Promoting choice and value
for all gas and electricity customers

Gas Security of Supply Report

Ofgem report to Government

Submitted: November 2012

Contact: Alex Whitmarsh, Stefan Bojanowski or Wil Barber

Tel: 020 7901 7000

Email: alex.whitmarsh@ofgem.gov.uk
stefan.bojanowski@ofgem.gov.uk
wil.barber@ofgem.gov.uk

Overview:

In November 2011, the Secretary of State requested Ofgem assess the potential risk to medium and long term gas security of supply in Great Britain and appraise potential further measures in the gas market which could enhance security of supply. This report responds to that request by:

1. Assessing the scale and nature of the risks to security of supply given developments in the global gas market;

2. Assessing the level of risk that remains after Ofgem's proposed reform of emergency gas cash-out arrangements;

3. Considering the range of potential measures in the UK gas market to mitigate risks that remain; and

4. Assessing the relative merits of each of these measures, including the risks of market distortion, unintended consequences and providing initial views on cost-benefit comparisons. It also provides initial thoughts on how these measures might be designed and implemented.

This report is intended to be considered by the Government as part of its wider review of security of supply.

Ofgem/Ofgem E-Serve 9 Millbank, London SW1P 3GE www.ofgem.gov.uk

Context

Since privatisation in the late 1980s, a competitive gas market in Great Britain has delivered secure supplies and witnessed high levels of investment. Since 2004, driven primarily by declining gas production on the UK Continental Shelf, Great Britain (GB) has been a net importer of gas. Since then, GB has relied increasingly on international gas markets. These international markets have so far been effective in supplying gas to Britain and encouraging investment in domestic infrastructure.

However, Ofgem has observed that there is some uncertainty over future developments in global gas markets. Some commentators have noted that gas markets may tighten over the coming years and opinion is divided over whether this situation will improve by the second half of this decade. Against this background, Ofgem has been looking to use the Significant Code Review (SCR) process to provide a greater incentive for firms to avoid a potential gas deficit in GB.

In its Gas SCR draft policy decision document the Authority[1] stated its intention to pursue reforms to introduce capped emergency cash out. It added, however, that the capped approach could leave a gap in the emergency arrangements, leading - in the most extreme cases - to consumer disconnection. Ofgem noted that the Government might decide this risk was significant enough to merit further intervention in the gas market.

The Department of Energy and Climate Change (DECC) supported the Authority's conclusions and requested that Ofgem undertake a review of medium to long term security of supply and explore potential measures which could be undertaken.

[1] The Gas and Electricity Markets Authority (the Authority) exists to protect the interests of current and future gas and electricity consumers. Ofgem, the Office for Gas and Electricity Markets, was created by the Authority to support it in the discharge of its duties. Everything undertaken by Ofgem is done in the name of the Authority, and the two terms are used interchangeably in this report.

Associated documents

Gas Security of Supply Report Risk and Resilence Appendix. November 2012.
http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/gas-security-of-supply-report/Documents1/Gas%20SoS%20Report%20-%20Risk%20appendix.pdf

Gas Security of Supply Report Further Measures Appendix. November 2012.
http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/gas-security-of-supply-report/Documents1/Gas%20SoS%20Report%20-%20Further%20Measures%20Appendix.pdf

Redpoint Further Measures modelling report. November 2012.
http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/gas-security-of-supply-report/Documents1/Redpoint%20further%20measures%20modelling%20report%20final.pdf

Proposed Final Decision - Gas Security of Supply Significant Code Review. July 2012. Reference number 111/12.
http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Documents1/120731_GasSCR_pfd.pdf

Impact Assessment for the Proposed Final Decision - Gas Security of Supply Significant Code Review. July 2012. Reference number 112/12.
http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Documents1/120731_GasSCR_IA.pdf

Draft Policy Decision - Gas Security of Supply Significant Code Review. November 2011. Reference number 145/11.
http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Documents1/Draft%20Policy%20Decision%20Gas%20Security%20of%20Supply%20Significant%20Code%20Review.pdf

Impact Assessment for the Draft Policy Decision - Gas Security of Supply Significant Code Review. November 2011. Reference number 146/11.
http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Documents1/Draft%20Impact%20Assessment%20Gas%20Security%20of%20Supply%20Significant%20Code%20Review.pdf

Project Discovery - Options for delivering secure and sustainable energy supplies. February 2010. Reference number 16/10.
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=73&refer=Markets/WhlMkts/monitoring-energy-security/Discovery

Contents

Executive Summary

Background

The decline in UK continental production has inevitably resulted in increased reliance on international gas markets to deliver security of supply to gas customers and electricity generation. This exposes Great Britain (GB) to a range of additional risks. For example, in recent years the GB market has been impacted by production problems in the Norwegian North Sea, a dispute between Russia and Ukraine over gas transit, tension and conflict in North Africa and the Middle East, and the consequences of the Fukushima nuclear disaster in Japan. As these events show, our security of supply arrangements need to take account of the possibility of disruption from a wide range of potential events - from natural disasters, to technical failure, to the geopolitics of energy.

In a more integrated European wholesale gas market we may potentially stand to benefit from increased security through greater diversification of supply sources. However, there are also risks from the actions of players beyond the control of the GB market.

Recognising that our current gas market arrangements needed to be refined to reflect an increased dependence on imports, Ofgem developed draft policy proposals for changes to the emergency cash out regime which we published in November 2011[2]. In that document we clearly signalled that these proposals, in themselves, may not be enough to ensure the desired level of security of supply.

The Department of Energy and Climate Change (DECC) supported this view and asked us to undertake further analysis on the need for, and the potential impacts of, the various further measures available. This report is the outcome of our analysis for consideration by the Secretary of State.

The risk of physical supply interruption

The impact of interruptions to gas supplies will affect different groups of customers in different ways. Some large gas customers have interruptible contracts and these provide a buffer against relatively small disruptions of supplies, with very little impact being felt. Large Industrial and Commercial users with firm contracts might face interruptions with more significant disruptions, but supplies could be restored relatively quickly. Our analysis shows that only the most extreme circumstances would result in large scale physical interruption to domestic customers and smaller businesses (who make up just under half of all gas demand). Depending on the severity of the winter, between 60% and 70% of all gas sources would need to be lost for there to be interruption of gas supplies to domestic consumers (assuming storage is 50% full at the start of the winter, compared to average levels of over 90%). To put these values in context, a 60% loss in supply capacity would represent

[2] We have since published our Proposed Final Decision and the accompanying Impact Assessment for the Gas SCR: http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Pages/GasSCR.aspx

losing all LNG supply, all imports over the interconnectors with Belgium and Netherlands, and a loss of fifty per cent of current UK production.

While events which could lead to physical disruption of gas supplies to domestic consumers are highly unlikely, their impacts would be severe. Restoring supplies to domestic customers after a large scale interruption would take several weeks, which would have profound consequences for individuals, society and the economy, all the more so during periods of cold weather.

Another consequence of a significant gas supply shortage would be an interruption to electricity supplies. In recent years around 40% of all electricity production is from gas fired power stations on average; a proportion that may increase to around 60% as older coal and oil stations close under European environmental legislation. A loss of gas supply of between 25% and 30% during a period of very high demand (again assuming storage to be 50% full at the start of winter) would probably result in a curtailment of gas supplies to power stations. Such circumstances might result in electricity outages, which would have less profound consequences than a disruption to domestic gas supplies, with much quicker reconnection times, but could still be serious.

The risk of an impact on gas prices

With our increased dependency on international gas markets it is difficult to envisage any measure that could insulate consumers against long term global market trends. In addition, short term price spikes provide an important role in attracting gas to the market and incentivising investment.

However, it could be a concern if features of the market resulted in GB consumers being disproportionately exposed to price spikes and medium term price cycles compared to neighbouring markets. While we have a broader diversity of supply sources, we have less gas storage relative to our consumption than any other major European economy and less of our gas is purchased under long term contracts. While this flexibility makes it possible for GB consumers to benefit at times of low prices, as the flexibility and stability provided by North Sea production declines, GB consumers could be more exposed to seasonal swings in gas prices and medium term volatility.

Can the gas market manage these risks?

In general the UK wholesale gas market has functioned well, albeit against a background of self sufficiency in gas production. Our market based approach has also attracted significant investment in gas import infrastructure in response to declining indigenous supplies. Even though we are now exposed to a wider range of possible sources of disruption, our analysis shows that the diversity and quantity of supplies that can be delivered to GB would protect consumers from supply disruptions in a broad range of events.

So, is there any reason to question the ability of our market to continue to deliver good outcomes for consumers?

Although Ofgem's proposed cash out reforms should help to attract gas when the market tightens, these proposals still limit the exposure of suppliers. This means the revised market arrangements would still not fully reflect the value of security of supply to consumers. This factor alone justifies consideration of whether further measures are required to address this "gap". There are a range of other factors that potentially reduce the ability of the market to respond in a way that best meets the interests of consumers or wider society.

- There are a range of **behavioural and institutional factors** that might impact the actions of market participants. These include a potential lack of price responsiveness, possible short-termism of market players, misalignment of incentives on individuals within firms and the consequences of firms pursuing similar hedging strategies. As a result, market participants may not be sensitive to the preferences of consumers for less volatile or cyclical prices.
- As for large scale, low carbon power generation, there are specific **challenges around financing long term investments** when returns are dependent on volatile and uncertain prices, particularly in the context of the ongoing financial crisis. These challenges are likely to make it difficult to finance investments in large scale seasonal gas storage.
- Even a well functioning market may not be able to fully reflect the potentially high **social costs of a serious interruption** given the likely profound economic and social consequences of a large scale, long term interruption to domestic consumers.
- There is a **moral hazard** risk because market participants may believe that Government would be forced to intervene to mitigate the profound impact of a supply shortage, reducing their inclination to take action themselves.
- **Inconsistent incentives in different countries** in the event of an emergency might result in behaviour by market participants that might precipitate or exacerbate a security of supply issue in GB. It is uncertain whether gas would flow from Europe in response to price signals in a gas emergency in GB because other member states may apply emergency arrangements, public service obligations and other factors that influence the flow of gas.
- Beyond the European Union, many large producers and consumers of gas are influenced by a wide range of factors other than the market, including **strategic energy security considerations, economic development and geopolitical factors**.

In addition to the above, we also show in this report that circumstances going forward are likely to challenge the GB market in unfamiliar and demanding ways, putting increasing pressure on GB security of supply. Furthermore, it is important that market arrangements properly reflect the importance of security of supply and its value to consumers.

Further measures

Serious consideration should be given to the case for further measures to reduce the risks from a gas supply shortfall in GB. It is, however, important to recognise that market intervention can bring risks, costs and undesirable consequences. It will be important to strike the appropriate balance between the benefits of increased security and the potential costs and risks of market intervention. However, before pursuing any further measures a much fuller and more rigorous assessment of the risks, costs and benefits of that measure would be needed.

A policy might be oriented towards minimising the risk of a large scale interruption of domestic customers, given the profound long term economic and social consequences that might result. Alternatively (or additionally) policy might be oriented towards addressing risks to electricity consumers from a loss of gas supply to power generation. A key issue to consider is whether further measures may influence the frequency and scale of price spikes and the extent to which market cycles impact consumers. The relatively low proportion of long term contracts and low levels of gas storage could result in GB consumers being more disproportionately exposed to this volatility. Some measures could serve to reduce this exposure.

Some options, such as measures aimed at increasing the provision of large scale gas storage, would not have any impact until towards the end of the decade, given the construction times for such facilities. If there is a need for measures that have a more immediate impact, other options would need to be considered.

Another critical aspect of energy policy is the extent to which it is appropriate for GB security of supply to rely solely on the actions of market participants responding to price signals, particularly given the potential market failures and associated risks we have identified. GB is one of the European countries that rely most on price signals in the market to incentivise market participants to take the necessary actions to secure gas supplies and meet the needs of customers. For example, many continental European countries have chosen to develop gas storage facilities under a regulated regime. Some European countries have also placed public service obligations on their domestic energy companies to ensure sufficient amounts of reliable supplies will be available when needed.

Way forward

The full range of measures we have considered is covered in detail in the report and accompanying appendices. These range from improving information to market participants to direct support for physical gas storage. While it is the role of Government to set the high-level policy framework, and this is necessary before further measures are taken forward, the responsibility for implementing measures under that framework may fall to either Ofgem or Government or a combination of both. As part of this, Ofgem has jointly launched a project with the Belgian and Dutch regulators to assess the efficiency of the GB gas interconnectors. We will also work with industry to further consider the case for introduction of other measures, including a requirement for increased information provision.

1. Introduction

1.1. This report has been written in response to a request by the Secretary of State for Energy and Climate Change[3]. The report considers potential future risks to gas security of supply assessing these risks under a base case where Ofgem's proposed reforms to the gas emergency cash-out arrangements have been introduced. It also considers the resilience to shocks of GB supply and storage infrastructure in the next decade and the extent to which we would expect the gas market arrangements in GB to manage these shocks and developments.

1.2. As part of the terms of reference, the report also considers a number of possible measures that could be taken should Government and/or Ofgem decide that there is a need for a greater level of insurance for GB consumers. We have studied a spectrum of measures from continuing with the current programme of work to enhance supply security, to significant interventions in the operation of the market. For all options, we comment on the ability of these measures to mitigate any future supply risks and the direct and indirect costs of pursuing such a policy.

1.3. This report is divided into three parts. In Chapter 2 we set out our thoughts on future gas market developments and key risks to security of supply, together with our analysis on the resilience to shocks that our supply and storage infrastructure provides. In Chapter 3 we set out our views on market effectiveness. In Chapter 4 we outline possible further measures that might be taken and assess which measures might be suitable against a range of criteria.

Next Steps

1.4. There are a number of areas where changes to market operation are already being considered which are likely to result in improved security of supply for GB consumers. These include the implementation of the cash-out reform proposals, as outlined in Ofgem's July 2012 Proposed Final Decision document, and work that Ofgem is taking forward in conjunction with the regulators of neighbouring Member States to ensure gas interconnectors between GB and Europe flow efficiently. It is also important to recognise developments arising from the European Gas Security of Supply Regulation (the Regulation).[4]

1.5. While it is the role of Government to set the high-level policy framework, and this is necessary before further measures are taken forward, the responsibility for implementing measures under that framework may fall to either Ofgem or Government or a combination of both. As part of this, Ofgem will continue work that falls within its remit. Ofgem has already jointly launched a project with the Belgian

---

[3] See Appendix 3 of this report for the Terms of Reference

[4] Regulation (EU) no. 994/2010 of European Parliament and of the Council concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC. See http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32010R0994:EN:NOT

and Dutch regulators to assess the efficiency of the GB gas interconnectors. We will also work with industry to consider the case for other measures, which may include a requirement for increased information provision.

2. Risks and Resilience

Chapter Summary

This chapter presents our analysis on future gas market developments and key risks to GB security of supply. We also present our resilience analysis which tests the level of defence that our import infrastructure and storage provides in the face of significant shocks to supply.

Introduction

2.1. Our assessment of gas market risks and resilience has been informed by a wide range of sources: Ofgem commissioned Redpoint Energy and MJM Energy to perform an extensive review of the most significant reports on GB security of supply and future market developments in the past five years. In addition, we carried out over twenty face-to-face interviews with key industry stakeholders, academics and market participants. We also held a well-attended industry event to discuss emerging findings.

2.2. This exercise identified the major drivers and uncertainties to future levels of supply and demand at the GB, European and global levels, including developments in the LNG market. It also identified key sources of potential shocks to GB gas security of supply. These are events that could have significant implications for GB gas supplies and that could arise with little or no notice. We discuss our findings on market developments and shocks to security of supply in the second section of this chapter.

2.3. We have drawn on this information to develop scenarios that describe different outcomes for future GB gas demand and supply. We have used these scenarios in our resilience analysis to investigate the level of defence that GB import infrastructure and storage provides in the face of high demand and shocks to supply, which we present in the third subsection of this chapter. We start this chapter with a short discussion on the recent history of GB gas supplies.

Recent history of GB gas supplies

2.4. The GB gas market has been liberalised since the 1990s and is the least concentrated[5] and most liquid amongst the larger countries of the European Union[6].

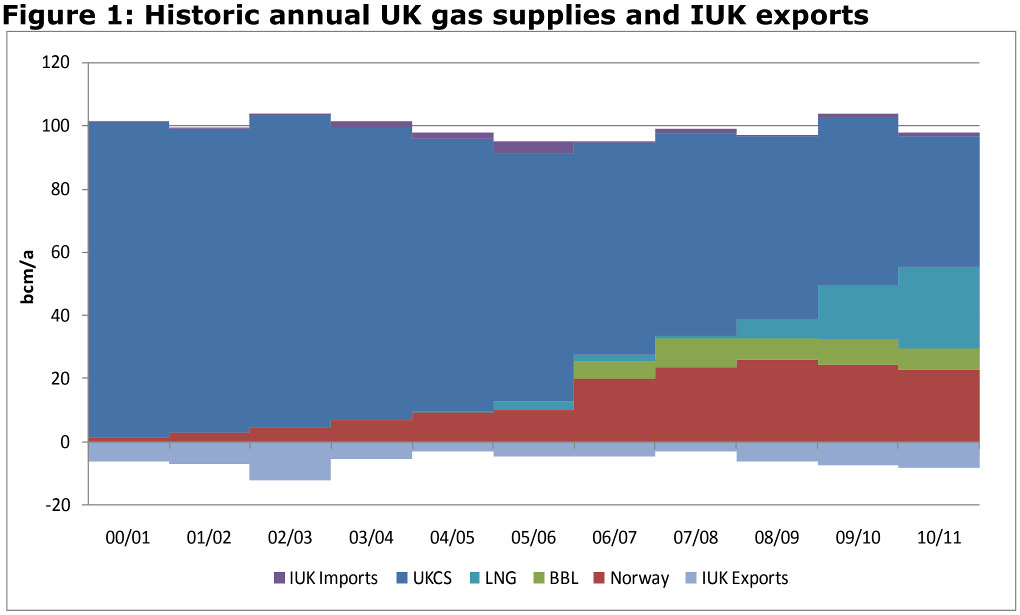
[5] GB has the least concentrated wholesale gas market in Europe. It is the only country in the EU (where data is available) that has a concentration ratio for the three largest wholesale companies of less than 40%. GB also has eight companies that import and produce gas with market shares over 5%, the largest number in the EU27. Source: European Commission Annual Benchmarking Report, 2010.

[6] The Churn ratio is a measure of the number of times a 'parcel' of a commodity is traded and re-traded between its initial sale by the producer and final purchase by the consumer and is a good measure of a given market's liquidity and depth. The Churn ratio of the NBP has historically been between twice and three times that of the Zeebrugge hub and between five and seven times the TTF. Source: Patrick

The GB market also exhibits some of the lowest gas prices for residential and industrial consumers across the EU27[7]. There has been sufficient confidence in these liberalised arrangements to attract significant investment in GB import infrastructure, which has led to a five-fold increase in GB gas import capacity in the last decade alone[8].

2.5. As indigenous supplies have declined, and import capacity has increased, the sources of GB gas supplies have changed. As recently as 2000, GB gas was sourced, almost wholly, from the North Sea. However, as Figure 1 shows, the situation today is quite different: as much gas is now sourced from Norway, the Continent and LNG, as GB produces itself. In 2004, GB became a net importer for the first time since North Sea discoveries of oil and gas[9].

Figure 1: Historic annual UK gas supplies and IUK exports



Source: National Grid Ten Year Statement 2011

2.6. New import infrastructure and sources of supply have exposed GB to European and global markets to a higher degree than in the past. For example, GB is a major customer of global LNG. In 2011, LNG imports totalled 25 bcm (around a quarter of total consumption), making GB the world's third highest importer in that year[10] and, of this, 87% came from Qatar[11]. Fluctuations in the global LNG supply

Heather, OIES, The recent evolution of the European gas market Towards oil-gas decoupling, 2011

[7] GB had the lowest gas prices after taxes for industrial consumers in 2010 and the second lowest, after Luxembourg, for household consumers. Source: European Commission Annual Benchmarking Report, 2010, Technical Annex.

[8] DECC Gas Security of Supply, A Policy Statement, April 2010

[9] Source: DUKES, Table 4.3 Natural gas imports and exports

[10] World's largest importers of LNG (bcm): Japan (107.0), South Korea (49.3), GB (25.3), Spain (24.2), India (17.1). Global trade 330.8 bcm. Source: BP Statistical Review of World Energy June 2012

[11] Source: ibid.

and demand balance or shocks to our major LNG suppliers could now have important implications on GB.

2.7. The importance of LNG to GB is even clearer when looking specifically at high demand days. National Grid analysis has shown that on the highest winter demand days during 2011/12, LNG supplies made up the second largest incremental source of supply after storage[12]. This shows that at least during last winter, LNG was used by suppliers to a greater extent than pipeline imports to meet high demand.

2.8. Prior to 1985, such seasonal flexibility was provided in a large part by the contracts held by British Gas with UKCS field owners[13]. From 1985, seasonal flexibility was further improved by the opening of the Rough storage facility by British Gas. However, with liberalisation in the 1990s, more flexible contracts on both new and old UKCS fields has allowed them to produce at close to full capacity year-round. This has resulted in a decline in UKCS seasonality and is expected to continue to do so[14].

2.9. As the flexibility from the UKCS has declined, there is evidence that seasonal swing in pipeline imports from the Netherlands and Norway, as well as LNG, have responded to fill the gap. GB imports have therefore become not only a necessary part of meeting annual demand; they also play an important role in providing the large swings required from seasonal demand.

Future Market Developments and Key Risks

2.10. The accompanying appendix on market developments and risks contains a more detailed account of our findings on supply/demand drivers and uncertainties. In this section, we summarise these findings, for the domestic, European and global markets in turn. Key drivers to gas demand at both the global and domestic level include the extent to which countries commit to a low carbon agenda, the pace of economic growth and the role that gas plays in the energy mix. On the supply side, the IEA has highlighted that the extent to which countries exploit their unconventional resources, such as shale gas and coal bed methane, will be a key determinate of future global gas supplies. Trade in gas will also continue to expand both through pipelines and LNG. We discuss how LNG markets are forecast to develop and show that there are a number of reasons to believe this market may become increasingly tighter towards the middle of the current decade.

[12] National Grid (2012) Winter Outlook.
[13] The majority of these contracts were buyer-nominated, i.e. the buyer nominates a volume of gas to be supplied from the field on a day-by-day basis.
[14] Howard Rogers (2011) The impact of import dependency and wind generation on UK gas demand and security of supply to 2025. Oxford Institute for Energy Studies. NG 54.

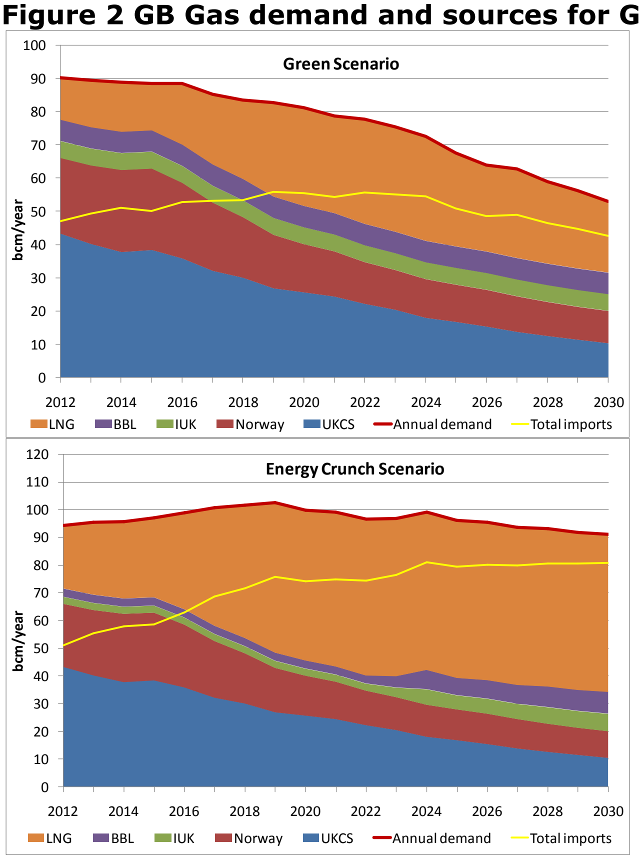
GB outlook

2.11. Gas demand in GB consists of gas for electricity generation, domestic use and the industrial and service sector. To capture the range of uncertainties on the availability and role of gas over the period to 2030, we have developed two scenarios for gas demand in GB, an approach similar to Ofgem's Project Discovery. The scenarios draw on the review of reports and interviews as well as our own analysis.

2.12. Our Green scenario describes a future with increasing renewable generation and significant progress on energy efficiency. This is similar to National Grid's Gone Green scenario which is used in NG's Ten Year Statement and the Statutory Security of Supply Report published jointly by DECC and Ofgem. In our Energy Crunch scenario, gas plays a greater role in the energy mix: in electricity generation, industry and in heat. We use these scenarios in our resilience analysis later in this chapter.

2.13. Figure 2 below presents the level of annual gas demand and sources of supply in our two scenarios. It also shows the resulting level of imports in the two scenarios.

Figure 2 GB Gas demand and sources for Green and Energy Crunch scenarios



Source: Ofgem

2.14. In the Green scenario, total GB gas demand falls 10% from current levels to 80 bcm/year by 2020. In the Energy Crunch scenario demand increases by 5%

over the same period to 100 bcm. This difference is primarily driven by the use of gas in power generation (but also by energy efficiency and the electrification of heat). In 2011, electricity generated from gas accounted for about 40% of total generation. In our Green scenario this proportion remains stable over the decade; however, in the Energy Crunch scenario the proportion grows to almost 60% by 2020, as nuclear power stations come to the end of their life spans and older coal and oil stations close under European environmental legislation.

2.15. After 2020, demand uncertainty is even greater, as gas demand from power generation decreases in our Green scenario as a consequence of higher levels of low-carbon generation and domestic demand is lower due to energy efficiency measures and electrification of heat. By 2030, total GB demand in our Green scenario is around 50 bcm/year, a decrease of around half compared to today. In the Energy Crunch scenario the decline in gas demand is much more modest, falling only about 10% by 2030, compared with today.

2.16. Looking forward, there is likely to be an increase in the need for flexibility from our gas supplies. This is to meet larger and faster swings in demand from gas-fired electricity generators as their role in balancing the intermittent output of a growing quantity of installed renewable generation increases. Studies by National Grid and Poyry model the size of the swing required. In their 2011 Ten Year Statement, National Grid model the effects of 30 GW of installed wind in 2020/21 and suggest this could lead to a possible increase in gas demand of the equivalent of 90 mcm over a single day[15] (around 30% of demand on a relatively high demand day)[16]. Similarly, Poyry's analysis shows the daily swing in power sector gas demand for the year 2029/30 assuming around 40 GW of intermittent generation. These swings are of a similar magnitude to those found by National Grid.

2.17. Turning to the supply side, domestic supply from the UKCS will continue to decrease according to most sources. National Grid estimate UKCS production to be between 20 and 40 bcm/year by 2020, with a central estimate of 26 bcm/year[17]. This represents a decrease of approximately 25% compared with current levels. Unconventional gas production in GB is expected to be very modest during this period[18]. As a result, and as figure 2 shows, we forecast LNG supplies to play an increasingly important role in meeting annual demand in both our scenarios. This is most notable in the Energy Crunch scenario where annual LNG imports could be around 60 bcm by 2030 or around 60% of demand.

2.18. Pipeline gas, by nature of the reliability and flexibility of the infrastructure, will also continue to be an important source of supply to GB. However, both our scenarios model a slight decline in the quantities coming from Norway[19], while the Energy Crunch scenario also assumes tighter supply from the continent. Counter to

---

[15] National Grid (2011) Ten Year Statement
[16] Ofgem analysis
[17] National Grid data excludes non-NTS gas to power stations and direct exports
[18] Poyry (2011) The impact of unconventional gas on Europe, A report for Ofgem
[19] In line with the National Grid's 2011 Ten Year Statement that assumes production at Norwegian fields begins to decline when approximately 50% of reserves are reached (following the trend observed in UKCS extraction). National Grid assume this point is reached in 2014.

this we see increasing quantities from the Netherlands via BBL in the early 2020s. How Europe both uses and sources its gas will therefore become increasingly important to GB. We discuss this further in the following section.

European outlook

2.19. The European market influences the GB market through a number of channels. On the one hand, Europe provides a source of supply to the GB market. Gas can be piped directly from the Norwegian continental shelf to GB receiving facilities and interconnectors with Belgium and the Netherlands can bring gas produced in Europe (eg Dutch gas) or further afield (eg Russian gas) to GB, if supplies react correctly to market signals.

2.20. On the other hand, the European market is a source of competing demand since Norwegian gas can land in other North-Western European countries, the interconnector between GB and Belgium (IUK) allows gas within the GB gas system to be exported[20], and a growing number of LNG re-gasification terminals across Europe will increasingly allow these countries to access gas from the global LNG market in competition with GB[21].

2.21. Future levels of European demand will depend on a number of factors such as the degree of gas use in power generation (which in turn will be affected by the relative costs of gas with other fuels, the impact of European legislation on fossil fuels, and the amount of renewable generation and nuclear capacity), the impact of carbon reduction policies in other areas and other factors that influence the price of gas (for example, oil prices and demand and supply conditions in the global gas market).

2.22. This uncertainty is illustrated by the wide range of gas demand scenarios for the EU countries. For example, compared to EU gas demand in 2009/10, two IEA scenarios[22,23] suggest an increase of between 8% and 17% to 2020 and between -4% and 23% from 2010 to 2030[24]. Two European Commission scenarios[25] suggest a change between -4% and 1% to 2020 and between -9% and -13% from 2010 to 2030.

---

[20] Natural gas is exported to Northern Ireland and the Republic of Ireland. Flows of gas through the interconnector with the Netherlands can also vary, to a degree, in response to market fundamentals.
[21] Total import capacity in continental Europe will exceed 180 bcm per year by 2016 when all facilities under construction come on stream. Source: GLE 2012. http://www.gie.eu/index.php/maps-data/lng-map
[22] Source: The New Policies scenario and 450 scenario. WEO 2011.
[23] The IEA New Policies Scenario for Europe assumes existing commitments are honoured and renewables reach 20% of energy demand by 2020. The 450 Scenario is based on a 30% reduction in emissions compared with 1990 by 2020.
[24] Additionally, the IEA's 'Golden Age of Gas' scenario (as set out in a special report) indicates that EU demand in 2035 could be 16 bcm higher still than projected by the 'New Policies' scenario as a consequence of ambitious gas policy in China, low growth of nuclear power, and more use of gas in road transport.
[25] European Commission, 2010. EU Energy Trends to 2030 – Update 2009. Luxembourg: Publication Office of the European Union. http://ec.europa.eu/energy/observatory/trends_2030/doc/trends_to_2030_update_2009.pdf

2.23. On the supply side, projections suggest that indigenous production of (non-UKCS) gas in Europe will fall from 2015 onwards[26]. There has been significant debate on the potential for unconventional sources of gas revolutionising European indigenous supplies. The largest resources are expected to be in Poland followed by Germany, the Netherlands, and France, though estimates are subject to a high degree of uncertainty. There are still significant questions over the timing of the projects, their costs and resource accessibility. The latter point has been underlined with the recent withdrawal of ExxonMobil from drilling in Poland, claiming the shale is too tight to use standard hydraulic fracturing techniques[27]. Even so, there continue to be reports of progress in this area[28].

2.24. The implications of the lower production projections are that EU imports of gas from the rest of the world are likely to rise significantly over the next two decades. The European Union currently imports around 60%[29] of its gas with around 40% of this coming from Russia. Projections show import dependence in the EU rising to over 85% by 2035[30]. Much of this projected increase is expected to come from global LNG markets[31], although as Figure 3 shows there are also a number of significant pipelines planned to increase import capacity to Europe.

2.25. Some of these pipelines will provide new supply routes for Russian gas to come to Europe, which the IEA use to predict that gas flows from Russia to Europe will continue to grow, albeit at a slowing rate. By 2030, the IEA predict Russian supplies to Europe will be around 200 bcm, up from around 150 bcm today[32].

---

[26] IEA WEO 2011 p.165

[27] Ofgem commissioned Pöyry Energy Consulting to, amongst other things, assess the drivers and barriers to unconventional gas production in Europe, and impacts on gas prices and security of supply in GB and Europe. It finds that significant production of unconventional gas is not expected before the 2020s and thereafter the amount of production is highly uncertain. In addition, even moderate production in Europe could keep gas prices in GB lower from 2020 onwards than they otherwise would be. http://www.ofgem.gov.uk/About%20us/PwringEnergyDeb/Documents1/033_PublicReport_UnconventionalGasOfgemLogo_v4_1.pdf

[28] http://www.naturalgaseurope.com/talismans-san-leon-szymkowo1-well-hits-shale-gas

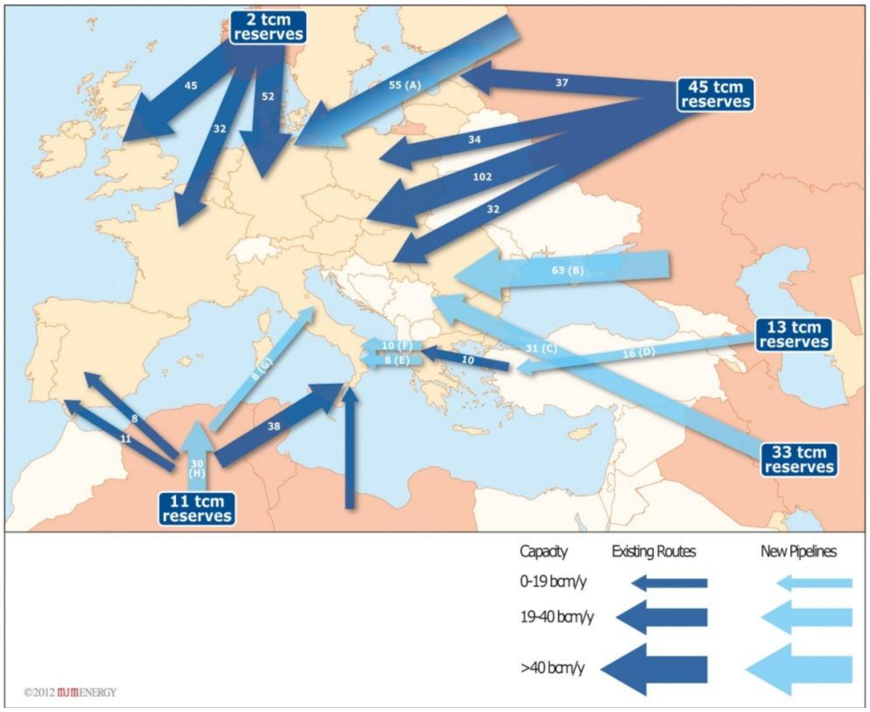
[29] The EU imported around 310 bcm in 2009 against total consumption of 508 bcm. Source: IEA WEO 2011.

[30] IEA WEO 2011. p 168.

[31] In Europe alone there has been significant investment in LNG receiving facilities; for example new terminals have opened recently in Italy and the Netherlands and terminals are under construction in Poland, Italy, France and Spain.

[32] IEA WEO 2011. p 338. Note: Europe in this context is the European Union, other OECD Europe and southeast European countries.

Figure 3 Existing and proposed European pipeline infrastructure

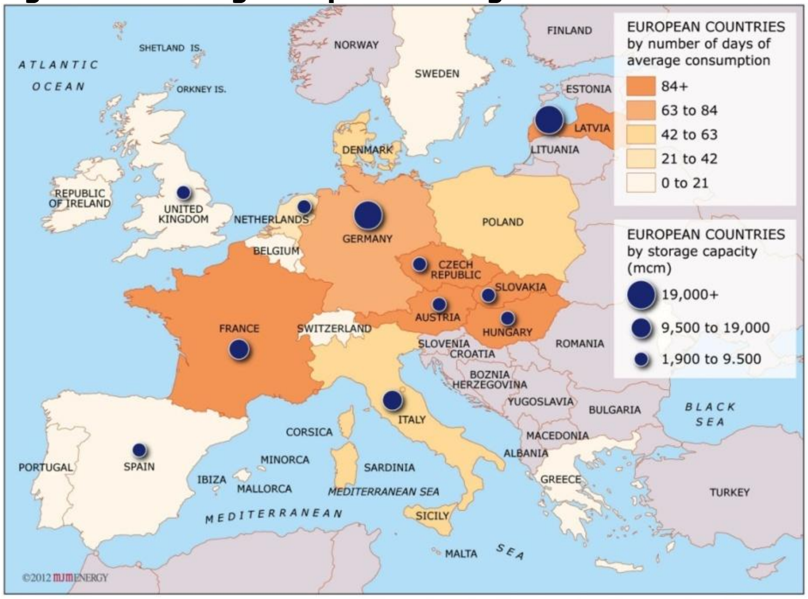


Source: National Grid and MJM Energy Research

2.26. Historically, most European countries have not had large indigenous supplies of gas, and instead have tended to rely on imported gas using long-term, take-or-pay gas contracts (with certain flexibility to adjust gas flows) and gas storage facilities to provide additional flexibility and security of supply. Where geology allows[33], and where they have had need for it[34], this has tended to lead to larger volumes of storage space being developed in many European countries in relation to annual gas demand compared to GB. Figure 4 depicts the capacity of the storage infrastructure present across Europe. It also shows roughly the number of days at average consumption that storage could meet demand. GB stands out (as does Spain) as having a low level of storage capacity[35]. This reflects GB's historic position as a gas producer and the fact that there has been significant investment in non-storage supply in recent years.

[33] For example, storage capacity in natural porous strata in Belgium is limited by geology.
[34] For example, Germany's gas demand is highly seasonal.
[35] These figures exclude storage at LNG importing facilities.

Figure 4 Existing European storage infrastructure



Source: MJM Energy Research

2.27. Investment continues in storage capacity in Europe. Natural candidates for storage facilities include depleted or partially depleted gas fields[36]. Much of continental Europe's gas fields are onshore and converting these fields to storage facilities is often more commercially attractive than converting offshore fields (offshore fields are characteristic of the GB market)[37]. Germany, Spain, Italy and Poland are seeing significant investment in storage capacity with around 15 bcm of additional space currently under construction[38,39].

2.28. In addition to the supply and demand characteristics noted above, how the European markets function, as well as the market and regulatory arrangements, are important in determining how GB interacts with the continental European markets. This is discussed further in Chapter 3 of this report. The next subsection discusses the impacts on GB of global gas market developments.

---

[36] In addition to depleted gas fields, salt caverns and aquifers can also be used to store natural gas. For example, France stores significant amount of gas in aquifers and Belgium's only storage facility is an aquifer. Natural gas can also be stored in liquid form, for example, Spain has a significant amount of LNG storage capacity.

[37] An example of an onshore field being developed into a storage facility in North-west Europe is the Bergermeer project which is 4.1bcm and would roughly double Dutch storage capacity. This facility is located close to the interconnector between GB and the Netherlands. http://www.bergermeergasstorage.com/ How accessible this gas will be to GB shippers depends on how interconnected the GB and Dutch markets are, which is discussed elsewhere in the report.

[38] Germany 4.6 bcm, Spain 4.3 bcm, Italy 3.5 bcm and Poland 2.6 bcm. *Source: Gas Storage Europe.*

[39] Some EU countries (such as the UK, France and Germany) have negotiated third-party access as the default regulatory regime and returns to investment in storage are determined by market forces. Other countries have a regulated third-party access regime (such as Spain, Italy and Poland) where returns to investment in storage are regulated and the level of storage capacity that is developed is centrally controlled. Unless an exemption is in place, this means that storage facilities in Europe must be allocated to customers in a transparent, objective and non-discriminatory way.

Global outlook

2.29. The global gas market will affect the GB market both directly, since GB will need to access the global LNG market, and indirectly, through the interaction of the global and European markets. The precise relationship between the GB market and other gas markets is complex; it depends on the relevant commercial arrangements (for example, whether LNG is sourced through long-term contracts or bought off spot markets), regulatory arrangements (for example, whether LNG is permitted to be exported from a country) and other factors.

2.30. The global demand for natural gas is projected to increase significantly by between 19% and 27% over the period to 2020, and between a further 6% and 22% by 2035[40]. This is driven largely by non-OECD (primarily Asian) economic growth. Moreover, there remains a risk that global gas demand will be higher than these projections suggest. For example, the IEA's 'Golden Age of Gas Scenario' shows growth of gas consumption of nearly 30% between 2020 and 2035[41].

2.31. Global gas resources are abundant, and are sufficient to meet even the highest demand projections provided these resources can be developed and brought to market in good time[42]. While global gas production is projected to come primarily from conventional sources in 2035, under the IEA's 'New Policies' scenario, the global share of unconventional gas production is forecast to rise from 13% to 15% by 2020 and to 22% in 2035. This comprises around 40% of incremental production in this period. The abundance of natural gas means that resource levels in themselves do not present a security of supply risk.

2.32. Further, gas production will become increasingly spread across the globe enhancing the role for inter-regional trade and transport infrastructure. In 2011, inter-regional trade of gas by pipeline and LNG was around 1 tcm (around one third of global gas demand) and is projected to grow by around 35% by 2017[43].

2.33. How the LNG market functions has a direct bearing on the GB gas market and, as noted earlier, is of significant importance to GB security of supply and prices. Trade in LNG has grown substantially in recent years and is expected to continue to grow. As shown in figure 5, Europe is expected to import increasing amounts of LNG and will need to compete with other regions for this supply; in particular with Asia

---

[40] IEA WEO 2011. Higher demand projections are from the New Policies scenario and lower demand projections are from the 450 scenario.

[41] IEA special report 'Are we entering a golden age of gas?'. This scenario uses the New Policies scenario from WEO 2010 as a starting point and makes additional assumptions that would favour gas consumption i.e. more ambitious gas use in China, favourable supply and demand fundamentals, greater use of gas for transportation and slower growth in Nuclear capacity.

[42] Proven gas reserves are estimated at 190 tcm, conventional recoverable resources at 400 tcm and conventional and unconventional resources combined at 800 tcm. This compares to current annual consumption of around 3 tcm per annum. Source: WEO 2011.

[43] IEA MTGMR, BP Annual Energy Statistics 2012

where demand is expected to grow rapidly. LNG is forecast to account for around 40% of the growth in inter-regional gas trade to 2035[44].

2.34. Of potential concern is that LNG demand is expected to grow faster than supply in the near future. Although currently fairly well supplied, the LNG market is expected to become increasingly tighter in the middle of the decade. This risk is flagged in a number of different reports,[45,46,47,48] including National Grid's Ten Year Statement. We reproduce figure 3.3K from this report in Figure 5 below.

2.35. The chart shows expected global LNG liquefaction capacity (the lines) against forecast global demand (the bars). The large uptake in liquefaction capacity in the middle of the decade (the dotted line) is largely due to the commencement of the large Australian LNG projects. The dashed line assumes only 50% of all proposed liquefaction projects go ahead. This line indicates that, all else equal, the global LNG market becomes increasingly tighter approaching 2014/15. Whether and when this tightness materialises (and when it might end) will depend on demand growth and any delays in new capacity. In particular, a prolonged slowdown in global economic growth could mitigate any tightening.

---

[44] IEA WEO 2011.

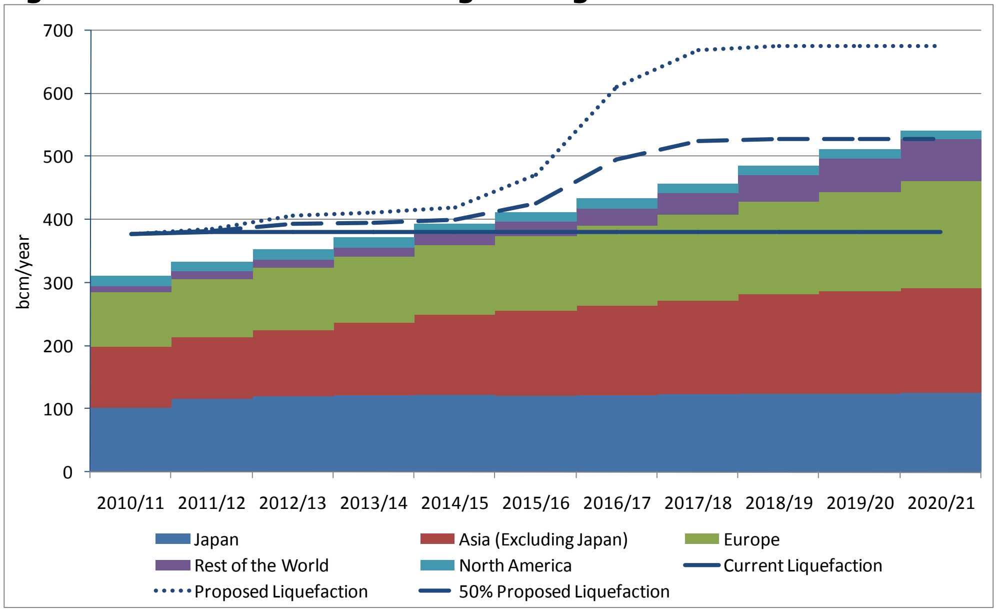
[45] National Grid analysis points to market tightening in the near future (see section 3.3.6). They reference *"National Grid, LNG journal, GIIGNL, BP, NATS PAN-EURASIAN, OIES, Various*" as a source of key data. http://www.nationalgrid.com/NR/rdonlyres/E60C7955-5495-4A8A-8E80-8BB4002F602F/50703/GasTenYearStatement2011.pdf

[46] The IEA's MTGMR (figure 48) also point to a temporary plateau in LNG capacity. The IEA state: "(LNG) markets will become increasingly tighter until mid-2014, as only 25 bcm out of a total liquefaction capacity of 114 bcm under construction as of late April 2012 is planned to come online over 2012-13". Source: IEA MTGMR p.101

[47] A recent press report suggests that Sanford C. Bernstein & Co. see tightness in the near future then followed by a glut http://www.bloomberg.com/news/2012-02-14/new-lng-supply-may-flood-gas-market-by-2018-bernstein-says.html

[48] A recent presentation by GDF Suez draws on a scenario by CERA produced in the Autumn of 2011 which shows that a tightening of the LNG market around 2013-14: http://www.gdfsuez.com/wp-content/uploads/2012/05/sg-oil-oil-services-lng-conference-april-3-2012-vdef3bis-1.pdf

Figure 5: Future LNG market tightening



Source: National Grid

2.36. A further source of uncertainty in the LNG market is how much LNG might be exported from the US and to where. One LNG facility (Sabine Pass, 23 bcm/year export) has already received regulatory approvals to allow construction, and there are developers for seven other projects[49]. It should be noted that even if large volumes of gas could be exported by the US, it does not follow that GB prices would fall to US levels, since a significant mark-up will be required to cover the export costs such as liquefaction and shipping.

2.37. Any tightness in the LNG market could lead to a disproportionately reduced availability of LNG on spot markets. This is because significant amounts of LNG are already under relatively inflexible buyer-nominated long-term contracts[50] by non-GB customers (in particular, by Asian customers where market prices for sellers are favourable) and suppliers will have to ensure these contractual commitments are met first before selling residual un-contracted LNG onto the spot market. The tightness could make LNG spot cargoes harder to source and / or more expensive; this in turn could feed through into GB wholesale gas prices and the ability of the LNG market to respond to resolve the impact of potential domestic and external shocks to gas supplies. We discuss the most significant of these shock events in the following section.

---

[49] If all facilities were to be built this would allow 142 bcm/year of gas to be exported. Source: IEA, Medium-term Gas Market Report, p. 118.
[50] Over 80% of new LNG supplies coming online in the period 2011-17 are contracted on a long-term basis. Source: IEA GMTMR 2012. p 106.

Key domestic and external shocks

2.38. In addition to future market developments, discussed above, our review identified a number of key domestic and external shocks that could arise in the near term, with little or no notice. These shocks could lead to a significant impact on the volumes of gas flowing into GB. Domestic shocks relate to events that have a direct impact on physical supplies to the GB market, such as the outage of a large piece of infrastructure. External shocks are geopolitical or natural events large enough to have a significant knock-on effect on GB. Historic examples include the Russia/Ukraine dispute over pipeline exports and the large increase in demand for LNG following the closure of Japanese nuclear plants after the March 2011 Tsunami.

In this section we set out the domestic and external shock that our review identified as having the most significant impact on GB security of supply. All of the shocks we discuss below are, by their definition, difficult or impossible to predict. We highlight them because of the size of their impact on GB, not because we think they are more likely than others to occur. This list is not exhaustive as a number of other shocks to security of supply have also been identified in reports and interviews. We list these shocks in the Risks and Resilience Appendix. We summarise the key shocks in the table below:

Domestic shocks	*External shocks*
Outage at a key import terminal	Closure of critical LNG shipping lanes
Outage of a key pipeline	Some curtailment of Russian supplies
	An environmental incident associated with shale gas production
	Another nuclear disaster, accelerating the closure of existing plants and increasing demand for gas for power generation

Domestic shocks

2.39. The most frequently quoted domestic shock in our interviews was an outage at a key import terminal. GB has nine major import terminals[51] with a total peak deliverability of 576 mcm/day. While the levels of deliverability vary between terminals, there are three: Bacton, Easington and St Fergus with peak levels above 100 mcm/day that together account for over 75% of total import capacity. Whilst

[51] These are as follows (the values in parenthesis are the 2010/11 NG forecasts for peak deliverability in mcm/day): Bacton inc. IUK and BBL (159), Barrow (15), Easington inc. Rough and Langeled (126), Isle of Grain (56), Milford Haven (68), Point of Ayr (0), St Fergus (111), Teeside (25), Theddlethorpe (16). Source: National Grid Ten Year Statement 2011, page 105.

there has never been a long-term failure at a UK terminal – and most terminals comprise a number of sub terminals – a prolonged outage could create problems. For example, a fire at Bacton in 2008 removed 30 mcm/day of supply for four days.

2.40. A number of interviewees also suggested that while the capacity of import infrastructure had increased dramatically in recent years (particularly LNG terminals), our pipeline supplies, consisting of a decreasing number of larger pipes, were becoming more concentrated. Historically, the network of pipelines in the North Sea and the large number of fields and facilities that supplied them gave GB diversity of sources and supply channels from the UKCS.

2.41. With fewer, larger pipelines, any damage or maintenance requirements would temporarily remove a larger proportion of GB's import infrastructure than in the past. Recent examples include liquid contamination of the IUK pipeline, which led to a shutdown of some two weeks to dry out the line and anchor damage to the CATS pipeline which required a maintenance shutdown lasting two months[52].

External shocks

2.42. The most frequently referenced external shock to GB supply was a closure of critical LNG shipping lanes preventing exports from Qatar or the UAE[53]. While the significance of such an event is closely linked to its duration, the IEA has examined the impact of a shipping lane closure long enough to require LNG buyers to seek alternative sources of supply[54]. In 2011, 57 bcm of Qatari and UAE LNG went to Asia, with 43 bcm to Europe (with half of this going to the UK)[55]. If these supplies were no longer available, the countries supplied would be forced to seek alternative sources. The IEA explain that those countries in Asia, who rely solely on LNG to supply their needs, would be forced to find alternative LNG supplies. This would increase the demand for un-contracted LNG, significantly increasing its price. European countries on the other hand have alternative supply options and would probably source lost Qatari or UAE LNG from additional pipeline imports. The IEA suggest the most likely candidates would be increases in pipeline exports from Russia, Norway or the Netherlands.

2.43. As noted above, Russia currently supplies around 150 bcm/year to Europe through six major supply routes with a total capacity of around 225 bcm/year[56]. Of this, around half must transit Ukraine. This suggests that pipeline capacity from Russia is currently sufficient to meet an increase in demand of the equivalent of around 75 bcm/year from Europe, enough to compensate a total loss of LNG supplies. However, it is not certain that Russia could make this additional volume of gas available at short notice, given its domestic demand requirements, the risk of

---

[52] Source: http://uk.reuters.com/article/2007/08/30/cats-gas-idUKL3058280220070830?sp=true
[53] A disruption of supplies from LNG exporting countries would also have a significant impact on global and GB LNG supplies.
[54] IEA (2011) Update on the Gas Market; focus on LNG trading, Anne-Sophie Corbeau
[55] BP Statistical Review of World Energy June 2012
[56] IEA WEO 2011. p 338. This will increase to around 250 bcm with the operation of the second half of the Nord Stream pipeline.

transit disputes (see below) and possible constraints in pipeline and interconnector capacities across Europe.

2.44. The impact of a closure of LNG shipping lanes was also quoted by interviewees who thought that GB LNG supplies had become too reliant on a single source, increasing GB's vulnerability to upstream problems. Since the middle of 2009, Qatar has contributed over 65% of total GB LNG imports. This proportion increased to over 90% in the three quarters following the Fukushima disaster in 2011[57]. While this is indeed a very high proportion, data from Wood Mackenzie suggests that GB has long-term LNG contracts with at least five exporting countries, around two thirds of which is made up of gas imports from Qatar[58].

2.45. The second most referenced external shock related to Russian supplies to Europe. Here respondents explained that a number of factors could lead to a reduction of Russian supplies in the future. The most likely, given that it has happened twice in the past, was another dispute between Russia and Ukraine. However, Russian civil unrest or deteriorating Western relations with Russia were also mentioned as possible factors.

2.46. Looking back, the last transit pipeline dispute with Ukraine in 2009 resulted in Russia cutting off pipeline supplies for 15 days. This led to a civil crisis in those countries almost wholly dependent on Russian imports. The impact on Bulgaria and Serbia was particularly severe as they also had very limited gas storage and few alternative fuel arrangements. It has been estimated that Bulgaria suffered a 9% loss in GDP[59]. Going forward, Russia is now a lot less reliant on Ukraine for its supplies to Europe as a result of the new Nordstream pipeline, the first part of which became operational in November 2011. With the second line, active from October 2012, Nordstream has full export capacity of 55 bcm/year, equivalent to around 35% of Russian supplies to Europe in 2010[60].

2.47. Another external shock highlighted in our review, was the impact of an environmental incident associated with shale gas production. Public campaigns in the US have raised the profile of environmental concerns related to shale gas production. These include the large volume of water required to fracture the rock, potential contamination of fresh water aquifers and greenhouse gas emissions. The IEA has recently studied these concerns in detail. A report, published earlier this year, recognises a number of environmental and social concerns associated with unconventional gas production (including shale). However, it also explains that mitigating these concerns is not beyond the scope of existing technologies or know-how. The report goes on to describe a set of 'Rules' for unconventional gas producers to limit environmental concerns[61].

[57] Source: DUKES, Table ET4.4 Supplementary information on the origin of UK gas imports
[58] Source: DECC (2011) Statutory Security of Supply Report, Risk Assessment and Ofgem analysis.
[59] Christie, E.h. et al. 2011: Vulnerability and Bargaining Power in EU-Russia Gas Relations.
[60] Ofgem analysis based on IEA WEO (2011) data, p 338.
[61] IEA (2012) Golden Rules for a Golden Age of Gas

2.48. Even so, the political sensitivity is such that a serious environmental incident could trigger a significant clamp down on shale gas production in a relatively short time period. If this happened and the US had to switch to become a net importer of gas, this would have a significant impact on the Atlantic LNG market, limiting and increasing the cost of LNG supplies to Europe. This shock might also have the likely knock-on effect of downgrading the outlook for unconventional gas production in Europe, and elsewhere in the world, limiting supplies of unconventional sources in the future.

2.49. The final key external shock was another nuclear-related problem somewhere in the world, which could lead to further reductions in the appetite for governments to pursue new nuclear programmes or could accelerate the closure of existing plants. If these changes were required quickly, it is likely that gas-fired generation would be called upon to fill the resultant gap in electricity generation, given the speed with which such plants can be constructed. An increase in worldwide demand for gas would have a knock-on impact on prices and available volumes.

2.50. Even without a further disaster, following the Fukushima Daiichi disaster, many countries are already reviewing their nuclear programs. To investigate a reasonably pessimistic view of future nuclear build, the IEA model a low nuclear case that assumes no new nuclear reactors are built in OECD countries beyond those already under construction and only 50% of the capacity additions projected in non-OECD countries in their New Policies Scenario (the IEA's base case) proceed as planned. Under these assumptions, nuclear energy falls from a projected 13% share of global electricity generation, to only 7% by 2035. The difference is made up from increases in coal, gas and renewable generation. The increase in gas generation in this scenario is forecast to be 122 GW. Such a large increase would put further pressure on global gas supplies, this tightening global markets.

2.51. Importantly, past experience has shown that significant domestic resources combined with a well supplied global market and adequate import capacity has resulted in no single shock leading to an outage to firm customers. On the other hand, there is little past evidence of how well the GB market can cope with developments that might lead to a tight supply environment, either on the continent, with LNG or combinations of large shocks, even though the likelihood of such large shocks are low.

2.52. This is an important reason why Ofgem has proposed changes to the gas cash-out arrangements. The proposed arrangements would set the price that shippers who are short would have to pay in a Gas Deficit Emergency (GDE) at £20/therm[62]. This will increase the ability of GB to attract additional gas supplies. It

---

[62] Ofgem is proposing to reform the gas cash-out mechanism so that the cash-out price would be set at £20/therm in a GDE for: all days of firm load shedding (where individual large customers are required to reduce their gas demand) and the first day of any network isolation. We are also proposing that a proportion of the cash-out payments from shippers would be used to fund payments for involuntary demand-side response services to those consumers whose gas supply has been interrupted. Firm customers would be paid £20/therm for each day they are without gas. If network isolation occurs, firm customers that are interrupted would be paid £20/therm for the first day of an interruption only.

will also provide a strong incentive to shippers to undertake actions which reduce the risk of a GDE occurring. However, the proposed arrangements would only apply for the first day of any network isolation. We recognise that this leaves a gap in the security of supply arrangements, even after cash-out reform, and this led to the initiation of this report. We discuss further measures that could close the gap in our security of supply arrangements in Chapter 4 of this report.

2.53. To complete our analysis of market developments and shocks an important step is to understand the potential impact they might have on GB. To do this we have carried out a number of modelling exercises. We detail our approaches and results in the following section.

Modelling impacts on GB

2.54. In this section we look at the impact that market developments and shocks could have on GB security of supply. Our focus is on interruptions to physical supply. However, gas market developments and shocks will also impact prices. We discuss potential price impacts at the beginning of the next chapter.

2.55. We have taken two approaches to assess the potential impact that gas market developments and shocks might have on physical gas supply to GB. First, we use a probabilistic approach to model the possibility of outages based on the frequency and severity of historic events. Second we apply resilience analysis to look at the impact of losses of supply sources on different customer groups, without assigning probabilities to these losses. We discuss these approaches in turn below.

Probabilistic modelling

2.56. It is difficult to predict the exact nature of geopolitical events. It is also very difficult and in many cases impossible to predict the probability of occurrence. However, for infrastructure outages and some global supply chain events it is possible to make some high-level assessments of their impacts and probabilities of occurrence. This is based on the frequency and severity of historic events. We have used the same model that has been developed to test the effectiveness of the proposed reforms to cash-out arrangements to investigate how some of the risks associated with infrastructure outages and global supply chain events, discussed above, may impact the GB gas market. The probability distributions associated with the different infrastructure outages and global supply chain events can be found in the associated Modelling Appendix[63].

2.57. Figure 6 below presents the high-level results from our modelling. It shows the probability of an interruption for five different categories of customers, presented as a 1 in x year chance of occurring. It indicates that while no category of

[63] See: http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/gas-security-of-supply-report/Documents1/Redpoint%20further%20measures%20modelling%20report%20final.pdf

customer is free from any risk of interruption, in most cases the probabilities of interruption are very small.

2.58. For example, domestic electricity and gas customers are the least likely groups to face an outage, with an average probability of interruption of 1 in every 316 and 162 years, respectively. In the electricity market, this is due to a number of mitigating factors, including distillate back-up for gas-fired generators[64], which would allow some CCGTs to continue to run in the face of low/no gas supplies. Running CCGTs also tends to only be necessary to meet domestic electricity demand during peak times. Even so, these results bring out the close interactions between the gas and electricity markets.

2.59. The results for domestic gas customers reflect the cushion that National Grid can create by diverting gas from CCGTs in the face of an emergency. Also, as this analysis assumes the proposed cash-out reforms have been enacted, we assume increases in gas demand side response (DSR) in the I&C sector, which should act as another cushion to domestic electricity and gas customer demand.

Figure 6 – Probability of interruption (under reformed cash-out), Green Scenario[65],

	2012	2016	2020	2030	Mean
Firm DM gas	1 in 136	1 in 214	1 in 150	1 in 100	1 in 140
NDM gas	1 in 150	1 in 214	1 in 188	1 in 125	1 in 162
Firm I&C electricity	1 in 71	1 in 52	1 in 88	1 in 107	1 in 74
Domestic & SME electricity	1 in 500	1 in 136	1 in 375	1 in 1500	1 in 316
Distillate	1 in 10	1 in 4	1 in 4	1 in 4	1 in 5

Note: Firm DM gas: daily metered customers are large industrial consumers.
NDM gas: non-daily metered include domestic consumers.
Source: Redpoint Energy

Resilience analysis

2.60. Our second modelling approach focuses on the impact of shocks to GB supplies and uses resilience analysis to understand the level of defence that our

[64] In a 2010 analysis (available online) Poyry indicated that there was 8.1GW of CCGT plant with distillate back-up connected to the GB grid. Based on recent permanent and temporary closure announcements, this could fall to as low as 3.3GW by the end of 2013, although some of this capacity could return following a period of mothballing. Of the 10GW of proposed CCGT new build in 2010, just 1.3GW planned to include distillate back-up.
http://www.decc.gov.uk/assets/decc/what%20we%20do/uk%20energy%20supply/energy%20markets/gas_markets/114-poyry-gb.pdf

[65] We note that there are some minor differences between the results in the above table and the results that we published in the Gas SCR Proposed Final Decision. These have arisen due to an error in the modelling assumptions of the average frequency of supply outage of Long Range Storage. Further details are provided in section 4 (page 19) of Redpoint's modelling report Energyreport. We have found that the error has little impact on the results, and no impact on the conclusions drawn from these results. We have amended the base case results in Table 6, but have retained the results presented in the Gas SCR Proposed Final Decision document for the sensitivities presented and modelling of further measures to enable consistent comparison (these results as labelled counterfactual).

supply and storage infrastructure provides GB customers under extreme circumstances. The analysis makes no assumptions around the cause or likelihood of the shock, only whether remaining supply and storage infrastructure is sufficient to meet demand.

2.61. We have looked at market resilience in two ways. First we present the findings from stress tests. These stress tests have been designed to reflect a combination of extreme events to understand whether future levels of supply and storage infrastructure in GB would be sufficient to cover large outages to supply and high demand. Second, we present the findings of our critical loss analysis. This analysis has looked at the size of the outage required to result in an interruption to different customer types.

2.62. The results of the resilience analysis highlight just how much supply infrastructure in GB would need to be unavailable before non-domestic or domestic gas customers are affected. Our stress tests indicate that even with losses to the Langeled pipeline, the IUK interconnector and a 25% reduction of LNG supplies, in an average winter, all demand would be served on a peak day and across winter in both 2015/16 and 2020/21 using remaining supplies and storage stocks.

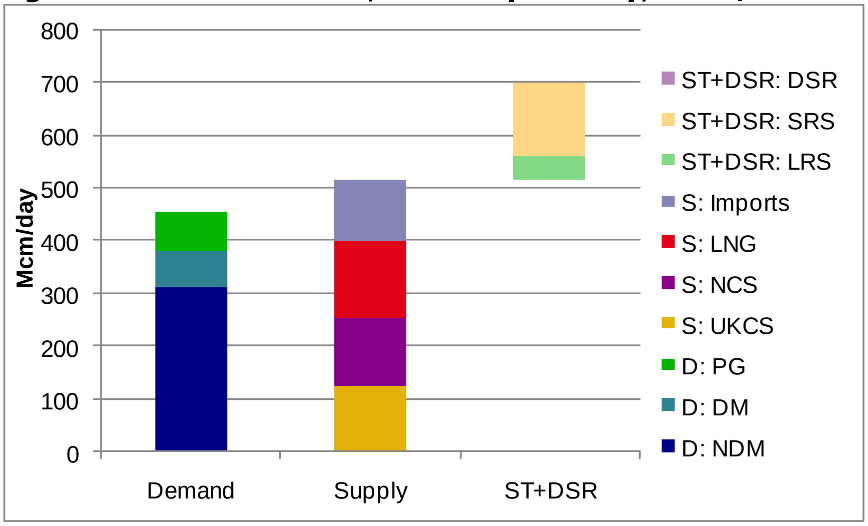
2.63. The results of our critical loss analysis show that depending on the severity of winter, we would have to lose between 60% and 70% of all gas sources for there to be an interruption of supplies to domestic consumers, assuming storage is 50% full at the start of the winter. To put these values in context, a 60% loss in non-storage supply would represent losing all LNG supply, IUK and BBL imports and a reduction in current UKCS supply of 50%.

2.64. Under normal circumstances, with import and storage infrastructure functioning to the full extent, it is important to recognise that the GB market is very well supplied. This can be seen in Figure 7. This presents our forecast for 1-in-20 winter peak day demand in 2015/16 for the Green scenario. The stack on the left hand side of the diagram gives the winter peak day demand, separated by domestic, non-domestic and power generation demand. The stack in the middle of the diagram presents the total available de-rated[66], non-storage supply available to GB in 2015/16 and the stack on the right hand side of the diagram shows the rate of storage deliverability.

2.65. The diagram indicates that on a 1-in-20 peak day, non-storage supply would be sufficient to meet all demand without the need to call upon storage. In the stress test analysis that follows, we treat storage as the marginal source of supply, but recognise it may not be the last source to be utilised.

[66] To better reflect the historical performance of supply infrastructure, we have applied de-rating factors to all pieces of supply infrastructure to reduce their rates of deliverability with respect to reported maximums. A detailed overview of the assumptions made can be found in our Risks and Resilience Appendix.

Figure 7: Green Scenario, 1-in-20 peak day, 2015/16

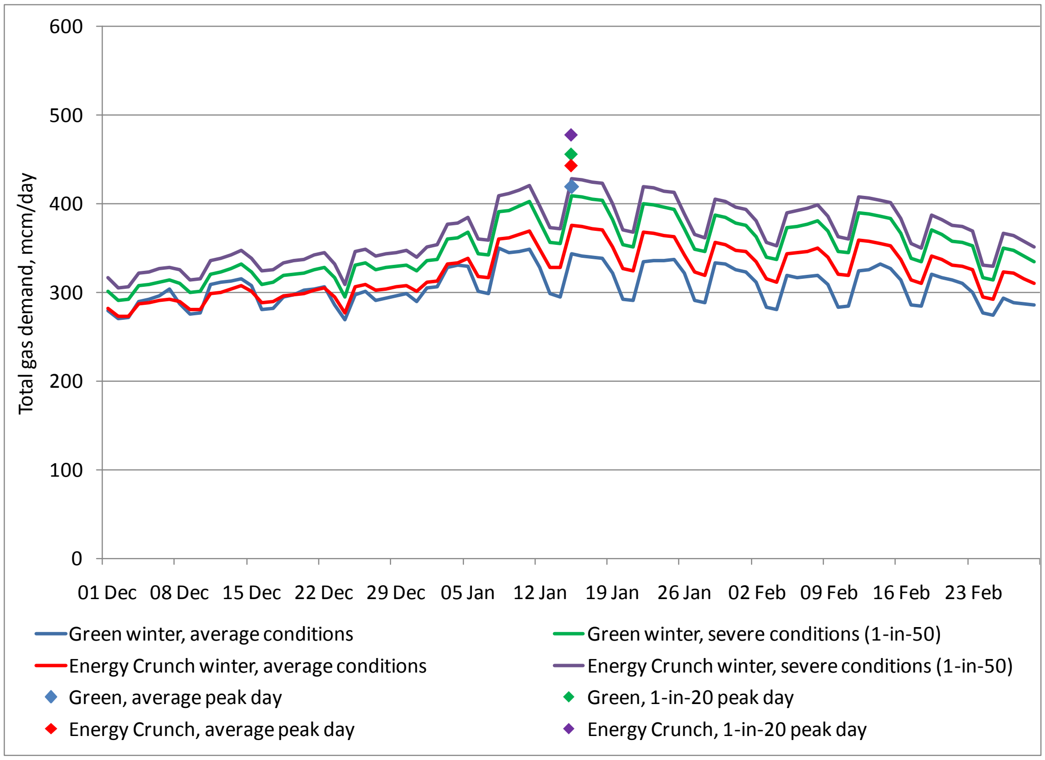


Source: Redpoint
Note: D: demand, PG: power generation, S: supply, ST: storage, LRS: long-range storage, SRS: short-range storage, DSR: demand-side response.

2.66. In addition to testing the resilience of GB supply infrastructure for a peak day, we also complete the analysis over an entire winter, with varying levels of demand. Figure 8 highlights the range of demand forecasts used in the resilience analysis. The figure shows both the winter profiles (lines) and peak day figures (chevrons) we use in our analysis. The lowest level of peak day and winter demand is in our Green scenario[67] under average conditions with the highest being our Energy Crunch scenario in severe conditions (either 1-in-50 winter[68] or 1-in-20 peak day[69]). The level of peak-day demand in the Energy Crunch scenario is around 500 mcm/day, which is some 10% above the highest gas demand day recorded in GB of 465 mcm/day on 9 January 2010.

[67] This is based on our Green scenario utilising National Grid's Gone Green demand figures.
[68] The volume of gas demand over a winter with average temperatures in line with the coldest expected in a fifty year period.
[69] The volume of gas demand on a peak day with temperatures in line with the coldest expected in a 20 year period.

Figure 8: Peak demand and winter profiles in 2015/16 with CCGTs running at normal levels



Source: National grid, Redpoint, Ofgem

Stress test analysis

2.67. Our stress test analysis consists of six tests of increasing severity. Test 1 studies the effect, under average winter conditions, of a loss of 70mcm/d. This is equivalent to the loss of our single largest source of supply, the Langeled pipeline and is part of the European Commission's Security of Supply Standard[70]. Test 2 repeats test 1, but under severe winter conditions. Test 3 combines a loss of Langeled with a loss of the IUK interconnector and a 25% reduction in LNG from our supply sources. Test 4 repeats test 3, but under severe winter conditions. Test 5 combines a loss of Langeled with a loss of both the IUK and BBL interconnectors and a 50% reduction in LNG from our supply sources. Test 5 is our extreme interconnector stress test and effectively models the removal of around half of maximum GB non-storage supply. Test 6 repeats test 5, but under severe winter conditions. We summarise the six tests in Figure 9, below:

[70] Members states must ensure gas supplies would continue to protected customers in case of the disruption of the single largest gas infrastructure under average winter conditions for 30 days.

Figure 9: Stress tests

Test	Description	mcm loss
1	Average conditions, minus 70mcm/d (N-1)	70
2	Severe conditions, minus 70mcm/d (N-1)	70
3	Average conditions, minus 70mcm/d, minus IUK, minus 25% LNG	170 – 180
4	Severe conditions, minus 70mcm/d, minus IUK, minus 25% LNG	170 – 180
5	Average conditions, minus 70mcm/d, minus BBL, minus IUK, minus 50% LNG	260 – 285
6	Severe conditions, minus 70mcm/d, minus BBL, minus IUK, minus 50% LNG	260 – 285

Note: mcm loss indicates the approximate range of losses in import infrastructure in each test across the two scenarios and two years we complete this analysis. Data presented to 2 s.f.

2.68. We have carried out each stress test in 2015/16 and 2020/21 and separately for our Green and Energy Crunch scenarios. In each scenario and for each year we have forecast the deliverability of supply sources and storage infrastructure. We have also completed the analysis for a peak day and over the course of winter[71]. Complete stress test input assumptions and results can be found in the Resilience Analysis Appendix.

2.69. Figure 10 presents the results of the stress tests. “OK” refers to a situation where the capacity and deliverability of non-storage supply sources are sufficient to cover all customer demand either on the peak day or throughout the whole winter without the need to call upon storage. “Storage needed” describes a situation where demand outstrips total levels of non-storage supply and storage is required to maintain supplies. “Interruption” means neither storage nor the remaining non-storage supplies are sufficient to meet total customer demand over the period of the analysis. In all cases, bar the winter analysis in tests 5 and the peak and winter analyses in test 6, remaining supplies plus storage are sufficient to meet total customer demand. If focusing on non-daily metered (NDM) customer demand (results not shown), supplies would cover NDM demand throughout winter in all of the tests, but storage would be needed for the peak days in test 5 and 6 and winter in test 6.

Figure 10: Stress test results for all customers, Green scenario (and Energy Crunch), 2015/16

Test	Peak day analysis	Winter analysis
1	OK	OK
2	Storage needed	OK†
3	Storage needed	Storage needed
4	Storage needed	Storage needed
5	Storage needed	Interruption
6	Interruption	Interruption

Note: † indicates storage needed in Energy Crunch scenario.
Source: Redpoint Energy analysis

[71] We define winter as the coldest three months of a year, namely: December, January and February.

2.70. The results for 2020/21 are shown in figure 11. For the peak day analysis, both the Green scenario and the Energy Crunch scenario require storage supplies under tests 2, 3, 4 and 5 to meet customer demand. Interruptions only occur in test 6. For the winter analysis, tests 1 and 2 show "OK" for the Green scenario, but "Storage needed" for the Energy Crunch scenario. For tests 3 and 4 the Green scenario shows "storage needed", for both tests, while under Energy Crunch an interruption is noted in test 4. Tests 5 and 6 show "interruption" in both cases for the winter analysis.

Figure 11: Stress test results for all customers, Green scenario (and Energy Crunch), 2020/21

Test	Peak day analysis	Winter analysis
1	OK†	OK†
2	Storage needed	OK†
3	Storage needed	Storage needed
4	Storage needed	Storage needed*
5	Storage needed	Interruption
6	Interruption	Interruption

Note: † indicates storage needed in Energy Crunch scenario, asterisks indicate interruption in Energy Crunch scenario
Source: Redpoint Energy analysis

2.71. The stress tests show that in all but the most extreme cases, current and forecast levels of GB supply and storage infrastructure are sufficient to meet all customer demand. Only in the tests where non-storage supply losses reach 50% of total is storage insufficient to meet total demand and some (non-domestic or CCGT) customers are interrupted. However, even in these cases domestic demand is protected.

Critical loss analysis

2.72. Our second approach to test market resilience looks at the proportion in non-storage supply infrastructure needed to avoid interruptions to the following four classes of customer:

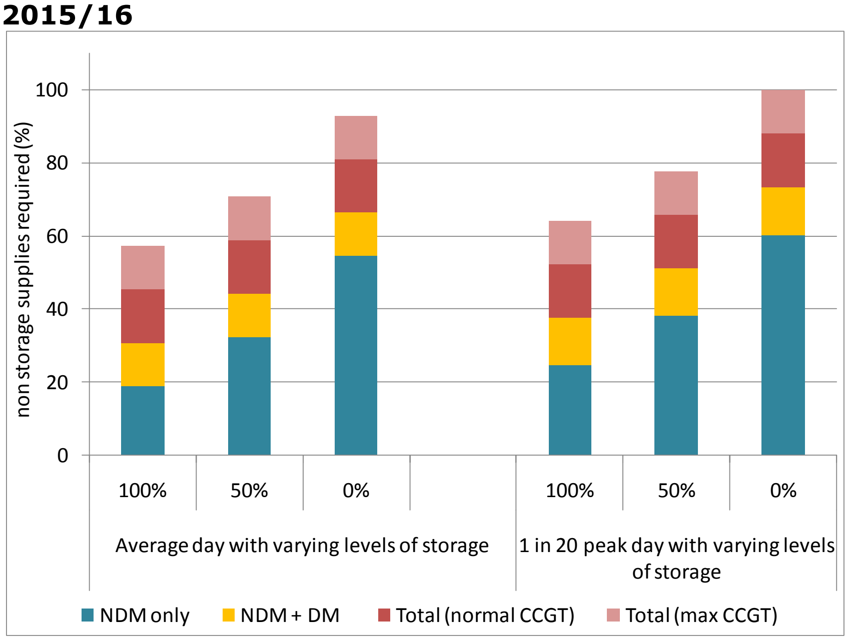
- CCGTs assuming they run at maximum levels
- CCGTs running at normal levels
- Daily metered (DM) customers (proxy for I&C demand)
- Non-daily metered (NDM) customers (proxy for domestic demand)

2.73. As with our stress tests we have also applied de-rating factors to supplies and carried out the critical loss analysis in 2015/16 and 2020/21 and separately for our Green and Energy Crunch scenarios. We have also completed the analysis for a peak day and over the course of winter. Complete critical loss input assumptions and results can be found in our Risks and Resilience Appendix.

2.74. Figure 12 presents the results of the peak day analysis for an average and a 1-in-20 peak day. Each bar represents the percentage of non-storage supply needed to ensure that the customer type does not risk interruption. For example, for the bar on the far left, showing the supplies needed on an average winter peak day with 100% storage availability, the percentage of non-storage supplies required to cover all NDM demand is only 20% of total. This implies that with full storage availability, the GB market could suffer a loss of 80% of its non-storage supply capacity before NDM customers were affected.

2.75. The other coloured bars present the percentage of non-storage supplies required to meet demand from the three other customer types. The top of the pink bar indicates the percentage of supplies required to cover CCGTs running at maximum capacity (just under 60% in the diagram); the top of the red bar indicates the supplies required to cover CCGTs running at normal capacity (around 45%), and the yellow bar indicates the supplies required to meet daily metered customers (around 30%).

Figure 12: Green Scenario, critical loss analysis, average and peak day, 2015/16

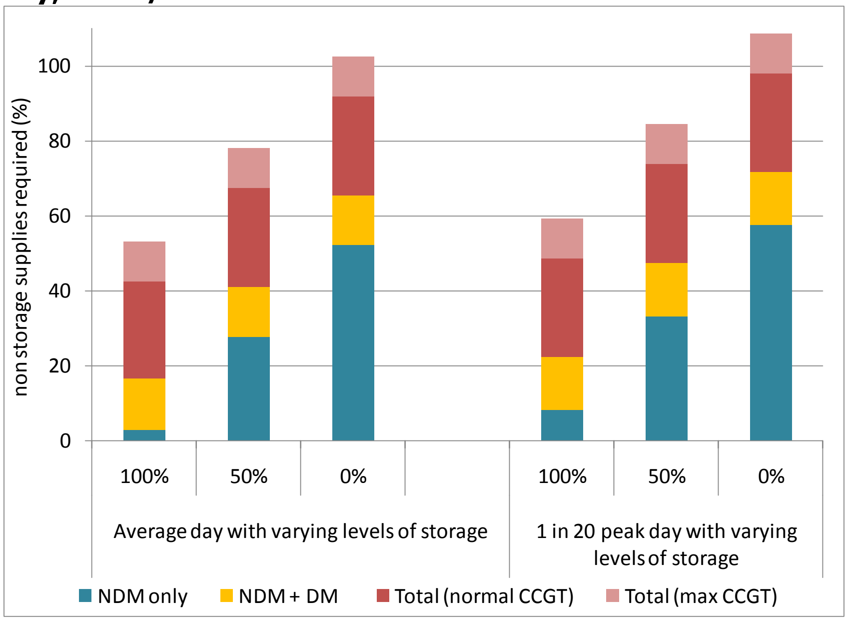


Source: Redpoint, Ofgem analysis

2.76. There is little change between the Green scenario results for 2015/16 (Figure 12) and for 2020 (results not shown). This is because we forecast only small decreases in gas demand between 2015 and 2020 and only small increases in supply. The results for the Energy Crunch scenario in 2015 are also similar to the Green scenario in Figure 12 owing to little divergence between the supply and demand conditions by 2015/16.

2.77. The most significant change is noted in the Energy Crunch scenario in 2020/21 (figure 13 below). Here, due to increases in forecast LNG and storage capacity, far less non-storage supply is needed to cover domestic customers. This is indicated by the very small green bar on the left hand side. However, due to higher forecast electricity demand, the height of the red and pink bars increases. The impact of this is most notable in the two tests with no storage. Here the pink bars in our average and severe scenarios are just above 100%. This indicates that in these cases there would be insufficient gas to supply CCGTs running at maximum capacity, as well as all NDM and DM customers.

Figure 13: Energy Crunch Scenario, critical loss analysis, average and peak day, 2020/21



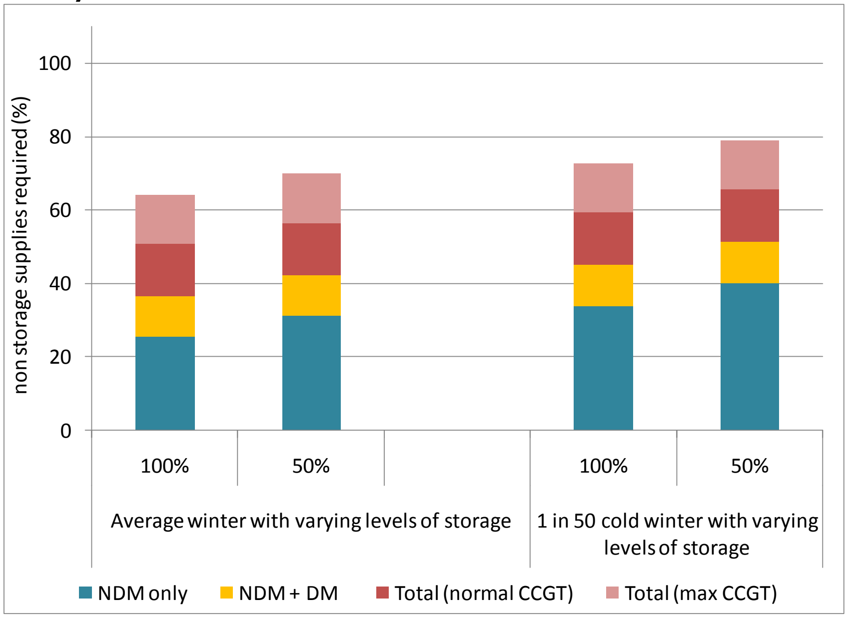
Source: Redpoint, Ofgem analysis

2.78. However, as noted earlier, a loss of gas supply to CCGTs may not lead to a cessation of CCGT generating activity due to the option for some CCGTs to call on back-up supplies of distillate. In addition, the pink bars assume maximum CCGT output for 24 hours and in this way provide a hypothetical maximum demand from CCGT generation. For example if it were required to run as a baseload source. We would normally expect gas-fired generators to run for only the peak 6 hours of the day[72].

2.79. Turning to the results of our whole winter analysis, this differs to the peak day approach, as it adds a constraint from storage capacity in addition to deliverability rates[73]. The whole winter analysis has been run for a case where there is 100% storage available at the beginning of winter and where there is only 50% available[74].

[72] Distillate switching and running gas-fired generation only at the peak 6 hours, could reduce gas consumption by power generators by as much as 80% against gas consumption at maximum output.
[73] In our peak day analysis, we assume storage delivers at its maximum deliverability rate. In our winter analysis, we use the same assumption, but limit the quantity that can be drawn upon over winter at the capacity of GB storage infrastructure.
[74] On average over the past 6 years, GB storage has been 94% full on 1 October.

Figure 14: Green Scenario, critical loss analysis, average and cold winter, 2015/16



Source: Redpoint, Ofgem analysis

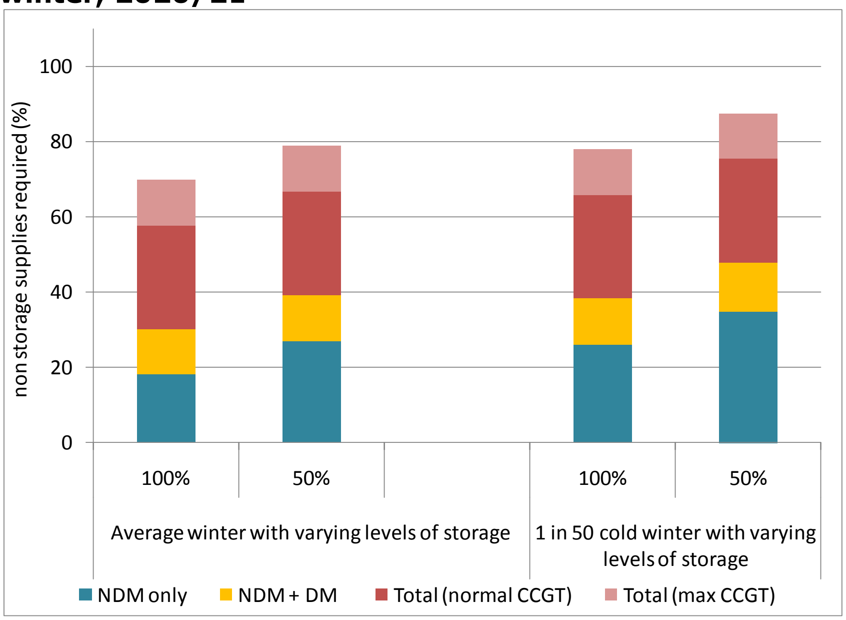
2.80. Figure 14 presents the results for our Green scenario in 2015/16. In the case where storage is full at the start of winter, the required supplies are slightly above those for the peak day analysis with 100% storage availability (depicted by slightly higher bars in the chart). This is because, over winter, storage volumes decline and many MRS and SRS sites empty completely. This dramatically reduces the maximum deliverability of storage, resulting in higher bars on the charts. This means the proportion of supply that could be lost over winter before some customers might face interruptions is lower than in the peak day analysis. However, where storage facilities start the winter at 50% capacity, the heights of the bars are similar to those in the peak day analysis. This indicates that in both winter and peak day analyses, with 50% storage availability, storage deliverability is the binding constraint, producing similar results for both peak day and winter analyses.

2.81. The results of the Energy Crunch scenario in 2015 (not shown) are very similar to those in the Green scenario (Figure 14). The 2020 results for the Green scenario (not shown) are also similar to the 2015 winter analysis. The Energy Crunch scenario, in 2020 (Figure 15), has slightly lower green and yellow bars compared with the Green scenario. This is because the Energy Crunch scenario includes higher forecast levels of storage, which mean lower non-storage supply is required to meet demand[75]. However, as seen in the peak day analysis, the Energy Crunch scenario

[75] The Green scenario assumes that only storage facilities currently under construction are built during this outlook period, in line with the timelines set out in the 2011 Ten Year Statement. As a result, no additional long-range storage facilities are constructed, while the completion of Stublach adds an additional 400mcm capacity and 32mcm/day deliverability to short-range storage by 2015. The Energy Crunch scenario assumes that market signals lead to the construction of an additional 2.5bcm of long-range storage capacity (49 mcm/day deliverability) by 2020, and an additional 100mcm of short-range storage capacity (18mcm/day deliverability) above that assumed in the Green scenario.

includes higher forecast levels of electricity demand which results in a higher supply requirement from CCGTs. This is seen by the higher red bars in figure 15 compared with the Green scenario in figure 14. Broadly, in the Energy Crunch scenario, across 2015 and 2020, between 75% and 80% of non-storage supplies (again assuming storage at 50% at the start of winter) are needed to avoid a curtailment of gas supplies to power stations. This is the same as saying GB could suffer a loss of gas supply of between 25% and 30% before CCGTs in this scenario would risk losing supply.

Figure 15: Energy Crunch Scenario, critical loss analysis, average and cold winter, 2020/21



Source: Redpoint, Ofgem analysis

2.82. Overall, our quantitative analyses show two important findings. First, using reasonable assumptions around the probability of infrastructure and supply outages, our stochastic modelling indicates that the chance of interruptions occurring to DM and NDM customers is extremely small. Second, our market resilience analysis shows the significant size of non-storage supply infrastructure failure required before non-domestic or domestic customers might be affected.

2.83. However, a key assumption to the resilience analysis is that available supply sources deliver without obstruction and follow price signals at times of stress beyond the de-rating factors we have already applied. We have already discussed some concerns around the price responsiveness of interconnectors. We return to this in the next chapter together with a number of factors we highlight as potentially impeding the proper functioning of gas markets and that could lower the likelihood of supply sources to deliver when expected.

3. Market effectiveness

Chapter Summary

In this chapter we discuss a number of behavioural and institutional factors, already present in the gas market that may reduce its effective operation. Either by themselves, or combined, these features may reduce the ability of markets to respond in a way that is expected or that best meets the interests of consumers or wider society.

3.1. All markets operate with uncertainty and the risk of shocks to supply and demand. These are typically managed through adjustments to supply, demand and price to ensure continuity of service and supply. In this chapter we present a discussion on a range of factors that may reduce the market's ability to respond in a way that best meets the interests of consumers and aligns with security of supply objectives. These include specific factors associated with European and global gas market functioning, in addition to a range of institutional and behavioural factors that may influence the actions of market participants to the detriment of security of supply.

3.2. This chapter is split into three sections. We start by considering how the market developments and shocks, discussed in chapter 2, may impact gas prices and how this may result in risks to infrastructure investment and ultimately supplies. We then discuss a number of features of the European and global gas markets that may limit its effective operation. Finally, we look at a number of possible distortions to agents' behaviour regarding risk management.

Price effects and risks to security of supply

3.3. As with other commodities, global gas market conditions will impact on global gas prices. Price cycles tend to mirror investment intensity, with high prices incentivising investments in supply or transportation infrastructure, followed by a period of lower prices as market tightness recedes. These medium-term commodity price cycles will have important implications for GB consumers, although in the short run, there is little that can be done to avoid these effects as they are driven by global supply and demand fundamentals.

3.4. Projecting future price trends and medium-term commodity cycles is notoriously difficult. However it is possible to make some high level comments. For example, currently there are significant differences in regional gas pricing with Japanese LNG prices at 122p/therm, GB NBP prices at 60.2p/therm and US (Henry

Hub) prices at 22.3p/therm[76]. There is a risk that further tightening of global markets could result in European and GB hub prices rising towards Japanese levels.

3.5. Over time, higher prices should incentivise investments globally and in GB, reducing the risk of a prolonged impact on GB consumers. However, if new investment is insufficient to meet growing demand, cycles will be of a fairly long duration. Estimates of GB (NBP) prices for 2020 range from 41p/therm to 102p/therm[77].

3.6. However, it could be a concern if features of the market resulted in GB consumers being disproportionately exposed to price spikes and medium term price cycles compared to neighbouring markets. While we have a broader diversity of supply sources, we have less gas storage relative to our consumption than any other major European economy and less of our gas is purchased under long term contracts. While this flexibility makes it possible for GB consumers to benefit at times of low prices, as the flexibility and stability provided by North Sea production declines, GB consumers could be more exposed to seasonal swings in gas prices and medium term volatility.

3.7. This may well be counter to what consumers in GB want to happen to energy prices. However, there are few mechanisms that allow consumers to express this desire. One way would be to enter a fixed price contract with their supplier, which would expose a preference for price stability. Few suppliers offer fixed price contracts longer than one or two years (with some notable exceptions); therefore consumers are not able to express a preference for long-term price stability (say 5 or 6 years).

3.8. In addition to medium-term price effects, sudden changes in supply and demand from the types of domestic and/or external shocks discussed above, will also impact gas prices in the short run. It is useful to distinguish two types of short run price dynamics: The first, price volatility, refers to price variations from one period (e.g. today's price) to the next (tomorrow's price). It can be measured using the variance or standard deviation of a series of prices. The higher the volatility, the greater the risk or uncertainty surrounding price changes for a given period. The second is a one off price spike. This refers to a quick, temporary and largely uninterrupted rise or fall in prices. In the UK gas market these spikes have tended to last from hours to a couple of days.

3.9. Under normal circumstances, neither of these two short-term price effects is likely to lead to significant consumer detriment. Price spikes and volatility are important elements of market dynamics, signalling shortages, which enable market participants on the demand and supply side to respond. Furthermore, suppliers are able to hedge their gas purchases, smoothing the price they pay for gas and avoiding the effects of price spikes and volatility. However, volatility might lead to consumer

---

[76] Source: Bloomberg, average prices in September 2012.
[77] In 2012 prices, DECC fossil fuel price projections 2012

detriment if it became very large and unpredictable, or no longer reflected market fundamentals due to missing or wrong information, or speculation and panic.

3.10. If volatility became very large, it would create significant uncertainty that would increase risks for producers, traders, consumers and governments. Under these circumstances risk-averse behaviour could lead to suboptimal gas purchase and investment decisions. It may also render an efficient investment project uneconomic as the greater risks result in a higher cost of capital. Suboptimal levels of investment or gas purchase strategies are likely to pass through to consumers as higher costs. In such cases, some form of intervention may be necessary to facilitate the actions needed to reduce very high volatility or avoid its continued detrimental effects.

Features of the gas market that reduce its effective operation

3.11. If the transition of the GB gas market from self-sufficiency to becoming a net importer is to continue to be a smooth one, the effective operation of European and global gas markets is key. However, there is evidence that the supply of gas through pipelines from Europe and from global LNG might not always be fully reactive to market fundamentals. We discuss, in turn below, factors that may reduce the effective operation of European and global markets.

Interconnectors with continental Europe

3.12. The Third Energy Package was agreed in 2009 and, amongst other things, provides for legally binding European Network Codes to implement more detailed rules where necessary, creates the Agency for the Cooperation of Energy Regulators (ACER) and gives National Regulatory Authorities powers to enforce these rules and principles and obliges regulators to cooperate across borders. Through this cooperation regulators proactively work on a range of topics, including through the Council of European Energy Regulators (CEER). The Gas Target Model[78] sets out a vision for well functioning and connected European wholesale markets and, building on existing European legislation, calls on European regulators to identify measures to achieve this goal.

3.13. At a time of GB scarcity, interconnectors or Norwegian pipelines are more likely to import into GB if our prices signal that we need more gas. However, this assumes the shocks driving GB demand are not also occurring in neighbouring countries and arrangements at interconnector points and in each market allow for gas flows to respond to price signals. Gas flows from Norway to continental Europe are often covered by long-term take-or-pay contracts, which means that available gas may be required to flow to continental Europe, even though the market price in GB is higher.

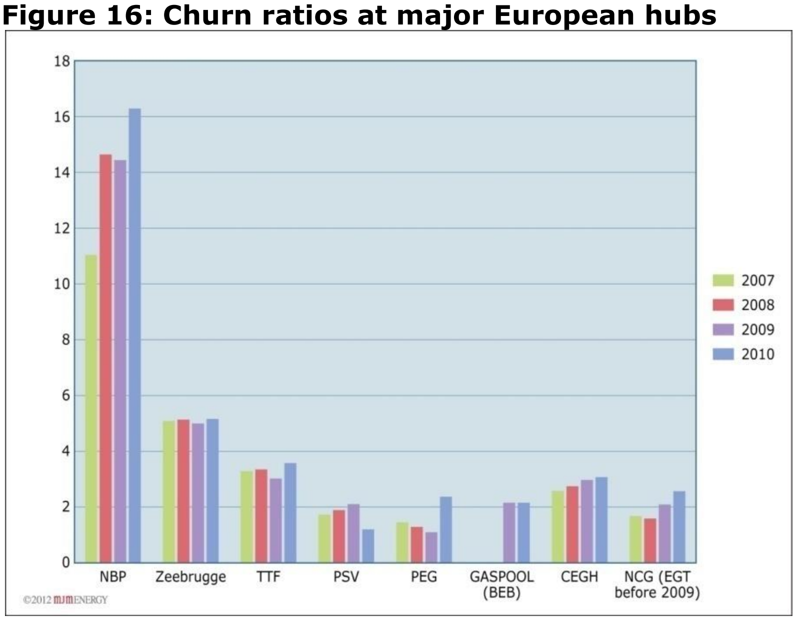
---

[78] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/GAS/Gas_Target_Model/CD/C11-GWG-82-03_GTM%20vision_Final.pdf

3.14. Initial Ofgem analysis (and evidence from the Competition Commission[79]) suggests that gas flows through the interconnectors with continental Europe are not always price responsive and that not all available capacity is utilised. For example, large price differentials are often associated with utilisation below maximum levels, and gas flows can flow in the opposite direction than expected[80]. For example, according to initial Ofgem analysis, aggregate daily utilisation levels on IUK and BBL are typically below 50% of maximum capacity[81].

3.15. In terms of physical volumes, traded volumes and churn rates, all continental spot markets are smaller and less liquid than NBP (although this situation is still a significant improvement in comparison to previous years). The churn rates of the major European hubs are shown in figure 16; the churn rates in Belgium and the Netherlands were higher than in other continental hubs though were still considerably lower than in GB between 2007 and 2010.

Figure 16: Churn ratios at major European hubs



Source: MJM energy

3.16. Liquid markets should allow GB shippers to enter into the relevant market, access the products they need and trade at robust prices (formed by a depth of trading) which reflect market fundamentals. The lower the levels of liquidity on continental European hubs, the harder it is for GB shippers to access the gas they might need from those hubs economically.

3.17. It is important that flows of gas through interconnectors are responsive to price differentials and all capacity is utilised where it is efficient to do so. This could

[79] Competition Commission (2011), Review of undertakings given by Centrica following acquisition of the Rough Gas Storage facility, see page 35
[80] This is even true when allowing for a reasonable level of marginal costs shippers may face.
[81] If flows are fully responsive to hub prices, gas should flow from the low hub price area to the high hub price area at an interconnector's maximum capacity. This number is partly affected by outages due to technical reasons.

be of vital importance in an emergency situation. While our initial analysis gives us cause for concern, we recognise that this is a complex area and that flows will be influenced not only by the interconnector's capacity allocation mechanisms, but factors in neighbouring markets, the GB market and/or the interface between these markets.

3.18. The Third Package contains a range of measures which are aimed at increasing the efficiency of cross-border flows across the EU. The effectiveness of these policies will depend on how they are implemented on the interconnection points between markets. Questions remain as to how to enhance market integration. To come to a view on what (if any) barriers to cross-border trade exist and which are the most significant we have published an open letter, in collaboration with the Belgian and Dutch regulators, calling for views on how to enhance market integration and the issues that need to be considered in seeking to remove any barriers to cross-border trade.[82]

Gas quality arrangements

3.19. Gas appliances and equipment in GB and Ireland are designed to operate using gas with the quality of gas from the UK Continental Shelf (UKCS) - a different gas quality to that used in continental Europe. If significant quantities of gas were required quickly from Europe to meet GB demand (potentially in an emergency situation), this could mean the rate of flow to GB from Europe is not as high as it could be, due to the time taken for gas quality adjustments to be made before the gas can enter the GB gas transmission system.

3.20. The Interoperability and Data Exchange Framework Guideline includes guidance on how TSOs should work together on mutually agreeable solutions in cases where gas quality differences are found across an interconnection point. The Framework Guideline (and subsequent Network Code) will not require gas quality harmonisation across Europe but instead will focus on ensuring that where gas quality differences are found, they are not permitted to become barriers to cross-border trade.

3.21. Future gas quality related barriers to trade might be mitigated by the fact that Fluxys (the Belgian TSO) has invested in a new gas ballasting facility (where gas quality can be adjusted) in Zeebrugge, which connects to the IUK interconnector. However, Fluxys has recently consulted on a charging regime related to gas quality variation that could decrease price responsiveness of gas flows into GB via Belgium. This is because the cost of gas quality adjustment would be passed on to shippers, thus increasing the GB-Belgian price differential necessary to signal shippers to flow gas to GB. Ofgem will consult with Fluxys as the charging methodology proposals develop, so as to monitor any potential detrimental effects on security of supply.

[82] http://www.ofgem.gov.uk/Europe/Documents1/120928_Interconnector_Open%20Letter%20Final.pdf

Public service obligations in Europe

3.22. European legislation permits public service obligations (PSOs) relating to security of supply. There are a range of obligations across European countries that put different requirements on the domestic supply companies to ensure gas would continue to flow at times of stress. Figure 17 summarises the PSOs and other regulatory requirements which are pertinent to security of supply in a number of major Western Europe countries.

Figure 17: Western European Countries' public service obligations and other notable regulatory requirements

COUNTRY	DESCRIPTION
Austria	In an emergency situation the ministry can impose *ad hoc* conditions for storage use, production, transportation, orders to end users, and regulate imports and exports.
France	Storage levels must reach a certain level by 1 November each year. Suppliers must ensure supplies to protected customers even in the event of high demand or a loss in supplies.
Germany	Suppliers must ensure supplies to non-interruptible customers at any time even in the event of high demand or a loss in supplies as long as it is economically reasonable. It is thought that this obligation is discharged via contracts with TSOs and storage operators/providers. Provisions in legislation can obligate power companies to keep sufficient stocks to generate electricity for 30 days.
Italy[83]	There is strategic storage of around 5 bcm which is reserved for emergency conditions. Storage fullness is also regulated with upper and lower bounds set for each month. The regulator also has information gathering powers in order to monitor the market. Oil stocks need to be held at gas power stations.
The Netherlands	The TSO is required to supply gas that equals peak demand during extreme cold weather conditions. It is thought that this obligation is discharged through contracts with GasTerra and Gasunine.
Spain[84]	A storage obligation requires that 20 days of gas demand is in store for winter. Import diversity requirements limit the amount of gas that can be sourced from one location.

Source: Ofgem analysis of various sources

[83] During the recent Russia / Ukraine gas dispute Italy decreed that all importers should nominate to the maximum of their contracts.
[84] If the gas system manager (emergency coordinator) is required to balance the system then a balancing charge is set based on a mark up of NBP and Henry Hub.

3.23. The PSOs that prevail in Europe can be categorised into one or more of the following categories:

- Enhancement to the supply side: For example, those that require certain levels of stocks;
- Supply standards: Those that require demand to be met under a range of conditions; and
- Ad hoc or interventionist arrangements: Those that allow a Member State to intervene in the market (e.g. by regulating storage flows, imports or exports flows).

3.24. If PSOs are transparent and are used in the way the market expects, market participants will be able to forecast and manage the potential impact of a PSO. On the other hand, where there is uncertainty about how market participants will honour their PSOs, once triggered, or if Governments enact surprise interventions without warning, the market will struggle to manage these risks effectively. This increases the uncertainty around whether gas would flow from Europe in response to price signals from a gas emergency in GB. We recognise that the EU Security of Supply Regulation promotes greater solidarity and cooperation between Member States in relation to security of supply and gives the Commission (and Member States) a greater formal role in scrutinising and influencing measures of other Members States taken to ensure security of supply. It also seeks to prevent Member States from implementing measures to ensure security of supply that could endanger the security of gas supply of other Member States or of the Union as a whole. Such regulatory developments should help to reduce potential detrimental effects of European PSOs on GB security of supply.

3.25. Furthermore, European regulators have already undertaken a process to identify a Gas Target Model for enhancing market integration. This identified steps to ensure that gas flows to where it is valued most. Legislation is already underway to achieve this, but regulators also committed to look at what further steps may be needed. As noted above our call for evidence on use of the gas interconnectors, in collaboration with the Belgium and Dutch regulators, is one example of such an initiative.

The price responsiveness of LNG

3.26. The same Competition Commission report that investigated the price responsiveness of interconnectors also found a lack of price responsiveness from LNG supplies. The CC report includes a number of examples that suggest LNG supplies might not be best relied upon to provide supplies at short notice, for example, during an emergency. National Grid comments in the report that it thinks an NBP price spike over a small number of days, would still be insufficient to change the dynamics of LNG cargo destinations[85]. Centrica also comments saying that their understanding is that it typically takes around 30 days to deliver an LNG cargo to GB from the date it

[85] Competition Commission (2011), Review of undertakings given by Centrica following acquisition of the Rough Gas Storage facility, Appendix C, p 11

is sourced (the duration being dependent on the location of the source). The CC concludes that logistics chains and the nature of LNG contracts mean that LNG supply is unlikely to represent a sustainable source of short notice supply compared with traditional gas storage.

3.27. The CC report also explores whether LNG storage capacity could present a source of short-term flexible gas. While the CC note that transmission rates from LNG storage can vary, they highlight a number of constraints that limit the flexibility of supply from LNG storage. First, LNG storage capacity is not large and so only able to accommodate a small number of cargoes. With tight shipping schedules LNG gas could not be held in storage for long before being transmitted to make space for the next cargo. Use It or Lose It rights (UIOLI—which allows unused capacity to be made available for others to bid for) also make it difficult to plan to vary the rate of transmission. The CC concludes that they have seen no strong evidence that stored LNG could be relied upon to be released in response to price or demand changes.

3.28. Finally, the CC used GB price data from 2009 and 2010 to test whether there was a statistically significant positive relationship between LNG flows and day-ahead NBP prices. The CC found no such relationship. However, they did not attach weight to these results, due to the short time period of the analysis. In recent years, this picture may have changed. National Grid in their 2011/12 and 2012/13 Winter Outlook Consultations show the flexibility of LNG terminals during times of high demand. In the 2012/13 Winter Consultation, National Grid report that when demand rose above 400mcm/day, the "supply response [was] dominated by LNG and Storage"[86].

3.29. During our interviews, a number of interviewees also raised concerns with the level of political influence over the LNG market. In particular, they highlighted the importance of maintaining strong diplomatic relationships with exporting countries. Whilst it seems GB has benefited from this to date, it will be important that GB continues to maintain strong relationships and that efforts are made to further improve the liquidity and efficient operation of the global LNG market.

Effectiveness of domestic infrastructure

3.30. We end this subsection with a short comment on the importance of the effectiveness of GB domestic infrastructure to respond to changing market dynamics. As discussed above, there are likely to be significant increases in the volatility of GB gas demand in the future. Both supplies and the transmission infrastructure will need to work effectively to both bring in and then distribute the gas to the relevant loads when required. On the latter point, National Grid Gas has raised concerns over the capability of the transmission network to deal with the gradual reversal (from North to South) and large swings in gas flow patterns.

[86] National Grid Winter Outlook Consultation 2012/13, pp 68, http://www.nationalgrid.com/NR/rdonlyres/9721EF19-2BA8-4DBD-880D-90406603C176/54880/WinterConsultationReport201214.pdf

3.31. In its RIIO-T1 submission, National Grid Gas has asked Ofgem to clear some capital expenditure to address changing gas transmission network flow patterns required by its users. This includes expenditure to reverse flows to support diminishing UKCS flows from St. Fergus; additional compression capacity in the South West; an unspecified quantity to deal with the dynamic nature of future flows (wind intermittency, central corridor congestion), and initial investments to fund projects to investigate future requirements.

3.32. At this stage, Ofgem believes only the funding for projects to enable reversal of flows towards Scotland to support peak demand and a contribution towards the future requirements projects are deemed appropriate. Instead Ofgem has set out in its Initial Proposals, published 27 July, to have a mid-period re-opener to give NGG a chance to build a more detailed case for specific investments. In addition, Ofgem will develop an uncertainty mechanism to allow NGG scope to acquire additional funding during the price control if it becomes apparent that it is required.

Agents' behavior regarding risk management

3.33. In this section we set out a number of behavioural factors that may reduce the ability of markets to respond in a way that best meets the interests of consumers or wider society. These exist in all markets, but may be of greater concern in markets of strategic importance to consumer welfare or the economy.

Myopia and short-termism

3.34. Myopia and short-termism results in investors placing greater weight on near-term earnings than those further in the future[87]. Short-term incentives also mean market participants may not respond rationally to price signals to allocate supplies and in investment decisions. In the context of infrastructure investments, such as gas storage or import terminals, myopia and short-termism leads to investors following strategies that maximise short-term profits. Such a strategy is likely to overlook large infrastructure investments that have payback periods over many years.

Challenges of capital intensive investment

3.35. Investments in gas infrastructure, whether LNG facilities, transmission pipelines or storage are long-term and highly capital intensive. This means there are specific challenges around financing such investments when returns are dependent on volatile and uncertain prices, particularly in the context of the ongoing financial crisis. For example, greater price uncertainty leads to greater project risks. This could lead to equity investors requiring a higher rate of return for their investments

[87] Hall, B.J. and Weinstein, D.E. (1996) The Myth of the Patient Japanese: Corporate Myopia and Financial Distress in Japan and the US, NBER Working Paper; Sewell, M. (2010) Behavioural Finance, behaviouralfinance.net, retrieved 04 October 2011, and Bushee, B.J. (2001) Do Institutional Investors Prefer Near-Term Earnings over Long-Run Value?

or limit the level of gearing that investors can apply to the project. Both these effects are likely to lead to an increase in the cost of capital for the investment.

3.36. A higher cost of capital will affect whether a project goes ahead or not. The cost of capital equals the payback required by investors. If the cost of capital rises too high, investors may deem the project un-financeable under current financial conditions.

3.37. Other market developments may also complicate investments in storage infrastructure. For example, in recent years the seasonal price spread in GB has narrowed significantly[88]. Hedging against the seasonal spread is one of the key reasons shippers use storage, therefore a fall in its level will lower demand for seasonal storage facilities.

Belief that government will intervene in a crisis (moral hazard)

3.38. If suppliers believe that the Government will intervene to either prevent or alleviate the effects of a physical interruption then they will not themselves undertake the appropriate measures to mitigate the impacts themselves. The existence of moral hazard is supported by evidence in other sectors. For example, safety nets and bailout expectations in the banking industry lead to additional risk taking[89].

Social costs to physical interruption higher than the private cost to suppliers (externalities)

3.39. The costs of a physical interruption to gas supply consist of private costs that are incurred entirely by suppliers responsible for the interruption (eg 'cash-out' charges), and wider social costs that are incurred by society (eg providing shelter, heating and food to disconnected consumers and damages due to social unrest). To the extent that suppliers are not facing the total costs of their actions, then they will likely under-invest in preventive measures. This reasoning rests on the concept of *externalities* – the situation where the consequence of an economic activity (or lack thereof), is experienced by unrelated third parties. In the case of a supply disruption, the Government will incur the humanitarian costs of protecting vulnerable customers.

---

[88] See para 79 http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/1065/106508.htm

[89] Dam, L., Koetter, M., (2012), "Bank Bailouts and Moral Hazard: Evidence from Germany", The Review of Financial Studies, Oxford University Press. Available here: http://rfs.oxfordjournals.org/content/early/2012/04/18/rfs.hhs056.abstract

Difficulty for domestic customers to learn about or express their level of security

3.40. Extreme events that might result in shortages are very rare and, as a result, difficult to predict[90]. This makes it difficult for customers to understand their level of security or the implications of such events which may increase the likelihood consumers do not sufficiently insure themselves against them. Individual-level behavioural aspects also lead to under-preparedness: for example, an innate difficulty in thinking about abstract probabilities as opposed to observed events. We therefore do not consider it appropriate that customers bear the risk associated with extreme events as, in general, they have the most limited means to assess and manage their exposure.

Conclusions

3.41. The following summarises the findings and implications of the analysis presented in chapters 2 and 3 of this report. Chapter 2 set out the significant changes that have taken place in the GB gas markets in recent years. Of most importance has been the declining level of UKCS production. As recently as 2003, GB was still a net exporter of gas, but such has been the speed of decline that GB is now no longer able to meet average peak day or winter gas demand from its own supplies and storage (although levels of storage and UKCS production are still high enough to supply domestic demand alone).

3.42. The market has reacted to these changes and, as production has declined, there have been significant investments in import infrastructure, both pipeline and LNG. These investments have been considerable: for example there has been a five-fold increase in GB gas import capacity in the last decade. GB now sources as much of its gas supplies separately from LNG and the Continent as it produces itself.

3.43. With declining production, new and diverse import infrastructure is good for GB security of supply. However, new sources of gas bring with them new risks and old risks remain. These risks have been explored in a range of reports in recent years, including Ofgem's Project Discovery, the Wicks Review and the Pöyry reports to DECC in 2010 – in addition to this current report. A common feature of these reports was to highlight the rise in the level of interconnection of the GB market with the rest of the world, compared with the past.

3.44. Greater dependence on Continental and international gas markets means that the availability of gas to GB is now dependent on future levels of global supply and demand. Global gas demand is likely to continue to increase, with some forecasts suggesting an almost doubling by 2035. How this will impact GB will depend on the speed that existing and new (including unconventional) sources of supply are exploited and the availability of transport capacity, whether pipeline or LNG. A key finding from our analysis is the extent to which LNG markets might

[90] Stern, J *(*2007*)* 'Gas-OPEC: A Distraction from Important Issues of Russian Gas Supply to Europe*.' Oxford Energy Comment,* and Goldthau *(*2008*)* Resurgent Russia? Rethinking Energy Inc. Five Myths about the "Energy Superpower."*Policy Review vol. 147 pp* 53–63*.*

tighten over the coming years, until Australian projects come online from 2015 onwards.

3.45. In addition to the above, our increased exposure to international gas markets has also increased the range and likelihood of possible sources of disruption, including certain shocks that could have profound impacts on GB security of supply. We draw attention in this report to the potential impact of the closure of critical LNG shipping lanes; an unexpected curtailment of Russian supplies; an environmental incident associated with shale gas production, and another nuclear disaster accelerating the closure of existing plants and increasing demand for gas for power generation.

3.46. The implications of these market developments and shocks are varied. They might increase the volatility or level of gas prices in the near team and/or lead to greater uncertainty around the volatility or level of future gas prices. They might also increase the likelihood and magnitude of medium term cycles faced by GB gas consumers. In the most extreme cases, they could increase the probability of a supply shortfall to GB.

3.47. While this may be the case, our resilience analysis, summarised in this report, indicates that the GB market has a high level of supply resilience. It shows that it would take a number of extreme events combined, such as no imports through the Langeled pipeline or the BBL and IUK interconnectors and a loss of 50% of LNG supply, to result in a supply shortfall to GB customers.

3.48. Although Ofgem's proposed cash out reforms should help to attract gas when the market tightens, these proposals still limit the exposure of suppliers. This means the revised market arrangements would still not fully reflect the value of security of supply to consumers.

3.49. The existence of this gap is one of the reasons why the market might not provide the appropriate level of security of supply. In addition, our research has highlighted a number of deficiencies in the effective operation of European and global gas markets. This includes evidence that interconnectors to Europe are not always reactive to market fundamentals and the presence of inconsistent incentives in the event of an emergency in different European countries that might precipitate or exacerbate behaviour not in the interest of GB security of supply. Our interviewees also emphasised the level of political influence over global LNG sales and why the destination of LNG cargoes can often go against price signals.

3.50. We have also set out a number of behavioural or institutional factors that might impact the actions of market participants. These include the possibility of short-termist or myopic behaviour by market players in their supply and investment strategies, specific challenges around financing long term investments when returns are dependent on volatile and uncertain prices, particularly in the context of the ongoing financial crisis, and the fact that markets may not be able to fully reflect the high social costs of a serious interruption. On the latter point, we believe there remains a very significant difference between the high social costs of a supply interruption and the private costs faced by a short shipper. Such a difference could result in shippers following supply and investment strategies that do not reflect the preferences of consumers.

3.51. We also discovered that a number of the risks currently identified are not mutually exclusive and could arise together. For example, the risk that LNG markets tighten during the current decade may increase the reliance on Russian supplies across Europe, increasing gas prices in many countries. If this situation arose and the operational efficiency of interconnectors between GB and the Continent had not been resolved, higher prices in GB may still not be enough to attract gas to GB shores. As a result, supplies from Norway, the UKCS and storage would be of paramount importance to ensure demand was met. Under these circumstances any event that restricted the free supply from these sources would have profound implications for the supply balance in GB.

3.52. The situation described above is only one combination of a range of possibilities that could arise in the medium term to the detriment of GB security of supply. The breadth of this range has grown considerably in recent years as the range of our supply sources have diversified. This has had an important impact, increasing the level of uncertainty associated with our supplies going forward. We also note that, given its history, the GB market has little experience of dealing with this uncertainty.

3.53. As the findings in this report have shown, circumstances going forward are likely to challenge the GB market in unfamiliar and demanding ways, putting increasing pressure on GB security of supply. Furthermore, it is important that market arrangements properly reflect the importance of security of supply and its value to consumers.

3.54. As a result, we believe, serious consideration should be given to the case for implementing further measures to reduce the impacts of European and global market developments on GB security of supply risk. At the same time, it is important to recognise that market interventions can themselves bring risks, costs and undesirable consequences.

3.55. We turn now to a range of possible further measures that could be considered for this purpose.

4. Identifying possible further measures

Chapter Summary

This chapter sets out the range of options for possible further measures that we have considered. It notes how quickly they could be effective and the parts of the market that they could target.

Framework for considering the need for additional measures

4.1. The analysis set out in Chapters 2 and 3 examines a number of developments and market features that suggest that we cannot be complacent about GB security of supply in the coming decade, and beyond. However, and importantly, to date the market has managed risks well, meeting the decline in indigenous gas supplies with new investment in import infrastructure.

4.2. However, we have raised questions including about the way in which markets may react to high impact, low probability events and whether it would provide appropriate levels of security in these circumstances, and how other market failures might arise. We understand that there may be some areas of concern and in this chapter we assess the extent to which the further measures we have identified are likely to alleviate possible concerns about security of supply in the gas market.

4.3. It is important to bear in mind that the measures identified are largely confined to measures in the gas market (in line with the Terms of Reference of this report[91]) and, therefore, are not exhaustive. Depending on the area of concern, other measures (both measures in other markets and broader policy measures) may have additional or greater benefits than those outlined here. These include measures in the electricity market, for example ensuring that the Electricity Market Reform package takes account of gas security in electricity generation under the Capacity Mechanism. They also include broader energy policy areas such as heat and energy efficiency policies.

4.4. Throughout this report we have considered that any further measures would be in addition to the range of measures we have categorised under "ongoing market improvements" outlined below. There are important interactions between the proposed reform of cash out arrangements and other possible measures. For example, one impact of the proposed cash out reforms is to transfer risks from customers to industry. However, since our proposals cap the exposure of industry, this means the revised arrangements would still not fully reflect the value of security of supply to consumers. Some of the potential security of supply options we outline

[91] The terms of reference are set out in Appendix 3.

below, such as the various "obligation" type measures, may alter the balance of risk-bearing, particularly amongst different industry parties.

Range of options

4.5. We set out in brief the range of options that we have considered below. These are set out in greater depth in the accompanying appendix document. The options that we have assessed here do not comprise the full spectrum of possible options. We undertook a brief qualitative exercise to provide a manageable range of options. Some options (referred to in Appendix 2) we considered to be beyond the scope of the report, while others were considered as less viable variations on the options that we have assessed. In addition to the ongoing market improvements (included for comparison as the base from which further measures would be implemented), the options that we have considered are:

- Information requirement
- Promoting standardisation of interruptible contracts
- Demand side response tender
- Back-up fuel requirements
- Financial reliability option
- Non specific service obligation on suppliers
- Service obligation on the system operator
- Storage obligation
- Semi-regulated storage
- Strategic stocks

4.6. In this chapter we set out a brief description of each option in turn and assess their suitability to address the challenges they may be required to meet. We consider in particular how quickly the measure can be effective and the extent of the market that it could cover. We also discuss the extent to which the measure works with the market and how adaptable it would be once it was in place.

Ongoing market improvements

- **Effective by:** The Gas SCR Proposed Final Decision document notes that we would expect our proposed reforms to be in place by Winter 2013/14. We note that the consultation on this proposed final decision closed on 24 October 2012 and, at the time of writing, responses are being considered.
- **Customers covered:** The whole market.

4.7. The base case sees Ofgem proceeding with the proposed implementation of the reform of cash out arrangements. Additionally we are undertaking work to ensure that our interconnectors flow efficiently. All the other measures set out in this chapter would be in addition to these developments.

4.8. Following discussions with stakeholders during the risk assessment process, one of the key themes that emerged was the concern that uncertainty over the future role of gas in the GB energy mix was leading to potential under-investment in the industry. This potentially represents a security of supply issue. However, a decision to proceed only with the enhanced base case approach we have set out could provide the additional clarity needed, with an appropriate response potentially bringing forward investment and leading to improved security of supply.

4.9. This approach does not target a specific sector of the market, but rather looks to encourage certain outcomes from the market as a whole which would have the effect of improving security of supply overall. This works with the grain of the market and seeks to place adequate incentives on participants to improve security of supply, and then leave them to manage risk in their own way. The proposed reform of cash out arrangements aims to get shippers to price in the risk of firm customer disconnection which allows them to find the most cost effective way of trying to improve security of supply.

Information requirements

- **Effective by:** Could be expected to be introduced within two to three years.
- **Customers covered:** Whole market.

4.10. This option would see an obligation placed on certain parties to provide clear and transparent information to market participants to enable them to take informed actions which would benefit security of supply. The aim of this measure would be to encourage competition and diversify sources of supply. It would seek to remove information asymmetries that prevent all market participants being aware of potential future risks. The measure could be targeted at the supply and/or the demand side. Alternatively, Ofgem could formalise the information request process undertaken in previous years to build a pre-winter picture of the state of gas procurement.

4.11. As with the base case, this measure works with the grain of the market by allowing market participants to have an enhanced oversight of risk and then leaves them to manage it in their own way. On its own this measure may not be sufficient to provide the market with the confidence to invest in security of supply to the extent to which consumers or Government would wish.

4.12. While it is preferable to maintain consistency and transparency to provide certainty to investors, the terms of the information provision could be revised annually without impacting too heavily on the certainty of the market.

Promoting standardisation of interruptible contracts

- **Effective by:** This option could be introduced within two to three years.
- **Customers covered:** Large I&C gas customers only.

4.13. This option would range from a set of guidelines or principles for the types of contract terms, to defined interruptible contract templates, which suppliers could be required to offer as an option when offering interruptible contracts in order to give greater confidence to customers. This measure could be introduced if it is believed that there are barriers to the negotiation of interruptible contracts. The contracts could provide a set of guidelines, standardised format, description, or category of terms which could remove some of the concerns that consumers have about entering into these types of contract.

4.14. This is an option that would seek to introduce greater flexibility into the demand side and would work with the grain of the market. It would complement the proposed reform of cash out arrangements. It would be targeted principally at large I&C customers. It would encourage the efficiency of large I&C customer disconnection by assisting those with lower VoLLs to provide a voluntary demand side response through commercial contracts. This would delay the involuntary firm load shedding of large I&C customers under a Gas Deficit Emergency. Thus, those customers with higher VoLLs would remain firm and be provided with additional security as a result of the buffer provided by the newly interruptible customers.

Demand side response tender

- **Effective by:** Potentially Winter 2016.
- **Customers covered:** Large I&C gas customers only.

4.15. This option would see the introduction of a tender process for I&C customers to offer volumes of gas demand reduction. This might take the form of a yearly, winter ahead process run by National Grid Gas (NGG) for a set of tranches of customers to reduce demand for gas which would be triggered following a set pre-emergency event (eg a gas balancing alert). Those customers who are requested to reduce demand by NGG under the tender would then receive an 'exercise price' (ie the price which they would accept for reducing demand at which they entered into the auction). Winning I&C bidders would then receive ongoing option payments in exchange for giving NGG the option to request a demand reduction. This option could be adopted if there was a concern that there was an insufficient "buffer" of interruptible customers protecting firm load customers from disconnection. The cost of this measure could be passed onto system users through NGG's price control process.

4.16. This option requires more significant changes to be made to the regulatory framework, assigning new responsibilities to the System Operator (SO) and requires the SO to undertake annual procurement rounds for the winter ahead period. It would require NGG to create internal processes to calculate the amount of demand side response to meet headline targets set centrally. On this basis, we believe that the measures could be in place within three to four years.

4.17. This option has similarities with the approach of promoting the standardisation of interruptible contracts, but would be more interventionist, seeking to impose greater levels of demand side response in the large I&C customer sector. It would therefore result in similar benefits in terms of greater efficiency in the merit order of disconnection, whilst bringing greater certainty around that response. However, it would also incur greater costs and, as with other options that impose solutions on one sector of the market, carries a certain amount of risk that cheaper, more efficient ways of reaching the same level of security may be excluded.

4.18. For this option it may be important to commit to a specific design a number of years ahead to allow those customers that it targets, who may invest in back-up supply options to cover their risk of being interrupted, to build a business case for this investment in reaction to the incentives being provided through the option payments that they could receive. Customers would need the certainty of recouping investment for the option to be effective.

Back-up fuel requirement

- **Effective by:** Towards the end of the decade.
- **Customers covered:** This option would only protect electricity customers.

4.19. This option would see a requirement on gas power stations to be able to switch to an alternative fuel in periods of gas system tightness. This could be introduced if there were significant concerns over the impact of gas deficits on electricity security of supply in particular. The measure could be targeted at new-build gas generation. Although it could also potentially be more wide ranging and target existing gas plant, not all existing plant would be able to meet back-up fuel requirements due to planning or engineering constraints. While fuel oil (or distillate) has been the traditional back-up fuel for gas generators, this measure could leave it to the discretion of generators as to how they backed up their plant.

4.20. For commercial reasons (self reduction of gas load in response to high prices) and for non-commercial reasons (firm load shedding by NGG in size order), gas fired generators would be some of the first customers to come off the gas system under tight supply/demand conditions. Thus, requiring gas fired generators to have back-up fuel facilities in place would provide little additional security of supply benefits to other firm load I&C and LDZ gas customers.

4.21. However, this measure would reduce the likelihood that disconnection of gas fired generation under tight supply/demand conditions would lead to electricity supply interruptions. While this measure could be very effective in ensuring electricity security of supply, it is likely to take far longer to implement and take effect than many other options. This is primarily because of the time involved in construction of new power stations that meet the criteria, or retro-fitting facilities to existing plant. As with the DSR tender approach, by being prescriptive about the type of technology pursued there is also a risk of ruling out cheaper, more efficient ways of reaching the same level of security.

Financial reliability options

- **Effective by:** 2016 at the earliest.
- **Customers covered:** Potentially whole market.

4.22. The financial reliability option is intended to work by establishing a "strike" price that would form an upper price that shippers (or potentially other parties) would seek to avoid the wholesale gas price from reaching. Should the wholesale price exceed the strike price then shippers (or other participants trading in the mechanism) would be liable for the difference between the two prices and would only be able to sell gas at the strike price. This should encourage them to avoid tight demand/supply conditions as a result. In order to incentivise shippers or other traders to take on this risk there would be an agreement whereby suppliers pay an ongoing reliability payment (or option fee) in return. A central body could act as an intermediary between shippers/traders and suppliers, auctioning options and passing on exercise payments. This option could be introduced if it was felt that suppliers were not adequately pricing in the risks of high price periods when making investment decisions.

4.23. As with the DSR tender, this option would require some significant changes to the regulatory framework, and would assign new responsibilities to the System Operator (SO). It would require the SO to undertake annual procurement rounds at least a year in advance of the delivery year. As such the development time might be broadly similar. However, although we anticipate that the financial reliability option could be in place by 2016, it is important to note there might be complications – owing to the complexity of the mechanism, the lack of precedents, and the potential requirement for primary legislation – which might push back the date by which this mechanism would be effective. Some versions of the design might also necessitate that the sale of options takes place more than a year in advance of the period to which they apply. Choosing these designs would also mean the mechanism would become effective at a later date than 2016.

4.24. This measure can be designed to target certain customers (eg all firm load), although it only provides a market based incentive to meet this level of security of supply, rather than placing obligations on any participants to meet this security level. While the incentive for achieving security of supply is placed on the market, it is left to industry players to determine how to meet it. However, there may be some credibility risks with this measure, in particular with the sanctions that can be placed on shippers/traders to ensure that they bring gas to market when the strike price is reached.

4.25. As with other options that seek to incentivise investment, it would be important to commit to a specific design a number of years ahead to allow sufficient investment to be realised and the option to be fully effective. Those interested in buying reliability options may invest in storage or other back-up supply options to cover their risk of being exposed where the market price exceeds the strike price.

They are likely to fund these back-up facilities through the option payments that they receive. It would be important to provide certainty that the initial investment and ongoing costs of back-up facilities could be expected to be recouped through the ongoing option payments.

Non-specific service obligation on suppliers

- **Effective by:** end of 2015 (for protected customers).
- **Customers covered:** Protected only. Alternatively, all firm customers.

4.26. This option would see a licence condition imposed on suppliers to meet a set security of supply standard. The default version of this approach would see an ongoing requirement on suppliers to meet the security of supply standards set out in the Regulation, which is targeted at “protected” customers (largely domestic customers, with other defined customers such as hospitals and care homes). Suppliers would demonstrate ex ante that they could meet the requirements. However, the way in which this was met would be left completely open to the supplier. Compliance would be assessed ex-post, with suppliers who did not have sufficient gas to supply their protected customers fined if any of these customers are disconnected. This option could be introduced if there were still concerns that a reform of cash out arrangements was not providing sufficient incentives to ensure the Regulation continued to be met.

4.27. The service obligation places a direct requirement on gas market players that could alter their current gas procurement strategies, making it potentially contentious, and therefore it may require a lengthy process of discussion and consultation with industry stakeholders. As such, it is reasonable to assume that the service obligation could take from two to three years to introduce.

4.28. An alternative version of this option would see it designed to meet a wider set of customers, possibly all firm load customers under specified conditions. This additional level of provision would be in excess of that required under the Regulation. As such, should this option explicitly target a higher security of supply standard than the 30 day period set out in the Regulation or impose any additional obligation for reasons of security of supply, the necessary conditions for exceeding this level of supply security (as set out in the Regulation) would need to be met and demonstrated. More information on these requirements is provided in Appendix 1.

4.29. While this option places an obligation on the market to meet a defined security standard, it leaves it to industry players to determine how to meet it. Setting an obligation does not guarantee that it will be delivered and it is challenging to monitor and enforce against on an ex-ante basis without becoming overly prescriptive. Therefore this option would rely on the threat of ex-post enforcement action.

4.30. In theory, this option allows for flexibility from year to year. However, the investment response that this might require may not be as flexible. Providing for the required level of supply security may require some up-front investment and if the level of the obligation subsequently falls then this additional expenditure may be stranded. Furthermore, this uncertainty may have a knock on impact on the long term trading strategies of suppliers which may lead to inefficient market results.

Service obligation on system operator

- **Effective by:** end of 2015 (for protected customers).
- **Customers covered:** Protected only. Alternatively, all firm customers.

4.31. This option would see an obligation on NGG (as SO) to have access to a volume of gas to meet a defined security of supply standard. NGG could be required to assess whether the market had, for example, procured enough gas to cover a short term gap in provisions for peak delivery capacity (eg for a seven-day period) as a result of a potential supply or demand shock. If a gap was identified, NGG could be required to procure enough gas to fill this gap. This could be done using either supply or demand sources (or a combination of the two). This measure could be introduced if there were concerns that the market was not able to react to certain shocks (eg delays in response from LNG cargoes).

4.32. As with other options that place NGG in a central role (such as the DSR tender), this option would require changes to be made to the regulatory framework, assigning new responsibilities to the SO, and would require the SO to undertake annual procurement rounds at least a year in advance of the delivery year. It would therefore require a broadly similar implementation period. On this basis, we believe that the measures could be in place within three years. Procurement could then be undertaken for the following winter and therefore be effective by the end of 2015 at the earliest.

4.33. Similar to both the non-specific service obligation and storage obligation (see below) on suppliers, there are different levels at which the service obligation could be set. By default it would be set to cover protected customers. As with other measures that have obligation levels, should a wider obligation be set the necessary conditions (as set out in the Regulation) for exceeding the 30 day period or imposing any additional obligation for reasons of security of supply level would need to be met and demonstrated. It should also be noted that setting the obligation wider would significantly increase the cost of the option.

4.34. As with obligation options based on suppliers, setting an obligation does not guarantee that it will be delivered (although failure to do so would constitute a licence breach, with the option to impose penalties). However, because NGG is already subject to similar regulatory controls under the System Operator incentives it is likely to be less challenging to monitor and enforce against the obligation. Similar to other obligations that might require investment there is a level of flexibility on the level set, but a risk of stranded investment should obligation levels vary significantly.

Storage obligation

- **Effective by:** End of 2016 (protected)/end of decade (all firm customers).
- **Customers covered:** Protected only. Alternatively, all firm customers.

4.35. This option would go beyond the non-specific service obligation by placing an obligation on suppliers to hold a minimum level of storage volume (and deliverability) to meet a defined security of supply standard. In its default form, suppliers could be required to hold enough gas with deliverability to meet the difference in demand for protected customers between an average and 1-in-20 peak winter. The volume could only be released to avoid disconnection of protected customers. The measure is intended to increase the protection of those customers in extreme winter conditions. Any increased costs for suppliers could be passed onto consumers.

4.36. The implementation time for this option would be similar to the non-specific service obligation, with there being sufficient storage capacity and deliverability in GB to meet the requirements for protected customers. However, as with the service obligation options, this obligation could be widened to meet the needs of other customers. Under those circumstances, there would be a need for additional time for the development of storage facilities should the required capacity and deliverability exceed that currently available in the market. This may not be possible until towards the end of the decade. Similar to other obligations should the level set exceed the 30 day period set out in the Regulation or impose any additional obligation for reasons of security of supply, then the necessary conditions as set out in the Regulation for exceeding this level of supply security or imposing additional obligations would need to be met and demonstrated.

4.37. This option differs from the other obligation options in that rather than letting the market directly or indirectly determine how to address security of supply, it centrally mandates and indirectly supports a certain type of technology. As with the DSR tender, this provides a measure of comfort that a mechanism will be in place that can be utilised to provide absolute security of supply, although the construction of additional storage (if required) is beyond the control of those that the obligation is placed on. However, with a mandated approach there is a risk of ruling out potentially cheaper, more efficient ways of reaching an equivalent level of security.

4.38. As storage sites can require quite “lumpy” investment, the level of flexibility in this option is fairly low. Small increments may not yield additional investment, while any reduction in the size of the obligation could lead to stranded investment.

Semi-regulated storage

- **Effective by:** Towards the end of the decade.
- **Customers covered:** Whole market.

4.39. This option would see a cap and collar regime introduced for storage projects which meet a set volume and/or delivery rate. The measure could be used to encourage the building of additional gas storage, and might be used to provide additional security and tackle excessive price volatility. It could provide storage operators with a minimum level of revenue (ie a floor) in return for a cap on excess profits, which would be returned to consumers. The design would seek to retain a balance between exposing storage operators to market risks, incentivising investment, and protecting consumers by guarding against inefficient investment.

4.40. This option would require some time to take effect. While developing the arrangements for the regulatory regime might require around two or three years (potentially, depending on the design, requiring primary legislation), there would then be a further gap whilst sites were developed in response to the new arrangements. Different storage sites have different lead times, although a further five years might be around the quickest a site could be delivered.

4.41. By encouraging investment in an additional gas storage facility, the semi-regulated storage option would provide an additional domestic supply source with volume and deliverability parameters that would deliver some level of additional security of supply for all customers. Since this option seeks to incentivise the building of new storage infrastructure which involves significant levels of upfront capital investment, it is likely that a minimum 25 year commitment would be required if the incentive is to work and provide value for consumers.

4.42. This option carries with it similar benefits and risks to other options which select a particular technology to ensure security of supply rather than leave that decision to the market (albeit some of the risk under this option is shared with the market), in that there is a reassurance of a facility being available, but an opportunity cost of potentially cheaper or more efficient options.

4.43. This option is fairly inflexible as storage facilities have a lifespan of between 25-40 years. While a period of supply scarcity may be finite, the infrastructure will last and be paid for over a potentially much longer period.

Strategic stocks

- **Effective by:** End of the decade.
- **Customers covered:** Protected customers. Alternatively, all firm customers.

4.44. This option would see the centralised procurement and storage of gas by the SO. Annual assessments of the required volume of gas to prevent disconnection could be undertaken by NGG, and extra storage capacity commissioned if necessary. The stocks could be held outside of the competitive market and only released to prevent disconnection, priced at VoLL. This measure could be targeted only at protected customers or widened to increase the protection of firm customers from the risk of disconnection.

4.45. This would take far longer to implement and take effect than many other options. This is primarily because of the time lag involved in construction, unless existing storage facilities were reserved and removed from the market (which would have the effect of reducing security of supply for non-protected customers). It is likely that this option would require primary legislation prior to commissioning and therefore would be unlikely to be in place prior to the end of the decade.

4.46. Similar to a number of other options, this option can be designed to cover protected customers consistent with the security standard set out in the Regulation or be designed to meet a wider set of customers, such as all firm load customers. Similar to other obligations should the level set exceed the 30 day period set out in the Regulation or impose any additional obligation for reasons of security of supply, then the necessary conditions as set out in the Regulation for exceeding this level of supply security or imposing additional obligations would need to be met and demonstrated.

4.47. By imposing a security of supply solution on the market and removing a large number of the incentives on market participants to take security measures (since it explicitly responds to the moral hazard risk by confirming that Government will step in where there is an extreme emergency), this is the most interventionist of the options that we have set out. It is also the least flexible, since it requires a significant sunk investment which will be borne by consumers.

Conclusions

4.48. We have set out in this chapter a wide range of measures. All the suggested measures have different features and come with varying advantages and disadvantages. We provide a much fuller assessment of the measures, including some initial modelling of the impacts which they might have on the potential for interruptions and effects on prices in the accompanying appendix document.

4.49. How desirable a measure might be depends on the balance of its advantages and disadvantages and on the precise issue that it would be intended to address.

Appendices

Appendix	Name of Appendix
1	Further considerations
2	Supplementary information
3	Terms of reference

Appendix 1 – Further considerations

1.1. Having identified the further measures, and their particular characteristics, that might be considered in Chapter 4, in this appendix we set out some broader considerations around adopting further measures. These include interactions with the electricity market, issues around costs and unintended consequences, European Security of Supply Regulation, and interactions with the European wholesale gas market.

Gas security and electricity generation

1.2. Gas currently plays a significant role in electricity generation, accounting for 47% of electricity supplied in 2010. In turn, electricity generation makes up a large proportion of total natural gas demand (around 34% in 2010)[92]. National Grid's 2011 Gone Green Scenario suggests that gas generation as a proportion of the generation mix will remain broadly similar up to 2020. We should therefore expect any interactions between the two markets to remain strong in the medium term at least, and possibly beyond.

1.3. Currently, gas plant often runs during high price (ie tight supply/demand) "peak" periods. It is expected that this role for gas plant as "peaking plant" will grow as a greater amount of intermittent renewable generation is deployed. This is because gas plant are flexible enough to increase electricity output when the renewable plant aren't generating, protecting against any potential generation shortfall. The Government is considering the introduction of a Capacity Mechanism to help support the deployment of this kind of peaking plant, and gas generators are likely to participate in the final mechanism.

1.4. Following recent announcements from RWE[93], E.ON[94] and GDF Suez[95], there are also potential for delays to the expected deployment of new nuclear plant. With their shorter lead times gas plant could be built to fill this gap in base load capacity as well.

1.5. Given the interactions and the potential for the increased role of gas in the electricity market, any decisions over intervening in either market is likely to have direct and indirect impacts that affect both. These interactions will become increasingly important if electrification of heating and transport is required as part of an overall decarbonisation strategy.

[92] DUKES 2010 p.98
[93]RWE npower announces strategic review of Horizon Nuclear Power:http://npowermediacentre.com/Press-Releases/RWE-npower-announces-strategic-review-of-Horizon-Nuclear-Power-1137.aspx
[94]E.ON looks to find new owner for Horizon Nuclear Power: http://pressreleases.eon-uk.com/blogs/eonukpressreleases/archive/2012/03/29/1802.aspx
[95] GDF Suez's nuclear reservations hit government energy policy – Guardian - http://www.guardian.co.uk/business/2012/apr/16/gdf-suez-nuclear-reservations-gerard-mestrallet?INTCMP=SRCH

1.6. As well as this important role in the future electricity market, gas-fired generators also currently play an important role in the gas market. As a consumer of significant volumes of gas, they can provide an effective, early demand side response by turning down/off their gas consumption which quickly reduces stress on the gas market. Many generators provided such a response in January 2010 when National Grid issued a Gas Balancing Alert following disruption to Norwegian gas pipelines. At the time this did not affect electricity supplies as generators were able to follow a policy of switching to other types of plant in their portfolio. Historically coal and gas plant with distillate back-up have provided this kind of fuel switching. However, the decline of coal in the electricity mix will reduce the diversity of flexible plant available.

1.7. Should gas-fired generators continue to provide Demand Side Response in the gas market, there is the potential that the electricity market will come under increasing stress if no alternative flexible plants are available. However, if the demands of the electricity market are such that generators continue to consume gas when previously they would have reduced demand, the gas market may experience greater stresses than before.

1.8. We are concerned by the potential effects of these interactions and have undertaken an additional, high level stress test looking into the risk to electricity security of supply from a shortage in gas supplies. These results included in Ofgem's first annual Electricity Capacity Assessment[96].

1.9. This assessment may imply that further consideration is required more broadly on measures to improve energy security. Measures that might be considered could include diversification of electricity generation or mandatory fuel switching capability for gas plant. Direct interventions into the electricity market and broader energy policy options are beyond the scope of this report, although we note that the Government is considering the issue of electricity security both through EMR, the Gas Generation Strategy and other security of supply workstreams. However, we have modelled a number of our suggested further measures to ensure that they significantly reduce the probability of electricity disconnections. Our intention here is to provide Government with initial analysis illustrating the likely costs and benefits of intervening in the gas market to ensure electricity security of supply. However, this should be considered in the round with options beyond the gas market that could achieve similar or better levels of security. Further details of the analysis can be found in the separate appendix document that accompanies this report.

[96] See: http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Pages/index.aspx

Costs

1.10. The majority of interventions in the market are likely to carry a cost, both directly in terms of the cost of the measure itself, and potentially also indirectly in the way that it alters the dynamics of the market. The scale of those costs may vary considerably depending on how a measure is designed. Extra costs placed upon market participants will increase consumer bills at a time when high wholesale energy prices are already placing financial pressures on domestic and business customers alike. It is therefore important to ensure that any measures introduced are proportionate and that the increased costs can be justified by the benefits received.

How costs relate to options

1.11. The costs of the options vary depending on the nature of the security of supply benefit that they are looking to provide. While the differing nature of the measures means that the costs are not directly comparable, some assumptions can be made about the relative costs of each. We provide more detailed views on the individual options in one of the two separate appendix documents that accompany this report, but set out a qualitative summary below.

1.12. The costs associated with each option would be made up from the following components:

Further measure	Cost components
Information provision	Administrative
Promoting standardisation of interruptible contracts	Administrative
Back-up fuel requirements	Administrative, attaching back-up facilities
DSR auction	Administrative, option and exercise fees
Reliability options	Administrative, hedging provisions of shippers, option and exercise fees
Non-specific service obligation	Administrative, costs of any additional market actions needed
SO service obligation	Administrative, costs of NG gas procurement
Storage obligation	Administrative, lost arbitrage opportunities/any additional storage investment needed
Semi-regulated returns	Administrative, additional storage facilities (on market), costs/payments associated with semi-regulated cap and collar (consumers)
Strategic stocks	Administrative, additional storage facility required

1.13. All options will have some administrative costs associated with their implementation and administration. However, relative to the amount of investment these options could bring forward these administrative costs would be negligible.

1.14. Costs of the **DSR auction** and **financial reliability options** will largely be a product of the option fees paid to auction participants on an annual basis in addition to the exercise price paid to customers for any disconnection under the auction or to suppliers in the case that the wholesale price rises above the strike price for the reliability options measure. In the case of the reliability options the incentives may also result in shippers investing in physical hedging to mitigate their exposure. This would add cost but with additional security of supply benefits.

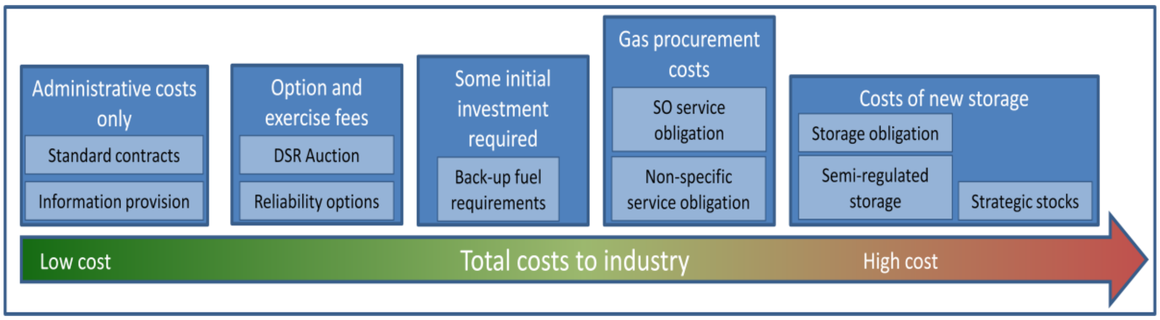
1.15. The remaining options all encourage/oblige additional investment to differing degrees and costs will largely be a result of the investment required. In the case of **back-up fuel requirements** for gas fired generators the required investment may discourage investment in new gas-fired power generation.

1.16. If targeted at the same level of supply security, we would expect the **SO service obligation** and **non-specific service obligation** on suppliers to have similar costs. Both allow the obligations to be met through the means considered most effective by the parties involved. It could be argued that targeting this obligation at suppliers would be the cheaper solution given competition between suppliers and their experience in procuring gas from the market. It should be noted that if it is considered that the market is already providing for the security of supply level identified then neither option should result in additional costs as no actions would be required. Again it could be argued that the market is more likely to take this view than the SO who may take a more risk averse approach and procure additional gas to ensure that it has met its obligation.

1.17. The costs of the **storage obligation** would depend on the level of the obligation set compared to the level already being provided by the market. It is possible that an obligation would not require storage levels additional to those which the market is already providing. In this case, there would be only administrative costs associated with the measure. If the storage requirements are substantial enough to impact on the levels of gas that market participants would otherwise withdraw and trade within a winter then there could be two cost impacts. The market could continue to function with the same levels of storage as previously but with market participants accepting that they would lose some arbitrage opportunities thus costing the industry compared to actions without the obligation in place. If this impact was sufficiently large and certain over a number of years then it may provide the business case for an additional storage facility. The capital and operating costs of this facility would then be countered by the reduction in costs to the industry due to their ability to benefit from arbitrage opportunities.

1.18. The **semi-regulated storage** option would result in the development of additional storage which would have some large capital and operating costs associated. However, we would expect much of this cost to be borne by the investor themselves thus the costs to the industry/consumers would not be as large. These costs would result from the periods when the floor set out under the semi-regulated returns option was required to support the investment made. These costs would then fall upon consumers. There may also be times when the cap applied to returns to the investor was reached. This would result in payments back to consumers.

1.19. Similar to the semi-regulated returns approach, the **strategic stocks** option would have large capital and operating costs associated with the long range storage facility delivered. However, unlike the semi-regulated returns option the costs of this would be fully passed on to the industry and eventually consumers. Further, the gas would be held in store rather than being available to the market so there would be no countering impact resulting from the additional supply provided by a new storage facility. Thus the strategic stocks option would be the most expensive method of securing a particular volume of gas.



Aligning costs and benefits

1.20. Our risk analysis has shown that except in the most extreme of circumstances domestic and small business consumers are broadly protected from the risks of disconnection. This may be less true for gas generators and large I&C customers (although the risks remain small). However, larger customers may be requested to provide demand side response to protect against disconnection of non-daily metered customers. This could see gas-fired generators significantly reducing their output, which in turn could place strain on the electricity network.

1.21. If on this basis a decision is made to intervene in the gas market to ensure greater electricity supply security, or to provide a greater level of protection to I&C customers, it is worth considering the distributional impact of the costs of doing so. When designing measures policy makers must ensure that the costs are apportioned in an equitable manner. As well as the distribution of costs between different classes of consumer, we note that the full benefit of some measures may only be felt for a relatively short period, while the cost of the measure is borne over a far longer time period, potentially leading to some future consumers bearing the costs of stranded investment.

Unintended consequences

1.22. While the measures that we set out in Chapter 4 are designed to target particular areas of the gas market, the consequences of introducing those measures may extend beyond the issue that they are targeting.

1.23. In Chapter 2, we set out how the GB gas market has provided security of supply since privatisation, even during a number of periods of tight gas supplies. Any assessment of measures should be made in the context of the gas market as it has developed over this period.

1.24. When considering whether to introduce further measures into the market, it is important to consider three key questions:

- What level of security of supply is required?
- What market failures mean that this standard will not be delivered either now or in the near future?
- How would any proposed measure overcome these failures and what other impacts might it have on the market?

1.25. We recognise that most of the further measures identified would come with a cost, both directly - with the financial cost of funding the mechanism - and indirectly by reducing competition and efficiency within the gas market. These indirect costs are unpredictable and therefore very difficult to quantify. However, some examples of these potential indirect costs are briefly highlighted below:

- **Reduced competition**: Reforms could benefit certain players in the market more than others – for example, firms who already have access to flexible sources of gas supply would not find certain security of supply provisions as onerous as other firms who can only trade at the National Balancing Point (NBP). The additional costs involved with adapting their business model could force the latter firms to exit the market (or make it more difficult for them to grow or enter in the first place).

- **Regulatory risks:** The relationship between interventions and the market in which they operate can be complex and difficult to predict. Interventions can displace the incentives on the market to invest in security of supply itself. This is because the measures might increase uncertainty over future gas prices, increasing the risks for investors leading to market participants holding back on making investment decisions on key infrastructure projects.

- **The emergence of a European market:** Consumers in Great Britain should benefit from the emergence of a more liberal European gas market – which it is the goal of the Third Package to deliver. These measures – which seek to deliver a single energy market – should result in more efficient interconnector flows and access to continental gas storage facilities – both of which would enhance security of supply in Great Britain. However, the adoption of a more interventionist (and therefore more protectionist) policy in Great Britain could act to slow the EU's current direction of travel, whilst any benefits would increasingly spread across all EU consumers.

- **Implementation time:** The different measures identified have varying lengths of implementation and delivery time. Those with longer delivery timescales could face the risk that by the time they are delivered the underlying rationale for intervening in the market has changed.

Unintended consequences specific to measures

1.26. Each of the further measures options comes with a risk of unintended consequences on the market. These range from small burdens on the industry to the potential to create an investment hiatus. We have set out the scale of the potential impacts of these unintended consequences below:

Minor industry burdens

1.27. If designed to cover protected customers only, we would expect that the **non-specific service obligation**, like the **information provision** and **promoting standardisation of interruptible contracts** options, would have only minor risks of unintended consequences. The primary consideration is whether the additional administrative burden placed on market players may hinder competition with other markets. Industry players may suggest that this, in combination with administrative burdens already in place within the market, may deter investors from the GB market, preferring instead to invest in countries with lower administrative burdens. However, it is possible to argue that the market may benefit, in particular from additional information and the facilitation of interruptible contracts, and that this might off-set the administrative burden.

Inefficient design

1.28. Some options look to encourage a supply and demand response to reduce the risk of supply disruptions. They do this by administratively setting an amount of response that is required (through the auction volume and exercise prices in the **DSR auction** and through the volume and strike price set under the **financial reliability option**) and then letting the market determine the appropriate response. Administratively setting the amount of response and the price of this will be difficult for any central body as opposed to normal market functioning. This raises the risk of inefficient design of the option. If the volume or price of response is set too high then this may result in an additional cost burden on the industry that is not necessary to provide the level of supply security being targeted. If these are set too low then this risks failing to deliver the required response, and as a result the desired security of supply level.

1.29. The **semi-regulated storage** option risks crowding out investment in commercial gas storage which may otherwise be delivered by the market without support requirements, along with other options that might be commercially delivered such as demand side response. This may apply not only to the types of storage targeted by the measure, but also to other forms of storage. The reasons for this would be that if, for example, the measure was targeted at long range storage facilities it would dampen prices (particularly summer-winter spreads), detracting from the business case for other storage facilities. It is possible that these additional storage facilities could deliver the same level of security of supply at lower costs to the consumer.

Credibility risk

1.30. Some options, such as the **storage obligation**, the **service obligation on the system operator**, and **strategic stocks** define a level of security of supply and then reserve gas (each through a different mechanism) to ensure that this security level is achieved. A trigger point is set for each option after which the reserves of gas can be released to avoid disconnection of the relevant consumers covered under the option. The key potential unintended consequence of these options is the possibility for the market to believe that this gas will be released before this trigger point is reached for political reasons (eg to avoid political backlash from very high prices).

1.31. If market participants believe that gas reserved under the obligation could be used earlier, and at lower prices, then this could reduce the incentive on them to invest in other sources of flexibility, such as other storage facilities to cover the desired security of supply level. This could lead to a continuous cycle in which the market delivers a lower and lower security level as the obligation is required to cover an ever increasing gap left by the market.

Investment hiatus

1.32. Options that seek to ensure investment in physical infrastructure (for example **back-up fuel requirements** or measures to incentivise the build of new storage facilities, such as **semi-regulated storage**) risk an investment hiatus while the measure is developed. Some potential storage projects which are either viable or near viable may wait to either see whether subsidy might be available to them, or to assess how the prospect of subsidy may affect the prospects of other projects and the affect that this may have on their business case. Options that can be implemented quickly will therefore reduce the impact of any investment hiatus.

1.33. For gas-fired generators, the additional cost and planning burden placed upon them as a result of the requirement to fit back-up fuel capabilities to their plant might also alter business cases and cause construction delays.

The EU Security of Supply Regulation

1.34. The Regulation[97] places a required security of supply standard on all EU member states including the UK. The Regulation obligates the Competent Authority (DECC) to require natural gas undertakings that it identifies to take measures to ensure gas supply to the protected customers of the Member State (non-daily metered customers and category A customers such as hospitals) in the following cases:

(a) extreme temperatures during a 7-day peak period occurring with a statistical probability of once in 20 years;

[97] Regulation (EU) No 994/2010 of the European Parliament and of the Council. See: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:295:0001:0022:EN:PDF

(b) any period of at least 30 days of exceptionally high gas demand, occurring with a statistical probability of once in 20 years; and

(c) for a period of at least 30 days in case of the disruption of the single largest gas infrastructure under average winter conditions.

1.35. The standards set out above are defined as minimum security of supply standards and, as such, the Competent Authority can decide to prescribe greater standards going beyond the 30 day period referred to in (b) and (c) above or impose additional obligations for reasons of security of gas supply should it wish to do so. However if the Competent Authority wishes to define a higher standard then it must provide necessary justification for this requirement. Further, any increased supply standard or additional obligation must meet a number of (potentially challenging) requirements. These include that the additional measures will not unduly distort competition or hamper the functioning of the internal market in gas and must not endanger the security of gas supply of other Member States or of the Union as a whole. In addition, the Competent Authority shall identify how any increased supply standard or additional obligation imposed on natural gas undertakings may be temporarily reduced in the event of a Union or regional emergency[98].

Current level of security of supply

1.36. As the Competent Authority for the UK, DECC have been assessing whether the UK meets the standards set out in the Regulation. Its most recent risk assessment reported that "*UK gas supply infrastructure is resilient to all but the most unlikely combinations of severe infrastructure and supply shocks*"[99]. In this risk assessment, DECC also referenced the success of the market in delivering diverse import and storage infrastructure and the ability of the market to respond to record demand and supply side pressures such as in the winters of 2009/10 and 2010/11. DECC did note however that there are challenges for the market in the medium to long term.

1.37. The risk assessment also suggested that the UK would meet the additional requirement to meet demand for a period of at least 30 days in *average conditions* in the event of failure of the largest piece of supply infrastructure[100].

Initial quantitative analysis performed as part of our Gas Significant Code Review (SCR) proposed final decision supports DECC's initial findings concerning the low probability of domestic interruptions.

Different levels of security of supply

[98] The full set of requirements can be found in the Regulation.

[99] Risk assessment for the purpose of EU Regulation 994/2010 on security of gas supply, an addendum to the Statutory Security of Supply report 2011, p.5

[100] There is also a "N-1 standard", which assesses the impact on gas markets of largest infrastructure failure during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years. In the risk assessment cited above, DECC did state that there were a number of potential scenarios under which the N-1 standard might not be met.

1.38. Some of the further measures we set out in Chapter 4 look to provide further assurance that the standard set out in the Regulation can be met. These measures aim to ensure that the market functions more efficiently and for as long as possible in the event of tight supply/demand margins. This may increase pressure on customers who do not have protected status, such as I&C customers and gas-fired generators since in some cases they may reserve options currently offered to the market as a whole to protected customers.

1.39. Should there be a desire to extend protection beyond domestic customers, there are broader sub-sets of customers that might be protected by aiming to achieve a different supply standard. These include:

- **All LDZ customers**: One difficulty in ensuring security of supply to protected customers as set out in the Regulation is that these customers cannot be physically prioritised over other users of the local distribution zone network (including small and medium enterprises (SMEs) for example). DECC have already noted this in their definition of protected customers and designing any further measures with the objective of providing further security to protected customers must account for this issue.

- **All firm load customers**: The “protected customers” definition does not account for firm gas customers that are directly connected to the gas transmission network (including I&C customers and gas-fired electricity generators). No explicit security standard is set out for ensuring supply to these customers. The conclusion might be drawn that the economic and social consequences of disconnection of these customers may merit a security standard being set to ensure their protection. In the case of gas-fired power generation, this would result in greater security of electricity supply to all electricity customers.

1.40. Given the view set out in DECC’s Statutory Security of Supply Report, which stated that GB is meeting the level of security of supply standard set out in the Regulation, a decision to introduce additional measures with the aim of further increasing security of supply would need to comply with the additional requirements set out in the Regulation.

European wholesale markets

1.41. The GB market is growing less isolated both physically, as gas import capacity increases, and in terms of the European legal and policy context. It is particularly important to consider the ways in which the GB market will become integrated with other European markets. Any actions taken in the market should be viewed in this context.

1.42. As domestic reserves of gas in the North Sea continue to decline, GB is becoming increasingly dependent on European and international gas markets to meet domestic gas demand. Increased interconnection with the continent and growing LNG import capability strengthens the link between domestic prices and those observed in these markets.

1.43. European legislation looks to encourage effective connection and functioning between EU markets. The Third Energy Package sets out some principles for European gas markets and provides for legally binding European Network Codes to implement more detailed rules where necessary. The Gas Target Model and Congestion Management Guidelines will encourage cooperation of European Member States to improve the efficiency and price responsiveness of national wholesale markets and cross border flows. A number of European Network Codes support these objectives.

1.44. As European markets become more and more integrated we would expect to see flows of gas responding to price signals and heading towards the markets with the highest wholesale price. This means that the development of additional gas infrastructure within any one Member State will not necessarily provide an equivalent increase in gas supplies, as gas in store cannot be 'reserved' for the market in which it is held. Rather this gas will increasingly become part of the EU market.

Appendix 2 – Supplementary information

1.1. This appendix contains additional information on a range of issues. This includes the interactions between this report and Ofgem's work with security of supply in networks, a summary of previous reports regarding gas security of supply, a summary of options that were considered to be beyond the scope of this report, and some supplementary comparative analysis of the options set out in Chapter 4.

Security of supply and networks

1.2. There are three security of supply standards relevant to our work on gas security of supply. These are as follows:

The EU Security of Supply standard Regulation:
Under this standard the Competent Authority must take measures to ensure gas supply to protected customers (domestics plus category A, eg hospitals) in:

- a one in 20 year seven day peak period
- a one in 20 year 30 day period of exceptionally high gas demand
- average winter supply for 30 days with failure of the single largest piece of infrastructure

Transporter standard (licence condition on NTS and DN transporters: SSC A9):
This requires the transporter to have in place capacity to meet all firm demand requirements on:

- a one in 20 year peak day.

Transporter requirement to 'place reasonable economic incentives on' suppliers to meet standard (licence condition on NTS and DN transporters: SSC A11):
This requires the transporter to place economic incentives on suppliers to meet domestic customer demand in:

- a one in 50 year;
- a one in 50 Winter;
- a one in 20 year peak day.

1.3. As National Grid already has a security standard in place to provide capacity to meet all firm demand requirements on a one in 20 peak day we have considered internal infrastructure standards to be out of scope throughout our work on gas security of supply.

1.4. However, we note that the EU supply standard does not set out any standards for failure of internal infrastructure. The probability of any failure of internal infrastructure may set an upper limit on the security of supply level provided to customers regardless of the level of security of supply which is set for the supply side. The probability of failures to internal infrastructure should be taken into account when considering further measures options and the level of security of supply set in the design of any further measures option. If a higher supply standard than that considered as in place on the internal gas infrastructure were to be set, then one option would be to place an explicit requirement on transporters to meet a specific 'failure' standard.

Previous reports

1.5. As we set out in Chapter 2, the GB gas market has functioned well and has responded to the challenge posed by the requirement for increased imports with significant investment. The market values regulatory certainty and its absence has the potential to cause an investment hiatus. In considering the broader impact on the market of any decision to introduce further measures, it is important to reflect on the message in previous reviews that both Government and Ofgem has provided to the market on security of supply in terms of both the risks and the role of the market in addressing these.

Consistency with previous positions on security of supply

1.6. Since 2006 there have been a number of reports which have reviewed Great Britain's Gas Security of Supply and assessed the potential for introduction of further measures. It is worth revisiting the conclusions made by these reports before a decision to introduce further measures is made. When drafting or responding to these reports, government has consistently concluded that there is not a strong justification for significant further intervention when considering the associated potential negative impacts that come with these kinds of measures. As such, it will be particularly important to clearly explain the rationale for any change of policy should the decision be made to do so.

1.7. Following the 2006 Russia-Ukraine gas dispute the Department of Trade and Industry consulted on the effectiveness of GB's gas security of supply arrangements. The resulting White Paper 'Meeting the energy challenge'[101] sought to improve gas security by encouraging energy efficiency, improving the planning and licensing regime for gas infrastructure projects; and promoting open and competitive international markets. These reforms were ultimately delivered through the Energy Act 2008, the Planning Act 2008 and the implementation of the third package of EU internal market legislation.

1.8. In August 2008, an independent review of GB Energy Security[102] was completed by the MP Malcolm Wicks. This report noted that the open, liquid nature of the GB gas market had done much to incentivise foreign investment. It did, however, highlight that reform of the regulatory regime might be needed to better reflect the UK's new status as an energy importer. Wicks also felt that greater volumes of gas storage would be required in the future – and that if this capacity was not met by

---

[101] Can be found at http://www.berr.gov.uk/files/file39387.pdf
[102] For the Wicks Review see here:
http://www.decc.gov.uk/assets/decc/what%20we%20do/global%20climate%20change%20and%20energy/international%20energy/energy%20security/1_20090804164701_e_@@_energysecuritywicksreviewbisr3592energyseccweb.pdf

either the market or through access to European storage the Government should consider the introduction of strategic storage.

1.9. Ofgem's Project Discovery[103] (February 2010) agreed in part with the findings of the Wicks Review. This report stated that growing import dependency might require the regulatory reform to allow the gas market to more accurately reflect the true value that consumers place on gas security. It also noted that the convergence of international markets and growing domestic reliance on gas generation would expose the GB market to more volatile gas markets. Ofgem also highlighted the large amount of investment required in energy infrastructure over the next decade in order to meet environmental goals – pointing out the significant impact this would have on consumer bills.

1.10. The Government response to the Wicks review[104] highlighted the resilience of the market in the 2009/10 winter and noting recent planning reforms and tax reliefs for cushion gas, which it felt would help incentivise storage investment. It also committed to monitoring the development of storage facilities - in case additional investment barriers emerged.

1.11. The Department for Energy and Climate Change (DECC) also published the findings of three gas reviews undertaken by the consultancy firm Pöyry[105] in July 2010. These noted that the future was not without risks, although DECC concluded that the documents paint a "broadly benign picture" of the outlook for gas security of supply. Pöyry also assessed 24 potential policy interventions; ascertaining that two options (the restoration of industrial and commercial interruptible volumes and a requirement on CCGTs to maintain a minimum distillate level) would provide a net benefit. Neither of these options were considered in DECC's Gas Policy Statement[106], which was published in the same year.

1.12. In the following year, the Energy and Climate Change Select Committee also carried out an inquiry into energy security. The eventual report (The UK's Energy Supply: Security or Independence?[107]) called on DECC to clearly define "energy security" and take a more holistic view when taking decisions on policy measures. For the gas market, it suggested that DECC should develop a strategy to incentivise the doubling of gas storage capacity by 2020.

---

[103] For Project Discovery, see here: http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/Discovery/Documents1/Project_Discovery_FebConDoc_FINAL.pdf
[104] Government response to Malcolm Wicks's Review of International Energy Security: http://www.decc.gov.uk/assets/decc/what%20we%20do/global%20climate%20change%20and%20energy/international%20energy/energy%20security/1_20100407102352_e_@@_wicksreviewgovresponse.pdf
[105] "GB Gas Security of Supply and Options for Improvement" Pöyry: http://www.poyry.co.uk/linked/en/news/A.pdf
[106] For the Gas Policy Statement, see here: http://www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/Energy%20markets/gas_markets/1_20100512151109_e_@@_gassecuritysupply.pdf
[107] For the Energy and Climate Change Committee report, please click here: http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/1065/1065.pdf

1.13. Responding directly to the Select Committee[108] at the start of this year, the Government reasserted that it felt the outlook for security of supply was "broadly benign" although high impact/low probability events, such as disruption to pipeline infrastructure, could pose a risk to security. It was noted that mechanisms seeking to achieve a set volume of storage could dampen incentives to pursue other sources of flexible supply and reduce competition between storage operators; both unintended consequences which might lead to higher prices for consumers.

Options beyond the scope of this report

Introduction

1.14. As part of our assessment we initially considered a number of policy options that were deemed to be beyond the scope of this report, for example because they fall outside of our competencies (eg planning reforms). We set these out below with some initial thoughts on the potential advantages and disadvantages of these options.

1.15. The policy options considered as not within scope were as follows:

- Support for indigenous supplies
- International agreements
- Planning reforms

1.16. The reasons these options were considered out of scope are explored below.

Support for indigenous supplies

1.17. There are numerous measures that the Government could adopt to incentivise exploitation of the UK Continental Shelf (UKCS), some of which were announced in the 2012 Budget. These measures do result in greater gas production; however, they do not necessarily result in greater overall security of supply. This is because historically UKCS has not just provided domestic gas but worked as a flexible reserve of gas, with 'swing' fields able to increase production during tight gas supply periods. The current emergency "command and control" arrangements are designed on the basis that there will be gas fields which can 'ramp up' production should the supply and demand balance tighten.

1.18. Traditional 'swing' fields like Sean and Morecombe are in decline and it seems unlikely that any of the new finds will be able to ramp up production during times of scarcity in Great Britain and fill the gap left if international sources were interrupted. On this basis, although supporting domestic production can result in a number of benefits such as protecting base load demand it would not necessarily deliver additional security of supply.

---

[108] For the full government response, see here: http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/1813/1813.pdf

1.19. Incentivising the production of unconventional gas such as shale gas was also suggested as an option for improving security of supply. As with new finds we believe that the resource lacks flexibility, and given the level of uncertainty around the future deployment of shale (and therefore uncertainty over its impact in the long term) this measure was considered outside of the scope of this review. Government may, however, wish to further explore possible measures in this area.

International agreements

1.20. Another measure initially raised was to put in place trading agreements between the UK and a European Union country or a gas exporting nation to deliver a certain volume of gas in the event of a gas deficit emergency in Great Britain. This agreement could take the form of a reciprocal agreement (similar to that in existence between Hungary and France) to provide gas. Alternatively, it could take the form of an option contract to ensure priority access to gas from a producing nation in an emergency (this could be LNG or pipeline gas).

1.21. However, Ofgem has concerns about the practicality of implementing such a measure. A number of our concerns could be overcome although the viability of this option ultimately depends on being able to identify a suitable country to partner with. As a result, this arrangement falls outside of Ofgem's competencies and a government department like the Department of Energy and Climate Change or the Foreign Office would be better placed to review and make a final decision on the viability of this option.

Planning procedure reforms

1.22. Engagement with stakeholders during consultation on Ofgem's Gas Significant Code Review and the drafting of this report revealed that some felt the current planning regime was acting as a barrier to the construction of new gas infrastructure, in particular gas storage projects. The suggestion was that more could be done to amend planning procedures to allow for the delivery of more gas infrastructure projects.

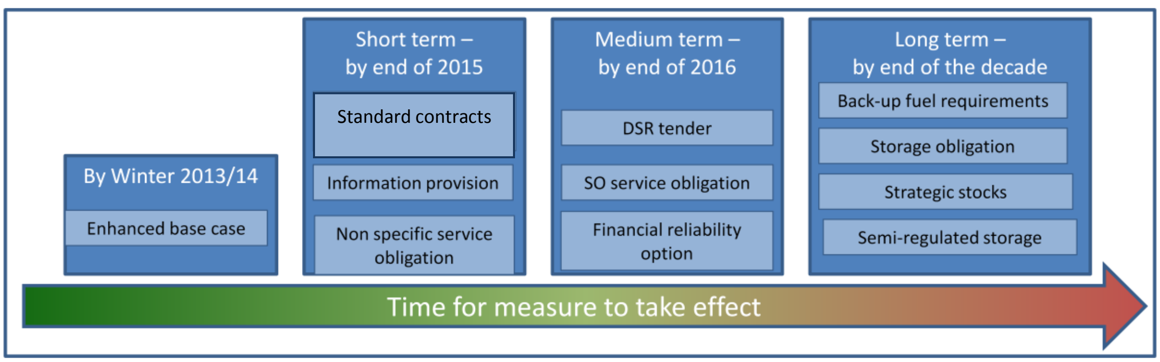
1.23. However, considerable legislative time (Planning Act 2008 and the Localism Act 2011) has already been devoted to this issue, and it is not clear at this stage that these reforms have been ineffective. It seems instead that the funding arrangements are currently the larger barrier to new development. On this basis, we would suggest that no further work needs to be undertaken in this area for the time being, however, government may wish to keep a watching brief on this issue to ensure that it does not emerge as a significant issue again in the future.

Supplementary comparative analysis of measures

1.24. Further to the description of measures that we set out in Chapter 4, we provide some additional comparative analysis of measures below with regards to the time they could be effective from, the extent of the market which they could cover, the extent to which they work with the market and how adaptable they might be once implemented.

Timing

1.25. In Chapter 2 we noted that we could see a tightening of LNG supplies towards the middle of the decade and that the outlook further out was less certain, but that the demand for gas from the electricity sector would be a key factor. We set out below indicative timeframes[109] for when different measures might become effective. It is important to note that these indicative timings assume that the measures are imposed by government or Ofgem on the basis of an assumption that the market will not deliver equivalent measures of its own accord. Therefore, for all of the policy options outlined above there will be some time lag between the decision to pursue the policy, its implementation, and its having an impact on gas security. The length of this lag time will depend on a variety of factors, including the complexity of the proposal, whether or not stakeholders find the measure controversial, whether legislative/regulatory changes are needed, and construction times. It may also take the market some time to react to the changes.



1.26. A number of the further measures are incremental improvements to the current market/regulatory regime. These seek to either allow the market to operate more efficiently or to cover gaps in the existing regulatory arrangements. The hurdles to the introduction of the measures will be the introduction of the necessary legislative, licence and code changes and the exact time lag is likely to depend on the length of the informal consultation process with industry. We cannot rule out that there may also be unanticipated delays to the indicative timescales (eg as a result of any legal challenges).

Customers targeted by the measures

1.27. In Chapter 2 we set out that it was very unlikely that domestic gas customers would be subject to interruptions to gas supplies. However, we concluded that there was a greater risk that larger customers and gas-fired electricity generators may be

[109] These timeframes are based on our current analysis of the options and could potentially change significantly if further work on the precise detail of these design options is undertaken.

subject to interruption, albeit that the risks were still very low except in extreme scenarios. In Chapter 4 we noted the particular segment of the market that could be targeted by each of the further measures.

1.28. The following table sets out the tranches of demand that each measure could be targeted at:

Large I&C gas customers only	Electricity customers only	Indirect protection for all gas (and electricity) customers	Protected customers/all firm customers including electricity (depending on design)
Promoting standardisation of interruptible contracts	Back-up fuel requirements	Information provision	Non-specific service obligation
DSR Auction		Reliability options	SO service obligation
		Semi-regulated returns	Storage obligation
			Strategic stocks

1.29. Some of the further measures we have identified may be designed to target domestic gas customers. This would be consistent with the Regulation, which sets out minimum standards for security of supply for "protected" customers.[110] In terms of the options we have identified we use the provision of additional security against the risk of LDZ isolation as a proxy for this.

1.30. Alternatively, some options may be designed to deliver a higher security standard by providing additional security against disconnection to all firm load gas customers. By protecting gas-fired generation against disconnection, a measure targeted at this level of security of supply would also reduce the risks of electricity load disruptions as a result of a shortage of gas supplies.

1.31. It should be noted that where any option is designed with a standard which is greater than the 30 day requirements set out under the Regulation, or any additional obligation imposed for reasons of security of supply, a number of criteria must be met and evidence provided of this to the Commission with information on how any increased supply standard or additional obligation imposed on natural gas

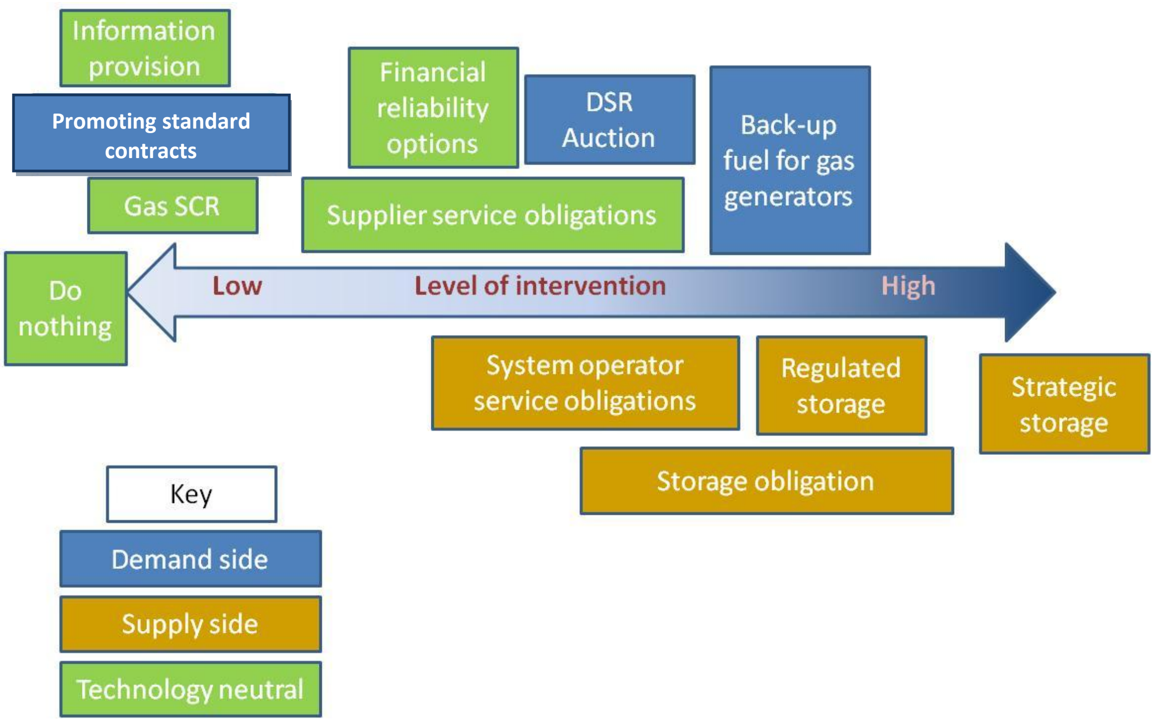
[110] Protected customers are defined in the Regulation as all households plus those customers classified as category A under the Gas Priority Users arrangements (which would include hospitals and care homes). This would largely consist of domestic gas consumers. However the physical nature of the gas system means that it is not possible to separately isolate other customers, including SMEs, on the Local Distribution Networks. In practice, therefore to maintain supplies to Protected Customers as defined above, it is necessary to make provision for all customers that are not separately isolatable on these local networks. For the purposes of calculation within the Regulation therefore, the gas demand from the relevant networks will be used.

undertakings may be temporarily reduced in the event of a Union or regional emergency.

1.32. Furthermore, the industry may react very differently to the options depending on the level at which they are set. DECC has set out that the market is already providing for the level of supply security required under the Regulation and that the risks of disconnection for protected customers are very low. A further measure designed to target this level of security would have little impact. However, a measure targeting a much wider share of the market is likely to have more fundamental impacts and be subject to more robust debate.

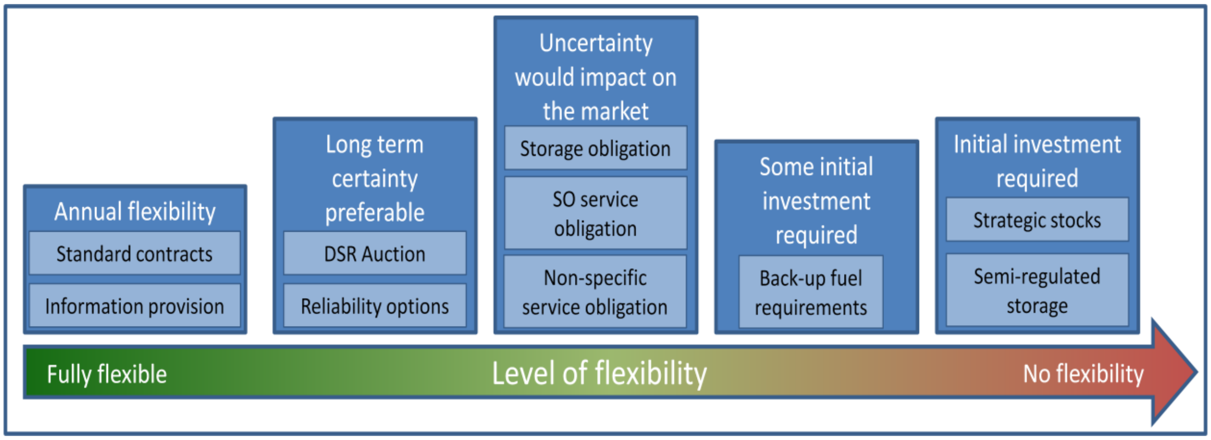
Working with the market

1.33. The questions of whether or not to impose further measures and, if so, how prescriptive these should be will be influenced by the level of confidence that government and Ofgem have in the market to deliver security of supply. Some of the measures we identify very much work with the grain of the market and facilitate market-led delivery of security of supply. Others impose a solution on the market and are prescriptive about the way that security of supply should be delivered. This is illustrated in the graphic below.



Adaptability

1.34. In Chapter 2 we noted that towards the middle of thedecade we could see a tightening of LNG supplies and that the outlook further out was less certain. On this basis the level of commitment and adaptability – in other words the ability to change the nature or level of the measure, including the ability to switch it on or off as needed – may be an important consideration. Certain measures, particularly those requiring large capital expenditure, by their nature trade off greater certainty against a lower level of flexibility.



Appendix 3 – Terms of reference

Terms of reference for a study into further interventions to enhance gas security of supply

Background

1. Under current arrangements, the cash-out price (the marginal cost to National Grid of buying gas to balance the system) during a "Gas Deficit Emergency" is frozen at the level immediately before the emergency and the costs of any interruption to gas supplies does not feed into this price. This means that gas prices may not rise sufficiently to attract gas into the country and that there is a gap in the incentives for gas supply companies to ensure that they have access to sufficient gas supplies to reduce the likelihood of an emergency occurring.

2. The Government supported Ofgem in undertaking a Gas Security of Supply Significant Code Review (Gas SCR) to reduce the likelihood, duration and extent of a Gas Deficit Emergency. DECC understands that Ofgem's Draft Policy Decision (DPD) for the Gas SCR will recommend that domestic consumers' value of lost load (VOLL) should set the cash-out price when firm consumers are interrupted in an emergency. Any firm customers (domestic, commercial or industrial) who are interrupted will receive a payment at this VOLL for the interruption services they have in effect been forced to provide. This should partially address the gap in the incentives for gas security of supply.

3. However, firm domestic and many firm commercial and industrial customers will only be paid for the first day of an interruption even though the interruption will likely last much longer and so a gap in the incentives will remain. In addition, Ofgem has broader concerns about whether price signals alone are sufficient to reduce the likelihood, duration and extent of a Gas Deficit Emergency, including in relation to any social externalities that may exist. For these reasons, Ofgem has recommended that work be undertaken to determine the extent to which further interventions are required alongside its proposed cash-out reform.

4. DECC agrees that there is merit in giving consideration to further interventions. These terms of reference set out the details of a project to consider the advantages and disadvantages of possible further interventions to enhance gas security of supply. DECC is asking Ofgem to undertake this project in parallel with it progressing the Gas SCR.

Deliverables

5. A report which includes:

- An assessment of the scale and nature of the risks to security of supply given developments in the global gas market – this should draw on existing analysis, only considering new modelling if a material gap in the existing analysis is identified.

- An assessment of the level of risk that remains in spite of Ofgem's proposed cash-out reform.
- An appraisal of the range of potential further interventions in the UK gas market to mitigate these risks.
- An appraisal of the relative merits of each of these further interventions, including the risk of market distortion, unintended consequences and initial views on cost-benefit comparisons.
- The development of proposals for the implementation of any further interventions that might be proposed, including the legislative, regulatory and institutional requirements.

Timing

6. This project would be announced on Tuesday 08 November 2011 (the date on which Ofgem will release the Draft Policy Decision for the Gas SCR).

7. The Government is asking that Ofgem provides a draft report to DECC by 17 July 2012. Next steps will depend upon the findings of the project, but are likely to include DECC and/or Ofgem consulting on the report and any measures identified within it.

Working arrangements between Ofgem and DECC

8. The project will be led by Emma Kelso and Kersti Berge at Ofgem in liaison with Chris Barton at DECC. Any issues of escalation will be dealt with in the first instance by Andrew Wright at Ofgem and Edmund Hosker at DECC.

9. DECC and Ofgem have agreed to hold regular working level meetings (a least monthly) to consider the scope of interventions to be discussed, the analytical approach to be taken and discuss progress on this project. Ofgem has agreed to provide DECC staff with the opportunity to attend stakeholder events and comment on internal analysis and drafts of any published reports relating to the project.