A REVIEW OF GAS SECURITY OF SUPPLY WITHIN GREAT BRITAIN'S GAS MARKET - FROM THE PRESENT TO 2035

A Report to the Department for Business, Energy & Industrial Strategy

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CONTENTS

EXECUTIVE SUMMARY

Studies undertaken on behalf of Government and Ofgem over the past decade have shown that Great Britain's (GB's) gas system is resilient to all but the most extreme and unlikely combination of events. BEIS commissioned this report to help improve its understanding of the scale and nature of these events, as well as the wider prevailing circumstances in world gas markets.

The decline of indigenous production from the UK Continental Shelf (UKCS) inevitably means that GB is more dependent on imports than previously. This will continue to be the case without the development of new indigenous sources such as shale. Whilst a reduction in indigenous production creates new risks to future supply—relating to production and transport disruptions, the failure of key infrastructure and a greater exposure to international events that affect global demand for gas[1]—it is also the case that diversification improves gas security.

This study concludes that shocks that lead to unmet gas demand in GB are extremely unlikely to occur and the scale and disruption of these shocks are completely unprecedented. Given the importance of reliable gas to GB consumers, it is nevertheless important to fully understand GB's exposure to these shocks.

The main findings are:

- **The GB system is resilient to almost all significant individual shocks under normal demand conditions**. We therefore focus on combined shocks during periods of high demand to stress test the system, even though these are less likely to occur simultaneously.
- The modelling shows that even **where there is an extreme shock to global LNG markets, GB demand can be met if GB consumers are willing to pay for it[2][3]**.
- The modelling shows that **GB demand for gas will be met** in circumstances where there is **an extreme disruption to Russian gas supplies to Europe** (for a 12-month period) **if GB consumers are willing to pay for it.**

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[1] These types of risks have also been explored in previous security of supply studies as discussed in ANNEX A to this report.

[2] The willingness to pay for GB consumers refers here to their Value of Lost Load (VoLL) and how this compares to the VoLL of consumers in competing markets (for example, in Continental Europe). This is not referring to the price that small individual consumers that are not exposed to market prices, actually pay at any one point in time as gas suppliers hedge when buying gas and retail prices remain fixed in the short-term. Only large consumers, such as industrial customers and gas-fired power generators are likely to see a near-term impact from higher gas wholesale prices in the unlikely event of a shock such as the ones considered in this study.

[3] When faced with unmet demand, in the majority of cases the government is likely to step in to mitigate the effects on consumers and remove any barriers to flowing gas to GB, for example by reducing or eliminating commodity entry changes. These measures are not included in the modelling although in some of the scenarios we account for the possibility of government interventions to restrict cross-border flows.

- The modelling shows that **as long as GB consumers are willing to pay sufficiently for scarce gas supplies, only in the most extreme (and highly unlikely) scenarios we considered** (a long disruption to Russian supplies combined with a GB LNG infrastructure outage in winter) **might there be some unmet demand**.
- The main insight from this work is that price is the primary determinant of whether sufficient gas is available to meet GB demand, but in some instances the availability of adequate import capacity and key infrastructure may also be critical.

Approach

The project involved the following steps: (1) identifying the most critical shocks to future GB gas security, including how the combination of those shocks might impact on gas security; (2) modelling the likely development of future GB gas supply and demand from the present to 2035; and (3) stress testing the system against unforeseen shocks under different demand conditions.

Critical shocks were identified from multiple sources, including stakeholder workshops and a literature review. We deliberately considered only those shocks that are likely to have the largest impact on the GB gas system and assessed the likelihood and potential impact of each identified shock. We modelled three distinct supply-side shocks, each with a deliberately high severity and duration in order to understand the impact of a severe shock on GB's gas security.

Further details can be found in Section 3.

Shocks	Source of disruption	Type of shock	Duration and timing
Shock 1	Loss of all Qatari LNG exports	Geopolitical	12 months starting April 2025
	Loss of all North African LNG and pipeline exports	Geopolitical	12 months starting April 2025
Shock 2	Disruption to all Russian pipeline gas flows to Europe	Geopolitical	12 months starting April 2025
Shock 3	Disruption to Russian land-based pipeline gas flows to Europe (Ukraine and Yamal pipelines)	Geopolitical	12 months starting April 2025
	Grain LNG outage	Infrastructure	3 months starting December 2025

We then modelled the impact of these shocks against three views of the future:

- **Baseline Scenario 1a**—based on the International Energy Agency's (IEA's) *"Current Policies Scenario"* ("CPS"). This projects increasing global and GB gas demand out to 2035. This scenario also assumes that the Rough gas storage facility remains operational until 2035;

- **Baseline Scenario 1b**—based on the same IEA CPS set of assumptions as Scenario 1a, but assumes that the Rough storage facility is closed from 2016;
- **Baseline Scenario 2**—based on the IEA's *"450 Scenario"* ("450"). This projects decreasing European[4] and GB gas demand and stagnant global demand from 2025 onwards. The Rough storage facility was assumed to be closed in this scenario.

Finally, each of the three supply shocks were also simulated against three daily demand scenarios in GB and Europe determined by:

- (1) seasonal normal temperature (50th percentile or "P50" demand);
- (2) 1-in-20 warm weather for each day of the year (5th percentile or "P5" demand); and
- (3) 1-in-20 cold weather for each day of the year (95th percentile or "P95" demand).

We modelled the P5, P50 and P95 demand profiles for the whole of GB and Europe for an entire year. Thus the assumed demand levels were more extreme than would normally be expected. We adopted this approach to allow us to test the impact of shocks under the most extreme situations.

The types of shocks modelled for this study were primarily global geopolitical shocks that could result in gas shortages worldwide or across an entire region, rather than specific to GB as may be the case, for example, in the case if a key piece of import or transport infrastructure were to fail. We adopted this approach because in our view it is these geopolitical shocks that are most likely to cause disruption to the GB gas system. However, adopting this approach required us to consider how scarce gas would be distributed within the affected region in such an eventuality. We assumed that gas will be allocated first to those willing to pay the most for it (Value of Lost Load). However, there is little evidence on how this would work in extreme situations and the possibility of politically-driven non-market interventions.

Given these uncertainties, we also modelled the three supply-side shocks under each of the three baselines, using three different sets of assumptions about the Value of Lost Load (VoLL)[5] levels in GB and the rest of Europe, namely:

- **VoLL levels in GB are higher than in the rest of Europe**—as the cost of interrupting GB consumers is higher than for the rest of Europe in this scenario, gas tends to flow to GB under the model's global cost-minimising objective (as the higher VoLL

[4] In this study, Europe was modelled as several regions which included: North West Europe (Germany, France, Denmark, Sweden and Benelux countries), the Iberian Peninsula (Spain and Portugal), Italy + Switzerland, Central and Eastern Europe (Austria, Hungary, Czech Republic and Slovakia), Poland, the Baltic region and South East Europe (Greece, Romania, Bulgaria and all Balkan countries).
[5] A measure of willingness to pay. We have used estimates for GB VoLL taken from the London Economics (2011) study for Ofgem. The study has estimated VoLL using a willingness to pay and willingness to accept approach.This means that the VoLL reflects the value that consumers place on not having their gas supplies interrupted.

compensates for GB's higher commodity entry charge), even if it results in demand being curtailed in the rest of Europe;

- **VoLL levels are equal in GB and the rest of Europe**—as the cost of interrupting consumers is the same in each market, gas flows in this scenario are determined primarily by the cost of transporting gas between markets. There is no government intervention to reduce the cost of transporting gas to GB or otherwise restrict gas flows; and
- **VoLL levels in GB are higher than in the rest of Europe but gas flows are restricted between GB and the North West (NW) European region[6] due to interconnector curtailments as a result of government intervention**—as above, consumers in the rest of Europe tend to be interrupted before GB consumers, but flows between NW Europe and GB are curtailed if there is unmet demand in NW Europe.

It is important to note that this is an area where there is limited evidence on consumers' willingness to pay and the actual events that might drive gas flow in a shock. Whilst the model does its best to incorporate possible real world outcomes, a lack of sufficiently detailed data on consumers' price response during extreme circumstances rendered it unable to fully capture the complexities of what might happen in practice under severe security of supply shock scenarios.[7]

Findings

Below is a summary of the findings from the simulations performed in this study. Further details can be found in Section 4.3.

- **Shock 1 does not pose a significant security of supply concern for GB**. Low levels of unmet demand would only occur in winter if the GB market were not able to attract any gas from other European markets, based on price differentials. Providing GB consumers are prepared to pay, in this scenario there is no unmet demand. This result holds whether or not the Rough storage facility is operating—in its absence, interconnector flows provide additional supplies.
- **Shock 2** would result in a shortage of gas across Europe, but would not result in unmet demand in GB as long as customers were willing to pay more for the scarce commodity than customers on the Continent, depending on interconnector curtailments. If GB customers were not willing to pay a higher price for scarce gas than customers in NW Europe (*i.e.* VoLLs are uniform), Shock 2 could cause significant unmet demand (although not every day during the disruption)—**the key result is that alternative**

[6] NW Europe is defined as Germany, France, Denmark, Sweden and the Benelux countries.

[7] The daily modelling assumes that demand curves are not price responsive (inelastic) up to price level set at estimates of value of lost load and then price responsive (elastic) from that point onwards. In practice we would expect a more granular demand response and we would also expect emergency rules/non-market interventions would be triggered in GB and other European markets if there is unmet demand.

supplies are *potentially* available to meet GB demand, but they come at a price. Unmet demand occurs primarily during the winter months but also during the first few weeks in April when storage is empty.

- **Shock 3** has a more severe GB security of supply impact than Shock 2, despite the fact that total global volumes of gas that are lost are lower. The results suggest that the GB system may be more vulnerable to the combination of a gas shortage in Europe and the failure of a large piece of infrastructure during the winter months (especially in January and February). **There is a relatively small amount of unmet demand** even if GB consumers are willing to pay a higher price for gas **in the normal demand scenario**, because the projected import infrastructure capacity would be insufficient to allow enough gas imports to serve all demand. As one would expect, this is most pronounced in the severe demand scenario.

All findings are based on a set of modelling assumptions so all results should be considered in the context of these assumptions when they are interpreted. The modelling does not account for demand response to higher prices at a daily granularity, but we have estimated the impact on different categories of consumers, such as power sector gas demand and industrial daily-metered gas demand, which can provide demand response, and non-daily metered gas demand (mainly domestic consumers), which would not be expected to respond to short-term price movements. In practice, a portion of the unmet demand estimated in our results would be mitigated through voluntary demand response rather than involuntary interruption. Also, the modelling assumes market participants have imperfect foresight and do not anticipate the shock. [8] See ANNEX C and Sections 4 and 5 of this report for further details on the modelling assumptions.

[8] If market participants were assumed to have perfect foresight regarding the occurrence of a shock and its duration, they would be able to use production and storage capacities optimally knowing exactly when and where gas shortages would occur. In the real world, market participants normally operate under imperfect foresight conditions, not only regarding unexpected disruptions but also future demand conditions, which prevent them from perfectly optimising their decisions.

1. INTRODUCTION

Shocks that lead to unmet demand for gas are generally low-probability but high-impact[9]. Studies undertaken on behalf of Government and Ofgem over the past decade have shown that the GB system is resilient to all but the most extreme and very unlikely combination of shocks[10]. BEIS commissioned this report to develop a more comprehensive understanding of the robustness of the GB gas system against these extreme but highly unlikely shocks under various circumstances affecting world gas markets.

In order to set the strategic direction on security of supply and to build on the existing evidence base, BEIS commissioned an assessment of gas security of supply. This report contributes to that assessment by studying the impact of shocks to GB gas supplies under different demand scenarios and their impact on security of supply in GB for 2016-2035.

The main aims and objectives of this study were to (1) identify the main shocks; (2) determine the probability and the likely impact of each shock; and (3) stress test the system to determine its resilience against the identified shocks. The main questions for the study were:

- What are the main shocks that could affect GB gas security of supply over the next 20 years?
- What is the probability of each shock occurring and what factors is it sensitive to?
- What is the likelihood/probability of shocks occurring simultaneously and/or successively?
- What are the key individual shocks and combination of shocks (scenarios) that the system is most vulnerable to?
- How would the market respond to these key scenarios? Would demand be met? If not, what is the volume of demand that is not met, and what are the sources of unmet demand?
- What sources of supply are critical in these situations?
- In each of the modelled scenarios, how does the market respond?

The rest of this report is organised as follows. In Section 2 we describe our approach to this study. In Section 3, we discuss the identified risks to GB's gas security of supply. In Section 4,

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[9] Arguably one of the most serious shocks to security of supply in recent history occurred in 2006 when GB had only one pipeline interconnection, and the Rough storage facility failed at a time of very cold weather across Europe. This event resulted in a clearing price of 295p/therm, the temporary closure of some industrial demand, and the flat out running of coal-fired power stations.

[10] Most recently, BEIS's Risk Assessment on Security of Gas Supply, submitted to the European Commission in September 2016, found that, in the short to medium term, UK gas supply infrastructure is resilient to all but the most extreme and unlikely combinations of severe infrastructure and supply shocks. The UK N-1 calculation exceeds the target of 100% with a score of 127%. This Risk Assessment is repeated biennially.

we present our baseline scenario results, while in Section 5 we present results from the stress testing, including main conclusions. [11]

[11] We note that the analysis in this report was primarily undertaken in the first half of 2016 and the views expressed in this report reflect information available at the time. In particular the analysis does not take into account any potential impacts on the GB and European gas markets from the June 2016 referendum vote on leaving the European Union.

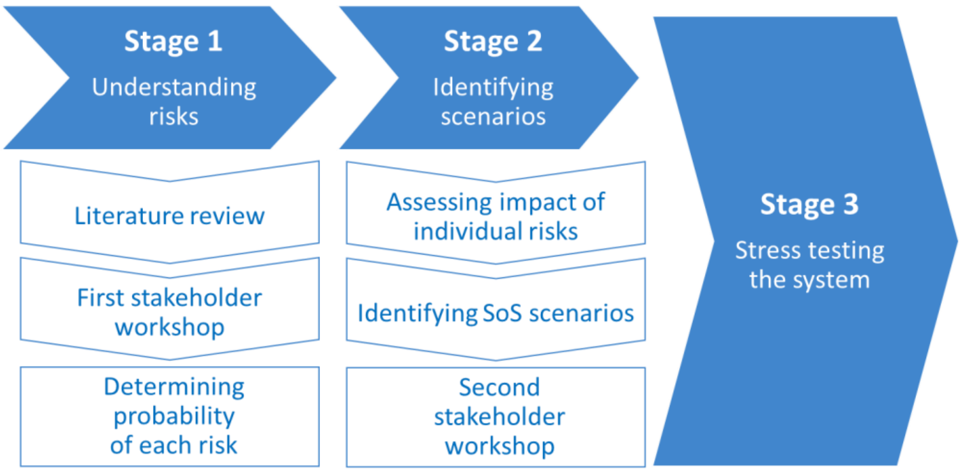
2. APPROACH

The methodology applied in this study drew on results and approaches from previous studies at each main stage of the project, which included:

- **Stage 1: Understanding risks**—involved developing a framework to compile a list of current and potential future risks to GB's ability to meet gas demand needs between now and 2035.
- **Stage 2: Identifying scenarios**—comprised of the following tasks: (1) conducting a high-level assessment of the impact of individual shocks on gas supply and demand; (2) identifying key vulnerabilities and combinations of shocks which could result in near or actual involuntary curtailments; and (3) determining whether any individual shock is likely to cause unmet demand as well as how those risks are likely to evolve over time.
- **Stage 3: Stress testing the system**—modelled the impact of supply- and demand-side shocks associated with the risks identified in the preceding stages. The key question posed for this stage was whether any of the shocks would result in unmet demand, and if so, what would be the level of disruption.

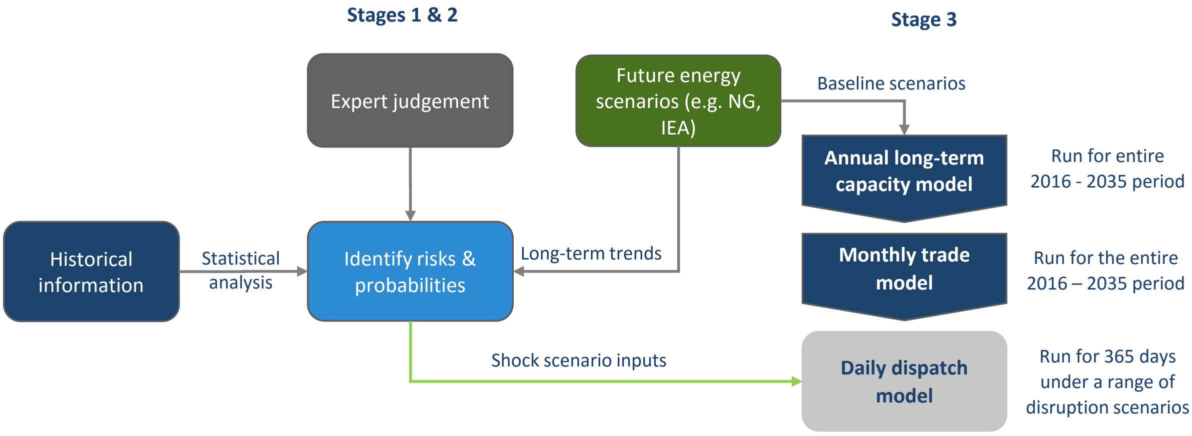
Figure 2.1 summarises the key activities we performed within each stage.

Figure 2.1: Main tasks performed at each key stage



Inputs in the first two stages were based on the gathering and analysis of historical information and data, long-term projections for global and GB energy markets from National Grid, the International Energy Agency (IEA) and other sources, as well as expert opinion and industry insights provided by BEIS, Ofgem, and stakeholders. Stakeholder views were gathered during two workshops organised by BEIS. The key outputs from the first two stages were probabilities and potential security of supply impacts for each identified shock, which served as inputs into the stress testing phase undertaken in Stage 3. Workflow of information between the three stages is illustrated in Figure 2.2.

Figure 2.2: Workflow, inputs, outputs for each stage



We discuss each of these activities in more detail below.

2.1. Stage 1 – Understanding risks

We classified potential security of supply risks by the two main types as:

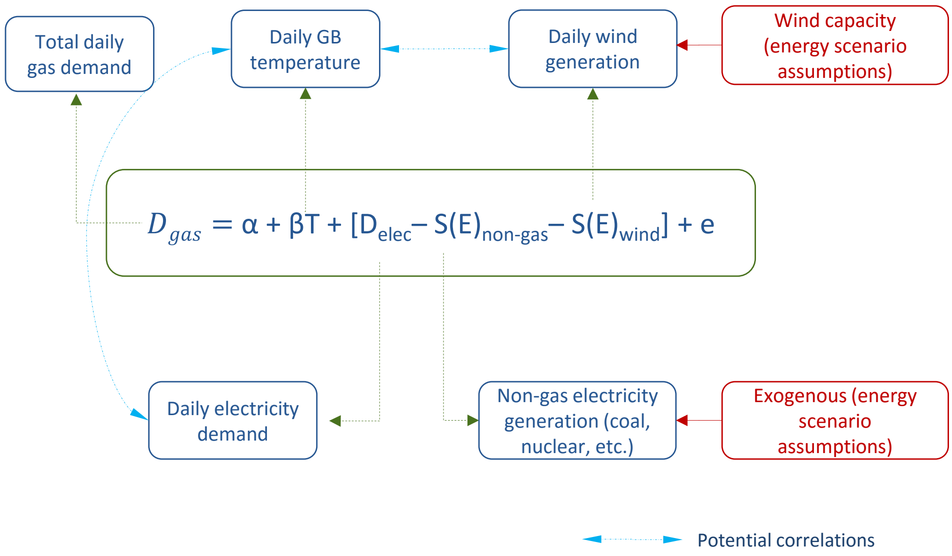
- *Demand-side risks*—generally, weather-related events, such as cold snaps or periods with low wind generation, or their combination; and
- *Supply-side risks*—which involve the loss of production or infrastructure facilities, and consist of two sub-types of potential disruptions to physical supplies:
    - Geopolitical risks; and
    - Infrastructure risks.

Individual risks were identified from multiple sources, including through stakeholder workshops and literature reviews. The risks considered were those that are likely to have the largest impact on the GB gas system. We also independently assessed the likelihood and potential impact of each identified risk. Our own assessment of these risks was generally consistent with stakeholder's views.

Assessing the likelihood of the identified risks

Demand-side risks are generally better understood and easier characterised than supply-side risks because most sources of those risks are known and potentially quantifiable. The analytical framework used in this study to quantify demand-side risks is illustrated in Figure 2.3 below.

Figure 2.3: Analytical framework to quantify demand-side risks[12]



This framework relates gas demand (D_{gas}) on a given day to temperature (T), electricity demand (D_{elec}) and also to the volume of electricity generated by non-gas-fired power plants ($S(E)_{non\text{-}gas}$). Thus, the main risks considered are: (1) a sudden drop in temperatures that increases weather-dependent demand by the residential sector; and/or (2) a sudden increase in gas demand by the power generation sector (*e.g.* because gas-fired generators are dispatched to replace a sudden decline in renewable generation).

Supply-side risks, especially those with the largest potential impacts are more difficult to quantify. For example, the infrastructure risks that are likely to have the largest impact, such as a complete outage of one or more gas terminals, tend to be rare events for which sufficient historical information is not available. As for demand-side risks, both the likelihood and the potential impact of most identified supply-side risks depend on the future state of the world. For example, a single supply source may be pivotal under tight market conditions and hence its loss could be a relatively high risk to security of supply, while in an oversupplied market such risks would be much lower. This highlights the importance of baseline conditions under which the stress testing is conducted. We performed these stress tests under three different baselines scenarios, as discussed in detail in Section 4.1. We estimated the probability of each identified risk, and assessed the likely gas security of supply impacts.

The methodology for assessing the likelihood and potential impact of each risk relied on stakeholder views gathered during two workshops that were organised by BEIS. Stakeholders were asked to score the likelihood and impact of each risk using a qualitative scale. The qualitative scale used in the workshops is presented in ANNEX D.

[12] The formula describes the main variables that affect fluctuations in daily gas demand – temperature and demand for gas in the power sector. The other main component is industrial gas demand which is relatively constant throughout the year. Industrial gas demand is captured in the intercept term of equation.

As part of our methodology, the assessment of the supply- and demand-side risks was also informed by a comprehensive literature review. Summary findings from the literature review are included in ANNEX A.

The results of our qualitative assessment of the likelihood and potential impact of supply-side risks are summarised in Section 3.

2.2. Stage 2 – Identifying scenarios

Having already identified in Stage 1 the probability that each shock could occur, in Stage 2 we estimated two parameters that characterise the impact of each shock:

- severity/magnitude (*e.g.* proportion of gas supplies affected); and
- duration (*e.g.* number of months with supply disruption).

Similar to the probability estimation discussed in the previous section, the impacts of many, particularly supply-side, risks are difficult or even impossible to quantify with any level of certainty largely because the shocks are so rare that little, if any, data is available. Therefore, the parameters for modelling such impacts were determined based on information gathered through the literature review, discussions with BEIS and Ofgem, and with input from stakeholders.

Once the impact of each individual risk had been (qualitatively) estimated, we ranked the risks in terms of their potential threat to security of supply (*i.e.* potential magnitude of unmet demand). This involved assessing the expected impact of each risk, taking account of both the impact and the probability of occurrence of each risk. At this stage, this was a high-level, qualitative and largely subjective assessment since the full quantitative analysis was undertaken using models in Stage 3. The aim of this task was to identify risks which merited more thorough analysis.

2.3. Stage 3 – Stress testing the system

The model we used in Stage 3 for the security of supply assessment consists of three modules:

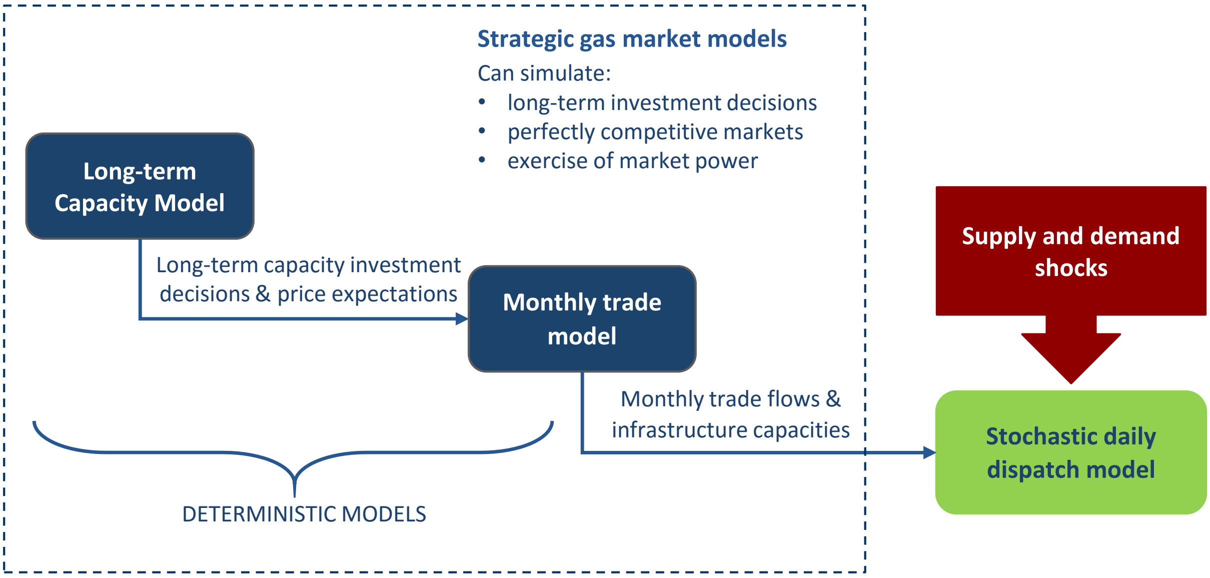
- **Annual long-term capacity model**—this model was run for the entire 2015-2035 study period, using a set of long-term baseline scenario assumptions, discussed in Section 4.1. The annual capacity model endogenously[13] determines future production and infrastructure capacity levels, and the results of this model were used to feed into our monthly trade model.

[13] This means decisions are taken by the model itself based on user inputs, in contrast to decisions made by the user which are then inputted into the model. See ANNEX B for more details.

- **Monthly trade model**— using the results of the annual model, this model was run for the entire time horizon—2015 to 2035—to derive monthly gas flows, including storage levels and the use of gas infrastructure.
- **Daily dispatch model**—using results from the monthly model, the daily dispatch model was run for 365 days to simulate different security of supply shocks identified from the risk assessment conducted in the first two stages of this project.

The three modules of the model interact with each other, such that investment decisions and price expectations from the annual model feed into the monthly model, which in turn generates monthly trade flow and infrastructure capacity inputs for the daily model as illustrated in Figure 2.4 below.

Figure 2.4: Graphical depiction of the modelling framework



Further details on the modelling approach can be found in ANNEX B with assumptions detailed in ANNEX C.

3. Risks to GB security of supply

Summary

This chapter focuses on identifying and assessing the main risks to GB gas security of supply.

The main risks identified were:

- *Demand-side risks: we conducted a demand-side Monte Carlo simulation which shows that the 95th and 99th percentiles of possible demand levels are significantly below the total current GB gas supply capacity. This suggests that the GB system can withstand a significant demand-side shock, assuming physical gas will be available to flow at maximum capacity. In reality, however, the availability of gas supplies may be affected by market conditions such as, for example, high gas demand in neighbouring countries, which is plausible given the correlation of regional weather patterns.*
- *Geopolitical risks include Qatari LNG disruption, North African disruption, and disruption to Russian gas supplies (along different routes). The initial qualitative assessment was that the highest-ranked geopolitical risk is a disruption to Qatari LNG supplies. This assessment suggested that a North African supply disruption may be more likely, but its impact on GB was deemed to be insignificant. Disruptions to Russian supplies are thought to be less likely though their impact could be significant.*
- *Infrastructure risks considered by the qualitative assessment involved the complete outage of a single facility from the following: (1) the Rough storage facility; (2) an LNG regasification terminal; (3) a GB interconnector; or (4) disruption to UKCS/NCS production, which would involve the disruption of a number of production fields from which gas is transported to a single gas terminal (e.g. Bacton).*

As discussed in the previous section, individual risks to GB security of supply were identified and analysed in the first two stages of our assessment. These are used to inform the 'best to test' shocks assessed in third stage of the study. In this section, we discuss the findings for the main demand- and supply-side risks including their likelihood and likely impacts on security of supply.

3.1. Demand-side risks

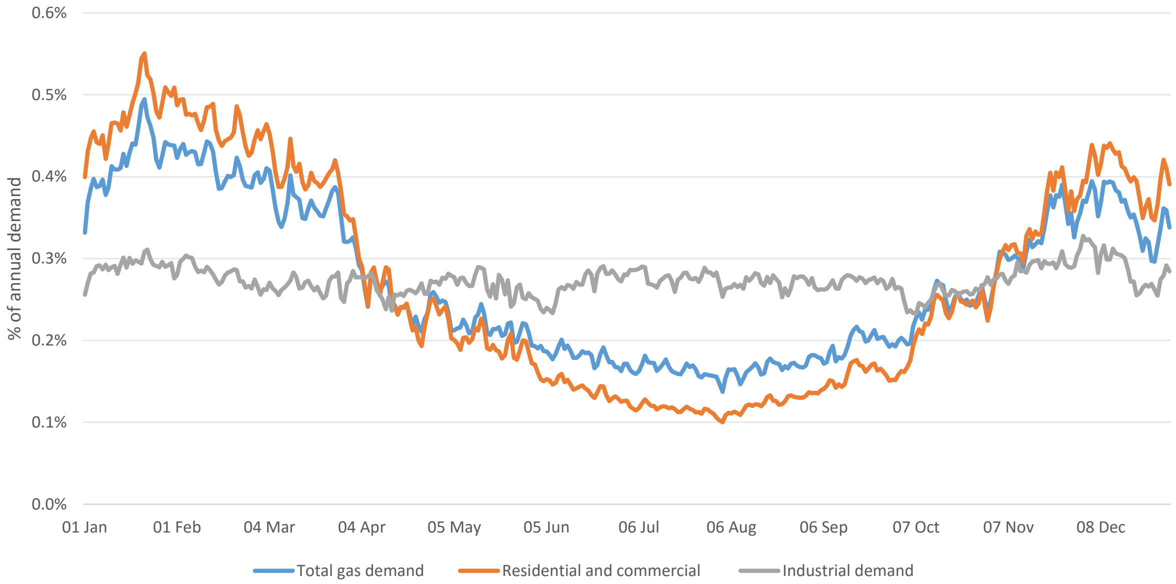
To estimate the likelihood and impact of demand-side risks, we conducted a Monte Carlo simulation to model extreme gas demand levels on a peak winter day. We separately determined extreme gas demand levels in each of the main sources of gas demand and summed these up to arrive at a total figure. The sources include:

- *residential gas demand* covering domestic and small business consumers—primarily used for space heating purposes;
- *gas demand for power* generation—gas used by gas-fired plants to generate electricity; and
- *industrial gas demand*.

Residential gas demand

Residential gas demand makes up the largest proportion of total gas demand: domestic and other final users represented approximately 49% of total gas demand in 2015[14]. It is driven by the requirement for space heating, and is therefore driven largely by variations in daily temperatures. Residential demand is also the main factor behind the distinct seasonal pattern of total annual gas demand. Figure 3.1 below illustrates the seasonal shape of annual gas demand, as well as demand by the residential and industrial sectors.[15] The residential and commercial sectors display higher seasonal variation than the total gas demand profile, with higher peaks in the winter, and lower profiles during the summer, compared to the industrial sector, which has a relatively flat demand profile without major seasonal variations.[16]

Figure 3.1: Gas demand profile in different sectors (5-year average)



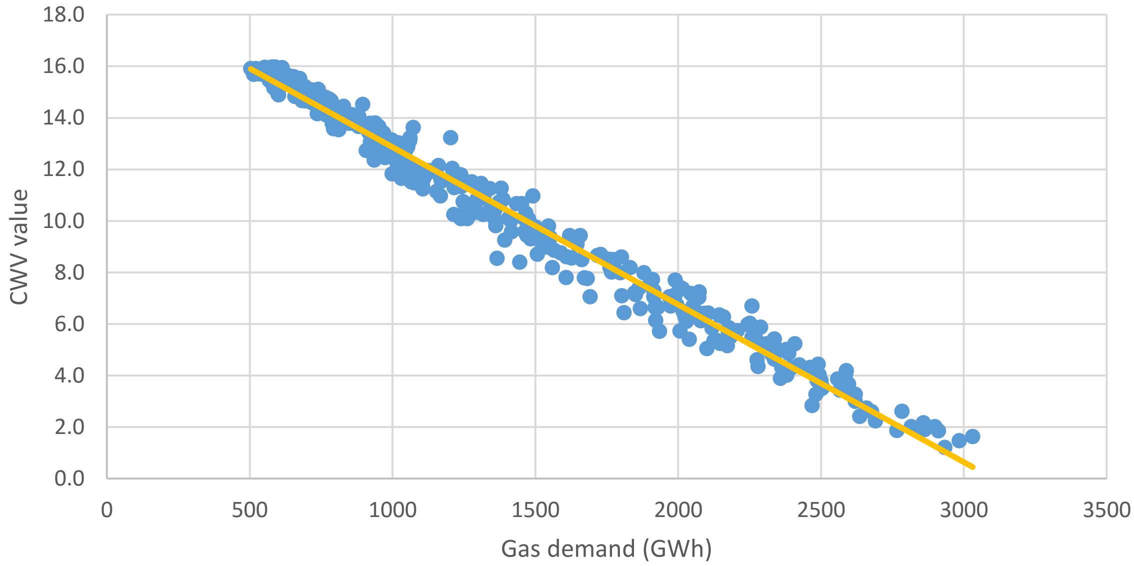
The first step in the analysis was to estimate the impact of temperature on residential gas demand using a linear regression analysis. The variation in daily residential gas demand can be explained almost fully by variations in temperature, as shown in Figure 3.2 below. National Grid uses the Composite Weather Variable (CWV) to forecast demand under different weather conditions. The CWV is a weather variable that takes into account actual temperature on the day, as well as the previous day's temperature and a wind chill factor.

[14] National Statistics, Energy Trends section 4: gas, Table 4.1, available here

[15] The profiles have been derived by averaging the annual profiles over the last five years (2011-2015).

[16] The residential gas demand profile has been estimated using National Grid historical data on daily gas demand at the Local Distribution Zone level. The industrial gas demand profile has been estimated using National Grid data on daily gas demand of large NTS (national transmission system) connected industrial customers.

Figure 3.2: Relationship between distribution-level gas demand (proxy for residential demand) and CWV - data for 2015



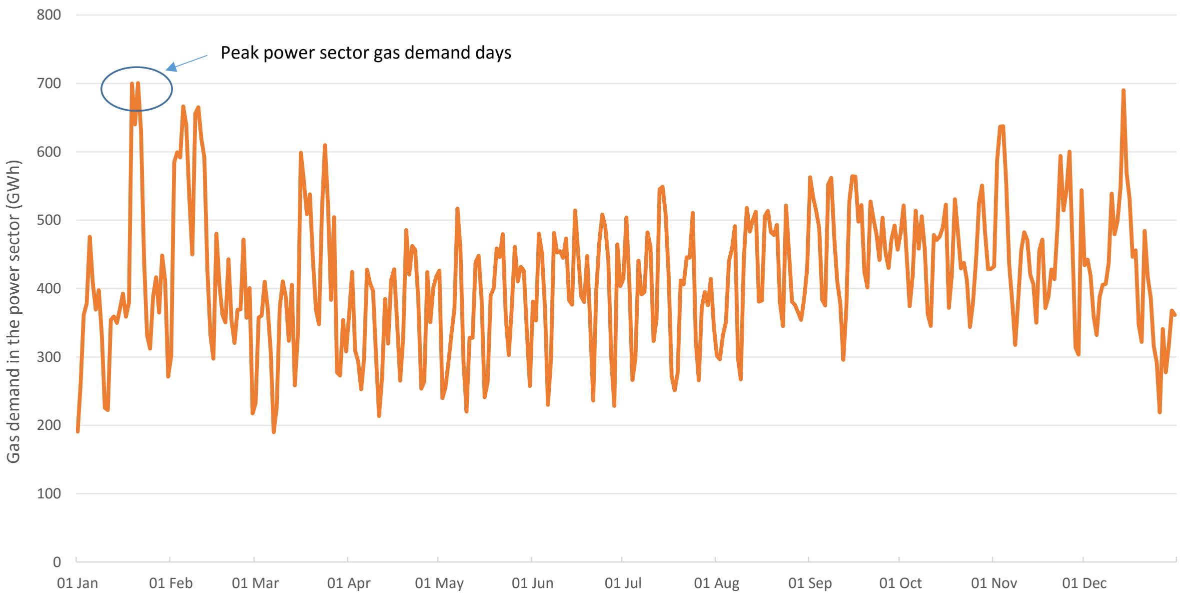
By using the parameters estimated in the regression, we stochastically simulated residential gas demand on a sample day in January by generating daily CWV values from an extreme value distribution, which was derived from the historical CWV values for each January over the last 50 years.[17]

Power generation gas demand

Power sector gas demand represents a significant proportion of total gas demand (c. 26% in 2015[18]). The profile of annual power sector gas demand is driven by the profile of electricity demand, and, more importantly, by the profile of intermittent wind generation which can result in large variations in daily gas demand in the power sector. Seasonal variations in power sector gas demand are less distinct than in residential demand, although the peaks of gas demand in the power sector also tend to be in the winter months. This is illustrated by a plot of the 2015 power sector gas demand, shown in Figure 3.3. The peak gas demand days in the power sector in 2015 were reached on two days in January, which represented days of high electricity demand, coupled with relatively low wind generation.

[17] January and February are typically the coldest months of the year. January was chosen for this analysis as it has a higher number of days and therefore offers a higher number of observations for estimating probability distributions. Using CWV values for January over a 50 year period gave us a sample of 1550 days.
[18] DECC, UK Energy Statistics, 2015 & Q4 2015 (March 2016), available here.

Figure 3.3: Gas demand in the power sector (2015)



Peak gas demand in the power sector was estimated based on the amount of gas-fired electricity generation required to meet electricity demand on a peak day, given an assumed level of non-gas baseload generation and a stochastically modelled wind output.[19]

Industrial gas demand

An estimate of large industrial peak gas demand was based on the maximum daily industrial gas demand registered in the last 5 years.[20]

Total gas demand

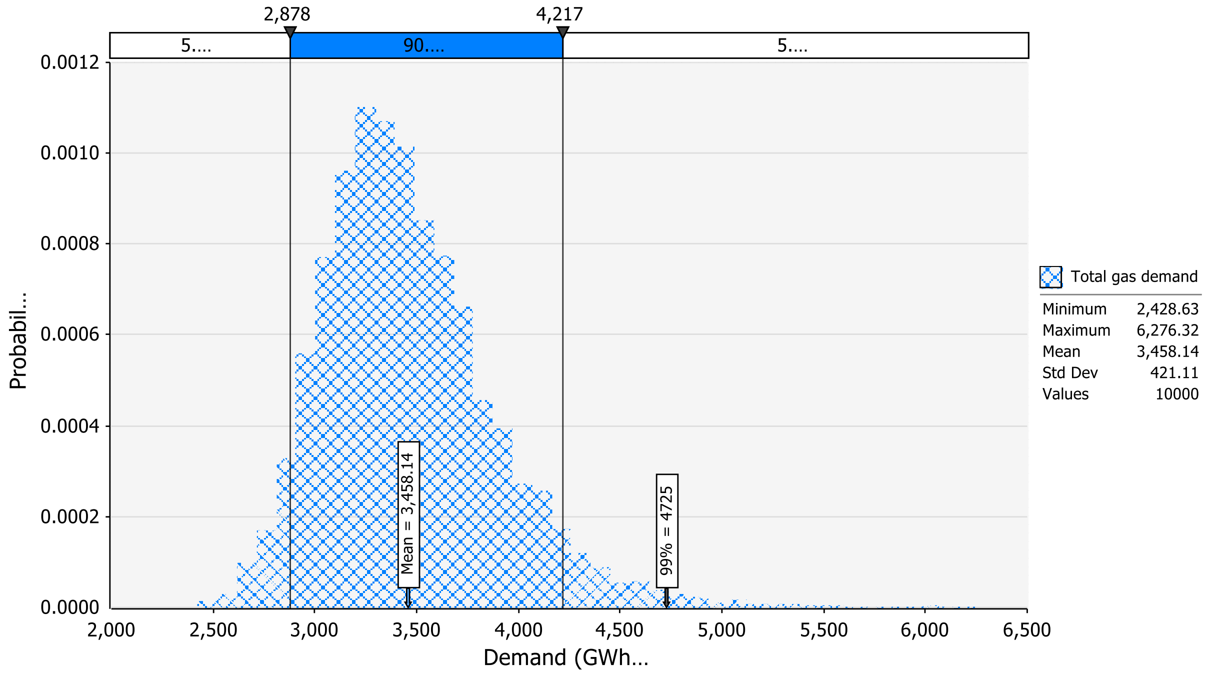
Total peak day gas demand was calculated as the sum of the simulated residential and power sector gas demand plus the assumed industrial gas demand. The simulation took into account correlations between CWV values (driving residential demand) and wind output (influencing power sector gas demand).[21] The resulting probability distribution of daily gas demand is shown below with the 5th (low demand), the 95th (high demand) and 99th (extreme high demand) percentiles highlighted as well as the mean of the distribution.

[19] Modelled using a Beta distribution derived from historical wind generation load factors for days in January over a five year period (a sample of 55 days).

[20] Industrial gas demand represents a relatively small share of total gas demand and the industrial gas demand profile is fairly stable throughout the year therefore the impact of this assumption is small.

[21] A (relatively weak) negative correlation (*i.e.* higher temperatures associated with lower wind output) was estimated from daily CWV values and wind load factors over a five year period.

Figure 3.4: Total daily gas demand probability distribution for a sample day in January



The 95th percentile of the distribution gives a gas demand level of around 4,200 GWh/day, and the 99th percentile has a predicted gas demand of 4,725 GWh/day. In comparison, the GB gas system currently relies on a supply capacity of around 6,600 GWh/day including storage, and just over 5,000 GWh/day excluding storage. Therefore, the results of the demand-side simulation suggest that the 95th and 99th percentiles of possible demand levels are significantly below the total GB gas supply capacity even if storage is excluded.

This, of course, assumes that physical gas will be available to flow at maximum capacity. In reality, however, the availability of gas supplies may be affected by market conditions such as high gas demand in neighbouring countries. This is plausible given the correlation of regional weather patterns. The interaction between the demand- and supply-side of the market can only be assessed using a global gas market model as we have done in Stage 3 of our analysis.

In the most extreme cases, the probability of demand being at or above 5,000h GWh/day is less than 0.5%, which means that there is less than 0.5% chance of unmet demand, assuming no gas in storage.

Table 3.1 below summarises the key demand-side risks to which the GB system is currently exposed.

Table 3.1: Demand side risk likelihoods and occurrence conditions

Individual demand-side risks	Likelihood	Conditions for occurring	Probability of unmet demand
Cold weather	95th percentile (less than 5% chance of occurrence)	Residential gas demand higher than 3250 GWh/day	-

Individual demand-side risks	Likelihood	Conditions for occurring	Probability of unmet demand
Low wind	95th percentile (less than 5% chance of occurrence)	Power sector gas demand higher than 930 GWh/day	-
Combined demand-side risk			
High total gas demand	95th percentile (less than 5% chance)	Total daily gas demand higher than 4,217 GWh/day	0%
	99th percentile (less than 1% chance)	Total daily gas demand higher than 4,727 GWh/day	0%
	Less than 0.5%	Total daily gas demand higher than 5,000 GWh/day	Less than 0.5% (if no gas in storage) 0% otherwise

3.2. Supply-side risks

The key supply-side risks were assessed using input from stakeholder workshops, our own analysis and the findings from the literature review in order to inform which shocks to model in the third stage of the study, based on the 'best to test' criteria established by BEIS[22]. The risks were analysed using the qualitative likelihood and impact scales presented in ANNEX D to provide a reference point to aid the selection of scenarios to analyse. In this section we present the final list of key supply-side risks, including a discussion of their current (perceived) likelihood.

The final list of supply-side risks consists of three sources of geopolitical risks and four types of infrastructure disruptions, which were selected because, when considering likelihoods and impacts together, they had either the biggest expected impact, or were seen as the 'best to test'.

We summarise the key geopolitical and infrastructure risks in Table 3.2 and Table 3.3, respectively. Based on stakeholder input (scoring using the scale presented in ANNEX D) and our own assessment, we present these shocks ranked on their impact and likelihood from largest impact to smallest impact and from most likely to least likely. The duration of a disruption was not discussed at this stage.

Geopolitical risks

As shown in Table 3.2, based on our workshops and assessments the highest-ranked geopolitical risk is a disruption to Qatari LNG supplies. A North African supply disruption was considered to be more likely, but its impact on GB was deemed to be insignificant. Disruptions

[22] 'Best to test' was defined as the scenario that is most likely to find the 'breaking point' of the GB gas system, *i.e.* the level of disruption at which unmet demand starts to occur.

to Russian supplies, under both scenarios, are thought to be less likely than a North African disruption. Their impact could be significant, even severe, but less so than a Qatari disruption. Note that the numbers in Table 3.2 represents rankings, calculated based on the methodology in ANNEX D, and do not directly correspond with the numbers set out in ANNEX D. These rankings were used for determining which shocks to model in Stage 3.

Table 3.2: Final list of geopolitical risks, ranked by impact and likelihood, as concluded by stakeholder workshops and our assessment

Risk	Likelihood (1 = most likely, 3 = least likely)	Impact (1 = largest, 4 = smallest)
Qatari LNG disruption	2	1
North African/Algerian disruption	1	4
Disruption to Russian supplies I. Ukraine transit	2	3
II. Ukraine + Yamal	3	2

Infrastructure risks

Infrastructure risks listed in Table 3.3 are generally defined as the complete outage of a single facility. In the GB context, this could be a failure of: (1) the Rough storage facility; (2) an LNG regasification terminal; or (3) a GB interconnector. One exception is the disruption to the UKCS/NCS production, which would involve the disruption of a number of production fields from which gas is transported to a single gas terminal (*e.g.* Bacton).

These infrastructure outages are assumed to be a sudden, unexpected loss of facilities for a short duration (a few months at most), not their permanent closure[23]. All infrastructure risks considered were seen to have a similar (moderate) impact on GB security of supply. The most likely infrastructure risk with respect to GB security of supply was deemed to be an outage of one of the LNG terminals. Note that the numbers in Table 3.2 represents rankings, calculated based on the methodology in ANNEX D, and do not directly correspond with the numbers set out in ANNEX D. These rankings are used for determining which shocks to model in Stage 3.

[23] Closure of infrastructure assets due to economic considerations or for maintenance purposes is accounted for in the baseline scenarios.

Table 3.3: Final list of infrastructure risks, ranked by impact and likelihood, as concluded by stakeholder workshops and our assessment

Risk	Likelihood (1 = most likely, 3 = least likely)	Impact
GB LNG regasification terminal outage	1	All assessed as having the same scale of impact
GB interconnector outage	2	
Rough storage facility outage	3	
UKCS/NCS production disruption	3	

3.3. Assessment of risk scenarios

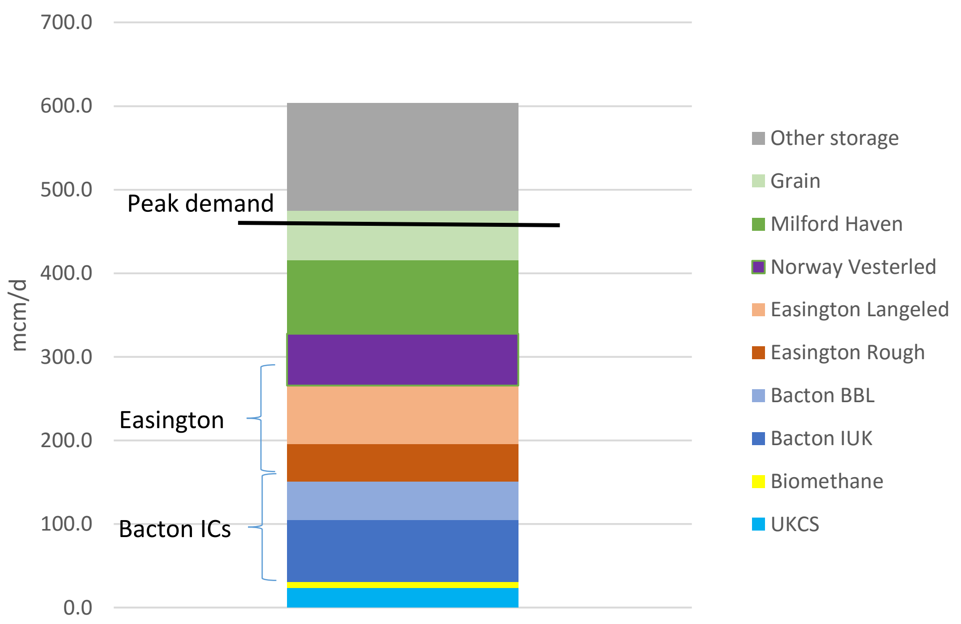
After the workshop, we conducted our own assessment of the proposed risk scenarios to help identify the 'breaking point' of the GB gas system and determine which shocks to test in the third stage of the study. The assessment indicated that, in general, the most likely scenarios were associated with lower impacts, while the high impact scenarios could be considered lower probability events.

We agreed with the stakeholder assessment classifying Russia (Ukraine transit) and North Africa disruptions as two of the more likely scenarios. This assessment is supported by both the current and historical geopolitical events and by the literature review of past studies which have widely considered disruption to Russian and Algerian supplies as the source of risks to gas security of supply in Europe.[24] While these two scenarios are deemed the most likely to occur, they are also likely to have a relatively small impact on GB gas security of supply. The other two scenarios identified as potentially having the biggest impact include disruption to LNG terminals.

We have also conducted a preliminary analysis of the potential impact of the main infrastructure risks on GB peak day supplies. This is based on an estimated peak demand of around 460 mcm/day, which is an approximation of peak-day demand across the entire period to 2035 in the two highest National Grid Future Energy Scenarios (No Progression & Consumer Power). The source of peak day supplies is shown in Figure 3.5 below.

[24] Ukraine transit disruption was considered by Egging et al. (2008), EWI (2010), Richter and Holz (2015), Martinez et al (2015), Chyong and Hobbs (2014), European Commission "Stress Test" (2014), Pöyry (2010). Algerian supply disruption was considered by Egging et al. (2008), EWI (2010).

Figure 3.5: Estimated peak day supplies (2035 – average of all National Grid Future Energy Scenarios)



Based on this analysis we calculated that the largest infrastructure risks involve an outage at the Bacton or Easington terminals. Under our assumptions, peak demand would still be met by supplies from other sources. However the residual supply index for both Bacton and Easington is around 104% suggesting that a combined shock involving Bacton/Easington combined with another shock is highly likely to result in some unmet demand in this situation. However, this is very unlikely to occur as it requires simultaneously complete failures of two pieces of infrastructure during peak demand conditions. It also assumes no voluntary demand response.

4. Baseline Scenarios

Summary

This chapter focuses on the main assumptions and results from our baseline scenario modelling. Three baseline scenarios were constructed:

- ***Baseline Scenario 1a****—increasing global and GB gas demand out to 2035 with the Rough gas storage facility operational until 2035;*
- ***Baseline Scenario 1b****—increasing global and GB gas demand out to 2035 with the Rough storage facility closed from 2016;*
- ***Baseline Scenario 2****—decreasing European and GB gas demand and stagnant global demand from 2025 onwards. The Rough storage facility is closed in this scenario.*

The main conclusions on future gas supply in GB and Europe reflect structural changes expected to take place gradually up to 2035, including:

- *Decline in European indigenous gas production including UKCS, Dutch and, to a lesser extent, Norwegian production—this will result in an increased reliance on imported gas across Europe;*
- *GB and NW Europe are most likely to be reliant on LNG and Norwegian gas supplies whereas the rest of Europe will be more balanced between Russian, Norwegian and (to a much lower extent) Dutch supplies, as well as growing LNG imports—this will have implications for flows between GB and the rest of Europe where interconnectors are more likely to be used as a daily balancing tool, rather than serving baseload demand;*
- *Modelling results show that the current ample GB gas capacity margins (supply capacity relative to peak demand) are projected to tighten gradually over the period to the mid-2020s but there were no years when capacity margins could be considered particularly tight.*

In this section, we first present the main assumptions used in the baseline scenario modelling, followed by the baseline scenario results against which the supply and demand shocks were applied[25].

4.1. Baseline scenarios: main assumptions

Following input from BEIS and the stakeholder workshops, we determined that the IEA's global scenarios from its 2015 World Energy Outlook[26] were the most appropriate for modelling the global gas market for this report. These were also complemented with additional detail on GB and European markets from public data sources, such as National Grid's Future Energy Scenarios.

As GB becomes more reliant on imported gas, it is a reasonable assumption that the importance of gas import infrastructure and storage will increase, so we paid particular

[25] The baseline scenarios represent possible future states of the world, not necessarily forecasts of the future.
[26] World Energy Outlook 2015 (Released on 10 November 2015) was the latest IEA predictions at the time the work was undertaken.
http://www.worldenergyoutlook.org/weo2015/

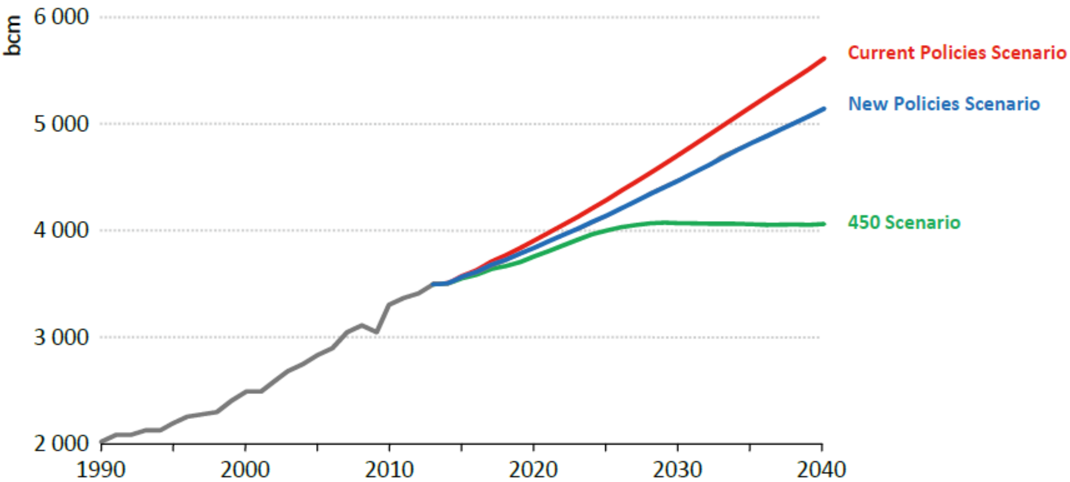
attention to modelling the key gas infrastructure assets in GB to capture the impact of potential investment/divestment decisions. With the ageing of these assets and market conditions having lately been unfavourable for some, their future operational viability may be questioned, potentially impacting on the GB gas security of supply position. One of the key infrastructure assets we considered was the Rough storage facility which, with a working capacity of 3.3 bcm/year, represents about 70% of total gas storage capacity in GB. In workshop discussions, stakeholders raised the uncertainty surrounding the availability of Rough in the future, especially given the recent falls in seasonal price spreads negatively impacting upon the economics of Rough. Therefore, in order to capture this uncertainty we assumed that Rough is not available for the entire study period in some of our baseline scenarios.

Specifically, three baseline scenarios were constructed:

- **Baseline Scenario 1a**—based on the IEA's *"Current Policies Scenario"* ("CPS"). This scenario projects increasing global and GB gas demand out to 2035, and also assumes that the Rough gas storage facility is operational until 2035;
- **Baseline Scenario 1b**—based on the same IEA CPS set of assumptions as in Scenario 1a, but assumes that the Rough storage facility is closed from 2016;
- **Baseline Scenario 2**—based on the IEA's *"450 Scenario"* ("450"). This projects decreasing European and GB gas demand and stagnant global demand from 2025 onwards. The Rough storage facility is closed in this scenario.

A comparison of IEA's global demand projections for the two scenarios used (CPS and 450), as well as their NPS scenario, is shown in Figure 4.1.

Figure 4.1: Comparison of IEA global demand forecasts by scenario27



The differences in the assumptions behind the two IEA scenarios are summarised in Table 4.1 below. It is important to note that a low gas demand scenario does not necessarily equate to

[27] Source: IEA WEO 2015, Figure 5.1. Note that while global gas demand is increasing under the 450 Scenario up to around 2025, GB and European demand are decreasing throughout the period.

a lower security of supply risk as lower gas demand globally is also likely to lead to lower investment (and possibly even divestment) in gas production and infrastructure capacity.

Table 4.1: Comparison of the two IEA scenarios that form the basis of the baseline scenarios

Assumption	Current Policies Scenario	450 Scenario (policies additional to CPS)
Main policy assumptions	Considers only those policies for which implementing measures had been formally adopted as of mid-2015, and makes the assumption that these policies persist unchanged.	Assumes policies consistent with a trajectory of emissions reduction that meets the goal to limit the rise in temperatures to 2 degrees Celsius.
EU	2020 Climate and Energy Package: • 20% cut in GHG emissions compared with 1990 levels. • Renewables to reach a share of 20% of total final energy consumption by 2020. • Partial implementation of 20% energy savings compared with a business-as-usual scenario. EU Emissions Trading System (EU ETS) reducing GHG emissions in 2020 by 21% below the 2005 level, covering power, industry and aviation sectors.	EU ETS strengthened in line with 2050 roadmap
China	Implementation of measures in the 12th Five-Year Plan, including 17% cut in CO2 intensity by 2015 and 16% reduction in energy intensity by 2015, compared with 2010. Increase in the share of non-fossil fuels in primary energy consumption to around 15% by 2020.	Stronger emission trading scheme for power and industry sectors.
All non-OECD	Fossil-fuel subsidies are phased out in countries that already have policies in place to do so.	Fossil fuel subsidies phased out in next ten years in all net-importing countries and in next twenty years in net-exporting countries (except Middle East)
All OECD		Introduction of CO2 pricing in all OECD countries including in US from 2020.

Although the baseline assumptions do influence our modelling, they do not completely determine the final results. Key outputs such as final global gas demand and supply are determined endogenously within the model. This is done through calibration using demand-side parameters (*e.g.*, price elasticity of demand) and supply-side parameters (*e.g.*, pipeline network and shipping routes with capacities and costs, gas production by country and region with aggregate marginal cost curves).

4.2. Baseline scenarios: results

In the remainder of this section we present simulation results for the three chosen baseline scenarios. When considering results in this section, note that the model was calibrated to 2014 data, the most recent year for which complete data was available at the time this work was undertaken. All results shown for 2016 onwards are forecasts reflecting the underlying baseline scenarios and are not meant to correspond exactly to observed flow/demand patterns in 2016.

4.2.1. Gas demand

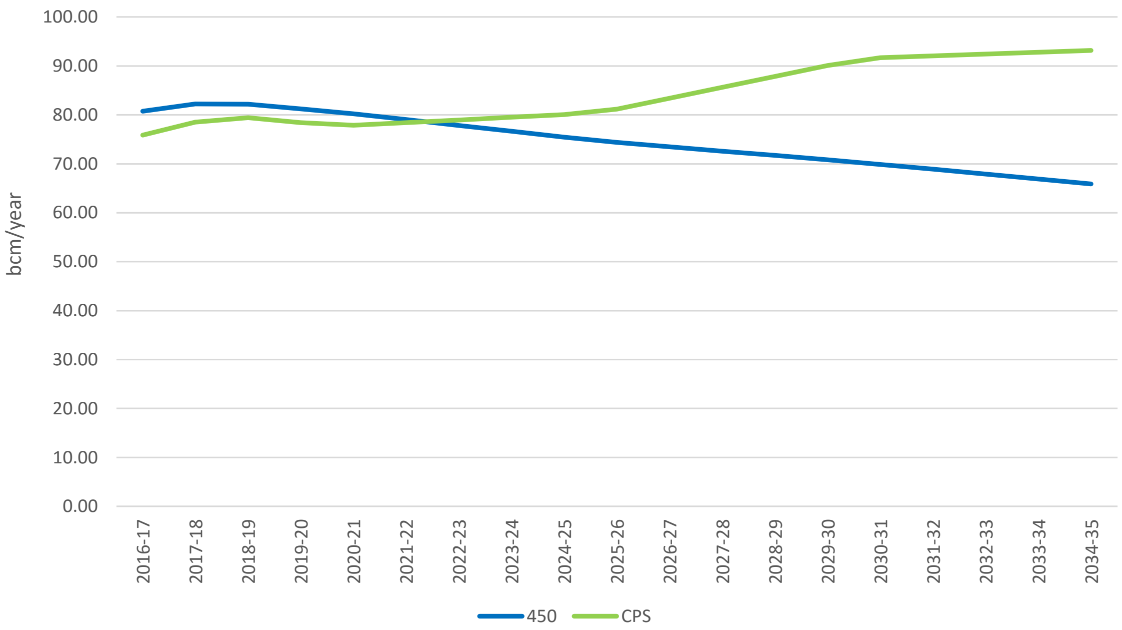
As a starting point, the model takes projections of future demand levels for the modelled regions and countries based on the two IEA scenarios selected. In the annual and monthly models, a portion of the final demand is assumed to be price-sensitive[28] so consumption is adjusted accordingly. Therefore, final gas consumption and cleared market prices are determined endogenously within our annual and monthly models based on original demand assumptions and gas supplies available to each market.

The modelled GB gas demand is shown in Figure 4.2 below. Note the following:

- GB gas demand under Baselines 1a and 1b is relatively stagnant during the first half of the study period then slightly increases more rapidly from 2025 onwards. Demand is similar under both baselines;
- Gas demand in Baseline 2 is higher than the demand in Baselines 1a and 1b in the first few years—this is due to price elastic demand in the model responding to lower gas prices. After the first few years, GB gas demand under Baseline 2 decreases, in line with the IEA 450 projections;

[28] The daily gas model minimises total system cost while taking demand (determined endogenously by the monthly model) and other physical constraints as given.

Figure 4.2: GB gas consumption in the baseline scenarios[29]



4.2.2. Gas supply

Gas production within the model is determined endogenously based on assumptions on costs and maximum technical production capacity. Technical capacity assumptions are mostly based on projections made by IEA in their scenarios in the WEO 2015 report regarding gas production from all major producers. We used alternative sources where recognised projections were available as we believed these provided a greater level of detail or accuracy compared to the IEA projections. Table 4.2 outlines the sources used to establish these assumptions. Note that levels gas exports from LNG exporting countries are dependent on assumptions for LNG liquefaction capacities in these countries. Details on the liquefaction capacity at the start of the modelling period can be found in ANNEX C with future capacities determined endogenously by the model.

Table 4.2: Summary of production capacity baseline assumptions

Variable	Source	Comments
UKCS production	Oil and Gas Authority (OGA)	OGA UKCS production projections (February 2016)
All non-EU gas production (incl. Norway but excl. US)	IEA WEO	Non-EU gas production (incl. Norway, Russia and Qatar) taken from IEA WEO
US gas production	EIA Annual Energy Outlook 2015	US future natural gas production—includes estimates of shale gas production
Dutch gas production	NL Oil and Gas Portal	NL Government projections—include production constraints on Groningen field

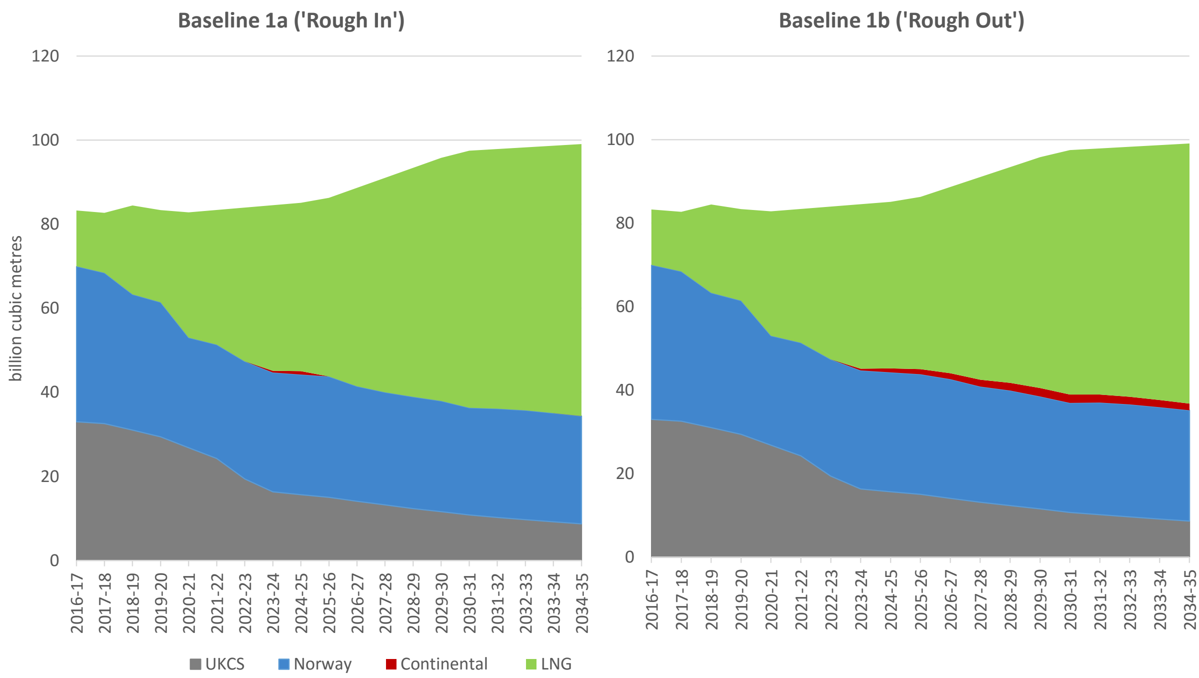
[29] This graph shows annual demand for the April to March period. Hence the data for the year 2016/17 represents demand in the period April 2016 to March 2017.

We used these forecasts as the upper bound on production capacity, but actual capacity was endogenously determined in the model taking into account factors such as marginal costs, existing production capacities and expected demand. In agreement with BEIS, we have assumed no GB unconventional gas production (e.g. shale gas) over the period studied. Such production is possible but data from exploration wells is needed to develop reliable estimates.

GB gas supply by source

Figure 4.3 below shows the estimated annual flows to GB from each supply source over the modelling period. Total flows add up to the sum of consumption, storage injections and exports.

Figure 4.3: Annual GB gas import flows by source in Baseline 1a ('Rough In') and Baseline 1b ('Rough Out')



Key trends in Baselines 1a and 1b are as follows:

- UKCS flows decline as a share of GB demand: from 40% in 2016/17 to 9% in 2034/35;
- Norwegian imports decline in absolute terms in the first few years and remain stable afterwards, but as a share of total GB supply Norwegian gas decreases from 44% to around 25% by 2035;
- LNG becomes the main gas supply source for GB with imports increasing almost fourfold, and by 2034/35 makes up over 60% of annual GB demand;
- Total annual interconnector imports from Belgium and the Netherlands are minimal under both baselines, providing little more than 1% of annual GB demand throughout

the period only with Rough assumed closed in Baseline 1b (this is discussed in more detail below);

- Rough is not utilised in Baseline 1a before 2025; after that it provides up to 3% of annual GB demand;
- In Baseline 1b, with Rough unavailable to meet demand for seasonal flexibility, imports from the Continent increase particularly during winter months.

A key finding related to Baselines 1a and 1b is that the gap created by the decline in UKCS production and Norwegian imports and growing domestic demand is increasingly filled by LNG imports.

Also, monthly gas import flows from the Continent are minimal[30]. Price convergence between GB and NW European hubs is achieved through LNG replacing much of the declining indigenous production in NW Europe, weakening the economics behind interconnector flows. Increasingly, central Europe is served by Russian gas exports (but not further west than Germany), and LNG imports and Norwegian gas represent the main source of supply in NW European markets.

Note that these results are based on the monthly model. Flows on the interconnectors could occur due to very short-term trading and arbitrage between hubs on a day-ahead or within-day basis. The monthly model does not capture this given its granularity.

Gas imports by entry point

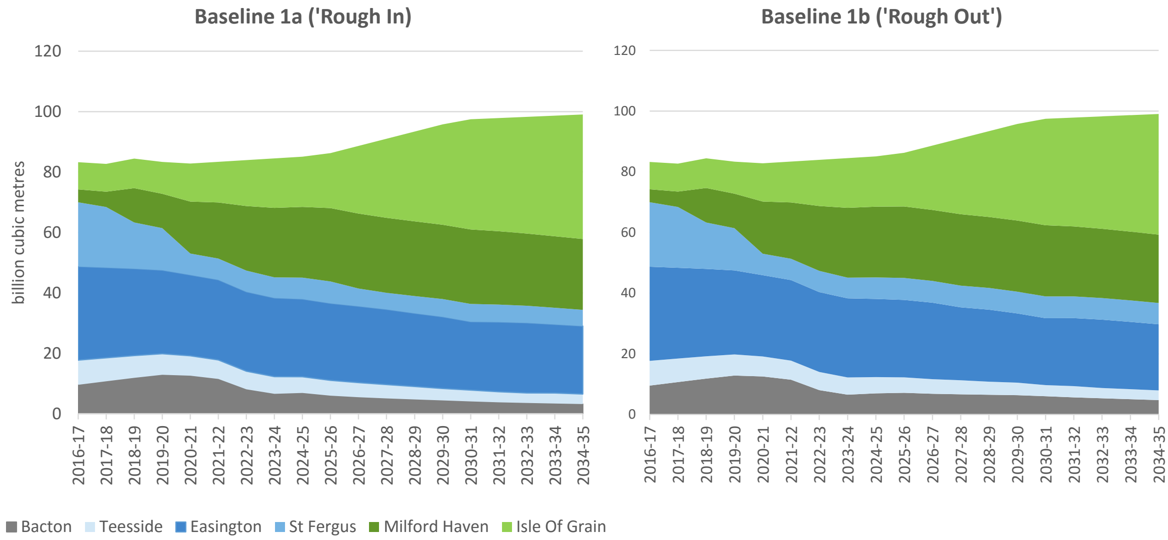
Next we show gas flows into the GB system by import point or entry terminal. These include: Bacton, Easington, Teesside, St Fergus, and the two LNG terminals at Isle of Grain and Milford Haven.[31]

[30] There are some exports on IUK from GB to Belgium during summer months. This is because some UKCS flows coming into Bacton flow through IUK to Zeebrugge rather than serving the GB market and paying the GB NTS entry tariffs at Bacton.

[31] Note that not all existing GB terminals were modelled explicitly. Production from other terminals (which are served by UKCS gas only) has been aggregated into the four terminals modelled as follows: Barrow flows have been included into Teesside, Theddlethorpe flows have been aggregated into Easington and Point of Ayr flows have been aggregated into Bacton.

Figure 4.4 shows annual flows into the GB system by gas terminal under Baselines 1a and 1b.

Figure 4.4: GB gas import flows by terminal in Baseline 1a (‘Rough In’) and Baseline 1b (‘Rough Out’)

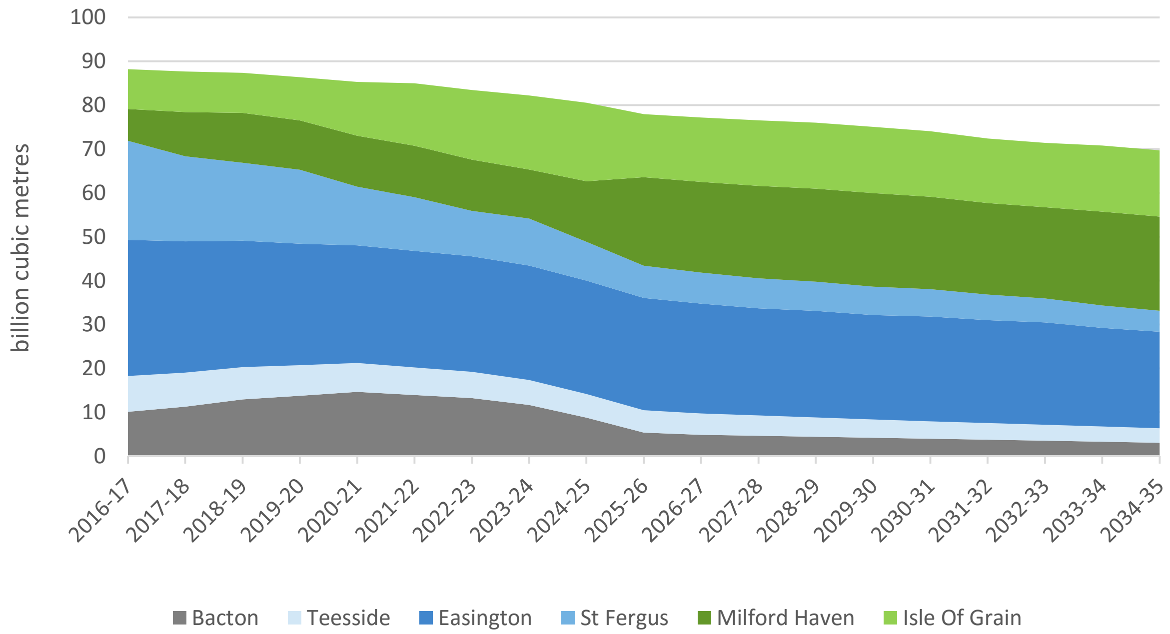


The key observations for Baselines 1a and 1b follow the key trends identified in the previous section:

- The growing importance of LNG imports means that there is increased utilisation of the two LNG terminals:
  - In Baseline 1a: Milford Haven and Isle of Grain are projected to supply a combined 13.2 bcm (16% of total demand) in 2016/17, which is projected to increase to 64.7 bcm (60% of total demand) by 2034/35;
  - Roughly two-thirds of LNG imports are delivered at Isle of Grain, and one-third go through Milford Haven in both baselines.
- The Grain LNG terminal becomes the main entry point for GB gas supplies as the model endogenously expands the terminal’s capacity in 2026;
- The share of gas flowing through Easington declines from around 37% (31 bcm) in 2016/17 as UKCS flows to the terminal decrease and total gas demand increases, but it still remains significant at 23% (23 bcm) at the end of the period;
- At St Fergus, flows decline by two-thirds by 2034/35, reflecting the decline in UKCS production and partly the decline in the absolute level of Norwegian imports;
- Flows at other terminals (Bacton, Teesside) also decline.

Overall there are no major differences between Baselines 1a and 1b. The only small difference arises from additional continental supplies coming into GB at Bacton from 2025 onwards under Baseline 1b when Rough is not available.

Figure 4.5: GB gas import flows by terminal in Baseline 2 (450)



Under Baseline 2 we observe that:

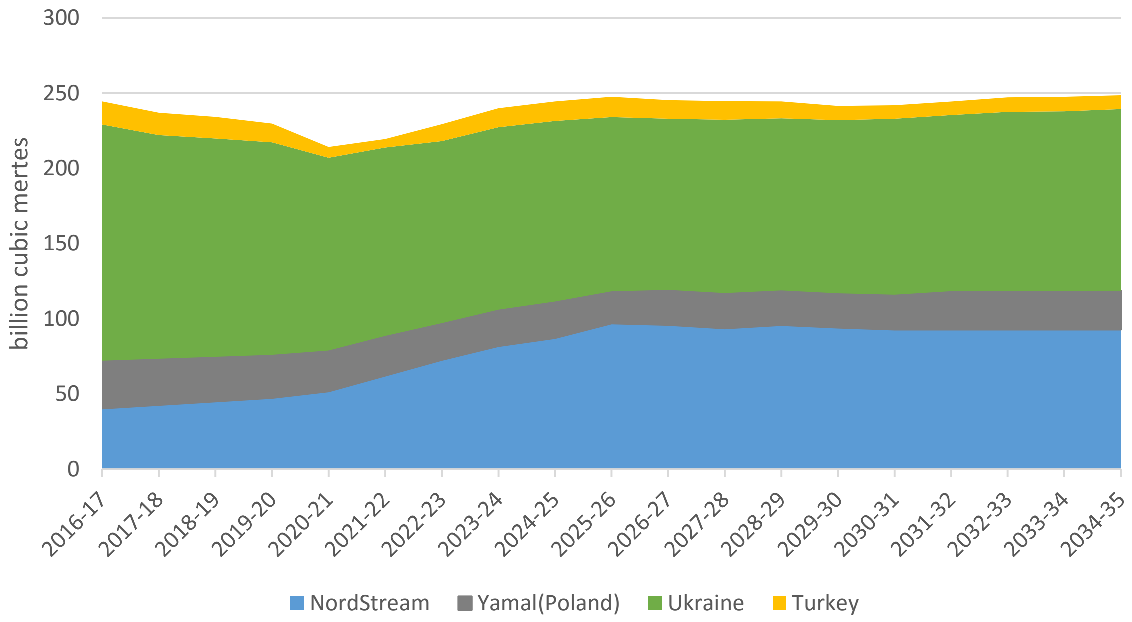
- Compared to Baselines 1a and 1b, there is no expansion of the Isle of Grain LNG terminal as LNG flows are growing less than under the other two baselines—after 2025 Milford Haven is the main entry point for LNG imports;
- Easington remains the main entry point for GB gas supplies under this baseline;
- The other entry points see declining flows over the period broadly similar to the other baselines.

Russian gas flows to Europe

Under Baselines 1a and 1b, an expansion of Nord Stream pipeline capacity was assumed, fully operational by 2025[32]. Figure 4.6 below shows the modelled Russian pipeline flows along the main transit routes under Baseline 1a. Nord Stream and Ukraine are the main transit routes for Russian gas flows to Europe. The volume of gas exported through Nord Stream increases as the capacity of the pipeline is expanded.

[32] The model could also *endogenously* expand pipeline capacity from Russia to Turkey (TurkStream) but the results show no expansion takes place given relative cost competitiveness of other routes and demand expectations.

Figure 4.6: Russian gas flows to Europe in Baseline 1a (Rough IN)[33]

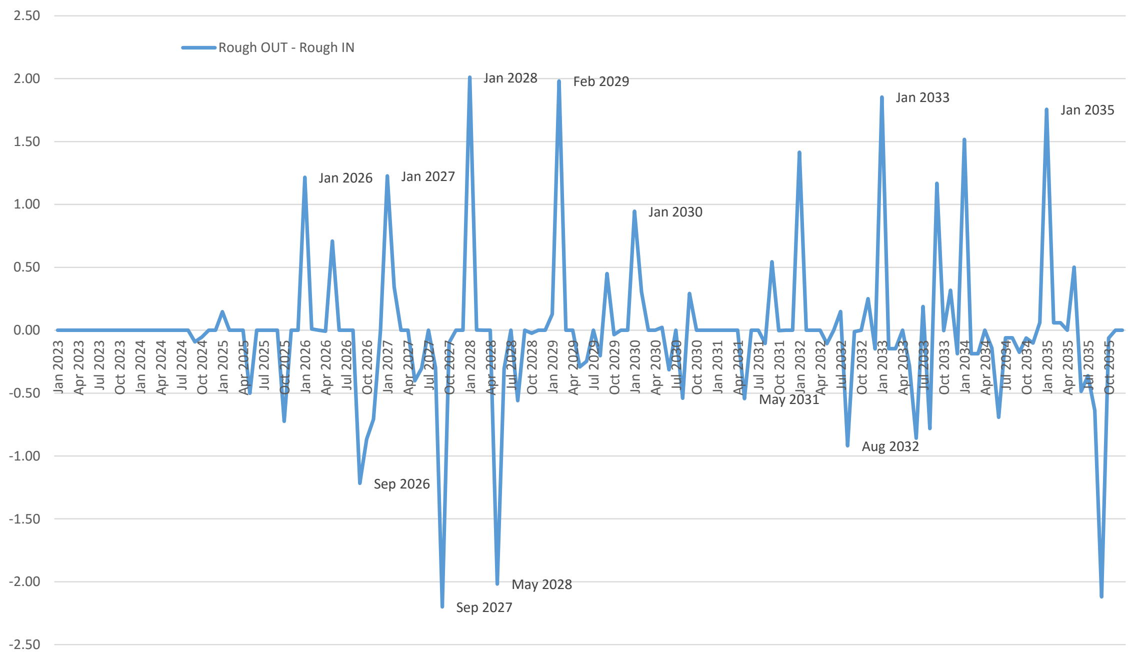


The volume of Russian exports to Europe remains fairly stable up to 2035, due to limits assumed on Russian production capacity expansion and growing gas demand in Russia under Baselines 1a and 1b. Given the increasing gas demand in Europe over the period, this means that the share of Russian gas in European gas imports declines, with LNG supplies taking over an increasingly larger share of the market.

The annual gas flows and route patterns for Russia remain largely unchanged in Baseline 1b, when Rough is assumed out, compared to Baseline 1a, but there are changes in seasonal flows with the model predicting that Russia provides additional flexibility in Baseline 1b. This is shown in Figure 4.7 below which shows the differences in monthly flows between Baselines 1a and 1b. In Baseline 1b, we observe higher flows out of Russia during the winter months, and lower exports during the summer months, as total European gas demand is lower when there are no injections into Rough. This suggests that under this baseline Russia can act as a swing supplier to Europe to a larger extent than other suppliers, such as Norway or LNG imports. This is partly due to Russia's high gas production capacity, but also due to the high gas penetration of its domestic power sector, which provides additional spare capacity by switching in the power sector to other fuels (such as coal which is abundant in Russia).

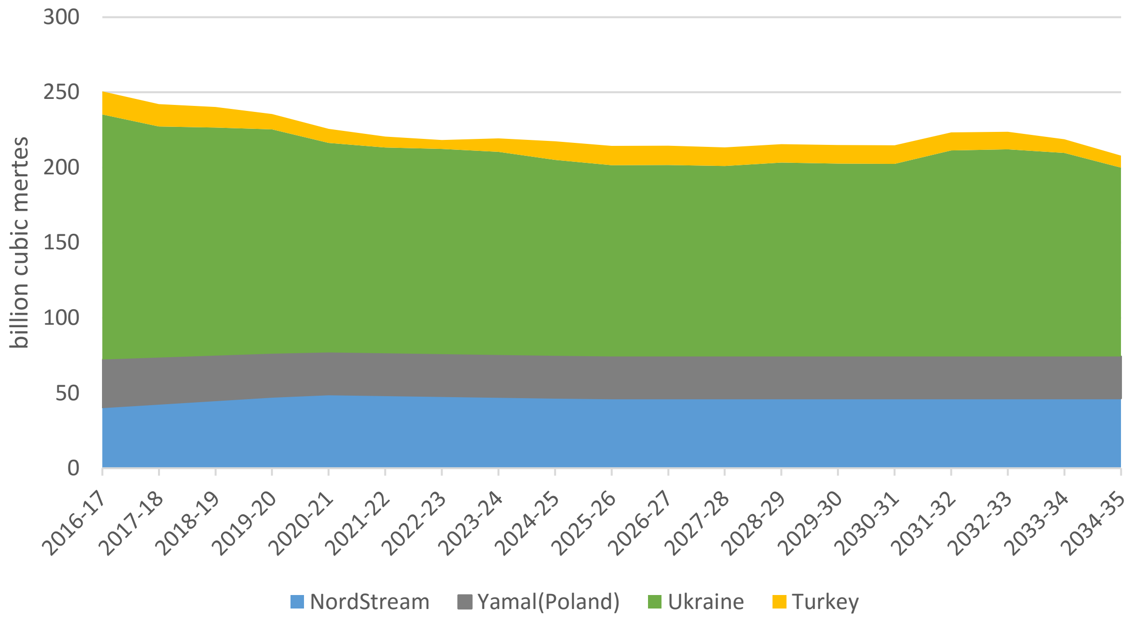
[33] The volumes shown for 2016-17 appear higher than current Russian gas flows to Europe. This is partly because the graph shows gas flows leaving Russia which also serve domestic demand along the transit route. Hence flows to Ukraine include gas used to serve Ukrainian domestic demand as well as exports to the rest of Europe. In addition, the European gas demand modelled using CPS assumptions is higher than actual demand observed.

Figure 4.7: Differences in flows – Baseline 1b (Rough OUT) minus baseline 1a (Rough IN)



Under Baseline 2, Russian exports decline gradually as European gas demand falls. In contrast to Baselines 1a and 1b, Nord Stream does not expand their capacity as the model judges it uneconomical.

Figure 4.8: Russian gas flows to Europe in Baseline 2



4.2.3. Key infrastructure assets

During workshop discussions, stakeholders highlighted the uncertainty surrounding the future viability of some of GB's infrastructure assets including the Rough storage facility and the two interconnectors (BBL and IUK). These concerns are largely driven by a predicted capacity oversupply over the next decade and the subsequent challenging business environment for these assets. The model results showing limited monthly baseload flows between GB and the rest of Europe point in the same direction.

In the case of Rough, it was exogenously assumed that it would remain open in Baseline 1a and close in Baseline 1b.

Capacity decisions for the interconnectors were modelled endogenously. Under all three baselines BBL and IUK capacity (in both GB import and export direction) is reduced from present levels. This is due to low projected flow levels making investment to maintain the capacity uneconomical.

4.2.4. Implications of baseline scenario results

The main conclusions on gas supply in GB and Europe up to 2035 are:

- Declines in European indigenous gas production including UKCS, Dutch and, to a lesser extent, Norwegian production will result in an increased reliance on imported gas across Europe;
- GB and NW Europe are most likely to be reliant on LNG and Norwegian gas supplies whereas the rest of Europe will be more balanced between Russian, Norwegian, Dutch (to a much lower extent) and growing LNG supplies—this will have implications on flows between GB and the rest of Europe where interconnectors are more likely to be used as a daily balancing tool, rather than to provide baseload supplies.[34]

These main trends hold under all baseline scenarios modelled, although the reliance on imports is greater under the higher demand baselines.

[34] This would also translate into challenges to maintaining interconnector capacity at current levels which may also affect security of supply. Furthermore, flows between GB and the rest of Europe may be dependent on the future UK-EU relationship however these were not considered as part of our analysis.

5. Stress testing the system

Summary

This chapter presents the results of the stress test modelling for each shock scenario. Three distinct supply-side shocks were modelled:

- ***Shock 1****: A large-scale LNG disruption, defined as a simultaneous disruption of Qatari and North African supplies, including loss of all LNG and pipeline exports.*
- ***Shock 2:*** *A large-scale international supply disruption, defined as a complete disruption of Russian pipeline gas flows to Europe along all three routes (Nord Stream, Yamal and Ukraine);*
- ***Shock 3:*** *A smaller-scale international supply disruption, defined as a disruption of Russian pipeline gas flows via the Ukrainian transit route and the Yamal pipeline, and the outage of the Grain LNG terminal;*

These shocks are extremely unlikely to occur and the scale, and disruption of these shocks are completely unprecedented.

The main findings of the stress tests were:

- ***Shock 1 does not seem to pose a significant security of supply concern for GB****. Low levels of unmet demand would only occur if the GB market were not able to attract any gas from other European markets. Providing GB consumers are prepared to pay, in this scenario there is no unmet demand.*
- ***Shock 2*** *would not result in unmet demand as long as GB customers were willing to pay more for gas than customers on the Continent, or if interconnector flows were not curtailed during emergencies. If GB customers were not willing to pay a higher price than customers in NW Europe, Shock 2 could cause significant unmet demand—****the key result is that alternative supplies are available to meet GB demand, but it comes at a price****.*
- ***Shock 3*** *has a more severe security of supply impact than Shock 2, despite total global volumes of gas lost due to the disruption being lower than under Shock 2. The key findings from Shock 2 apply to Shock 3 but, in addition, our results suggest that the GB system may be vulnerable to the complete failure of a large piece of infrastructure during the winter months (especially in January and February) under market conditions represented in the higher demand baselines.* ***Some unmet demand would occur even if GB consumers are willing to pay a higher price for gas, because the projected import infrastructure capacity would be insufficient to allow sufficient gas imports to serve all demand if there is a failure of a large infrastructure asset.***

All findings are based on a set of modelling assumptions so all results should be considered in the context of these assumptions when they are interpreted. The modelling does not account for demand response to higher prices at a daily granularity, but we have estimated the impact on different categories of consumers, such as power sector gas demand and industrial daily-metered gas demand, which can provide demand response, and non-daily metered gas demand (mainly domestic consumers), which would not be expected to respond to short-term price movements. In practice, a portion of the unmet demand estimated in our results would be mitigated through voluntary demand response rather than involuntary interruption.

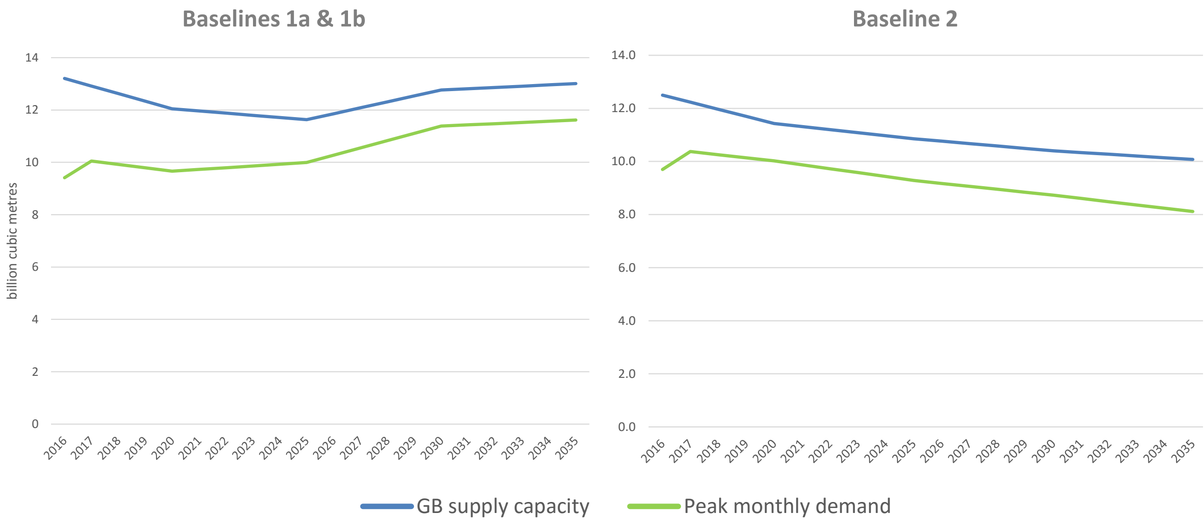
Based on the baseline scenario results, we stress-tested the GB system by modelling supply- and demand-side shocks. In this section we discuss the main underlying assumptions behind the nature of the shocks and present the results of the stress tests.

5.1. Year chosen for stress testing the system

The monthly modelling results up to 2035 allowed us to identify years when gas markets are expected to be tighter, and supply disruptions are thus likely to have a bigger impact. Tighter gas markets can be identified by high gas prices and/or lower capacity margins.[35]

Figure 5.1 below shows projected gas capacity margins for GB over the modelling period. This includes monthly UKCS production and all import capacity but excludes storage.

Figure 5.1: GB capacity margins Baseline 1a/1b (CPS) and Baseline 2 (450)

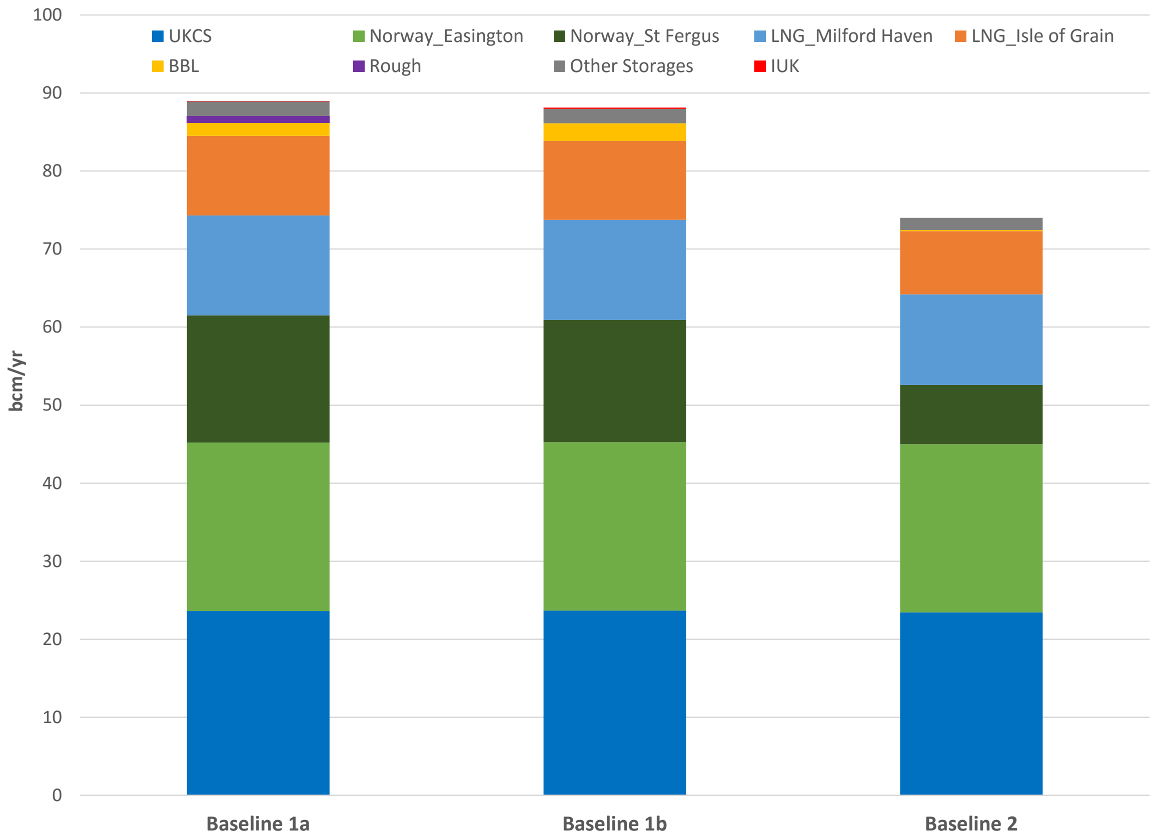


Under Baselines 1a and 1b, the GB capacity margin reduces gradually until mid-2020s largely due to reductions in supply capacity as UKCS production declines and interconnector capacity is reduced.[36] After 2025, demand levels start to increase but supply capacity also increases due to expansion of LNG import capacity. Under Baseline 2, the GB capacity margin stays largely constant as GB demand, UKCS production and import capacity declines. No new capacity is added under this baseline.

Based on these results, the most relevant period for testing security of supply seems to be from mid-2020s onwards when capacity margins tighten. While there were no years when capacity margins could be considered extremely tight, in conjunction with BEIS, we decided to focus our disruption modelling on 2025/26. We report the baseline results from our daily model for 2025/26 for all three baselines in Figure 5.2 below.

[35] Defined as available gas production and import capacity relative to peak demand in a market in a given year.
[36] For modelling purposes, infrastructure capacity reductions occurred gradually over a number of years to avoid creating a cliff-edge effect where capacity drops suddenly due to a complete shutdown of an asset.

Figure 5.2: Annual GB gas flows by source 2025/26 (baseline results – no disruption)



Note: total flows add up to consumption plus storage injections plus exports. Although gas consumption is the same, total flows are lower in Baseline 1b than under Baseline 1a because storage injections are lower when Rough is not available.

Almost all the gas flowing to GB in 2025/26 comes from UKCS production, Norwegian pipelines (entering the GB system at Easington and St Fergus) and LNG terminals. Under Baselines 1a and 1b, Norway is the largest source of gas supplies covering 43% of annual gas flows, with UKCS production providing around 27% of gas supplies and LNG a further 25%. Under Baseline 2, Norwegian gas accounts for 39% of total supplies, with UKCS providing 32% and LNG a further 27% of total annual gas supplies.

5.2. Shocks modelled and main characteristics

The amount of unmet demand that would occur in GB following a shock depends on these assumptions:

- *The nature and magnitude of the shock*—including the total volume of gas or capacity that is no longer available following a shock, the timing and duration of the shocks, and the level of reliance on the disrupted supply source;
- *How much GB and other European gas consumers would be willing to pay for gas supplies*—we assumed that, when global gas supplies are disrupted and involuntary curtailments are imminent, consumers in each market would be willing to pay a price

equal to their VoLL for gas. Relative differences in VoLL between markets and regions are important when gas supplies are insufficient to meet all demand, since in scarcity situations the price of gas is determined by consumers' willingness-to-pay. Suppliers sell their gas in the market where they receive the highest effective price, and under scarcity condition, all else equal, this implies that the best price can be achieved in the market where consumers have the highest VoLL.

5.2.1. Supply-side shock scenarios

We established and modelled three distinct supply-side shocks, each of a different magnitude:

- **Shock 1**: A large scale LNG disruption, defined as a simultaneous disruption of Qatari and North African supplies, including loss of all LNG and pipeline exports;
- **Shock 2:** A large-scale international supply disruption, defined as a complete disruption of Russian pipeline gas flows to Europe along all three routes (Nord Stream, Yamal and Ukraine);[37]
- **Shock 3:** A smaller-scale international supply disruption, defined as a disruption of Russian pipeline gas flows via the Ukrainian transit route and the Yamal pipeline, and the outage of the Grain LNG terminal.

The shocks modelled represent a range of potential supply-side disruptions that affect various supply sources (e.g. both LNG and pipeline supplies), and can occur due to a variety of causes (e.g. both geopolitical and infrastructure failures).

All shocks were run for the period from April 2025 to March 2026. We chose a three-month outage duration for infrastructure-related shocks, and a one-year duration for geopolitical shocks. Our view, confirmed by workshop discussions with stakeholders, is that geopolitical disruptions could potentially spread over a longer time period and the duration is hard to predict even when the shock occurs. On the other hand stakeholders suggested infrastructure disruptions are unlikely to last more than a few months and their duration is likely to be better defined. We assumed that the 3-month outage for infrastructure assets would start in December, because that would cover the most critical period with high demand, while also include different levels of storage availability (determined endogenously by our models), with significant storage stocks in December and potentially depleted stocks in February. Geopolitical shocks with a one-year duration were assumed to last for the entire year modelled (from April to March). April was chosen as the start of the disruption because it is the typical start of the gas storage fill-up cycle. This is also a worst-case scenario as it means

[37] BEIS asked us to consider a total disruption to Russian supplies along all three routes rather than a Ukraine transit or land-based pipelines disruption only as this represents a very severe shock of a larger magnitude than has been considered by previous studies and thus test the limits of the GB security of supply.

disruption occurs when gas storages are depleted and their ability to fill-up over the summer is potentially affected by the supply disruption.

The main characteristics of the supply-side shock scenarios modelled are summarised in Table 5.1 below. The shocks modelled are very severe, both in the magnitude of disruption and their timing and duration, but they serve to test the resilience of the system under the most challenging conditions.

Table 5.1: Main characteristics of supply-side shock scenarios tested

Sample	Source of disruption	Type of shock	Duration and timing
Shock 1	Loss of all Qatari LNG exports	Geopolitical	12 months starting April 2025
	Loss of all North African LNG and pipeline exports	Geopolitical	12 months starting April 2025
Shock 2	Disruption to all Russian pipeline gas flows to Europe	Geopolitical	12 months starting April 2025
Shock 3	Disruption to Russian land-based pipeline gas flows to Europe (Ukraine and Yamal pipelines)	Geopolitical	12 months starting April 2025
	Grain LNG outage	Infrastructure	3 months starting December 2025

Market participants were modelled with imperfect foresight with respect to the occurrence and duration of shocks. Specifically, we assume that every shock occurs as a surprise. Once a shock has started, market participants assume that it will last for another month.[38]

The types of shocks modelled for this study are primarily global geopolitical shocks that result in gas shortages across an entire region, rather than affecting a single market, which may be the case with some infrastructure-related shocks. The distribution of scarce gas within the affected region, as a function of the willingness-to-pay and cost of interruption (VoLL) in each market, is important. How demand would respond during the massive shocks modelled (with unmet demand), and how that response differs across Europe is uncertain and potentially has a big impact on the estimated level of gas supplies flowing to GB. Therefore, it is sensible to model scenarios with a wide range of VoLL values.

[38] If market participants were assumed to have perfect foresight regarding the occurrence of a shock and its duration, they would be able to use production and storage capacities optimally knowing exactly when and where gas shortages would occur. In the real world, market participants normally operate under imperfect foresight conditions, not only regarding unexpected disruptions but also future demand conditions, which prevent them from perfectly optimising their decisions.

We modelled each shock using three sets of different assumptions about VoLL levels in GB and the rest of Europe, namely:[39]

- **VoLL levels in GB are higher than in the rest of Europe**—as the cost of interrupting GB consumers is higher than in the rest of Europe, gas flows to GB even at the cost of interrupting customers in the rest of Europe (as the higher VoLL overcomes the higher gas transportation cost to GB);[40];
- **VoLL levels are equal in GB and the rest of Europe**—as the cost of interrupting consumers is the same in each market, gas flows in this scenario are determined primarily by the cost of transporting gas between markets; and
- **VoLL levels in GB are higher than in the rest of Europe but gas flows are restricted between GB and the NW European region due to interconnector curtailments as a result of government intervention**—as above, consumers in the rest of Europe tend to be interrupted before GB consumers but flows between NW Europe and GB are restricted if there is unmet demand in NW Europe.

The "merit order" of demand curtailments is as follows:

- 1. Daily Metered (DM) demand in NW Europe is curtailed first (having the lowest VOLL);
- 2. DM demand in GB is curtailed next (VoLL higher than European DM demand but lower than Non-Daily Metered (NDM) VoLL anywhere in Europe);
- 3. NDM demand in NW Europe is curtailed next (lower than GB NDM VoLL);
- 4. NDM demand in GB is curtailed last (with the highest VoLL).

Under the second set of VoLL assumptions, GB is disadvantaged by the higher cost of transporting gas to GB compared to other neighbouring markets (due to the relatively high gas entry capacity and commodity charges). Based on our discussions with BEIS, we understand that, in a gas shortage situation, the Government may consider measures to reduce the cost of gas transportation, and thus facilitate the import of gas to GB. Our modelling assumed there is no such regulatory action during the crisis, meaning gas transportation costs remain higher in GB than the rest of Europe. In the final set of VoLL assumptions, interconnector flows from NW Europe to GB are curtailed if there is still unmet NDM demand in NW Europe after all GB DM demand is curtailed. This departs from a pure market-based mechanism, but reflects our view of possible political realities during a shock.

[39] Note that the modelling assumes a least cost optimisation where gas flows to the higher priced markets subject to transportation costs and capacity constraints. It does not take into account any administrative procedures that may constrain market based flows.
[40] We have used estimates for GB VoLL taken from the London Economics study for Ofgem (2011).

5.2.2. Demand-side shock scenarios

Supply-side shocks were modelled within the context of several demand scenarios. Some of these scenarios represent extreme events, and thus can be considered shocks.

Demand-side shock scenarios represent large increases or decreases in gas demand in a given year compared to normal levels. These are different from the gas demand assumptions used in the baseline scenarios, which refer to trends in gas demand over a long period of time.

Changes in gas demand over a year are most likely driven by weather conditions where colder than normal weather drives up gas demand in the residential sector above the annual consumption level estimated using the long-term baseline scenarios, and vice versa.

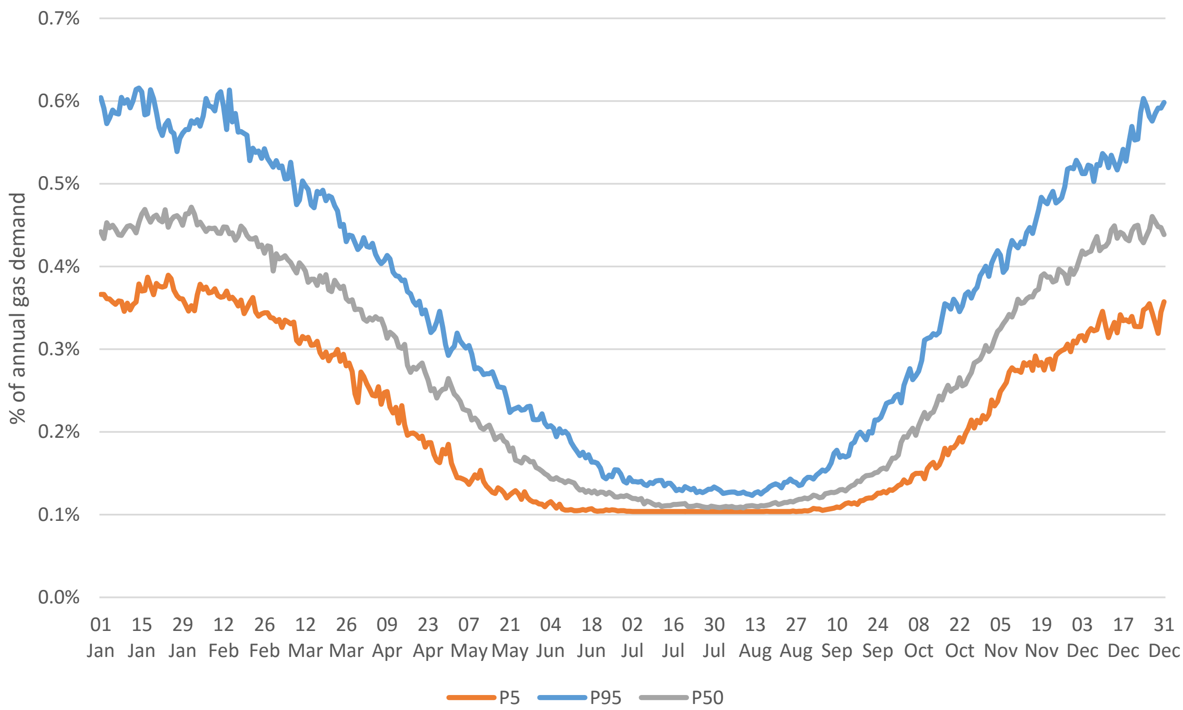
Each of the three supply shocks were simulated against three daily demand scenarios in GB and Europe determined based on:

- (1) seasonal normal temperature (50th percentile or “P50” demand);
- (2) 1-in-20 warm weather for each day of the year (5th percentile or “P5” demand); and
- (3) 1-in-20 cold weather for each day of the year (95th percentile or “P95” demand).

We have modelled the P5, P50 and P95 demand profiles for GB and Europe for an entire year. Thus the resulting demand is more extreme than what would normally be expected but this allowed us to test the impact of shocks under the most extreme situations.

Using more than 50 years’ worth of daily CWV data from National Grid, we calculated seasonal normal (*i.e.* P50) CWV values, as well as 1-in-20 cold weather (*i.e.* P95) and 1-in-20 warm weather (*i.e.* P5) for each day of the year. We used these values to predict residential gas demand for each day of the year and to create daily demand profiles (as a percentage of annual demand) consistent with P5, P50 and P95 demand conditions.

Figure 5.3: Residential daily gas demand profiles under different weather conditions



Future power generation gas demand profile

Future demand for gas in the power sector may vary due to changes in the power generation mix and its increasing use to fill gaps in intermittent wind generation.

We estimated future daily power sector gas demand profiles in the following way:

- used the 2014 daily electricity demand profile and predicted annual electricity demand as per the IEA's CPS and 450 scenarios to calculate expected daily electricity demand in 2025;
- uplifted the 2014 wind generation profile for projected installed wind capacity in 2025 (based on National Grid's Future Energy Scenario projections - Slow Progression, for Baselines 1a/1b, and Gone Green, for Baseline 2);
- assumed electricity generation from other sources remains the same as in 2014 with the exception of coal-fired generation, which is assumed to be phased out by 2025;[41]
- calculated the daily gas fired generation needed to meet residual electricity demand (after netting off wind and other generation) and converted this to a power generation gas demand using a 55% efficiency factor;
- applied the resulting power sector daily gas demand profile (as a percentage of annual demand) to the annual gas demand projections derived from the IEA scenarios.

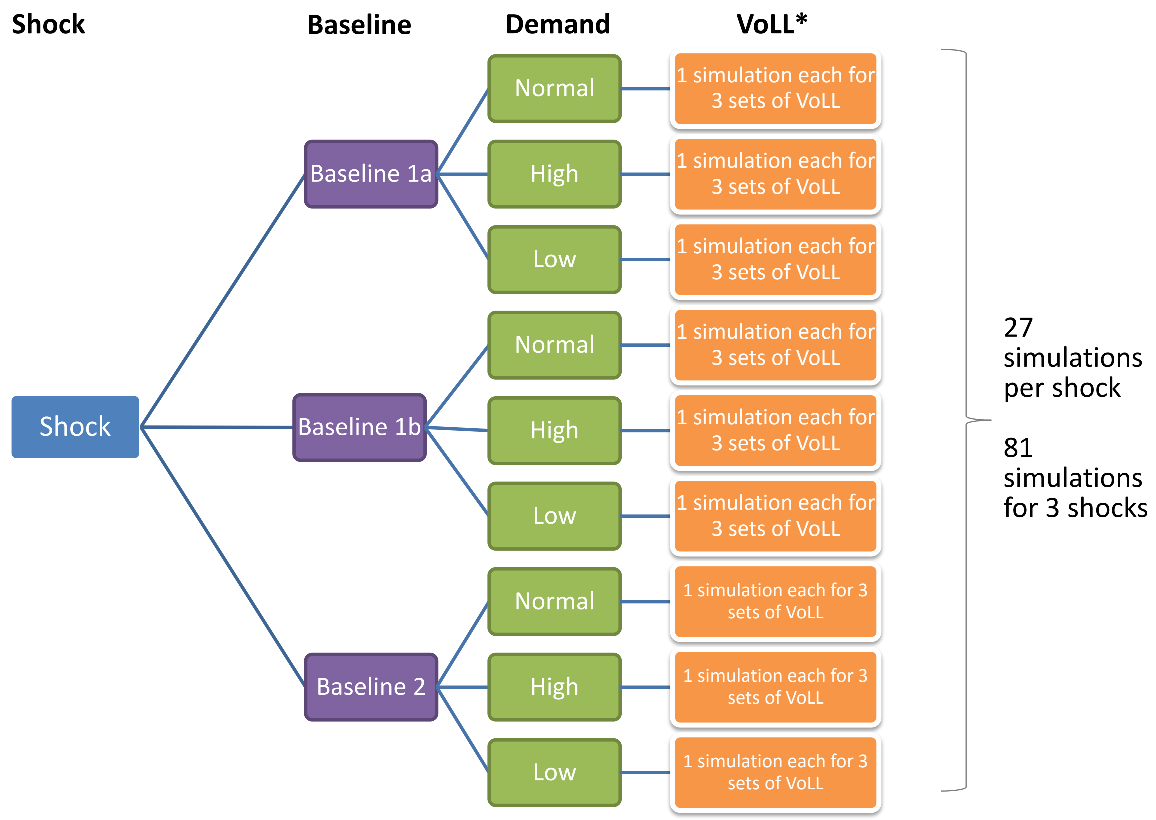
[41] We assume nuclear generation levels remain constant over the period to 2025 and do not take into account new nuclear plants such as Hinkley Point C whose development was still uncertain at the time the analysis was undertaken.

The power sector gas demand profile was combined with the residential gas demand (P5, P50 and P95) and industrial gas demand profiles to create an annual gas demand profile for each day in 2025/26.

5.3. Shock scenario results

In this section, we present the results of the shocks, comparing these against the baseline scenarios. In total, we modelled three supply-side disruptions, three demand-side scenarios and three VoLL assumptions against the three baselines, for a total of 81 model simulations. Figure 5.4 below illustrates the number of simulations we ran for each shock.

Figure 5.4: Simulations run for each shock scenario



*3 sets of VoLL were modelled: (1) uniform VoLL; (2) higher GB VoLL; and (3) highed GB VoLL with gas sharing

We assessed the annual demand volumes that would be affected by a disruption, differentiating the impact between DM and NDM customers. We also assessed changes in gas flows under each of the disruption scenarios, and identified the source of any additional supplies released or diverted to mitigate the shock. Our model estimated unmet demand as the portion of gas demand that does not receive gas supplies. Our daily model does not explicitly incorporate demand response to market prices. However, we estimated demand response by analysing the results for unmet demand within the different demand tranches.[42]

[42] For more information regarding demand response assumptions, see Section C.7 in ANNEX C.

The demand tranches considered and their assumed order of interruption, according to their VoLL, were: [43]

1. Gas-fired generators with back-up distillate generation capacity[44] – this is the first tranche to lose gas; the demand volume represents potential voluntary demand response in the power sector;
2. DM industrial & commercial consumers are the next tranches to lose gas – this tranche includes both voluntary demand response and involuntary demand interruptions;
3. NDM gas consumers is the final tranche to lose gas – we assume this tranche does not provide demand response as these consumers are generally not exposed to short-term movements in wholesale gas price.

We adjusted the results of the model ex-post to identify the impact of unmet demand on different tranches of customers. When interpreting our shock scenarios results, it is useful to note that:

- Any power sector unmet gas demand volume can be entirely resolved through voluntary demand response in the power sector;
- The volume of unmet demand in the industrial and commercial sector can, at least partially, be met through voluntary demand response;
- When NDM demand is curtailed, it means that all voluntary demand response in the power and industrial sectors has already been utilised, and unmet NDM demand can only be mitigated through emergency procedures and government interventions.

5.3.1. Shock 1

Under Shock 1, the simultaneous outage of the Qatari and North African production results in a loss of almost 300 bcm in global gas supplies in Baselines 1a and 1b, and around 225 bcm under baseline 2. Although this represents a larger share of the global market than the other two shocks modelled, it has a smaller impact on GB and the European markets. Given that we modelled a simultaneous disruption of the two supply sources for an entire year, this represents an extreme, low probability shock.

Impact on GB demand

The main results from Shock 1 are:

- When we assume that GB VoLL is higher than in NW Europe, Shock 1 does not result in any unmet demand in GB with or without interconnector curtailments. Curtailments

[43] VoLL represents the value that gas consumers place on using the gas, hence it should be the case that these consumers would be willing to pay for the gas up to the point where the gas price equals their VoLL.
[44] We used the Pöyry (2014) estimate of 10 mcm/day available distillate back-up capacity.

do not affect the results because there is no unmet NDM demand in GB or NW Europe, and thus no need to prevent gas flows.

- Under the assumption of equal VoLLs in GB and the rest of Europe, a relatively small amount (0.4-0.5 bcm) of unmet demand is projected in February and March (when storage stocks are depleted). In practical terms, this could largely be avoided by voluntary demand response.
- In 25-30 days some DM demand is unmet. These are days when LNG import capacity is fully utilised and imports from other sources are limited by gas shortages in Europe. A significant portion of unmet DM demand would however be covered by voluntary demand response.

Table 5.2: Shock 1 – Unmet demand by sector (bcm/year)

Scenario	Total unmet demand	% annual demand	Power sector	I&C DM	NDM gas	Highest daily NDM (bcm/day)
Higher GB VoLL						
Baseline 1a	0.0	0.0%	0.00	0.00	0.00	0.00
Baseline 1b	0.0	0.0%	0.00	0.00	0.00	0.00
Baseline 2	0.0	0.0%	0.00	0.00	0.00	0.00
Uniform VoLL						
Baseline 1a	0.4	0.5%	0.11	0.24	0.05	0.04
Baseline 1b	0.4	0.5%	0.14	0.29	0.00	0.00
Baseline 2	0.5	0.7%	0.11	0.26	0.10	0.03
Higher GB VoLL and interconnector curtailments						
Baseline 1a	0.0	0.0%	0.00	0.00	0.00	0.00
Baseline 1b	0.0	0.0%	0.00	0.00	0.00	0.00
Baseline 2	0.0	0.0%	0.00	0.00	0.00	0.00

Shock 1 does not result in any unmet demand when a higher GB VoLL is assumed with or without interconnector curtailments. Under the assumption of a uniform VoLL and no regulatory intervention, unmet demand occurs only under the extreme high-demand scenario, as shown below.

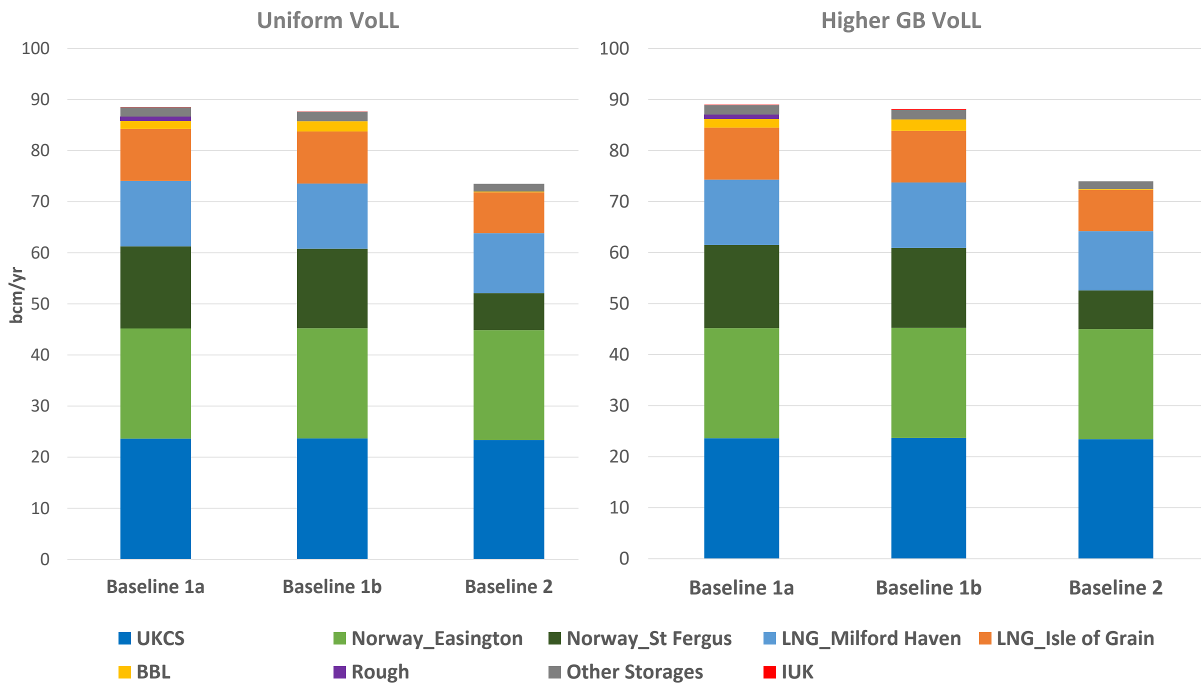
Table 5.3: Shock 1 – Uniform VoLL: Unmet demand under demand-side sensitivities (bcm/year)

Scenario	Total unmet demand	% annual demand	Power sector	I&C DM	NDM gas	Highest daily NDM (bcm/day)
BASELINE 1a (CPS - ROUGH IN)						
Low demand	0.0	0.0%	0.00	0.00	0.00	0.00

Scenario	Total unmet demand	% annual demand	Power sector	I&C DM	NDM gas	Highest daily NDM (bcm/day)
Severe demand	3.6	3.5%	0.59	2.03	0.99	0.08
BASELINE 1b (CPS - ROUGH OUT)						
Low demand	0.0	0.0%	0.00	0.00	0.00	0.00
Severe demand	6.0	5.7%	0.77	3.13	2.05	0.14
BASELINE 2 (450)						
Low demand	0.0	0.0%	0.00	0.00	0.00	0.00
Severe demand	2.5	2.9%	0.38	1.27	0.88	0.10

Impact on gas flows

Figure 5.5: Annual GB gas flows by source under Shock 1



Compared to Shocks 2 and 3, changes in annual flows to GB are modest, as summarised in Table 5.4. Flows under Shock 1 are similar to corresponding baseline flows, with small changes in Norwegian flows diverted to the continent and additional LNG coming to GB. Even under the uniform VoLL assumption unmet demand is relatively small hence the impact on total gas flows is minimal.

Table 5.4: Change in annual gas flows to GB under Shock 1 compared to baselines (bcm/year)

Supply source	Baseline 1a	Baseline 1b	Baseline 2
Higher GB VoLL			
UKCS	-0.2	-0.1	-0.3
Norway	-2	2	-4
LNG	3	-2	4
Continental ICs	-1	0	0
Uniform VoLL			
UKCS	-0.2	-0.1	-0.4
Norway	-2	2	-4
LNG	3	-2	4
Continental ICs	-1	0	0

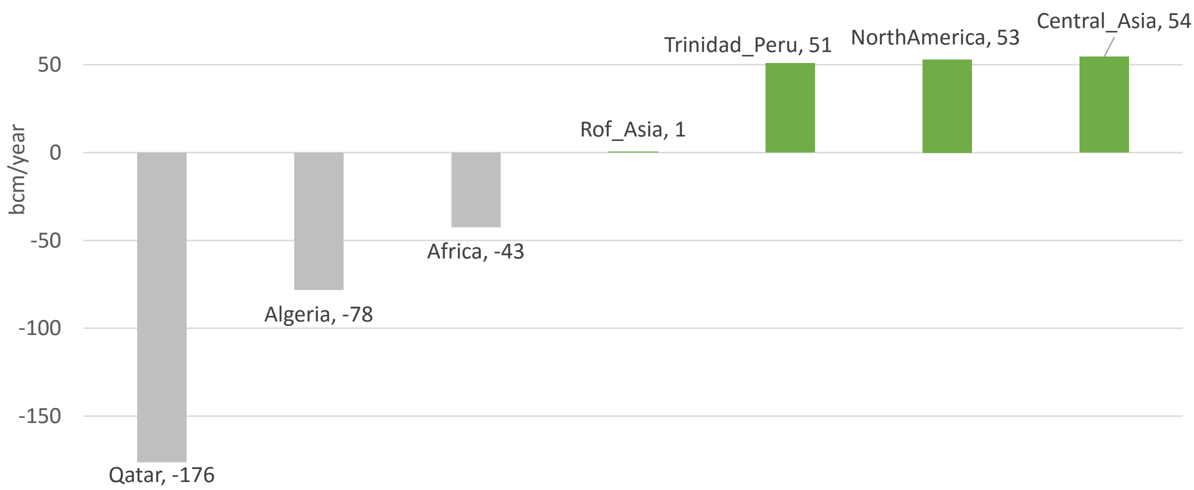
Note: A positive number represents more gas flows to GB under the disruption scenario, and vice versa.

From a global perspective, the loss of Qatari and North African production is very significant. Figure 5.6 illustrates the changes in global production by producing region. In addition to the loss of Qatari and North African gas, gas production from the rest of Africa is lower under Baselines 1a and 1b. Production increases in North and South America and in Central Asia under all three baselines.

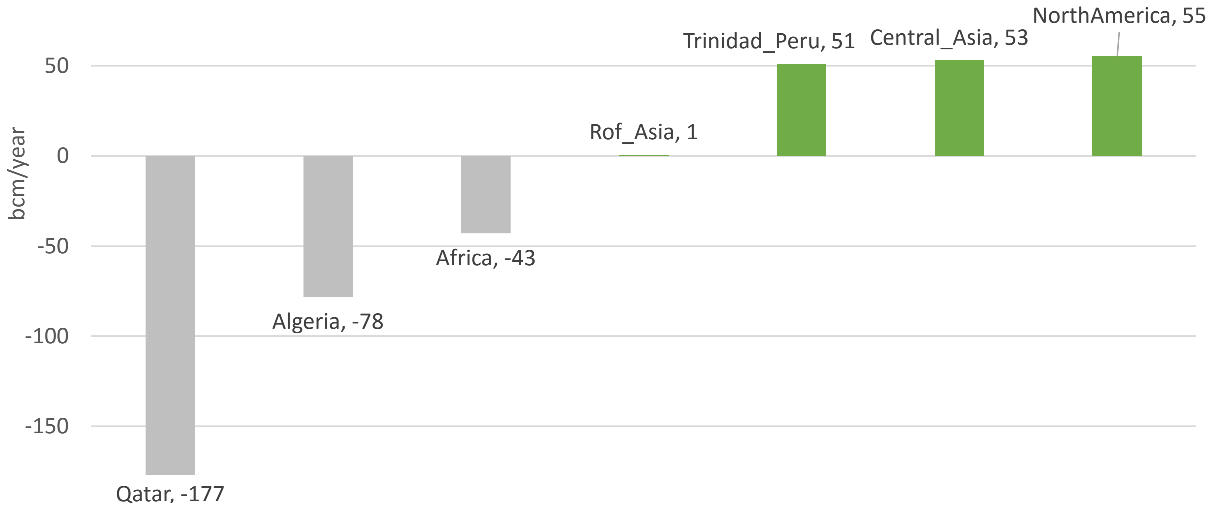
Increased production from these sources, as well as diversion of LNG supplies to Europe from non-European markets, are the reasons for demand in Europe being relatively less affected under this shock scenario. The only market in Europe significantly affected by the disruption is Italy which suffers from the loss of North African pipeline imports, coupled with constraints on LNG and pipeline import capacity. In contrast, spare LNG import capacity in the Iberian Peninsula means the Iberian market can receive sufficient additional LNG to fully mitigate the loss of North African pipeline imports.

Figure 5.6: Changes in global gas production relative to Baseline 1a

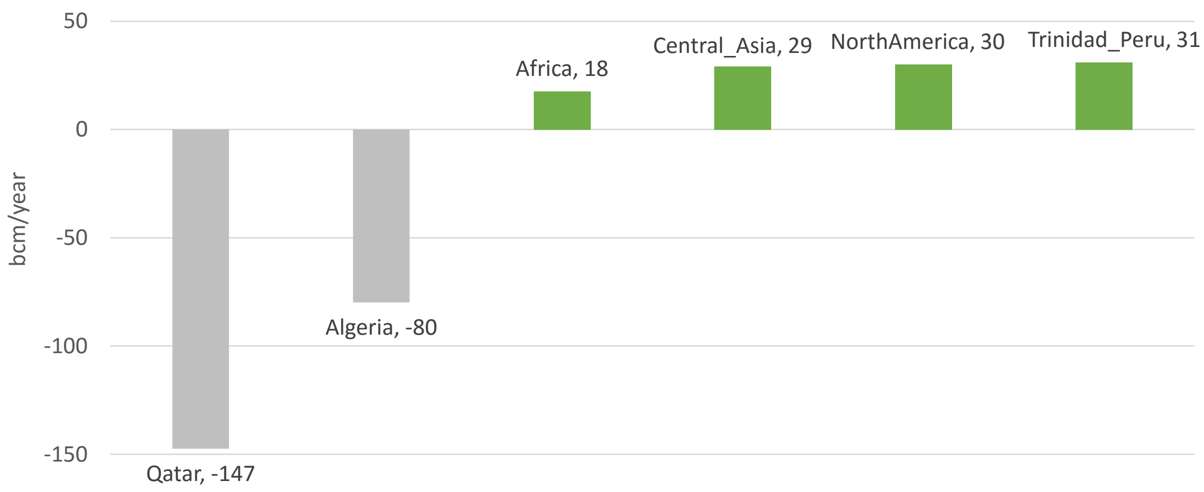
Baseline 1a



Baseline 1b



Baseline 2



5.3.2. Shock 2

Shock 2 involves a large-scale international supply disruption, including a complete loss of Russian pipeline gas supplies to Europe via all main routes: Nord Stream, Yamal and Ukraine. This represents a loss of about 260 bcm of annual global gas supplies under Baselines 1a and 1b and 195 bcm under Baseline 2. We assumed that this disruption would last for the entire 2025/26 period.

The complete disruption to Russian supplies is a big impact and low probability event. Given the assumed length of disruption (one year), this would be best characterised as an extremely rare event.

Impact on GB demand

Under the assumption of higher GB VoLL compared to the rest of Europe, there is no unmet demand, as sufficient gas supplies flow to GB with sufficient import capacity to accommodate these flows. The higher VoLL implies that the GB market is able to attract sufficient volumes of gas, such that even voluntary demand response is unnecessary.

Under the assumption that VoLL is uniform across Europe with no government intervention, and that normal demand conditions prevail, Shock 2 results in high levels of unmet energy in GB as summarised in Table 5.5 below. The shock triggers not only voluntary demand response, but also significant involuntary interruptions to the DM and NDM demand. Unmet energy occurs primarily during the winter months when overall demand is the highest, but also during the first few weeks in April (the start of then gas year) when storage is assumed to be empty. Total unmet demand as a share of total (expected) demand represents about 17%-23% of annual demand, depending on the assumed baseline scenario. As explained later in this section, this is because, under a uniform VoLL assumption, gas is diverted to other markets due to the higher costs of transporting gas to GB.

Under our third assumption about VoLL—that there are interconnector curtailments during emergencies—there is no or very little unmet NDM demand in GB under any of the baselines (with normal demand conditions). However, significant GB DM demand response is required to mitigate unmet NDM demand in NW Europe throughout the winter months, including March (when demand starts declining, but still significant, while storage stocks are depleted). Most of the demand response needed in this situation could be provided voluntarily by power sector and industrial gas consumers.

Table 5.5: Shock 2 – Unmet demand by sector (bcm/year) under normal demand

Scenario	Total unmet demand	% annual demand	Power sector	I&C DM	NDM gas	Highest daily NDM (bcm/day)
Higher GB VoLL						
Baseline 1a	0.0	0.0%	0.00	0.00	0.00	0.00
Baseline 1b	0.0	0.0%	0.00	0.00	0.00	0.00
Baseline 2	0.0	0.0%	0.00	0.00	0.00	0.00
Uniform VoLL						
Baseline 1a	15.0	17.4%	1.50	5.98	7.50	0.11
Baseline 1b	15.2	17.7%	1.52	6.05	7.68	0.11
Baseline 2	16.6	22.9%	1.70	5.73	9.18	0.10
Higher GB VoLL and interconnector curtailments						
Baseline 1a	6.6	7.7%	1.39	5.19	0.03	0.02
Baseline 1b	6.6	7.7%	1.39	5.23	0.03	0.02
Baseline 2	4.8	5.6%	1.24	3.55	0.00	0.00

Table 5.6 shows unmet demand under Shock 2 under extreme high and extreme low demand-side sensitivities, for the three sets of VoLL assumptions.

When GB was modelled with a higher VoLL than the rest of Europe, there is barely any unmet demand even under the extreme high-demand scenario. Thus, when GB consumers are willing to pay a higher price than consumers in Europe under a combined large supply- and demand-side shock, the market will ensure that sufficient gas will flow to GB.

When a uniform VoLL across Europe and no government intervention is assumed, as expected, there is less unmet demand under the low-demand scenarios, and more unmet demand under the severe high-demand scenarios than under normal demand conditions. However, there is unmet demand even under the least severe demand scenarios, resulting in disruptions to all demand tranches, including NDM customers, even though a portion of this would be covered by voluntary demand response.

The results with higher GB VoLL and interconnector curtailments show an intermediate outcome: there is some unmet demand, but NDM customers are affected only under the most extreme high-demand scenario. Most of the power sector and I&C DM unmet demand can however be accounted for through voluntary demand response.

Table 5.6: Shock 2 – Unmet demand under demand-side sensitivities (bcm/year)

	Higher GB VoLL						Uniform VoLL						Higher GB VoLL with interconnector curtailments					
Scenario	Total unmet demand	% annual demand	Power sector	I&C DM	NDM gas	Highest daily NDM	Total unmet demand	% annual demand	Power sector	I&C DM	NDM gas	Highest daily NDM	Total unmet demand	% annual demand	Power sector	I&C DM	NDM gas	Highest daily NDM
BASELINE 1a (CPS - ROUGH IN)																		
Low demand	0.0	0.0%	0.00	0.00	0.00	0.00	8.0	11.0%	1.36	4.38	2.25	0.08	2.9	4.0%	0.93	1.99	0.00	0.00
Severe demand	0.1	0.1%	0.05	0.03	0.00	0.00	27.5	26.5%	1.92	9.18	16.42	0.18	11.3	10.9%	1.63	8.59	1.11	0.03
BASELINE 1b (CPS - ROUGH OUT)																		
Low demand	0.0	0.0%	0.00	0.00	0.00	0.00	8.0	10.9%	1.34	4.36	2.25	0.08	2.9	4.0%	0.92	1.98	0.00	0.00
Severe demand	0.0	0.0%	0.00	0.00	0.00	0.00	29.0	28.0%	2.00	9.55	17.47	0.18	11.2	10.8%	1.35	8.65	1.18	0.01
BASELINE 2 (450)																		
Low demand	0.0	0.0%	0.00	0.00	0.00	0.00	9.1	12.5%	1.37	3.99	3.70	0.09	1.2	1.6%	0.43	0.72	0.00	0.00
Severe demand	0.2	0.1%	0.10	0.06	0.00	0.00	27.0	31.0%	1.96	7.98	17.07	0.17	8.5	8.2%	1.45	7.03	0.01	0.01

Impact on gas flows

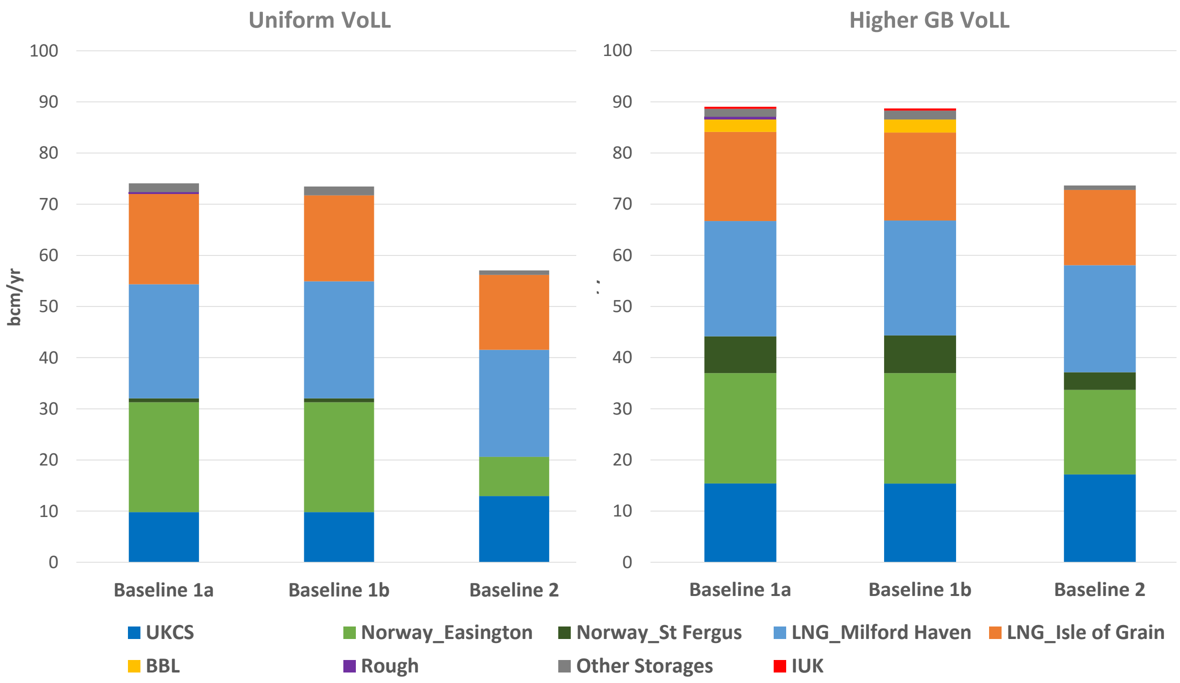
The loss of all Russian supplies for an entire year results in large shortages of gas in Europe. As implied by the results on unmet demand above, the scarce gas supplies that are available are attracted to the markets that are willing to pay the highest prices. This is determined by the price of gas on the market minus any transportation costs incurred in delivering the gas to that market. Given the high levels of demand interruptions throughout Europe, market prices often rise to the assumed VoLL level.

Figure 5.7 shows the annual gas flows to GB by entry point under Shock 2 with uniform VoLL and higher GB VoLL. Since each baseline scenario represents a different set of market conditions, total flows vary by baseline. To illustrate the impact of Shock 2 on gas flows, we show differences in flows between Shock 2 and the baseline levels (*i.e.* flows that would occur without the shock) in Table 5.7.

Under the higher GB VoLL assumption, we see additional LNG supplies being attracted to GB. Norwegian and UKCS gas is used to meet GB demand in the first instance, with additional gas being diverted to NW Europe.

Under the assumption that VoLL levels are uniformly equal in all European markets, transportation costs become a crucial factor in determining the flow of gas within Europe in the modelling. The cost of transporting gas to GB is generally higher than to other markets due to relatively higher gas transmission entry capacity tariffs in GB and the impact of the GB commodity entry charge. As a result, without government intervention to reduce gas transportation tariffs during the shock, there is a diversion of gas supplies away from the GB market to the Continent, which explains the large modelled volumes of unmet demand under the uniform VoLL assumption.

Figure 5.7: Annual GB gas flows by source under Shock 2



Under the uniform VoLL assumption, total gas shortage in GB amounts to around 15-16 bcm over the year. This is largely the result of a decrease in UKCS deliveries to GB, which instead are diverted to the Continent through IUK, as well as the loss of Norwegian supplies (primarily at St Fergus), which are also diverted to NW Europe. In contrast, there is an increase in LNG supplies to GB (and also the rest of Europe), but it does not offset the loss of pipeline gas that is diverted to other markets.

Table 5.7: Change in annual gas flows to GB under Shock 2 compared to baselines (bcm/year)

Supply source	Baseline 1a	Baseline 1b	Baseline 2
Higher GB VoLL			
UKCS	-8.4	-8.4	-6.6
Norway	-11	-7	-13
LNG	19	15	20
Continental ICs	0	1	0
Uniform VoLL			
UKCS	-14	-14	-11
Norway	-17	-13	-25
LNG	19	15	20
Continental ICs	-2	-2	0

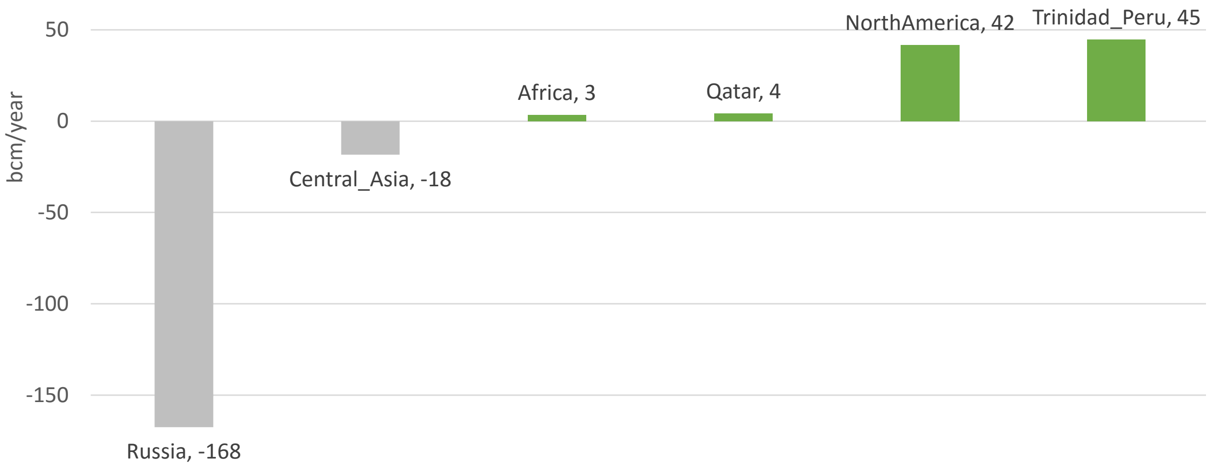
Note: A positive number represents more gas flows to GB under the disruption scenario, and vice versa.

Figure 5.8 below illustrates the response of the main gas producing regions showing the annual changes in gas production by producing region and by baseline scenario.[45] As expected, given the nature of the shock, we see a major decline in Russian gas production against all three baseline scenarios. Central Asian production also declines since some of their pipeline export routes to Europe are disrupted. Under Baselines 1a and 1b, North and South American (LNG) gas production increases the most, with relatively small increases in Africa and Qatar. Under Baseline 2, the largest production increases occur in North America and in Africa.

Any differences between the results or Baselines 1a and 1b top are caused by the presence or absence of Rough, where seasonal demand patterns change, with lower injections and thus lower demand for gas in the summer while demand in the winter is higher. This may have an impact on how other gas storage facilities are optimised and could result in changes in global flows and supply patterns as shown in the figure below.

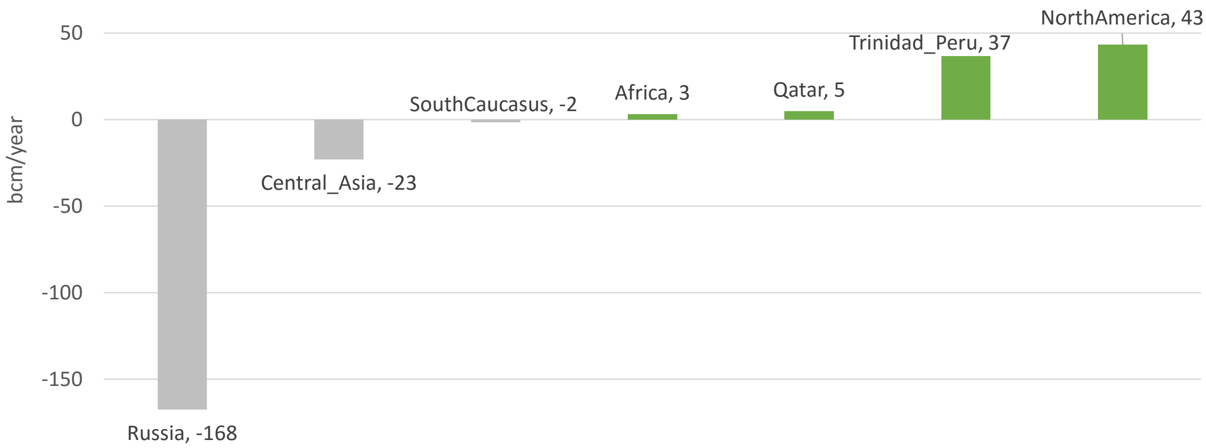
Figure 5.8: Changes in global gas production relative to the three baseline scenarios

Baseline 1a

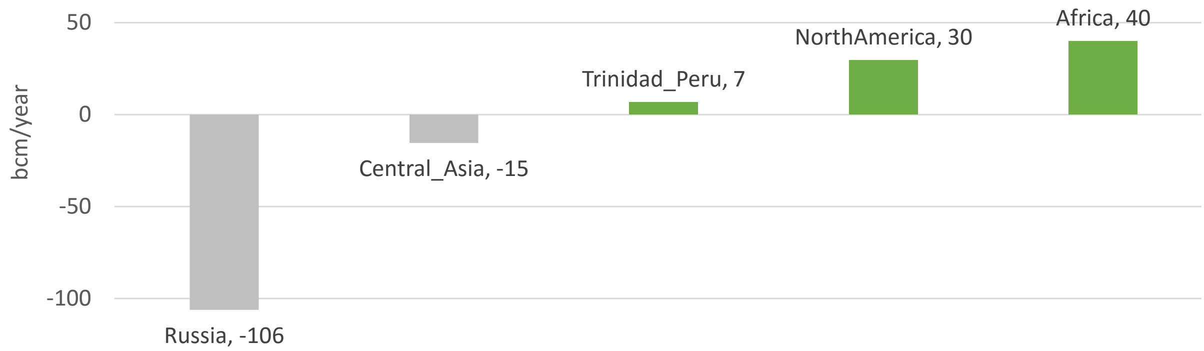


[45] These results hold under all VoLL assumptions given these assumptions determine how gas supplies are allocated in scarcity conditions but do not have an impact on overall gas supply levels.

Baseline 1b

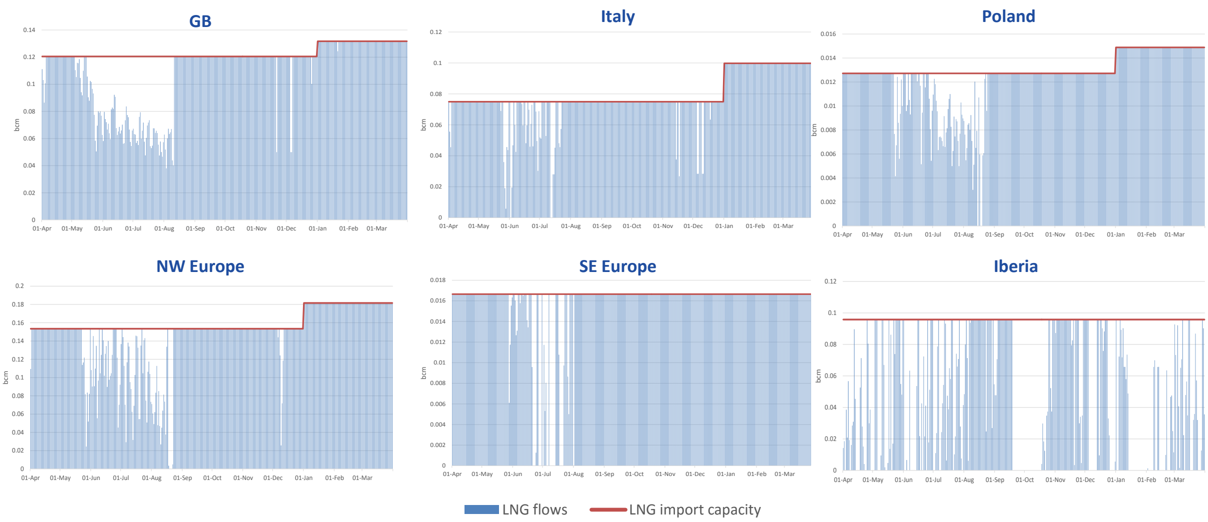


Baseline 2



Lastly, we examine in more detail LNG inflows to Europe, given that LNG makes up most of the additional supplies under the shock. Figure 5.9 shows LNG imports and import capacity by European market region under the assumption that GB has a higher VoLL than NW Europe. LNG terminals in most European markets are fully utilised apart from low-demand periods such as the summer months. The only exception is the Iberian market, where LNG import capacity is more than enough to meet local demand across the vast majority of the year.

Figure 5.9: LNG flows to European regions under Shock 2 with higher GB VoLL compared to NW Europe relative to import capacity[46]



In total, an additional 100 bcm of LNG supplies are delivered to Europe, including GB, under Shock 2 relative to Baseline 1a (a 175% increase in annual European LNG imports). This helps to mitigate the impact of the shock; however, it is not enough to replace all gas supplies lost. The same pattern is observed under all baseline scenarios.

5.3.3. Shock 3

Shock 3 is a lower-magnitude shock from a global perspective, because disruptions to Russian supplies to Europe only affect the land-based transit routes for Russian gas (*i.e.* Ukraine transit and Yamal pipelines are not operational, while Nord Stream remains available), but it is potentially a bigger shock than Shock 2 for GB because we have also assumed the additional loss of the Grain LNG import terminal in the peak winter months. Given the combination of the two shocks and the one-year duration modelled for geopolitical shocks, this shock also represents a rare, low probability event.

Impact on GB demand

As for Shock 2, the impact of Shock 3 on demand depends on the assumed GB VoLL relative to other markets. Our results imply that:

- The impact on GB demand is more severe than for NW Europe as GB's import capacity is severely reduced due to the loss of Grain LNG terminal over the high-demand winter period. NW Europe demand is affected to a lesser extent than under Shock 2 as significant Russian supplies through Nord Stream are still available.

[46] Changes in LNG import capacity are the result of new LNG import capacity coming online at the start of the year as determined endogenously by the annual model.

- There are days when import infrastructure constraints are binding, which results in higher levels of unmet NDM demand in GB compared to Shock 2. Infrastructure constraints become binding after mid-January when storage stocks are depleted and last until the beginning of March when the outage at Grain LNG terminal is assumed to end. Voluntary demand response could contribute to alleviating the situation on most days; however, there would still be an impact, including on NDM demand under some of the scenarios considered.
- As shown in Table 5.8, even under the assumption that GB has a higher VoLL than NW Europe, there is still some unmet demand under Baselines 1a and 1b from mid-January to beginning of March, although this is almost entirely confined to DM demand, and voluntary demand response could largely remove this unmet demand. This is one of the main differences from Shock 2, in which there was no unmet demand with higher GB VoLL.
- Total disruption in GB is slightly higher than under Shock 2 under the assumption of uniform VoLL values in GB and NW Europe, and without government intervention during the shock. Unmet demand is concentrated on fewer days, but the total level of unmet demand on peak winter days is higher. This is caused by the loss of Grain LNG import capacity.
- There is less total unmet demand (but slightly higher NDM unmet demand) in GB under Shock 3 with interconnector curtailments than under Shock 2, because there is less shortage of gas in Europe than under Shock 2 and thus less need for Europe to curtail interconnector flows to GB to avoid some demand disruptions. There is, however, relatively high unmet NDM demand in GB on a few days in late January and early February when curtailments mean interconnector imports are cut off (as there is unmet NDM demand in NW Europe). Nearly half of all unmet demand with interconnector curtailments is due to import infrastructure constraints.
- There is no unmet demand under Baseline 2 with higher GB VoLL because infrastructure constraints are not binding due to gas demand being lower. Additionally, with the capacity of Grain LNG import terminal being lower, the loss of Grain has a smaller impact since it represents a smaller portion of total GB supply mix than under Baselines 1a and 1b.[47]

Table 5.8: Shock 3 – Unmet demand by sector (bcm/year)

Scenario	Total unmet energy	% annual demand	Power sector	I&C DM	NDM gas	Highest daily NDM (bcm/day)
Higher GB VoLL						

[47] The capacity of the Grain LNG import terminal in 2026, endogenously determined by the model, was 22.2 bcm/year in Baselines 1a/1b versus 18.2 bcm/year in Baseline 2. This represents 16% and 14%, respectively, of total GB supply capacity.

Scenario	Total unmet energy	% annual demand	Power sector	I&C DM	NDM gas	Highest daily NDM (bcm/day)
Baseline 1a	1.4	1.6%	0.44	0.89	0.01	0.01
Baseline 1b	1.5	1.8%	0.54	0.97	0.01	0.01
Baseline 2	0.0	0.0%	0.00	0.00	0.00	0.00
Uniform VoLL						
Baseline 1a	15.4	17.9%	1.13	4.52	9.79	0.17
Baseline 1b	16.1	18.7%	1.14	4.57	10.41	0.17
Baseline 2	18.7	25.8%	1.36	4.62	12.69	0.16
Higher GB VoLL and interconnector curtailments						
Baseline 1a	2.6	3.1%	0.45	1.25	0.94	0.08
Baseline 1b	2.8	3.3%	0.56	1.33	0.94	0.08
Baseline 2	1.9	2.6%	0.66	1.20	0.04	0.01

Table 5.9 summarises unmet demand for Shock 3 under extreme high and extreme low demand-side sensitivities for the three sets of VoLL assumptions.

When a higher GB VoLL is assumed, NDM customers do not face any unmet demand under the low-demand scenario. As in Shock 2, when a uniform VoLL across Europe is assumed and there is no government intervention, there is less unmet demand under the low-demand scenarios, and more unmet demand under the severe high-demand scenarios than under normal demand conditions. There is unmet demand, including for NDM customers, even under the least severe demand scenarios. As under normal demand conditions, there is more unmet demand under extreme demand conditions in Shock 3 than in Shock 2. As before, some of the unmet demand would be met by voluntary demand responses.

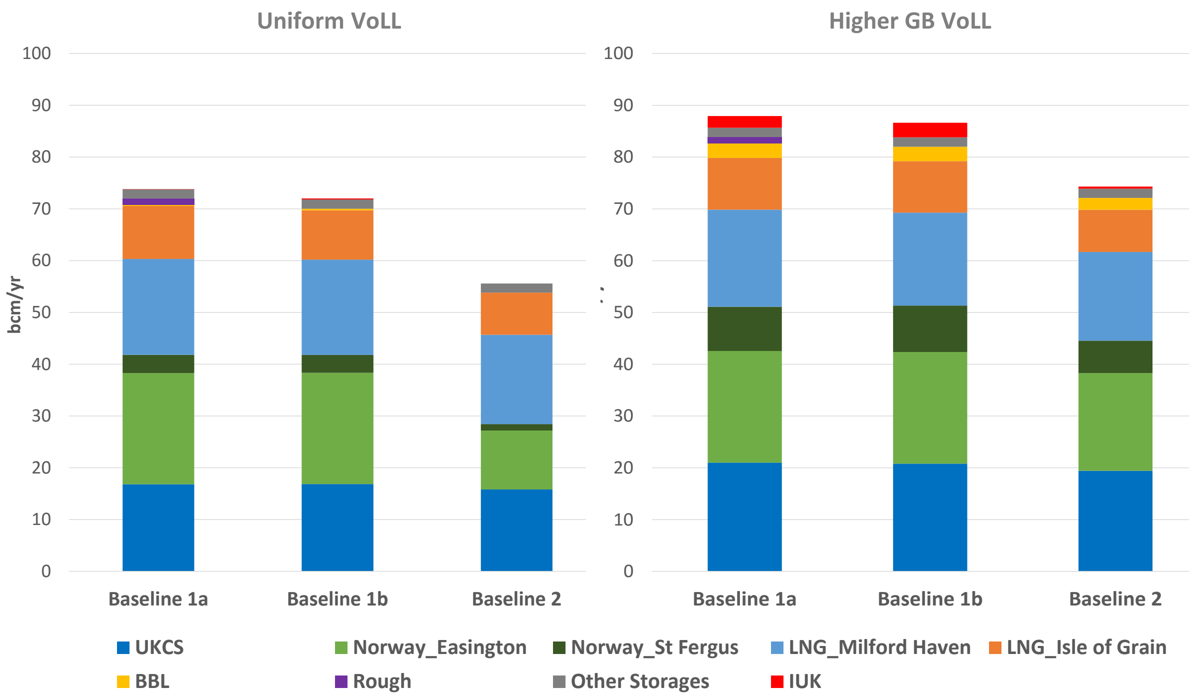
Table 5.9: Shock 3 – Unmet demand under demand-side sensitivities (bcm/year)

	Higher GB VoLL						Uniform VoLL						Higher GB VoLL with interconnector curtailments					
Scenario	Total unmet demand	% annual demand	Power sector	I&C DM	NDM gas	Highest daily NDM	Total unmet demand	% annual demand	Power sector	I&C DM	NDM gas	Highest daily NDM	Total unmet demand	% annual demand	Power sector	I&C DM	NDM gas	Highest daily NDM
BASELINE 1a (CPS - ROUGH IN)																		
Low demand	0.0	0.0%	0.00	0.00	0.00	0.00	7.6	10.4%	0.70	2.43	4.45	0.12	0.1	0.1%	0.07	0.02	0.00	0.00
Severe demand	4.3	4.2%	0.54	3.00	0.81	0.05	25.1	24.2%	1.37	6.66	17.09	0.24	9.1	8.8%	0.70	3.45	4.97	0.12
BASELINE 1b (CPS - ROUGH OUT)																		
Low demand	0.0	0.0%	0.00	0.00	0.00	0.00	7.6	10.5%	0.71	2.43	4.48	0.12	0.1	0.1%	0.07	0.02	0.00	0.00
Severe demand	5.1	4.9%	0.27	2.17	2.66	0.07	26.4	25.5%	1.39	6.92	18.10	0.24	10.1	9.8%	0.38	2.57	7.20	0.14
BASELINE 2 (450)																		
Low demand	0.0	0.0%	0.00	0.00	0.00	0.00	10.0	13.8%	0.97	2.76	6.26	0.12	0.2	0.3%	0.13	0.05	0.00	0.00
Severe demand	3.4	3.9%	0.74	2.41	0.23	0.02	26.8	30.8%	1.48	6.10	19.21	0.22	8.3	9.6%	0.99	3.85	3.50	0.08

Impact on gas flows

Annual gas flows to GB by entry point under Shock 3 are shown in Figure 5.10. The impact of Shock 3 on gas flows, measured as the difference between the baseline and Shock 3 flows, is summarised in Table 5.10.

Figure 5.10: Annual GB gas flows by source under Shock 3



Our main observations are:

- Compared to Shock 2, the amount of additional LNG imports is smaller caused by the unavailability of the Grain LNG terminal as LNG imports cannot make up the shortfall from lost European imports.
- Some Norwegian and UKCS gas is diverted to Europe but to a lesser extent than under Shock 2. The level of gas shortage in Europe is lower since the decrease in Russian gas imports is smaller.
- When Rough is unavailable, unmet GB demand is only marginally higher than when Rough is available. This is because other sources of flexibility, such as IUK (the interconnector with Belgium), fill the gap as long as the GB market is able to attract the gas through higher VoLL. Rough being unavailable has only a small impact on a small additional number of days (compared to Baseline 1a) when infrastructure constraints bind.
- Under the higher GB VoLL assumption, we see the similar levels of additional LNG supplies being attracted to GB; however Norwegian and UKCS supply diversion only occurs when the gas is not needed to meet GB demand.

- Additional supplies are also received from the Continent.

Table 5.10: Change in annual gas flows to GB under Shock 3 compared to baselines (bcm/year)

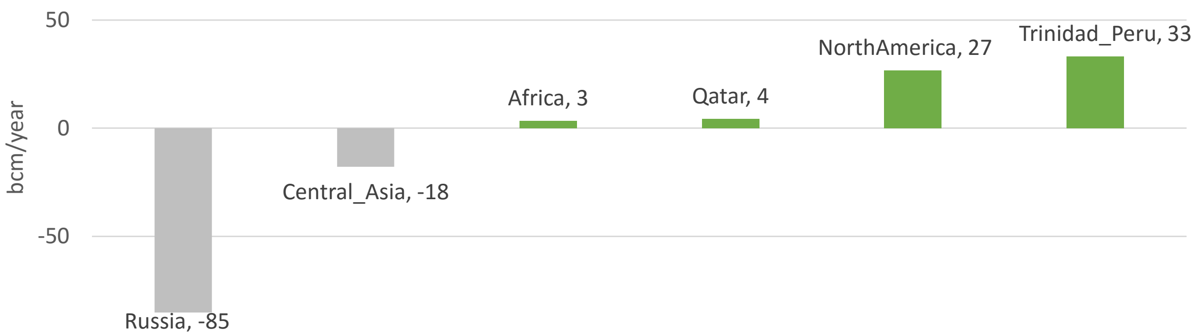
Supply source	Baseline 1a	Baseline 1b	Baseline 2
Higher GB VoLL			
UKCS	-3	-3	-4
Norway	-10	-5	-8
LNG	8	3	10
Continental ICs	3	3	2
Uniform VoLL			
UKCS	-7	-7	-8
Norway	-15	-11	-20
LNG	8	3	10
Continental ICs	-2	-2	0

Note: A positive number represents more gas flows to GB under the disruption scenario, and vice versa.

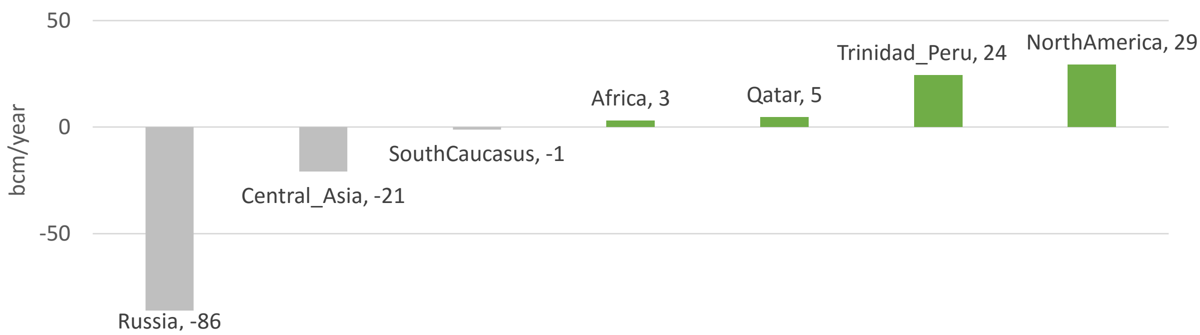
Changes in global gas production, shown in Figure 5.11 for Baseline 1a, are similar to Shock 2, except the magnitude of changes is smaller since the lost Russian production that needs to be replaced is lower.

Figure 5.11: Changes in global gas production relative to the three baselines

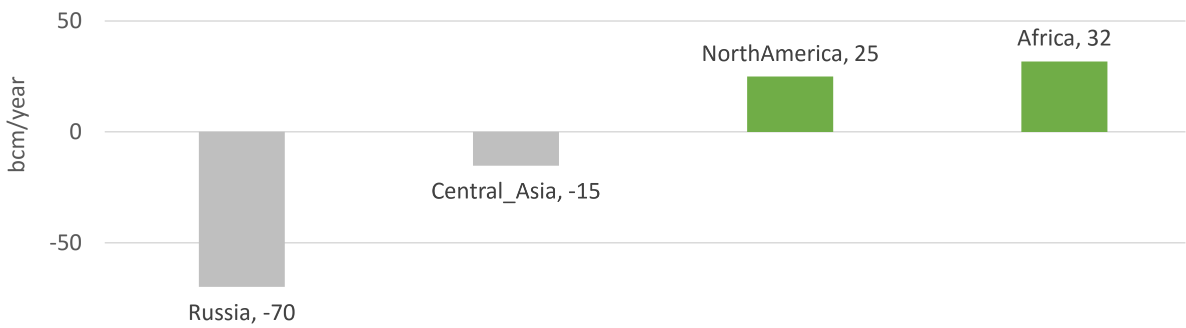
Baseline 1a



Baseline 1b



Baseline 2



As under Shock 1, additional LNG supplies delivered to Europe under the disruption scenario help to mitigate the impact of the shock but—due to infrastructure limitations—are not enough to prevent gas shortages in GB.

5.3.4. Findings

Figure 5.12 summarises the impact of the modelled shocks on unmet demand for all scenarios in this study:

- **Shock 1 does not seem to pose a significant security of supply concern for GB**. Low levels of unmet demand only occur in winter if the GB market were unable to attract any gas from other (specifically European) markets. This result holds whether or not the Rough storage facility is operating – in its absence, interconnector flows provide additional supplies.

- **Shock 2** does not result in unmet demand as long as GB customers are willing to pay more for gas than customers on the Continent and if there are no interconnector curtailments during emergencies. If GB customers are not willing to pay a higher price for scarce gas than customers in NW Europe (*i.e.* VoLLs are uniform), Shock 2 could cause significant unmet demand—**the key result is that alternative supplies are available to meet GB demand, but it comes at a price**. Unmet demand occurs primarily during the winter months but also during the first few weeks in April when storage is empty.
- In **Shock 3** the UK is more exposed despite total global volumes of gas that are lost being lower. Our results suggest that the GB system may be vulnerable to the complete failure of a large piece of infrastructure during the winter months (especially in January and February), where this is coincident with a disruption in global supplies of gas and under market conditions represented by Baselines 1a and 1b. **In these circumstances some unmet demand occurs even if GB consumers are willing to pay a higher price for gas, because the projected import infrastructure capacity is insufficient to allow gas imports to serve all demand if there is a failure of a large infrastructure asset.** Note that this is based on our projection that Grain LNG import capacity will be expanded, while import capacity via the interconnectors will be reduced.[48]

All findings are based on a set of modelling assumptions. Therefore, all results should be interpreted in the context of these assumptions. The modelling does not account for short-term demand responses due to higher prices, but we have estimated the impact on different categories of consumers, such as power sector gas demand and industrial daily-metered gas demand, which can provide demand response, and non-daily metered gas demand (mainly domestic consumers), which would not be expected to respond to short-term price movements. In practice, a portion of the unmet demand estimated in our results would be mitigated through voluntary demand response rather than involuntary interruption. Also, the modelling assumes that market participants do not anticipate the shock and have imperfect foresight about the duration of the shock. See ANNEX C and Sections 4 and 5 of this report for further details on the modelling assumptions.

We can draw the following conclusions from these results:

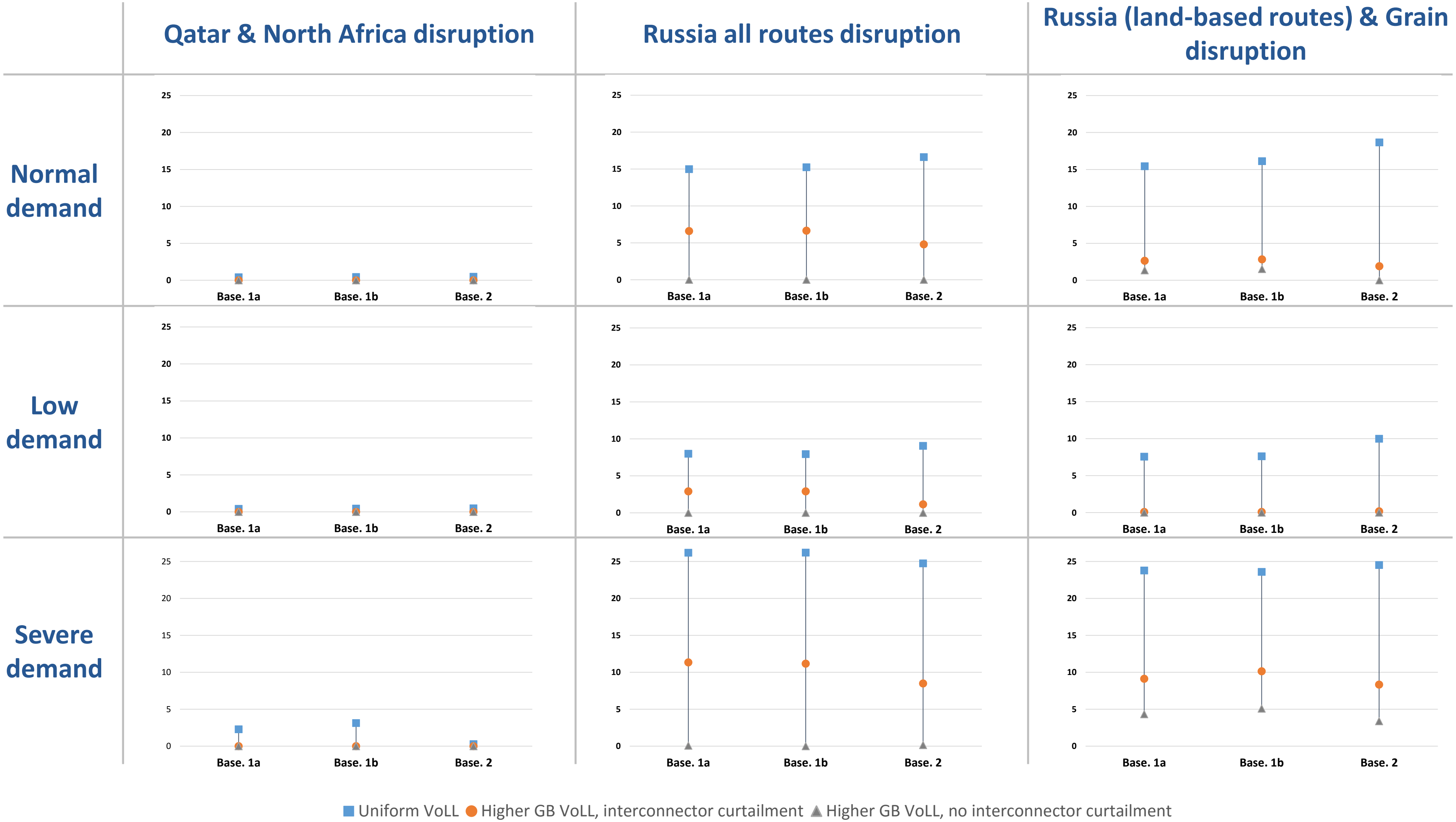
- The modelling shows that even **under an extreme shock to global LNG markets, GB demand could be met if GB consumers are willing to pay for it**.

[48] Given the results are based on projected rather than current infrastructure capacity, this should not be interpreted as GB currently failing the N-1 security of supply test. What this implies is that higher concentration of capacity resulting from reduction in import capacity along one route (in this case the continental interconnectors) coupled with expansion of import capacity along other existing routes (in this Grain LNG) may leave GB vulnerable to infrastructure failures under certain scenarios.

- The modelling shows that even **under an extreme shock to European supplies** (i.e. no Russian supplies for a 12-month period), **GB demand will be met if GB consumers are willing to pay for it.**
- The modelling shows that **as long as GB consumers are willing to pay sufficiently for scarce gas supplies, only in the most challenging (and unlikely) scenario**—combined long disruption to Russian supplies alongside a GB LNG infrastructure outage in winter—**there would be some unmet demand**.

The primary insight is the importance of price: gas tends to flow to those who are willing to pay for it. However, the availability of adequate import capacity and key infrastructure may also be critical under some circumstances.

Figure 5.12: Summary of stress test results – total unmet demand (bcm/year)



Overall, our analysis has highlighted three key dimensions of GB's vulnerability to future security of supply problems (bearing in mind the shocks modelled are all very low probability and very high impact):

- Origin of the risk (*i.e.* the nature of the shock, where the disrupted supplies come from, etc.);
- Availability of gas versus the price consumers are willing to pay for it;
- Availability of adequate import infrastructure capacity to meet GB demand.

At a high level, our findings suggest that, of these three dimensions, willingness-to-pay for gas will be the most important factor in the foreseeable future: as long as GB consumers are willing to pay more for scarce gas than their European counterparts (*i.e.* GB VoLL is higher), the GB system will be robust to a range of severe shocks.

Nevertheless, availability of adequate import capacity may also be critical under some circumstances. Some key infrastructure assets face not only the risk of a physical outage, but also a risk associated with their economic viability. Should they be divested purely for economic reasons this could have security of supply implications.

Regarding the origin of the risk, Russia is the most important source of gas for continental Europe in 2025 under all baseline conditions considered. Whilst GB receives little Russian gas directly when supplies are disrupted, this increases worldwide LNG demand and demand for Norwegian gas with possible diversions of UK supplies if European prices are higher. Although, previous studies suggested that LNG may be a source of risk, we find that the loss of LNG from key exporting countries are not a risk to GB security of supply.

We also note the role imperfect foresight played in our analysis. Had we implemented our modelling without assuming imperfect foresight, the estimated impact of the shocks would have been smaller because storage operation and gas production would have been re-optimised in response to the shock.[49] This, however, would not have been realistic for the shocks we modelled, which we assumed would be unexpected.

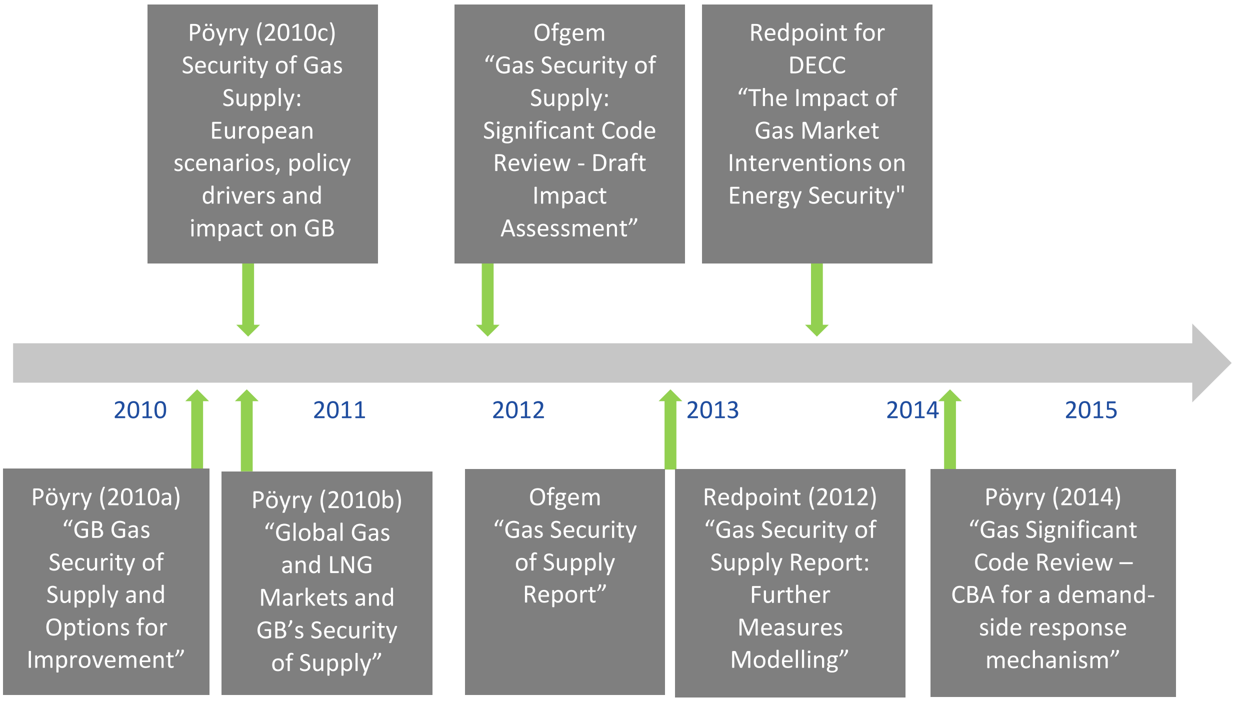
Lastly, the shocks modelled are much more severe (and less likely) than those that have previously been modelled both as a result of their duration as well as the magnitude of disruption. These types of shock are by definition extreme, very low probability and were specifically designed to test the limits of the GB gas system.

[49] Note that imperfect foresight affects storage operation and gas production globally not only in GB, particularly given the global nature of the shocks modelled.

ANNEX A Previous studies on GB's gas security of supply

Several forward-looking studies on GB's gas security of supply have been conducted in recent years, shown in the timeline in Figure A.1. In this section, we summarise the most relevant of these studies with a focus on the main results and methodological differences.

Figure A.1: Recent gas security of supply reports for DECC, Ofgem and the Gas Forum



Pöyry (2010a) analysed the impact of a range of supply shocks between 2010 and 2025, and concluded that the GB gas system was sufficiently diversified and was able to withstand most foreseeable security of supply problems. The study concluded that much of GB's future supply would come from the global LNG market which, given its diversity, makes each individual market more resilient to any local problems while also driving a global convergence of gas prices. Similar to our study, they assumed that gas moves around globally in response to commercial prices signals subject only to physical infrastructure constraints. Pöyry (2010a) concluded that GB would have access to sufficient gas storage, including European facilities, and indirectly to US storage. This indirect access to US storage is provided by greater LNG interconnections, meaning that the market for seasonal flexibility services becomes a global market via LNG trade. Supplies to GB in the winter could be met with direct LNG deliveries and other supplies from the Continent due to lower requirements for imports into the USA market because of high storage capacity there. Due to greater LNG interconnections, the global gas market is able to use all storage capacity more optimally.

Furthermore, Pöyry (2010b) concluded that GB's gas supply was likely to be robust to even highly extreme combinations of possible shocks. The minor amount of demand-side response that would be needed to mitigate the disruption could be provided by fuel switching by gas-fired power stations and some industrial consumers switching from gas to distillate. The study in Pöyry (2010b) relied on the Perseus gas market model. A notable difference to Pöyry (2010a) was the implementation of imperfect foresight regarding the level of future demand as well as some correlation in regional gas demands, but only for a limited set of countries.[50]. The model assumed that LNG cargoes are dispatched with only a 'reasonable' estimate of future demand, and thus LNG may not be able to respond to a short cold spell or unplanned infrastructure outages.

Similar to the earlier two studies, Pöyry (2010c) found that the GB gas system was sufficiently resilient to security of supply shocks posed by disruptions to interconnections and to main pipeline gas supplies to Europe. However, it also found that there would be more pressure on gas security of supply if demand rose significantly in GB or across the rest of Europe, requiring more pipeline and LNG import capacity. Pöyry (2010c) appears to have modelled the European system at a greater level of detail than the previous studies, and assumed some correlation in weather-driven demand between GB and NW Europe.

Redpoint (2012a) assessed the potential risks to medium- and long-term gas security of supply in GB and appraised potential further measures to enhance security of supply in the GB gas market. The methodology employed by Redpoint (2012a) centres on stochastic modelling of the GB gas market, using distributions of outcomes that could cause, or contribute to, a gas emergency and curtailment of firm load. Due to the nature of questions being asked, the stochastic model developed by Redpoint (2012a) was focused on the GB market and flows between different markets were not endogenously modelled. Much of the analysis relied in distributions derived from historical data.

The starting point of our modelling framework is to use best practices implemented by these studies as well as relevant studies from academia (see table at end of this Annex) and, where possible, improvements in the methodology were undertaken to ensure a robust range of answers to the research questions posed by this study. First, we aimed to fully represent all producing and consuming regions and markets in our global market models, including in a stochastic version of our model. For example, China, India, and Central and South America are represented as distinct regions in all our models while they were aggregated into larger regions in Pöyry (2010a).[51] We also represented imperfect foresight in our models and in particular limited foresight by market participants of security of supply events, which by definition are low probability, high impact. The imperfect foresight assumption means that the models do not 'know' exactly the timing and impact of the tested shock scenarios, which can counter the 'overoptimisation' and underestimate of the potential impact of a security of supply events that a perfect foresight assumption can generate.

Further, our annual capacity model derives infrastructure investment and divestment decisions endogenously, mimicking the least-cost investment decisions of market participants

[50] Correlation was assumed between GB daily gas demand with those of Ireland, France, Belgium, Luxembourg, Netherlands, Germany and Denmark. All other markets were modelled using seasonal-normal demands.
[51] We presume that GB was modelled as a separate zone.

given assumptions on investment costs, the potential mismatch between supply and demand and behavioural assumptions of market participants, such as pricing power of large producers.[52]

On the demand side modelling, we have explicitly taken into account possible correlation of gas demands between GB and Europe, as these possible correlations have been proven to be an important feature of daily supply and demand balancing in Europe and GB.

A.1. Summary of literature review on risks to security of supply

Risk	Source	Length	Magnitude
Geopolitical risks			
Disruption of Ukraine transit pipelines	Egging et al. (2008)	One year	All transit capacity (171bcm/year)
Disruption of Algerian supplies	Egging et al. (2008)	One year	All Algerian production capacity
Russian gas (Ukraine disruption + other transit pipelines)	EWI (2010)	4 weeks	5.3 to 10bcm depending on scenario
Algerian supplies (LNG + pipeline)	EWI (2010)	4 weeks	320-343mcm/day
Ukraine disruption	Richter & Holz, 2015	One year (2015)	All transit capacity
Gazprom disruption	Richter & Holz, 2015	One year (2015) 25 years (2015-2040)	All Russian exports to Europe and Gazprom-owned storage facilities in Europe
Strait of Hormuz blockage	Growitsch et al.	6 months (from Nov 2012)	
Ukraine disruption	Growitsch et al.	6 months	All transit capacity

[52] Taking into account pricing power of large producers would yield a more realistic outcome for long-term gas trade and investments projections see e.g., Chyong and Hobbs (2014) (Section 3) for a numerical test of different market structures and their 'fitness' with the historical gas market data.

Risk	Source	Length	Magnitude
Geopolitical risks			
Disruption of Russian gas to Ukraine	Martinez et al. (2015)	2 weeks 3 months 6 months 1 year	All Russian supplies to Ukraine
Reduction in Dutch production (legal restrictions due to earthquake risks)	Holz et al. 2015.	Long-term	6 bcm in 2015 and
Disruption of Russian gas	Holz et al. 2015.	Long-term	All Gazprom majority-owned pipelines + reduced storage capacity (Gazprom-owned)
Disruption to Ukraine gas transit + all Russian gas to Europe	European Commission Gas 'Stress Test' (2014)	1 month	All Russian gas to Europe
		6 months (Sep - Feb)	
Ukraine transit gas	Pöyry (2010a)	One year	All transit capacity (2010 & 2015)
Loss of Qatar LNG liquefaction capacity	Pöyry (2010a)	One year	All Qatar LNG capacity (2020, 2025)
Ukraine transit disruption	Chyong and Hobbs (2014)	3 weeks	All transit capacity
Ukraine transit disruption	Chyong and Hobbs (2014)	6 weeks	All transit capacity

Risk	Source	Length	Magnitude
Infrastructure risks			
Loss of Rough storage capacity	Pöyry (2010a)	One year	No Rough capacity available for each year modelled (2010, 2015, 2020, 2025)
Loss of Qatar LNG liquefaction capacity	Pöyry (2010a)	One year	All Qatar LNG capacity (2020, 2025)

Bacton terminal loss	Pöyry (2010a)	One year	Impact on UKCS and European imports (2010)
Loss of Sleipner platform (Norwegian gas)	Pöyry (2010a)	One year	Impact on Norwegian imports to GB and rest of Europe (2015)
Loss of Milford Haven LNG terminals	Pöyry (2010a)	One year	All Milford Haven capacity (2020, 2025)

Risk	Source	Length	Magnitude
Demand-side risks			
Cold weather	Martinez et al. (2015)	1 month (Feb)	Cold weather modelled in combination with 2 weeks and 6 months of supply disruption scenarios above
Cold weather	European Commission Gas 'Stress Test' (2014)	2 weeks (Feb)	In combination with Russian gas disruption as above

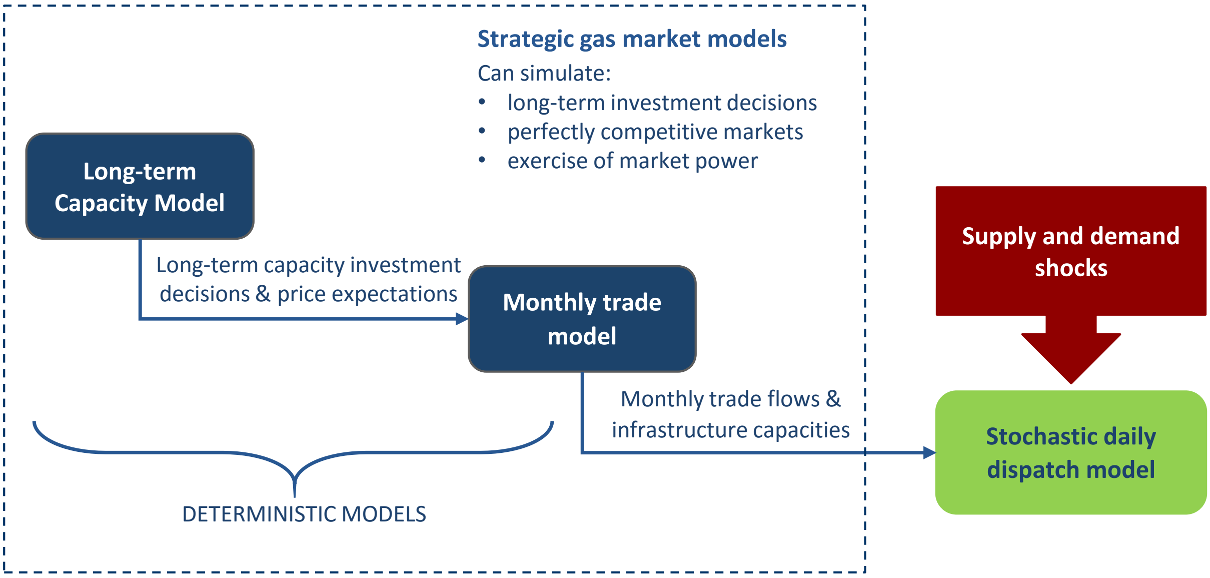
ANNEX B DESCRIPTION OF THE GAS MARKET MODEL

This note describes the set of gas market models used in the gas security of supply analysis conducted for BEIS by CEPA and Dr. Chi Kong Chyong at the University of Cambridge. A detailed and public version of the modelling framework used for the annual capacity has been published in an academic peer-reviewed journal.[53]

The suite of models includes a strategic global gas market model covering all major gas consuming and producing regions. The model can simulate pricing power of suppliers which can be important when considering gas security of supply shocks. In addition, a daily global dispatch model optimises flows by minimising system costs under the assumption of perfect competition. This assumption is similar to other commercial models such as those used by Pöyry, Nexant or Wood Mackenzie.

The strategic global gas market model includes an annual long-term capacity model and a monthly trade model. The annual long-term capacity model was run for the whole 2015-2035 period using a set of long-term energy scenario inputs (*e.g.* IEA's World Energy Outlook, National Grid's Future Energy Scenarios, etc.). Next, the monthly trade model was run using outputs from the annual model, such as total production and transport capacities, realised demand and cleared annual prices, to derive monthly results such as endogenous storage fill and withdrawal. Realised monthly flows are then fed into our daily stochastic dispatch model to simulate different security of supply shocks. Note that the daily stochastic dispatch model explicitly accounts for imperfect foresight. This process is illustrated in Figure B.1: below.

Figure B.1:13 Analytical approach and information flows between models



[53] Chyong, C.K. and B.F. Hobbs (2014)

B.1. General specification of the strategic gas market model

B.1.1. Imperfect foresight

An important feature of our model is the comprehensive treatment of imperfect foresight. The model simulates the decisions of agents across the full gas market value chain, including gas producers, gas infrastructure assets and final consumers. Imperfect foresight was incorporated into these decisions through the sequential use of the three models. This closely replicates gas market realities, where transactions are undertaken in advance based on future expectations, but re-optimised in the short term in light of new information received.

Firstly, the *Annual long-term capacity* model determines long-term capacity investment decisions, such as those related to gas production, pipeline and LNG capacity. After this, the *Monthly trade model* makes decisions such as on investment in storage capacities and optimal storage operations. Using these models sequentially, we reflect uncertainties between investment in energy infrastructure and operational decisions. In the *Monthly trade model*, operational decisions are made after and taking into account capacity investment decisions from the *Long-term capacity model*.

The *Daily stochastic model* explicitly accounts for imperfect foresight by using a rolling-horizon optimisation framework, similar to the approach to account for imperfect foresight that was used by Pöyry (the 'Prometheus' model) to study the GB security of supply for DECC in 2010.

B.1.2. Endogenous investment and divestment decisions

- The model makes capacity expansion and divestment decisions for gas infrastructure by computing the net present value (NPV) of the assets for the entire planning horizon, up to 2035, given demand and supply conditions ensuring that it chooses the level of capacity that maximises the NPV. For example, if demand for capacity is low due to either high asset costs or low GB demand for gas, then the model will choose not to expand or not to maintain existing capacity. Instead, it will decommission a portion of the asset to reduce costs associated with that particular level of capacity. In contrast, should demand for capacity be high enough to justify either capacity expansion or maintenance, then the model will do so, as long as it maximises overall NPV to 2035;

B.1.3. Imperfect competition

A notable feature of the strategic gas market model is its *ability to endogenously derive outcomes of perfectly competitive* gas markets, but also *imperfect (oligopolistic) competition* in the gas supply chain. In particular, for the latter, the model can take into consideration the fact that large producers can exercise their market power by adjusting their investment, production and supply levels in order to raise wholesale prices and hence marginal revenue. For this study, imperfect competition has been assumed for Russia and Qatar. All other producers have been assumed to behave competitively.

We model the full gas market value chain, including the following market players with corresponding competitive behaviour:

1. **Gas producers and large importers/traders:** can be modelled as behaving imperfectly (exercising market power) or perfectly competitive (marginal cost pricing)
2. **Pipeline transmission operator**: price pipeline transport services efficiently i.e. with no market power; large transit corridors can be simulated as having pricing power
3. **LNG terminal operator**: price liquefaction and regasification services efficiently i.e. with no market power
4. **LNG shipping**: marginal cost based pricing or can be simulated as having pricing power
5. **Gas storage operator**: storage services are priced efficiently, *i.e.* reflective of marginal costs
6. **Final markets** are represented by inverse demand curve where the clearance price depends on total supplies to that market

The main outputs from this set of models are:

- Equilibrium prices and final gas consumption for all markets considered in the model[54];
- Equilibrium prices for gas transmission services and LNG services (liquefaction, shipping, regasification);
- Quantity of gas traded between contracted parties;
- Production quantities at each production field or groups of fields (country- or region-level aggregation);
- Storage withdrawals/injections;
- Gas flows for pipeline and LNG shipping;
- Investment in production capacity;
- Investment in pipeline and LNG capacity;
- Investment in storage capacity (withdrawal, injection, and working volume capacities).

The current model version has been calibrated to simulate global gas trade to 2040 for all major importing, exporting and producing regions in the world. It has been used for energy policy analyses (cost-benefit analyses) and long-term global gas market fundamentals.

B.2. Data sources for the model

The model inputs for future annual demand levels in various regions/countries, existing and planned transmission network and storage capacity, and production capacity are informed by

[54] The notion of *'equilibrium'* prices means that prices are determined at the intersection of demand with supply.

publicly available information. The sources for these main assumptions have been set out in the main body and Annexes to this report.

Other data sources for the model are based on non-public and confidential information which we cannot disclose. These data sources include:

1. Database on long-term gas supply contracts;
2. Production supply curves;
3. Long-term and short-term marginal cost of infrastructure (pipelines and LNG facilities).

ANNEX C MODELLING ASSUMPTIONS

The key modelling inputs and assumptions include:

- *Gas demand* for the regions/countries in the model and associated price elasticity of demand in the annual and monthly models;
- *Production capacities*—projected production capacities place a cap on potential production capacity expansion, determined endogenously by the annual capacity model – where production capacity investment is not economical, the endogenously determined production capacity will be lower than the specified cap;
- *Existing and planned infrastructure capacities*—the model will determine additional investment in infrastructure if it is economic to do so;
- *Other assumptions*, such as fuel (*e.g.* oil) prices, Value of Lost Load (VoLL), as well as market participant behaviour (*e.g.* oligopolistic or competitive).

In addition to the strengths of the modelling framework outlined in ANNEX B, the following data limitations should be noted:

- While price elasticity of demand is explicitly modelled in our annual and monthly models, daily demand was assumed to be non-responsive to prices due to lack of sufficient data to be able to explicitly represent such price response within the model. Instead, demand curves in the daily model were assumed to be non-price-responsive (inelastic) up to the price level set at the VoLL estimates, and then price-responsive (perfectly elastic) from that point onwards (i.e. demand drops to zero above VoLL). In practice, we would expect a more granular demand response as individual consumers would have different levels of willingness-to-pay for gas supplies before involuntary interruptions are imminent.
- Total unmet demand was quantified using our daily model. To determine the impact on Daily Metered (DM) and Non-Daily Metered (NDM) customers, we conducted an off-model assessment. Our model estimated unmet demand as any portion of expected gas demand not met due to a shortage of gas supplies. To align our findings with previous security of supply studies, which did not consider voluntary curtailments as unmet demand, we adjusted the initial results from our model ex-post. This allowed us to identify the impact of unmet energy on different tranches of customers, and assumes an order of interruptions, starting with voluntary curtailments before NDM demand is affected.
- The modelling framework assumes that gas flows will be fully determined by market-based mechanisms. It does not capture the impact of potential non-market procedures (*e.g.* gas emergency procedures) during scarcity periods, although we do consider a form of such mechanism using interconnector curtailment assumptions in some of our modelling runs.

C.1. Cross-border and LNG capacities

Data on existing cross-border and LNG import capacities in Europe have been sourced from ENTSOG's 2015 transmission capacity map.[55] We have assumed these capacities stay online until 2035 subject to gradual linear (technical) depreciation.

New cross-border and LNG import capacities in EU that have achieved final investment decision status—as outlined in ENTSOG's 2015 Ten-Year Network Development Plan (TYNDP) report[56]—have been added in the model, with the start time and capacities as reported for these projects.

For the cross-border points in Europe, we assumed that existing transportation costs as reported in ACER's latest (2015) Market Monitoring Report[57]. Entry/exit capacity and commodity charges in GB were taken from National Grid's NTS Transportation Charging Statement.[58]

For LNG export terminal capacity, we used information on existing capacity plus projects that have achieved final investment decision collected from various sources: the International Gas Union (IGU) World LNG report (2015)[59]; the TYNDP report and, where applicable, information from company websites (especially for US and Australian LNG export projects).

C.2. Gas storage

Data for existing storage capacities was sourced from IEA's 2015 Natural Gas Information report.[60] We assumed that these capacities would stay online until 2035 subject to gradual linear (technical) depreciation.

New storage capacities in EU which have achieved final investment decision status—as outlined in the TYNDP report—were added in the model with the start time and capacities as reported for these projects.

All storage capacity was aggregated at a country/regional level, with the exception of Rough, which was represented separately.

C.3. LNG response times

For the shock scenarios modelled, we implemented a four-day response lag for LNG flows. This means that no additional LNG supplies arrive in the UK in the first four days following a shock even if market price differentials would make such flows profitable. The four-day lag

[55] http://www.entsog.eu/maps/transmission-capacity-map/2015
[56] http://www.entsog.eu/publications/tyndp/2015#ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2015
[57] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015.pdf
[58] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Gas-transmission/Charging-Statements/
[59] http://www.igu.org/sites/default/files/node-page-field_file/IGU-World%20LNG%20Report-2015%20Edition.pdf
[60] http://www.oecd-ilibrary.org/energy/natural-gas-information-2015_nat_gas-2015-en

was estimated by consultants from Poten and Partners in a study commissioned by Ofgem, which was shared with us for the purposes of this modelling. This estimate reflects higher flexibility in the LNG market in the future with the lag declining from 7-day lag estimated for the present market.

This assumed delay in delivery reflects all operational and logistic limitations associated with diverting LNG cargos to new destinations. Following this initial period, the model adjusted the delivery of spot cargos to take account of price differentials.

C.4. Fossil fuel prices

Baseline fossil fuel prices (*e.g.* oil prices) were been taken from IEA's WEO 2015 report[61]—Current Policies Scenario or 450 Scenario—consistent with the baseline scenarios modelled.

C.5. Daily Metered and Non-Daily Metered demand profiles

Our modelling estimated the gas security of supply impacts on different demand tranches namely:

1. Gas-fired generators with back-up distillate generation capacity;
2. DM industrial & commercial consumers;
3. NDM gas consumers.

We used the 10 mcm/day distillate back-up capacity for gas fired generators, estimated by Pöyry (2014). We assumed that only generators with distillate back-up capacity are able to provide consistent demand response, and the rest of power sector gas demand was not included in DM demand response.

Daily gas demand levels for DM industrial and commercial and NDM customers were estimated using historical demand profiles.[62] The demand data published by National Grid includes a breakdown of total gas demand for each day into distribution level offtakes, transmission-connected industrial consumers and transmission-connected power station gas demand, as well as a breakdown of distribution level demand into DM and NDM demand for each day of the year.

The estimated DM demand levels include the daily metered portion of distribution level demand plus industrial gas demand connected to the transmission level.

C.6. European daily demand profiles

To derive daily demand profiles for all regions in Europe for all demand side scenarios (P5, P50 and P95), we estimated historic correlations between daily gas demand in GB and in other

[61] http://www.worldenergyoutlook.org/weo2015/

[62] Available from National Grid

countries in Europe for which data was available. Data on daily gas demand for EU countries was obtained from the ENTSOG Transparency Platform[63] or from national TSO websites.

We then used the GB P5, P50 and P95 daily gas demand profiles, derived as explained in Section 5.2.2, and the estimated correlations with gas demand in other countries in Europe, to derive a set of seasonal normal, warm, and cold weather profiles for each region in Europe.

C.7. Demand response

Our daily model does not explicitly model demand response to market prices. However, we did estimate demand response by analysing the results for unmet demand within different demand tranches. For this analysis we assumed that the different demand tranches would respond to prices, according to their VoLL[64]:

1. Gas-fired generators with back-up distillate generation capacity[65] is the first tranche to lose gas;
2. DM industrial & commercial consumers are the next tranches to lose gas;
3. NDM gas consumers is the final tranche to lose gas.

We assumed that power generators with distillate back-up capacity have a much greater ability to respond to gas prices than other power generators[66]. Therefore, for these other generators we assume that demand would respond at very high gas prices (above the NDM gas VoLL) because of the high electricity market VoLL and penalties under capacity contracts.

[63] https://transparency.entsog.eu/

[64] VoLL represents the value that gas consumers place on using the gas, hence it should be the case that these consumers would be willing to pay for the gas up to the point where the gas price equals their VoLL.

[65] We used the Pöyry (2014) estimate of 10 mcm/day available distillate back-up capacity.

[66] The Pöyry (2014) study found that few generators, other than those with distillate back up, would be able to provide gas market demand response without causing an interruption to electricity supplies.

ANNEX D QUALITATIVE SCALE USED FOR SCORING RISKS

As mentioned in Section 2.1, the methodology for assessing the likelihood and potential impact of each risk relied on gathering stakeholder views during the two workshops organised by BEIS. Supply-side risks to security of supply, especially those with the largest impact, tend to be rare events for which sufficient historical information is not available and are thus more difficult to quantify. Therefore stakeholders were asked to score the likelihood and impact of each risk using a qualitative scale.

This Annex presents the qualitative scales used to score the likelihood and impact of the risks. The scales are consistent with the approach recommended by the European Commission research paper on best practices for conducting gas security of supply assessments.[67] The same scales were used to score both geopolitical risks and infrastructure risks.

The qualitative scale used to assess the likelihood of the risks is shown in Table D.11Table D.11: Qualitative scale for likelihood of the identified security of supply risks below.

Table D.11: Qualitative scale for likelihood of the identified security of supply risks

Likelihood score	Likelihood of occurrence before 2035	Description
1	Rare	One-off ('black swan') event that is very unlikely to occur in the next 20 years; < 1% chance
2	Unlikely	A one-off or potentially recurring but uncommon event that is not likely to happen in the next 20 years; < 30% chance
3	Possible	Typically a recurring event that may or may not happen with equal probability; 30%-70% chance
4	Probable	A recurring and/or foreseeable event with a 70%-99% chance
5	Almost certain	A common or foreseeable event with > 99% chance

In addition to estimating the probability of each identified risk, we also assessed the likely gas security of supply impacts. In order to assess the security of supply implications of the identified supply-side, we applied the qualitative impact scale shown in Table D.12.

Table D.12: Qualitative scale for impact of the identified security of supply risks

Impact score	Impact on gas security 2035	Description
1	Insignificant	Very low impact with respect to security of supply, with a potentially limited price impact
2	Significant	Low risk of unmet demand, with some price impact
3	Severe	Significant price impact and some risk of unmet demand
4	Major	High probability of unmet demand and high price impact

[67] Bolado et al (2012).

Impact score	Impact on gas security 2035	Description
5	Catastrophic	Almost certain risk of unmet demand

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