SECURITY OF GAS SUPPLY: EUROPEAN SCENARIOS, POLICY DRIVERS AND IMPACT ON GB

A report to Department of Energy and Climate Change

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EXECUTIVE SUMMARY

Having secure supplies of gas is of vital importance to many parties: the UK government, regulators, industry participants and consumers. However, despite recent sizeable investments in pipelines with Norway and continental Europe as well as in LNG import capacity, concerns continue to be voiced about the adequacy of the Great Britain's (GB) security of gas supply and the ability of existing physical and regulatory arrangements to mitigate supply disruptions. This is inextricably linked to its increasing dependence on imports, and its inter-relationship with the rest of Europe. In this context, relations with major pipeline suppliers to Europe, such as Russia, become important.

DECC commissioned Pöyry to undertake a detailed qualitative and quantitative analysis of the key risk factors affecting the security of gas supply in relations to supplies coming from the European market. We analysed the supply-demand situation, including under severe winter conditions and high demand in Europe and GB, and performed a series of viable stress tests and supply shocks to pipeline gas to Europe in order to evaluate the resilience of the GB gas market and to estimate the impact on wholesale gas prices.

The scenarios Pöyry modelled and a summary of their outcomes are shown in Table 1. Given the moderate investment in capacity we have assumed is constructed, security of GB gas supply is shown to be maintained under a combination of a severe winter and **two** prolonged outages to pipeline supplies through Ukraine and via Sleipner from Norway in all the scenarios until 2024/25.

The Nord Stream pipeline, from Russia to Germany, provides a significant contribution to GB's security of supply by allowing Russian gas supplies to reach NW Europe under circumstances where there is a disruption to supplies through Ukraine. If Nord Stream is delayed, GB's reliance on the LNG market is increased during supply disruptions and prices pushed up further than would otherwise be the case. If Nord Stream phase 2 is cancelled, the impact of outages is considerably increased and more demand side response is required in GB.

Gas quality problems are not clearly identified as a threat through the modelling, although prices peak higher when continental imports are not available. However, security is maintained through increased dependence upon imports directly from Norway and/or via the world LNG market, so gas quality problems do increase GB's vulnerability.

It is clear that disruptions to gas markets which influence the world LNG market have an increased impact upon GB, especially as GB's dependence on LNG becomes more significant. In the case of the scenarios modelled, these are: Italy, Greece and France. Projects that help ensure the security of these states, reduces the likelihood of high prices in GB, and these include the South Stream and Nabucco projects.

Under a sensitivity of very high GB demand (up to around 120bcm) and high European demand there would be a need for significant new gas facilities from 2020, thus highlighting the importance of current energy efficiency policies.

It is therefore our opinion that, under most circumstances, Britain has sufficient capacity and diversity of supplies of gas. It is sufficiently resilient to the security of supply risks posed by interconnections to and the major pipeline supplies to Europe. However, should gas demand rise significantly in GB or across the rest of Europe there will be more pressure on gas security of supply, such that more pipeline and LNG import capacity will be required.

In the report, we make a number of policy recommendations on how to further gas security of supply, but our overarching conclusion is that no dramatic changes are required to the existing policies with respect to European supplies.

Table 1 – Summary table of scenario outcomes

	Weather severity	Event	Additional sensitivity		Base case	High European demand	High GB demand	High GB and European demand
	'Typical'	None		2009/10				
				2014/15				
				2019/20				
				2024/25				
				2029/30				
STRESS TESTS	'Severe'	1. Ukraine off (Oct-Mar)		2009/10				
				2014/15				
				2019/20				
				2024/25				
				2029/30				
	'Severe'	1a. Ukraine off (Oct-Mar) & N Stream delayed		2009/10				
				2014/15				
				2019/20				
				2024/25				
				2029/30				
	'Severe'	2. Ukraine off & Sleipner off (Oct-Mar)		2009/10				
				2014/15				
				2019/20				
				2024/25				
				2029/30		*		
	'Severe'	3. Gas out of UK spec – **no** I/C imports		2009/10				
				2014/15				
				2019/20				
				2024/25				
				2029/30				
Additional sensitivities under stress test 2	'Severe'	2a. Ukraine off & Sleipner off (Oct-Mar)	Gas out of UK spec – **no** I/C imports	2009/10				
				2014/15				
				2019/20				
				2024/25				
				2029/30				
			Nabucco under supplied	2009/10				
				2014/15				
				2019/20				
				2024/25				
				2029/30				
			No phase 2 Nord stream	2009/10				
				2014/15				
				2019/20				
				2024/25		*		
				2029/30		*		

Scenario not modelled
Scenario modelled and no penal prices
Scenario modelled and there are penal prices and * indicates demand side response in GB
Scenario modelled and there are penal prices and unserved energy in GB

1. INTRODUCTION

1.1 Overview

Gas security of supply is a significant issue that faces the Government, industry participants and consumers. Significant investments in pipeline and LNG import capacity, have taken place in recent years. However, some concerns remain that the UK may not have adequate security of supply to mitigate supply disruptions, particularly in light of increasingly diverse sources of gas.

This issue has been examined by the Government on a number of occasions in recent years. Various elements of the security of gas supply issue have been considered, including the potential need for strategic storage and cost/benefit analyses of potential measures for improving security of gas supply. These studies have broadly concluded that with the infrastructure being delivered in GB there has been no material likelihood of systematic breaches of gas security of supply, but have recommended additional measures to mitigate risks.

Most recently, GB gas security of supply has been examined by:

- The Wicks Review – which reached a number of conclusions in relation to the security of UK gas supply, including that the Government should foster relations with major gas producing countries (Norway and Qatar) to facilitate future imports and that there might still be a case for further consideration of strategic storage; and
- Project Discovery – the Ofgem study, which included consideration of gas security of supply issues, and, under its ‘Dash for Energy’ scenario, concluded that there would be a sharp increase in GB’s gas import dependence and that gas supply would be tight and gas prices high.

A key issue, when considering GB’s gas security of supply, is the increasing dependence on imported supplies and crucially the trade in gas between GB and continental Europe including Norway. Governments, international bodies and market players are already working to address European security of supply problems, including the implementation of the third energy directive, the EU Regulation on Gas Security of Supply[1] and major new infrastructure projects. These include new pipelines from Russia, Algeria, the Caspian region, LNG terminals, interconnectors and storage.

There is a large degree of flexibility around the volumes of gas sent by Norway or by LNG to either GB or continental Europe. It could be argued that European Member States also compete for gas with GB, particularly in times of stress. There is thus some uncertainty regarding how the above measures will perform and markets would react in such situations.

DECC has therefore commissioned this study to provide a detailed qualitative and quantitative analysis, including what a realistic ‘High European demand case’ scenario would look like, what its impact on GB could be, what risks or combination of risks pose

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1 It has suggested a so-called ‘N-1 rule’ for gas supply security, whereby European Member States must provide that they are able to withstand the loss of their major gas import route and continue to provide gas supply to domestic (or, otherwise-defined, high priority) customers. The details of the draft Regulation are expected to be finalised in spring 2010.

the greatest threat to UK security of supply or price levels (and volatility) and how might those be best mitigated against.

The scope of this study is to answer the following questions:

- What are the key risks or combination of risks arising from the European gas market that could impact on GB's security of supply?
- How stress-tests in a baseline and worst-case state of the world affect UK security of supply?
- What are the EU or UK policies that might impact on the drivers and risks, so as to increase UK security of supply?

1.2 Structure of this report

This study undertakes a detailed quantitative analysis of the European market to assess how it will react in the future under a number of different scenarios given severe demand conditions and certain physical and regulatory constraints. This analysis helps explain the risks on security of gas supply particularly in relation to GB and identifies policy areas which the Government should concentrate its efforts domestically, bilaterally or in shaping EU policies to improve the UK security of gas supply.

The report is structured as follows:

- in Section 2 we provide an overview of the European gas markets, including their structure, gas demand by sectors, current sources of supply and the development of trading hubs;
- in Section 3 we describe the key risk factors to the security of gas supply in Europe, including a detailed examination of the planned production of gas from the enormous reserves in Russia;
- in Section 4 and Section 5 we describe our approach to modelling the risk factors and the development of scenarios and stress tests, and present the outcomes; and,
- Section 6 outlines the policy options available and how they could impact upon security of supply to GB.

1.3 Conventions

1.3.1 Europe

Throughout this report reference to Europe should be taken to mean the European countries covered by our Pegasus model, more details of which can be found in Annex A. Within the Pegasus structure gas flows to Northern Ireland and the Republic of Ireland are treated as being in the same zone and separate from GB.

1.3.2 Sources

Where tables, figures and charts are not specifically sourced they should be attributed to Pöyry Energy Consulting. All data is in gas years (where the year '2009' runs from 1 October 2009 to 30 September 2010), unless specified.

2. MARKET OVERVIEW

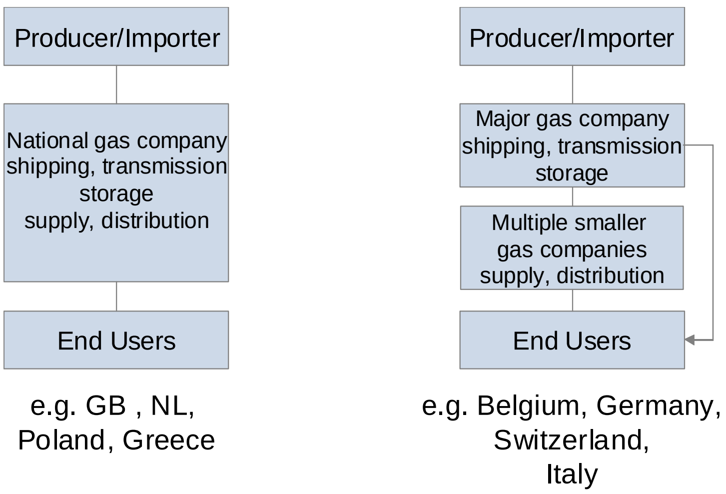
The gas markets across Europe have developed in various ways and at different pace based on their political structures, access to gas supplies and gas usage. The liberalisation of energy markets that started in the north-west of Europe has gradually spread, but all markets are currently at different points in the liberalisation process. Many countries are still dominated by the incumbents that own both networks and supply businesses, while others have a variety of suppliers and have embraced the trading of gas at hubs.

In this section we provide an overview of how the markets across Europe have developed in recent years and their relative sizes. In terms of the UK security of supply, we also look at the current sources of gas, both to Europe and the UK, with particular attention to the development of trading hubs and access to flexibility, two key aspects of functioning markets.

2.1 Market structures

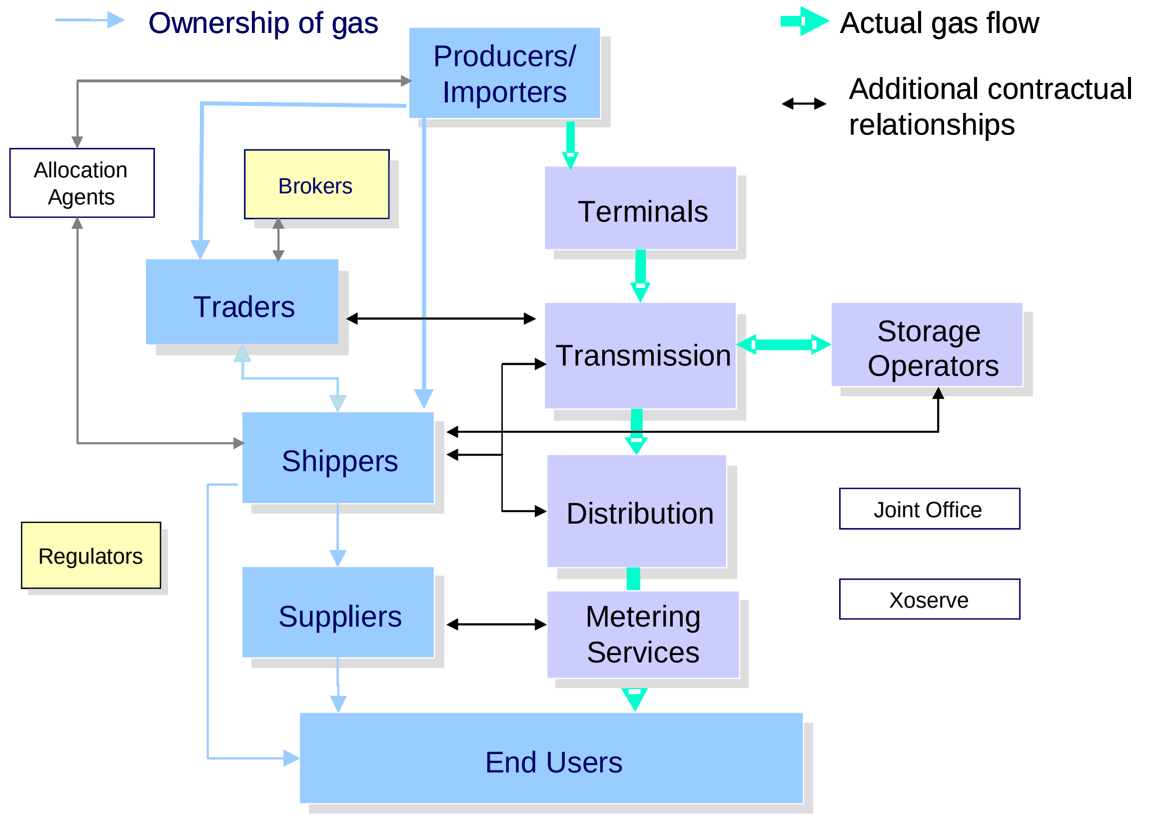
In the past, there have been two main structures present in Europe, which are represented in Figure 1. One of these had a centralised national gas company which handled not only shipping, transmission and storage, but also supply and distribution. In the other, the supply and distribution elements of the supply chain were split out and were the preserve of multiple smaller gas companies.

Figure 1 – Traditional market structures



However, there have been changes in the last 15 years or so either due to specific initiatives from Member States, such as GB, or due to requirements set out by the EC through its directives to develop an integral gas market across the EU. These new market structures can at first sight be more complex, as illustrated by the GB market structure in Figure 2. However, they allow far greater levels of transparency across the value chain, and thus either better regulation (where the service is provided by a monopoly) or more efficient price discovery (where there is competition for gas supply).

Figure 2 – GB gas market structure



Through the First[2] and Second[3] gas directives, most countries have been moving towards a similar market structure, although the differentiation between shippers and suppliers, and the separation of metering services from distribution have not been considered necessary in many places. Additionally, only the Third package[4] has introduced a requirement for separating storage from shippers/suppliers. In many cases the main transmission and/or distribution companies have the same parent company as the dominant shipper/ supplier.

In most countries there are just one, or maybe two, gas transporters. The main exception is Germany where there are eighteen transportation networks. This initially caused problems in relation to disaggregation; however, the system operations have been merged and since October 2009 there have been three hi-CV gas and three low-CV gas balancing areas each with their own standard rules.

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2 EU Gas Directive 98/30/EC dated 22 June 1998.

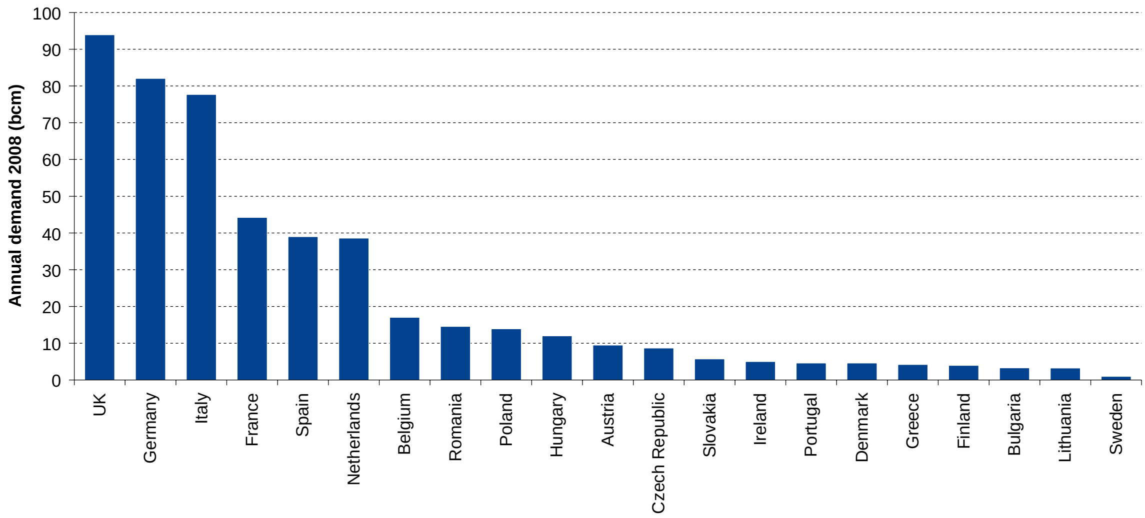
3 EU Gas Directive 2003/55/EC dated 26 June 2003.

4 EU Gas Directive 2009/73/EC dated 13 July 2009.

2.2 Gas demand

In the context of European gas demand, the UK and Germany have the highest demand, followed by Italy, France, the Netherlands, Poland and Spain, as shown in Figure 3.

Figure 3 – European gross gas demand by country in calendar year 2008



Source: IEA

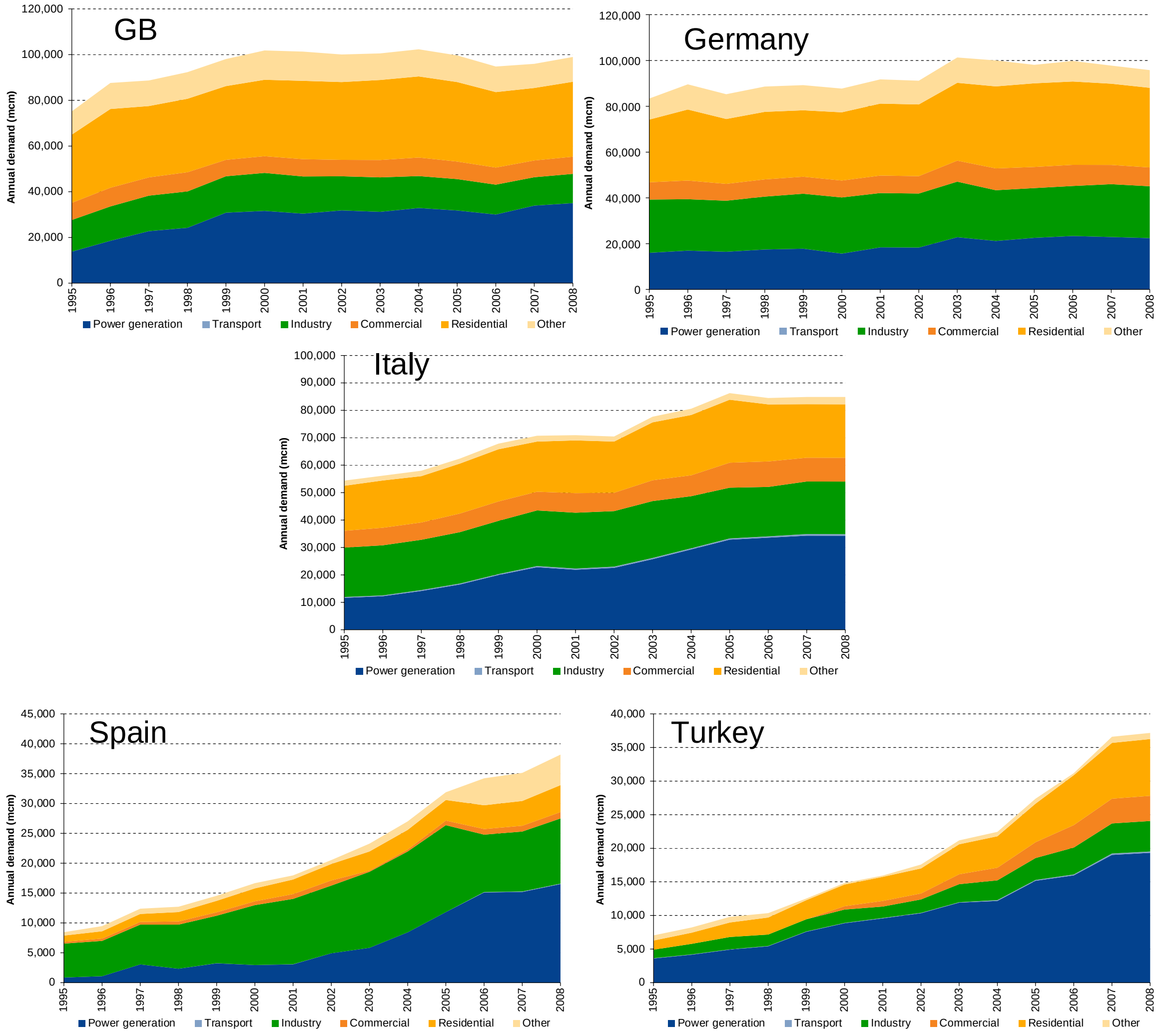
Much depends on population size, industrial intensity, the power generation mix and access to cheap supplies. Moreover, as mentioned above, all these markets are at different stages of development. There are three main types of markets in the context of their gas demands: established (e.g. Germany and GB), transient (e.g. Italy) and growth markets (e.g. Spain and Turkey). Details are provided in Figure 4.

In Germany and GB, the two largest European gas markets, the focus has been largely on the residential sector. In conjunction with this, GB has in the last 20 years seen an upsurge in gas demand from power generation, adding over 15bcm in demand between 1995 and 2005. This growth in power generation demand – seen to a lesser extent in Germany – arises as the industrial demand plateaus and starts to decline. However, the German industrial sector has a higher market share than any other country observed here.

Italy has traditionally been a user of gas, especially in the industrial sector. It has not seen large increases in general gas usage apart from growth coming from power generation.

Turkey and Spain are typical growth markets. Both have seen expansion across all market segments especially in the power generation sector. In Spain, this expansion has happened at the same time as significant investments were made in renewables, including wind and solar power. The Turkish gas market has the potential to grow even further, depending on future CCGT build and its expanding population.

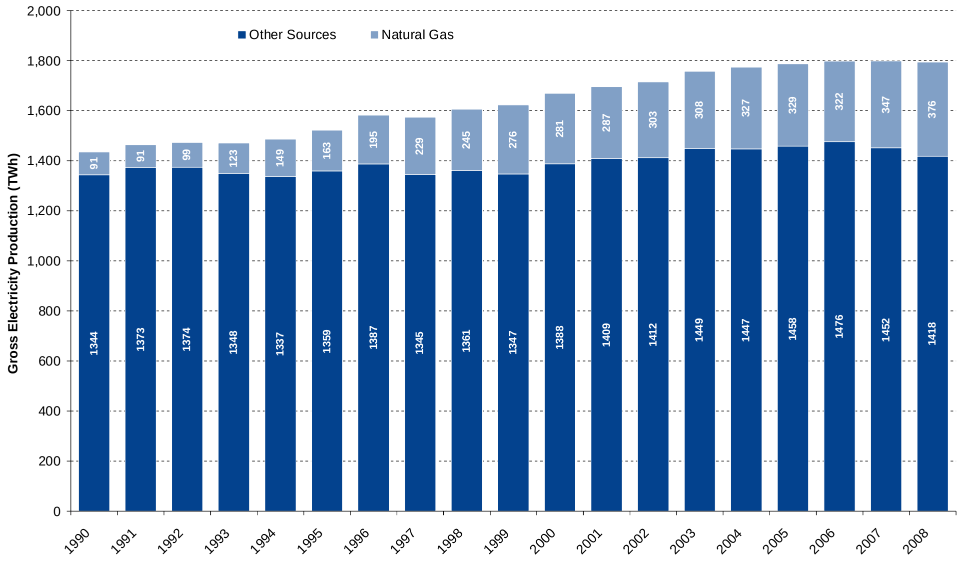
Figure 4 – Sectoral gas demand in GB, Germany, Italy, Spain & Turkey to 2008



All values are in calendar years

A key expansion across Europe during this time has been the growth of gas-fired power generation. As can be seen in Figure 5 there has been an 80 % increase across North-West Europe between 1990 and 2008. This has been attractive because: they are relatively fast and cheap to build; have a higher energy efficient technology of around 50%; have less environmental regulation risk as they emit lower CO2 per KW when compared to coal, and positive economics at intermediate loads. In addition, gas sellers, looking for new growth segments, have found the power sector a keen buyer, while the owners of both assets have been able to capture value from spark spread arbitrage opportunities.

Figure 5 – North-west European power generation



Source: IEA and Pöyry analysis; all values in calendar years

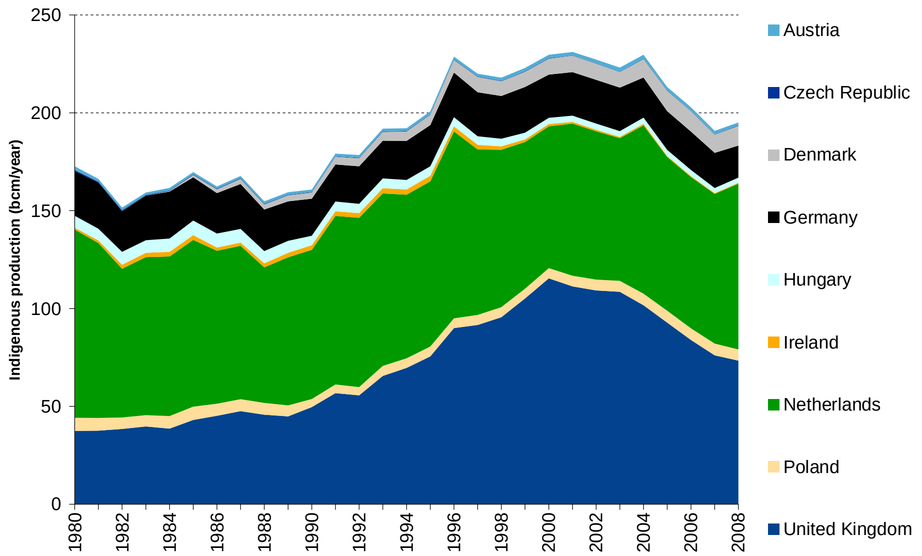
2.3 Gas supply

Gas is supplied from indigenous sources and from pipeline and LNG imports. This section describes the sources of gas that are available to meet European gas demand.

2.3.1 Indigenous supplies

Historically, the EU has had two main sources of indigenous supplies: GB and the Netherlands, as seen in Figure 5.

Figure 6 – Europe indigenous supplies



Source: IEA and Pöyry analysis; all values in calendar years

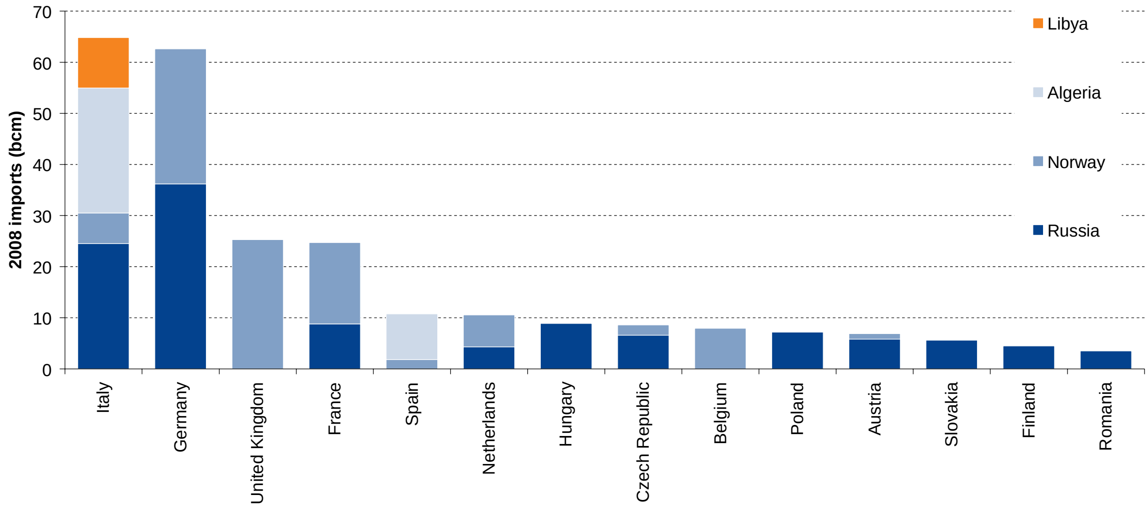
Both countries were self-sufficient in gas and exported it to other countries in Europe. GB has had significant supplies from the UKCS and the East Irish Sea, while the Netherlands has had the giant Groningen low CV field. The Netherlands has also promoted the development of small offshore fields through a targeted development policy.

However, the depletion of indigenous supplies has already led to a greater emphasis on imports for the UK, which has significantly higher gas demand than the Netherlands.

2.3.2 Pipeline imports

In 2008, Italy was the largest importer of pipeline gas from the sources outside of the EU; this was closely followed by Germany. Figure 7 also highlights that for all countries, apart from Italy, there is very little diversity in supply options, with all having only one or two sources. Such dependence raises the security of supply concerns, although the level of indigenous production, access to LNG and interconnection between the markets help to reduce such dependence. Whilst most of Europe's gas comes from Russia and Norway, the role of North Africa will increase with the start-up of new pipelines, such as Medgaz and Galsi, that will link it to Spain and Italy.

Figure 7 – Pipeline imports into Europe, calendar year 2008

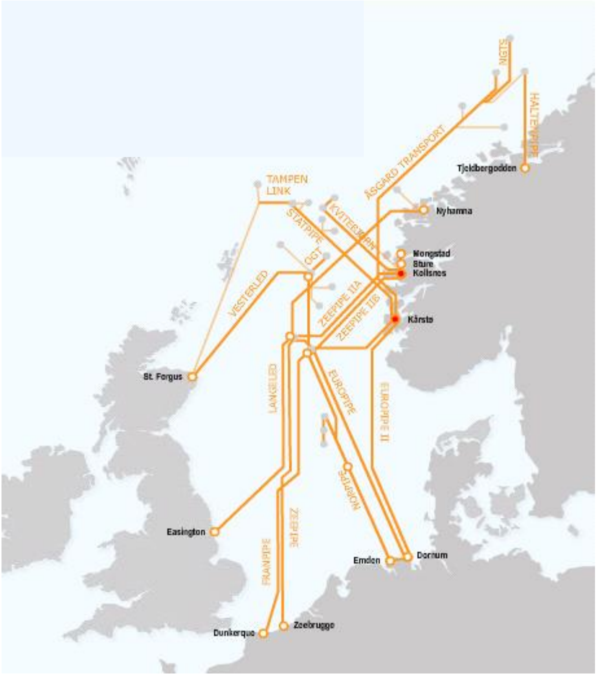


Source: BP Statistical Review of World Energy 2009

Norway is and will remain a significant supplier of gas to the EU and the UK. Norwegian gas production has risen steadily over the last 20 years and a network of offshore pipelines has been developed to enable it to supply Germany, Netherlands, Belgium, France and the UK, as shown in Figure 8 overleaf.

This network also allows Norwegian producers to control flows into different markets according to contractual commitments, maximise value based on different market prices and support supplies when fields trip. Politically motivated interruptions of supply from Norway are not an issue, while a robust E&P programme is aimed at ensuring reserves recovery and the sustainability of production. However, the levels of investment in E&P will need to be maintained if production is to remain relatively stable in the period to 2030. Moreover, technical problems and outages at fields cannot be ruled out, as was the case in the winter of 2009/10. These can be expected to be relatively short-lived, but we examine the effect of potential Norwegian outages in our modelling in Section 5.

Figure 8 – Norwegian gas infrastructure

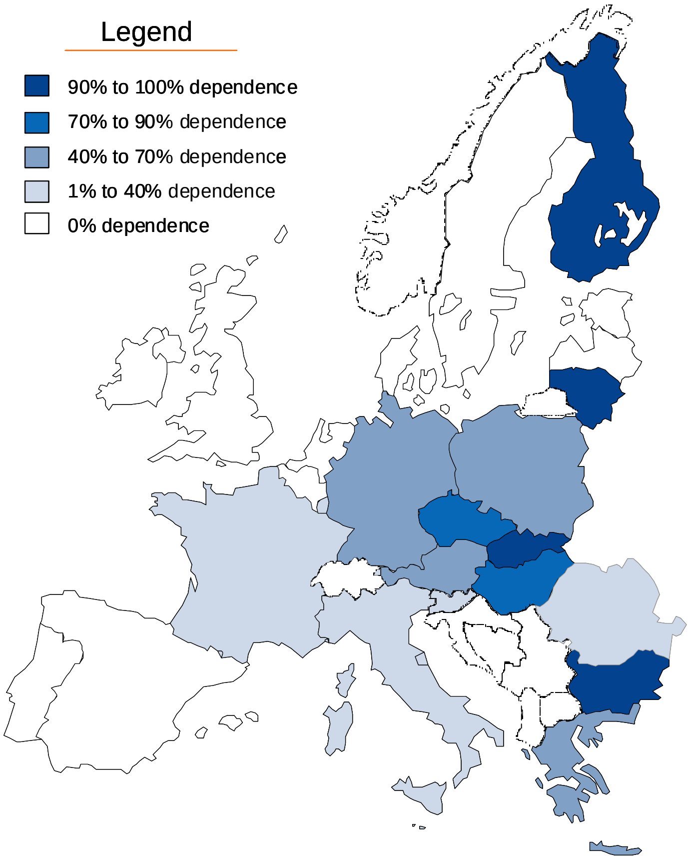


Source: GASSCO

Russia has the largest gas reserves in the world and has supplied West European markets since 1969. It now annually supplies some 160bcm of gas to the EU. Most of the markets in Central and Eastern Europe are almost entirely dependent on supplies from Russia, as shown in Figure 9 overleaf. State-owned gas company Gazprom has a monopoly on gas exports from Russia – the so-called ‘unified export channel’. Together with long-term contracts that govern the relationships between Gazprom and its customers in Europe, the unified export channel from Russia restricts European buyers in negotiating competitive supplies. The reliance on a single producer has a big impact on the security of supply in the region, particularly given the precarious relationships Russia has with the transit states, most notably Ukraine, through which the bulk of its gas must flow to be delivered to Europe. This is discussed further in Section 3.4.

Italy and Spain import gas through pipelines from North Africa with one connection already established between Algeria and Spain, and two connections – one from Libya and one from Algeria via Tunisia – to Italy. Algeria exports some 43bcm/annum of gas to Europe by pipeline, but this volume will increase in 2010 following the completion of the Medgaz pipeline to Spain. This is discussed further in Section 3.6.2. The state-owned gas company, Sonatrach, must be involved in each gas contract, but there are a number of partners in the developments. This again raises security of supply concerns, but there have been no politically motivated disruptions of supplies from Algeria. However, during the Algerian civil war (1991-98), attacks by militants on the oil and gas sector were not unusual, raising concerns about the adequacy of security measures in place and the ability of the government to protect major fields in desert locations, such as the Hassi R’Mel field that supplies the pipelines to Europe. Although the security situation is currently far more stable, the risk of a terrorist attack cannot be ruled out and the state of emergency, imposed in 1992, remains in place to the present day.

Figure 9 – Countries reliant on Russian supplies (calendar year 2008)



Source: BP World Statistics 2009

2.3.3 LNG imports

LNG has become a key new supply of gas across Europe. Figure 10 shows the level of imports in 2008. Recent changes to the Spanish gas market and the expansion of re-gasification terminals there have seen it becoming the leading importer of LNG. This has been followed by France.

GB imported very little LNG during 2008, but the situation changed in 2009, as shown in Figure 11. New LNG re-gasification terminals at Milford Haven were commissioned in 2009 and gas was delivered on a regular basis from Qatar to South Hook. In addition, many more spot cargos were delivered to the Isle of Grain and Dragon terminals. The import capacity expanded further in 2010 when the second phase at South Hook was completed in April. The third phase of Isle of Grain is on target to be completed by the winter of 2010/11. Details of how LNG impacts the market can be found in our global gas and LNG markets report.[5]

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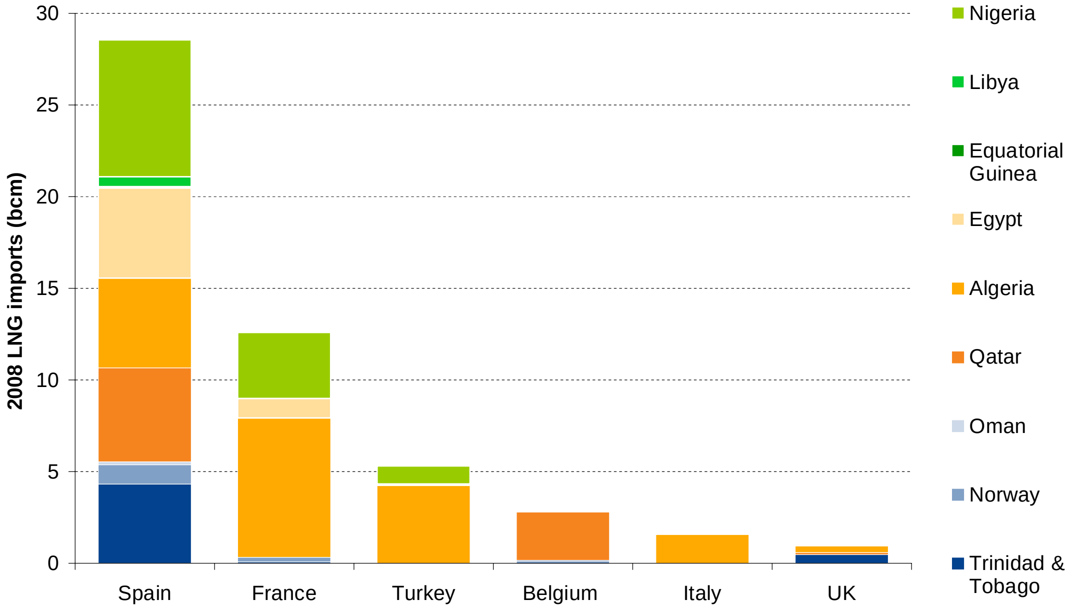
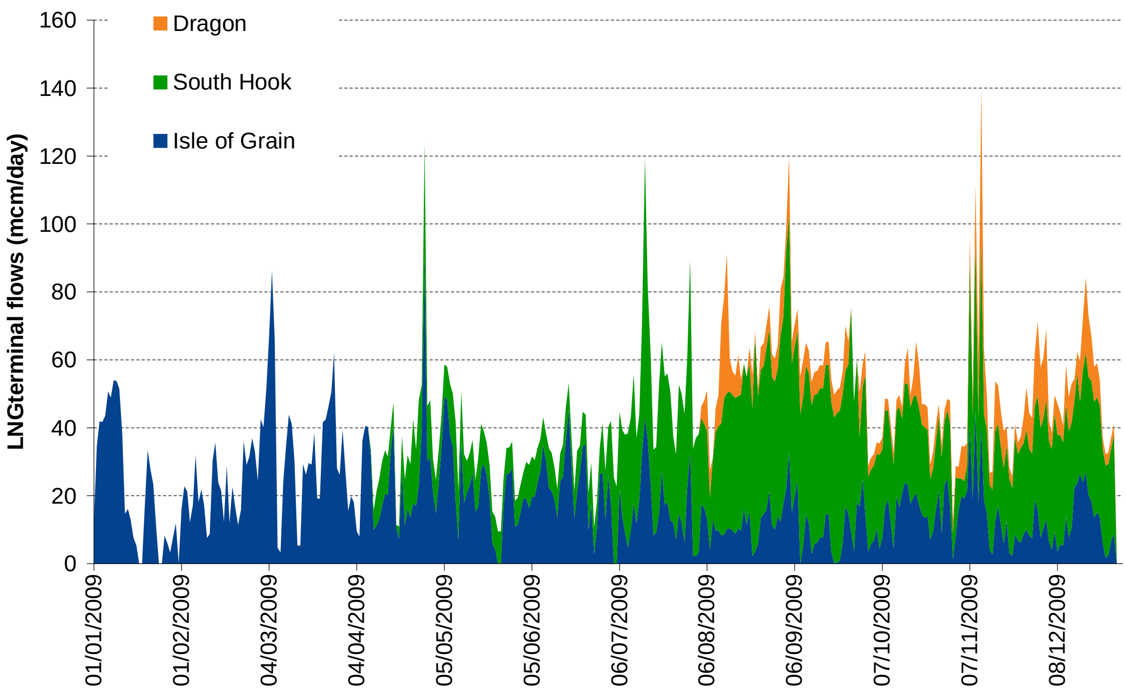
5 'Global Gas and LNG Markets and GB's Security of Supply' a report to DECC, June 2010.

Figure 10 – LNG imports into Europe in calendar year 2008



Source: BP Statistical Review of World Energy 2009

Figure 11 – LNG flows into GB during calendar year 2009



Source: National Grid

2.4 Development of trading

Despite the presence of EU directives in 1998 and 2003 that were aimed at opening the European gas market, competition has been limited by the lack of gas available on short-term contracts. To resolve this, there are a number of hubs around Europe where trading of gas may occur. Whilst most of the trading is OTC, many of the hubs also have exchanges for clearing futures and short term trades.

Of the hubs shown in Figure 12, the NBP, established in 1996, is the most liquid. Other hubs, including the TTF (or Title Transfer Facility) in the Netherlands and Zeebrugge in Belgium, are also growing in liquidity, but they are still some way off in approaching the scale of the NBP. This can be seen in Figure 13, where the three most transparent and liquid hubs are shown. Transparency issues still dog the other hubs, but we foresee this problem easing into the future.

Whilst the NBP, where 65% of gas entering GB is traded, has a daily cash-out with no tolerance to incentivise shippers to trade all imbalances, the rest of NWE has hourly and/or daily balancing with tolerances.

On the Continent, the TTF has grown to become the most liquid hub, and the main reference point for continental Europe. It is then followed by the Zeebrugge hub, which differs from the NBP and the TTF in that it is a physical location, as opposed to a virtual trading point. Virtual hubs are relatively easier than physical hubs for traders to operate in, due to the guarantee of delivery and the lack of requirement for traders to obtain capacity.

Figure 12 – Hub trading

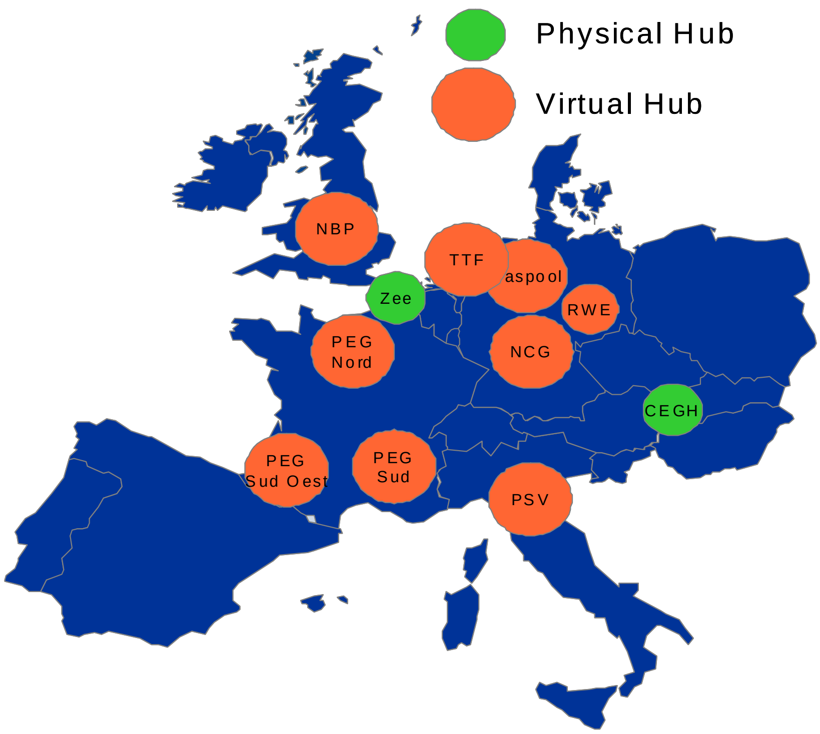
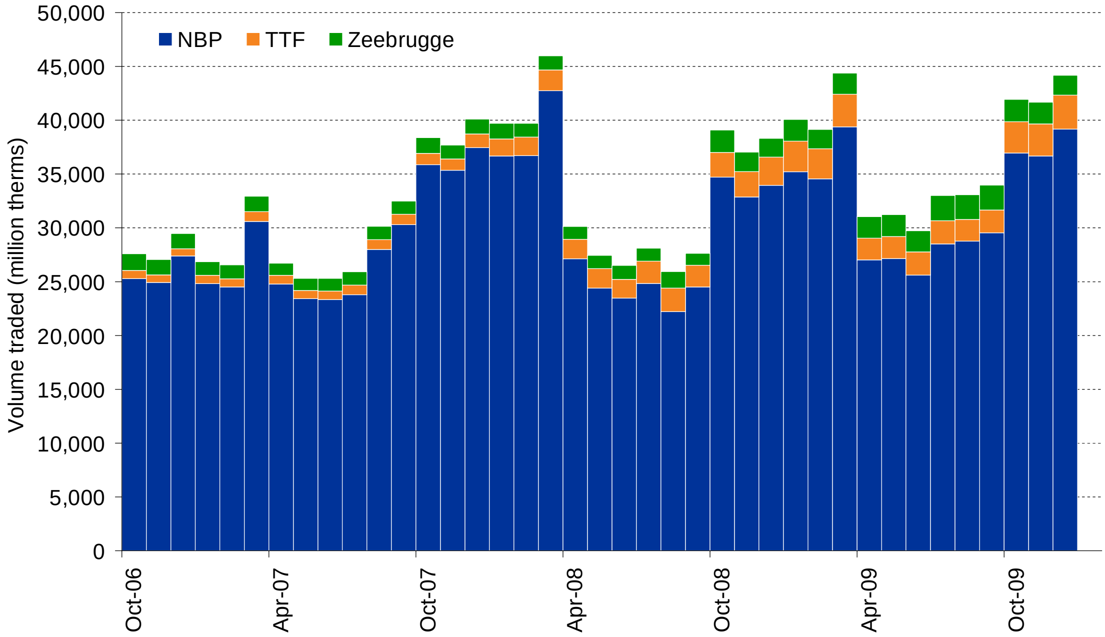


Figure 13 – Hub flows for the most liquid hubs



Source: Huberator, APX, National Grid.

Liquidity in the European spot gas markets is currently still concentrated in GB. Trading activity in other countries remains low but the potential for liquidity improvement is huge. To this end, France and Germany are reducing the number of market areas in anticipation that this will consolidate volumes and number of participants in their hubs.

2.5 Sources of flexibility

Every gas market requires a range of different types of flexibility. These can be categorised by the period over which the variation in supply is required – that is, seasonal, weekly, daily and hourly. The sources of these types of flexibility range from flexible contracts to compressed gas bullets and this section summarises a selection of the more common measures and presents them in Table 2 overleaf.

LNG terminals in GB and Belgium import flexibility from other markets around the world through Atlantic arbitrage opportunities. The large volumes of North American gas storage facilities effectively allow some of their flexibility to enter the global LNG market.

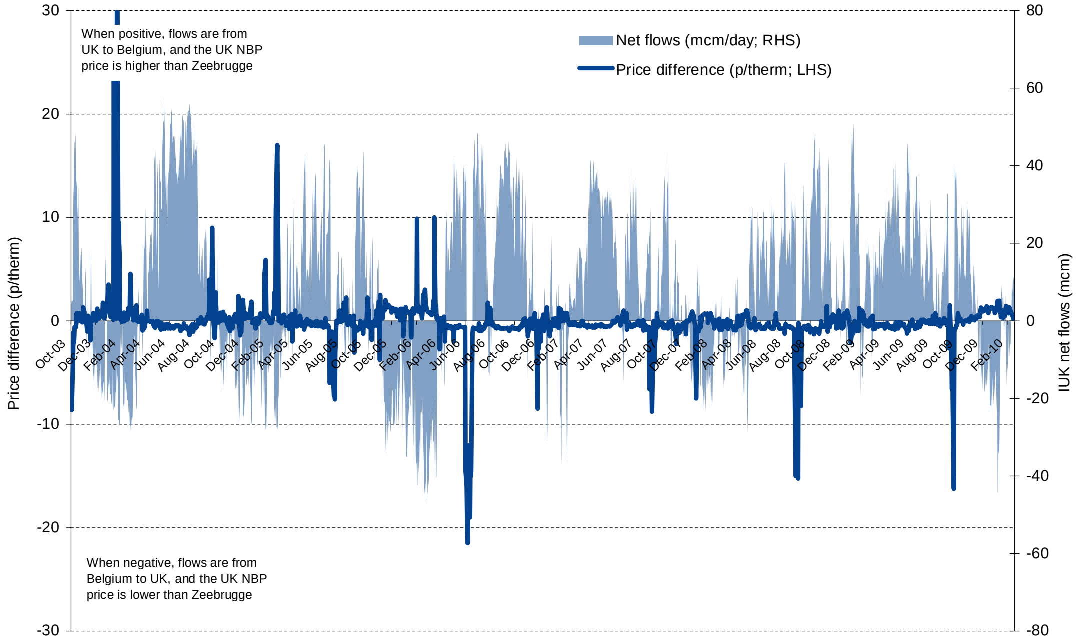
There is a limited scope for flexibility from pipelines entering Europe from Norway and Russia due to contractual issues and the long distances involved. Nevertheless, some flexibility can be derived from the interconnecting pipelines between European states, through price relativities resulting in interconnector flows. Figure 14 overleaf show the difference in price between the traded hubs in Belgium and GB, and the accompanying flows through the interconnector.

Figure 15 on page 17 highlights the use of the interconnectors during the Ukrainian crisis in the early months of 2009. It also highlights how, during the second half of February 2009, the IUK was flowing in reverse – importing gas from the Continent into GB, just as exports through BBL dropped. This occurred before the Dragon and South Hook LNG terminals came online, as well as the Aldborough storage facility, which became operational in July 2009.

Table 2 – Sources of flexibility

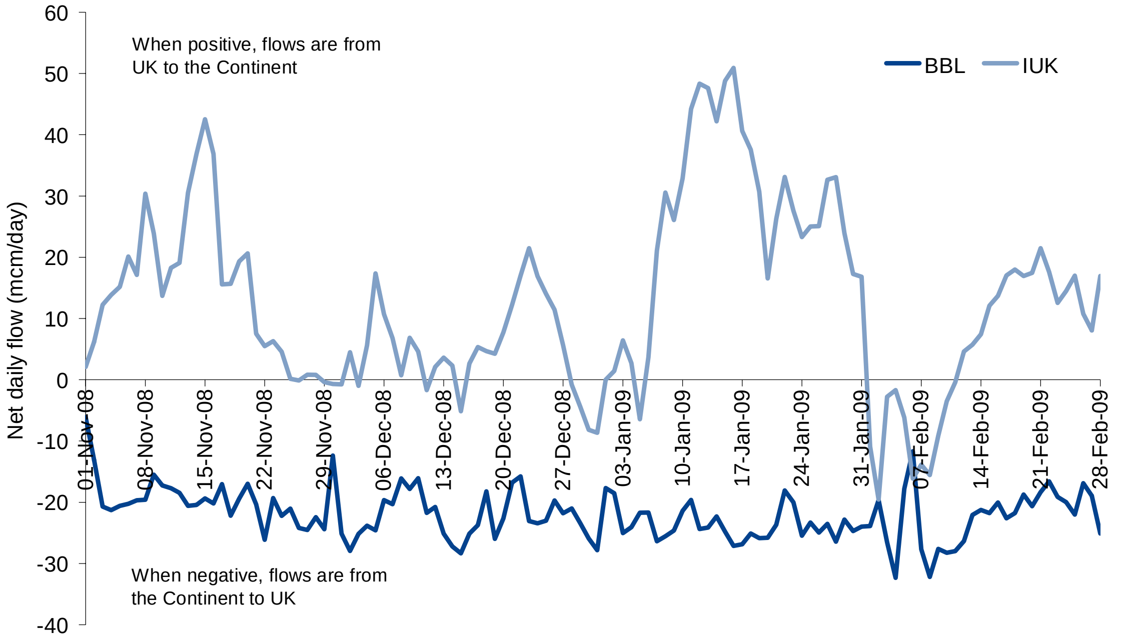
Flexibility tool	Seasonal	Weekly	Daily	Hourly
Long distance production swing	✓	✓		
LNG imports	✓	✓		
Short distance production swing	✓	✓	✓	
Depleted Fields & Aquifers	✓	✓	✓	
Salt caverns		✓	✓	✓
Interruptible contracts		✓	✓	✓
LNG peaking storage			✓	✓
Compressed gas 'bullets'			✓	✓
Line pack			✓	✓

Figure 14 – Interconnector UK monthly flows 2003 – 2010



Source: ICIS Heren, Interconnector UK

Figure 15 – BBL and IUK flows over winter 2008



Source: Interconnector UK, National Grid

The Groningen field, located a short distance offshore the Netherlands, provides considerable swing in its production profile. But other indigenous European production is already in decline. This has been especially felt in GB where the main southern basin fields were built with typically 167% swing and the Morecambe South field had over 200% swing. Figure 16 overleaf shows the profile based on the historical average of the previous five years. The Groningen field is designated as a swing producer and is technically capable of highly flexible production. It responds to market demand in the Netherlands and has a slightly different profile, peaking earlier than all the other fields.

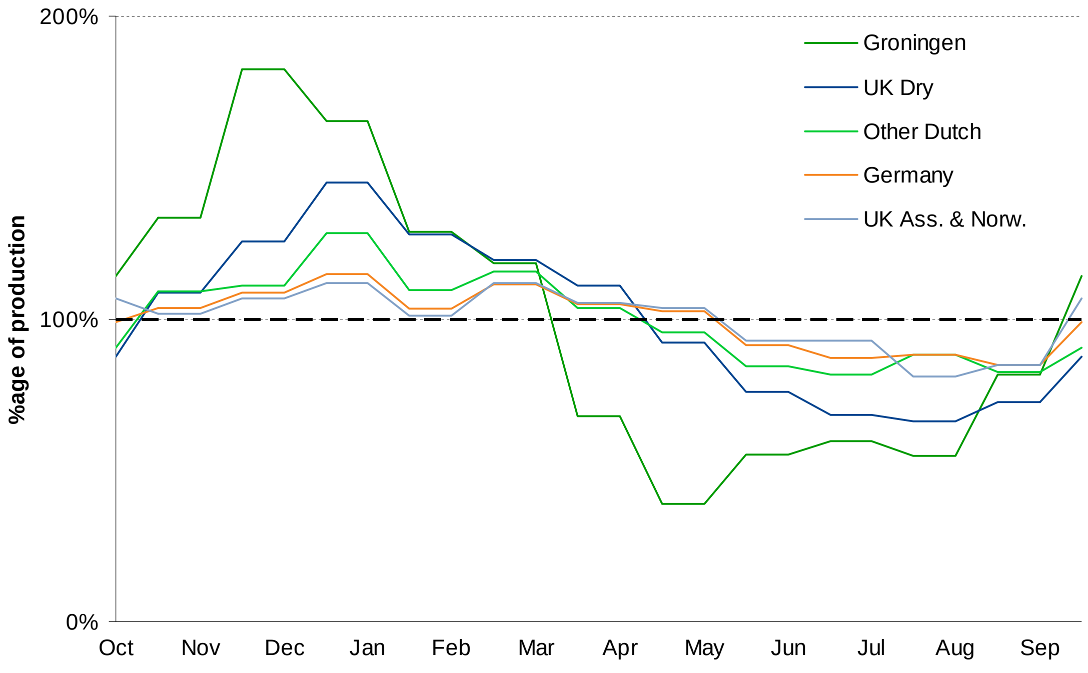
Different types of gas storage have differing properties: depleted fields and aquifers have large volumes of cushion gas and relatively slow injection and withdrawal rates, whereas salt caverns have faster cycles. A good range of storage facilities can provide flexibility all the way through from seasonal to daily. This is discussed in greater detail in Section 3.8.1.

LNG peaking storage normally has fast withdrawal rates, but very long liquefaction rates, whilst compressed gas 'bullets'[6] are very small and only used by system operators. Both are usually used for locational constraints, at peak times, within a gas grid.

Line pack is generally only available to the system operator for within day and intra day balancing and system safety limits the amount available to the market.

6 Compressed gas 'bullets' are created by compressing gas in to the end of a pipeline, to be released at times of peak demand. They are used by some distribution system operators on the continent.

Figure 16 – Indigenous source of swing



Source: IEA and individual government statistics

Power generators and industrial gas users can also provide flexibility by turning down production and selling their gas back into the market. Such use of interruptible contracts can be used for either system balancing by the grid operator or portfolio balancing by the gas supplier.

Greater interconnection and increased infrastructure capacity across Europe means that it is becoming easier to use flexibility tools in other markets where the flexibility requirements are different.

3. KEY RISK FACTORS

In this section we examine the key risk factors affecting gas security in Europe. These include: the level and variation in demand around Europe and the availability and quality of gas supplies. We have focused on gas supplies available to Europe via pipelines, as the accompanying project considers the world's LNG market in more detail and its impact on GB. Russia, with its largest gas reserves in the world, is the biggest external supplier of gas to the EU. The extraction of Russian gas and the geopolitical issues surrounding their delivery to Europe are analysed at length. Finally, risks associated with market regulations within the EU and access to storage are also discussed in this section.

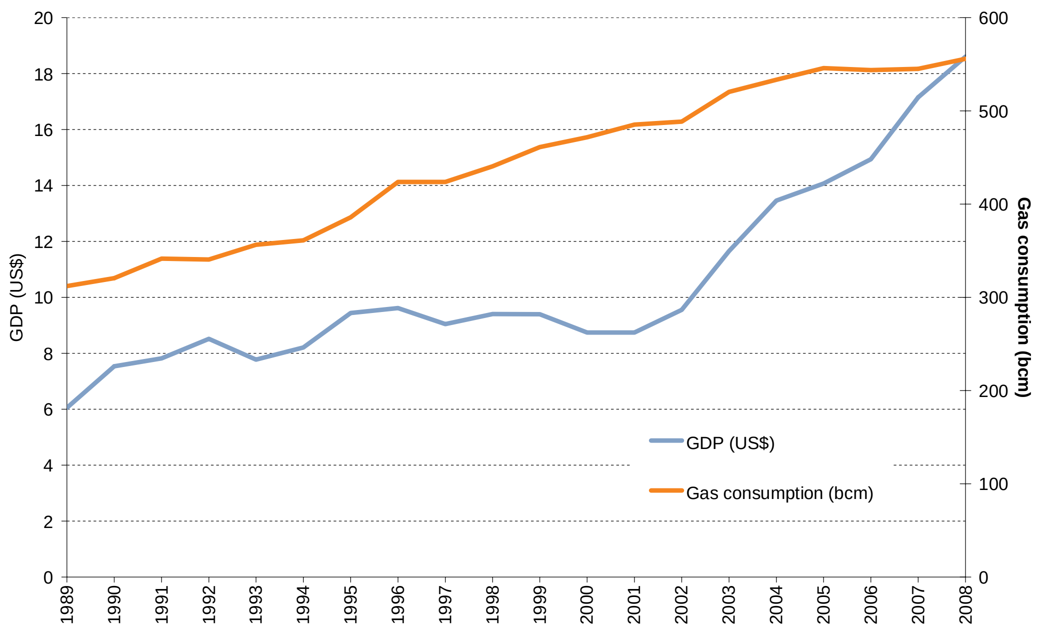
3.1 Gas demand

Overall gas demand in NW Europe is expected to remain stable, as energy efficiency measures reduce domestic and industrial demand at the same time as gas used in power generation is set to increase in some countries. However, in other regions gas demand across all sectors may grow and divert gas away from the NW Europe. Growth in gas for power generation is most likely in the Balkans, Poland, Turkey, and Germany (depending on decisions to replace retiring nuclear and coal plants).

3.1.1 GDP

In the 1990s, there appeared to be a link between European GDP and gas demand, as gas became the fuel of choice for industry. However, with new efficiency measures and an increase in renewable energy production, the link has weakened. Figure 17 shows a rapid increase in GDP from 2003 to 2008, while gas consumption levels off.

Figure 17 – OECD Europe GDP and gas consumption



Source: World Bank, IEA

3.1.2 Power generation

In this section, we aim to investigate the role that gas will play in Europe's power sector in the period to 2030.

In the last two decades, the share of gas in electricity production increased consistently. Amongst the main reasons for this development was the need to diversify the fuel mix, the flexibility and relatively faster build time of the gas plants, higher efficiency (around 50% HHV) and lower carbon emissions i.e. gas plants having half the carbon intensity of coal plant. Gas plants are also flexible with load factors and have tended to have positive economics at intermediate loads.

This upward trend is continuing and the share of electricity generated by gas-fuelled power stations is on the increase in numerous electricity markets across Europe. To investigate this in more detail, we have divided Europe into three regions: North West, Central and Southern Europe. Figure 18 to Figure 20 below show electricity generation from gas and other fuel sources based on Pöyry's base case.

3.1.2.1 North West Europe

Figure 18 overleaf shows the evolution of gas consumption in the power sector in North West Europe out to 2030. A distinct characteristic of the North West European market is its mature nature in terms of liberalisations and market structure. The policies in place in the energy market ensure a good balance between security of supply, environmental regulations and the dynamics of the electricity market. There is a substantial amount of nuclear capacity in France, Germany, Belgium and GB. The life time of this technology is likely to be extended, but further nuclear build is not favoured by some of these countries. For example Germany which currently has over 20GW of installed nuclear capacity has no plans for new nuclear build. However, these countries have ambitious renewables targets, and the gap created by the retiring nuclear and old carbon intensive coal plants is projected to be met by renewables generation, gas-fired generation (CHPs, CCGTs and OCGTs) and clean coal technologies. As a result of this transformation, gas demand in the power sector increases by 25% from 2010 to 2030.

3.1.2.2 Central Europe

Figure 19 overleaf shows the evolution of gas consumption in the power sector in Central Europe out to 2030. Central Europe here covers Poland, Romania, Hungary, Slovakia, Czech Republic, Austria and Slovenia. There is a lot of hydro and pumped storage capacity in the region particularly in Austria, Czech Republic, Romania and Slovakia, as well as nuclear. The capacity mix also includes substantial quantities of coal/lignite capacity as the region is rich in these fuels. This is especially true of Poland, Romania, Czech Republic and Hungary. This coal fleet stays online throughout most of the period being modelled but most of the new entry in the region is gas-fired plants. As a result, gas-fired generation increases from 34TWh in 2010 to 138TWh by 2030.

Figure 18 – Electricity generation from gas and other sources in NW Europe, 2010 – 2030

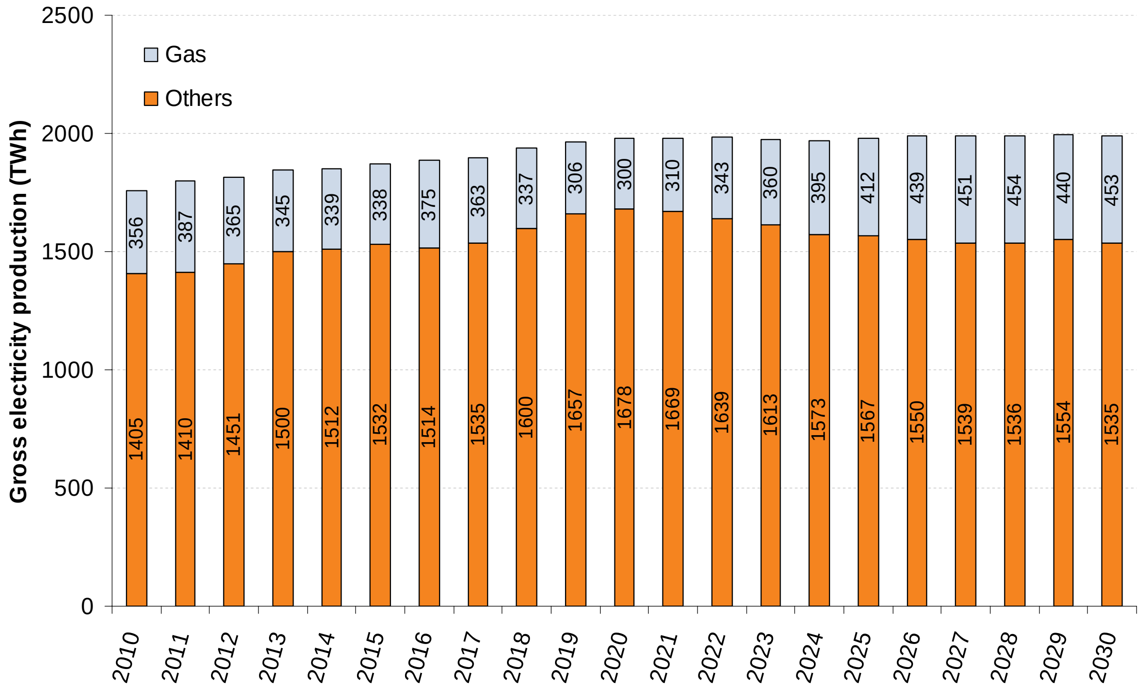
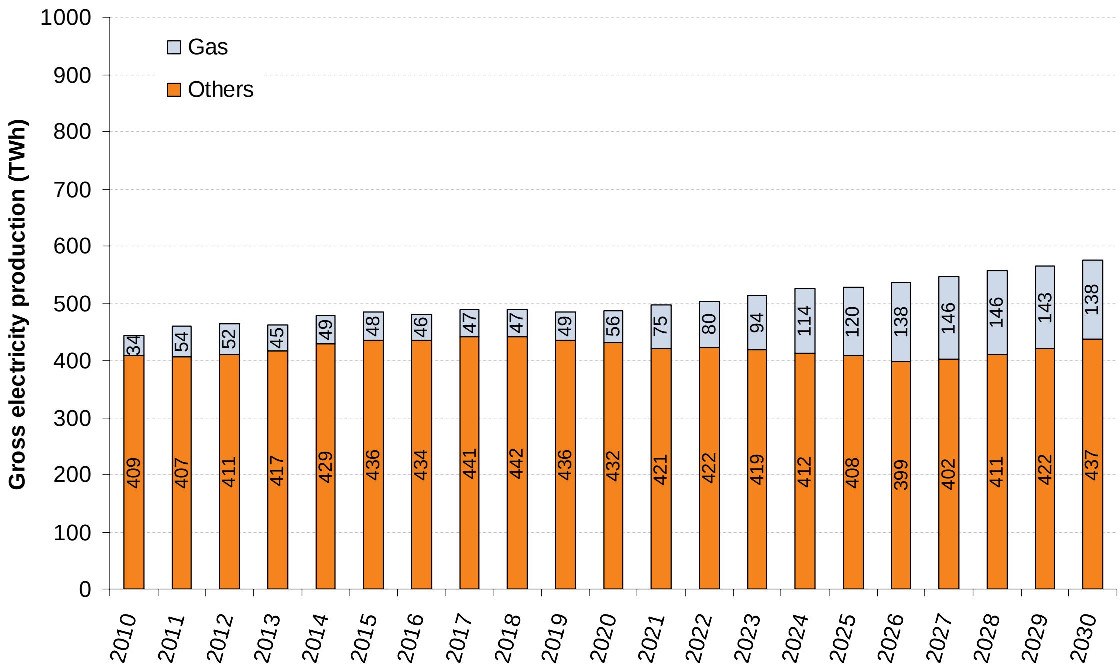


Figure 19 – Electricity generation from gas and other sources in Central Europe, 2010 – 2030



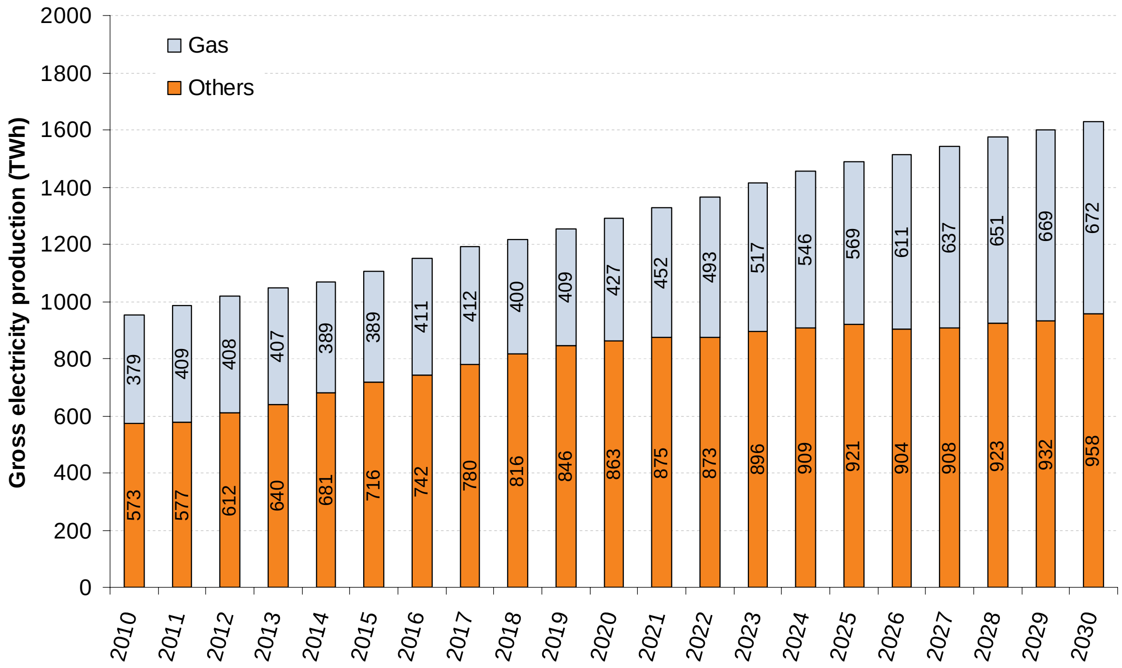
3.1.2.3 Southern Europe

Figure 20 below shows the evolution of gas consumption in the power sector in Southern Europe to 2030. This region covers the area from Portugal in the west to Turkey in the east. It has the most rapidly growing power demand; therefore gas consumption in the power sector also grows substantially over the years, as shown in Figure 20. The main characteristic of the region is power generation from hydro and coal/lignite. The latter is prominent due to its indigenous availability, but it also makes it difficult to reduce carbon emissions. Nevertheless, most new build capacity is gas plants and renewable generation. Some countries in the region – notably, Turkey, Italy and Hungary – have plans to develop new nuclear capacity in the future. However, these comprise a small portion of the total capacity.

One important point is that Southern Europe benefits from multiple sources of gas, which increases its competitiveness. High demand zones, such as Turkey, will absorb a lot of the gas delivered to the region. However, they will also create new transit routes for Middle Eastern and Caspian gas en route to Central and NW Europe. When projected gas prices are combined with carbon prices, gas is able to compete effectively with coal generation.

Gas-fired generation increases from 380TWh in 2010 to 672TWh by 2030, according to our modelling of Southern Europe. Annex B.1 has more details on our modelling assumptions, including those around carbon targets in Europe.

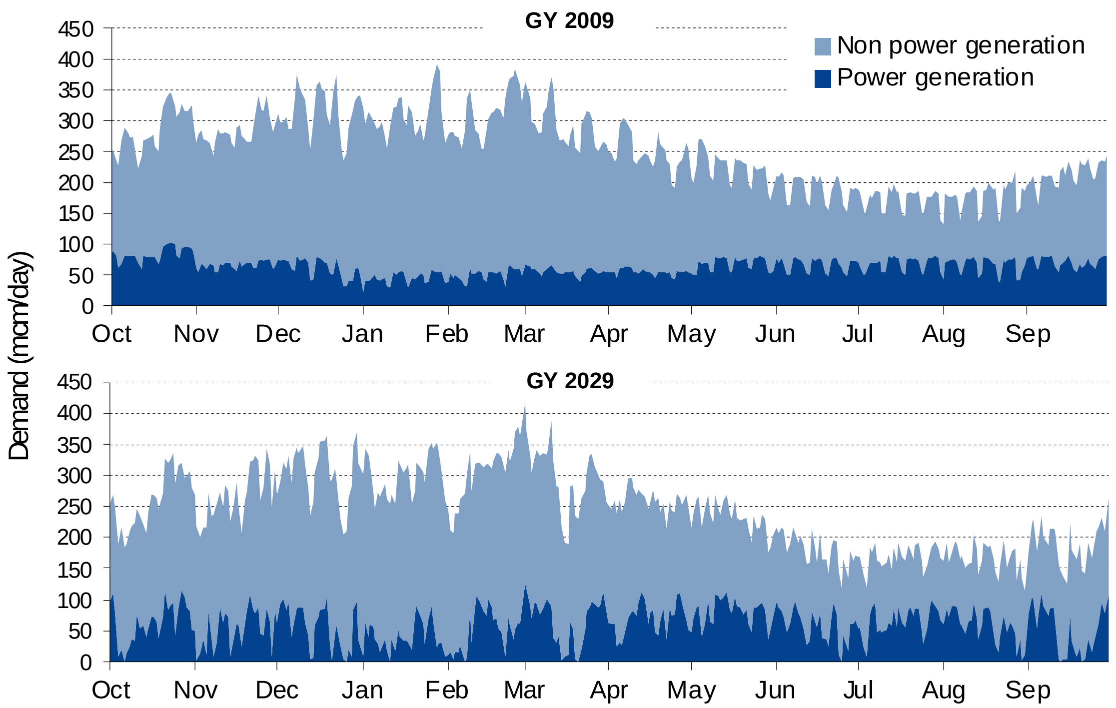
Figure 20 – Electricity generation from gas and other sources in Southern Europe, 2010 – 2030



3.1.3 Daily volatility in demand

Linked to the change in the power generation mix and the effect that increased wind generation will have on the system, we expect the variability of demand to increase, as illustrated in Figure 21. Gas year 2009/10 shows seasonal shape with weekday and weekend variation. However, by gas year 2029/30, the impact of wind variability feeds through to gas demand. This means that the system has to cope with high volatility, which, in turn, has an impact on the potential sources of flexibility and their required levels.

Figure 21 – Daily GB demand with 2003 weather pattern



3.1.4 Seasonality

Patterns of seasonality vary around Europe depending on the proportion of gas used in space heating relative to power generation, and the local climate. A large proportion of gas demand in Germany and GB is used in space heating, and, as they have similar climates, their seasonal gas demand profiles, shown in Figure 22[7], have the same shape. The winter peaks in Germany are higher because more gas is used in space heating there than in GB.

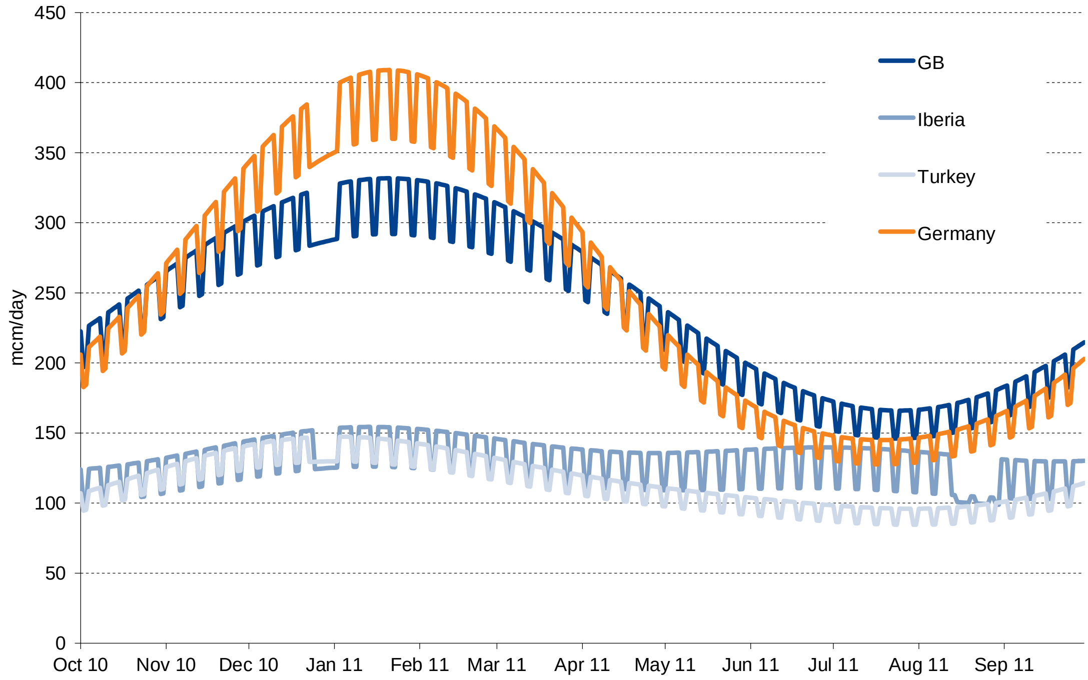
A large proportion of gas demand in Spain is used in power generation and the hot summers lead to greater demand for power due to air conditioning in the summer months. Gas used in Spain for heating has a winter peak, which, when combined with the gas

7 The gas demand profiles in Figure 22 show average daily demands over an average year, and the country profiles shown have been chosen to illustrate the range of different profiles found in gas demand around Europe and how different factors can influence them.

used in power generation, leads to a fairly flat overall gas demand profile over the year (see Figure 22). Obviously, if the proportion of gas used in power versus that used in heating changes, then the seasonal demand pattern will also change.

Turkey has similar weather patterns to Spain and a mix in its final use of gas. However, the proportions of space heating to power generation lead to a slightly higher winter demand.

Figure 22 – Gas demand profiles around Europe



Changes causing gas demand to peak in several regions simultaneously is a risk which could put more pressure on the sources that provide flexibility. Moves away from gas-fired heating in low-carbon economies and counter-seasonal utilisation of gas-fired generation could mitigate this risk in the longer term.

3.2 Indigenous and Norwegian reserves

European production is set to decline rapidly as reserves are exploited. This is shown in Figure 23. By contrast, Norwegian production (in Figure 24) will remain stable for the next decade, but it too will enter a period of slow decline in the 2020s. The maturation of existing reserves could potentially be offset by new, Norwegian, sources originating in the Arctic. However, the technical challenges of producing gas in such a harsh climate and the related issues of bringing that gas to market, means that we not expect to see new sources of gas from the Arctic coming on stream before 2030.

Over the long term, European and Norwegian production will be affected by the levels of investment in E&P and infrastructure. As reserves become depleted, new finds are likely to become more expensive and represent a higher investment risk. A period of prolonged low gas prices could threaten future investment levels.

Figure 23 – Indigenous production within Europe

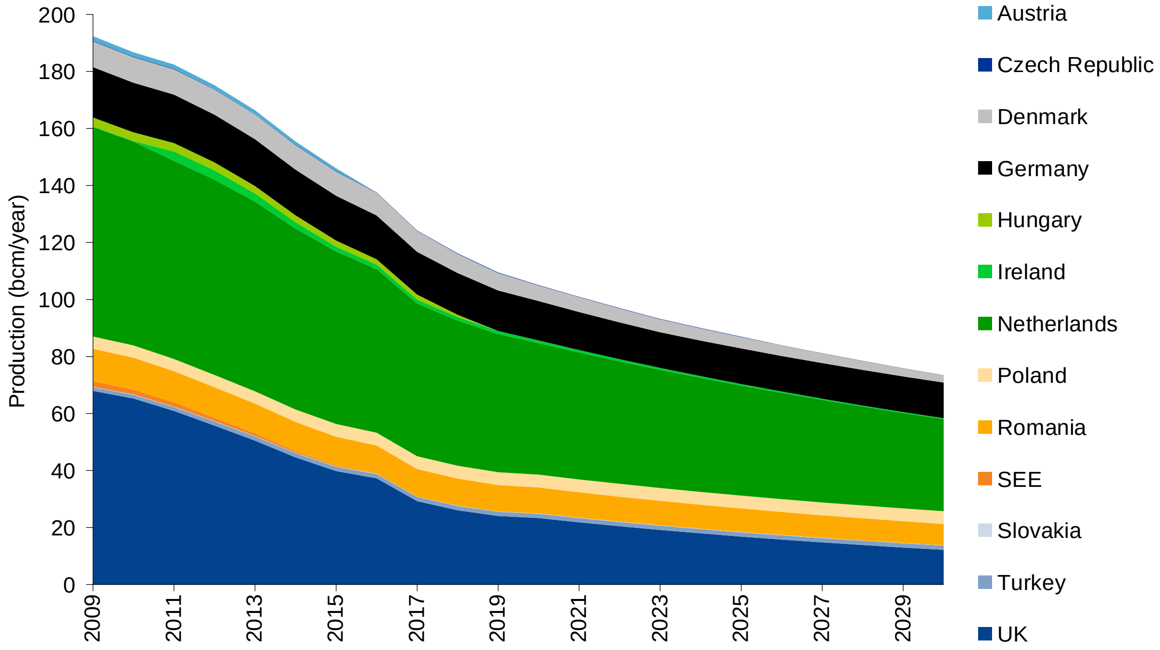
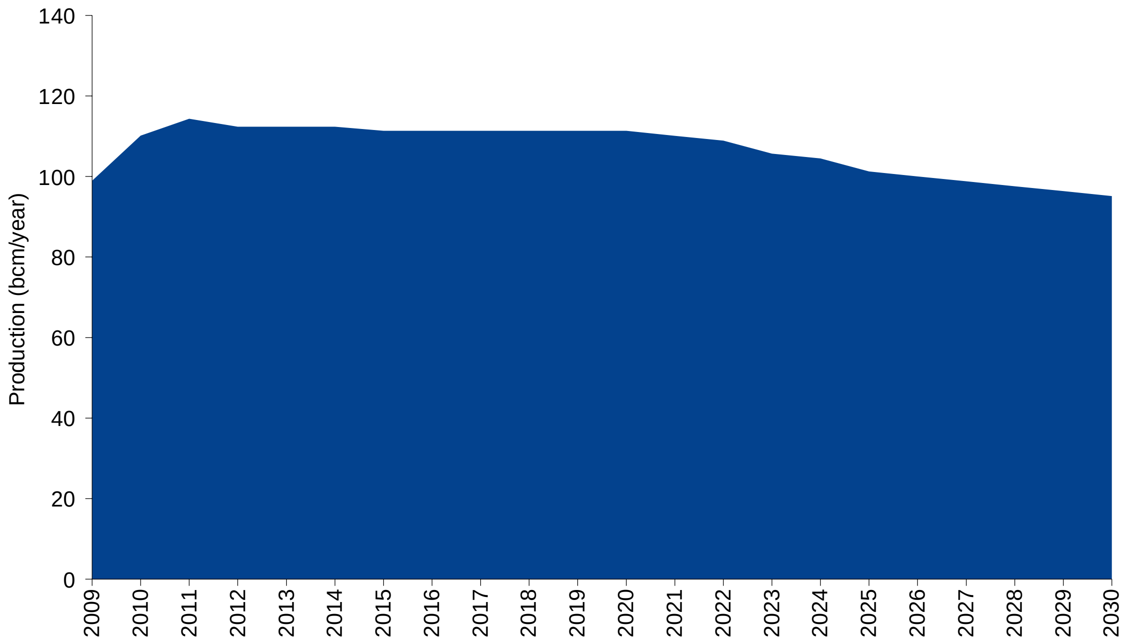


Figure 24 – Norwegian production



Infrastructure investment could be restricted if regulatory pressure reduced the rates of return for transmission companies to levels that would not allow adequate returns for potentially riskier new investments. This would result in spare capacity being taken out of the system. It is likely that new interconnections will rely on long-term capacity commitments through auctions or open seasons rather than the historical long-term contracts.

Alternative sources, such as unconventional gas in Europe, may prove to be geologically difficult to extract. Its development is also likely to become contentious and be delayed on environmental grounds.

3.3 Russian reserves and production

This section focuses on Russia's reserves, drawing special attention to the differences in reserves valuation methodologies in Russia and the West. It then examines reserves replenishment by region before analysing production from Russia's traditional gas province and the prospects for the emergence of the next strategic region – Yamal.

Russia's total gas reserves that it considers to be fully extractable stood at 47.8tcm as of 31 December 2008 (latest data available).

- Of these, Gazprom's share was 33.1tcm. Its reserve base grew by 4.8tcm in 2008 alone, reflecting primarily the allocation of 'strategic fields' to the state monopoly in line with the law on strategic sectors.
- Other companies, including state oil company Rosneft and Novatek, Russia's second largest gas producer in which Gazprom has a 19% share, controlled 10.2tcm of the total.
- Some 4.5tcm remained in the undistributed fund.

Western reserves appraisal methods differ materially from the Russian classification, which was developed under the Soviet centrally planned economy. The latter paid no attention to economic or commercial factors in developing and extracting hydrocarbons. Even within Russia, this classification methodology is increasingly accepted as being out of date.

The two most widely used methodologies for classifying Western reserves are Society of Petroleum Engineers (SPE) International Standards[8] and US Securities and Exchange Commission (SEC) standards. Although reserves definitions differ between the two, an important common feature is that both take into account economic factors and use consistent price and cost assumptions that meet disclosure requirements.

By contrast, the Russian classification methodology is driven by the actual physical presence of gas (and oil) in geological formations *without* accounting for commercial factors, such as the cost of development and transportation. Under international standards, both geological and commercial/economic factors are taken into account.

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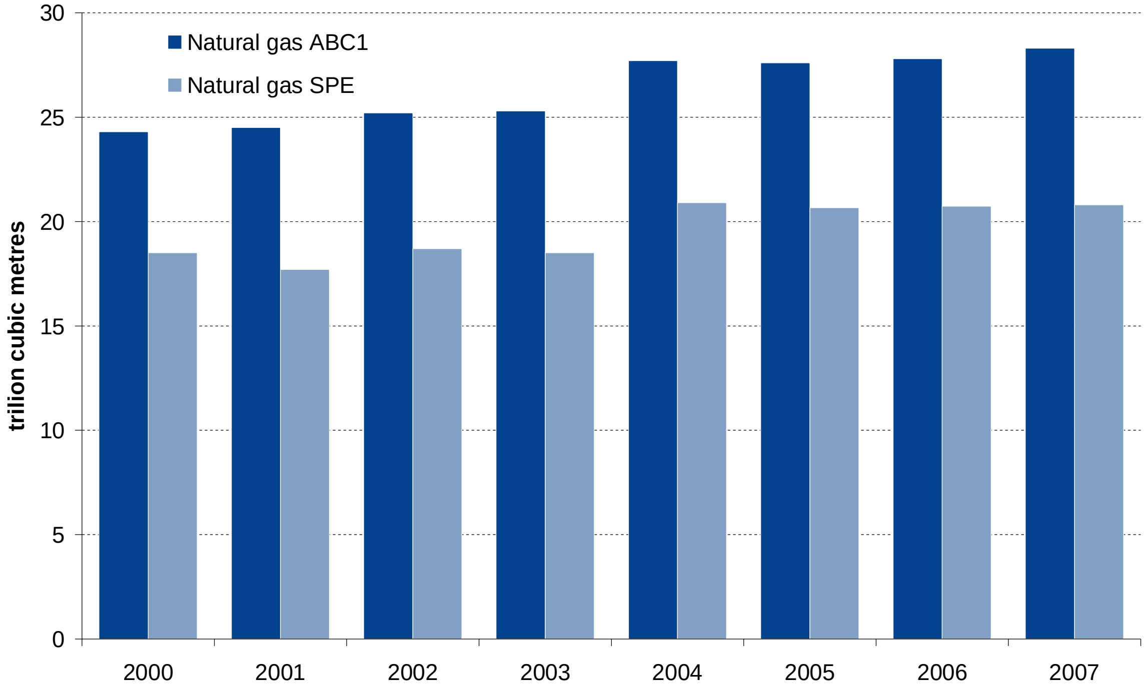
8 The SPE methodology is also referred to as the Petroleum Resources Management System (PRMS). The PRMS standards are co-sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE). PRMS is also endorsed by the Society of Exploration Geophysicists (SEG).

3.3.1.1 *Independent audit and comparisons of Russian reserves*

The Russian classification system is not widely recognised outside the former Soviet Union. For instance, it is not recognised under the rules of the London Stock Exchange. However, the LSE accepts the valuation of reserves under the SPE and SEC standards. Therefore, in addition to having their reserves audited by Russian state bodies (a licence requirement), most Russian oil and gas companies have their reserves assessed by independent auditors. Gazprom's resources, for example, have been audited by DeGolyer and MacNaughton since 1997, while reserves of the monopoly's oil branch, Gazprom Neft, are evaluated by Miller & Lents.

Figure 25 – Gazprom's natural gas reserves in Russian and SPE standards (tcm)



* Excluding Gazprom Neft, which, according to Miller & Lents had 22.4bcm of gas as of 31 December 2007.

The Russian reserves system is based solely on the analysis of the geological attributes of reserves and examines the actual physical presence of hydrocarbons in geological formations or the probability of such physical presence. The Russian classification is sub-divided into A, B, C1, C2, C3, D1 and D2 categories:

- explored reserves are represented by categories A, B and C1;
- preliminary estimated reserves by category C2;
- prospective resources by category C3; and
- forecasted resources by categories D1 and D2.

Gazprom considers natural gas reserves in A, B and C1 categories to be fully extractable. For simplification purposes, many Western sources frequently assume that ABC1 reserves roughly correspond to the proven, probable and possible reserves in Western classification. This is not wholly accurate.

On IEA estimates, only 30% of C1 reserves will subsequently shift to B and then A categories. This is corroborated by evidence from Russian sources and appears to apply to both oil and gas deposits. Furthermore, because the Russian methodology does not take into account economic factors, it includes in ABC1 those resources that are technically recoverable, even though their recovery may be economically unviable due to location and/or using currently available technology.

By contrast, the Western methodologies classify reserves as recoverable only if their extraction is economic on the basis of existing technologies, current prices and costs. This, as the discussion below will demonstrate, is a material difference, which given the maturity of Russia's producing deposits will affect the pace at which Russia adds new supply sources in the future.

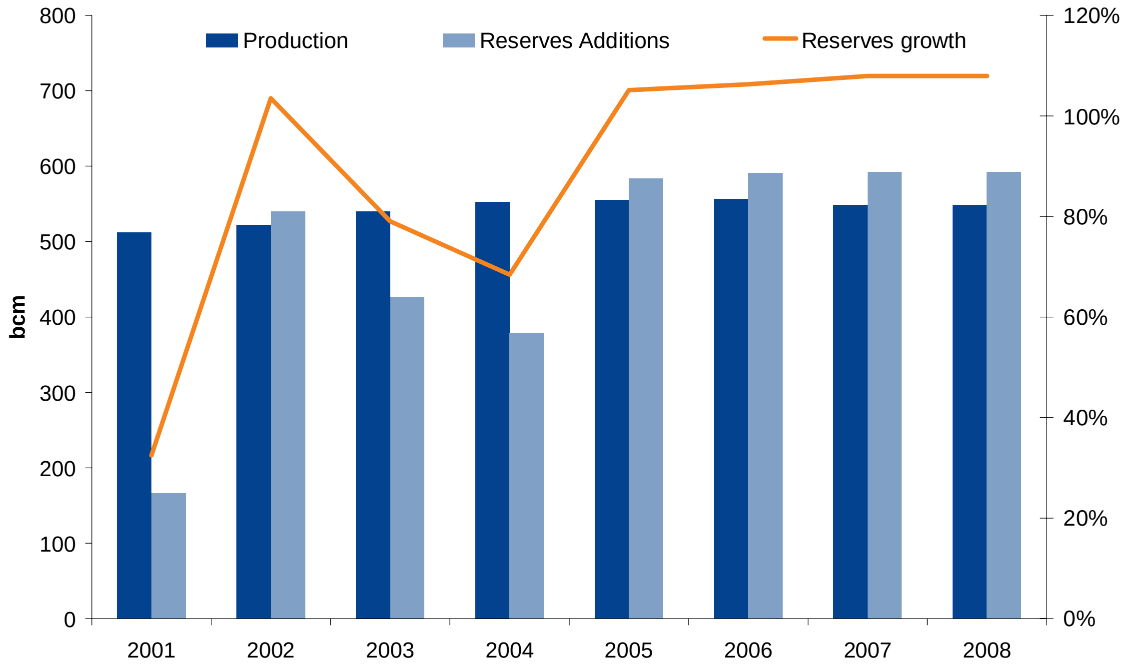
At the level of production of 560bcm/annum, Gazprom's ABC1 reserves will be sufficient to last over 50 years, thus covering the period to 2050. However, the company's internationally audited reserves will cover the same level of production for only 37 years. In its strategic assessment, Gazprom expects to produce 610-615bcm/year by 2015 and 650-670bcm in 2020. The increases reflect both the expected rises in domestic demand (post-recession) and export obligations, particularly to Asian customers. Such production forecasts highlight the need to raise the reserves-to-production ratio.

3.3.2 Reserves replenishment

Despite the methodological differences presented in the section above, there is no doubt that Russia's gas reserves are vast and its potential colossal. Rosnedra, Russia's federal subsoil agency, estimates the country's ultimately recoverable conventional gas reserves at 220.7tcm. However, further exploration is needed to translate resources into proven reserves. The slow pace of exploration in the late 1980s and throughout the 1990s was partially overcome in the 2000s, as demonstrated in Figure 26. However, the situation with prospecting remains difficult, as the Soviet scientific research fleet has been reduced to some 84 vessels, most of which are on average 25 years old. In the period of 2000-08, only one small hydrographic survey vessel was added to the fleet. Currently, there are indications that exploration has been affected by the economic recession. Nevertheless, the government and Gazprom have begun paying more attention to the issue, raising it in key state and industry policy documents, such as Energy Strategy and the General Scheme for the Development of the Gas Industry to 2030.

Gazprom's proclaimed objective in geological surveying is to maintain parity between production rates and reserves growth until 2010. Reserves growth is due to pick up after 2010, primarily due to the intensification of exploration in East Siberia and offshore. However, in the short term, Gazprom will continue to rely on its best explored province of West Siberia.

Figure 26 – Gazprom production, reserves additions and the rate of reserves replenishment, 2001–07



3.3.3 *Russia's gas potential and production by region*

This section outlines the historical and current patterns of gas production in Russia. It emphasises each region's potential reserves and the level of prospecting that needs to be undertaken before production takes place. It reveals that Russia's key gas producing province, West Siberia, is also its best explored one. It still contains significant gas deposits, although these are relatively difficult to access. However, any development there will benefit from well developed infrastructure. The latter is far from being the case in Russia's next strategic gas region, Yamal, where railways and pipelines are being laid and new production infrastructure is being built prior to the commencement of gas extraction, currently scheduled for late 2012.

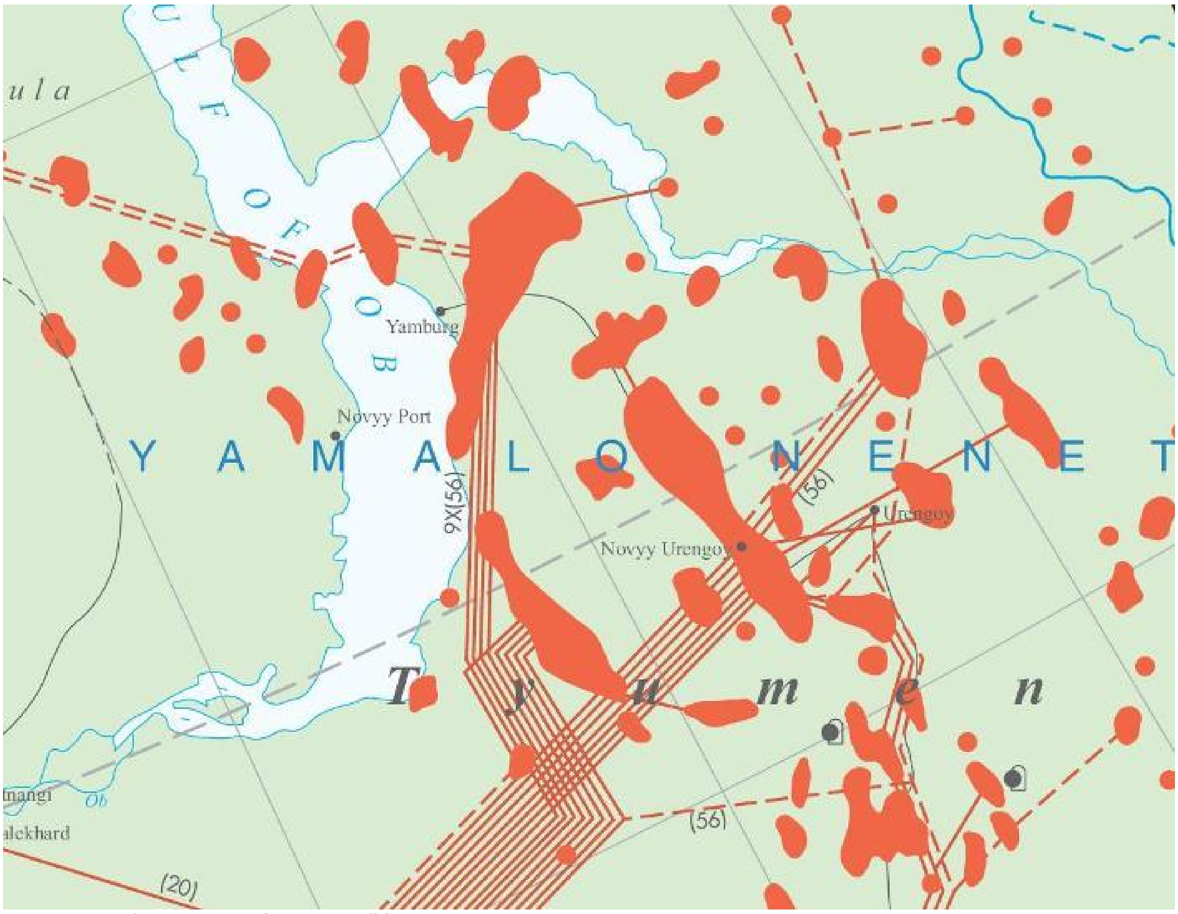
Until 2009, the magnitude of the projects undertaken by Gazprom raised doubts as to the timescales in which the company could realistically expect to complete them. These doubts, in turn, raised concerns over Russia's ability to export gas to Europe, particularly in the light of the expected growth in gas demand in the future. However, development of shale gas in the United States and the launch of new liquefaction projects, coupled with currently depressed gas demand as a result of the recession, have created an opportunity for Gazprom to revise its schedules and develop the projects in less demanding timeframes. This has already been done for the Bovanenkovo field of Yamal, which has been delayed by one year. Its timely completion now looks more likely than before.

However, the 'gas glut' has also created significant uncertainty over whether and how long it will last. Indeed, in its estimates, the IEA believes that the over-supply will last until 2015. Such forecasts have cast doubts on the timing of developing the Shtokman project, which is now likely to be delayed until after 2015. These considerations are also part of the larger picture in which the Russian leadership and Gazprom give serious thought to the country's traditional strategic orientation towards Europe and ask not *whether* but *to what degree* a diversification towards the Asia-Pacific basic is desirable between 2010 and 2050.

3.3.3.1 West Siberia

West Siberia is a key gas-bearing region of Russia, which currently accounts for some 90% of its gas production. The bulk of production has traditionally come from the 'Big 3' fields in the region: Yamburg, Urengoi and Medvezh'e. These are shown in Figure 27.

Figure 27 – The map of main producing fields in West Siberia



Source: Petroleum Economist, 2008 edition

All three fields are super-giants.[9] Their combined gas reserves before production stood at almost 14tcm. The bulk of this gas was in the Cenomanian formations and was relatively easy to extract due to shallow reservoirs (at the depth of 1.0-1.3 km) and porous rock.

- Urengoi was, at the time of its discovery in 1966, the largest natural gas field in the world, with reserves of 7tcm. First gas from the field was produced in 1978, with peak output reached in 1987, at 276.2bcm/annum. This level of production from one field

9 Super-giants are the largest fields in international classification with reserves exceeding 850bcm of gas each. Together with giant fields, which contain between 85-850bcm of gas, super-giants represent less than 1% of the world's total known gas fields.

alone enabled the Soviet Union to become the world's largest producer of natural gas.

However, by 1991, production at Urengoi entered a period of decline. In 2007, output from the initially developed area of Urengoi fell to 84.4bcm. As of January 2009, the field was 65.1% depleted. These estimates relate only to the Cenomanian layers of Urengoi, which still contains very sizeable reserves in its deeper layers as well as its peripheral areas and satellite fields.

- Yamburg was at the time of its development in the mid-1980s Russia's second largest field, with original reserves of over 4.7tcm. As with Urengoi, these were concentrated mostly in Cenomanian reservoir rocks. Yamburg reached peak production in 1994 when it produced 174.2 bcm of gas. By early 2008, its Cenomanian deposits were 52.1% depleted.
- The Medvezh'e field was the first but the smallest of the three super-giants to be developed. It marked the beginning of the transformation of the Yamal-Nenets Autonomous District into Russia's largest gas province. First launched in 1972, it reached its peak output of 75.3bcm in 1983. Seven years later, it was still producing at 72bcm. However, it has since rapidly matured, producing only around 20bcm in 2005.

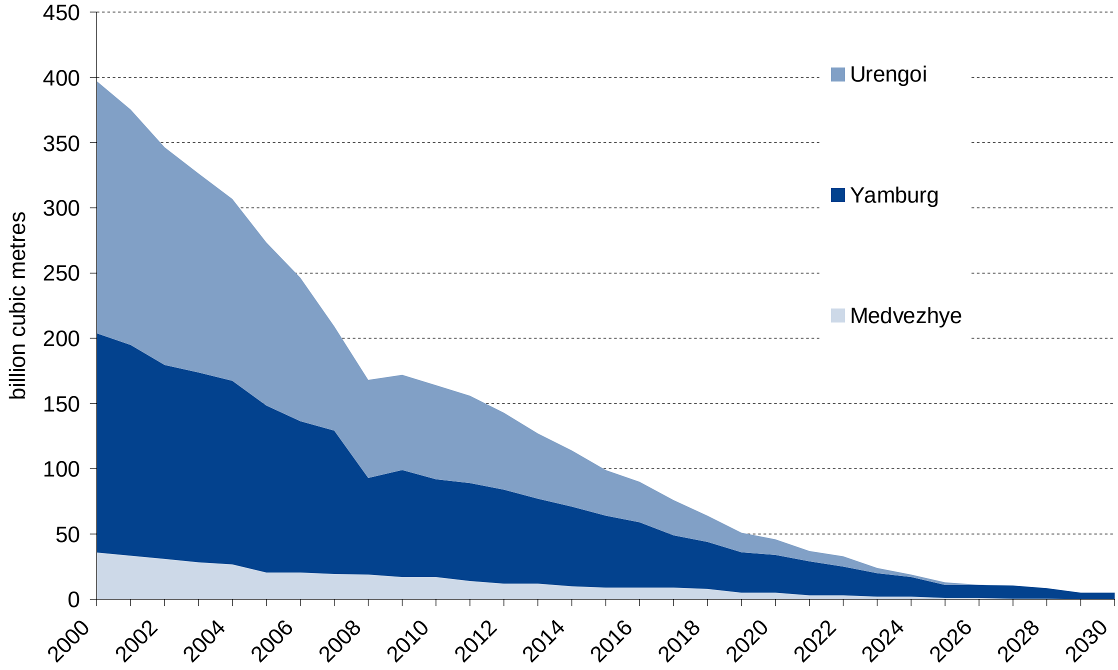
Despite the intensity of gas production under the Soviets, the Siberian super-giants have lasted well into the 2000s. What made this 'survival' possible was the generally late start in developing gas fields compared to oil. Production of natural gas began later and proceeded slower than of oil deposits. However, by the mid-1990s, declining production at mature fields in the Nadym-Pur-Taz area was a reality. Two factors need to be highlighted here:

- Since the late 1990s, Medvezh'e, Urengoi and Yamburg have been in irreversible decline, losing 6-7% of output on average (or a combined total of 25-30bcm/annum).
- The need to develop new gas regions became apparent. This came hand in hand with the tasks of having to build new production infrastructure and lay very long pipelines from new and inhospitable producing regions.

Figure 28 demonstrates the declines at the three fields, taking into account historic rates of depletion. The maturation at the fields is a natural process, but in the case of the West Siberian super-giants, it has been precipitated by the intensive schedules of development widespread in the Soviet hydrocarbons industry and the lack of investment, particularly in the 1990s.

In 2008, the three mature super-giants produced a total of 168.1bcm. However, the drop in late 2008-09 was due not only to the maturation of the fields but also reduced demand for gas in Russia and Europe, which led Gazprom to close a number of wells. Gazprom now says that the rate of decline at the fields has slowed down, but it has not revealed any estimates. It is likely that, currently, lower rates of production have led to lower rates of declines; however, with the resumption of demand growth and increased production, the rate of decline at the fields will accelerate again.

Figure 28 – A depletion pattern at the three West Siberian super-giants, in bcm



*The estimates are for the fields' original areas of development only. The drop in 2008-09 is due to the closure of wells. Slower rates of depletion are assumed until 2012, but the previous rates resume in later years.

The need to develop a successor to West Siberia was first recognised in the 1970s, when industry experts expressed concern over the insufficient number of exploratory wells being drilled in new provinces. The disintegration of the Soviet Union and the long economic rehabilitation period that followed, coupled with low oil (and therefore gas) prices in the mid- and late 1990s, and yet another economic collapse and default in 1998, led to the lack of capital investment into both geological exploration and development of new fields.

As a result, the last West Siberian super-giant, Zapolyarnoye, was launched in October 2001. Its original reserves stood at 3.2tcm, which enabled production to grow rapidly, reaching the original design plateau of 100bcm in late 2004. Gazprom's subsequent reassessment of the field's reserves revealed that the plateau production could be raised to 115bcm/year from the Cenomanian layers and 15bcm from the Valangian deposits. In other words, Zapolyarnoye could increase production to 130bcm/annum, but the new level of production has been delayed until 2011–12 due to the economic recession, low gas demand and the 'gas glut' created following the start of large-scale development of shale gas in the United States.

Thus, Gazprom currently has excess capacities, which is influencing its thinking on whether and when to develop new provinces, such as Yamal and the super-giant offshore field of Shtokman. These are discussed in detail in Sections 3.3.3.2 and 3.3.3.3. Here, suffice it to say that the Nadym-Pur-Taz region, which is part of the West Siberia basin where the bulk of production is taking place, has been well explored and benefits from well developed infrastructure. This makes it possible to increase production there relatively easy.

In addition to the super-giant fields, it is known to contain:

- 27 fields with reserves of between 100bcm and 300bcm; and
- 81 fields of between 30bcm and 100bcm.

There are still very significant reserves left in the deeper layers (e.g. Valangian, Achimov, Yur) and the neighbouring areas of the super-giant fields, which Russia is currently developing.

Smaller fields are considered important in the short term, and main additions to output have been coming from there. Table 3 and Table 4 show the fields that Gazprom launched in 2002-06 and the ones that are expected to come online by the end of this year. In total, they will give over 270bcm of capacity over a period of eight years.

Table 3 – Main fields launched in 2002-06 and volumes of gas produced

Main fields brought online in 2002-06	Production from the field (bcm)
Zapolyarnoye	100.0
Pestsovoye	27.5
Yeti-Purovskoye	15.0
Yen-Yakhinskoye	5.0
Vyngakhinskoye	5.0
Aneryakhinskaya area	10.0
Kharvuta area	10.0
Tab-Yakhinskaya area	5.0
Total	**177.5**

Source: Gazprom

This has enabled Gazprom to stave off falls in production from the depleting fields. The absence of new super-giant fields in Nadym-Pur-Taz explains Gazprom's inability to grow production as rapidly as before (e.g., Zapolyarnoye alone gave an additional 100bcm/annum), although increases in volumes remain substantial.

Table 4 – Main fields to be brought online in 2007–10

Main fields to be brought online, 2007-10	Total production from the field (in bcm)	Production level to be maintained (in years)
Kharvuta area	30.0	4
Yuzhno-Russkoye	25.0	9
Zapolyarnoye (neocom deposits)	15.0	14
Achimov deposits	16.2	6
West Pestsovaya area	2.0	13
Yarey area of Yamsovey	0.5	18
Nadin area of Medvezh'ye	2.0	10
Gubkinskoye Severnoye	2.0	2
Total	**92.7**	

S

ource: Gazprom

After 2012, Gazprom's new strategic region of Yamal will see its first super-giant field becoming operational. This will mark a new era for Russian gas.

3.3.3.2 Yamal

The slow pace of exploration in the 1990s has translated into a high degree of uncertainty regarding proven reserves even in Gazprom's next strategic region – the Yamal peninsula. The region's best prospected field is Bovanenkovo (3.2tcm), which is due to be launched in late 2012. Meanwhile other fields often have their reserves stated in C1–C2 categories, indicating a need for further exploration before production begins. An analysis of official sources suggests that Yamal's total reserves in ABC1 and C2 is currently at 10.4tcm. However, some of the fields have offshore extensions, which in the majority have been poorly studied. Yamal's potential reserves are put at over 50tcm.[10]

Yamal has been the region of Gazprom's strategic interests since 2003. The peninsula is known to have:

- 8 gas fields, of which 5 are super-giants;
- 10 gas and condensate fields; and
- 8 crude and condensate fields.

The fields are divided into the Central, Northern and Southern groups. Of these, the only fields that have been explored sufficiently well to lead to production are the onshore fields in the Central group: Bovanenkovo (4.4 tcm), Kharasavei onshore (1.4tcm) and Kruzenshtern (964bcm). The reserves of these fields are in the ABC1 category.

The Central group will constitute the next generation of super-giant fields to be brought online. The first of these, Bovanenkovo, will be launched on official estimates in late 2012, but the delay of about a year is likely and has been factored into our modelling in the Central scenario.

- Bovanenkovo will start at 7.9bcm/year. Output will build up over three years to 115bcm/year. Its plateau production could reach 140bcm, although no timeline has been indicated as to when this will happen. Early plans suggested that production would grow gradually from 115bcm to 140bcm over a period of six years, but projections show that a fast-rising demand in Russia and Europe following the recovery from the recession could lead Gazprom to choose an 'intensive' path of the field's development.
- Prior to the economic downturn, first production from Kharasavei was discussed for 2014. The decision on whether to develop the field and within what timeframe will be taken this year. The expected output from the field is 39bcm/annum by 2019.
- Kruzenshtern could be the third in the group to be developed. Gazprom received this field from the undistributed fund without a tender in May 2008. The development of the Kruzenshtern field will be linked directly to Bovanenkovo and Kharasavei.

The Northern group of fields is located, as the name suggests, further north on the peninsula. In this group, the most promising is the Tambei group, which has combined reserves of over 3.6tcm.

Fields in the Southern group are numerous and located close to the super-giant Yamburg field, which could facilitate the transportation of gas, using the existing infrastructure. The climate to the south of the Baidaratskaya Bay is milder and more similar to Nadym-Pur-

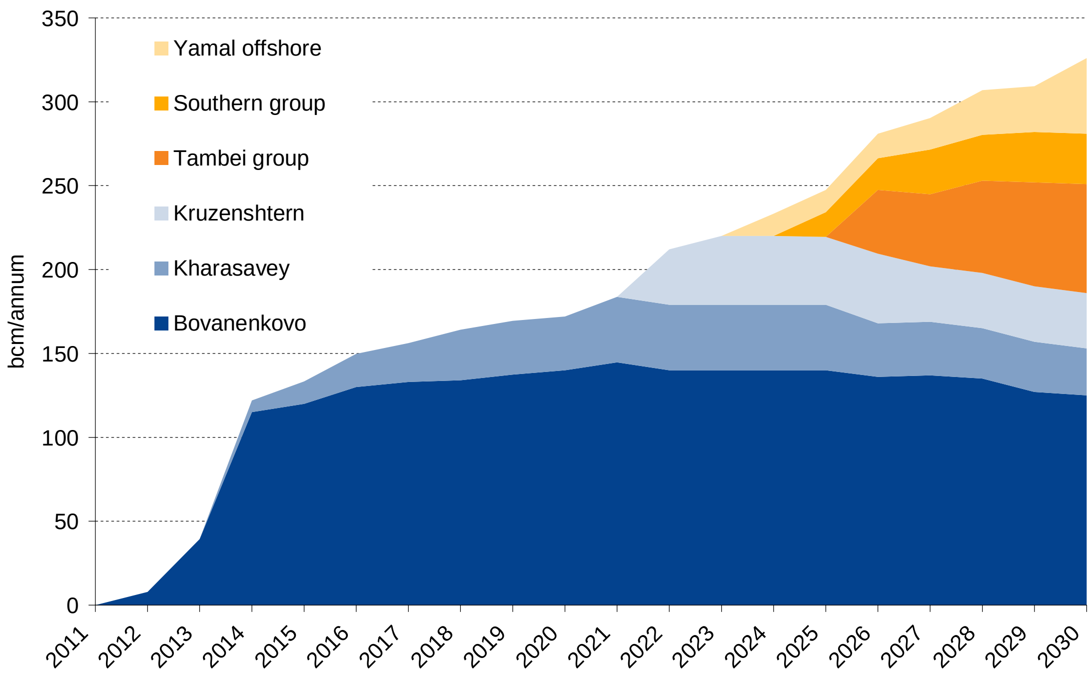
10 Some Gazprom estimates put this figure at 22 tcm for C3+D3 reserves (Yamal Megaproject, Gazprom).

Taz than to the rest of the Yamal peninsula. This combination of factors makes the southern group strategic in Gazporm's production profile to 2030.

Yamal's offshore is highly promising and its resources are vast. For instance, the Leningradskoye and Rusanovskoye fields in the Kara Sea are believed to have the combined reserves of 8tcm. Exploration has until now been limited to two exploration wells drilled on each field. Another 16 wells are expected to be drilled after 2010. Working offshore presents additional challenges to the already difficult working conditions on Yamal. Therefore, even at the time of record high gas prices in 2007-08 Gazprom made no announcements as to when these fields would be developed.

Figure 29 shows a production profile for the Yamal peninsula, as envisaged by Gazprom.

Figure 29 – A profile of production from Yamal fields to 2030



To transport gas from the new remote region, Gazprom will construct some 4,137 km of pipelines before new gas can reach Europe.

3.3.3.3 Shtokman

Shtokhmanovskoye, commonly known in the West as Shtokman, is a gas and condensate field in the Barents Sea. Discovered in 1988, it is one of the largest deposits in the world, with C1+C2 reserves of 3.9tcm. The field's reserves have been revised upwards several times, with the latest addition of 100bcm in February 2010. Gazprom explained that the boost came following the revision of existing data. The field is also known to contain 31 million tonnes of gas condensate.

Figure 30 – The location of the Shtokman field

Source: Petroleum Economist, 2008 edition

In July 2007, Gazprom and Total signed a framework agreement on the main conditions of cooperation at Shtokman's Phase I. A similar document was subsequently signed by Gazprom and StatoilHydro. Swiss company Shtokman Development AG was established, with 51% owned by Gazprom, 25% by Total and 24% by StatoilHydro.

The agreement with Total and StatoilHydro represent an outcome towards which Gazprom had been moving for several years. It gives the partners access to participating in the development and operation of Phase I production for a period of 25 years, while the majority ownership remains with Gazprom. It is highly notable that Shtokman Development AG will develop only the first phase of the project.

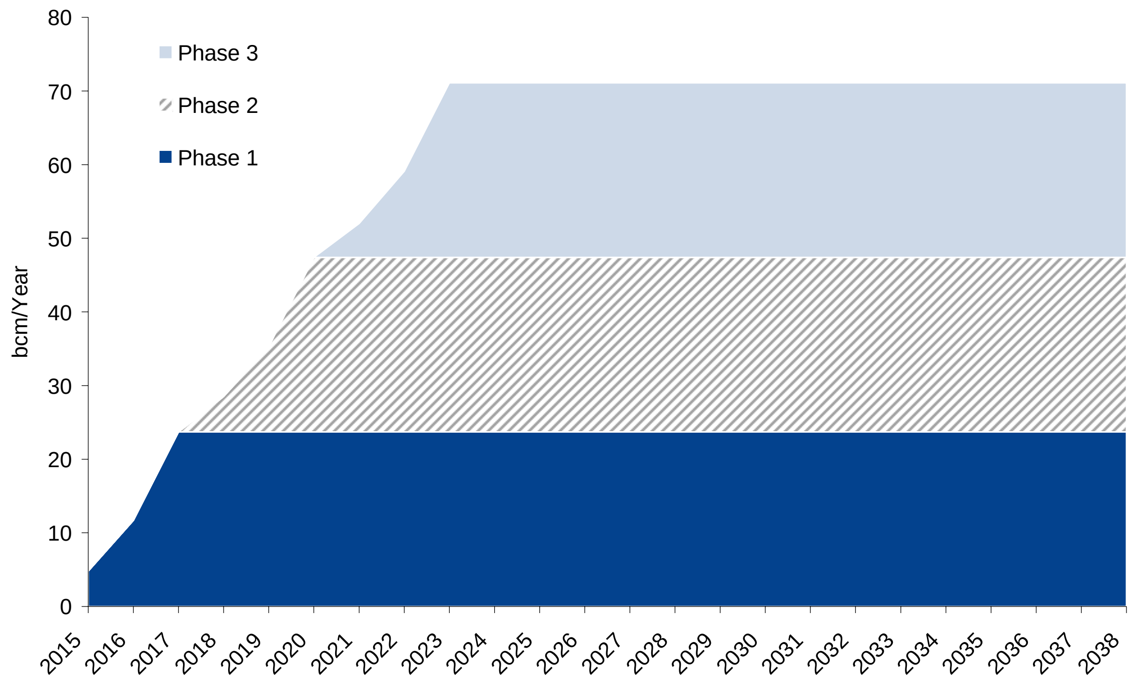
In late February 2010, just a month before the final investment decision (FID) was due, Gazprom decided to delay the project in the light of the uncertainty over LNG demand, following what it called 'the shale gas revolution'. The FID has now been delayed until late 2011, but even that deadline has been made subject to improved market conditions.

The official schedule for bringing Shtokman online is now likely to move from 2013 to 2015-16. The timeline for starting LNG production, previously expected in 2014, is currently uncertain. Some 11.3bcm/annum of the Shtokman gas is to be exported through the second line of Nord Stream, but the pipeline is due to be completed in 2012, while no concrete deadline has been set for the field.

On the one hand, delaying Shtokman's development – which is due to produce 7.5mt/annum of LNG from Phase I – might be a good sign, as it shows that Gazprom closely follows industry developments and is capable of adapting to market changes. But, on the other hand, it emphasises the point that more gas will be diverted away from Ukraine and sent to Europe via Nord Stream. Furthermore, the decision to delay Shtokman appears to be at odds with the assessment of Gazprom's foreign partners, which, prior to the official announcement of the delay, insisted that the project was technically and economically viable. It is notable that just a week before delaying FID, Gazprom rejected SD AG's plan to build an LNG loading terminal near Teriberka (near Murmansk). It proposed an alternative site at the larger Orlovka bay, on the grounds that there would be more space for LNG carriers to manoeuvre and more scope for future expansion (i.e. in Phases II and III). This suggests that Gazprom is concerned that the planned infrastructure covers only Phase I of the project's development, and the burden may prove excessive for Gazprom Dobycha Shelf, which is due to operate Phase II and III. The fact that the Teriberka site was rejected when the front-end engineering design (Feed) study was almost complete suggests that Gazprom uses the period of a 'gas glut' in the market not merely to delay the project but to make foreign shareholders take into account its long-term interests when designing infrastructure.

The development plan assumes a time lag of three years between each phase. If production starts in 2015, and a three-year build-up period is applied to production, the plateau production of 71bcm/year can be reached in 2023.

Figure 31 – Shtokman production profile



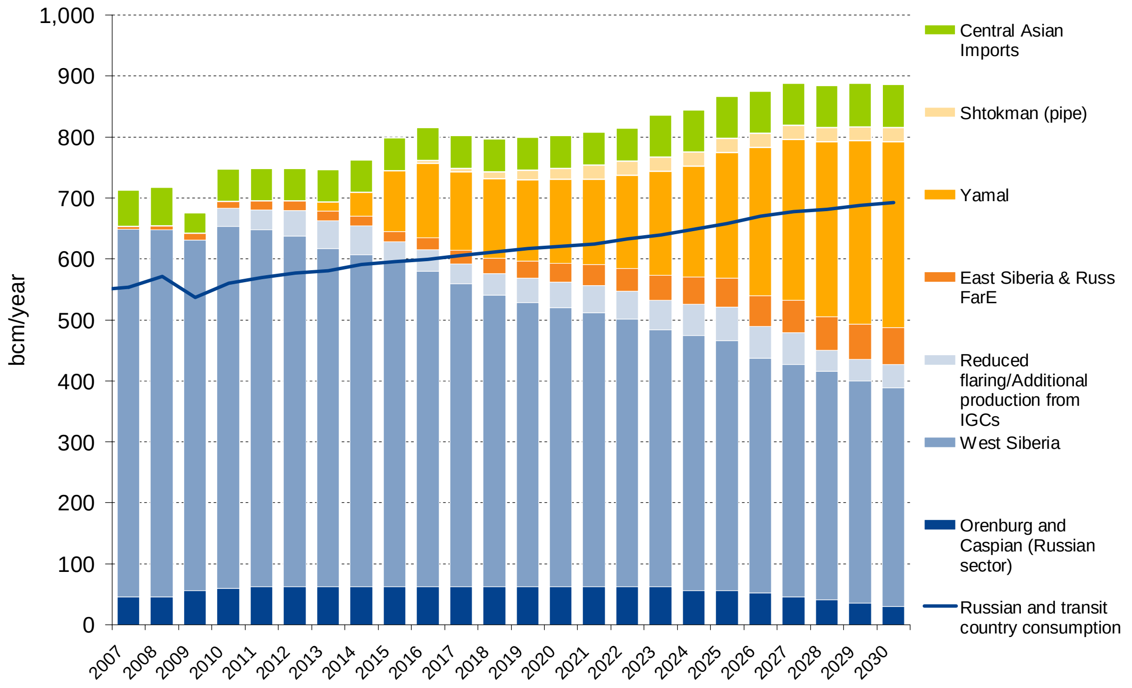
Phase II will be, according to Gazprom's existing plans, a copy of Phase I, with the same split of capacities between piped gas and LNG. Phase III will also be similar to Phase I for the offshore part, but the current assumption is that all gas in this phase will be LNG. Both phases are presently envisaged to be developed without the participation of foreign partners.

3.3.3.4 Regional production to 2030

The above sections vividly demonstrate that Russia possesses vast reserves, but the era of 'easy gas' when Gazprom could extract large volumes from only a handful of very large fields, is coming to an end. Developing new super-giants is expensive and risky, particularly in the current economic climate and at a time of a 'gas glut'. Nevertheless, investment funds continue to be allocated to the development of the Bovanenkovo field on Yamal, which has so far been delayed by only a year. The outlook for Shtokman is less certain.

Figure 32 gives projections of Russian gas production by region to 2030. It highlights the point elaborated in earlier sections that West Siberia dominates Russian gas production and will continue to do so to 2030. A key addition to the production profile will be the Yamal peninsula, with the start of the Bovanenkovo field in 2012 and the addition of the Kharasavei and Kruzenshtern fields in the medium term. We envisage first gas from Shtokman after 2015. Central Asian imports are seen as relatively stable throughout the period. Political issues surrounding the import of Central Asian gas to Russia are set out in Section 3.5.

Figure 32 – Russian production to 2030, in bcm by region



3.4 Politics and geopolitics of Russian gas

Gazprom makes no secret of its goal to raise its market share in Europe from the current 28% to 33% by 2015. It also makes no secret of its other goal: to supply 25% of global LNG supply by 2030. The two goals are seldom articulated in the same policy documents or public speeches, as having them side by side reveals the enormity of the task and raises the question of its achievability.

Add to this the policy of pipeline diversification to bypass the 'troublesome' transit states and the need to develop not just new gas fields but pristine gas provinces in the Russian north. Domestic demand that consumes over 70% of Russian gas output is a well-known burden on the state monopoly, which has a social responsibility to gasify the country, including its eastern regions, some of which lack even basic infrastructure.

There is also the need to upgrade parts of Russia's Unified Gas Supply System that comprises over 158,000 km of pipelines, making it the largest network in the world. Gazprom is the operator of this network, but this is a mixed blessing, as almost a quarter of the lines are over 33 years old, and 40% of them are between 21 and 33 years of age. The enormity of the tasks is apparent, as is the stark need to prioritise some projects over others.

In this section, we look at three sets of factors that will affect the flows of Russian gas to Europe. Firstly, we examine Moscow's policy of diversification, its origins and the new pipelines that will be used to carry Russian gas directly to European markets. We then look at Russia's legal framework governing gas and recent revisions that have formalised the concept of strategic sectors and fields. The implications of these revisions for gas are both profound and long-lasting, and will have an impact on translating resources into reserves as well as reserves into production. Finally, we analyse the development models for large-scale projects that Gazprom and Russia's political leadership currently favour, considering some of its main advantages and shortcomings, which will influence foreign investor decisions on whether to get involved in the Russian oil and gas sector. These factors acquire even greater relevance at a time of the global economic downturn and uncertainty in the gas market.

3.4.1 Establishing priorities

Priorities are often determined by two sets of factors: Gazprom's policies and the preferences of the Russian state, which may or may not converge with those of Gazprom. On some issues, such as redirecting gas flows to avoid Ukraine, they do coincide, which facilitates the implementation of the policy, as discussed in Section 3.4.2. On other issues, such as the development of Russia's eastern regions or the construction of pipelines to China, the situation is more complex, as Gazprom is reluctant to sponsor the construction of pipelines that it perceives to be uneconomic. The outcome is frequently the result of behind-the-scenes negotiations, after which Gazprom promises to advance the policy of gasifying remote Russian regions and is in return allocated licences for new fields.

There is then the third category of actions: those to which the Russian state awards priority and pressures Gazprom to have them implemented. An example of this is the opening in August 2009 of the Dzuarikau-Tskhinvali gas pipeline to supply gas from Russia to South Ossetia, one of Georgia's breakaway regions, which after the Russian-Georgian war last year was recognised as an independent state by Russia. The gas pipeline was clearly a gesture from Moscow to emphasise Russia's support for the breakaway region. It was inaugurated less than a year after its announcement and was made to coincide with the first anniversary of South Ossetia's proclamation of independence. At the opening, Prime Minister Vladimir Putin stated that "in case of need" South Ossetia would be able to become a transit state for Russian gas. Whether Putin meant that South Ossetia will re-export Russian gas or simply allow for its transit is unclear. What is remarkable, however, is the indication implicit in Putin's statement: that South Ossetia, which remains unrecognised by the international community and where tensions with Georgia are running high, is potentially more reliable for the transit of Russian gas than Ukraine or Belarus, which Russia has been seeking to bypass on the grounds of reliability of supplies to Europe.

3.4.2 The policy of bypass pipelines: The cases of Nord Stream and South Stream

Statements that raise the possibility of South Ossetia becoming a transit point for Russian gas detract from the otherwise relatively coherent and consistent strategy pursued by Gazprom for over a decade. Gazprom has promoted the policy of avoiding transit states since 1996, when after several severe interruptions of gas supplies from Ukraine to Turkey via the then only existing 'western' route', it announced the construction of the pipeline under the Black Sea – Blue Stream. Gazprom's determination to bypass all transit states grew over time to encompass Belarus and Poland. It has also acquired political overtones and saw increased involvement from the government, as demonstrated, for example, by Prime Minister Putin taking a lead in negotiations with Ukraine during the January 2009 dispute.

It is little known that Gazprom's original plan was to transport gas from the Yamal peninsula via two lines that would run across Belarus and Poland. In 1999, the first of the lines – Yamal-Europe I – was completed, and its capacity was gradually raised from 10bcm to 28bcm. Gazprom preferred to use the Belarusian-Polish route instead of the Ukrainian for moving new gas – from Yamal – to the export markets. In the event, Yamal was delayed and the Yamal-Europe I line has since been used to transport West Siberian gas.

Continued difficulties with Ukraine in the early 2000s led Russia to think through alternatives to exporting even old gas – from West Siberia – via Ukraine. Among the early plans was the creation of a link between Poland and Slovakia (from the already existing Yamal-Europe I pipeline) that would have fed into the network in Slovakia bypassing Ukraine. The plan envisaged raising the capacity of the existing Yamal-Europe line and constructing a parallel one, with perhaps a parallel link to the Slovakian network.

Russia and Slovakia came to an agreement on the matter, but Poland had objections and the plan never got off the ground. Had it been realised, it is likely that Russia would have never opted for expensive pipelines under the Baltic Sea. But difficulties with Poland, which over time acquired distinctly political overtones, compounded by increasingly uneasy relations with Belarus, led Moscow to decide that supplies would be safest if they avoided transit states altogether, with the gas being delivered directly to Germany. Gazprom subsequently rejected the Amber project – from Torzhok across the Baltic states to Poland and Germany – which Warsaw proposed as an alternative to the undersea Nord Stream pipeline.

Presently, Gazprom plans to construct two key bypass pipelines: Nord Stream and South Stream. Their envisaged combined capacity will be 118bcm, of which Nord Stream will account for 55bcm and South Stream for 63bcm. This pipeline capacity far exceeds the additional contracts that Gazprom expects to sign with its European customers. These stand at 30-38bcm, according to the General Scheme of the Gas Industry Development to 2030. The resultant excess pipeline capacity highlights Russia's strategy of pipeline diversification, which Gazprom believes will increase the safety of gas deliveries to Europe by reducing reliance on Ukraine as a transit state. From the perspective of the Russian state and Gazprom, a critically important outcome of this strategy will be Moscow's increased control over its strategic export commodity – gas.

The Nord Stream and South Stream projects represent an evolution in Russian strategic thinking in gas, with neither Gazprom nor the Kremlin concealing the real reason for its implementation. Though couched in the diplomatically acceptable vocabulary of the diversification of supplies, Gazprom's primary aim is to create alternative – direct – outlets for its gas to European markets. Gazprom's preparedness to invest in costly new routes highlights the fact that European markets continue to take centre-stage in Gazprom's strategic thinking, and the monopoly continues to see Western Europe as its main customers in the long-term.

Nord Stream

The construction of Nord Stream began in 2005, with the laying of the foundation of the onshore section from Gryazovets to Vyborg. This part of the line, fully financed by Gazprom, will be 917 km in length. It will run through the Vologda and Leningrad regions before reaching the Portovaya Bay (near the town of Vyborg). Currently, over 600 km of the Gryazovets-Vyborg pipeline have been constructed, with the remainder due for completion by the end of 2010. Meanwhile, Gazprom started works on the Portovaya compressor station in mid-January and the building of the offshore section of the pipeline began in April 2010.

The underwater section under the Baltic Sea will be 1,220 km in length. It will exit in Greifswald, Germany, from where two onshore connections will be built to the south and west of the country. The total length of these extensions will be 850 km and they are to be built by WINGAS and E.ON Ruhrgas. From Germany, gas can be transported onwards to Denmark, the Netherlands, Belgium, France and GB.

Figure 33 – The route of the Nord Stream pipeline

Source: Nord Stream

The project's main shareholders are Gazprom (51%), Wintershall (20%), E.ON Ruhrgas (20%) and Gasunie (9%). The project is being constructed by Nord Stream AG. Gazprom has signed 'ship or pay' agreements with the operator, thus accepting to bear the risk of shortage in supplies.

First gas from Nord Stream is scheduled to be delivered in 2011. Initially, one pipeline will be built with annual transport capacity of 27.5bcm. In the second phase, which, according to the official schedule, is due to be completed in 2012, a parallel pipeline will be laid to double the capacity to 55bcm.

Some 22.5bcm of the first phase have been contracted:

- WINGAS, Germany – 9bcm/annum;
- E.ON Ruhrgas, Germany – 4bcm/annum;
- Gaz de France, France – 2.5bcm/annum;
- Dong Energy, Denmark – 1bcm/annum; and
- Gazprom Marketing & Trading, UK – 6bcm/annum.

In October 2010, Gazprom and DONG Energy signed a contract for an additional 1bcm/annum for an 18-year period. This gas is to be delivered via the second string of Nord Stream.

The contract for the pipelines for the second phase was awarded in late January 2010 following a tender. Three companies have been selected: Germany's Europipe (65%), Russia's OMK (25%) and Japan's Sumitomo (10%). The contract is worth €1 billion and the delivery of pipes will start in May 2010. The project is benefiting from the economic crisis, which has reduced the price of steel, making it significantly cheaper than the consortium initially estimated. This could ultimately reduce the cost of the Nord Stream project, which in March 2007, was revised upwards from €5 billion to €7.4 billion.

Nord Stream has been recognised by the European Commission as a Trans-European Energy Networks (TEN-E) project. The project is therefore considered 'of European interest', which has strengthened the consortium's stance in negotiations with the littoral states. These have at times been difficult, particularly over the permitting process. Denmark became the first country to grant a construction permit in October 2009. It was followed by Sweden and Finland in November, and Russia and Germany in quick succession in December. A major hurdle has now been overcome, putting the construction back on schedule.

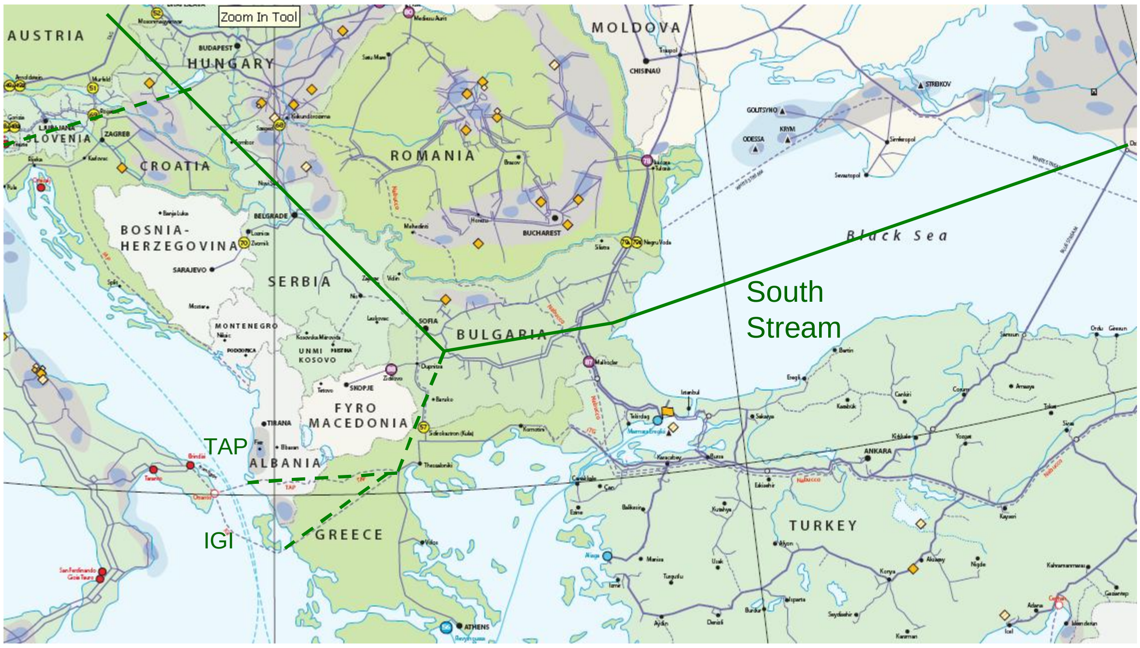
South Stream

The South Stream project was announced in June 2007, with Gazprom and ENI signing a Memorandum of Understanding to execute the project. Moscow made no secret that the project had been initiated with the purpose of avoiding transit states. In January 2008, a company, South Stream AG, was registered in Switzerland, jointly owned by Gazprom and ENI. At the signing ceremony, Gazprom Deputy Chairman Medvedev said that the MOU was a 'further step towards the tangible execution of Gazprom's strategy to diversify Russian gas supply routes towards European countries'.

In December 2008, Eni's CEO stated the whole South Stream project would cost €10 billion. The Kremlin estimates that the Bulgarian section alone would cost €1.4 billion. However, since then the capacity of the pipeline has risen from 31bcm/annum to 63bcm/annum. An agreement to this effect was signed with ENI in May 2009, and the influence of the January 2009 Russian-Ukrainian gas crisis, which strengthened Russia's resolve to further divert pipeline flows away from Ukraine, appears obvious. The latest cost estimate came from Gazprom CEO Alexei Miller in May 2009 when he put the total for both the offshore and onshore sections of the route at €8.6 billion.

South Stream envisages the construction of a 900-km pipeline to Bulgaria under the Black Sea (maximum depth at which the pipeline is to be laid is 2 km). From there, the pipeline will fork, with the north-western route going across Serbia, Hungary and Austria, and the south-western route running through Greece and Italy, as demonstrated in Figure 34.

Figure 34 – Proposed route of South Stream pipeline



Source: GTE and Pöyry Energy Consulting

The construction of the undersea section of the pipeline is expected to start in 2013, but the deadlines for individual onshore sections are yet to be set. Feasibility studies for the onshore sections are planned to be completed by the fourth quarter of 2009, and consolidated feasibility studies in 2011. The target completion date for the entire project is currently set for December 2015.

The pipeline will start at the Beregovaya compressor station in Dzhubga, Russia, and run to Varna on the Bulgarian coast. The starting point for the pipeline is the same as for Blue Stream to Turkey. The most economic route for a pipeline from Dzhugba to Varna would be across the middle of the Black Sea; however, this design would infringe on the EEZs of Ukraine and Romania, and lead them to try and block the project.

In February 2009, there were indications that Moscow had asked Turkey for permission to build the undersea section across the Turkish EEZ. This was confirmed in the Ankara Accord signed in August 2009, in which Turkey allowed its territorial waters to be used for the construction of the South Stream pipeline.

Although the South Stream pipeline crossing its EEZ is in line with Turkey's ambitions to transit regional gas, it also has other interests at stake, which it has sought to advance. For instance, Turkey has used its position as the most amenable partner of the potential transit states for South Stream to convince Russia to join the proposed Samsun-Ceyhan pipeline – to be built by ENI and Turkey's Calik Holding – to carry oil to the Mediterranean. The work on the pipeline could start after the feasibility study and is in revision of Russia's earlier position when it supported the Bourgas-Alexandroupolis oil pipeline from Bulgaria to Greece. The two countries also agreed to cooperate in atomic energy.

Meanwhile, Russia has pressed on with signing inter-governmental and corporate agreements with the countries that are interested in participating in South Stream.

- In January 2008, Bulgargaz agreed with Gazprom to jointly own and operate the section of the pipeline passing through Bulgaria. Gazprom had been pushing for a controlling stake but settled for 50%. On 15 May 2009, an agreement was signed in Sochi between Gazprom and Bulgarian Energy Holding, paving the way for a 50:50 JV that will conduct the feasibility study for South Stream's Bulgarian section, build and run it.
- In January 2008, Srbijagas and Gazprom agreed to form a joint owned company to build and operate a gas storage facility in Serbia and a section of pipeline leading from Bulgaria into Hungary. Overall, Gazprom's deal with Serbia was wide-ranging. It gave Gazprom Neft a 51% stake in Serbia's oil company as well as the opportunity to own and operate half of a new storage facility.
- In April 2008, Russia and Greece signed an agreement for South Stream to pass through Greece.
- In March 2009, Gazprom and Hungarian Development Bank sign cooperation agreement to build and operate the section of South Stream passing through Hungary. In addition, Hungarian MOL will build and operate a gas storage facility in partnership with Gazprom.
- The latest agreement was signed with Slovenia in November 2009. Gazprom and Slovenia's Geoplin Plinovodi will form a join venture to operate the pipeline in a 50:50 JV. For Slovenia, the construction of the South Stream pipeline is perceived as beneficial because of potential transit fees that would accrue if Hungary and Italy were to be connected to South Stream through Slovenia.
- Austria has until now been the most reluctant of the countries that Gazprom would like to join because it leads the Nabucco consortium, which plans to build a 31bcm line to deliver gas from the Caspian region and Central Asia to central Europe by 2012–13. However, in November 2009, the Austrian Economy Ministry said that it had opened negotiations with Russia regarding its potential involvement in South Stream. An intergovernmental agreement needs to be secured before Gazprom could begin direct negotiations with OMV.
- The latest boost to South Stream came in February 2010 after Romania confirmed interest in participating in South Stream. It agreed to have a feasibility study conducted in its Exclusive Economic Zone for a possible pipeline route across Romania. This development is significant because Romania is one of the two staunchest supporters of the Nabucco pipeline. Having a possibility of laying the South Stream pipeline through the Romanian EEZ will strengthen Russia's bargaining position vis-à-vis Turkey and even Bulgaria. Indeed, in one of its press releases, Gazprom stated that it did not rule out Romania's inclusion 'in place of Bulgaria, depending on the level of interest shown by the parties'. Nevertheless, at this stage of negotiations, it appears that Bulgaria will host the pipeline, but constructing the line via Romanian territorial waters would result in a shorter undersea stretch and lower costs. Meanwhile, to keep the dialogue open with Turkey, Russia can keep Blue Stream II as a possibility in its discussions with Ankara.
- Remarkably, Ukraine's new president, Viktor Yanukovich, has expressed interest in joining South Stream. Speaking to foreign journalists, he stated that Ukraine would prepare proposals to join this project and to create a consortium with the participation of the EU and Russia that would refurbish the Ukrainian network, thus raising its transit capacity to 200bcm/annum. These developments suggest that relations with Kiev could improve over the coming weeks and Russia's perceived need for a 63bcm-

pipeline will recede. In this case, Russia could return to its original plan to construct a 31bcm pipeline. Relations would have to improve significantly more – perhaps beyond what is politically feasible in the short term – in order for Moscow to consider cancelling South Stream altogether.

Provided all intergovernmental and corporate agreements are in place, the key question for South Stream becomes: Where will the gas from South Stream come from?

Some volumes could, no doubt, come from projected new production from the Russian sector of the Caspian Sea, and some from the development of the onshore areas in the south of Russia. Moscow has made no secret of its ambition to purchase all output from Phase II of Azerbaijan's Shah Deniz field in the Caspian Sea, for which it now competes with the Nabucco consortium. In an effort to buy the bulk of Central Asian gas, it changed in December 2008 the formula at which it buys Turkmen, Kazakh and Uzbek gas to reflect the international price of gas (minus transportation costs and other expenses), but the economic crisis and falls in gas demand have led it to stop taking the contracted volumes in April 2009. Exports from Turkmenistan were resumed almost nine months later, in January 2010, but at a lower level. The states of Central Asia have already begun to diversify their export routes, which will reduce the volume available to Russia. This is discussed in Section 3.5.1. For South Stream, this means further diversions of gas from the currently used 'Central corridor' via Ukraine to the 'Southern corridor' via Bulgaria and onwards to Western Europe.

That the main reason behind South Stream is the re-direction of the currently flowing volumes of gas away from Ukraine is acknowledged at the highest level. For instance, the General Scheme for the Gas Industry indicates that South Stream is aimed at increasing Russia's manoeuvrability with regard to gas exports to Europe and enabling it to shift some gas exports away from the Ukrainian route. In a recent statement, Miller reinforced the point when he stated that the Nord Stream and South Stream projects are being realised to reduce transit risks, while an increase in export volumes is being considered as an "additional opportunity".

3.5 Central Asian and Caspian production and exports

Traditionally, Russia has bridged the deficit in its own production by importing gas from Central Asia. The current geopolitical shifts in the region, however, are making the sustainability of this policy increasingly uncertain. Turkmenistan's determination not to sell gas to Gazprom at a price lower than the one stipulated in the December 2008 contract led to a supply halt in April 2009. The dispute was finally resolved in late December 2009, following a high-profile visit of a Russian delegation to Turkmenistan. The new agreement stipulates new export volumes to Russia – 30bcm in 2010 and through to 2028. This is significantly lower than the 70–80bcm/annum contained in the previous agreement and the 50bcm that Russia imported from Turkmenistan in 2008. The price was not revealed, but it is clear that Ashgabat's position throughout the negotiations was strengthened by its increased options to export gas to countries other than Russia. Indeed, in December 2009, it opened a pipeline to China, followed in January by a new pipeline to Iran.

Another project that could broaden Turkmenistan's options is Nabucco. This project has received support from the EU, but has been dogged by numerous delays. Although the Nabucco line will not displace or pose any serious competition to Russian gas, Moscow has been keen to preclude the entry of this marginal source of gas into Europe by promoting the South Stream project. It has also expressed interest in buying up all the gas from Phase II of the Shah Deniz field in Azerbaijan, intended to supply the Nabucco pipeline. Without the Azerbaijani gas, Nabucco is unlikely to be viable any time in the future because alternative sources – from Iran and Iraq – are not currently available.

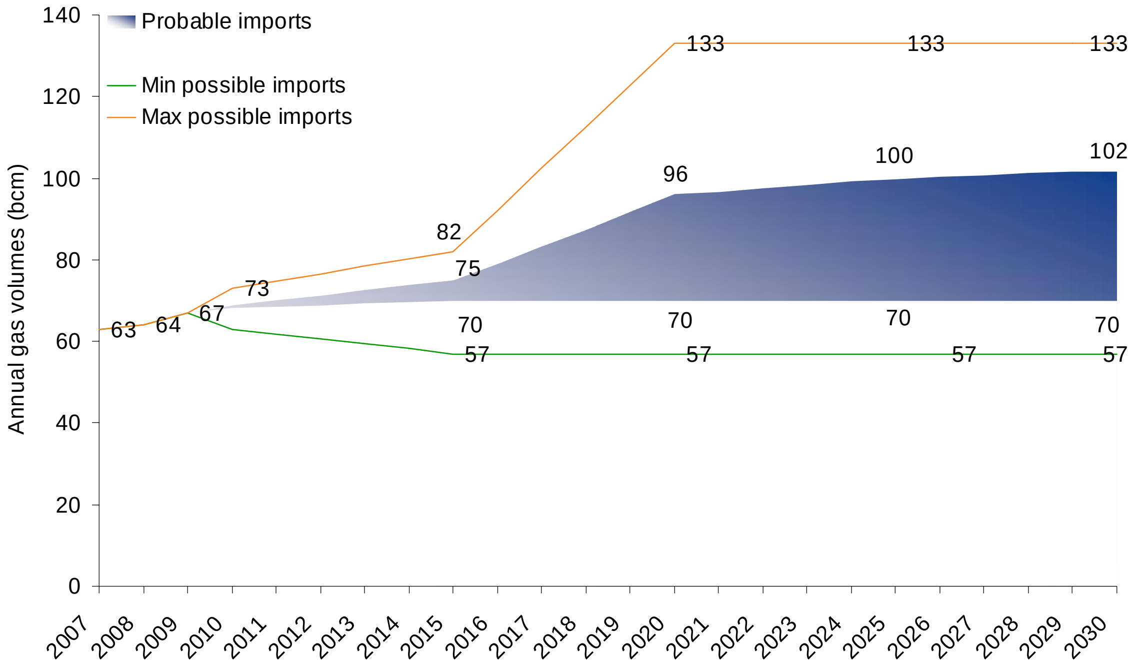
3.5.1 Russian imports from Central Asia

The total that Russia could import from Central Asia if all government agreements were honoured would be 133bcm/year in 2020. This is more than double the volume that Russia imported from Central Asia in 2007 (63bcm) and what it imported in 2008 (64bcm).

However, remarkably, in the General Scheme for the Development of the Gas Industry, Russia considers only modest growth in imports from Central Asia between 2007 and 2030. These are illustrated in Figure 35.

Although 70bcm is at the lower end of projected imports, it is this figure that has been assessed by the Russian Energy Ministry as 'the most likely and justified scenario' of combined exports from Uzbekistan, Turkmenistan and Kazakhstan in the long run.

Figure 35 – Gazprom's expectations of imports from Central Asia



Source: Gazprom, Pöyry Energy Consulting

This assessment is predicated on three factors:

- Russia recognises Central Asia's production constraints, despite the existence of large reserves;
- it recognises pipeline capacity constraints to Russia and the need for refurbishment, but is not particularly optimistic about the prospects for constructing new lines (such as the Caspian Littoral Pipeline); and
- it takes into account the determination of the Central Asian states to diversify their outlets to energy markets and implicitly acknowledges that it is unable to preclude them from constructing new pipelines that bypass Russia.

Based on the first two assumptions, the Russian ministries and Gazprom estimate the following volumes of gas to be exportable from Central Asia in 2015-20:

- Uzbekistan: 10bcm largely unchanged from the present levels, due primarily to large domestic demand in Uzbekistan as well as large energy inefficiencies and lack of sufficient infrastructural investment ;
- Turkmenistan: 84bcm in 2015 (in contrast with the Turkmen government's projection of 125bcm) and 102bcm in 2020 (vs.140bcm); and,
- Kazakhstan: 20bcm in 2015 and 26bcm in 2020.

The aggregate numbers reveal that in its projections, Gazprom has factored in exports to China (30bcm) and Iran (14bcm). The Turkmenistan-China pipeline inaugurated in December 2009 will carry up to 40bcm/year, while the second line to Iran opened in January 2010 has raised Turkmenistan's export capacity in that direction from 8bcm to 14bcm/annum. The latter runs from Turkmenistan's Dauletabad field to Iran's gas processing plant in Khangiran. This 30.5 km pipeline was constructed in five months and its capacity can be raised to 20bcm/annum. Thus, the volume of gas that could flow from Turkmenistan to the east can be up to 60bcm/annum. The volume of gas that Russia has contracted to receive from Turkmenistan is 30bcm, which is lower – and more in line with the General Scheme – than the one stipulated in the earlier bilateral agreement.

The fact that Gazprom no longer expects all of Central Asia's exportable output to be sent to Russia represents an evolution in the country's political relations with the region. Nevertheless, a more pragmatic approach to Central Asia's pipelines to China and Iran is not matched with a similar approach to potential pipelines from the Caspian region to the EU. A pipeline of special importance here is Nabucco.

3.5.2 EU's 'Southern corridor' pipelines: Nabucco

Nabucco is one of the pipelines in the Southern Gas Corridor – a term used by the European Commission to describe planned infrastructure projects to bring gas from the Caspian and the Middle East to Europe in order to improve the security of supply. The pipelines of the Southern Corridor would bypass Russia.

Nabucco is one of the key projects in this regard. It has been in gestation for over eight years. First talks on the project took place in February 2002 between Austria's OMV and Turkey's Botas. Subsequently, Hungary, Romania and Bulgaria joined the project. In June 2002, all five parties signed a protocol of intent to jointly construct a new gas pipeline that will connect Middle Eastern, Egyptian and Caspian gas reserves with Austria and take them further to West European markets.

Currently, Nabucco has six shareholders, all holding 16.7% each. Four of these, Botas, Bulgargaz, Transgaz, and MOL are the national transporters of the transit countries for the pipeline. OMV operates the Central European Gas hub in Austria where half the gas transported in Nabucco is expected to end up, and the most recent shareholder to join project is RWE.

Azerbaijan and Turkmenistan are currently envisaged as the main suppliers to Nabucco, but an easing of the international situation around Iran would raise the country's profile as a potential supplier. Some overtures, mostly informal, have been made to probe Russia's willingness to contribute gas to the pipeline, in the initial stages. Russia did not refuse outright, but it has little incentive to support Nabucco, as it competes with its South Stream pipeline both for markets and the sources of supply.

Figure 36 – The route of the planned Nabucco pipeline from the Caspian

Source: www.nabucco-pipeline.com

The question of the sources of supply is particularly relevant for both projects considering the depletion of Russia's southern gas fields at Orenburg and the rapid maturation of the producing fields in West Siberia. The most economic sources of gas for South Stream would be from the fields in the Caspian Sea and Central Asia. For this, Russia would have to grow output in its sector of the Caspian Sea and ensure supplies from other Caspian/Central Asian states. However, delivering the gas across Russia would leave spare capacity in Nabucco, rendering the pipeline unviable.

The main source for Nabucco is to be Azerbaijan's Shah Deniz field, which is currently exporting 8.2bcm. The export volume is expected to rise after Phase II of the project comes online, raising production to 19.6bcm/annum. However, delays to Phase II have been announced by project partner StatoilHydro, which cited difficulties in negotiating transit terms for this gas with Turkey. The expected launch date for Phase II has been moved from the initial 2012 to 2016, initially, for technical reasons and currently, pending the signing of a commercial agreement.

Difficulties in negotiating with Turkey are two–fold. On the one hand, they are of economic nature, as Turkey would like to buy larger volumes from Shah Deniz. A solution that would be acceptable to all parties is yet to be found, but the construction of Nabucco is impossible without Turkey, as over 2,000 km of the pipeline will run on Turkish soil.

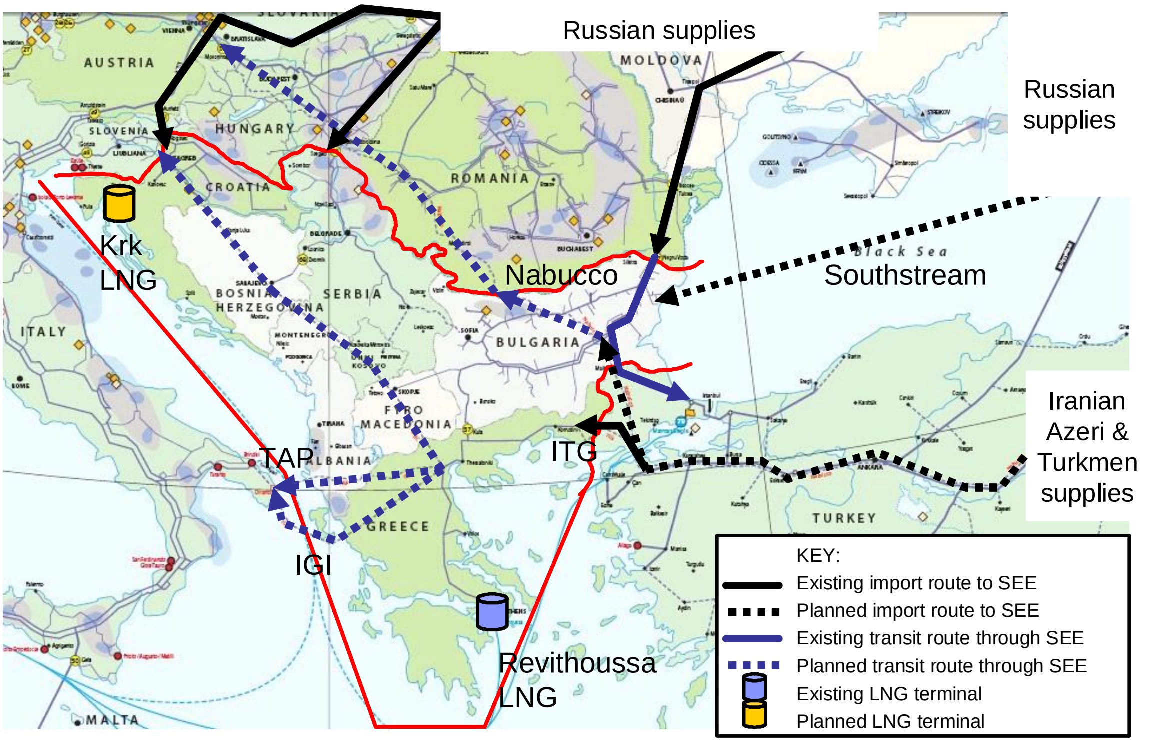
On the other hand, the difficulties have acquired increasingly political overtones, with the Turkish leadership linking an agreement on gas transit to Europe with Turkey's prospects of acceding to the EU. Political relations with Azerbaijan are also becoming increasingly complex, as Turkey considers opening borders with Armenia, with which Azerbaijan has the unsettled conflict over Nagorno-Karabakh. Turkey closed its borders with Armenia in the early 1990s in support of Azerbaijan, but its currently changing political stance is leading Azerbaijan to reconsider sending all of its gas exports via Turkey. Baku has expressed readiness to sell gas from Phase II to Russia for 'transit to Europe'. Indeed, first supplies of Azerbaijani gas started in January 2010, with Gazprom characterising the event as highly significant. The agreement reached between Gazprom and Azerbaijan's Oil and Gas Company, SOCAR, states that early export volumes to Russia will be 500mcm/year, but it does not set the upper limit, thus leaving the competition for Shah Deniz gas open. It is possible that Baku hopes to drastically increase the production of gas from the Azeri-Chiraq-Guneshli complex of fields where gas wells are expected to be drilled.

Turkmenistan remains even more undecided than Azerbaijan. After sending equivocal signals to both Russia and the West on the preferred route for its gas, Ashgabat has completed its section of the pipeline to China, which will eventually connect to the East-West pipeline. Ashgabat has given no indication that it will commit to the Trans-Caspian pipeline that would link with Nabucco in Azerbaijan. Thus, there are still no secure suppliers that would guarantee the necessary volumes to the pipeline. Baku is likely to prefer Nabucco to exporting all of its Phase II output to Russia, and Nabucco shareholders are adamant that the project is economically viable. Even so, the pipeline will need a second supplier to fill the projected 31bcm capacity.

3.5.3 EU's 'Southern corridor' pipelines: TAP and ITGI

In addition to difficulties with securing supplies from the east, two Western projects find themselves in competition with Nabucco for Azerbaijani and, to a lesser extent, Iranian gas. These are the Trans-Adriatic Pipeline and the Turkey-Greece-Italy Interconnector (IGI).

Figure 37 – A map of planned gas pipeline projects in SE Europe



Source: GIE and Pöyry Energy Consulting

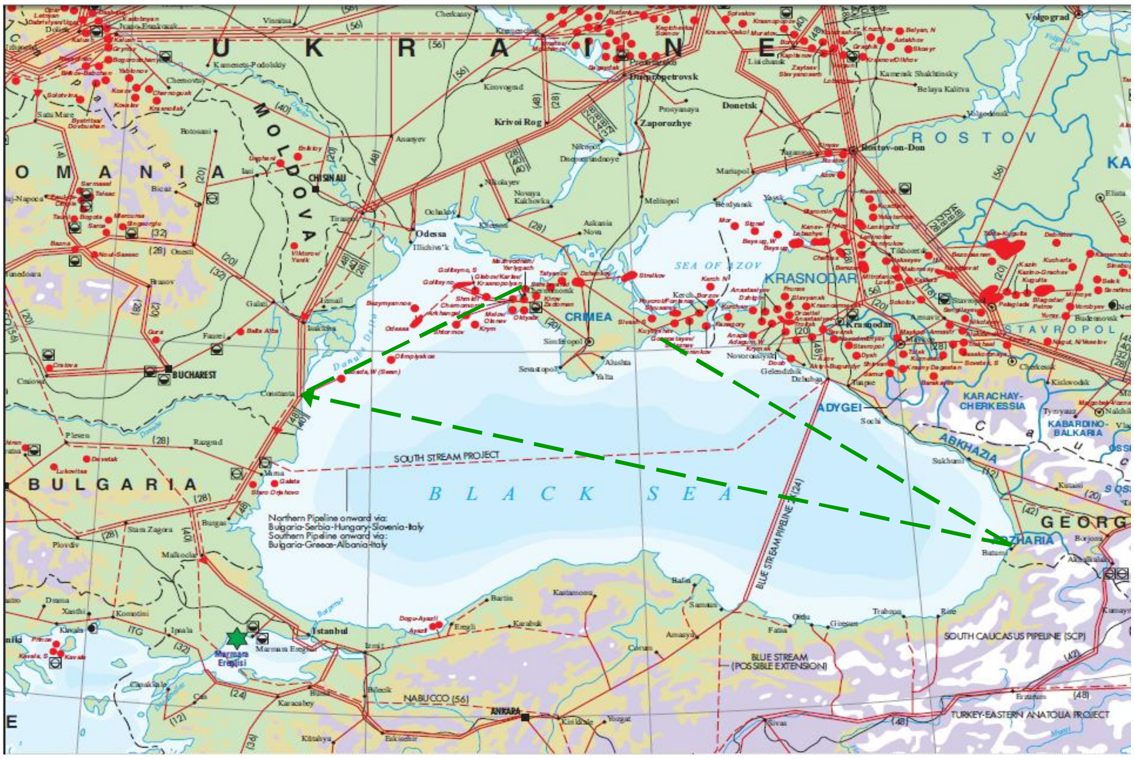
TAP would take gas from Greece to Italy across Albania. It is a project that is being promoted by EGL, but until recently, there existed vast uncertainty over the sources of supply. In March 2008, EGL and the National Iranian Gas Export Company signed an agreement for the supply of up to 5.5 bcm of gas through the existing Iran-Turkey link for a 25-year period. Perhaps more importantly, at around the same time, EGL and StatoilHydro established a JV to develop, build and operate TAP, which has given the pipeline a significant boost because StatoilHydro owns a 25.5% stake in the Shah Deniz field and will now seek to develop this pipeline as an outlet for Caspian gas. There has been recent talk of a LNG terminal in Albania, which would be a potential supply source to Italy, particularly as LNG terminals have had such difficulty in obtaining planning permission in Italy.

A project competing with TAP is IGI, which has a planned offshore section, with Edison and Depa as 50/50 partners. The offshore section, also known as the Poseidon project, would have capacity of 8 bcm/annum. Edison and DEPA hope to fill the section with gas from Phase II of Shah Deniz. In two separate inter-governmental agreements, Azerbaijan has indicated its readiness to supply gas to the two companies. However, in 2009, Baku announced that it failed to reach an agreement with Turkey on the transit of additional volumes of gas to Greece (Azerbaijan is currently supplying 1bcm of gas to Greece through the BTE and the Turkey-Greece Interconnector).

3.5.4 EU's 'Southern corridor' pipelines: White Stream

The White Stream pipeline, which would deliver Caspian gas to Ukraine and Central Europe, is less likely to be implemented than either Nabucco or South Stream. The idea to construct this pipeline was born of frustration in Kiev with the Russian government and Gazprom's demands to raise gas prices to the European level.

Figure 38 – A map of the planned White Stream project



Source: Petroleum Economist and Pöyry Energy Consulting

The route for this pipeline remains undecided, but two main options are being considered:

- The first would link Georgia with Ukraine and Romania.
- The second would have a longer sub-sea section, and link Georgia directly with Romania.

The latter would not alleviate Ukraine's energy problems, but it would help diversify gas sources for Central and South-east European states, which are currently heavily reliant on Russia.

3.5.5 Investment in Turkmenistan

Clearly, the proposed pipelines cannot be filled with gas from Azerbaijan alone. In this context, securing supplies of gas from Turkmenistan becomes increasingly important. The country has recently received a lot of attention, especially in comparison with the scant international exposure it had under late President Saparmurat Niyazov. Its potential role in providing the gas to enable the implementation of the Southern Corridor projects was enhanced after the results were announced of an international audit conducted by Gaffney, Cline & Associates. This audit confirmed the existence of large reserves in the fields of South Yolotan-Osman and Yashlar. Even at the lower estimate of 4tcm, the super-giant South Yolotan-Osman field is larger than Russia's Shtokman field. The top-end estimate for the field could be as high as 14tcm, as much as the total proven reserves of countries like Nigeria or Algeria. South Yolotan-Osman is not without its difficulties: it is, for example, expected to contain high levels of sulphur, but its development is likely to be far less technologically challenging than the launching of the Shtokman field in the Barents Sea. Yet controversy continues to surround the results of the audit, with questions raised over the quality of geological and other data provided by the Turkmen government and Gaffney, Cline & Associates' lack of direct access to wells. This has not precluded many of the investors showing keen interest in the country.

3.6 Middle Eastern and North African exports

Russia, Qatar and Iran are the three most important gas reserve holders in the world, accounting for over a half of total proven reserves. They are significant producers of gas, but together account for only 27% of world production. In this section we look in a little more detail at Iran and Algeria, as both have pipelines into Europe – Iran into Turkey, and Algeria into Spain and Italy.

3.6.1 Iran

Russia and Iran are very large users of gas. Iran holds the third place in gas consumption in the world, after the United States and Russia. Its domestic demand almost doubled in 2000-08 and is expected to continue to grow rapidly, albeit at a slower pace. Iran has therefore sought to ensure the opening of new pipelines from Central Asia, such as the Turkmenistan-China line. Iran is currently a net gas importer. It has been exporting around 4-6bcm to Turkey since 2003 and importing some 6bcm from Turkmenistan, but this capacity has been raised to 14bcm and could be raised further to 20bcm.

An increase in exports, especially LNG, is unlikely in the short to medium term. The situation with the growing domestic demand, in part the result of subsidies, is compounded by a complex political situation around Iran and the application of sanctions by the United States, which preclude large-scale international investment in the country. However, Iran's geographical location, coupled with large reserves, will enable it to become a significant exporter of gas in the long term.

Iran's largest field is South Pars. Located in the Gulf, it is the world's largest gas field. Two countries share the field – Iran and Qatar. Iran planned to drastically increase production to 195bcm this year from 107bcm in 2007 (excluding gas re-injected for oil production). But this is unrealistic, as there are a number of problems in the upstream development: insufficient investment, politically motivated decisions in the choice of contractors, inability to install LNG trains without external technical expertise and financial burden-sharing.

3.6.2 Algeria

There are more than 15 natural gas fields in Algeria, of which ten have been developed on a large scale. Hassi R'Mel is the first and by far the largest gas field in Algeria. It was discovered in 1956, along with the giant oil field of Hassi Messaoud. Its recoverable reserves have been estimated at 2.4tcm. Probable reserves have been estimated at 2.7-3.0tcm. The field supplies both the domestic market and export markets. Gas from it is pumped to the Mediterranean terminals of Arzew and Skikda.

Hassi R'Mel has processing facilities with a capacity of 100bcm/year to produce 91bcm/year of dry gas, 18.2mt/annum of condensates and up to 3.84m t/y of LPG. Most of these facilities were installed in the 1970s and 1980s:

- Algeria's oil and gas industry was nationalised in 1971. Back then, Hassi R'Mel was producing only 4bcm/year. Its annual capacity increased to 14bcm in 1974, which enabled it to supply the Skikda LNG plant.
- A second major development programme was completed in October 1980. It enabled Algeria to supply LNG plants at Arzew. It also established new production and re-injection zones. The programme required the drilling of 110 production wells, compared to 21 in operation in 1974. The drilling work was completed in 1979.
- In 1993, the Hassi R'Mel 's upstream and gas processing plants were revamped . This was one of the projects which received financing from the Japanese government. The contract was financed under a deal signed in 1992 between Sonatrach and a group of Japanese banks led by the state's Export-Import Bank of Japan, to expand gas export capacity.

Pipelines into Europe include the existing Transmed and planned Medgaz, expected in 2010, into Spain and the Galsi pipeline, which is planned to Italy. The completion of this project has been delayed several times and the route has been changed in part due to seismic activity of the sea. Permits are now expected in 2011, with the pipeline's completion in 2014. However, there are indications that this could be delayed further.

3.7 Pipelines and interconnections

As seen in Section 3.5 countries in Eastern and South-East Europe have very limited options relating to sources of gas supply. This situation was highlighted in January 2009 during the two week Ukrainian/Russian transit dispute, which saw German companies supplying gas to Slovakia, Slovenia, Hungary, Croatia, Bosnia Herzegovina and Serbia.

The outcome of this was not only the move by the EC to revise the gas security of supply directive, see Section 3.9.5, but also a move to improve the interconnections between Member States, and from west to east in particular. This has also resulted in new plans for capacity between Hungary and Romania, as shown in Figure 39.

Figure 39 – Increased west to east interconnection

Source: GIE and Pöyry Energy Consulting

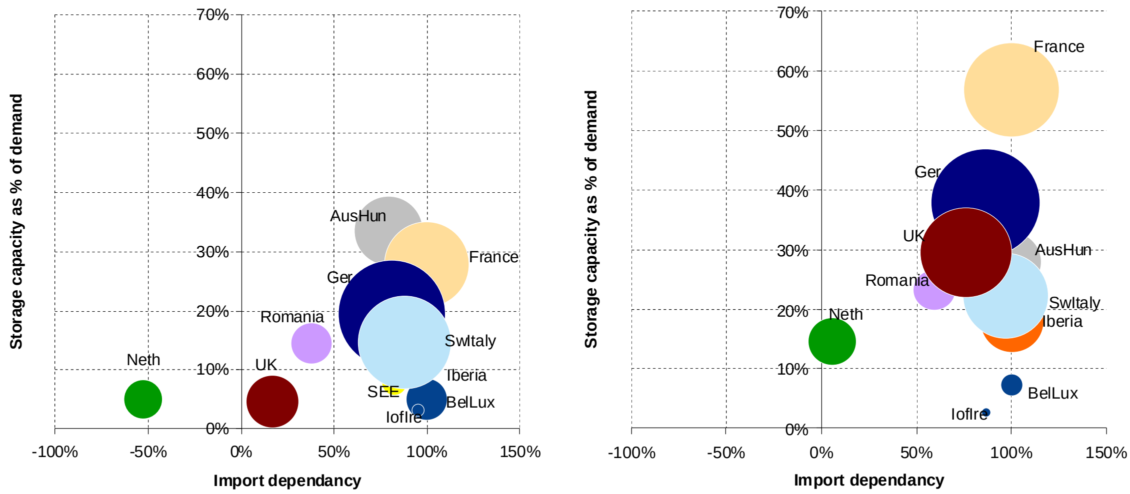
3.8 Storage

3.8.1 Storage as a source of flexibility

Historically different markets across Europe have had varying amounts of gas storage, especially when considered against the level of import dependency that each country faces with its gas supplies.

Figure 40 shows the current position and the expected position in 2020, assuming all the planned storage capacity is constructed. The sizes of the circles indicate the volume of storage capacity; the horizontal axis shows the degree of import dependency; and the vertical axis, the storage volume as a percentage of demand. The figure illustrates that as countries move towards higher levels of import dependency, levels of storage capacity increase in relation to demand.

Figure 40 – Storage levels compared with import dependency in 2009 and in 2020



3.8.2 *Limitations on storage due to inefficiencies and security measures*

However, effective use and access to storage can be constrained by various market inefficiencies and security measures imposed by Member State governments and/or regulators.

3.8.2.1 Backup obligations

This covers obligations placed on shippers to hold gas in storage as back-up for security of supply. Examples across Europe include:

- GB – NGG maintains a safety monitor based on criteria from its Safety Case (driven by Health and Safety legislation), which means shippers cannot reduce storage stocks below the monitor. This is applied at market level, rather on individual shippers. Monitor can only be breached in extreme weather conditions to support domestic consumers.
- NL – GTS procures storage gas to meet consumers' increased demand when temperatures drop below -9ºC (down to -17ºC).
- France – shippers supplying domestic & public interest customers are required to withstand a loss of their main supply for a 6-month period under normal weather conditions, and to ensure supplies for both a 1-in-50 winter and an extremely cold period (a 3-day 1-in-50 period) by ensuring availability to alternative sources (storage, short-term contracts, LNG, etc.). There is an additional legal requirement to have minimum and maximum amounts in stock at any one time. The outcome of this is illustrated in Table 5 and results in French storage being subject to minimum and maximum level constraints.

Table 5 – French storage backup obligation constraints

	Minimum storage level	Maximum storage level
January	39%	99%
February	35%	96%
March	2%	70%
April	0%	50%
May	1%	52%
June	14%	67%
July	21%	71%
August	44%	85%
September	55%	92%
October	83%	100%
November	90%	100%
December	90%	100%

Source: Storengy[11]

3.8.2.2 Strategic storage

These are requirements laid down by governments for specific volumes to be set aside and only to be used under its direction or by the body given this public service obligation. They are modeled by applying a price premium over normal storage LRMC levels.

Some examples across Europe are:

- Belgium – The TSO, Fluxys, has a mandated public service obligation (PSO) to be able to supply all uninterruptible customers in the case of severe temperatures that would occur based on the winter of 1962/3 or 5 consecutive days with temperature < -11ºC. For this purpose Fluxys maintains reserved strategic storage (gas and capacity), which are charged to users through transmission tariffs.
- Italy – approx 40% of storage is reserved for strategic storage, whose release is controlled by the ministry. Additionally there is a legal obligation on each importer to maintain 10% of its import requirements in storage (minimum quantity specified by Ministry for Industry each year).
- Denmark – TSO is obliged to procure storage capacity to meet demand of non-interruptible customers at 60-days at normal winter temps, 3-days at -14ºC (equivalent to 1 in 50 peak day).

11 Facilities observed: Serene Nord, Sediane, Sediane Littoral, Sediane B, Saline. An average was then taken and applied across all modelled French facilities. The model constrains the storage levels between the limits shown.

- Hungary – planning for strategic storage volume to be increased to 1.2 bcm by January 2010, with daily withdrawal capacity of 20 mcm available for at least 45 consecutive days. Major industry players pay a fee based on their system throughput. The use of the strategic storage is authorised by the government based on notification by the TSO or energy ministry.

3.8.2.3 Contracting inefficiencies

This is when there is additional contractual demand for storage due to individual market participants booking flexibility to cover their own maximum needs rather than that required just for the market as a whole.

Historically, players in Germany had obligations and incentives to cover a severe winter position and potential loss of supply without the ability to access other players' storage. Linked to this was the impact of long-term contracts for storage booked by an incumbent's affiliate and with continued inability to access flexibility through TPA it results in the desire for new entrants to build more storage.

However, the German regulator, BNetzA, is developing TPA and UIOLI arrangements to release some of this ring-fenced capacity to the market but as the impact of this has yet to be demonstrated we have modelled this by ring-fencing 33% of German storage capacity.

In other markets, such as GB and the Netherlands, TPA exemptions can increases this effect to a certain extent, although again UIOLI obligations should mean that the flexibility it provides ought to be delivered to the NBP and TTF markets respectively.

3.9 Market and regulatory arrangements

European reforms have two primary principles:

1. completion of the EU internal market – to remove trade barriers between all the European countries; and
2. establishment of a competitive European natural gas market based on the belief that competition will deliver the lowest prices for consumers and the most efficient outcome.

In addition there are some secondary objectives which related to a view that monopolies existed and were not in the best interests of consumers and so not compatible with Article 85 of the Treaty of Rome. The new more competitive framework intended to:

- increase efficiency;
- reduce prices;
- raise standard of service; and
- increase competition.

In order to deliver the principles and the secondary objectives the Gas Directives have aimed to be objective, non-discriminatory, transparent, efficient, economic, deliver security, protect consumers, achieve fair prices, be cost reflectivity, and environmentally friendly.

To achieve the liberalisation of the EU gas market has required a combination of five key deliverables:

1. Legal market opening.

2. Third party access (TPA).
3. Unbundling.
4. Interoperability and harmonisation of rules.
5. Independent regulators.

3.9.1 Legal market opening process

The process of establishing a legal framework across all EU Member States had not been easy. This has let to a stage by stage delivery of the principles and objectives. The timetable and key features of the legal process can be summarised as follows:

- First Gas Directive 1998 – established market opening thresholds, initial steps towards changes in market structure and network access, with the introduction of legal unbundling and negotiated and regulated TPA.
- Second Gas Directive 2003 – required full market opening by 2007, regulated TPA for networks and negotiated and regulated TPA for storage, management unbundling, introduction of national regulatory authorities, and market based instruments favoured but none is specified.
- Gas Security of Supply Directive 2004 – established a Gas Coordination Group, Member States to adopt and publish national emergency provisions, and EC can monitor interconnection capacity, gas storage and liquidity.
- Regulation 1775 2005 – introduced thoughts on a common network code, specifying capacity allocation mechanisms and capacity congestion mechanisms. Structural changes in the regulatory framework to tackle remaining barriers to the completion of the internal market in particular regarding the trade of gas. Additional technical rules, in particular, regarding third party access services, principles of capacity allocation mechanisms, congestion management procedures and transparency requirements.
- 3rd Energy Package 2009 – established independent regulator requirement, unbundling, improved market operation, notably greater transparency, effective access to storage facilities and LNG terminals. Essential focus is on improving the operation of retail markets.

The impact of the legislative process on improving the deliverables is shown in Figure 41.

Figure 41 – Legal market opening improvements

	Unbundling of networks	Access to networks	Market opening	National regulation
First legislative package	Separate management and accounts	Negotiated or Regulated TPA	33% by 2008	Mechanism for regulation
Second legislative package	Separate subsidiary	Regulated TPA	Fully open market by July 2007	Specific regulator for energy
Third legislative package	Separate ownership or operator including storage	Regulated TPA including storage	Achieved (see above)	Upgraded and harmonised powers for national energy regulators
	Unbundled transmission	Third Party Access	Retail competition	National regulator

3.9.2 Madrid Forum

In 1999 the European Commission took the initiative to set up the European Gas Regulatory Forum of Madrid consisting of national regulatory authorities, Member States, the European Commission, transmission system operators, storage operators, producers, gas suppliers and traders, consumer groups, network users, and gas exchanges.

The Forum convenes twice a year in Madrid and was set up to discuss issues regarding the creation of a true internal gas market, which are not addressed in the Directive.

The most important issues addressed currently at the Forum concern cross border trade of gas, in particular the applications of tariffs at cross border gas exchanges, the allocation and management of scarce interconnection capacity and other technical and commercial barriers to the creation of a fully operational internal gas market.

3.9.3 Market opening status

Full market opening was required within the 2005 Second Gas Directive and there has been significant progress in market opening with almost all European countries having fully opened their gas markets to competition by 2007, although Latvia and Portugal have a derogation until 2010. The current status is shown in Table 6.

Table 6 – EU market opening status

	2006	2007
Austria	100%	100%
Belgium	90%	100%
Bulgaria	0%	0%
Czech Republic	69%	100%
Denmark	100%	100%
Estonia	95%	100%
Finland	0%	0%
France	73%	100%
Germany	100%	100%
Greece	70%	74%
Hungary	10%	25%
Ireland	100%	100%
Italy	100%	100%
Latvia	Derogation until 2010	Derogation until 2010
Lithuania	81%	100%
Luxembourg	79%	100%
Malta	0%	0%
Netherlands	100%	100%
Poland	71%	100%
Portugal	0%	43%
Slovakia	72%	100%
Slovenia	90%	100%
Spain	100%	100%
Sweden	100%	100%
UK	100%	100%

3.9.4 Regulated tariffs

Downstream regulation is still present in most European countries through regulated tariffs. A large number of countries still have retail price controls, which results in the development of competition being hindered by maintaining these price controls. The status of these is summarised in Table 7.

Table 7 – EU regulated tariffs status

	Regulated tariffs – Industrial users	Regulated tariffs – Small commercial users	Regulated tariffs – Households
Austria	No	No	No
Belgium	No	No	Yes
Bulgaria	Yes	Yes	Yes
Czech Republic	No	Yes	Yes
Denmark	Yes	Yes	Yes
Estonia	No	No	Yes
Finland	-	-	-
France	Yes	Yes	Yes
Germany	No	No	No
Greece	-	-	-
Hungary	Yes	Yes	Yes
Ireland	Yes	Yes	Yes
Italy	No	No	
Latvia	Yes	Yes	Yes
Lithuania	No	Yes	Yes
Luxembourg	No	No	No
Malta	-	-	-
Netherlands	No	No	No
Poland	Yes	Yes	Yes
Portugal	Yes	Yes	Yes
Slovakia	No	No	Yes
Slovenia	No	Yes	Yes
Spain	Yes	Yes	Yes
Sweden	No	No	No
UK	No	No	No

3.9.5 EC Regulation on security of gas supply

The EC has proposed a new Regulation taking in the context of geopolitical events, such as the January 2009 Russian-Ukrainian gas crisis, which revealed certain inadequacies in the current Directive 2004/67/EC, in particular the lack of coordination between Member States.

The Regulation proposes to repeal Directive 2004/67/EC and replace it with legislation which more clearly defines the respective roles of the gas industry, Member States and the Community institutions in the event of a supply disruption in the short term and also lays down provisions for necessary infrastructure developments in the longer term.

The EC believes the new Regulation will improve the framework for investment in new cross-border interconnections, new import corridors, reverse flows capacities and storage facilities.

Each Member State will appoint a Competent Authority who will be responsible for:-

- a biennial risk assessment;
- establishment of Preventative Action Plans;

- establishment of the Emergency Plan; and
- continuous monitoring of security of gas supply at national level.

The Regulation requires the Competent Authority to ensure that in the event of a disruption of the largest gas supply infrastructure, the remaining infrastructure (N-1) has the capacity to deliver the volume of gas necessary for the normal functioning of services.

This volume is calculated as the volume necessary to satisfy total gas demand during a day of exceptionally high gas demand statistically occurring once every twenty years.

The Regulation lays down the criteria under which an emergency will be declared and also outlines the procedures that will need to be followed when an emergency has been declared. In an EU emergency, the Commission will be responsible for coordinating the actions of the Competent Authorities. The Regulation should enable natural gas undertakings and customers to rely on market mechanisms for as long as possible when coping with disruptions. Even in an Emergency, market based instruments should be given priority to mitigate the effects of the supply disruption.

The Regulation recommends that joint emergency plans at regional level, should be established where possible and necessary. To strengthen the solidarity between Member States in the case of a Community Emergency and in particular to support Member States which are exposed to less favourable geographical or geological conditions, Member States should devise specific measures to exercise solidarity, including measures such as commercial agreements between natural gas undertakings, compensation mechanisms, increased gas exports or increased releases from storages. Solidarity measures may be particularly appropriate between Member States for which the Commission recommends the establishment of joint preventive actions plans or emergency plans at regional level.

The Gas Coordination Group, which was established by Directive 2004/67/EC, will continue to assist the Commission on issues related to the security of gas supply.

3.9.6 Market and regulatory arrangements – modelling

As described above the liberalisation process should provide increasing TPA to infrastructure and interoperability across networks. However, national security of supply concerns may mean that progress on liberalisation is very slow across Europe and the third package does not achieve some of its objectives. We assume that country/regional trading hubs develop where gas can be bought and sold and prices become transparent.

However, market power still exists through oil-indexed contracts and access to storage is limited e.g. Germany, France, Hungary and Italy, all of which is included in base case assumptions.

3.10 Contracts

West Europe has been importing Russian gas since 1969 – the year when first supplies were delivered to Italy. Negotiations over the contract with Ruhrgas to supply East Germany commenced in the same year, followed in 1970 by the signing of the famous East-West ‘gas-for-pipes’ deal, which led to the construction of the first major export pipeline from the Soviet Union to Western Europe. Indeed, exports to Central and Eastern Europe had begun much earlier: Poland was the first to receive it in the 1940s followed by Czechoslovakia in 1967. Between 1973 and 1980, the export of gas to Europe increased 11 times to 55bcm/annum, making Russia the most important supplier of gas to Europe. By 2008, Gazprom's obligations had increased three-fold, reaching 158.8bcm/annum.

Today, Russia is responsible for 42% of all gas imports to the EU. It is determined not only to keep its positions but to reinforce them by gaining a larger share of the European import market and establishing itself in the downstream sector. Concerns over the security of supply and overdependence on Gazprom have marred relations between the EU and Russia, as well as individual European governments and Russia since 2005. However, major companies, such as E.On Ruhrgas and ENI that have developed relations with Gazprom over the past 50 years favour extending the existing long-term contracts and building new export pipelines in partnership with the Russian monopoly, as analysed in Section 3.4.2. In fact, many of the contracts have already been extended to 2030-35, signalling that Russia will remain a key source of gas to Europe in the foreseeable future.

Gazprom also prefers to continue with long-term oil indexed contracts, which, it argues, provide it with the security of demand that it needs to invest in new, expensive and difficult to access regions. In our scenarios, we expect long-term oil indexed contracts to continue.

3.11 Gas Quality

The key gas quality requirement applying to the delivery of any gas into pipelines that supply consumers is the Wobbe Index (WI) which is a measure relating to the heating, or calorific, value of the gas.

As can been seen in Figure 41 GB has a narrow range of acceptable WI, primarily as a result of the continuing need to supply to older UK gas appliances[12]. The WI of supplied gas can vary significantly, depending on the source and how much the hydrocarbons are removed before entering the gas distribution network.

Across Europe supplies with lower WI have included the South Morecambe gas field in the East Irish Sea and the Groningen gas field in the Netherlands. Delivery of these to consumers can be handled either by blending with richer gas supplies, as happened at Lupton for South Morecambe, or by operating a separate low CV gas pipeline network, as is the case in the Netherlands, north-west Germany and Belgium.

Other supplies, such as some Norwegian gas, LNG and Russian supplies from the Nord Stream pipeline, will often have a WI which is unacceptably high for GB's requirements.

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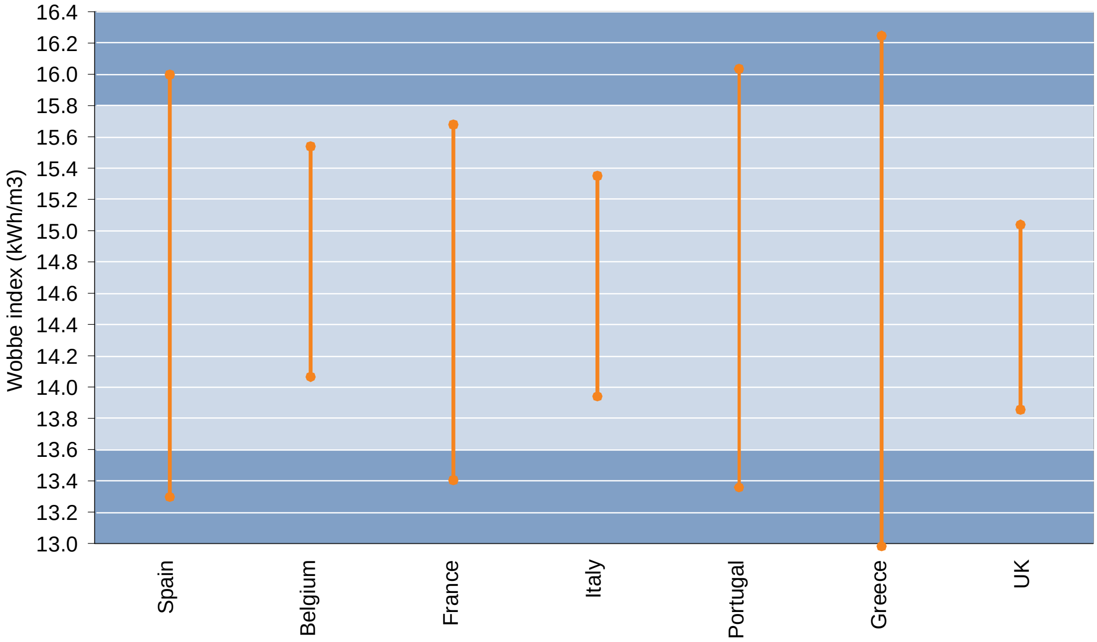
12 Council Directive 90/396/EEC of 29 June 1990 was introduced to create a single market throughout Europe in domestic and commercial gas appliances. By making the rules for the design of gas appliances the same in every member state of the EU, manufacturers and hence consumers, should benefit from economies of scale and the reduction in costs that these will bring. The Directive was originally enacted in 1990 but was modified in 1993 by Directive 93/68/EEC to make the requirements for the use of the CE mark and the attestation modules more consistent with the other CE marking directives. The Directive became mandatory from 1 January 1996. In the intervening period, appliances could be sold without having to be CE marked, but only if they met the national requirements of the country in which they were to be sold. From 1 January 1996, all appliances within the scope of the Directive and sold within the EEA have to be CE marked. In late 2009, the Commission introduced 2009/142/EC, a codified directive which brought together the original text of 90/396/EC and its amendments in a single document, and simplified the language in some places, which came into force on 5 January 2010.

Figure 42 – Wobbe index ranges across Europe



Source: MVV Consulting Report (May 2008)

For LNG it is necessary to reduce the WI of delivered LNG by ballasting with nitrogen. All GB's re-gasification terminals have been equipped with nitrogen ballasting facilities. Isle of Grain, Dragon and Teesside Gasport have sufficient ballasting to be able to accept LNG from most sources. South Hook has installed a reduced nitrogen ballasting capability (on the basis that it will be receiving 'lean' Qatari LNG), and therefore cannot accept higher Wobbe LNG e.g. Oman, Pacific Basin LNG, without a re-gasification capacity reduction.

Use of nitrogen ballasting will add extra cost to the gas supplied, but this is unlikely to be material. As an example, at Dragon the £20m cost for the ballasting facility translates (over 15 years for the 6bcm terminal capacity) to an additional cost of less than 0.2 p/th at 50% load factor.

So GB re-gasification terminals can therefore receive and process the vast majority of global LNG. Given this position, gas quality is unlikely to be a material constraint on LNG flows to GB.

However, looking forward blending in Belgium may be a problem for Fluxys following the introduction of the expected higher CV gas from Nord Stream and the continued decline in low CV Dutch reserves. As such there is a risk that the UK-Belgium Interconnector will not accept any such out of specification gas. It is also not clear who has responsibility for resolving the issue as Fluxys currently perform the service for the benefit of all IUK shippers whereas Ofgem is responsible for the gas quality specification.

Currently there is no change planned in GB specification until 2020. However, some of the energy efficiency measures being delivered, including the recent boiler scrappage scheme, might mean a faster replacement that previously assumed and potentially allow this date to be brought forward.

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4. SCENARIOS AND MODELLING

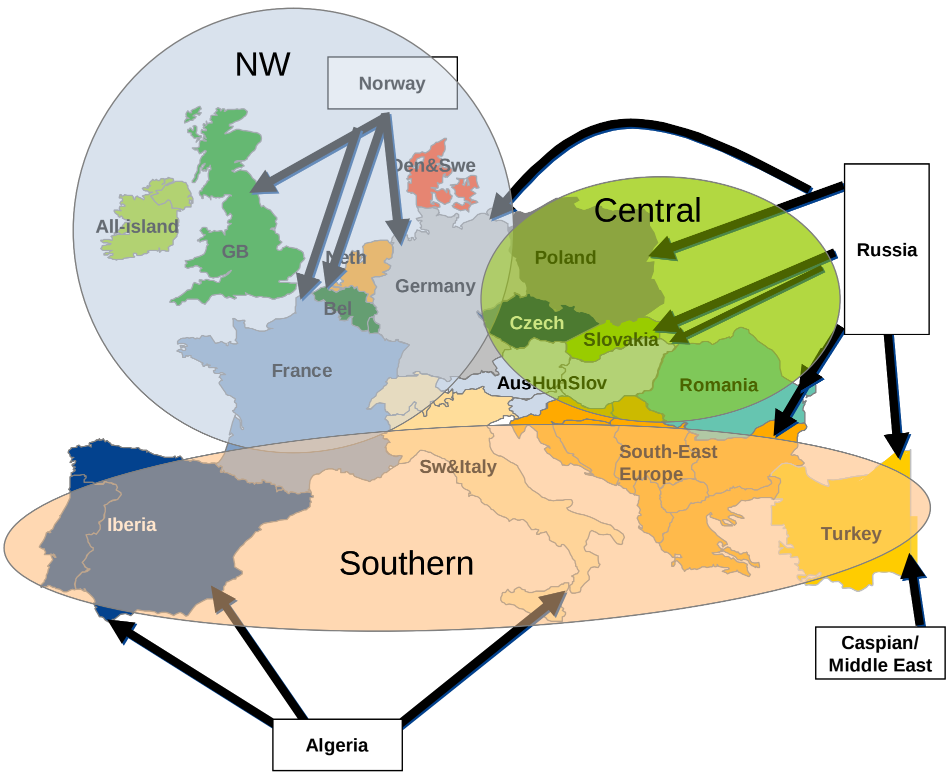
The purpose of the modelling in this study is to test the resilience of the GB gas market to supply shocks from the wider European market. Firstly, we have established a base case assuming realistic capacity and demand projections, which we have gone on to test under stress. Secondly, DECC also wished to develop a worst-case scenario for European gas markets in relation to GB's security of supply, and further examine how this affects the GB gas market's resilience. In this section we describe the two main scenarios we have developed and later in section 5 we describe the stress tests and sensitivities we used to test their resilience.

The two main scenarios were developed in association with DECC and called the Base case and the High European demand case. The High European demand case combines high projections for gas demand across the rest of Europe with better west-to east interconnection, thus encouraging the flow of gas away from GB and putting greater pressure of its security of supply. These have been analysed using our Pan-European gas and worldwide LNG model, Pegasus (see Annex A for more detail), to assess the potential flows of gas and prices in the European gas market.

4.1 Base case scenario

In order to help describe our Base case assumptions we have aggregated Pegasus's European zones into three regions: NW, Central and Southern, which are shown in Figure 43.

Figure 43 – Regions within Pegasus



Each region has its own distinct characteristics, although they are all interconnected, and interact closely with one another. The regions have been chosen to illustrate the location of demand growth around Europe, the relative size of different markets and the evolving sources of gas supply. They do not reflect any constraints in the model. Interconnection constraints exist between the zones, but not within the zones, which are shown in different colours. Full details on our Base case assumptions may be found in Annex B.

4.1.1 Demand and capacity overview

Figure 44 overleaf shows on the left hand side demand growth projections in each of the regions in our Base case split by demand zone, alongside the projected sources of gas supply capacity.

The gas capacity charts, on the right-hand side, show the projected indigenous production in each zone, the individual import pipeline capacities and the total projected LNG re-gasification capacity. In addition each region can receive gas via its interconnections with other regions: for example, the Switzerland and Italy zone receives gas (via the TAG pipeline) from the Central region and via France and Germany from the NW region.

4.1.2 Daily demand profiles

The annual demands for GB are modelled at a daily resolution by scaling the projected annual demand on to the actual daily pattern of gas consumption experienced in 2007, a typical year including occasional weeks with above average demand during the winter period. For more severe winter conditions, the winter demand pattern from 1985, an extremely cold year, has been used for six months, from October to March. Figure 45 on page 68 shows the daily gas demands as a proportion over the entire gas year, which we then apply to our annual demands to create a daily profile[13].

These daily demand patterns have been used to project daily demand for all the NW European gas markets, thus ensuring when GB experiences cold weather and high gas demand this coincides with NW Europe experiencing similar conditions. The 1985 weather pattern was applied to our stress tests, to simulate a cold winter with severe peak day demand.

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13 The impact of increased wind generation on the variability of demand was identified as a risk in section 3.1.3. We have not modelled this increased intermittency in this study because our modelling has been focused on the European network. However, it is modelled in the accompanying Pöyry study, "Global gas, LNG markets and GB's security of supply", April 2010.

Figure 44 – Demand and capacity projections by region in Pegasus

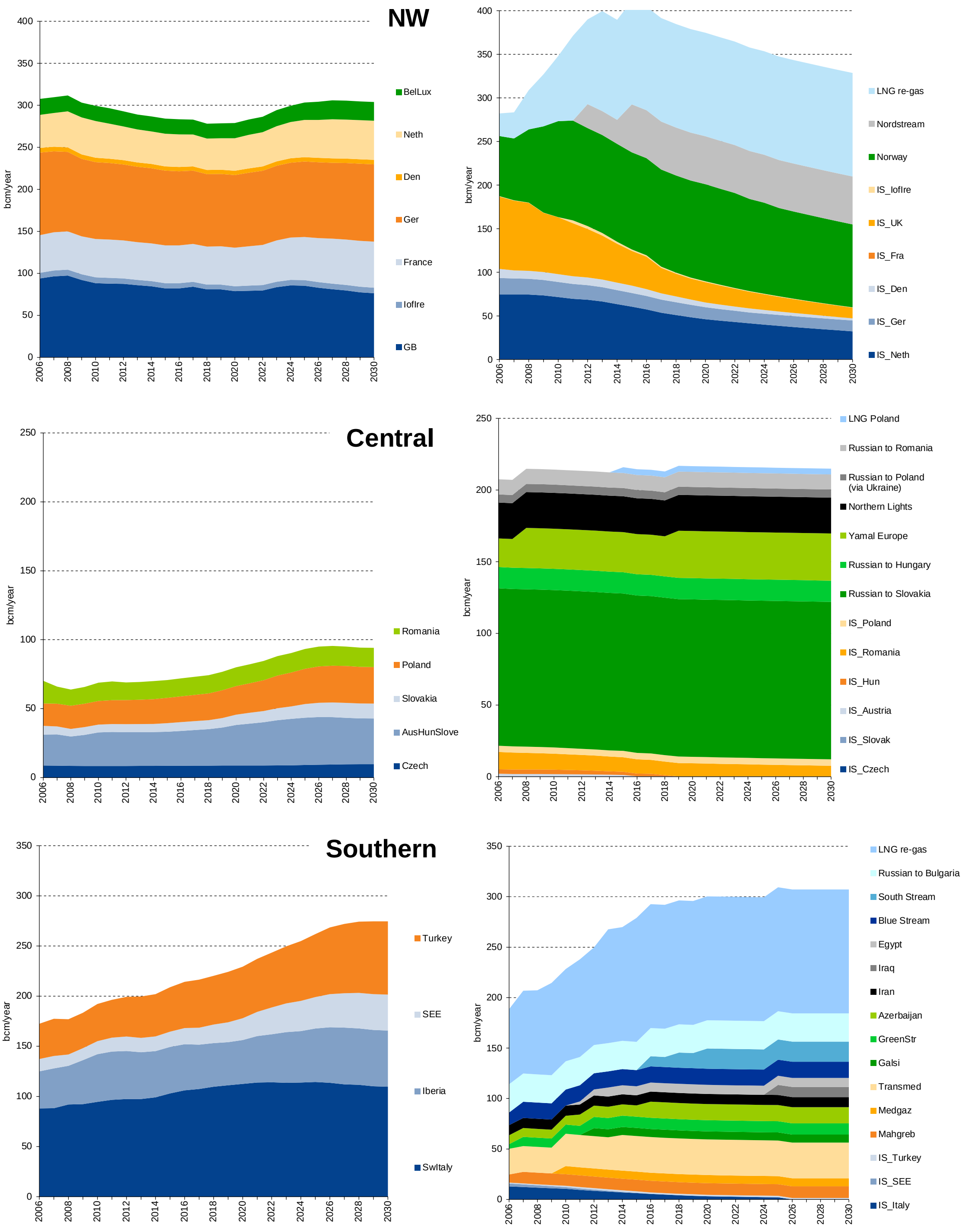
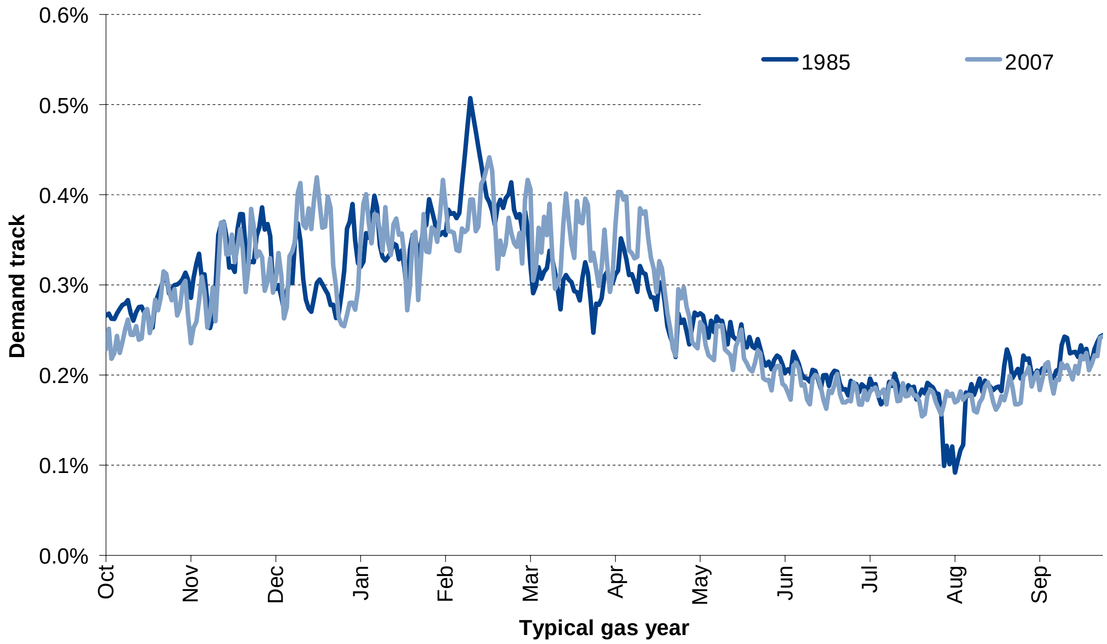


Figure 45 – Projected daily weather profiles for GB over a typical gas year



Source: National Grid and Pöyry analysis

4.1.3 Supply and interconnections

Figure 44 gives an overview of the capacity available to Europe from indigenous reserves and new import infrastructure.

The NW European region encompasses all the declining reserves in the North Sea (as described in Section 2.3.1), which will be replaced with imported gas. This will be achieved through new gas supplies and capacity coming on stream between the years of 2010 and 2030, including the following:

- around 15bcm/year of new Norwegian production, which is projected to rise to around 114bcm/year in total by gas year 2011/12, reach a plateau and then fall gradually from 2020;
- the Nord Stream pipeline from Russia into Germany, of which, its phase 1 capacity of 27.5bcm/year is projected to be commissioned in October 2012, and phase 2 (another 27.5bcm/year) in October 2015; and
- 44bcm/year of new LNG re-gasification capacity by 2015, at the South Hook and Isle of Grain terminals in GB, at Fos, Montoir and Dunkerque in France, and at the Gate and Liongas terminals in the Netherlands.

Of this new capacity included in the Base case, all the LNG re-gasification capacity is under construction or financially committed, accept the 9bcm/year of the Liongas terminal in the Netherlands. Nord stream phase 1 is under construction and the financial commitment of buying the pipes for phase 2 has been made.

The Central region is dominated by Russian pipeline gas, much of which transits to other regions. The only increase in capacity into this region is through the Yamal Europe pipeline via Poland.

The Southern region has very small indigenous reserves, but it hosts many of the existing and planned pipelines from North Africa, the Middle East and the Caspian region. Considerable volumes of Russian gas also make their way south via Bulgaria, under the Black Sea to Turkey and via the TAG pipeline to Italy after transiting the Central region.

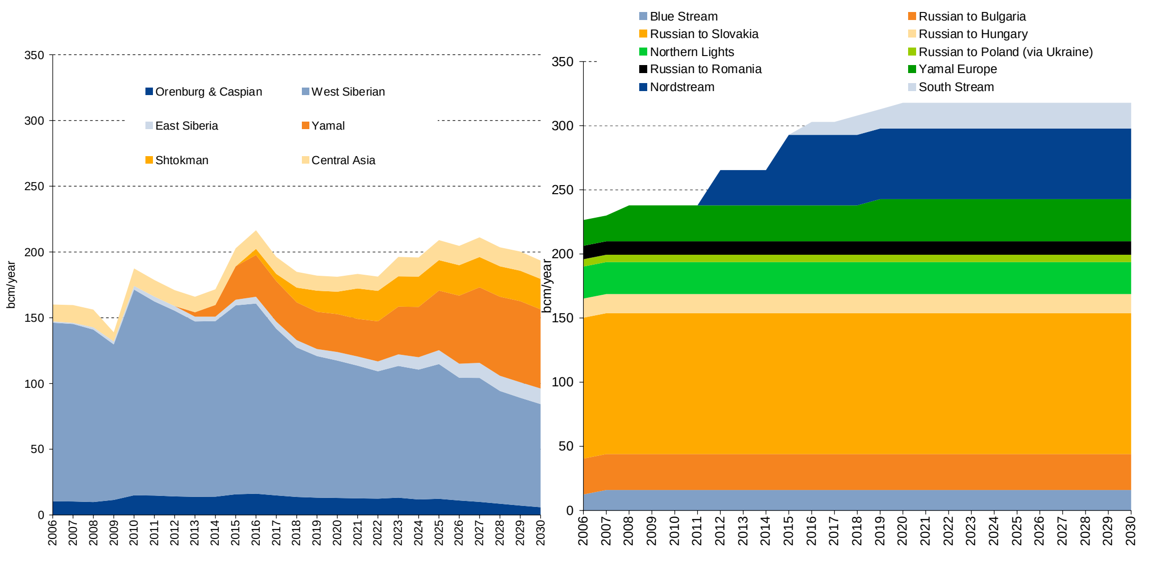
The Southern region also includes an additional 30bcm/year of LNG re-gasification capacity between 2010 and 2015.

New pipeline capacity into the Southern region includes the key strategic pipelines of South Stream and Nabucco. South Stream carries Russian gas to Europe from 2016 with a capacity of 10bcm/year, which rises to 31bcm/year by 2027. Nabucco does not appear in Figure 44 because it is modelled as an interconnector between zones, which is included from 2020 and amounts to about 25bcm/year of capacity linking Turkey into Bulgaria, and then further smaller interconnections all the way to Austria. Countries supplying Nabucco are currently envisaged as Azerbaijan and Iraq.

4.1.4 Russian gas flows

Russian gas production was discussed in Section 3.3, and in this section we describe how the Russian supplies are modelled. Figure 46 shows the sources of Russian gas available for export to Europe via pipeline (less Russian and transit country consumption, other exports and gas produced for LNG) alongside the pipeline capacity into Europe. In Pegasus we take account of long-term contracts by placing minimum take-or-pay restrictions on certain pipelines.

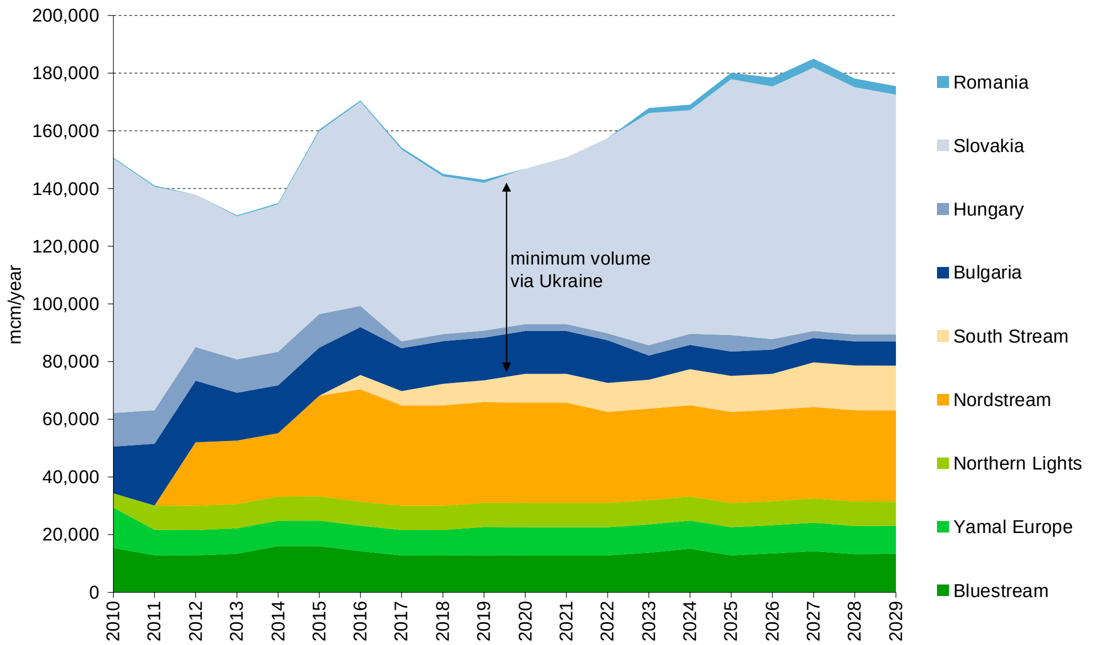
Figure 46 – Russian gas production available for export and export pipeline capacity to Europe



The modelled flows of Russian gas into Europe under the Base case presented in Figure 47 show how the commissioning of new lines, such as Nord Stream, divert gas away from the pipes crossing Ukraine to Romania, Slovakia, Hungary and Bulgaria shown as the blue shaded areas. South Stream, which is expected to land in Bulgaria, diverts gas from its existing route into Bulgaria via Ukraine and Romania.

The new pipelines maintain throughput at a steady level throughout the period and it is the volumes via Ukraine that absorb all the variations in Russian production. Importantly, even following the completion of the new export pipelines, the size of pipeline capacity across Ukraine will not be fully substituted. In the Base case scenario, annual volumes transiting Ukraine do not fall below 68bcm/year, which occurs in 2020, in part as a result of the decline in production from Western Siberia. However, the development of other regions, most notably the gas-rich Yamal peninsula, supports the level of transit volumes via Ukraine once other export pipes have filled. The rise also takes into account a potential increase in Russia's export obligations to Europe.

Figure 47 – Base case flows of Russian gas



4.1.5 *Gas costs*

In this Base case scenario, we have assumed that long-term oil-indexed contracts from Russia and Norway will persist into the future and that LNG contracts to the Far East will remain oil indexed. LNG contracts to Europe also follow an oil indexed formula but are priced below pipeline contracts with Russia and Norway. Our oil price and exchange rate assumptions can be found in Table 16 in Annex B.

Indigenous supplies and uncontracted Norwegian supplies are priced at long-run marginal cost and tend to run ahead of the oil-indexed contracted gas.

We have also extended our model to look at the supply demand situation up to 2050 in the Base case. Using demands provided by DECC for GB, we have extended current trends in the EU and rest of the world out to 2050 as follows:

- GB shows a significant demand reduction through to 2050 (using the projection from the Low Carbon Transition Plan) as carbon abatement measures become increasingly effective – at DECC's request we have set GB demand in 2050 at 20 million tonnes of oil equivalent i.e. 22bcm.

- Europe shows steady growth in overall demand through to 2030 (although the pattern varies between countries), followed by demand reduction to 2050 as carbon abatement and energy efficiency measures become effective – resulting in a demand reduction of 9% over the period 2030 to 2050.
- US demand shows a modest increase over the period through to 2050 – carbon abatement measures are resisted by a strong coal lobby – we have projected to 2050 based on the IEA WEO demand growth rate (2020 to 2030) – resulting in a demand increase of 4.5% 2030 to 2050.

The Far Eastern demand for LNG, which includes China and India, increases through to 2050, whilst the Rest of World demand for LNG shows an increase in early years but is then largely flat through to 2050. For the Far East and Rest of World (LNG demand only), we have extrapolated the 2020 to 2030 trend through to 2050, which gives an increase of 24% for the Far East and a flat demand for the Rest of the World.

4.1.6 Storage constraints

One of the key factors that affect security of supply in Europe is the way some countries limit access to their storage facilities, as highlighted in Section 3.8.2. We represented this in Pegasus by partitioning sections of storage in specific countries and attaching a high price to it to simulate strategic storage. We have partitioned off 40% of Italian storage facilities and 13% of Hungarian storage, pricing them at a higher level than other storage facilities. This causes Pegasus to only use these strategic storage tranches in times of very high demand and as a last option.

In addition to this, 34% of German storage facilities are assumed to be reserved to cover the potentially high penalties associated with system imbalances. We have also constrained French storage to have a minimum and a maximum volume in store over the course of the year, based upon Storengy data, which can be seen in Table 5 on page 55.

4.1.7 Summary of GB infrastructure assumptions for Base case scenario

We have summarised the key GB infrastructure assumptions for the Base case scenario over five selected years in Table 8. Full details of all the demand, supply and interconnector assumptions are provided in Annex B.2.

Table 8 – Capacities of GB infrastructure for Base case scenario (bcm/year)

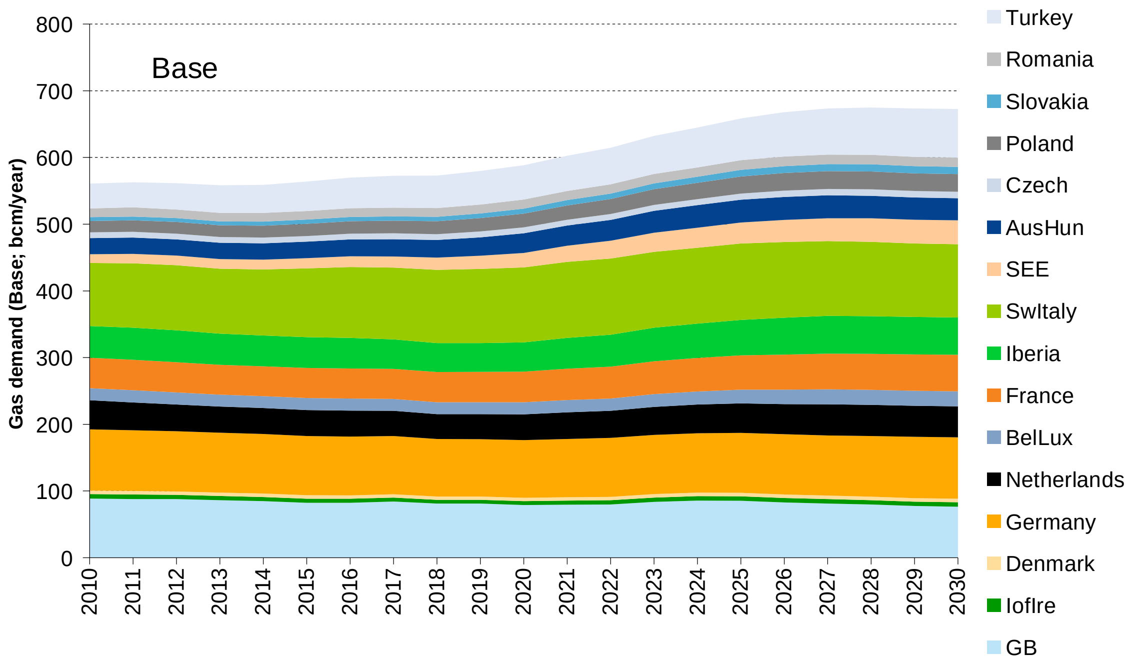
	2009/10	2014/15	2019/20	2029/30	2049/50
Indigenous production (UKCS)	68	45	24	13	0
Norwegian pipeline	42	46	46	46	46
NL to GB interconnector	14	17	17	17	17
GB to NL interconnector	0	0	17	17	17
Bel to GB interconnector	24	24	24	24	24
GB to Bel interconnector	20	20	20	20	20
GB to Ire/NI interconnector	11	11	11	11	11
LNG regasification	34	51	51	51	51
Storage	5	10	11	11	11

4.2 High European demand case scenario

The main Base case assumptions have been described in Sections 4.1.1 to 4.1.6. The High European demand case has been designed to investigate the impact of high demand in the rest of Europe and increased capacity from west to east, allowing more gas to flow in that direction during an interruption in the east.

The differences between the two main scenario assumptions are shown in Figure 48 and summarised in Table 9 overleaf.

Figure 48 – European demand projections under Base and High European demand cases



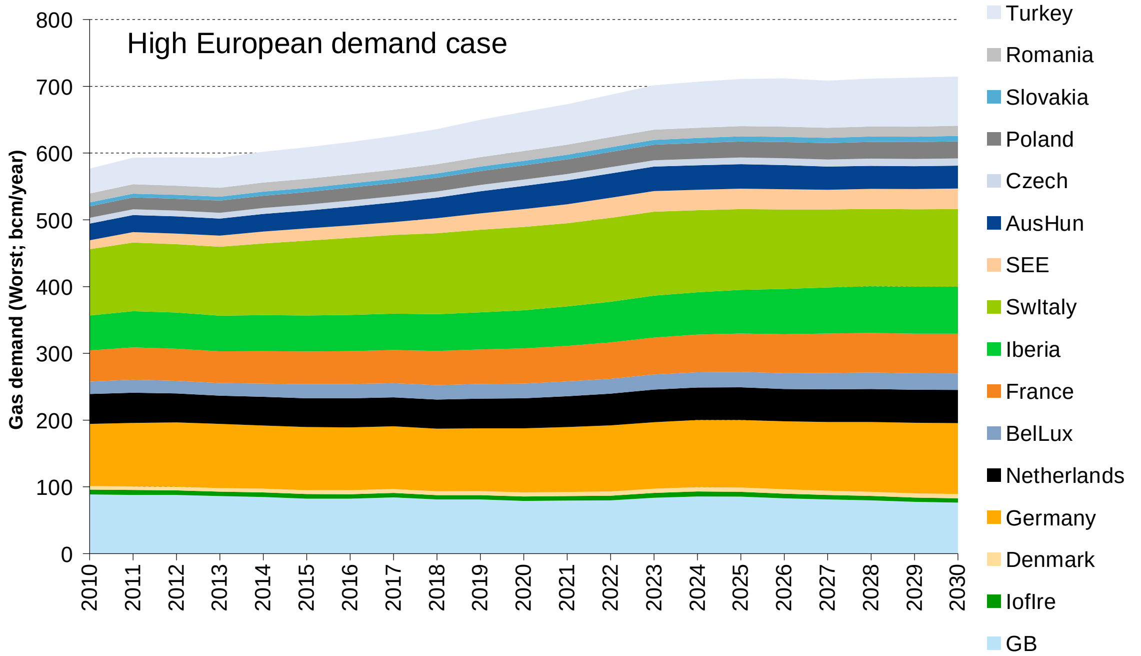


Table 9 – Base case and High European demand case assumptions

	Base case	High European demand case
Weather profile	2007	2007
GB demand	DECC post-Transition Plan central case	DECC post-Transition Plan central case
Rest of Europe demand	Pöyry Central scenario	Pöyry High scenario
Interconnection	GTE+	GTE+ but with 100% reverse flow from West to East

4.3 Analysis of supplies under Base and High European demand cases

Figure 50 overleaf shows the modelled sources of gas to supply GB under the Base and High European demand scenarios. Under the High European demand scenario, the higher demand from the rest of Europe means that LNG is drawn in to Continental Europe making less available to GB during the winter months of 2015 to 2018. However, due to exports to the Continent, the GB LNG terminals have a higher load factor up to 2024 than in the Base Case.

LNG imports have increasing importance after 2020 in both scenarios and by 2024 there is an investment case for new re-gasification facilities. The high gas demand in the rest of Europe assumed under the High European demand scenario draws greater exports from GB, shown in Figure 49, further tightening the GB market in the winter months.

Figure 49 – Net imports through interconnectors with Continent

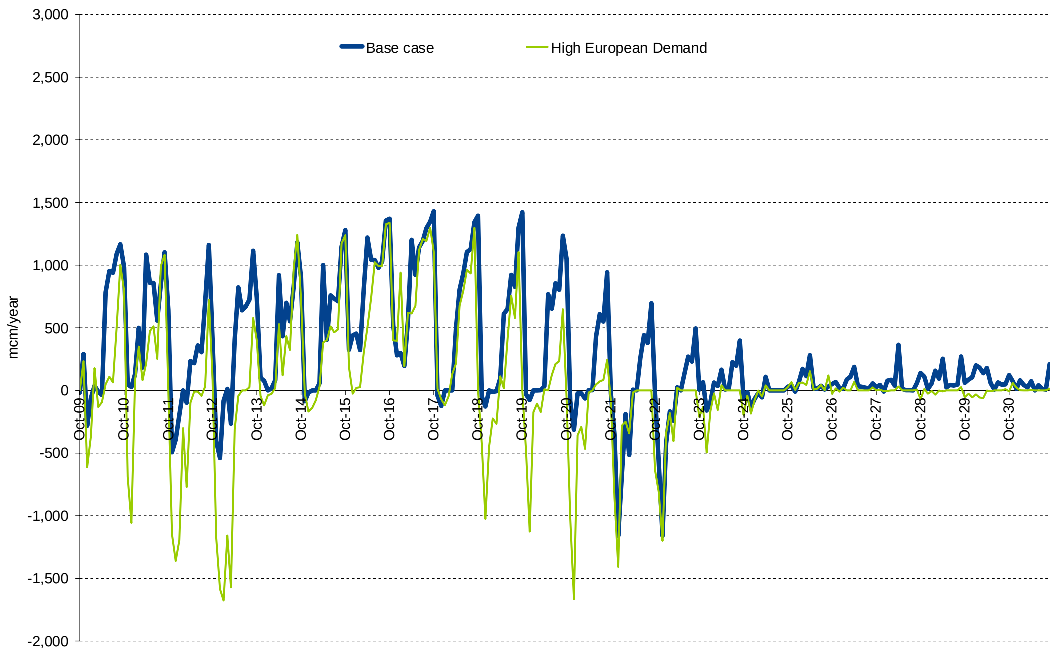
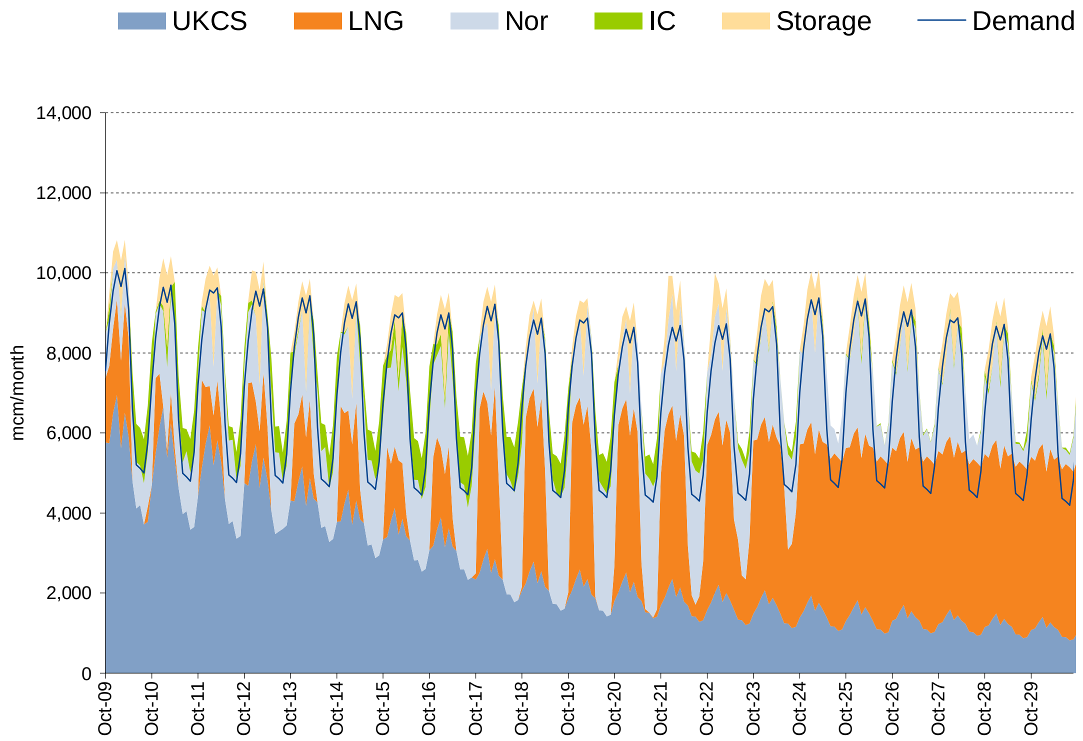


Figure 50 – Sources of supply to GB under Base and High European demand cases



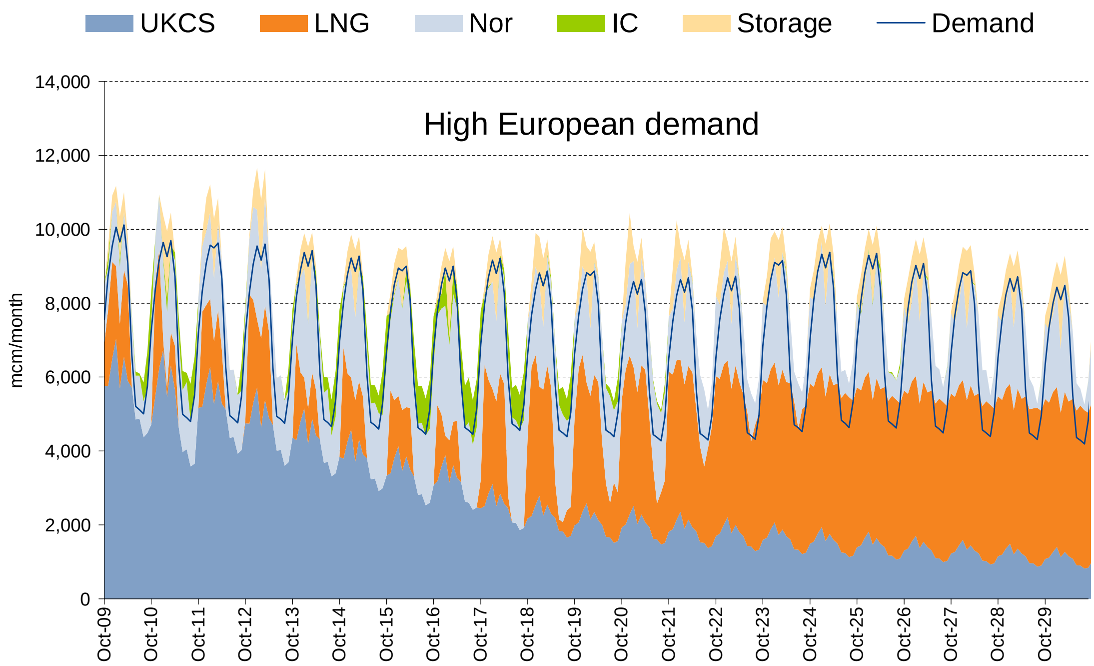
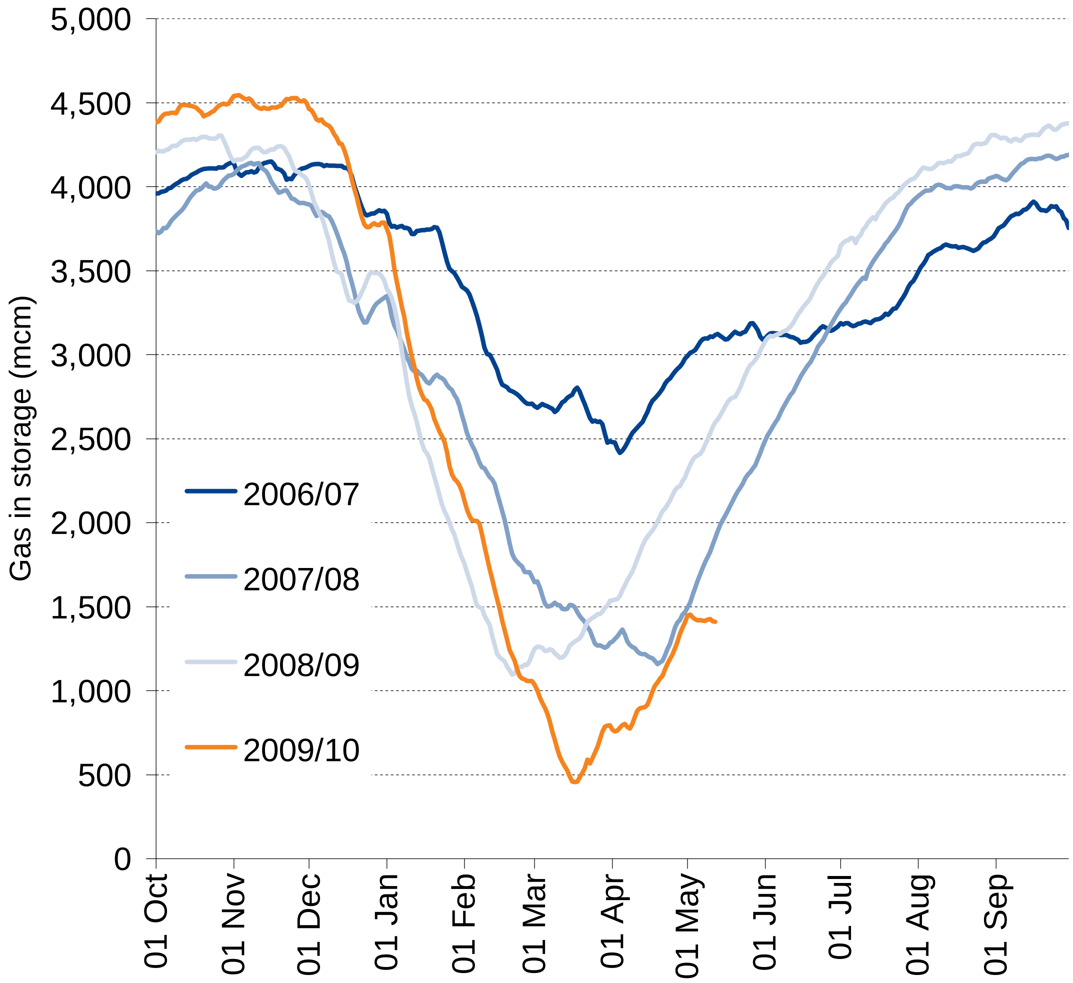


Figure 51 shows the recent history of levels of gas in storage since gas year 2006/07 to date. The quantity of gas utilised ranges from about 1.5bcm/year up to 4bcm/year in the recent severe winter.

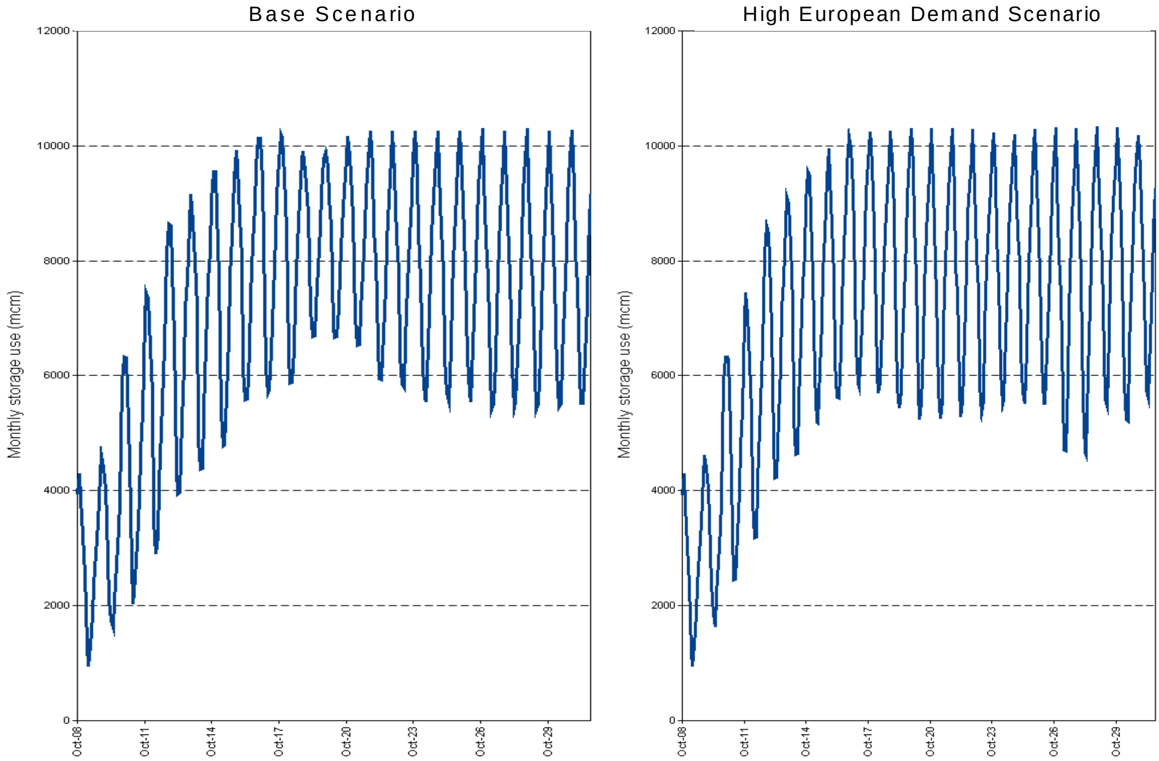
Figure 51 – Historic levels of gas in store



Source: National Grid

The historical storage utilisation is interesting when compared to that projected under the two scenarios. Figure 52 shows how demand for storage modelled in GB increases over time **under normal winter conditions** from just over 3bcm/year in 2010 to over 4bcm by 2012 and up to about 5bcm after 2020 in the Base scenario. The requirements for storage are greater in the high European demand scenario, to satisfy the higher exports from GB to the Continent in the winter months. However, given the growth in gas storage in our assumptions the amount of gas left at the end of the winter by 2016 is more than the current capacity.

Figure 52 – Gas storage stocks in GB in Base and High European demand case scenarios



4.3.1 Prices

Under the main scenarios, no new infrastructure is needed beyond that which is already included in the model (see Section 4.1.3), the vast majority of which is financially committed or under construction. In the short term summer prices are largely set by the LRMC price of the declining UKCS, with storage setting the winter price. As the UKCS depletes, news sources of gas such as LNG starts to set the price in the summer. This continues until 2026, by which time increasing demand from LNG markets in the Far East and the US causes GB to start setting its prices with oil-indexed sources.

In order to further analyse the current gas infrastructure assumptions in the Base scenario, we have also modelled gas year 2049/50, shown in Figure 53. As can be seen, due to a decrease in demand, both the overall price, as well as the seasonality, falls by this time.

Figure 54 highlights the High European demand scenario – where a tighter supply demand situation causes demand to be met by more expensive marginal sources at a faster rate than in the Base scenario. Additional, more expensive, sources of gas are also needed in order to meet demand towards the end of the period.

Annual gas price projections shown in Figure 55 on page 79 highlighting the impact of each of two main scenarios. Higher gas demand in the rest of Europe has a significant impact on prices and they are consistently 6 to 14p/therm higher than in the Base scenario. By 2030, new infrastructure and sources of gas over and above that assumed in our model will be required under all but the Base case scenario.

Figure 53 – Wholesale prices for the Base case scenario

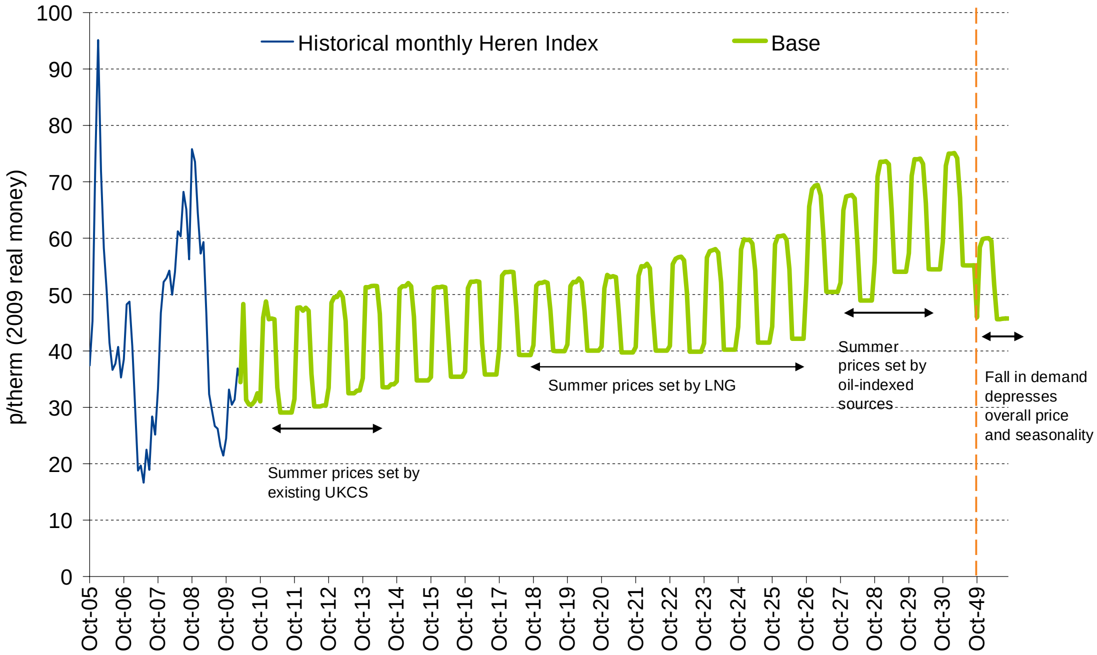


Figure 54 – Wholesale prices for the High European demand scenario

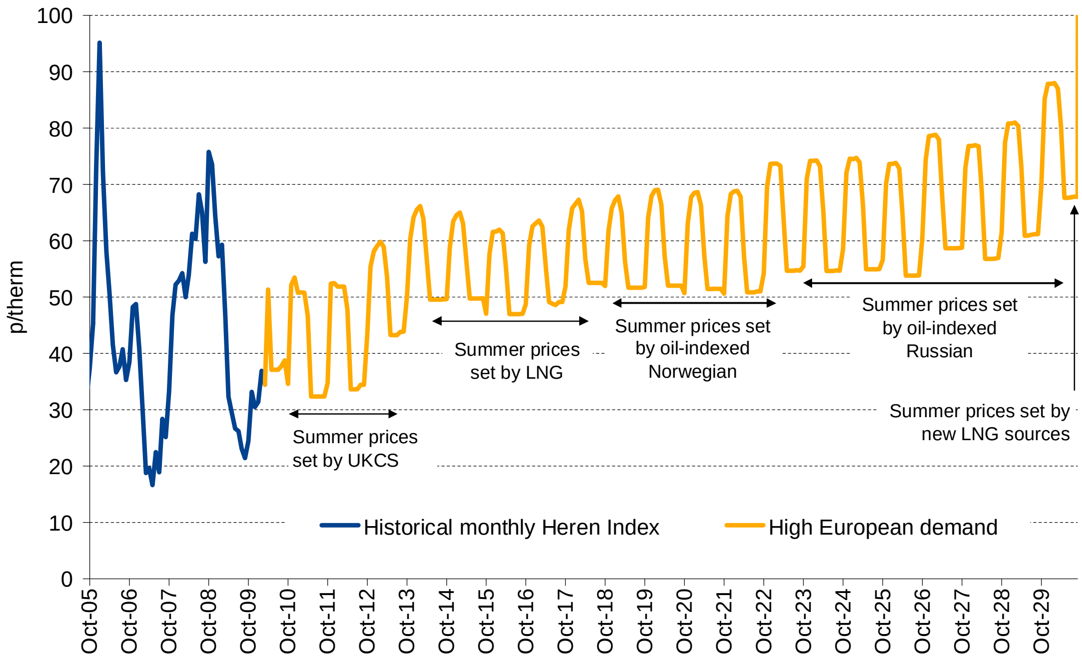
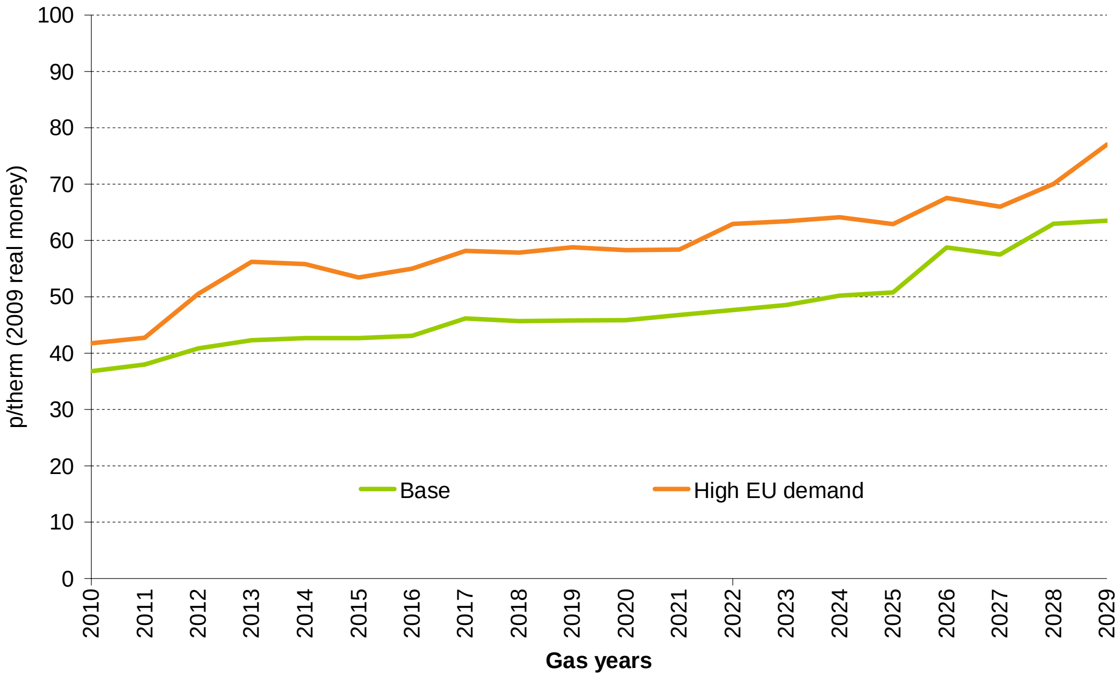


Figure 55 – GB annual gas price projections



4.4 Base scenarios – modelling conclusions

The main conclusions from the analysis using the Base case scenario are as follows:

- Assuming seasonally normal weather and no outages, there are plentiful supplies of gas available for GB, and no further capacity is required in the period modelled to 2030.
- UKCS flows to GB decline steadily over the period, reflecting the declining availability of GB's indigenous reserves, and Norwegian supplies are gradually displaced by LNG flows, particularly after 2020.
- Storage usage increases over time, but the growth in storage capacity planned in GB more than makes up for that.

The main conclusions from the analysis of the High European demand scenario are:

- Assuming seasonally normal weather and no outages, there are plentiful supplies of gas available for GB, and no further capacity is required in the period modelled to 2030.
- The higher demand from the rest of Europe means that LNG is drawn in to continental Europe making less available to GB during the winter months of 2015 to 2018.
- Due to higher exports to the continent the utilisation of the GB storage facilities is higher compared with the Base case scenario
- Utilisation of re-gasification terminals to 2024 is higher to accommodate the higher exports to the continent in the winter and additional refilling of storage in the summer.

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5. STRESS TESTS AND SENSITIVITIES

In this section we describe the main assumptions behind the sensitivities and stress tests we have analysed. We draw out the messages from the modelling and describe how new infrastructure in Europe should improve the security of gas supply in GB.

Based on the risk factors discussed in Section 3 we have constructed sensitivities and stress tests to investigate the impact of key factors across Europe and on GB in particular. We have chosen to look at the impact of high GB demand growth, and to investigate gas supply problems, including: a severe winter throughout NW Europe, interruptions of Ukrainian pipelines and offshore Norwegian problems at Sleipner. Table 10 summarises the 20 scenarios, stress tests and sensitivities which have been modelled.

Table 10 – Scenarios and stress tests

	Weather severity	Event	Additional sensitivity	Base case	High European demand	High GB demand	High GB and European demand
	'Typical'	None		•	•	•	•
STRESS TESTS	'Severe'	1. Ukraine off (Oct-Mar)		•	•	•	
STRESS TESTS	'Severe'	1a. Ukraine off (Oct-Mar) & N Stream delayed		•	•	•	
STRESS TESTS	'Severe'	2. Ukraine off & Sleipner off (Oct-Mar)		•	•	•	
STRESS TESTS	'Severe'	3. Gas out of UK spec – **no** imports from continent		•			
Additional sensitivities under stress test 2	'Severe'	2a. Ukraine off & Sleipner off (Oct-Mar)	Gas out of UK spec – **no** imports from continent	•	•		
Additional sensitivities under stress test 2	'Severe'	2b. Ukraine off & Sleipner off (Oct-Mar)	Nabucco under supplied	•	•		
Additional sensitivities under stress test 2	'Severe'	2c. Ukraine off & Sleipner off (Oct-Mar)	Nord stream delayed, no phase 2	•	•		

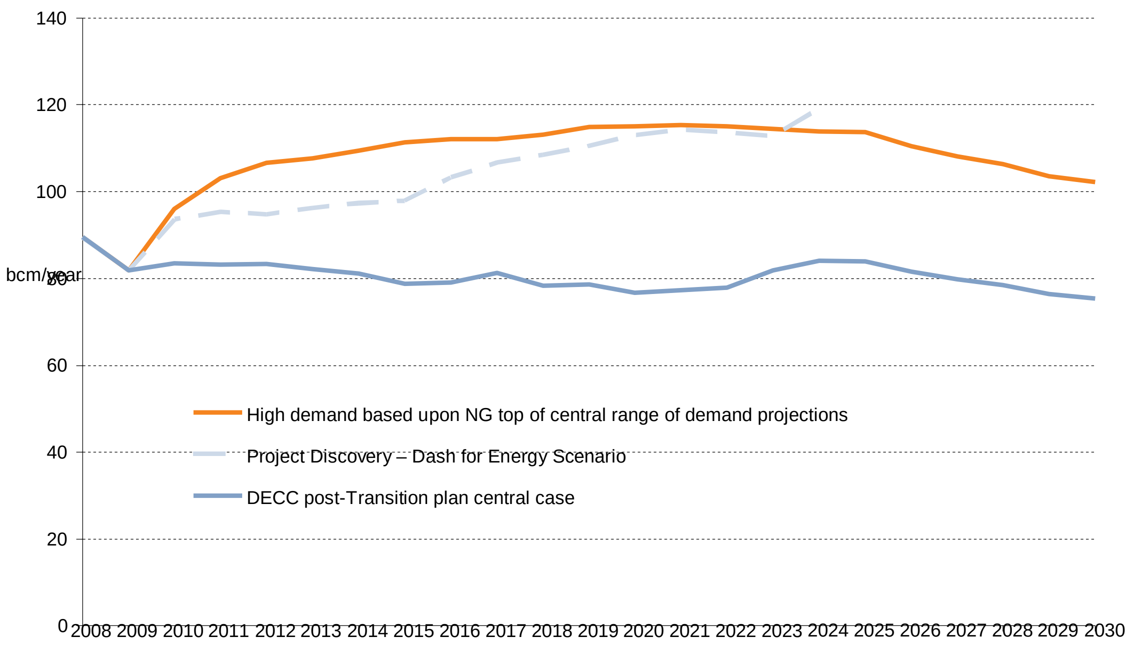
Scenario not modelled (grey)
• Scenario modelled

The additional sensitivities carried out on our second stress test were designed to investigate the relative impact of gas quality problems, Nabucco shortfalls in suppliers and the second phase of Nord Stream capacity, at times of system stress.

5.1 High GB demand assumptions

The sensitivity we have applied to both the Base and High European demand scenarios is that of high GB demand, based upon the top of the central range of demand projections published by National Grid in its Ten Year Statement[14], and shown in Figure 56. This central range is described by National Grid as including a number of sensitivities around a number of variables – economic, weather, energy conservation, fuel prices, exports and power generation. National Grid explained that these variables were not assumed to be mutually exclusive and formed internally consistent sensitivities.

Figure 56 – GB annual demand projections



Source: DECC, National Grid, Project Discovery; all values in calendar years

5.2 Overall capacity margins in GB

Pöyry's central capacity assumptions for GB include the expansions of the South Hook and Isle of Grain LNG re-gasification facilities and a number of gas storage projects. Combining these capacities with the two demand projections shown in Figure 56, it is possible to calculate the supply margins on a 'typical' and a 'severe' peak day in GB, under each of the projections.

The complex question of how much of the capacity of the LNG re-gasification facilities and the interconnectors is utilised on a particular day, is tackled through the detailed modelling. However, in order to present an overview of the supply margins in GB in Figure 57, we have assumed the available capacity is 50% of LNG facilities and 50% of interconnectors.

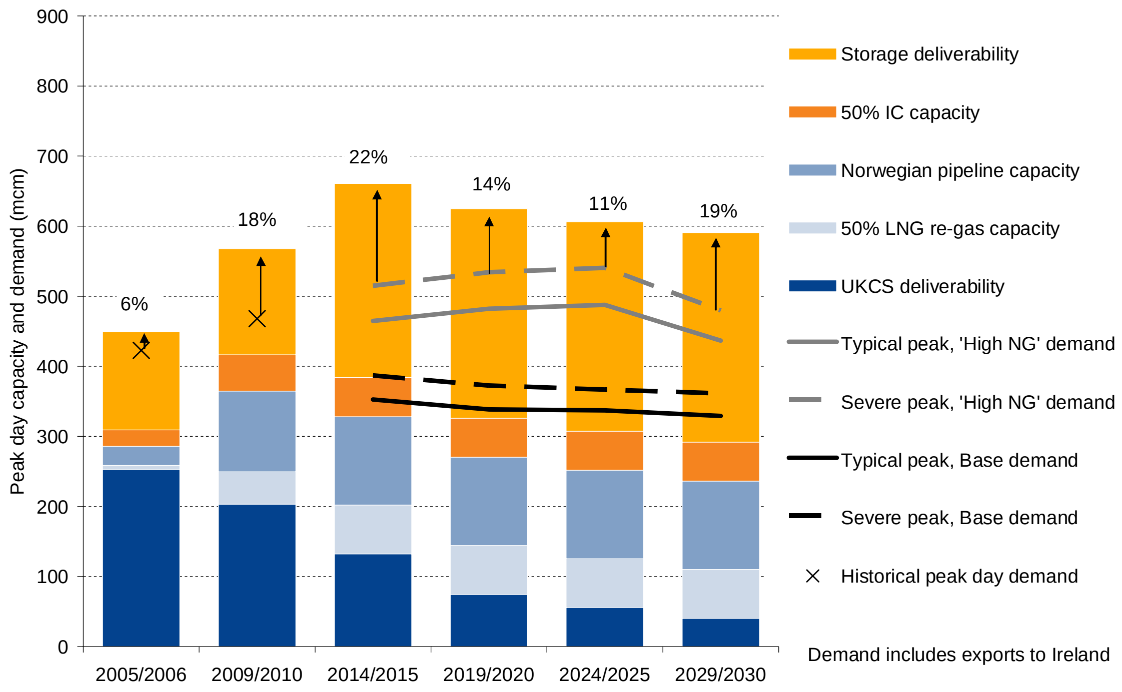
Figure 57 shows the percentage capacity margin on a 'severe' peak day under the high GB demand projection, alongside the actual peak days in 2005/06 and 2009/10. Historically, 2005/06 was a winter when supply margins were especially tight due to

14 http://www.nationalgrid.com/NR/rdonlyres/E60C7955-5495-4A8A-8E80-8BB4002F602F/38866/TenYearStatement2009.pdf; Section 3.7, page 42.

delays in commissioning planned LNG re-gasification capacity at Milford Haven. The improvement in the capacity margin by 2009/10, through the new LNG capacity, the commissioning of the Langeled pipeline and the increased interconnector capacity, is clear.

By 2014/15 despite decreases in UKCS supplies, the capacity margin looks set to improve further with new gas storage deliverability. Under the high GB demand projection and on a 'severe' peak day this margin decreases beyond 2014/15, but does not fall back to that seen in 2005/06. Although, if gas demand continues to rise until 2024/25 the market does become relatively tight and it is around this time that some of the stress tests described later in this section begin to have a greater impact on GB gas prices.

Figure 57 – Capacity margins under severe peak day and high GB demand



This analysis of the GB capacity margin only forms part of the picture, as under the high European demand scenario the capacity is obviously tighter across Europe. It is only under the sensitivity combining high GB demand with high EU demand that any additional import capacity is required. This is described in section 5.3.1 below.

5.3 Impact of high GB demand

The impact of the high GB demand sensitivity is examined through the sources of gas supplying the GB market, the utilisation of the interconnectors and storage and its impact on prices.

5.3.1 Sources of supply

The large increases in GB gas demand projected in the sensitivity draws in more LNG, bringing forward the date of base-loading LNG terminals in GB to 2022 (see Figure 58) and considerably increases imports from the Continent and our reliance on the two interconnectors.

Figure 58 – Sources of supply – Base case with high GB demand sensitivity

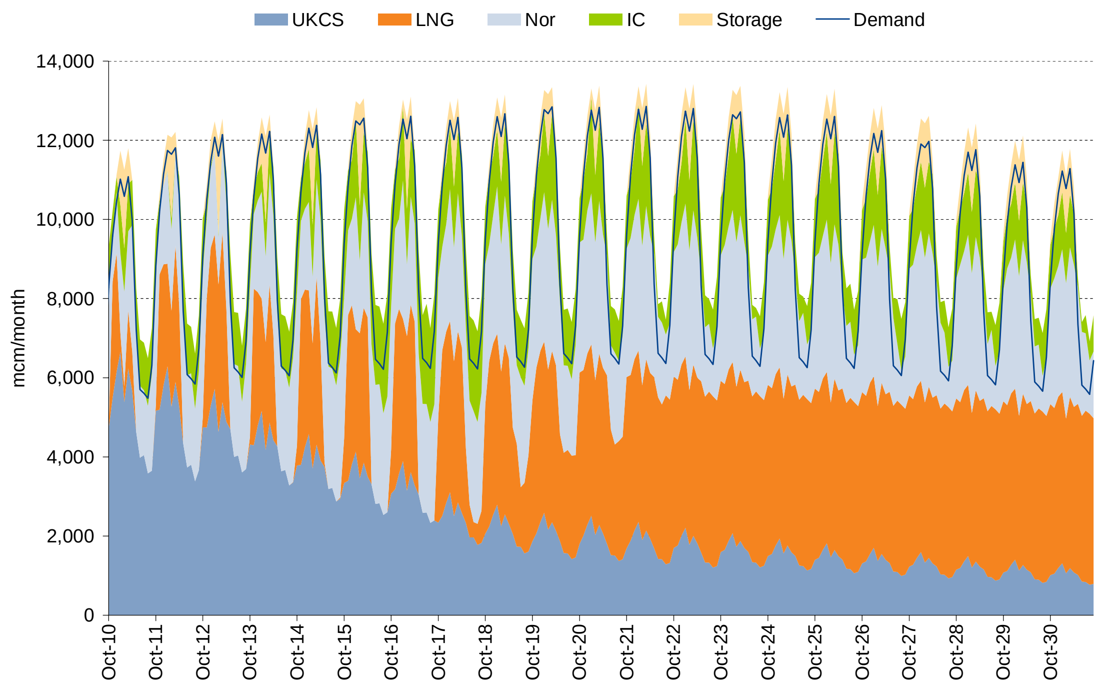


Figure 59 shows the sources of supply to GB under high European and high GB demand. When these high demand projections are combined further gas supplies are required to come in to Europe by around 2020, in addition to those which we have already assumed in our Base case scenario (see section 4.1).

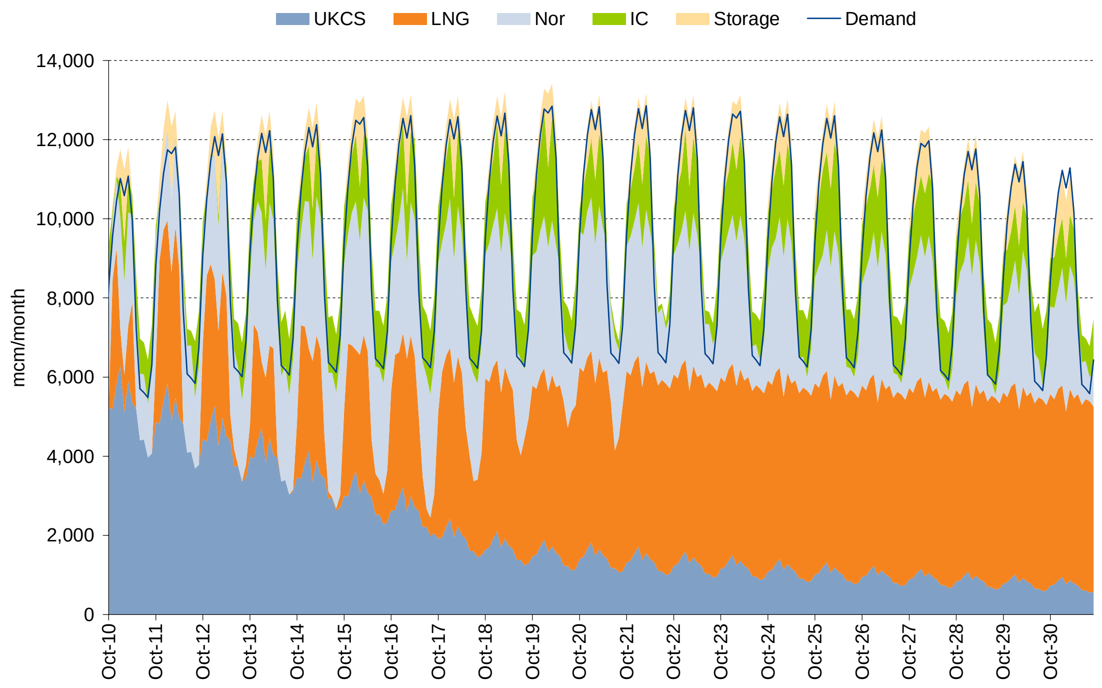
We have assumed that the world market would respond to the high demand with the construction of an additional 40bcm of LNG liquefaction capacity, and an expansion of re-gasification facilities in Europe. Our assumptions include:

- a further 12bcm/year of LNG re-gasification in the Netherlands from 2015;
- the construction of Shannon LNG in Ireland (4bcm/year) in 2020;
- a further expansion of the Isle of Grain terminal in GB (6bcm/year) in 2020;
- a further 12bcm/year of LNG re-gasification capacity in France from 2024; and,
- a further 5bcm/year of LNG re-gasification capacity in GB from 2028.

The additional 40bcm of liquefaction capacity, which would supply this re-gas capacity, could come from a variety of sources, which include current sources such as the Middle East, Russia and Central Asia; and new sources, such as unconventional gas in the US and Asia.

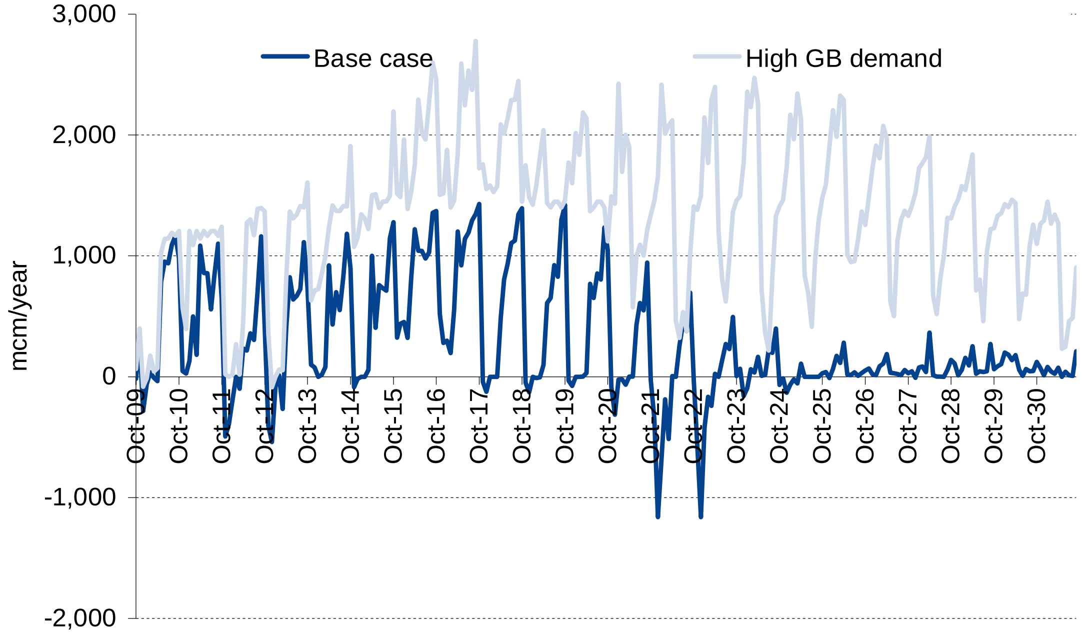
Due to the timescales involved, the most likely of these additional sources is from the Caspian region and/or Iran. In relation to Iran we have already noted in Section 3.6.1 that its current standing with Western states such as the USA and the EU may make this difficult. However, Iran enjoys a growing relationship with China who is currently investing heavily in Iran's energy sector, including South Pars. This, combined with the technical and political difficulties involved in building a pipeline from Iran to China (which would extend across either Pakistan or Central Asia), would make LNG projects the most attractive option to investors and so add to potential sources for supply to GB and Europe.

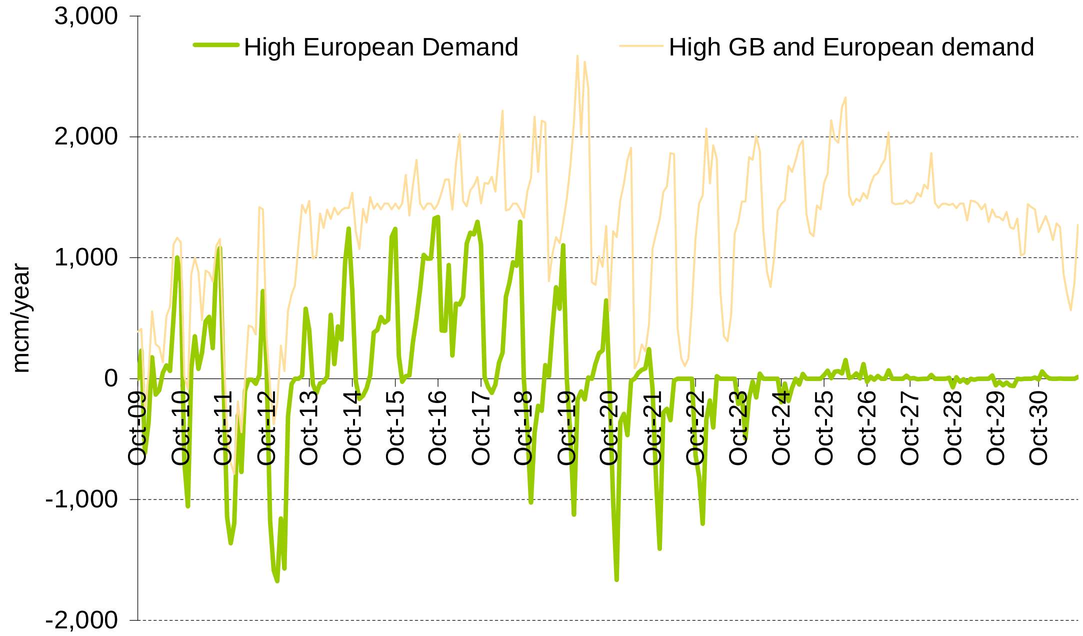
Figure 59 – Sources of supply – High GB and High European demand sensitivity



Net imports from the Continent under both the main scenarios are shown in Figure 60 and illustrate the major impact of high GB demand. Under the high European demand assumptions, net imports from the Continent are generally lower, despite a tighter supply margin in GB. This is due to high demand on the Continent reducing the gas available for export to GB. This increased dependency on continental imports could make GB vulnerable to gas quality issues.

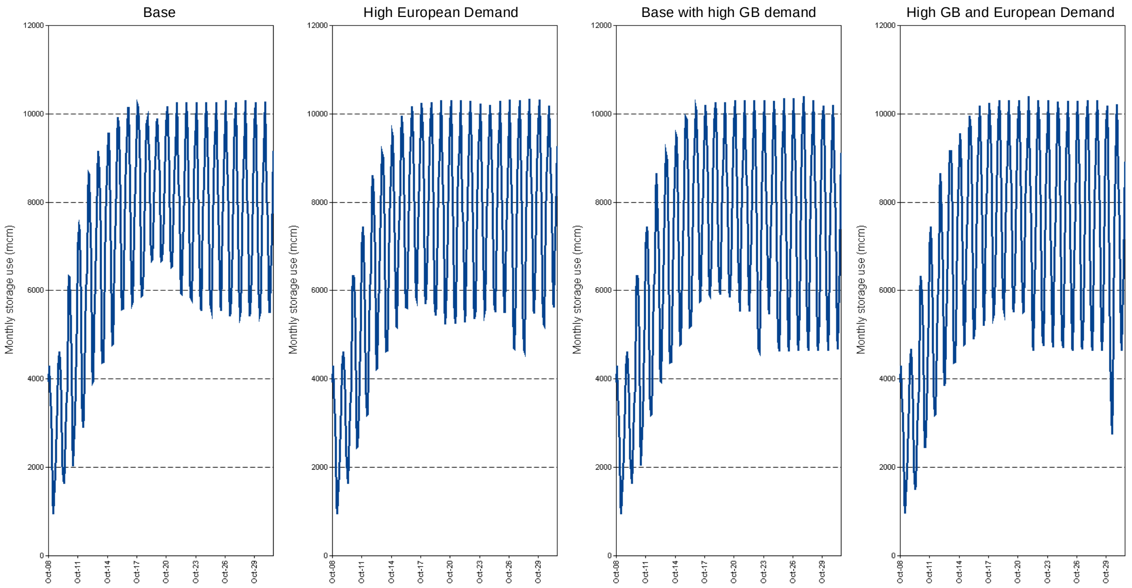
Figure 60 – Net imports through interconnectors with Continent under high GB demand sensitivity





The additional GB demand increases the use of storage, such that over 5bcm/yr would be used in the long term under the Base case with high GB demand under typical winter weather patterns and nearly 6bcm/yr in the High GB and European Storage under the same conditions. This is increase is still less than the projected growth in GB storage in that period.

Figure 61 – Storage usage in GB under high GB demand sensitivity

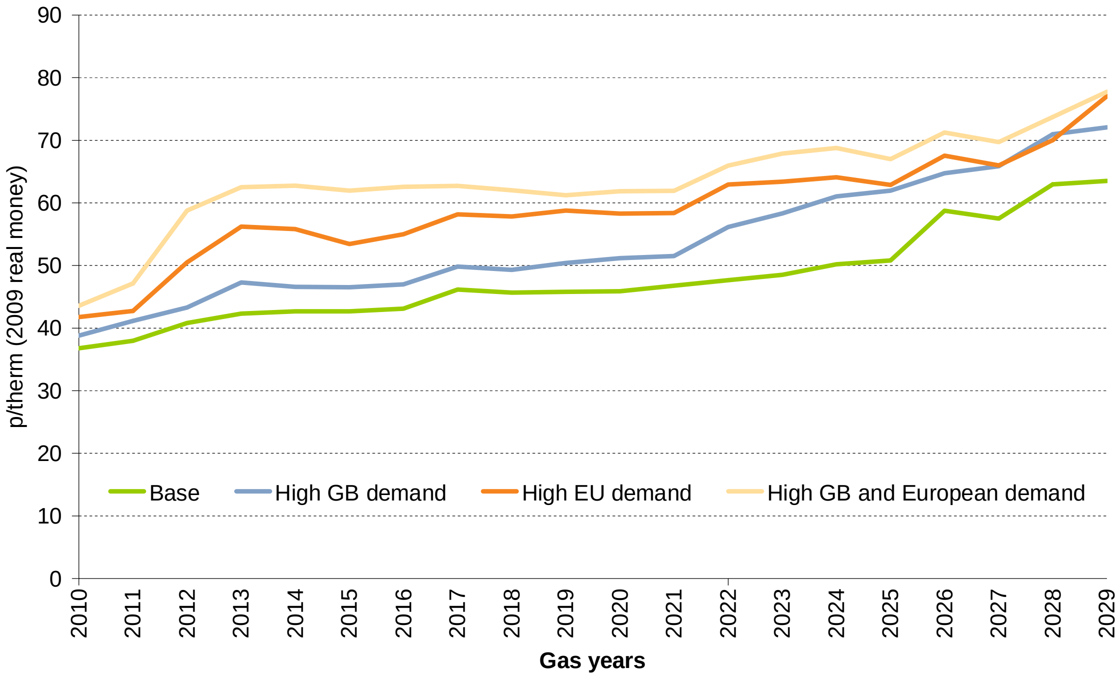


5.3.2 *Prices*

Annual gas price projections shown in Figure 62 show the impact of each of two main scenarios and the sensitivities with high GB demand. High gas demand from the rest of Europe has the greatest impact on prices in the medium term because continental Europe has less LNG re-gasification capacity and the summer gas price rapidly reaches oil-indexed contract prices. Even though the level of demand increase in the high GB demand scenario is similar to that under the high European demand scenario, the impact on prices is softened by the availability of LNG, until in the longer term high GB demand eventually pushes prices up to the same oil-indexed levels.

From 2030 onwards, new infrastructure and sources of gas will be required under all but the Base case scenario. Under the combination of high GB and European demand new infrastructure projects amounting to 22bcm/year are brought on stream in 2020 (see section 5.3.1 above) and another 17bcm/year by 2028, in order to avoid very high winter gas prices.

Figure 62 – GB annual gas price projections under high GB demand sensitivity



5.4 Stress test 1 – interrupting Ukraine during a severe winter

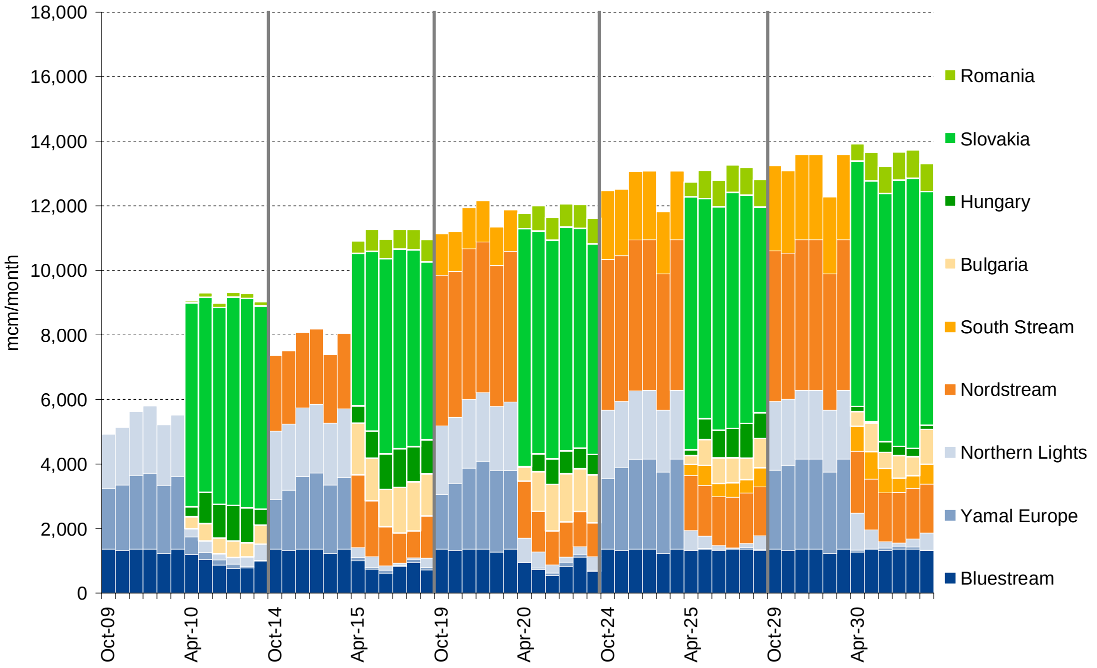
We have carried out analysis of the two week interruption of Russian supplies through Ukraine in January 2009 and the results of this analysis are included in Annex C. For this stress test we have used a longer period of the same supply disruption, covering the winter six months, from October to March for gas years of 2009, 2014, 2019, 2024, and 2029 and assumed a severe winter in NW Europe, similar to that encountered in 1985/86.

Currently when Ukrainian pipes are turned off there are a limited number of other routes for the gas to take. Figure 63 shows the destinations and names of all the pipelines flowing gas from Russia (existing and planned). Those flowing to Romania, Slovakia, Hungary and Bulgaria all cross Ukraine. Currently when these pipelines are interrupted the only alternative routes in to Europe are Yamal-Europe and Northern Lights via Poland.

Figure 63 shows how the throughput of the routes via Poland increases when Ukraine is cut off in October 2009, before returning to normal levels in April 2010. During this first stress test, the impact of the proposed new projects to bring Russian gas to Europe bypassing the Ukrainian network, Nord Stream and South stream, is clear. Nord Stream is on line by 2014 and clearly reduces the impact of the Ukrainian interruption. By 2019, when Nord Stream phase 2 and South Stream are online, the Ukrainian flows are nearly completely substitutable, except for some winter peaks[15].

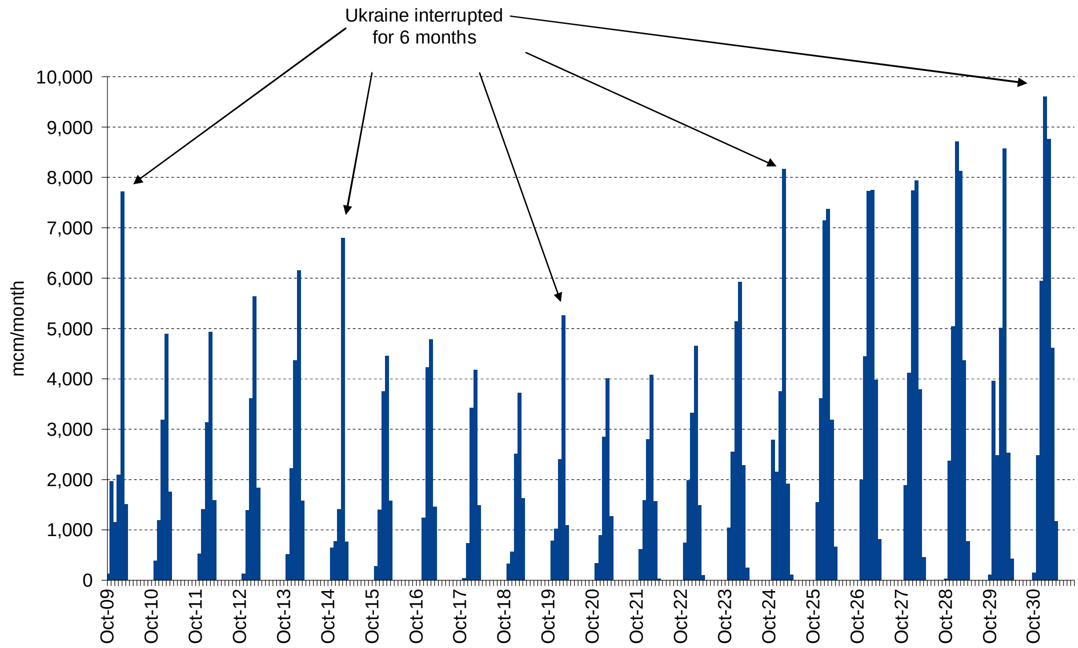
15 Although volumes of Russian gas can reach Europe via other routes on a short-term basis, Russia would not be able to meet its contractual commitments to countries in Central and SE Europe without gas flowing via Ukraine. This is discussed in section 4.1.4.

Figure 63 – Interrupting flows via Ukraine in sample years (Base case)



The associated storage withdrawals from the four major gas markets, UK, Germany, Italy and France, are shown in Figure 64. The peaks in storage withdrawals at the time of Ukrainian interruptions can be seen and as the overall tightness of the market increases towards the end of the period storage utilisation increases, although the impact of Ukraine is lessened once South Stream has also commissioned and has reached full capacity.

Figure 64 – Storage withdrawals from UK, France, Germany and Italy (Base case)



The impact of these interruptions on interconnector flows in Europe is clear and shown in Figure 65, as west to east flows increase when Ukraine is disrupted. Flows from Turkey into Greece and Bulgaria also increase when Ukraine is interrupted.

Figure 65 – West to East interconnectors and Turkey to SEE (Base case)

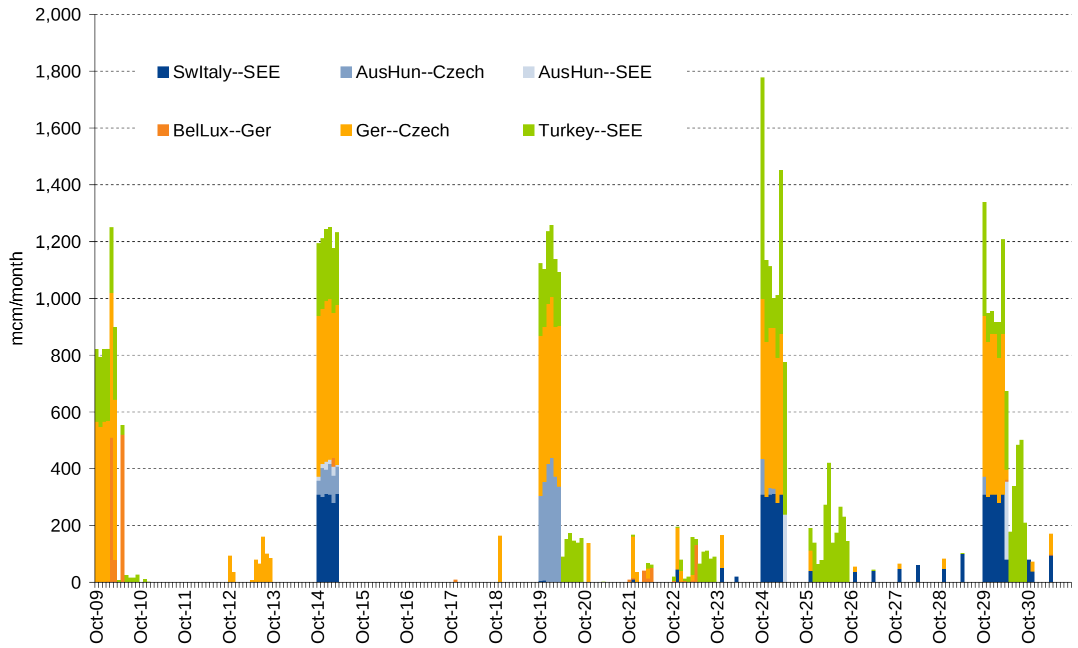


Figure 66 – Net imports to GB under Base case and with interruptions of Ukraine

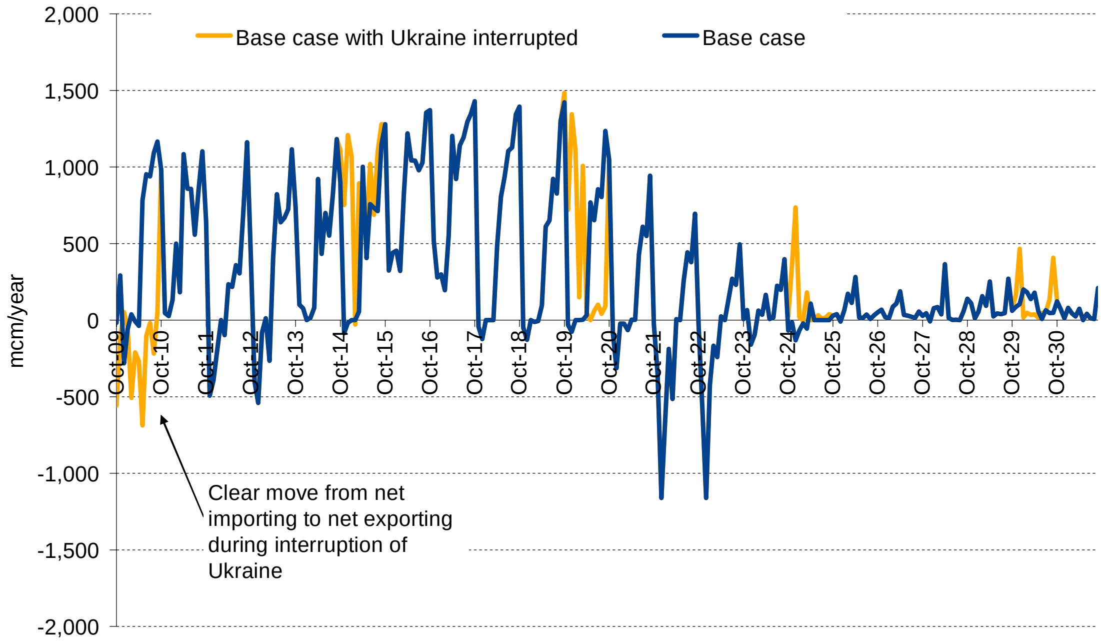


Figure 66 examines the impact this has on flows through the interconnectors between GB and the Continent, which we have done by comparing the net imports to GB under the Base case and then with the six month interruptions of Ukraine. This shows a move from net importing to net exporting in the 2009 gas year but becomes mitigated during the interruptions in the other sample years.

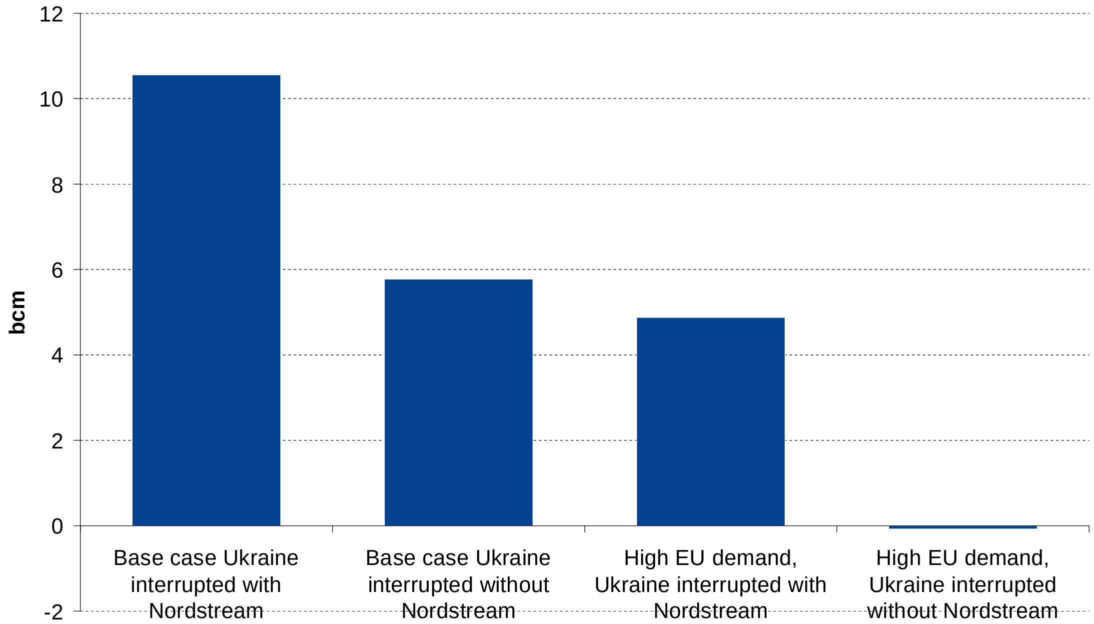
Our investigations show that once Nord Stream is commissioned and there is an interruption across Ukraine, Russian gas can enter Germany and flow southeast towards the Czech Republic and Slovakia to meet shortfalls in Russian gas which should have flowed via Ukraine. This goes some way to alleviate the pressure on gas to flow away from GB during a Ukraine crisis. Later, when South Stream is commissioned, this further reduces the importance of Ukraine and keeps GB more secure. We go on to illustrate this further in the next section, looking at the impact of Nord Stream in 2015.

5.5 Stress test 1a – the importance of Nord Stream

All the indicators are that the pressure on gas supply to NW Europe is less once Nord Stream has been constructed. For this variation to stress test 1 we have delayed Nord Stream start-up to after 2015. Its impact on GB is clearly illustrated in Figure 67, which shows how much greater the net imports are to GB during a year with an interruption of Ukraine, if Nord Stream is on line. Under the high European demand scenario, without Nord Stream on line during gas year 2014, there are actually small net exports from the GB to the Continent. The impact on GB gas prices is described in section 5.9.

This stress test indicates that any delay in the start up date for Nord Stream leaves GB more vulnerable to high prices during interruptions via Ukraine. In section 5.10 we describe a further sensitivity we carried out to examine the impact of failing to complete phase 2 of the Nord Stream project and increase its total capacity to 55bcm/year.

Figure 67 – Net imports to GB via interconnectors in gas year 2014, with six month interruption of Ukraine and Nord Stream start up delayed

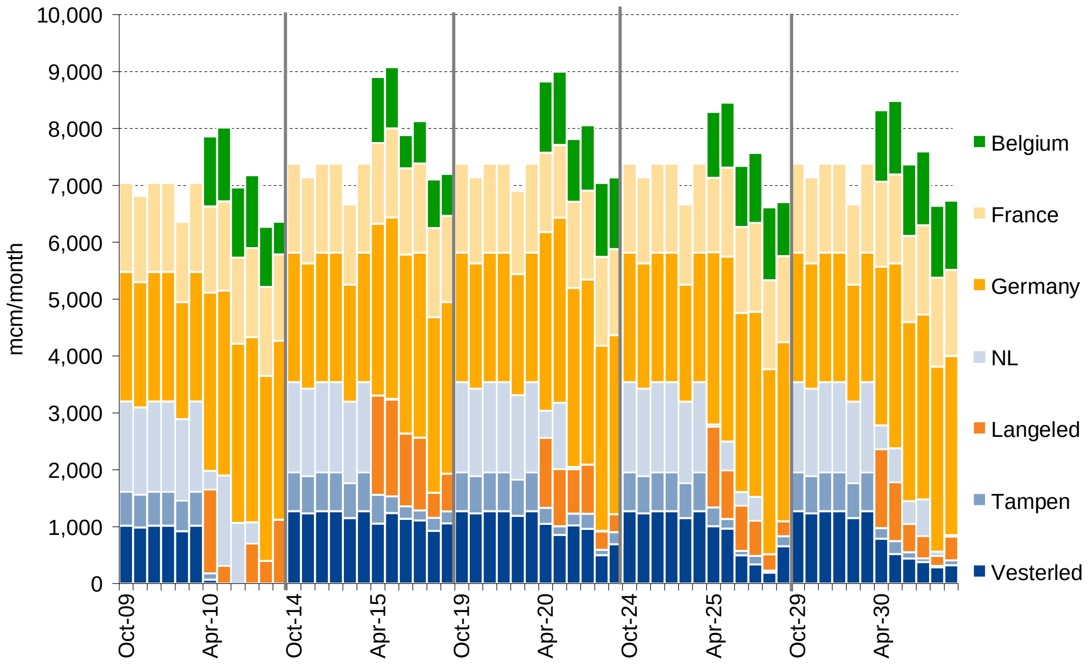


5.6 Stress test 2 – combining Ukraine and Norwegian interruptions

Our second stress test is the combination of interrupting flows via Ukraine for six months at the same time as problems are experienced on the Norwegian offshore infrastructure at Sleipner, all taking place during a severe winter in NW Europe. Figure 68 shows the impact on flows from Norway to NW Europe when the two problems occur at the same time. The Sleipner interruption affects gas flows into Belgium, Germany and down Langeled to GB, and as a result more gas flows via the Netherlands and through the Tampen link.

These are severe conditions and there are interruptions around Europe when they occur. For GB its LNG import capacity allows it to respond well to the supply disruptions and there is no need for demand side response until 2029 and at a level which can easily be covered by the current distillate backup capability at CCGT power stations (see Section 5.8). Prices spike very high in GB in gas years 2024 and 2029 under these conditions (see Figure 72) as the LNG market gets very tight and Ireland experiences interruptions.

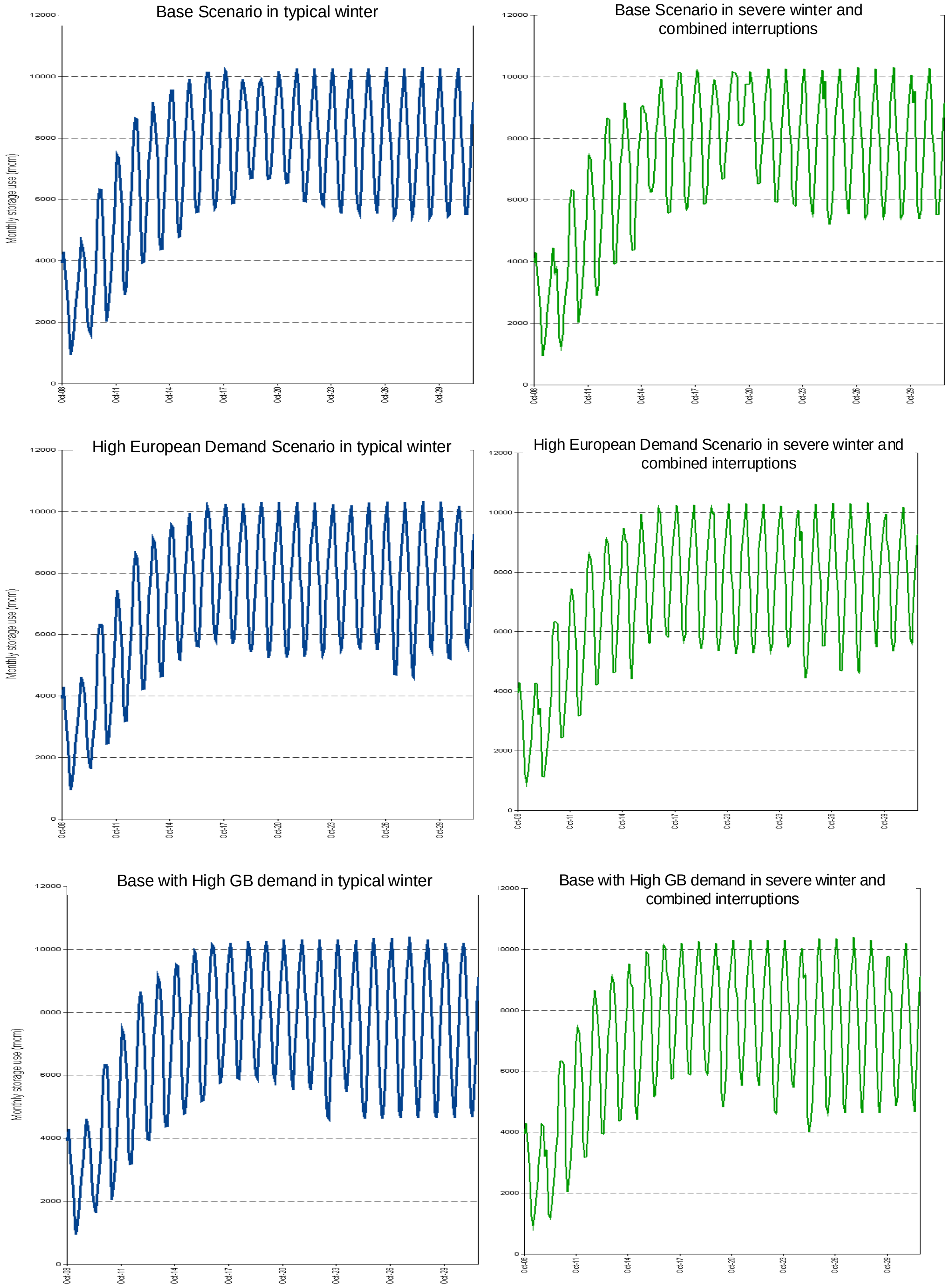
Figure 68 – Interrupting flows via Ukraine & Sleipner in sample years (Base case)



The assumed increased storage capacity in GB is sufficient to cope with the increased demands placed on it during a severe winter and combined supply shocks, as shown in Figure 69. Even in the situation with high GB demand in the bottom two charts the most amount of storage required is only around 6bcm.

Current levels of storage capacity in GB are 4bcm: another 1.4bcm is currently under construction, and a further 1.7bcm has planning permission. So, the 6bcm required in the modelling should be easily reached. There are many more projects proposed, both onshore and offshore, some of which have been included in the model, bringing the potential available storage capacity up to the 10bcm shown in Figure 69.

Figure 69 – Gas storage utilisation in GB with Ukraine & Sleipner interruptions

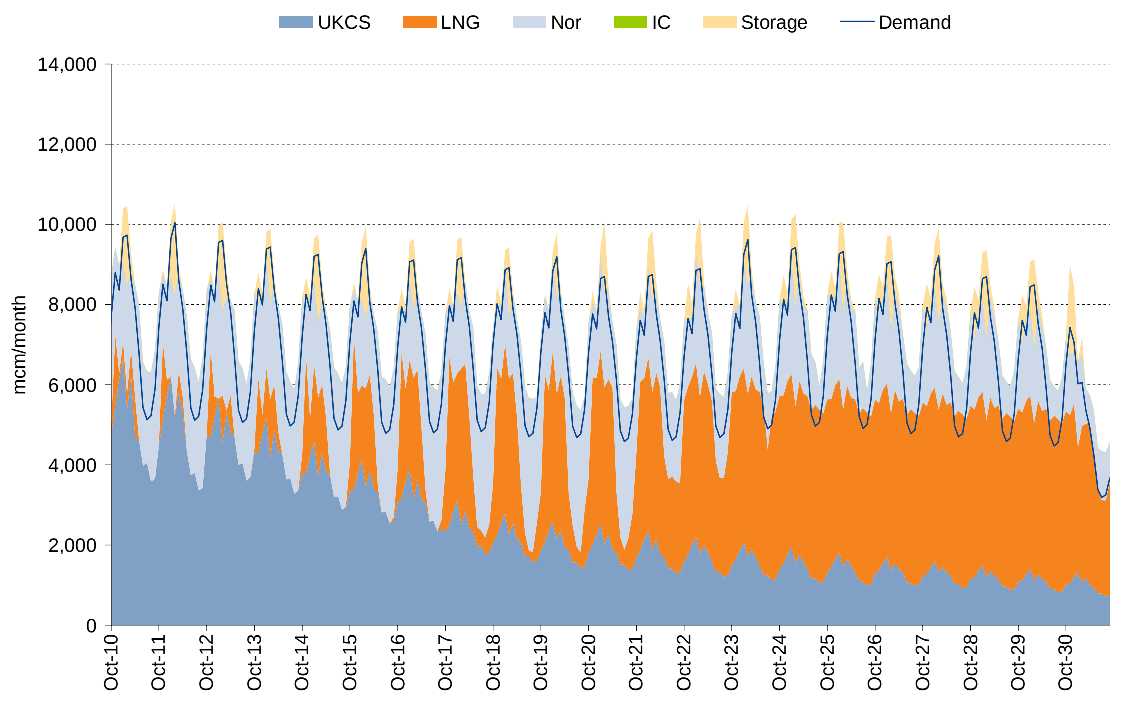


5.7 Stress test 3 – continental gas out of UK gas quality specification during a severe winter

As there is a potential risk that gas arriving at the IUK and BBL interconnectors may be outside the UK gas quality specifications, as discussed in Section 3.11, we have carried out a third stress test on the Base scenario under severe winter conditions to assess whether GB could cope with the loss of imports from the continent. It is not certain when and for how long the excursions outside the UK quality limits would be, so we have assumed a full loss of both interconnectors from 2012/13 to 2019/20.

Our analysis indicates that as most of the imports from the continent over this period would be in the summer and shoulder periods, GB is able to cope with the loss of the interconnectors by increasing imports from Norway, as shown in Figure 70, at the same time as Norwegian supplies to the continent are reduced. This, however, does rely on suitable volumes of Norwegian supplies being available with UK gas quality specifications.

Figure 70 – Gas flows to UK in Base scenario and Gas Quality stress test with severe winter



Interestingly, storage usage is decreased in this situation, as there is less cheap gas available to fill the storage in the summer and so it is more optimal to increase winter imports than summer imports and use storage.

5.8 Demand side response around Europe during stress tests

During the stress tests, which include severe weather in NW Europe, some zones within Pegasus are unable to meet demand in the sample years modelled. Table 11 and Table 12 show which zones need demand side response or would experience unserved energy under each stress test. The pattern seems to illustrate that Nord Stream improves the security of gas supply up to around 2024/25, at which time, tightness in the overall supply-demand balance starts to make some countries vulnerable again.

The years shown in red in Table 11 and Table 12 indicate years in which GB experiences extremely high prices due to the disruptions to supplies around Europe, even though not necessarily experiencing demand side response itself. It appears that when interruptions occur in a zone containing an LNG re-gasification terminal (Italy, SE Europe or France), then the price impacts on the world LNG market, and has a dramatic affect upon prices in GB.

This does not apply in 2009/10 when prices are high during the disruptions but do not peak to extremely high levels even though Italy and SE Europe are experiencing interruptions. This is because, at this time, GB is not heavily dependent upon LNG and has other supplies from Norway and the Continent to soften the impact on prices.

The impact of the disruptions on GB prices is further described in section 5.9.

Table 11 – Zones experiencing demand side response and/or unserved energy under stress test 1

			Ukraine interrupted		
			Base case		
	2009/10	2014/15	2019/20	2024/25	2029/30
Czech Rep	X	X		X	X
Austria & Hungary	X				X
Slovakia				X	X
Italy	X				
			High EU demand		
	2009/10	2014/15	2019/20	2024/25	2029/30
Czech Rep	X	X	X	X	X
Austria & Hungary	X	X	X	X	X
Slovakia				X	X
Italy	X				X
SEE	X	(X if no Nordstream)			
			High GB demand		
	2009/10	2014/15	2019/20	2024/25	2029/30
Czech Rep	X	X		X	X
Austria & Hungary	X				X
Slovakia				X	X
Italy	X				X

GB and Ireland require demand side response in a severe winter in 2029/30, under the high European demand scenario when Ukraine and Sleipner are interrupted. The level of demand side response is 103mcm, which can be met by current levels of CCGT distillate backup in GB (see Table 13).

Under the high GB demand sensitivity and a severe winter in 2029/30, when Ukraine and Sleipner are interrupted, GB and Ireland experience more severe interruptions. All the demand side response available (see Table 13) would be required and there would be in the region of 900mcm of unserved energy.

Table 12 – Zones experiencing demand side response and/or unserved energy under stress test 2

Ukraine and Sleipner interrupted					
Base case	2009/10	2014/15	2019/20	2024/25	2029/30
Czech Rep	X	X		X	X
Austria & Hungary	X				X
Slovakia			X	X	X
Italy	X				
High EU demand	2009/10	2014/15	2019/20	2024/25	2029/30
Czech Rep	X	X	X	X	X
Austria & Hungary	X	X	X	X	X
Slovakia				X	X
Italy	X			X	X
SEE	X	X		X	
Romania			X		
France					X
GB and Ireland					103 mcm
High GB demand	2009/10	2014/15	2019/20	2024/25	2029/30
Czech Rep	X	X		X	X
Austria & Hungary	X			X	X
Slovakia			X	X	X
Italy	X			X	X
SEE	X				X
GB and Ireland					5189 mcm

Table 13 – Demand side response categories in GB

Name	Mcm/d	mcm/mth	bcm/yr	Notes
CCGT Distillate	24	114	0.57	Restocking constrains monthly and annual volume
I&C interruptibles	10	310	3.72	Monthly/annual volumes would be further constrained by load factors

5.9 Prices during stress tests

GB gas prices under each of the scenarios and stress tests are shown in Figure 71, Figure 72 and Figure 73. They illustrate how GB prices spike during the supply disruptions and how GB prices are generally more sensitive when demand is high across Europe or in GB. Under the Base case the system manages disruptions well and prices do not spike extremely high. If demand growth is high across Europe then by 2025, GB prices stay very high across the entire year when Ukraine and Sleipner are interrupted for six months. If GB demand is very high then by 2030, an interruption from Ukraine alone pushes GB prices very high. The effect of Sleipner being interrupted not only has a larger effect in times of high demand, but the effect is more prolonged as well (see Figure 73).

Figure 71 – GB Monthly gas prices in Base case scenario under stress tests

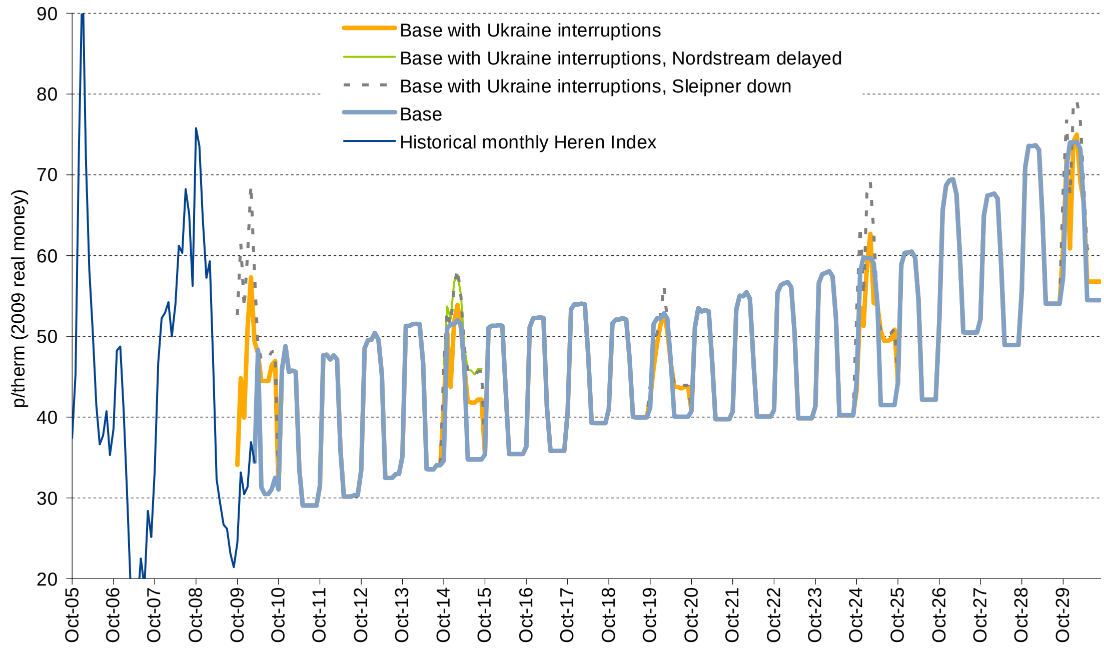


Figure 72 – GB monthly gas prices in High European demand scenario under stress tests

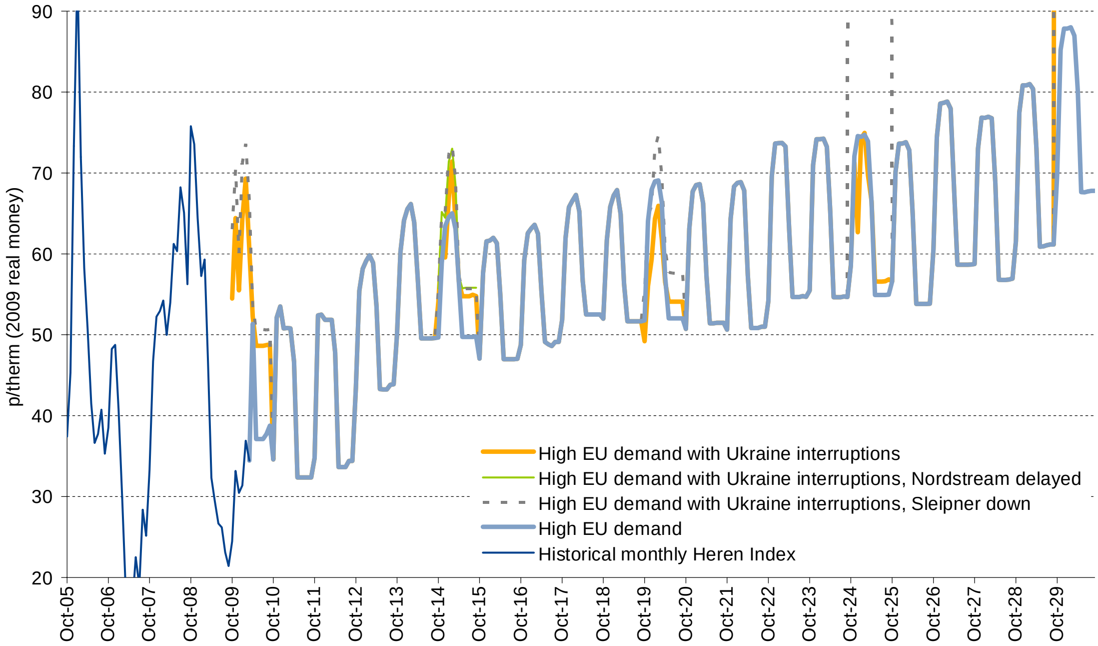
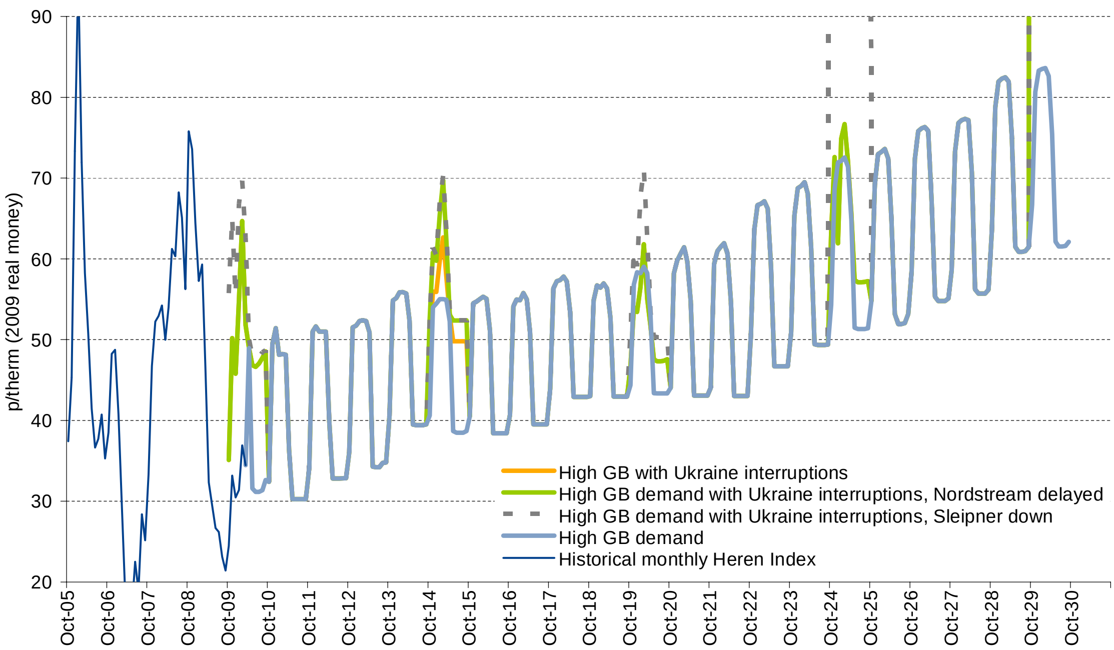


Figure 73 – GB monthly gas prices in Base sensitivity under stress test



5.10 Additional sensitivities under stress test 2

In order to further investigate the impact of our stress tests, we created a series of sensitivities around both the Base and High European demand scenarios and interruptions to Ukraine and Sleipner; see Section 5.6. These are:

- Gas quality sensitivity.
- Sensitivity around the reduction of Nabucco sources.
- Reduction in Nord Stream capacity.

The Gas Quality sensitivity is to simulate gas quality issues with Continental gas being outside the UK quality specification, so no gas is permitted to flow from the Continent into the UK, although GB exports to the Continent are still possible. This removal of Britain's import capability takes place from gas year 2012 onwards, and was applied to both the Base and High European demands.

Nabucco is included in the modelling from 2020 and amounts to about 25bcm/year of capacity linking Turkey into Bulgaria, and then further smaller interconnections all the way to Austria. It is the sources that supply Nabucco in Turkey that will allow additional gas to make its way to Europe, and it is these we reduce in our sensitivity. So, for the Nabucco sensitivity we reduce the Nabucco sources by keeping Azerbaijani gas production constant from 2011 onwards, and removing all Iraqi gas as a future supply.

The Nord Stream sensitivity looked at the reduction in Nord Stream capacity by assuming that only Phase 1 came online, in 2012, and that Phase 2 was postponed indefinitely.

The price effects of these additional sensitivities relative to the 'original' combined impact of Ukraine and Sleipner interruptions can be seen in Figure 74 and Figure 75. It can be seen that under times of high European demand not only is the overall price level higher but there are more frequent and extreme price spikes.

Of the three additional sensitivities, removing any further expansion of Nord Stream's capacity beyond its first phase has the largest effect on wholesale prices. This effect is more pronounced when European demand is high, and in 2024/25 and 2029/30 demand side response is required from the GB market. This amounts to 36mcm of demand side response in 2024/25 and 114mcm in 2029/30, both of which can be met through CCGT distillate backup and/or I&C interruptible contracts (see Table 13).

It can also be seen that removing the ability of the interconnectors to import gas into Britain has had no effect on the price, indicating that the UK has sufficient alternative capacity and supply sources to cater for any reduction in flows due to gas quality issues from Belgium and the Netherlands. However, this is dependent upon increased volumes flowing from Norway directly to Britain, which could potentially also be out of UK gas quality specification. In addition, without imports from the continent, GB's dependence upon LNG is also much greater, potentially making GB more vulnerable to disruptions in the world LNG market.

It was shown in section 5.3.1 that under the high GB demand sensitivity, GB became much more reliant on imports from the Continent. Hence, another concern would be that if GB demand outturns significantly higher than the central projection, gas quality could potentially become a more important issue.

Figure 74 – Additional sensitivities under combined stress test – Base case

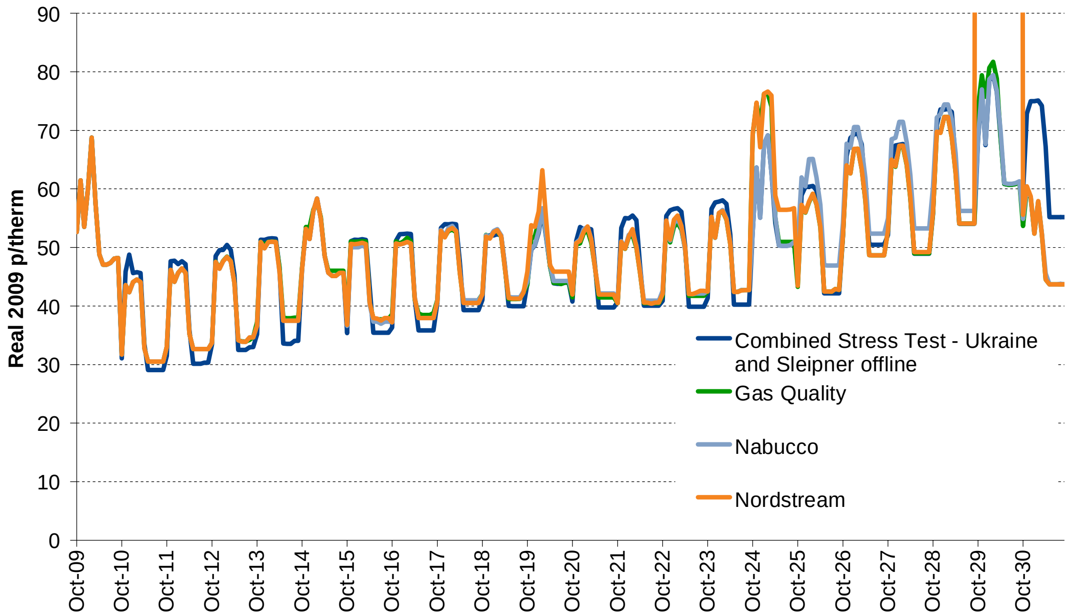
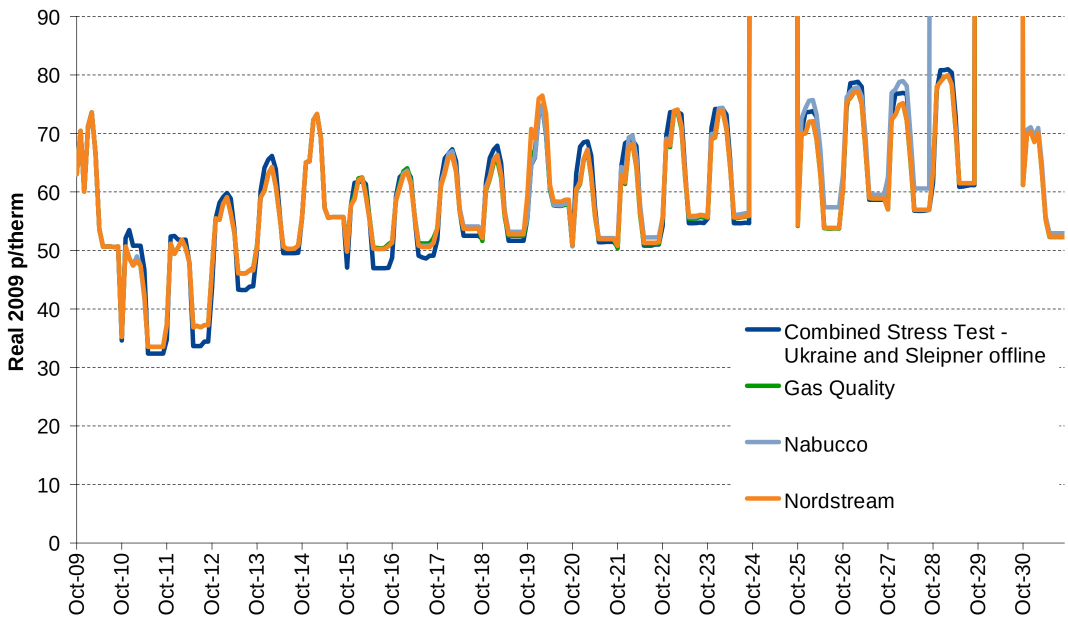


Figure 75 – Additional sensitivities under combined stress test – High European demand



5.11 Modelling summary

Table 14 summarises the peak prices in each gas year of all the scenarios, sensitivities and stress tests modelled during this project. Assuming the investment in capacity goes ahead as projected, there appears to be no security of supply concerns before gas year 2024/25 in any of the stress tests and sensitivities modelled.

Table 14 – Summary table of peak prices

	Weather severity	Event	Additional sensitivity		Base case	High European demand	High GB demand	High GB and European demand
	'Typical'	None		2009/10	50	57	50	67
				2014/15	52	65	55	74
				2019/20	53	69	59	72
				2024/25	60	75	73	81
				2029/30	74	88	84	94
STRESS TESTS	'Severe'	1. Ukraine off (Oct-Mar)		2009/10	57	69	65	
				2014/15	54	71	63	
				2019/20	53	66	62	
				2024/25	63	75	77	
				2029/30	75	479	480	
	'Severe'	1a. Ukraine off (Oct-Mar) & N Stream delayed		2009/10	57	69	65	
				2014/15	58	73	70	
				2019/20	53	66	62	
				2024/25	63	75	77	
				2029/30	75	479	480	
	'Severe'	2. Ukraine off & Sleipner off (Oct-Mar)		2009/10	69	74	70	
				2014/15	58	73	70	
				2019/20	56	75	71	
				2024/25	69	461	467	
				2029/30	79	480*	481	
	'Severe'	3. Gas out of UK spec – **no** imports from continent		2009/10	49			
				2014/15	51			
				2019/20	53			
				2024/25	61			
				2029/30	73			
Additional sensitivities under stress test 2	'Severe'	2a. Ukraine off & Sleipner off (Oct-Mar)	Gas out of UK spec – **no** I/C imports	2009/10	69	74		
				2014/15	58	73		
				2019/20	57	75		
				2024/25	76	468		
				2029/30	82	480		
	'Severe'	2b. Ukraine off & Sleipner off (Oct-Mar)	Nabucco under supplied	2009/10	69	74		
				2014/15	58	73		
				2019/20	57	75		
				2024/25	69	479		
				2029/30	79	480		
	'Severe'	2c. Ukraine off & Sleipner off (Oct-Mar)	No phase 2 Nord stream	2009/10	69	74		
				2014/15	58	73		
				2019/20	63	76		
				2024/25	77	480*		
				2029/30	465	480*		

Scenario not modelled
Scenario modelled and prices below 80p/therm
Scenario modelled and peak prices between 80 and 100p/therm
Scenario modelled and there are penal prices and * indicates demand side response in GB
Scenario modelled and there are penal prices and unserved energy in GB

Table 14 shows the scenarios which were modelled and experienced no significant price spikes in green. The five sample years are also shown on the table to indicate the timing of exposure.

The scenarios and years in which the peak price rises over 80p/therm, but remains below 100p/therm, are shown in yellow. The scenarios and years in which the prices reach penal levels are shown in amber. In some of these years there is clear demand side response output by the model (indicated by * in Table 14), while in other years there is no definite requirement for demand side response; although, at the price levels indicated, there would almost certainly be some demand side response.

There is only one year modelled in which there is clearly unserved energy in GB and this is shown in red.

5.11.1 Base case

The outcome of our modelling under the Base case assumptions is that there should be plenty of capacity and available gas supplies to satisfy demand without any security of supply concerns. The only penal price spikes are experienced in 2029/30 in the event of two major supply shocks and a severe winter, in conjunction with the failure to develop Nord Stream phase 2.

5.11.2 High European demand

By 2024/25, under the High European demand scenario, penal prices are only experienced in the event of two major supply shocks, and a severe winter. By 2029/30, a single supply shock in Ukraine, and a severe winter, results in penal prices; some demand side response is required if Sleipner is affected at the same time.

The failure to develop Nord Stream phase 2 increases the impact of the double supply shock and severe winter, under the high European demand scenario, and demand side response is also called upon in GB in 2024/25, as well as in 2029/30.

5.11.3 High GB demand

The system has been further tested against the National Grid TYS high demand scenario, where GB demand is approximately 40bcm/yr higher than the central demand projection. GB gas security of supply still remains resilient until 2024/25, when under the double supply shock and severe winter, prices peak. By 2029/30, the same stress test leads to all GB's options for demand side response being utilised (see Table 13) and even then around 900mcm of energy would still remain unserved.

5.11.4 High European and GB demand

Meeting the combination of high GB demand with high demand across the rest of Europe requires further investment in LNG, including:

- 40bcm/year more liquefaction capacity on top of that projected in our central case; as well as
- another 39bcm/year of re-gasification capacity in NW Europe (on top of the 44bcm/year assumed in our central projection).

There are a number of proposed projects which are not included in our central case which could be developed to create this additional capacity, and there is also the possibility of new sources of unconventional gas being developed. By 2029/30, the capacity margin becomes extremely tight across Europe, and winter prices reach 94p/therm, even without supply shocks or severe weather.

5.12 Modelling conclusions

Given the moderate investment (shown in Table 8 and illustrated in Figure 57) in capacity we have assumed is constructed, security of GB gas supply could be maintained under a combination of a severe winter and **two** prolonged outages to pipeline supplies through Ukraine and from Norway in the Base scenario until 2029/30.

If demand growth is considerably higher than our central case in either Europe or GB, further investment in capacity would be needed by 2024/25 to maintain the same level of security of supply. Although GB can still withstand **one** major outage via Ukraine during a severe winter at any time up to 2024/25, even with the higher levels of projected demand.

Nord Stream provides a significant contribution to GB's security of supply by allowing Russian gas supplies to reach NW Europe under circumstances where there is a disruption to supplies through Ukraine. Modelling a delay in Nord Stream's initial start-up date, and modelling the cancellation of Nord Stream phase 2 capacity, both indicate the pipeline's importance. If Nord Stream is delayed, GB's reliance on the LNG market is increased during supply disruptions and pushes prices up further than would otherwise be the case. If Nord Stream phase 2 is cancelled, the impact of outages is considerably increased and more demand side response is required in GB.

Gas quality problems are not clearly identified as a threat through the modelling, although prices peak higher when they are not available. However, security is maintained through increased dependence upon imports directly from Norway and/or via the world LNG market, so gas quality problems do increase GB's vulnerability.

The disruption to gas supplies around Europe and how they impact on GB is discussed in section 5.8. It is clear that disruptions to gas markets which influence the world LNG market have an increased impact upon GB. In the case of the scenarios modelled, these are Italy, Greece and France. Projects that help ensure their security, reduces the likelihood of high prices in GB, and in the south east of Europe these include South Stream and Nabucco.

Improved access to gas storage in France and Italy could also potentially improve the region's security, as might building more gas storage in the region.

6. POLICY OPTIONS

The modelling scenarios and sensitivities described in the previous section illustrate that, provided GB gas infrastructure expands as assumed in response to changing supply-demand conditions, our main security exposure occurs when tightness in the continental supply-demand balance, for whatever reason, reduces the range of gas sources on which we can call.

Consequently, the intention of any policy options should be to minimise the impact of specific supply shocks on the NWE market and/or reinforce the diversity and reliability of GB's import options. In this section we focus upon policies affecting gas supplies available to Europe via pipelines.

However, it should be borne in mind that, as the scenario analysis has shown, the security of GB's gas supplies is equally dependent on the timely delivery of GB gas infrastructure and development of a global LNG market. These two influences on GB gas security have been considered separately. Risks associated with, and policies to support, the LNG market have been discussed in the accompanying report, Global Gas and LNG Markets and GB's Security of Supply[16], whereas the range of policy options that could be taken *within* the GB gas market were considered in a report last year on GB gas security of supply[17].

6.1 Overview of policy options

We have identified a short list of potential policy options for improving NWE security of supply and hence minimising the market price and physical security risks faced by the GB market. These policies have been grouped under four broad areas.

- *Promotion of competition and liberalisation* – policies that serve to improve the operation of the competitive market across NWE, helping to improve efficiency in gas flows, infrastructure utilisation and network investment and interconnection.
- *Facilitation of import infrastructure development* – policies that support a favourable investment environment for key import infrastructure projects to improve the diversity and reliability of import routes to NWE and key LNG competitors.
- *Harmonisation and co-ordination across markets* – policies aimed at reducing administrative or operational barriers to cross-border flows or cooperation.
- *Improved resilience of direct GB import sources* – policies aimed specifically at raising the reliability of GB import routes and the sources of supply.

The specific policies that we have considered under these headings are listed below:

1. Commercial access to gas storage in Europe (Competition and liberalisation).
2. Consolidation of a NW European gas hub (Competition and liberalisation).
3. Pipeline imports from Caspian and/or Middle East (Import infrastructure).

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[16] 'Global Gas and LNG Markets and GB's Security of Supply', Pöyry Energy Consulting, June 2010, a report to DECC.

[17] 'GB Gas Security of Supply and Options to Improve', Pöyry Energy Consulting, March 2010, a report to DECC.

4. Enlargement of the EU (Import infrastructure).
5. Gas quality conversion (Coordination and harrmonisation).
6. Regional emergency plans (Coordination and harrmonisation).
7. Extra resilience of Norwegian supplies (Direct imports).

Though all these options are external to the GB market, they differ in the proximity of their effect to the GB market, as shown in Figure 76. This geographic dimension raises important considerations for the effectiveness of any policy option. The more remote to the GB market that the effect of the policy is observed, the more indirect is both the impact on GB security of supply and the means through which the GB government can deliver the requisite policy action. However, while the ability to influence unilaterally is much lower than within the national market and the domestic benefits possibly less immediate and certain, it does not mean active policy engagement is not desirable. It is against this background that the specific policy options are described and assessed in the remainder of this section.

Figure 76 – Geographical target of policy options

Key: 1 – Commercial access to gas storage in Europe; 2 – Consolidation of a NW European gas hub; 3 – Pipeline imports from Caspian and/or Middle East; 4 – Enlargement of the EU; 5 – Gas quality conversion; 6 – Regional emergency plans; 7 – Resilience of Norwegian supplies.

6.2 Promotion of competition and liberalisation

Though the modelling scenarios presented earlier in this report incorporate some of the existing rigidities in European gas markets – specifically, restrictive take-or-pay contracts and national strategic storage provisions – the general results are those of a well-functioning, competitive gas market where price signals deliver efficient utilisation of current infrastructure (especially storage and interconnectors) and optimal long-run investment decisions. Policies that directly promote the liberalisation of the EU gas market should therefore be expected to ensure the risk to GB consumers from pipeline import uncertainty is as low as is indicated in Sections 4 and 5.

We recognise that energy market liberalisation has been a key focus of EU energy policy and the implementation of the EC Third Energy Package should address a range of market imperfections and maintain, and even speed up, progress towards a more fully liberalised gas market across the EU. However, in practice, the speed and form of implementation will vary significantly by country. For the UK, the out-turn in countries that are more closely linked to the UK will have the most direct impact; ensuring implementation in these countries does not introduce or sustain distortions will be of greatest benefit to the UK's gas security of supply.

Our proposed policy options complement and reinforce the general provisions within the Third Package.

6.2.1 Greater commercial access to gas storage

Our analysis has indicated that effective access to storage across the EU can reduce the risk of interruptions and price spikes. However, large volumes of storage capacity are often not available to the market under normal conditions. In the short-term this can increase the risk of entering emergency situations when there are supply or demand shocks, and in the long-term may lead to over investment and higher costs to consumers.

There are requirements in the Third Energy Package to improve third party access to gas storage and to offer anti-hoarding provisions, such as short-term capacity and use-it-or-lose-it (UIOLI) mechanisms. At present there are significant volumes of gas storage and flexibility (in Netherlands, France, Germany) that do not become available as commercial storage due to lingering inefficiencies and security measures, as described in Section 3.8.2. There is a risk that these remain excessive compared with the EU requirement.

Active policy support for the development of storage regulations through the European Commission and ACER may address this. It would help facilitate the replacement of restrictions of backup obligations and long-term contracts with more transparent and more precise obligations, and to progressively reduce the size of the restrictions to free up more storage for use by the commercial market. This may then lead to a regional rather than a country-by-country requirement for storage to cover supply emergencies.

The analysis of security of supply on an N-1 basis (loss of largest single source of supply) might then be performed on a regional basis rather than a country by country basis. A regional approach would tend to further reduce the requirement for security of supply and free up more storage for the commercial market. Though there would still be the need to access stored gas in a supply emergency the policy would reduce the likelihood of a supply emergency in the first place in any one country through making a greater proportion of stored volumes available to the commercial market.

As mentioned above, requirements to improve third party access to gas storage and to offer anti-hoarding provisions are included in the Third package. As this is an active area of policy engagement, the additional cost of focussed promotion of specific arrangements should be minimal.

6.2.2 Consolidation of a NW European gas hub

If trading markets are not liquid, then the price signals they produce will be inefficient and a less reliable indicator of periods of market tightness, potentially distorting, or discouraging necessary investment and cross-border flows.

As markets liberalise, the natural response is for each country to develop its own separate gas trading hub – or, as in the case of France and Germany, a number of trading hubs (see Figure 12 on page 14) – to meet the local market requirements. As there will only be a limited number of players and a small number of sources of supply, there is a risk to efficient market operation because of insufficient liquidity or depth. Removing barriers to entry by ensuring that new players have access to infrastructure (transportation and storage) encourages the development of liquidity and enables market players to trade across borders. To mitigate this risk, a potential policy option would be to promote good access arrangements and encourage the amalgamation of trading hubs in NW Europe.

This would have the benefit of creating more liquid hubs with increased resilience in the traded market and the ability to share resources. If GB became part of a NW European hub, storage in the Netherlands and Germany could more easily be accessed by shippers in GB to help manage their flexibility and security of supply requirements, and vice versa.

In the longer-term, a more liquid hub may accelerate the establishment of a credible alternative to oil-indexation for the pricing of long-term gas supply contracts. Contracts with gas-indexed prices would shift price risk upstream to the producer and leave the buyer with gas priced 'at the market' creating the option to sell at the hub with little or no price exposure.

However, to deliver this option in the short-term may be costly. To produce the full benefits, requires two conditions to be met:

- unconstrained capacity between the different systems within the hub; and
- compatible balancing and capacity rules to apply across the whole area.

The investment required to provide unconstrained capacity across the networks may cost billions of Euros; though some of this investment is already planned, such as between Belgium and the Netherlands.

Our modelling assumes gas can flow between markets assuming consistent balancing and capacity rules that do not hinder trade across borders. Compatible balancing and capacity rules are also envisaged through the Third package, but there is no call for them yet to be identical. The Belgian and Dutch systems and interconnectors include hourly balancing rules as well as daily balancing. The difficulties of merging the different rules across the different jurisdictions should not be underestimated and might take years of negotiations and consultations.

There are also possible unintended consequences from expanding hub sizes. Because gas takes a significant amount of time to travel through the network, local imbalances would need to be maintained for longer by TSOs or locational balancing signals might be required. This leads either to a bigger network (e.g. linepack), or to increased scope and requirements for TSOs to take locational balancing actions.

These issues do not mean that a single hub cannot be achieved. We have seen in Germany in recent years how it is possible for different Transmission system owners to co-operate and create market areas that cover more than one system. This had a positive involvement from both the gas industry and regulators and took place without the need for years of negotiations and without significant investment. As of October 2009, there were three H-gas market areas three L-gas market areas in Germany, which have been reduced from a total of eighteen market areas just two years prior to this; there are also plans for further market area mergers in the future. So far these have taken place where there has been a single jurisdiction and there are no precedents yet for gas market area mergers across borders, although there is now a single electricity market for Ireland and Northern Ireland and plans in place to develop combined arrangements for gas in the same zone.

It is also likely that further policies, such as those related to gas quality conversion (see below) would need to be pursued in parallel to support the consolidation of the Zeebrugge physical hub with the NBP virtual hub.

6.3 Facilitation of European import infrastructure

As Table 14 shows, the largest risk of GB market price spikes and of physical outages, occurs if there are delays to some of the key import infrastructure projects that have been proposed for development. In the face of major supply shocks – for example, the combined Ukraine and Sleipner outages – lack of progress with major infrastructure projects such as Nord stream and Nabucco will exacerbate potential adverse effects on the GB market.

This is because without these projects the diversity of supply sources to NWE is reduced. The impact is direct in relation to Nord stream and indirect from Nabucco (as it increases competition for LNG supplies from southern European markets). Delivering these projects will not remove price spikes, but it would reduce their impact and lower the likelihood of requiring demand side response.

Policy options that improve the investment environment within which to take forward these projects may have a significant benefit for GB and the wider EU market. Below we have identified two potential policy areas that may facilitate this situation – creation of import consortia to guarantee/underwrite import volumes through specific routes; and enlargement of the EU enabling the internalisation of foreign policy negotiations.

6.3.1 Pipeline imports from Caspian and/or Middle East

As mentioned in Section 3.5, there are a number of competing buyers for the various sources of gas in the Caspian region. Pipeline projects need to source the gas they will deliver and therefore an inability to provide long-term commitments to the sellers can put a project in jeopardy. This is a possible issue for the Nabucco consortium that the EU has backed to bring gas – nominally from Azerbaijan and Turkmenistan – via Turkey to Bulgaria, Romania, Hungary and Austria.

Because the consortium is a group of relatively small gas companies they are unable to give the same commitments to the sellers as a large, single buyer, like Gazprom. Gazprom would like to purchase these supplies to fill the proposed South Stream pipeline under the Black Sea to Bulgaria and on to other countries in SE Europe, reinforcing its position in the region.

This increases the risk for the Nabucco consortium, not only because it may have to take a very long position to guarantee volumes, but if it cannot find agreement with these sellers it would need to source its gas from Iran and Iraq. Volumes from these sellers may be insufficient to fill the pipe in the short to medium term and there are the added political difficulties related to sourcing Iranian or Iraqi gas.

In Section 5.10 we modelled a sensitivity with reduced gas supplies through Nabucco but no change to South Stream and found that under times of high European demand not only is the overall price level higher but there are more frequent and extreme price spikes, although the levels are less than the case of delay in Nord Stream phase 2.

For the EU, the risk is that it will be unable to secure new gas supplies from the Caspian region, which has been traditionally perceived to be remote.[18] As a result, it could miss out on an opportunity to diversify its sources of supply and introduce some kind of competition amongst the suppliers to SE Europe.

The EU is considering a scheme where companies can act collectively to buy gas from the Caspian region. The vehicle, known as the Caspian Development Corporation (CDC), would allow the EU companies to aggregate their buying power to stimulate investment in the Nabucco project. The EC is currently awaiting the results of a feasibility report to assess how it would work. If it does go ahead, it will provide a stronger counterparty for Azerbaijani and, particularly, Turkmen gas producers.

The CDC will not be limited to Nabucco partners and could be used to support any of the transportation projects from the region. Nevertheless, coordinated action by the EU could help decide the winner so that a pipeline gets built to transport gas from the Caspian region to the EU. There have been concerns that it is not compatible with EU competition law, but the EC does not envisage there to be a problem with the competition rules and had carried out a thorough analysis of competition issues.

Although, as shown in our modelling, it does not affect the UK's security of supply significantly, DECC could provide support to the EC in its creation of the CDC and promote it amongst British companies. This is also consistent with the recommendation of the Wicks Review that the Government should foster relations with major gas producing countries to facilitate future imports – the difference being that this is a more coordinated approach at an EU level.

6.3.2 Enlargement of the EU

As has been seen in our discussions in Sections 3.4 and 3.5, two of the key transport routes to the EU cross Ukraine and Turkey. Although security of gas supply for the EU is not the main driver for accession to the EU, by supporting their accession the Government could significantly help to improve the security of supply in central and south-east Europe. The direct security of supply benefits to the UK would not be significant.

Any benefits would be realised through two routes. First, with the countries being within the EU, they would have to comply with the energy directives and allow third party access to pipelines and other infrastructure. They would also be subject to EU law, where destination clauses and the inability to sell on imported gas have been made illegal. Although physically this would not change the dependence on Russian gas, it would improve integration between the markets.

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18 Note that new gas supplies can be sourced from countries remote to the EU if there is access to port facilities suitable for LNG shipping.

Second, it would improve prospects for some pipeline developments if strategic transit countries were part of, rather than outside, the EU. For example, Turkey is strategically located to enable the transit of gas to the EU from the Middle East and Central Asia. As the proposed Nabucco pipeline is intended to cross Turkey, the project's chances of success could be significantly improved if Turkey was able to accede to the EU. Any impact on the GB gas security through this route would be indirect, through relieving supply constraints in Southern Europe.

Supporting Ukraine's integration into EU structures is equally important, as it is not only a strategically important transit state for Russian gas but also has over 30bcm of gas storage – five times the total current storage volume in GB. Setbacks in Ukraine's NATO membership in late 2008 and the presidential election of January 2010, which brought to power a government relatively sympathetic to Russia, have moderated Kiev's ambitions to accede to Western institutions. The overtures made to NATO and the EU by the previous government led to a sharp deterioration of relations between Moscow and Kiev, contributing to the January 2009 gas crisis.

Dialogue with the new Ukrainian government should encourage integration, but Russia will continue to take keen interest in developments across its Western border and the encouragement of stable working relations between Moscow and Kiev is in EU interests. Trilateral EU-Ukraine-Russia discussions could be a viable policy option aimed at finding and preserving areas of mutual interest, such as the interrupted transit of Russian gas via Ukraine en route to the EU.

Though energy policy will be a key consideration in any decision regarding accession, it is difficult to assess the full economic impact and due regard would need to be paid to the wider economic and social issues of EU membership.

6.4 Harmonisation and coordination across markets

We have already noted, in our discussion around gas hubs, that better harmonisation and consistency of operation would facilitate more efficient movement of gas between markets and utilisation of gas infrastructure. One important barrier to cross-border flows is gas quality differences. As our sensitivities show, if this becomes a major issue, then it prevents the GB market from using continental interconnectors thus reducing the diversity of import capacity and leading to an increased risk of price spikes in times of stress.

Separately, during times of system stress, such as the Russia-Ukraine dispute in January 2009 (see Annex C for detailed analysis), the EU gas system has responded to supply shortages. Formalising these coordinated emergency responses would help to reinforce this response and ensure that markets react quickly and effectively to major shocks, minimising the risk of further short-term dislocation in the market.

6.4.1 Gas quality conversion

As discussed in Section 3.11, there is evidence from Fluxys that the sources supplying the commingled gas imported to GB via the IUK pipeline have a Wobbe Index (WI) which is increasing over time and that blending in Belgium may become a problem for Fluxys as the mix of gas sources changes. If gas for import exceeds the specification then imports would be interrupted until such time as the quality of the commingled gas stream could be brought back within the GB specification. This effectively removes one possible source of flexible supply to the UK in times of stress.

At present, it is not clear who has responsibility for resolving the issue as Fluxys currently perform the service for the benefit of all IUK shippers whereas the UK gas quality specification is included in the Gas Safety (Management) Regulations (GS(M)R) and requires Government action to change.

Specific policy options may help clarify this responsibility and lead to timely investment and recognition of the problem. There are several options.

One policy option is to require that the GB system is capable of accepting any gas delivered by pipeline from Europe that meets the EASEE gas quality specification. This requirement would entail substantial investment to enable ballasting gas imports with nitrogen either at Bacton or Zeebrugge, to produce a quality that is within specification.

Regardless of who this responsibility would fall on – IUK, the shippers or National Grid Gas (NGG) – there would be major investment and the lead time for plant could be around 3 years (assuming no hold ups obtaining planning permission). It also has unintended consequences for the local community, for example, large numbers of tankers delivering nitrogen every day through the villages of Norfolk.

Following a cost benefit study carried out in 2006, BERR consulted on this issue and in 2007[19] concluded that, due to the cost and complexity involved, no change to the GB specification would be considered until 2020. We suggest that this decision should be reconsidered at an earlier stage. The European Commission is currently undertaking a gas quality cost benefit analysis, which is due to report in 2012. Depending on the results of this, it may be worthwhile DECC revisiting its study to consider how the evolution of appliances has changed. An extension of the boiler scrappage scheme to include all gas appliances over 15 or 20 years old could encourage a faster changeover to acceptable equipment and have the added benefit of assisting with the push for greater fuel efficiency ahead of 2020.

Alternatively, a regulatory change to the GS(M)R to allow a wider tolerance of gas quality to enter the NGG terminal or even the NTS may be easier to implement. It would not, however, necessarily lower the cost. NGG has argued that, as it is not responsible for the quantities of gas arriving at the terminals each day, it cannot guarantee that there would be enough within-spec gas to blend the high Wobbe gas with. It would therefore need to install and maintain ballasting equipment anyway, in case the blended quality does not match. In such a case, at least the ballasting equipment could potentially be installed further downstream avoiding the unintended consequence highlighted under the first option.

6.4.2 Regional emergency plans

The EU Regulation on Gas Security of Supply should enable natural gas undertakings and customers to rely on market mechanisms for as long as possible when coping with disruptions. Even in an emergency, market based instruments should be given priority to mitigate the effects of the supply disruption. The European Commission recommends the establishment of joint preventive actions plans or emergency plans at regional level.

The risk is that the Regulation does not result in a coordinated response and that there remain inconsistencies with the international arrangements.

A potential policy option is for the UK to work closely with countries to which it is directly connected (Ireland, Belgium and Netherlands) and with their neighbouring countries, to

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19 'Government Response to consultation on future arrangements for Great Britain's gas quality specifications', URN 07/1626

ensure that the emergency plans are tested and will work when used in anger. This would require joint plans that identify early warnings when a security of supply situation is developing, that contain the steps to be taken to access gas through the commercial market to prevent an emergency developing and, in the case of an emergency, that coordinate actions to bring the situation under control.

DECC and Ofgem should therefore work with the European Commission, the Agency for the Cooperation of Energy Regulators (ACER) once it is established in 2011, and ENTSO-gas to ensure that these arrangements are brought into place as quickly as possible, that arrangements are put in place to minimise the necessity for emergencies to be called and that the interests of UK consumers are given sufficient priority and profile in the agreed arrangements.

It should be noted that European countries further from the UK may also be able to help, but in the first instance the coordinated response would be with countries adjacent to GB.

This development would be assisted by policies promoting competition in the market, such as liquid market hubs on the continent, as these create conditions where a wide range of supply and interruption options could be transacted.

6.5 Improved resilience of direct GB import sources

6.5.1 Extra resilience of Norwegian infrastructure

In terms our analysis of the impact on the GB market, the loss of Norwegian supplies was a major issue if coinciding with an outage in Eastern Europe. Even though there is the capability to satisfy demand from other sources, it has a large pricing impact if the loss extended over a few months.

It is worth considering whether there are policy options that would serve to improve resilience of this core gas supply source. This may be achieved through incentives to the Norwegian system operator to develop extra resilience to its system, so that long-term outages to the UK are minimised.

It should be noted that the Norwegian system has proved to be very reliable in the last 40 years and any outages have only lasted a relatively short time (usually recovered within 24 hours). Outages of a number of weeks or even months could therefore be unrealistic given existing standards. Depending on the nature of the outage, it may also be possible to increase supplies to the Continent and effectively re-route some of the gas to the UK via the interconnectors. We therefore do not consider this policy option worthwhile.

Adding resilience to Norwegian supplies could include measures to ensure GB supplies are prioritised in the event of offshore incidents. At the moment many Norwegian producers sell their gas directly into the GB market on annual, monthly or spot contracts. They are flexible to modify a proportion of their output or direct their gas depending on the price in the German, Dutch, Belgian and GB markets. Prioritising supplies to GB could be done by encouraging GB shippers to take out long-term contracts with Norwegian producers, so that they have first call on the gas produced. However, in order to attract sellers, GB buyers would have to pay a premium above the spot and forward prices, either through a higher price for a flexible contract or for a call option if the contract is for winters only, which adds to their costs and would be passed on to customers throughout the year.

As this discretionary/flexible gas is price sensitive, the price just needs to be higher than the neighbouring markets on the days of constraint. The cost effective option would therefore be to assess the balancing rules against the rules in neighbouring countries to ensure that the incentives on GB shippers to balance are no worse than in Germany, Netherlands, Belgium and France.

6.6 Summary of policy options

We have described above the specific policy options that may assist in improving the security of supply for the GB gas market and qualitatively discussed their impact, cost and effectiveness. As indicated at the start of this section, the policy actions and impacts are more indirect than those we may assess for the domestic market. This makes a detailed assessment of the policy options more difficult. Therefore, in summarising the policies here, we have employed a qualitative assessment against the following broad criteria:

- impact on GB security of supply – this is linked back to the exposure on prices and physical outages described in the scenario stress tests and sensitivities;
- ability of GB government to influence – which we have linked to the proximity to the GB market and the extent to which pan-EU or cross-governmental coordination would be required;
- cost of policy – any indication of the direct cost associated with the policy;
- implementation timescale – whether the policy could be implemented relatively quickly.

The conclusions are summarised in Table 15. The criteria are ranked from 1 to 5 in terms of their effect, 1 being the least beneficial and 5 the most.

Table 15 – Assessment of policy options considered

Option	Impact on GB security	Ability to influence	Cost of policy	Time to implement
Storage access	2	3	4	4
Gas hubs	2	2 – 3	4	2 – 3
Caspian supplies	3	1	2	2
EU Enlargement	3	1	1	1
Gas quality	2	4 – 5	1	3
Regional emergency plans	2	3	4	4
Norwegian supplies	3	2 – 3	4	2

The fact that the assessment is qualitative, and that the rankings between criteria have not been normalised – from review of the scenario results it may appear that all policy options will have a very limited impact on GB security – mean this summary must be read with caution. However, in our opinion it shows that:

- the impact of policies on GB security of gas is limited as anticipated market developments imply a relatively diverse and resilient GB system;

- the ability to exert direct policy influence is limited and most policies require coordination with other EU states and/or supply countries;
- the direct cost of the policies are therefore relatively low and generally involve providing support to and influencing existing European policy initiatives. Only in dealing with gas quality issues would direct investment be substantial;
- as the majority of issues emerge in the longer-term, the policy options are likely to be implemented over a longer time frame.

Where policies are linked to ongoing EU initiatives – for example, regional emergency plans, storage access or support of infrastructure projects – the limited cost and broad overlap with current activities suggests they are low risk policies to promote.

The fact that policy impacts may not be immediate is not an issue provided there is sufficient notice of potential issues to enable a timely response. In these circumstances, monitoring of indicators of market development and operation over time should provide DECC with an 'early warning system' for potential risks.

One area where earlier action may still be required is in respect to the gas quality issue. Though the DTI, Ofgem and HSE study in 2006 concluded that, due to the cost and complexity involved, no change to the GB specification would be considered until 2020, likely evolution in gas mix may necessitate a review of this conclusion. The European Commission is currently undertaking a study on gas quality issues at borders across Europe and there may be interesting results from that which may be useful for DECC in its next assessment.

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ANNEX A – MODELLING METHODOLOGY

Gas prices and flows are projected using our pan-European and US gas model, Pegasus ('Pan-European GAS + US'). The model examines the interaction of supply and demand worldwide on a daily basis. Pipeline imports and interconnections between GB, Continental NW Europe (NWE), Spain, Italy and South East Europe (SEE) are modelled in detail, alongside all existing and proposed LNG terminals, and their interaction with the global LNG market.

Examining daily demand and supply across these markets gives a high degree of resolution, allowing the model to examine weekday/weekend differences, flows through the interconnectors and gas flows in and out of storage in detail.

Pegasus itself is comprised of a series of modules. The main solving module is based in XPressMP, a powerful Linear Programming (LP) package, which optimises to find a least-cost solution to supply gas to these 19 zones over a gas year. The solution is subject to a series of constraints, such as pipeline or LNG terminal sizes, interconnector capacities and storage injection/withdrawal restrictions.

Figure 77 – Geographic coverage of Pegasus

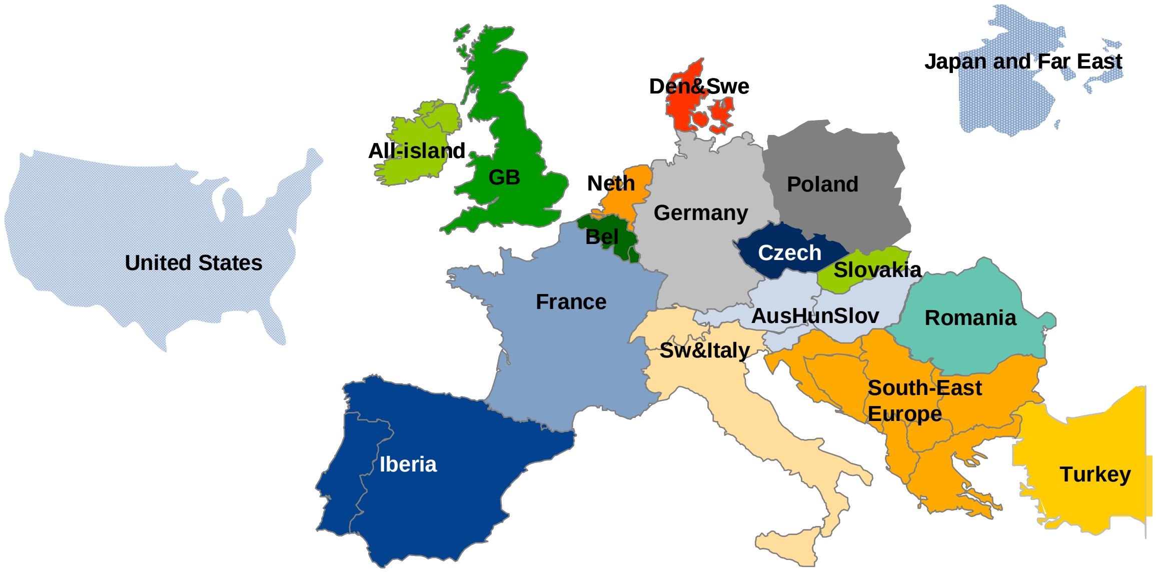
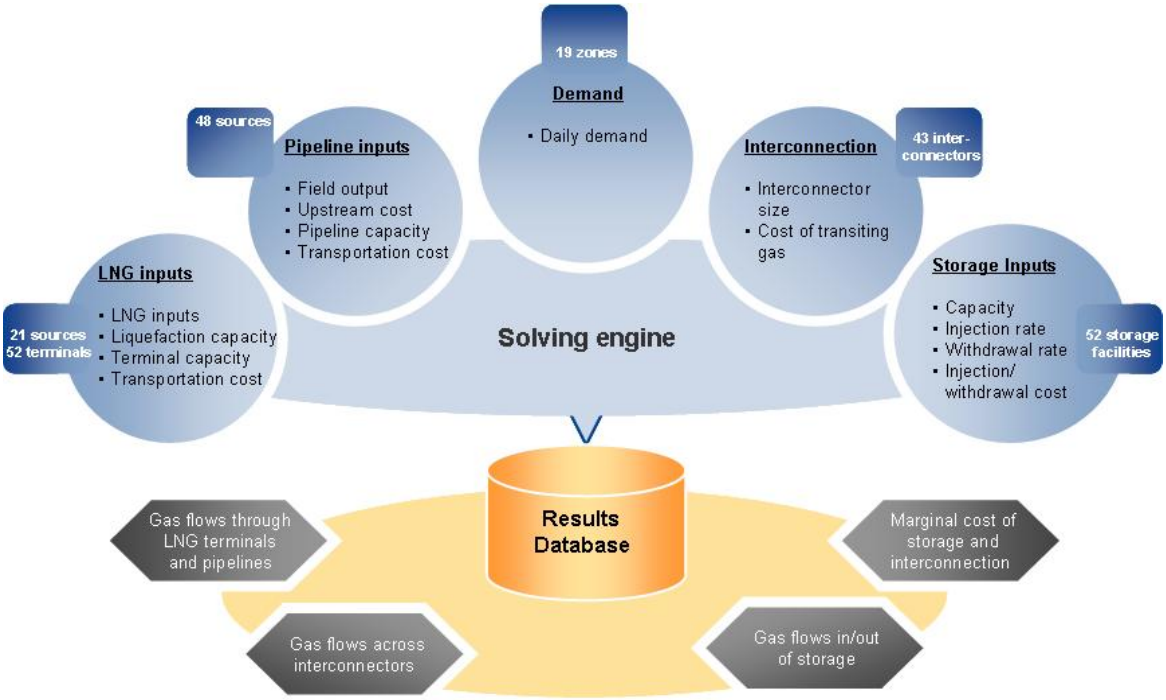


Figure 78 – Structure of Pegasus



The solving module takes input files generated by a series of Excel/VBA modules, which allow a variety of scenarios to be created by changing variables such as supply, demand, costs, storage and interconnectors. The outputs from the model, such as prices and flows of gas, are sent to a database to allow easy extraction of data at either a daily, monthly or annual resolution.

Interconnection from GB to the Continent has become increasingly important as the size of the interconnection between the two regions has increased. The optimisation algorithm in Pegasus minimises the cost of supplying gas to both zones, subject to both the capacity and the cost of transiting gas across the interconnectors. These patterns naturally change over time with differing assumptions on gas cost and new import projects and their location. The daily resolution in the model means that during certain periods, the interconnectors (particularly between GB and NWE) switch back and forth between import and export.

Modelling storage accurately is important to understanding price formation in Europe, as it affects both summer and winter prices, along with weekday/weekend prices. Pegasus models the major storage types of salt cavern, depleted field, aquifer and LNG for each zone, each with its own injection and withdrawal rates, total storage capacity and cost of injection/withdrawal. The optimisation algorithm used not only means that gas is injected into storage during the summer and withdrawn during the winter, as expected, but also that injection takes place for high cycle facilities during the winter weekends and Christmas periods due to lower demand, as seen in reality.

We model European and US storage in three generic types – depleted field, salt cavern and LNG. This lower level of detail is sufficient for European storage due to the non-commercial nature and opaqueness of use of much of the storage facilities. In Italy we take account of the fact some storage is designated 'strategic', which increases its value.

This storage modelling differs from that of GB where we are able to model specific sites based on their withdrawal and injection rates.

Pegasus also models the worldwide LNG market. All existing, under construction, proposed and conceptual LNG liquefaction projects worldwide are included under different scenarios, from a total of 24 countries (or ‘sources’). And similarly all LNG re-gasification terminals are modelled. In Europe and the US each terminal is identified separately, except in the longer term when generic LNG terminal capacity may also be included. The terminal capacity in the Far East, Canada and South America, and the rest of the World, is grouped within zones.

LNG cargoes can be ‘delivered’ from any source to any LNG terminal. As a result, LNG cargoes can be delivered to different destinations depending on which market is most profitable for a particular cargo – for example, LNG will deliver preferentially to Montoir or Zeebrugge when prices are higher in NW Europe than in Italy. Thus the NW European market is linked to the Italian market not just through the interconnectors but also via LNG arbitrage. Furthermore, the interaction with the US and the rest of the world’s LNG markets means that gas markets become linked worldwide based upon supply and demand for LNG.

As a core part of our modelling, we carry out iterations with our electricity model to understand the effect of changes in gas price on demand for gas, and changes in demand for gas on price. This iteration between the two models ensures that our assumptions on gas prices and gas demand remain realistic and reflects the elasticity of gas demand given high gas prices.

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ANNEX B – BASE CASE SCENARIO ASSUMPTIONS

Other factors driving gas prices include the price of oil and the corresponding exchange rate assumptions (in particular, the US dollar to Euro exchange rate). These are shown below.

Table 16 – Economic and commodity assumptions

Commodity (in 2008 real money)	2009/10	2014/15	2019/20	2029/30	2049/50
Oil ($/bbl)	80.00	80.00	80.00	80.00	80.00
Coal ($/tonne)	75.00	75.00	75.00	75.00	75.00
Carbon (€ /tonneCO2)	15.00	35.00	35.00	35.00	35.00
Exchange rate ($/£)	1.65	1.80	1.80	1.80	1.80
Exchange rate (€/£)	1.11	1.25	1.25	1.25	1.25

B.1 Value of carbon allowances

The Pöyry carbon model is used to derive projections of European Union Allowance (EUA) CO_2 credit prices that are internally consistent with the fuel prices and electricity demand projections in our corresponding electricity price scenarios. Demand for abatement (or credits) is largely driven by electricity demand and the underlying capacity mix. Supply of abatement comes from switching away from carbon intensive fuels in the power sector, industrial sector abatement and the import of UNFCCC project credits from non-European Kyoto signatory countries.

As of early January 2010, European level negotiations around the Copenhagen Accord had not reached a conclusion on the level or allocation of a EU GHG reduction target for 2020. Our EUA price scenarios are consistent with the current proposal for a 20% reduction over 1990 levels by 2020.

We assume a 100% pass-through of carbon prices into wholesale electricity prices.

We have imposed a long-run floor price of €10/tCO_2 from Phase III onwards to recognise the political dimensions to the carbon market. This constraint is binding in the Low scenario from 2013 to 2030 but is breached during Phase II as significant political intervention in an ongoing Phase would be difficult at this stage. Below this price, modelled supply and utilisation of UNFCCC project credits is severely restricted and EU and national government commitments may push them to react, bringing the price back to its floor level.

As market players become more confident in a progressively tighter GHG cap in Phase III and Phase IV, they will tend to bank more credits both within and between Phases. This will tend to increase prices in early years and decrease them in later years, compared to what they would have been in the absence of banking and borrowing. The theoretically optimum price path is a smooth, upward sloping trend towards the long-run marginal CO_2 price. Market sentiment is gradually moving towards an increase in longer term thinking (including an increase in banking between Phases). We do not project prices to move completely to the optimal 'long-run marginal' price path as we believe short-term considerations will limit the ability of firms to react optimally to long-run price signals.

B.2 Assumption matrices

Table 17 – Modelling factors within NWE demand zones

<table>
<tr><th></th><th>GB</th><th>Ireland</th><th>France</th><th>Belgium + Luxembourg</th><th>Netherlands</th><th>Germany</th><th>Denmark + Sweden</th></tr>
<tr><td>Domestic, I&C demand</td><td>Decrease in 22% from 2008 to 2025</td><td>Decrease until 2018, by 2.5%/Y then increase by 1.5%/Y</td><td>Stable until 2018, then increase, by 1.6%/Y on average</td><td>Increase from 2010 to 2030, by 1.05%/Y on average</td><td>Slight decrease until 2018, then increase by 2.0%/Y</td><td>Decrease in demand until 2019, then increasing by 6% to 2030</td><td>Decrease in demand until 2019, then increasing by 4% to 2030</td></tr>
<tr><td>Powergen demand</td><td colspan="7">Output from Pöyry’s EurECa model</td></tr>
<tr><td>Demand profiles</td><td colspan="7">Historic + modelled</td></tr>
<tr><td>Storage capacities</td><td>6.5bcm in 2010 to 10.8bcm by 2018</td><td>0.2bcm throughout</td><td>11.9bcm in 2010; 13.9bcm from 2015</td><td>0.8bcm in 2010; 1.1bcm from 2015</td><td>2.5bcm in 2010; 6.4bcm from 2015</td><td>16.5bcm in 2010, 23.7bcm in 2030</td><td>1bcm throughout</td></tr>
<tr><td>LNG terminals</td><td>34 to 51bcm by 2011</td><td>0 to 4bcm by 2012</td><td>23 to 54bcm by 2014</td><td>9bcm, no further expansion</td><td>0 to 33bcm by 2012</td><td colspan="2">None</td></tr>
<tr><td>Import pipelines</td><td>Nor – GB offshore connection</td><td colspan="4">Nothing new</td><td>N.Stream + Norway connect-ion</td><td>None</td></tr>
<tr><td>ICs</td><td colspan="2">Nothing new</td><td>Expansion of SPA link</td><td>Expansion of NL link</td><td>Expansion of Bel link</td><td>Reverse connect-ion with CZ, AT</td><td>Nothing new</td></tr>
<tr><td>Indigenous production</td><td>In decline</td><td>Corrib then decline</td><td>In decline</td><td>Negligible</td><td>Sm fields in decline Gron 2015</td><td colspan="2">In decline</td></tr>
<tr><td>Take-or-Pay contracts</td><td colspan="2">None</td><td colspan="4">Renewal of existing contracts</td><td>None</td></tr>
</table>

Table 18 – Modelling factors within South Europe demand zones

	SE Europe	Turkey	Italy	Iberia
Domestic, I&C demand	Increase from 9.5bcm in 2010 to 16.9 in 2030	Increases from 22.8bcm to 36.8bcm	Increases from 67.8bcm to 94.3bcm, mainly in residential	Stable, increases slightly from 26bcm in 2010 to 27.8bcm
Powergen demand	Output from EurECa			
Demand profiles	Historic + modelled			
Storage capacities	1.8bcm throughout	3.03bcm throughout	Increase from 17.5bcm to 22.3bcm in 2030	Increase from 8.9bcm to 10.1bcm
LNG terminals	5.3bcm in 2010 to 15.3bcm	Constant 12bcm throughout	Doubling from 16.5bcm to 32bcm by 2030	64 to 75 bcm by 2013
Import pipelines	South Stream in 2016	Nabucco	Galsi, Greenstream	Mahgreb, Medgaz
Interconnectors	Increase in 2020 with Romania as Nabucco comes online	Increase in 2020 with SEE as Nabucco comes online	Addition of TAP and IGI increases interconnection with SEE	Link with France
Indigenous production	Negligible; decreases to 0 by 2016	Negligible	Decreases to 0 by 2026	Negligible
Take-or-Pay contracts	Renewal of existing contracts			

Table 19 – Modelling factors within Central Europe demand zones

	Poland	Czech	Slovakia	Austria Hungary + Slovenia	Romania
Domestic, I&C demand	Slight increase of 6bcm from 2010 to 2030 (2% YoY)	Increasing from 8.5bcm in 2010 to 10.9bcm in 2030	Increasing from 5.5bcm in 2010 to 8.1bcm in 2030	Doubling of demand from 2010 to 2030	An increase of 2bcm by 2030, reaching 13bcm.
Powergen demand	Output from EurECa				
Demand profiles	Modelled				
Storage capacities	Doubling from 1.7bcm to 3.4bcm in 2030	Slight increase from 3bcm to 3.2bcm	No increase, constant throughout	Increase from 9.3bcm to 10.5bcm	Constant throughout
LNG terminals	A single LNG terminal of 4bcm	None			
Import pipelines	Russian connections	None	Russian connections		
Interconnectors	Increase in German IC in 2012	AusHun to Czech IC comes online in 2011	No change	AusHun to Czech IC comes online in 2011	Increase in 2020 with SEE as Nabucco comes online
Indigenous production	Negligible				Negligible; decreasing indigenous
Take-or-Pay contracts	Renewal of existing contracts				

Table 20 – Modelling factors within the rest of the world demand zones

	US	Far East	RoW
Domestic demand	Stable until 2020, then steady increase until 2025, declining from 2026 onwards	Steady increase from 2010 onwards at an average of 1.6%/Y	Steady increase until 2012, then stable from 2013 onwards
Powergen demand			
Demand profiles	Seasonal normal profile		
Storage capacities	Constant throughout	Not modelled	
LNG terminals	150 to 346bcm by 2014	313 to 355bcm by 2016	76 to 116bcm by 2013
Import pipelines	From Canada	N/A	
ICs	N/A		
Indigenous production	EIA forecast		
Take-or-Pay contracts	Not modelled		

ANNEX C – BACK-CAST OF JANUARY 2009

In order to understand how Pegasus models flows of gas around Europe we have back-cast the events of January 2009, when supplies from Ukraine were interrupted for nearly two weeks at the beginning of the year, and compared them with the actual flows out of storage and through the UK-Continental interconnectors seen at the time.

Looking at the supplies to Bulgaria over the 2008 gas year in Figure 79, the interruption of Russian gas is clear and the quantity of un-served demand in January 2009 was in the region of 100mcm. The historical Bulgarian figures can be compared with the sources of gas supplying the SEE zone in Pegasus, which includes Bulgaria, Greece and the Balkan states, as modelled over the 2008 gas year and shown in Figure 80.

It should be noted that, Pegasus assumes there are no constraints within the SEE zone; that is, imports into Croatia and Serbia can flow freely to Bulgaria and LNG imported via Revithoussa can make its way out of Greece. This flexibility, combined with fewer market constraints throughout Pegasus than exist in the ‘real’ European gas market, allows the reduction in Russian supplies to be replaced with imports from Austria, Hungary and Slovenia.

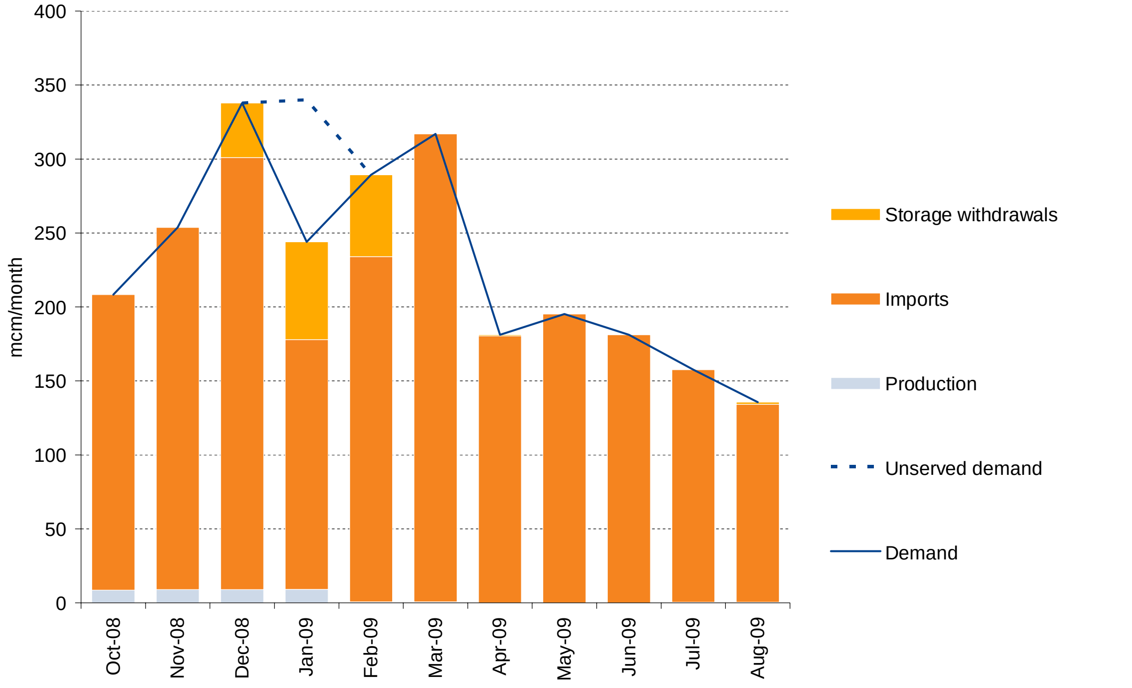
The impact on other countries in Europe, as seen in January 2009, is reflected in Pegasus through withdrawals from storage and re-direction of interconnector flows. There is no historical data available on the flow of gas from west to east during the crisis (although we go on to look at these in the outputs from our modelling, in section 5.3.2), so here we have compared historical withdrawals from storage with those modelled. Figure 81 compares actual withdrawals from storage in France, Germany, Italy and the UK with those modelled in Pegasus in January 2009.

Figure 81 also shows the actual deliveries from storage in January 2008, when there was no interruption in Ukraine alongside those in January 2009, during the crisis. The overall increase in withdrawals from Continental storage, when Ukraine is interrupted, is replicated well in the Pegasus model but one notable difference between the actual storage withdrawals and those modelled, is the relative size of withdrawals from German and Italian storage.

Pegasus finds it more economically efficient to extract greater quantities from Italian storage and utilise less German storage, than was actually the case during the crisis. Italy is in a good location to help meet a deficit in Russian supplies, and the constraints between zones in Pegasus make it hard for Germany to flow gas into some of the countries affected. The reality was some interconnections from Germany flowed west-to-east when they were not designed to do so, and the barriers to utilising Italian storage were greater than expected.

Finally, the export of gas from GB to Belgium during January was of some concern at the time. Pegasus models both the import of gas from the Netherlands and the export of gas to Belgium and in the interest of economic efficiency will net these off one another. At the time of the crisis GB was importing gas from the Netherlands at the same time as exporting to Belgium. The net imports in Pegasus dip considerably during an interruption from Ukraine and Figure 82 shows how these compare with the actual net figure in January 2009.

Figure 79 – Gas supplies to Bulgaria during the 2008 gas year



Source: 'Eurostats', European Commission

Figure 80 – Sources of gas supplying the SEE zone of Pegasus

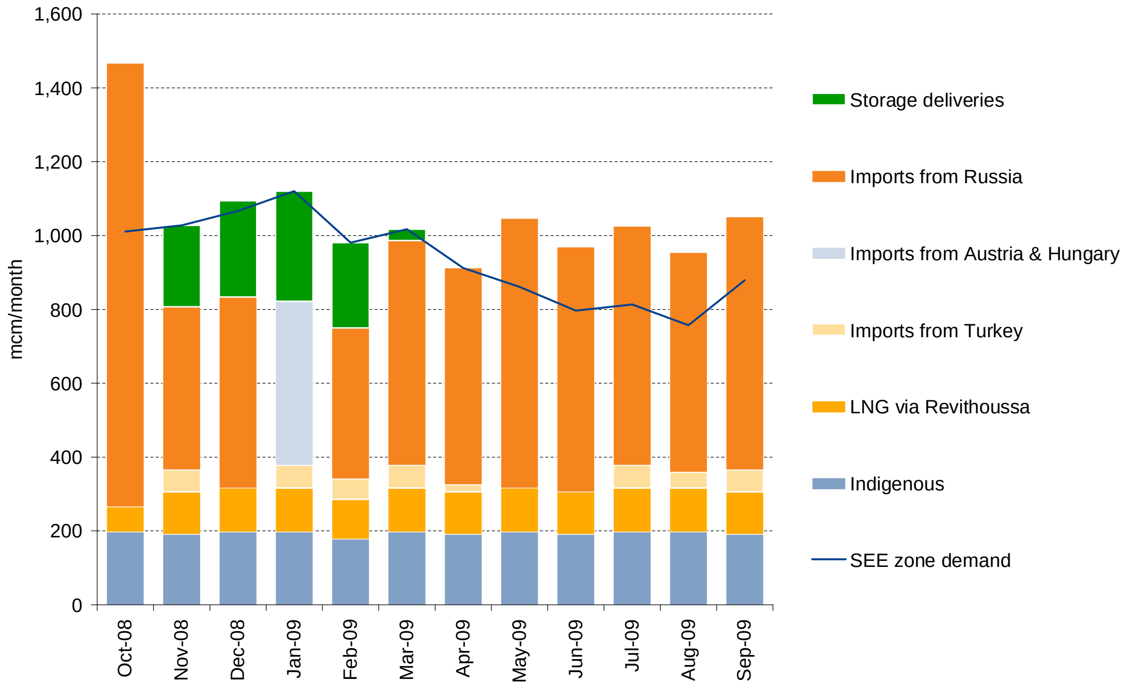
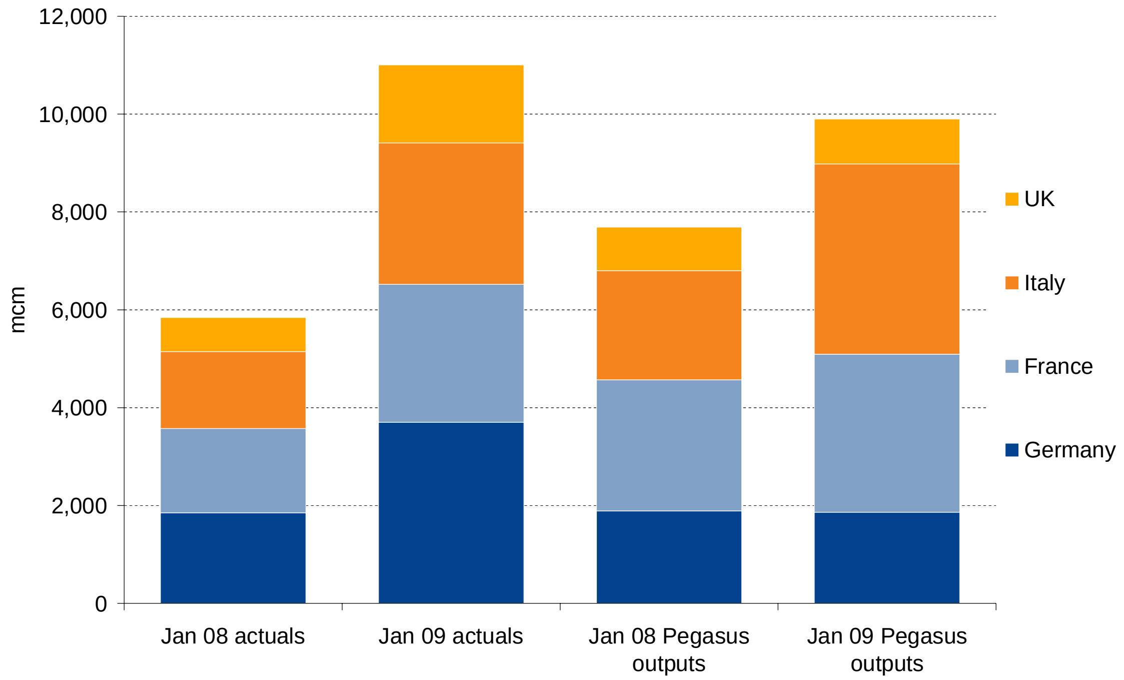
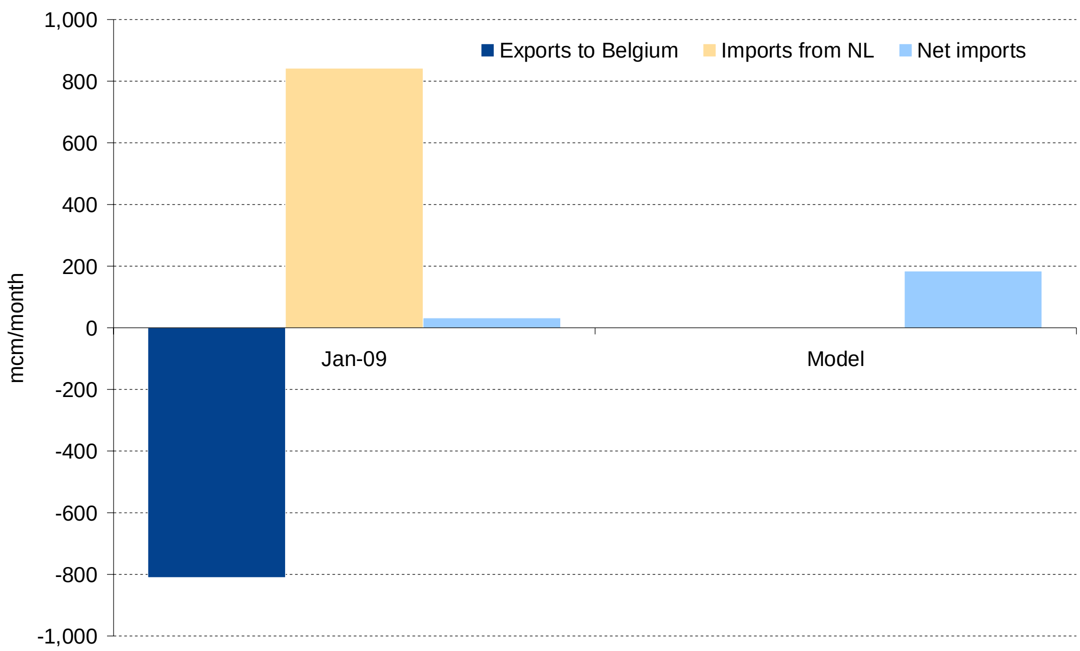


Figure 81 – Deliveries from storage in January 2009



Source: 'Eurostats', European Commission, Pöyry analysis

Figure 82 – Net imports to UK from Continent in January 2009



Source: National Grid, Interconnector UK and Poyry Energy Consulting

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