



International
Energy Agency
Secure
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Together



Global Gas Security Review

*How Flexible are
LNG Markets in Practice?*

2016



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INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 29 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
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International Energy Agency
9 rue de la Fédération
75739 Paris Cedex 15, France

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Foreword

Energy security has been the core of the International Energy Agency (IEA) mission since its foundation in 1974. At the time, the aim was to ensure the security of oil supplies amid geopolitical tensions. While the world has since changed, this mission remains at the core of our mandate and is the foundation for the IEA's expertise on energy markets.

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The IEA has also evolved. Since I became Executive Director last year, we have opened our doors to some of the key emerging countries, reflecting the fact that the growth in energy demand around the world now comes from the developing world. Since 2015, the People's Republic of China, Indonesia, Thailand, Singapore and Morocco have all joined the IEA family as association countries. And Mexico and Chile are in talks to join our organisation as well.

Faced with the threat of climate change, we are also helping to steer governments towards a clean energy transition. The IEA has become a hub for clean energy technologies and is a global leader in understanding the future role of renewables and energy efficiency in the global energy system.

Still, our security mandate remains critical. In fact, we have broadened our definition of energy security as we witnessed the emergence of new energy security challenges beyond the oil markets. These include electricity stability and integration, and, of course, they include gas.

In response to these new challenges, our member countries tasked us to add gas security as a new IEA mandate. As this report shows, the security of natural gas supplies should not be taken for granted. It is true that the growth in the global gas trade, and the diversification of supply sources, bring important supply security benefits to consumers. But this globalisation of the trade also means that demand and supply shocks that were once confined to single regions may now have repercussions in more distant places as well.

As the role of gas in the energy system evolves, a narrow approach to gas security focusing on gas as a standalone fuel in an individual region is no longer appropriate. In this report we address two fundamental aspects of global gas security: how much slack is there in the global gas system? And how flexible are LNG markets in practice?

We aim to provide more transparency for LNG markets and assess the degree of flexibility they can provide in the event of a demand or supply shock in the global gas markets. The analysis builds on an extensive set of data and feedback from industry's contacts across the world.

It is my sincere hope that this report, which is the first of a new annual series, will make a positive contribution to our understanding of global gas security.

Dr Fatih Birol
Executive Director
International Energy Agency

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Executive summary

Low natural gas prices, along with expectations for continued well-supplied liquefied natural gas (LNG) markets over the medium term, are giving some a sense of comfort over markets' ability to adjust to potential demand or supply shocks without placing national and regional gas systems under unacceptable stress.

There is no doubt that today's market conditions are helpful for global gas security. A massive expansion of LNG export capacity is coming at a time of weaker-than-expected global gas demand. The temporary excess of supplies resulting from this situation is providing a buffer that would mitigate the impact of possible supply disruptions.

Yet, the supply security architecture of an energy system should not be based on cyclical factors. Today's oversupply should not be regarded as a structural feature of the market and thus as an expression of the higher level of security that LNG markets can bring. On the contrary, it stems from a step change in the pace of global gas demand expansion that caught industry by surprise, and as such it highlights the challenges of accurately forecasting demand (and supply) in a rapidly evolving energy system. What is clear is that market conditions change, often unexpectedly, and the global gas security structure should be – as much as possible – resilient to sudden shifts.

This report focuses on two essential elements of a global gas security assessment: how much redundancy is embedded in LNG infrastructure – particularly the liquefaction portion – and how flexible LNG supplies are in practice.

Little volume flexibility in LNG liquefaction infrastructure

LNG export infrastructure has lower physical production flexibility than commonly perceived. Today, around 15% of export capacity is offline – roughly the equivalent of the combined exports of Malaysia and Indonesia. The lack of feedstock gas is the main factor explaining the large level of unusable capacity. The remainder is attributable to a combination of hard security issues and technical problems.

Once all unavailable capacity is excluded it becomes clear that LNG plants are operated as baseload facilities. Utilisation is very high and has hardly changed since 2011. This reflects both the cost structure – characterised by very high upfront capital costs – and the technical characteristics of LNG export plants. As such, the business model underpinning LNG production is by definition rigid. The result is a basic lack of short-term upswing capability in LNG production. The large wave of new LNG capacity that is currently entering the market has the potential to push utilisation levels lower, as a means to rebalance the market. This should be regarded as a cyclical rather than a structural development, however, since neither US nor Australian LNG plants are built with the explicit objective to operate below full rate.

Destination flexibility is increasing thanks to the arrival of US volumes

Under normal circumstances, continued growth in LNG trade does not result in additional volume flexibility, owing to the reasons just described. From a security of supply standpoint, therefore, the degree of destination flexibility of existing and future supplies is an important determinant of the resiliency of the global gas system. The possibility to re-direct LNG as needed according to price signals would allow for an efficient low-cost allocation of available supplies. In the event of a supply disruption or a demand shock, LNG trade flows would rapidly shift so that gas can reach the regions that need it most.

A detailed analysis of contracted volumes and trade flows shows that a wide range of contractual structures exists, as well as a wide range of producers' attitudes towards allowing gas supplies to be re-directed. Broadly speaking, demand for flexible LNG supplies can be met via one of three ways: LNG production volumes that are uncontracted; volumes that are contracted to a specific destination but re-directed; or contracted volumes open to multiple destinations (which enable gas to flow to demand). These three ways of delivering flexible volumes – to those who require them – have played a similarly important role over the past five years.

From a producer perspective, Qatar has accounted for more than half of overall uncontracted supplies while Nigeria, Trinidad and Tobago, and Equatorial Guinea – alongside Qatar – have provided most of the flexible volumes delivered via diversions or through open destinations.

Looking ahead, the arrival of large volumes of US LNG will markedly increase the destination flexibility of the LNG trade, by augmenting the share of gas sold via open destinations. Roughly half of incremental LNG production between 2016 and 2021 is forecast to come from the United States. The fully flexible contractual model underpinning US export capacity will improve the ability of the global gas system to react to potential demand or supply shocks by making it easier to shift volumes from one destination to another.

There is already clear evidence that contractual structures are becoming less rigid. By comparing contracts signed before and after 2009, three major trends are apparent. First, volume per contract has become smaller. This reflects a gradually more open market, with a higher number of buyers and sellers, and growing participation of smaller LNG importers in emerging markets. Second, the predominance of oil indexation as the pricing mechanism has been diminishing. And third, the share of contracts with flexible destinations has steadily increased. For contracts signed in 2015 this share has reached close to 60%, from just around 33% for those signed before 2009. The value of destination flexibility is evidenced by buyers' willingness to lock themselves into longer contracts when the terms are flexible. Contracts signed in 2014 and 2015 with flexible destinations were, on average, one-third longer than those with fixed terms.

Crucially, however, destination flexibility is a tool to provide the volume flexibility required in the case of a demand/supply shock. Such volume flexibility would need to come from the demand-side, production, or pipeline import flexibilities that different regions can offer and that LNG supplies can help aggregate.

Flexible power systems are a key contributor to global gas security

Japan's experience in dealing with the electricity supply shortage that followed the Fukushima nuclear accident illustrates well the importance of having flexible energy systems to address sudden disruptions. The availability of substantial fuel-switching potential – mainly in the form of oil-fired capacity – in addition to robust power demand restraint capability, was a critical component of Japan's response to the accident. Between 2011 and 2013, gas replaced around one-third of the nuclear loss, an amount similar to the combined contribution of oil and coal over the period, highlighting the importance of a diversified demand structure in responding to the crisis.

On the other hand, it was lower gas demand in Europe, mostly caused by the financial crisis and the flexibility of a well-diversified power generation mix that freed up the incremental LNG volumes needed by Japan. Between 2010 and 2013, coal-fired generation in Europe increased by 7%, offsetting roughly one-third of the fall in gas-fired generation over the period. Strong growth in renewable sources also contributed to lower gas demand in the power sector. At the same time, Europe's ability to arbitrage between LNG and pipeline imports made it possible to increase reliance on pipeline supplies at the expenses of LNG: in particular, Russia's production flexibility

was called upon, with European imports from Russia reaching new highs in 2013 just as LNG imports were plummeting, to be re-directed to the more lucrative Asian markets.

As a result of these adjustments, Europe was the main provider of flexible LNG volumes to global LNG markets in the post-Fukushima period, accounting for two-thirds of the flexible supply released via demand-side adjustments in 2013.

A main lesson from the experience in this period, therefore, is the importance of fuel-switching capabilities for crisis management and, more broadly, global gas security. The flexibility of the power sector has proved to be a major relief valve for gas in periods of tight markets, shortages or demand shocks in gas.

Fuel-switching capabilities in Europe, however, are decreasing substantially. Gas-fired generation has fallen by one-third since 2010. In most European countries, gas is now mostly dispatched for balancing or via combined heat and power systems. Even with coal-fired capacity available, displacing this portion of gas demand would be much more difficult owing to its rigid nature. Furthermore, a substantial amount of coal-fired capacity will be shut down in coming years as a result of a combination of environmental policies and plants reaching the end of their life-time. This will further reduce coal-to-gas switching potential where it still exists. Projections from the *World Energy Outlook 2016* (IEA, 2016) point to a fall in coal-fired generation capacity in Europe of between 27% and 45% by 2030, depending on the scenario. While continuing operation of low-efficiency coal plants is not compatible with environmental objectives, the changing structure of the power mix has implications for the ability of gas markets to adjust to potential shocks and must be taken into consideration by policy makers. Similarly, Japan has depended upon oil-fired generation to avoid black-outs in the post-Fukushima period. More than 60% of Japan's oil units are older than 40 years, which means that the country faces a steep decommissioning profile in the absence of active government policies to keep them on line.

Storage is a key component to a secure gas system.

From a global gas security standpoint, declining fuel-switching capabilities will lower Europe's ability to serve as a major provider of flexible LNG volumes in the event of a global disruption. It will also alter the region's ability to respond to domestic shocks. Europe's changing supply structure towards higher reliance on imports also poses challenges. In particular, both pipeline imports – transported over long-distances – and LNG supplies – originating from countries outside Europe – need to rely on sufficiently filled European gas storages. These assets help re-structure the seasonal supply profile into one that matches demand variations and are also key to balance daily fluctuations.

As result of low spreads between summer and winter gas prices, shippers have become more hesitant to book storage capacities, putting European gas storage operators under economic pressure. So far, a lack of economic incentives has had limited impact on storage levels owing to a combination of legacy long-term capacity bookings and regulatory provisions in specific countries. However, as those long-term bookings roll off, economic pressure will mount for storage operators fully open to competition.

This development must be carefully assessed as storage provides an important contribution to Europe's ability to respond to demand and supply shocks. From a global security perspective, injecting less gas in European underground gas storages during summer would potentially raise Europe's call for flexible imported volumes during winter which – if coming in the form of LNG – would reduce flexible supplies available to others. From a domestic perspective, any disruption that could occur along the transportation route of long-distance pipelines or LNG imports would pose higher security concerns in the absence of sufficiently filled gas storages close to European demand centres.

Introduction

Gas security challenges are evolving as the energy system evolves. In particular, the increasing globalisation of gas, through the expansion in the trade of liquefied natural gas (LNG), and the deep interactions that gas has with the rest of the energy system are creating a more interconnected environment, where shocks in one region reverberate in another. As a result, there is the need for a broader approach to gas supply security that takes into consideration both the functioning and characteristics of the LNG value chain and the demand-side aspects of supply security.

While a comprehensive assessment of global gas security is complex and beyond the scope of this report, this analysis aims to tackle specific aspects that are pertinent to the subject. The main aim is to track and analyse how this evolving structure of gas markets is impacting the ability of the market itself to respond to potential shocks.

Today, ample supply, low prices, and the prospect of additional LNG from the United States and Australia give credence to the view that a new era of enhanced gas security is coming, characterised by a rising share of LNG, a more diverse range of suppliers, less rigid contractual structures and greater market flexibility, all of which point to a more fluid movement of gas in response to price signals across increasingly interconnected regions.

But how much slack is there in the system? And how flexible are LNG markets in practice? This year's edition attempts to answer these questions by providing a detailed analysis (insofar as data allow) of all the elements of this emerging globalised gas system, focusing in particular on LNG, and wherever possible separating out the cyclical factors in a well-supplied market from underlying structural flexibility levels.

Without such an analysis, there is the risk that the current market situation could give policy makers and consumers an elevated level of comfort about gas security, which could evaporate quickly once market conditions change.

Chapter 1 looks at LNG infrastructure, how much is available and how it is being utilised. It explores in detail the level and cause of various outages in the system, to assess the actual size of the “buffer” in global LNG supply.

Chapter 2 turns to the issue of flexibility, starting with the analysis of how demand for flexible volumes has evolved and where it stands today. The latter part of Chapter 2 considers how requirements for flexible volumes could evolve in the future, primarily as a function of developments in Asia.

Chapter 3 looks into who provides that flexibility and how it is delivered. There are three distinctive elements of such flexibility: first, LNG production that is uncontracted; second, volumes that are contracted to a specific destination but can be diverted or redirected to meet short-term needs; and third, volumes that are contracted but open to multiple destinations (including the volumes held by so-called “portfolio” players or aggregators).

Chapter 4 and 5 cover two case studies. First, we assess the way that LNG markets responded to the impact of the Fukushima nuclear accident which led to the closure of Japan's nuclear power plants, and the circumstantial and structural elements that allowed LNG to be diverted to meet Japan's needs. Second, a detailed analysis of the elements of flexibility within the European gas market, noting in particular the declining flexibility coming from indigenous production and, to a degree, storage and fuel-switching capabilities. This report analyses whether more flexible external supplies can compensate for these trends, whether from LNG or from spare capacity in Russian Federation production/transportation, and examines the implications of both for the debate over the security of the European gas supply.

1. Global LNG infrastructure

The world had an export capacity of 445 billion cubic metres (bcm) of liquefied natural gas (LNG) at the end of October 2016, but close to 65 bcm is off line – equal to combined exports from Malaysia and Indonesia. The level of unusable LNG export capacity more than doubled between 2011 and 2016, and its share relative to total installed capacity increased as well. This implies much less supply flexibility compared with that suggested by gross capacity figures.

Lack of feedstock gas is the primary reason for the large underutilisation of LNG plants, accounting for roughly three-quarters of the unusable export infrastructure. The rest is attributable to a combination of hard security issues and technical problems. Extreme weather accounts for just around 1% of unavailable capacity.

Average utilisation of LNG export plants – excluding all unavailable capacity – has remained stable at close to full rates in recent years. High utilisation reflects a key feature of LNG systems, mainly the fact that liquefaction facilities are built to operate base load. The result is a basic lack of additional liquefaction capacity to readily meet short-term upswing in LNG demand.

The arrival of Australian and United States (US) LNG on the market just as growth in global gas demand slows is challenging these basic operational principles. New capacity additions are now so large that they are outstripping both ongoing disruptions and incremental demand. The year 2016 could be the first year when actual utilisation of LNG export capacity (utilisation of the capacity technically able to run) is not at maximum.

The presence of a supply buffer – through a period of oversupply – will have a positive impact on global gas security. Yet it should be clear that this is not the result of successful gas security policies, nor is it a permanent feature of the market (the supply buffer will be worked off and LNG plants will return to operate base load over time). And it certainly was not the purpose of LNG project developers when they took final investment decisions (FIDs) for those projects. On the contrary, it underscores the challenges of accurately forecasting demand in a rapidly changing energy system: global gas demand proved much weaker than previously expected. It would be unwise to regard today's oversupply as a permanent expression of the higher level of security that LNG markets offer.

Liquefaction capacity additions over the 2015-22 period stem from investment decisions taken between 2009 and 2015. By the early 2020s, the impact of the current supply wave will run out. Unless new investment decisions are taken in the next two to three years, LNG production will flatten out by that time.

So far this year just 5 bcm of new liquefaction capacity has been sanctioned, compared with an annual average of around 35 bcm over the previous five years. Similarly, new contracts – a key prerequisite and leading indicator of future FIDs – have plummeted since 2015 and stayed at rock-bottom levels in 2016. This points to continued low FIDs into 2017.

Investments in new regasification infrastructure are not subject to the same long investment cycles typical of liquefaction projects, due to much lower capital costs and much shorter construction times. Unlike liquefaction plants, regasification terminals cater to the needs of a specific country (or at most a region) and are often built to address swings or variability in the demand profile of a specific country. They are built as part of an integrated infrastructure system and contribute towards a country's broader energy security objectives. Due to all these factors, regasification terminals – unlike liquefaction facilities – tend not to operate at full capacity, although the exact level of utilisation ranges widely depending on the function and purpose of the specific terminal.

From a global perspective, the presence of an extended, geographically diversified regasification infrastructure – if reflective of an extended, geographically diversified LNG trade – would allow for the aggregation of a wider range of demand/supply flexibilities that exist across different domestic/regional gas systems. This is beneficial to the gas security of all countries.

LNG export capacity: How much is actually available?

Getting a reliable snapshot of global LNG infrastructure is a more complex task than the simple compilation of existing projects. At any point in time, actual LNG production capacity differs from nominal capacity. Many factors – ranging from technical issues to security conditions and maintenance status – can affect actual LNG export capacity. Tracking those fluctuations – and particularly the emergence of any lasting trend – is key in providing an accurate picture of what is actually going on on the supply side of global LNG markets.

LNG liquefaction capacity is generally expressed in terms of million tonnes per year of nameplate capacity, which refers to the intended full-load sustained output of the facility. However, nameplate capacity normally differs from the level of capacity actually available to the market. Various factors affect the utilisation of a facility. Usually, they limit (rather than increase) available capacity relative to the designed one. The most common factors affecting the capacity of an LNG facility, in addition to planned maintenance, are as follows:

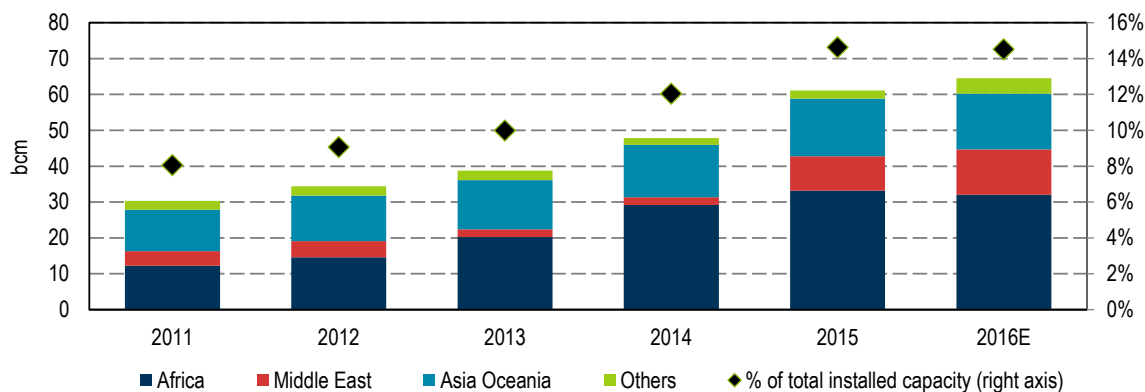
- **Lack of feedstock gas.** Production from the gas fields “feeding” the LNG export plant is either in decline or insufficient to meet both export needs and domestic consumption. As a result, the gas flow into the LNG plant is cut below maximum levels. This is by far the most common factor limiting actual capacity of existing LNG facilities.
- **Technical problems.** LNG plants are complex sites and they regularly undergo maintenance. Yet unexpected technical problems can emerge (more often during the start-up period), causing unplanned shutdowns. These can be shorter or longer depending on the extent of the problem and the scale of repair work involved. In some cases, especially prevalent during early years of operations, they can last for years.
- **Security problems.** Several LNG facilities are located in politically unstable regions where unrest is frequent and security is poor. This can (occasionally or periodically) result in the evacuation of personnel and the partial or total shutdown of the LNG facility. In the worst cases, the export plant itself can be damaged due to direct attacks or collateral damage.
- **De-bottlenecking/technical upside.** This refers to the (relatively limited) cases of LNG plants consistently running above their nameplate capacity. This is usually due to unreported de-bottlenecking of the facility or implementation of projects aimed at reducing boil-off. In some cases – often in very cold climates – the plant can produce above its designed level as low external temperatures allow for higher-than-average efficiencies. Notably, the positive impact from this category is much less significant than the impact from any of the limiting factors described above.

While actual capacity fluctuates over time, depending on the evolution and interaction of the factors described above, the past five years show a consistent trend of increasing volumes going off line (Figure 1.1).

This report estimates that between 2011 and 2016, the level of LNG capacity unavailable to the market more than doubled, reaching about 65 bcm. This roughly equals combined exports from Malaysia and Indonesia – in 2015, Malaysia ranked as the third-largest LNG exporter and Indonesia the fifth-largest. The share of capacity off line relative to the total installed capacity has

also increased. Overall, this implies much less production flexibility in the system than what is indicated by gross capacity figures (see appendix table 1).

Figure 1.1 • LNG capacity off line by region



Source: IEA analysis based on ICIS (2016), *ICIS LNG Edge*.

From a regional perspective, Africa displays the poorest utilisation levels across the regions, with only around 65% of LNG capacity on the continent actually able to run. All producers, with the exception of the small exporter Equatorial Guinea, have experienced problems of some sort. Underutilisation in Algeria and Egypt results predominantly from lack of feedstock gas. Egypt completely halted its exports in 2015 as the government prohibited them, leading to *force majeure*. In Algeria, LNG exports have fallen by 30% over the past ten years, despite a sizeable increase in installed capacity. Theoretically, this could be a consequence of weak demand in Europe (the primary export market for Algerian gas) but in practice this is unlikely, as evidenced by the lack of any short-term production and export response to the tight LNG market, high Asian-premium period of 2011-14. Rising domestic demand, lack of infrastructure to take new fields to LNG liquefaction plants and a prioritisation of pipeline over LNG exports resulted in lower LNG exports from Algeria.

In both Algeria and Egypt (as well as across several other major LNG producers), domestic gas prices have been regulated at levels below the cost of new upstream developments. This has discouraged investments while fuelling inefficient consumption, leaving large and growing chunks of export infrastructure stranded. While Egypt has raised gas prices over the past two years, exports are unlikely to restart in the near future, as new supplies will first be allocated to address the large shortages in the domestic market. In Nigeria, LNG exports have stayed remarkably resilient in the face of persistent security challenges (utilisation rates have run at an average of 85% over the past five years). However, 2016 has witnessed an escalation in violence and a higher number of attacks on oil and gas installations, triggering large production losses and export disruptions. For 2016 to date, Nigerian LNG exports are down by around 15% year-on-year (y-o-y), mostly reflecting the deteriorating security conditions. A recovery in volumes is possible, but the recent volatility in output is an alarm bell warning against taking the country's available capacity at face value.

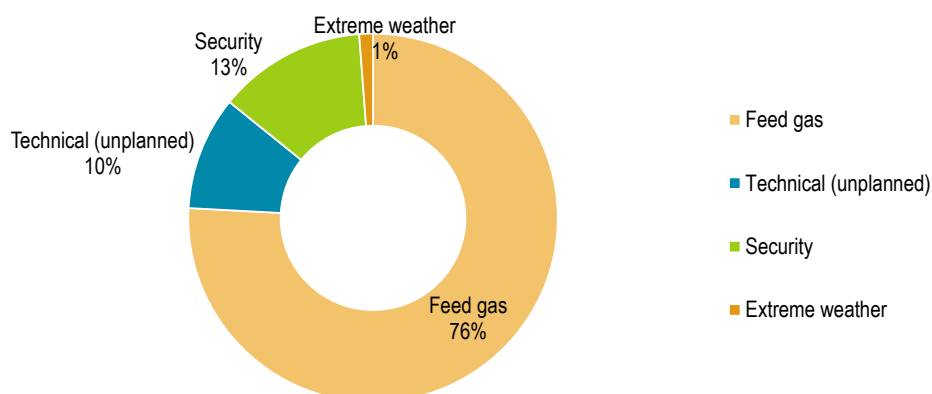
In absolute terms, the Asia Oceania region shows the second-highest level of unavailable capacity (mostly concentrated in Indonesia, especially because of feed-gas issue at Bontang LNG terminal), while in relative terms Latin America ranks second. Disruptions in Latin America are due to steep decline rates at mature producing fields in Trinidad and Tobago that are constraining the country's ability to export. Both 2015 and 2016 to date have shown double-digit

export falls. This year, Trinidad and Tobago LNG exports are on track to be one-third below what they were in 2009, although existing installed capacity has remained constant.

The Middle East has historically exhibited high utilisation levels due to reliable and consistent performance of plants in Qatar, the LNG production giant in the region. Yet here as well, regional exports have fallen well below designed capacity levels due to a sharp decline in exports from countries other than Qatar. The complete collapse of Yemeni output in 2015 as civil war ravaged the country has wiped 9 bcm per year of capacity out of the market. At the time of writing, there is no indication when exports could resume. Meanwhile Oman – which also holds sizeable LNG capacity – is faced with challenges in sustaining export levels, caught between flattening production and fast-growing domestic demand.

Worldwide, lack of feedstock gas is the primary reason explaining the large underutilisation of LNG plants (Figure 1.2). The rest is attributable to a combination of hard security issues and technical problems. It is worth mentioning that this categorisation provides just a rough indication; often, severe security threats cause a fall in investment that in turn leads to a poor upstream performance and shortages of feedstock gas.

Figure 1.2 • Unavailable LNG export capacity, breakdown by type, average 2011-16



Source: IEA analysis based on ICIS (2016), *ICIS LNG edge*.

In addition to these unwanted shutdowns, LNG plants routinely undergo planned maintenance that requires the temporary closure of the site. Normally, export plants go off line for around ten days a year for light maintenance. Every two and a half to three years, they undergo a heavier maintenance that usually lasts for about a month. This means that the average downtime of an export plant due to planned maintenance is around 5%, or 20 days per year. Planned maintenance is usually conducted during the shoulder seasons, when demand is low, to minimise disruptions to the market.

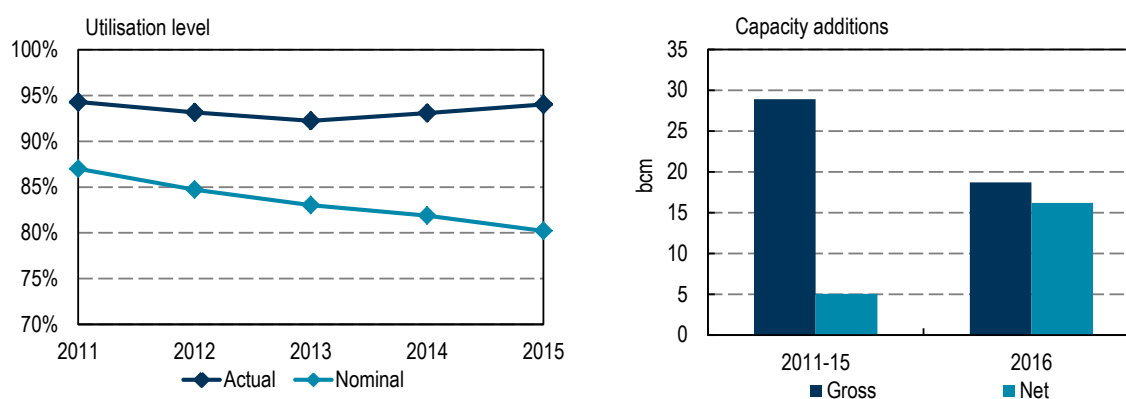
While listed as “existing”, by and large this capacity is literally unavailable and not able to run even if prices indicate that it is economic to do so. This means that it does not constitute a supply buffer and thus does not contribute to the security of supply of the global gas system. Planned maintenance could be the only exception given that operators generally have some flexibility in bringing forward or pushing back routine work, depending on market conditions. While bigger overhauls are less likely to be rescheduled, there might be some room for manoeuvre for lighter maintenance.

All the above point to the importance of differentiating between gross capacity, defined as “steel in the ground”, and actual capacity, defined as the capacity actually available to operate. Figure 1.3 illustrates this point. When looking at LNG exports relative to gross capacity, utilisation



appears to have steadily declined between 2011 and 2015. In reality, if unavailable capacity is excluded, the picture looks very different: excluding the downtime due to planned maintenance, actual utilisation of LNG export infrastructure has remained quite stable over the time frame at around 93-94% (i.e. 25 days downtime). This means that once maintenance is accounted for, actual utilisation would get close to 98-99%, which really means full rate, considering that 100% utilisation is probably unattainable due to the need for a minimum of operational flexibility.

Figure 1.3 • LNG export infrastructure utilisation level and gross and net LNG capacity additions



Evidence of stable, high utilisation across years reflects a key feature of LNG plants: the fact that liquefaction facilities are built to operate base load. This is primarily due to their cost structure, characterised by very large up-front investment costs and relatively low operating costs through the lifetime of the plant. This means that once the plant is built it tends to produce at full rate; this is – under normal business conditions – economically attractive as LNG prices are generally higher than marginal production costs. Contractual structures have traditionally mirrored these operational features, as most of the capacity of integrated LNG projects is sold under long-term contracts. While these contracts usually embed some volume flexibility, this is normally small. Moreover, both the limited quantity of capacity that remains in the hands of equity investors (and is not sold under long-term contracts) and the downward tolerance in contractual volumes that buyers might not call upon are routinely sold through tenders and short-term deals. The result is a basic lack of short-term upswing capability in LNG production, as evidenced by flat utilisation levels for global LNG capacity during the surge in Japanese gas demand post-Fukushima. Moreover, limited storage for LNG – mainly due to its cost – makes the production-to-consumption cycle more just-in-time.

The massive wave of new liquefaction capacity that is ramping up in Australia and the United States is now challenging these basic operational principles to which the LNG industry has been accustomed. Unlike the 2011-15 period, when roughly 75% of gross capacity additions were offset by losses elsewhere, so far in 2016 disruptions and outages account for just around 15% of the capacity that is entering into service. This is due to two things: first, a stabilisation (at high levels) in the scale of capacity off line, and second, the large scale of new capacity coming on line (Figure 1.3). In 2016 alone, incremental actual capacity is on track to be more than twice the cumulative increase of the previous four years. This steep increase, at a time of weak demand, is now testing the flexibility of the global gas system to absorb all the new supplies. Spot LNG prices have fallen close to the cash cost (operating + shipping costs) of the most expensive LNG projects to run. In August this year, the chief executive officer of Santos, the operator of the GLNG project in Australia, stated that he would consider running the facility at reduced rates. Such action seems to reflect project-specific issues, in particular the lack of sufficient gas reserves and the heavy reliance on third-party gas. This is relatively expensive, often based on unconventional

coalbed methane production, which requires high continuous levels of drilling, so feed gas is generally more expensive than large conventional gas, even offshore. However, it also indicates how in an environment of very low prices, high marginal operating costs could result in shut-in production. Also, US projects have a different cost profile and are characterised by a more elastic supply function. For these plants, domestic prices are a key input cost that is also variable. An important implication of this different cost structure is that utilisation could start to be adjusted downward at higher price levels than for LNG plants that are based on a traditional integrated model and rely on conventional gas as feedstock source. Monthly data for 2016 through October suggest that average utilisation has already started to be adjusted downward. As described in the *Medium-Term Gas Market Report 2016* (IEA, 2016a), this trend is likely to accelerate and intensify over the next three years before global gas markets start rebalancing again.

Global gas security clearly benefits from a period of oversupply. However, without the significant – and largely unexpected – deceleration in global gas demand post-2008, the market situation would be very different. Most worryingly, the fact that such a large portion of LNG production has been affected by feedstock problems after a sustained period of high oil and gas prices – i.e. high prices did not adequately incentivise upstream activities, result in successful discoveries or support commercialisation – raises questions on how things might develop should there be a prolonged period of low oil and gas prices. Broadly speaking, having a supply-security architecture that delivers high levels of security only in an oversupplied market is hardly reassuring. While there have been important improvements in the overall functioning of the market, cyclical aspects should not provide too much comfort.

LNG export infrastructure update

Due to the capital-intensive nature and the long lead times of the LNG industry, LNG production is shaped by investment decisions that can date back several years. After a FID is taken and enough capital is laid out, project construction tends to remain on course, independently from price moves and demand variations. As a result, the short and medium-term profile of LNG production tends to be quite rigid.

The large wave of new LNG supplies entering the market between 2015 and 2021 is the product of investment decisions taken between 2009 and 2015 and linked to contracts signed up to 2014, ahead of the oil and gas. These projects will generate robust growth in LNG production through the end of the decade.

As of October 2016, there are 15 LNG projects under construction globally for a total capacity of around 150 bcm per year, equal to almost half of the traded LNG volumes worldwide today (Table 1.1).

Table 1.1 • LNG projects under construction (as of October 2016)

Country	Project	Capacity (bcm/y)	Major participants	FID year	First cargo
Malaysia	MLNG (T9)	4.9	Petronas	2013	2016
Malaysia	Petronas FLNG SATU	1.6	Petronas	2012	2016
Australia	Gorgon LNG (T3)	7.1	Chevron, Shell, ExxonMobil	2009	2017
Australia	Wheatstone LNG (T1)	6.1	Chevron, KUFPEC, Woodside	2011	2017
Indonesia	Sengkang LNG	0.7	Energy World Corporation	2011	2017
United States	Sabine Pass (T3-T4)	12.2	Cheniere Energy	2013	2017
Australia	Prelude FLNG	4.9	Shell, Inpex, KOGAS, CPC	2011	2018

Table 1.1 • LNG projects under construction (as of October 2016) *cont'd.*

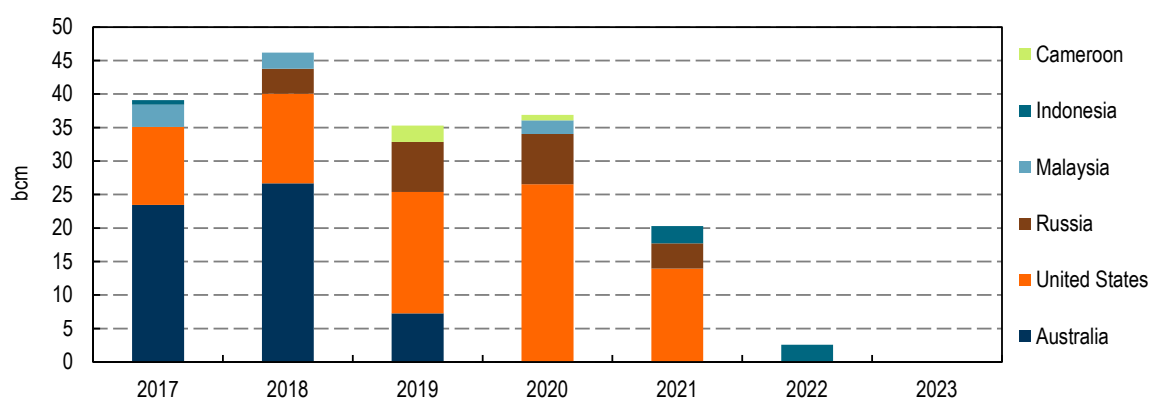
Australia	Ichthys LNG (T1-T2)	12.1	Inpex, Total	2012	2018
Australia	Wheatstone LNG (T2)	6.1	Chevron, KUFPEC, Woodside	2011	2018
Russian Federation*	Yamal LNG (T1)	7.5	Novatek, Total	2013	2018
United States	Cameron LNG (T1)	6.1	Sempra Energy	2014	2018
United States	Dominion Cove Point LNG	7.1	Dominion	2014	2018
Cameroon	Cameroon FLNG	3.3	SNH, Perenco, Golar	2015	2019
Russia	Yamal LNG (T2)	7.5	Novatek, Total	2013	2019
United States	Corpus Christi LNG (T1)	6.1	Cheniere Energy	2015	2019
United States	Cameron LNG (T2-T3)	12.2	Sempra Energy	2014	2019
United States	Freeport LNG (T1-T2)	12.6	Freeport, Macquarie	2014	2019
United States	Sabine Pass (T5)	6.1	Cheniere Energy	2015	2019
Malaysia	Petronas FLNG 2	2.0	Petronas	2014	2020
Russia	Yamal LNG (T3)	7.5	Novatek, Total	2013	2020
United States	Corpus Christi LNG (T2)	6.1	Cheniere Energy	2015	2020
United States	Freeport LNG (T3)	6.3	Freeport, Macquarie	2015	2020
Indonesia	Tangguh LNG (T3)	5.2	BP	2016	2021
Total		151.3			

* Hereafter "Russia".

Notes: y = year; T= Train; MLNG = Malaysia LNG; FLNG = floating LNG; KOGAS = Korea Gas Corporation; KUFPEC = Kuwait Foreign Petroleum Exploration Company; SNH = Société Nationale des Hydrocarbures. Trains currently ramping up are not included. Start dates as announced by the operator of the project.

Source: IEA compilation based on information from companies' websites and own estimates.

Given the above project list and standardised assumptions on ramp-ups for new LNG trains, liquefaction capacity additions are on track to peak in 2018 at just above 45 bcm per year (Figure 1.4). Incremental supplies will remain high until 2020 and then drop sharply in 2021-22 as the last few projects reach a plateau. If no new FIDs are taken in the next two to three years, production will flatten out by 2023. Of course, slippages remain possible. Yet the overall picture would not change much. By the early to mid-2020s, the impact of the current production wave will have run its course.

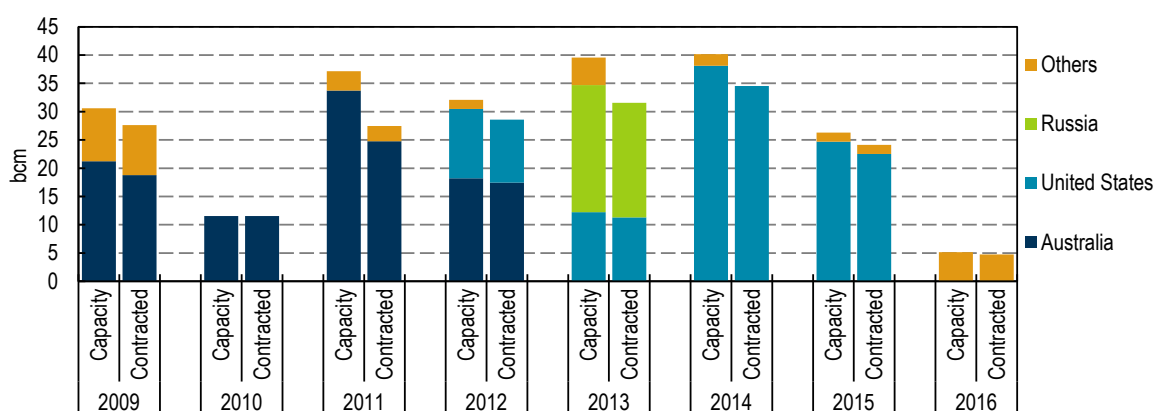
Figure 1.4 • Incremental liquefaction capacity under construction y-o-y

What happens after that is a function of the scale of investments signed off on today or in the near future. Recent data indicate that a massive readjustment is ongoing. In 2016, as of October, just one project has reached FID. At the beginning of July, BP and partners pushed ahead with the decision to develop a third train (with capacity of 5.2 bcm per year) at the existing Tangguh LNG export project in the Papua Barat province of Indonesia. The expansion was agreed after off-take agreements with the Indonesian state electricity company PT PLN (Persero) and the Kansai Electric Power Company in Japan were secured.

This 5 bcm of additional investment so far in 2016 is a far cry from the 35 bcm sanctioned annually on average between 2011 and 2014. While a correction from the previous trend of overinvestment is a natural and economically justified readjustment, a protracted period of low investment within an industry with long lead times poses risks of tighter markets into the next decade. While this is not in itself a threat to security of supply, market tightness amplifies the impact of potential supply disruptions – a mirror image of how today's oversupply diminishes it. The presence of rigid contractual structures and lack of adequate price signals (through market-based price mechanisms) further accentuate the problem. In this context, the monitoring of LNG investments can be regarded as an important component of an assessment of gas supply security.

A critical condition for a liquefaction project to obtain FID is to have a sufficient level of capacity booked under long-term contracts. In the absence of a liquid, deep and reliable LNG spot market, off-take agreements are a prerequisite for securing financing at reasonable rates. This is true irrespective of the underlying business model of the project (e.g. tolling or integrated). Data for all projects sanctioned between 2009 and 2016 indicate that an average of 86% of the total capacity was booked in advance of the investment decision. With the exception of few projects where specific characteristics might justify lower committed volumes, high pre-FID booking levels are a shared feature across regions, with the Australian projects showing an average pre-FID booking of 87% and the US projects 91% (Figure 1.5). In addition, the Yamal project in Russia managed to secure around 90% of its capacity in 2013.

Figure 1.5 • Capacity versus contracted volumes of projects obtaining FID after 2009



Note: contracted volumes of each project are allocated to the year when FID took place even if they were signed before that year.

Source: IEA analysis based on information from multiple sources and own estimates.

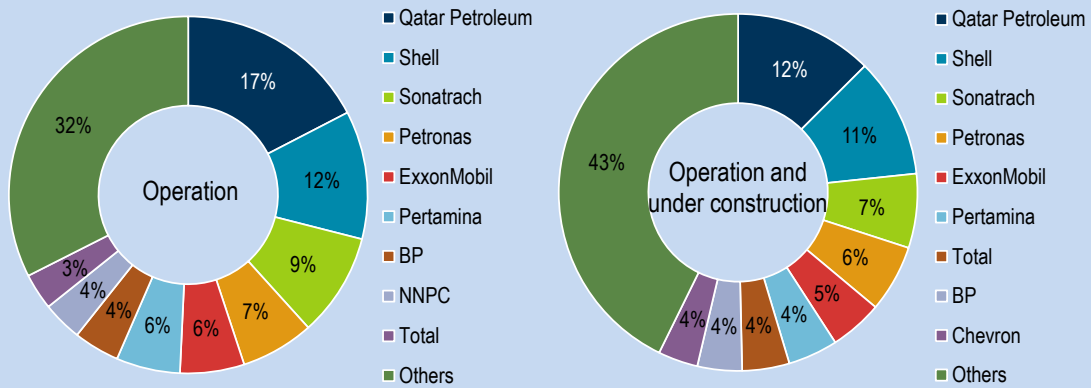
Box 1.1 • How concentrated is the ownership of LNG export infrastructure?

LNG production has traditionally been concentrated in the hands of a few companies. The complex engineering, project management and large up-front capital costs required for the successful development of an integrated LNG facility mean that few companies have the know-how and financial resources to become major LNG players. Smaller producers, mid-streamers and LNG buyers

have routinely taken minority stakes in LNG production projects; the operatorship and dominant stakes have tended to be the priority of large independent or national oil companies.

Today, the two largest LNG producers (Qatar Petroleum and Shell¹) account for a combined market share of 29%; the top five producers together represent a share of 50% and the top nine producers a share of 68% (Figure 1.6). The level of market concentration is lower than in other segments of the energy industry – such as oil upstream.

Figure 1.6 • Ownership of LNG export capacity, operational and under construction as of 2016



Notes: NNPC = Nigerian National Petroleum Corporation. Market share of US plants is calculated based on capacity bookings rather than on terminals' ownership.

Source: IEA analysis based on CEDIGAZ (2016), *CEDIGAZ LNG service*.

Ownership of LNG export capacity has become more diversified in recent years with the market share of the first five producers falling from 54% in 2011 to 50% today. The new wave of LNG projects that is coming to the market will further reinforce this trend. These projects will not just broaden the geographical origin of LNG supplies but also increase the number of companies involved in LNG development. Once liquefaction capacity under construction is also accounted for, the ownership structure of LNG export infrastructure looks much more diversified: the share of the two largest LNG producers falls to around 23% (minus six percentage points), that of the top five producers to 41% (minus ten percentage points) and that of the top nine producers to 57% (minus eleven percentage points).

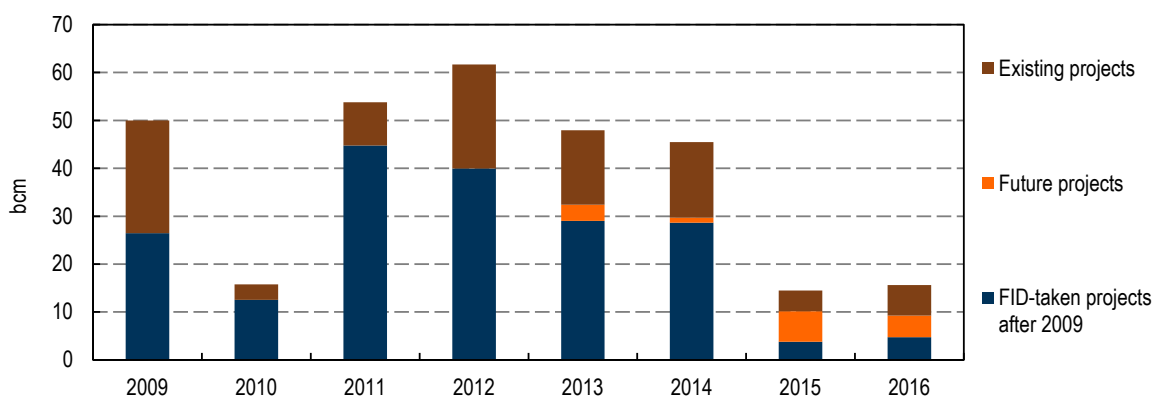
The new US projects have a key role in driving the increased level of ownership diversification (much more so than the Australian ones). The business model that underpins US projects – which basically separates upstream development and construction of the LNG plant itself – has meant that the involvement of traditional majors is far less essential to complete the whole project. Most projects are developed by mid-stream companies that then sell the plant capacity based on long-term capacity reservation contracts. While some of the off-takers are large LNG players, others are electric utilities from Asia (and Europe) and trading houses, such as those from Japan. Both from a terminal's ownership perspective and from a capacity booking perspective, US plants provide substantial diversification in ownership structure.

¹ Shell's share also includes BG.

When looking at the path for future investment, the evolution of new (binding) long-term contracts provides a first rough indication of what to expect next. In any given year, contracts signed tend to outstrip the capacity of sanctioned projects (Figure 1.7). This is for two reasons: first, some of them are contract renewals for existing capacity – given that usually the lifetime of a terminal outstrips the length of initial contracts; second, a deal could relate to capacity of projects that will then not receive FID (this can be due to a variety of reasons, for example better competing alternatives for the sponsor, deteriorating market conditions, etc.).

From 2009 to 2014, several contracts for large volumes of capacity were signed, equivalent to almost 45 bcm per year on average. Figure 1.7 shows a breakdown of those contracts in relation to the capacity they underpin. Contracts for “existing projects” refer to deals that underpin projects already in operation in 2009. Contracts for “FID-taken projects” refer to deals that back projects that received FID sometime between 2009 and 2016. Contracts for “future projects” refer to deals that underpin projects that have not yet received FID.

Figure 1.7 • Contracted volumes of existing projects, FID-taken projects after 2009 and future projects



Around 66% of the contracts signed between 2009 and 2014 were backing projects that took FID between 2009 and 2016 (mainly in Australia and the United States). In 2014, when oil prices had not yet started to fall sharply, several contracts were still signed (mainly in the United States). These contracts explain the relatively high level of FIDs that still went through in 2014, in spite of the marked deterioration in market conditions. New contracts then plummeted in 2015 and have remained at similarly low levels so far in 2016 (through October). The decline in both the number of contracts signed and the level of FIDs taken reflect the sharp deterioration in project profitability due to low oil and gas prices, as well as the reduced pool of capital available for companies to invest (without overleveraging), particularly for greenfield integrated projects. From the buyer side it might also reflect a desire to take advantage of low spot LNG prices and shift – at least to some extent – from long-term contracts to short-term or spot base LNG trades.

Between 2009 and 2016, contracts for around 15 bcm of liquefaction capacity were signed that refer to “future projects”, i.e. projects that are yet to be sanctioned. Coral FLNG, Corpus Christi LNG train 3, Elba Island LNG and Sabine Pass LNG train 6 have contracts in place for an average of 76% of their nameplate capacity. While factors other than the presence of off-takers determine whether a project will move forward, these four projects are well poised to take FID in the near future. Notably, the overall capacity of these projects adds up to 20 bcm, well below the annual average sanctioned between 2011 and 2015.

LNG regasification investments

Much lower capital investments and much shorter lead times make timely investment in new regasification infrastructure less of an issue than for export infrastructure. Nowadays, floating storage and regasification units (FSRUs) can be ordered, be moored and start operations in around 12 months after an investment decision is taken. Costs are five to ten times lower – on a per-tonne basis – for regasification infrastructure than for liquefaction. Shorter construction times allow better visibility on demand prospects, and overall investment risks are much smaller. Moreover LNG import capacity is often built to cater for variability in demand. As a result, LNG

regasification facilities tend not to operate at full capacity (unlike liquefaction plants, which tend to operate base load).

Unlike liquefaction plants, regasification terminals serve a specific country's needs – at most, those of a region. Consequently, the operational flexibility and supply-security advantages of any spare capacity directly benefit the consumers of that specific country. Alongside lower costs, this facilitates incorporating redundancy at importing sites.

From a global perspective, the presence of an extended, geographically diversified regasification infrastructure – if reflective of an extended, geographically diversified LNG trade – allows for the aggregation of a wider range of demand/supply flexibilities that exist across different domestic/regional gas systems. This is beneficial to the gas security of all countries.

As of October 2016, new regasification capacity equivalent to 118 bcm is either under construction or likely to move forward for a start-up by 2019 (Table 1.2). Two-thirds of these additions are slated to come from greenfield projects, while FSRUs account for 30% of the incremental capacity. The overwhelming majority of the new capacity (~82% of the total) is being built in Asia.

Table 1.2 • LNG regasification terminals under construction (as of October 2016)

Country	Project	Capacity (bcm/y)	Major participants	Start up
People's Republic of China*	Diefu LNG	5.4	CNOOC, Shenzhen Energy	2016
China	Guangdong Dapeng LNG Expansion	3.1	CNOOC, BP	2016
China	Guanghui LNG	0.8	Guanghui Energy, Shell	2016
China	Hainan LNG Expansion	1.3	CNOOC	2016
China	Jiangsu Rudong LNG Expansion	4.1	CNPC (Kunlun Energy)	2016
China	Qingdao Expansion	4.8	Sinopec	2016
China	Shenzhen	4.1	CNPC (Petro China)	2016
China	Yuedong LNG	2.7	CNOOC	2016
Colombia	Cartagena FSRU	4.1	Sacyr Industrial	2016
Greece	Revithoussa Expansion	2.0	DESFA SA	2016
Haiti	Maurice Bonnefil LNG Import Terminal	0.4	Haytrac Power and Gas	2016
Philippines	Philippines LNG	4.1	Energy World Corp.	2016
Sweden	Gothenburg LNG	0.7	Swedegas	2016
China	Tianjin North	4.1	Sinopec	2017
Ghana	Ghana FSRU	7.5	West African Gas, Golar LNG	2017
Indonesia	Cilacap FSRU	1.6	Pertamina	2017
Malta	Malta FSRU	0.6	Electrogas Malta	2017
Pakistan	Pakistan FSRU 2	7.8	Pakistan GasPort	2017
Korea	Boryeong LNG	4.1	GS Caltex, SK E&S	2017
Korea	Samcheok Expansion	6.3	KOGAS	2017
Thailand	Map Ta Phut Expansion	6.8	PTT LNG	2017
Uruguay	GNL del Plata FSRU	5.5	Gas Sayago, Mitsui OSK Lines	2017
Bangladesh	Bangladesh FSRU	5.2	Excelerate Energy, Petrobangla	2018
China	Fujian LNG Expansion	1.5	CNOOC	2018

Table 1.2 • LNG regasification terminals under construction (as of October 2016) *cont'd.*

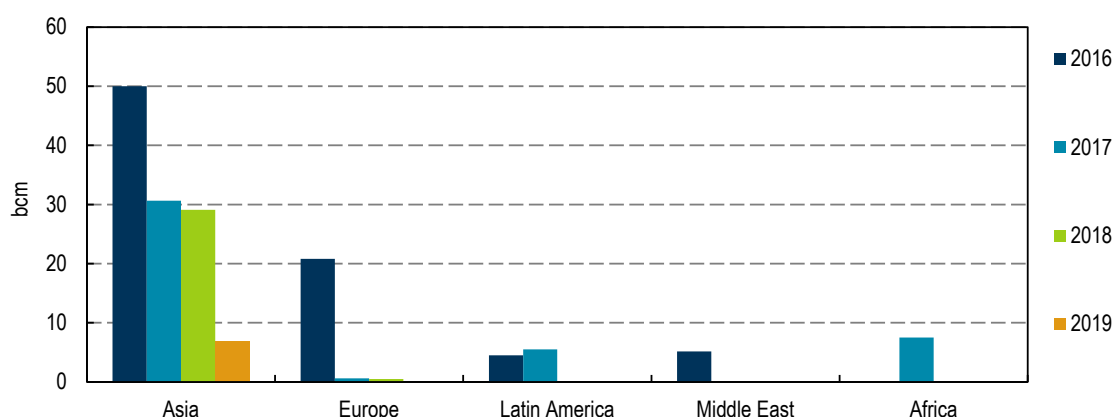
China	Zhoushan ENN LNG	4.1	ENN	2018
Finland	Manga LNG	0.5	Manga Terminal Oy	2018
India	Ennore LNG	6.8	Indian Oil Corporation	2018
Japan	Soma LNG	1.4	JAPEX	2018
Japan	Toyama Shin-Minato	1.4	Hokuriku Electric	2018
Singapore	Jurong Expansion	6.7	SLNG	2018
Chinese Taipei	Taichung Expansion	2.0	CPC	2018
India	Dhamra LNG	6.8	Indian Oil Corporation	2019
Total		118.2		

* Hereafter "China".

Note: CNOOC = China National Offshore Oil Corporation; CNPC = China National Petroleum Corporation; JAPEX = Japan Petroleum Exploration Company; SLNG = Singapore LNG Corporation.

Source: IEA compilation based on information from companies' websites.

As of October, 2016 has seen a massive 40 bcm of new regasification capacity starting operations, led by additions in Europe and in China (which together have accounted for 88% of the total). China will continue to dominate the next round of additions (most of which are still scheduled to start this year but will likely to slip into 2017). Past that, the picture will become more diversified, although Asia is set to remain the epicentre of new import infrastructure additions (Figure 1.8).

Figure 1.8 • Incremental regasification capacity in the world, 2016-19

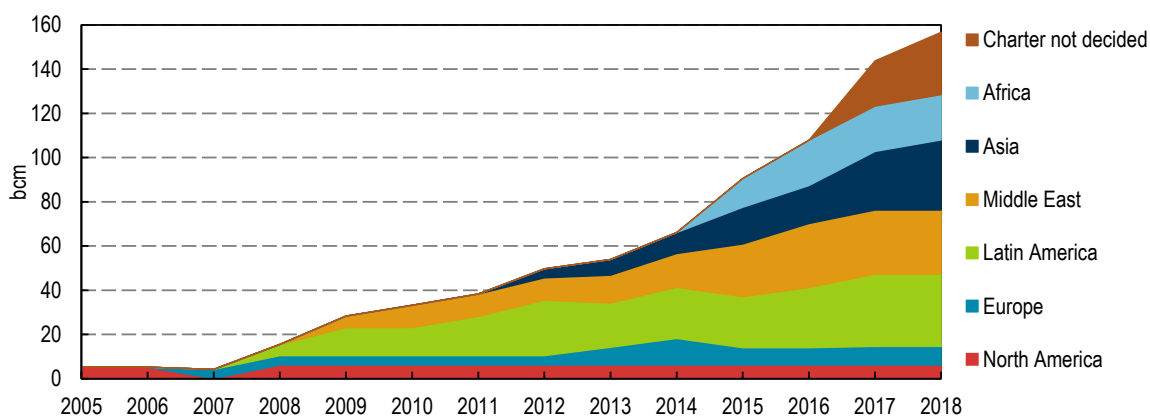
Source: IEA compilation based on information from companies' websites.

In developing Asia (excluding China), the Middle East, Latin America and Africa, FSRU technology is becoming the technology of choice. While from a pure cost-per-tonne perspective, building an FSRU is not necessarily cheaper than building an onshore facility; the lower initial capital cost and the much higher flexibility it offers with respect to length of commitment well suits the needs of countries characterised by rapid evolution in their demand profile/energy mix and with lower financial capabilities. The advent of this technology is injecting higher flexibility through the LNG supply chain. In doing so it allows the unlocking of pockets of demand, better deployment of gas-to-power back-up solutions and a higher contribution of gas to the energy security of the system into which it flows.

FSRU regasification capacity has increased rapidly since 2008, reaching 100 bcm per year in 2016 (Figure 1.9). Today it represents 10% of global regasification capacity (versus 2% in 2008) and its share is set to continue to increase steeply, judging from the number of FSRUs under construction. Today FSRUs with total capacity of 60 bcm are under construction and scheduled to

be in operation by 2018, and just around half of them have been chartered (and included in Table 1.2). This portion already represents 25% of the total capacity under construction. The share is ultimately set to be higher than that, once the carriers that are currently under construction but not yet chartered find a home.

Figure 1.9 • FSRU capacity: Existing and under construction



At 160 bcm, regasification capacity that has been added in 2016 or is scheduled to start operations between 2016 and 2019 are 11% above the level of liquefaction capacity set to begin operations over the same period. As regasification infrastructure does not usually run base load, however, additional infrastructure (more than that already under construction) or higher utilisation at existing terminals (if these can serve regions of demand growth) will be required to absorb the large wave of new LNG supplies.

Today, global LNG import capacity is roughly three times the level of global export capacity, and global utilisation is around 30%. Yet there are large variations in the level of redundancy at each terminal (and more generally each region) as well as the reasons for that. In some cases, low utilisation is due to unexpectedly low demand. In others it is linked to the specific business case or strategic rationale of the plant, which can be based on the need to respond to seasonal demand fluctuation or specific supply diversification objectives (as with most of new terminals built in Europe).

This means that the impact that new regasification capacity has on market balances and supply security depends on the system it is added to. For example, the contribution of the newly built Dunkirk terminal in northern France in reshaping the demand and supply-security picture of North West Europe is relatively low compared with that of a newly built terminal in Pakistan with respect to Pakistan's demand and security. Whereas North West Europe has many means to receive and transport gas, Pakistan, which experiences chronic shortages of gas, actually had no infrastructure to import gas until last year.

Similarly, the increase in regasification infrastructure associated with back-up gas-fired generation (mostly for hydro-heavy systems) would have limited impact on market balances under normal conditions. Under stressed hydro situations, however, they would bring strong positive benefits for the security of the gas and electricity supplies of that specific country but to the detriment of the overall system if coinciding with other shocks elsewhere (by placing a high, unusual call on the volume flexibility that the global gas system is able to release).

Looking specifically to Asia – where more than 70% of regasification capacity under construction today is located – there are different types of capacity under development with different potential implications for the global gas system. Overall, average utilisation of Asia's import infrastructure is around 42%, 11% above the world average. This is explained by the fact that

large Asian importers (Japan, Korea and Chinese Taipei) are much more dependent on LNG imports to feed their base load.

Japan and Korea have utilisation rates in the region of 30-40%. New terminals under construction in both countries are likely to help satisfy specific pockets of demand that cannot be met via existing infrastructure or to serve to increase domestic competition (for example, oil plants replaced by gas units; terminals built by non-incumbents). At an aggregate level, however, the additional infrastructure is unlikely to dramatically change the import profile of the two countries and their supply-security situation. Overall, both Korea and Japan have relatively high (and stable) redundancy embedded in their gas import infrastructure. For example, in the aftermath of the Fukushima accident, the availability of spare regasification infrastructure was not a major bottleneck in responding to the crisis.

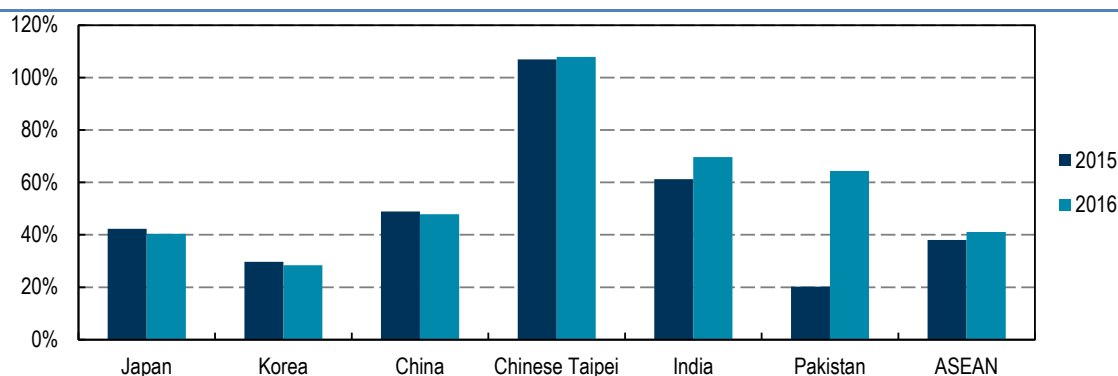
By contrast, the utilisation of import facilities in Chinese Taipei is already close to maximum (Figure 1.10). In this case, the supply-security contribution of additional regasification capacity would be substantial, particularly in light of the country's rigid supply structure (lack of domestic production or alternative pipeline imports).

India and Pakistan are primary examples of how the combination of additional infrastructure and low prices can boost demand. Both countries face regular power shortages that make the concept of supply security closely intertwined with that of energy access and affordability. Both countries have shown a marked increase in the utilisation level of their existing LNG import infrastructure in 2016, with consumption boosted by low gas prices and, in the case of Pakistan, the start-up of the country's first import terminal.

In India, the average utilisation of import terminals has increased from 60% in 2015 to around 70% in 2016. Taking into account existing bottlenecks at the Kochi facility (under 10% utilisation due to lack of pipeline takeaway capacity) and at the Dabhol facility (reduced capacity due to the inability of the terminal to operate during the monsoon season, from June to September, due to lack of a breakwater), there is little spare capacity left for additional imports. This means that the build-out of new import facilities is likely to be directly linked to the creation of additional demand (certainly at today's low LNG prices). A similar story holds for Pakistan.

Import facilities that unlock new demand have positive security benefits for those individual countries but would tighten up supplies for the rest of the world. On the other hand, as LNG imports become more diversified across countries, any supply-security event could be more easily addressed by tapping into a larger pool of flexibility options across a wider range of gas systems.

Figure 1.10 • Utilisation rate of regasification capacity in Asia



Note: ASEAN = Association of Southeast Asian Nations.

Sources: IEA analysis based on GIIGNL (2016), *The LNG industry in 2015*; ICIS (2016), *ICIS LNG Edge*; IEA estimates.



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2. A demand perspective: Flexibility required

Introduction: How flexible is the LNG market?

As illustrated in Chapter 1, one main feature of liquefied natural gas (LNG) production is its tendency to be base load – in other words for export infrastructure to run at full rate. This means that under normal circumstances, continued growth of LNG trade does not result in additional “volume flexibility” in the market. From a supply-security standpoint, the key question, therefore, is the extent to which current and additional LNG supplies have “destination flexibility”. In its basic form, this is largely a contractual issue. Traditional long-term LNG contracts often feature destination clauses that prevent buyers from reselling cargoes into the global LNG market. By limiting the free movement of LNG, before and after delivery, destination restrictions are clearly detrimental to the development of a functioning, fully flexible LNG market. (In Europe they were banned at the beginning of the last decade.) Yet even when destination restrictions do not feature in a contract, optimisation of LNG flows – and full destination flexibility – can be restricted by the selling (and pricing) point of the gas. In delivered ex ship (DES) contracts – where the exchange of ownership occurs at the port of destination – the redirection of cargoes before arrival at the intended port requires negotiations among buyers and sellers. Given that, DES contracts tend to result in less destination flexibility than free on board (FOB) contracts (which set the exchange of ownership of the gas at the port of loading). Lower flexibility in rerouting cargoes diminishes the contribution LNG can have in responding to global gas shocks.

What is the demand for flexible LNG volumes today and how has that demand been met? Looking at flexibility from the supply side, the major factors to consider are:

- The scale of **uncontracted LNG supplies**, i.e. LNG volumes that are not sold under short-, mid- or long-term contracts but are routinely marketed by LNG suppliers. By being uncontracted, these volumes are fully flexible and can be directed to the best bidders. By definition these supplies are spot sales.
- The scale of **diversions** by primary suppliers. These refer to LNG supplies that have a fixed intended destination but are diverted to a different customer from the original intended one. In most cases, these volumes are not subject to contractual destination restrictions and therefore can be diverted by the off-takers to where it makes more sense from an economic or strategic point of view. At other times – when destination clauses apply – diversions need to be negotiated between the seller and the buyers. **Reloading** – which refers to a situation when a cargo is actually unloaded and then reloaded at an LNG port to then sail off to a different destination – can be considered a form of diversion. When reloads become a tool to bypass destination restrictions, they are a costly form of diversion.
- The share of **aggregators** into the markets. These are large LNG players that aggregate supplies from various sources/projects into a portfolio from which they resell to various customers. The customers are entitled to a certain volume and to a certain quality but not to a specific origin. Aggregating volumes has implications that go beyond the provision of flexibility to the global LNG system. For example, it allows for better risk sharing and risk management. From a flexibility standpoint – which is the main subject of this analysis – the presence of aggregators allows a specific project to be de-linked from a specific buyer. This, in turn, allows injecting **time flexibility** in contractual structures as aggregators (at least in part) can bridge the producers’ needs for long-term contracts and the consumers’ needs for shorter durations.

A key point remains that supply-side flexibility options are a “tool to link” (via destination flexibility) rather than a “final means to provide” of the volume flexibility that a demand or supply shock in global gas markets would ultimately require. Such volume flexibility would need to come from the demand-side/production/pipeline import flexibilities that different regions can offer and that LNG supplies can help aggregate.

Without flexible LNG supplies, such aggregation would be impossible. Yet by the same token, without the volume flexibility that can be squeezed out of the various regional gas systems, flexible LNG supplies would not help achieve much.

The arrival of large volumes of United States (US) LNG over the next few years will markedly increase the destination flexibility of LNG trade. Roughly half of incremental LNG production between 2016 and 2021 is forecast to come from the United States. The contractual structure of US projects is very different from that of traditional integrated facilities. In the United States, LNG plants are underpinned by long-term capacity reservation contracts with ship-or-pay provisions. The off-takers pay a fee to the LNG developer for the liquefaction service (and in some cases for the marketing of the gas). Once they lift the LNG, off-takers are then free to ship it where they wish. By lowering costs of redirecting volumes, US supplies will increase market efficiency and contribute to global gas security. Crucially, however, US LNG will not by itself change the volume flexibility overall available to the global gas system.

This chapter and Chapter 3 analyse in detail the evolution of these various types of LNG flexibility over the past five years: they look at who were the key takers of flexibility and who were the key providers. While precise quantification is impossible, the analysis carried out allows setting orders of magnitude as well as identifying key trends that can help when conducting gas security assessments.

Methodology

The analysis conducted in this chapter and Chapter 3 is based on a detailed country-level analysis of contractual positions of exporters and importers and their actual traded volumes. To do so, the International Energy Agency (IEA) has relied on a new LNG contract database – which assembles data from various public and private sources – counting more than 700 different contracts (including some that have already expired and some that have yet to begin).

While the data are of course neither perfect nor complete – and the results of the analysis should be taken as an indication rather than a point estimate – the results obtained should be robust and consistent with the developments that can be observed across LNG markets on both a global and regional basis. The analysis focuses in particular on the concept of flexibility: what sort of flexibility can be provided, how much, and who is in the position to provide it.

Demand flexibility required

This analysis defines flexibility required by an importer as those LNG quantities imported above contracted volumes with a specific exporter (or from exporters where no contracts are in place) – or in other words, uncontracted volumes. There are different reasons buyers might source volumes above their contractual levels. This can be due to domestic factors (for example, steeper-than-expected declines in domestic production, extreme weather, nuclear shutdowns) or external factors, such as shortfalls in LNG deliveries from specific exporters that must be replaced by higher imports from alternative exporters.

Understanding why a country is importing flexible volumes, and to what extent that call for flexible supplies is reflective of a country’s need to keep the lights on or an expression of an

economic choice, requires a detailed analysis of each country's energy system, which is beyond the scope of this report. That said, understanding how demand for flexible volumes evolves, where those volumes come from and where they are heading is a key starting point in providing an assessment of a potential system response to a disruption in the global gas markets.

The past five years have witnessed substantial variations in the call for flexible LNG volumes. At the global level, the period 2011-13 saw a steep increase in flexibility requirements. Demand for flexible volumes peaked in 2013 at above 60 billion cubic metres (bcm) and has since declined meaningfully. By 2015, however, the call for flexible LNG supplies was still 11 bcm above that of 2011.

Japan has played a dominant role in shaping the trend. The need for higher LNG imports in the aftermath of the Fukushima accident prompted Japan to look for volumes above and beyond those implied by its contractual levels, thus triggering a sharp increase in the call for flexible supplies. By 2013, Japan accounted for 45% of the global demand for flexible supplies. As conservation and efficiency measures kicked in, renewable generation ramped up and new LNG contracts began, two-thirds of the initial increase for additional flexibility had been unwound by 2015. By then Japan's share of flexible volumes had fallen to about 35%.

Alongside Japan, Latin America has proved a major taker of LNG supply flexibility. The region's demand for flexible volumes reached a peak of 14 bcm in 2014 – increasing by more than 8 bcm since 2011 – and remained at about the same level in 2015. Together, the flexibility requirements of Brazil and Argentina stood at around two-thirds of those of Japan in 2015, reflecting the region's strong dependence on spot and short-term LNG.

The year 2015 witnessed an impressive rise of new, less established LNG buyers as large takers of flexible LNG volumes. Demand-and-supply dynamics suggest that this trend is likely to continue (IEA, 2016a), as several countries, often with limited long-term contracts in place, take advantage of today's low gas prices, tapping into the spot and short-term market.

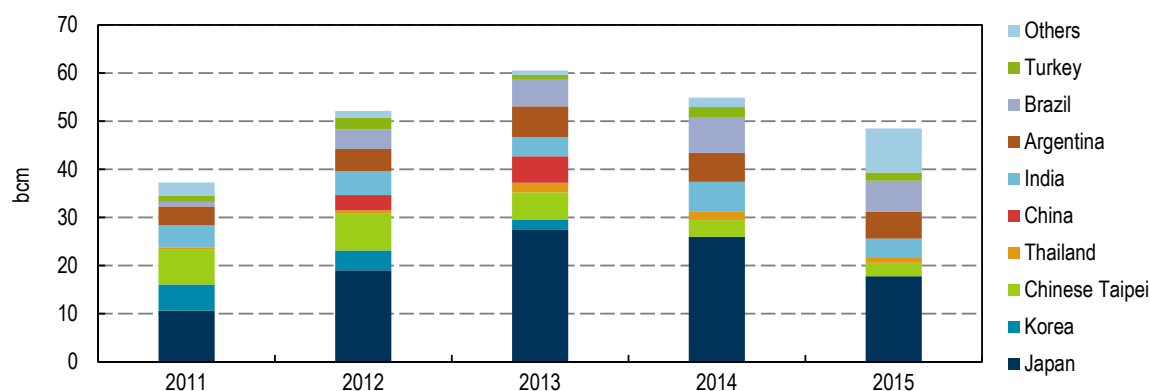
A detailed analysis of Asian countries' contractual positions and the likely evolution of their import needs points to marked changes through 2021. In particular, the possibility that Japan will transition from being the largest taker of flexibility to the largest provider cannot be ruled out. This would have major spillover effects on the future demand/supply balance for flexible volumes. This transition would benefit from increased flexibility in contractual structures, including the removal of destination clauses.

Demand for flexible LNG volumes: Changing drivers

Demand for flexible LNG volumes almost doubled between 2011 and 2013, peaking at around 60 bcm in 2013 – roughly equal to one-fifth of global LNG trade. Two-thirds of that increase is attributable to Japan's surge in LNG needs post-Fukushima (Figure 2.1). The rest is spread across countries, with Brazil and Argentina in particular accounting for a significant share. The reversal in the trend after 2013 is driven by the unwinding of the increased call from Japan. Indeed, excluding Japan, the call for flexible LNG volumes has remained stable since 2013 albeit with some notable changes in its composition.

Latin America's (Argentina and Brazil) high share of global demand for flexible LNG volumes – which stood at roughly one-fourth of the total in 2015 – is significant not just in absolute terms but also compared with the region's limited share of global LNG trade, which is just 4%. This is due to the lack of long-term contracts for LNG purchases. In fact, neither country has long-term contracts in place. Both tap the LNG market on a spot/short-term basis, thus placing a direct bid for flexible volumes.

Figure 2.1 • Demand flexibility required by LNG importers, 2011-15



This unusual contractual behaviour makes Latin America a significant swing factor for flexible LNG. In the case of Brazil, LNG needs are heavily affected by changes in hydro availability and climate conditions given the country's strong reliance on hydro in power generation (~75% on average over the past five years). While industrial and residential base-load demand is met via pipeline gas imported from neighbouring Bolivia (under long-term contracts), large fluctuations in the level of gas burned in power generation are predominantly addressed via changes in LNG spot purchases. When the country experienced a severe drought, which started in 2012 and extended over the following three years, Brazil's LNG spot purchases shot up. As hydro conditions started to improve markedly in 2016, Brazil's LNG intakes have been adjusted downward (imports were halved for the first nine months of 2016).

Argentina's reliance on spot/short-term LNG purchases is less affected by fluctuations in hydro generation compared with Brazil. Hydro has a meaningful role in the country's electricity mix (roughly a share of 25%) but it is not the fuel of choice – gas is. The dominance of gas in Argentina's energy mix dates back to the country's long history as gas producer and exporter. This meant that when gas production started to decline in the middle of the last decade, Argentina had very limited demand-side flexibility to bridge the widening gap between domestic demand and domestic supply. As a result, flexibility came mainly from the supply side instead: Argentina halted pipeline exports to Chile and commenced importing from Bolivia and most recently from Chile. Once all the supply-flexibility gains associated with changing flows in the intraregional pipeline trade had been exhausted, Argentina turned to LNG markets for its remaining requirements.

Lack of visibility on future production trends – due to Argentina's vast resources and high output potential but alongside falling domestic production – and the poor creditworthiness of its state-owned operators made it difficult (or undesirable) to lock in LNG volumes under long-term contracts. While Enarsa and YPF have routinely conducted tenders of various durations, they have done so for deliveries over a relatively short period of time.

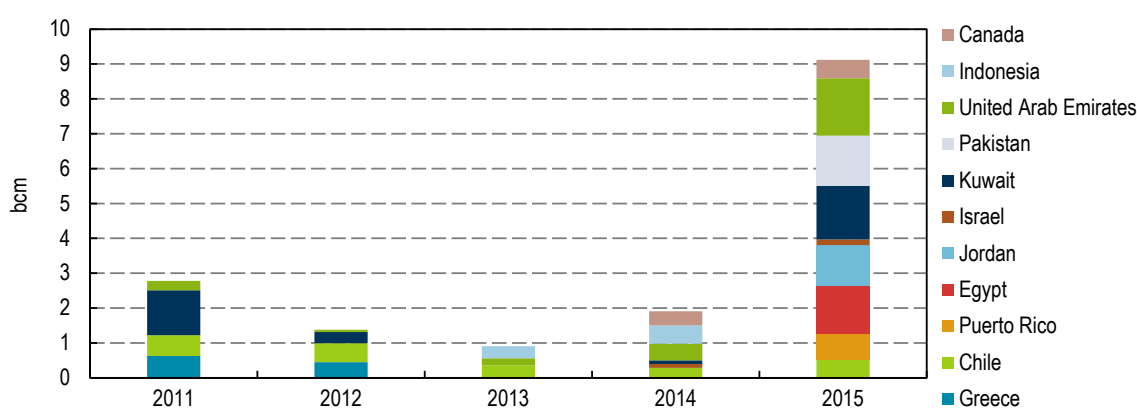
Latin America has thus acted as meaningful "flexibility taker" in recent years. To what extent it will maintain this role hinges on a number of factors, two of which look particularly critical. First is the speed and scale of shale gas development in Argentina. Resources are vast, and the country's potential production is much higher than that of today. Yet development costs remain high and investment levels moderate, which indicates that it might take time before an inflection point in production is reached. That said, when such a point is finally reached, not only would Argentina's LNG import needs be eliminated but the additional supplies would free up pipeline gas for other LNG importers in the region (mainly Chile and Brazil). Second is the strength and mix profile of Brazil's electricity generation. If electricity consumption growth continues to be

met predominantly with hydro and other renewables (Brazil has large and cheap wind resources) this would increase the need for back-up generation (and in turn for flexible LNG supplies). Variations between windy and wet years and still and dry years could become very large. According to projections from the Oxford Institute of Energy Studies (OIES, 2016), the swing in gas consumption for power generation between a wet and dry year in Brazil could amount to as much as 30 bcm by 2030.

As highlighted at the beginning of this section, demand for flexibility excluding Japan has remained broadly constant since 2013. The call from Latin America did not change much over the period. Yet there was an evident shift in behaviour across other importers. In particular, large Asian LNG importers, notably excepting India (thus Korea, the People's Republic of China [hereafter "China"], Thailand and Chinese Taipei), all reduced their call for flexible volumes. While each country has its own specific circumstances, the common element here is the broad-based slowdown in Asian gas consumption against a backdrop of increased contracted volumes. The consequence has been a large decline in reliance on spot and short-term trading (~12 bcm between 2013 and 2015).

This slowdown was offset by the impressive rise of other importers as flexibility takers. These are smaller, less established LNG buyers that, in aggregate, took in an impressive 8 bcm of additional flexible volumes between 2013 and 2015 (mostly in 2015) (Figure 2.2). Many of these countries are new importers and are mainly located in Central and South America and the Middle East and North Africa region. For at least some of them, the consumption pattern is highly price-sensitive, and the jump in imports partly reflects the impact of much lower gas prices in 2015.

Figure 2.2 • Demand flexibility required by LNG importers, breakdown of category 'others', 2011-15



Note: The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Asia gas demand and its role in driving the call for flexible volumes

A marked slowdown in Asian gas consumption just as new contracts started to come into force has been the key driver for the lower call for flexible LNG volumes since 2013. Asia's prominence in LNG trade means that the region will shape both the speed of market rebalancing and the evolution of flexibility requirements. In this light, this section looks at the contractual structure of traditional and emerging LNG buyers relative to their import profile and examines the potential impact of recent trends on LNG market functioning and regional and global gas security. This section refers to the forecasts published in the *IEA Medium-Term Gas Market Report 2016*, (*MTGMR 2016*) (IEA, 2016a).

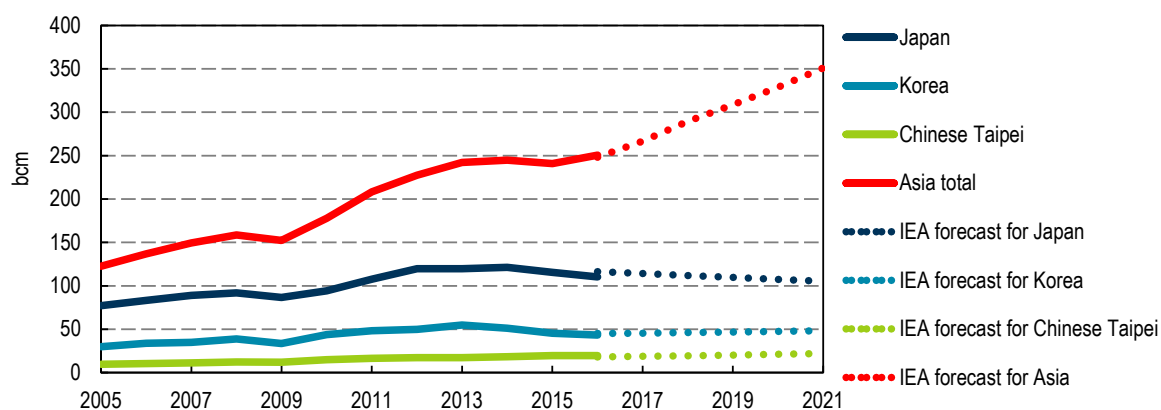
The IEA forecasts a strong increase in Asian LNG imports over the medium term, projecting they will reach 350 bcm in 2021, an increase of 40% relative to the 2016 level. This will slightly increase the Asian share of total LNG trade to 74% from 72% in 2015. But where will demand originate within the region? This is a critical question when analysing the evolution of flexibility requirements.

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The projected import increase over the next five years is mainly supply driven. This means that the new liquefaction capacity that is coming to the market is largely unaffected by low prices or weak demand. Most projects have now passed the “point of no return” where too much capital has been invested for the sponsor to pull the plug. Moreover, long-term contracts underpin the bulk of those new supplies, which ensures producers a minimum cash flow, even in a low-demand, low-price environment. As a result, imports will have to increase to match those additional volumes. Prices will adjust as necessary in a process that can be defined as a production push rather than a demand pull. (Alternatively, liquefaction plants will need to be shut down or run below capacity. This is possible and at times will likely happen, but it is unlikely to become the primary tool for market rebalancing.) Where the additional demand materialises, it has no real impact on how quickly the global LNG market rebalances. Yet it affects the need for flexible LNG volumes. As long as incremental demand matches the contractual profile of new supplies, there will be no need for additional flexibility.

By contrast, if new potential demand lies in countries with no contracts in place (or if demand in those countries exceeds their own contract levels), then the call for flexibility would increase substantially. This analysis of contracts, demand and import prospects points to a mismatch between the intended contractual destination of new supplies and the location of new import demand. Such a mismatch indicates the need for additional market flexibility. Notably, in a supply push, demand for flexibility is more a rebalancing tool than the expression of a supply-security requirement.

Figure 2.3 • Asia, Japan, Korea and Chinese Taipei LNG imports: Historical and forecast, 2005-21



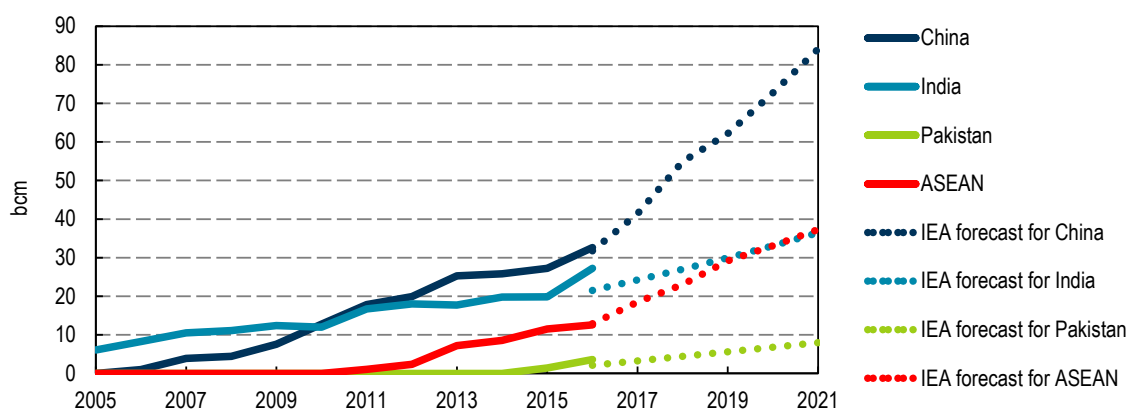
Sources: IEA (2016a), *Medium-Term Gas Market Report 2016*; IEA (2016b), *Natural Gas Information* (database).

As Figure 2.3 illustrates, the IEA forecasts that demand from Japan, Korea and Chinese Taipei – which in 2015 accounted for 54% of global LNG imports – will decline by 5 bcm in absolute terms by 2021. Their combined share of total LNG imports is expected to dip towards 36% by 2021. Actual data for 2016 so far show that imports from those three countries are following a path slightly below that projected in the *MTGMR 2016*, mainly due to lower-than-expected Japanese intakes.

By contrast, LNG import demand from the rest of Asia is expanding more rapidly than that forecast in the *MTGMR 2016*, mainly due to a surge in India LNG intakes and strong Pakistani

imports (Figure 2.4). China LNG imports have also rebounded, in line with the IEA's earlier projections. The recovery in LNG imports illustrates well the price sensitivity of developing Asia.

Figure 2.4 • China, India, Pakistan and ASEAN LNG imports: historical and forecast 2005-21



Note: ASEAN = Association of Southeast Asian Nations.

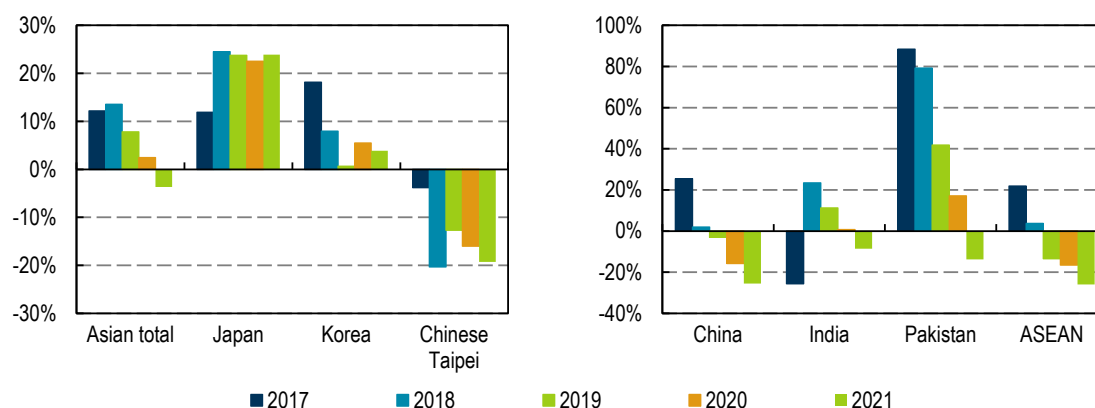
Sources: IEA (2106a), *Medium-Term Gas Market Report 2016*; IEA (2016b), *Natural Gas Information* (database).

Asia's LNG import behaviour as of October 2016 illustrates well the different price sensitivity of different countries' groups. The strong increase in Indian and Pakistani imports reflects the better economic position of gas at current low prices. Both countries have underutilised gas-fired capacity, spare gas import infrastructure and power deficits. With much of the supply chain infrastructure cost sunk, lower prices have boosted the economic viability of gas. Looking ahead, LNG importers in developing Asia are likely to play the dominant role in absorbing the large incremental LNG volumes coming onto the market. Price sensitivity (both to the upside and to the downside) is much higher in these markets than among established LNG buyers. At lower prices, new demand pockets are opening up in China, India, Pakistan and ASEAN countries, but not in Japan or Korea, where the medium-term outlook for gas demand is determined much more by the electricity demand profile and capacity availability of other forms of generation rather than gas prices (unless LNG prices fall consistently below coal prices, which is unlikely).

A key implication is that while Asia, as a region, looks relatively balanced from a contractual versus demand standpoint by 2021, this does not come from the aggregation of balanced country-level positions (Figure 2.5). In particular, Japan's contractual obligations in 2021 are set to be roughly 20 bcm above those of 2016. While the demand outlook is heavily dependent on the path for nuclear capacity, the range of possible demand variations is likely to be flat to significantly lower, rather than flat to significantly higher. Using IEA medium-term forecasts for gas demand as a benchmark, Japan's over-contracted position would stand at around 25 bcm by 2021 (the position in 2016 was a net deficit of 7 bcm). By contrast, many developing countries in Asia would show deficits by that date (i.e. demand levels above their contractual positions).

At an aggregate level, Asia will reach a peak in contractual surplus in 2018, after which the surplus will start tailing off, in line with the slowdown in incremental supplies and the opening up of new demand outlets via additional infrastructure. In volume terms, the large expected contractual surplus in Japan will be offset by contractual deficits elsewhere, mainly in China and ASEAN countries. As a result, Japan would transition to become a large provider and China a large taker of LNG supply flexibility. A possible limitation to this is the role that destination clauses could play in limiting the free flow of LNG from a flexibility provider to a flexibility taker (Box 2.1).

Figure 2.5 • Ratio of over-/under-contracted LNG volumes versus IEA demand forecasts, 2017-21



Note: 10% means that contracted volumes exceed IEA's projected demand by 10%.

To a large extent, the expected shift in relative contractual positions mirrors different trends for demand prospects and import growth. In particular, the fact that China will gain relevance relative to Japan and Korea as an LNG importer could bring important global security benefits. The traditional Asian LNG importers of Japan and Korea have isolated energy systems with no domestic upstream potential and no electricity or pipeline interconnections with other countries. All of this is translated into price-inelastic LNG demand and switching to oil as the only measurable demand response possibility. China has a continental-scale energy system with a large domestic fuel-switching potential between coal and gas. Increasingly, strict environmental regulations limit this potential to an extent, but the latest generation of Chinese coal-fired power plants is equipped with modern environmental controls, and coal will remain the backbone of power generation there. Although China's import dependency is rising, it will see a meaningful increase of domestic production. Tight gas already plays a major role in China and shale is expected to do so, which as in the United States can lead to a domestic upstream that is price-elastic in the medium term. Moreover, China has also been successful in building a diversified pipeline import structure, from Central Asia and Myanmar (and the Russian Federation probably in the future) as well as a domestic pipeline infrastructure that is increasingly able to link different regional supplies to demand centres. All of this means that China is one of the countries that can potentially reduce LNG purchases were LNG markets to tighten unexpectedly.

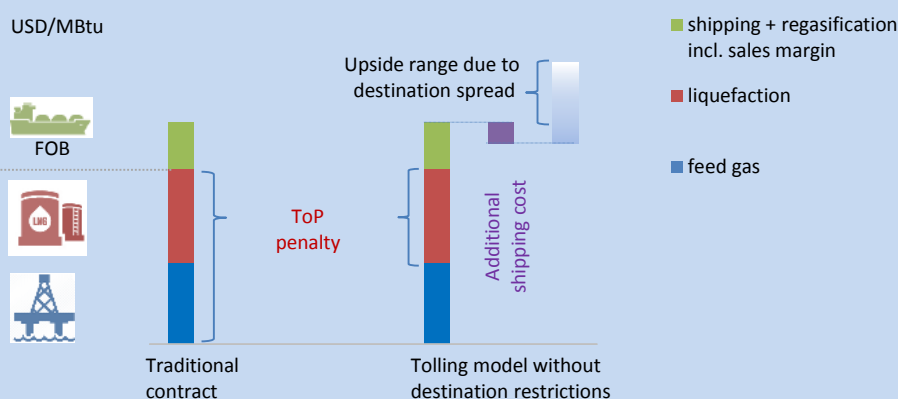
Box 2.1 • Destination and take-or-pay clauses in LNG contracts: What's the deal?

In the currently oversupplied market, traditional buyers are seeking more flexibility in the contract terms. As an example, US LNG contracts provide such flexibility in two ways: the contracts do not contain restrictions in the form of destination clauses, and the penalty for not taking contractually agreed cargoes is limited to the tolling (or liquefaction) fee rather than the full take-or-pay (ToP) penalty of traditional contracts (Figure 2.6), as the LNG buyer tends to be responsible for sourcing the feed gas, which can be arranged on a shorter-term basis. So, what is this flexibility worth? At face value, the traditional ToP penalty appears harsh, but the sting is taken out of these clauses in traditional contracts by allowing the LNG buyer to lower the annually agreed contract volume (ACQ) by typically about 10% and give the buyer the option to take delivery of the cargoes at a later point in time. However, the payment for the cargo occurs as per the agreed delivery schedule, so the buyer incurs at least the cost of time value of money, which, depending on the discount rate used, can equate to a few percent of the buyer's anticipated annual revenue. The much larger value driver is the elimination of destination clauses, which in the past specified that the buyer could not resell the cargo at another offloading point. The motive for selling at other destinations can be that the buyer is over-contracted at the intended LNG sales destination due to lack of demand there or seeks an



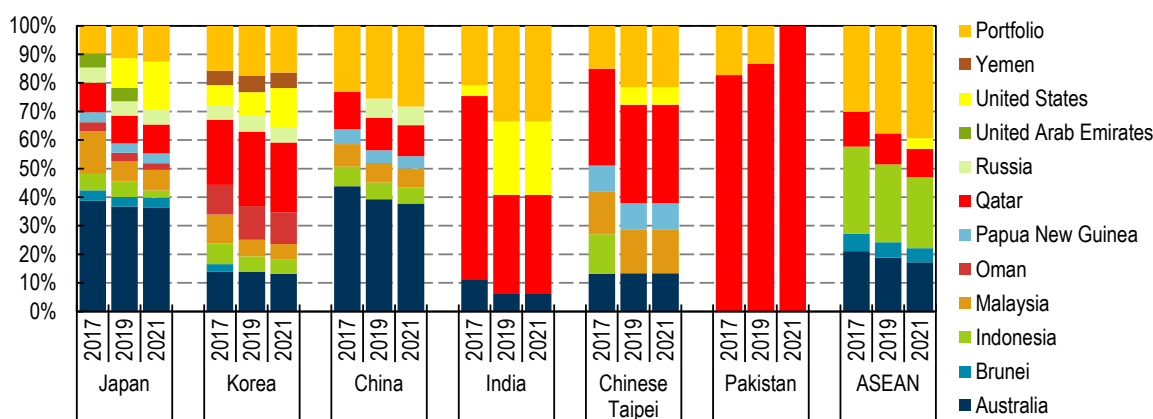
arbitrage opportunity because the LNG price at other destinations is higher (referred to as destination spreads between locations). For example, the spread between LNG prices in Japan and Europe were on average 6 US dollars (USD) per million British thermal units (MBtu) between 2011 and 2015, resulting in a fair amount of re-exports provided the contracts allowed it. While regional spreads and thus scope for arbitrage opportunities have been reduced markedly this year – and are not likely to regain the high levels of 2011-14 – the flexibility to sell cargoes anywhere can present a significant upside for the buyer. Depending on the difference between purchase costs and sales price of the LNG at the final destination (but using historical spread rates as a guide), such flexibility can amount to an additional 10% of the annual sales revenue relative to a traditional contract.

Figure 2.6 • The upside of tolling fees and destination freedom – an illustrative example using unit costs



From an individual country standpoint (rather than from a global one), a diversified contractual structure has important security advantages. It is not surprising, therefore, that large, LNG-dependent importers procure supplies from several producers under a variety of contracts. In a market that until now has been characterised by low liquidity, limited spot trading and constrained flexibility, supply diversification has proved the most obvious hedge against possible supply disruptions. Figure 2.7 shows the contractual structure of major Asian importers.

Figure 2.7 • Contracted LNG volumes: Country's share, 2017-21



Japan and Korea have well-diversified contract portfolios, both importing from around ten different countries. Japan has a higher reliance on Australia, at around 35%, but volumes there are sourced from different projects across the country (around 70% from the west, 24% from the east, 6% from the north). Korea's key supplier is Qatar, with a share of around 25%. Chinese Taipei also relies on Qatar as its dominant supplier with a share of roughly 35%.

China's supply structure is more dependent on Australian and portfolio volumes. Portfolio players also play a meaningful role in India and ASEAN countries (with a share of 30-40% in this region). LNG imports from this type of supplier are by definition more diversified as they are aggregated from different projects around the world.

India's import structure will grow more diversified and less dependent on Qatari gas in coming years as US volumes gradually ramp up. After 2019, the share of contracted Qatari LNG will be smaller and India will rely almost equally on Qatar, United States and portfolio players for its contracted supplies.

Pakistan relies heavily on Qatar – for over 80% of its contracted volumes – and by 2021 Qatar will be the only contractual supplier to Pakistan. While relying on just one supplier might be a risky long-term strategy, Pakistan has just become an LNG importer and its imports are still limited, which explains (and justifies) the concentration of its imports from one source. That said, as LNG imports grow, increased diversification in its contractual base would be a desirable move.

Box 2.2 • LNG storage: A supply-security option for Asia?

Unlike Europe and the United States, most Asian gas consumers have limited or no storage capacity. In Europe and the United States, underground storage capacity represents around 20% of the country's annual demand. The high relevance of storage in these regions is a function of their high seasonal demand fluctuations, typical of temperate climates, as well as favourable geological conditions. While gas consumption in South-East Asia does not follow a winter-summer cycle, heating is an important driver of gas demand in north-east Asia. Yet due to geological constraints, both Japan and Korea lack underground storage. China has underground storage potential but the absence of adequate price signals have so far discouraged the construction of storage sites, which today average just around 5 bcm (equal to 2.6% of the country's total gas consumption).

The primary purpose of commercial storage – and so the underlying business case for its construction – is the need to respond to demand fluctuations. However, once in operation, storage can also act as a "first response" tool in the case of a supply disruption, serving as a bridge to a more comprehensive set of readjustments and response mechanisms characterised by a longer reaction time. Asia's dependency on long-distance LNG imports, amid little to no underground storage, raises the question of the degree of operational flexibility in the LNG supply chain that could offer a "first response" mechanism to possible disruptions of LNG flows.

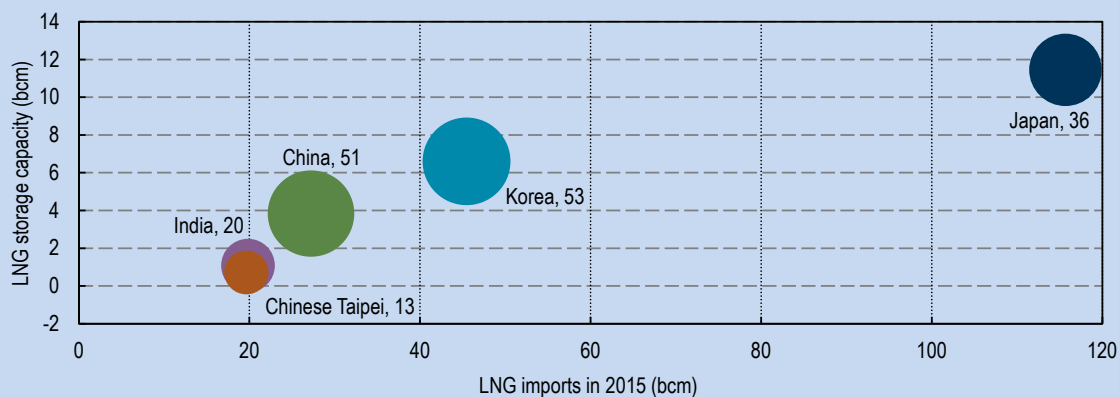
LNG storage can offer some short-term relief. Regasification facilities normally incorporate LNG storage tanks, as they provide operational flexibility at the site. The size of LNG storage differs from terminal to terminal depending on the design of the facility and its operational purposes. Broadly speaking, the higher the capacity of LNG storage relative to that of the regasification facility, the higher the operational flexibility of the site. Facilities that offer additional services such as "parking", "break-bulk" and reloading tend to have larger storage tanks. For example, among the main European LNG importers, Spain has the largest LNG storage capacity relative to the size of its regasification infrastructure, reflecting the country's dominant role for ancillary services.

In the absence of underground storage, the flexibility provided by LNG tanks can be attractive for security-of-supply reasons and helps to cover short-term interruptions. However, LNG storage cannot provide a large-scale security option due to its costs – mostly linked to the boil-off of gas. Overall, the Asian region tends to have larger LNG storage capacity compared with Europe in relation to the size of its regasification infrastructure (~50% higher), reflecting the lack of alternative options to respond to demand (or import) fluctuations. But how much of a buffer does this capacity offer?

Figure 2.8 illustrates the maximum contribution that LNG storage could provide in a supply disruption across different Asian LNG importers. The days of import cover – defined as LNG storage capacity divided by LNG imports in 2015 – would vary between 53 for Korea and 13 for Chinese Taipei. Countries such as Chinese Taipei and India that operate their regasification facilities at high utilisation rates tend to have fewer days of coverage.

In practice, actual coverage would be lower than that for at least two reasons. First, storage tanks are usually not full. For Japan and Korea – countries for which data on storage levels are available – the average inventory level during 2015 was around 50% of the storage capacity in both countries. Using actual storage levels rather than capacity as the indicator, days of coverage for Japan would drop from 36 days to 17 days and for Korea from 53 days to 29 days. Second, if pipeline connections among various regasification terminals are not sufficient, days of cover would differ for different regional demand areas: gas could be available at one storage site but not be useful to address demand shortages at a different location.

Figure 2.8 • LNG imports in 2015, LNG storage capacity and operational days



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3. Flexibility provided

Due to the lack of short-term upswing production capacity of liquefied natural gas (LNG), demand for flexible LNG volumes can be met in three ways: via LNG production that is fully uncontracted, via volumes that are contracted to a specific destination but redirected, or via contracted volumes open to multiple destinations.

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International Energy Agency (IEA) analysis shows that demand for flexible LNG volumes peaked in 2013 at around 60 billion cubic metres (bcm) and then decreased towards 50 bcm in 2015. On average, 30% of that demand was met thanks to the flexibility provided by uncontracted supplies. Qatar accounts for around half of these volumes.

Supplies initially contracted to a specific country but then shipped to another one cover around 30% of the demand for flexible volumes. The rerouting of these supplies has occurred via both direct diversions (i.e. not through portfolio aggregators) and reloading. From a technical standpoint, diversions occur when gas is redirected to the final destination before reaching the intended country (and often at the port of loading). Reloads occur when the gas reaches the initial intended destination but is then reloaded and shipped to another – usually higher-priced – market.

To occur, diversions require an agreement between the two parties of a contract. Data show that some producers – specifically Nigeria and Trinidad and Tobago – are more inclined to allow diversions than others and have accounted for the vast majority of direct diversions that have occurred over the past five years.

Diversions and reloads hinge on exploiting the flexibility embedded in the gas system of the intended country. Such flexibility can originate from different sources: stronger reliance on pipeline imports and fuel switching in the power sector are the key mechanisms to free up LNG volumes for where they are most needed.

Over the past five years, structural changes in the European and United States (US) gas markets have left many buyers in these regions severely over-contracted. Most recently – in 2014 and 2015 – some Asian countries have also been displaying a higher contractual position than needed. Today, the aggregate over-contracted position in global LNG markets is around 70 bcm, an all-time peak. In practice, the production underperformance of some LNG exports – as described in Chapter 1 – has offset some of that. Overall, however, the flexibility that over-contracted positions offers to global gas markets remains high.

The contractual long position of the United States and Europe after 2011 was the key underpinning of the large increase in the redirection of gas from these markets to others characterised by a short contractual balance. Freeing-up flexibility during the 2011-14 period of tight LNG markets in Asia was made possible by exceptional changes in the European and US markets.

The missing link in tying together demand and supply of flexible volumes is provided by contracts that are not tied to any specific destination. A large proportion of these contracts are in the hands of portfolio players, whose role in global LNG markets has increased substantially in recent years. The need to commit to large volumes and the associated high risks involved in entering a long-term LNG supply agreement mean that such agreements cannot easily be handled by many potential new entrants to the market. Portfolio players can distribute those volumes and risks among the aggregation of smaller demand sources more readily than the traditional LNG uptakers can. Consequently, portfolio players have a very important role to play as demand enablers for new pockets of demand.

Flexibility provided by uncontracted volumes

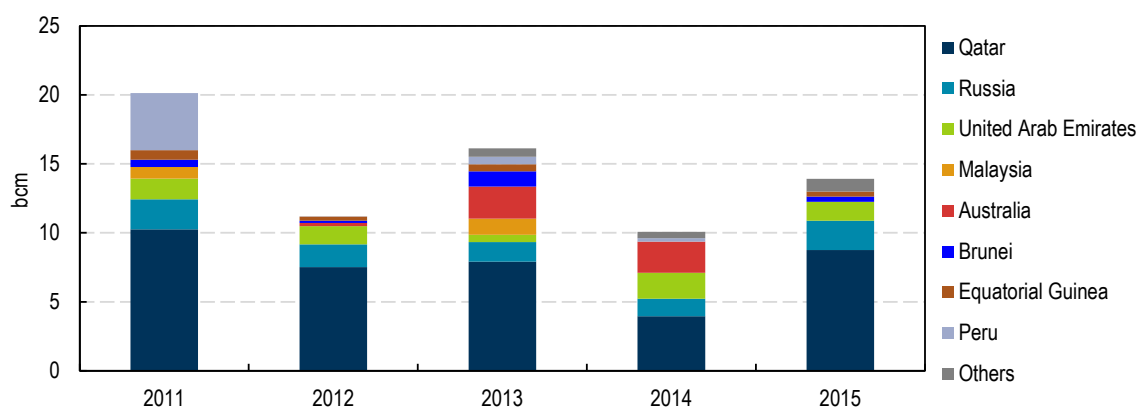
The capital-intensive nature of the LNG industry forces promoters of LNG export plants to lock a large proportion of production into long-term sales agreements with offtakers before the project can actually go ahead. Such deals – by ensuring a minimum level of future cash flows – are a crucial security guarantee for the financial institutions backing the project. Selling production forward is a prerequisite to obtaining project financing which, in turn, is needed to progress to final investment decision. Across all projects, therefore, the common approach is to book most of the annual output via long-term contracts and leave small quantities to be sold on a merchant basis.

The exact split depends on the lenders' requirements, which are often linked to the specific risk profile of the project. The level of country risk, the desired financial structure (equity versus debt) and the government's control over assets are examples of factors considered that shape the lender's perception of the likely stability of future cash flows.

This analysis – based on the comparison of contracted volumes and export flows – suggests that there are mainly four countries, specifically the Russian Federation (hereafter "Russia"), Qatar, the United Arab Emirates and Equatorial Guinea, that have consistently provided some production flexibility in the form of uncontracted volumes (Figure 3.1). Other producers have occasionally done so. This means that the marketing entities of the respective liquefaction projects are directly responsible for marketing that gas in the spot/short-term market.

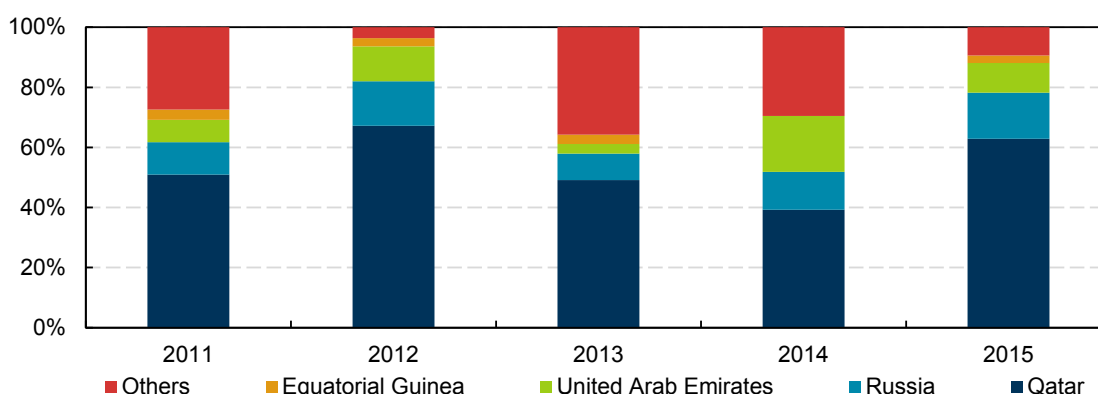
Supplies for Equatorial Guinea and Qatar are subject to a 90% long-term, 10% spot/short-term split (although, of course, in absolute terms this translates to a much higher level of uncontracted volumes for Qatar given the different scale of the two suppliers). The level of long-term contracts in Russia is around 85%, and in the United Arab Emirates it is around 80%. Achieving a higher share of uncontracted volumes in projects has proved difficult due to lenders' objections.

Figure 3.1 • Flexibility provided by producers' uncontracted volumes, 2011-15



It is important not to mistake the flexibility offered by uncontracted capacity with short-term swing production capability, which refers to the ability to increase exports, as a function of prices, above the prevailing export level and not relative to contracted volumes. Holders of uncontracted capacity routinely sell it in the spot/short-term market. As a result, at any given point in time, they cannot increase sales above what they are already exporting. However, the short-term nature of those sales means that primary sellers can swiftly redirect volumes at short notice and as they wish.

Figure 3.2 • Share of uncontracted capacity by exporting country, 2011-15

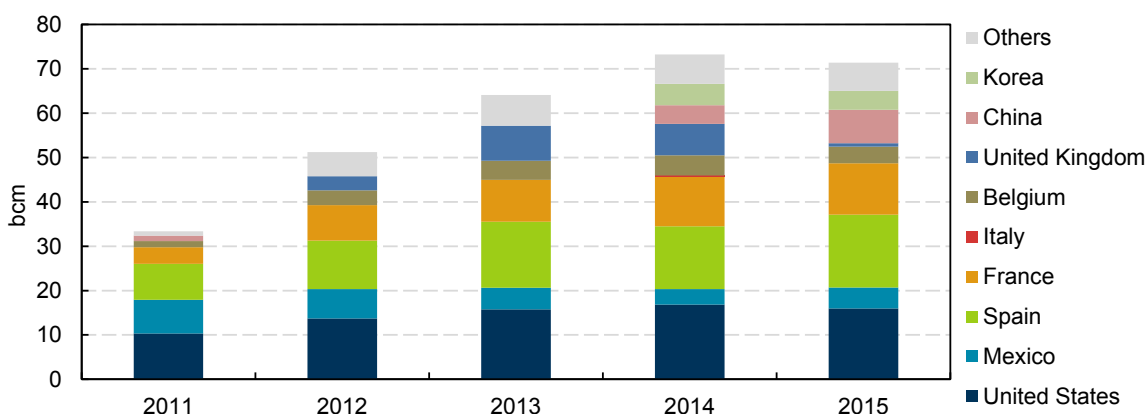


Since 2011, the annual flexibility provided in the form of short-term sales of uncontracted capacity has ranged from 10 bcm to 20 bcm. This is a relatively small volume, representing just around 2% to 4% of global liquefaction capacity. Qatar's share of uncontracted capacity is by far the largest and has fluctuated between 40% and 70% of the total since 2011 (Figure 3.2).

Flexibility provided by the demand side

Much of the flexibility provided by the demand side over the past five years is linked to the over-contracted position of a few countries. Spain and the United States rank high among them accounting for almost half of the total (Figure 3.3).

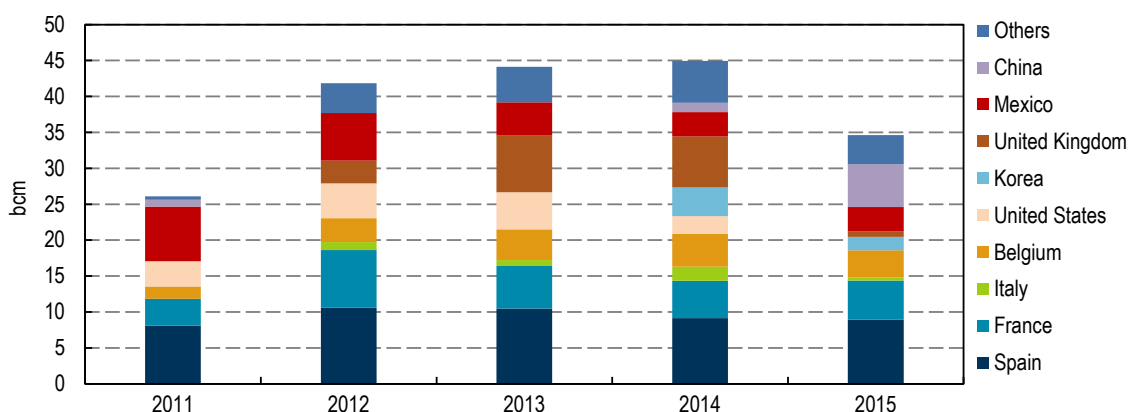
Figure 3.3 • Over-contracted position of LNG importers, 2011-15



While the flexibility provided by the demand side is closely linked to the aggregate over-contracted position of different LNG importers, it is less than that, due to the fact that in some cases producers have not been able to meet minimum contractual volumes because of a variety of supply problems (see Chapter 1). An estimate of the flexibility provided by the demand side once outages are taken into account is shown in Figure 3.4.

The volume flexibility made available by both the United States and Spain is the consequence of large structural changes in the markets – in other words rapid unexpected shifts in fundamental developments – that left both markets heavily over-contracted for new LNG supplies. Other European countries have experienced similar shifts to those that have affected Spain – although not by the same magnitude. In Europe, those structural changes were demand driven; in the United States were supply driven.

Figure 3.4 • Estimated flexibility provided by the demand side, 2011-15



In practice, during the tight market of 2011-13 and in the aftermath of the spike for flexible volumes driven by a surge in Japan's import needs, North America and Europe provided 100% of the additional volumes required. The flexibility that these two regions managed to provide is also linked to the abilities of both regions to arbitrage between pipeline supplies and LNG.

A new trend began in 2014 and 2015 in which Asian countries – notably the People's Republic of China (hereafter "China") and Korea – emerged for the first time as net providers (rather than net takers) of flexibility in the LNG markets. As discussed in the section "Asia gas demand and its role in driving the call for flexible volumes" in Chapter 2, recent fundamental developments suggest that a number of Asian countries – but in particular Japan – could move rapidly from takers to providers of flexible LNG volumes.

The United States

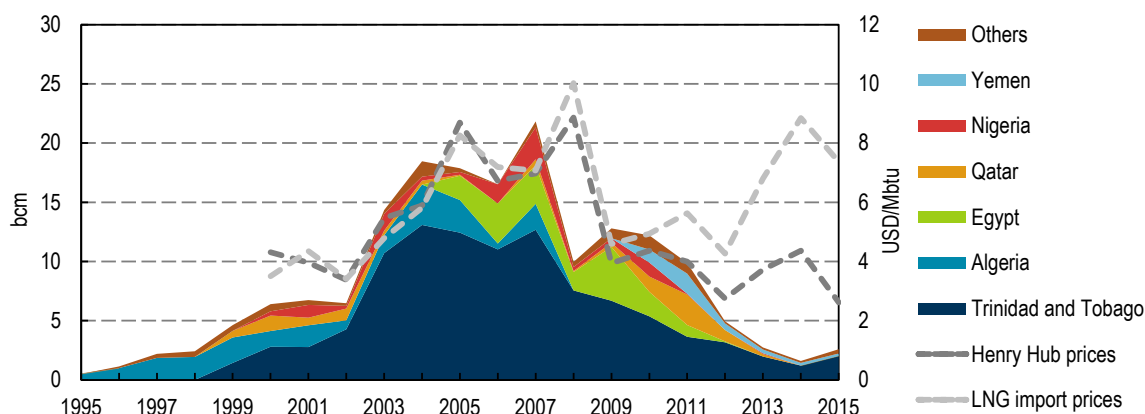
The contribution of the United States as a provider of LNG volume flexibility to the global gas market is linked to significant structural changes that this market has undergone in recent years. These changes are described in this section.

The first wave of LNG regasification terminals in the United States was built back in the 1970s, starting with Everett (1971, New England) followed by Elba Island (1978, Georgia), Cove Point (1978, Maryland) and Lake Charles (1981, Louisiana). After reaching a peak in LNG imports in 1979 – to stand at around 1% of total US gas demand – LNG imports fell sharply, causing the mothballing of both Elba Island and Cove Point in 1980. Everett and Lake Charles kept operating in the following years but at low utilisation levels.

This change in fortunes was spearheaded by the deregulation of the US gas market. Reforms in the 1980s and 1990s brought about the deregulation of wellhead prices and unbundling of gas transmission services. This reform process – which was mostly completed by 1993 – helped stimulate upstream investments, leading to higher indigenous production and declines in import needs. Meanwhile Algeria, the sole LNG supplier to the United States at the time, was not willing to adjust prices to levels consistent with the new reality of the US gas market.

By the early 2000s, gas prices started increasing again on the back of strong growth in gas-fired power generation at a time when LNG exports from both Trinidad and Tobago and Nigeria were ramping up. All together this helped bring the Elba Island terminal back on line in 2001 and Cove Point back in 2003. LNG imports doubled between 2002 and 2003.

Figure 3.5 • US LNG imports by source, 1995-2015



Sources: HH data: Bloomberg Finance LP; LNG import price data: EIA (2016b), Natural Gas Prices (database); EIA (2016a), *US Natural Gas Imports by Country* (database).

At the time, there was a strong consensus that US LNG imports would have continued to increase rapidly. In 2004, the Energy Information Administration was forecasting US LNG imports to reach 60 bcm by 2010 and 136 bcm by 2025 (EIA, 2004). Shale gas development had not yet taken off and consequently did not even figure as a meaningful source of future additional supplies. This widely accepted expectation of a fast deterioration of the US gas market balance and an associated sharp increase in the reliance on LNG imports was rapidly reflected in higher and more volatile Henry Hub (HH) prices, which jumped from around 3 US dollars (USD) per million British thermal units (MBtu) in 2002 to above USD 8/MBtu in 2005. By the end of 2003, there were 21 proposals lined up to build new LNG regasification facilities amid strong competition between the United States and Europe to gain access to long-term LNG supplies. Such expectations for a huge increase in LNG import requirements prompted a rush to bring new LNG supplies to the United States. Many private companies were actively involved in developing liquefaction projects, but also some governmental organisations, such as EXIM, the export credit agency of the United States, and the Overseas Private Investment Corporation, provided some financial support. With the aim of securing the required LNG import volumes, the United States was involved across the main LNG developments serving the Atlantic basin such as Nigeria, Trinidad and Tobago, Egypt, Equatorial Guinea and even Qatar.

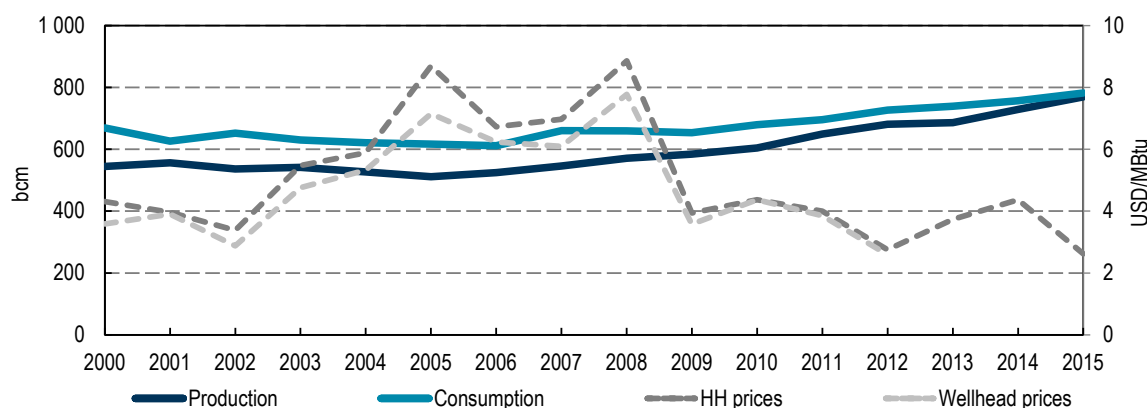
The second wave of LNG importing terminals arrived in 2008, just a few years after the start-up of operations of Egypt's liquefaction plants. Northeast Gateway (offshore Boston), Freeport (Texas) and Sabine Pass (Texas) all started up in 2008, followed by Cameron (2009, Louisiana), Golden Pass (2010, Texas) and Gulf LNG (2011, Mississippi), adding 120 bcm to the 62 bcm of existing regasification capacity.

Improvements in drilling technology and higher prices helped to develop production of more costly resources. By 2007, shale gas started to be recognised as a significant source of supply, able to drive meaningful production increases in the short to medium term that were later confirmed in 2009, coinciding with the end of high HH prices. Despite a much better than expected performance of shale gas production, it was not until 2011 that projections started to point to a transition of the United States to a net exporter of LNG by 2016 and a net exporter of natural gas by 2021.

As the rationale for importing LNG into the US disappeared, import volumes started to decrease rapidly after reaching a peak of above 20 bcm in 2007. Today imports have dwindled to almost nothing, with the exception of small volumes that continue to be delivered in the Everett

terminal in New England. There, in a region highly reliant on gas for electricity, insufficient pipeline capacity connections make LNG imports still viable.

Figure 3.6 • Evolution of demand and domestic production in the United States, 2000-15



Sources: HH data: Bloomberg Finance LP; Wellhead price data: EIA (2016b), *Natural Gas Prices* (database); IEA (2016a), *Natural Gas Information* (database).

The large over-contracted position of the United States has freed substantial amounts of LNG for other markets and has created strong demand-side incentives to trigger diversions. In the case of the United States, a structural change in the domestic supply outlook was by far the main factor behind its emergence as key provider of volume flexibility in global LNG markets.

The sheer scale of the shale gas revolution in the United States (Figure 3.6) is also responsible for Mexico's role as a flexibility provider. Mexico is importing LNG mainly through three long-term LNG contracts, each linked to one of the country's three import terminals. However, LNG received is significantly lower than the annual contract quantity (ACQ). This might indicate that some contracted volumes have been released to supply gas consumers elsewhere, while the originally intended LNG volumes to Mexico might have been replaced by pipe imports from the United States. US gas exports to Mexico have offered an attractive alternative to LNG – particularly up to 2014 when HH prices were trading at a several-dollar discount to other benchmarks around the world.

Europe

Alongside the United States and Mexico, Europe was the major contributor to the provision of volume flexibility to global LNG markets between 2011 and 2015 (Figure 3.4), led by Spain, and to a lesser extent France and the United Kingdom (UK). Similar to the case of the United States, large structural changes in the market left most European countries – but especially Spain – with over-contracted volumes for LNG.

Unlike the United States, however, the dramatic shift in Europe's gas market fundamentals proved mainly demand driven rather than supply driven. The combination of the euro crisis and a much larger deployment of renewables than initially anticipated resulted in a steep downward adjustment in expectations for gas demand and much lower import needs. In the Europe region of the Organisation for Economic Co-operation and Development (OECD) power generation from renewables grew robustly, reaching 34% of total power generation in 2015. As power demand growth stagnated between 2011 and 2015 and the share of nuclear and coal was roughly the same in 2015 as it was in 2011, gas demand in the power sector declined by 25% from 185 to 140 bcm over the period 2011-15.



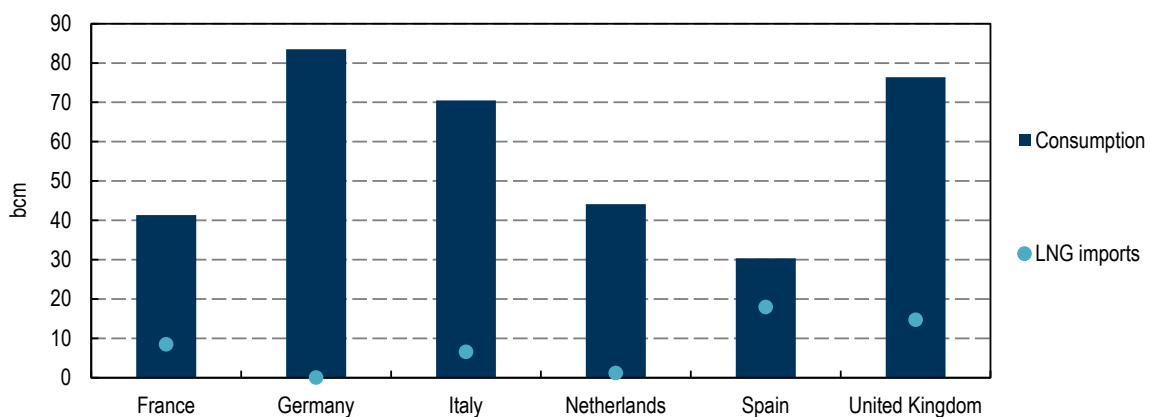
Adding to this, Europe's ability to arbitrage between pipeline gas and LNG further reduced Europe's call for LNG imports as LNG prices generally yielded better returns elsewhere and could be diverted (when an agreement with suppliers could be found).

Spain

While the storyline is more or less the same across Europe, Spain stands out as the most dramatic example. There are four factors that make the Spanish case worth highlighting.

First, Spain is fundamentally more dependent on LNG than any other country in Europe (Figure 3.7). This is due to lack of indigenous production, small underground storage capacity and limited interconnections with the rest of the continent.

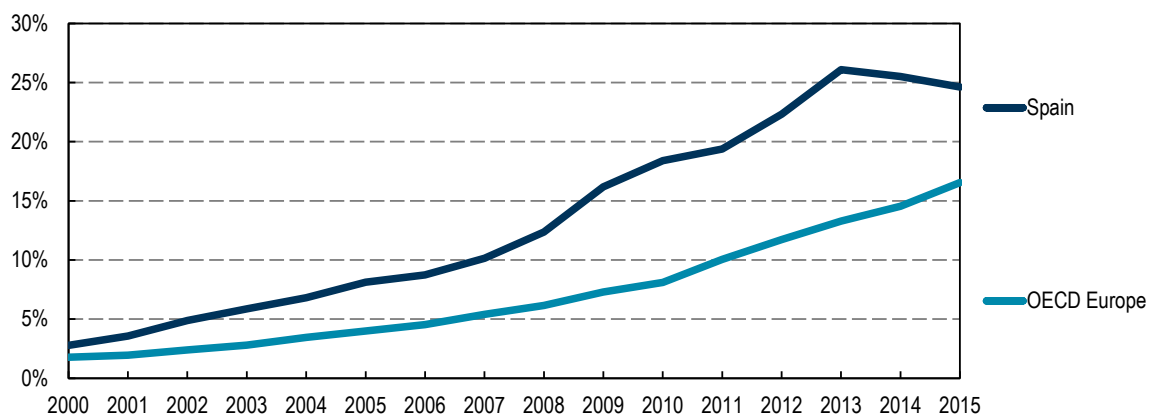
Figure 3.7 • Average gas consumption and LNG imports across key European gas consumers, 2011-15



Source: IEA (2016a), *Natural Gas Information* (database).

Second, the economic crisis was more severe in Spain than other main European countries (at least over the period 2009-13), which resulted in larger losses for power and gas consumption. Third, deployment of renewables was much higher in Spain than in other European countries (Figure 3.8).

Figure 3.8 • Share of renewable generation (excluding hydro) in total power mix, 2000-15



Note: OECD Europe comprises Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom. For statistical reasons, this region also includes Israel.

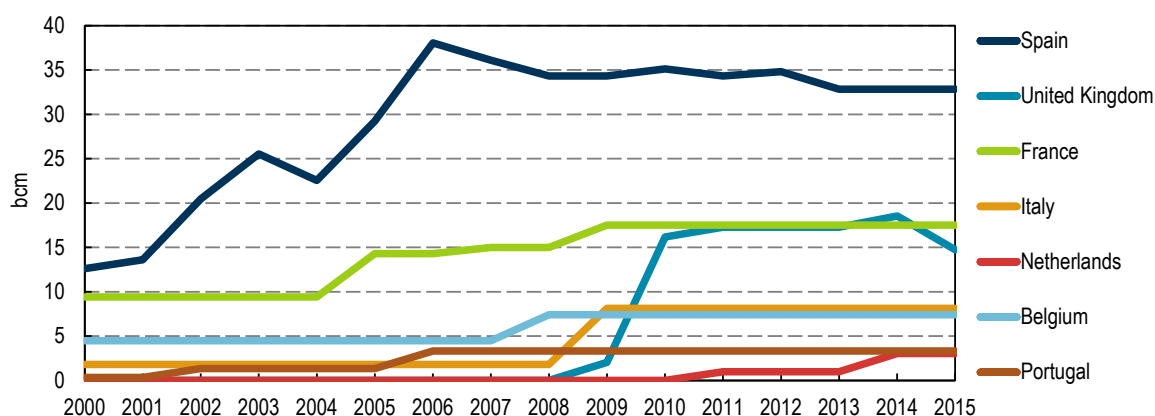
Source: IEA (2016b), *Electricity Information* (database).

Fourth, legislation to support domestic coal was introduced in Spain in 2011 (and remained in force until 2014), and it further deteriorated the position of gas in the energy mix. In accordance with the royal decree, a group of coal power plants consuming domestic coal were dispatched with priority by the transmission system operator. Although the volumes dispatched through this mechanism were moderate (13 terawatt-hours [TWh] in 2011, 12 TWh in 2012, 4 TWh in 2013 and 3 TWh in 2014), this should be put in a context of shrinking demand, higher renewables and stable nuclear generation.

Gas demand in Spain grew steadily until 2008, driven by the power sector. This led to a rapid deployment of combined-cycle gas turbines (CCGTs), both to supply incremental demand and to replace older, less efficient power plants. This created a rapid change in market structure, with the share of CCGTs reaching 40% of total power-generating capacity in 2008 from zero in 2000.

In anticipation of continued robust electricity demand growth, 25 gigawatts (GW) of CCGTs were built between 2000 and 2010 and more than 20 GW were planned for this decade, although they were ultimately cancelled. As a result, Spanish utilities entered into long-term LNG contracts to procure the required feedstock to run this large, brand-new CCGT fleet (Figure 3.9). At the time, most plants were built to run around 5 000 hours per year. The final outcome turned out to be very different, with the average load factor for CCGTs in 2014 below 10%, roughly equivalent to 900 hours of full working capacity. As a result of the financial and economic crisis, gas demand in the power sector fell by more than 70% between 2008 and 2014. Electricity demand reverted from a positive growth trend of around 2-3% per year to a negative trend post-2008. The fallout of the economic crisis meant a step back of more than ten years in terms of demand, with today's projections for 2020 at the level of demand in 2008. Adding to this, the fast roll-out of renewables together with the prioritisation of domestic coal introduced in 2011 further worsened the situation for CCGTs.

Figure 3.9 • LNG contracted volumes by different European countries, 2000-15



The downward adjustment in expectations for future LNG intakes was so dramatic that – similar to the case of the United States – LNG regasification capacity was mothballed. In 2009, a seventh LNG terminal, El Musel, started construction and was then completed in 2012. However, this terminal has never become operational and was immediately mothballed.

IEA analysis shows that over-contracted volumes in Spain reached around 15 bcm by 2013, and have stayed at similar levels since. To put things into perspective, this is roughly half the level of Spain's overall gas consumption today – a clear testament of the extraordinary turnaround in the country's gas market balances.

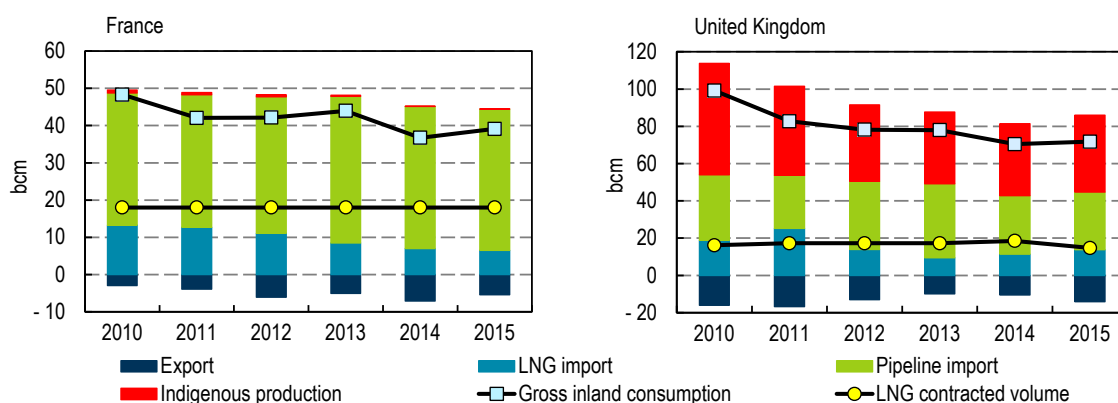
Such large LNG procurement levels left Spanish utilities with the dilemma of how to best manage them in the context of their overall supply portfolios. Data show that there was a clear choice to maximise pipeline imports and minimise LNG intakes. Between 2008 and 2015, Spain's pipeline imports increased by around 8 bcm, mainly from Algeria following the opening of the Medgaz pipeline, but also from North West Europe via higher exports through France. The potential to extract higher value for LNG via sales in other markets – through diversions and reloads – led to a deliberate choice to use pipeline supplies to serve domestic demand and ship LNG elsewhere.

France and the United Kingdom

Both France and the United Kingdom have also accounted for a substantial portion of the flexible volumes released into the global LNG market over the past five years. In 2014 they accounted for a combined 18 bcm of LNG volumes contracted but not taken.

French gas demand declined by around 9 bcm between 2010 and 2015, comparatively less than in other European countries, mainly due to the smaller share of gas in the power sector. During this period, net pipeline imports remained relatively stable, which resulted in large declines in LNG imports (Figure 3.10). Similar to the case of Spain, French utilities have maximised pipeline over LNG deliveries. With LNG contracted volumes unchanged between 2010 and 2015, France was able to release to the market 3.5 bcm on average in the form of LNG contracted but not taken.

Figure 3.10 • France and United Kingdom: LNG contracts versus market balance, 2010-15



Source: IEA (2016a), *Natural Gas Information* (database).

In contrast to the French case, gas demand in the United Kingdom fell very sharply, dropping by 27 bcm between 2010 and 2015. Roughly two-thirds of this fall was offset by declines in domestic production. Over that time, the composition of imports – and the relative role of pipeline and LNG – changed markedly, however. Until 2013, the United Kingdom experienced an increase in pipeline imports and a sharp decrease in LNG intakes, very much in line with that seen in Spain and France as well. Yet unlike the case of France and Spain, this trend clearly reversed after 2013 and in fact, by 2015 the United Kingdom barely provided any flexibility to the market. Such a development is likely due to a combination of factors: the large drop in Groningen production that has reshaped pipeline trade flows in North West Europe, a rebound in gas demand in 2015 driven by the impact of the UK carbon price floor on gas-fired generation, expiration of some LNG contracts and the large role that Qatar has as LNG supplier to the United Kingdom. In the aftermath of Fukushima, between 2011 and 2013, UK LNG imports fell by 60%, almost all from Qatar, as those volumes were quickly redirected to Japan. But from 2014 onward, when regional spreads compressed dramatically, Qatar reacted to changing market conditions – seemingly more quickly than others did – increasing LNG exports to the United Kingdom and demonstrating once again the unique flexibility of this major producer.

China

China is a clear example of a fast-evolving importing country. China began importing LNG in 2006 and by 2015, import volumes had grown to 27.2 bcm – representing 8% of global LNG imports. In 2015, China emerged for the first time as a provider of volume flexibility to the global LNG market with over-contracted volumes estimated at around 6 bcm. Much weaker than expected demand – the rate of growth fell to its lowest level since 1998 – at a time of rising contractual levels following the start-up of new projects in Australia led China to enter the market from the selling side for the first time. Whether this will continue to be the case remains to be seen. LNG imports have rebounded in 2016, suggesting that the weakness of 2015 was at least partly due to temporary factors (IEA, 2016a). Forecasts in the *IEA Medium-Term Gas Market Report 2016 (MTGMR 2016)* point to strong increases in China's LNG imports over the next five years, which should lead China's contractual position to flip back to the short side after 2018 (IEA, 2016c). This of course remains heavily contingent on LNG prices and the relative competitiveness of gas versus other alternatives.

Flexibility provided in the form of diversions

Beyond the flexibility provided by uncontracted capacity, diversions of volumes intended for a specific country, reloads, and volumes sold to offtakers without a specific destination attached (most of which are in the hands of portfolio aggregators) are the main tools to link the flexibility required and the flexibility offered by various LNG importers. This section covers the role of diversions.

Estimating diversions is not an easy task, and providing a point estimate of the volume of gas actually diverted is not possible. In particular, when LNG trades involve swaps, partial unloading of the same cargo in different countries or multiple destination agreements, knowing if specific cargoes are meeting long-term contracts or not becomes virtually impossible and only the parties involved can know the exact volumes diverted. Nevertheless, tracking the parts of LNG trades that are trackable already helps identify interesting patterns – and different exporters' approaches – with respect to diversions.

As a starting point of the analysis, this report looks at LNG volumes delivered by an exporter to countries other than those intended as the destination in the sales and purchase agreement (SPA). Excluded from the calculation are the contracted volumes with multiple destinations, as these tend to be in the hands of portfolio aggregators. While portfolio aggregators will also divert cargoes, tracking those diversions – as mentioned above – is extremely challenging. As a result, the overall level of diversions will actually be higher than that estimated here. Yet the analysis conducted already offers a useful indication of which producers have shown a more flexible approach to diversions. The growing role of portfolio players and their impact of LNG markets is analysed later in this chapter (in the section "Flexibility from portfolio players").

When it becomes apparent that exporters have shipped significant volumes to countries other than those intended in underlying contracts and, simultaneously, have not reached the full ACQs with the intended countries, it is assumed that diversions have occurred. Indeed, these redirections in volumes must result from an agreement between the parties of the long-term SPA (unless diversions result from buyers opting for minimum take-or-pay levels, in which case the seller can freely sell the remainder of the gas where it sees fit). If not, offtakers could flag it as a contractual breach and claim penalties and compensation.

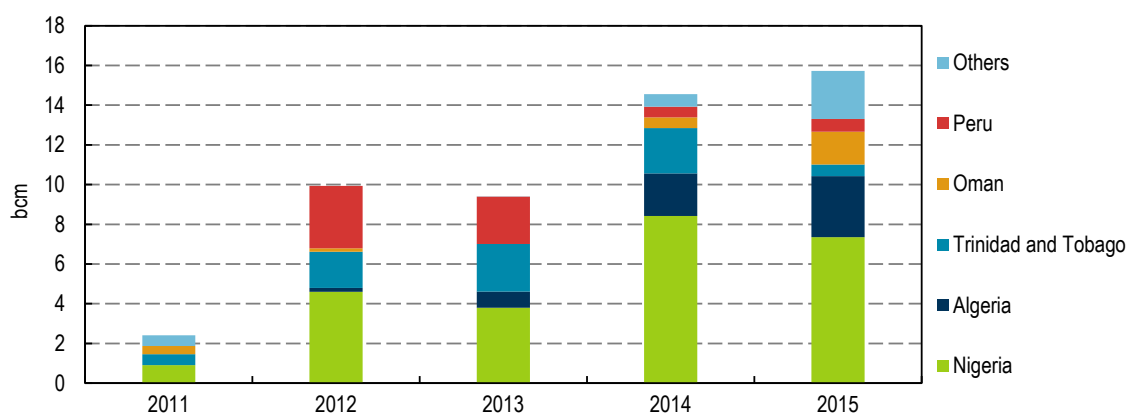
In the case of SPAs with fixed destination clauses, the offtaker must have the consent of the seller before diversions can occur to avoid a breach of the contract. From the seller's point of view, the rationale for destination clauses lies in the desire to price the gas in relation to the specific competitive alternatives of the destination market. In practice, destination clauses create

market segmentation and hamper competition as well as a transition towards a more globalised gas market by protecting sellers' revenues in markets where fewer alternatives are available. While destination clauses continue to underpin most Asian LNG contracts, they were made illegal in Europe at the beginning of the last decade. Full investigation of suspected cases and executing decisions when necessary took some time, however, highlighting the complexity of effectively eliminating those anti-competitive practices. In the case of fixed destination contracts, destination flexibility can be provided either through profit-sharing mechanisms or through different pricing structures for deliveries to markets not recognised under the original destination clause, normally by means of net-back calculations based on the more relevant hub price in the traded area. Where destination clauses are not present – but the gas is sold delivered ex ship (DES) – diversions also require negotiations between the two counterparties involved as the gas does not change ownership until it reaches the port of destination. Diversions are usually the product of amicable commercial negotiations between buyers and sellers in search of a shared upside. When common ground cannot be found, a solution can be forced only in the event of major structural changes in the market that allow buyers to invoke specific review clauses.

It is commonly accepted that offtakers must manage both seasonal demand fluctuations through the year (usually via annual delivery programme) and volume fluctuations across years. In this respect, downward tolerance in long-term contracts is a useful tool. However, in the case of steep structural declines in demand, which are very difficult for the offtaker to manage and somewhat outside its control, then the general practice is for both parties in the SPA to negotiate in good faith towards a shared best outcome to keep honouring the contract and preserve a good commercial relationship. In this case it is more likely that the supplier will agree to relax destination restrictions to keep the contract economically viable and avoid its anticipated termination. Yet a price adjustment should normally be expected in these circumstances, although within reasonable ranges of prevailing prices at global or regional/national level.

Overall, diversion activity – according to the definition utilised here – has increased rapidly, reaching in 2015 a level seven times higher than that in 2011 (Figure 3.11). Early this decade, LNG diversions were not common, but they took off between 2011 and 2014, helped by several factors – including a widening gap across regional benchmarks prompted by the Fukushima nuclear accident and generally a growing mismatch between who holds the contracts and who needs (or is willing to take) the gas. Nigeria and Trinidad and Tobago have accounted for the majority of diversions since 2011, reflecting specific characteristics of their projects that are described in detail in the following sections.

Figure 3.11 • Flexibility provided by diversions, 2011-15



Trinidad and Tobago

Trinidad and Tobago's LNG ventures – unlike those of Nigeria – benefited from a stable political context and full support from the national government. Train 1 capacity was entirely allocated through SPAs signed in 1995 with Cabot in Boston (United States) and Enagas (Spain). Both companies had tried to secure volumes from Nigeria, but with the Nigeria LNG project mired in delays, Trinidad and Tobago offered a faster path. After sales agreements were signed in 1995, first deliveries started in 1999. Project expansion followed rapidly, with construction of trains 2 and 3 starting in 2000. When the expansion was completed in 2003, Spain had secured, through different SPAs, slightly more than half of the supplies from the first three trains, or around 7 bcm. The remaining 6 bcm were secured by US companies.

Enagas and Cabot had a long-standing relationship that built on their roles as offtakers of Algerian LNG supplies. Since the beginning of the negotiations, the two companies maintained a collaborative approach, looking to agree to flexible destination conditions with the sponsors of the Trinidad and Tobago liquefaction project. The final goal was to deliver LNG either to Spain or to the United States according to the shared interest of both parties. Such an approach to the project forms the basis for the flexibility that characterises Trinidad and Tobago's supplies. Interestingly, during the 2004-07 period, significant volumes that were intended to be delivered to Spain reached the United States instead, coinciding with the country's peak in LNG imports ahead of the shale gas revolution.

Finally, the construction and marketing structure of train 4 was based on a pure tolling model, with BP, BG and Repsol entitled to the gas in relation to their feedstock gas contribution and obviously under flexible destination conditions.

Nigeria

The original idea behind developing LNG export facilities in Nigeria was to ship LNG to the United States and Europe. This was well signalled by the early interest of companies such as Cove Point Trading of Maryland, Cabot of Boston, Snam of Italy and Enagas of Spain to join SPA negotiations.

The political instability in Nigeria, lack of host government support for the project and financing difficulties led some of the initial offtakers to abandon the venture. While others joined in, such as British Gas and Enel, sales negotiations did not proceed smoothly and it took several years for SPAs to be agreed. Ultimately, the first long-term contracts were signed with GdF (France), Enel (Italy) and Enagas (Spain) as offtakers, later joined by Botas (Turkey) on a DES basis. However, unlike the case of Trinidad and Tobago, destination flexibility was not part of the deal.

Financing closure occurred only at the end of 2002. Unlike most LNG projects, which are paid for through project finance, Nigeria LNG was financed through the balance sheet of the shareholders sponsoring it – ENI, Shell, Total and the Nigerian state oil company. Moreover, after the first three trains were completed, financing of the additional three trains was done by giving lenders security for the loan over the whole liquefaction project without asset segregation, with a financing structure that is understood to have an unusually high equity share (around 50%).

These particular characteristics of Nigeria LNG have resulted in a high share of volumes contracted to offtakers – some of which are also sponsors of the project – not linked to any specific destination. (These volumes, while highly flexible, are not treated as diversions but analysed in this chapter in the section “Flexibility from portfolio players” as part of portfolio volumes). On top of it, around one-fourth of the overall volumes of the projects were sold under contracts intended to serve Spain and the United States but enjoying destination flexibility. These volumes are likely behind the high level of diversions from Nigeria as shown in Figure 3.11.

Oman and Algeria

While less significant than those of Nigeria and Trinidad and Tobago, Oman and Algeria have also accounted for a meaningful share of diversions over the past five years – more prominently during 2014 and 2015. Oman’s diversions mainly stem from lower intakes by Japan and Korea – relative to contracted volumes – over those two years. In the case of Algeria, increased diversions in 2014 and 2015 largely reflect increased export capacity (with a new plant starting up in 2014) in the absence of any substantial pick-up in LNG imports from Algeria’s main contracted customers (Italy, Spain and France).

Peru

The contracts governing activity of the Peruvian LNG export facility are flexible with respect to possible destinations. However, offtakers lifting cargoes from the terminal must pay a royalty to the Peruvian government based on the net back from the final destination of the LNG. This rule also applies to a long-term contract signed in 2007 between Repsol and the Mexican Federal Electricity Commission (Comisión Federal de Electricidad [CFE]), which is understood to be priced at a discount to the HH index. This choice of pricing has been – and continues to be – a source of debate and controversy in Peru, in light of low gas prices in the United States and associated low royalty gains for the Peruvian government.

When Repsol and CFE agreed to link the pricing of LNG to HH, it was 2007 and HH was trading around USD 7/MBtu. However, the contract was for gas to be delivered at the Manzanillo receiving terminal, which did not start operations until 2012. By then, the shale revolution in the United States was in full swing and natural gas prices had fallen to much lower levels, trading most of the subsequent four years in a range of USD 2/MBtu to USD 4/MBtu. This was yielding much lower than expected royalties to the Peruvian government compared with what could have been obtained from higher prices prevailing in most other markets. Due to this low margin, deliveries under this contract have been under pressure and negotiations between the parties are ongoing. These will likely explore a number of alternatives, such as reducing LNG contracted volumes and compensating for it via higher pipeline deliveries from the United States to Mexico, as well as changes in the price indexation terms. These pricing issues are likely behind the diversions witnessed from Peru in 2013.

Each LNG exporting project has different characteristics. Sponsoring a project is generally the easiest way to gain access to flexible destinations. The financing structure of the project, the participation of national export credit agencies and the debt/equity ratio are all factors that generally affect the capacity level that is not pre-committed through long-term bookings and that forms a first important portion of supply flexibility. Moreover, specificities of each project such as the host government’s approach to foreign investment, the sponsor’s determination to take the project forward (and what this might mean in terms of financial arrangements and contractual structures), and the particular characteristics of the offtakers are all factors that can shape the terms of the contracts as well as the ability to amend those terms and thus provide an easier (or harder) platform for diversions.

Flexibility from reloading activity

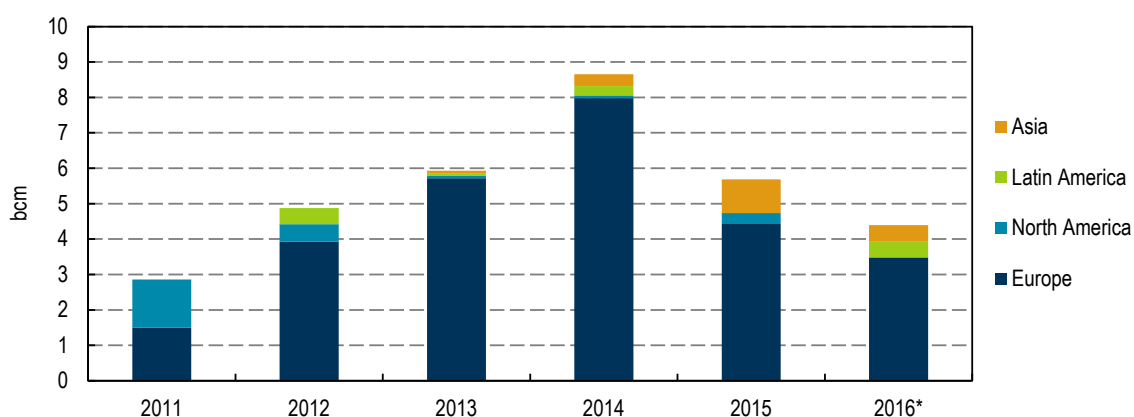
Another tool to deliver volume flexibility to importers that require it is reloading. Reloads are often used when diversions cannot be agreed between the two original parties of a contract; because unloading and reloading incur a cost, direct diversions are a more efficient way to reroute the gas. Reloads generally require higher regional spreads than diversions for them to be

economic. As a consequence, the destination countries for reloads tend to be those commanding a higher premium.

Reloading activity experienced steady growth between 2011 and 2014, with reloads peaking at almost 9 bcm in that year (Figure 3.12). The initial impetus of this activity came from the United States. While contracted volumes from Trinidad and Tobago were fully flexible, and most Nigerian volumes were likely diverted, reloads data suggest that volumes under different contracts might have been less flexible. Over time, changes to the initial contracts are likely to have been agreed to reflect the permanent shift in US gas market balances. By 2013, North America reloads were all but gone.

Since 2012, reloading activity has been driven by European countries. This is in line with the growing over-contracted position of the region at a time of tight markets in Asia (and corresponding high price differentials). In 2013 and 2014, Europe accounted for virtually all reloading activity. In 2015, reloads fell to around 6 bcm, reversing the trend of steady growth that had been in place since 2011. Data for the first three quarters of 2016 point to levels for the full year broadly in line with those of 2015. When considering the massive fall in regional spreads, today's reload levels look quite robust. As for diversions, this probably stems from a persistent mismatch between who owns contracts and who needs additional LNG supplies.

Figure 3.12 • Reloadings by exporting regions, 2011-16



* 2016 data is for January through September.

Sources: IEA analysis based on GIIGNL (2011-16), ICIS (2016), *ICIS LNG Edge*.

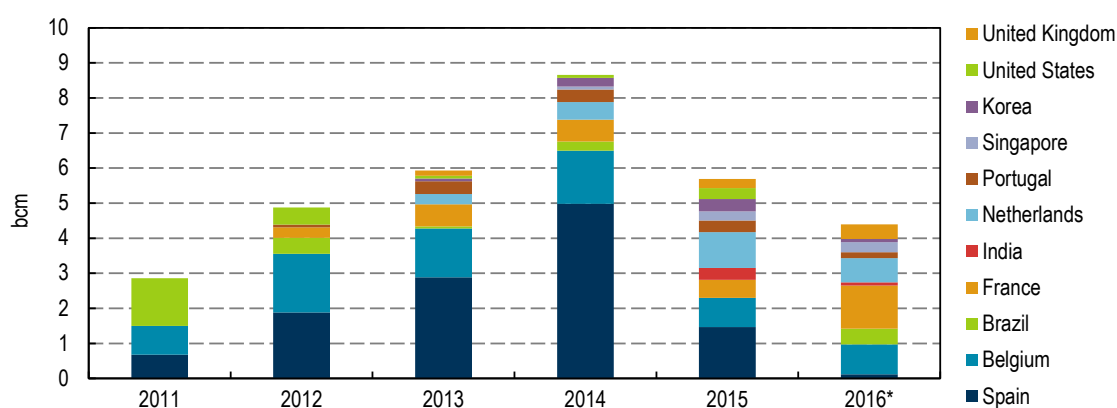
From a country perspective, Belgium and Spain dominated the picture in Europe until 2014. The role of Spain in particular increased dramatically in 2014 when the country's reloads accounted for 60% of the global total. In 2015, reloading activity collapsed in Spain and diminished as well in Belgium. By contrast, reloads have increased in both France and the Netherlands (Figure 3.13).

The different role of various European countries with respect to reloading is linked to two main drivers. First, the availability (or lack) of reloading facilities, and second, the supply portfolio of each country. Most reloading facilities in Europe were added to terminals early this decade. For example, the Netherlands did not have reloading infrastructure until 2013 and the United Kingdom had none until 2014. Other importers, such as Italy, still do not have this capability. Moreover, upgrades at existing infrastructure allowed improvement of the operating efficiency of reloading services over time. Better efficiency and lower costs have helped make reloads more widespread. The composition of the supply portfolio of each country is also a driver for reloading activity. For over-contracted importers, the need for reloads stems from the difficulty of negotiating diversions with suppliers, with some producers more open than others to doing so.

Reloads from Belgium and Spain appear linked to volumes initially sourced from Qatar (Belgium, in particular, has long-term contracts only with Qatar). In the case of France and Spain, some reloads might have also originated from Algerian gas.

In 2015 and 2016, Singapore has emerged as a reloading facility in Asia as the country develops the infrastructure and trading capabilities needed to support its ambitions to become a major LNG trading hub in the region.

Figure 3.13 • Reloadings by exporting country, 2011-16

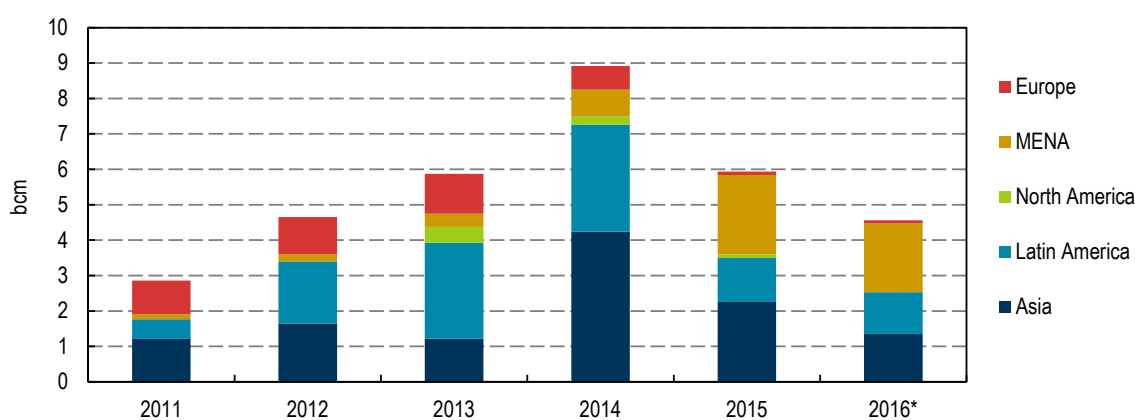


* 2016 data is for January through September.

Sources: IEA analysis based on GIIGNL (2011-16), ICIS (2016), *ICIS LNG Edge*.

From a destination perspective, most of the reloaded volumes were then shipped to markets in Asia early in the decade. In 2012, Latin America emerged as main destination for LNG volumes that were previously reloaded in re-exporting countries (Figure 3.14). This was due to a sharp increase in the call from Brazil, as the country's LNG needs soared as a way to cope with a severe hydro crisis. In 2014, Latin America's LNG intakes stabilised, but those of Asian markets jumped higher, with all major countries experiencing sharp increases. In absolute terms, Korea was the largest destination for reloads that year among Asian countries (Figure 3.15). Contrary to a general belief, Japan has never emerged as the preferred destination of reloads since this activity took off.

Figure 3.14 • Reloadings by importing region, 2011-16



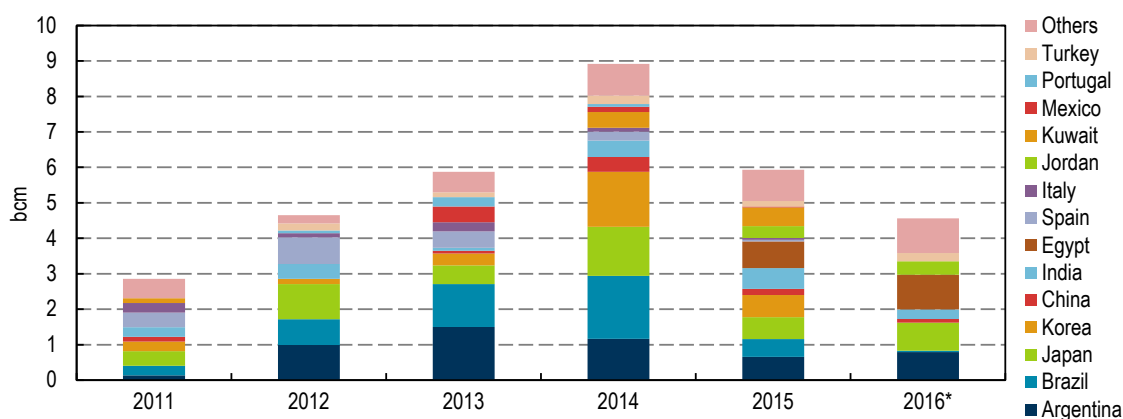
Note: MENA = Middle East and North Africa. * 2016 data is for January through September.

Sources: IEA analysis based on GIIGNL (2011-16), ICIS (2016), *ICIS LNG Edge*.

Since 2014, the MENA region has emerged as a significant and growing destination for reloads, led by strong intakes from Egypt, which was the single largest destination for re-exported LNG in 2015 and in 2016 through September.

On average, around 20% of global reloading activity occurs within the same region. There are, however, huge differences across regions. For example, there are no intra-regional trades of reloaded volumes within MENA countries or North America. This is in contrast to the situation in Europe, where all volumes received through reloads originate from European ports. In the case of Latin America, Brazil often acts as a re-exporting country for volumes to Argentina.

Figure 3.15 • Reloadings by importing country, 2011-16



* 2016 data is for January through September 2016.

Sources: IEA analysis based on GIIGNL (2011-16), ICIS (2016), *ICIS LNG Edge*.

Overall, the trend in reloading activity in recent years is aligned with the picture gathered from the analysis of demand and supply of flexible volumes. Europe and North America have been the key providers of flexibility via reloads, first to Latin America and Asia and second to MENA.

Flexibility from portfolio players

LNG volumes referred to as “portfolio” are contracted volumes, initially de-linked from any specific destination or end client. The counterparties are the marketing entity of a liquefaction project on the seller side and the LNG offtaker on the buyer side (portfolio player). Portfolio contracts tend to be long-term contracts whose related quantities are priced on the basis of a net-back calculation subject to the final market of the deliveries. The destination link to the downstream side is normally established once the initial contract has been divided into smaller portions and relevant quantities are resold by the portfolio player to end clients, which tend to be utilities and independent players. Portfolio players act as demand aggregators, and supplies usually come from a variety of sources.

Portfolio players are normally major oil and gas companies such as Shell, Total, BP, Gazprom, Eni, Engie, Gas Natural Fenosa and Petronas. In many cases, portfolio volumes are a result of the companies’ role as sponsors of the liquefaction projects being entitled to receive a proportion of LNG sales on the basis of their equity share, which normally is not subject to destination restrictions. In recent years, some of the big utilities followed this approach and nowadays are sponsors of liquefaction projects. By taking additional risks they gain access to supplies fully flexible from a destination point of view.

Moreover, it is important to notice that some of today’s portfolio volumes are the result of the significant change in the dynamics of the US LNG market, evolving from a net importer of LNG to

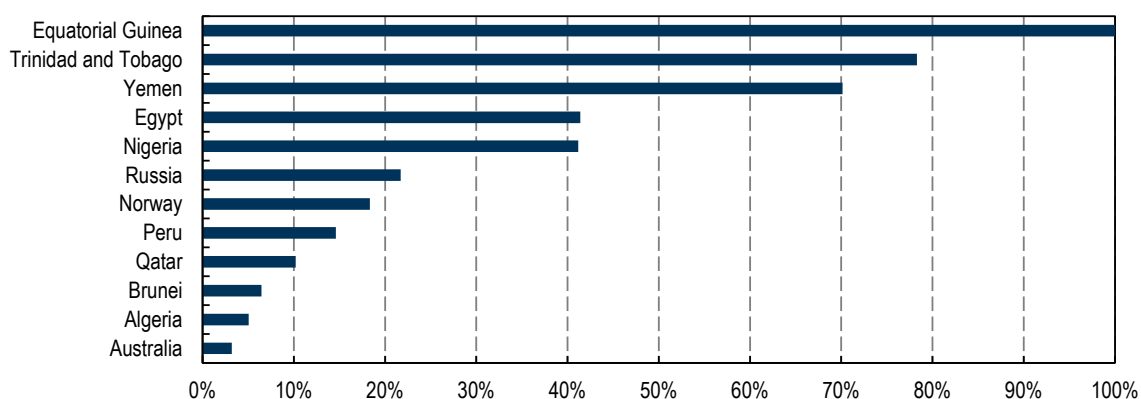


a net exporter in the coming years. A majority of the supply contracts originally intended to supply the United States are understood to have turned into portfolio contracts, as the reason to receive LNG quantities widely disappeared with the changing dynamics of the US market. This is probably the result of negotiations between seller and buyer, establishing a long-term solution by allowing multiple destinations.

Finally, another source of portfolio volumes are new US LNG export projects, which will introduce a much more flexible and modern concept of LNG trade without destination restrictions and priced indexed to HH plus a liquefaction tolling fee.

Analysing the amount of LNG export capacity that is linked to portfolio contracts, the proportion across the exporting countries is quite diverse, with the average between 2011 and 2015 ranging from 100% of the capacity feeding portfolio volumes in Equatorial Guinea to no more than 5% in the case of Algeria and Australia (Figure 3.16).

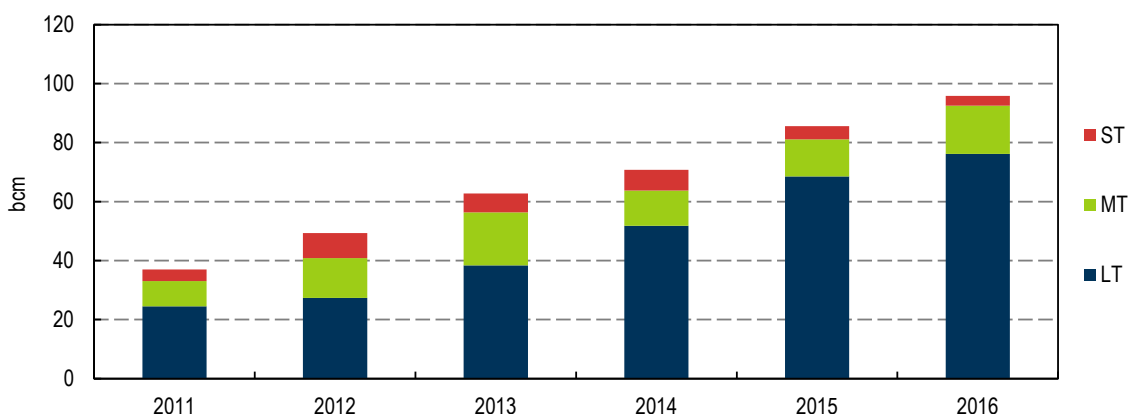
Figure 3.16 • Share of LNG exporting capacity subject to portfolio contracts (average over 2011-15)



Interestingly, Trinidad and Tobago reaches almost 80% of volumes and Nigeria just 40%. This is linked to what was explained in the section about diversions (“Flexibility provided in the form of diversions”). Compared with Trinidad and Tobago, Nigeria provides a higher degree of flexibility in the form of diversions. In the case of Trinidad and Tobago, diversions are lower because there is a big proportion of contracted volume that is not subject to any intended destination. It is also important to highlight that there has been a significant loss of flexibility with respect to Egypt and Yemen due to the relevance of such volumes as supply sources for portfolio players in those countries.

Another interesting feature observed in portfolio contracts is the amount of volumes still traded on a long-term basis (Figure 3.17). It is true that short- and medium-term contracts sourced from portfolio players have gained increased relevance since the Fukushima accident. However, the proportion of volumes contracted on a long-term basis and secured from portfolio players in both 2015 and 2016 is still a high 80%. As explained in the section “Flexibility provided by uncontracted volumes”, the possibility of having significant volumes freed up for the spot and short-term market is subject to lenders’ requirements when debt financing is needed, and only a few projects can afford to have some capacity uncontracted. The proportion of long-term sales from portfolio players declined between 2011 and 2013, reaching a low of around 60%. This was driven by specific market conditions at the times that made it particularly attractive to sell volumes in a tight, high-priced spot market. Yet in 2014, the proportion of long-term sales increased again, and it stabilised at around 80% in 2015 and 2016. It is important to highlight that if additional flexibility were required, the contribution from portfolio volumes would be limited to the portion of them that are not locked into long-term commitments.

Figure 3.17 • Breakdown of contracted volumes from portfolio players by type of contract, 2011-16

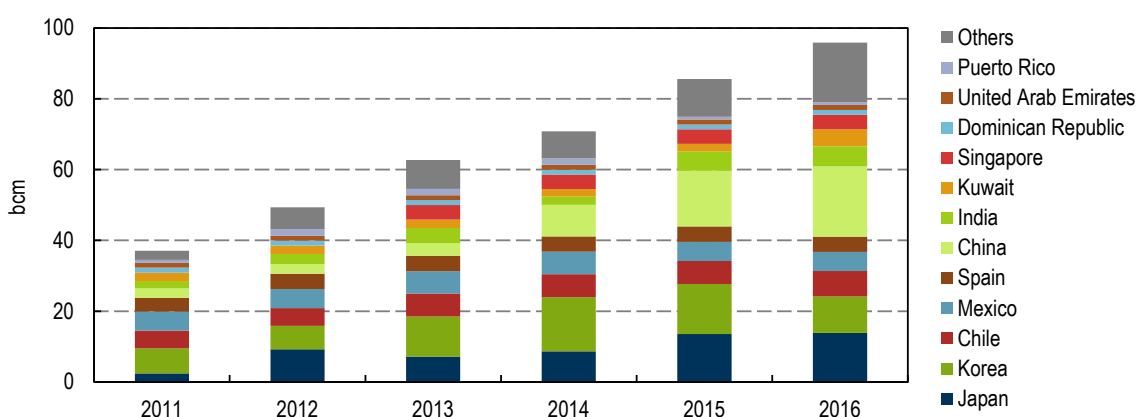


Note: ST = short-term; MT = medium-term; LT = long-term.

At the present, it is difficult to get financing for big liquefaction projects due to unpredictable demand and price volatility. Big utilities are wary of entering into long-term commitments based on increased demand uncertainty – particularly in the power sector, which has been the main driver for demand growth so far. In particular, the future decarbonisation path after the 21st Conference of the Parties (COP21) agreement and how the Intended Nationally Determined Contributions (INDCs) will be implemented remain a big question marks for gas demand.

By agreeing a SPA with portfolio companies, sponsors of the liquefaction project exchange volume and credit risks for destination flexibility. Portfolio players not only provide the required comfort in terms of financial and technical requirements, but they are also better placed to handle volume risk, as they have in-depth knowledge of the downstream business due to regular contacts with clients in different regions whose demands are then aggregated and supplied from different sources. By doing so, portfolio players facilitate access of new entrants, often smaller sized, to the LNG market that would have not be able to directly sign an SPA with the sponsors of a liquefaction plant.

Figure 3.18 • Contracted volumes from portfolio players by country, 2011-16

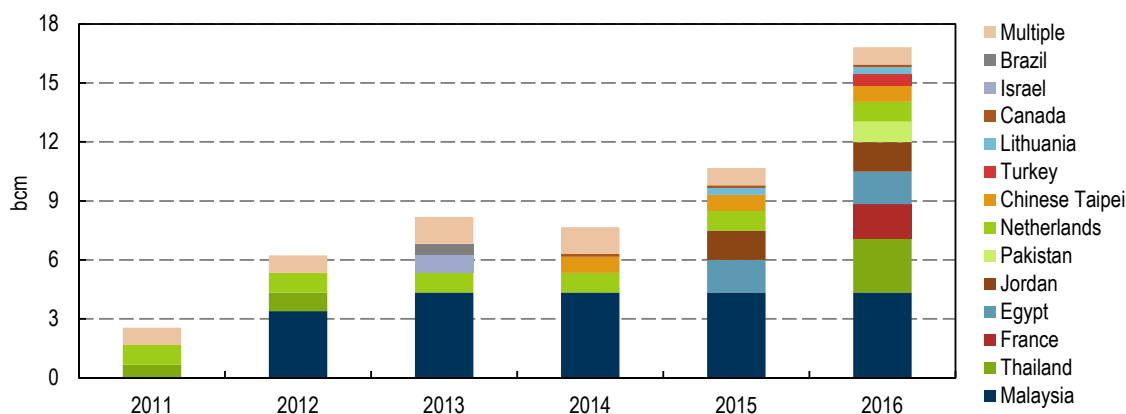


There has been a remarkable change in recent years around the destination of contracted volumes from portfolio players. Since the beginning of the present decade, OECD countries such as Chile, Japan and Korea have been the main destination of portfolio contracts. However, in recent years, the relevance of non-OECD countries has grown substantially as key markets for portfolio sales. Indeed, volumes sold via portfolio contracts to non-OECD countries reached those

of OECD countries in 2014, and by 2016, non-OECD countries were receiving around 20 bcm more than OECD countries as portfolio sales.

Creditworthiness of consumers is a new risk that portfolio players must manage. In the past, offtakers used to be incumbents from OECD countries. Nowadays – due to demand growth in emerging countries – there is a surge in LNG import demand from both independents and incumbents in the developing world. In several instances, these potential consumers do not enjoy a strong credit rating.

Figure 3.19 • Breakdown of category “others”: Contracted volumes from portfolio players by country, 2011-16



Overall, portfolio players act as demand enablers and have an important role in facilitating the trend of a higher portion of independents and smaller-sized companies entering the LNG market. Thanks to the accessibility gained through portfolio contracts, new pockets of demand can be reached. Figure 3.19, which corresponds to the breakdown of the category “others” in Figure 3.18, illustrates how portfolio players are serving an increasingly fragmented market.

Recent developments in LNG contracts

After a thorough analysis across the IEA’s LNG contract database, this report can identify important changes in contractual structures when comparing contracts signed before and after 2010 (Table 3.1). In particular, three characteristics clearly emerge.

First, the size of contracted volumes tends to get smaller, with an observed reduction of around 11% in the average contract size across the two periods. This is likely to reflect gradually more open markets with a higher number of participants and a growing participation of smaller LNG importers in emerging markets.

Table 3.1 • LNG contracts’ evolution

	ACQ (bcm/y)	Average length (years)	Price indexation		Destination clause		Shipping mode	
LNG contracts signed until 2009	1.75	18	Oil-linked	76.0%	Fixed	67.0%	DES	59.0%
			Gas to gas	24.0%	Flexible	33.0%	FOB	41.0%
LNG contracts signed since 2010	1.55	13	Oil-linked	49.5%	Fixed	49.0%	DES	46.0%
			Gas to gas	50.5%	Flexible	51.0%	FOB	54.0%

Note: y = year; FOB = free on board.

Second, the length of contracts has decreased by more than 25% across the two periods, reflecting the higher portion of short-term and spot trades in recent years. Third, there is a

substantial shift in pricing formulas away from traditional oil-indexation terms and towards more direct gas linkages. The weighting of oil indexation has fallen from around 76% for contracts signed before 2010 to around 50% for newer contracts.

The trends described above seem to have intensified further during the last two years (Table 3.2).

Table 3.2 • Recent LNG contracts by year

	ACQ (bcm)	Average length (years)	Destination clause	
Signed in 2014	1.40	16	Fixed	51.0 %
			Flexible	49.0 %
Signed in 2015	1.15	14	Fixed	39.5 %
			Flexible	60.5 %

Focusing on contracts signed in 2014 and 2015, and particularly on the differences between contracts under fixed and flexible destination terms, the analysis observes that offtakers seem to be much more willing to enter into long-term commitments when the destination clause is flexible, locking in higher volumes than average (Table 3.3). This is likely to reflect a compromise through negotiations whereby the seller has a guarantee over committed volumes for a longer period and the buyer sheds some risk by gaining the possibility of diversions. Additionally, while fixed destination volumes were normally linked to oil indexation, flexible destination volumes are usually priced under hub indexation.

Table 3.3 • Recent LNG contracts by destination clause flexibility

	Destination clause	ACQ (bcm)	Average length (years)
Signed in 2014	Flexible	1.41	20
	Fixed	1.35	12
Signed in 2015	Flexible	1.55	17
	Fixed	0.90	11

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4. Response to Fukushima: Learning lessons for LNG consumers

Japan's experience in dealing with the electricity supply shortage following the Fukushima nuclear accident provides a reference case in assessing the supply-security contribution that liquefied natural gas (LNG) can offer in responding to a gas demand shock or a supply disruption (in the case of producers that are not LNG exporters). However, the Fukushima accident and the response it triggered must be placed in the context of the particular situation of global gas markets at the time.

By September 2013, a total of 49 gigawatts (GW) of nuclear capacity was shut down. This was the equivalent of 17% of Japan's total power capacity at the time. By March 2012 – one year after the disaster – around 185 terawatt-hours (TWh) of base-load electricity generated by nuclear was lost. By March 2013, an additional 85 TWh were made idle.

Demand-side responses had a substantial role in addressing the crisis: power generation fell by 6% in the 12 months following the accident, equivalent to 65 TWh, mainly a result of conservation policies. The availability of back-up oil-fired capacity also proved essential, with oil-fired generation increasing by more than 60 TWh between the fiscal year (FY) 2010 (which ran from April 2010 to March 2011) and FY 2011. Its contribution was particularly critical in the first quarter of 2012 when winter demand pushed the call for thermal units well beyond what gas- and coal-fired capacity could provide.

As a result, growing reliance on LNG covered just around 40% of the loss in nuclear generation, highlighting the importance of a well-diversified mix of demand-side measures in countries with limited supply-side alternatives. From a global gas market perspective, this prompted a jump in the call for flexible gas supplies; between FY 2010 and FY 2011, Japan's LNG imports soared by 18 billion cubic metres (bcm) and increased by a further 6 bcm between FY 2011 and FY 2013, 85% of that increase was met via flexible volumes.

Crucially, however, procuring that flexibility proved much less costly for Japan than would have been the case had global gas markets been at a different juncture. First, the fallout of the massive shift in United States (US) gas market fundamentals had left supplies from Nigeria, Trinidad and Tobago, and Equatorial Guinea mostly up for grabs. In 2011, most of those supplies – once bound for the United States – had found a home. Yet they were not bound for a particular market, leaving room for a quick price-driven reallocation. Second, the euro area crisis and the simultaneous steep deployment of renewables there had left Europe's utilities massively over-contracted (see Chapter 3, in the "Europe" section of "Flexibility provided by the demand side"). This created the preconditions for freeing up LNG volumes to Japan: between FY 2010 and FY 2013, Europe's LNG imports fell by almost 50 bcm, roughly double Japan's additional intakes (the fall in Europe was magnified by a very warm first quarter of 2014, however). The redirection of Qatari volumes underpinned this large shift in trade flows.

Notably, while global LNG supply increased between 2010 and 2011 – mainly thanks to new Qatari capacity coming on line – global LNG exports actually decreased during the subsequent two years as outages outstripped new capacity coming on-stream. Moreover, existing plants did not manage to increase output, highlighting the tendency of liquefaction plants to operate base load (see Chapter 1). LNG made available to Japan came mainly via a reallocation of existing supplies. If it had not been for the structural shifts that were under way in the United States and Europe, procuring the required additional volumes would have proved much more expensive for Japan than it turned out to be.

Supply-side flexibility – in the form of both contractual and logistical flexibilities – is crucial to ensure an efficient, low-cost allocation of available LNG supplies. Yet the lack of short-term swing production capabilities means that actual volume flexibility is ultimately provided by the aggregation of upstream/pipeline and demand-side flexibilities of the various regional gas systems. In this light, while the arrival of US LNG will make the supply chain substantially more flexible, it will not itself become a provider of volume flexibility, under normal business conditions.

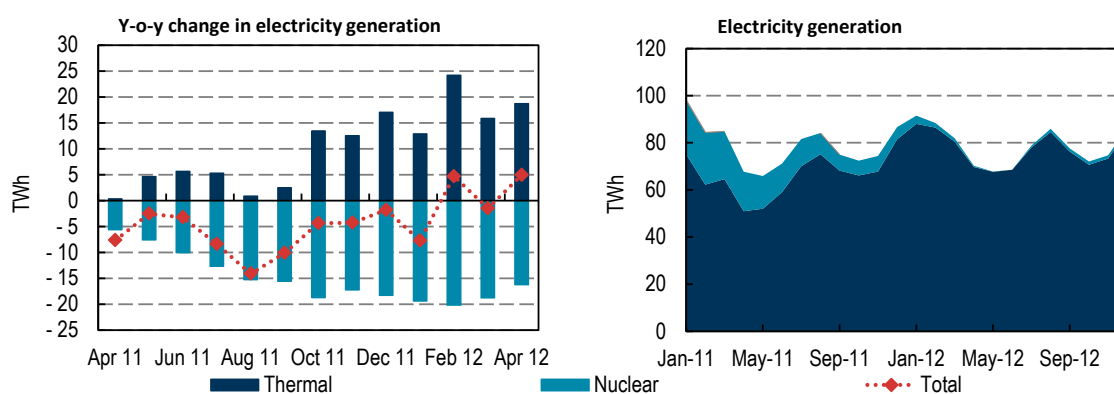
At a global level, fuel-switching potential of key LNG importing regions, alongside upswing capabilities in domestic production/pipeline imports, is the ultimate provider of volume flexibility for LNG consumers. In this context, the outlook for coal- and oil-fired capacity closures across most developed markets – and particularly Europe and Japan – could substantially diminish the global gas market's flexibility to respond to overall shocks.

Japan's response to the Fukushima nuclear accident

In the aftermath of the Fukushima Daiichi nuclear accident, all 54 of Japan's nuclear reactors went off line between March 2011 and September 2013. At the time, this equalled 49 GW, or roughly 17% of Japan's total generation capacity (although even before the accident, average utilisation of the nuclear fleet was relatively low at below 70%). By early 2012, 91% of the nuclear fleet had already been shut down. Around 185 TWh of base-load electricity generation was lost within one year from the disaster and had to be replaced by alternative generation sources. For a large LNG importer such as Japan, with a well-diversified LNG contract portfolio, key security questions are what contribution LNG provided in responding to the loss of nuclear capacity, and where the required extra supply-side flexibility to meet Japan's incremental LNG needs came from.

Monthly electricity data show that Japan's electricity demand fell in the aftermath of the nuclear accident. Adding to the usual downswing in demand between the end of the winter and the spring shoulder months, demand fell as a result of a national effort, called Setsuden, to save electricity as well as take efficiency measures: overall electricity demand in FY 2011, from April 2011 to March 2012, fell by around 65 TWh, or 6%, relative to FY 2010. Yet the demand loss was far from enough to offset the losses in nuclear generation: as nuclear capacity progressively shut down, thermal generation reached new all-time highs (Figure 4.1).

Figure 4.1 • Japan's electricity supplied by type



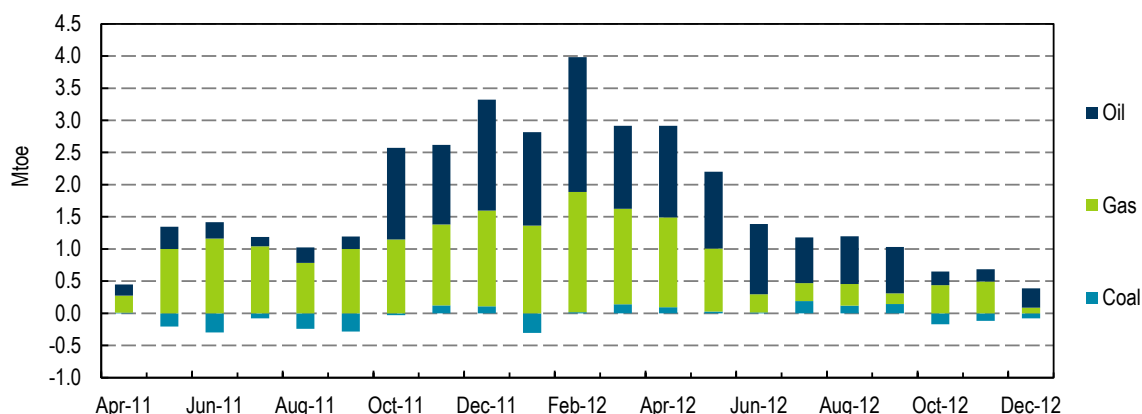
Note: Y-o-y = year-on-year.

Source: IEA (2016), *Electricity Information* (database).

The fact that the nuclear accident occurred at the end of the winter demand season had important implications on both the way Japan responded to the crisis and the level of flexibility that the LNG market could provide. While thermal generation increased strongly from May 2011 onward, it did not reach all-time highs until Q1 2012, partly thanks to a mild summer. This had two main implications: first, gas-fired plants (and in turn LNG, given Japan's almost full dependence on imports) played a very large role in the early part of the crisis. Gas units did not ramp down from their seasonal highs as they normally do when winter demand drops in the spring, but kept running strongly with utilisation at levels more consistent with winter. Mirroring this, LNG imports also remained high, missing their usual seasonal drop, as Japan took advantage of the relatively high level of supply flexibility in global LNG markets that mirrors the seasonal slowdown in global gas demand.

With more nuclear capacity shutting down and electricity demand rising seasonally, thermal generation soared towards new highs in Q1 2012. At 85 TWh per month, it stood 26% above the Q1 2011 level and 33% above the average of the previous five first quarters. With gas-fired power plants already running at high levels entering Q1 2012, oil-fired units accounted for most of the additional generation requirements through this peak demand period (Figure 4.2). Coal-fired generation fell slightly in the first year following the Fukushima accident. Most coal units were already running base load ahead of the accident and could not ramp up production further. Less efficient plants – which normally have lower utilisation levels – increased production to maximum capacity, but this was largely offset by the loss of 0.7 GW of coal-fired capacity in the region affected by the earthquake and tsunami.

Figure 4.2 • Japan's fuel consumption in power generation: Y-o-y change



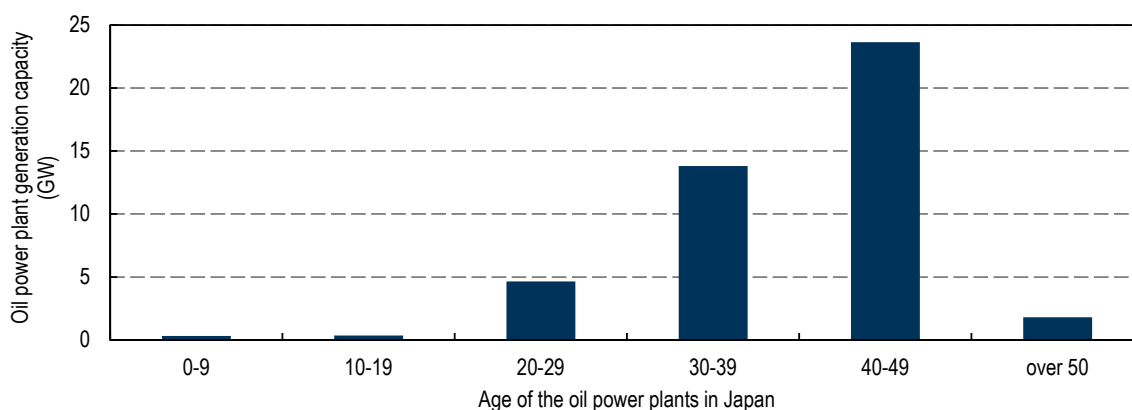
Note: Mtoe = million tonnes of oil equivalent.

Sources: FEPC (2016), *Electricity Generated and Purchased* (Bulletin).

Without such a large contribution of oil-fired generation to balance the system in Q1 2012 (as well as during the following peak demand periods of summer 2012 and winter 2013), Japan would have faced major power curtailments. This raises questions on how Japan would respond to a similar disruption in the absence of this large back-up oil-fired generation capacity. The question is relevant given the age profile of the country's oil-fired power fleet (Figure 4.3) and the potential implications of the ongoing deregulation of the electricity sector. In particular, increasing competition among power utilities will pressure them to reduce operational costs. In this case, old, less efficient and underutilised facilities, such as old oil-fired power plants, could be expected to be decommissioned. With almost 60% of Japan's oil-fired generation capacity older than 40 years, the country is facing a steep decommissioning profile in the absence of active government policies to maintain oil units on line as part of its emergency response toolkit. While from a cost and environmental standpoint, it is undesirable to maintain oil-fired generation

plants in production, back-up oil-fired capacity offers a valuable supply-security contribution for short-term emergencies, due to the easy storability of oil, well-developed infrastructure and liquid global markets. A potential challenge in maintaining stand-by oil capacity (besides the cost of the capacity itself) would be to ensure that the associated supply chain is maintained and in place to deliver oil at the site if required.

Figure 4.3 • Japan's oil power plants by age group



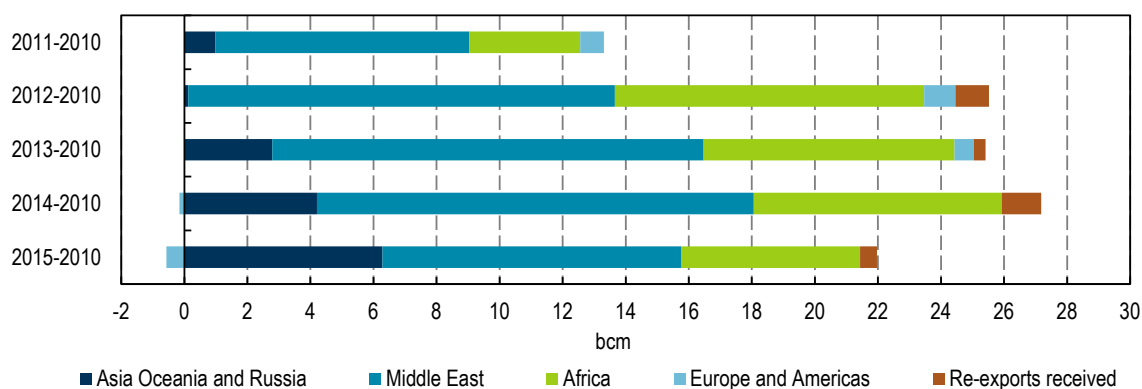
Source: IEEJ(2016), IEEJ database.

The above analysis shows that the loss of nuclear power was made up for via a combination of increased gas-fired generation, oil-fired generation, power conservation and efficiency measures. Given the lack of domestic gas production, around 3 bcm per year, and gas storage facilities (besides the limited LNG storage at LNG import plants, which is used predominantly for operational purposes), the incremental gas burn required a parallel (and almost immediate) increase in LNG imports. On an annual average, Japan's import volumes increased by 18 bcm between FY 2010 and FY 2011 and by an additional 6 bcm in the subsequent two years. But what was the source of the needed supply flexibility?

Demand for flexible supplies: How was it met?

From a regional basis, the Middle East and Africa provided the biggest supply swing. By contrast, LNG imports from Asia Oceania and the Russian Federation (hereafter "Russia") – Japan's largest supply region – did not increase in the first two years after the crisis. Also contrary to widespread commentary, LNG re-exports (which mainly originated from Europe) provided very limited additional flexibility to Japan, at less than 1 bcm per year (Figure 4.4).

Figure 4.4 • Incremental LNG import volumes of Japan by region, against 2010



Source: IEA analysis based on GIIGNL (2011-16).

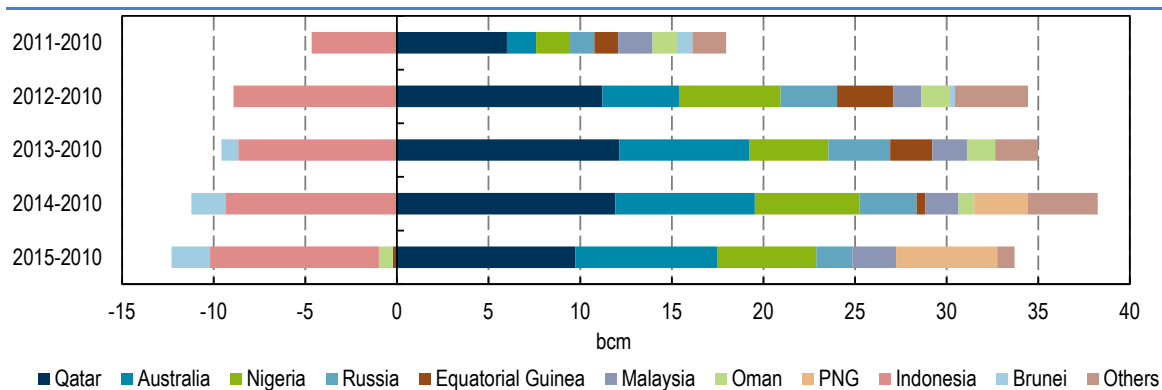


Before the Fukushima disaster, Japan imported only 2.3 bcm of LNG from African suppliers (~2.5% of its total imports in 2010), who instead mainly targeted Europe. In 2012, however, Japan imported almost 10 bcm of additional LNG from the African region, mostly from Nigeria and Equatorial Guinea (Figure 4.5). The large contribution of these two exporters to Japan's sudden need for additional imports is mostly attributable to the flexible contractual structure underpinning their supplies. Around half of Nigerian contracted volumes have large LNG portfolio players as offtakers and target multiple destinations, while all volumes produced by Equatorial Guinea are sold according to this marketing structure.

Middle East supplies, led by Qatar, provided the largest upswing in LNG volumes to Japan. As explained in Chapter 3 ("Flexibility provided by uncontracted volumes"), Qatar is one of few countries to have measurable uncontracted volumes (around 9 bcm in 2015). It also holds sizeable quantities of flexible contracts. Even pre-Fukushima, Japan accounted for almost one-fifth of overall Qatari exports. The speed and size of Qatar's response is not surprising considering Japan's importance as a Qatari customer, as well as the deep commercial partnership between the world's largest importer and world's largest exporter of LNG. While the volumes redirected to Japan were sizeable, one could argue that based on the flexibility of Qatari contracts, higher levels of supply could have been rerouted.

In aggregate, Asia Oceania and Russia's suppliers show a limited increase in exports to Japan. However, this masks different behaviours among regional producers. On the one hand, Japan's LNG imports from Indonesia decreased by almost 10 bcm annually between 2010 and 2012. This was almost entirely due to the expiration of long-term contracts between the two countries, which largely mirrored Indonesia's lower export capabilities due to a combination of stagnant production and rising domestic demand. Even after this steep fall in the contractual base, Indonesia barely met its supply obligations with Japan, indicating a lack of any real flexibility in either pushing production higher or diverting supplies across different customers (as Indonesia was under-delivering to other buyers of its gas during the period).

Figure 4.5 • Incremental LNG import volumes of Japan by country, against 2010



Note: PNG = Papua New Guinea.

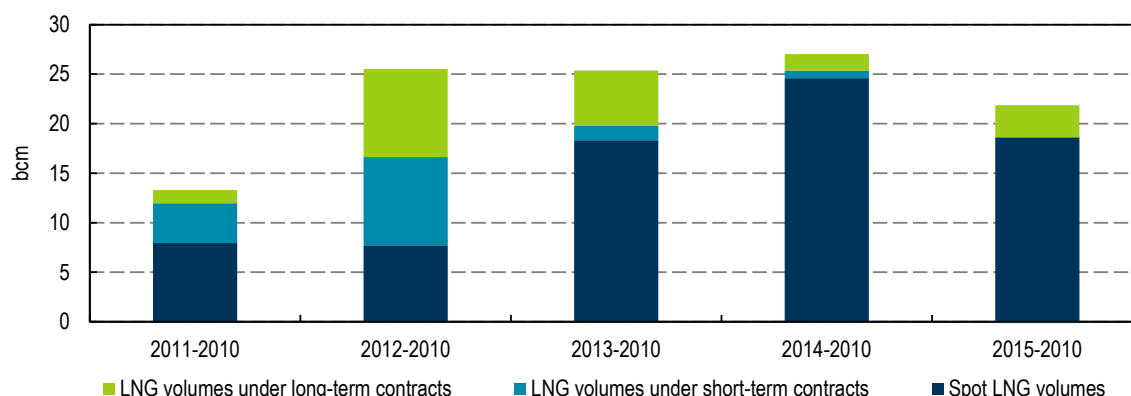
Source: IEA analysis based on GIIGNL (2011-16).

Once the sharp decline in Indonesian imports is accounted for, Asia Oceania and Russia's LNG exporters show a substantial upswing in overall exports to Japan between 2010 and 2012 by around 10 bcm. These volumes are comparable in size to those from the Middle East and Africa.

Figure 4.6 shows a breakdown of Japan's additional volumes by contract type. In 2011, Japan sourced most of its additional LNG via the spot market and short-term contracts. In 2012, the reliance on long-term contracts increased, due to an increase in the underlying contractual base and maximisation of upward tolerances; short-term contracts were also extended. From 2013 onward, the contractual composition started to change: a chunk of contracts with Indonesia

expired together with a large portion of short-term deals signed soon after the Fukushima accident. This prompted a sharp increase in the reliance on the spot market – by 2014, 90% of incremental volumes relative to 2010 were sourced in the spot market. This procurement behaviour suggests several important points. First, volume flexibility in long-term contracts is limited. Y-o-y changes were mostly driven by changes in the contractual basis. Second, short-term deals were the preferred procurement option of Japanese importers at the onset of the crisis, probably due to high uncertainty over the quantities available in the spot market (and how the market itself would be affected by the sudden surge in demand) as well as the possible timing of nuclear restarts (given that most plants were off line not because of physical or technical damage). Once the level of uncertainty eased and import needs stabilised, Japanese importers tended to switch from short-term deals to stronger reliance on spot purchases.

Figure 4.6 • Incremental LNG import volumes of Japan by type of contracts, against 2010

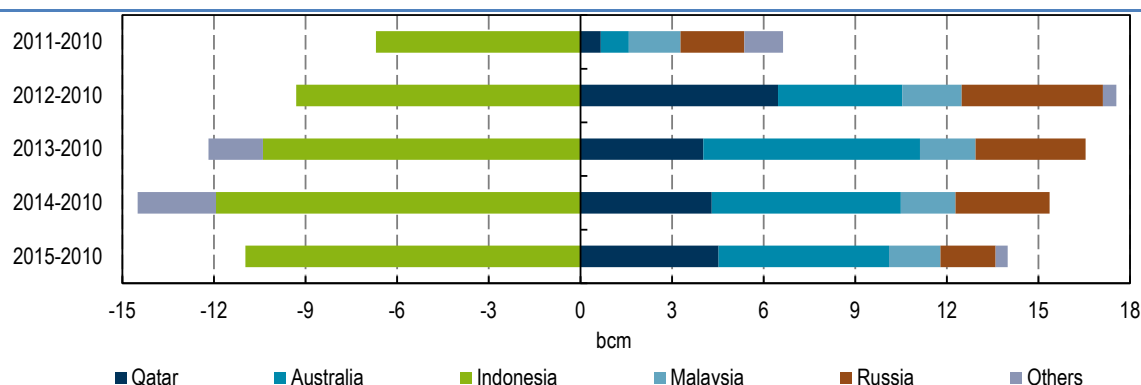


Note: LNG volumes under short-term contracts are IEA estimates. Spot LNG volumes are calculated by subtracting IEA estimated short-term LNG volumes from GIIGNL’s spot and short-term LNG volumes. LNG volumes under long-term contracts are calculated by subtracting GIIGNL’s spot and short-term volumes from GIIGNL’s total traded LNG volumes.

Source: IEA analysis based on GIIGNL (2011-16).

Countries’ individual contributions to changing Japanese imports by type of contract are illustrated in the next three figures. Higher volumes via long-term contracts are estimated to have predominantly come from Australia, Qatar and Russia (Figure 4.7), largely offsetting the decline in Indonesian deliveries. Part of the volume increase attributed to long-term contracts is likely to have been sourced through portfolio players (although linking portfolio contracts to a specific source of supply is by definition virtually impossible and not something this analysis attempted to do).

Figure 4.7 • Incremental LNG import volumes of Japan under long-term contracts, against 2010



Note: LNG volumes under long-term contracts are calculated by subtracting GIIGNL’s spot and short-term LNG volumes from GIIGNL’s total traded LNG volumes.

Source: IEA analysis based on GIIGNL (2011-16).

Qatar and Nigeria were the largest swing factors in short-term and spot purchases (Figure 4.8 and Figure 4.9). These two countries together accounted for more than half of Japan's incremental short-term and spot imports post-Fukushima. While spot Russian deliveries to Japan fell, volumes were maximised through higher deliveries via long-term contracts. The strong reliance on West African imports (but also on cargoes coming from Latin America) indicates difficulties sourcing volumes closer to home that would have resulted in shorter shipping distances (and lower freight costs).

Figure 4.8 • Incremental LNG import volumes of Japan under short-term contracts, against 2010

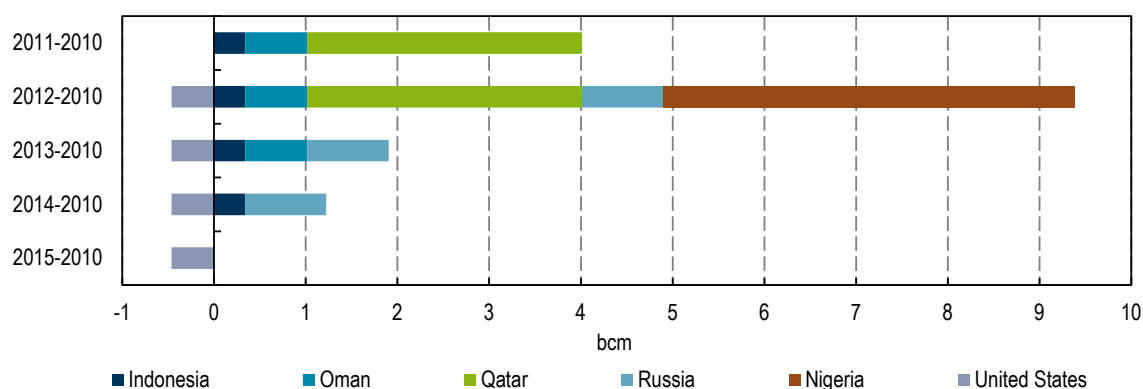
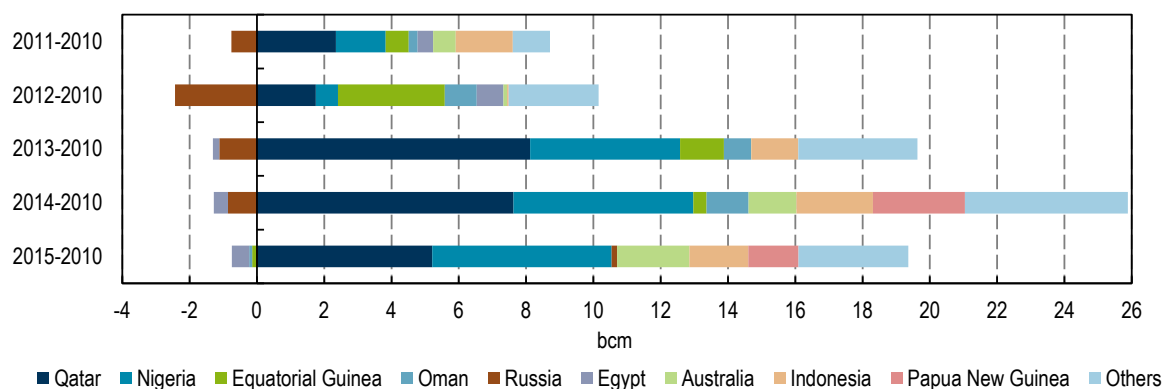


Figure 4.9 • Incremental spot LNG import volumes of Japan, against 2010



Note: LNG volumes under short-term contracts are IEA estimates. Spot LNG volumes are calculated by subtracting IEA estimated short-term LNG volumes from GIIGNL's spot and short-term LNG volumes.

Source: IEA analysis based on GIIGNL (2011-16).

Opportunities and limitations of LNG for global gas security

Japan's experience in dealing with the Fukushima disaster provides a reference case in assessing the supply-security contribution of LNG in responding to a demand shock or a supply disruption (in this case of producers that are not LNG exporters).

The fact that Japan could rely on emergency response measures other than just simply ramping up LNG volumes and gas-fired generation – mainly switching to oil and implementing conservation measures – has been an important factor in dealing with the crisis. Growing reliance on gas-fired power made up for almost 40% of the loss in nuclear generation during the first year after the accident and around one-third during the first three years after the accident. This translated to almost 25 bcm of additional import needs between FY 2010 and FY 2013. To put it

into context, this equalled around 8% of global LNG trade at the time. Those volumes were procured mostly through a redirection of existing LNG flows given that, with the exception of a ramp-up in Qatari output in 2011, there was no production upswing at an aggregate level.

The ultimate provider of the additional 25 bcm of gas to Japan was a significant demand response in Europe. Over the same period (FY 2010 to FY 2013), the region's LNG imports decreased by almost 50 bcm. The scale of this fall is magnified by the time period used for comparison, as the first quarter of 2014 was extremely warm. Yet, the fall is nonetheless structural. Using calendar year data, Europe's LNG imports fell by 40 bcm between 2010 and 2013. Crucially, the demand response required for triggering that adjustment did not prove very costly to Europe as the euro area crisis – in combination with robust deployment of renewables – created a demand shock almost parallel to the loss of nuclear generation in Japan. Had the Fukushima accident occurred during a period of strong demand growth in Europe, triggering that adjustment – while technically possible given Europe's flexibility options – would have proved much more expensive.

The availability of flexible LNG supplies in the market then made it possible to link the demand flexibility required by Japan with the supply flexibility provided by Europe. In a rigid point-to-point structure it would have been impossible for those two flexibilities to be linked. Therefore, it is not surprising that Nigeria and Qatar – both of which have highly flexible contractual structures – covered around 65% of Japan's additional LNG import requirements. It is also telling that a small LNG producer such as Equatorial Guinea, which was sending just around 15% of all its exports to Japan in 2010, managed to lift that share to 75% (or 3.1 bcm) as of 2012. As in the case of Qatar and Nigeria, Equatorial Guinea has a flexible contractual structure (with all its gas sold with a multiple destination option) that allowed a quick and large redirection of flows. As a comparison, while Equatorial Guinea exported just about one-fifth of the LNG that Australia did in 2010, its upswing in deliveries to Japan between 2010 and 2012 was 75% of that of Australia.

Japan's experience with the aftermath of the Fukushima crisis illustrates well the opportunities and limitations that LNG has as a contributor to global gas security. The scale of flexible LNG supplies in the market – in other words volumes that can be remarketed and redirected in large scale at short notice – is critical to the role that LNG can play in responding to disruptions. In this light, the restrictions that destination clauses impose on the free circulation of LNG limit its security contribution by keeping the overall LNG supply chain unnecessarily rigid.

Even with fully flexible supplies, however, the lack of short-term swing LNG production capability (see Chapter 3) is a structural limit to the contribution of LNG to global gas security. Of course, today's extreme oversupply could result in underutilisation of export infrastructure in the next few years (thus creating a supply buffer). This, however, should be regarded as a temporary market adjustment rather than a permanent feature of the LNG supply structure. As a result – barring brief periods of extreme oversupply – LNG production itself does not provide the volume flexibility needed to respond to gas demand shocks or supply disruptions. Instead, it is the aggregation of the upstream/pipeline and demand-side flexibilities of the various regional gas systems – made possible by a flexible LNG supply chain – that is critical to maintain global gas security.

In this light, while the arrival of US LNG will make the supply chain substantially more flexible and allow for quicker and cheaper diversions, the key provider of volume flexibility – which is really the backbone of gas security – remains determined by the demand-side flexibilities and alternative pipeline options that individual regions have to free up LNG imports for the disrupted countries.

From the demand side, the likely loss of fuel-switching capabilities due to the retirement of coal- and oil-fired generation capacity as the decarbonisation of the energy system deepens is something that policy makers must consider in the context of global gas security, as these were

the key response measures to the Fukushima disaster (more oil generation in Japan; more coal generation in Europe).

On the supply side, the only pipeline gas producer (and exporter) with substantial short-term upswing potential is Russia. This means that any large demand shock or supply disruption across relevant LNG importers would require a volume contribution from Russia. This should serve as a damper on overoptimistic expectations over the short-term crisis management contribution of LNG markets should Russian supplies also be disrupted.

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5. Europe: A changing picture for flexibility

In the aftermath of the Fukushima accident, Europe was able to balance out the global gas market rather smoothly. Imported liquefied natural gas (LNG) volumes to Europe dropped significantly in response to high Asian LNG demand, mainly enabled by a simultaneous decrease in European gas demand, a consequence of the euro area crisis, and a steep deployment of renewable energy sources. In the expected European supply mix of the future, decreasing domestic production and production limits on the Netherlands' Groningen field are accelerating the need for additional quantities, likely to originate from Russian and LNG imports in the medium-term as Norway's production is expected to stay stable up to 2020. Depending on the share of LNG in the European gas supply mix, Europe's future contribution to balancing variations in global gas demand could change. Still, Dutch production and gas storage are expected to remain the main provider of seasonal flexibility to Europe in the next years.

Within Europe, the decline in Groningen production does not appear to have impacted the potential of the Netherlands to export low-calorific gas (L-gas) quantities to the relevant markets. Additional volumes from Norway and the Russian Federation (hereafter "Russia"), converted to L-gas, have replaced the decline in Dutch production. Pipeline imports, which are being transported over long distances to Europe, and LNG quantities originating from countries outside Europe are both options to fill the gap left by decreasing domestic production. Both options would need to rely on sufficiently filled European gas storage, as this asset helps restructure the seasonal supply profile into one that matches demand variations. Storage helps balance daily fluctuations and offers the economic advantage of exploiting existing infrastructure. Higher reliance on long-distance pipelines without storage would require higher capacity at gas import points as well as in the relevant gas transportation system downstream (with associated higher costs) to provide for peak demand that is not needed throughout the whole year.

Such a system value of gas storage, together with the advantages of storing natural gas close to European demand areas and of mitigating technical or geopolitical risks that could occur along the transportation routes of pipeline or LNG imports, is currently not rewarded. In the context of current low summer-winter spreads, shippers are increasingly reluctant to book storage capacities.

Hence, European gas storage operators are facing economic pressure, especially in markets where gas storage assets are fully exposed to competition (e.g. Germany). Storage operators are already reacting, writing off assets and mothballing sites; further decommissioning of storage facilities is expected to follow, especially as long-term capacity bookings of storage sites reach the end of their contracted periods, and the resulting available capacity will prove difficult to sell on an economically sustainable basis.

Among alternative flexibility options available to Europe to replace losses of domestic production and, possibly, storage, LNG is often regarded as the most viable one. However, as noted in the previous chapters of this report, availability of flexible LNG supplies, while improving, has its own limitations and cannot be taken for granted.

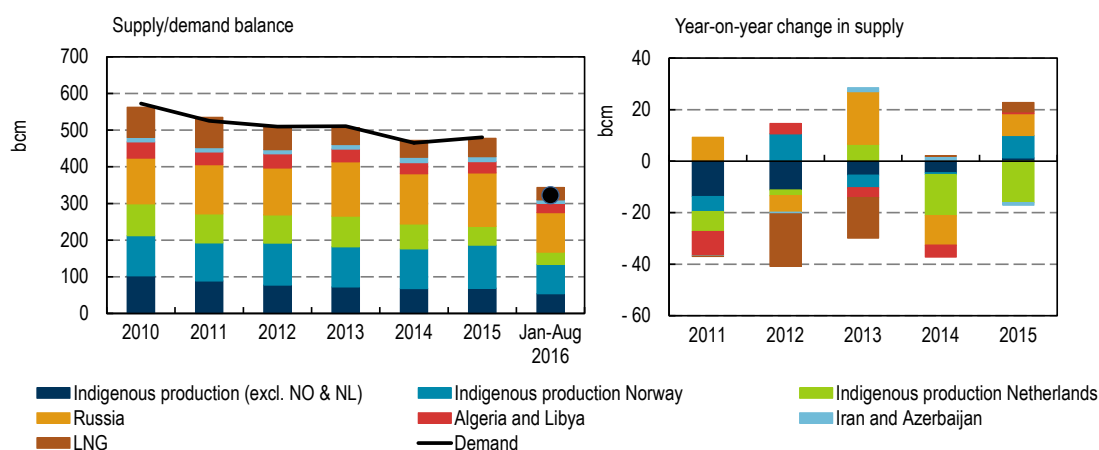
Demand-side flexibility – in the form of switching from gas to coal – has also been an important mechanism to balance the global gas market and offer increased levels of supply security. Today, the potential level of gas-to-coal switching is lower than in the past. European countries are already using gas predominantly for balancing intermittent energy sources or in combined heat and power (CHP) plants where switching is significantly harder. The expected coal plant retirements over the next five to ten years will further reduce this key demand flexibility mechanism and increase the reliance on flexible pipeline or LNG imports.

OECD Europe's gas balance: A changing supply mix

Between 2010 and 2015, two major developments shaped the gas balance in the Europe region of the Organisation for Economic Co-operation and Development (OECD): first, a change in the suppliers' contribution to the supply mix with an increasing share of Russian and Norwegian quantities; and second, lower gas consumption, mainly caused by lower gas usage from the power sector (IEA, 2016a).

The changes in the supply mix, shown in Figure 5.1, have different explanations: one significant factor is a decline in domestic production, led by the Netherlands and the United Kingdom (UK), falling in total from around 190 billion cubic metres (bcm) in 2010 to about 130 bcm in 2015, a development that has been faster than anticipated with respect to the Netherlands due to the production cap on the Groningen field imposed by the Dutch government. Two other explanations are lower LNG imports, falling from 90 bcm to 50 bcm (or from 15% to 10% of the supply portfolio) – mainly due to European gas hub prices below Asian gas prices in the past years – and the drop in Africa's contribution to the supply mix (from 45 bcm to 30 bcm), largely caused by lower pipeline volumes from Algeria (lack of investment and growing domestic demand) and Libya (political unrest).

Figure 5.1 • OECD European supply and demand balance



Notes: NO = Norway; NL = Netherlands. Stock changes are minor on a calendar year basis and are not shown. 2015 and Jan-Aug 2016 are preliminary data.

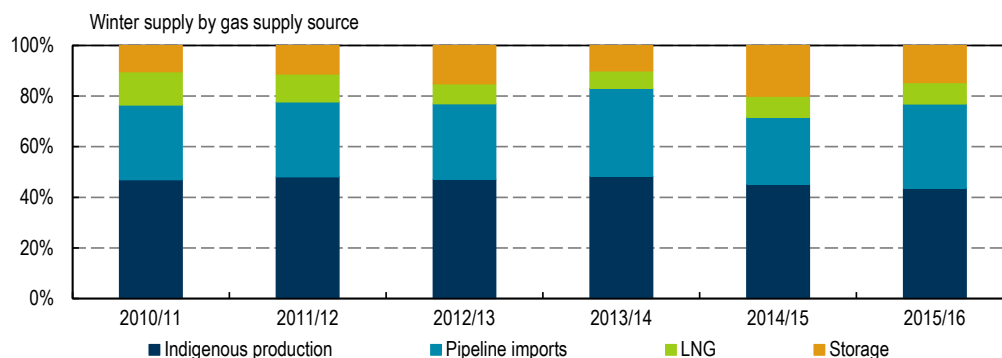
Sources: IEA (2016b), *Natural Gas Information* (database); IEA (2016c), *Monthly Gas Data Service*; IEA (2016d), *Gas Trade Flows* (database).

Although overall demand declined, the importance of heat-driven gas demand in OECD Europe still remains. The ability of a supply source to increase its share in the supply mix (e.g. due to a cold spell or lesser contribution from another source) is crucial to react to imbalances – thus the composition of the supply mix is significant as the sources provide different characteristics in providing flexibility. This composition is affected by different factors apart from long-term developments like the decline of the indigenous production, such as the relative price level of one source to another, technical issues, and geopolitical tensions in the country of origin or along the transit route.

Following the winter of 2013/14, indigenous production steadily decreased, mainly balanced by a higher contribution from gas storage or gas imports as can be seen in Figure 5.2. OECD Europe's indigenous production is expected to fall further; consequently, the share of gas imports will rise, but the origin of OECD Europe's supply sources is not clear yet as either pipeline imports or LNG quantities could principally replace the declining domestic production. The European Commission

presented a strategy to push forward the integration of gas markets in the European Union (EU) and to attract further LNG import quantities (Box 5.1), as diversification of the European supply mix with LNG has so far been limited. Moreover, improvement of LNG imports' interaction with European gas storage, to realise seasonal and load flexibility, is part of this strategy.

Figure 5.2 • OECD Europe winter supply balance



Note: This chapter makes use of the term “gas year”, which starts on 1 October 06:00 hrs and ends on 1 October 06:00 hrs of the following year. For example, gas year 2014/15 begins 1 October 2014 and ends 1 October 2015. The winter season in Europe is 1 October to 1 April. Summer is 1 April to 1 October.

Sources: IEA (2016c), *Monthly Gas Data Service*; IEA (2016d), *Gas Trade Flows* (database).

Box 5.1 • EU strategy for liquefied natural gas and gas storage

The European Commission released the EU strategy for LNG and gas storage in February 2016 as part of the Sustainable Energy Security Package. The strategy aims at raising the diversification and flexibility potential of the EU gas system by improving access to international LNG markets and gas storage.

The strategy outlines the following main areas the European Union wants to focus on. Within these areas, several action points are defined for the European Commission to push forward the relevant items.

Completing missing infrastructure

In the European Union, the existing LNG regasification capacity is mainly concentrated in Western Europe, and availability and distribution of storage types differ among member states. Particularly for member states that still have a high dependence on one single supplier (and are hence prone to supply interruptions), specific gas infrastructure projects need to be built or reinforced in order to gain access to other sources of gas or LNG regasification capacity located in another member state. Key projects of common interest are already identified, the implementation of which is still to be prioritised. As to the commercial viability of LNG infrastructure projects, the European Commission is principally prepared to help finance projects that are of particular importance for security of supply but otherwise have a weak commercial context.

Completing the internal gas market

In order to ensure supply diversification with LNG, the European Union puts emphasis on the full implementation of important EU energy legislation (Third Energy Package and network codes). This should establish the European gas market as an attractive destination for LNG quantities. National regulatory authorities should therefore erase any existing barriers that prevent the member states from having access to (regional) gas hubs. Concerning gas storage, several aspects should be pursued to allow the full exploitation of gas storage's potential and optimise the significance for security of supply (e.g. by improved cross-border access). These aspects include, among others, eliminating regulatory and administrative barriers so that gas storage operators can compete on a level playing field with other flexibility instruments, including across borders (e.g. in the areas of tariffs, cross-border access, or product development and innovation).

Strengthen co-operation with international LNG partners

The European Union is expecting global LNG prices to decrease due to well-supplied gas markets caused by an increase in liquefaction capacity. EU energy diplomacy instruments should be used to engage with international partners to promote transparent and liquid LNG markets, as this serves the interest of the European Union as an importer of LNG.

Promote LNG in areas that support the European Union’s sustainability objective

The European Commission strives to further promote LNG as an alternative fuel in the transport sector to reduce negative impacts on the environment. As specific action points, the Commission calls on member states to fully implement the relevant directive and plans to establish a sound framework, encouraging stakeholders to develop the use of LNG in shipping.

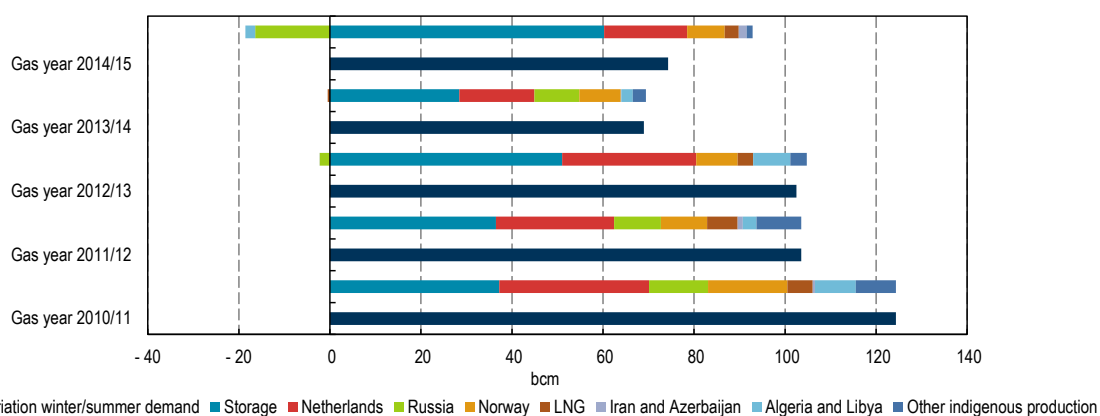
Source: European Commission (2016a).

Contribution of different supply sources to seasonal demand variations

Indigenous production’s role is limited by declining domestic production

As shown in Figure 5.3, indigenous production, most notably the production of the Netherlands, has been an important flexibility provider for OECD Europe, normally contributing 20% to 30% to seasonal variations between winter and summer – however, this flexibility source will not contribute to the same extent it used to. This development has been anticipated and also taken into account on the demand side, as the gradual replacement of L-gas with high-calorific gas (H-gas) will take place over the next 15 years.¹

Figure 5.3 • Variation of winter-summer demand and supply sources’ contribution



Note: Seasonal variations calculated on the bases of differences between winter and summer of a gas year, which starts on 1 October and ends on 1 October of the following year to reflect relevant yearly volume limitations of gas import contracts. Summer gas demand includes storage injections.

Sources: IEA (2016c), *Monthly Gas Data Service*; IEA (2016d), *Gas Trade Flows* (database).

However, the pace accelerated: in 2013, the yearly production of Groningen was about 54 bcm (Government of the Netherlands, 2014) but was capped in the following years, most recently to a

¹ Germany, the second-largest L-gas market after the Netherlands, took into consideration a decline of Dutch production and consequently incorporated a gradual replacement of L-gas to H-gas in the Network Development Plan – the switch will be almost completed by gas year 2029/30 (FNB Gas, 2016).

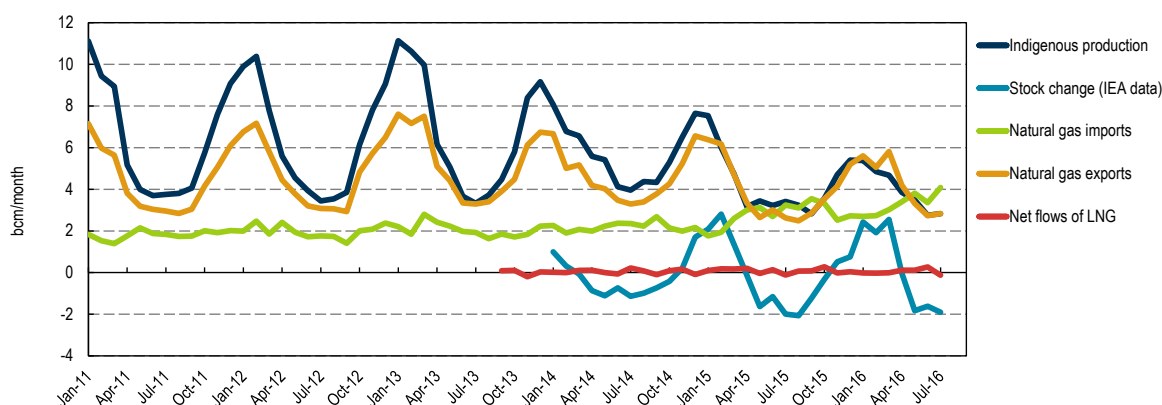


yearly cap of 24 bcm from 1 October 2016 onward for a consecutive period of five years.² The decision included the guideline to keep the production as flat as possible in order to minimise seismic activity in the area, which will have implications for the production swing potential of the Groningen field and require higher contributions from other sources, and possibly leading to higher costs, assuming for instance that gas imports along with nitrogen injection will be costlier than providing L-gas flexibility directly from the production swing of the Groningen field.³

In any case, in a scenario where a changing composition of supply sources faces limitations in ensuring security of supply, Dutch production variations could increase again: the decision to limit the production level and variations of the Groningen field was taken by the Dutch government against the background of the Dutch TSO's view that security of supply of L-gas to Dutch customers as well as customers in neighbouring countries is guaranteed (Government of the Netherlands, 2016a) (Box 5.2). This implies that fluctuations in production are still allowed and production from the Groningen field could be increased under specific circumstances if needed to provide for security of supply (Government of the Netherlands, 2016b).

Both the decreasing production level and a lower variation between summer and winter production are illustrated in Figure 5.4. Lower Dutch production levels have been offset by higher gas imports to the Netherlands since the beginning of 2015 (along with nitrogen injection to convert H-gas to L-gas and blending H-gas with L-gas⁴), which allowed for a relatively stable gas export level of the Netherlands.

Figure 5.4 • Development of gas supply sources and gas exports in the Netherlands



Note: IEA = International Energy Agency.

Sources: Statline (2016), *Natural Gas Balance Sheet, Supply and Consumption* (database); IEA (2016c), *Monthly Gas Data Service*

A comparison of average daily flows in the first and second half of the winter season (Q4 versus Q1) of 2014/15 and 2015/16 shows that during this period daily L-gas quantities at the relevant cross-border points from the Netherlands to Germany and Belgium have not decreased since the Dutch minister of economic affairs imposed a production cap on the Groningen field.

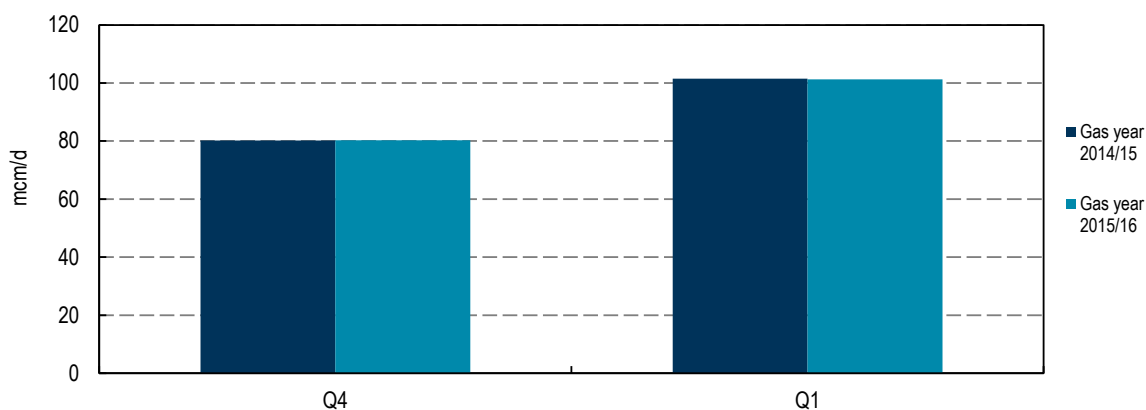
² The Dutch government's data are given in normal cubic metres, i.e. energy content of ~35 megajoules per cubic metre. The latest production cap includes the possibility that an additional 6 bcm per year (y) can be produced if defined circumstances are met (specific winter is colder than an average winter).

³ The Dutch transmission system operator (TSO) is responsible for assuring gas has the right quality (L-gas or H-gas) at the transmission system exit points and the associated costs are socialised over the transmission tariffs. As the Title Transfer Facility (TTF) has no gas quality label, all shippers contribute to gas quality conversion costs.

⁴ Mixing H-gas with L-gas to increase the supply of L-gas volumes is possible up to the level where the maximum allowed Wobbe index is reached. The Wobbe index is a parameter for gas quality but is not equal to the energy content of natural gas that is generally used.

Figure 5.5 shows that total L-gas exports from the Netherlands to Germany and Belgium increased from 80 mcm per day (d) to 102 mcm/d (Q4 versus Q1) in 2014/15, whereas the rise went from 80 mcm/d to 101 mcm/d (Q4 versus Q1) in 2015/16, averaging daily flows during the relevant quarter.

Figure 5.5 • L-gas flows from the Netherlands to Germany and Belgium, quarterly average of daily flows



Note: L-gas flows to Belgium include L-gas exports to France.

Source: GTS (2016a), *Dataport* (database).

Box 5.2 • Groningen L-gas flexibility

The Groningen field produces L-gas that is used in a limited number of countries in the North West European market (i.e. the Netherlands, Germany, Belgium and France), as opposed to H-gas that is also used in these countries as well as in the rest of Europe and the world.

The Netherlands supplies roughly 60 bcm/y of this European L-gas market in a cold year. The supply side needs to be flexible since a high share is the household segment, which has a strong seasonal, daily and intraday demand pattern. According to Dutch TSO Gasunie Transport Services (GTS), the Groningen system (which is the Groningen field and the L-gas storage facility Norg) and the other L-gas production options¹ are still capable of supplying the L-gas demand flexibility, even though production fluctuations from the Groningen gas field should be minimised (GTS, 2015b).

Historically, the Groningen field was able to produce up to 350 mcm/d (NAM, 2009). When all low-calorific supply options are fully used, a peak delivery capacity of about 8.4 mcm/hour is needed from the Groningen production system at a temperature of -17 degrees Celsius, and the needed peak delivery capacity will decrease during the coming years (GTS, 2015b). As no specific decision on the maximum daily production level or maximum hourly production for the Groningen system has been made, there is no limitation to meeting the remaining peak demand for the Groningen system. There are production limitations in place on specific production clusters, but they allow for additional production only to maintain security of supply.

The question remains how the low-calorific volumes and flexibility could be replaced if the Groningen gas field is capped beyond the current yearly cap of 24 bcm. Additional volumes would be likely to originate from Norway and Russia; however, the existing maximum conversion capacity from H-gas to L-gas limits the potential of these H-gas sources.² The existing technical capacity of the Dutch conversion facilities amounts to roughly 33 bcm/y; however, GTS aims at an average utilisation level of 85%, leaving the potential to additionally convert around 5 bcm/y in case it is needed during a cold year. Since the production from the small low-calorific fields cannot be increased significantly, L-gas storage will play a significant role for delivering peak-level quantities (GTS, 2015a).

It is expected that from 2020 onward, the stress on the L-gas supply/demand balance will go down in volumetric as well as in flexibility terms. Pressure is likely to be reduced from the demand side; between 2020 and 2030, Dutch exports of L-gas are forecast to decline as L-gas markets will be

converted to H-gas. Belgium, France and Germany currently foresee this process taking ten years, starting in 2020 (GTS, 2016b).

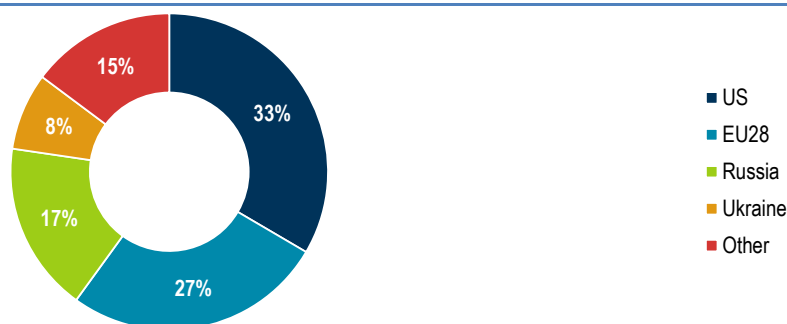
¹ L-gas production options are nitrogen injection and blending of H-gas and L-gas.

² The option to increase nitrogen injection capacity in order to enhance the production of L-gas from H-gas has been taken into account in GTS' security-of-supply assessment of the 24 bcm production cap, but the decision to build additional conversion capacity in the Netherlands has been postponed for one year.

European gas storage in the context of a difficult economic environment

Underground storage in the 28 member states of the European Union (EU28) currently totals a technical working gas volume (WGV) of some 108 bcm, around one-fourth of the global WGV. Taking Russia, Ukraine and the EU28 together, this represents a WGV share of more than 50% (Figure 5.6).

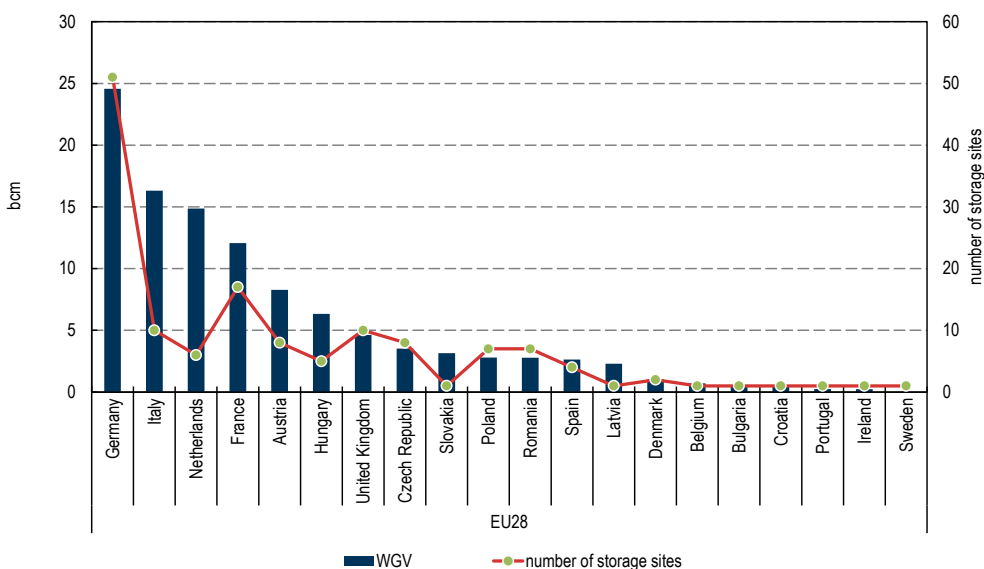
Figure 5.6 • Distribution of global underground storage



Sources: IEA (2016b), *Natural Gas Information* (database); GIE (2015a), "GIE storage map".

More than two-thirds of storage capacity in the European Union is held by five member states: Austria, France, Germany, Italy and the Netherlands have 70% of total EU WGV. All but the Netherlands are net importers of gas. The distribution of storage in the European Union is shown in the next figure.

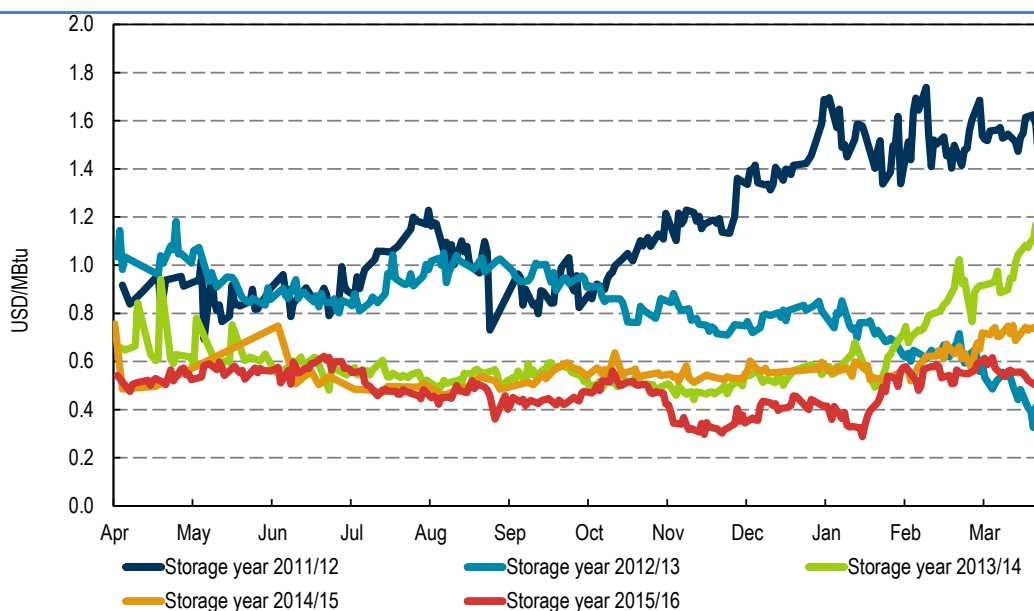
Figure 5.7 • Underground storage in the EU28



Sources: IEA (2016b), *Natural Gas Information* (database); GIE (2015a), "GIE storage map".

The traditional business model of European gas storage providers – providing seasonal and load flexibility – is confronted with significant changes in gas market fundamentals.⁵ Important developments – generally well-supplied gas markets and declining European demand – led to lower seasonal spreads (Figure 5.8) and consequently to a lower market value of underground storage. European storage operators report that shippers are hesitant to book storage capacities and ask operators to give storage tariff discounts on capacities that are not booked on a long-term basis, as the potential profit from seasonal spreads becomes increasingly unattractive (BBH et al., 2015). From the shipper’s point of view, low differentials between summer and winter gas prices provide a low incentive to book storage capacities: the possible value from the summer-winter gas price differential potentially does not earn the expected margin, taking into account the costs that have to be incurred by the shipper to inject and withdraw gas. Price volatility could contribute to the market value of gas storage, particularly for storage sites with a high churn rate. This means that although price volatility appeared to have increased again during 2016 seasonal storage will still face a tough economic environment.

Figure 5.8 • TTF winter-summer spread, historic forwards

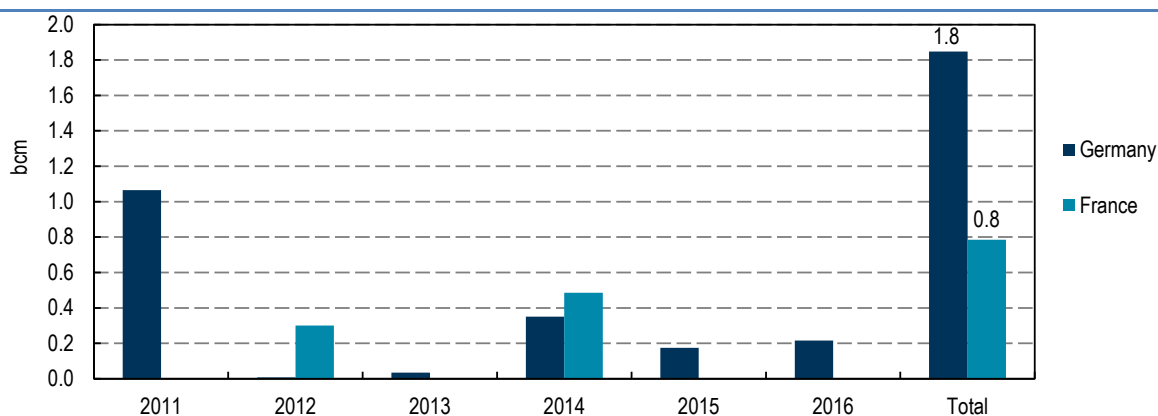


Notes: USD = United States dollar; MBtu = million British thermal units. Winter-summer spread of a relevant storage year is defined as the difference between the relevant historic winter season forwards and summer season forwards of the following seasons. Example: Winter-summer spread of storage year 2011/12 is defined as the difference between the historic forwards of the TTF winter season 2012/13 and TTF summer season 2012 during the period 1 April 2011 until 31 March 2012.

Source: Bloomberg Finance LP.

The storage market has already reacted to the increasingly tough market environment: between 2013 and 2015, extraordinary depreciations amounted to around 4.5 billion euros in North West Europe. Moreover, approximately 2.6 bcm of underground storage facilities were mothballed between 2011 and 2016 (Figure 5.9); however, storage operators still seem to be reluctant to carry out gas storage decommissioning on a larger scale, presumably as the closure of storage assets also entails decommissioning costs, which need to be taken into account. But the market might face further decommissioning of working gas capacity if long-term storage capacity bookings come to an end and seasonal spreads do not open up. Indications are already being given that some North West European storage assets are not covering operational costs.

⁵ For different characteristics of storage types see Box 5.4.

Figure 5.9 • Decommissioning of underground storage facilities in the European Union

Sources: GIE (2015b), *GSE Investment Database* (database); GIE (2015c), *Paper on the GSE Investment database 2015-2025*.

Economic pressure on gas storage facilities is projected to remain, assuming continuing low winter-summer spreads and the opportunity for shippers to choose alternative flexibility options. Consequently, this is likely to lead to very low investment activities for additional storage capacity. Still, the Gas Storage Europe (GSE) investment database (status May 2015) shows projects under construction, leading to a working gas capacity increase of around 7 bcm between 2015 and 2021 (compared with approximately 12 bcm between 2009 and 2015), with Italy and Germany recording the largest increase (GIE, 2015b). However, updated information on the progress of storage projects is no longer provided on a regular basis by most of the storage operators, so it is unclear how many storage projects were already completed in 2015 or really will start operation by 2021.

In Italy, only Bordolano, a new facility from storage system operator Stogit, could potentially be in operation in the future. On all other facilities, no information on project progress could be found. For Germany, the largest provider of WGV, the State Office for Mining, Energy and Geology reports that working gas additions of approximately 4 bcm are planned or under construction. But it seems unlikely that Germany, being an unregulated storage market, will see such an increase, as current low spreads do not give any incentive to storage operators to invest in new sites. In other EU countries, GSE shows expansion of working gas capacities of approximately 0.6 bcm, but it is very uncertain whether they will be built.

The relevance of gas storage filling levels

Until now, the decreasing market value of gas storage sites, which is a significant parameter for shippers to book storage capacities, is not yet reflected in storage filling levels. Despite low summer-winter spreads during the last five years, EU storage facilities were filled above 80% as Figure 5.10 shows.⁶

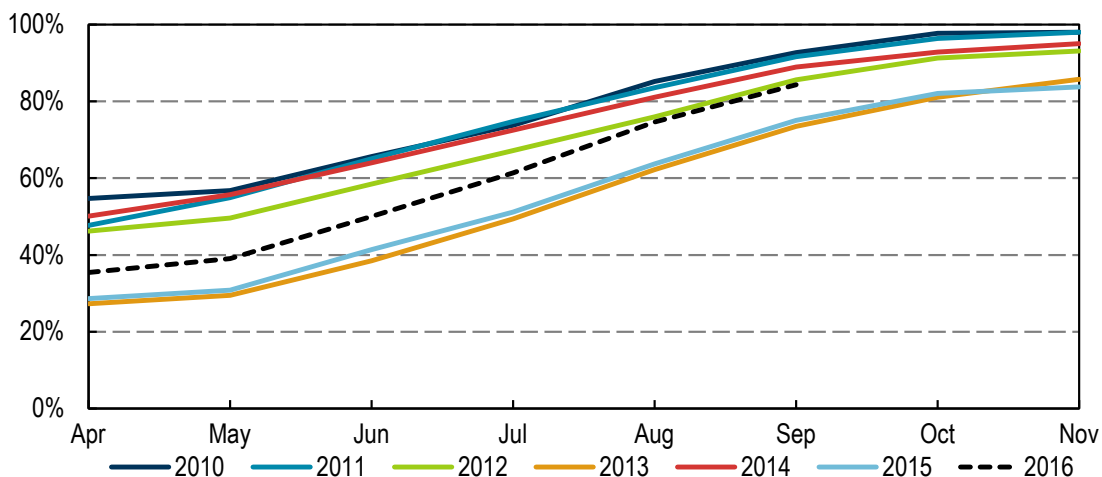
Still, storage sites might benefit from long-term capacity bookings of the past, but this situation is going to change in a competitive environment where shippers tend to book shorter-term contracts (one to three years).

With respect to the gas year 2016/17, the contribution of gas storage flexibility for North West Europe is expected to be strongly influenced by the outage of the Rough storage site in the United Kingdom, which stopped further injection of natural gas at the end of June 2016 when testing and verification works identified issues that resulted in an enhanced testing programme

⁶ Corrected for the limited storage level in the Rough storage, United Kingdom.

estimated to be completed in April 2017 (Centrica Storage, 2016). Rough’s filling level just reached about 40% of the storage’s capacity when injection stopped in June 2016 (Figure 5.11).

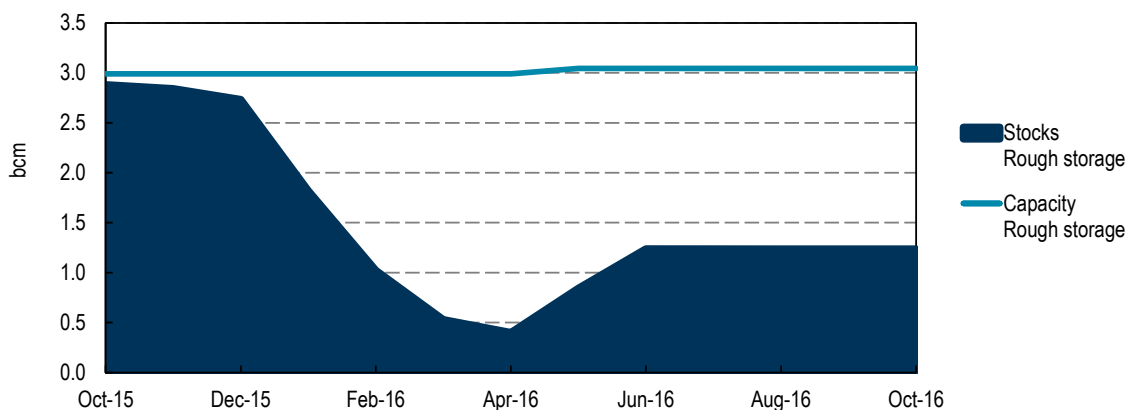
Figure 5.10 • Storage filling levels in the European Union



Notes: data do not cover all European storage sites. Filling levels refer to values at the beginning of the month.

Source: GIE (2016), AGSI+ Transparency Platform (database).

Figure 5.11 • Development of Rough storage’s filling level



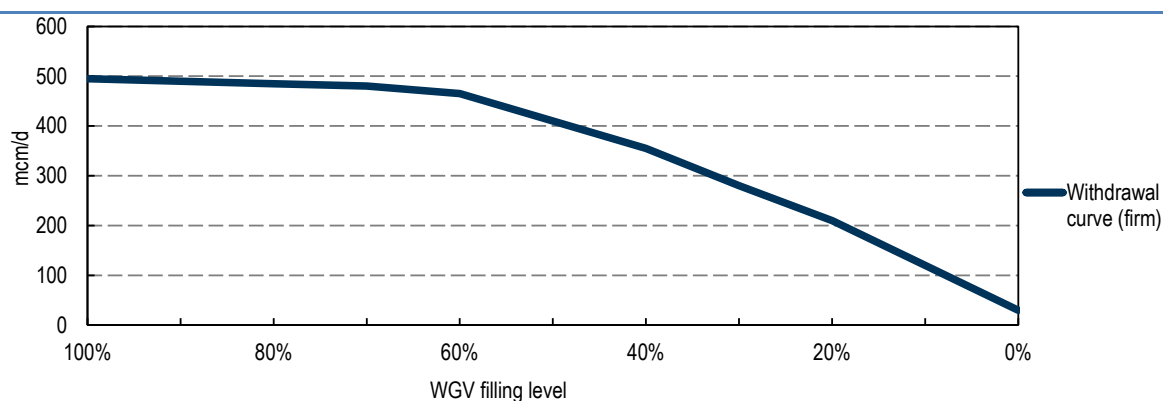
Source: National Grid (2016), Storage and LNG Operator Information.

Other sources of the European supply mix, most likely pipeline gas and gas storage on the Continent, will need to enhance their flexibility contribution during the upcoming winter season as Rough’s contribution, accounting for approximately 70% of the United Kingdom’s storage capacity, is expected to be 8 mcm/d on average, in contrast to 17 mcm/d during the winter season 2015/16 (ICIS, 2016a).

The development of Rough’s filling level in 2016 has two major implications for the upcoming winter: first, both the significance of Norwegian quantities being delivered to the United Kingdom and the potential of gas storage to supply demand variations via Interconnector UK (Belgium-United Kingdom) and BBL (the Netherlands-UK) will rise. In combination with the limitations on the production swing potential of the Groningen field, relevant gas storage sites in the continental North Western market already show filling levels well above 90%; this gas could be delivered via Interconnector UK and BBL pipelines if price signals in the UK market create an incentive.

Second, Rough's low filling level and the related decrease of daily withdrawal rates illustrate an important correlation: gas storage filling levels are important to maintain the ability to deliver load flexibility, necessary to supply peak demand, especially during the end of the winter. Although the aggregated curve of Figure 5.12 of all German gas storage sites⁷ does not specifically show different characteristics of pore storage and cavities, the example elucidates that a filling level of less than 60% can lead to a significant drop in withdrawal rates.

Figure 5.12 • Relation between filling level and withdrawal rate based on an aggregated curve for German storage sites, schematic

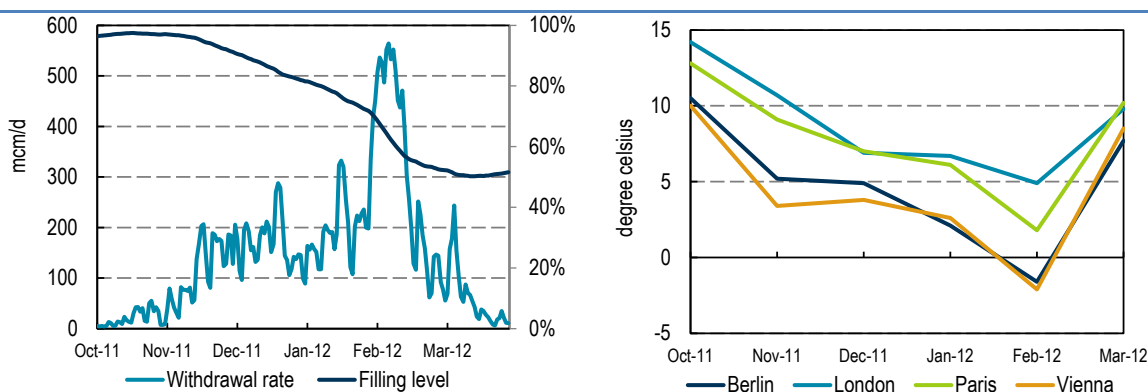


Source: Graph based on data provided by INES.

Based on the supply standard of EU Regulation 994/2010, published analysis focusing on the German gas storage market shows that at the beginning of February, a filling level of German gas storage facilities of approximately 30-40% is necessary to supply the relevant daily peak demand load to protected customers during a seven-day peak cold-temperature period. Approximately 40-50% filling level during a 30-day period of exceptionally high gas demand would be necessary at the beginning of February to supply the relevant quantities during this period (INES, 2016; BBH et al., 2015).

At EU level, the importance of gas storage's filling level is relevant, especially at the end of the winter when storage levels below a certain threshold, as indicated above, would not be able to cover peak demand: Figure 5.13 shows that at the beginning of February 2012 – when European gas storage was filled at a level of about 70% – a cold spell led to withdrawal rates between 260 mcm/d and 560 mcm/d during a time period of about 12 days. Across Europe, countries are reacting differently to the concern that low storage levels at the end of the winter might lead to constraints in withdrawing needed gas quantities.

Figure 5.13 • EU gas storage performance during winter 2011/12



Notes: Withdrawal rates are converted from gigawatt hours per day to mcm/d (11.1 kilowatt-hours per centimetre). Temperatures are mean monthly temperatures.

Source: GIE (2016), AGSI+ Transparency Platform (database); DWD (2016), *Global Climate Data – Monthly* (database).

⁷ Austrian gas storage sites Haidach and seven fields included with a share of 50%, as both are partly used for Germany.

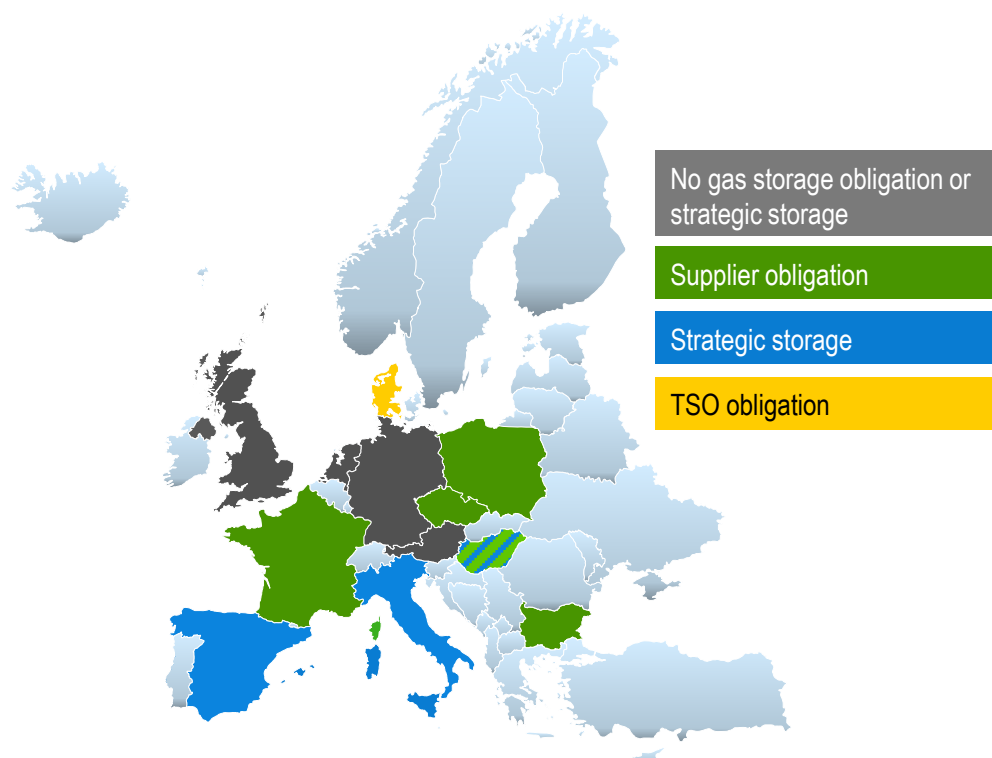
No level playing field for gas storage in Europe

Figure 5.14 shows that most European countries, except for the United Kingdom, Germany, the Netherlands and Austria, have some form of gas storage obligation or strategic storage in place – however, regulatory provisions vary considerably in different member states. Against the background of low market incentives for shippers to book storage capacities, the provisions were adjusted in several cases to prevent gas storage facilities from being underutilised and/or to allow returns, which cover full operational expenditures. Adjusted regulatory frameworks resulting in higher storage capacity utilisation provide another reason for the relatively high filling levels, besides long-term gas storage capacity bookings from the past. However, different preconditions for European storage – in addition to those regarding transport capacity rights – also mean that changes in market fundamentals are affecting storage operators and users differently within European countries and market areas.

France is addressing the issues of storage operators, auctioning off capacities in a market environment with tightening seasonal spreads. The public consultation of the French Energy Regulatory Commission states that “storage capacities subscriptions made by suppliers have gradually decreased over the years, to such an extent that, during winter 2013-2014, the French gas system was not able to handle a cold spell” (CRE, 2016). Public authorities reacted with a reform of third-party access to storage facilities, and the adjustments made by the draft order foresee that French storage capacities will be marketed through auctions.

This guarantees that regulated revenues as the positive or negative difference between the storage operators’ income from the auctions and the regulated revenue will be compensated “through the introduction of a dedicated term in the tariff of use of the gas transmission networks” (CRE, 2016). Moreover, the French regulator safeguards that on 1 November of each year, gas suppliers store not less than 80% of annual quantities sold to customers that are connected to the distribution grid. Changes are most likely to come into force for the storage season 2017/18 (ICIS, 2016b).

Figure 5.14 • Gas storage-related security-of-supply regimes of selected countries in Europe



Source: European Commission (2015a), *The Role of Gas Storage in Internal Market and in Ensuring Security of Supply*.

In the Netherlands, because it is a net exporter of gas, most of the storage capacity comes from depleted gas fields. A large part of it does not provide third-party access, and the risk that this storage capacity is not booked due to lower summer-winter spreads seems to be remote, as the bulk of the capacity is part of the Groningen system and is needed to deliver flexibility that has to compensate the decreasing production swing of Groningen (Komduur, 2009). The remaining sizeable storage facility Bergermeer, which partly offers third-party access, has already dedicated about 46% of storage capacity to Gazprom (DIW, 2014). Moreover, GTS has the responsibility to supply peak demand at temperatures between -9 degrees Celsius and -17 degrees Celsius, which also could incentivise storage capacity booking despite a decreasing market value.

Italy has established a strategic gas storage reserve, the level of which is set by the Ministry of Economic Development on a yearly basis. The minimum level for the strategic storage capacity is among others dependent on the quantities related to the single-most-used import infrastructure's technical capacity during a supply period of 30 days. The strategic storage capacity for 2015/16 amounted to 4.6 bcm, representing about 30% of the total storage capacity in Italy (European Commission, 2015a).

While gas storage facilities as flexibility providers are safeguarded in France despite their decreasing market value, gas markets fully exposed to competition might react differently. In Germany, as an example of a storage market being completely exposed to competition, storage operators face difficulties auctioning off storage capacities at a tariff level that is claimed to be economically sustainable. Further decommissioning of storage capacity as a possible consequence might be detrimental from a gas security point of view as well as an economic one.

Gas storage offers a system value in addition to the market value, guaranteeing a relatively stable load during a year and also being more cost-efficient for the whole gas infrastructure (CEER, 2015). By injecting gas quantities during the summer season, gas storage allows for a relatively high flow compared with the summer season's demand needs in a heat-driven gas market. Hence, a higher load factor of the gas transportation infrastructure over the year can be achieved, which optimises that infrastructure's investment cost; furthermore, it prevents cross-border gas import points from being designed just for peak demand and from being used only a few times in a year, incurring a higher investment cost. Moreover, importing and storing gas in summer provides the opportunity to increase a country's resilience against disruptions of the LNG or pipeline supply chain during the winter season.

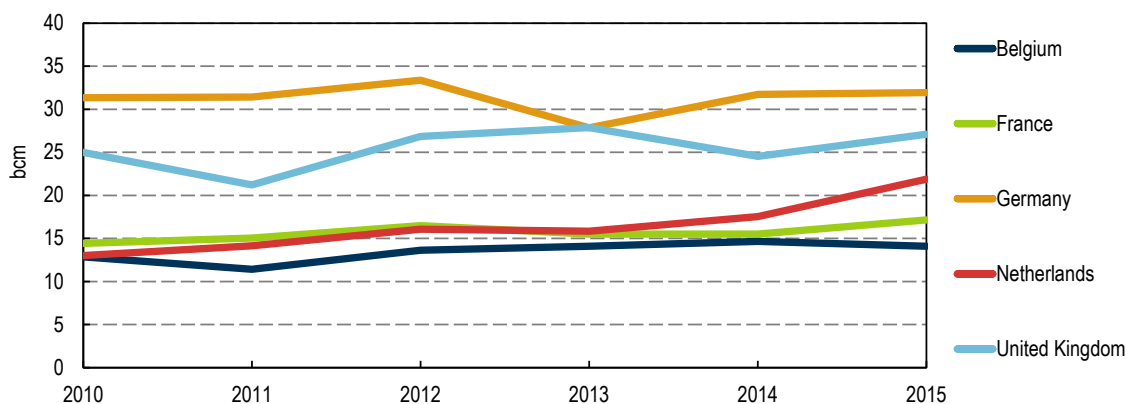
So far, the share of two significant partners for Europe, Norway and Russia, is relatively stable but not dominant in providing seasonal flexibility via pipeline swing. As pipeline gas is imported over long distances, the flexibility provided for Europe potentially has certain limitations when daily fluctuations in demand have to be balanced. Hence, pipeline imports in principle go along with gas underground storage, which structures the relevant gas import quantities and allows tapping the full flexibility potential, including daily flexibility in the specific areas where load flexibility is needed most. At least until 2020, when the demand for L-gas will gradually decrease due to the conversion from L-gas to H-gas areas, especially the Netherlands – importing more gas from Norway and Russia – is expected to use gas storage more intensively in order to provide flexibility that can no longer be delivered by the Groningen field.

Supply from Norway

In 2015, Norway produced a record high volume and exported a total of 113 bcm to: Germany (32 bcm), the United Kingdom (27 bcm), the Netherlands (22 bcm), France (17 bcm), Belgium (14 bcm) and Denmark (less than 1 bcm). Exports to France and Belgium have been relatively stable, and high year-on-year (y-o-y) changes can be observed in Germany and the United Kingdom. Over the last six years (2010-15) the imports to the Netherlands increased by almost

9 bcm. Other countries increased their imports between 1 bcm and 3 bcm, with varying y-o-y changes as shown in Figure 5.15.

Figure 5.15 • Annual Norwegian pipeline gas exports to Europe

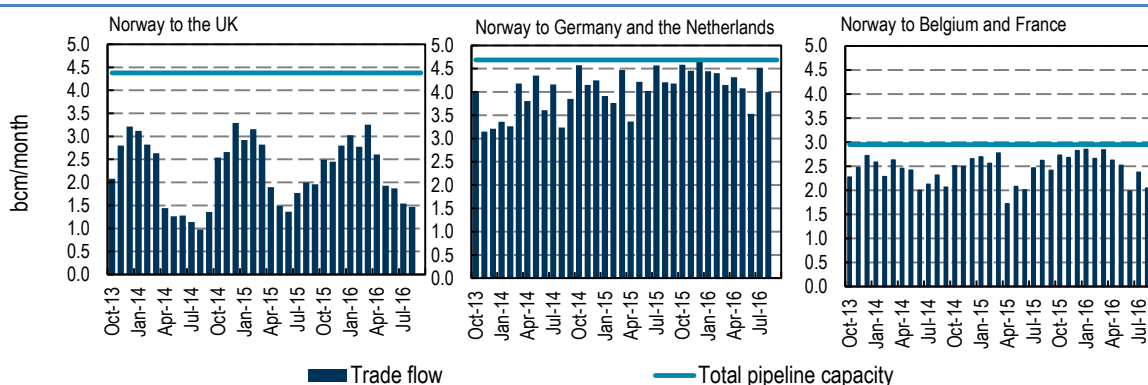


Source: IEA (2016d), *Gas Trade Flows* (database).

The Norwegian Petroleum Directorate’s production forecast currently foresees peak production in 2016, which stabilises thereafter until 2020 at a slightly lower level (NPD, 2016a) – a consequence of the falling oil price, which raised uncertainties for the petroleum industry and led to a postponement of investments in operating and new fields (NPD, 2016b). Gas supplies from Norway are therefore not expected to contribute beyond what has been delivered so far.

The Norwegian pipeline system is well-connected to the United Kingdom and to the Continent. Whereas capacities to the United Kingdom still leave room for Norway and provide the potential to benefit from higher prices in relation to the European Continent, capacities to the Continent are already well-utilised (Figure 5.16). However, based on the production level forecast, the limiting factor will be the overall production, providing the opportunity to shift quantities between the two destinations in case prices provide the incentive, but an increase in total volumes is not expected.

Figure 5.16 • Norwegian gas flows to Europe



Sources: ENTSO-G (2016), *ENTSO-G – the European Natural Gas Network (Capacities at cross-border points on the primary market)*; Gassco (2014), *Bringing Norwegian Gas to Europe*; IEA (2016d), *Gas Trade Flows* (database).

Supply from Russia

Between 2010 and 2015, the yearly average of Russian supply to OECD Europe amounted to 144 bcm but varied from year to year. The trend indicates an increase of Russian quantities to OECD Europe, both in absolute terms and also in relation to OECD European gas demand: the



period 2013-15 saw a combination of higher Russian imports and lower demand compared with the period of 2010-12, where imports were lower and demand was higher. In the last three years, Russia has supplied OECD Europe with an average 30% of demand, compared with 25% in 2010-12. Preliminary data for Europe show that January-August 2016 exports to OECD Europe were about 10% higher than in the same period last year.

Comparing the period 2010-12 with 2013-15, increases in imports from Russia were highest in Germany and Italy. Imports by Turkey increased between 2010 and 2011 by about 7 bcm from 18 bcm to 25 bcm, mainly via the Blue Stream gas pipeline. The import level stayed relatively stable thereafter.

Pipeline imports from Russia to Europe come from a number of routes: direct connections of Nord Stream to Germany and Blue Stream to Turkey and direct supplies to Estonia, Latvia and Finland; and using transit routes through Belarus and Ukraine.

The Yamal transit line through Belarus reaches Lithuania, Poland and Germany. The Brotherhood and Soyuz lines through Ukraine reach a number of countries in Central and Eastern Europe and beyond. The Trans-Balkan Pipeline further transits gas through Romania and Bulgaria to Greece and Turkey. While the Brotherhood and Soyuz pipelines hold the largest technical transit capacity of around 104 bcm/y to Poland, the Slovak Republic and Hungary, the completion of Nord Stream in 2012 opened up 55 bcm/y of direct supply capacity to Germany and further into Europe.

In the case of decreasing European domestic production or lower supplies from other countries of origin, imports from Russia could be increased to a certain extent depending on spare pipeline capacity, production ramp-up possibilities from the Russian fields, EU regulatory issues, and political willingness from the European Union and Russia to do so.

Over the last three years an average of 63% of total annual pipeline capacity was used to deliver gas to Europe, resulting in a theoretical spare pipeline capacity of 95 bcm/y. In the winters, Yamal and Blue Stream have high utilisation levels, leaving little to no spare capacity. Nord Stream and the Ukraine transit routes offer significant spare capacities in both winter and summer. Whether the full technical capacity for the Ukraine transits could be realised is questionable because parts of the transit infrastructure are in need of maintenance or upgrades to reach the full transit capacity again.

For the summer period, IEA analysis estimates – based on Russian experts' opinions – that a short-term production ramp-up in Russia should be possible in about two weeks and could equal 0.3 bcm/d to 0.4 bcm/d (this is based on the difference between the level of very high Russian winter production levels and the current summer production level). There would be a further transport time of about four days from the Russian gas fields to Germany.

Based on average flows over the last three winters and summers, it could be technically possible to increase Russian deliveries in summer to Germany by up to 1.3 bcm/month via Nord Stream in roughly three weeks. An additional potential of 5 bcm/month could be delivered through the Ukraine transit system;⁸ this is, however, considered a maximum potential because the technical maximum capacity is unlikely to be reached. Another 0.3 bcm/month could be supplied through the Yamal transit line, and 0.3 bcm/month through Blue Stream as well. Lastly, the Trans-Balkan Pipeline offers 0.6 bcm/month spare capacity for the summer period. On the basis of these assumptions, there is a maximum potential of 7.4 bcm/month additional supplies from Russia (the sum of available spare capacities). In this case, pipeline capacity availability is the key constraint. While these estimates are calculated based on maximum technical capacity through Ukraine, the relatively high figure suggests that even if available transit capacity through Ukraine

⁸ This spare capacity calculation excludes the exceptional low winter 2014 (from October 2014 – March 2015) transit volumes.

were lower than estimated, there should be enough room during summer to accommodate a substantial increase in Russian deliveries.

Box 5.3 • Ukraine supply and demand

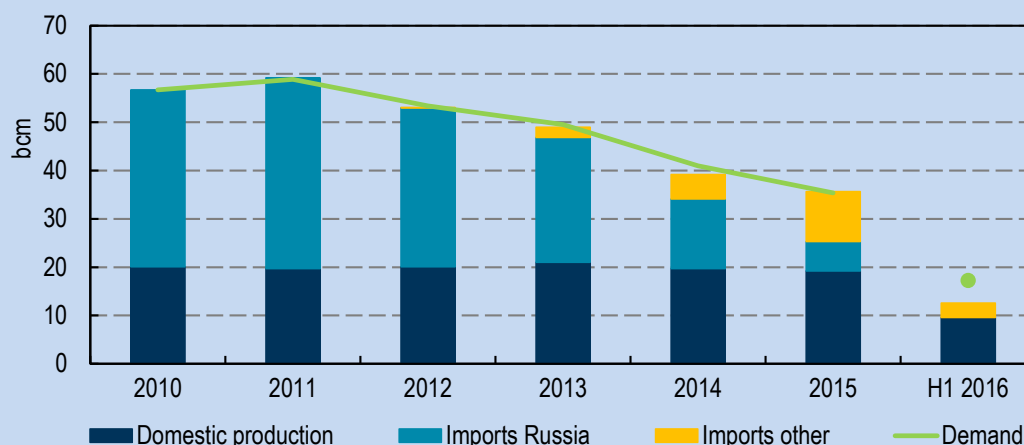
Ukraine’s gas consumption has fallen dramatically and stands at 60% of its level in 2011. Household usage has gone down steadily since 2010 following several measures to decrease consumption in the sector such as lower district heating guaranteed temperatures and sharp tariff increases. Recent mild winters are an additional factor in the decrease in household consumption. Meanwhile, consumption in the industrial sector has continued to suffer as a result of the severe economic recession.

The sharp fall in demand has allowed Ukraine to reduce its direct imports of Russian gas; yearly imports have gone down from 40 bcm in 2010 to 6 bcm in 2015 (see Figure 5.17). In the period January through August 2016 (i.e. up to September 2016), there were no imports from Russia. Domestic production now covers more than 50% of the country’s gas consumption, while increasing reverse flow capacity has allowed for increased flows from Europe. In calendar year 2017, reverse flow capacity will equal up to 15 bcm from the Slovak Republic, of which about 10 bcm is firm and the remaining interruptible.

The residential sector accounts for about 55% of total Ukraine demand (Naftogaz, 2016). In the case of a cold winter, this segment’s demand will pick up significantly. In the last years, winters have been mild with a corresponding decrease in demand. It is not possible to determine how much of the residential demand decline can be attributed to policy measures and how much to mild temperatures.

In winter of 2016, Ukraine filled its storage facilities to about 14.5 bcm (Ukrtransgaz, 2016), which is a lower level than in previous years. In the previous two winters, Ukraine used about 50% of the stored volumes over the winter, equalling 8 bcm to 9 bcm (as shown in Figure 5.18). It is important to note that not all gas in storage can be used though – the level of cushion gas is about 6 bcm to 7 bcm.

Figure 5.17 • Ukraine supply and demand

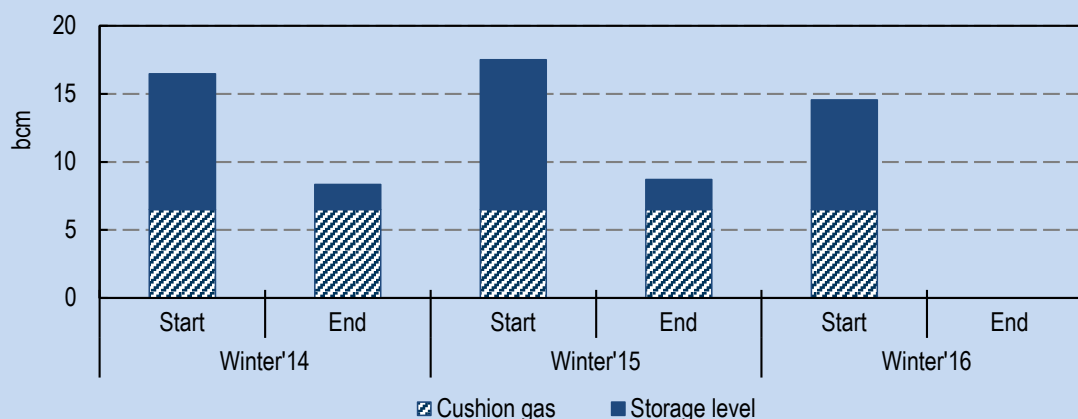


Note: Storage use is not included in the figure, and is assumed to be volume-neutral over the years. Demand and supply are not equal for the first half of 2016 because of storage use; there was more storage withdrawal in Q1 2016 than injected in Q2 2016.

Sources: Naftogaz (2016), *Natural Gas Consumption in Ukraine*; IEA (2016b), *Natural Gas Information* (database); IEA (2016d), *Gas Trade Flows* (database); IEA estimates.

However, with the increased reverse flow capacity from the Slovak Republic and the drop in Ukraine’s gas demand (see Figure 5.17), the country has improved its winter supply resilience compared with a number of years ago, provided that reverse flows are available in cold periods.

Figure 5.18 Ukraine storage levels



Notes: Winter'14 runs from October 2014 till the end of March 2015.

Sources: GIE (2016), AGSI+ Transparency Platform (database); Ukrtransgaz (2016), Real time data (database).

During a winter period that is not too severe in both Russia and Europe, Russian production could be ramped up by 0.1 bcm/d to 0.2 bcm/d (this equals the difference between Gazprom's maximum production level in 2012 and Russia's high winter production levels). In a scenario where additional volumes from Russia are needed, the lower production figure is used for this calculation to come to a monthly production ramp-up potential (0.1 bcm/d for 30 days = 3 bcm/month). In a situation where there is a cold spell in both Russia and Europe, potential Russian exports could not fully benefit from the production ramp-up because the Russian domestic market demand would be higher as well.

In the winter, Yamal and Blue Stream run on very high utilisation levels. The average Ukraine transit is higher in winter than in summer. In total, the upside potential of additional deliveries to Europe is about 3 bcm/month, which can be divided between Nord Stream (1.7 bcm/month of spare capacity) and the Ukraine transit routes (4.5 bcm/month of spare capacity). In this case the maximum production ramp-up is the bottleneck because the technical spare capacity is higher. Again, this figure depends on the possible utilisation level of the Ukraine transit system and on the condition that there is no simultaneous cold spell in Russia and Europe, which would bring down the spare production volumes available for additional exports.

In conclusion, there is a significant potential for additional Russian volumes to Europe, especially in summer. This would increase the share of Russian gas in the European supply mix. To what extent Russia is willing to substantially increase transit volumes through the Ukraine remains to be seen. In October 2016 the European Commission revised the exemption decision on the OPAL pipeline⁹. The decision has not been published yet, but it is expected that Gazprom could increase its gas flows through OPAL, which in turn would make it possible to use a higher share of Nord Stream's capacity.

Pipeline supply from Africa and the Caspian region

Pipeline supply from the African continent has decreased since 2012. In 2014 and 2015, Algeria and Libya maintained steady exports to Spain and Italy of about 30 bcm each year, compared with roughly 40 bcm in 2012.

⁹ The OPAL pipeline runs from Greifswald in North Germany (where it connects to Nord Stream) to Olbernhau, close to the German–Czech Republic border.

The flexibility potential of imports from Africa is difficult to assess, as gas output in the region has often underperformed in recent years. Algeria, the most significant gas exporter in the African continent for Europe, faces difficult financing conditions and a lack of investors' interest (IEA, 2016a). Additionally, gas demand in Algeria increased by roughly 10 bcm between 2010 (27 bcm) and 2015 (36 bcm), which might result in difficulties maintaining its export capacity (IEA, 2016f).

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Africa's share of flexibility contribution decreased during the past years and it is unlikely under the current circumstances that the relevant countries would be able to significantly increase quantities if European gas markets were to demand more, especially on a daily basis.

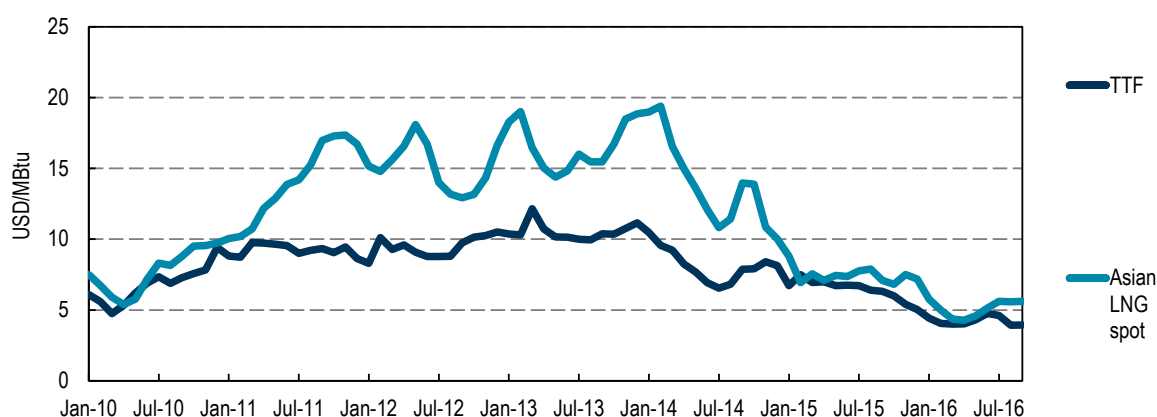
Flexible quantities from Iran are currently delivered to Turkey only (about 8 bcm/y), and Iran's natural gas production is already estimated to have reached a historical peak (IEA, 2016a). As the domestic consumption is expected to grow, higher export levels would be possible only along with investments and involvement from foreign countries. Against the background of the current European gas price level, it is not likely that gas exports will be increased in the short term.

Supply from LNG

Despite a significant increase in LNG regasification infrastructure over the last years in the United Kingdom, France, Italy, the Netherlands, Poland and Lithuania, the utilisation levels dropped from about 45% to 25% between 2011 and 2015. The drop in LNG imports from 2010 until 2014 ended, with 2015 seeing an almost 20% increase in imports year-on-year. The United Kingdom, Italy and Spain increased their LNG imports significantly in 2015 but are still far from the 2010 and 2011 volumes.

LNG import quantities compete on a global market: although OECD Europe's technical capacity expanded by some 30 bcm between 2011 and 2015 (from 179 bcm to 211 bcm), the utilisation rate of the regasification capacity is about 25%, which has led to a relatively low contribution of LNG imports to OECD Europe's flexibility so far. Besides strong competition with pipeline gas, higher Asian gas prices compared with European gas hub prices have been the main reason for the low utilisation despite the regasification capacities' potential.

Figure 5.19 • Asian LNG spot prices versus TTF (monthly average of day-ahead prices)



Sources: TTF data: Bloomberg Finance LP. Asian LNG spot data: Platts ©2016 by McGraw Hill Financial, Inc.

Although spreads between Asian LNG spot and European gas hub prices have tightened since the beginning of 2015, a strong price signal would be needed from European markets to attract LNG quantities.

Box 5.4 • Flexibility supply from underground gas storage and LNG

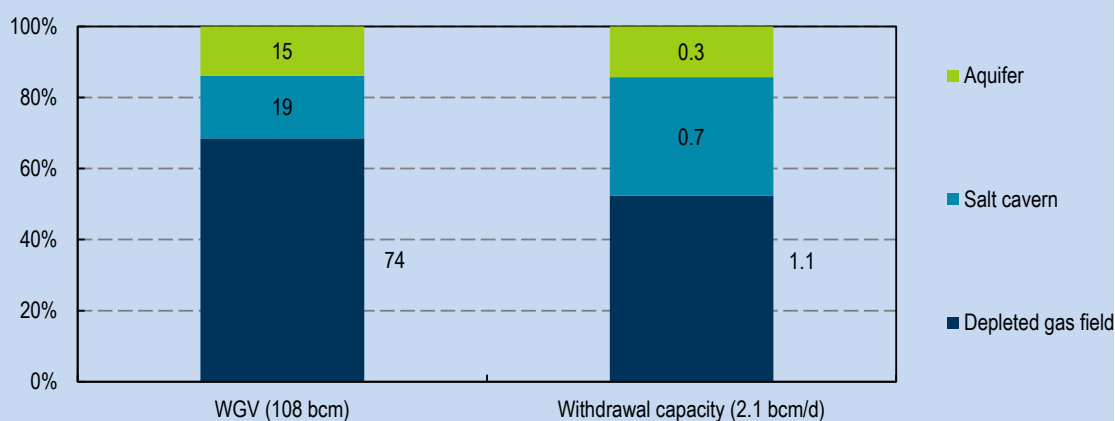
Flexibility supply from LNG and underground gas storage is to a certain extent not interchangeable due to different operational characteristics and geographical location. This box provides a general overview of types of storage and their typical use, and how this generally differs from flexibility provided by LNG.

Underground storage facilities can be roughly divided into three groups with their own storage volume and capacity characteristics. The volumetric and capacity breakdown per type of storage is shown in Figure 5.20.

1. Depleted gas field storage facilities are seasonal, with typically a high storage volume (varying from 200 mcm to currently 7 bcm), and withdrawal capacity can be high when the storage is relatively large. This type of storage is filled during the summer season and offers a full winter season withdrawal capacity. The withdrawal capacity is highest when the storage is fully filled and goes down when a certain volume is used. The storage needs cushion gas to fill up the depleted field to a level where a basic pressure is reached. On top of that, the actual storage volumes are injected and withdrawn. The storage pressure lowers when there is less gas in the facility and a related loss of withdrawal capacity varies per site; a general rule of thumb is that a deterioration of withdrawal capacity occurs when depleted gas field storage facilities are filled at 60% or less. The depleted gas storage volume in Europe is now 74 bcm (69% of total storage volume) and the withdrawal capacity is 1.1 bcm/d, which equals more than 50% of total storage withdrawal capacity.
2. Salt caverns are storage facilities with a relatively high withdrawal and injection capacity and can therefore be used multiple times a year – multi-cycle storage¹. These sites have an average injection capacity of about 60% (GIE, 2015a) of the withdrawal capacity, and the capacity is high in relation to the volume. Salt cavern capacity makes up 0.7 bcm/d or 35% of total withdrawal capacity with only 17% storage volume.
3. Aquifers have roughly the same volume and capacity characteristics as depleted gas field storage facilities. They account for 15 bcm or 14% of total European storage volume, and the withdrawal capacity amounts to 0.3 bcm/d – 12% of total European storage withdrawal capacity.

Total storage peak withdrawal capacity in Europe is about 2.1 bcm/d.

Figure 5.20 • Storage volume and capacity in the EU-28



Sources: GIE (2015a), "GIE storage map"; IEA (2016b), *Natural Gas Information* (database).

LNG regasification facilities provide a high regasification capacity; globally this amounts to up to 1 080 bcm of gas in the gaseous state (IEA, 2016b). A high concentration of regasification capacity is found in Japan (286 bcm) and Korea (161 bcm). In Europe there is 211 bcm regasification capacity installed, mainly located in South and North West Europe. For the winter period this equals a potential LNG supply of 105 bcm in Europe, about the same WGV as underground storage. LNG in Europe can provide about 0.55 bcm/day of peak regasification capacity.

When needing to secure (temporarily) additional supplies, maximum LNG withdrawal capacity can be maintained only when LNG tanks are continuously replenished. If shippers have not ordered maximum supplies of LNG, the LNG regasification facilities will run out of supplies fast when withdrawal volumes are high. It could take approximately two to four weeks to (re)direct LNG vessels to the European continent.

From a security-of-supply perspective, the geographical distribution of LNG regasification terminals and storage facilities is a detrimental factor. LNG terminals are located on the coast, while peak demand situations in large countries or regions may require gas to be stored closer to high demand areas. In this respect, storage facilities offer a geographical advantage in certain markets.

¹ Salt caverns have a layer of salt in the cavern that is impenetrable for gas. In comparison with the porous rock in depleted gas fields, this allows for higher withdrawal and injection rates.

Demand flexibility

Rebalancing the gas supply/demand balance can be done by increasing supply from various sources but also by adjusting demand downward. Generally there are two ways to adjust demand while ensuring supply to protected customers; these are interruptible contracts and fuel switching. In short, interruptible contracts are generally sold to customers that consume large volumes (e.g. industry), and in return for a discount on gas prices it is agreed that supplies can be interrupted for a certain number of days. Fuel switching by gas customers is done by switching the supply fuel of their process (e.g. thermal generation). Next to switching fuel in a plant itself, the power generation system could also rely on available spare capacity of non-gas-fired plants, such as coal- and oil-fired power generation plants.

Gas power generation switch to coal and oil power generation

OECD Europe has experienced stagnating power consumption and production over the last years; the gross electricity production in 2010-15 varied in the range of 3 530 terawatt-hours (TWh) to 3 640 TWh. Electricity generation from natural gas went down from 850 TWh to 575 TWh in the same period, which equals a drop of more than 60 bcm to about 135 bcm of gas input in 2015.¹⁰ In OECD Europe the utilisation rate¹¹ of gas-fired power production units went down from 46% to 31% over the period 2010-15, and most European countries have experienced a drop in utilisation level as well (Figure 5.21).

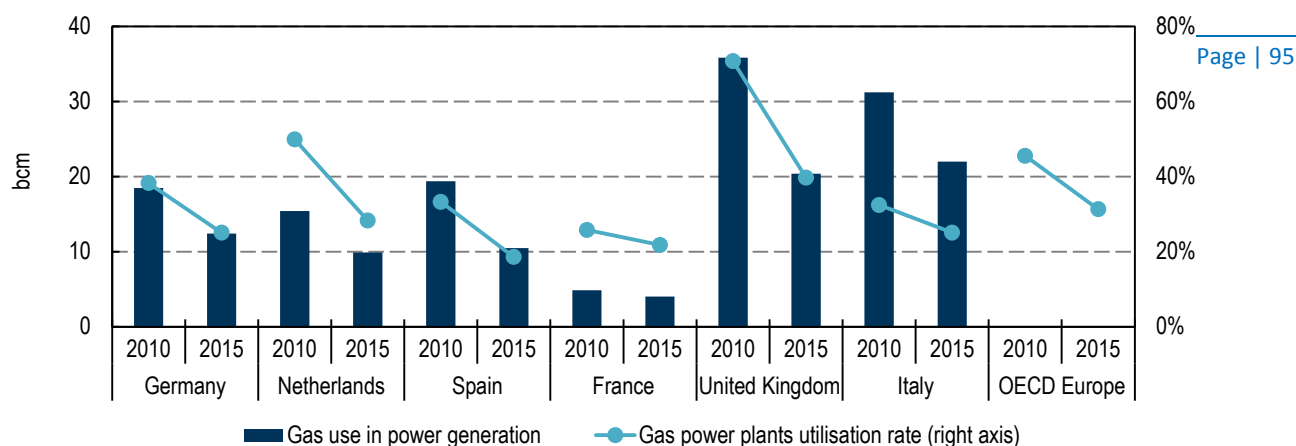
In the power generation mix, nuclear, coal-fired power generation and Combined Heat and Power (CHP) are regarded as base-load power supply sources, renewables as base-load but variable and intermittent supply, and gas-fired power generation can have the role of base-load generation or as a more variable supply. The main drivers of the drop in gas-fired power plant utilisation level have been the deployment of more renewables, very low coal prices, low electricity prices and a low carbon price, resulting in coal being favoured over gas for power production. In all OECD Europe countries, except Turkey, the Czech Republic and Poland, power generation from natural gas declined over the last five years. There was a small uplift though of +10 TWh in 2015 compared with 2014. Whereas Italy, France, Spain and Portugal contributed to the increase with 28 TWh, Turkey pulled the overall OECD Europe generation number down by 20 TWh, driven by a recovery from low 2014 levels of hydropower. In the United Kingdom, the

¹⁰ Based on preliminary data from *Electricity Information* (database) (IEA, 2016e) and *Natural Gas Information* (database) (IEA, 2016b).

¹¹ Utilisation rate = power generated divided by installed nameplate capacity.

carbon floor price and the low gas prices have lifted the spark spread above the dark spread, and an increase of power generation from gas can be observed over the first half of 2016 (DECC, 2016).

Figure 5.21 • Gas-fired power generation in OECD Europe

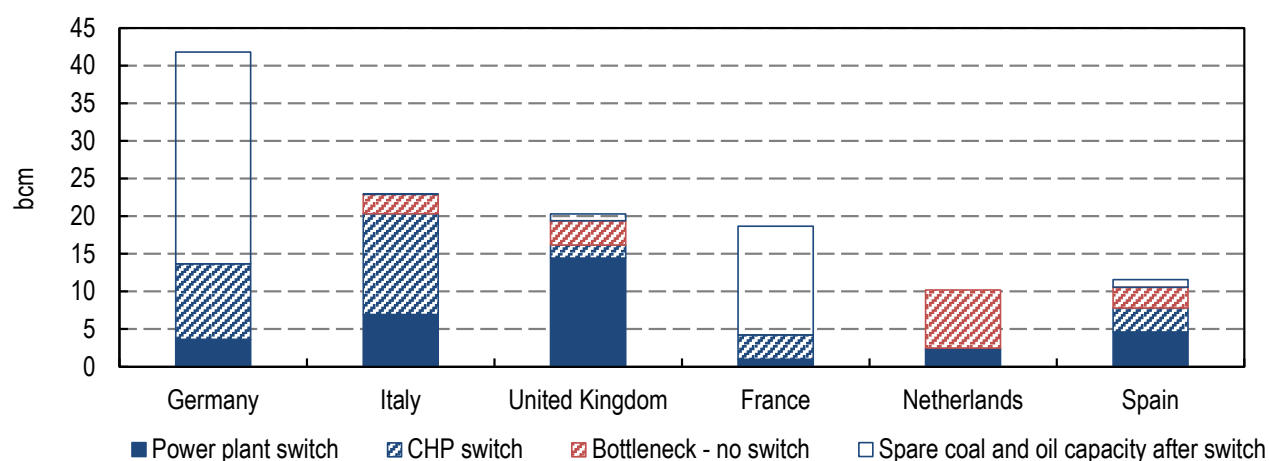


Source: IEA calculations based on ENTSO-E (2016b); IEA (2016e), *Electricity Information* (database).

Together with the increasing deployment of renewables and with the limited shutdown of conventional power plants, the power market is oversupplied, and most countries have ample spare coal- and oil-fired plant capacity available on a yearly average production base. Accordingly, in case of a gas supply disruption, gas demand could be curtailed by switching away from gas-fired power generation to spare coal and oil power generation capacity.

On the basis of monthly aggregated data over 2015, an indicative maximum potential gas saving for six major European power-producing countries – Germany, Italy, the United Kingdom, France, Spain and the Netherlands – could be 33 bcm per year on gas-fired power plants and another 32 bcm on CHP plants as shown in Figure 5.22. The limitations to this maximum potential are described below.

Figure 5.22 • Maximum potential annual gas savings by switching to coal- and oil-fired power generation



Notes: IEA calculations are based on monthly power generation data and capacity data for 2015 from ENTSO-E (2016a; 2016b) and annual power generation data from IEA (2016e). Power plant closures in 2016 are included.

Sources: ENTSO-E (2016a), *Yearly Statistics & Adequacy Retrospect 2014*; ENTSO-E (2016b), *Statistical Database for Production and Consumption Data* (database); IEA (2016e), *Electricity Information* (database).

Limitations to switching away from gas-fired power generation

The role of CHP

In OECD Europe, gas-fired power generation has a high share of CHP plants. In 2014, 43% of all gas-fired power generation was generated by CHP. In most Western and Southern European countries, CHP is mostly used for supplying power and heat to the industry segment and to the market. In a number of Eastern European countries, CHP is also used for district heating. Switching away from CHP for power generation will affect the industrial sector, and in a number of countries, also the district heating system.

In many countries, the power generation from CHP plants is higher than conventional gas-fired power plants. In Germany, for example, most of the gas-fired power is generated by CHP plants and actually acts as a continuous source of power. When assessing the potential gas savings, the switch away from CHP-generated power will have a profound impact on the industry segment and district heating systems, and should thus be considered as a last resort.

Daily and intraday flexibility

The hourly variation of power demand, the changing marginal power generation technology, and the difference between base-load (high load factor) and variable intermittent power generation do not allow spare coal and oil power generation capacity to be fully transferable to the role natural gas-fired power generation has in the power generation mix. In Spain, for example, combined-cycle gas turbine (CCGT) units ran for about 900 hours and CHP units for about 4 000 hours in 2014. This indicates that CCGT is mostly used as a balancing and marginal variable source and would be difficult to replace with base-load type capacity with a high load factor. In Germany, most gas-fired power generation comes from CHP and is regarded as a base-load supply of power.

Considering a peak demand day, or a day with a very high demand, most countries should rely to a relatively high extent on their base-load power capacity and would need flexible sources (and/or power imports) to bring supply up to the level of demand. When taking gas out of the equation, the possibility of matching the supply with the high demand becomes challenging, as reliance on variable and intermittent sources as base-load power is increasing. Monthly aggregated data over 2015 show that the variation in available spare coal and oil capacity and gas-fired power generation levels already indicate monthly bottlenecks¹² that do not occur on a yearly average base. Taking this further to the daily variation of gas-fired power generation and spare coal and oil capacity, it is very likely that additional bottlenecks occur that are not shown on a monthly average base. The potential gas savings as calculated in this analysis does not take into account any intra-month restrictions from the merit order of power generation that could occur on a daily or intraday base.¹³

Power transmission bottlenecks

Focusing on the larger North Western and Southern power-producing countries, it becomes apparent that Italy, the United Kingdom, the Netherlands and Spain do not have enough spare

¹² The bottleneck in this context is a situation where the gas-fired power generation is higher than the available spare coal and oil capacity in a month and the switching potential is thus limited to the spare coal and oil capacity rather than the full gas-fired power generation in a month.

¹³ This describes a situation where CCGT is the marginal production technology at a number of hours or days and supplies the remaining part of the peak demand that is not supplied by the other sources, which were dispatched at a lower cost. Replacing the specific flexibility that the CCGT offered at those particular hours or days will put a higher strain on the system, perhaps up to the level where there is no available capacity from other sources.

coal and oil capacity to switch away from gas-fired power generation. Germany and France have enough spare capacity in place to switch away from their own gas demand for power generation and potentially increase their power exports to other countries. The regional and international power transmission network then sets the limits on how much power can be exported to neighbouring countries.

On the basis of average available transfer capacity data for 2013 published by ACER, the United Kingdom has very limited spare import capacity from France and the Netherlands (ACER, 2014). Italy basically has very limited spare power import capacity available from any surrounding country. For the Netherlands, the import capacity from Germany is limited, and imports from France would be difficult because Belgium would need additional imports from France as well. These additional imports to Belgium would be larger than the export capacity from France to Belgium.

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Spain would also need to import more power from France; together with the increased demand from Belgium, the Netherlands and the United Kingdom, this would put an increasing strain on the French power system. In short, for a number of the observed countries in need of additional power imports, the available transfer capacity with their neighbouring countries is limited. France would be able to relieve its surrounding countries with a maximum of 3.5 bcm of gas, with 2 bcm for Belgium and the Netherlands, 1 bcm for Spain and 0.5 bcm for the United Kingdom.¹⁴

The EU electricity interconnection target for 2020 aims at having a minimum of 10% of installed power capacity in each member state to be transported to neighbouring countries (European Commission, 2015b). The Projects of Common Interest, the main tool to achieve this interconnection target, addresses a number of abovementioned interconnection bottlenecks (European Commission, 2016b). Generally, this could increase the potential to switch away from gas because countries with insufficient spare coal and oil capacity could import more power, increasing the opportunity to bring down gas-fired power generation.

Medium-term capacity retirements and additions

For the 2025 horizon, significant coal and oil power capacity retirements are expected in OECD Europe.

On the basis of the New Policies Scenario of *World Energy Outlook 2016*, there will be 47 gigawatts (GW) of coal capacity retirements and 28 GW of oil capacity retirements in OECD Europe between 2016 and 2025 (IEA, 2016g). About half of the coal capacity retirements are in the United Kingdom, Germany, France and Italy, with only small capacity additions in these countries. The total net decrease of coal capacity is 26 GW and 27 GW of oil capacity in OECD Europe between 2016 and 2025 (IEA, 2016g).

These capacity retirements will further deteriorate the switching potential in Italy and the United Kingdom (these countries already are restricted in their gas-switching potential because of limited spare coal and oil capacity). These retirements are expected to impact Germany and France to a lesser extent because these countries have abundant spare capacity.

In the Netherlands and Spain, there is uncertainty about how many coal-fired power plants will close. In the Netherlands, three coal plants were closed in 2016, and by July 2017 two additional coal plants will be closed, bringing the installed coal capacity down by about 2.5 GW to 4.6 GW. From the remaining five power plants, two 1990s plants with 0.6 GW capacity each are awaiting a possible closure decision to be made this year. In Spain, about 5 GW could be closed in the

¹⁴ Based on IEA analysis and data from ACER (2014), ENTSO-E (2016b).

coming years, but there is high uncertainty about the outcome of a decision and when this will take place.

In the New Policies Scenario of the *World Energy Outlook 2016*, OECD Europe's coal power generation capacity decreases by 11%, while oil-fired power generation capacity falls by 47% and nuclear capacity declines 20%. Gas-fired power generation capacity in OECD Europe increases by 23% and all renewable capacity will increase by 44% between 2014 and 2025 (IEA, 2016g).

The loss of coal and oil capacity, the increase of renewable sources and the increase of gas-fired power generation capacity make the switching potential from gas to coal and oil capacity more challenging and will make the gas system rely more on supply flexibility. The current maximum switching potential of 33 bcm will decrease in the coming years.

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Appendix

Table 1 • Adjusted liquefaction capacity and outages by type (bcm)

Country	Capacity and Outages	2012	2013	2014	2015	2016
Africa	Nameplate capacity	74.7	80.5	87.7	95.3	96.8
	Adjusted capacity	60.1	60.3	58.5	62.0	64.8
	Feedgas	13.6	15.5	24.2	25.4	27.0
	Security	0.8	2.5	-	-	-
	Technical	0.2	2.1	5.0	7.8	5.0
	Weather	-	-	-	-	-
Algeria	Nameplate capacity	23.3	27.3	31.0	36.8	38.4
	Adjusted capacity	16.5	19.5	22.9	28.3	28.3
	Feedgas	6.8	7.8	8.2	8.2	10.1
	Security	-	-	-	-	-
	Technical	-	-	-	-	-
	Weather	-	-	-	0.3	-
Angola	Nameplate capacity	-	1.8	5.3	7.1	7.1
	Adjusted capacity	-	1.8	0.3	-	3.4
	Feedgas	-	-	-	-	-
	Security	-	-	-	-	-
	Technical	-	-	5.0	7.1	3.7
	Weather	-	-	-	-	-
Egypt	Nameplate capacity	16.6	16.6	16.6	16.6	16.6
	Adjusted capacity	9.8	9.8	0.5	-	-
	Feedgas	6.8	6.8	16.1	16.6	16.6
	Security	-	-	-	-	-
	Technical	-	-	-	-	-
	Weather	-	-	-	-	-
Equatorial Guinea	Nameplate capacity	5.0	5.0	5.0	5.0	5.0
	Adjusted capacity	5.0	5.0	5.0	5.0	5.0
	Feedgas	-	-	-	-	-
	Security	-	-	-	-	-
	Technical	-	-	-	-	-
	Weather	-	-	-	-	-
Nigeria	Nameplate capacity	29.8	29.8	29.8	29.8	29.8
	Adjusted capacity	28.8	24.1	29.8	28.4	28.1
	Feedgas	-	1.0	-	0.7	0.3
	Security	0.8	2.5	-	-	-
	Technical	0.2	2.1	-	0.7	1.4
	Weather	-	-	-	-	-

Source: IEA analysis based on ICIS (2016), *ICIS LNG Edge* (see References section in Chapter 1).

Table 1 • Adjusted liquefaction capacity and outages by type (bcm) (continued)

Country	Capacity and Outages	2012	2013	2014	2015	2016
Asia Oceania	Nameplate capacity	121.1	124.0	125.9	136.9	158.7
	Adjusted capacity	108.4	110.3	111.3	120.8	143.2
	Feedgas	11.6	11.6	14.6	14.6	12.4
	Security	-	-	-	-	-
	Technical	0.5	0.4	-	1.3	3.2
	Weather	0.6	1.7	-	0.1	-
Australia	Nameplate capacity	30.1	33.0	33.0	40.8	60.4
	Adjusted capacity	29.6	31.1	33.0	39.8	57.3
	Feedgas	-	-	-	-	-
	Security	-	-	-	-	-
	Technical	-	0.3	-	0.9	3.1
	Weather	0.5	1.7	-	0.1	-
Brunei	Nameplate capacity	9.8	9.8	9.8	9.8	9.8
	Adjusted capacity	9.8	9.8	9.2	9.2	8.8
	Feedgas	-	-	0.5	0.5	1.0
	Security	-	-	-	-	-
	Technical	-	-	-	-	-
	Weather	-	-	-	-	-
Indonesia	Nameplate capacity	46.2	46.2	43.5	42.0	43.4
	Adjusted capacity	34.1	34.5	29.4	27.7	32.0
	Feedgas	11.6	11.6	14.1	14.1	11.4
	Security	-	-	-	-	-
	Technical	0.5	0.1	-	0.2	-
	Weather	0.1	-	-	-	-
Malaysia	Nameplate capacity	35.0	35.0	35.0	35.0	35.8
	Adjusted capacity	35.0	35.0	35.0	35.0	35.8
	Feedgas	-	-	-	-	-
	Security	-	-	-	-	-
	Technical	-	-	-	-	-
	Weather	-	-	-	-	-
Papua New Guinea	Nameplate capacity	-	-	4.7	9.4	9.4
	Adjusted capacity	-	-	4.7	9.2	9.3
	Feedgas	-	-	-	-	-
	Security	-	-	-	-	-
	Technical	-	-	-	0.2	0.1
	Weather	-	-	-	-	-

Source: IEA analysis based on ICIS (2016), *ICIS LNG Edge* (see References section in Chapter 1).

Table 1 • Adjusted liquefaction capacity and outages by type (bcm) (continued)

Country	Capacity and Outages	2012	2013	2014	2015	2016
Middle East	Nameplate capacity	136.0	136.0	136.0	136.0	136.0
	Adjusted capacity	131.5	133.8	133.9	126.4	123.4
	Feedgas	1.7	1.7	2.1	2.5	2.5
	Security	2.4	-	-	7.0	9.1
	Technical	0.4	0.5	-	-	1.0
	Weather	-	-	-	-	-
Oman	Nameplate capacity	14.1	14.1	14.1	14.1	14.1
	Adjusted capacity	12.4	12.4	12.0	11.6	11.6
	Feedgas	1.7	1.7	2.1	2.5	2.5
	Security	-	-	-	-	-
	Technical	-	-	-	-	-
	Weather	-	-	-	-	-
Qatar	Nameplate capacity	104.9	104.9	104.9	104.9	104.9
	Adjusted capacity	104.5	104.4	104.9	104.9	103.9
	Feedgas	-	-	-	-	-
	Security	-	-	-	-	-
	Technical	0.4	0.5	-	-	1.0
	Weather	-	-	-	-	-
United Arab Emirates	Nameplate capacity	7.9	7.9	7.9	7.9	7.9
	Adjusted capacity	7.9	7.9	7.9	7.9	7.9
	Feedgas	-	-	-	-	-
	Security	-	-	-	-	-
	Technical	-	-	-	-	-
	Weather	-	-	-	-	-
Yemen	Nameplate capacity	9.1	9.1	9.1	9.1	9.1
	Adjusted capacity	6.7	9.1	9.1	2.1	0.0
	Feedgas	-	-	-	-	-
	Security	2.4	-	-	7.0	9.1
	Technical	-	-	-	-	-
	Weather	-	-	-	-	-
North America	Nameplate capacity	2.0	2.0	2.0	2.0	5.7
	Adjusted capacity	0.7	0.7	0.7	0.7	4.4
	Feedgas	1.4	1.4	1.4	1.4	1.4
	Security	-	-	-	-	-
	Technical	-	-	-	-	-
	Weather	-	-	-	-	-
United States	Nameplate capacity	2.0	2.0	2.0	2.0	5.7
	Adjusted capacity	0.7	0.7	0.7	0.7	4.4
	Feedgas	1.4	1.4	1.4	1.4	1.4
	Security	-	-	-	-	-
	Technical	-	-	-	-	-
	Weather	-	-	-	-	-

Source: IEA analysis based on ICIS (2016), *ICIS LNG Edge* (see References section in Chapter 1).

Table 1 • Adjusted liquefaction capacity and outages by type (bcm) (continued)

Country	Capacity and Outages	2012	2013	2014	2015	2016
Latin America	Nameplate capacity	26.6	26.6	26.6	26.6	26.6
	Adjusted capacity	26.0	26.6	26.3	25.7	24.5
	Feedgas	-	-	-	0.5	1.4
	Security	-	-	-	-	-
	Technical	0.6	-	0.2	-	0.7
	Weather	-	-	0.1	0.4	-
Peru	Nameplate capacity	6.1	6.1	6.1	6.1	6.1
	Adjusted capacity	6.1	6.1	6.0	5.6	5.4
	Feedgas	-	-	-	-	-
	Security	-	-	-	-	-
	Technical	-	-	-	-	0.7
	Weather	-	-	0.1	0.4	-
Trinidad and Tobago	Nameplate capacity	20.5	20.5	20.5	20.5	20.5
	Adjusted capacity	20.0	20.5	20.3	20.1	19.1
	Feedgas	-	-	-	0.5	1.4
	Security	-	-	-	-	-
	Technical	0.6	-	0.2	-	-
	Weather	-	-	-	-	-
Eurasia	Nameplate capacity	19.3	19.3	19.3	20.9	20.9
	Adjusted capacity	18.6	18.0	19.1	20.9	20.1
	Feedgas	-	-	-	-	-
	Security	-	-	-	-	-
	Technical	0.7	1.3	0.2	-	0.9
	Weather	-	-	-	-	-
Norway	Nameplate capacity	6.3	6.3	6.3	6.3	6.3
	Adjusted capacity	5.6	4.9	6.1	6.3	6.3
	Feedgas	-	-	-	-	-
	Security	-	-	-	-	-
	Technical	0.7	1.3	0.2	-	-
	Weather	-	-	-	-	-
Russia	Nameplate capacity	13.1	13.1	13.1	14.7	14.7
	Adjusted capacity	13.1	13.1	13.1	14.7	13.8
	Feedgas	-	-	-	-	-
	Security	-	-	-	-	-
	Technical	-	-	-	-	0.9
	Weather	-	-	-	-	-
Total	Nameplate capacity	379.8	388.4	397.6	417.8	444.8
	Adjusted capacity	345.4	349.7	349.8	356.6	380.2
	Feedgas	28.3	30.2	42.4	44.5	44.7
	Security	3.2	2.5	-	7.0	9.1
	Technical	2.3	4.3	5.4	9.1	10.7
	Weather	0.6	1.7	0.1	0.5	-

Source: IEA analysis based on ICIS (2016), *ICIS LNG Edge* (see References section in Chapter 1).

Table 2 • Demand Flexibility required by LNG importers (bcm)

Country	2011	2012	2013	2014	2015
Argentina	3.9	4.6	6.4	6.0	5.5
Brazil	1.0	4.1	5.7	7.3	6.5
China	-	3.2	5.5	-	-
Chinese Taipei	7.2	7.6	5.6	3.5	2.8
India	4.6	5.0	4.0	6.1	4.0
Japan	10.6	19.0	27.4	26.0	17.8
Korea	5.5	4.1	2.2	-	-
Thailand	0.4	0.7	2.0	1.8	1.0
Turkey	1.2	2.5	0.8	2.3	1.7
Others	2.8	1.4	0.9	1.9	9.1
Total	37.2	52.1	60.5	54.9	48.5

Table 3 • Flexibility provided by producers' uncontracted volumes (bcm)

Country	2011	2012	2013	2014	2015
Australia	-	0.2	2.3	2.3	-
Brunei	0.5	0.1	1.1	-	0.4
Equatorial Guinea	0.7	0.3	0.5	-	0.4
Malaysia	0.8	-	1.2	-	-
Peru	4.1	-	0.5	0.2	-
Qatar	10.3	7.5	7.9	3.9	8.8
Russia	2.2	1.7	1.4	1.3	2.1
United Arab Emirates	1.5	1.3	0.5	1.9	1.4
Others	-	-	0.6	0.5	0.9
Total	20.1	11.2	16.1	10.1	13.9

Table 4 • Over-contracted position of LNG importers (bcm)

Country	2011	2012	2013	2014	2015
Belgium	1.4	3.3	4.3	4.6	3.8
China	1.3	-	-	4.2	7.6
France	3.7	8.0	9.5	11.2	11.6
Italy	-	-	-	0.3	-
Korea	-	-	-	4.8	4.3
Mexico	7.6	6.6	4.9	3.5	4.7
Spain	8.1	10.9	14.9	14.1	16.4
United Kingdom	-	3.2	7.9	7.1	0.7
United States	10.3	13.7	15.8	16.9	16.0
Others	0.9	5.4	6.9	6.6	6.4
Total	33.3	51.2	64.1	73.2	71.4

Table 5 • Flexibility provided by diversions (bcm)

Country	2011	2012	2013	2014	2015
Algeria	-	0.2	0.8	2.1	3.1
Nigeria	0.9	4.6	3.8	8.4	7.4
Oman	0.4	0.2	-	0.5	1.6
Peru	-	3.1	2.4	0.5	0.6
Trinidad and Tobago	0.5	1.8	2.4	2.3	0.6
Others	0.5	-	-	0.6	2.4
Total	2.4	9.9	9.4	14.6	15.7

Table 6 • Breakdown of contracted volumes from portfolio players by type of contract (bcm)

Country	2011	2012	2013	2014	2015	2016
Long-term	24.5	27.3	38.4	51.8	68.5	76.2
Medium-term	8.6	13.5	17.9	12.0	12.6	16.3
Short-term	3.9	8.5	6.4	7.0	4.5	3.3
Total	37.0	49.4	62.7	70.8	85.6	95.9

Table 7 • Contracted volumes from portfolio players by country (bcm)

Country	2011	2012	2013	2014	2015	2016
Chile	5.0	5.0	6.5	6.5	6.5	7.2
China	2.7	2.7	3.6	8.9	15.8	19.9
Dominican Republic	1.4	1.4	1.4	1.4	1.4	1.4
India	2.0	2.9	4.3	2.4	5.5	5.6
Japan	2.4	9.2	7.2	8.6	13.6	13.9
Korea	7.1	6.6	11.3	15.3	14.2	10.3
Kuwait	2.4	2.4	2.4	2.1	2.1	4.8
Mexico	5.4	5.4	6.3	6.3	5.4	5.4
Puerto Rico	0.8	1.8	1.8	1.8	0.8	0.8
Singapore	-	-	4.1	4.1	4.1	4.1
Spain	3.8	4.3	4.3	4.3	4.3	4.3
United Arab Emirates	1.4	1.4	1.4	1.4	1.4	1.4
Others	2.6	6.2	8.2	7.7	10.7	16.8
Total	37.0	49.4	62.7	70.8	85.6	95.9

Table 8 • Gas supply to Europe (bcm)¹

	2011	2012	2013	2014	2015	Average 2011-15	Jan-Aug 2015	Jan-Aug 2016
Norway	93	106	102	103	113	104	74	74
Russia	154	145	165	150	159	155	102	111
<i>Direct</i>								
Nord Stream (Germany)	1	11	24	34	38	27 ²	24	28
Blue Stream (Turkey)	14	14	13	14	15	14	10	8



Estonia, Latvia and Finland	6	6	6	5	4	5	3	
<i>Transit</i>								
Yamal ³	34	35	40	39	38	37	25	26
Brotherhood/Soyuz ⁴	81	62	64	41	47	59	30	36
Trans Balkan Pipeline ⁵	18	17	18	17	16	17	10	11
Africa	34	40	34	29	30	33	17	25
Algeria	31	33	28	23	23	28	15	22
Libya	2	6	6	7	7	6	2	3
Caspian region	12	12	13	15	14	13	9	9
Azerbaijan	4	3	4	6	6	5	4	4
Iran	8	8	9	9	8	8	5	5
LNG import⁶	86	66	47	45	52	59	34	34

¹ Europe includes OECD Europe, EU member countries, Albania, Bosnia and Herzegovina, Former Yugoslav Republic of Macedonia, Kosovo, Montenegro and Serbia. It excludes Norway to show pipeline exports from Norway to other European countries.

² Average over 2013-2015; Nord Stream reached full capacity in Q4 2012.

³ Includes deliveries to Lithuania.

⁴ Includes deliveries to Romania.

⁵ Excludes deliveries to Romania.

⁶ Net LNG imports (corrected for reloading). Norwegian LNG exports are not taken into account.

Sources: IEA (2016b), *Natural Gas Information* (database); IEA (2016c), *Monthly Gas Data Service*; IEA (2016d), *Gas Trade Flows* (database); public TSO data (see reference list chapter 5).

Acronyms and abbreviations

ACQ	annual contract quantity
ASEAN	Association of Southeast Asian Nations
CCGT	combined-cycle gas turbine
CFE	Comisión Federal de Electricidad (Mexican Federal Commission of Electricity)
CHP	combined heat and power
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
COP21	21 st Conference of the Parties
D	day
DES	delivery ex ship
EU	European Union
EU28	28 member states of the European Union
FID	final investment decision
FLNG	floating LNG
FOB	free on board
FSRU	floating storage and regasification units
FY	fiscal year
GIIGNL	International Group of Liquefied Natural Gas Importers
GTS	Gasunie Transport Services
H-gas	high-calorific gas
HH	Henry Hub
IEA	International Energy Agency
INDC	Intended Nationally Determined Contribution
JAPEX	Japan Petroleum Exploration Company
KOGAS	Korea Gas Corporation
KUFPEC	Kuwait Foreign Petroleum Exploration Company
L-gas	low-calorific gas
LNG	liquefied natural gas
MENA	Middle East and North Africa
MLNG	Malaysia LNG
NL	Netherlands
NO	Norway
OECD	Organisation for Economic Co-operation and Development
SLNG	Singapore LNG Corporation
SNH	Société Nationale des Hydrocarbures
SPA	sales and purchase agreement
ToP	take-or-pay
TSO	transmission system operator
TTF	title transfer facility
UK	United Kingdom
US	United States
USD	US dollars
WGV	working gas volume
Y	year
y-o-y	year-on-year

Units of measure

Bcm	billion cubic metres
GW	gigawatts
MBtumillion	British thermal units
Mcm	million cubic metres
Mtoe	million tonnes of oil equivalent
TWh	terawatt-hours

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Global Gas Security Review 2016



How Flexible are LNG Markets in Practice?

As the energy system becomes more globalised and interconnected, gas security challenges are evolving.

The current period of gas oversupply – driven by overcapacity in the LNG market – should not overshadow the critical importance of global gas security.

Global Gas Security Review 2016, the first edition of a new annual series, examines the evolving global gas market structures and looks at the market's ability to respond to potential shocks. It shows that the current situation could lead to a false sense of comfort about gas security, which could evaporate quickly once market conditions change.

The report also analyses how LNG markets responded to the Fukushima accident through case studies focusing on Japan and Europe. Both regions have fuel-switching potential but also face structural changes as coal and oil-fired capacity retires, affecting the gas market's flexibility to respond to overall shocks.

Global Gas Security Review 2016 also addresses two critical forward-looking questions: how much redundancy is embedded in the LNG upstream and liquefaction chain, and how flexible is LNG production?