the Covid-19-induced lockdowns, plummeting domestic gas production and increased competition for LNG due in part to a strong recovery in Asian demand. Adding to these bullish fundamentals, the reduction in Russian gas deliveries to Europe in Q4 2021 resulted in a tight gas market, driving both prices and volatility to then-record levels. Month-ahead prices at the Dutch TTF hub reached USD 60/MMBtu in December 2021, nearly eight times the January-June 2021 average.

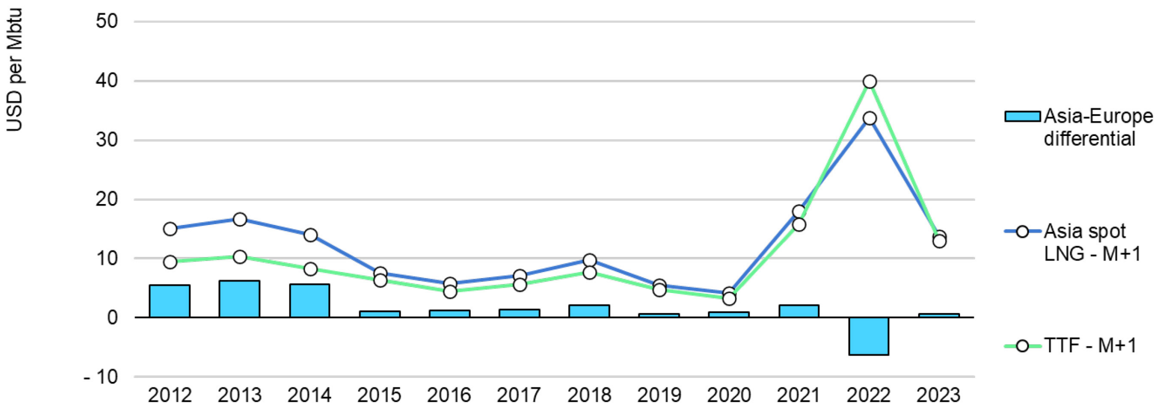
Asian spot LNG price swings grew similarly over 2021, highlighting the continued strong correlation between European and Asian gas price benchmarks. As European gas prices skyrocketed, Asian spot LNG prices were also dragged up, reaching above USD 45/MMBtu in late 2021, nearly five times the first-half 2021 average. This high degree of correlation between European and Asian prices was driven by growing volumes of destination-flexible and spot LNG globally, as well as the broader evolution in marketing strategies towards greater contractual optionality, allowing for the more efficient redirection of LNG flows in response to demand pressures across different demand basins.

Throughout 2022, global market tightness further intensified, pushing global gas and LNG prices to their highest-ever levels and uncovering new price dynamics both within the European market and between Europe and Asia. The constitution of Europe's gas market, from both an infrastructure and regulatory standpoint, has long ensured ideal conditions for the exchange of natural gas. Multiple pipeline and LNG entry points, harmonised third-party access rules on gas infrastructure, extensive interconnections between EU member states with harmonised auction rules and multiple liquid and well-traded hubs have generally ensured a high degree of correlation between Europe's multiple pricing points, with TTF as the leading hub. Under this structure and these conditions, market participants have been able to react efficiently to price signals stemming from temporary market imbalances, minimising price spreads across the continent.

However, the cut in Russian gas deliveries to Europe induced a significant reconfiguration of the dominant gas flows across the continent, undermining some of the key factors that had ensured a strong intra-European price correlation. While imports of Russian gas had previously led to a predominantly east-to-west pattern of gas flows, the rapid influx of LNG to replace the missing Russian volumes switched the direction of flows as incremental LNG imports accessed the market largely through Northwest Europe, a region with substantial regasification capacity.

Through 2022, gas flow patterns across the continent increasingly took on a west-to-east direction, straining the intra-European interconnection capacity that had long been dimensioned to absorb significant Russian pipeline volumes. As a result of these interconnection constraints, bottlenecks arose, and unprecedently high spreads appeared between European hubs that had traditionally tended to converge.

Month-ahead gas prices in Asia and Europe and the Asia-Europe price differential, 2012-2023



Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

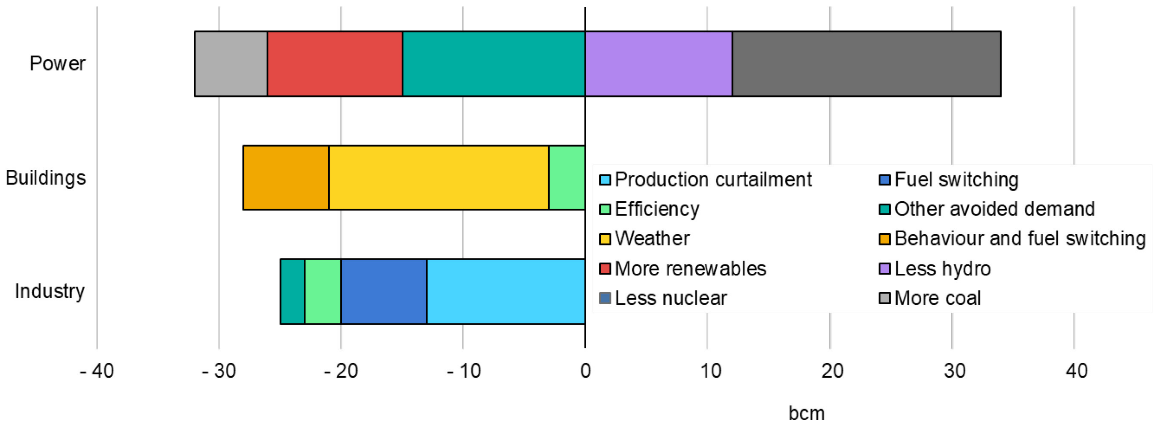
New price dynamics also emerged between Europe and Asia amidst the market tightening of 2022. While European and Asian prices remained highly correlated through the gas crisis, the longstanding Asia-Europe price spread was inversed. Traditionally, Asia had commanded an LNG price premium over Europe, reflecting the need to attract LNG volumes not only from the Pacific Basin but also from the Atlantic Basin. Periods of stronger European demand would reduce this premium (generally inversing it only over short periods of time), sending a sufficient market signal to attract extra LNG cargoes.

This changed in 2022 with Europe's exceptionally strong pull on the LNG market, instilling a persistent European premium over Asian prices, reaching as high as 60% and leading to a record redirection of LNG cargoes from Asia to Europe. This phenomenon eased in 2023, with Asian LNG prices recovering a steadier premium to European hub prices by the second quarter, leading to a progressive redirection of LNG flows from Europe to Asia.

Demand impact

In the wake of the Russian supply shock to Europe and the surge in gas prices, European natural gas demand contracted by a record amount. In OECD Europe, demand in 2022 fell by 13%, or over 70 bcm, the steepest y-o-y volumetric drop in history. Shifts in the energy mix, fluctuations in economic activity, weather effects, policy interventions and behavioural changes all contributed to this dramatic shift in natural gas consumption, with varying degrees of intensity across different sectors and different periods of the year.

Estimated drivers of change in natural gas demand in the European Union, 2022 versus 2021



Source: IEA (2023), Europe's Energy Crisis: What Factors Drove the Record Fall in Natural Gas Demand in 2022?

Distribution network-related demand registered the largest absolute reduction, falling by 34 bcm (15%) and accounting for nearly half of the total demand reduction compared to 2021 levels. Unseasonably mild temperatures in October and the first half of November delayed the start of the European heating season by close to a month, weighing on space heating requirements.

The high-price environment also incentivised a degree of fuel switching, energy efficiency measures and conservation efforts in the residential and commercial sectors. Government campaigns raised awareness about gas savings, and evidence suggests that consumers adjusted household heating temperatures to reduce their consumption. The continued implementation of energy efficiency measures, such as improving insulation, replacing boiler systems and installing heat pumps, also contributed to reducing demand. These structural reductions in gas use during seasonal peaks will carry over into future years. Given the predominance of space heating-related gas savings, over 40% of the total reduction in annual demand was concentrated in Q4 2022.

In industry, gas demand fell by close to 20%, or 30 bcm, with high gas prices driving fuel switching and leading to production curtailments across multiple industrial segments. Gas- and energy-intensive industries were the first to respond to price shocks in Europe, with plants in certain sectors reducing their output as production costs became too high to compete with imported final goods. In other cases, high gas prices led to an increase in imports of intermediate gas-intensive goods. This explains why industrial production in some gas-intensive sectors – such as fertilisers, steel and aluminium – on average decreased by less than gas demand in these sectors. Fuel switching – particularly towards oil products and alternative gases – also contributed to this phenomenon of a greater reduction in industrial gas demand than industrial production.

The power sector contributed the least to the reduction in European gas demand, falling by just 4%, or 6 bcm, driven by various opposing power market fundamentals. Ongoing policy support for renewables drove strong capacity additions, with a record high of nearly 50 GW of wind and solar capacity installed in the European Union in 2022. These additions avoided the need for around 11 bcm of natural gas in the power sector, the single largest structural driver of reduced natural gas consumption in the European Union.

The combination of high gas prices and lower electricity demand also contributed to reduced power sector gas burn. High prices drove gas-to-coal switching as coal-fired plants became increasingly economical to run. With gas plants at the margin of the power mix, reductions in electricity demand had a direct impact on gas consumption for power generation. Despite these factors inducing a fall in power sector gas demand, countering dynamics also came into play. Exceptional outages in the French nuclear plant fleet and low water reservoir levels led to a sharp decline in nuclear power and hydropower output to decade-low levels, softening the overall decrease in gas consumption in the power sector.

Policy and infrastructure implications

The Russian invasion of Ukraine and the global energy crisis it triggered once again reminded the world of the importance of ensuring energy security, highlighting the need to reduce vulnerabilities linked to fossil fuel import dependency and accelerate clean energy transitions. In Europe, this led to a swift reaction in policy and infrastructure developments as the European Union confirmed its dual objective of diversifying its gas supply away from Russia and fast-tracking its decarbonisation agenda.

Policy developments

REPowerEU

The REPowerEU plan, announced just days after the start of the war in Ukraine and subsequently published in May 2022, synthesised the European Union's policy objectives. The plan reinforced the existing ambitions set out in the European Union's Fit for 55 package, but it also called for both a "speed-up and scale-up" in key measures targeting energy savings, supply diversification and renewable development. This included strengthening binding targets in the existing Energy Efficiency Directive, accelerating the rollout of key heating and electricity production technologies, and boosting targets for renewable hydrogen and biomethane production.

The REPowerEU plan also highlighted the importance of investment in European energy infrastructure needs in response to the development of new energy flows and supply chains. Taken together, these proposed actions aimed to significantly change the European energy system and phase out fossil fuel imports from Russia on an accelerated time horizon, paving the way for a number of explicit EU policy measures to support those objectives.

Demand reduction

At the end of July 2022, the European Union adopted a regulation on co-ordinated demand reduction measures for gas demand, setting a target of 15% voluntary demand reduction compared to the five-year average between 1 August 2022 and 31 March 2023. In the instance of the substantial risk of a severe gas supply shortage or insufficient cuts in gas demand, a "Union alert" could be declared by the European Council upon the European Commission's proposal. The declaration of such a Union alert would render the gas demand reduction target mandatory.

EU member states successfully reduced their gas demand on a voluntary basis over the period, achieving a reduction of 19% in total EU demand compared to the 5-year average. As a result of its initial success, the 15% demand reduction regulation was extended in March 2023 to cover the April 2023-March 2024 period, again letting member states choose the measures by which to reach the target.

Gas storage

Although part of a medium-term plan to cease Russian gas imports, EU policy action equally responded to immediate-term gas security of supply imperatives. One such measure was the EU storage regulation adopted in June 2022. The regulation, in line with the analysis and recommendations published by the IEA in

A 10-Point Plan to Reduce the European Union's Reliance on Russian Natural Gas in March 2022, set out minimum fill levels for EU gas storage ahead of winter. With an adequate buffer of gas in storage facilities, the European Union could more easily respond to further supply-side constraints and potential seasonal demand spikes through the winter.

Under the regulation, EU member states' gas storage would have to be filled to at least 80% of capacity by 1 November 2022, rising to a 90% target by the start of subsequent winter seasons. The regulation also included intermediate storage level targets aimed at achieving an optimal storage cycle through the year and allowing for the early detection of potential shortfalls in injection trajectories. Several member states adopted even more stringent storage regulations, setting higher fill levels for the November target.

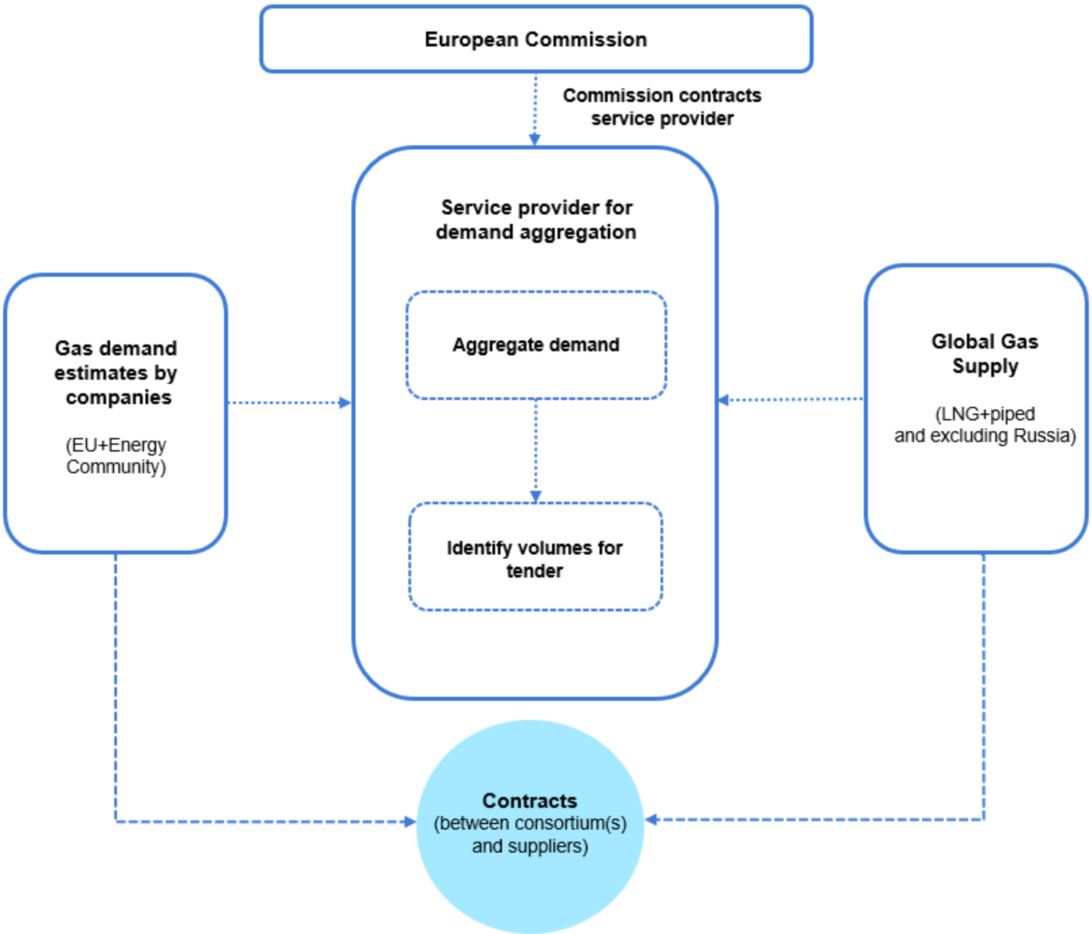
Ahead of the 2022/23 winter, storage fill in the European Union surpassed the 80% target, reaching 88% by late September and climbing as high as 96% by mid-November. In 2023, storage injections again outpaced the set target, surpassing the 90% target in the month of August.

While the storage fill targets were successful in terms of ensuring sufficient gas in storage, they may well have had unintentional price effects. In some instances, the entities entrusted with the task of filling the stores had a strong volume incentive but no price incentive. This may not only have led to an increased storage filling bill but may also have contributed to higher overall European gas price levels.

Joint gas procurement

Among the European Union's headline policy initiatives resulting from the gas crisis was an effort to enhance solidarity through the better co-ordination of gas and LNG purchases at the European level. In December 2022, the European Council adopted a regulation setting up the Joint Purchasing Mechanism, intended to create a framework and platform for the European Union to aggregate demand and purchase gas jointly.

Simplified representation of the EU Joint Purchasing Mechanism for gas



Source: IEA analysis based on European Commission (2022), EU Energy Platform.

The platform provides a mechanism to aggregate demand volumes submitted by EU companies and match them against volumes proposed by non-Russian gas suppliers through tendering rounds, acting as a marketplace to connect demand-side and supply-side market actors. Following the matching of demand and supply, market participants can voluntarily conclude supply contracts. While the conclusion of contracts is voluntary and not compulsory, there is a requirement for member states to ensure the participation of companies in the demand aggregation step by a volume equivalent to 15% of their gas storage requirements, as set out by the EU gas storage regulation. At the EU level, this meant a minimum required participation of approximately 13.5 bcm, or 3% of EU gas consumption, in 2021.

The first three aggregation tenders launched in 2023 gathered a total bid call of nearly 45 bcm and a total supply bid of over 20 bcm, leading to nearly 35 bcm of aggregated demand being matched to supply in the process. Information about the volumes of gas contracted following the matching process and the contract prices have not been communicated, but the European Commission has reported that 25 suppliers participated in each of the first two tenders and 39 companies submitted demand bids in the third round.

However, four industry associations, the International Association of Oil & Gas Producers, the European Federation of Energy Traders, Europex and the International Gas Union, have been critical of the joint purchasing mechanism, expressing their preference for using existing commercial channels and energy exchanges and stressing that, in their view, the proper functioning of the EU internal energy market is at the core of solving the supply crisis.

As highlighted by the IEA report, How to Avoid Gas Shortages in the European Union in 2023, the joint purchasing of natural gas could increase the bargaining power of EU companies, enable more sophisticated risk-sharing arrangements in a highly volatile price environment and potentially facilitate the sharing of best practices related to bringing low-emission gas to market. Despite the European gas market being already well developed in connecting demand-side and supply-side market actors, joint gas procurement could potentially add value in helping certain buyers contract new sources of gas supply (notably LNG), particularly in Central and Eastern European markets, which historically relied heavily on imports of Russian gas. These markets are often relatively small, face logistical issues in sourcing LNG (being landlocked) and have limited experience in LNG sourcing and trading.

Infrastructure developments

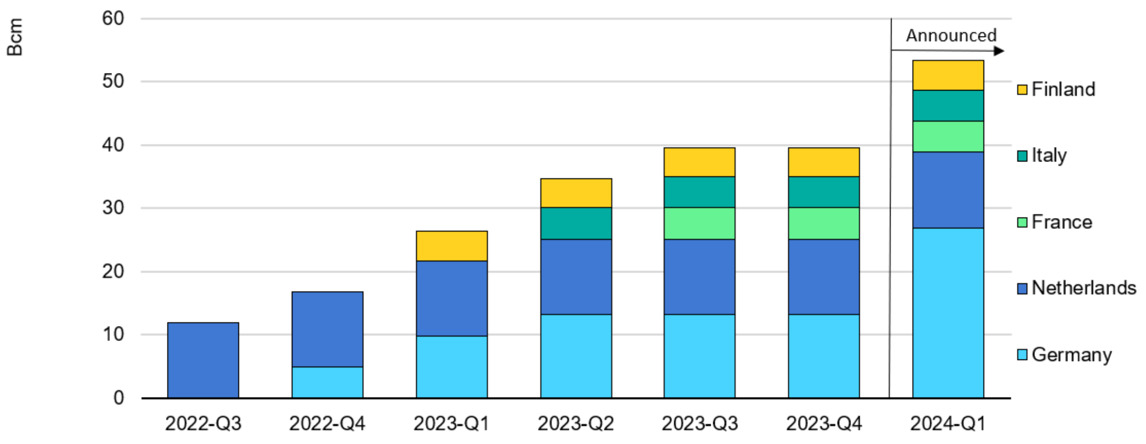
In tandem with the policy developments in response to the gas supply crisis, the European Union saw equally important and rapid advances in infrastructure development aimed at facilitating the shift away from Russian gas and upholding defining facets of the EU market.

Regasification terminals and floating storage and regasification units

LNG proved central in offsetting the dramatic decline in Russian gas flows to Europe through 2022. Spare regasification capacity at existing LNG terminals allowed the European Union to import 70%, or 35 bcm, more LNG in the first 8 months of 2022 than over the same period in 2021. However, with utilisation rates near nameplate capacity in Northwest Europe ahead of the 2022/23 winter, existing infrastructure was potentially unable to deliver further incremental imports of LNG.[1]

[1] Despite high regasification utilisation rates across much of Europe, limited pipeline interconnection between Spain and the rest of the continent has limited the use of this country's LNG import infrastructure, leading to significant spare regasification capacity.

Cumulative regasification capacity additions in Europe by quarter



Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Planned debottlenecking and capacity expansion programmes at existing plants and the leasing of FSRUs allowed the European Union to expand its regasification capacity by 15% (or 25 bcm/year) during the 2022/23 heating season. In addition to the expansion of the onshore Gate terminal (4 bcm/year) in the Netherlands, FSRU projects included the startup of the Eemshaven LNG terminal (8 bcm/year) in the Netherlands, three FSRUs in Germany (with a combined capacity of about 13 bcm/year), and the joint Estonia-Finland FSRU (approximately 5 bcm/year).

Further regasification capacity was installed or expected to come online through 2023 and the 2023/24 heating season, including an FSRU in France and further import facilities in Germany, with yet further plans to transition certain FSRUs into more permanent land-based capacity later in the decade. However, while the European Union's expanding regasification capacity provides additional possibility to import LNG, it does not necessarily guarantee an increase in LNG supply. Several European Union-based companies secured additional LNG supply via tenders and long-term LNG contracts since the start of the gas crisis, but the majority of further incremental LNG supply in the short term is expected to be sourced from the spot market.

Beyond the new LNG import capacity that has been installed or is currently under construction, many further regasification projects have been proposed in Europe with varying construction timelines. However, exactly how much of this proposed capacity will be built remains unclear as Europe balances short-term security of supply requirements, uncertainty in medium-term LNG demand and the challenge of building infrastructure in line with its climate and energy objectives.

A key element in aligning these three factors is the fact that the majority of these new European regasification projects – whether recently installed, under construction or announced – are FSRUs. These FSRUs are generally leased for a defined period of time (often for 5 years) to respond to an immediate and short-term import need without necessarily committing EU markets to long-term infrastructure lock-in.

The European debate around natural gas infrastructure development has incorporated the idea of "future-proofing" new assets to reduce the risk of investing in stranded assets or locking in future fossil fuel consumption. Under this approach, new and more permanent LNG-importing terminals would need to allow for conversion into renewable energy carriers, such as hydrogen and hydrogen derivatives. However, the planning of "hydrogen-ready" infrastructure is still in the relatively early stages, with a degree of uncertainty remaining around the technical, financial and market aspects.

Interconnectors

The longstanding EU goal of creating a single energy market was built on a robust network of infrastructure links between member states. In gas markets, interconnectors have ensured the flow of gas from import entry points (LNG and pipeline supply) towards demand centres. Furthermore, these pipeline links have brought flexibility to the European market, with bidirectional interconnection capacity allowing flows to respond to both spontaneous and seasonal variability in supply and demand dynamics. This infrastructure network has effectively acted as the backbone for the free flow of gas within the European market.

With imported gas flow patterns evolving strongly as a result of reduced deliveries of Russian gas, reinforcing the security of gas supply in the European Union was also a matter of improving and adapting interconnectivity between member states. While most of these interconnectors were developed many years before Russia's invasion of Ukraine for more generic purposes, these pipeline projects help ease potential bottlenecks and facilitate the dispatch of gas volumes to where they are most needed within the European Union. As import supply routes have evolved, so too has interconnection infrastructure.

The Baltic Pipe, inaugurated in September 2022, was among the key infrastructure developments in Europe, providing an alternative supply route into the Baltic region, which had previously been highly reliant on imports of Russian gas. As part of the broader Baltic Energy Market Interconnection Plan (which precedes the Russian invasion of Ukraine by more than a decade), the pipeline connects Norway to Poland with 10 bcm of transmission capacity, with a further 3-bcm link between Poland and Denmark. As such, the Baltic Pipe provides an extra supply route for Europe's now-largest pipeline supplier to orient volumes in response to evolving market dynamics on the continent.

The bidirectional Gas Interconnector Poland-Lithuania (GIPL), commissioned in May 2022, is another key piece of infrastructure aimed at strengthening interconnectivity in the Baltic region, adding 2 bcm of transmission capacity towards Lithuania and 1.9 bcm of interruptible capacity towards Poland. Together, GIPL, Baltic Pipe, and the interconnection expansion between Latvia and Lithuania mark an additional step towards the full integration of the Baltic market zone into the EU internal energy market, enhancing the flexibility of and accessibility to the existing gas supply infrastructure in the zone, notably LNG regasification terminals in Poland and Lithuania, and underground storage in Latvia.

In August 2022, Gas Interconnector Poland-Slovakia was inaugurated. With a capacity of 4.7 bcm towards Slovakia and 5.7 bcm towards Poland, the interconnector establishes a physical link between the two countries and advances the implementation of the North-South Gas Corridor, which aims to better connect Central and Eastern European countries. In October 2022, both Gas Interconnector Greece-Bulgaria (3 bcm towards Bulgaria) and the expansion of transmission capacity between Romania and Hungary were inaugurated, facilitating access to pipeline gas imports from Azerbaijan and regasified LNG via Greece's LNG terminals as supply alternatives to lost Russian flows.

Another key pipeline infrastructure development came in direct response to the disruption in Russian gas. In October 2022, France's transmission system operator announced the first physical delivery of natural gas from France to Germany. The only existing interconnection point between France and Germany was originally designed to operate in the Germany-France direction as part of the network of infrastructure delivering gas from east to west. With a number of technical adjustments co-ordinated between the transmission system operators of both countries, a reverse flow capacity of up to 3.3 bcm/year became available from France to Germany.

Underground gas storage and liquefied natural gas storage

The global energy crisis triggered by Russia's invasion of Ukraine put the spotlight on natural gas storage and its regulation. Natural gas storage plays a key role in meeting seasonal demand swings and ensuring gas supply adequacy in markets with cold and temperate climates, notably in Europe. For instance, storage withdrawals met over 40% of EU gas demand during the coldest winter days in early December 2022 and late January 2023. In addition, the short-term deliverability provided by fast-cycling storage sites (such as salt and rock caverns) is crucial in meeting the fluctuating needs of the power sector through all periods of the year, especially in markets where coal-fired power generation is being phased out and reliance on gas-fired power plants is increasing. In terms of absolute storage volume, the European Union's total storage capacity of around 100 bcm is equivalent to approximately one-quarter of its annual gas demand in recent years.

While storage sites are not the only providers of gas supply flexibility, practical experience shows that they are typically the most reactive in instances of supply and demand shocks. Bringing additional volumes of LNG to the market usually takes at least several days; piped imports can be ramped up more quickly, but there is usually a limit in volumetric terms. In contrast, storage sites are typically located close to demand centres and, hence, are readily available to meet additional demand or make up for lost supplies. Storage can therefore provide a significant security buffer for gas and the wider energy system.

Europe's underground gas storage (UGS) capacity is set to increase in the short term, largely driven by Türkiye. By the end of 2022, the Silviri storage site was expanded from 3.2 bcm to 4.6 bcm, and the Tuz Gölü (salt cavern) storage facility is set to increase its working capacity from 1.2 bcm to 5.4 bcm.

Storage capacity expansions are also expected in the European Union. In Poland, the capacity of UGS Strachocina was increased from 0.36 bcm to 0.46 bcm from the start of the 2023/24 winter season. In addition, UGS Wierzchowice is set to be expanded from 1.3 bcm to 2.1 bcm by 2025. In Bulgaria, the working capacity of the Chiren storage site was set to almost double from the current 0.55 bcm to 1 bcm in 2024. In Romania, the Bilciurești storage site will be enhanced, increasing its storage capacity from 1.31 bcm to 1.42 bcm and its daily withdrawal capacity from 14 mcm/d up to 20 mcm/d by 2027. In the United Kingdom, the Rough gas storage facility was reopened ahead of the 2022/23 heating season with a capacity of 0.85 bcm, although this represented just 25% of its pre-closure capacity in 2017. The working capacity of Rough was set to increase by 0.2-0.25 bcm ahead of the 2023/24 winter season. Additionally, new FSRUs across Europe, the reopening of the El Musel LNG terminal in Spain, and the expansion of the Gate terminal in the Netherlands are set to add slightly more than 1 bcm of LNG storage capacity over the 2023-26 period.

While the European Union's policy response to the fall in Russian gas deliveries to Europe aimed to maximise the utilisation of existing storage facilities, the loss of Russian supply flexibility has raised questions about the dimensioning of European underground gas storage infrastructure. Increased storage capacity could allow for more countercyclical buying, easing seasonal pressure in the global gas market. Improved withdrawal capacities could equally help ease the loss of daily flexibility as regasification infrastructure already operates at high utilisation rates and alternative pipeline supply routes have relatively limited room to ramp up deliveries.

Medium-term considerations and liquefied natural gas contracting

Structural changes

The European gas market has traditionally provided a significant amount of flexibility to the global gas market, intervening in both the demand and supply sides. The power sector was a key driver of this flexibility on the demand side. Significant coal- and gas-fired capacity across Europe facilitated fuel switching in power generation, providing a key source of price-responsive demand. In tightening gas market conditions, higher gas prices would drive a shift towards coal-based power plants, reducing gas burn in the sector. Conversely, easing gas prices would tilt generation economics in favour of gas plants, leading to greater gas consumption in the sector.

On the supply side, the continent's flexibility came from the predominant share of Russian pipeline gas supply in the European gas mix. Contractual terms and extensive infrastructure allowed for both seasonal and annual supply flexibility. As such, Russian gas deliveries responded to domestic weather-driven heating demand patterns, rising in winter periods and decreasing in summer periods. Moreover, pipeline imports of Russian gas proved reactive to global fundamentals, evolving in relation to the attractiveness of LNG imports from year to year.

Together, these dual elements of demand- and supply-side flexibility lent Europe the role of market of last resort for LNG. With ample and varied supply sources, Europe could forego a share of its LNG imports in periods of tight global market conditions but could also absorb surplus volumes in periods of oversupply. Effectively, Europe acted as the balancing market for global LNG trade.

However, the steep reduction in Russian gas deliveries observed since late 2021 jeopardised this balancing role. The loss of Russian pipeline volumes reduced Europe's supply margin and implied the loss of supply-side flexibility across the continent as the utilisation of alternative pipeline and LNG infrastructure increased to replace lost Russian volumes.

As a result, LNG has progressively gained market share in the European supply mix, replacing Russian pipeline volumes as the baseload supply to Europe. Over the first half of 2023, LNG accounted for almost 40% of European gas consumption, a share similar to Russia's before its invasion of Ukraine. Meanwhile, Russian piped gas exports to OECD Europe fell by an estimated 65% year on year in H1 2023 alone, bringing the share of the region's gas demand met by Russian piped gas to below 10% over this period.

Furthermore, these drastic supply-side changes intervened at a time of longer-term and progressive demand-side evolutions that also acted as a limiting factor on flexibility. Europe has made progress towards decarbonising its electricity mix by steadily phasing out coal-fired plants and increasing its share of renewable electricity generation, notably from non-dispatchable sources. Together, the retirement of coal-fired plants and growing additions of solar PV and wind capacity suggest a progressive reduction in price-responsive gas demand in Europe, limiting a key source of historical demand-side flexibility.

Under these new market conditions, gas market flexibility has been transferred from Europe towards other markets. Despite a significant reduction in European gas demand as a result of the gas crisis, the continent's strong pull on LNG volumes resulted in an equivalent reduction of LNG imports in other markets, particularly in Asia. Markets with higher price elasticity of demand became the new source of demand-side flexibility in response to the gas crisis, acting as the new markets of last resort for LNG.

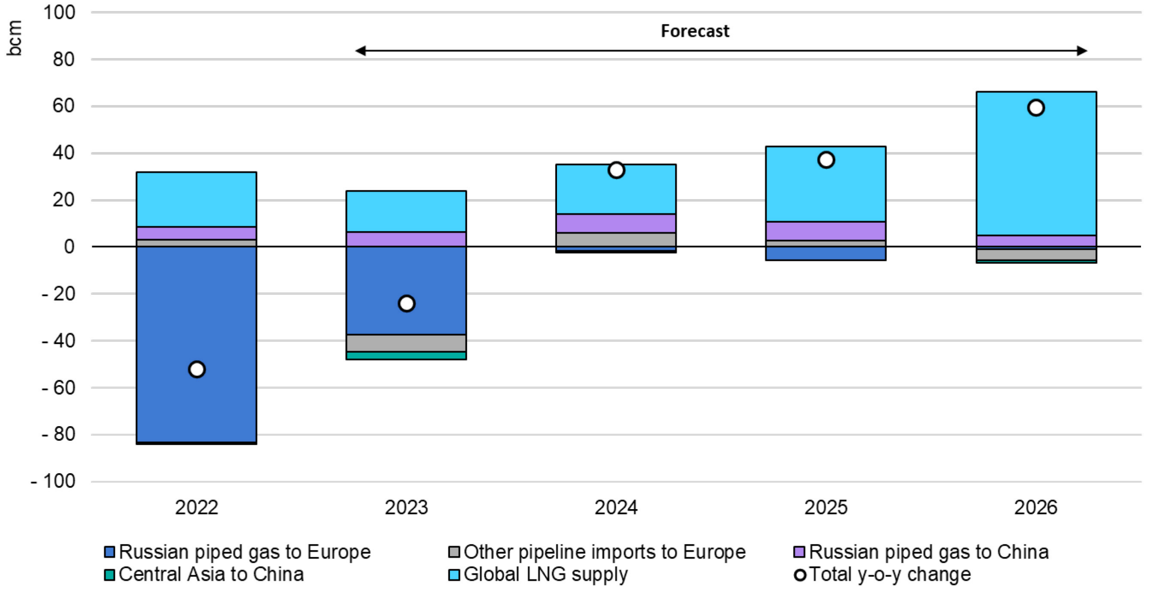
Medium-term liquefied natural gas market outlook

Global LNG trade is forecast to grow by nearly 25% (or just over 130 bcm) by 2026 compared with 2022 levels, with over 70% of incremental supply expected to arrive on the market in 2025 and 2026. Although project delays and varying ramp-up schedules could alter the forecast, this strong growth in LNG supply is expected to ease market tensions in the second half of the decade, moderating gas supply security risks.

North America and Qatar are set to drive the expansion of LNG exports in the medium term, together accounting for over 80% of incremental supply through 2026. While no growth is expected from Australia over this period, the country will remain the third-largest LNG exporter, far ahead of the next largest export markets. Incremental LNG demand over this period will be concentrated in the Asia Pacific region, with growth markets – led by the People's Republic of China (hereafter, "China") – far outweighing the slowdown in mature markets in the region.

However, uncertainty remains surrounding LNG demand growth in emerging Asian gas markets as affordability and market stability continue to be key factors in the take-up of natural gas in certain sectors and countries. An increasingly globalised LNG market – driven by growing inter-regional trade – will lead to greater interdependence across regions. As experienced in the crisis that unfolded in 2022, events that induce price volatility and supply uncertainty in one region can impact price fluctuations and supply-demand dynamics in geographically distant markets. An increasingly globalised gas and LNG market will reinforce the need for careful planning of security of supply at the national level and for enhanced co-ordination between producers and consumers at the international level.

Year-on-year change in key piped natural gas and global LNG supply, 2022-2026



Source: IEA analysis based on ENTSOG (2023), Transparency platform, and ICIS (2023), LNG Edge.

Liquefied natural gas contracting

The LNG market has gained in depth and liquidity in recent years.[2] Total contract volumes expanded by 60% between 2016 and 2022, progressing to a situation where both buyers and sellers have a variety of options to choose from. The share of destination-free contracts has increased from 30% in 2016 to over 46% in 2022, providing flexibility in trading.

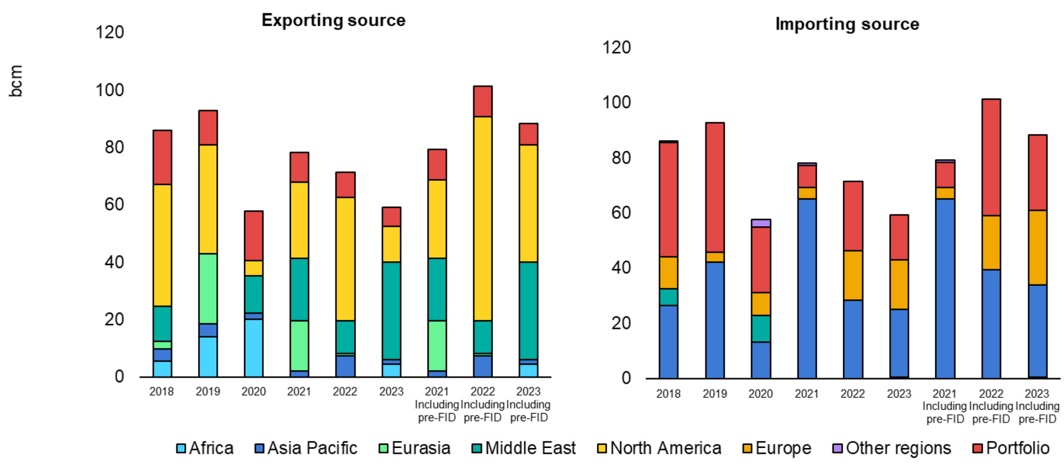
Main sources of liquefied natural gas supply

For post-final investment decision (FID) projects, 71 bcm/yr of new contracts were concluded in 2022, a 10% decrease in contract volume compared to 2021. However, when pre-FID contracts are taken into account, the total contract volume in 2022 increases to just over 100 bcm/yr, a 28% increase compared to 2021. Europe's share of contracted volumes as a buyer increased from 5% in 2021 to 25% in 2022.

[2] This analysis is based on the contractual positions of exporters and importers and their actual contract volumes using the IEA's internal LNG contract database. Unless otherwise stated, only firm supply contracts are taken into account. These include LNG sale and purchase agreements, equity entitlements and tolling agreements linked to an LNG supply project that is either operational, under construction or has reached a final investment decision.

On the export side, North America continued to dominate LNG contracts, accounting for 60% of contracted volumes in 2022 (or 43 bcm/yr). The next largest export area was the Middle East, accounting for 16% (or 11 bcm/yr). When pre-FID contracts are taken into account, North America's share increases further, accounting for 70% of the 2022 contract volume (or 70 bcm/yr). This means that there are a number of plans under consideration for FID in this area. On the import side, portfolio players drove contract volumes in 2022, accounting for around 35% (or 25 bcm/yr). Asia continued to dominate contract volumes in 2022, accounting for 40% (or 28 bcm/yr) of new contracts. European buyers increased their LNG contract volumes in 2022 due to the impact of Russia's invasion of Ukraine. European LNG contract volumes increased from 4 bcm/yr in 2021 to 18 bcm/yr in 2022, the highest level in the past 5 years.

Contract volumes concluded by region and exporting or importing source, 2018-2023



Notes: Contracted volumes used for the analysis are associated with confirmed export projects that have taken FID. The label 2023 indicates the volumes signed by the end of December 2023. "Portfolio" volumes are contracted by a market player who may source a product from one or multiple regions to fulfil contractual obligations.
Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Portfolio players' share of the total contract volume (including pre-FID contracts) rose from 12% in 2021 to over 40% in 2022. This indicates that portfolio players are playing an important role in bridging the gap between certain buyers who are reluctant to sign long-term contracts and sellers who have to secure long-term contracts so that new projects can be approved.

The total contract volume signed in 2023 (including pre-FID contracts) was around 90 bcm, 10% above the 3-year average from 2020 to 2022. New contracts with post-FID projects accounted for about 70% of the total volume contracted in 2023.

On the export side, the Middle East accounted for around 60% of contracted volumes and North America for about 20% of new contracts in 2023. When including pre-FID contracts, North America's share rises to over 45%. On the import side, Asian buyers continued to dominate, accounting for around 40% of the contracted volume, with China alone signing 20% of the contracted volume. Europe accounted for 30% of contracts signed in 2023,[3] the highest level since 2016.

Portfolio players made up a significant share of contracting activity in 2023, accounting for 27% of volumes signed, or 31% when including pre-FID contracts.

Contract types

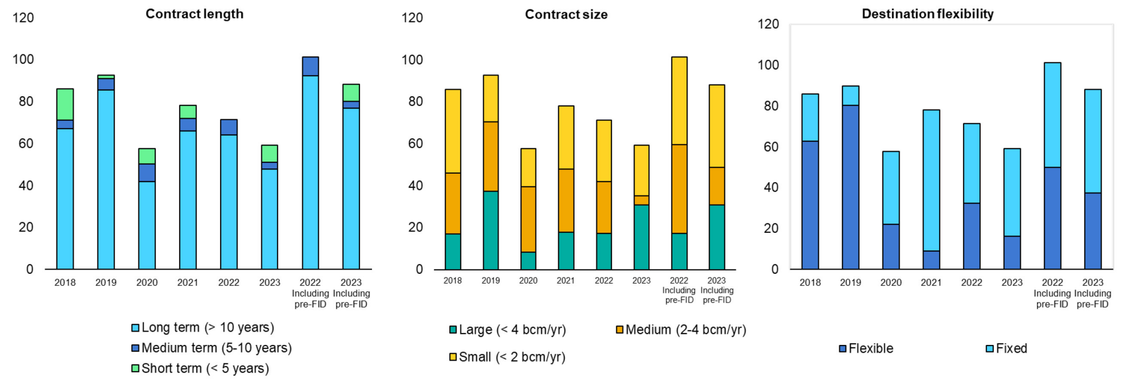
In 2022, LNG contracts showed trends of long contract durations, large volumes and an increase in destination-flexible contracts.

Long-term contracts (with a duration of over 10 years) accounted for 90% of LNG contracts in 2022, the highest share since 2020. This high share was driven by Asian buyers, who accounted for 44%, with 29% from China alone. In 2023, the share of long-term contracts reached 81%. For Europe, around 90% of the contract volume has been long-term since 2022. The extreme price volatility and increased supply uncertainty seen in 2022 may have reminded both buyers and sellers of the importance of long-term contracts to ensure stable price prospects and limit short-term price volatility.

In terms of contract volume, large contracts (over 4 bcm/yr) accounted for 24% in 2022. Medium contracts (2-4 bcm/yr) accounted for 35% and small contracts (<2 bcm/yr) 41% in 2022. In 2023, 41% of the contracts were small contracts, and 52% were large contracts. Since 2022, the share of large contracts among contracts where the portfolio player is the buyer has been higher than 40%, indicating a tendency for portfolio players to take risks to secure contract volumes.

[3] This does not take into account the amount of supply to Europe by portfolio players.

Contract volumes concluded by contractual element, 2018-2023



Note: The label 2023 represents the volumes signed by the end of December 2023. Destination flexibility is only for indicative purposes, assumed in the absence of a clear source of information.
Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

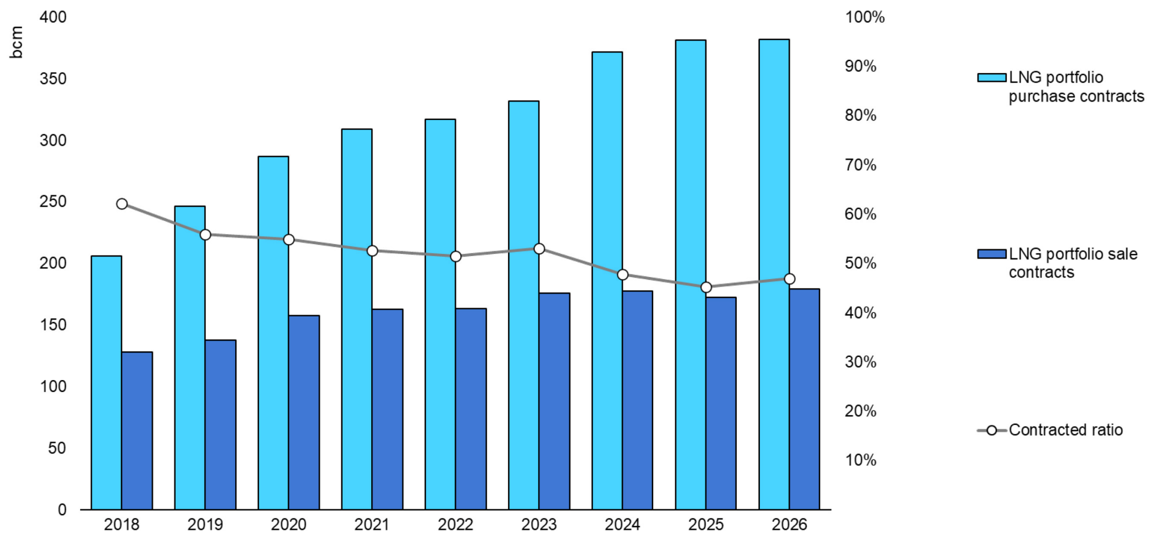
In 2022, the share of destination-free contracts increased compared to 2020 and 2021, accounting for about half of the new contract volume. The majority of destination-free contracts were related to projects in North America, with buyers mainly from portfolio players and Europe. In contrast, the majority of destination-fixed contract volumes came from Asian buyers, with China accounting for over 40% of these contracts. In 2023, the share of destination-free contracts was around 30% of the contract volume. When including pre-FID contracts, the share of destination-free contracts was over 40%. For destination-free contracts, the majority were related to projects in North America, while Asian buyers accounted for the majority of destination-fixed contracts, continuing the trend from 2022.

Portfolio players

Portfolio players play an important role in meeting buyers' growing needs for volume and supply source flexibility. They procure a mix of LNG supplies from different origins and resell them to customers to meet demand through term and spot contracts. The role of portfolio players has once again increased significantly in recent years. In volume terms, the share of contracts procured by portfolio players in total LNG contracts rose from 26% in 2016 to over 40% in 2022 and remained at the same level in 2023. The average duration of new purchase contracts concluded by portfolio players increased from 5 years in 2017 to over 15 years in 2022. The share of large contracts (over 4 bcm/yr) increased from 30% in 2018 and accounted for about 50% of contracts concluded by portfolio players in 2022. In 2023, the average contract length of contracts where the portfolio player was the buyer was 9 years, and the share of large contracts accounted for about 50% of all contracts concluded by portfolio players.

The proportion of contracts where portfolio players are sellers fell from 50% of total contract volumes in 2017 to just 11% in 2022. In 2023, the volume of contracts where portfolio players were sellers was still low at around 11%. This might be reflective of portfolio players' preferences under current market conditions to sell their LNG volumes on the spot market rather than sign term contracts. Portfolio players' contract ratios – sales offtake as a percentage of purchase obligations, a metric of relative exposure to certain types of market risk – declined to 52% in 2022 from 71% in 2017. This means that the share of their purchase obligations not covered by term sales contracts – or their net open positions – increased from 29% to 48% between 2017 and 2022.[4] Based on existing contracts, their net open position is set to increase to an average of close to 52% between 2023 and 2026. The growing net open position of portfolio players will contribute to market stabilisation through increased trading flexibility with regard to contract duration and volume.

LNG portfolio players' contractual position and contracted ratio, 2018-2026



Note: This graph represents the volumes signed by the end of December 2023.
Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

Medium-term outlook for Europe's natural gas balance

The gas supply shock triggered by Russia in 2022 reinforced the structural drivers accelerating the decline in European gas demand over the medium term. Natural

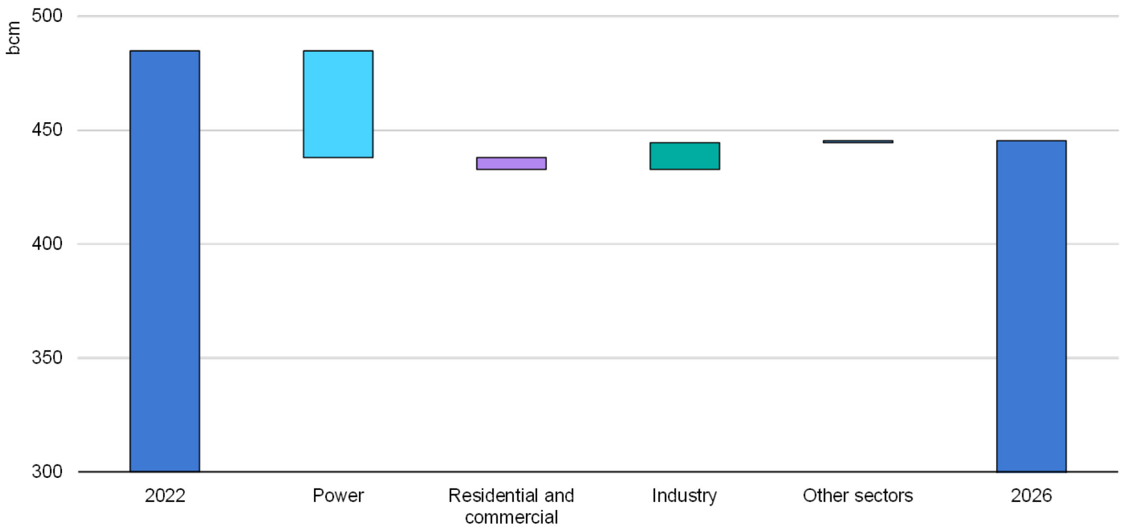
[4] Sales contracts exclude various hedging arrangements and do not necessarily capture the downstream sales directly performed by portfolio players.

gas demand in OECD Europe is expected to decline by 6% (or 32 bcm) between 2022 and 2026, standing at nearly 20% (or 116 bcm) below the 2021 peak by 2026.

A relatively high gas price environment is set to weigh on demand recovery in industry, while a more rapid deployment of renewables is expected to reduce the call on gas-fired power plants. Nevertheless, the flexibility provided by natural gas will remain crucial for ensuring the security of energy and electricity supply in the medium term. In the residential and commercial sectors, energy efficiency gains, together with the more rapid installation of heat pumps, are set to reduce gas use during the forecast period.

Our forecasts assume that more than half of the industrial gas demand lost in 2022 will not be recovered over the medium term, as the relatively high gas price environment weighs on the prospects of the gas-intensive European industries. The relocation of European industries to other regions – with a structurally lower cost of gas supply – remains a major downside risk to industrial gas demand in Europe. As highlighted in a recent survey, almost a third of Germany's industrial companies are relocating capacity abroad or restricting production at home, or are planning to do so, in light of the impacts of the 2022 energy crisis.

Expected change in natural gas demand by sector in OECD Europe, 2022-2026



Source: IEA (2023), Medium-Term Gas Report 2023.

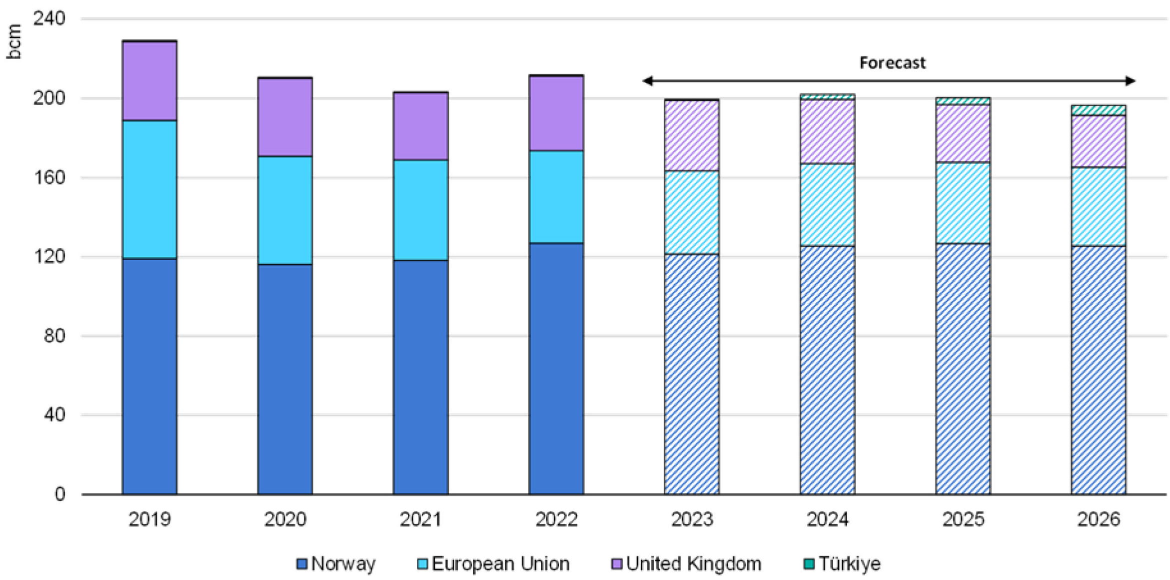
Europe's natural gas production is forecast to drop by 7% (or close to 15 bcm/yr) by 2026 compared with 2022, as the increase in natural gas output in Eastern European markets will not be sufficient to offset the declines projected in Northwest Europe.

Norway is set to remain the backbone of European gas production, with the country's natural gas output expected to remain broadly flat and average 125 bcm/yr between 2023 and 2026. In the United Kingdom, ageing gas fields in the North Sea are expected to reduce the country's natural gas output by over 30% (or more than 10 bcm) by 2026 compared with 2022. The government's plan, announced in July 2023, to grant more than 100 new licences for oil and gas production in the North Sea could provide upside potential to the current forecast.

In the Netherlands, the giant Groningen field was closed (as scheduled) on 1 October 2023, marking the end of its phase-out, which started in 2018 due to earthquakes caused by production from the field. Production from small fields is expected to continue to decline over the forecast period, leading to an overall decrease of over 40% (almost 10 bcm) in Dutch natural gas output by 2026 compared with 2022.

In Türkiye, the giant Sakarya gas field was commissioned in April 2023. Natural gas production is expected to ramp up to 3.6 bcm/yr during the first phase in 2023-25, later growing to around 15 bcm/yr during the second phase after 2026.

Natural gas production in OECD Europe, 2019-2026



IEA. CC BY 4.0.

Source: IEA (2023), Medium-Term Gas Report 2023.

Pipeline imports from Azerbaijan and North Africa into Europe are expected to remain broadly flat through the 2022-26 period. The future of Russian piped gas deliveries to Europe is a key uncertainty in our forecast. Russian piped gas deliveries almost halved in 2023 compared to 2022, falling to 45 bcm. Russia's gas transit contract with Ukraine is set to expire at the end of 2024. Ukraine's energy minister has ruled out the possibility of extending the contract, following

Russia's invasion of the country. Hence, our base forecast assumes that only TurkStream string 2 (15.75 bcm/yr) will supply Russian piped gas to the European Union starting in 2025. While short-term capacity booking options might continue to be available along the Ukrainian transit route for European importers of Russian piped gas, this upside potential is not included in our baseline forecast.

LNG will continue to play a key role in Europe's natural gas supply and is expected to account for a relatively stable 34% share of the region's natural gas demand through 2026. In absolute terms, Europe's LNG imports are expected to average around 166 bcm through the forecast, remaining close to the levels reached in 2022.

Recent developments in the Korean gas market and its outlook

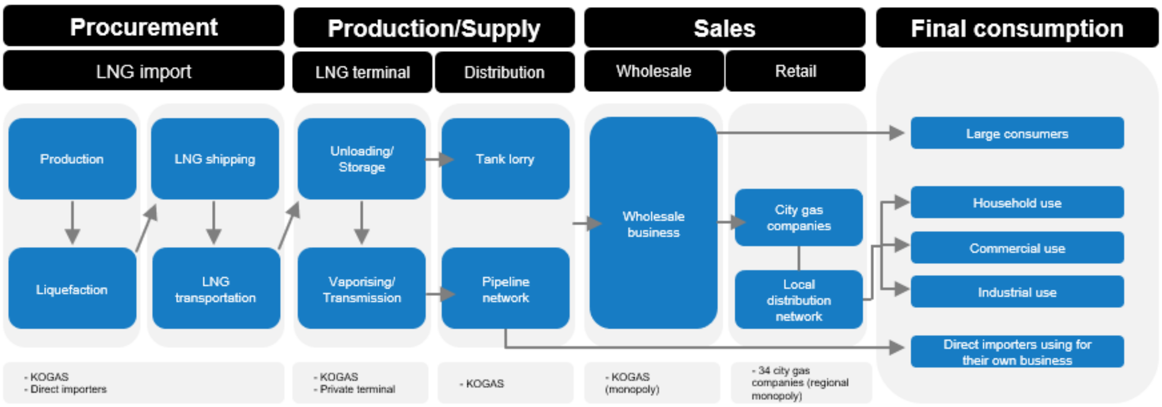
Current situation of the Korean gas market

Natural gas industry status

The natural gas industry in Korea is largely divided into the wholesale and retail sectors. The wholesale sector is managed by the Korea Gas Corporation (KOGAS), while the retail sector is handled by regional city gas companies.

KOGAS is a market-oriented, state-owned enterprise, and the government is the largest shareholder. It holds a dominant position across the domestic gas supply chain, from LNG imports to distribution and the wholesale market. KOGAS imports natural gas in the form of LNG from overseas and supplies it to high-demand consumers, such as power producers, industrial users and city gas companies, through national pipelines and tank lorries.

Natural gas market structure in Korea



Source: KEEI (2023), as modified by the IEA.

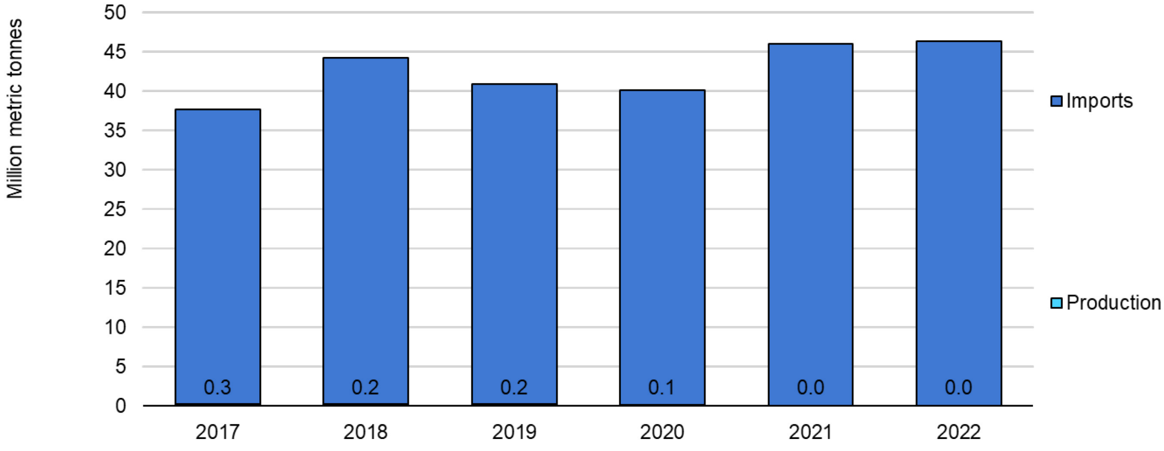
The 34 city gas companies each hold exclusive selling rights in their respective regions and all purchase their natural gas from KOGAS. They then deliver it to their household, commercial and industrial consumers through regional retail pipelines.

Large-scale consumers, including power producers and industrial users, have the option to directly import LNG once they meet certain facility standards and registration requirements. These direct importers are only allowed to import natural gas for their own consumption and are prohibited from selling the imported LNG within the domestic market.

Natural gas supply status

As of 2022, Korea ranked as the world's third-largest LNG importer following Japan and China and accounting for 12% of global imports. The country's domestic natural gas production, primarily from the Donghae-1 gas field, contributed less than 1% to total consumption before the field was depleted in 2021.

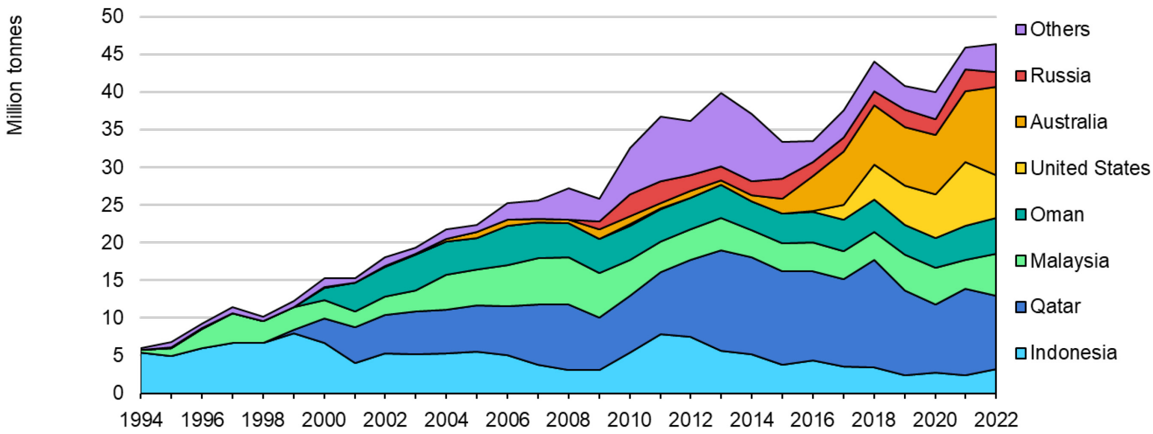
Natural gas imports and production in Korea, 2017-2022



Source: IEA analysis based on KEEI (2023), Monthly Energy Statistics.

Korea's reliance on LNG imports has been increasing over the years, rising from 2.23 million tonnes in 1990 to 46.39 million tonnes in 2022. The country began importing LNG from Indonesia in 1986 and has since diversified its sources to include regions like the Middle East, Asia Pacific, North America and Europe.

LNG imports by source country, 1994-2022



Source: IEA analysis based on KEEI (2023), Monthly Energy Statistics.

Korea is actively diversifying its LNG import sources to mitigate the risk of supply disruptions from regional conflicts and production challenges. In 2022, the primary LNG suppliers to Korea were Australia (25.1%), Qatar (21.0%), the United States (12.4%) and Malaysia (11.9%). This indicates a notable shift in reducing reliance on Middle Eastern imports while increasing imports from Australia and the United States.

Share of Liquefied Natural Gas imports by country, 2022

Export country	Australia	Qatar	United States	Malaysia	Oman	Indonesia	Others
Share of imports (%)	25.1	21	12.4	11.9	10.3	7	8.2

Source: KEEI (2023).

Direct LNG importers – mainly private power and industrial companies – have significantly expanded their operations for power generation and industrial use. From 2006, the proportion of direct LNG imports gradually increased, rising from around 4% in 2006 to approximately 20% in 2020.

However, this growth trend has slowed recently due to escalating LNG prices, influenced by changes in the global landscape. Notably, after the second half of 2021, global spot LNG prices surged due to various factors and reached unprecedented levels following the Russian invasion of Ukraine in February 2022.

Proportion of direct Liquefied Natural Gas imports, 2006-2022

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014
Share (%)	4.3	4.3	3.1	5.4	9.2	5.1	4.5	3.6	3.7
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	
Share (%)	5.4	6.3	12.7	14.0	18.4	22.9	18.8	15.9	

Source: Private LNG Industry Association (2023).

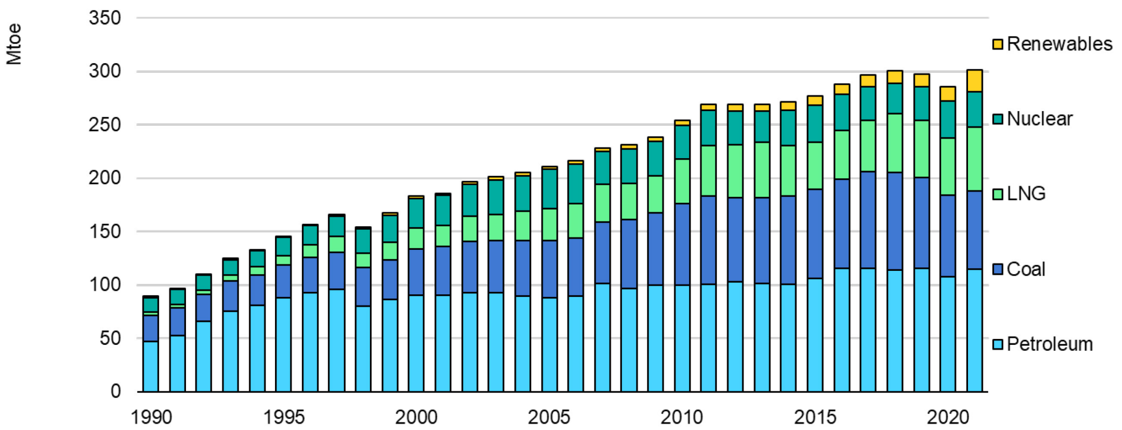
Although spot prices briefly stabilised, they spiked again in late August 2022, driven by the halt in LNG supplies through the Nord Stream pipeline and exacerbated by heightened tensions arising from Russia's reaction to Western sanctions.

Spot prices later moderated, influenced by early winter stockpiling, reduced demand due to high prices, emergency demand reduction measures by countries and milder weather conditions. Despite these adjustments, the recent trends indicate a decline in the proportion of direct LNG imports.

Natural gas consumption trends

In response to the oil crises of 1973 and 1979, Korea recognised the vital importance of energy security and began introducing natural gas as an alternative to oil. Due to its environmental benefits and ease of use, natural gas quickly became a popular choice for residential fuel. Advancements in power generation technologies and supportive distribution policies also significantly contributed to its adoption.

Primary energy demand trend in Korea, 1990-2022



Source: IEA analysis based on KEEI (2022), Yearbook of Energy Statistics.

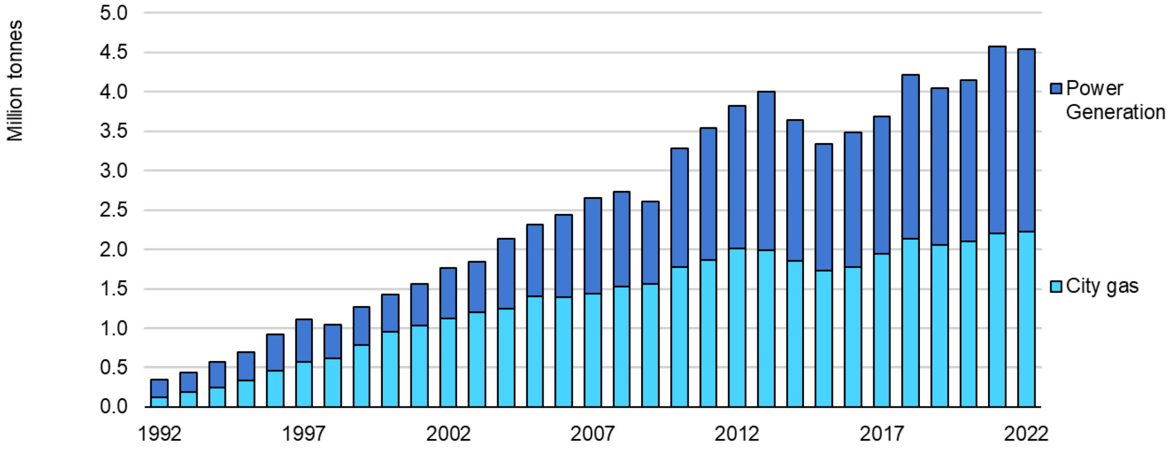
As a result, the proportion of natural gas in Korea's primary energy supply increased from 3.3% in 1990 to 19.5% in 2022. The domestic demand for natural gas has seen an average annual growth rate of 10.0%, escalating from 1.61 million tonnes in 1987, the year after its introduction, to 45.40 million tonnes in 2022.

Domestic natural gas demand and average growth, 1987-2022

	Demand (10 000 tonnes)									Average annual growth rate (%)		
	1987	1997	2002	2009	2013	2015	2018	2021	2022	1987-2002	2003-2022	1987-2022
City gas	7	577	1 119	1 563	1 995	1 727	2 137	220	2 231	40.3	3.3	17.9
Power generation	154	538	651	1 041	2 013	1 609	2 085	2 337	2 309	10.1	6.9	8.0
Total	161	1 115	1 770	2 604	4 008	3 336	4 222	4 573	4 540	17.3	4.9	10.0

Source: MOTIE (2023).

Domestic natural gas demand trends, 1992-2022



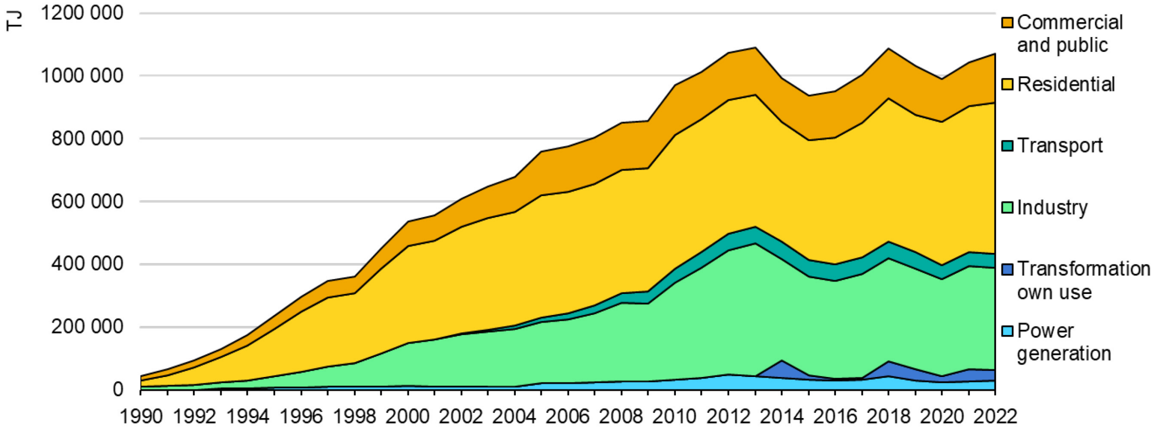
Source: IEA analysis based on MOTIE (2023), 15th Plan for Long-Term Natural Gas Demand and Supply.

Demand for city gas

In Korea, the demand for natural gas is primarily split into two sectors: city gas and power generation. City gas demand has grown significantly, increasing from 70 000 tonnes in 1987 to 22.31 million tonnes in 2022. Its share of total natural gas consumption has also risen, from 4% in 1987 to 49% in 2022.

During the 1990s, city gas demand surged, particularly in metropolitan areas and major cities, driven by the widespread distribution of gas for heating and cooking. This led to a marked increase in domestic consumption and, consequently, a rapid rise in overall natural gas usage. From 1987 to 2002, the annual average growth rate of city gas consumption was a remarkable 40.3%.

City gas consumption in Korea, 1990-2022



Source: IEA analysis based on KEEI (2023), Monthly Energy Statistics.

However, as the 2000s began, the expansion of residential city gas distribution reached maturity, leading to a slowdown in the growth of domestic demand. Nevertheless, with high oil prices enhancing the price competitiveness of gas and environmental policies favouring cleaner energy sources, there was a noticeable increase in gas demand in the industrial and commercial sectors.

From 2003 to 2022, the growth rate of city gas consumption significantly decelerated to an annual average of 3.3%. City gas demand, initially driven by infrastructure development like pipeline networks, has now entered a mature stage. In this stage, consumption remains stable, with fluctuations influenced by factors such as temperature and economic conditions.

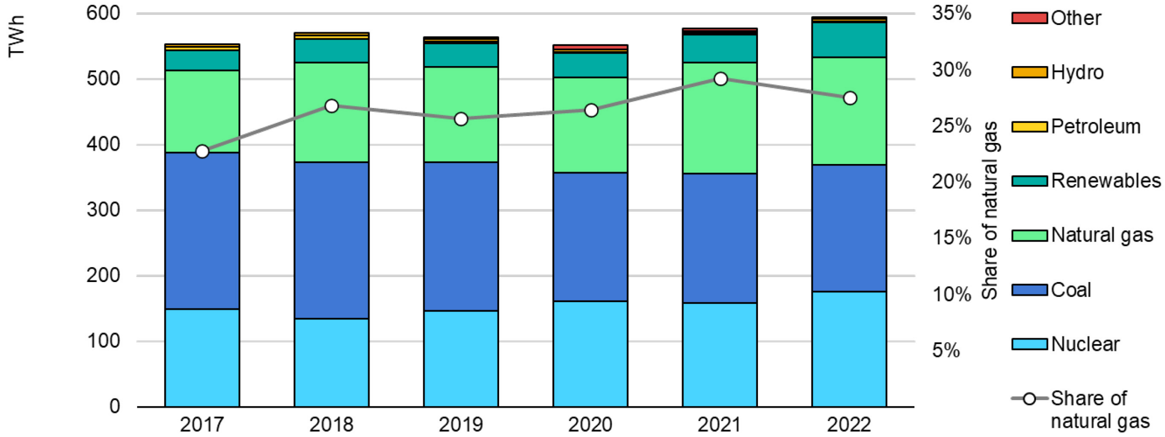
In 2022, while the industrial consumption of city gas remained at the previous year's level, there was a noticeable increase in building consumption, leading to an overall rise of 3.6% compared to the previous year. The modest growth in industrial consumption was impacted by global economic slowdowns and increased raw material costs. Notably, the petrochemical and machinery sectors saw a rise in gas usage, while the steel and transportation equipment sectors experienced a decline. The growth in building consumption of city gas was attributed to temperature fluctuations and the easing of social distancing measures, resulting in higher demand for both residential and commercial purposes.

Demand for gas in power generation

The demand for natural gas in power generation in Korea has seen a significant increase, rising from 1.54 million tonnes in 1987 to 23.09 million tonnes in 2022. During this period, the share of gas used for power generation in total natural gas demand shifted from 96% in 1987 to 51% in 2022.

This consistent growth in demand has been influenced by several factors, including the requirement for clean fuels in metropolitan power plants, the construction of combined heat and power plants for district heating in new cities, economic growth leading to increased electricity demand and the expansion of natural gas power plants in the metropolitan regions.

Power mix and share of natural gas, 2017-2022



Source: IEA analysis based on Korea Electric Power Corporation (2023), Monthly Report on Major Electric Power Statistics.

Particularly notable was the period up until the early 2010s, which was marked by a shortage of baseload power generation, such as nuclear and coal. This led to a significant drop in the capacity reserve margin to single digits and a consequent rapid increase in natural gas power, which primarily manages peak loads. However, this trend experienced a downturn post-2013, attributed to a slowdown in electricity demand and an increase in baseload power generation capacity. In 2016, the trend saw another upward shift, driven by a decrease in nuclear power utilisation, tighter restrictions on coal power generation and lower winter temperatures.

The demand for gas in power generation now experiences significant annual fluctuations, influenced by the completion of baseload power plants, the rise of renewable energy and changes in electricity demand. These fluctuations are expected to continue in the future.

Nuclear power generation is projected to increase, with new facilities coming online and higher utilisation rates. For instance, Shin Hanul Unit 1, with a capacity of 1 400 MW, began commercial operations in December 2022, contributing to an increase in nuclear capacity. Additionally, a slight increase in the nuclear power plant utilisation rate is anticipated to add to the growth in nuclear generation.

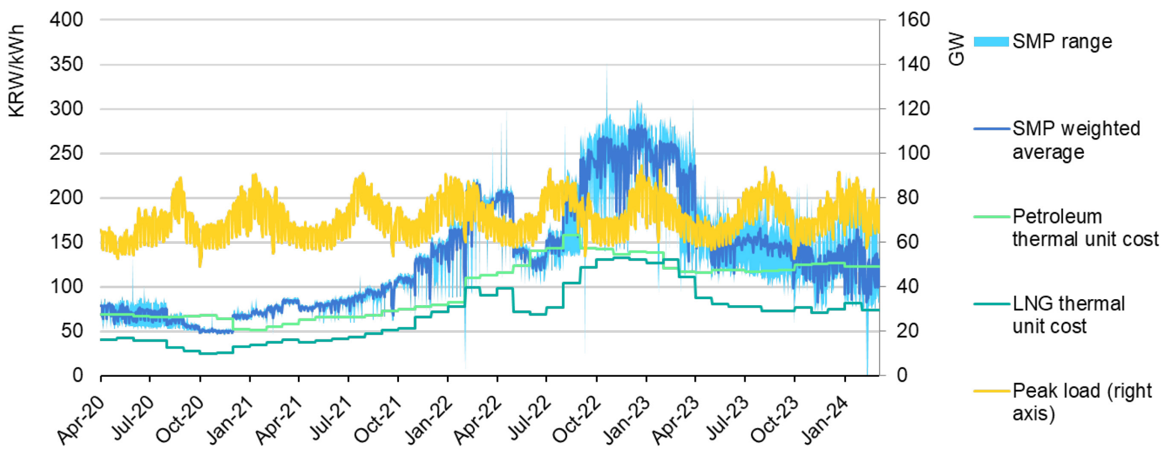
Meanwhile, renewable power generation, primarily driven by solar energy, has grown rapidly but is estimated to have increased by only 10% in 2023 compared to the previous year. This slowdown can be linked to factors such as a reduced Renewable Portfolio Standards mandatory supply ratio, stricter local setback regulations and rising interest rates, all of which are expected to limit the growth of solar power generation in the near term.

Despite ongoing expansions in capacity, coal power generation is anticipated to decline, primarily due to transmission line limitations on the east coast and operational challenges arising from the increasing share of renewable energy. While older coal power plants are progressively being retired, new units have been added, such as Gangneung Anin Unit 1 in October 2022, Gangneung Anin Unit 2 in May 2023 and Samcheok Thermal Unit 1 in October 2023.

Nevertheless, a significant number of these new, large-scale power plants are located on the east coast. The existing transmission lines that link these plants to the high-demand areas in the metropolitan regions are unable to fully support their output. Additionally, the expanding presence of renewable energy sources, particularly solar power, is expected to further challenge the generation of coal. The variability and unpredictability associated with the growth of renewable energy present additional hurdles for coal power generation, which struggles to rapidly adapt to fluctuations in power supply and demand.

Given these factors, gas generation, which typically handles peak loads, is expected to remain relatively stable at the annual level as overall power generation from nuclear, coal and renewable sources is expected to remain comparable to the levels recorded in 2022.

Thermal unit cost and System Marginal Price



Source: Electric Power Statistics Information System (2023), Market Review, as modified by the IEA.

Currently, gas power generation accounts for approximately 30% of Korea's power mix. In the first quarter of 2023, the cost per thermal unit for gas power generation was reported at KRW 142 600 (Korea won)/Gcal. This rate was 2.6 times higher than that for coal and 55 times more than nuclear power. Gas power generation typically determines about 90% of the system marginal price (SMP) in Korea's electricity wholesale market. The ongoing Russian invasion of Ukraine and other tensions have significantly increased fuel costs. In the first quarter of 2023, the average thermal unit cost of LNG saw a 38% increase compared to the same period in the previous year, reaching KRW 142 600/Gcal. Consequently, the SMP experienced a 31.3% rise from KRW 180.46/kWh in the previous year to KRW 236.99/kWh.

Thermal unit cost by fuel type

	LNG	Petroleum	Coal (domestic)	Bituminous coal	Nuclear	Average thermal unit cost
			(KRW/Gcal)			
Q1 2022	103 226	123 205	33 210	38 527	2 565	97 709
Q1 2023	142 400	145 358	42 960	54 086	2 560	137 957
Change	+38%	+18%	+29%	+40%	-0.2%	+41%

Source: Korea Power Exchange (2023).

To address the economic uncertainties caused by the increasing SMP, the Korean government has introduced a SMP cap. This cap is activated when the average SMP over the previous 3 months ranks in the top 10% of the average SMP for the past decade. The cap is set at 1.5 times the average SMP of the last 10 years. This mechanism cannot be applied for more than three consecutive months and is scheduled to be phased out after 1 year.

SMP determination ratio by fuel type

	LNG	Bituminous coal	Petroleum	Anthracite coal
Q1 2022	90%	9%	1%	0%
Q1 2023	89%	5%	6%	0%
Change	-1 pp	-4 pp	+5 pp	-

Note: pp = percentage point.
Source: Korea Power Exchange (2023).

Natural gas supply infrastructure

Liquefied natural gas terminals

Korea features a comprehensive infrastructure for natural gas, encompassing seven operational LNG terminals with a combined capacity of 14.09 million kilolitres. KOGAS manages the majority of these facilities, operating five LNG terminals in Pyeongtaek, Incheon, Tongyeong, Samcheok and Jeju. These KOGAS terminals have a total storage capacity of 12.16 million kilolitres. Additionally, POSCO, a private entity, owns an LNG terminal in Gwangyang, which has a capacity of

0.8 million kilolitres. The Boryeong terminal, with a capacity of 1.20 million kilolitres, is operated under a joint venture between GS Energy and SK E&S.

Liquefied Natural Gas terminals in Korea

Source: IEA (2023), Korea Natural Gas Security Policy.

Domestic LNG terminal operation status

Company	Location	Operation start date	Site area (km^2)	Storage tank capacity (10 000 kl)	Regasification and transmission facilities (tonnes/h)
KOGAS	Pyeongtaek	November 1986	1.3	336	4 950
	Incheon	January 1996	1.4	348	6 270
	Tongyeong	September 2002	1.1	262	3 030
	Samcheok	July 2014	0.9	261	1 320
	Jeju	October 2019	2.3	9	120
POSCO Energy	Gwangyang	July 2005	0.1	73	810
Boryeong LNG Terminal Co.	Boryeong	January 2017	0.1	120	1 230

Note: Information as of April 2023.
Sources: KOGAS, POSCO Energy and Boryeong LNG Terminal Co.

Korea is also actively enhancing its LNG infrastructure, targeting a storage capacity of 19.98 million kilolitres by 2036. KOGAS is expanding its Dangjin No. 5 Terminal, which will add 2.7 million kilolitres of storage capacity by 2030. In addition, private companies are expanding their storage capacity in Boryeong, Ulsan, Gwangyang and Tongyeong, which will add 2.66 million kilolitres by 2026.

Pipeline facilities

Korea's natural gas pipeline network, under the exclusive management of KOGAS, incorporates pipelines that link individual self-consumption facilities to the main network. These connecting pipelines are constructed and funded by the facility owners themselves. As of January 2023, KOGAS operated a main pipeline system stretching over 5 027 kilometres and managed 425 supply management stations. These stations include various pressure and block stations, along with valves, that are integral to the network's operation.

Major direct LNG importers, such as POSCO, GS Energy, SK E&S, and Korea Midland Power, primarily import LNG through private terminals. They lease the main pipeline network from KOGAS for distribution purposes, complying with the regulated third-party access rule. Furthermore, according to the 15th Long-Term Natural Gas Supply Plan, there are plans to expand the network. By 2036, the main pipeline is planned to be extended to approximately 5 840 kilometres.

Recent institutional changes

The individual tariff plan is a system in which KOGAS applies individual tariffs to each plant, instead of applying the same average tariff to all of the power plants to which KOGAS supplies natural gas. Previously, KOGAS had averaged the prices of LNG under its import contracts, applying the same price to all power plants under the average tariff plan.

Since 1 January 2022, the individual tariff plan has been applied to new power plants and plants whose existing contracts with KOGAS have ended. These plants can choose between direct imports or the individual tariff plan.

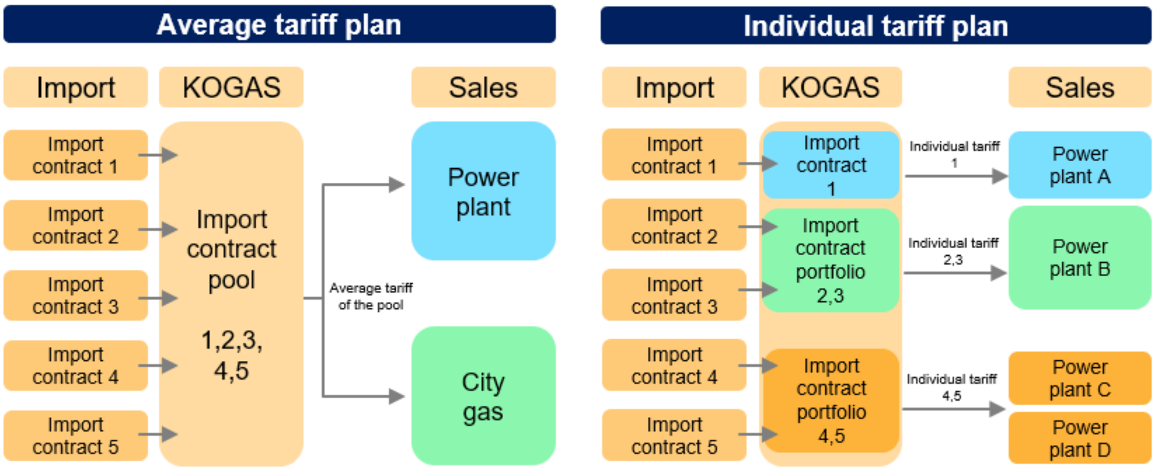
Since 2017, the proportion of direct imports of natural gas for power generation has significantly increased, necessitating improvements to the existing average tariff plan to manage national supply effectively and establish a fair and competitive structure among power companies.

Direct importers are allowed to choose the more favourable pricing system based on global market conditions, which had been a constraint on fair competition between companies using direct imports and those under the average tariff plan.

The government expects that the introduction of the individual tariff plan for power generation will enhance the efficiency of the gas import market and strengthen fair competition within the electricity market. By allowing power companies to choose between direct imports and the individual tariff plan, the country's overall LNG import costs are expected to decrease. This cost reduction is expected to lead to increased competition among power companies and reduce fuel costs, which will in turn lower the power purchase costs for Korea Electric Power Corporation and ultimately reduce electricity bills for consumers.

Moreover, while the volume of direct imports is challenging to manage on a national level, the volume under the individual tariff plan can be managed collectively by KOGAS. This improved management is expected to enhance the country's ability to respond to national emergencies, such as sudden increases in power demand.

Introduction of individual tariff plans for power plants



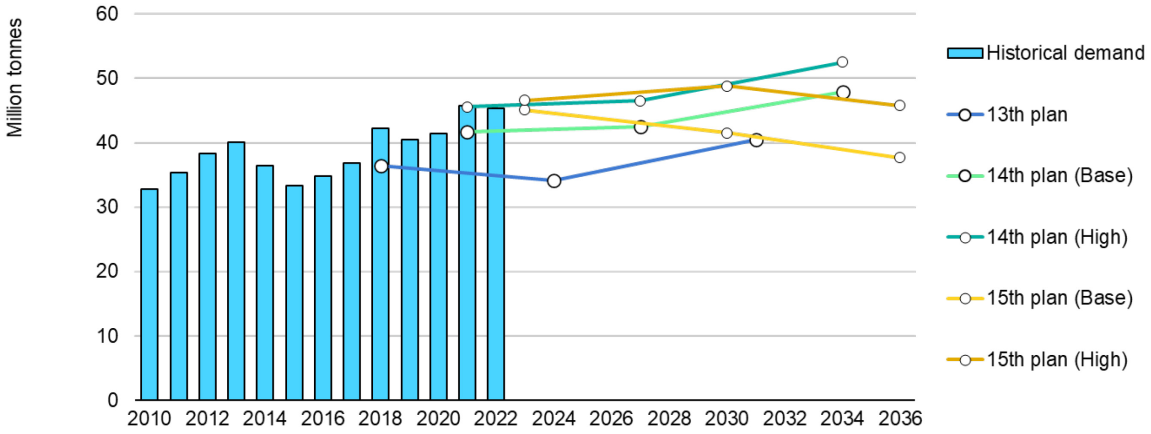
Source: KEEI (2023), Ministry of Trade, Industry and Energy approves individual rate system for natural gas power generation, as modified by the IEA.

Korean gas market outlook

Gas demand outlook

In April 2023, the Korean government released the 15th Long-Term Natural Gas Supply and Demand Plan with natural gas demand outlooks from 2023 to 2036, reflecting the new government's energy policy direction. The 15th plan diverges from the projections of the 13th and 14th plans, which anticipated a long-term increase in natural gas demand in line with the previous government administration's policy of reducing reliance on nuclear power and coal. Instead, the 15th plan indicates a long-term decrease in natural gas demand, mainly due to decreases in natural gas demand for power generation. Meanwhile, it also suggests the potential for variations in demand contingent upon advancements in nuclear power expansion, the adoption of new and renewable energy sources and the pace of implementation of hydrogen co-fired power generation.

Natural gas demand outlooks from national plans



Sources: IEA analysis based on MOTIE (2018), 13th Plan for Long-term Natural Gas Supply and Demand; MOTIE (2021), 14th Plan for Long-Term Natural Gas Supply and Demand.

The plan provides two distinct outlooks, comprising a baseline outlook (base) and an alternative outlook (high), which takes into account demand volatility. In terms of utilisation, the outlooks are mainly categorised into applications for city gas and power generation.

According to the base outlook, the anticipated decline in domestic natural gas demand is projected to average 1.38% annually from 2023 to 2036, starting from 45.09 million tonnes. This decline is primarily attributed to the diminishing demand for power generation. Meanwhile, the demand for natural gas in city gas is expected to rise, driven by industrial usage, at an average annual growth rate of 1.39% until 2036. In contrast, natural gas demand for power generation is forecast to decrease at an average annual rate of 5.42% over the same period, reaching only 11.09 million tonnes in 2036 – merely half of the demand recorded in 2023.

Base outlook of the 15th Natural Gas Supply and Demand Plan

Year	City gas (10 000 tonnes)			Power generation	Total
	Residential	Industry	Subtotal		
2023	1 261	959	2 220	2 289	4 509
2030	1 308	1 186	2 494	1 656	4 150
2036	1 313	1 344	2 657	1 109	3 766
Average annual growth rate	0.31%	2.63%	1.39%	-5.42%	-1.38%

Notes: "Residential" indicates use for residential, general, commercial heating, HVAC, and combined heat and power, etc. "Industry" refers to use for industry and transport.
Source: MOTIE (2023), 15th Plan for Long-term Natural Gas Supply and Demand.

The alternative outlook considers the possibility of an increase in gas demand based on fluctuations in the economic growth rate, temperature, relative pricing and the utilisation of base power generation. Particularly, the gas demand for power generation is subject to variations depending on the pace of nuclear power expansion, the growth of renewable energy and the implementation of hydrogen co-fired power generation, making the potential for change relatively high.

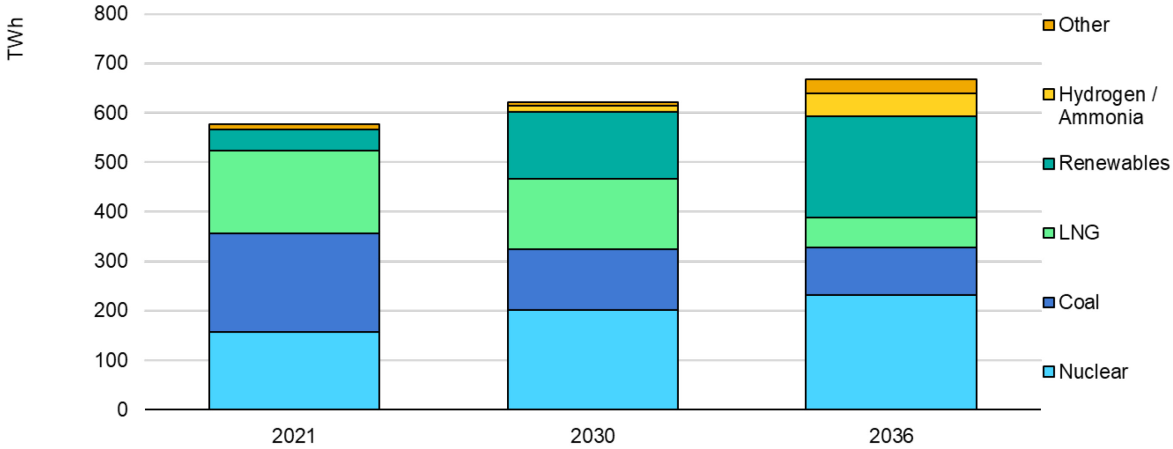
Alternative outlook of the 15th Natural Gas Supply and Demand Plan

Year	City gas			Power generation	Total
	Residential	Industry	Subtotal		
	(10 000 tonnes)				
2023	1 275	968	2 243	2 419	4 662
2030	1 420	1 281	2 701	2 178	4 879
2036	1 453	1 460	2 913	1 667	4 580
Average annual growth rate	1.01%	3.21%	2.03%	-2.82%	-0.14%

Notes: "Residential" indicates use for residential, general, commercial heating, HVAC, and combined heat and power, etc. "Industry" refers to use for industry and transport.
Source: MOTIE (2023), 15th Plan for Long-term Natural Gas Supply and Demand.

The alternative demand projection for city gas in 2036 is 29.13 million tonnes, approximately 10% higher than the baseline demand forecast of 26.57 million tonnes, representing an increase of 2.56 million tonnes. Additionally, the alternative demand projection for power generation in 2036 is 16.67 million tonnes, reflecting a 50% increase compared to the baseline demand forecast of 11.09 million tonnes, with a rise of 5.58 million tonnes. Nevertheless, the alternative outlook, like the baseline demand projection, still anticipates a long-term decrease in gas demand due to decreases in natural gas demand for power generation. Over the period from 2023 to 2036, domestic natural gas demand is expected to decrease at an average annual rate of 0.14%, reaching 45.8 million tonnes in 2036, down from 46.62 million tonnes in 2023.

Power mix outlook of the 10th Basic Plan for Long-term Electricity Supply and Demand, 2021-2036



Source: IEA analysis based on MOTIE (2022), 10th Basic Plan for Long-Term Electricity Supply and Demand.

The anticipated long-term decrease in natural gas demand for power generation is based on the 10th Basic Plan for Long-Term Electricity Supply and Demand announced prior to the 15th Long-Term Natural Gas Supply Plan. According to the 10th Plan, LNG is expected to be maintained at a certain level of power generation in the medium term, following the replacement of ageing coal-fired power plants. However, it is anticipated that LNG generation will decrease from 142.4 TWh in 2030 to 62.3 TWh in 2036. During the same period, the share of power generation is expected to decrease from 22.9% to 9.3%, influenced by factors such as the continued operation of nuclear power plants and the expansion of renewable energy.

Key issues in the mid- to long-term gas demand outlook

The uncertainty in gas demand for power generation is a prominent issue in the mid- to long-term domestic gas demand forecast, as highlighted by the disparity between the two perspectives presented in the 15th Long-Term Natural Gas Supply and Demand Plan. Gas power generation serves as a flexible resource in the domestic electricity market, and the expansion of carbon-free power sources to achieve greenhouse gas reduction introduces various scenarios that can result in volatility in gas power generation. This volatility underscores the complexity and challenges associated with forecasting gas demand for electricity in the evolving landscape of energy production and environmental goals.

The 10th Basic Plan for Electricity Supply and Demand is based on an active utilisation of nuclear power, which includes the ongoing operation of existing nuclear power plants and the completion of new ones. The plan envisions an increase in installed nuclear power capacity from 26.1 GW in 2023 to 28.9 GW in

2030 and further to 31.7 GW in 2036, achieved through the completion of six new nuclear power plants and the continued operation of ten existing ones. The share of nuclear power generation is projected to rise from 23.4% in 2018 to 32.4% in 2030 and 34.6% in 2036. Nonetheless, it cannot be ruled out that the expansion of nuclear power plant facilities may be delayed depending on the progress of the continued operation of nuclear power plants or the construction of new nuclear power plants. In response to this, the amount of LNG power generation used as a flexible power source is also subject to change.

It is interesting to note the emphasis on hydrogen power generation in the 10th Basic Plan for Electricity Supply and Demand, especially as part of efforts to reduce greenhouse gases. The integration of hydrogen into LNG combined-cycle generators is a significant step, and the gradual increase in the ratio of hydrogen in these generators indicates a commitment to transitioning towards cleaner energy sources.

The targets for hydrogen power generation to reach 6.1 TWh in 2030 and 26.5 TWh in 2036 highlight the scale and ambition of the plan. This signals a substantial investment in technology development and pilot projects by power generation companies.

However, the success of the plan depends on several key factors, including the following:

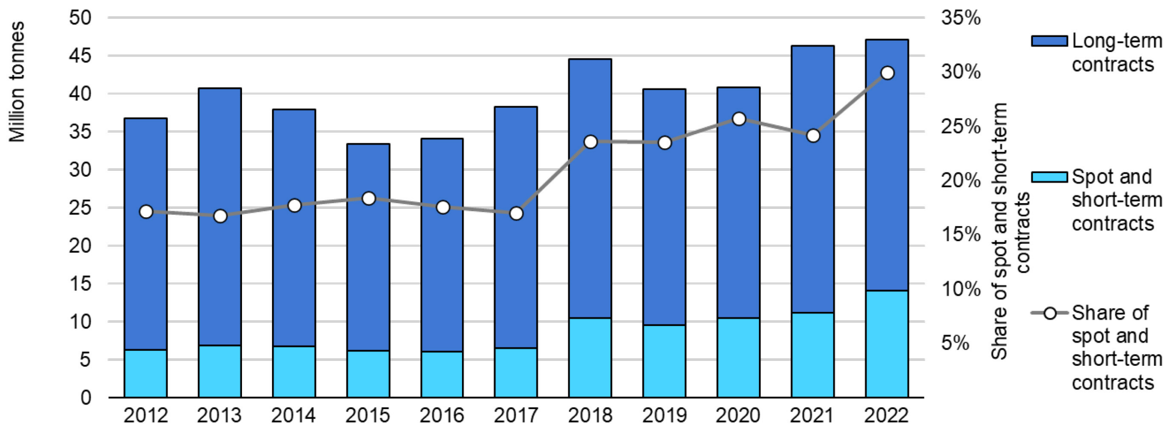
- Hydrogen production base: Establishing a reliable and efficient hydrogen production base is crucial. This might involve scaling-up current production methods or investing in new, more sustainable hydrogen production technologies.
- Supply chain development: Creating a robust supply chain for hydrogen is essential to ensure a steady and consistent source of hydrogen for power generation. This involves transportation, storage and distribution infrastructure.
- Institutional foundation: The development of an institutional framework is necessary to regulate, monitor and support the growing hydrogen industry. This could involve creating policies, regulations and incentives to encourage the adoption of hydrogen power.

In summary, while the plan outlines ambitious goals for hydrogen power generation, its success hinges on addressing the logistical and institutional challenges associated with scaling-up hydrogen production and integrating it into the existing energy infrastructure. It is a positive sign that power generation companies are actively involved in technology development and pilot projects, as this collaboration is crucial for the successful implementation of the plan.

Gas supply outlook

In Korea, traditional long-term contracts constituted over 80% of the total import volume until the mid-2010s. However, there has since been a shift towards short-term contracts, including spot contracts. The move towards greater flexibility and adaptability in energy procurement strategies reflects an understanding of the challenges posed by volatility and uncertainty, particularly in sectors like power generation.

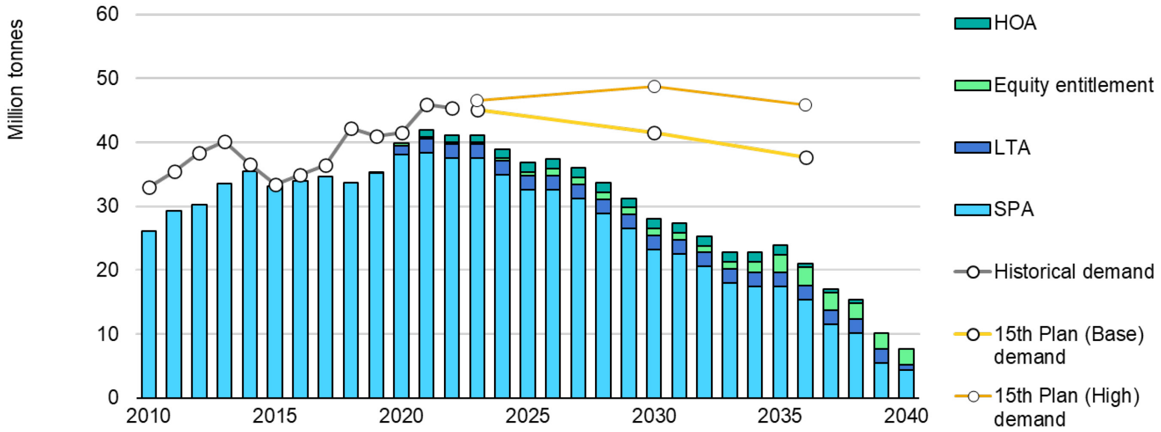
Trends in Korean term contracts, 2012-2022



Source: IEA analysis based on S&P Global Commodity Insights, ©2024 by S&P Global Inc.

Since the mid-2020s, Korea has entered a phase where existing long-term contracts are gradually nearing their conclusion. Consequently, there is a need to consider negotiating new contracts to replace those set to expire, with the anticipation of future demand. However, given the ongoing volatility in future gas demand and the current constrained conditions in the international LNG market, domestic businesses are highly likely to procure gas through short- to medium-term contracts or spot transactions to address their demand.

Contracted LNG supply by contract type versus LNG demand in Korea



Sources: IEA analysis based on MOTIE (2023), 15th Plan for Long-term Natural Gas Supply and Demand; S&P Global Commodity Insights, ©2024 by S&P Global Inc.

Mid- to long-term government policy direction

Since declaring carbon neutrality in October 2020, Korea has continued its policy efforts to achieve carbon neutrality. In September 2021, the Basic Law on Carbon Neutrality Green Growth for Climate Crisis Response was enacted, legally committing to reduce the country's greenhouse gas emissions by over 35% from their 2018 levels by 2030. The implementing decree subsequently raised the national reduction target to 40% compared to 2018, exceeding the initial nationally determined contribution.

In December 2021, the upgraded 2030 National Greenhouse Gas Target was formally submitted to the United Nations Framework Convention on Climate Change. Additionally, the government has been working on establishing institutional foundations for carbon neutrality, including the announcement of the first National Carbon Neutrality Green Growth Basic Plan in April 2023.

As part of these efforts, the role of gas is expected to diminish in the long term. However, based on the current national plans for electricity and natural gas, it appears that gas will continue to serve as a bridging resource for a certain period.

The government's policy direction for the gas market can be discerned through the 15th Long-Term Natural Gas Supply and Demand Plan. The plan outlines policy recommendations for natural gas imports, supply and demand management, and LNG infrastructure aligned with the previously analysed demand outlook.

Natural gas imports

The natural gas procurement policy outlined in the 15th Long-Term Natural Gas Supply and Demand Plan places a significant emphasis on creating solutions to ensure both supply and price stability. Specifically, the plan highlights the necessity of preparing for potential surges in spot prices and strives to enhance import competitiveness and negotiation power. To achieve these goals, the plan underscores the importance of collaboration between KOGAS and the private sector domestically, as well as fostering external co-operation with neighbouring countries.

The policy recommendations for ensuring supply stability can be delineated in three key aspects. First is the continued emphasis on diversifying LNG-importing countries and supply routes. The plan recommends expanding the acquisition of gas from companies with diversified sources while carefully evaluating imports from countries with a high risk of supply disruptions due to political and diplomatic uncertainties, as witnessed in recent cases of price surges linked to events like the Russian invasion of Ukraine and geopolitical instability in the Middle East.

Second, the plan encourages the diversification of contract durations to enhance flexibility in responding to domestic supply fluctuations. It underscores the importance of diversifying contract portfolios, including long-term, short-term, medium-term and spot contracts. The plan particularly suggests actively utilising mid-term contracts during periods of elevated LNG market prices to mitigate the prolonged impact of high international market prices on the domestic market.

Third, the plan proposes enhancing the co-operation systems with Korea's neighbouring countries. This involves expanding information exchange, engaging in joint purchasing initiatives and acquiring equity in LNG projects through collaboration with neighbouring countries such as China and Japan, both at the government and private levels.

The policy alternatives for ensuring price stability in domestic LNG imports involve strategies to reduce unit import prices and manage the risks associated with international LNG price surges. The first strategy emphasises the importance of collaboration between KOGAS and the private sector to strengthen their negotiation power in determining gas purchase prices. With the expansion of direct imports and the increasing number of participants in the domestic gas market, joint purchasing initiatives between KOGAS and private direct importers could leverage collective bargaining power to induce a reduction in domestic LNG import prices.

The second strategy focuses on diversifying the spot contract price index, moving away from the current reliance on the natural gas price index. This shift aims to mitigate the risk of rising domestic import prices caused by surges in the international natural gas spot price so that the domestic market becomes more resilient to sudden price fluctuations in the global LNG market.

Key policy areas on natural gas imports in the 15th Long-Term Natural Gas Supply and Demand Plan

Policy goal	Policy recommendation	Specifics
Supply stability	Diversification of supply sources	Increasing imports from companies (portfolio players) with diversified supply sources
	Diversification of contract duration	Long-term, short-term, medium-term and spot contract portfolios
	Enhancement of co-operation with neighbouring countries	Information exchange, joint purchasing and securing equity of LNG projects
Price stability	Co-operation between KOGAS and the private sector	Enhancing price negotiation power through co-operation between KOGAS and the private sector
	Diversification of price index	Diversification of spot contract price index

Source: KEEI based on MOTIE (2023), 15th Plan for Long-term Natural Gas Supply and Demand.

Natural gas supply and demand management

The natural gas supply and demand management policy presented in the 15th Long-Term Natural Gas Supply and Demand Plan focuses on expanding management tools compared to the previous plan.

In order to strengthen natural gas demand management, it suggests actively utilising liquefied petroleum gas (LPG) heating facilities and co-mixing operations and expanding the city gas demand reduction programme. It suggests actively utilising LPG blending within the scope of ensuring stability as a demand management tool for supply and price stability when international LNG prices rise.

In addition, the plan proposes a review of the expansion of the residential City Gas Saving Cashback and the industrial demand reduction programme as a policy alternative for achieving city gas demand reduction. City Gas Saving Cashback is a programme operated by KOGAS to encourage a reduction in household city gas use during the winter season (December to March). In 2022, cash was returned based on the saved amount if there was a reduction in use by more than 7% compared to the previous winter, with the potential to lower the threshold in subsequent years.

The city gas demand reduction programme aims to encourage a reduction in city gas use during the winter season among industries and buildings. In 2022, funds were provided to industries that achieved a reduction of more than 15%

compared to the same period in the previous year and to buildings that achieved a reduction of more than 7%.

In the event of a national supply crisis, the plan proposes a co-ordinated response involving the government, KOGAS and the private sector as the primary policy direction, along with specific policy details. Specifically, it advocates for the establishment and operation of a winter natural gas emergency supply consultation committee that includes the government, Korea Electric Power Corporation, Korea Power Exchange, power generation companies, KOGAS and private direct importers. In the case of a national supply crisis, if necessary, adjustment of the scale and timing of direct imports would be permitted through regulatory orders. Additionally, the promotion of the sale or exchange of surplus volume from direct importers to KOGAS, the gas wholesale business operator, could be encouraged to address the supply crisis.

Furthermore, the 15th Plan put forward the flexible adjustment of KOGAS's reserve requirement as a policy alternative for addressing unforeseen spikes in demand resulting from factors like extreme cold waves.

Key policy areas on demand and supply management in the 15th Long-Term Natural Gas Supply and Demand Plan

Policy goal	Policy recommendation	Specifics
Enhancing demand management	Utilisation of LPG heating facilities and mixing	Utilising LPG mixing as a means of supply and demand and price stability when LNG prices rise
	City gas demand reduction programme	Expanding household city gas savings cash-back and industrial demand reduction programmes
Improving management capabilities in case of supply and demand disruption	Joint public/private response	Co-operation and joint response among energy-related organisations such as power and gas Regulatory orders for direct importers Promotion of sales or exchange of surplus volumes from direct importers to KOGAS
	Strengthening supply and demand management in preparation for abnormal temperatures	Raising KOGAS' reserve requirement if necessary

Source: KEEI based on MOTIE (2023), 15th Plan for Long-term Natural Gas Supply and Demand.

Natural gas supply infrastructure

In the supply infrastructure sector, along with the plans for expanding supply facilities, the 15th Long-Term Natural Gas Supply and Demand Plan proposes alternative measures to enhance supply efficiency and stability by advancing the operation of supply facilities.

The measures seek to upgrade the operation of supply facilities and enhance stability by promoting the advancement of next-generation pipeline inspection systems using robots and hydrogen drones. They include the following:

- utilising robots for the internal maintenance of low-pressure pipeline sections and inspection for physical defects and corrosion both inside and outside the pipelines
- real-time monitoring of pipeline information on-site using mobile devices and for emergency response
- addressing blind spots in pipeline patrols and preventing incidents, including unauthorised excavation work based on the hydrogen drone pilot project.

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Security of supply options for the Korean gas market in a fluctuating global liquefied natural gas context

Globalised energy markets and the growing trade in energy carriers have contributed to delivering dispersed energy sources to demand centres across the globe. As energy flows have grown in reach and complexity, so has the interconnectedness of supplier and consumer markets, creating links through which regional market ripples are felt globally. Developments in the global gas and LNG markets have been no different, exemplified by the vast price oscillations and diversions in gas flows experienced over the past 4 years, from the Covid-19 pandemic to the war in Ukraine.

Faced with an increasingly globalised gas market, policymakers have sought ways to shield their countries from market cycles and disruptions, striving to uphold three key pillars of energy policy, namely the stability and affordability of energy supply, as well as its compatibility with a global framework that aims at keeping greenhouse gas emissions on a pathway in line with a 1.5°C increase in global average temperatures by mid-century. In this context, managing exposure to the volatility experienced by global gas markets in recent years has emerged as a key policy issue in both mature and emerging gas markets alike.

These challenges are of particular relevance for Korea as natural gas plays an important role across multiple demand sectors and as LNG represents the only source of gas supply for the country. As the third-largest importer of LNG, accounting for nearly 12% of global LNG imports in 2022, the Korean market is – and will likely remain – exposed to global LNG market fluctuations. Although planned global liquefaction capacity additions are expected to ease LNG market tensions in the second half of the decade, reverberations from any unexpected supply shocks could still have global effects. As such, understanding the risks associated with this exposure and the various policy and market options available for minimising these risks is key to ensuring security of natural gas supply for Korea.

This section of the joint study focuses on the security of supply options available for the Korean gas market in the context of LNG market dependency. It explores options centred on the domestic market, as well as on interactions with the global gas and LNG markets.

Domestic market flexibility as a safeguard for security of supply

Integrating flexibility into a country's domestic gas market – on both the demand side and the supply side – represents an important element of consideration in responding to gas market volatility and risk. Faced with global market realities, developing domestic mechanisms and infrastructure to adapt to volatility can play a key role in curbing security of supply risks.

The European Union's example

In the European Union, two of the most visible elements of gas market flexibility have been the large underground gas storage capacity – equal to approximately one-quarter of EU annual gas demand – and the large fuel-switching potential between coal and natural gas in the power sector. The large volume of gas storage relative to demand in Europe has allowed the continent to smooth its gas import profile despite a highly seasonal demand profile. Additionally, storage facilities have provided extra injection points at the grid level, helping respond to extreme and volatile weather phenomena more efficiently than certain import options at Europe's borders. On the supply side, gas storage has proven highly responsive to market dynamics, helping smooth price volatility over prolonged periods of time.

On the demand side, one of the primary flexibility options has been provided by the power sector. Abundant gas- and coal-fired capacity in the European Union has allowed for switching across these fuels in line with evolving natural gas and coal price dynamics. High gas prices – the result of tighter gas market fundamentals – favoured coal plant economics, leading to a reduction in power sector gas demand. Lower gas prices relative to coal led to the opposite effect as power sector economics favoured increased gas burn.

This combined flexibility fostered a degree of price-sensitive supply and demand response, contributing to the smoothing of volatile prices through the year and, most importantly, in periods of domestic or international gas market tightness. However, as the European energy system evolves, notably with the retirement of coal-fired power capacity and the growing integration of intermittent renewables, finding alternative avenues of gas market flexibility – on both the demand side and the supply side – will be essential to maintaining a layer of protection from international gas market volatility. Likewise, other markets, such as Korea, will have to ensure coherence between the market flexibility options they seek and the other energy market objectives they may have, including decarbonisation and the overall minimisation of energy system costs.

Demand-side flexibility

As power systems integrate a growing share of non-dispatchable renewables and the residual load falls over time, the price elasticity of gas demand in the power sector is likely to play a diminishing role in providing demand-side flexibility in any given energy system at the wholesale level. However, although gas demand in power generation may tend to become less price-elastic as gas increasingly serves as a backup to volatile renewable power generation, exploring levers of demand flexibility in alternative sectors remains important.

Demand-side response can be developed in the industrial, commercial and residential sectors in line with the specific response parameters required (e.g. the duration, volume and timing of the turndown in demand). Developing such potential requires a robust regulatory and legal framework that sets out the rules and incentives for participation in the scheme across different sectors.

Importantly, this requires diving down to the retail market level and synchronising measures with network regulation, adapting measures to a country's market particularities. Korean efforts with the Energy Pause programme and the technological automation of demand response are examples of such effective measures. However, continued testing and regulatory experimentation can provide further benefits by broadening the actor base targeted by demand response measures, fine-tuning business models for implementing energy savings and improving technologies deployed at the appliance scale to take advantage of more flexibility opportunities.

A central element of functional demand-side response is the transmission of price signals to energy consumers: transparent price signals are key in guiding consumer behaviour. The challenge is in striking an acceptable balance between protecting consumers from a degree of price volatility and aligning demand behaviour with security of supply considerations – instead of demand behaviour exacerbating supply shocks in a scenario where no price signal transmission takes place between the wholesale and retail markets. Maintaining price sensitivity is, therefore, central to developing demand-side flexibility as a further tool for managing market volatility and uncertainty.

While much of the demand response currently deployed in Korea focuses on electricity demand, exploring gas market options directly could open the door for further flexibility gains.

Supply-side flexibility

Natural gas storage remains a key supply-side flexibility option in managing security of natural gas supply, providing seasonal and daily – and even more granular – responsiveness to market fluctuations. Maintaining – and potentially expanding – LNG storage in Korea (or even in neighbouring markets) is therefore an essential element in countering gas market volatility, and dimensioning this capacity in volumetric and send-out terms should be done in relation to the anticipated market requirements.

Energy storage can also be considered on a wider scale, integrating various solutions to the issue of supply flexibility into the broader energy system. Gas-fired power plants provide key supply-side flexibility to the electricity market at times of peak demand or of lower renewable supply. As such, the links between the power and gas markets can be explored to put in place broader energy storage solutions, integrating flexibility options across different time scales and including LNG storage and electricity storage, such as batteries.

A system-wide assessment of the flexibility requirements is the first step to deploying these technologies and placing them in the context of both supply flexibility and network flexibility. Capturing the greatest benefit from the technologies requires considering them in the wider network planning process. Facilitating the integration of these flexibility options and limiting the cost and regulatory barriers to their proper functioning are also key. As electricity storage capacity grows, updating the regulatory frameworks might be necessary to ensure the full capture of benefits to the market.

Different energy storage options will offer different solutions in the market – seasonal versus daily flexibility, for example – and should be dimensioned to have the greatest effect on securing energy supply and reducing system costs. While LNG storage acts directly on the gas market and offers both short-term and (to some extent) seasonal flexibility, electricity storage options such as pumped hydro or grid-scale batteries can complement the security of gas supply architecture through additional gas demand-side flexibility in the power generation sector. As such, strengthening gas market flexibility can be the result of integrating both gas and power storage options.

Diversification and flexibility in sourcing gas on the international market

As Korea’s LNG imports have grown, so has the diversification of its supply sources, with LNG volumes being sourced from multiple exporting countries spanning both the Atlantic and Pacific Basins. Diversification – in terms of supply source, contract duration and contract pricing terms – as outlined by the 15th Long-Term Natural Gas Supply and Demand Plan, has taken a step in the right direction in establishing a complementary gas supply portfolio that can respond to international LNG market dynamics. The greater the flexibility within individual contracts and across the broader national portfolio, the easier it becomes to ease price and supply pressures.

Other options exist in terms of LNG contracting to ensure a degree of flexibility in tackling LNG market cycles, notably by safeguarding extra LNG volumes beyond those deemed necessary under commercial undertakings. Establishing a national buffer by over-contracting LNG can ensure optionality on LNG supply, particularly in periods of expected volatility and uncertainty. Efforts by LNG buyers to secure an increasing degree of destination flexibility in long-term LNG contracts can make this option more viable, offering the possibility to resell unneeded LNG volumes in the global market.

Diversification and flexibility in the gas market can also extend to developing natural gas alternatives, including biomethane, hydrogen and its derivatives, and other gases. Quantifying the potential role of these alternative gases is key to establishing the scope for reducing both volumetric and volatility exposure to the LNG market.

Developing such alternatives again rests on the implementation of targeted policy that ensures a reduction in lifecycle greenhouse gas emissions while avoiding unacceptable social, environmental and economic impacts. These policies should take advantage of market realities in related areas, including in agriculture and waste systems. Furthermore, they should follow the principle of targeting the highest-value uses for bioenergy and waste-derived fuels, which means that arbitration between biogas and other biofuels could be necessary in a system-wide energy approach. As such, a system-wide approach could reveal that gas may not be the most appropriate fuel to benefit from the potential, depending on the flexibility and decarbonisation values attached to different fuel options.

The development of a hydrogen market (driven by imported and domestically produced hydrogen) also has important potential as an alternative to natural gas as it is used today in the Korean energy system. However, its development should rest on a cross-sectoral and co-operative approach at the international level so as to take advantage of mutualised investments, as well as technological and market developments.

Domestic hydrogen production and consumption targets, R&D spending, infrastructure investment, pilot projects and end-market stimulation (notably in low-carbon industrial goods and appliances) are all key domestic levers for promoting the development of a hydrogen market. However, developing a market for hydrogen and other low-carbon alternative gases to natural gas will have the largest impact if it is done in co-operation with broader global market trends and can benefit from developments in neighbouring and partner countries.

Reducing gas demand in the medium term

For mature gas-consuming markets, reducing gas demand in the medium term can represent a pathway to managing exposure to the volatility of the global gas market. Structurally lower demand, in the case of an importing country, has the added benefit of reducing national current account outflows. However, potential security of supply challenges and pitfalls remain, even under such a demand reduction pathway.

The reduction of import dependency on natural gas does not necessarily resolve the issue of overall import dependency for energy supply, just as limiting reliance on the supply of a particular energy source does not necessarily solve the issue of evolving demand dynamics. Reducing natural gas demand in the medium term is therefore a balancing act between energy demand realities and the reliability and affordability of alternative energy supply.

Heating demand: End-use efficiency and the electrification of heat

Heating demand is one of the more decentralised energy consumption categories, relying on distribution networks, household-level boiler systems and appliances, and building norms. Managing demand in this sector therefore relies on the careful alignment of policies across different market segments.

Incentivising the deployment of certain boiler technologies and promoting adequate insulation levels across a country's building stock are key to improving energy efficiency in heating applications and aligning this demand sector within the broader energy system. The electrification of heat – through the deployment of heat pumps,[5] for example – and the development of district heating networks also provide potential avenues to improve energy efficiency and, in the case of district heating, centralise fuel and technology choices in response to the market context.

Technology and policy decisions towards alternative fuel options for heating take time to implement and require precise implementation. Restructuring energy demand in heating applications in the future requires early policy action. Examples of such policy action are reducing upfront costs through subsidies for more efficient technologies (such as heat pumps), taxation on more polluting fuels (such as gas) and gradually more stringent energy efficiency norms for commercial and residential buildings. On this last point, enforcement, monitoring and compliance practices should be streamlined to facilitate administrative

[5] The IEA report on the future of heat pumps in China deals with this topic in significantly more detail. Although the geographical scope of that report obviously differs from this one, many of the policy recommendations are relevant to consider for Korea as well.

procedures for building owners as well as to ensure the effectiveness of efficiency objectives and the money spent to attain them.

Complementary to investment in the building stock and the deployment of new boiler technologies, consumer behaviour has a role to play in delivering energy savings in the residential and commercial sectors. As evidenced by the campaigns rolled out in the European Union (and globally) in the wake of the 2022 energy crisis, disseminating (and potentially incentivising) best practices in terms of consumer behaviour is an essential lever in realising structural shifts in energy consumption habits, for instance with respect to when and how much to heat.

Power sector demand: Reducing the residual load

Natural gas demand in the power sector accounts for approximately half of current total natural gas consumption on an annual basis in Korea, and for over one-quarter of total annual power generation. Given the importance of natural gas in this sector, power sector dynamics are central to the broader trend of gas use in the Korean economy, representing a key lever for demand reduction (or stabilisation) in the medium term.

Increasing the share of priority-dispatched, low-carbon power generation capacity represents a structural approach to reducing the residual load in a power system. In the case of Korea, this has happened over a number of years through the development of renewable power generation – notably solar PV capacity additions – as well as through the maintenance of existing nuclear reactors and the development of new nuclear capacity.

The role of natural gas in the power sector is therefore highly sensitive to the timeliness and order of magnitude of the deployment of these technologies, leading to potentially wide uncertainty ranges in power sector gas demand over the medium- and long-term time horizons. Managing the residual load – and therefore the power sector's exposure to natural gas – through higher renewables deployment and sustained nuclear baseload generation is therefore highly reliant on the stability, efficiency and visibility of the renewables policy over time.

Long-term targets and policy stability are essential in ensuring investor confidence and continued growth in renewable technology deployment, while policy flexibility remains important in adapting to changing energy market conditions. The choice and design of such policy instruments are also crucial and should be based on evidence taken from the global market. For example, despite myriad available policy instruments to support renewable power (including feed-in tariffs, quotas and portfolio standards), auctions for the centralised competitive procurement of renewables have emerged as a key instrument across many countries, proving crucial in discovering renewable energy prices and containing costs.

Effective policy and regulatory structures are also key to ensuring the successful deployment of these technologies. While oversight and shared responsibilities among different government agencies in permitting and project approval remain important to ensure the legitimacy of projects in both the wider energy market and society, removing bottlenecks in the project approval process is crucial. Simplifying administrative procedures, reducing delays and involving government agencies in project site identification are examples of principles that should be considered to create a fertile environment for the uptake of renewable power generation.

Finally, integrating these renewable capacities into the power system is an equally important policy and infrastructure challenge. As such, developing a renewable electricity production base must be done in tandem with policy pertaining to such issues as energy storage, demand-side management and the strengthening of grid infrastructure. Any incoherence between the promotion, deployment and integration of renewable capacity creates the likelihood of inefficiencies and bottlenecks, in turn jeopardising the full advantages of renewable energy objectives and their effectiveness in reducing reliance on imported fossil fuels.

Driving elements behind the successful development of renewable power capacity

Tendering	Deployment	Integration
Choosing the best instruments to drive renewable projects (e.g. **auctions**)	**Removing bottlenecks in project approval and deployment** processes, including the optimisation of permitting procedures	Ensuring **adequate grid development** in line with renewable power projects
Minimising system costs and maximising data transparency (e.g. promoting renewables development must be rooted in **creating a competitive environment**)	**Minimising the risks and uncertainties** relative to project timelines and challenges (e.g. balancing deployment objectives with project legitimacy in society)	**Integrating renewables production** through coupling with storage solutions, alternative gaseous carriers and demand-side management

Industrial demand: Ensuring energy supply for the future industrial base

By its commercial nature, the industrial sector is incentivised to optimise its use of energy in production processes. However, policy terms and incentives remain relevant in shaping energy consumption trends in the sector, and even more so in ensuring that a country's energy system develops in step with the evolution of industrial activity.

Existing industrial processes evolve over time through technological progress, and new industries develop, leading to potential changes in the energy consumption profile of an economy. The electrification of industrial processes and the development of electricity-intensive activities – such as the growth in data and computing centres – are examples of potential shifts in industrial energy demand. While such demand-side developments may happen on commercial terms, policy support can have a role in shaping the future industrial energy demand profile, just as it has a role to play in ensuring that developments in energy supply and the energy system support evolving industrial energy needs.

The reduction of natural gas demand in industry continues to face challenges, hand-in-hand with the broader challenge of decarbonising the industrial sector, notably in heavy industry and high-heat applications. Moving away from gas (and other fossil fuels) in industrial processes through low-carbon technologies has proven relatively slow and expensive and led to only modest progress at the global scale. Looking forward, energy challenges in the industrial sector will be closely linked with the broader challenge of decarbonisation.

Most policy in tackling the challenge of CO_2 emissions from industrial activity rests on a combination of both economic levers – such as carbon pricing or carbon border adjustments – and co-operation at the regional and global scales in order to limit carbon leakage from uneven policy implementation. International co-ordination and co-operation in this direction provide the benefit of establishing common rules, reducing uncertainty for governments and industrial players alike in shaping the industrial energy profile of a country.

Industrial investments are typically high-cost and high-risk and are characterised by long asset lifetimes. In the case of Korea, examples of such investments could pertain to improving material efficiency in high-value chemicals and the steel sector by shifting production assets to integrate a greater share of recycled materials or better capture waste heat. Alternatively, another type of potential investment could be aimed at shifting the entire industrial process towards alternative energy sources. An example of this could be the transition towards hydrogen-based steel production. As such, reducing the commercial risks for industrial players in both the development and deployment of new technologies is key and extends to multiple segments of the industrial value chain, spanning research and development, the buildout of supporting infrastructure and the fostering of end-markets for low-carbon industrial goods. Government policy decisions have a key enabling impact on technological breakthroughs given the long lead-times for bringing new technologies and processes to market. These policy decisions should focus on interlinking the multiple stakes of the industrial sector, including – but not limited to – the promotion of industrial activity, decarbonisation of energy-intensive processes and maintenance of energy accessibility through the transition process.

However, key industrial specificities also need to be considered in deploying policy strategies. The iron and steel sector, foundational to Korea's industrial fabric, is one such example where the challenges of decarbonisation and reducing exposure to natural gas could be seen as difficult to reconcile. Decarbonising steel production will require a move away from unabated coal use in basic oxygen furnaces, which accounts for nearly 70% of Korean steel production today. Alternative technologies, such as electric arc furnaces – the second-most deployed steel-producing technology in Korea – or direct reduction of iron, could have an impact on natural gas consumption. This is where careful and targeted policies will be necessary to make sure that industrial developments are adequately accompanied by energy system developments.

Renewables as an opportunity and a challenge for gas market dynamics

The increasing role of renewables in the Korean power market is set to reduce the country's requirement for fossil fuels, including gas, in the power sector. However, while higher renewable power generation will constrain volumetric exposure to global gas markets, it poses alternative challenges in the power sector that may have knock-on effects on gas market dynamics. As such, the way in which new capacities are integrated into the power system is key in dimensioning the residual role and requirements that the gas market will have to fill in the power sector and beyond.

One such challenge is the production profile of renewable technologies. The nature of solar PV – currently the most deployed renewable technology in Korea – creates high production variability on both daily and seasonal scales. Solar PV deployment will reduce gas demand in power generation on a yearly scale, but it may have a more limited impact on reducing peak daily natural gas demand in this sector, notably on cold winter days with lower solar radiation. As such, the simple addition of renewables might not guarantee a reduction in gas system costs and could have a limited effect on peak infrastructure and sourcing requirements.

While an increasing share of renewables can exacerbate the challenges associated with volatility and the production profiles of certain renewable technologies, the integration of complementary technologies can help temper these impacts on the system, ultimately translating into less volatile demand for back-up capacity in the electricity market. In principle, the more variety in the type of renewable technology, the more effective the benefits in both volumetric and volatility terms. Careful consideration of renewable capacity development in the power market is therefore of utmost importance in structuring the role that natural gas will play as a baseload or back-up technology in the power system.

Domestic gas market reform

The Korean gas market has integrated an increasing share of direct LNG imports, diversifying contracting from the historical importer and distributor, KOGAS. Although the conditions under which market actors can import LNG directly remain narrow, this represents a development in the dynamic management of the country's LNG requirements. The creation of this option offers certain companies a complementary lever in managing their gas supply portfolios and strategies.

In other markets, such as in the European Union, this ability to source gas through direct imports or through portfolio wholesalers is accompanied by a further element of dynamic portfolio management. In addition to the ability to source gas freely and independently of state-level considerations (even large, historically public gas buyers generally no longer answer to government imperatives in their sourcing strategies and activities), gas market actors are also able to manage their energy portfolios through reselling gas as necessary on the internal European market. This affords an additional layer of flexibility to gas buyers in responding to fluctuations in their own activity as well as in the broader gas market.

This ability for all market players to act independently on both the buy side and sell side has played a significant role in developing a highly liquid and dynamic gas market that transmits price signals efficiently across the energy system, allowing for demand and supply responsiveness to market pressures. Developing this market liquidity has depended on extensive regulation guaranteeing third-party access to gas import, storage and transmission capacities, as well as the development of gas hubs to facilitate gas trading. Furthermore, market development has rested on clear regulatory rules regarding market segmentation between network operation on the one hand as a regulated monopoly, and supply, trade and retail activities on the other hand as competitive activities, breaking up the integrated structure that previously prevailed in the European gas market. The role of independent, neutral regulatory bodies has been essential in managing the various (and potentially conflicting) interests of gas market participants, ensuring the smooth functioning of a liberalised market.

The flexibility in sourcing and trading gas and the clear separation of roles in the market have helped the EU market adapt to both domestic and international uncertainties, ranging from evolving domestic energy demand and supply trends to geopolitical events and their effects on global energy supply flows. However, for the European Union, this market structure has developed in the particular context of a large import-dependent market with multiple supply options. Replicating similar market liberalisation policies in other market contexts – such as in Korea – requires careful consideration of the potential advantages and challenges of diluting market concentration and decentralising market flexibility. Decentralising the management of gas supply and trade while fostering greater liberty for market participants to manage their supply portfolios could lead to trade-offs in the sourcing of natural gas from the international market.

Moving away from the centralised planning of LNG supply could, in certain circumstances, reduce bargaining power in international markets to the extent that decentralised buyers would handle smaller volumes than a central buyer. Equally, distributing the responsibility for LNG buying could imply relinquishing a degree of central oversight of sourcing strategies and objectives. Commercial logic will drive private actors' actions in the market, which are further removed from policy objectives than, say, a central buyer with close ties to the state. As such, the alignment of private and national interests rests in great part on gas market participants having access to clear market signals – notably with respect to the transmission of international gas pricing to the domestic market – and to import, transport and storage infrastructure. Decentralisation of sourcing responsibilities must be accompanied by decentralisation of the means to act efficiently in the market.

In considering domestic gas market reforms, the potential challenges LNG sourcing decentralisation would bring – as well as their respective probabilities and impacts – should be weighed against the potential advantages of added flexibility in dealing with market uncertainty.

International co-operation

Just as the security of gas supply at the national scale relies on the interplay of fuels, markets and policies across an energy system, the mutualising of risk and flexibility at the international scale can have a role to play in shielding a market from international LNG market fluctuations and volatility. Co-ordination among LNG-importing countries can open the door to an additional avenue of supply flexibility, particularly among markets with complementary gas demand profiles.

This complementarity can notably be found in the LNG import or overall gas demand profiles of two or more given markets throughout any given year. Co-ordination among markets with opposite – or at the very least staggered – demand profiles could pave the way for supply to be diverted from an LNG importer in a low-tension market situation (low seasonal gas demand) to an importer in a high-tension situation (peak seasonal demand). Such complementarity could respond to volumetric imbalances between markets but also equally respond to imbalances in volatility profiles, taking into account the notion of urgency in the demand requirement in contrast to the size of the demand requirement. While international spot pricing of LNG already provides a market mechanism to measure the import needs of one market in relation to another, co-ordination and co-operation among these importing markets could allow for improved visibility and a degree of protection against sudden price movements stemming from the competition to attract waterborne LNG volumes.

Beyond the notion of the complementarity of gas demand profiles across countries, co-operation at the international scale in LNG sourcing – whether through joint purchasing or simple dialogue – could have a role to play in reducing uncertainty in periods of market tightness and volatility. Transparency in policy mechanisms and information-sharing among LNG-importing markets are preliminary steps in this direction but could form the basis of more dynamic and co-ordinated responses to supply constraints in the global LNG market.

Such exchanges must be initiated through government-level dialogue to create a framework for collaboration. However, this process should ensure the involvement of gas market players to foster links at both the governance and industrial levels, increasing the chances for dialogue to turn into tangible co-ordination benefits. Potential joint purchasing of LNG with neighbouring and partner countries is likely to be facilitated by a similar approach, establishing clear guidelines at a governance level within which market actors can respond to a flexibility requirement in LNG sourcing.

Conclusion

Potential measures to fortify security of gas supply are multiple, providing the opportunity for tailor-made approaches for different energy market contexts. However, a number of overarching realities remain, highlighting key considerations to take into account when devising security of supply solutions.

Natural gas markets – at both the domestic and international levels – are part of a wider energy market context. As such, solutions for reducing volume and volatility exposure in the gas market might not reside solely within the realm of the natural gas market. Likewise, gas market policies and developments can have impacts on other energy markets, which need to be taken into account. Thinking outside the confines of a strict gas market context is therefore key to making sure that, on the one hand, security of gas supply considerations fit within a broader system-wide approach to energy security and, on the other hand, that system-wide evolutions support the specificities of the gas market.

Additionally, while many market and policy solutions can be developed and implemented at the domestic-market level, others require international co-operation in order to unlock further benefits. As highlighted by the energy crisis in 2022, challenges to the security of gas supply are cross-border and cross-regional. Solutions to these challenges must therefore capitalise on policy and market co-ordination at the international scale so as to better anticipate and respond to global market dynamics.

Finally, gas – and broader energy – market and policy developments, whether pertaining to security of supply or other challenges, are highly codependent on the challenge of decarbonisation. It is therefore virtually impossible to make an abstraction of the decarbonisation agenda in working towards security of gas supply objectives, and making progress on the latter often depends on making progress on the former. In this context, it is evident that addressing security of gas supply challenges is most effective through cross-challenge, cross-market and cross-border approaches.

Abbreviations and acronyms

EU	European Union
FID	final investment decision
FSRU	floating storage and regasification unit
IEA	International Energy Agency
KEEI	Korea Energy Economics Institute
KOGAS	Korea Gas Corporation
LNG	liquified natural gas
LPG	liquified petroleum gas
OECD	Organisation for Economic Co-operation and Development
R&D	research and development
SMP	system marginal price

Glossary

bcm	billion cubic metres
bcm/yr	billion cubic metres per year
Gcal	gigacalorie
GW	gigawatt
TWh	terawatt hour

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