Department of Energy & Climate Change

UK Risk Assessment on Security of Gas Supply

Report completed for EU Regulation 994/2010

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Contents

1. Executive summary

Over the period 2014-16, the UK gas market is set to remain resilient to all but the most extreme combination of severe infrastructure failure or supply shocks. In addition to completing a national risk assessment, we have also considered a separate regional approach alongside the Government of Ireland, given that Ireland (along with Northern Ireland), relies on Great Britain for more than 90% of gas supply.[1]

1.1 This document forms the risk assessment required by the EU Regulation on Gas Security of Supply (994/2010) ('the Regulation') and fulfils the requirement on the UK Government, under Article 9 of the regulation, to update the first *Risk Assessment on Security of Gas Supply* published in November 2011.[2]

1.2 The Regulation's aim is to demonstrate to gas customers that all necessary measures are being taken to ensure gas infrastructure adequacy across EU Member States and that safeguards are in place to allow for exceptional climactic conditions or disruptions to supply. Whilst we consider the relative probabilities of particular disruption events and climatic conditions, we are not required to pass judgment on availability from particular sources. The Regulation also recognises that its objectives should be achieved in the most cost-effective way and its requirement should not affect the competitiveness of gas relative to other fuels.

1.3 The assessment of gas security is based on a number of common elements set out in the Regulation, including use of the N-1 calculation, which is the formula indicating the proportion of a Member State's gas demand that could be met in the event that it loses supply from its single largest piece of gas infrastructure. In this case, the 100km Felindre pipeline connecting the two liquefied natural gas (LNG) terminals located at Milford Haven to the national transmission system (NTS) is the UK's single largest piece of gas infrastructure.

1.4 As required by the Regulation, the *Risk Assessment* also considered supply standards, a description of the market, stress tests, and interactions with other Member States. On the basis of the *Risk Assessment*, Member States prepare *Preventive Action Plans* and *Emergency Plans*, which will be published by December 2014. Member States are required to update the *Risk Assessment* every two years, with the next update in June 2016.

1.5 The analysis in this report found that, in the short to medium term, UK gas supply infrastructure is resilient to all but the most extreme and unlikely combinations of severe

[1] The United Kingdom comprises Great Britain and Northern Ireland and, where appropriate, relevant information relating to Northern Ireland has also been included in this risk assessment.

[2] Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of supply and repealing Council Directive 2004/67/EC.

infrastructure and supply shocks. The UK N-1 calculation exceeds the target of more than 100% with a score of 112-13%.[3]

1.6 There are, however, challenges in the medium to long term: gas demand from electricity generation is expected to increase as gas-fired power generation replaces coal-fired plants, and gas is increasingly necessary to provide flexible back-up for further deployment of intermittent renewables. Along with this increase in gas demand for power generation, demand reduction may become less flexible as the power sector becomes less able to switch to alternative forms of generation, such as coal, at times of high gas demand.

1.7 The Governments of the UK and Ireland have also undertaken a regional assessment of gas security, which is published separately. The island of Ireland obtains approximately 93% of its gas supply through pipelines from Great Britain. Where a Member State cannot meet the N-1 principle on its own, as is the case with Ireland, Article 6 of the Regulation allows the Competent Authorities to adopt a regional rather than national approach in meeting the requirements of the regulation.

1.8 This document takes an initial view of risk from the point of view of the UK market alone. An over-arching regional risk assessment for the UK and Ireland together has been submitted in parallel with this document and the corresponding national risk assessment submitted by Ireland.

1.9 Further work for Government is identified to ensure that the UK gas market continues to remain secure to severe supply disruption.

[3] The figures used to calculate the N-1figure in this document exclude demand of 20mcm/d for exports to Ireland. Regional N-1 calculations that include Irish exports alongside UK demand are featured in the Regional Risk Assessment submitted to the EU Commission alongside this document

2. Introduction

This *Risk Assessment* discharges the Government's duty, set down in EU regulation 994/2010, to assess the security of gas supply over a number of scenarios involving high demand and supply disruption. It complements other on-going work on security of gas supply.

Security of supply overview

2.1 The UK's gas supply infrastructure must be sufficient to:

- meet 'peak' demand, including sufficient capacity and deliverability to ensure the gas we have can be accessed with minimal delay;
- ensure the safe and efficient transportation of gas from domestic production, storage facilities, and import points to consumers across the country; and
- provide access to the most competitively priced gas supplies.

2.2 Diversity of gas suppliers, sources, and routes to market is a key feature of UK supply security. Due to the UK's interaction with the Continental European market, European-wide efforts to encourage supply diversity further improve our security. The principle of further supply diversity was, amongst other issues, reaffirmed at the meeting of G7 Energy Ministers on 6 May 2014.

2.3 Security of supply in the UK is delivered through an effective gas market with investment in infrastructure driven by price signals. Through these price signals, the GB market has responded to declining domestic gas production and, since 2001, has delivered an increase of more than 500% in the UK's gas import capacity and a 16% increase in storage capacity. We have import infrastructure with the capability to meet nearly 190% of our annual demand. Currently, 60% of this infrastructure is utilised, offering much flexibility.[4]

2.4 This flexibility has been demonstrated in recent times and the market responded well to the challenges of recent winters, including March 2013, when it met a sustained period of late cold weather coupled with supply-side pressures. Detailed case studies of extraordinary gas market conditions are outlined in section 4 of this document.

2.5 Price signals have proved to be an effective means of delivering security of supply. Gas transportation licenses include a condition on shippers to balance what they are putting into and taking out of the system. Shippers pay a penalty, called the 'cash-out price', for oversupply (being 'long') or undersupply (being 'short'). These charges are designed to recoup the costs to the System Operator of entering the market and buying or selling gas to balance the grid.

[4] Figures derived from DECC's *Digest of UK Energy Statistics (DUKES) 2013*.

2.6 However, the Government is not complacent. Whilst we believe the gas market is robust to a range of adverse events, the risk of supply shortfalls in extreme circumstances cannot be ruled out, nor the risk that there may need to be significant rises in wholesale gas prices to balance the market during times of system stress.

2.7 The Government considers that market incentives have a key role to play in ensuring, and where possible enhancing, security of supply. In the previous 2011 *Risk Assessment*, DECC reported that it had given Ofgem a new power in the Energy Act 2011 to sharpen commercial incentives on gas market operators to ensure sufficient gas is available to reduce the likelihood, duration, and severity of a gas shortage. This work has progressed since then and is outlined in further detail on paras. 3.32-35.

Developments since the 2011 Risk Assessment

2.8 It is important to recognise that this document is designed to meet the requirements of EU regulation 994/2010 and is not the sole way in which the UK manages security of gas supply, nor should it repeat in detail the findings of related studies. There is on-going risk assessment and bespoke work, carried out by the Government, System Operator, and Regulator. Since the 2011 *Risk Assessment*, the following publications have been made relevant to gas security of supply:

Assessments and reports

- DECC and Ofgem's *Statutory Security of Supply Report* for 2012 and 2013: an annual requirement of UK law which provides analysis on gas and electricity markets;
- National Grid's *Winter Outlook* for 2012/13 and 2013/14: provided annually to gas market participants with the security of supply outlook for the coming winter;
- National Grid's *Gas Ten Year Statement* 2012 and 2013: an annual publication with a rolling ten-year forecast of gas supply and demand and the consequences for the operation of the National Transmission System;
- National Grid's *UK Future Energy Scenarios* 2012 and 2013: an annual forecast into credible energy scenarios out to 2035 and 2050;
- Ofgem's *Gas Security of Supply Report* in November 2012: produced at Government's request to analyse the risks to UK gas security and assess potential interventions to minimise those risks;
- The *State of the Market Assessment* by Ofgem, the Office of Fair Trading, and the Competition and Markets Authority in March 2014: after which Ofgem announced a consultation on a referral of the gas and electricity markets to the Competition and Markets Authority. An investigation into the energy markets by the CMA may take around 18 months to complete.
- Northern Ireland transmission system operators also carry out an assessment of the transmission network through the *Northern Ireland Gas Capacity Statement*, most recently published in February 2014. This provides an assessment of the ability of the Northern Irish gas transmission network to deliver gas over a number of potential scenarios within the next ten years; and
- Northern Ireland's Premier Transmission *Winter Outlook 2013/14*, which assessed the supply and demand situation for that winter. The Irish Authorities also conduct similar

assessments and these are shared between both jurisdictions to support joint planning assumptions between Northern Ireland and Ireland.

2.9 Alongside general monitoring of gas security of supply, Government has taken some specific decisions on gas supply security. Details of these decisions and the analysis which underpinned them include:

Policy decision publications

- Redpoint Energy's *The Impact of Gas Market Interventions on Energy Security* in July 2013: commissioned by Government to review the costs and benefits of developing some of the gas market interventions identified in Ofgem's *Gas Security of Supply Report*;
- Pöyry's *Gas Significant Code Review Cost Benefit Analysis for a Demand-Side Response Mechanism*: a report published in January 2014, which was commissioned by Ofgem, and included analysis of potential interventions to enhance security of gas supply; and
- Ofgem's Gas Security of Supply Significant Code Review (Gas SCR): a process whereby the Regulator has considered changes to gas codes to reduce the likelihood, severity, and duration of a gas supply emergency. A final policy decision was announced in February 2014.

2.10 Overall, the above publications concluded consistently that the UK gas market is robust in all but the most extreme and unlikely combination of high demand and supply disruption and the flexibility of its varied supply sources means it is likely to remain resilient, with the prospect that this will be further improved by the Gas SCR.

2.11 Government has also continued work on various strands of policy development which will have an impact on gas demand and supply and, therefore, gas security. This includes:

- the Electricity Market Reform (EMR) program, which began in 2011, and contains a range of measures to ensure sufficient electricity generation, such as incentives for the deployment of low-carbon technologies and a Capacity Market which will incentivise both demand-side response and adequate gas-fired power generation;
- publication of the *Gas Generation Strategy* in December 2012 which set out our expectations for the future of gas-fired power in the UK, including the role of Carbon Capture and Storage;
- initiatives to incentivise the uptake of energy efficiency measures by domestic and small business consumers, such as the Green Deal and Energy Company Obligation. New incentives to promote adoption were announced on 1 May 2014;
- the launch of the Renewable Heat Incentive, which will encourage the deployment of low-carbon heat generation technologies;
- continued work on the Smart Meter program, which requires GB suppliers to install gas and electricity smart meters for all non-daily metered customers between 2015 and 2020;
- creation of an Office for Unconventional Gas and Oil within DECC to take forward the development of indigenous unconventional hydrocarbons; and
- publication of the independent *UKCS Maximising Recovery Review: Final Report* (the 'Wood Review') with suggestions for maximising the production of the UK's remaining North Sea oil and gas.

Consultation

2.12 This *Risk Assessment* was subject to an informal consultation period in early 2014 with the Regulator and System Operator. In addition, we shared this document in draft with the Regulator and Government of Ireland, the relevant governmental and regulatory agencies in Northern Ireland, and the Government of the Netherlands.

2.13 Furthermore, much of the underlying data and assumptions derive from the documents outlined above, many of which were themselves subject to formal and informal consultation periods.

3. Gas market context

Current UK indigenous gas production and existing import infrastructure is more than sufficient to meet demand in all but the most extreme and unlikely combination of infrastructure failures and is likely to remain so in the near future. Looking further ahead, import infrastructure will have to adapt to changing demand and supply profiles. Known proposed gas storage and new LNG facilities suggest that the market will deliver this between now and the 2020s.

Demand

3.1 The UK consistently has one of the largest and most liquid gas markets in Europe. In 2012, UK consumption was the second largest in Europe, just behind Germany.[5] High levels of liquidity at the UK's hub, the National Balancing Point (NBP) is evidenced by the level of trades there: 6,600TWh in 2012, or 63% of all gas traded in Europe.[6]

3.2 Figure 3.1 below shows the sources of UK gas demand broken into major components in 2011 and 2012.

Figure 3.1 – Gas demand in the UK 2011-12

Source	2011 (bcm)	2012 (bcm)
Electricity generation	29	20.2
Domestic	27.7	32
Services/industry	27.8	27.6
Total demand	**84.5**	**79.8**

Source: Digest of United Kingdom Energy Statistics 2013

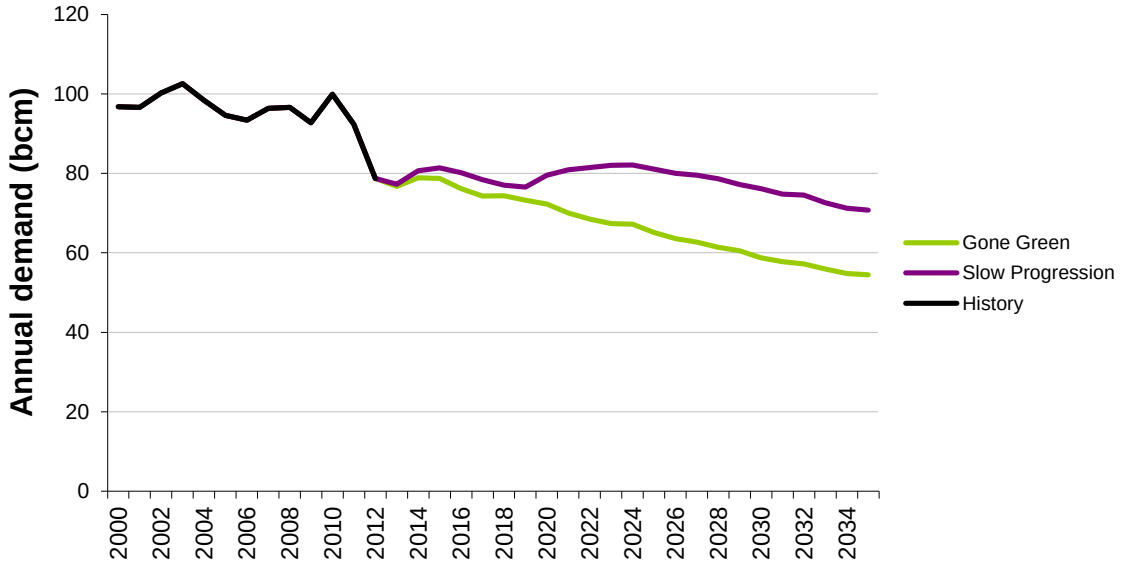
3.3 Figure 3.2 shows two future gas demand scenarios produced by National Grid out to 2035.[7] The 'Gone Green' scenario assumes that the UK meets its EU and national legislative targets: 15% of all energy from renewable sources by 2020, greenhouse gas emissions meeting carbon budgets to 2027, and an 80% reduction in greenhouse gas emissions by 2050. The 'Slow Progression' scenario assumes that renewable and low-carbon energy deployment is slow, with the consequence that the 2020 renewable target is not met, and that the carbon reduction target for 2020 is met but the indicative target for 2030 is not.

[5] Eurostat, *Energy statistics – supply, transformation, consumption – gas – annual data*.

[6] European Commission, *Quarterly Report on European Gas Markets*, Volume 6, issue 2, pp.6-8.

[7] National Grid, *Future Energy Scenarios* (2013). Although these figures do not take into account the direct effects of the temporary capping of the Carbon Price Floor, carbon price sensitivities within the two scenarios should cover this new maximum value.

Figure 3.2 – Historic and projected annual UK gas demand



Source: National Grid

3.4 Under Slow Progression, gas demand remains around 80bcm/y until the mid-2020s owing to relatively little change in residential demand and a steady demand from power supply. By the 2030s total demand is only marginally below today's demand at around 70bcm/y. Under Gone Green, gas demand declines in the residential, industrial and commercial, and power generation sectors after 2020, resulting in a steady reduction in total demand to around 50bcm/y by the 2030s.

3.5 Figure 3.3 below shows actual peak UK demand in 2011 and 2012. Peak demand is influenced to a great extent by annual weather conditions.

Figure 3.3 – Peak gas demand in the UK 2011-13

	2011/12 (mcm/d)	2012/13 (mdm/d)
Actual maximum gas demand	436	411

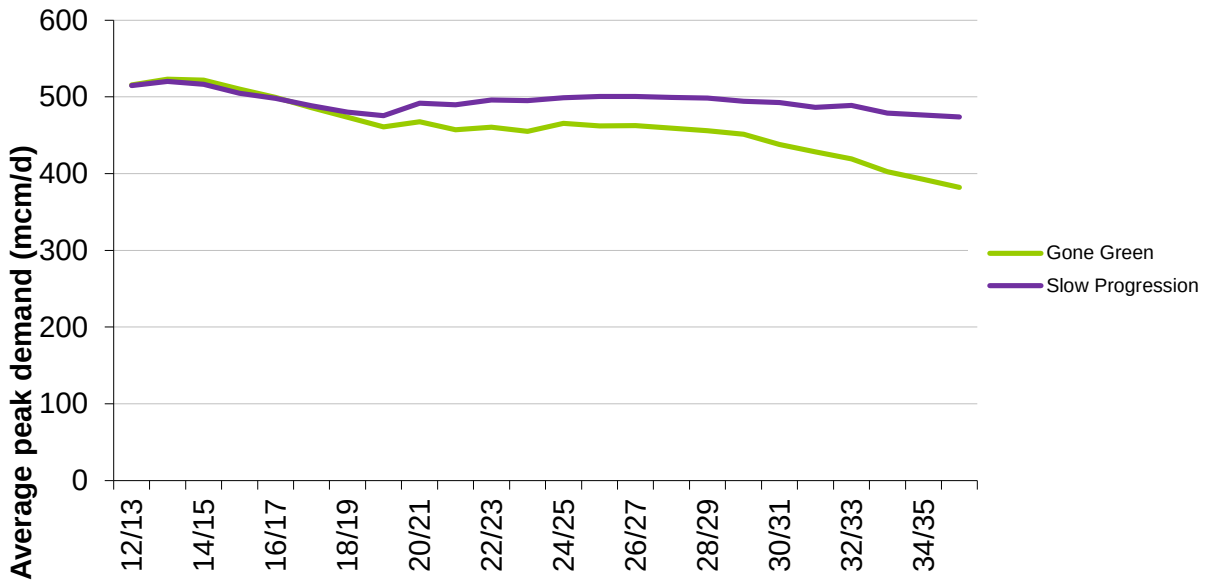
Source: UK Energy in Brief 2013 Dataset[8]

3.6 The ability to meet peak demand on a particular day, or a more prolonged period such as a severe winter, is particularly relevant in the context of security of supply. Gas market participants build redundancy into their supply arrangements, above the minimum amount to meet peaks, to manage the risk that other capacity may not be available.

3.7 Peak diversified day gas demand is projected in Figure 3.4 in the Gone Green and Slow Progression scenarios, with 2013/14 peak diversified demand estimated at around 530mcm/d. Both Gone Green and Slow Progression show a net decline in peak diversified demand to around 480 mcm/d by 2020. Under Gone Green, peak demand is projected to remain around that level to the end of the 2020s then to decline in the 2030s. Under Slow Progression, peak demand increases to around 500 mcm/d until the end of the 2020s.

[8] Data originally presented in TWh/d and converted into mcm/d.

Figure 3.4 – Projected peak diversified demand to 2035



Source: National Grid

Demand Side Response (DSR)

3.8 DSR is a mechanism used in times of market tightness to balance supply and demand by voluntary shedding of demand. The power generation sector provides an opportunity for switching demand away from gas to coal or oil generation, reducing overall gas demand. However, in recent years, this facility has been limited as low coal prices have encouraged maximum use of coal-fired power stations at the expense of gas. Coal and oil generation capacity is progressively closing through the Large Combustion Plant Directive (LCPD) and the Industrial Emissions Directive (IED), further limiting the long-term use of fuel switching to manage demand.

3.9 Price signals in the UK gas market allow larger non-domestic consumers to respond by either changing their demand profile or reducing demand altogether. Larger industrial consumers may have the ability to switch to alternative fuels during times of high gas prices. A conservative estimate by Ofgem was that around 1.2% (0.4mcm/d) of industrial and commercial daily metered gas volumes are currently on interruptible contracts.[9]

3.10 Ofgem's reform of the gas cash-out mechanism, through the Significant Code Review, will sharpen the incentives on gas market participants to invest in measures to enhance security of supply. Ofgem have also announced a tender process for a demand-side response mechanism with the aim of encouraging greater participation and efficiency of demand-side response actions by commercial and industrial consumers. Modelling undertaken as part of the Gas SCR estimated that the volume of industrial and commercial DSR will increase from a negligible level currently to up to 26mcm/d, which could be up to 76mcm/d with the inclusion of gas-fired DSR, although this will depend on the exact design of the mechanism.[10]

3.11 Currently, non-daily metered consumers (domestic consumers and small businesses) are not so exposed to fluctuations in wholesale prices and therefore have no short-term signal to

[9] Ofgem, *Gas Significant Code Review Impact Assessment for Final Policy Decision*, p.16.

[10] Ibid.

reduce gas demand. Following the roll-out of smart meters across the UK, beginning in 2015 and ending in 2020, it is expected that the provision of real-time consumption and cost information will result in consumers using energy more efficiently, and will incentivise consumers to install energy efficiency measures. Cumulatively, smart meters are expected to reduce direct demand for gas by domestic and small business consumers under normal market conditions by 1bcm in 2020, remaining roughly constant out to 2030.[11]

Supply

3.12 The UK has a wide range of gas supplies and sources. This includes significant levels of domestic gas production, access via pipelines to Norwegian gas production, interconnection with the Continent through the IUK and BBL pipelines and some of the largest and most modern LNG infrastructure in Europe. In response to decreasing indigenous supply, the GB market has delivered a 500% increase in import infrastructure with capacity to meet 189% of annual demand (2012 figures) alone. Figure 3.5 outlines sources of UK gas in 2011 and 2012.

Figure 3.5 – annual sources of UK gas in 2011 and 2012

Source	2011 (bcm)	2012 (bcm)
Total pipelines:	**28**	**36.5**
Belgium	0.4	1.3
Netherlands	6.3	7.4
Norway	21.3	27.8
Total LNG:	**24.6**	**14.0**
Algeria	0.2	0.1
Egypt	0.1	0.01
Nigeria	1.2	0.04
Norway	0.9	0.2
Qatar	21.0	13.6
Trinidad	0.5	-
USA	0.1	-
Yemen	0.6	-
Total imports	**52.5**	**50.6**
UK production	**47.9**	**42.7**
Total exports	-16.7	-12.4
Total supply	82.3	80.9

Source: Digest of United Kingdom Energy Statistics 2013

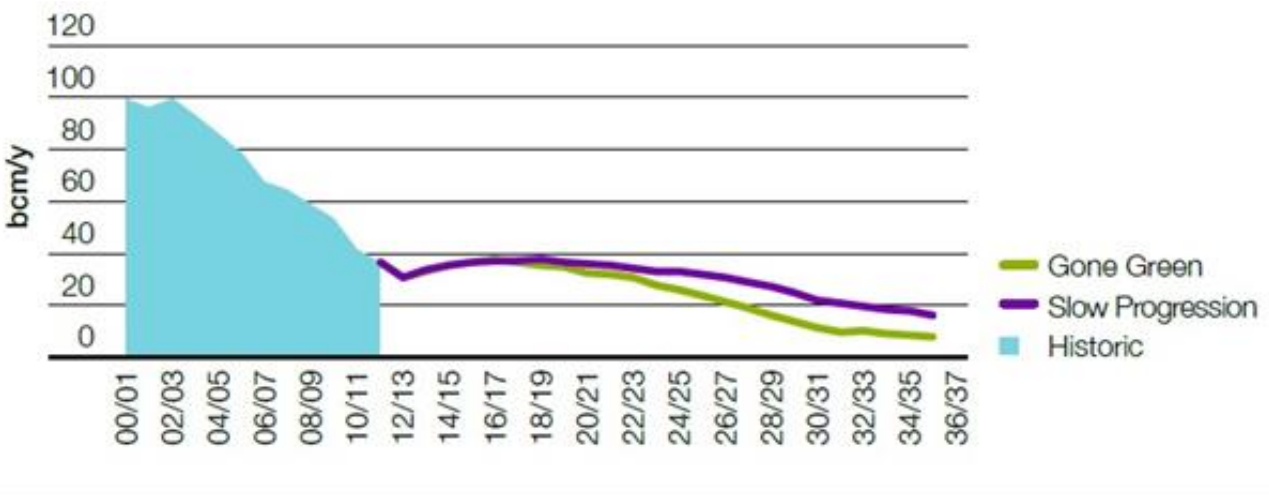
UK Continental Shelf (UKCS) Production

3.13 Domestic North Sea production is still the UK's single largest source of gas, meeting 54% of UK demand in 2012. However, North Sea production is set to decline significantly out to 2035; import dependency will rise despite decreases in demand. Figure 3.6 shows National Grid's projections for future UK Continental Shelf (UKCS) production under both the Slow Progression and Gone Green scenarios. The difference between the two scenarios is minimal in the medium term as predictions are based on existing operational fields and a number of new fields projected to come online soon. It is these new fields that account for

[11] DECC, *Impact Assessment: Smart meter roll-out for the domestic and small and medium non-domestic sectors (GB)*. (IA No: DECC0009).

the slight increase in UKCS production overall between now and 2019. In both scenarios, domestic UKCS production is predicted to fall to low levels.

Figure 3.6 – Historic and project UKCS production



Source: National Grid Future Energy Scenarios 2013

3.14 However, these projections do not include the possible impact of the Wood Review, announced in February 2014, which may see greater volumes of production from the North Sea. The Wood Review predicts that full implementation of its recommendations may see an additional 3-4 billion boe produced from the UKCS over the next 20 years,[12] although it is not possible to split oil and gas production. Despite this, overall production from the North Sea is still set to decline as a UK gas source in the long term.

Unconventional Gas Production

3.15 National Grid also forecast a likely increase in on-shore gas production coming from possible new developments in biogas and shale gas. As a proportion of UK demand, the contribution of onshore gas sources in the Gone Green and Slow Progression scenarios increases from near zero today to c.2% in 2020 and 8–10% in 2035. How this is made up varies between the two scenarios with shale gas accounting for most of the increase in the Slow Progression scenario and biogas in the Gone Green scenario. There is, however, significant uncertainty as to the timescales and the volumes that may be generated from any on-shore production.

Import infrastructure

3.16 Currently, the UK has an import deliverability of ~54 bcm/y from Norway, ~46 bcm/y from capacity connected to the Continent, and ~53 bcm/y from LNG import terminals. Figure 3.7 below, shows the range of completed import projects that currently make up the UK's import infrastructure.[13]

[12] Wood, I., *UKCS Maximising Recovery Review: Final Report*, p.7.

[13] National Grid, *2013 Gas Ten Year* Statement, p.138.

Figure 3.7 – Existing GB import infrastructure

Project	Operator/ Developer	Type	Location	Capacity (bcm/y)
IUK	Interconnector (UK) Ltd	Pipeline	Bacton	26.9
BBL Pipeline	BBL Company	Pipeline	Bacton	17.6
Isle of Grain 1-3	National Grid	LNG	Kent	20.4
GasPort	Excelerate Energy	LNG	Teesside	4.1
South Hook 1-2	Qatar Petroleum & Exxon Mobil	LNG	Milford Haven	21
Dragon 1	BG Group & Petronas	LNG	Milford Haven	7.6
Langeled	Gassco	Pipeline	Easington	26.3
Vesterled	Gassco	Pipeline	St Fergus	14.2
Tampen	Gassco	Pipeline	St Fergus	9.8
Gjøa	Gassco	Pipeline	St Fergus	6.2
			Total	**154**

Source: Digest of United Kingdom Energy Statistics 2013

Norwegian Continental Shelf Production

3.17 Norway is a crucial gas supplier to GB, supplying around 38% of total gas demand in 2012. The vast majority of this comes through pipelines with very small quantities of LNG. Norway currently has the infrastructure capacity to export 53.8 bcm/y to the UK: the 25.3 bcm/y Langeled pipeline supplying gas to Easington; the 13.1 bcm/y Vesterled pipeline supplying gas to St Fergus; the 9.1 bcm/y Tampen link and the 6.2 bcm/y Gjøa link, both of which feed into the FLAGS pipeline. Despite this overcapacity in annual terms, Norwegian infrastructure flows at near full capacity in the winter.

3.18 Total Norwegian production is currently c.114 bcm/y. However, there is uncertainty surrounding future Norwegian production beyond 2020 due to lack of knowledge about the extent of gas resources in the Barents and Norwegian Seas. More information about the resource base and infrastructure options is expected in the coming years.

Interconnectors

3.19 The UK currently has four interconnectors with other Member States:

- Interconnector UK (IUK), which flows gas in both directions between Bacton and Zeebrugge in Belgium;
- the BBL pipeline, which flows gas from Balgzand in the Netherlands to Bacton;
- the Moffat interconnectors (IC1 and IC2), which are currently configured to flow gas from Moffat in Scotland to Ireland; and
- the South North Pipeline (SNP), operated by BGE (UK), which can supply gas from Gormanston in Ireland to Northern Ireland. Gas does not currently flow via this route as all gas is supplied to Northern Ireland through the Scotland to Northern Ireland Pipeline (SNIP).

3.20 During winter 2012/13, gas interconnectors with Belgium and the Netherlands played a more significant role in meeting the UK's gas demand, supplying 16.5% of the UK's gas

supply over the winter period. They are increasingly taking a role in flexing supply by responding to price signals.

3.21 One of the UK's interconnectors, IUK, has bidirectional flow enabled. The remaining three are currently subject to an exemption from mandatory bidirectional flow, which expires on 3 June 2014. Section 5.12 of this document considers the current situation with regards to bidirectional flow and assesses the appropriateness of continued exemption.

3.22 The interconnectors between Great Britain, Northern Ireland, and Ireland, which are critical for gas security on the island of Ireland, are considered separately in the *Regional Risk Assessment*.

Liquefied Natural Gas (LNG)

3.23 The UK is connected to global gas markets through four LNG import terminals. The UK currently has the infrastructure capacity to import 54 bcm/y of LNG through: South Hook (21bcm/y), Dragon (7.6bcm/y), Teesside GasPort (4.1bcm/y); and Isle of Grain (20.4bcm/y). This means that the UK has the second largest LNG infrastructure in Europe, behind Spain.[14]

3.24 These terminals theoretically connect the UK to any LNG producing country, although historically the majority of UK LNG has come from Qatar, the world's largest LNG producer. Volumes of LNG delivered into the UK have declined in recent years, driven by the price differential between the European and Asian markets, which is in turn largely linked to increased Asian demand linked to the Fukushima incident and economic growth.

3.25 Despite this decline in LNG volumes destined for the UK, the market has adapted well with no significant adverse effects. It would be reasonable to expect that, under a period of profound market tightness, UK prices would rise to a level sufficient to attract increased volumes of LNG. Under current market conditions, this trend is set to continue until the latter years of the 2010s, when large volumes of new LNG production are expected to hit the market, notably from Australia and the US. The announcement of a LNG supply deal from Sabine Pass, USA by UK-based Centrica in 2013 may be indicative of future trends of US gas arriving in Europe.

Gas storage

3.26 The UK currently has nine commercial gas storage facilities. Storage space has increased by around 25% (1bcm) in the last 10 years to a present level of around 4.6bcm. However, deliverability, the rate at which gas can be supplied to the network, has increased over 50% from 100mcm/d to 154mcm/d following the expansion at Aldbrough and the start-up of the Holford facility. There are two storage projects under construction at Hill Top Farm and Stublach. Incremental completion of all facilities is expected between 2013-18, and will bring deliverability up to around 200mcm/d.

3.27 The UK is comparatively under-served by gas storage by European standards, largely due to the existence of significant domestic gas reserves. However, it is worth noting that the UK market is over-served in other import infrastructure compared to other Member States, notably in LNG infrastructure and pipelines, and it would seem that, thus far, the market has opted for these solutions rather than storage.

3.28 In July 2013, the UK Government announced that it would not intervene to incentivise further gas storage, based on a cost-benefit analysis study by independent consultants,[15]

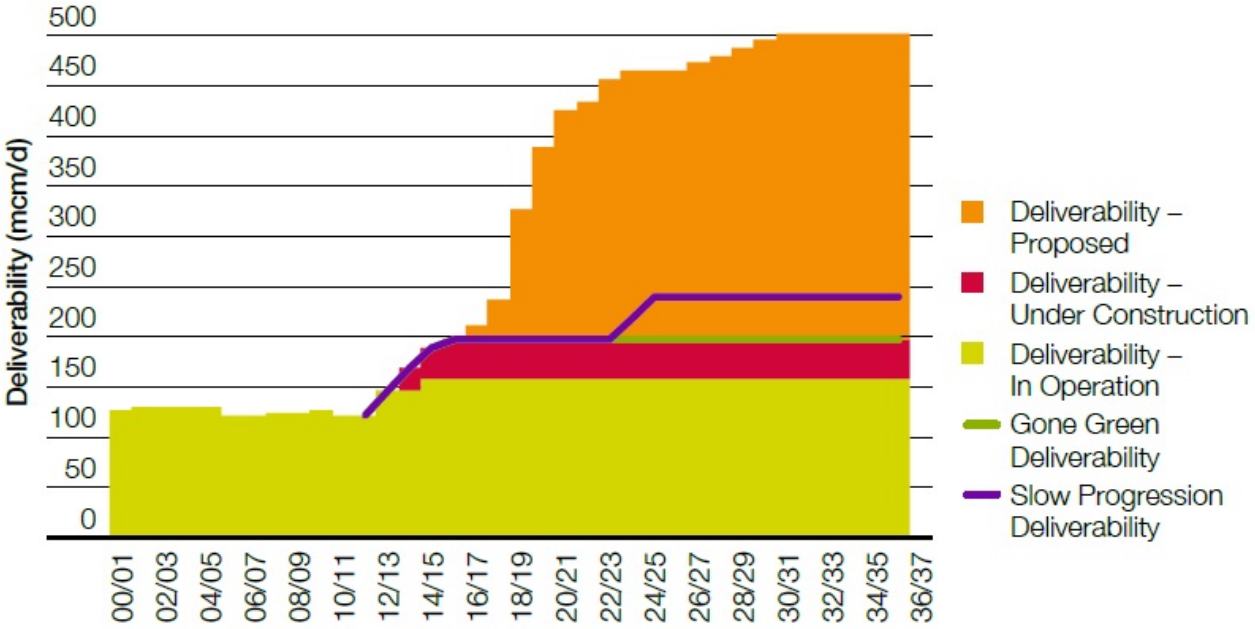
[14] International Energy Agency, *Natural Gas Information 2013*.

[15] Redpoint Energy, *The Impact of Gas Market Interventions on Energy Security*.

which highlighted that the costs of intervening largely outweigh the possible costs of low storage levels in the event of a gas deficit. The report also highlighted the risk of unintended consequences of intervention, principally disincentivising construction of certain types of gas storage.

3.29 Even without intervention, there are numerous potential storage projects with planning permission which could double current storage capacity. Figure 3.8 shows the potential for growth of storage capacity in the UK based on existing and proposed storage projects. In the Slow Progression scenario it is expected that more long-range seasonal storage comes into operation as the UK becomes more dependent on imports. In the Gone Green scenario there is potentially a need for more short-range flexible storage that can be called upon to help balance intermittent power supply from renewables.

Figure 3.8 – Current and proposed UK gas storage levels



Source: National Grid

Proposed new UK import infrastructure

3.30 Figure 3.9 outlines the list of possible import infrastructure projects of which Government is currently aware. It should be noted that there is no guarantee that these projects will materialise.

Figure 3.9 – Proposed UK import infrastructure

Project	Operator /Developer	Type	Location	Start up	Capacity (bcm/y)	Status
Isle of Grain 4	National Grid	LNG	Kent	-	-	Open Season
Norsea LNG	ConocoPhillips	LNG	Teesside	-	-	Planning granted, no FID. Currently on hold.
Port Meridian	Port Meridian Energy	LNG	Barrow	2016+	5	Open Season
Amlwch	Halite Energy	LNG	Anglesey	-	~30	Approved Onshore
				Total	**30+**	

Market actors

3.31 The main participants in the GB energy market can be broken down as follows:

- The **Department of Energy and Climate Change** (DECC): the 'Competent Authority' as defined in the Regulation. DECC leads energy and climate change policy for the GB market, including international engagement with key energy suppliers.
- The **Department of Enterprise, Trade, and Investment** (DETI): the relevant government department in the devolved administration of Northern Ireland.
- The **Utility Regulator Northern Ireland** (UREGNI): the energy regulator in the devolved administration of Northern Ireland.
- The **Office of Gas and Electricity Markets** (Ofgem): the independent 'Regulator' responsible for protecting the interests of present and future energy consumers, including security of supply, supervising market function, and competition. Ofgem's role and responsibilities will be further clarified over the next year through the *Strategy and Policy Statement*.
- **National Grid**: the 'System Operator', who own and operate the National Transmission System with the right to buy, sell, and store gas to keep the system in balance. National Grid also own and operate four of the eight local distribution networks and one of the four LNG import terminals. National Grid is the natural gas undertaking required to meet supply under the conditions outlined in Article 8 of the Regulation.
- **Gas shippers**: licensed shippers buy gas from producers and importers, arrange for its transportation through the National Transmission System, and sell gas to suppliers. In April 2014, there were more than 200 licensed gas shippers.
- **Distribution network operators**: gas which leaves the National Transmission System is distributed to end customers through eight regional, regulated monopolies owned and managed by four separate companies.
- **Suppliers**: There are an increasing number of licensed suppliers who buy gas from shippers and compete to supply both domestic and business consumers. Over 90% of

the domestic market is dominated by the six larger suppliers,[16] although the number and market share of small suppliers is on the increase.[17] In the larger daily metered and non-daily metered market, the position of the six larger suppliers is less dominant.

Figure 3.9 – UK NTS

Figure 3.10 – Gas distribution

Ofgem's Gas Significant Code Review (SCR)

3.32 As part of the process referred to in section 2.6, Ofgem has published a final policy decision on the Gas SCR setting out how current market arrangements could be improved to further enhance security of supply. Ofgem's Gas SCR consultation process has involved discussions with UK gas shippers and considered how shippers can best meet their market obligations. The final proposals concentrate on cash-out arrangements and a decision to proceed with a demand-side response mechanism.

3.33 Until now, cash-out prices have been frozen during a Gas Deficit Emergency (GDE), a period where there is a risk of insufficient gas supply to maintain safe operating pressures in the gas network. Frozen cash-out prices can mean the incentive to bring gas to the GB market could be weakened at precisely the time when it should be sharpest.

[16] Centrica, EDF, Scottish Power, SSE, E.ON, nPower

[17] Ofgem, *State of the Market Assessment*, pp.7-9.

3.34 The final policy proposals from the Gas SCR include the unfreezing of cash out prices so that they can reflect market conditions during the emergency. The proposals, which would entail various code and licence modifications, are planned to be in force by winter 2015/16.

3.35 The final policy also includes proposals for a demand-side response mechanism to encourage greater demand-side participation from industrial and commercial users, to be administered by the System Operator, to help avoid an emergency. These are set out in section 3, Demand Side Response.

Gas Quality Issues

3.36 Natural gas is predominantly methane with a variety of other components, the combinations of which affect the quality of gas. The calorific content of gas, which is particularly important within the UK context, is measured by the Wobbe Index. The specification of gas conveyed into the NTS is regulated for safety reasons by the Health and Safety Executive.[18]

3.37 Much internationally traded gas, for example in the continental EU and LNG, has a Wobbe Index above the range permitted in GB. From 2002-2007, DECC's predecessor departments (DTI and then BERR) reviewed the case for modifying the characteristics permitted, in order to minimise the requirement to process imported gas. A published Impact Assessment in 2007 pointed to the 'no change' option.[19] On this basis, the government of the day confirmed that it would not propose any change to our regulated specification to take effect before 2020 and, on the evidence, after 2020 either. This has led to commercial investment in gas processing plants at our major new gas import terminals: Isle of Grain, Teesside GasPort, South Hook, Dragon, and Easington.

3.38 Overall, the UK market framework allocates the risk of being unable to source gas of suitable specification to shippers, via the daily balancing requirement. They may rely upon a number of supply and demand-side measures, such as indigenous production, withdrawals from storage, imports via other routes, or demand-side response, in order to ensure their portfolios are balanced.

3.39 In January 2007, the EU Commission gave a mandate to the standardisation body CEN to draw up European wide standards for gas quality that are the 'the broadest possible within reasonable costs'. This work is currently on-going. It is expected that the draft standard will be issued for consultation in 2014 and finally published in 2015. It is not expected to be made legally binding for Member States to adopt.

Conclusion

3.40 At present, the UK has more than adequate indigenous production and import infrastructure to meet demand; import infrastructure alone could meet 189% of 2012 demand. Putting aside the stress tests of the N-1 calculation, Ofgem's Gas Security of Supply Report found that, in a normal winter, the GB gas market would have to lose 50% of non-storage supplies for there to be an interruption to gas supplies to large industrial users and/or the power sector. Between 60-70% of all gas sources would have to be lost for there to be an interruption of supplies to domestic customers, equivalent to losing all LNG supply, all imports from the Continent, and 50% of indigenous production at the same time.

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[18] Gas Safety (Management) Regulations 1996 (GS(M)R).

[19] Department of Trade and Industry, *Partial Regulatory Impact Assessment – Future Arrangements for Great Britain's Gas Quality Specifications* (2005).

3.41 Looking to the future, the UK is predicted to have both changing supply and demand profiles. The exact balance of supply and demand for gas will be dictated by global market conditions and the extent to which the UK decarbonises its economy. Between now and the next *Risk Assessment* in 2016, existing import infrastructure is very likely to remain adequate. Looking further ahead, it is likely that the market will bring forward further import infrastructure, evidenced by the list of current potential projects.

4. Risk assessment – risk identification and analysis

Risk analysis suggests that UK infrastructure can meet protected gas demand across a range of scenarios, up to and including a combination of exceptional demand caused by severe weather with the failure of a large proportion of import infrastructure.

4.1 This section identifies and assesses risks relevant to the gas supply infrastructure, as required by the Regulation. First, the impact of a supply shock equivalent to the loss of the largest single piece of gas supply infrastructure (the Milford Haven to Felindre pipeline) is analysed over the course of a day, week, month and entire winter, under both average and severe demand conditions.

4.2 The Regulation requires us to test UK resilience to disruption using the 'single largest gas infrastructure', which is the 100km Milford Haven to Felindre pipeline. This connects the two LNG facilities at Milford Haven, South Hook and Dragon, to the National Transmission System, and is therefore theoretically responsible for conveying up to 28.6bcm/year of gas.

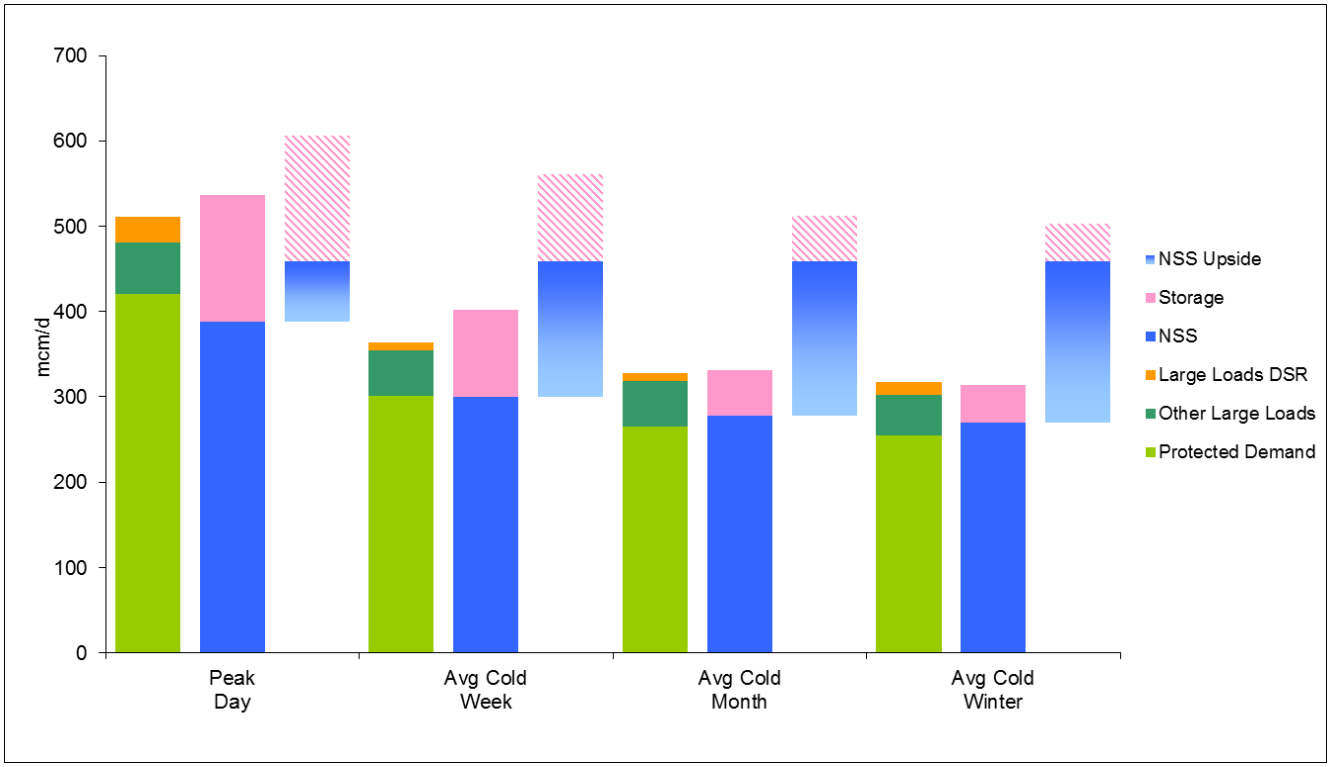
4.3 The loss of this piece of infrastructure, or equivalent piece(s) of infrastructure up to this total, is then tested over the course of a day, week, month, and entire winter, and under both average and extreme demand conditions.

Demand modelling – average conditions with no supply disruption

4.4 Figure 4.1 shows the ability of UK infrastructure to meet demand under average UK winter conditions over four durations:

- The coldest day, on average -2°C
- The coldest week, on average 1°C
- The coldest month, on average 3°C
- The coldest three months, on average 5°C

Figure 4.1 – Demand analysis under winter conditions with no supply disruption



Source: National Grid

4.5 The chart shows three bars for each level of demand. The first bar (light green, dark green, and orange) shows demand as three components:

- 'Protected demand': all customers protected by National Grid's Safety Monitor;[20]
- 'Other large loads': Large loads that are not expected to respond to a short-term increase in gas price;
- 'Large loads DSR': Large loads that are expected to respond to a short-term increase in the gas price and therefore provide a demand side response.

4.6 The DSR is shown as a range from 10-30 mcm/d. Approximately 5-25 mcm/d of this response is assumed from gas-fired power stations, arising through increasing prices during a period of high demand, a supply shortage, or a combination of both. For weekdays at high gas demand, the DSR could be as low as 0–10 mcm/d.

4.7 The low assessment for DSR from power generation arises as coal-fired power stations rather than gas is assumed for base-load power generation. Other generating assumptions also limit the response, namely low wind (8%), relatively low nuclear availability (83%) and some electricity interconnector exports.

4.8 For each additional GW of non-gas generating plant available, the DSR increases by about 4.5mcm/d. Though not shown, an additional DSR of typically 10mcm/d may be possible for a limited time through use of distillate as an alternative fuel source.

[20] 'Protected demand' includes all loads up to 5860MWh non-daily metered (including residential and small business consumers), flows to Ireland, and priority load. Priority load is split into three categories: Category A includes any customer where disruption could lead to loss of life (e.g. hospitals, care homes); Category B includes those that would have been in Category A except that they have signed interruptible contracts (because they have access to alternative generation) and can continue to use gas during the time it takes for them to switch to the alternative; and Category C, customers where interruption would lead to damage in excess of £50 million.

4.9 The second bar represents supply differentiated by non-storage supply (NSS) in blue and gas storage in pink. The third bar shows the theoretical NSS upside in blue with storage on top in hatch pink. This illustrates the significant amount of supply flexibility that is available within the UK.

4.10 The analysis shows that, for average conditions, demand is met by central case (i.e the second bar) supplies for most of the scenarios featured but that some demand-side response may be needed over the course of an entire winter. Protected demand is readily met by non-storage supplies for all scenarios other than the peak day scenario, which could require low injections of storage gas.

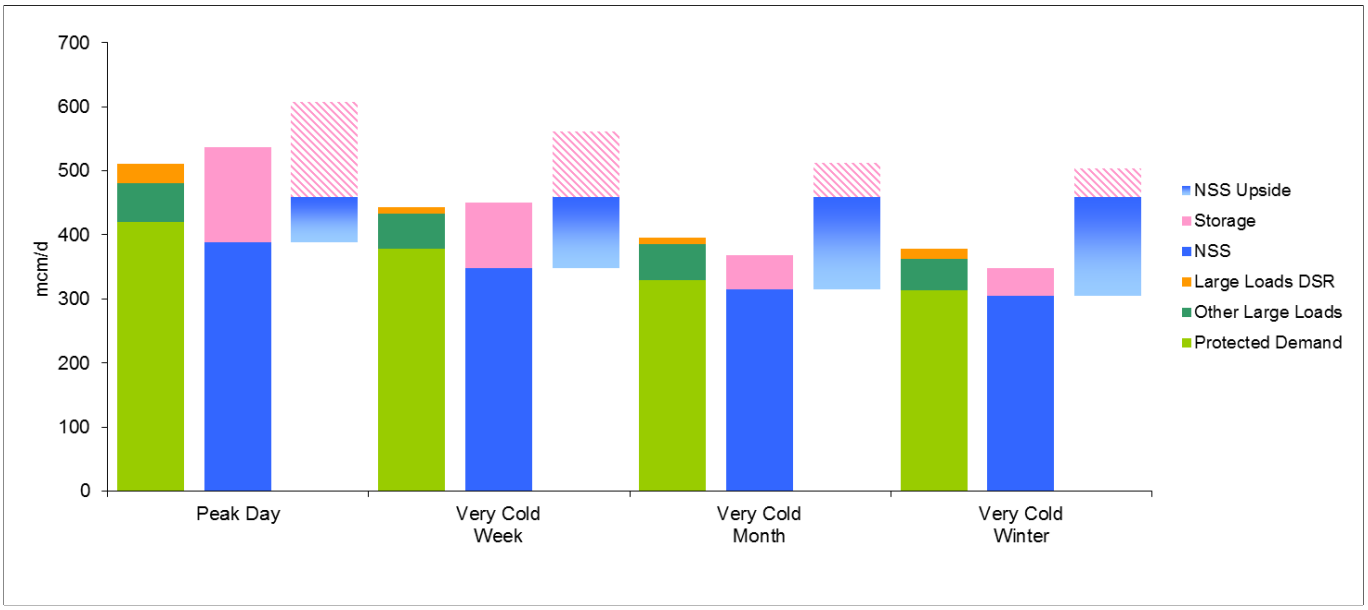
Demand modelling – severe conditions with no supply disruption

4.11 Figure 4.2 shows a similar analysis for severe 1-in-50 demand conditions with no supply disruption:

- The peak day,[21] on average -5°C;
- The coldest week, on average -3°C;
- The coldest month, on average -1°C; and
- The coldest three months, on average 1.5°C.

4.12 Note that this is a more stringent test of UK infrastructure than the Regulation requires, which is 1-in-20 demand conditions; 1-in-50 conditions have been used in order to maintain consistency with National Grid's Safety Monitor calculations. These calculations ascertain the level of gas that is required to remain in storage to enable safe operation of the network.

Figure 4.2 - Demand analysis under winter conditions with no supply disruption



Source: National Grid

4.13 Central case supply, including storage, meets protected demand in all scenarios.

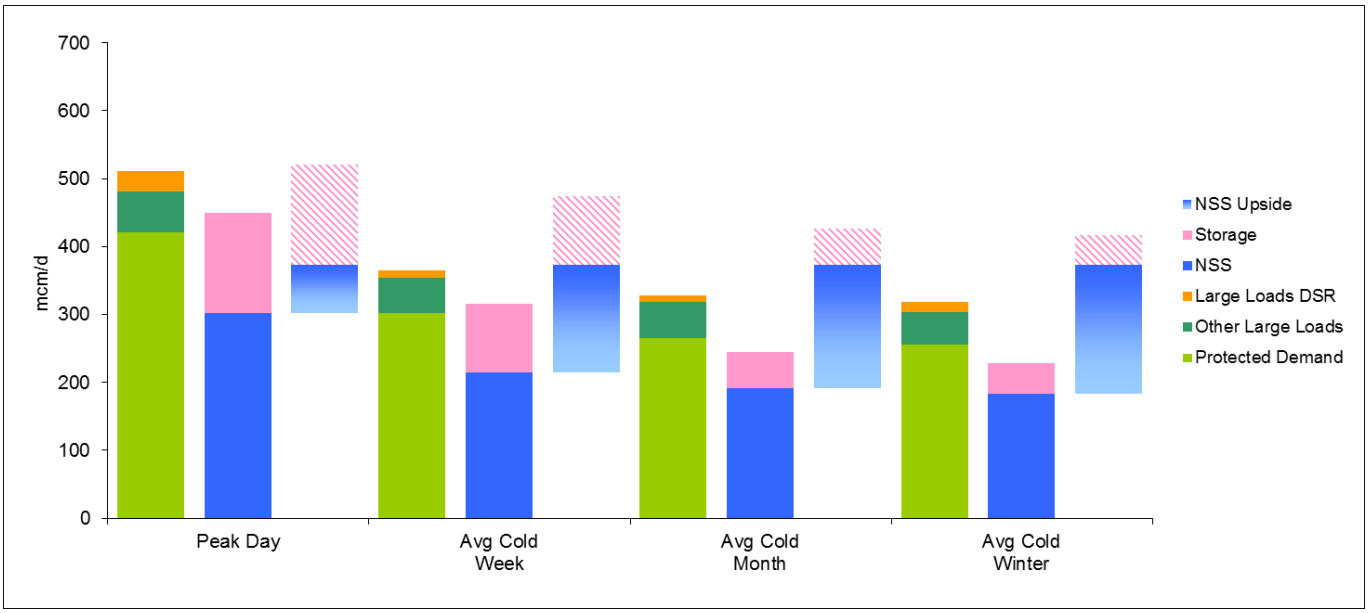
[21] Peak day conditions are based on 1-in-20 demand conditions. A peak day does not always occur in a severe year. The coldest day in the last 80 years, 13 January 1987, was in a 1-in-3 winter.

4.14 It is also sufficient to meet all demand in the 'peak day' and 'very cold week' scenarios. Some demand-side response and/or market-led acquisition of additional supplies may be required in the case of a 'very cold month' or 'very cold winter'.

Demand modelling – average conditions with supply disruption

4.15 Chart 4.3 shows analysis for average demand conditions, as outlined in paragraph 4.4, but with an 86mcm/d supply loss, shown as a reduction in non-storage supply applying in all time periods. An 86 mcm/d supply loss is consistent with the loss of the current largest piece of supply infrastructure, namely the Milford Haven to Felindre pipeline and meets a requirement of the regulation.

Figure 4.3 – demand analysis under average winter conditions with supply disruption



Source: National Grid

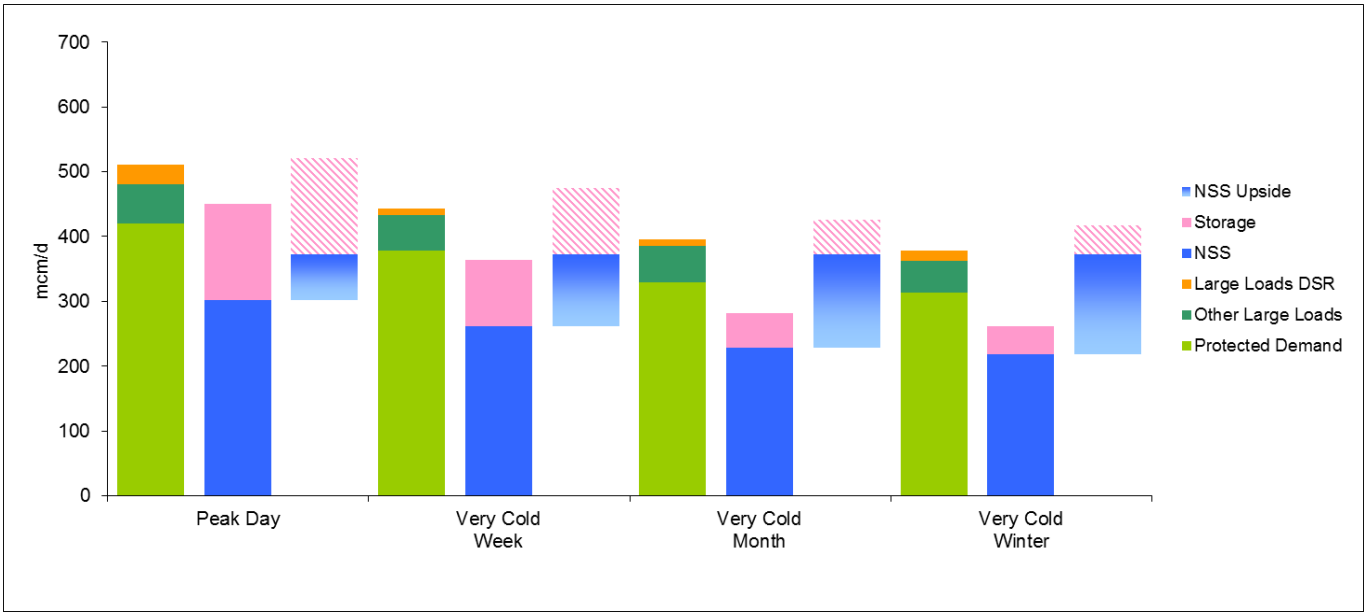
4.16 The resulting analysis shows a requirement for an increase in non-storage supply and storage and potentially a demand-side response.

4.17 Protected demand is met by non-storage supply and storage for the 'peak day' and 'average week' scenarios but there may be a need for additional non-storage supply and/or further demand side response if the supply loss were to continue for a month or an entire winter.

Demand modelling – severe conditions with supply disruption

4.18 Figure 4.4 shows analysis for severe demand conditions, as outlined in paragraph 4.11, with an 86mcm/d supply disruption equivalent to the loss of the Milford Haven-Felindre pipeline. Again, the 1-in-50 demand conditions are more severe than those required by the regulation.

Figure 4.4 – demand analysis under severe winter conditions with supply disruption



Source: National Grid

4.19 For the 'peak day' scenario protected demand is met by non-supply storage and storage but in the other three scenarios there is a risk that such a major supply loss during a 1-in-50 cold week, month or winter would mean the lower estimates of the supply range may not meet protected demand even with demand side response and additional supplies would need to be found via the flexible supply sources outlined in section 3 - Supply.

Case studies – gas market disruption

Case Study 1 – Infrastructure failure

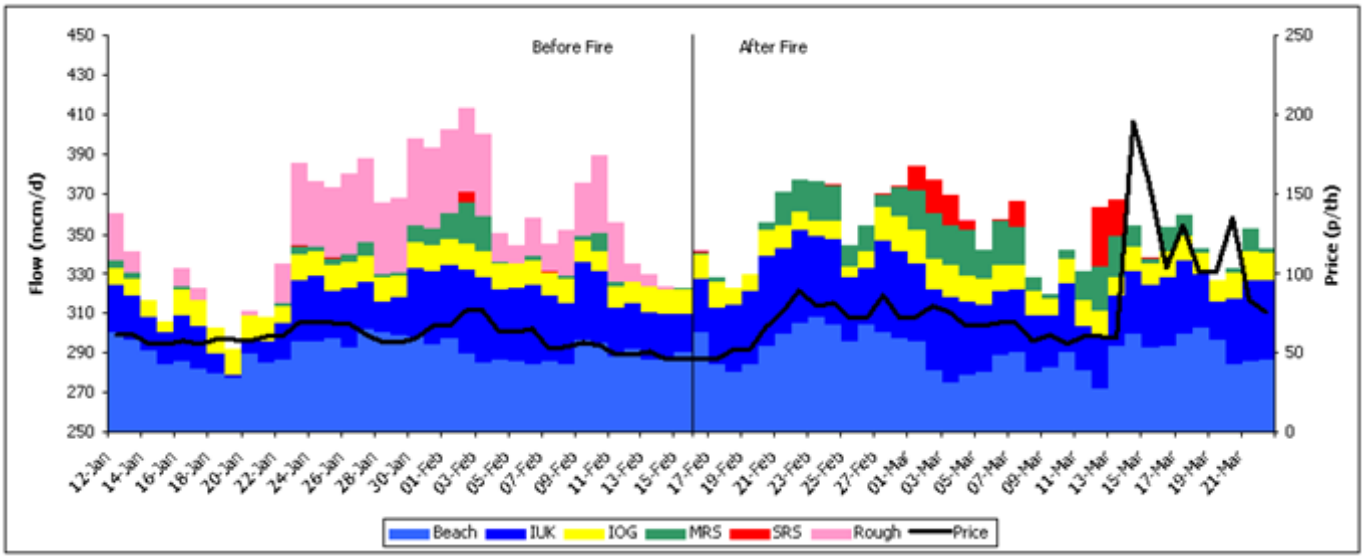
Fire at the Rough Storage Facility

4.20 In February 2006, a failure of a cooler unit on the Rough storage platform caused an explosion and fire resulting in the closure of the facility between February and June. The Rough facility, off the east coast of England, is by far the UK's largest gas storage facility accounting for 70% of total available storage capacity today. At the time of the fire in 2006 this percentage was even higher.

4.21 Considering the significance of this particular facility, the length of time for which it was inactive, and the time of year at which it occurred, this incident represents one of the most notable unplanned supply disruptions in recent years.

Market Response

4.22 The diagram below contrasts the 35 day period before and after the fire. The pink areas on the left show the significance of Rough as a major supply source during January of that year. The area on the right shows the sharp increase in supplies from medium- and short-range storage facilities. The initial steady price rise following the fire and then the sharp price increase (around the 13 March) that coincided with National Grid issuing an alert are notable.



Source: National Grid

4.23 The table below shows how the loss of Rough represented a 21mcm/d shortfall over a 35 day period and details how that shortfall was met through a combination of other storage and increased imports through the IUK interconnector.

	Beach	**IUK**	**Isle of Grain**	**Rough**	**Med range storage**	**Short range storage**	**Total supply**	**Price (p/therm)**
12 Jan-15 Feb	291	26	12	21	3	0	353	60
16 Feb-22 Mar	291	34	12	0	11	3	352	81
Difference	0	9	0	21	8	3	-1	21

Source: National Grid

Implications and risk of future re-occurrence

4.24 This case study demonstrates the flexibility of supply options open to the UK and how the integrated European market can act to bolster supply at alternative entry points when a major source suffers a disruption.

4.25 A report by Pöyry for Ofgem examined a more extreme scenario which included the loss of the Rough facility and all Norwegian supplies delivered to GB through Langeled and Belgium through Zeepipe.[22] This outage was modelled to last for a 60 day period beginning on 1 January during a 1-in-50 winter in 2016, 2020, and 2030.

4.26 The report modelled against National Grid's Gone Green scenario and a high demand scenario and found that GB infrastructure met demand in the Gone Green scenario, with some unserved energy under a high-demand scenario in 2020 and 2030.

4.27 The report estimated the probability of loss of both Rough and Norway at 1%.

[22] Pöyry, *Gas SCR – Cost-benefit Analysis for a Demand-side Response Mechanism*.

Case Study 2 – Very cold weather with infrastructure failure

22 March 2013 – IUK disruption

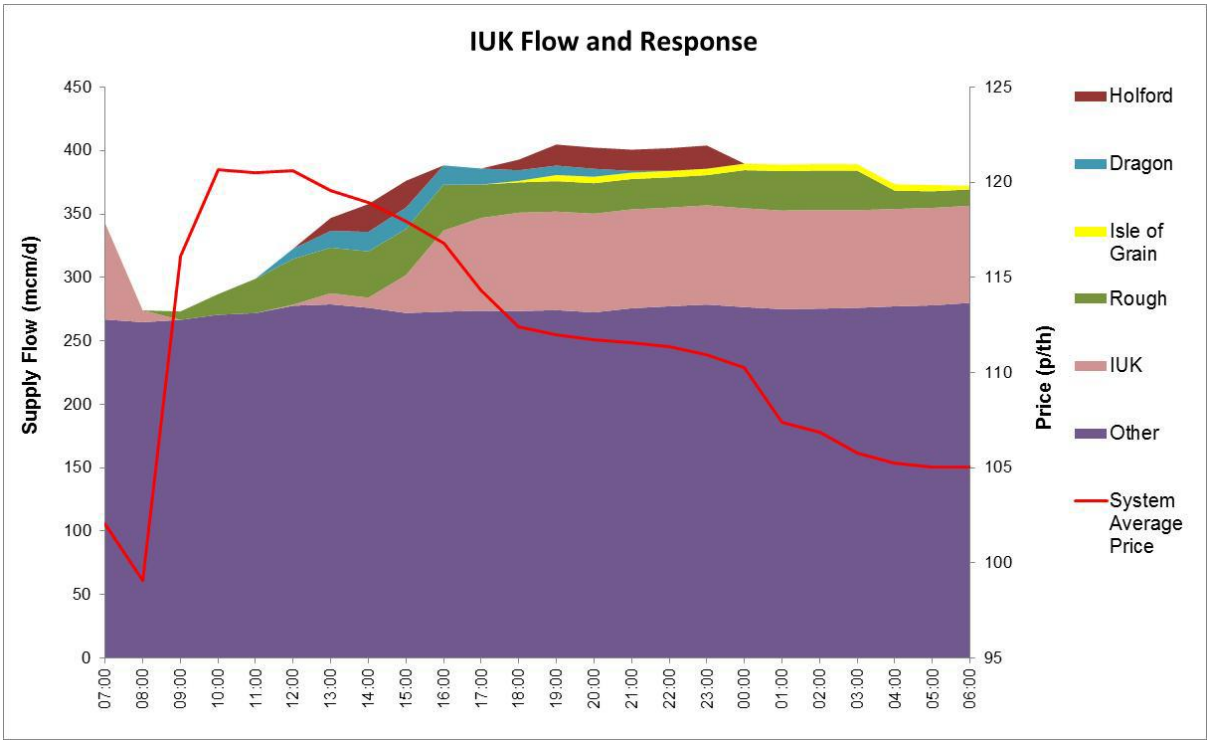
4.28 March 2013 was the coldest March in the UK since 1962 with a mean temperature of just 2.2°C across the month and, as it was towards the end of winter, storage levels were low.

4.29 Gas prices in GB had not been particularly high over most of the winter and GB had not attracted many LNG cargoes. As the winter extended into March, the IUK interconnector from Belgium played an important part in the supply mix, flowing at record import supply levels and accounting for just over 20% of total supplies at the peak of the coldest period.

4.30 On the 22 March IUK experienced an unplanned shut down due to a steam release from a heater pump, which triggered an automatic cessation of flows from Belgium.

Market Response

4.31 The 'within-day' wholesale price increased in response to the market sourcing alternative gas supplies to make up the shortfall and briefly reached a maximum of 150p/therm, before falling back as new replacement supplies came from storage at Rough and Holford and an increase in LNG flows from the Isle of Grain and Milford Haven. The chart below shows the prevailing supply portfolio against the within day System Average Price (SAP), illustrating how new supplies responded following the IUK loss.



Source: National Grid

4.32 IUK resolved the problem by noon the same day, steadily returning flows to previous importation levels by mid-afternoon. By the end of the gas day, National Grid needed to sell gas back to the market to balance an oversupplied system, a combination of the return of IUK and the continued supply from some of the storage sites.

Implications and risk of future reoccurrence

4.33 This event is a good demonstration of how normal market operation ensure a secure UK gas supply even in the most unusual conditions and allowing for a major supply shock.

4.34 Again, the Pöyry report mentioned above modelled the loss of all Continental interconnection through an infrastructure failure at Bacton.[23] Using the same parameters, demand was met under the Gone Green scenario across all the modelled years. The Stressed scenario saw some unserved demand in 2020 and 2030 but not 2016.

4.35 The report estimated the loss of Bacton at a probability of 2%.

Case Study 3 – Geopolitical events

2009 Russia/Ukraine supply disruption

4.36 Since the signing of a new gas supply contract between Naftogaz and Gazprom in 2009, Ukraine's ability to pay for Russian gas for its own consumption and the level of payment debts has been a concern, as has the wider situation.

4.37 It is prudent to consider the UK's resilience to a disruption in supplies, given that in January 2009, a gas dispute between Russia and Ukraine saw all gas supplies to Ukraine, including transit gas for delivery to the EU, cut off for two weeks. This equated to 30% of EU gas imports at the time.

Operational response

4.38 None taken – see market response.

Market response

4.39 The greatest impact was in Central and Eastern Europe, where a number of countries were completely dependent on Russian gas routed via Ukraine, and had very limited or no alternative pipeline routes to access other gas supplies. By comparison the dispute impacted little on UK gas wholesale prices and supply continued to meet demand with strong imports from Norway and the Netherlands.

4.40 The main impacts in the UK were increased exports through the Interconnector (in response to higher prices in continental Europe) and some additional drawdown of UK storage.

Implications and risk of reoccurrence

4.41 Since 2009, various actions have taken place to enhance gas supply resilience and to reduce/mitigate against the impact of a recurrence of such a supply disruption in the future.

4.42 The 55bcm Nord Stream pipeline – completed in 2011 – now transports Russian gas directly to Germany. This diversity provides added supply security to the European gas market and benefits the UK through increased supply to the north-west European gas

[23] Ibid.

market. On 6 May 2014, G7 Energy Ministers recommitted to the principle of enhancing security of supply by encouraging diversification of gas routes and suppliers into Europe and, in the long term, to diversifying our energy mix in line with decarbonisation objectives.

4.43 Measures and obligations in the EU Security of Gas Supply Regulation, which require preventive and emergency plans and detail supply and infrastructure standards, have led to greater EU cross-border pipeline interconnection, reverse flow capabilities, and investment in additional storage capacity.

4.44 In the event that the 2009 supply cut-off had been further prolonged, we might have expected an increase in UK prices, reduced price differential with continental Europe, and, in turn, reduced exports, together with increased imports from the global gas market.

5. N-1 Calculation and bidirectional flow

The UK N-1 calculations show that the UK passes the requirements of the Regulation with a result of 112-113%. Our projections over two different demand and supply scenarios suggest that we will continue to pass the test out to 2030. On the basis of this favourable outlook, DECC, as Competent Authority, has decided to issue further exemptions on bidirectional flow requirements to those pipelines which already hold them.

N-1 assumptions and calculation

5.1. In accordance with the Regulation, DECC, as the Competent Authority for the Regulation, asked National Grid Gas, as System Operator, to calculate the N-1 figure as at January 2014.

5.2. As there is a lag in collection of statistical data, the assumptions behind the overall level of gas demand and the gas supply mix is taken from predictions made in the *UK Future Energy Scenarios 2013*, with the location of this capacity further detailed in the *Gas Ten Year Statement 2013*. The level of gas supply capacity is determined by an assessment of UK indigenous supply along with all existing import and storage projects as well as those where a final investment decision has been taken.

5.3. The assessment is based on a failure affecting the single 100km pipeline connecting Milford Haven to Felindre, which would lead to a loss of supplies from South Hook and Dragon LNG terminals, which could be up to 86 mcm/d. However, there are a number of scenarios where a series of infrastructure failures within the NTS could lead to a loss of supply greater than that assessed for the N-1 calculation.

5.4. We have outlined the figures using both the Gone Green and Slow Progression scenarios.

5.5. The N-1 formula, as described in Annex I of the Regulation, is as follows:

$$N-1\,[\%] = \frac{EP_m + P_m + S_m + LNG_m - I_m}{D_{max}} \times 100, \quad N-1 \geq 100\%$$

5.6. Whereby in the Gone Green scenario:

	Capacity (mcm/d)	Notes
Main Infrastructure (I_m)	**86**	Felindre Pipeline to reflect the combined capacity of both Milford Haven LNG terminals
Max imports (EP_m)	**253**	Excludes LNG imports (includes IUK (74), BBL (48), Langeled (70), Vesterled (36), FLAGS - Tampen & Gjoa (25)
Max indig. production (P_m)	**120**	
Max storage (S_m)	**168**	
LNG (LNG_m)	**162**	Includes South Hook (59), Dragon (27), Grain (59) and Teesside Gasport (17)
Max demand (D_{max})	**552**	Undiversified 1-in-20 firm demand. Includes gas flows to Northern Ireland but excludes Ireland

5.7. At peak: N-1 (Gone Green) = (253 + 120 + 168 + 162 - 86) / 552 = **112%**

5.8. Whereby in the Slow Progression scenario:

	Capacity (mcm/d)
Main Infrastructure (I_m)	**86**
Max imports (EP_m)	**253**
Max indig. production (P_m)	**121**
Max storage (S_m)	**168**
LNG (LNG_m)	**162**
Max demand (D_{max})	**549**

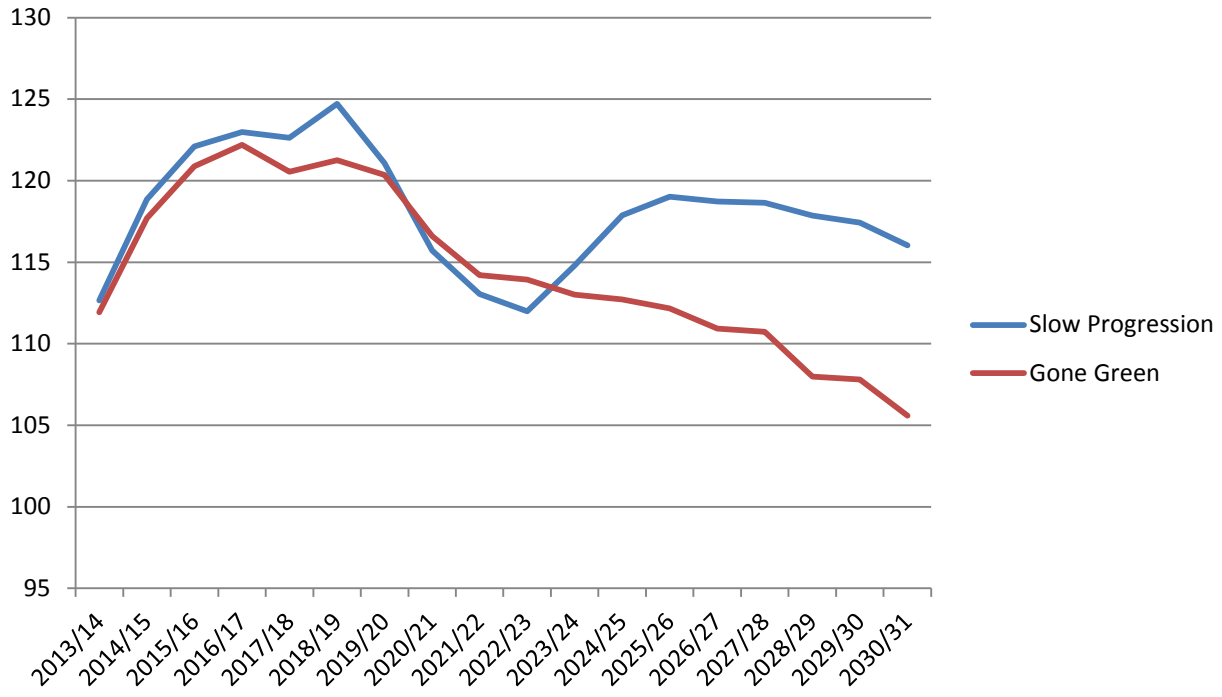
5.9. At peak: N-1(Slow Progression) = (253 + 121 + 168 + 162 - 86) / 549 = **113%**

Projected N-1 calculations until 2030

5.10. Along with the calculations for 2013/14, National Grid also provided a projected annual N-1 calculation until 2030, as shown in Figure 5.1. This chart suggests a net reduction by 2030 in the Gone Green scenario, as reductions in UKCS supply are not entirely matched by increased storage and an overall reduction in demand. Regardless, the UK continues to meet the N-1 requirement.

5.11. Under Slow Progression, the N-1 projections improve until 2020 largely because of a less steep decline in UKCS gas generation coupled with significant increases in storage. The N-1 result is not projected to dip below today's level and, by 2030, is significantly above today's results.

Figure 5.1 – Projected N-1 calculations by year to 2030



Source: National Grid

Bidirectional flow (reverse flow requirements)

5.12. As per Sections 3.19 – 3.21, three of the four interconnectors between the UK and other Member States do not have bidirectional flow: IC1/IC2 flowing from the Scotland to Ireland; the BBL interconnector flowing from the Netherlands to the UK, and the South North Pipeline flowing gas from Ireland to Northern Ireland. The IUK interconnector between Belgium and the UK has bidirectional flow.

5.13. DECC has laid out a process through non-legislative guidance and informal consultation for reviewing the status of bidirectional flow exemptions. DECC has continued to take account of market developments and notes the following:

- The Netherlands is a net gas producer and has little to no market demand to import gas from the UK in the short term. Like the UKCS, Netherlands gas production is declining but net gas export is expected beyond the term of this *Risk Assessment*.
- Ireland will continue to rely on the GB market for the overwhelming majority of its gas beyond the term of this *Risk Assessment* and, therefore, any gas deficit within GB would similarly affect Ireland. We have noted that the Shannon LNG facility is not expected to commence commercial operation until 2018 at the earliest; the ultimate deliverability of the facility is projected to be approximately 28 mcm/d. The Corrib gas field is expected to produce first gas in October 2015, with the expectation that it will produce approximately 9mcm/d for the first year, decreasing to approximately 4 mcm/d by the ninth year of production.
- Islandmagee Storage Limited is progressing plans to develop an underground natural gas storage facility, in Larne, Northern Ireland. A total gas storage capacity of

approximately 500mcm with a withdrawal rate of 22mcm/d is planned. Commercial operations are forecast to start in 2018.

5.14. With this in mind, it is highly unlikely that there will be market demand for gas from the UK for use in the Netherlands or from Ireland for use in the UK over the course of this *Risk Assessment* (before June 2016).

5.15. The UK Government's view is that it would be disproportionate to expect Transmission System Operators to commence investment in facilitating bi-directional flow on the assumption that some or all of the developments mentioned above may be operational in the next three to five years. Therefore, we have decided to grant exemptions on the UK side of operations for a further two years to all interconnectors which do not have bidirectional flow.

5.16. However, if market demand does develop between now and the next *Risk Assessment*, a Transmission System Operator may at any time respond to that demand by enabling bidirectional flow over their infrastructure. Furthermore, the terms of the exemptions issued allow the UK Government to revoke them if there is disagreement with their issuance at EU level or a clear security of supply need for bidirectional flow during the issuance period. We will review the case for further biennial exemptions during the drafting of the next *Risk Assessment*.

6. Further security of supply work and conclusions

The UK gas market is resilient to all but the most unlikely combination of high demand and supply disruption. Our analysis suggests that protected demand is met in all circumstances. Nevertheless, we will continue to watch risks to our gas security of supply and will carry on with work to strengthen our position.

6.1. Security of gas supply in the UK is provided through effective gas market arrangements with sharp commercial incentives on shippers to supply their customers. The UK already carries out significant ongoing risk assessment, and National Grid has regular consultative processes to collect data on supply and demand and inform the market.

6.2. The analysis presented in this *Risk Assessment* demonstrates that UK gas supply infrastructure is resilient to all but the most unlikely combinations of supply shocks. The upper ends of supply ranges are sufficient to maintain supplies to protected consumers in all scenarios. However, in some extreme scenarios the lower end of those supply ranges show a potential for supply difficulties and highlight the need for continued efforts in establishing robust and dependable demand-side response and a continued need for increased storage as indigenous supplies decline.

6.3. Despite the favourable picture of gas security of supply presented in this report, the Government is not complacent. Since the last *Risk Assessment*, we have developed work on security of supply, ruled out some measures, and will continue with others.

6.4. We have ruled out any intervention in the gas storage market, based on cost-benefit analysis of the interventions and suggestions of unintended negative consequences associated with a variety of interventions.

6.5. We continue to progress initiatives such as the Green Deal and the Smart Meters Implementation Programme to encourage energy efficiency among consumers.

6.6. The principle means by which Government will enhance security of supply over the coming years is through the Significant Code Review undertaken by Ofgem. The final policy announcement by Ofgem in February 2014 focussed around:

- Cash-out reform; and
- Procurement of a centralised demand-side response mechanism.

6.7. Subject to consultation, full implementation of cash-out reform is expected ahead of winter 2015/16 with a demand-side response mechanism available by winter 2016/17.

6.8. Government will also continue with existing work:

- to maximise domestic gas production, by conventional means through the Wood Review and unconventional methods through an appropriate regulatory framework focussing on safety and the environment;
- through continued cultivation of international relationships with major gas producers to encourage continued supply diversity and reliability; and

- by further implementation of EU Network Codes to facilitate the flow of gas around Europe.

6.9. The UK will use the analysis presented in this Risk Assessment to inform the development of the Preventive Action Plan and Emergency Plan required by the Regulation by December 2014.

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