GB GAS SECURITY OF SUPPLY AND OPTIONS FOR IMPROVEMENT

A report to Department of Energy and Climate Change

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EXECUTIVE SUMMARY

Concerns regarding security of Great Britain's (GB) gas supply have increased over recent years. There are many reasons behind these concerns including; the increasing import dependency, the failure to fully liberalise the energy market in Continental Europe, the developing role of Liquid Natural Gas (LNG), high and volatile wholesale prices and a question mark as to whether the commercial market can provide for low probability high impact events.

DECC commissioned Pöyry Energy Consulting to examine the security of GB's gas supply between 2010 and 2025, and advise as to whether Government needed to introduce any additional measures, including storage and demand side response, to protect consumers.

It is our opinion that the GB gas market will be sufficiently resilient to security of supply risks and able to withstand most foreseeable problems, and that no major changes to current policies are required.

Security of gas supply background

Gas security of supply was recently the subject of both the Wicks Review and Ofgem's Project Discovery, with both raising concerns about the GB market, particularly in the latter's scenario of rapidly increasing gas demand.

In addition, gas security of supply has been recently tested by the weather this current winter, which has so far been the worst in 31 years. This sustained period of low temperatures, with the week beginning 4 January 2010 having 7 of the 16 coldest days in the last 14 years, led to a new highest recorded demand of 465mcm/d on 8 January. At the same time the market also experienced shocks on the supply-side with significantly reduced flows from Norway. Yet, the market responded well. Prices throughout the period remained largely unaffected and at relatively low levels compared to recent winters.

Supply and demand shock tests and probability analysis

Looking to the future we modelled a range of supply shock tests for the years 2010, 2015, 2020 and 2025 to investigate whether supply and demand will balance and to estimate the impact on wholesale gas prices. These supply shocks covered a major outage lasting the whole of the gas year; and included losing the Rough gas storage facility, a major import terminal (Bacton or Milford Haven) or gas supplies from a major source (Russian gas via Ukraine or Qatari LNG). We then combined the two worst cases to further stress test the system.

Our results show that GB has sufficient diversity and capacity to receive gas from LNG terminals, Norwegian pipelines, storage and interconnectors to meet all but the most extreme demands.

Capacity to receive gas is not, of course, sufficient in itself and we further examined whether there would be sufficient gas in store, pipeline gas and also LNG around the world to meet demand in these extreme circumstances.

The results show that, including projects already believed committed as at April 2009, there will be sufficient storage capacity available to the GB market. Any commercial new build from the proposed 18 bcm of storage projects will further improve this position. As Europe moves to a more liberalised gas market it will become increasingly possible to directly access European storage over and above their strategic stocks through the interconnectors. It is also possible to indirectly access US storage through the integration of energy supplies by LNG arbitrage and cargo diversions as the global LNG gas market develops.

Our analysis is based on gas moving around Europe based on commercial price signals, subject to existing physical direction restrictions. This is supported by strong existing commercial positions, established EU political mechanisms and recent EU proposals to invest in West to East and cross-border pipelines.

Sensitivity to demand levels has been tested against different reduction achievements (100% and 50% of GB 2020 renewable and efficiency targets) and severe weather (1 in 50 winter and 1 in 20 peak demand). We found that demand side response (DSR) should only be needed when there was extreme supply disruption combined with very high peak demand circumstances, and even then most DSR can be met by gas-fired power generation (CCGT) distillate backup or very occasionally by invoking interruptible contracts at appropriate industrial and commercial (I&C) sites.

The likelihood of particular supply events happening was also analysed using a probabilistic simulation approach against a wide range of demands, including a worst case annual demand of 123bcm and peak of 700mcm/d. Assuming a reasonable mix of uncertainties pertaining to demand, supply shocks and oil prices, and no additional infrastructure other than that already committed, the probability of the market needing to use:

- existing CCGT distillate backup is once in every 3 years;
- I&C interruption due to supply/demand balancing[1] is once in every 15 years; and
- any interruption of gas supply to firm customers (unserved energy) is about once in every 19 years.

We calculate that the amount of this unserved energy would be relatively small in these events and could be covered completely by an additional 500mcm of storage over and above that already committed with deliverability of around 25mcm/d.

Pricing impacts

We found a minimal impact on monthly wholesale prices arising from our range of shock tests. When a major disruption occurs there are a number of short-term price spikes and a few instances of higher absolute levels for extended supply outages. Whilst the market may respond with higher prices in the short-term than the prices seen in this report, we believe that volatility will be dampened and prices pushed back to a marginal basis by the diversity of supplies and excess capacity.

Our probabilistic analysis, which takes into account risks across many failure events, supports the observation from the shock analysis that any individual major supply shock has a small impact on monthly prices, and shows that very high prices are expected to be extremely rare.

1 This does not include the probability of using interruption to manage local constraints, as was seen in January 2010.

Policy options

We then investigated whether there are any additional policy options that might improve the security of gas supply, either through delivering additional physical gas to GB, or improving the flexibility of gas demand relative to that which is forthcoming through existing commercial and regulatory arrangements.

Further improvements to security of supply might be found from two broad areas: long-term, large strategic facilities designed to provide significant volumes over a longer period; and shorter-term, rapidly available facilities designed to overcome periods of short term distress.

We examined 24 potential policy options targeted at improving security of supply, but found only two options which may provide a net benefit under the scenarios investigated. These were restoring I&C interruptible volumes to historic levels and an obligation on existing CCGTs with backup capability and on new CCGTs to maintain a minimum distillate level (reflecting their significant contribution to protecting other gas consumers). These would have the effect of halving any risk of unserved energy. However, both would require regulatory changes so that the costs borne by I&C and CCGT sites can be appropriately recovered.

The policy option of investing in strategic storage to cover the relatively small level of unserved energy identified under the probabilistic analysis would be expensive, and is unlikely to provide sufficient benefit in improving security of supply to justify its costs.

Conclusion

Our opinion that the GB gas market is becoming more resilient to security of supply risks and able to withstand most foreseeable problems, and that no major changes to current policies are required, is dependent on a number of key assumptions.

Existing Government policies of increasing energy efficiency and the 2020 renewable targets provide a significant contribution to improving gas security of supply.

GB has completed its move from a position of potential supply constraints to one of excess supply capacity and diverse sources. Much of GB's future supply will come from the global LNG market. This has the benefit of interconnecting the world's energy markets, making each individual market much more resilient to any local problems, and drives a convergence of gas prices globally. LNG supplies are both geopolitically and commercially diverse. Whilst LNG has traditional been traded via fixed long-term contracts there has been an expanding spot market in the last few years, which has been a key contributor to the supplies experienced in the recent cold winter. This must continue to develop to ensure that LNG moves in response to demand and prices, and policy makers should keep this progress under review.

GB will have access to sufficient gas storage, including European facilities and indirectly US storage through LNG arbitrage. Current policies to promote the liberalisation and interoperability of the European markets, and storage in particular, through the Third Energy Package and Madrid Forum will assist in allowing parties in one jurisdiction access to facilities in another. There are a significant number of potential storage projects being considered in GB. Any commercial new build will further improve the level of GB's security of supply and more than cover the potential unserved energy shortfall we found in our modelling.

Policy makers should monitor whether recent market changes to the treatment of interruption mean that existing CCGT and I&C sites are decommissioning distillate backup facilities and/or insufficient capability is being built at new sites. Should this be the case and it is determined that further levels of protection are deemed necessary then the most cost reflective solution (out of the options considered in this report) would be to implement one or both of these policy options; to introduce a new mechanism to restore I&C interruptible volumes to their historic levels, and a new obligation on some CCGTs to maintain and/or install backup fuel facilities and stocks. However, there are also other qualitative considerations with these options too.

We believe that the policy option of directly investing in strategic gas storage would be expensive and would not, based on the analysis in this report, provide sufficient benefit in improving security of supply to justify its costs.

1. INTRODUCTION AND BACKGROUND

1.1 Gas security of supply background

The issue of security of gas supply is ever-present. The move from self-sufficiency to becoming dependent on imported gas, limited liberalisation in Continental Europe, potentially tight LNG markets, high and volatile wholesale prices, and potentially limited market coverage for high impact low probability events add to these concerns.

Gas is crucial to GB's energy mix. We rely on it to heat our homes and businesses, as well as to generate electricity, and provide process heat and feedstock for industry. Ensuring that our gas supplies continue to be secure, while we move to a low carbon economy, is one of the most important obligations for the Government.

However, while the GB gas market has been delivering the infrastructure we need to date, even a fully functioning market can be undermined by factors beyond its control, such as major supply disruptions or extreme weather. There is a greater degree of uncertainty the further ahead we look into the future.

Gas security of supply has recently been examined by:

- The Wicks Review[2] – an independent review on 'Energy Security: a national challenge in a changing world', which looks in detail at a range of energy security issues, including gas market issues.
- Project Discovery[3] – a report by Ofgem which considers amongst other things gas security of supply.
- DECC's and Ofgem's annual publication regarding security of supply 'Energy Market Outlook'[4]. This document published a range of gas demand projections, which were based on a range of different assumptions and considered scenarios where the demand for gas increased as well as fell.
- National Grid's annual 'Ten Year Statement'[5].

Both the Wicks Review and Project Discovery raised concerns regarding gas security of supply, particularly in scenarios where the demand for gas increases. The key messages from these and the implications for this study are considered in Sections 1.2 and 1.3 below.

The GB's gas security of supply has been recently tested. Low temperatures in December and January led to a period of sustained high demand for gas. On two occasions this led to the highest demand for gas in a day that has been recorded. Added to these demand side pressures, the market also experienced shocks on the supply-side which significantly reduced the flows of gas to the GB market from Norway. Despite these pressures, the market responded well and as expected. Prices only briefly responded to

2 http://decc.gov.uk/en/content/cms/what_we_do/change_energy/int_energy/security/security.aspx

3 http://www.ofgem.gov.uk/Markets/WhlMkts/Discovery/Pages/ProjectDiscovery.aspx

4 http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/markets/outlook/outlook.aspx

5 http://www.nationalgrid.com/uk/Gas/TYS/current/TYS2009.htm

these very high demands before returning to previous levels, which have been generally low compared to recent winter prices. Overall the market was able to balance supply and demand, with only some limited transportation interruption. The recent winter experience is discussed further in Section 2.11.

A key issue, when considering the GB's gas security of supply, is the increasing dependence on imported supplies and crucially the trade in gas between GB and continental Europe including Norway. Governments, international bodies and market players are already working to address European security of supply problems including the implementation of the third energy directive, the EU Regulation on Gas Security of Supply[6] and major new infrastructure projects, including new pipelines from Russia, Algeria, the Caspian region, LNG terminals, interconnectors and storage. It is worth noting that the original draft EU Regulation on Gas Security of Supply published in November 2008[7] looked at a range of options including the possibility of requiring strategic storage and backup distillate at gas-fired power stations, although the current version does not have either as a compulsory option.

DECC commissioned Pöyry Energy Consulting in 2009 to carry out this study, to estimate the size of a variety of gas security of supply provisions, identify a range of security of supply policy instruments, focusing on storage, distillate back-up and demand side response, and determine their costs and the degree to which they could work successfully in a non-distortionary manner, in GB's liberalised market-based regime.

1.2 Wicks review

Malcolm Wicks MP, a former energy minister and in his role as the Prime Minister's special representative on international energy, was asked to carry out a review of international energy security and how developments internationally are likely to affect GB's own energy security in the coming decades.

In his report published in August 2009 he stated that "an energy policy must aim at achieving:

- physical security: avoiding involuntary interruptions of supply;
- price security: providing energy at reasonable prices to consumers; and
- geopolitical security: ensuring the UK retains independence in its foreign policy through avoiding dependence on particular nations".

He also references that according to the Centre for Strategic and International Studies, "a secure energy system will tend to be characterised by:

a) A diverse mix of different energy sources and fuels, with the capability to switch between these when necessary.

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

7 Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions – Second Strategic Energy Review : an EU energy security and solidarity action plan {SEC(2008) 2870} {SEC(2008) 2871} {SEC(2008) 2872}

b) Diversity of suppliers of energy, without excessive reliance on imported supplies, which have a risk of disruption beyond the host country's control.

c) Diverse routes of imported supply, avoiding excessive reliance on particular 'supply corridors'.

d) Reducing 'energy intensity': the amount of energy required to produce a unit of national output.

e) Reliable and well-managed physical infrastructure.

f) Stable and affordable energy prices.

g) Feasible and commercially-viable plans for technological improvement for the future".

The report made various recommendations, including for gas that the Government should ensure that we maximise economic production from the UK's own still considerable reserves and this requires continuing attention to the tax and regulatory regimes for producers. It identified the need for more gas storage to enable demand to be met should there be a supply disruption or a prolonged period of high demand, such as in a very cold winter, and said consideration should be given to providing strategic gas storage facilities as an insurance policy to help improve the country's energy security. It also said that better arrangements were needed to enable effective moderation of demand at times of supply difficulty.

This study will further review the above in terms of the ability of the GB gas system to meet security of supply standards against some extreme stress tests and to what level more gas storage, including any strategic facilities, and demand side response is required.

1.3 Project Discovery

Project Discovery was launched by Ofgem in March 2009. In October 2009 it set out its views on the risks and challenges facing the gas and electricity industries in GB over the next 10–15 years through its energy scenarios document[8]. This identified four possible scenarios, summarised as follows:

1. Green Transition – GB demand reduces from 95bcm and peak of 506mcm/d in 2010 to 77bcm and peak of 478mcm/d by 2020. Renewable targets met. LNG acts as the source of 'swing' with terminal utilisation rate assumed at 20%.

2. Green Stimulus – GB demand reduces from 96bcm and peak of 507mcm/d in 2010 to 81bcm and peak of 472mcm/d by 2020. Renewable targets met. LNG acts as the source of 'swing' with terminal utilisation rate assumed at 25%.

3. Dash for Energy – Global economies bounce back strongly but security of supply concerns prevail over environmental concerns. Generation build dominated by CCGTs and renewables target is not met. GB demand increase from 94bcm and peak of 500mcm/d to 113bcm and peak of 584mcm/d by 2020. Gas supply is tight with high prices and planning delays push back storage investments resulting in a shortage coinciding with peak prices in 2015. Global demand from LNG trebles even with very limited requirement from the US because of continued expansion of unconventional sources. LNG terminal utilisation assumed to be 70%.

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8 Ofgem's analysis was updated in February 2010, with slightly lower demands, but as there were no published data tables the original reference has been retained.

4. Slow Growth – Impact of recession and credit crisis continues resulting in low levels of investment. Increasing dependence upon CCGT generation and renewables target is not met. GB demand increases from 90bcm and peak of 488mcm/d to 103bcm and peak of 527mcm/d by 2020. LNG terminal utilisation assumed to be 60%.

This study uses a similar Average annual and peak demand case to Ofgem's Green Transition and Green Stimulus scenarios, reflecting the base assumption of achieving the 2020 renewable targets, but uses a higher Severe demand case to reflect a 1 in 50 winter compared to Ofgem's 1 in 20 winter, see Section 2.6. In addition we have undertaken a Very High demand sensitivity which has a similar annual and peak demand level to Ofgem's Slow Growth scenario, see Section 4.2.1.

However, this study does not consider a specific case with a significant increase in gas demand growth envisaged in Ofgem's Dash for Energy scenario. Instead we have performed a probability analysis, see Section 4.3, which includes a worst case of an annual demand of 123bcm and peak demand of over 700mcm/d (including Irish exports) in order to determine the likelihood of there being some unserved energy.

In addition, throughout the deterministic modelling we have restricted the supply side by saying there will be no new GB infrastructure (apart from those already committed when this study was commissioned). Should demand increase across the next decade as projected in Dash for Energy we would fully expect various new infrastructures projects to be built, with the potential addition of up to 18bcm of gas storage and 35bcm of LNG regasification terminals plus new gas supplies from West of Shetland and Norway.

We also note that the peak demands projected in the Dash for Energy scenario is another 59 mcm/d compared to the NGG 2009 TYS estimate and such an increase would more than likely require further investment in the NTS, which will depend on the CCGT location (as well as addition investment in the high transmission electricity network) or the added CCGTs will have to have an interruptible supply contract (and this may not provide the level of security required by the electricity supply).

Ofgem also performed some stress tests, including re-direction of LNG supplies (40% reduction in a 1 in 20 winter period), a Russia-Ukraine dispute (50% IUK export, 0% BBL import over 1 in 20 winter period), and an outage at Bacton (zero supplies on a 1 in 20 peak day). As will be seen in Section 4.1 a similar but more extreme set of stress tests is considered as part of this study.

1.4 Report structure

Section 2 of this report sets out our assessment of current levels of physical supply infrastructure, gas storage, gas-fired power generation distillate backup and demand side response through interruption of industrial and commercial customer. We then forecast future levels of these (without further government intervention) for gas years 2010, 2015, 2020 and 2025. A gas year runs from 1 October to 30 September the following year, so throughout this report 2010 means from 1 October 2010 to 30 September 2011 and the same for the other years analysed.

We also present three GB demand scenarios to be used in testing the security of supply: Average (to achieve DECC's 2020 targets); Severe (1 in 50 representation of the Average across North-West Europe); and Central (partial achievement of 2020 targets). For each year a 1 in 20 peak day is included so that achieving the peak demand is appropriately considered.

In addition to this, Pöyry's assumptions regarding infrastructure build, as well as assumptions regarding the market's potential for demand side response measures are laid out within this section. Using a combination of publicly and privately available information, we developed, in conjunction with DECC, a set of inputs that will serve to inform the modelling within later sections. These not only include technical inputs (capacities, production rates etc.) but also economic inputs, such as the costs associated with storage and distillate backup usage.

In Section 3 we identify the drivers for investment decisions as well as the significant barriers to the provision of commercial gas storage and distillate backup, which is used to prevent gas supply interruptions to firm users. This section explores the main drivers behind investment decisions, based upon Pöyry's assumptions formed from historical data. A look is also taken at the main stages in constructing a storage facility, with the attendant issues and milestones inherent in doing so. In addition to this, the section also sets out the barriers that exist both now and into the future for creating additional investment within storage, distillate backup and demand side response. These barriers encompass environmental, financial, practical and technical issues, and where possible we have used examples based upon currently existing facilities for clarity.

Section 4 aims to quantify any potential shortfall in gas supply to GB, for the years 2010, 2015, 2020 and 2025, due to low probability, high impact events. For this section, we assume that no further government intervention occurs, and within this case the volumes of gas available or which can be freed up for other use, or the volume of demand reduction, is observed. Against the demand scenario assumptions we model first a series of supply shocks and then consider the security of supply risks from a probabilistic analytical approach.

The first stage of analysis was to review the impact of specific predefined supply shocks. We developed, in conjunction with DECC, shocks that might have the greatest impact during the time period being modelled. To further stress test the analysis we have combined the two cases with the biggest impact on potential energy unserved and prices to form a combined shock case. These shock combinations would thus vary over the different years.

The next stage of our analysis was to consider the supply risks to GB on a probabilistic basis. The aim of this analysis is to produce probability distributions for likely wholesale price distributions, energy unserved, and annual demand flows. It will then be possible to calculate appropriate summary statistics to describe the data and to draw broad conclusions.

In Section 5 we have identified a number of potential policy instruments for increasing the provision of gas storage and distillate backup, for increasing demand side response, and review these against a set of selection criteria. This serves to outline the various options which have the potential to mitigate any effects of unserved energy and who would have the responsibility for its delivery. We have reviewed security supply policies currently in place within other European countries and selected examples from across the world. Then using the probabilistic analysis results from Section 4 we have evaluated whether the selected policy options provide a net benefit compared to any costs, risks and unintended consequences (e.g. displacement, distortions, etc.) and recommend which, if any, policy options should be considered for adoption.

1.5 Report conventions

1.5.1 Sources

Where tables, figures and charts are not specifically sourced they should be attributed to Pöyry Energy Consulting.

2. CURRENT MARKET POSITION

The first part of this study is to review the current market situation in GB in terms of its physical supply infrastructure and how much potential distillate backup and industrial and commercial demand side response ('DSR') could be utilised in the event of a national shortage. In addition to this, our assumptions regarding infrastructure build, as well as assumptions regarding the market's potential for demand side response measures are laid out within this section. Using a combination of publicly and privately available information, we have developed in conjunction with DECC a set of inputs that will serve to inform the modelling within later sections. These not only include technical inputs (capacities, production rates etc) but also economic inputs, such as the costs associated with storage and distillate backup usage.

2.1 Security of supply

First we will identify the various factors to consider when defining gas security of supply, such as 1 in 50 annual demand, 1 in 20 peak day demand, the gas balancing alert mechanism, storage monitors, emergency rules, etc.

The basic requirement of a secure gas supply is that it is sufficient to balance most gas demands in all but the most extreme circumstances. The system should be able to cope during severe cold weather, or when an event has physically interrupted some of the supply to the system. Within the GB gas industry, it is traditional to consider this at a daily and annual resolution. Daily resolution is considered as it is reflective of the physical balancing needs of the network, which are also embodied in the prevailing commercial arrangements in place in the GB gas market. Annual resolution is considered as it captures seasonal variation in an aggregate figure, enabling comparisons and growth/decline rates to be considered.

Within this definition of security, it is necessary to examine the market drivers and elasticity of the elements of total demand and total supply, to understand where there might be crossover and where demand might be sensitive to price.

2.1.1 Demand

Demand can be categorised according to end use purposes, as:

- domestic – supplying homes and small commercial premises for primarily space and water heating purposes;
- industrial and commercial – again providing primarily space heating;
- feedstock – providing natural gas as a feedstock to the chemical industry (i.e. not as a heating fuel), especially in the manufacture of nitrogen fertilisers;
- combined heat & power;
- power generation; and
- other uses (e.g. gas transportation).

2.1.1.1 Weather sensitivity

As the majority of gas demand is used for space heating purposes it is very sensitive to weather. A study of weather sensitivity, the relationship between demand and weather, and the extremities of weather is beyond the scope of this document. However, understanding that GB demand is related to weather and therefore that very high demand levels are driven by extreme weather conditions is a crucial element in understanding that very high demand levels are very rare. Further information on the precise relationship between demand and weather may be found in publications from National Grid Gas plc (NGG).

2.1.1.2 Security standards

The gas transportation licence contains provisions that define certain demand levels as security levels[9]. These are the 1-in-20 peak day – the level of daily demand that could be expected to be exceeded only once in 20 years (1:20); and the 1-in-50 winter – the level of demand over a winter period (October to April) that could be expected to be exceeded only once in 50 years (1:50).

The 1:20 demand level is used to specify the capability of the network and therefore acts as the main driver of investment in the pipeline network. The 1:20 demand level used by NGG for the purposes of identifying investment is a summation of the weather sensitive forecasts of individual regional 1:20 forecasts and large loads at contractual levels (i.e. it is undiversified). It therefore overstates what could be considered a national (or diversified) 1:20 demand level quite significantly. The appropriateness of the 1:20 demand level is outside the scope of this study but we have used this level as a 95th percentile for our modelling.

The 1:50 demand level used to form part of the gas supply licence and provided an obligation on suppliers in respect of their domestic customers. However, it had become effectively toothless through the concept that purchases at the National Balancing Point (procured via a shipper) were sufficient to meet the condition. The supply licence condition was removed from the supply licence during 2007; however it was necessary to include a similar concept in the network code conditions of the gas transporter. A national (diversified) 1:50 demand curve is usually published by NGG as part of its Ten Year Statement (TYS).

2.1.1.3 Price sensitivity

Since the introduction of supply competition in the 1990s a traded wholesale gas price has evolved within the daily balancing regime and some consumers, especially large consumers are now considered as price sensitive.

These price sensitive consumers offer some scope for reducing their demand in response to pricing signals. An alternative way of viewing this ability is to treat it as a source of supply, and to consider the complete original demand as demand. Price sensitive demands are discussed further in Sections 2.8 and 2.9.

2.1.2 Supply

The supplies of gas available over a period can also be categorised according to upstream source:

- United Kingdom Continental Shelf (UKCS), comprising;
  - associated gas, being gas produced as a by-product of oil production;
  - dry gas, being gas produced in it's own right;

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9 http://epr.ofgem.gov.uk/index.php?pk=folder132658

- Gas storage, being gas held in gas storage facilities;
- Continental European imports, via the two interconnectors (from Belgium and the Netherlands); and
- LNG imports.

We discuss each of these in Sections 2.2, 2.3, 2.4 and 2.5.

2.1.3 Storage monitors, operating margins, and the Gas Balancing Alert mechanism

Various mechanisms have been used since the inception of the Network Code to enable the gas transporter to help ensure that suppliers and shippers are able to meet demand through the winter.

2.1.3.1 Storage monitors

Storage monitor curves describe minimum volumes of gas that need to be held in storage through the winter period to ensure that certain demands can continue to be met if the remainder of the winter was to suffer a particular weather severity. There are two monitor curves used: the safety monitor and the firm monitor.

The safety monitor is the curve that ensures the safety of the gas pipeline network, and enables 'the preservation of supplies to domestic customers, other non-daily metered ('NDM') customers and certain other customers who could not safely be isolated from the gas system if necessary in order to achieve a supply-demand balance and thereby maintain sufficient pressures in the network.'[10] As such, the safety monitor represents an element of the safety case of NGG, and use of this gas in store would only be considered in the event of a gas supply emergency.

The firm monitor is published by NGG for information purposes only, and represents its view of the level of gas in store required to ensure that all 'firm' gas demand can be met in a 1:50 winter.

The volumes of gas in store, and the storage monitor curves are published by NGG. The picture in respect of the winter 2009/10 to date is shown in Figure 1 overleaf.

2.1.3.2 Operating margins

Operating margins ('OM') are options to procure volumes of gas, held by NGG (following a tender process), that could be exercised for a variety of reasons. These reasons are split into three groups:

- Group 1 – events that are rarely expected to occur e.g. a loss of supply or loss of infrastructure;
- Group 2 – events that are expected to occur e.g. a loss of compression on the network, routine forecasting errors, or a significant supply loss; and
- Group 3 – a declared gas network emergency, for the orderly rundown of the system.

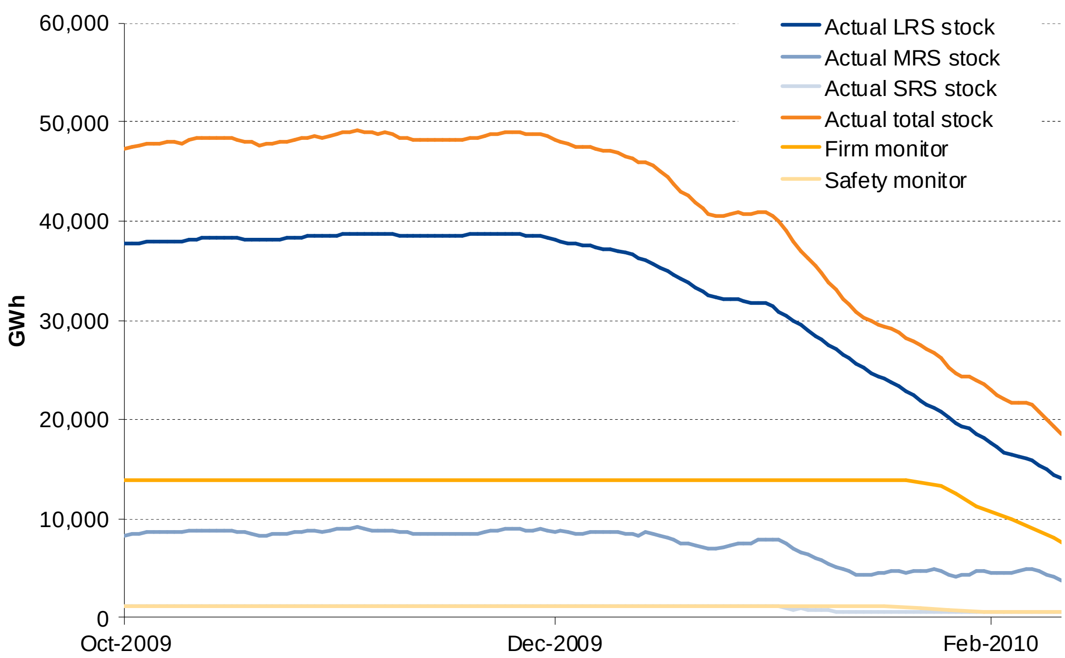
The volumes required by each group are calculated independently by NGG. Group 1 events examined include a major loss of UKCS production due to the loss of the Forties offshore liquid pipeline system, loss of St. Fergus beach terminal, and the loss of the main

[10] NGG, 'Safety Monitor and Firm Gas Monitor Requirements', September 2008

sub-terminal at each of the beach terminals. Group 2 events are calculated with the use of summary statistics on compressor reliability, etc.

OM were historically provided by LNG peak facilities, however due to a number of reasons (primarily licence changes introduced by Ofgem, but also a decreasing need for locational OM services), NGG now tenders for these services from a variety of sources, including demand-side sources.

Figure 1 – GB Storage monitor curves and stocks



Source: National Grid

2.1.3.3 Gas Balancing Alert

The Gas Balancing Alert ('GBA') mechanism has been introduced to indicate to the market when NGG considers it likely that some form of demand-side response or additional supplies might be required to ensure the physical balance of, and the future safety of the network. NGG publishes a demand level that it considers can be met, based on the current capability and recent reliability of supplies to the market. A basic trigger level is set based on assumptions that are consistent with the assumptions used to calculate safety monitor, and the trigger level is revised to reflect actual supply performance during the winter and if storage stocks get within two days of the safety monitor. A GBA is issued if tomorrow's forecast demand is above the trigger level.

Since its introduction, the GBA has only been issued on five occasions. The first was on Monday 13 March 2006, when Rough storage facility was unavailable, there were a couple of planned outages, and there was a forecast of cold weather and therefore high demand. The market reacted, with day ahead wholesale prices rising from the previous Friday's forward price of approximately 60p/th, opening at 190p/th and peaking within day at 255p/th. During the day the weather was less severe than forecast and the forecast demand did not materialise. The following day the market opened in a long position (where forecast supplies were greater than forecast demand). Prices gradually returned to their previous position.

Pöyry understands that NGG came close to issuing a GBA during the Ukrainian transit crisis of January 2009, but did not actually do so. Prices during this period remained mostly stable, averaging 60p/th and fluctuating between 53p/th and 70p/th.

The other four occasions happened in January 2010 during the coldest winter in 30 years so far. Further details are included in Section 2.11 on page 42.

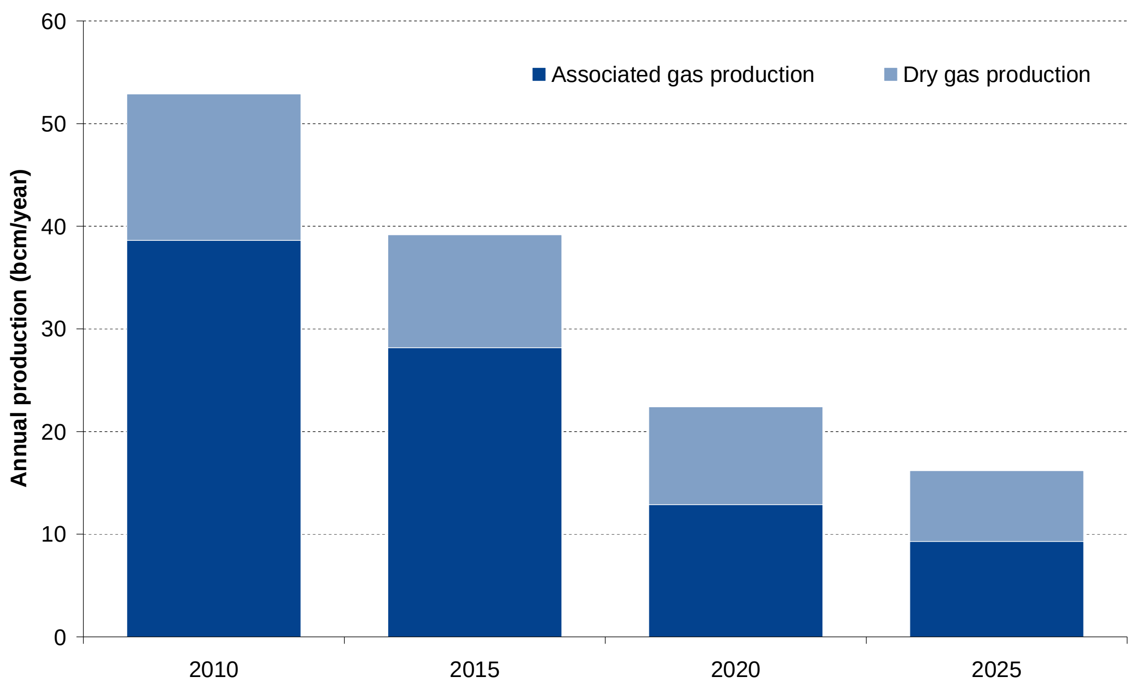
2.2 Indigenous production

GB has historically been mostly self-sufficient in gas with supplies coming from the UK continental shelf (UKCS). This gas entered GB through a geographically diverse number of reception terminals at St. Fergus, Easington, Bacton, and Barrow. The offshore gas fields were developed with certain levels of swing, which provided the suppliers with higher output in the winter and lower output in the summer. However, these have been in decline from their peak production in 2003 and this is forecast to continue during the next decade.

This was then supported by the Rough depleted gas storage facility to provide long-term support during the winter, Hornsea salt cavity storage for medium-term storage and five LNG peak storage facilities for short-term transportation support at specific locations across the country.

The current and projected levels of UKCS production for the time period of this study is shown in Figure 2 below.

Figure 2 – UKCS gross gas production (bcm)



We have estimated the future levels of annual production using projected depletion rates, based on the relationship between the original recoverable reserves, the 2009 values for the recoverable reserves from DECC, the peak and historical flow rate and whether the fields are associated with oil production (generally a longer depletion period) or not. We have checked this against data from the TYS published in 2009, and extended to 2025 based on our database of fields, reserves and production rates. We have not included any supplies from potential new areas, such as West of Shetland, although we note the recent tax changes aimed at assisting such developments. Should these new fields be forthcoming it will have the affect of reducing the rate of decline in UKCS production.

2.3 Gas storage

2.3.1 Gas storage in GB

There are currently just six underground storage facilities in GB (Rough offshore depleted field, Humbly Grove and Hatfield Moor, both onshore depleted fields, and Hornsea, Hole House and Aldbrough salt caverns). In addition, there are three peak LNG storage facilities (Avonmouth, Partington and Glenmavis).

It is interesting to note from the figures presented in Figure 1 that only about 60% of available storage capacity has been used during 2009/10 to 11 February 2010, during a winter that has been the coldest in the last 30 years so far.

Previous years have utilisation rates as set out in Table 1 below, where the utilisation rate in 2006/07 is explained by mild weather and in 2005/06 by the Rough outage. In 2008/09, which saw a major interruption of Russian gas through the Ukrainian transit routes at the same time as a colder than average January, the utilisation rate was only around 75%.

Long-, mid- and short-range storage are defined in the 'Safety & Firm Gas Monitor Methodology' December 2006, National Grid. They can be loosely considered to represent Rough & other depleted field facilities, salt caverns and some faster cycle depleted field facilities, and LNG storage, respectively.

Table 1 – Storage space utilisation rates

Gas Year	Long range (%)	Mid range (%)	Short range (%)	Overall (%)
2005/06	49	77	75	55
2006/07	42	55	40	45
2007/08	78	70	42	75
2008/09	77	64	74	74
2009/10 (to 11/2)	63	61	50	62

Source: National Grid

For the purposes of the modelling part of this study we have assumed that only projects that have received financial approval will be built. These figures have been gathered from the GSE and Platts. We have delayed Humbly Grove's expansion to 2011, as this is still under construction by Star Energy (it was originally forecast to be complete in 2008)[11].

11 Platts European Gas Daily 09 February 2009.

Table 2 shows each of the existing GB gas storage facilities and those assumed to be available as part of the later modelling.

Table 2 – Assumed GB Storage Facilities (mcm)

		2010	2015	2020	2025
Albury	Depleted	0	170	170	170
Caythorpe	Depleted	0	210	210	210
Hatfield Moor	Depleted	116	116	116	116
Humbly Grove	Depleted	280	340	340	340
Rough	Depleted	3,340	3,340	3,340	3,340
Avonmouth	LNG	81	81	81	81
Glenmavis	LNG	47	47	47	47
Partington	LNG	52	52	52	52
Aldbrough	Salt	420	840	840	840
Hole House	Salt	55	55	55	55
Holford (Byley)	Salt	0	165	165	165
Hornsea	Salt	325	325	325	325
Stublach	Salt	0	203	406	406
Total		**4,716**	**5,944**	**6,147**	**6,147**

There is a range of potential gas storage projects at various stages of project development and these are listed in Table 3 below. These facilities, however, are still in the conceptual stage, and therefore for the purposes of the modelling in Section 4 they have not been included.

Table 3 – Proposed storage facilities within GB

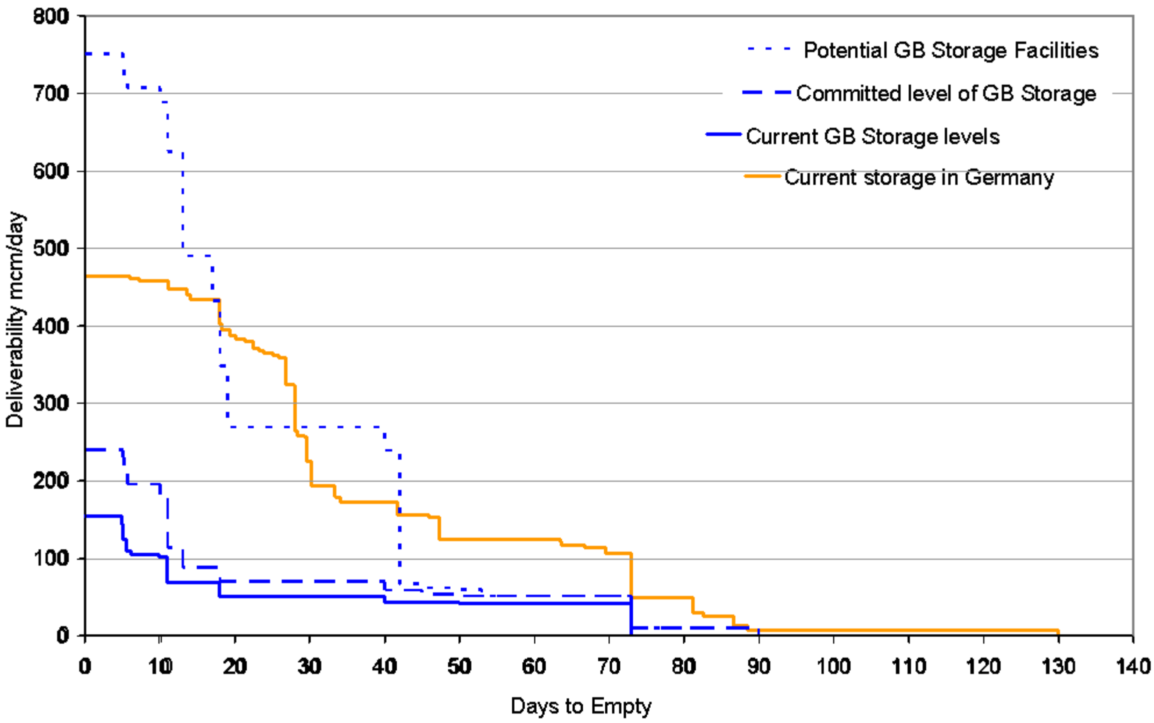
Facility	Type	Capacity (mcm)
Bains	Depleted	570
Baird	Depleted	1,700
Esmond, Forbes & Gordon	Depleted	4,200
Hewett	Depleted	5,000
Saltfleetby	Depleted	400
Welton	Depleted	450
British Salt	Salt	1,000
Fleetwood	Salt	1,200
Gateway	Salt	1,500
Isle of Portland	Salt	1,500
White Hill Farm	Salt	420
Total		**17,940**

Source: GSE, Platts

As can be seen in Figure 3 should they all be built then there would be a significant increase in available capacity to GB gas security of supply especially when considered against an expected normal conditions peak demand of 400mcm/d. In addition the volumes shown do not take into account how much cycling could be achieved over a year. Whether all or any of these are required in the future will be informed through the modelling results in Section 4.

For comparison Figure 3 also shows the current storage capacity in Germany. Whilst the level of storage is more than GB, and German expected normal conditions peak demand is higher at c.580mcm/d, they have historically needed a higher ratio of storage cover to reflect the limited number of its supply sources.

Figure 3 – Potential growth in GB Gas Storage



Source: GSE

GB peak shaving LNG storage

At the beginning of 2009 GB had four peak shaving LNG storage facilities which had been built in the 1970s. Their objective was to be situated in strategic locations close to areas of high demand or at the extremities of the network. Their key feature has been their location and their ability to rapidly revaporise the natural gas and so provide high deliverability and short term support to the NTS. As a result, LNG storage is able to provide a peak gas supply to shippers and supplement NGG's network capacity. In addition, LNG Storage has been used as a contingency against the risk of emergencies such as system constraints, failures in supply or failures in end user interruption.

In November 2008 NGG proposed disposing of its peak shaving LNG storage facilities at Dynevor Arms which was previously at an extremity of the NTS and provided locational operating margin services. The local need had been superseded by the development of the Milford Haven pipeline and the two new LNG entry terminals in South Wales. However, after receiving insufficient interest in a sale the site was closed from the end of April 2009.

On 18 August 2009 NGG then announced a review of the remaining three facilities reflecting the consequences of the development and expansion in gas storage and changes to the pattern of gas flows within the NTS. It again asked for expressions of interest in long term capacity, up to 20 years, from shippers.

Since the modelling analysis was completed NGG announced on 21 December 2009[12] that it had again found insufficient interest to justify the required investments. It said the next stage would be a risk and economic review and no commercial liquefaction will take place during the summer of 2010 and customers might wish to plan their stock positions based on the potential reduction in storage services from May 2011.

This review will also need to consider that 80mcm was required to flow in January 2010 and although we have included the three sites in our assumed storage facilities, as shown in Table 2, the results in Section 4.1 show no use is made of the three LNG peak storage facilities in the main scenarios from 2015 due to cheaper available sources compared to the cost of summer refilling.

2.3.2 Strategic storage across Europe

Various countries have either explicitly defined levels of strategic storage or mechanisms that could be considered as 'de-facto' strategic storage. Countries that have been identified as having this are Italy, France, Hungary, Poland, Portugal, Slovakia, Belgium, Spain, Denmark, and Romania. We look at these in more detail in Section 5.3.

We do not explicitly consider 'de-facto' strategic storage in the model, because, whilst we recognise its presence, the model is trying to determine the economic dispatch of the markets. The model is free to use 'strategic storage', which is set at a very high price, where it is economic to do so, however, it is rarely economic compared with other options (e.g. UKCS swing, or the US storage/LNG flexibility observations) and therefore remains unused in normal conditions.

2.3.3 Gas storage in the United States and Europe

When considering the level of storage any country may need, it is important to consider how much storage there maybe available in other nearby countries.

The linkage of GB with continental Europe means it has the potential to access large amounts of storage providing it is open to third parties to access and there are no transportation constraints in bringing the gas across Europe to GB.

In addition, the expansion of LNG around the world means that Europe and GB can access storage in the US by acquiring LNG cargoes destined for the US in the winter, which can supplement this supply with its own large quantities of gas storage.

The potentially available capacity of gas storage in the US, Europe and GB shown in Figure 4 highlights how much storage there is in the major western gas markets, although not all will be available due to competing demands and constraints.

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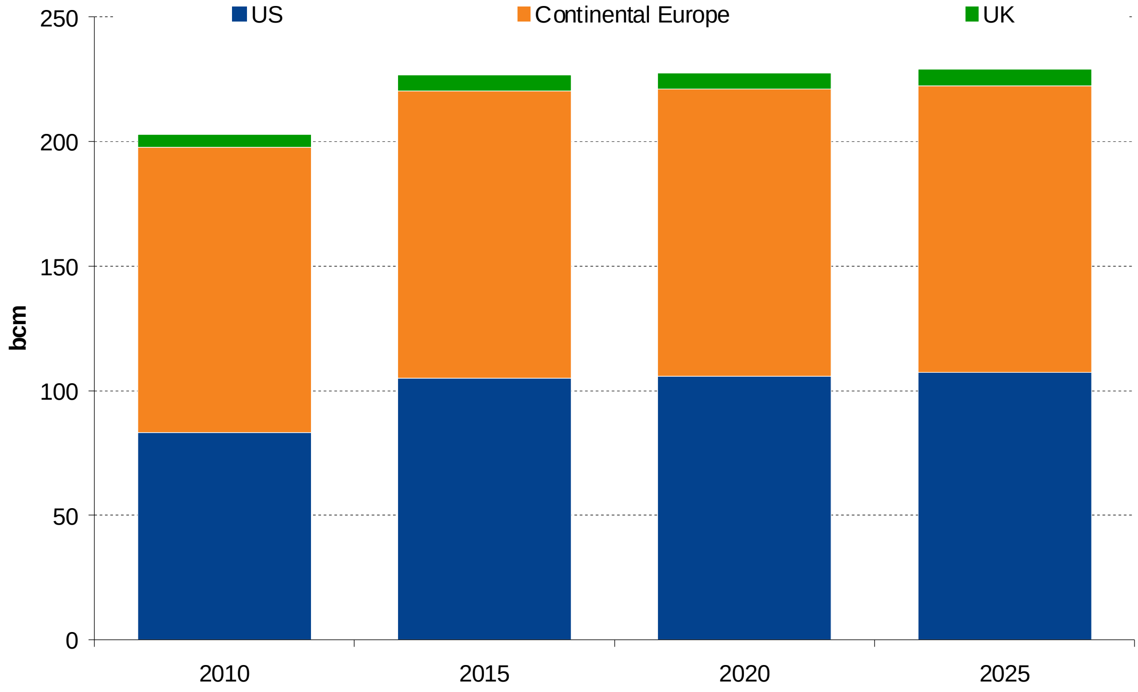
[12] http://www.nationalgrid.com/uk/Media+Centre/PressReleases/18.12.09.htm

Figure 4 – US storage levels compared to Europe and GB



2.4 Pipelines and interconnectors

As the level of gas supply from the UKCS has declined in recent years various new infrastructure projects have been built to increase the capacity of imported gas, whether though LNG or pipeline from Norway and continental Europe. We have an infrastructure database which is updated regularly with information from trade publications and industry sources. Table 4 shows the capacity assumptions we believe will be in operation from 2010 to 2025.

We have assumed that the Netherlands to GB Interconnector, the BBL pipeline, will have physical reverse flow by 2015 and have commercial 'virtual' reverse flow in 2010, with the latest news being that virtual reverse flow might be available in Q2 2010.

The Tampen Link connects Norwegian gas fields, including Statfjord late-life gas, to the St Fergus terminal via the FLAGS pipeline system. This allows more Norwegian gas to take the place of declining UKCS supplies into St Fergus. The Tampen link has a capacity of 10bcm/yr but exactly how much additional Norwegian gas will flow in the direction of GB is unclear. We have reflected this by adding 1bcm/yr of Norwegian gas from the gas year 2007/08, for 5 years.

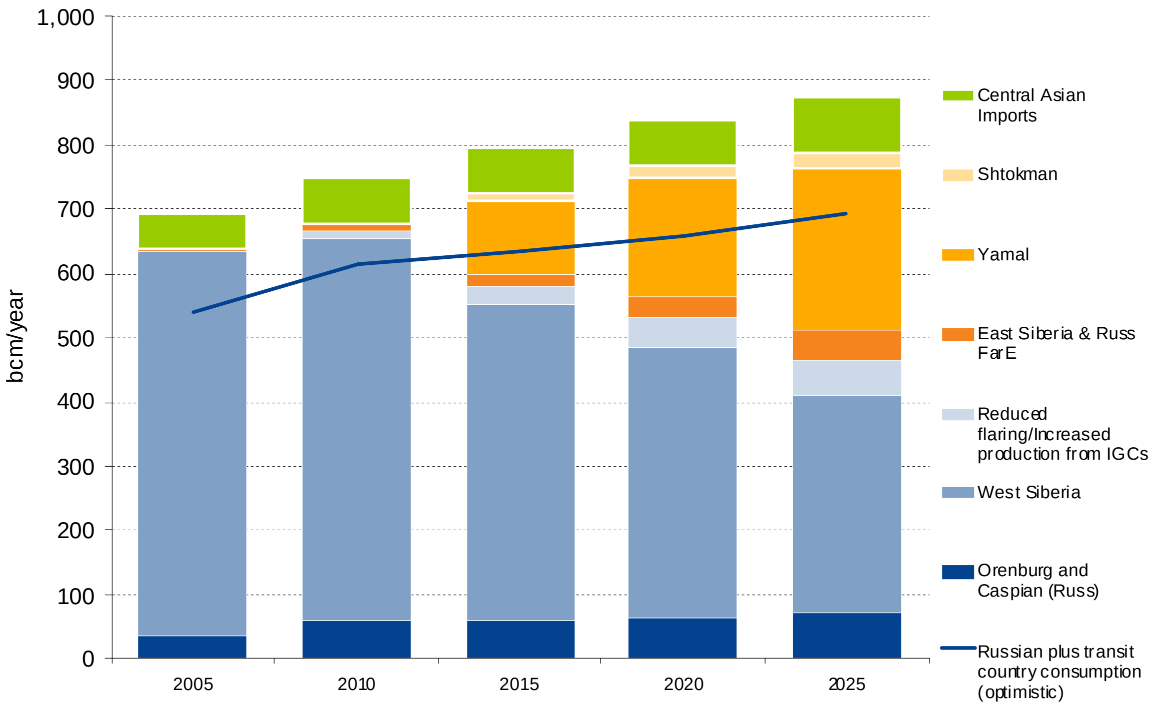
We also holds details on the capacities of pipelines across Europe as the ability of gas to flow across countries will assist in allowing gas to flow to where it is needed most and especially when there is a severe supply disruption. We take existing trans-Europe interconnection capacities from GIE. As a simplifying assumption we ignore internal capacity constraints within each demand zone, see Annex A for details of the demand zones.

Table 4 – Pipelines and interconnectors to GB (bcm/yr)

	2010	2015	2020	2025
GB to Neth	0.0	17.0	17.0	17.0
Neth to GB	17.0	17.0	17.0	17.0
GB to Belgium	20.0	20.0	20.0	20.0
Belgium to GB	23.7	23.7	23.7	23.7
GB to Island of Ireland	11.3	11.3	11.3	11.3
Island of Ireland to GB	0.0	0.0	0.0	0.0
Langeled	23.0	23.0	23.0	23.0
Vesterled	10.0	10.0	10.0	10.0
Additional Norwegian capacity to St. Fergus	3.0	5.0	5.0	5.0

Growth in interconnection across Europe occurs with new major pipelines. For this study we have forecast that Nordstream is online by 2012 with a capacity increase for phase 2 in 2016. We are assuming Southstream is not constructed but that Nabucco is introduced over the period 2016 to 2018, on a phased basis. Nabucco is filled by dedicated supplies which come on stream at the same time as pipeline capacity (probably from Commonwealth of Independent States (CIS) and Middle East, but possibly also Russia). With regards to major developments in Russian supplies, we have forecasted the Shtokman field to come online in 2015, reaching its maximum capacity in 2018, and Yamal fields to come online in 2014. The expected Russian gas flows from existing and assumed new fields is shown in Figure 5 below and further detail can be found in the Pöyry report ‘Russian Gas: will there be enough to go around, April 2009’ (see Annex E).

Figure 5 – Existing and assumed Russian gas flows into Europe



We have also increased French/Iberian interconnection, German/Austrian interconnection and Hungarian/Romanian interconnection (in both directions in all cases) prior to 2015, in line with proposed projects. We assume a far greater east to west capacity than west to east. For example capacities (in mcm/d) from Slovakia into Czech Republic and Austria/Hungary are 144 and 145 respectively, but their counter-directional capacities are 12.4 and 0.0 respectively. There are similar asymmetries across Europe.

2.5 LNG facilities

This section not only looks at the development of regasification facilities in GB, but given its global nature also takes a wider perspective and discusses the development of international facilities for liquefaction and regasification and trading based on international price signals.

2.5.1 GB regasification

Table 5 shows our assumptions for GB's LNG re-gasification terminals in 2010. For the purpose of the modelling in Section 4 we have assumed that no more LNG regasification facilities will be constructed, apart from Isle of Grain phase III to be operational by 2010 and South Hook phase II by 2011. There is a notional 4 bcm capacity at the Excelerate Energy LNG gas port at Teesside but it has no permanent re-gasification terminal and so no ability to respond to within day and short term needs.

Table 5 – Current LNG terminals within GB (bcm)

	2010	2015	2020	2025
Dragon	6.00	6.00	6.00	6.00
South Hook	10.50	21.00	21.00	21.00
Isle of Grain	20.28	20.28	20.28	20.28
Teesside	4.00	4.00	4.00	4.00

Into the future there is the possibility that there will be the various expansions and new regasification terminals built and these are shown in Table 6. Whilst this shows a potential for another 35 bcm of capacity it is our view that there are some challenges in bringing these to commercial operation, with the most likely to proceed being Dragon phase 2. In addition, Isle of Grain announced in August 2009 that it was seeking expressions of interest in developing phase IV but no potential capacity was proposed. To be conservative none of these have been included in the modelling in Section 4.

Table 6 – Potential LNG expansion within GB

Facility	Capacity (bcm)
Canvey Island	5.4
Gateway LNG	2.7
Port Talbot	4.1
Anglesey LNG	20.0
Dragon phase 2	3.0

Source: Pöyry Energy Consulting, Platts

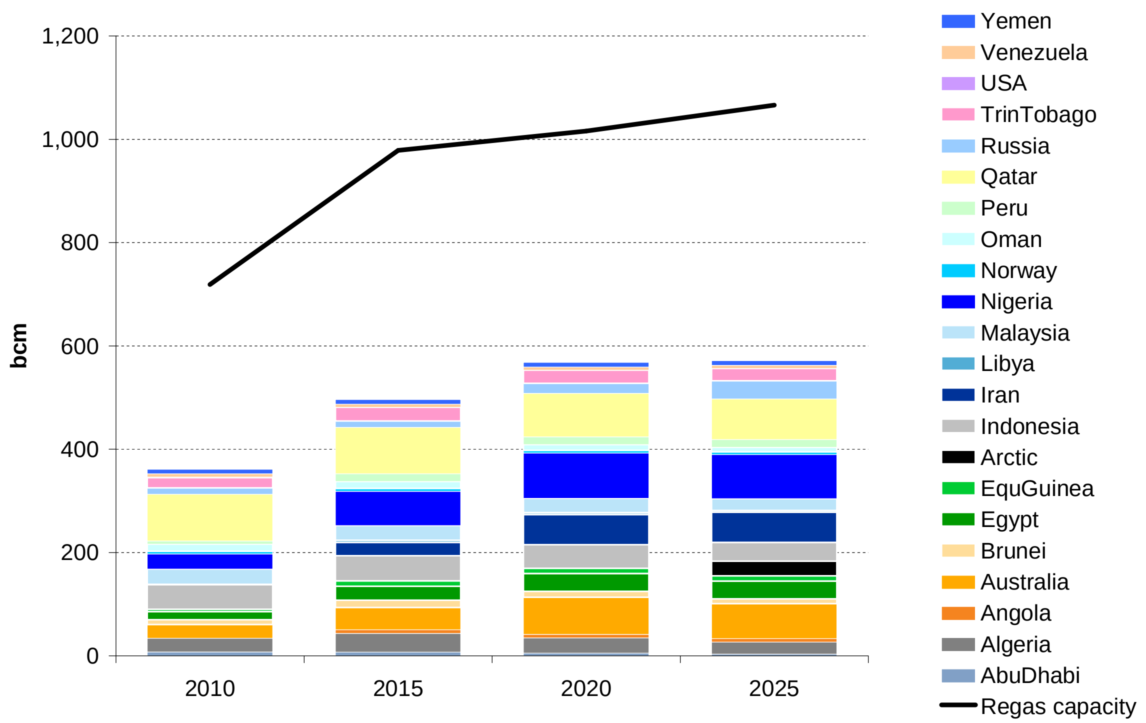
2.5.2 Global liquefaction & regasification

There are many projects proceeding and being planned for new LNG liquefaction plants throughout the period, significantly in Australia, Algeria, Brunei, Egypt, Iran, Nigeria, Qatar and Trinidad and Tobago. We have also assumed that there is some decline in older liquefaction capacity. Most of the growth is assumed to be from now until 2016 with only Russian supplies increasing after that. We assume that capacity available in 2000 declines from 2015 at a rate or 5% per annum, as seen in Figure 6, below.

The major source for LNG export to GB and Europe will be Qatar, throughout the period 2010 to 2025. Nigeria significantly increases production over the same period to reach a similar level to Qatar by 2025. It can be seen that liquefaction capacity increases by 57% from 2010 to 2020.

Figure 6 also highlights that global regasification capacity is significantly higher than global liquefaction capacity. This is discussed in more detail in Section 2.5.3.

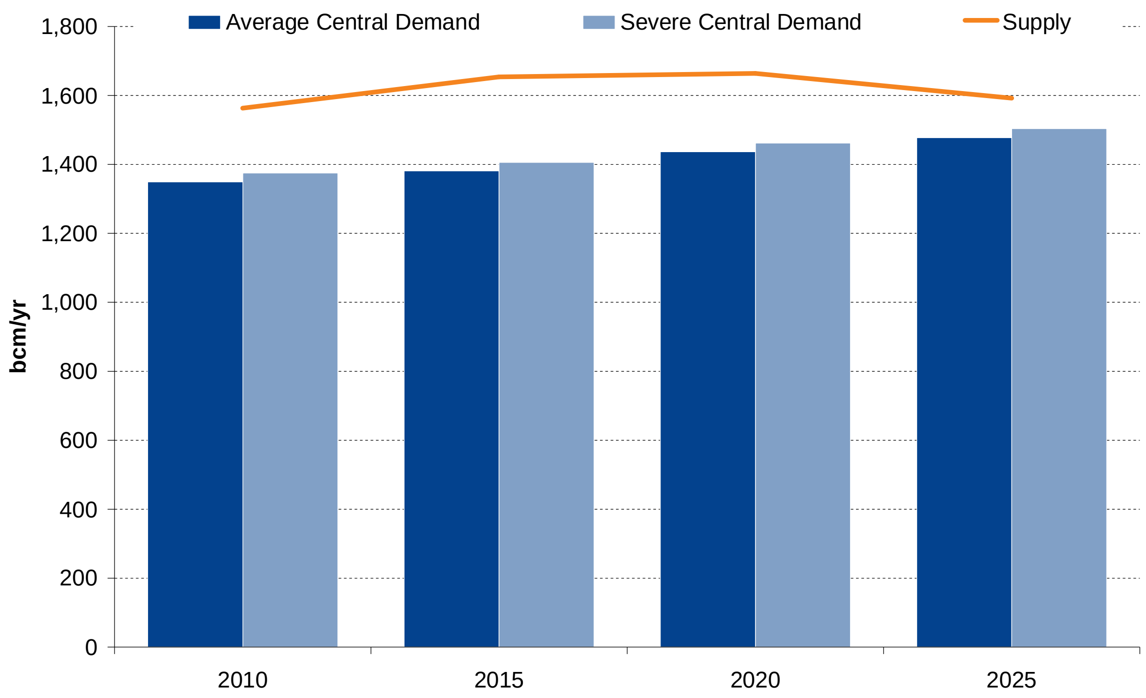
Figure 6 – Global LNG liquefaction and regasification capacity



Demand for LNG can only be considered as part of the wider global gas industry, and LNG liquefaction capacity can only really be considered in this global context against other global supplies, which we show in Figure 7. This shows that under both the Average demand and the Severe weather demand across GB and North-West Europe and colder than average demand in the US scenarios, as described in Section 2.6, there is a growing and then slight shrinking of global supply margins, which means there is sufficient LNG supplies across this period to those markets seeking supplies.

We expect that the following LNG re-gasification terminals will be commissioned in Europe: Rovigo (also known as Adriatic LNG; Italy) and Aliaga[13] (Turkey) come online in 2009; Sagunto and Sines have additional capacity by 2011; various generic Italian regasification capacity come online by 2012, along with Lion Gas, Le Verdon, Gate, Dunkirk, Eemshaven. Shannon is due to come online in by 2017, reflecting the continuing uncertainty over its construction.

Figure 7 – Global supply and demand



2.5.3 LNG value chain

It is also important to understand how the market sees regasification as part of the LNG value chain. As can be seen in Table 7, it typically represents about 10% of the total capital expenditure and as seen in Figure 6 there is a significant excess of regasification compared to liquefaction.

This is vital to the LNG industry as it provides it with the ability to supply different geographical markets based on price variations and seasonal demand patterns whilst allowing production to continue throughout the year at steady levels. So, regasification facilities are considered for their option value and more are built than strictly needed to just cover the liquefaction output.

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13 Whilst Aliaga was officially completed in 2003, it has yet to be put into operation due to it not being connected to the Turkish national grid and the operator, Egegaz, is also awaiting the provision of an operating licence from the Turkish government.

Table 7 – Typical LNG value chain

	Capex $/mtpa
Production	150 – 500
Liquefaction	200 – 275
Shipping	150 – 200
Regasification	75

Note: Illustrative numbers, which do not represent a real chain/contract

2.5.4 LNG source diversity

Potential LNG supplies to GB are both geopolitically and commercially diverse as shown overleaf in Figure 8, with GB being ideally located to sources such as Nigeria, the Middle East, Trinidad and Tobago and now Norway. Supplies to Asia have been excluded from the total supplies available in Figure 8 as they would not normally be available to European buyers due to the extra shipping costs and the potential knock-on to steady-state liquefaction train production.

Traditionally, LNG has been traded via fixed long-term contracts, but there have been recent changes to this behaviour, as noted above, and across all LNG supplies, with a significant expansion in spot cargo trades. In a discussion paper presented at the Madrid XV follow-up forum held in Bilbao on 12th and 13th March 2009, DG TREN stated:

"Traditionally, LNG-production was sold in long-term contracts, but as more LNG comes on stream, projects optimise their output, and demand for LNG increases, there is a tendency to sell some LNG in contracts of intermediate or short-term duration. It is estimated that 13% of global gas supply is 'flexible' and that by the end of 2009 this share can grow to 21%. Of the new supplies becoming operational worldwide in 2008-2009, nearly 40% can be considered as 'flexible', more than half of which is situated in the Middle East and with easy access to all LNG markets.

As LNG markets develop, short-term trading is also developing. In 2007 it accounted for 20% of global LNG sales compared to 16% in 2006. As these percentages do not show the arbitrage opportunities taken by integrated companies that can divert flows within their overall portfolio, these numbers are likely to underestimate the flexibility of LNG-trading. Moreover, there is a tendency for LNG producers to contract less of the output in fixed long-term contracts in order to profit from market opportunities."[14]

So the expansion of available LNG supplies taken together with the growth of Russian gas supplies, see Figure 5, into Europe provides a healthy picture of competition between expanding supply sources.

This is supported by comments from Tony Haywood, Chief Executive of BP, in an interview in February 2010 with the BBC[15] in which he says there is "unreasonable paranoia about gas supplies to the UK" and it was "curious as to why there is so much

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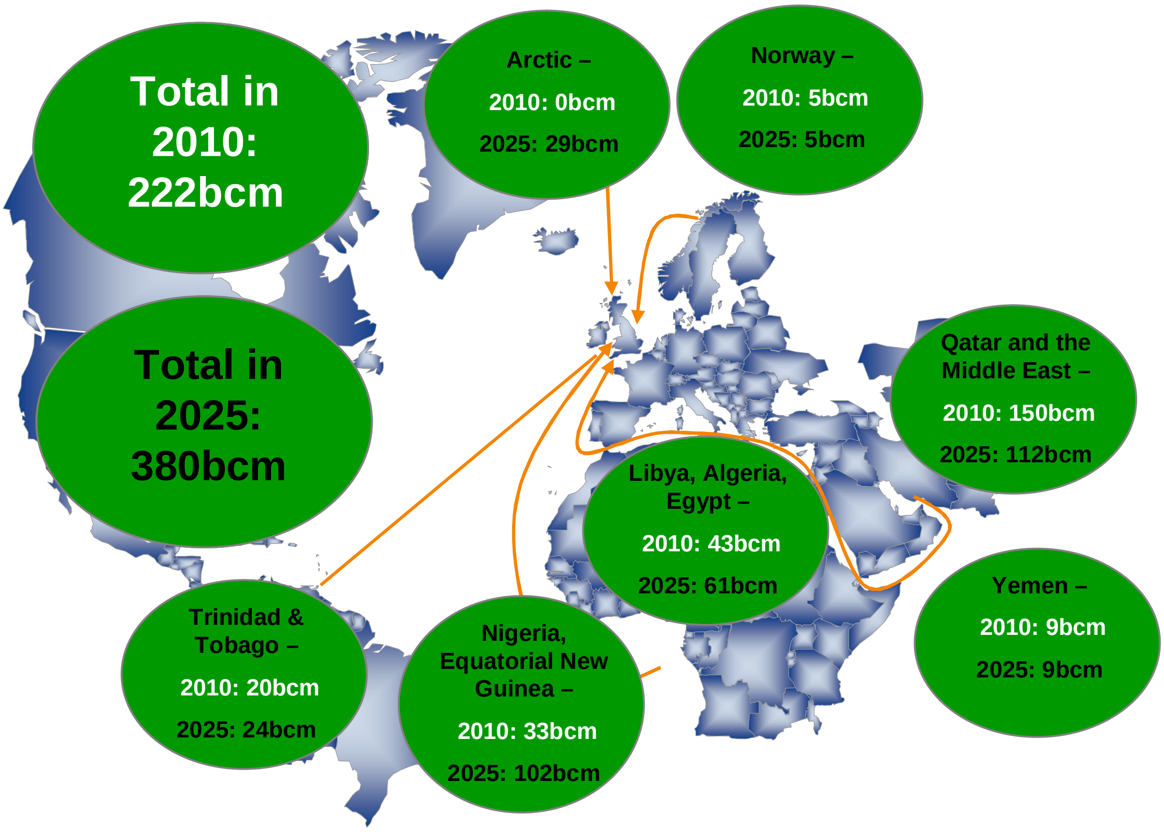
14 'LNG Discussion Paper by DG-TREN', published at http://www.gie.eu.com/workshop/

15 http://news.bbc.co.uk/today/hi/today/newsid_8497000/8497578.stm

concern about us becoming more reliant on imported gas". He added that "there's a lot of gas available from many diverse sources," and said that in the past six months GB had sourced supplies from countries including Norway, Algeria, Egypt and Trinidad. He stated that "It's a very sensible way to bridge between where were are today and where we all want to be in twenty or thirty years' time."

Figure 8 – LNG liquefaction capacity available to Europe & US in 2010 and 2025



Note: Total figures only for countries represented.

The only caveat to this could be the emergence of a gas cartel in a similar manner to that of Opec in the oil market. Competition between LNG suppliers for satisfying growing LNG demand should ensure prices are not artificially maintained at levels not supported by the market fundamentals. For such a cartel to be established it would require key members such as Qatar, to join in. However, in an interview in April 2009 Qatar's energy minister and deputy prime minister, Abdullah bin Hamad Al Attiyah, conceded that the near-term surplus of LNG will have a softening effect on prices. When asked about the prospect of LNG prices falling as low as $2.50/mmbtu (16p/therm) in summer 2009, he replied: "*…we have to live with the prices. The price is a cycle, it goes up and down. You can never guarantee what will happen with the price. People have short memories. Ten years ago the price of oil was below $10/bbl. We can cope. Demand will come back again. No one can live without energy."*[16] Hence, we are assuming that there is no great urgency to form such a cartel over the period of this study.

[16] LNG Business Review – April 2009 – www.lngbusinessreview.com

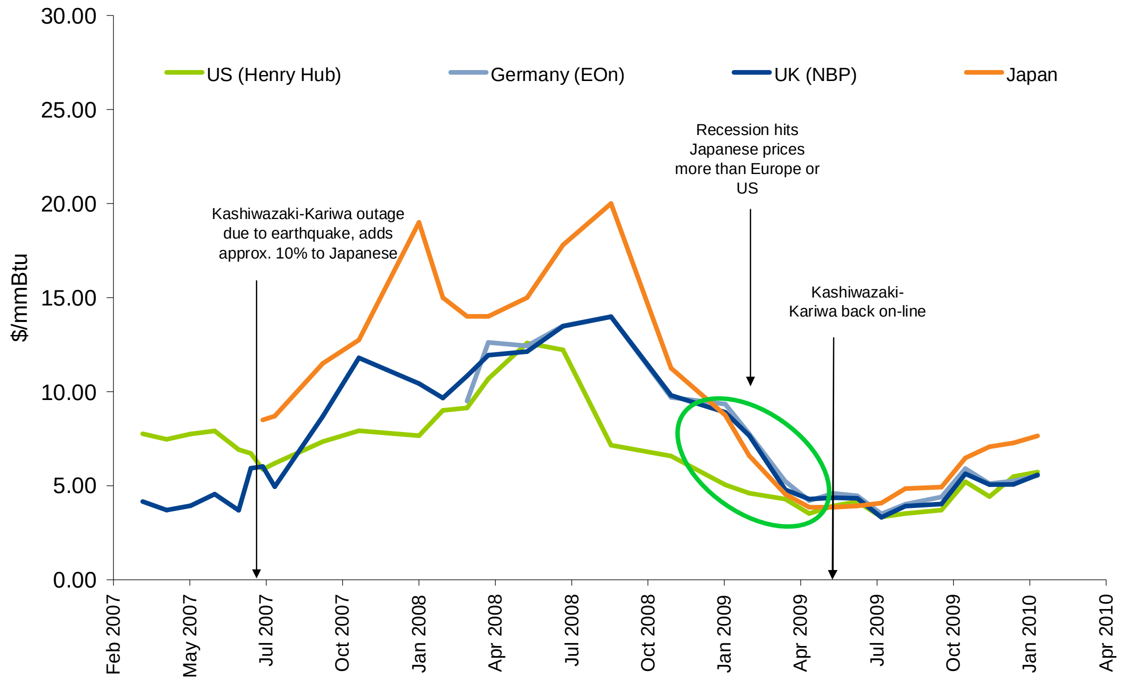
2.5.5 LNG price signals

Figure 9 below shows the recent evolution of global LNG prices. The big rise in Japanese prices started in 2007 following an earthquake that was outside its design tolerance at the Kashiwazaki-Kariwa nuclear power station. This meant that the whole 8GW of capacity was shutdown and significant additional supplies of LNG (approximately 5% to 10% of CCGT usage) were needed at CCGTs to supplement this missing generation.

As the majority of Japanese LNG imports are priced on the Japanese customs-cleared crude oil price basket (also known as Japan Crude Cocktail or 'JCC'), it provides an obvious marker for pricing spot LNG trades. If demand for LNG outweighs the JCC based supplies, the JCC prices are generally a much more attractive price signal than European or US oil-indexed prices and any opportunity to divert cargoes from west to east will be exploited.

As the recession took hold, Japanese demand fell allowing increased flows of LNG to western markets. Kashiwazaki-Kariwa returned to operation in late May 2009 which further depressed Japanese demand for LNG. We expect that spare or spot LNG will flow to the markets that value it the most, and that LNG should be considered as a reliable source of supply if the price signals are right, as it has been for Japan during 2007 and 2008.

Figure 9 – International gas prices



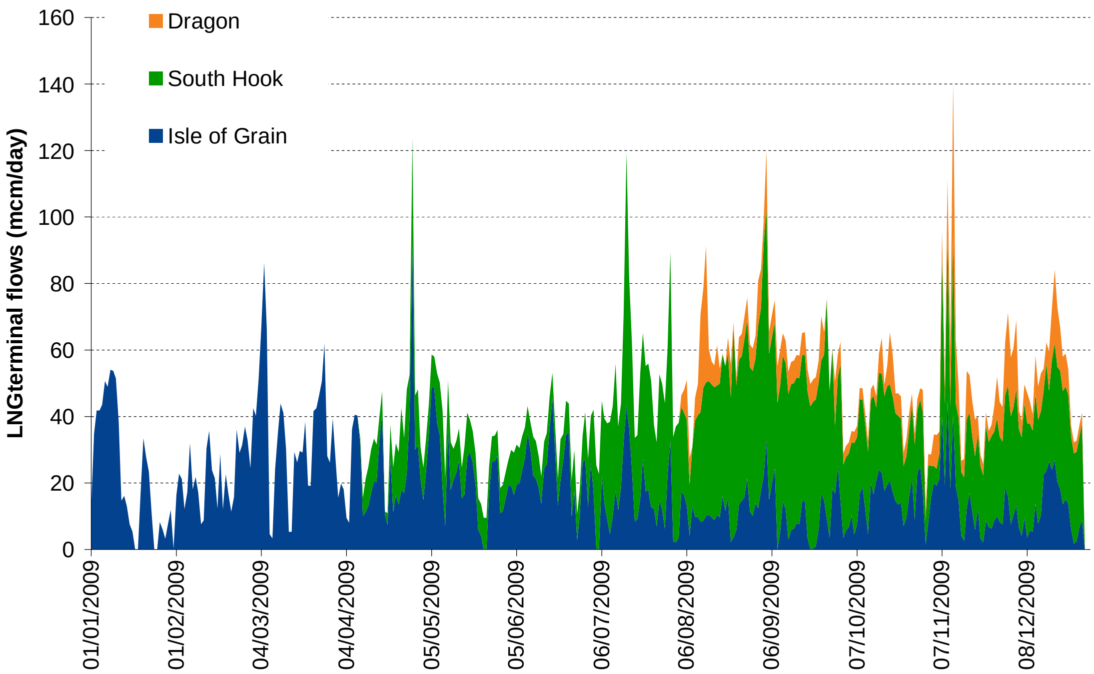
Source: Pöyry analysis of Platts data

2.5.6 LNG supplies to GB 2009

Whether sufficient levels of LNG supplies materialise in the GB market still remains to be proven in the long-term. However, we have the experience of 2009 to see the impact of the recent capacity increases at Milford Haven and Isle of Grain phase 2 and how this has changed the attractiveness of GB to LNG suppliers. We believe this is consistent with the rapidly growing body of evidence that suggests that LNG will flow when the price signals are right.

As can be seen in Figure 10[17] below GB has seen a significant increase in LNG flows. This reflects the recent increase in global LNG liquefaction, lower LNG demand levels in Asia, steady flows from Qatar to South Hook and very cold period in January/February 2009 and December 2009.

Figure 10 – LNG flows into GB 2009



Source: National Grid

It is worth noting some specific activities relating to the expansion in the flows shown in Figure 10:

- On 6 April 2009[18] the Isle of Grain LNG terminal had taken delivery of its 100th cargo.
- On 10 April 2009, Isle of Grain LNG took first delivery of Norwegian LNG, which had been purchased by Centrica through its import rights at the facility.
- South Hook received its first commissioning cargo on 20 March 2009, with subsequent cargoes at the end of April and early May. Since then a fairly consistent flow had been delivered reflecting the linkage with the Qatar liquefaction plant.
- Dragon, the other Milford Haven regasification terminal, received its first commissioning cargo on 14 July 2009.

17 excludes the Teesport cargo in April 2009.

18 www.nationalgrid.com/NR/exeres/4E880BCE-1D60-4C6C-821F-34E3AB1D4445.htm

2.6 Annual and peak demand

This section outlines our demand assumptions for GB, all-island of Ireland and the other key markets contained in our Pegasus model, both in terms of overall annual demand but also daily demand. For the deterministic modelling in Section 4.1 we have developed three demand scenarios based on a combination of Pöyry's own views of future demand and DECC's forecasts, which we have called 'Average', 'Severe' and 'Central'. The probabilistic approach in Section 4.3 takes the Average and Severe annual demand forecasts and applies these as 50th and 98th percentiles of the Gumbel-Jenkinson distribution to generate a range of demand figures, as described in Section A.2.1.

2.6.1 GB gas demand forecasts to 2025

We have used three demand scenarios for Great Britain. It should be noted that exports through interconnectors to the all-island of Ireland and the Continent are derived from the model and are based on the economics of supplying the markets and gas flows in the most efficient way to satisfy demands.

2.6.1.1 Average

The Average case annual demand is based on a combination of Pöyry's Central demand projection taking into account the expected impact of the current recession and switch to CCGTs as coal and nuclear power stations are decommissioned and DECC's forecasts for achieving the 2020 renewables, energy efficiency and carbon targets, which is consistent with the Government's policies.

Supporting this is the expected benefits that will arise from the on-going expenditure from the Carbon Emissions Reduction Target ('CERT') programme. The purpose of CERT is to help electricity and gas consumers in the GB household sector to reduce the carbon impact of their home through promoting measures which improve the energy efficiency of the fabric of the property, use energy more efficiently, reduce energy consumption and assist in using energy from micro-generation sources. In its 21 December 2009[19] consultation and impact assessment DECC reports that the current and proposed enhancements will mean an average domestic customer will be contributing £52 per annum, representing c.4.5% of their total bill.

The reduction in demand caused by the economic slowdown has been reported for both the winter 2008/09 and for summer of 2009. In its 2009 summer outlook[20], NGG predicted that the impact of the recession is anticipated to reduce NDM demand by 6%, in line with their winter experience. Previous experience in other markets, such as the US and Japan, indicates that not all of this demand will return and so there is some permanent demand destruction from the economic slowdown.

2.6.1.2 Severe

The Severe scenario takes the Average scenario annual demand and inflates it by approximately 13% to replicate the effects of the increased consumption in a severe winter. It also seeks to replicate the curvature of the 1 in 50 load duration curve published from time to time by NGG, which has the effect of increasing the 'spikiness' of demand.

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19 http://www.decc.gov.uk/en/content/cms/consultations/cert_ext/cert_ext.aspx

20 www.nationalgrid.com/NR/rdonlyres/491E346E-49F4-40A1-98D0-7D0C0075E75B/33228/Summer_Outlook_Report_Final1.pdf

2.6.1.3 Central

We have also included a scenario whereby the 2020 targets encourage more renewables and energy efficiency but the targets are not met until 2030 and there is a higher gas demand accordingly. For this 'Central' case we use Pöyry's Central Case demand projections from its ILEX Energy report on the GB gas market. Further details on the assumptions can be found in Annex B.

2.6.1.4 Summary of GB gas demand forecasts to 2025

The annual GB only demands used in the modelling are outlined in Table 8 below. The Average case is 2.5 mcm higher in 2010 than that shown in the NGG 2009 TYS but is lower than the 87mcm in 2015, although this higher demand level is covered by the demand assumptions in the Central case. The Average case is in line with DECC's expectation of what is required in order to deliver the 2020 renewable targets.

Table 8 – GB only annual demand cases

Annual demand, bcm	Average	Central	Severe
2010	86.0	90.5	97.2
2015	80.2	88.2	90.6
2020	79.0	86.9	89.3
2025	77.3	84.9	87.3

2.6.2 Republic of Ireland and Northern Ireland gas demand

We use Pöyry's Central Case demand projections for all three scenarios in this all-island of Ireland (including both the Republic and Northern Ireland markets which are due to be combined in a single market in the next few years). This assumes that the market makes progress towards the 2020 targets but does not fully meet them and is based on seasonal normal demand. Table 9 shows the projection for the all-island of Ireland gas demand. We assume Corrib production starts in 2011, Shannon LNG from 2017 and new salt cavern storage in Northern Ireland from 2016. The balance of gas demand will continue to be met from the Moffat interconnector.

Table 9 – All-island of Ireland gas demand (mcm)

	Power gen. (ex CHP)	CHP	Industrial	Commercial	Residential	Other	Total
2010	4,298	0	933	545	981	334	7,091
2015	4,090	0	987	576	1,038	354	7,045
2020	4,228	0	1,038	606	1,092	372	7,336
2025	4,495	0	1,115	651	1,172	400	7,832

2.6.3 North-West Europe gas demand

The integrated nature of the Pegasus model and the linkages between GB and continental Europe mean that we also need to estimate the growth rates for the large demand countries in North-West Europe and these are shown in Table 10. These are aggregate figures, and are inclusive of power generation demand and consideration of renewables, etc. We assume that the effects of the current recession will continue into 2010 before a return to economic growth.

Table 10 – Pöyry Central case demand growth rates (compound annual)

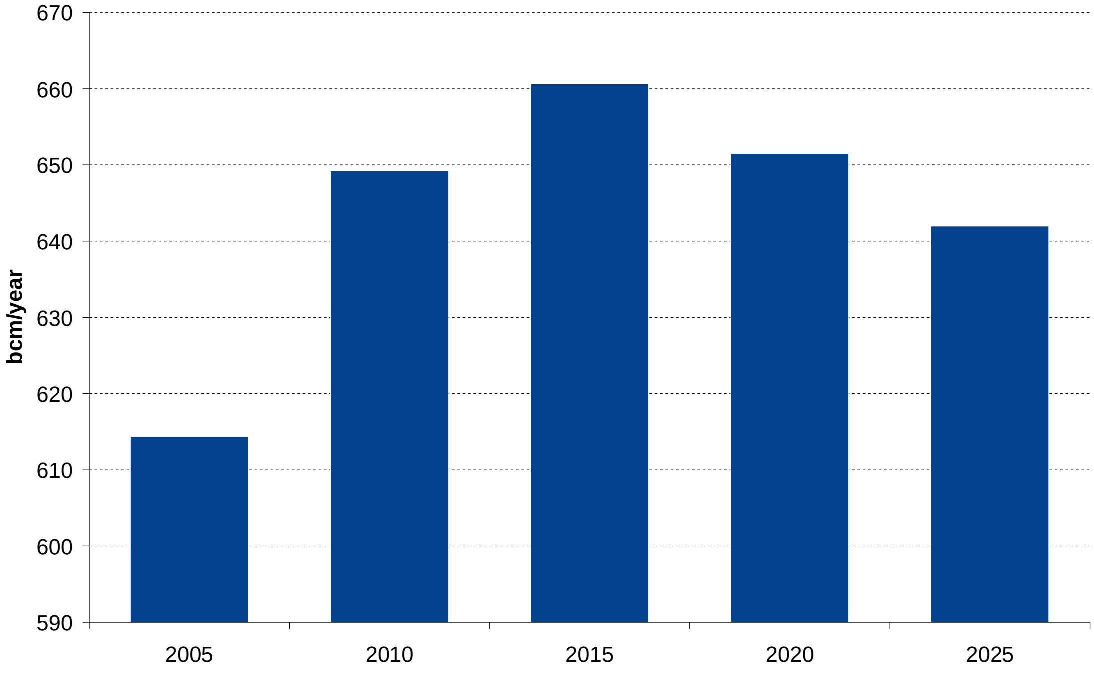
Period	Belguim & Luxembourg	Germany	Island of Ireland	Netherlands	France	Denmark
2009-2015	0.47%	-1.20%	-0.26%	-2.50%	0.25%	0.96%
2015-2020	3.80%	1.40%	1.10%	0.58%	0.42%	1.60%
2020-2025	8.20%	0.95%	0.31%	2.50%	1.00%	0.75%

For the Severe scenario, gas markets in Germany, Belgium, Netherlands and Luxembourg are based on annual demands inflated by 11%, replicating the effects of a severe winter in these countries at the same time as one in GB.

2.6.4 Demand in United States of America

Again the integrated nature of Pegasus means that LNG can flow to markets in Europe, Asia and North America. The size of the United States market means that the extent to which LNG is required to meet its annual demand will have an interface with LNG supply to Europe and GB. We have used the 2008 EIA (Energy Information Administration) reference case as the source of US demand forecasts, as shown in Figure 11. In this, US demand varies between 635 and 665bcm/yr over the period. We have taken this central projection for all three of our scenarios. The 2009 EIA report indicates up to 9% lower demand from 2010 to 2020, but 3% higher demand in 2025. This means the numbers used in the modelling is more akin to colder than seasonal weather at the same time as severe weather in GB and North-West Europe.

Figure 11 – US annual demand



Source: Energy Information Administration

2.6.5 Daily demand profiles

The annual demands for GB are modelled at a daily resolution by scaling to the actual pattern of consumption experienced in 2006/07 and are shown in Figure 12. In the Severe case this means a peak daily demand of 508 mcm/d in 2010 including Irish exports, of which 486mcm/d is GB demand only. As a comparison, this is 5% higher than the highest recorded daily NTS throughput recorded by NGG of 465mcm/d on 8 January 2010.

Daily demand in gas markets in other parts of the world are applied at a daily resolution using unmodified Fourier series analysis. Demand patterns for both the Average and Severe demands for the US, Germany & Benelux and GB & all-island of Ireland are shown in Figure 13 below, which highlights their relative sizes.

Figure 12 – GB daily demand profile

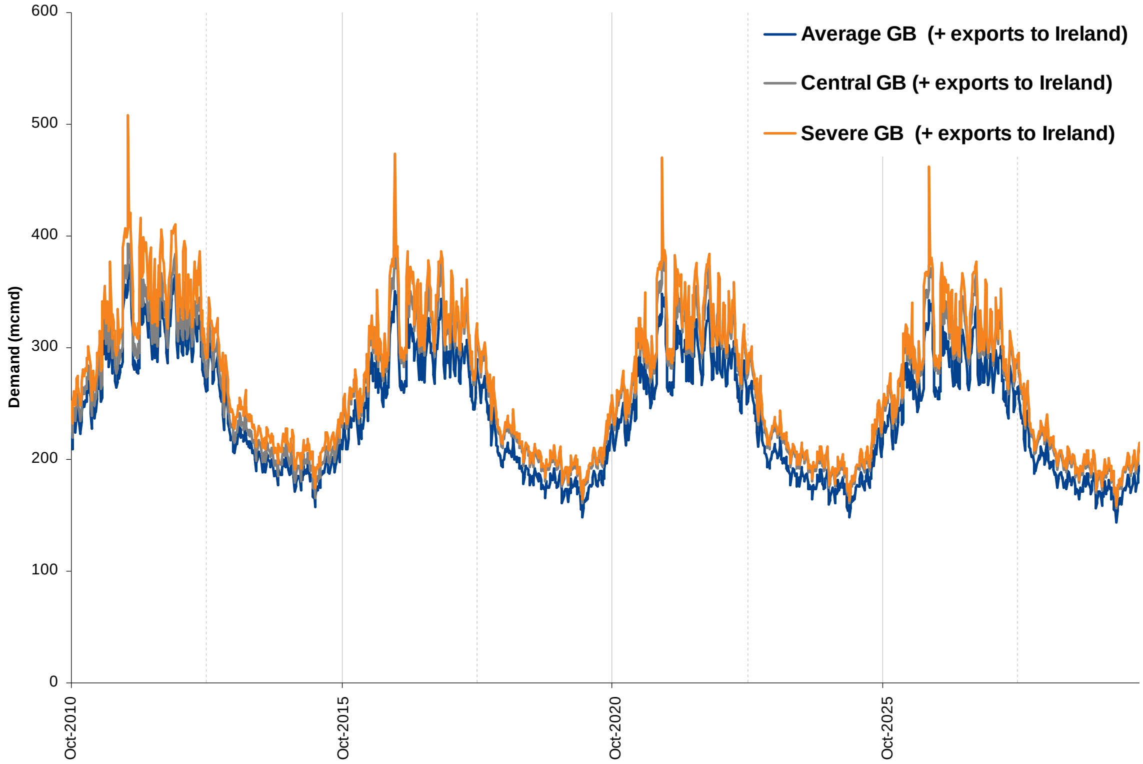
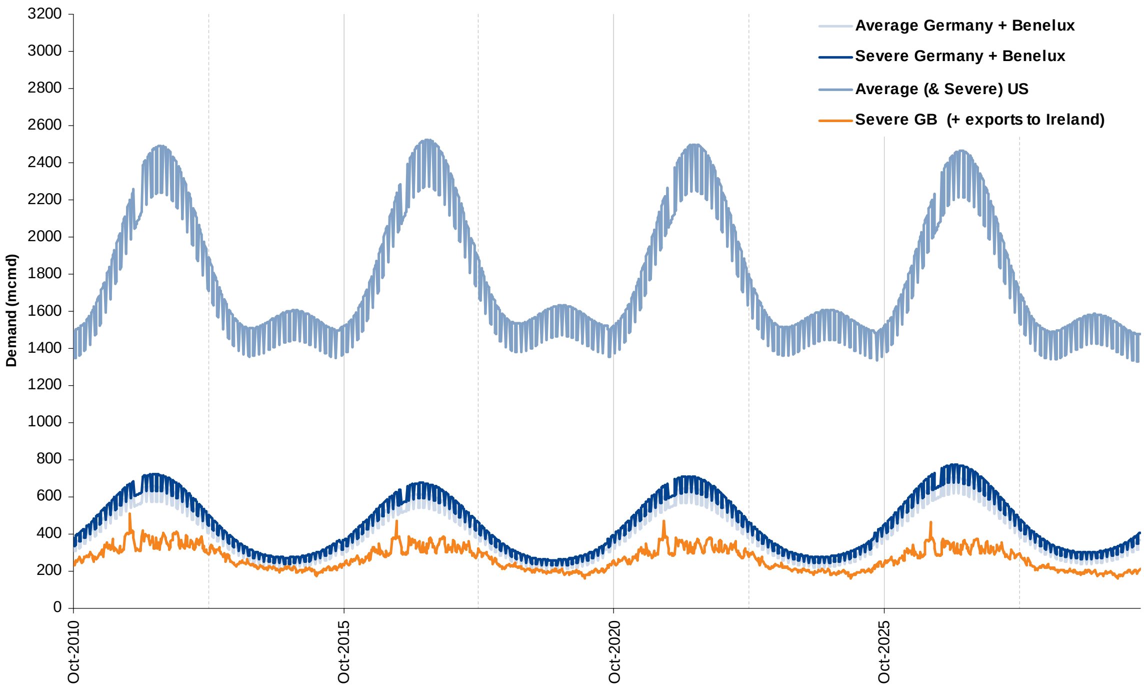


Figure 13 – Selected other demand patterns



Peak days

The resultant peak day demands are shown below in Table 11.

Table 11 – Peak day demand in selected markets (mcm/d)

	2010	2015	2020	2025
GB – Average	353	328	324	317
GB – Severe	486	452	446	437
GB – Central	371	361	357	349
Irish exports – Average, Central & Severe	22	22	24	25
Germany & Benelux – Average & Central	656	614	646	703
Germany & Benelux – Severe	722	675	711	773
US – Average, Central & Severe	2490	2524	2500	2463

2.7 Demand Side Response

In addition to gas storage and a diverse source of supplies, security of supply to firm consumers can also be provided by a demand side response. This can be categorised in to the following groupings:

- Power generation – where some gas fired power stations can switch to distillate in order to keep generating. Further details are discussed in Section 2.8 below.
- Industrial and commercial (I&C) interruptible load – where gas consumers accept cessation of the gas supply from time to time, and keep alternative means of maintaining the majority of their economic output (e.g. alternative/backup fuels) or limit production and utilise stock management, albeit at a marginally reduced level. Further details are discussed in Section 2.9 below.
- Unserved energy, where commercial and/or domestic gas consumers involuntarily cease consuming gas in order to match supply to demand, thereby significantly impacting the value created in the wider economy. Further details are discussed in Section 2.10 below.

It should be recognised that there is more than one type of demand side response 'backup' product available to the market; there are at least three types:

a) **Transportation insurance** – this is the traditional product whereby the site invests in backup capability as insurance against lack of transportation capacity, having generally chosen interruptible transportation.

b) **Demand side response** – this is where the site has chosen to install backup capability, even though it has firm transportation, for the upside of when spot gas prices are higher that the backup fuel price and there is still a positive fuel/electricity spread. This is generally limited to large NTS connected power stations.

c) **Demand side insurance** – in the event of a major disruption to the gas supply infrastructure sites that can switch to backup capability or cease consumption and so aid the provision of firm gas supply to NTS and DN loads (particularly domestic customers).

Traditionally (c) has been a 'free' by-product of (a) and/or (b). The NTS and DN interruption contracts allowed the supply and demand to match by in effect providing an additional gas source when the sites ceased using gas. For the cost of the transportation discount both the gas and electricity security of supply benefit by reducing the likelihood of unserved energy occurring, although there is a cross-subsidy occurring from firm to interruptible consumers in terms of normal operations.

For the purposes of the modelling, and using the analysis in Sections 2.8, 2.9 and 2.10 below, we have calculated the levels of all demand side response available for supply/demand matching and tranches of firm customers, as represented in Table 12: For the avoidance of doubt any required use of CCGT distillate backup or I&C interruption for transportation constraints is not modelled in our analysis.

Table 12 – Demand side response categories & assumptions

Name	Cost (£/th)	mcm/d	mcm/mth	bcm/yr	Notes
CCGT Distillate	0.90	24	114	0.57	Restocking constrains monthly and annual volume
I&C interruptibles	2.00	10	310	3.72	Monthly/annual volumes would be further constrained by load factors
Unserved Energy Tranche 1	12.00	5	155	1.86	
Unserved Energy Tranche 2	23.00	15	465	5.58	
Unserved Energy Tranche 3	51.28	1000	31000	372	Nominal costs/volumes for modelling purposes

2.8 Distillate backup at power generation

2.8.1 Current distillate backup capacity at power stations

Table 13 below shows the gas-fired power generation stations that have distillate backup and typical levels of on-site storage. The total capacity of distillate backup at CCGTs is 39mcm/d. Table 14 shows the remaining CCGTs which do not have distillate backup.

Table 13 – Existing CCGT distillate backup in GB

Name	Efficency	Capacity (MW)	Commission	Gas use (mcm/day)	Gas connection	Oil back-up	Days oil storage capacity
Barking	0.46	1,000.00	1994	4.88	NTS	Yes	10.0
Brigg	0.45	257.00	1993	1.28	NTS	Yes	6.0
Corby	0.45	401.00	1993	2.00	NTS	Yes	10.0
Cottam	0.50	395.00	2000	1.76	NTS	Yes	N/A
Derwent	0.46	228.00	1994	1.11	DNO	Yes	7.0
Fawley		138.00			DNO	Yes	2.0
Immingham	0.48	734.00	2004	3.40	NTS/Theddlethorpe	Yes	14.0
Keadby 1	0.46	735.00	1994	3.59	NTS	Yes	3.5
Little Barford	0.46	665.00	1994	3.25	NTS	Yes	4.0
Medway	0.46	690.00	1995	3.37	NTS	Yes	8.5
Peterborough	0.45	380.00	1993	1.90	NTS	Yes	10.0
Roosecote	0.45	229.00	1991	1.14	NTS	Yes	14.5
Sellafield	0.42	168.00	1993	0.89	NTS	Yes	14.0
Shotton Paper	0.45	207.00	2001	1.02	NTS	Yes	5.0
Teesside	0.45	1,876.00	1992	9.37	NTS/Teesside	Yes	3.0
			Subtotal:	**38.96**		**Average:**	**7.96**

Table 14 – CCGTs without distillate backup in GB

Name	Efficency	Capacity (MW)	Commission	Gas use (mcm/day)	Gas connection	Oil back-up	Days oil storage capacity
Grangemouth	0.40	120.00	1999	0.67	NTS	No	-
Baglan Bay	0.53	552.00	2002	2.31	NTS	No	-
Barry	0.50	245.00	1998	1.10	DNO	No	-
Brimsdown/Enfield	0.50	390.00	1999	1.73	NTS	No	-
Connahs Quay	0.46	1,380.00	1996	6.74	NTS/Pt of Ayr	No	-
Coryton	0.50	743.00	2000	3.30	NTS	No	-
Damhead Creek	0.50	805.00	2000	3.58	NTS	No	-
Deeside	0.46	495.00	1994	2.42	NTS	No	-
Didcot B	0.50	1,462.00	1996/2007	6.56	NTS	No	-
Great Yarmouth	0.50	420.00	2000	1.89	NTS	No	-
Humber 1	0.46	769.00	1996	3.75	NTS	No	-
Humber 2	0.49	516.00	1998	2.34	NTS	No	-
Killingholme (Centrica)	0.45	665.00	1993	3.32	NTS/Theddlethorpe	No	-
Killingholme (EOn)	0.45	900.00	2003	4.44	NTS/Theddlethorpe	No	-
Kings Lynn A	0.46	340.00	1996	1.66	NTS	No	-
Peterhead 2	0.48	790.00	2000	3.66	NTS	No	-
Rocksavage	0.49	754.00	1997	3.42	NTS	No	-
Rye House	0.45	715.00	1993	3.57	NTS	No	-
Saltend	0.50	1,215.00	1999	5.40	NTS	No	-
Seabank	0.50	1,222.00	1998	5.43	NTS	No	-
Shoreham	0.51	400.00	2001	1.74	DNO	No	-
Spalding	0.51	880.00	2005	3.81	NTS	No	-
Sutton Bridge	0.50	800.00	1998	3.59	NTS	No	-
			Subtotal:	**76.43**			

2.8.2 Future distillate backup at power stations

Table 15 below shows that of the nine committed CCGTs in GB only two are proposing distillate backup, of which one is an extension to an existing CCGT situated next to an oil refinery and the other also provides local electricity black-start services.

Table 15 – Proposed CCGT distillate backup in GB

Name	Efficency	Capacity (MW)	Commission	Gas use (mcm/day)	Gas connection	Oil back-up	Days Oil Storage Capacity
Immingham CHP 2	0.49	450.00	2011	2.04	NTS/Theddlethorpe	Yes	Not available
Langage	0.51	885.00	2009	3.86	NTS	Yes	Not available
Carrington	0.52	860.00	2013	3.65	NTS	No	-
Marchwood	0.51	842.00	2010	3.64	NTS	No	-
Pembroke	0.52	2,000.00	2015	8.55	NTS	No	-
Severn Power (DONG)	0.52	800.00	2011	3.44	NTS	No	-
Staythorpe	0.51	1,600.00	2011	6.92	NTS	No	-
West Burton CCGT	0.52	1,200.00	2011	5.16	NTS	No	-
Grain	0.49	1,275.00	2010	5.78	NTS	N/A	-
			Subtotal:	**112.20**			

2.8.3 NTS interruptible transportation changes

Modification (Mod) 0195AV to the Uniform Network Code (UNC), will introduce a new transportation regime for exit capacity from the NTS from October 2012. This introduces a new ‘off peak’ transportation product, largely designed to replace the current interruptible product. However, the new product has to be bid for in an auction process on a daily basis, at the day ahead stage, and NGG has some discretion on the levels made available to the market on a daily basis. There are a number of issues about the new process:

- The mechanics of applying for the 'firm' product are clearly laid out in Mod 0195AV, but the mechanism for applying for the 'off peak' product still has to be defined;
- Pricing mechanisms are still subject to consultation, but propose that the daily interruptible capacity auctions will have a reserve price set to zero.
- Both firm and interruptible sites will have to pay for the SO and TO exit commodity charges, where as currently NTS interruptible sites don’t have to pay the latter.
- Will NGG offer contracts to buy-back firm capacity?
- Capacity remains on a nodal basis, although there has been speculation that it may change to a zonal basis at some time in the future.

The process for obtaining the new ‘off peak’ product is currently considered to be more risky, complex and time intensive than the present interruptible product (which has guaranteed availability and pricing discount). It could be expected that NTS sites that have interruptible transportation at present and who have the option of converting under Mod 195AV to convert to firm transportation in the new regime will do so, with the consequence that they will decommission their backup capability, and once it has been removed it will prove very hard to reinstate.

Also many older CCGTs that have distillate backup may be decommissioned over the next 15 years as they become less competitive and need to upgrade due to environmental legislation.

Table 13 and Table 15 indicate that there is potentially over 40mcm/d of demand from gas fired generation that could potentially be switched to oil. However, for the reasons mentioned above, including decommissioning, we have taken a more conservative position, with 24 mcm/d of distillate power generation being available from 2010 onwards.

2.8.4 Distillate cost

These will cover tanks, bunds, delivery facilities and fire protection, estimates of which have been provided in Section 3.3.1.1. This gives a cost of £313/tonne, equivalent to around 74p/th. We then factor in the reduced efficiency, shut-down time to switch between fuels and increased maintenance costs of running on distillate, which means that there would only be worth switching when the gas price is in excess of about 90p/th.

2.9 Industrial & commercial interruptible load

In addition to the CCGT distillate backup potential discussed in Section 2.8 the other source of interruptible load is predominantly from industrial and commercial sites.

2.9.1 DN connected I&C interruptible sites

The largest sites connected to the Distribution Networks (DNs) include a few CCGT stations (Derwent, Barry and Fawley Cogen, as indicated in Table 13). However, the bulk of these are industrial and commercial sites, which have been interruptible for many years. The majority of this load is used for steam raising for process and heating purposes in large boiler plant, and this plant is most amenable to dual fuel firing. These sites have traditionally almost always had backup capability with distillate for their boiler plant, and hence the value of lost load (VOLL) is the cost of this fuel.

It is important to note that where gas is used directly in process applications, such as furnaces, metal smelting, heat treatment, ceramics firing, etc, there are practical and technical difficulties to convert to duel fuel. This means that for a process load site, VOLL is always the cost of loss of production and is in general very high in comparison to historical gas prices; there are very few sites where interruption would be economically viable.

There has been much debate in the industry about the development of additional demand side response products to encourage smaller DN connected sites to provide such a service, but success has been very limited. The reasons for this include:

- for medium and smaller sites, the perceived value of the fuel switching upside has simply not been great enough to encourage DN sites to take part; and
- sites cannot contract to provide this product directly either to NGG or the DN Operator (DNO), but must do it through their suppliers. This makes the process much more cumbersome, particularly in a competitive environment where the site might change its supplier every year.

2.9.2 Current I&C interruptible capacity position

There are currently about 1200 customers on the DNs with interruptible transportation. It has been difficult to find out exactly what interruptible capacity this amounts to since this does not seem to appear in any of the Mod 90 consultations, nor in the TYS, nor in the DNO Long Term Development Statements. However, the 2008 TYS does state that there were 86 TWh of gas used by interruptible consumers in 2007 (out of a total of 623 TWh). We have assumed that the interruptible sites continue to operate at their historical load factor of about 60%, which gives a maximum daily interruptible gas capacity of about 390GWh/d (about 36mcm/d).

2.9.3 I&C interruptible transportation changes

However, the commercial regime for these DN connected sites has recently changed with the introduction of UNC modification (Mod) 90. This removes the interruptible status of all sites from October 2011, and hence their rights to discounted transportation charges (I&C interruptible sites previously did not pay either NTS or LDZ Exit Capacity charges). Mod 90 introduces a new ‘universal firm’ regime on the DNs, but does provide for a mechanism whereby the DNOs could specify their interruption requirements in each zone of their DN areas, and then provides for an annual auction mechanism whereby the sites could bid in their interruption capability in annual blocks from October 2011 onwards.

So whilst the transportation interruption status and physical constraints are being removed the contribution I&C interruptible sites make to demand side insurance mentioned in Section 2.7 is not being replaced. This reduction in available demand side response from interruptible consumers will have an impact on security of supply and may make it more likely that emergency actions will be called into play earlier than otherwise might have been the position before these changes, unless new mechanisms are forthcoming to provide additional peak supply or a demand side insurance incentive.

2.9.4 I&C interruption capacity changes

The result of the 2008 auctions for 2011/12 was a stated DN interruption requirement of 252GWh/d (23mcm/d) but with only 13GWh/d (1.2mcm/d) contracted. Of the original 1200 sites about 200 participated with only 27 bids accepted.

The 2009 auctions stated a DN interruption requirement of 77.6GWh/d (7.2mcm/d) for 2012/13 but with only 7.1GWh/d (0.66mcm/d) contracted. The consequence of this had been a commitment from the DNOs to make new reinforcement investments to remove transportation constraints before the new regime starts in 2011 and all are reporting they remain on track to deliver these on time.

Many sites that have interruptible transportation at present are considering moving to firm transportation in the new regime and consequently decommissioning their backup capability, and once it has been removed it will prove very hard to reinstate.

So, of the current 36mcm/d of I&C interruptible capacity the future requirement for 2012/13 has been reduced by 80% and only 2% of current levels has been contracted for. However, not all these sites will decommission their backup facilities as the risk associated with any firm load shedding from a gas supply emergency may be too high when compared to the capital expenditure from any damage to processing plant or disruption to the company’s product sales. Thus we have assumed that 72% of current backup facilities will be decommissioned and that the equivalent of 10mcm/day will by available for demand side response.

It will be important that the actual level of interruption available to meet supply and demand balancing over and above that contracted for transportation needs is kept under review as shippers and sites negotiate new contracts for October 2011 onwards. It is not clear that I&C interruptible consumers are fully aware of the extra costs they will face when being offered ‘firm’ supplies and it is likely that will recover some of this be decommissioning their current backup capability.

We have used a price of 200p/th, which corresponds approximately to historical highs in the GB NBP day-ahead price[21], as the point where I&C interruptible load would voluntarily switch to alternative/backup fuel or undertake other measures to cease burning natural gas.

2.10 Economic impact of unserved energy

Previous analysis undertaken by Pöyry Energy Consulting[22] (an approach that was then used in subsequent analysis by Oxera[23]) sought to estimate the economic costs of unserved energy. We have replicated parts of the analysis, updating the data from the latest Office of National Statistics (ONS) and Digest of UK Energy Statistics (DUKES) sources as appropriate.

Within this analysis, it is assumed that the loss of Gross Value Added[24] (GVA) provides a proxy for the effect of unserved energy – i.e. the economic impact of a loss of load. This is the approach previously used by Pöyry and Oxera. The main features of this approach are that:

- interruptions are assumed to follow a ranking of industries by GVA/mcm (adjusted so that energy intensive industries are interrupted first); and
- indirect or knock-on effects on upstream and downstream industries are also included.

Figure 14 overleaf shows the analysis. We have also included an adaptation of the original Pöyry analysis undertaken in 2006 as a comparator in Figure 15, which shows similar patterns of increasing impact and overall effects broadly reflective of inflation. The charts show that even for modest losses of firm load, measured in tens of mcm/d, there are some significant impacts to the economy, measured in hundreds of £m/day.

The analysis assumes a simple, proportionate relationship between gas use in a sector and its GVA potential, with similar relationships across the supply chain. In general, these estimates are likely to represent an upper bound on the GVA impact as they do not account for the impact of stocks or flexibility in delivery profile that may mitigate some of these effects. The analysis does not account for the consequential reduction of electricity demand and therefore gas-fired generation. However, the GVA analysis does give an indication of the orders of magnitude involved when there is an involuntary curtailment of supplies.

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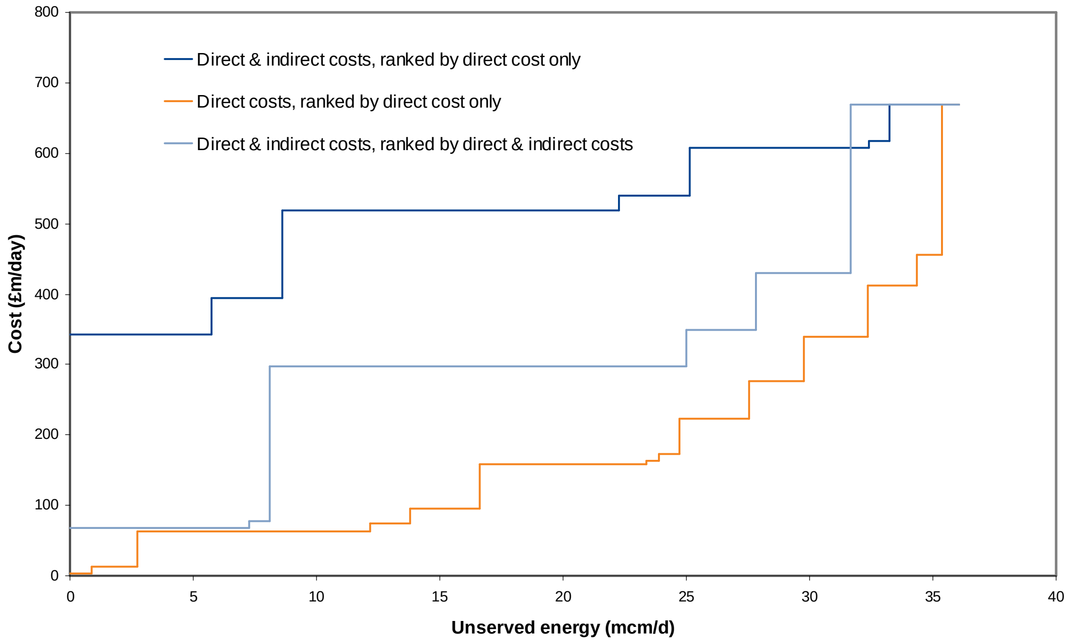
21 On 13 March 2006 the day-ahead price rose to 195p/th.

22 'Strategic storage and other options to ensure long-term gas security'; ILEX, 2006 http://www.berr.gov.uk/files/file31788.pdf

23 'An assessment of the potential measures to improve gas security of supply'; Oxera, 2007 http://www.berr.gov.uk/files/file38980.pdf

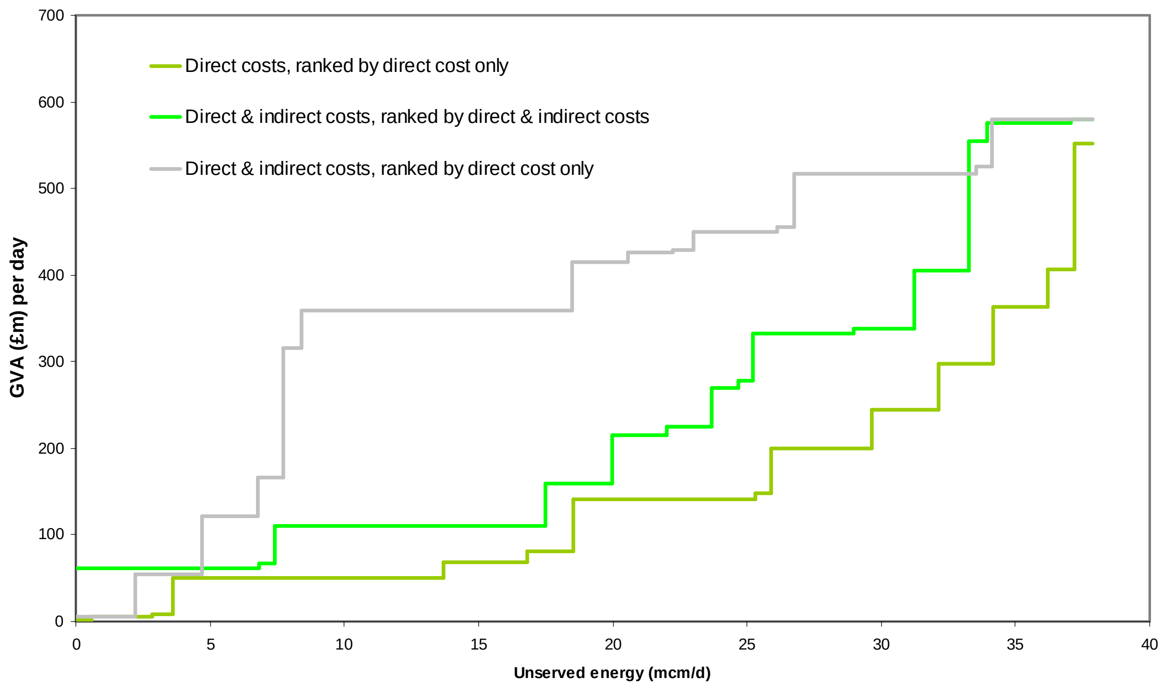
24 ONS definition: GVA (value of goods and services less the value of the products used to make them) + taxes on products – subsidies on products = Gross Domestic Product. GVA is therefore a measure of the commercial value added to the whole economy.

Figure 14 – Updated GVA impact of demand curtailment



Source: Pöyry Energy Consulting from ONS and DUKES; costs shown are at 2007 prices.

Figure 15 – Original GVA impact of demand curtailment



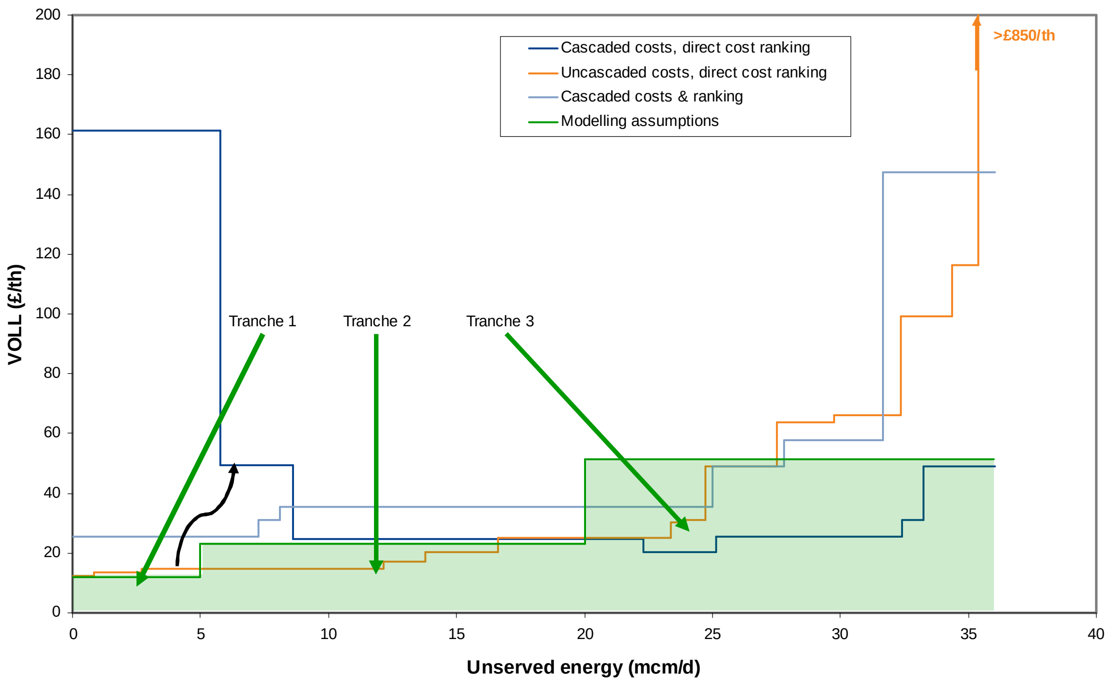
Source: adapted from Ilex Energy Consulting after ONS, DUKES (2006); costs shown are at 2004 prices.

From the work examining Gross Value Added (GVA) and distillate and interruptible capabilities in Sections 2.8 and 2.9, we have generated raw prices that represent the GVA created by gas consumption for each sector, as shown in Figure 16. We have converted GVA figures into a value of lost load (VOLL) for ease of comparison with historical gas prices.

The orange line shows the direct VOLL for each industry, ranked by each industry's individual energy intensity – it does not consider the consequential impact on related industries. The dark blue line shows the actual VOLL that might be expected if the individual energy intensity ranking is followed, and the light blue line shows the VOLL that might be expected if aggregate intensity rankings are followed.

Figure 16 also shows the modelling assumptions for the prices at which we would expect to see unserved energy, identified as the green line/area. We have assumed three separate tranches – broadly in line with the above VOLL considerations – though recognising the potential for efficiencies to be discovered during any gas supply curtailment. These unserved energy tranches are included with the CCGT and I&C interruptible backup fuel prices the summary Table 12 on page 35.

Figure 16 – Unserved energy analysis and assumptions



Source: Pöyry Energy Consulting after GI, ONS and DUKES

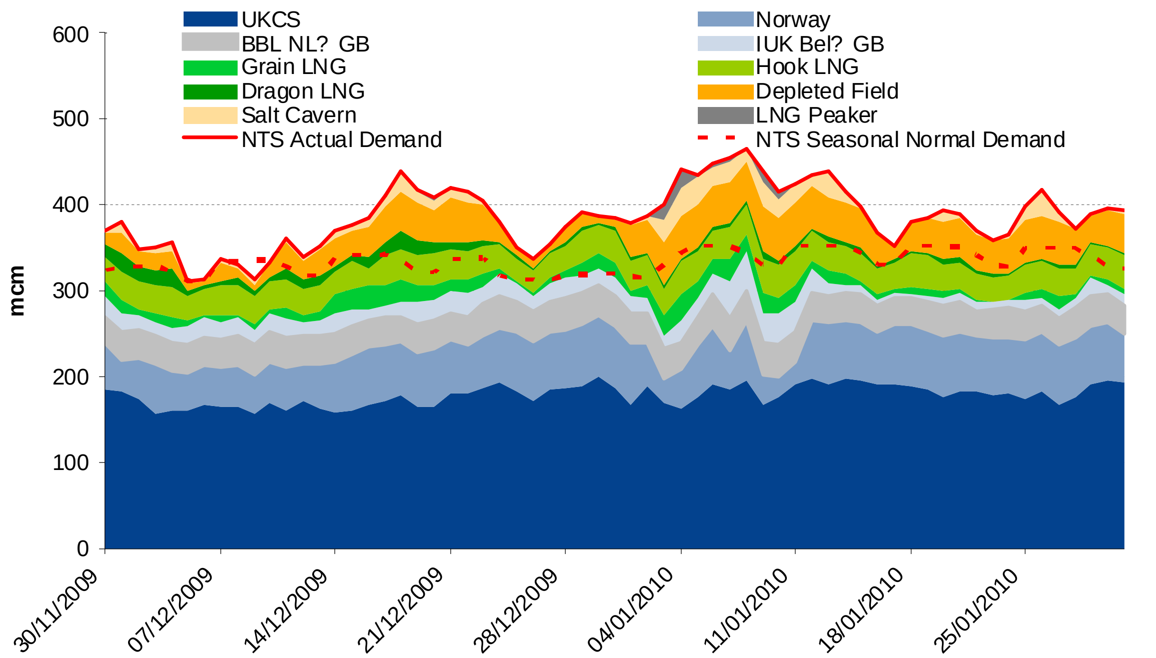
2.11 January 2010 review

Since the study analysis was completed GB has experienced a very cold period during December 2009 and January 2010, with the week beginning 4 January 2010 having 7 out of 16 coldest days in the last 14 years.

Despite the press headlines of major gas shortages, the GB gas market reacted as planned and without any major volume or price disruption. As shown in Figure 17 there was sufficient supply to meet demand, although it is worth noting the following points:

- GBAs were issued for gas days 4, 7, 9 and 11 January 2010, due to Norwegian supply disruptions and linked to very high demand, but expired at the end of the day as more than adequate supplies were forthcoming from alternative supplies.
- Record demand of 465mcm/d occurred on 8 January, which is 35% higher than seasonal norms.
- Despite there being no long term fixed destination contracts into GB, LNG provided significant volumes over the whole period requiring regular delivery of cargoes. This capability will further expand with the forthcoming completion of South Hook phase 2 and Isle of Grain phase III in 2010.
- National Grid DNOs (East Anglia, East Midlands and North West) undertook both localised constraint and volume interruption for 7 I&C interruptible consumers on 4 January rising to 107 on 7 January and with all supply returned on 10 January[25]. On 7 January 2010 they interrupted 4.15mcm/d which compares with the 0.4mcm/d they have contracted for in 2011/12.
- 80mcm of LNG peak storage was used during January 2010.

Figure 17 – GB gas supply & demand in December 2009 & January 2010



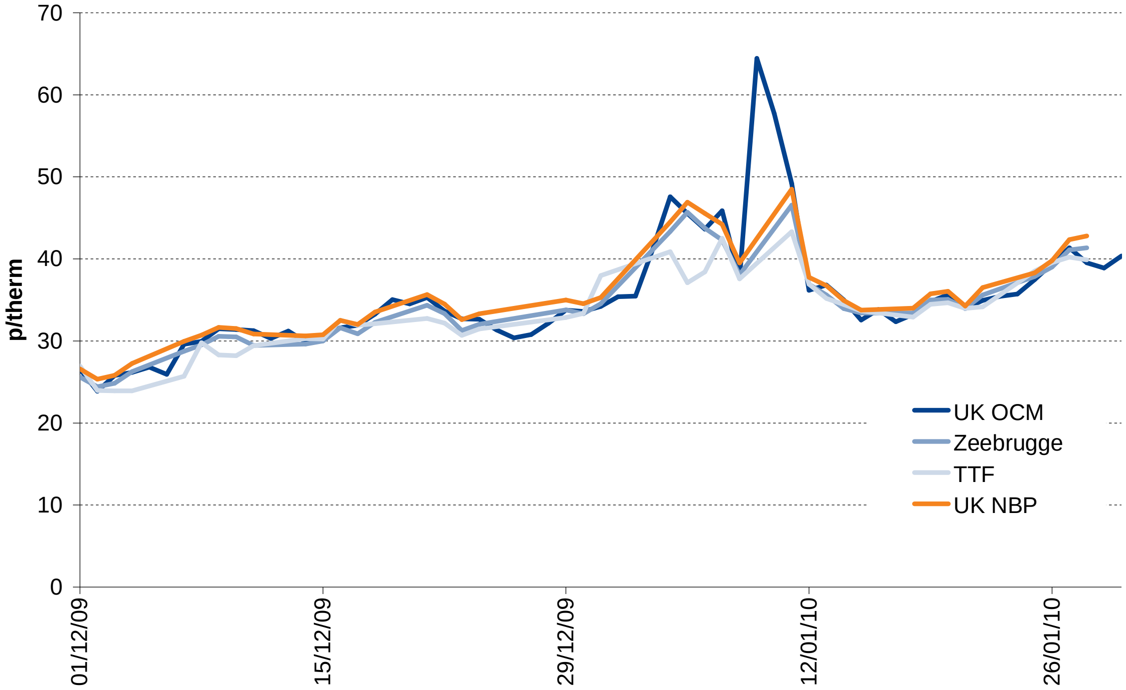
Source: Pöyry analysis of National Grid data

Market prices, as shown in Figure 18, underline the points raised in Section 2.5 that GB is a sufficiently attractive market for both pipeline and LNG imports. Although there was a

25 National Grid presentation to GCF on 25 January 2010.

very brief price spike in early January, NBP prices remained in line with continental spot markets. This also supports the findings in Section 2.3 and 2.4 that Europe currently has more than sufficient gas supply and storage.

Figure 18 – Market prices in December 2009 & January 2010



Source: Pöyry analysis of Platts data

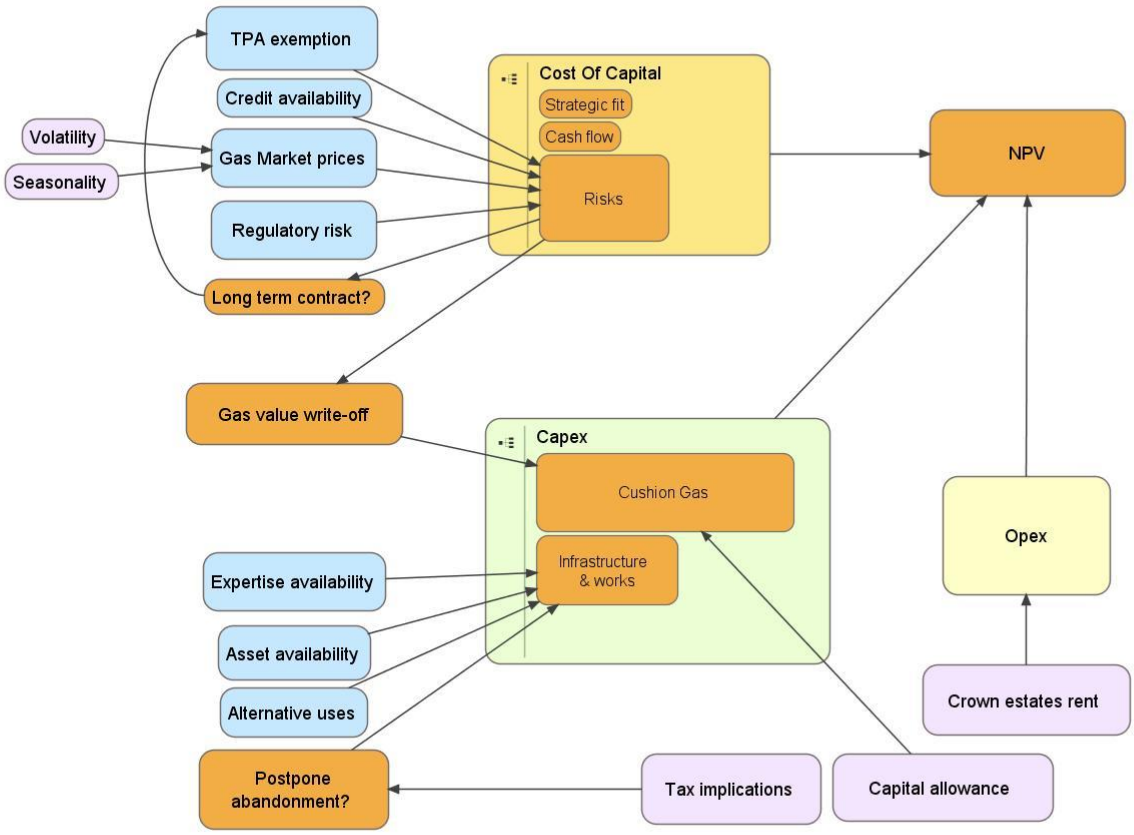
3. INVESTMENT DRIVERS AND BARRIERS

This section explores the main drivers behind investment decisions, based upon Pöyry's assumptions formed from historical data. A look is also taken at the main stages in constructing a storage facility, with the attendant issues and milestones inherent in doing so. In addition to this, the section also looks at the barriers that exist both now and into the future for creating additional investment within storage, distillate backup and demand side response. These barriers encompass environmental, financial, practical and technical issues, and where possible we have used examples based upon existing plant for clarity.

3.1 Infrastructure investment Drivers

Infrastructure projects will likely receive financial approval to proceed provided the project economics and free cash flows show a positive return against the company's cost of capital and against a range of risk sensitivities. These are summarised in Figure 19.

Figure 19 – Summary of investment drivers and risks



3.1.1 Cost drivers and barriers

There are two main cost types: capital expenditure ('capex') and operating expenditure ('opex'). The former relates to the costs of physical equipment and services during the construction phase and any major plant refurbishments during the lifetime of an asset. The latter relates to the on-going costs of running the facility such as staff, minor maintenance, and consumables, including any gas compression costs.

3.1.1.1 Capex

Key influences for capex will include the planning application process and imposed constraints, lead time for development, expected asset life, any new technical innovation being used, need for cushion gas in gas storage facilities, brine disposal method for salt cavities, complexity of the supply chain, expected abandonment costs, and environmental impact assessment and mitigations. The barriers that will influence the level of capex will include:

- the planning process and the level of uncertainty it introduces for project developers;
- supply chain and limited number of key equipment suppliers e.g. there are only four main CCGT suppliers around the world and only two offshore wind turbine manufacturers;
- new technology will increasing the risk of construction delays;
- the level of capital allowance that can be claimed for different capital items;
- tax treatment for future expenditure, such as abandonment provisions; and
- environmental restrictions either from regulatory or planning obligations e.g. limitations on brine disposal when leaching salt cavities.

3.1.1.2 Opex

The main drivers here will be the asset life and its availability. This will influence how much maintenance will be required and to what extent major capital items will need to be replaced during the full asset lifecycle. The barriers that will influence the level of opex will include:

- lack of available skilled staff;
- gas costs for compressor running;
- fees, if required, to the Crown Estates;
- environmental restrictions, such as noise levels and emission limits; and
- health and safety hazards, such as dangerous and flammable materials.

3.1.2 Revenue drivers and barriers

Revenues for gas facilities will come from the selling price for the gas, either into a spot market, traded exchange or through long-term contracts and the asset availability. For storage facilities providing swing to gas suppliers with flat supply profiles the revenue drivers will be the seasonal winter-summer spread and the amount of daily and within-day volatility. The more flexible the facility the more it is able to capture revenues from the latter and the greater the amount of space available the more it can capture the former.

The main barrier will be if the market mechanisms fail to provide the correct or sufficient pricing signals for both the seasonal spread and the volatility. Long-term contracts provide a hedge against such a situation, which is why they are often required to underpin investment in major new infrastructure developments. For example the gas contracts signed by Centrica assisted in underpinning the required investment in the Langeled and

BBL import pipelines from Norway and the Netherlands respectively. They are also normally required when new gas liquefaction trains are built.

3.1.3 Project hurdle rate

When discounting future cash flows the project will need to pass a hurdle rate which is determined initially by the cost of capital for the company. It is then modified to reflect the risks or benefits associated with the project.

Drivers that will improve a project's position will include whether it is able to obtain an exemption to Third Party Access[26] ('TPA') or whether the company is investing in a certain geography or market for strategic reasons. Hurdle rates will also be better if the company has the expertise, competence, and experience of developing and operating similar facilities.

Barriers that will impact a project hurdle rate will include the cost of financing the investment, whether that is because of a low credit rating of the company or because of a lack of available credit, especially since the recent credit crunch. Another barrier can be on the regulatory regime and its expectations on the cost of capital for such a project. For example in some countries storage is treated as being a 'utility service' and will have a typical cost of capital c.5-7% where in other more market orientated regulatory regimes storage may be seen as a commercial venture with higher cost of capital of greater than 10-15%.

3.2 Gas storage investment

Gas storage will be developed to provide a service to gas suppliers that cannot readily be provided by alternative means or where it is the cheapest of various options.

Gas suppliers in Great Britain have to balance their supply with their customers' demand on a daily basis, and face imbalance charges which provide a financial incentive to achieve this balanced position.

Typically, gas storage has been developed to meet long-range, medium-range and short-range flexibility requirements.

Long-range storage has been developed to provide large scale infrastructure that allows gas to be stored in the summer for use in the winter. With demand higher in the winter to reflect consumers' space heating needs the gas supply also needs to be higher in the winter than the summer. However, many gas supplies can only provide gas on a flat even supply across the year. Long-range storage allows the suppliers to still meet their daily balancing obligations without having to pay additional costs for 'swing' from the actual gas supply. The difference between winter and summer gas prices is a key driver in setting the value of long-range storage. Depleted gas fields have typically provided this type of gas storage.

Medium-range storage is there to provide a more flexible service. It has faster injection and withdrawal rates than for long-range storage. This helps suppliers handle large demand variations driven by weather variation over a number of days, as well as within-day demand variation, as the demand volatility will feed into spot gas prices which can in-turn be mitigated through the use of medium-range storage. Salt cavity storage has

[26] Some regulatory regimes require infrastructure providers to provide access to other parties through Third Party Access rights.

typically provided medium-range storage in the GB market, but is usually smaller than depleted field storage and more expensive per unit of storage.

Short-range storage is there to provide very large quantities over a very short timeframe. It has traditionally been used in the GB market to provide emergency safeguards, and commercially as an insurance against a few days' worth of very high prices.

In even shorter timescales both line-pack[27] within the higher pressure gas networks, and local diurnal storage 'gas holders' within a local distribution network might be considered as another form of gas storage, however they are very short lived, and primarily considered as a within-day tool for the use of the network operators.

Gas storage projects may also provide a benefit to suppliers if they are located at key hub points. In GB this is not a significant factor as the NBP covers the whole of GB, but at physical hubs such as the CEGH at Baumgarten it provides critical flexibility for trades.

Alternatives to gas storage include: swing production from gas fields; LNG imports from the global LNG market; and demand reductions from interruptible agreements (i.e. DSR). The development of storage has to be measured against the ability and efficiency of the alternatives to provide the level of flexibility required by the market.

3.2.1 Phases of a gas storage project

To track the development of storage projects we will describe the different development phases in terms of what approvals/decisions have been taken, as shown in Figure 20.

3.2.1.1 Conceptual phase

A perception of need for storage usually grows from observations regarding physical supply and demand balance, price seasonality and/or price volatility. The significant number of planned GB storage projects shown in Table 3 on page 17 might, for example, stem from the observation of UKCS decline coupled with stationary or growing demand. The developmental opportunity of a storage facility relies to a large extent on the geological potential of proposed sites (in GB this is predominantly depleted fields or salt strata). The concept of a storage project results from these initial conditions.

The high-level engineering and initial design of the storage facility is considered, producing both estimation of the total project cost and possible storage performance characteristics (injection and withdrawal rates). Land and access negotiations (if necessary) are concluded, such that formal Environmental Impact Assessments can be undertaken. During the conceptual phase an application for planning permission will be made to the appropriate authority. Before the project can move on to the construction phase two critical milestones must both be passed:

- the project must receive approval from the planning authority; and
- a final investment decision (FID) must be made to commit capital to the project.

A project with planning approval is more likely to eventually be built. However, it is not until the FID has been taken that we can be confident of a project being delivered. As we can see in a number of examples in Section 3.2.2, obtaining planning approval can be a very length and costly process, and can lead to significant project delays.

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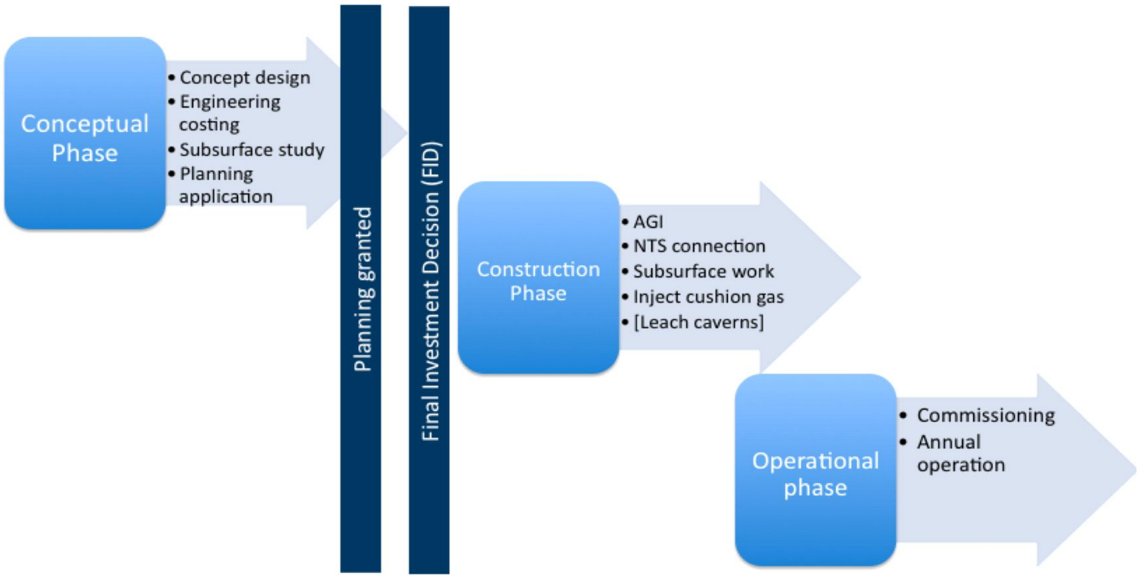
27 A volume of gas contained within a pipeline by virtue of the fact that the gas is under pressure.

Figure 20 – Phases in the development of a storage project



3.2.1.2 Construction and operation phases

During the construction phase, work begins on site to install machinery, connect the necessary services including a connection to the relevant transportation network (usually the NTS), carry out subsurface work, leach the caverns (for salt cavern storage) and inject the cushion gas.

The operational phase will begin towards the end of the construction phase (but not necessarily at the very end) with the commissioning of the facility. The available storage capacity may increase over a period of time, for example as more caverns are leached. Once the full operational capacity is available the construction phase will cease and the operational phase will continue for the life of the project.

Some projects will subsequently be expanded and, to the extent that the permissions and services in the initial project are sufficient for the expansion, the development of a second stage or an enhancement to a project can be relatively quick compared to the development times for the original project.

3.2.2 Examples of storage projects

Table 16 below gives a list of the storage projects that were listed in the TYS published in 2005. The table then gives the status of the same projects as reported in the 2008 TYS. The project status is classified according to the phases shown in Figure 20: that is a project is conceptual until it has been granted planning permission[28]. Table 16 gives the dates at which planning permission was granted.

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28 In the 2008 TYS, National Grid separately identifies those conceptual projects that are awaiting a planning decision i.e. planning potentially imminent. Given the uncertainty of the planning process (a project may have its application refused) we only show when a project has planning approved.

Table 16 – Storage Projects in Ten Year Statements

Project	Planning Granted	TYS 2005 Status[1]	Projected operation date 2005	TYS 2008 Status[1]	Projected operation date 2008	Slippage
Aldbrough	Feb 2000	Construction	2007/08	Construction	2008/09	1+ years
Holford	May 2004	Awaiting FID	2008/09	Construction	2010/11	2 years
Stublach	Jun 2006	Conceptual	2009	Construction	2013/14	4 years
Caythorpe	Feb 2008	Conceptual	2007	Construction	2011/12	4 years
Portland	May 2008	Conceptual	2008	Awaiting FID		>4 years
Albury I		Conceptual	2008/09	Conceptual		>4 years
Saltfleetby		Conceptual	2009	Conceptual		>4 years
Albury II		Conceptual	2010	Conceptual		>3 years
Fleetwood		Conceptual	2009/10	Conceptual		>4 years
Welton		Conceptual	2008/09	Conceptual		> 4 years
Bletchingley		Conceptual	2009	Not listed		-

1. Status based on the terminology shown in Figure 1

Source: National Grid Ten Year Statements 2005 and 2008

The most noticeable feature of the projects listed in Table 16 is that by 2008 none of the projects had met the timescales quoted in 2005. Instead, of the eleven projects listed in 2005:

- one already under construction in 2005 had slipped by a year;
- one with planning permission but awaiting a final investment decision in 2005 was now under construction but had slipped by two years;
- two projects that subsequently obtained planning permission had moved to the construction phase but the timescales had slipped by 4 years (and since the TYS 2008, Caythorpe has returned to awaiting final investment decision[29]);
- one project had obtained planning in 2008 but was awaiting a final investment decision due to the credit crunch and lack of available credit; and
- of the remaining six projects five had not yet received planning and one was no longer listed as a project.

In every case the development times anticipated in 2005 proved to be overly optimistic.

The planning application process can be protracted. For example, Caythorpe submitted a planning application in December 2005, had its application refused by the Local Authority in June 2006; a public enquiry took place in April 2007, and it was finally approved February 2008. Other projects have been unsuccessful in getting planning approval. For example, Welton submitted in November 2003 and had planning refused by the Local

29 Centrica presentation to analysts, 9 December 2009 – status awaiting FID, due in Q3 2010

Authority in February 2006. We also note the process being followed by the Fleetwood proposal, which has resubmitted a planning application following a failed appeal to the Secretary of State.

The main barrier to the prompt development of storage facilities appears to be planning delays. This has been addressed in the past year with the new strategic planning process and it remains to be seen how this will improve the situation. We have also seen financing as a barrier recently. In the future, potential barriers may include the risk of diminished revenues due to over capacity of flexibility from storage, LNG and interconnection, with reduced gas demand due to efficiency improvements and more renewables. However, more renewables could lead to more volatility and greater need for short- and medium-term storage.

3.3 Distillate backup investment

The drivers for investing in distillate backup will vary depending on whether this is being considered for new plant or as retrofitting at an existing station. In this section we consider both situations.

3.3.1 New gas fired power station

The issues for a new gas fired CCGT when considering whether to install distillate back up capability can be divided into the following:

3.3.1.1 Cost of installation

The cost of distillate includes three main elements, the wholesale price, the cost of delivery and duty. The current price of distillate is about $500/tonne[30] CIF North West Europe for prompt delivery, or about £313/tonne at £1=$1.60. To this must be added transport and duty costs. We estimates that transport by rail from a refinery to be in the order of £10/tonne. With regard to duty, on 1 December 2005 the government announced a 100% rebate on distillate used for power generation, such that the duty is now zero. The total delivered cost to fill two 5000 m^3 tanks (or 8,400 tonnes) is therefore in the region of £2.7 million.

We have assumed costs for a 10,000 m3 'module' of distillate storage with a single rail delivery siding adjacent to a Network Rail line, with a single fire protection system. We have then multiplied this up to give indicative costs for higher volumes of storage. Clearly this is a simplified approach, since there will be economies of scale for both bunding and tanks. However, bearing in mind the fact that the costs will also be dependent on site conditions, contracting market conditions and other site-specific issues, we still believe that they are a reasonable approximation of the cost of distillate backup. A 400MW 'F' class CCGT module (i.e. a single gas turbine and single steam turbine/HRSG combination) that is often used in GB will burn approximately 1500 tonnes per day at 50% efficiency.

3.3.1.2 Transportation issues

In considering distillate as a form of gas security of supply during a severe supply disruption it must be recognised that replenishing stocks at power stations will be a

30 Source: Reuters 'ICE GAS OIL Future Front Month Continuation' – average from January to October 2009

significant logistic exercise and the volumes required will place a substantial strain on the existing distillate production capacity and distribution network.

Using figures from DUKES[31], UK production of distillate is about 26 million tonnes a year, with another 8 million tonnes imported, and about 6 million tonnes exported, leaving a net UK capacity of about 27 million tonnes. Current stock levels are about 3 million tonnes.

Of this 27 million tonnes, about 21 million tonnes is used in motor vehicles as diesel (DERV), about 3 million tonnes in industry (including power generation), and the rest for other uses including domestic heating, railways etc.

A key practical problem is the white/red issue, with motor duty exempt gasoil dyed red, which means that generally tankers are used for one or the other, but not both, as it is a very difficult job to clean out a gasoil tanker for use as a DERV tanker.

We estimate that a 400MW CCGT module will consume about 1500 tonnes a day at full load, so with about 5.4GW of plant with distillate backup, this will require about 20,000 tonnes a day to refill, which compares to the current supply of red gasoil of about 8,000 tonnes a day, and the total supply of gasoil/DERV combined of about 70,000 tonnes a day. For a prolonged outage, and taking the worst case scenario of all stations being supplied by road, Pöyry estimates that about one third of GB distillate tanker fleet would be needed, and probably a higher proportion of the drivers.

From data made available to Pöyry, the mean storage capacity at power stations is about 8 days of consumption, or a total of about 160,000 tonnes. To fill this 5 times a year will therefore require 800,000 tonnes of gasoil. This volume needs to be seen in the context of the total volume of UK consumption of distillate of about 27 million tonnes a year, and also in the context that there is a highly liquid market for this product at the North West Europe, Amsterdam/Rotterdam/Antwerp (ARA) hub. UK prices are in fact NWE ARA prices, and in effect distillate is sourced as a product in a Europe wide market of about 200 million tonnes per year. As an example of the liquidity of this market, the ICE futures market for NWE ARA distillate trades about 100,000 tonnes a day for prompt delivery. In our opinion therefore, this additional volume of distillate could be sourced without difficulty in the current distillate market.

An additional problem for generators is the summer/winter issue, because distillate is not generally treated with anti-waxing chemicals in the summer, and therefore it is very risky for a generator to buy since, if it is not burnt before the winter, it will freeze in the tanks when the temperature gets low and when it is needed. Alternatively it will need to pay the additional costs associated with adding the anti-waxing chemicals.

Taking all of the above into account the total distillate backup costs have been summarised into Table 17 overleaf.

[31] www.berr.gov.uk/energy/statistics/publications/dukes/page45537.html

Table 17 – Costs for higher volumes for a 400MW CCGT

Oil Storage (m^3)	Days	Tanks	Distillate	Bund	Fire/Siding	Total (millions)
10,000	0	£1,100,000	Zero	£300,000	£400,000	£1.8
10,000	6	£1,100,000	£2,700,000	£300,000	£400,000	£4.5
50,000	30	£5,500,000	£13,500,000	£1,300,000	£700,000	£21
150,000	90	£15,000,000	£40,600,000	£4,000,000	£1,000,000	£60.6

3.3.1.3 Gas transportation charges

In the early 1990s, British Gas Transco (now National Grid Gas) operated a 'deep connection policy' where any new connection to the network that required firm capacity would be required to pay for all the investment necessary to support its load on the network as an upfront, capital lump-sum. Most of the CCGTs at the time opted for interruptible capacity which avoided the liability for these costs (it was cheaper for them to invest in backup facilities and hold the appropriate stocks), and lowered ongoing transportation charges. In the late 1990s, the policy changed to a 'shallow connection policy' where the investment recharge was calculated to cover only local investment (deeper system investment was absorbed into Transco's general cost base), although the discounted transportation charges remained. The decreased transportation charges alone were not sufficient to maintain the incentive to invest in backup facilities, so most CCGTs built in the second 'dash for gas' had firm connections.

NTS-connected interruptible sites currently benefit from cheaper transportation charges, although this will likely change following the approval of Mod 0195AV, as described in Section 2.8. This modification means there is less incentives for new CCGTs to invest in backup capability, so we consider that there will be very little or no investment in backup capability, unless electricity incentives for a range of auxiliary services are required at either the local level or for national security of supply.

3.3.1.4 Gas/Distillate arbitrage

The installation of distillate capability clearly enables the operator to benefit when gas prices are higher than equivalent distillate prices, and there is still a positive electricity/fuel spread. This will also depend on the accounting system used by the operator to price the distillate, and the level of storage. This is because the price of distillate will tend to be linked to that of gas, and if the distillate is priced at replacement cost, rather than actual cost, then the electricity/fuel spread value will of course be reduced. This effect is limited the greater the storage level, and therefore the greater the flexibility the operator has to choose the time (and hence price) at which the tanks are refilled.

This is further affected by the fact that distillate is supplied in bulk either in 'winter grade' or 'summer grade' depending on the time of year that it is produced and delivered. This in turn means that the ability of a station to refill the tanks in the summer, when prices are generally lowest is limited due to the risk of 'waxing' in the winter.

Historically, there have been very few days over the past 10 years or more that gas has been more expensive than distillate, so this would not normally be a key factor in deciding to build distillate tanks.

3.3.1.5 Reduced efficiency

All CCGTs in GB are designed to fire on natural gas as the primary fuel. This means that the Heat Recovery Steam Generators (HRSGs) are optimised for gas firing such that the design exhaust temperature from the HRSG into the stack is minimised, while maintaining sufficient stack buoyancy. When firing on distillate, there is a risk that the flue products will condense in the stack leading to corrosion as a result of the fact that distillate contains sulphur, such that it is usual practice to run the HRSG with the final feed heater section isolated. This therefore increases the exhaust temperature from the HRSG to minimise condensation risk, but at the penalty of reduced HRSG efficiency. This reduction is in the order of 2% of overall cycle efficiency. Clearly this reduction will need to be taken into account in the calculation of any potential gas/distillate arbitrage upside above.

3.3.1.6 Electricity imbalance risk

It is our understanding that the reliability of gas turbines, and in particular the higher efficiency ‘F’ class machines, is lower on distillate than on gas. This means that there is a higher tripping risk, and therefore a higher imbalance risk. Bearing in mind that distillate is likely to be burned when both the gas and electricity systems are under stress, the electricity imbalance cash out price is likely to be high, and therefore this risk significant.

3.3.1.7 Practical issues

The primary practical issues to tackle are to ensure that there is sufficient land available for the distillate tankage and bunding, and there is a suitable delivery mechanism. The land issues can be very significant if large volumes of distillate are envisaged to provide a prolonged backup capability prior to further deliveries being organised. It is our view that road tanker delivery is impractical in most circumstances, due to the inability to source large numbers of tankers and drivers in the event of a prolonged distillate requirement. This means that the site must be adjacent to: a large distillate facility, such as a refinery or storage depot; a rail line or siding; or a suitable river, canal or coastal facility.

3.3.1.8 Environmental Issues

There are significant regulatory and environmental issues involved with the storage and burning of distillate. The Control of Major Accident Hazards Regulations 1999 (as amended by the Control of Major Accident Hazards (Amendment) Regulations 2005) (COMAH) lay out the safety systems required for large hazardous industrial sites. Although it applies mainly to the chemical industry, it also applies to other industries where certain threshold quantities of dangerous substances are stored. It therefore applies to power station sites that store distillate in quantities in excess of 2500 tonnes, which therefore includes virtually all oil backup facilities at CCGTs. Another important feature of COMAH is that it lays out two levels of hazard management systems required, depending on the amount of the hazardous substance stored, ‘lower tier (LT)’ and ‘top tier (TT)’. The regulatory requirements for top tier are obviously much more onerous than for lower tier, and are triggered at storage levels above 25,000 tonnes. Although all CCGT sites with oil backup are caught by the regulations, they will be in lower tier, since we are not aware that any CCGT site in GB stores more than 25,000 tonnes of distillate. However, if there is to be a significant expansion of storage to meet prolonged gas interruptions, then the site will become top tier, with a significantly increased regulatory and hence cost burden on the site.

3.3.1.9 Technical issues

It is our understanding that virtually all new CCGT installations under consideration in GB are to be built using 'F' class technology. Most of the existing stations with backup capability use the more established lower temperature 'E' class technology. It is also our understanding that the experience of running on distillate for extended periods of time on models of 'F' class gas turbine is very limited. In addition, there will be an additional maintenance penalty for running on distillate. We also understand that water injection may be required for NOx control while running on distillate, and this will require significant volumes of demineralised water which may not be available without appropriate water treatment plant and storage.

3.3.2 Existing Plant Retrofit Issues

Of the issues raised above, the key ones for an existing plant are likely to be the following:

3.3.2.1 Space

A new site is very likely to have additional space available adjacent to the site for the station itself, since it is unlikely to be constrained precisely to that required. However, an existing site is much less likely to have additional space available for the installation of the tankage and bunding required. Clearly, if the space is not available, then the installation of backup will not be possible.

3.3.2.2 Access to delivery mechanism

Again, a new site will have some flexibility as to its precise location, and hence its proximity to a pipeline connection, a rail connection or a barge terminal. However, this will clearly not be the case for an existing site, and if there are no such connection possibilities, then the installation of distillate backup is in our view impractical due to the difficulties identified with road delivery. For example, the nearest distillate supply for a CCGT power station in Devon is in Southampton, making road delivery and even rail deliveries not feasible because of the distance and poor transport connections.

3.3.2.3 Technical Issues

An existing station is likely to have a lower risk profile for the installation of distillate backup than a new station. This is because it is likely to have older gas turbine technology, which will have been proven over a number of years, and is also likely to have some form of experience running on distillate somewhere in the world. However, there would be significant down time to re-configure the fuel systems.

Indeed, the Institute of Mechanical Engineers has stated that most old 'E' class CCGTs could be retrofitted to run on distillate[32]. They recommend pursuing this strategy in preference to the compulsory installation of dual firing to new CCGT units. The suggestion is that retrofitted old CCGTs could form a standing reserve similar to that provided by current oil firing plants such as Grain and Littlebrook. However, as noted in Section 3.3.2

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32 Institution of Mechanical Engineers, response to consultation into effectiveness of current gas security of supply arrangements, January 2007.

there would be many financial and practical barriers to be overcome in order to achieve such a retrofit.

3.3.2.4 Financial

A number of financial issues that apply to new facilities, (e.g. cost of installation, reduced efficiency, imbalance risk, etc.) apply to retrofitting existing CCGTs.

Overall, we consider it impractical to globally retrofit distillate backup to all existing power stations. However, those that do currently have backup facilities could be encouraged to keep and maintain them, even though Mod 0195AV encourages them to become firm. This increases their transportation costs and reduces the benefit from having backup facilities. As these facilities have ongoing costs many may wish to decommission them.

4. MODELLING GB GAS SECURITY OF SUPPLY

In this section, we aim to quantify any potential shortfall in gas supply in Great Britain, in the timeframe 2010 to 2025 due to low probability, high impact events. We attempt to assess both the annual volume shortfall and the number of days in the year during which the shortfall pertains. This section is largely concerned with likelihood, so for each level of shortfall we attempt to assign a probability of its occurrence.

We need first to define what we mean by 'shortfall', or – another word that we use synonymously – 'gap'. This is the extent to which the market will not meet firm customer demand and is the measure of unserved energy, as defined and discussed in Section 2.10. The shortfall or gap does not include interruption of interruptible consumers provided through alternative fuel backup, nor does it include self-curtailment by gas consumers in response to price, which are included as measures to provide security of supply[33].

We have adopted two approaches to modelling the security of gas supply. Firstly, in a deterministic way, creating low probability scenarios to assess the extent to which GB and other countries would meet the tight conditions and how much firm demand might be lost. For the deterministic modelling we have used our pan-European and US gas model, Pegasus ('Pan-European GAS + US'). The model examines the interaction of supply and demand on a daily basis in the GB, all-island of Ireland, Iberia, France, Belgium & Luxembourg, the Netherlands, Germany, Denmark & Sweden, Czech Republic, Slovakia, Austria & Hungary, Romania, SE Europe[34], Italy & Switzerland, the US and the Far East. Examining daily demand and supply across these markets gives a high degree of resolution, allowing the model to examine weekday/weekend differences, flows of the Interconnectors and gas flows in and out of storage in detail.

The second is a probabilistic approach, where we have attributed probabilities to different parameters, such as demand and supply shocks. Pöyry has developed the 'Prometheus' model for examining the effects of unexpected and/or extreme events on the GB gas market. At its core, Prometheus uses the same optimisation criteria as our deterministic gas model, Pegasus, however Prometheus is notably different in two ways. Firstly, it includes a stochastic model of the GB gas market that captures the likelihood and magnitude of a variety of natural, technical and political events. Secondly, to avoid a massive computation problem, we have simplified the level of interconnection by decreasing the number of zones from 17 in the deterministic modelling to four in the stochastic modelling. In effect, Prometheus models a simple four-zone Atlantic gas market, and drives thousands of slightly different scenarios though the Pegasus engine.

Further details on Pegasus and Prometheus can be found in Annex A.

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33 This gap is not synonymous with a requirement for provision of strategic storage or other measures (although it does show the potential requirement). The economics of these measures depend on several factors that we address in later sections, including the costs of its provision, the economic damage caused by a gas supply shortfall, and unintended consequences of its provision. The economics also depend on the extent to which the gap may be reduced, because the success or otherwise of a policy in covering a loss in supply depends on the characteristics (volume and rate of supply in particular) of the measures and whether it can cover the magnitude and duration of the interruption.

34 In our model, SE Europe includes Bulgaria, Greece, Albania, Macedonia, Montenegro, Serbia, Bosnia, Kosovo and Croatia.

This section has therefore been divided into two main sections – deterministic and probabilistic analyses.

Assumptions summary

As shown in Section 2 throughout the period indigenous supplies in GB, the rest of Europe and the US are in decline and Europe will be importing more gas by pipeline from Norway, Russia, the Caspian Region and North Africa. It should be noted that in order to provide conservative modelling scenarios we have not assumed any additional new build for new gas supply infrastructure within GB over and above that which is already committed. In addition we have applied a 5% reduction in available supplies across indigenous, pipeline and LNG sources to reflect unavailability due to planned and unplanned maintenance.

We have three GB demand scenarios: Average (to achieve DECC's 2020 targets), Severe (1 in 50 representation of the Average across North-West Europe) and Central (partial achievement of 2020 targets). For each year a 1 in 20 peak day is included so that achieving the peak demand is appropriately considered.

If gas demand was to increase significantly above these figures we would expect a number of potential projects to be developed. Our forecasts for gas imports into the rest of Europe do include projects that have yet to be confirmed, but the start dates are generally on the pessimistic side.

We also include the two types of demand side response in the form of distillate back up related to oil prices and I&C interruptible load as extra supplies, as it has the same effect as a reduction in demand. Any firm demand not being met would be identified as unserved energy.

4.1 Deterministic supply shock analysis

The main aspect of the deterministic approach was to analyse the impact of specific predefined supply shocks against the supply/demand scenarios described above. Following discussions with DECC, the supply shocks outlined in Table 18 below were selected as being those that might have the greatest impact during the time period being modelled – although they are at the very extreme level of plausible assumptions. The shock combinations vary over the different years. To further stress test the analysis we have combined the two cases with the biggest impact on potential energy unserved and prices to form a Combined shock case.

These supply shocks are assumed to last for the duration of the gas year being modelled. In addition, Pegasus assumes perfect foresight so it believes that alternative supplies are available when required, e.g. LNG is available on the day it is required and that the storage facilities are full at the start of the gas year. We look separately in Section 4.2.2 at whether there is sufficient supplies and storage available to cater for any major supply shock before any further LNG supplies can reach GB.

Table 18 – Supply shock cases

Case	2010	2015	2020	2025
No loss	Base	Base	Base	Base
No Rough	No Rough capacity available to GB market for year	No Rough capacity available to GB market for year	No Rough capacity available to GB market for year	No Rough capacity available to GB market for year
Terminal Loss	Loss of in-flow facilities at Bacton, affecting UKCS production and European imports	Loss of Sleipner platform, affecting Norwegian imports to GB and to mainland Europe	Loss of Milford Haven terminals	Loss of Milford Haven terminals
Import Loss	Loss of all Ukrainian transit gas	Loss of all Ukrainian transit gas	Loss of all Qatari liquefaction capacity	Loss of all Qatari liquefaction capacity
Combined shock	Bacton (import & export) + Ukraine losses	Sleipner + Ukraine losses	Milford Haven + Qatari losses	Milford Haven + Qatari losses

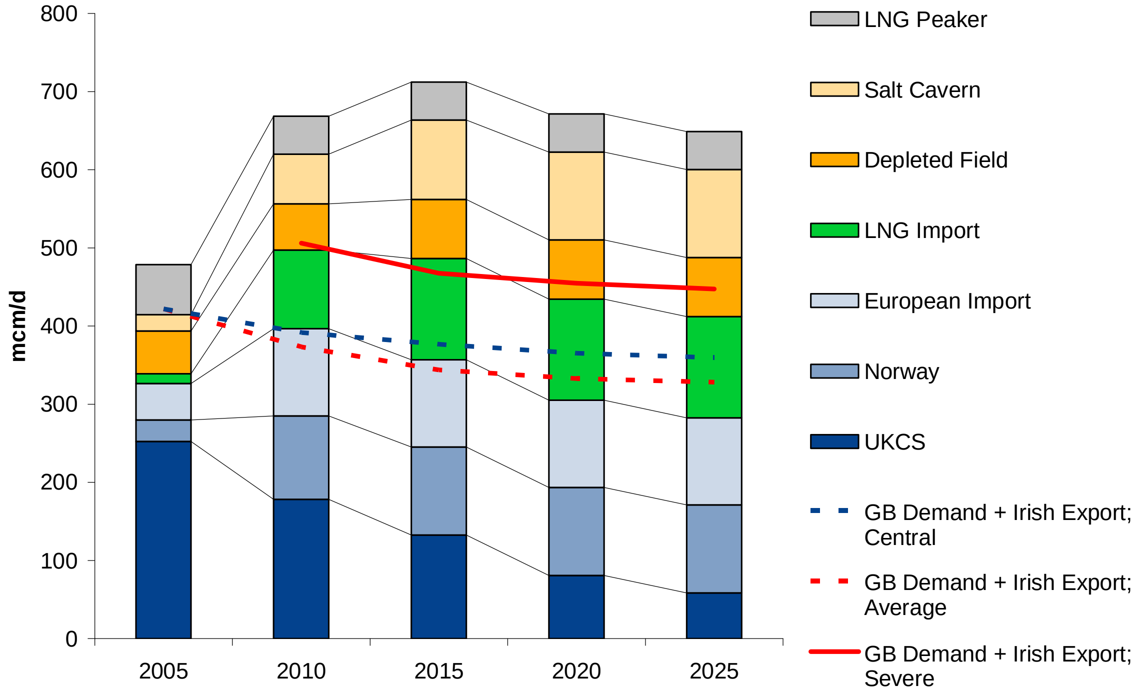
4.1.1 Capacity and demand

The charts in Figure 21 to Figure 24 below show the capacity capable of providing physical gas into the GB market and compare it to assumed peak GB demand plus exports to all-island of Ireland to reflect their dependence on supplies from GB, under the Average, Central and Severe demand cases identified in Section 2.6.1 and 2.6.2. These figures do not show the potential demand side response capability, which can be seen as additional supply capacity.

The following charts also show the position in 2005, using the actual peak demand day (1 February 2006, 411 mcm/d) as a reference point. The tightness of the system can be clearly seen and was a major factor behind the high prices seen that winter. The figures clearly show the enhancement in supply capacity since 2005 due to the new LNG terminals, Norwegian import pipelines, interconnectors with the continent and storage facilities.

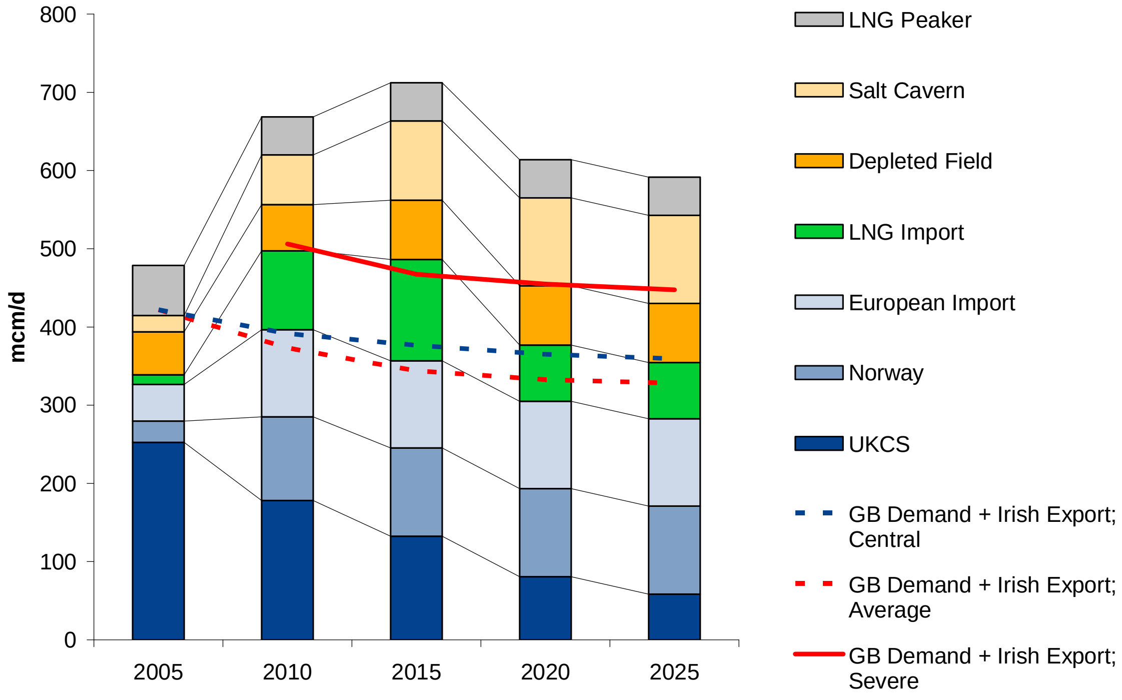
In all supply shock cases, including the Severe demand, there is sufficient capacity to meet peak daily demand using the existing and committed infrastructure and storage. The tightest supply capacity to demand occurs in the terminal loss case of losing Bacton in 2010, as shown in Figure 24.

Figure 21 – Supply capacity against peak demand; no supply loss (mcm/d)



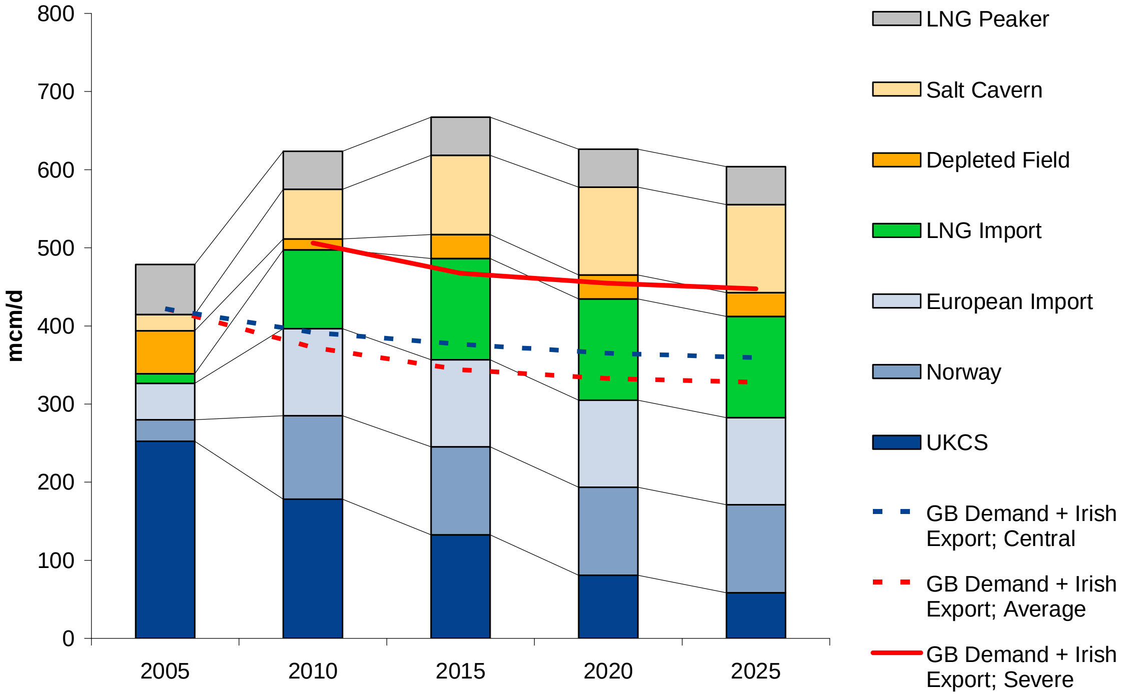
Source: Pöyry Energy Consulting, National Grid, Bord Gais

Figure 22 – Supply capacity against peak demand; import loss case (mcm/d)



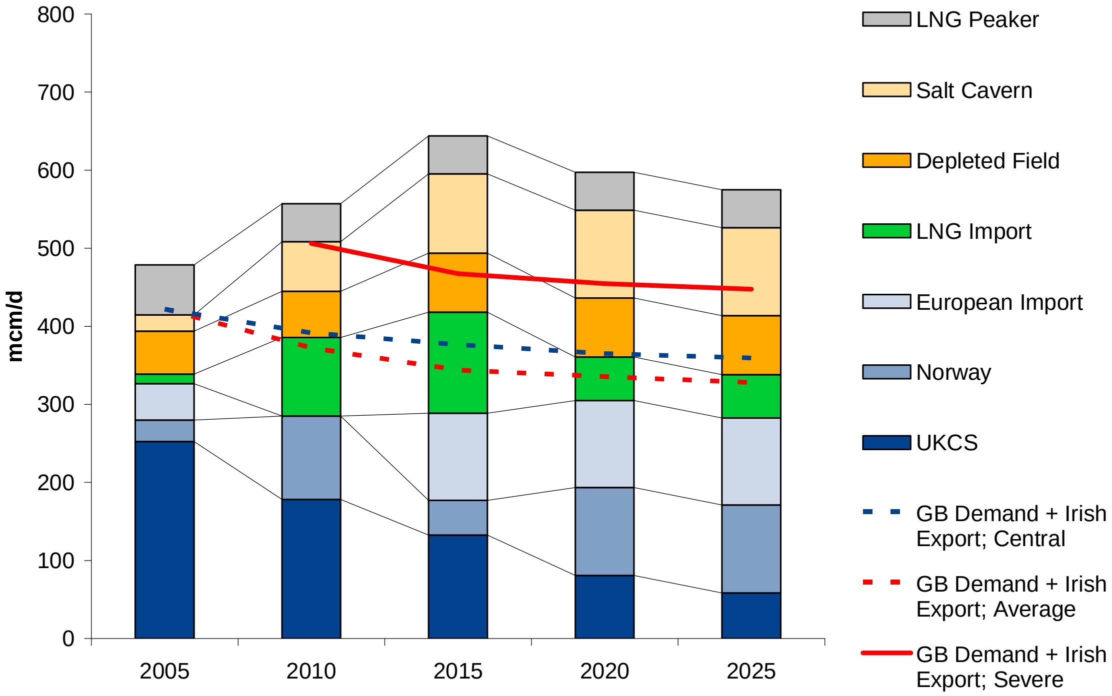
Source: Pöyry Energy Consulting, National Grid, Bord Gais

Figure 23 – Supply capacity against peak demand; no Rough stress test (mcm/d)



Source: Pöyry Energy Consulting, National Grid, Bord Gais

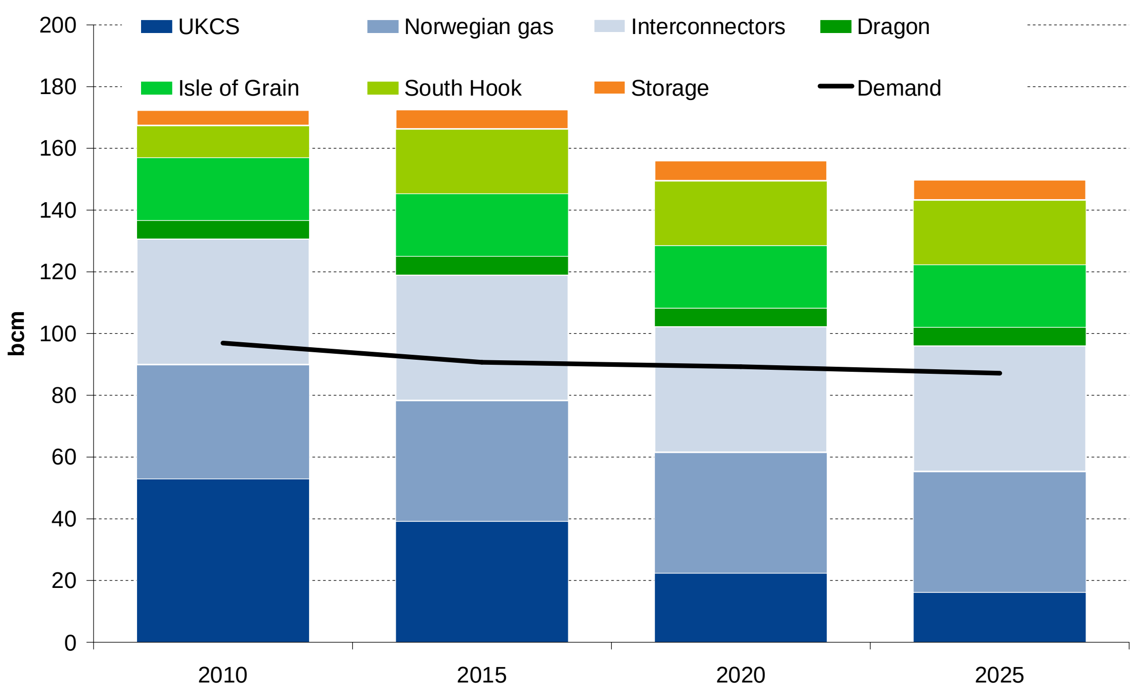
Figure 24 – Supply capacity against peak demand; terminal loss case (mcm/d)



Source: Pöyry Energy Consulting, National Grid, Bord Gais

It is also interesting to consider the annual supply capability. Figure 25 shows the annual capacity of GB supplies against the Severe demand level based on there being no disruption. It uses the UKCS flows as per Section 2.2 and assumes that import pipelines from Norway, interconnectors and LNG flow to their maximum capacity across the year. Storage facilities are full at the start of the year but do not cycle to provide any additional supplies within year. It shows that there is sufficient supply capacity and availability across the diverse sources such as Norwegian, European interconnection, LNG and existing storage facilities.

Figure 25 – Annual capacity and demand in the Severe Central case



4.1.2 Supply and demand

Our deterministic modelling looks at the supply/demand situation over the whole gas year and optimises the flows to match supplies with demand subject to physical and contractual constraints at lowest cost.

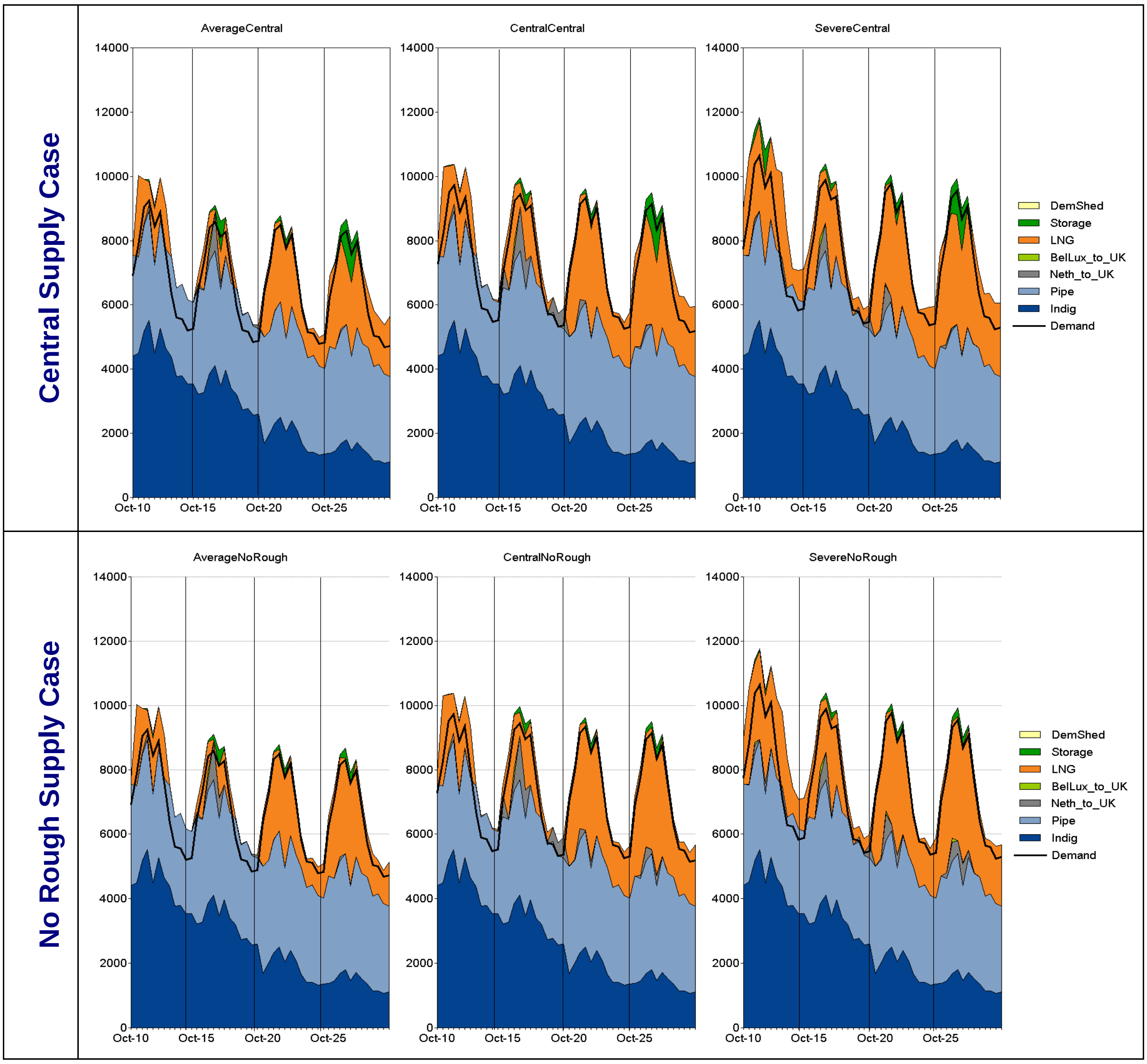
The charts in Figure 26 show the monthly demand and supply from each source in each of the scenarios. The supplies in excess of the demand line indicate exports to all-island of Ireland and to the Continent, and/or filling of storage. The Import Loss case in 2010 (loss of Ukrainian supplies to Europe) shows a large increase in LNG imports which is translated into exports through the Interconnector to satisfy the loss of Ukrainian supply in Europe.

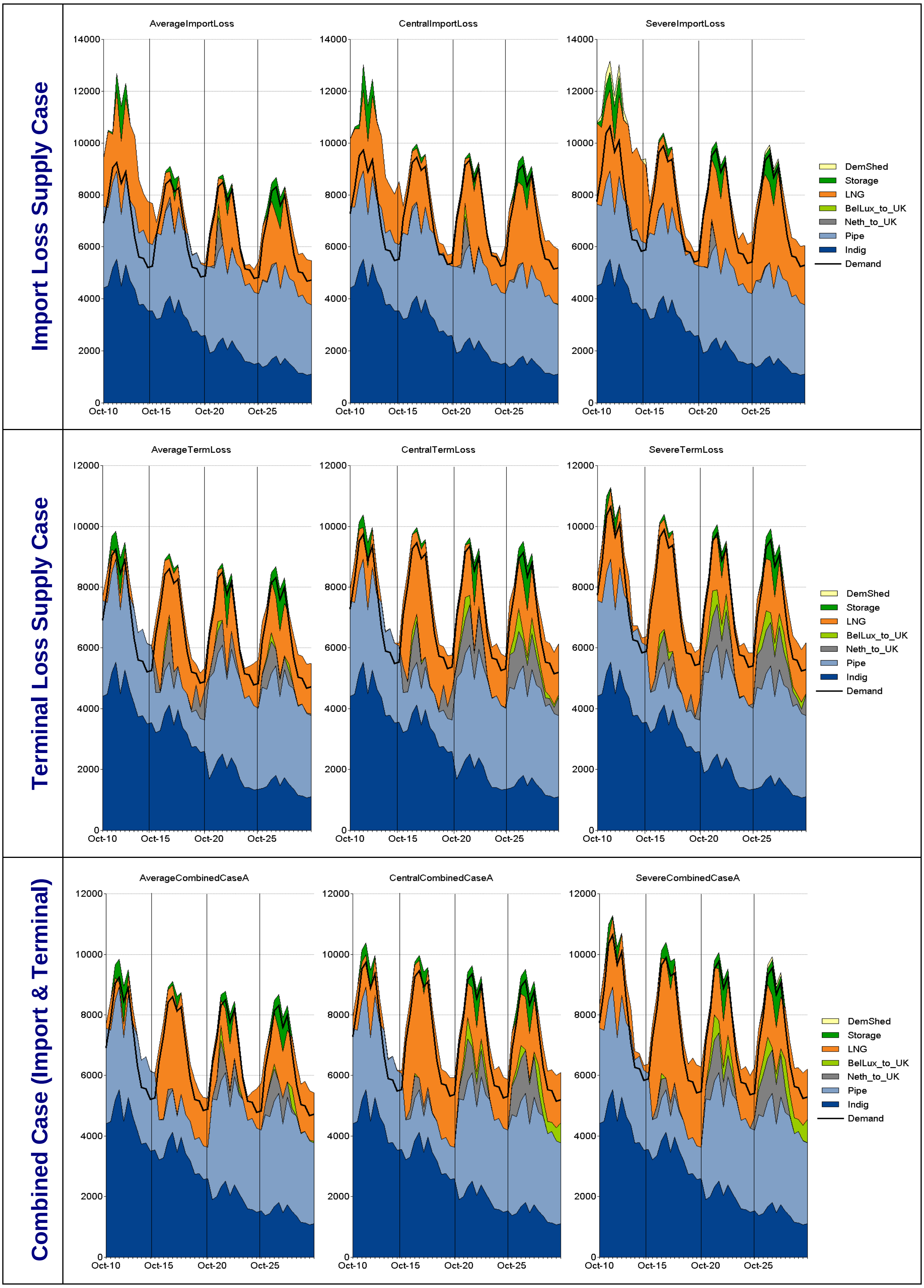
In the Terminal loss supply case in 2015 to 2025 (loss of Sleipner in 2015 and Milford Haven in 2020 and 2025) there are significant imports from the Continent through the interconnectors to compensate for the Norwegian and LNG supply losses.

The results indicate that demand side response is generally not required in GB apart from under the following two situations:

- the Major Import Loss case with Severe demand in 2010 (loss of Ukraine) and 2025 (loss of Qatari liquefaction) – note it also shows that GB is exporting in such circumstances to support the loss of demand on the Continent; and
- the Combined case with Severe demand (loss of Milford Haven and Qatar liquefaction) in 2025.

Figure 26 – Supply and demand balances for supply stress tests (mcm/mth)

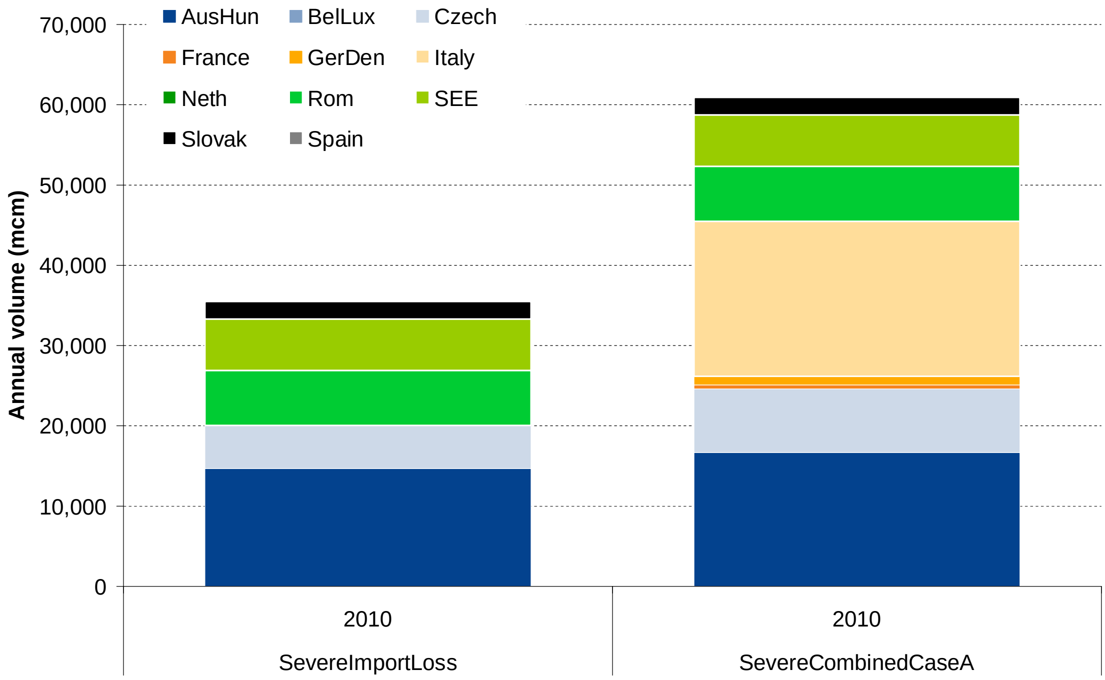



Import Loss Supply Case
AverageImportLoss
CentralImportLoss
SevereImportLoss
Terminal Loss Supply Case
AverageTermLoss
CentralTermLoss
SevereTermLoss
Combined Case (Import & Terminal)
AverageCombinedCaseA
CentralCombinedCaseA
SevereCombinedCaseA
DemShed
Storage
LNG
BelLux_to_UK
Neth_to_UK
Pipe
Indig
Demand
Oct-10
Oct-15
Oct-20
Oct-25

Although our results indicate that there would not be a supply gap in GB in these circumstances, there would be a need for demand side response and a risk of unserved energy in other markets under severe weather conditions, such as south-east Europe with the loss of supplies through Ukraine. Whilst some of the countries in the more affected region such as Italy, Greece and Turkey do have LNG terminals and strategic storage to help support the region, their capacities in 2010 are not sufficient to support Severe demand levels in Hungary, Czech Republic, Slovakia, Romania and the rest of South-East Europe with loss of supplies through Ukraine for a whole year. This is demonstrated in Figure 27, which also shows that Italy and Germany would also be affected in the Combined loss case, where supplies from GB through the interconnectors are also unavailable for a year, as the high demand in North-West Europe is met before moving gas further south and east.

Greater interconnections, new routes for Russian gas and increased LNG supplies will help to overcome this by 2015.

Figure 27 – Severe demand, Combined & Import Loss: European DSR



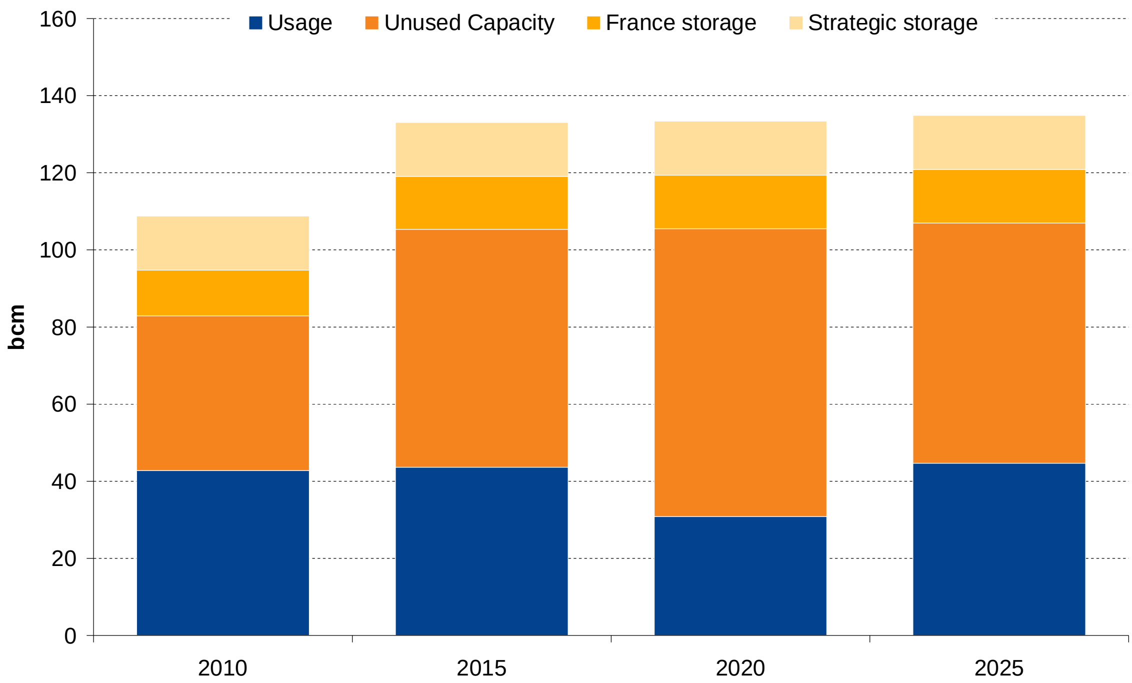
4.1.3 Storage usage

Storage usage is an important indicator on whether unserved energy will potentially be the outcome from a major supply disruption. Figure 28 shows that, even in the Severe demand case, the levels of storage utilisation are still well within the amount of storage capacity available across Europe. Whilst France has gas storage stocking obligations in place which require suppliers of domestic consumers, on any day, to maintain specific stocks of gas in store, the minima and maxima are profiled throughout the year, thereby forcing the utilisation of storage – it is therefore questionable as to whether this constitutes strategic storage so we have shown French storage separately. We have also separated the quantities of 'strategic storage' identified in the analysis in Annex C.

In the Combined supply disruption case (Import Loss and GB Terminal Loss), there is an increase in European storage usage of over 4bcm compared to Figure 28, in 2010. In addition, there is an increase of 25bcm in total storage capacity by 2015. This expansion is mainly coming from the Netherlands, Germany, Italy and Romania.

This means that even in a severe supply disruption and demand case there still remains plenty of storage notionally available to the market.

Figure 28 – European storage usage in the Severe demand, Central supply case



4.1.4 LNG regasification usage

As shown in Figure 26 LNG often provides the swing required to meet GB demand, especially under the Severe demand case. Table 19 shows the actual level of LNG utilisation resulting from the modelling optimisation – and the capacity has already been constrained by 5% from the total published capacity throughout. Not surprisingly this reaches 100% in the most extreme supply disruption shock tests, for example in 2010 Import Loss of Ukrainian transit routes for the year. Similarly, in the Terminal Loss case for 2020 and 2025, where there are no Milford Haven terminals for the year, the remaining LNG capacity is 100% utilised. Again we see increased LNG utilisation, as would be expected, in the 2015 Terminal Loss case (no Sleipner platform) which again underpins the fact that LNG will be a significant provider of swing in the future.

Under normal supply conditions and the Severe weather case it is typically in the range of 65–75%, which is similar to that assumed in the Ofgem's Project Discovery 'Dash for Energy' scenario.

Table 19 – GB LNG regasification usage

Central	Average	Central	Severe
2010	24.9%	31.9%	66.1%
2015	12.0%	22.8%	34.1%
2020	44.3%	60.1%	63.6%
2025	53.4%	69.2%	74.2%
No Rough			
2010	24.9%	31.9%	66.1%
2015	11.9%	22.8%	34.1%
2020	44.3%	59.8%	62.7%
2025	53.3%	67.7%	70.2%
Import Loss			
2010	76.3%	83.5%	100.0%
2015	16.2%	33.2%	38.7%
2020	38.0%	54.1%	61.0%
2025	53.2%	69.2%	73.3%
Terminal Loss			
2010	9.9%	21.4%	39.4%
2015	52.5%	66.3%	75.4%
2020	85.1%	99.7%	100.0%
2025	98.3%	100.0%	100.0%
Combined Case			
2010	9.9%	21.4%	39.4%
2015	64.7%	77.9%	81.9%
2020	76.6%	96.8%	99.1%
2025	98.3%	100.0%	100.0%

Note: Above utilisation excludes the assumed 5% reduction to total published capacity.

4.1.5 Demand side response

Using the available DSR, both distillate backup at power stations and I&C interruptible load) shown in Table 12 the amount of demand side response required is zero in almost all cases, as shown in Table 20 below[35]. It can be seen that in the Severe demand and Import Loss supply case of 2010 (loss of Ukraine) there is 1146mcm per annum of I&C interruption, whilst in the other three supply cases there is none. All four scenarios have distillate switching occurring at CCGTs, with distillate cycles constrained and reflecting the issues raised in Section 3.3.

[35] This does not include any requirement of using interruption to manage local constraints.

Table 20 – Demand side responses in Severe demand, supply stress tests

Supply case	Supply case description	Year	I&C Interruptible demand side response (mcm)	CCGT distillate switching (mcm)
Import Loss	Loss of Ukraine transit	2010	1944	570
Import Loss	Loss of Qatar liquefaction	2025	0	570
Combined	Loss of Ukraine transit & Bacton in-flows	2010	0	11
Combined	Loss of Qatar liquefaction & Milford Haven	2025	0	570

This data is shown graphically in Figure 29 and Figure 30 below at a monthly resolution. As can be seen in Figure 29, in December 2010 there would be 105mcm of CCGT switching and 310mcm of I&C Interruption demand side response, whereas for the same time period in Figure 30, there is only 11mcm of CCGT switching on the peak day and there would be increased demand side response and unserved energy on the Continent, as indicated in Figure 27 on page 65.

Figure 29 – Severe Demand, Import Loss Supply stress test

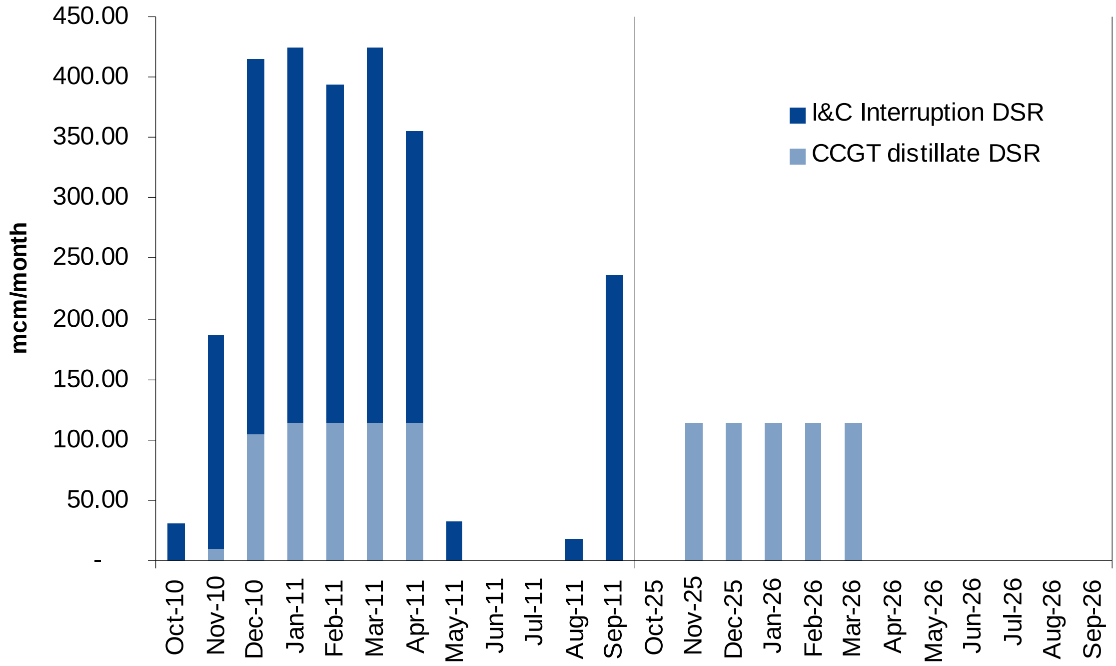
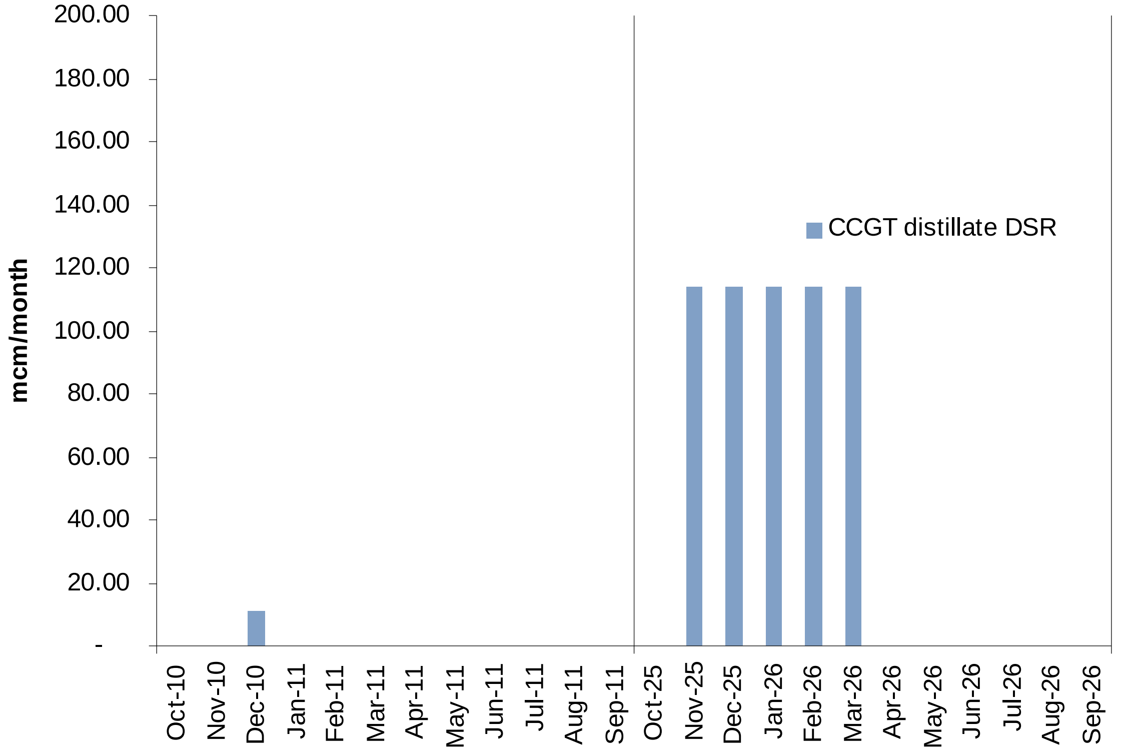


Figure 30 – Severe Demand, Combined stress test



4.1.6 Monthly prices

In most of the cases studied there is only a relatively small impact on the wholesale GB gas price, due to an excess of import and production capacity able to serve a declining GB gas market, coupled with an assumption of continued indexation of gas prices to oil and derivative products on the continent and in the Far East. However, the existing and continued surplus of LNG regasification capacity relative to liquefaction capacity ensures a certain amount of flexibility to arbitrage between the different markets.

In the cases that examine the Combined effects of Ukrainian transit disruption and Severe GB and northern Europe gas demand (perhaps due to coincident severe weather) in 2010, there is evidence that where the GB market continues to be interconnected to the European market, the severe stress of losing Russian imports drives GB and European prices above the point at which CCGT fuel switching might be considered to occur. Similarly for the Severe demand and Combined shock case in 2025 (loss of all Qatar liquefaction capacity for a year and Milford Haven terminal) we would expect to see prices rise such that there would be fuel switching by CCGTs.

It should also be noted that these prices are based on a combination of oil-indexed contracts and LRMCs described in Section B.1.4, so short-term market reactions to any significant supply disruption may be higher than modelled but any such 'premium' market price combined with the diverse supplies will attract additional supplies and so return the market to LRMC costs quicker than would otherwise be the case. These observations are demonstrated in Figure 31, Figure 32 and Figure 33 below for the Average, Central and Severe cases respectively.

Figure 31 – Monthly prices in the Average demand, supply stress tests

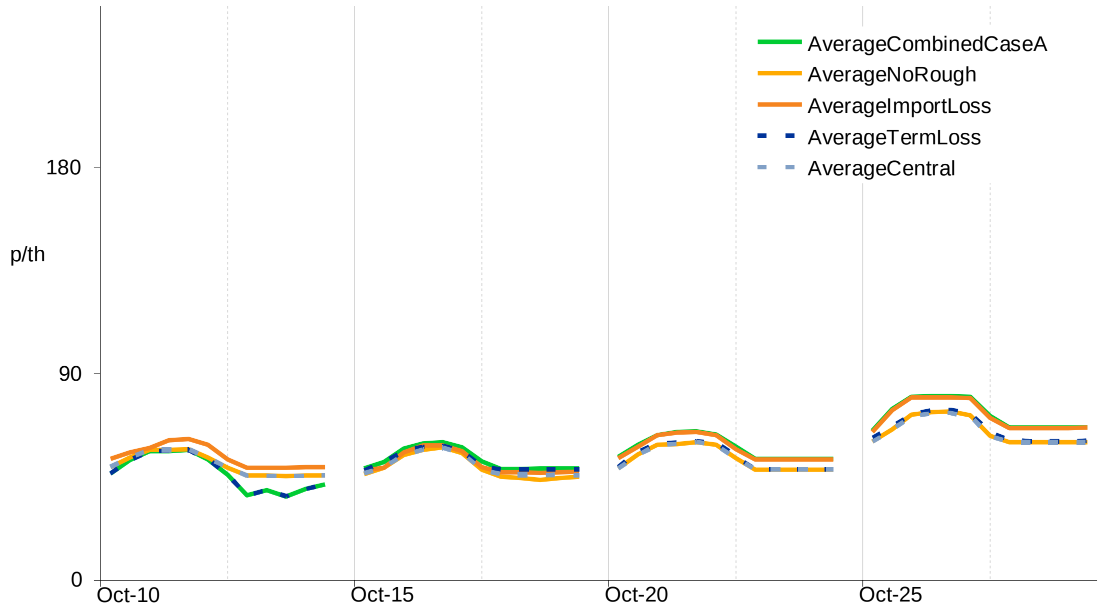


Figure 32 – Monthly prices in the Central demand, supply stress tests

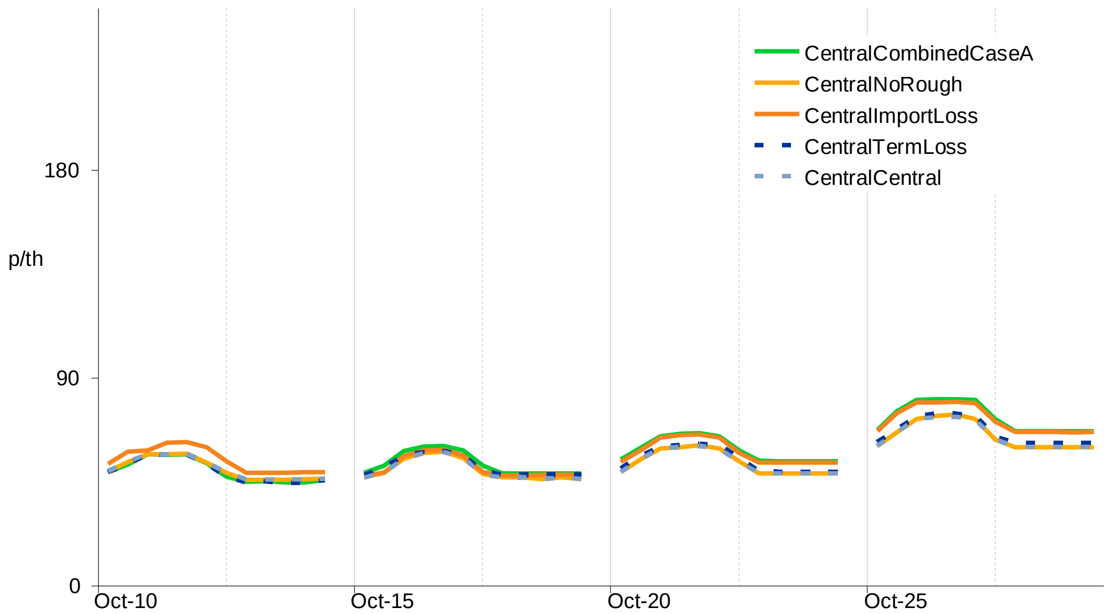


Figure 33 – Monthly prices in the Severe demand, supply stress tests

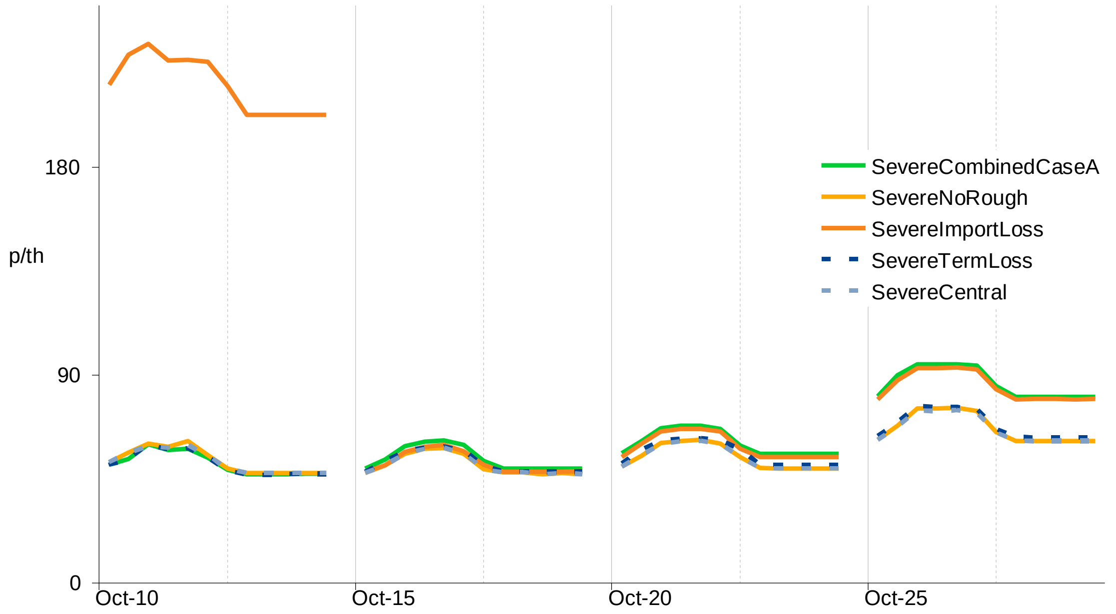


Figure 33 shows that for extreme test scenario of the Severe demand with Import Loss of Ukraine supplies case in 2010 prices reach the level assumed for I&C interruption. This is because GB maximises our supplies via the Interconnectors to help Continental Europe, as seen in Figure 26. In the Combined case, with the additional loss of Bacton as an export route in 2010, GB prices are delinked from the Continent, and given the limited number of LNG terminals in the most affected regions cargos cannot be easily diverted.

4.2 Deterministic sensitivity analysis

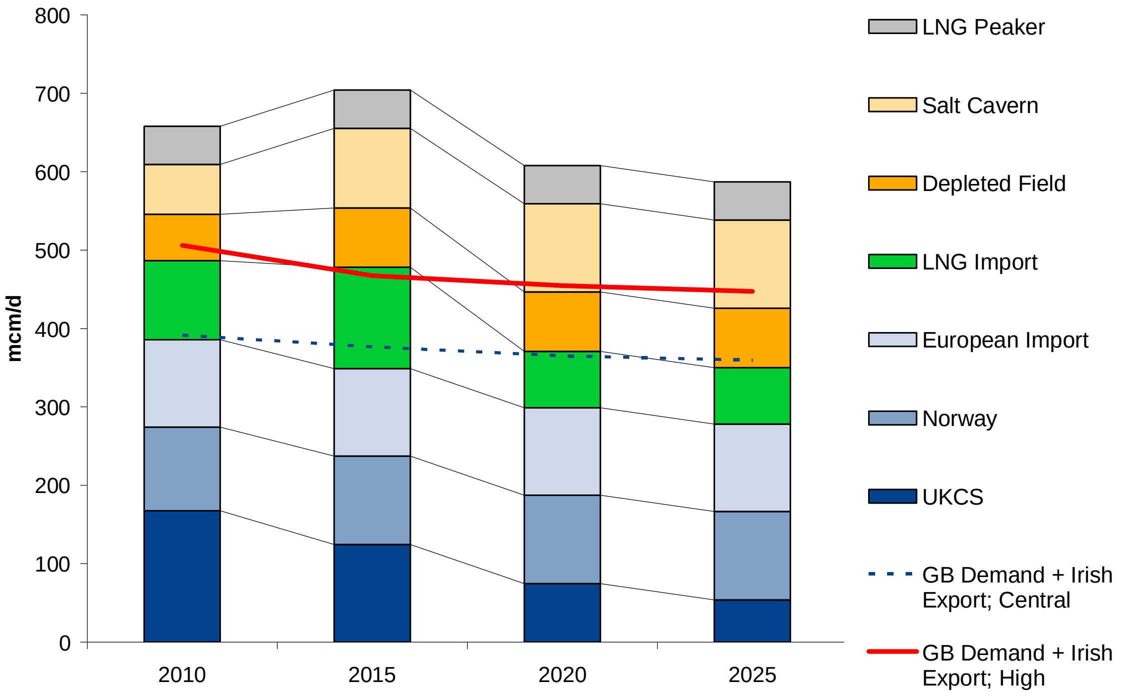
To further test the results we have run sensitivities for two key assumptions: demand reflecting efficiency and renewable targets; and availability or delays of LNG.

4.2.1 Very high demand sensitivity

For the sensitivity analysis based on very high demand, we have used the Pöyry Central demand case and applied a severe weather pattern to it in the same manner as shown in Section 2.6.1.2. This gives a peak demand of 511mcm/d for GB only and 533mcm/d when including exports to all-island of Ireland in 2010, which is another 5% higher than the Severe demand case and it remains higher in later years (493mcm/d GB & all-island of Ireland in 2025). The high demand sensitivity case has an annual demand of 114.5bcm in 2010, which is 28% higher that the NGG annual demand forecast from the 2009 TYS.

As was seen in Section 4.1.4 demand side response only occurs in the Import Loss case in 2010 and 2025 so we have repeated the analysis for this case. The resulting capacity and demand position is shown in Figure 34.

Figure 34 – Capacity demand balance in High demand, Import Loss sensitivity



In 2025, peak demand in the Average Demand with Import Loss case could be met solely by a combination of UKCS, European imports, Norwegian imports and storage. In the High Demand with Import Loss sensitivity, however, significantly higher use of existing storage is needed in order to service this peak demand.

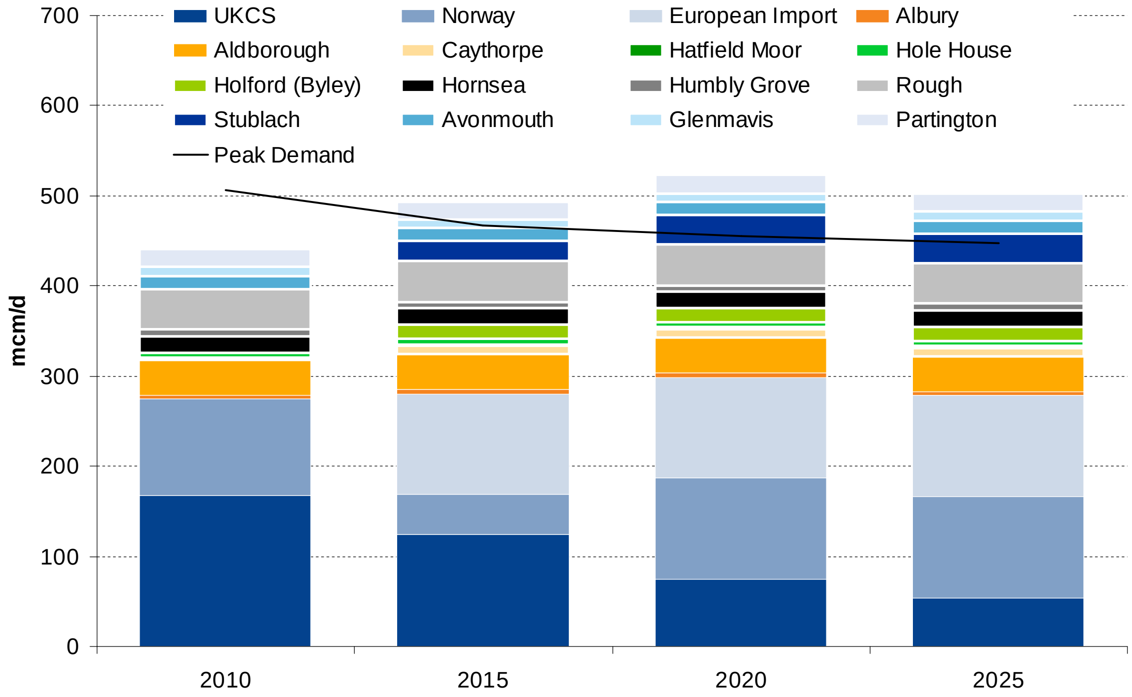
It is also worth repeating that this is an extreme sensitivity as we have assumed no new build in gas storage, LNG import capacity or pipeline infrastructure over and above that already committed; an unlikely situation as we should expect supply to react to a return to demand growth well within the decade time period.

4.2.2 LNG delays sensitivity

We have also analysed potential supply/demand gaps in the event of LNG cargoes being delayed and stocks being empty at the time of the peak day in a Severe winter[36]. These delays would limit the volumes available to meet demand. Figure 35 shows how the Severe demand peak measures up against the GB supplies in the Combined shock case with all the LNG terminals being empty.

[36] The positions shown in Figure 35 are at the most extreme and is beyond current security standards discussed in Section 2.1.

Figure 35 – Impact of LNG delays in Combined Shock under Severe peak demand



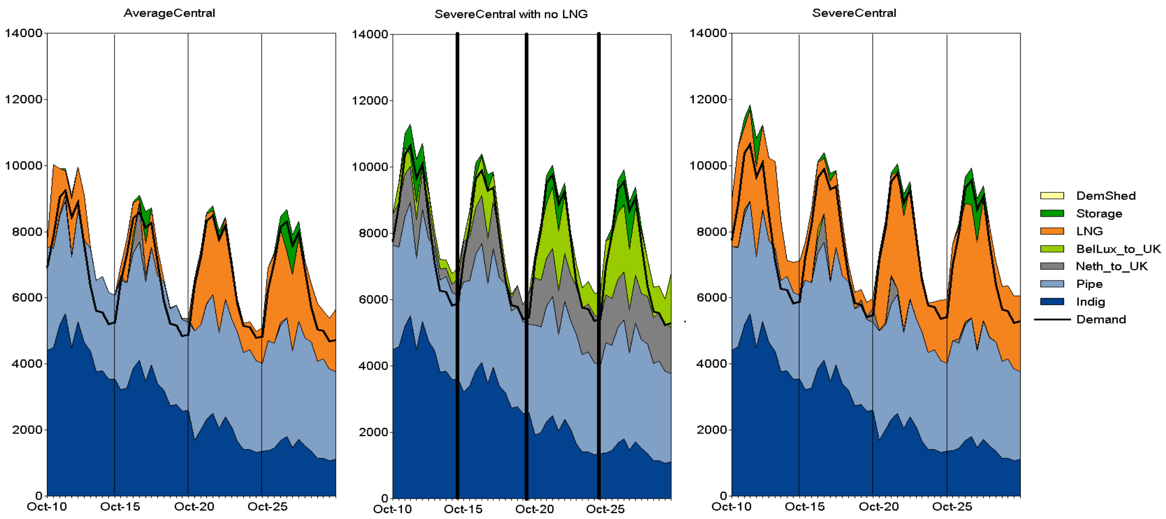
In the 2010 Combined shock case (loss of supplies through Ukraine and the loss of Bacton terminal), there is a risk of unserved energy should LNG supplies be delayed. This is because there would be no flows of European supplies through the interconnectors. In other years there appears to be sufficient capacity to meet the Combined shock cases against the peak Severe demand, as they only assume loss of LNG.

4.2.3 Restricted LNG sensitivity

With the supply shocks only showing limited usage of distillate backup at CCGTs and very limited usage of interruptible industrial & commercial (I&C) contracts we have carried out an additional sensitivity to see the impact of a very remote possibility, where no LNG supplies are available to GB for the whole year, possibly through other countries having significantly increased demands and a higher capability to pay for LNG cargoes, thus outbidding GB suppliers for the cargoes, or all GB terminals being affected by co-ordinated terrorist action.

This sensitivity assumes no LNG flows into GB for the whole gas year with all other assumptions the same. The resulting annual flows are shown in the middle chart in Figure 36 with comparisons shown for the Average and Severe demand with no major supply disruption.

Figure 36 – Supply-demand balance with no LNG to GB; Severe demand case (mcm/mth)



Under the Severe Central case with no supply disruption (right hand chart) there is a small amount of excess supply to demand, which is being exported to the all-island of Ireland and to continental Europe through the interconnectors. There is some usage of storage, particularly in 2025, reflecting the assumption of no additional facilities being built during this period.

In the Severe Central with no LNG sensitivity (middle chart) we see significant usage of the interconnector and BBL pipeline to bring supplies into GB from Continental Europe, where LNG cargoes have been diverted and more supplies come from Russia. There is also increased usage of GB storage across the years, but as there are no other significant outages, demand is met without resorting to demand side response.

As we did in Section 4.1.3, we can analyse the projected level of storage usage across Europe in this no LNG sensitivity case. Figure 37, shows increased use of storage in a Severe demand case compared to the levels indicated in Figure 28 on page 66, but still with sufficient spare capacity and no use of 'strategic storage'.

The impact on prices from this no LNG sensitivity is shown in Figure 38. It shows increases over the time period with prices peaking in the winter close to the cost of using distillate backup at CCGT power stations, but the use of storage mentioned above is sufficient to prevent this being required.

Figure 37 – EU storage usage with no LNG to GB; Severe demand case

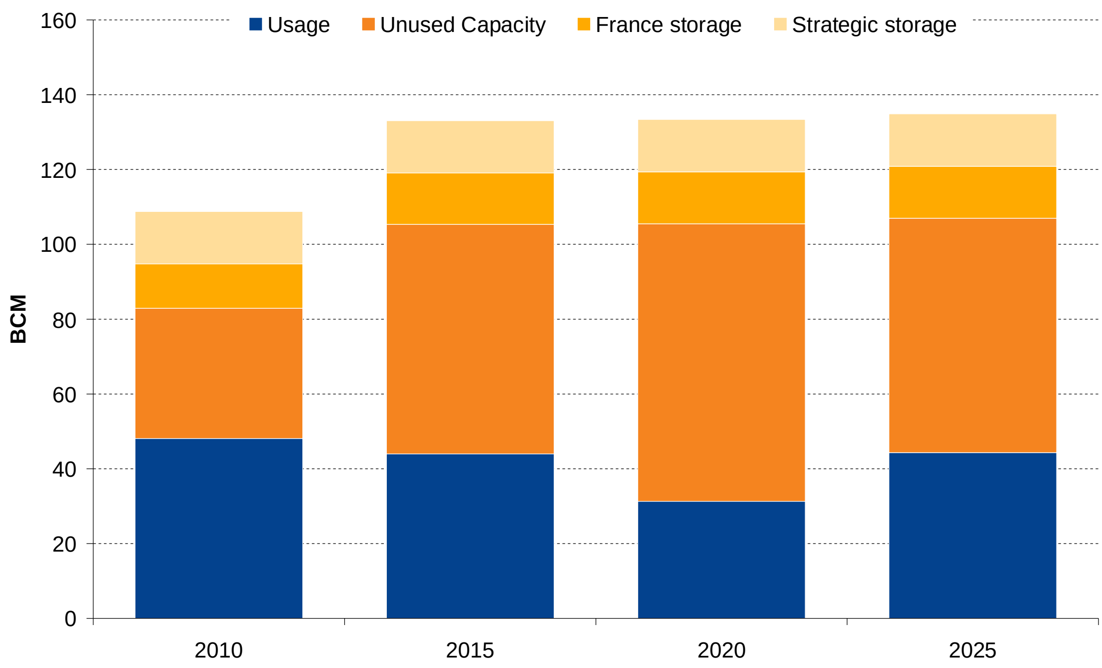
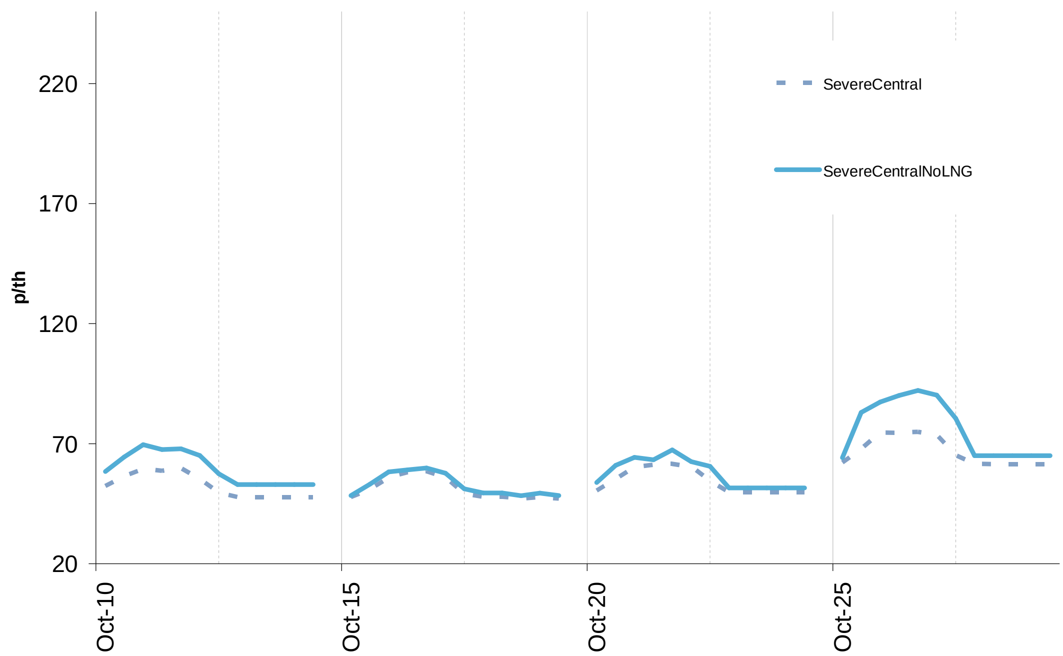


Figure 38 – Monthly prices with no LNG to GB; Severe demand case



4.2.4 *Conclusions from deterministic supply shock modelling*

The key message that comes from the above modelling is that only in situations of very extreme supply shocks with Severe demand does any unserved energy become apparent in GB, and only in 2010 is there any demand side response over and above use of distillate backup in CCGT power generation. This is summarised in Table 21.

Table 21 – Supply shock effects in Severe demand case

Supply Shock (applicable for the whole gas year)	**2010**	**2015**	**2020**	**2025**
Rough not available	Increased LNG importation – cargoes diverted from US where storage utilisation is increased Negligible price impact			
Import loss (international supply loss) Ukraine (2010, 2015) Qatari LNG (2020, 2025)	CCGT and I&C DSR with major price impact Unserved energy in SE Europe	Unserved energy in SE Europe	Minor GB price impacts	CCGT distillate use in winter with price impact
Terminal loss Bacton (2010) Langeled/Sleipner (2015) Milford Haven (2020, 2025)	Decrease exports, greater GB storage utilisation	Greater LNG & European imports	Greater European imports (LNG diverted to Continent) & GB storage	
Combined shock (Import loss and Terminal loss)	Increased LNG importation and some price impacts		Greater European imports and GB & European storage CCGT distillate use	

4.3 Probabilistic analysis

The second modelling approach we have used is to consider the supply risks to GB on a probabilistic basis. The aim of this analysis is to produce probability distributions for unserved energy, and potentially also for demand flows and supply flows as well as any shortfall between them and the impact on wholesale prices. From the resulting distributions, it is possible to calculate appropriate summary statistics to describe the data and to draw broad conclusions.

The probability distributions are determined from a simulation modelling approach, using input distributions for short-term losses in different sources of supply, and variations in demand due to weather and other factors. These random fluctuations are imposed on the Average demand, Central supply scenario developed in Section 4, and the input distributions replicate the considerations that fed into the other scenarios (i.e. outage and severe demand).

The probabilistic analysis therefore examines the combined effects of severe GB demand, losing LNG supplies, losing Norwegian and losing continental imports with appropriate probabilities.

In addition, we estimate the economic impact of disruptions through a consideration of the GVA of the sectors that may experience the disruption. Disruptions may occur through involuntary curtailment or from voluntary load shedding that arises from price volatility.

Pöyry has developed the 'Prometheus' model for examining the effects of unexpected and/or extreme events on the GB gas market. At its core, Prometheus uses the same optimisation criteria as our deterministic gas model, Pegasus; however, Prometheus is notably different in two ways. Firstly, it includes a stochastic model that captures the likelihood and magnitude of a variety of natural, technical and political events. Secondly, to avoid a massive computation problem, we have simplified the level of interconnection by decreasing the number of zones from 17 in the deterministic modelling to four in the stochastic modelling.

More detail of the model and the assumptions used in the model can be found in Annex A.

4.3.1 Supply outages

A supply outage (or outage) is an unplanned loss of supply. In the model an outage has a rate of loss, expressed as a percentage of the supply prior to the outage, and a duration. Following an outage, supply is restored to the level of supply prior to the outage. In the model the causes of a supply outage are grouped into two broad types:

- technical failure – examples would include mechanical failure of a part, a man made accident or an act of God, such as a lightning strike; or
- political – a dispute or unrest or an event potentially unrelated to the internal workings of the gas industry.

The main difficulty with modelling outages is the lack of detailed or comprehensive information about outage events. Indeed many outages do not ever get reported. This means that the probabilities on which outages occur has to be informed by a limited amount of experience. We are also required to take a view of the reliability of new LNG supplies where the historical experience in GB is extremely limited.

In an earlier study on security of gas supply that was undertaken in 2006[22], it proved to be very difficult to reach consensus on the probabilities of supply interruption. The outage probabilities were set on an empirical approach and the probability estimates were intended to broadly match observed historical events that have affected Britain's gas supply. The outage proportions were based on the relative sizes of individual fields in the UKCS, while it was assumed that an individual LNG source or pipeline could be completely curtailed.

Table 22 below gives a list of notable outage events that have, or could have, affected the security of supply to GB since 2006. From these incidents we observe that:

- in all cases the impact on GB supply was managed and the loss of supply was offset by additional supply from other sources (possibly including a demand side response); and
- interconnection between GB and Europe has benefited both GB security of supply (with imports following the Rough fire), and European security of supply (with exports during the Ukraine dispute).

Table 22 – Notable gas supply outages 2006 to 2010

Date	Location	Description and impact
Feb 2006	Rough storage	Fire on offshore platform results in all storage service from Rough being suspended. Stocks from other storage sites in GB drawn down and Interconnector (GB) imports. Gas Balancing Alert triggered on one day but no enforced curtailment. Injection restored at Rough in July 2006, and withdrawal restored in November 2006.
Jul 2007	CATS pipeline	Vessel dragged its anchor damaging pipeline resulting in a 10 week shutdown.
Feb 2008	Bacton Shell terminal	Fire at terminal interrupts flows from the Sean field. Flows restarted after 3 days.
Apr 2008	Grangemouth	48-hour strike at the oil refinery leads to Forties pipeline being closed down. Loss of gas production from Forties fields amounted to up to 70mcm.
Jan 2009	Ukraine transit	Dispute between Gazprom and Naftogaz leads to interruption to transit gas flows through the Ukraine, resulting in 20% reduction in Europe's gas supply for two weeks. GB supply not impacted. IUK increases exports to Europe during the dispute.
Jan 2010	Norwegian disruptions	On 7 January Europe's largest gas field, Troll, tripped but was returned to production within 2 hours. Then on 11 January Europe's third largest field, Ormen Lange, was shut down for 2 days because of bad weather in Norway.

The frequency and extent of the outages observed since 2006 could potentially be included within the types of outage modelled and appear to be broadly consistent with the probabilities assumed in 2006[37]. On the basis of the observations in the last four years we believe it is appropriate to not change the probabilities of outages modelled on a limited data set of 'notable' outages[38]. Therefore it appears reasonable to continue using the same empirical approach and probabilities used in the 2006 study, as shown in Table 23.

37 In the model the probability that in any winter we observe one or more two-week outages or 1-winter outages on the total of UKCS pipelines, import pipes and storage is 39% (that is 1 minus the probability that no two-week or 1-winter outages occur). Over the three winters we observed one such outage on UK infrastructure – the Rough fire (other events were either in the summer months or of less than two weeks duration).

38 Using the 'notable' outages in the last four years on their own to form our view of probabilities could give a skewed picture as it does not include smaller potentially more frequent outages included in the earlier modelling.

Table 23 – Source outage events and probabilities

	Proportion affected		1-day event	2-week event	1-winter event	
			Per winter	Likelihood	Likelihood	
	Technical	Political			Technical	Political
UKCS Associated	10%	0%	3	2%	1%	0%
UKCS Dry gas	10%	0%	3	5%	1%	0%
Dragon LNG	100%	50%	6	20%	2%	2%
South Hook LNG	100%	50%	6	20%	2%	2%
Isle of Grain LNG	100%	50%	6	20%	2%	2%
Langeled (to GB)	100%	50%	3	10%	1%	2%
Ukrainian transit to Europe	100%	50%	3	10%	1%	2%
Vesterled	100%	0%	3	5%	1%	0%
GB Long Range Storage	50%	0%	1	2%	1%	0%

Source: modification of Pöyry Energy Consulting 2006.

4.3.2 Other detailed assumptions

Various other detailed assumptions have been used within Prometheus, which are described in Annex A.2. These include considerations of:

- annual demand and winter severity;
- peak daily demand;
- oil price and long-run marginal cost uncertainties;
- statistical sampling methodologies; and
- sample size.

4.3.3 Results

For the probabilistic analysis Prometheus was run for 5000 iterations and created a wide range of demand and supply situations. It contemplated a situation with a maximum annual demand of 123bcm in GB, and contemplated a maximum daily demand level of over 700mcm/d.

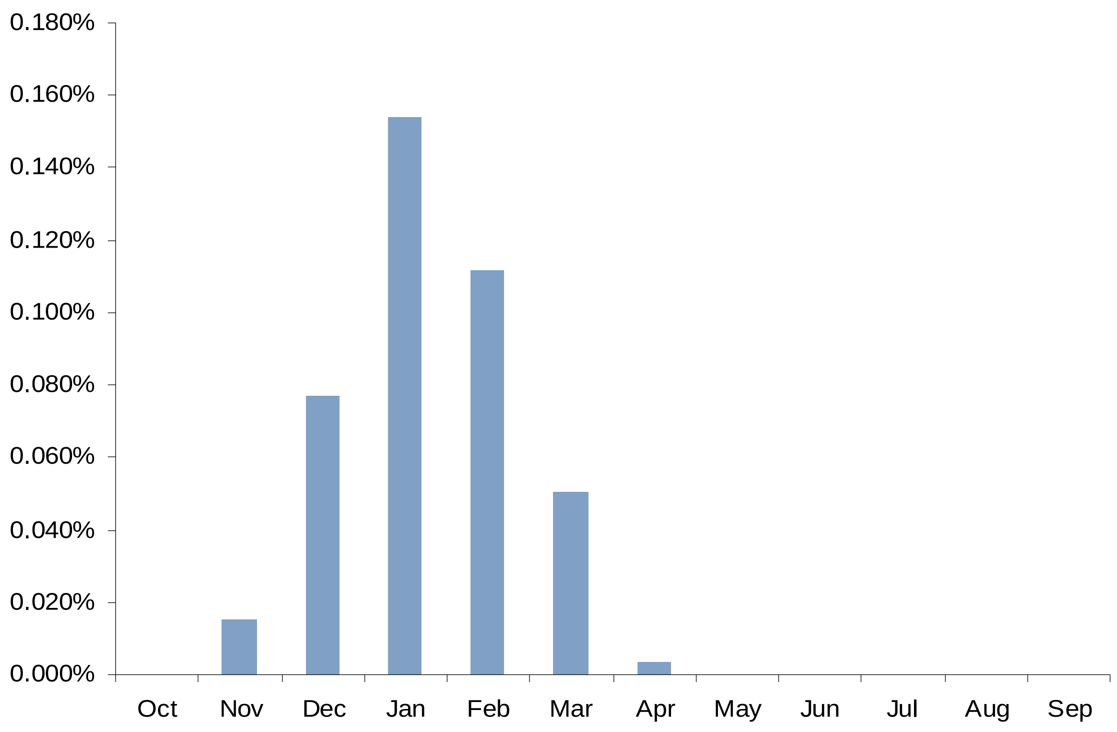
4.3.3.1 Demand side response and use of distillate

Based on the situation contemplated in 2010, the results indicate that we would expect:

- use of distillate backup at existing CCGTs to occur once in every 3 years;
- use of I&C interruption for supply/demand balancing (excludes interruption for local transportation constraints) to occur once in every 15 years; and
- unserved energy to firm customers to occur once in every 19 years.

Results for 2025 are broadly similar: very unlikely events have a smaller impact; however, there are a greater number of instances where DSR is experienced in the market. As this report is focused on low probability, high impact events, we have used the figures from the 2010 analysis to inform the further analysis set out below. Considering the distributions of volumes required presents an alternative mechanism to view these results. Figure 39 below shows the probability of requiring distillate response through the 2010 gas year.

Figure 39 – Distillate response probabilities, 2010



4.3.3.2 Impacts on the economy

Examining the most severe iterations produced by Prometheus, we estimate in Table 24 the probabilities for volumes of unserved energy.

Applying the GVA analysis described in Section 2.10, we can estimate the impact to GVA of the above unserved energy volumes, and can convert this to an expected annual average cost by multiplying through the probability. Impacts are illustrated in Figure 40 below.

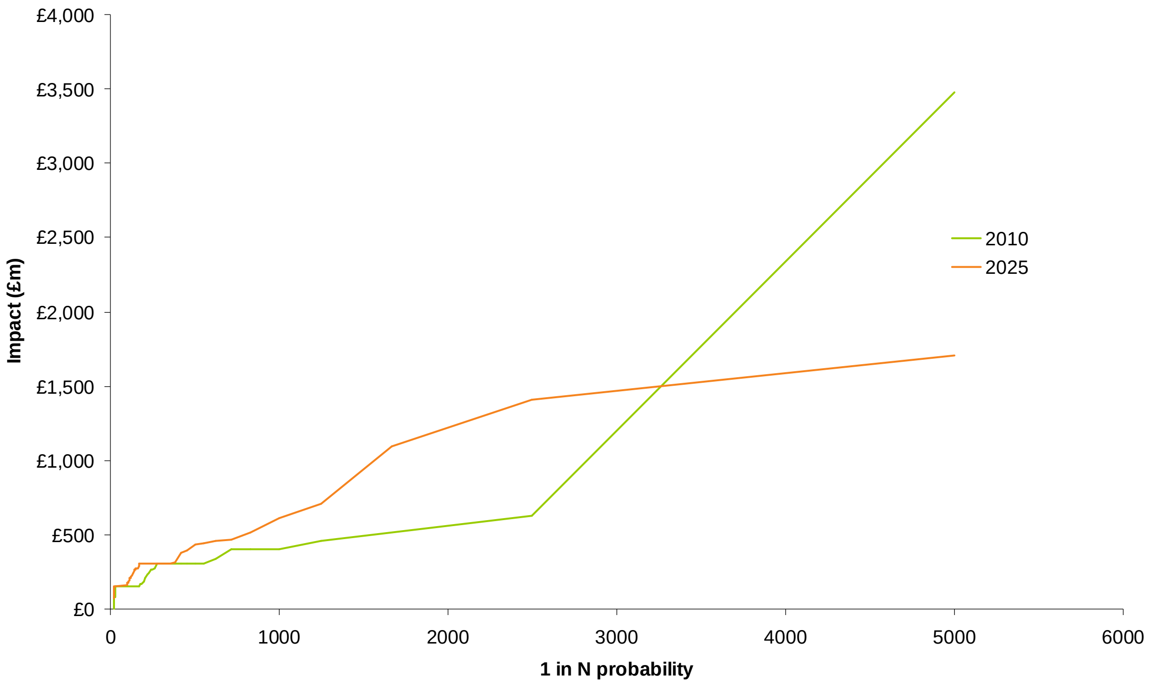
The 1:30 and 1:25 probability levels account for a high number of observations of exactly the same volume of unserved energy: all observations contain the full use of unserved energy tranches 1 and 2 for a single day. This means that more than one day of unserved energy would only be expected to occur once in every 167 years (based on 2010), or once in every 96 years (based on 2025).

By examining the annual GVA impact of each iteration we can estimate the expected value across all iterations – this gives us the expected value of unserved energy in an average year. We calculate this figure as £7.8m per annum based on 2010, and £10.0m per annum based on 2025. The calculation is illustrated in Table 25 on page 82.

Table 24 – Probability of volumes of unserved energy

Probability	Expected volume of unserved energy (bcm)	
	2010	2025
1:5000	0.474	0.231
1:2500	0.089	0.196
1:1250	0.062	0.101
1:1000	0.055	0.087
1:200	0.027	0.041
1:30	0.021	-
1:25	-	0.021
1:19	0.001	-
1:15	-	0.001

Figure 40 – GVA impact of unserved energy



We observe that the values (and capacities) discussed in the preceding analysis are relatively small compared to the investments currently being contemplated within the existing market. These commercial investments are driven primarily by market forces: the absolute level of wholesale prices; the seasonality and volatility of wholesale prices; the relativity to other markets (however, due perhaps to illiquidity in the wholesale market they are also, in part, driven by their investors' physical portfolio positions and their exposure to unforeseeable, force-majeure events). We also note that commercial investments currently under consideration by the industry have not been included in the above analysis and could lead to significant reductions in the potential for unserved energy.

Table 25 – Expected value of unserved energy (based on 2010)

Severity of iteration	GVA Impact (£m)	Probability	Expected value of iteration (£m)
1	3476	1/5000	0.70
2	624	1/5000	0.12
3	459	1/5000	0.092
4	459	1/5000	0.092
⋮	⋮	⋮	⋮
259	1	1/5000	0.0002
260	0.3	1/5000	0.0001
261	0.00	1/5000	0.0000
⋮	⋮	⋮	⋮
5000	0	1/5000	0.0000
		Total (£m)	**7.8**

By examining the impact and probability of any individual iteration we note that a high level of protection against any single extreme unserved energy event is less cost effective than a lower level of protection. It is guarding against single day events that presents the most cost effective opportunity for guarding against the impacts of unserved energy. The single day events that lead to unserved energy are only experienced against a background of longer outages (associated with other infrastructure) and very high demand levels. With a background of a long-term outage and a near-term forecast of cold weather/high demand, we would expect the market to perceive this risk and increase premiums on forward gas prices accordingly.

This price signal provides some limited forewarning to the market that alternative energy sources, e.g. distillate stocks, could be of significant value in the near-term. However, it is unlikely to provide any forewarning beyond the near-term capability of forecasting cold weather/severe demand. It is therefore unlikely that significant restocking of distillate (if necessary and appropriate for the particular alternative source), can happen within these timescales.

4.3.3.3 Prices

The model also produces price distributions for each day of the year. Figure 41 shows the price distributions for 2010 and 2025, the latter having a wider distribution reflecting the tighter supply to demand position coming from the restrictions made to any new supplies and storage facilities.

In addition, we have aggregated these and selected monthly information in Figure 42 overleaf. The price distributions show a higher probability of high prices in the winter than of low prices in the summer – i.e. there is more certainty of winter prices. Interestingly, the model also suggests that there is a higher probability of a high or a low price (than of a mid price) in shoulder month periods.

Figure 41 – 2010 and 2025 price distributions across the year

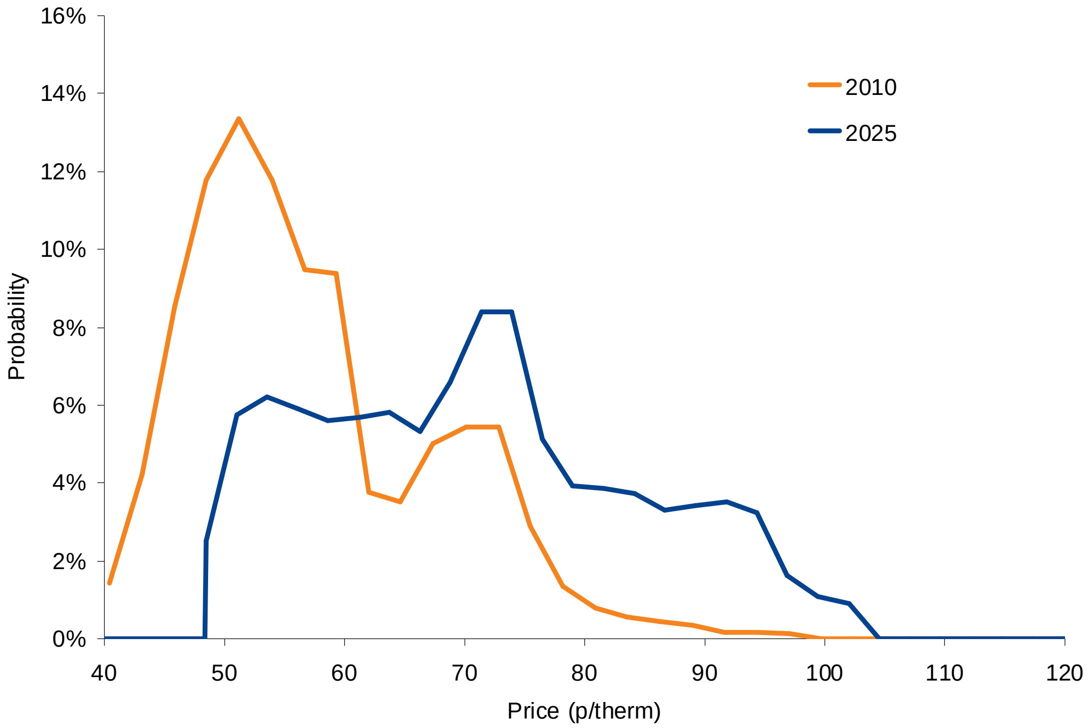
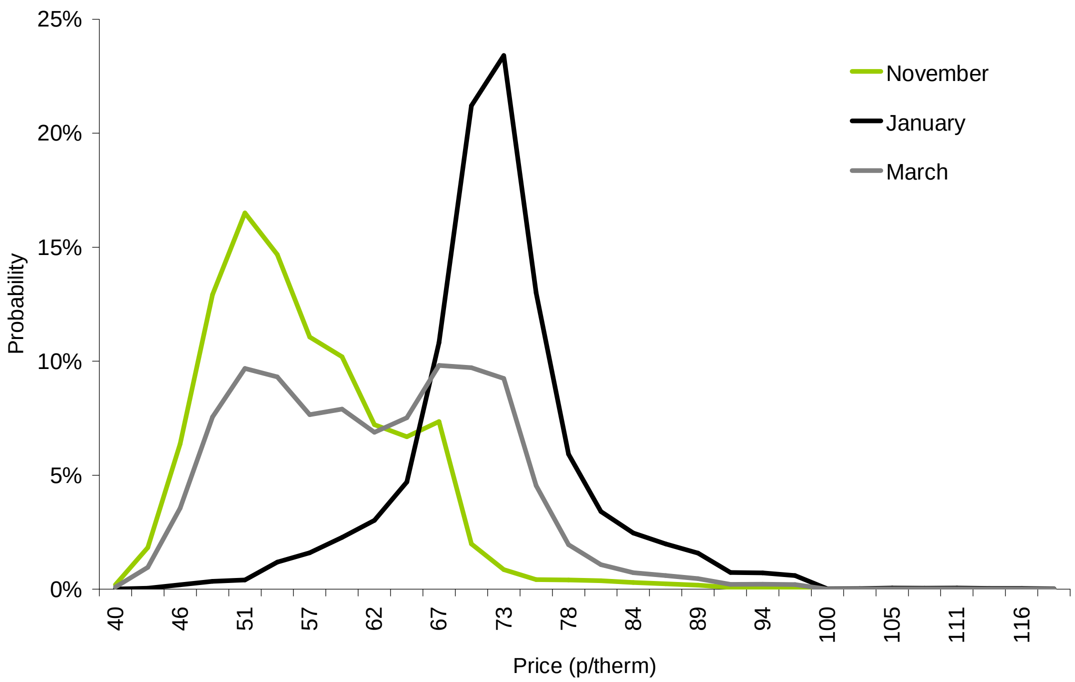


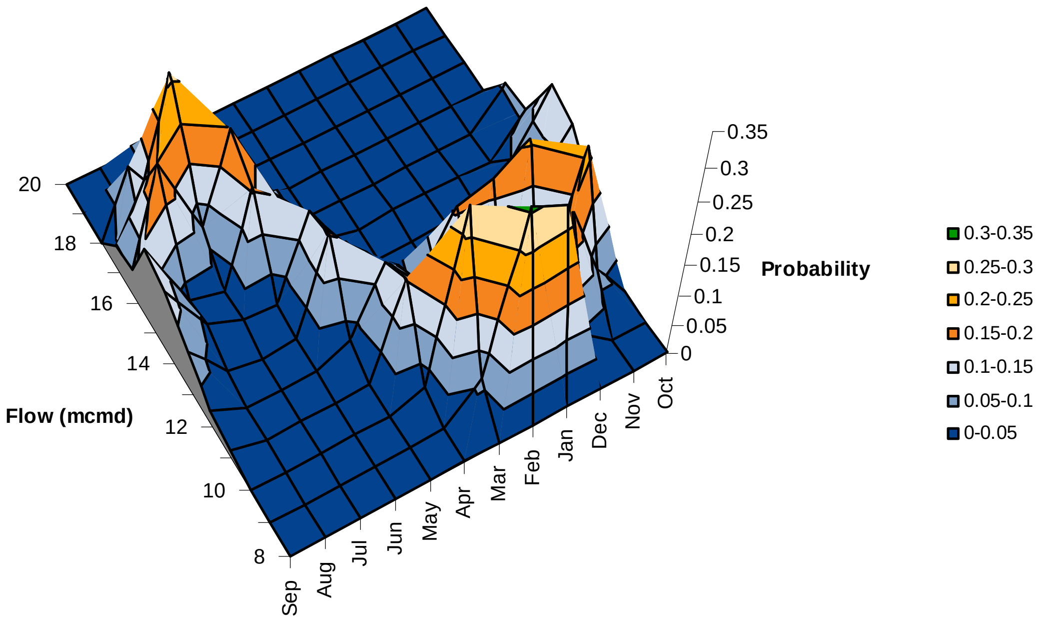
Figure 42 – 2010 price probabilities for selected months



4.3.3.4 Flow data

In addition to the above outputs, the model provides interesting information regarding the probabilities of flows through delivery points and points of interconnection. This is demonstrated in Figure 43, which shows the probabilities for export flows from GB to the Continent. (Figure 43 does not show the instances of zero flow or import flows).

Figure 43 – GB export flow probability, 2010 Base Case



4.4 Modelling conclusions

The deterministic modelling suggests that security of gas supply is only potentially of concern in severe circumstances. It also suggests that into the future, because of existing policies that have the effect of reducing future gas consumption, and despite significant decline in UKCS production, security of supplies continue to be of concern only in such severe circumstances.

The deterministic supply shock modelling has several main messages which were summarised in Table 21 on page 76.

The probabilistic modelling supports these observations: it provides the conclusion that under current and projected supply and demand situations, and considering the potential for adverse supply-side events, disruptions to the demand side that result in unserved energy not covered by CCGT distillate backup or I&C interruptible contracts can be expected to occur less than one day in every 19 years. The expected impact to the economy of unserved energy is small.

Only in the worst case of supply disruption and severe weather is there small amounts of energy unserved, and this is primarily handled through distillate backup at power stations. The probability of CCGT distillate backup being required is once in 3 years.

One of the key drivers of gas security of supply supporting the analysis is that there is sufficient LNG around the world and marginal volumes will react to price signals. It assumes that the growth in LNG market trades will remain at current levels and continue to be responsive to demand and price signals and that GB prices will be adequate for GB shippers and customers to have sufficient ability to pay. This LNG market also provides integration with the North America market and allows the GB and European markets to access the vast quantities of relatively cheap storage in the United States through the diversion of LNG cargos in response to appropriate price signals.

In addition, the continued interconnection of GB to Continental Europe provides it with access to significant quantities of flexibility in the Netherlands and Germany, and for Continental Europe and the all-island of Ireland to have access to flexibility in GB. However, this is dependent on there being no overzealous protectionism into the future that might limit the gas flows around Europe over and above any physical restrictions. The analysis also assumes that any proposed tightening of the EU directive on security of supply does not decrease the effectiveness of European storage.

It should be noted that there are some important assumptions in the modelling, such as the base case demand assuming that the Government's 2020 energy efficiency and renewable energy targets are achieved. That said, the Very High demand sensitivity case and the maximum level used in the probability analysis has annual and peak demand well above the highest recorded levels, and we have constrained the potential new build to only those facilities where investment has been committed.

The analysis shows that prices are only impacted, as would be expected, in the extreme circumstances of very low probability and high impact events. The expansion in diversity of supply sources means that any market price reaction to a severe supply disruption will be limited, and it will return to marginal prices faster than otherwise would be the case.

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5. ALTERNATIVE POLICY OPTIONS

5.1 Identification of policy options

Any policy option considered must improve the security of gas supply either through delivering additional physical gas to GB, or improving the flexibility of gas demand relative to that which is forthcoming through existing commercial and regulatory arrangements.

However, the additional policy must also be justified in terms of addressing specific market barriers or imperfections – there is generally no gain to be had if the market is considered to be working efficiently at present. While the analysis to date does not indicate significant concerns in terms of physical outage risk or price variability, we have qualitatively identified several potential market imperfections or barriers:

- high costs to develop facilities that may have low utilisation;
- limited forward market liquidity;
- linkages between gas and oil prices;
- the impact of the credit crunch and other capital market imperfections;
- the security of supply being an externality, the full value of which is not rewarded to providers of said security;
- potential 'public good' aspects of insuring against extreme events, such that nobody in the commercial market invests to insure against them;
- the inability of some customers to signal their value of lost load to the market or for this value to be recognised in the current interruption and firm capacity process;
- lack of exposure of suppliers to the true costs of unserved energy;
- different public and private views on the value of security and the reliability of sources; and
- unintended impacts on gas demand flexibility from regulatory changes in other areas.

Since there are several dimensions of security of supply incidents – probability, scale and duration – we have differentiated the potential impact of these failures/barriers on two types of security issue:

- the occurrence of low probability/high impact events – commercial operators may not assess their exposure to these risks in the same way as society or policymakers; and
- the availability of short-term flexibility in the market – through appropriately priced demand side adjustments.

5.1.1 Low probability/high impact events

The review in Sections 2.8 and 2.9 has already shown the distillate backup and I&C Interruptible DSR cannot adequately manage a long duration or very severe supply disruption. In such circumstances, in order to avoid any impact of unserved energy, some form of reliable physical supply backup is required. This can be provided either through having sufficient diversity of supply sources or through accessing reserves in domestic storage facilities. While it is not evident from our analysis that GB requires such strategic storage to accommodate less than 1-in-19 year events – there appears to be sufficient commercial storage already available – in some countries this is not necessarily the case.

Strategic storage has, in these cases, been considered and used to provide the additional volume required. Consequently, we would consider a policy that provides additional physical gas capacity to be worthy of consideration for further investigation.

5.1.2 Short-term flexibility issues

Other forms of security events may be short-lived or less dramatic in scale. Here, some short-term flexibility in demand may be required before alternative supplies can be brought into the market e.g. time for LNG ships to arrive from the liquefaction plants. Historically, DSR (through interruption of industrial customers on interruptible contracts) and use of fuel switching in power generation have been key contributors to providing this short-term flexibility, as well as the existing gas storage facilities. It is also clear from the review in Sections 2.8 and 2.9 that the availability of distillate backup and I&C Interruptible DSR may have been compromised by recent UNC rule changes and so have had the unintended consequence of reducing this flexibility for major supply shocks.

Other sources of short-range flexibility have included the swing in supply contracts and medium-term storage. With the decline in UKCS supplies supply-side swing is reducing, although this can be offset by the interconnectors with the Continent responding to short-term price signals and the increased levels of LNG regasification terminals being able to provide more cargoes within a week or so.

Thus, in addition to looking at policy options for providing longer duration cover, it is appropriate to review further policies that could maintain or improve the flexibility of GB gas demand to mitigate any adverse supply shocks.

5.2 Responsibility for delivery

The delivery of any new policy may fall to suppliers/consumers, network operators or the government. This distinction may influence the cost of implementation, the effectiveness of the policy and the extent to which it is prone to unintended consequences. This is particularly relevant in physical storage provision options, as discussed below.

5.2.1 Government

Government provision can most easily be ring-fenced from the market and current commercial rules, with the use of reserves defined in relation to specific events and less susceptible to challenge on cost recovery or reflectivity concerns from regulatory oversight. However, any set of rules would be ‘incomplete’ and hence susceptible to uncertainty and policy risk, thereby creating unintended consequences.

5.2.2 Suppliers

Providing obligations on the suppliers has the advantage of ensuring that the management of the provision is being done through incentives, market mechanisms and rules. However, monitoring may be problematic and minimum provisions may distort competition and prevent new entrants in supply/shipping. Furthermore, there may be additional issues relating to the manner in which use of the physical gas could be triggered. For example, trigger rules such as breaching a security threshold, or offering the gas at a set price into the market may have unintended consequences. Market players might manipulate behaviour to trigger a security threshold, whereas a set price to bid into the market may raise concerns over regulatory cost recovery conditions as well as distortions to infra-marginal OCM bidding behaviour, thereby increasing balancing costs.

5.2.3 National provider

This would work in a similar way to the suppliers but would be provided by one national provider, with NGG as the main transportation provider the obvious choice. There would be the potential issue of cost recovery conflicting with regulatory objectives. Allowing a regulated utility to recover costs for events that are not likely to happen and identifying an acceptable rate or return will not be easy. There would need to be clear rules for discharging the obligation and whether it had been done in the most economic manner, and achieving agreement on these between all stakeholders would not be easy. However, monitoring of the scheme may be more manageable and less costly to implement than for a range of suppliers and would have the effect of socialising the cost of security provision across all suppliers (minimising distortions to supply competition).

5.3 Security of supply in other countries

We have investigated how security of supply is discharged in other countries to see what lessons can be learned and considered in developing alternative policy options that could improve the situation in GB and these are summarised in Annex C.

There are a wide variety of arrangements that have been put in place depending on each country's perceived risk to supply failure, historical market structure, availability of suitable gas storage (i.e. geology) and the government's market philosophy.

In some countries, such as Hungary, there are explicit strategic stocks that are only released on instructions from the relevant ministries. In others, such as Italy, there are strong incentives[39] to maintain strategic stocks, with flows being controlled by the TSO. In most others there are obligations on shippers and/or transmission system operators (TSOs) to maintain stocks, which are effectively strategic as their use is administered by a central body (TSOs and/or government ministries).

In Germany, which has the largest amount of gas storage in Europe, there are no security of supply obligations. However, there are severe penalties on shippers not supplying firm customers, which, with the lack of TPA in the past and good geology has arguably acted as an incentive to over build gas storage. Each major shipper has developed its own storage to satisfy its own worst case scenario, which in aggregate is worse than the worst case for the market overall.

Looking further afield, Japan is a major importer of LNG as it has very little indigenous energy supplies. It also uses nuclear power for some of its electricity generation. During recent safety related shutdowns it had to significantly increase its LNG supplies. Whilst this at first sight increased its exposure to the LNG market, when challenged on this a vice-minister of Japan's Ministry of Economy, Trade and Industry was reported in 2007 as saying 'that the country did not need to build national strategic reserves of LNG. "LNG is bought under long-term contracts that last for 20 to 30 years. With supply committed under such contracts, there's no need to build national reserves," said Takao Kitabata, glossing over the potential for unforeseen supply disruptions. He also suggested that the country's position as the world's biggest importer of LNG meant the country had significant enough buying power to overcome supply shortfalls'[40].

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[39] Stocks can be used under normal conditions, subject to a penalty. Relief from the penalty can be given on instructions from the relevant ministry.

[40] Heren LNG 23/2/07.

We would like to highlight some specific examples of short term measures introduced across Europe in specific circumstances:

5.3.1 Italy

In winter 2005/2006 a combination of factors led to a gas shortage in Italy:

- a cold winter which led to an increase in demand for heating (+ 3 billion cm);
- an increase in demand by electricity producers (+ 13% in 2005); and
- a reduction in imports (- 190 million cm), especially from Russia, via Ukraine.

The government therefore activated an emergency procedure, on 19 December 2005, and took a number of temporary measures to face the crisis. The following provisions were adopted:

- Resolution No. 10/2006: the Authority introduced an auction mechanism to activate a temporary interruption system of the natural gas supply;
- Ministerial Decree of 24 January 2006: the Ministry of Productive Activities relaxed emissions limits to the power generation plant up till 31March, in favour of the use of oil; and
- Ministerial Decree of 25 January 2006: the Ministry of Productive Activities reduced the allowed temperature limit in residential buildings from 1 to 28 February.

Additionally, strategic storage was also used in February 2006. On 22 March 2006 the Emergency Committee declared the end of the crisis.

5.3.2 Spain

In 2005 Spain perceived that it faced a potential lack of gas supplies. As can be seen in this press report the Spanish regulator, CNE, intervened by ordering strategic LNG storage and tightening balancing rules in an effort to ensure that gas was not diverted to the US or GB.

- 'Raising the quantity of LNG in storage, onshore and afloat, is central to the measures to ensure winter supply announced by the Spanish government last week. Two loaded tankers will be chartered and held in reserve ready to unload from 1st December to 15th March, the industry ministry said. Levels at terminal storage tanks will be increased by an unspecified amount among a raft of measures, including daily government monitoring of the supply-demand balance. The package goes further than that announced for the winter of 2003-04, when one tanker was kept anchored in the Mediterranean from December to March. It focuses mainly on storage – long identified as a weakness in Spanish gas infrastructure and regulation'[41].

5.4 Potential additional policy options

We identified a number of policy options that could potentially increase the levels of storage, distillate backup and demand side response, which can be categorised as follows:

- provision of physical storage;
- backup fuels for power generation;

41 Heren LNG 17/11/05

- demand side response from other users;
- other direct security policies;
- fiscal incentives; and
- other indirect regulatory incentives.

5.4.1 Policy shortlist

The following selection criteria were identified as appropriate measures to evaluate the effectiveness of the alternative policy options:

- time for implementation;
- speed of response at the time of need;
- complexity;
- potential volume towards annual demand;
- potential volume towards peak demand;
- reliability;
- legality;
- which failures/barriers it addresses;
- industry support; and
- unintended consequences.

We then assessed each of the identified policy options within the categories and against the above selection criteria to provide an initial view on options which may have a positive contribution. This assessment is summarised in Table 26 below and uses a traffic light system to show each option's contribution against the criteria identified above. A more detailed explanation against each policy option is contained in Annex D.

When considering which policy option to consider we have given extra weighting to the selection criteria for either the need to provide sufficient and reliable volumes to provide cover for a serious loss of supply that may occur in a low probability high impact event or to cover short-term flexibility issues. We have then considered who would have responsibility for delivery and looked at a group of criteria to judge whether it is feasible to implement (time for implementation, complexity, legality, industry support). We have also considered whether there would be any unintended consequences, and the potential impacts on market behaviour.

On the basis of the shortlisting exercise, we have selected the following policy options to be taken further and analysed. These reflect a range of policies to deliver both long-term security and short-term flexibility, chosen for their anticipated materiality on mitigating the two security aspects and their different implications for unintended consequences and market behaviour. The five policy options shortlisted are:

- restoring I&C interruptible volumes to historic levels;
- a minimum distillate obligation requirement;
- investment in strategic storage;
- a supplier stocking obligation; and
- top-up support.

Table 26 – Policy option selection against criteria summary

		Timeframe for implementation	Speed of response at the time of need	Complexity	Potential Volume	Potential Peak Volume	Control mechanism Govt v Mkt	Reliability	Legality	Does it target failures/barriers?	Industry support	Un-intended consequences
Physical storage options	Strategic storage	Red	Green	Red	Green	Green	Gov't	Green	Amber	Green	Red	Red
	Extra LNG tanks	Red	Green	Red	Amber	Green	Gov't	Green	Amber	Green	Red	Red
	LNG offshore (Spain example)	Amber	Green	Amber	Red	Green	Gov't	Green	Green	Amber	Red	Red
	Stocking obligation	Red	Green	Red	Green	Green	Ofgem	Green	Amber	Green	Red	Red
	Top-Up contracts – long-term and medium-term	Green	Green	Red	Amber	Amber	Central control	Amber	Green	Green	Amber	Red
	Storage Capacity Buyer of last resort	Amber	Green	Red	Amber	Amber	Central control	Amber	Green	Green	Amber	Amber
	Capacity mechanism for gas	Red	Green	Red	Green	Green	Central control	Green	Red	Amber	Red	Red
Back-up fuels	Minimum distillate storage requirement	Amber	Green	Green	Amber	Green	Ofgem	Green	Green	Green	Amber	Red
	Coal plant post LCPD	Red	Green	Green	Green	Green	Market	Green	Red	Amber	Amber	Red
	Capacity mechanism for Power	Amber	Amber	Red	Green	Green	Market	Amber	Red	Amber	Amber	Red
Demand side Response	Restore I&C interruptible volumes	Green	Green	Green	Amber	Amber	Market	Amber	Green	Green	Red	Amber
	End users to bid directly into OCM	Amber	Green	Red	Amber	Amber	Market	Amber	Amber	Green	Red	Amber
	Live price information for DSR providers	Green	Red	Amber	Amber	Amber	Market	Red	Green	Red	Red	Green
	Crisis price incentives e.g. double overnight tariff (through smart	Amber	Green	Amber	Amber	Green	Gov't	Amber	Amber	Amber	Amber	Red
Other direct security policies	Supplier obligation incentive (1 in 50)	Red	Green	Amber	Green	Green	Ofgem	Green	Red	Green	Red	Red
	Security Obligation Certificate	Red	Green	Red	Green	Green	Market	Green	Red	Green	Amber	Red
Fiscal	Fiscal incentives – grants, allowances, loans, etc. (counter any	Red	Red	Amber	Amber	Amber	Gov't	Red	Red	Amber	Green	Red
	Cushion gas capital allowance	Red	Red	Amber	Amber	Amber	Gov't	Red	Red	Amber	Green	Red
Indirect policies and regulatory incentives	Energy efficiency to significantly reduce demand	Red	Amber	Amber	Green	Green	Gov't	Amber	Amber	Amber	Green	Green
	Smart meters	Red	Amber	Red	Amber	Amber	Gov't	Red	Green	Green	Green	Amber
	Improvements to the planning process	Green	Amber	Red	Green	Green	Gov't	Green	Amber	Green	Green	Green
	More interconnection with & within the EU	Red	Green	Green	Green	Green	Gov't	Green	Amber	Green	Green	Green
	TPA Exemptions	Amber	Amber	Amber	Green	Green	Gov't	Amber	Amber	Amber	Amber	Red
	Gas Quality	Red	Green	Red	Green	Green	Gov't	Green	Amber	Green	Green	Amber

Red signifies a negative assessment, amber signifies an ambiguous or potentially negative assessment, green signifies a positive assessment.

5.5 Evaluation of shortlisted policy options

The shortlisted policy options are described in detail, below. For each option, we discuss its shortlisting criteria and, on the basis of each option's encapsulated assumptions, we evaluate the potential benefits of each option. These benefits are then compared in Section 5.6 and the analysis is carried forward to draw the conclusions set out in Section 5.7. As most of the policy options would rely on the occurrence of specific, pre-defined events, they have proven to be difficult to model – the models either assume they are or are not available to the market, as set out below:

- where the security instrument is deemed available for use at a preordained price, its use prevents known quantities of unserved energy;
- where the security instrument is deemed available only under specific circumstances which have not been met, the modelling reports no impact; and
- where the security instrument is deemed available only under specific circumstances which have been met, its use prevents known quantities of unserved energy.

The specific circumstances need careful definition and consideration alongside existing emergency arrangements.

Investment appraisal assumptions and asset lives

To express annual expected values in net-present terms we have assumed a discount rate of 3.5%, consistent with HM Treasury's Green Book.

The actual asset life of a storage facility will depend on the type of the storage facility, and the component parts of the whole asset will depreciate at different rates. Considering a salt cavity facility as an example: part of the capitalised costs of salt cavern storage would include the costs of leeching the caverns – once leeched, the caverns will not need re-leeching, so arguably this element of the investment costs should not be depreciated or should be depreciated over a very long time; another part is the mechanical compression equipment which might be designed to last 10 to 20 years. Other types of geological facilities – depleted fields and aquifers – have similar constituent parts and therefore relatively long asset lives; non-geological facilities – LNG or distillate storage – are mainly mechanical in nature and would therefore have much lower asset lives. In general, longer appraisal periods would increase the attractiveness of an investment, as ongoing benefits are counted for longer.

We have assumed an asset life of 30 years as a reasonable average, and have therefore used 30 years as the appraisal period for analysing the strategic storage option. To ensure consistency across the evaluations of the policy options, we have assumed 30-year appraisal periods for the other policy options. We note this would be considered to be a particularly long appraisal period for a commercial investment appraisal and it is longer than appraisal periods used by Ofgem in analysing regulatory impact, however it might be considered to be a short period for a direct government investment.

5.5.1 Restoring I&C interruptible volumes to historic levels

This policy option seeks to maintain the levels of demand side response that has historically been provided by I&C interruptible consumers and so would require the market to maintain the alternate fuel capability. As stated in Section 2.9.4, the current levels of alternate capability have been estimated at approximately 10mcm/d; this policy option would restore this figure to around 36mcm/d.

Having this extra 26mcm/d of backup supply for a number of days would provide enough cover to avoid the situation of energy unserved in the 1 in 19 and 1 in 30 probabilities, as outlined in Section 4.3.3.

The introduction of Mod 90 has not fully taken into account the demand side insurance contribution provided under the historical I&C interruptible contract. This policy option would be to encourage I&C Interruption to remain at historic levels by:

- Introducing an auction to provide a demand side insurance incentive on shippers, on behalf of I&C sites (as the UNC prevents a direct interaction with consumers), which is independent of the transporters' needs for capacity constraint interruption.
- Allowing the SO to set the level of required volumes for a fixed period, say 5 years, based on its forecast of any gap in severe annual and peak supply and demand positions. It would then recover any costs from the community as a whole to reflect the benefit being provided to improve security of supply.
- Encouraging I&C sites to maintain their backup supplies and enter into contracts with shippers to provide the DSR capacity to the market.

Logically, there is already a potential incentive on large I&C sites to enter into these arrangements as these would be amongst the first consumers to be interrupted if there was a gas supply emergency, for which they would receive very limited recompense. However, the current perception that the market has sufficient supplies available to it means that this occurrence is perceived as very rare, so the incentive is negligible.

Implementation might be difficult. All parties will need to reach agreement on the rules to be followed on establishing any future level of I&C interruption required. Some parties may prefer to invest in storage directly under their control rather than accept the unknown costs arising from an auction, believing this would provide a more appropriate contribution to improving security of supply.

Any party to the UNC could raise a new modification to introduce such a new mechanism. The procedure for raising modification proposals is well established: a high level brief as outlined here would be sufficient to enable relevant UNC signatories and other interested parties to collectively finesse a formal proposal, with legal text being commissioned by the relevant gas transporters at the appropriate time. It may also be necessary to modify the licence of the system operator to establish the obligation it will need to discharge through this option.

There is, however, a risk to this policy option as I&C sites may already be planning to decommission and remove their backup facilities. Should it be identified that this policy option is required then it will need to be progressed quickly, as any delays may reduce the amount of backup capacity available as it will likely be uneconomic to restore removed or decommissioned facilities.

5.5.1.1 Selection criteria

We consider that the time for implementation would take about a year for the UNC modification to be developed in full and receive approval, and so any required volumes of DSR could be achieved before existing facilities are dismantled. The direct investment costs for this option would range from being relatively minor if no action is required by I&C sites to the potential for more substantial costs associated with maintaining or returning the backup facilities and fuel stocks.

5.5.1.2 Evaluation

We have examined the effect of this policy option directly within Prometheus. The probability of unserved energy in 2010 would move from 1 in 19 years to 1 in 32 years and in 2025 from 1 in 15 years to 1 in 28 years, as a direct result of returning to historic levels of I&C interruptible contracts. We also calculate that, with the policy option implemented, the expected value of unserved energy falls from £7.77m per annum to £3.60m per annum (based on 2010), and from £10.0m per annum to £4.56m per annum (based on 2025). We therefore calculate benefits of £4.18m per annum in 2010 rising to £5.45m per annum in 2025. This provides a NPV of £95.5m (extrapolating a linear interpolation between 2010 and 2025 over 30 years at a discount rate of 3.5%).

If this policy option is implemented before any decommissioning in backup fuel facilities are made by I&C interruptible sites and stock levels have not been reduced there should be only limited implementation costs. However, as noted in Section 2.9.4, it is difficult to assess whether stocks have been maintained and so this policy option may require restocking investment at the least. We anticipate that initial restocking will require at least 125,000 tonnes of distillate stocks, i.e. an investment in stocks of £39m (at £313/tonne as per Section 2.8.4). We do consider there to be significant risk involved in this estimate, such as delivery charges, actual stock levels or reinstating mothballed equipment, so we have therefore assumed that the investment in distillate would cost between £50m and £125m. This investment would need to be recovered by I&C sites through the auction process so we would expect to see some price impact in consumer gas prices; however, the average impact to consumers would be very thinly spread and therefore negligible in p/therm.

5.5.2 Minimum distillate obligation requirement

This policy option is based around a mandate that CCGTs must hold specific levels of distillate at particular point in time to provide some assurance that there is some short-term flexibility available for a period following that point in time (actual timing and levels are discussed below). This provides additional, relatively short-lived support to cover shorter-term events, and potentially provides a degree of longer-term security if distillate stocks can be replenished. It is a policy that has been adopted in countries that do not have much gas storage, such as Croatia and even New Zealand, as it is relatively small scale and short duration.

Placing an obligation on all gas-fired generators to maintain a minimum amount of backup fuel on site would be very difficult to implement, as most existing sites and those under construction do not have distillate backup and retrofitting would be very expensive, time consuming and in some cases impossible (due to limited space, environmental considerations and planning permission issues). Therefore it is our opinion that it is only practical to place the obligation on existing sites that have the facility and new sites coming on stream in at least 3 or 4 years' time.

We therefore expect to see an increase in capability implied from the current commercial stock levels of 24mcm/d by 15mcm/d to the capability of 39mcm/d (as identified in Section 2.8). This option would therefore cover the energy unserved with 1 in 19 years probability, but not fully cover the occasions with lower probability.

We expect that the mandate would require that at some date prior to the winter existing facilities will be 100% full of distillate stocks. The variation of the number of days covered, as shown in Table 4 on page 17, means that it would not be possible to have a specific number of days that covers all sites. Away from this date, power station operators are free to utilise their distillate stocks as they see fit, which, given expected gas and coal prices would probably not be used unless there was an issue with gas supply. Whilst alternative options might include applying a profiled minimum stock level or a minimum level to apply throughout the winter, similar to the storage monitor, we consider these options would increase the risk of unintended consequences without delivering additional effective security.

We expect that the implementation of this policy option would be more involved than restoring I&C interruptible volumes to historic levels. The generators with distillate backup will require compensation for holding these stocks, which may never be used, otherwise they will be at a disadvantage to those generators that do not have the backup facilities. This could be through the new short-term off-peak capacity product, although this is also available to all CCGTs.

Portfolio generators may also argue that they have generation at other sites, particularly until 2015, which can provide backup from coal or oil. The other issue is that many of the older CCGTs that do have backup will be coming to the end of their lives in the next ten years or so, and may not be around to provide the backup, which is why the mandate would need to apply to new CCGTs commissioning after 2013 or so.

5.5.2.1 Selection criteria

The policy option has a reasonable timeframe for implementation, and some successes (a higher level of security) can be obtained relatively quickly. The policy does not necessarily need to be complex; however, it would need to be considered in the context of the electricity market where it may decrease the attractiveness of new CCGT build, and because the need for it to provide black-start capability is already covered by existing electricity market practices. Legal powers already exist to implement this option, and industry support would very much depend on the cost recovery method.

It has the benefit of being easy to monitor but there are various practical issues to be considered such as replenishment capability, which would limit the number of days it would be available, interactions between the gas and electricity codes, and on whom (i.e. which CCGTs) the obligations should fall.

The direct interaction with the electricity market means that there are potential distortions in that market as a consequence of this policy, such as the potential for decreasing the general profitability of CCGTs, and with an obligation on new facilities to install distillate backup the costs of new entry would increase by about 2%.

5.5.2.2 Evaluation

This policy option has a similar benefit per unit volume, at each probability, as the option to restore I&C interruptible volumes to historic levels described in Section 5.5.1.2 above, although it would provide a smaller DSR volume. This means that the policy option presents a benefit of approximately £2.34m per annum (based on 2010) and £3.05m (based on 2025) – a net present value of approximately £53.5m (extrapolating a linear interpolation between 2010 and 2025 over 30 years at a discount rate of 3.5%).

Just as in restoring I&C interruptible volumes to historic levels we expect initial restocking to require about 100,000 tonnes of distillate stocks, i.e. an investment in stocks of £31m (at £313/tonne as per Section 2.8.4). However, we consider there to be significant risk involved in this estimate, as well as delivery charges so we have therefore assumed that the investment in distillate would cost between £40m and £100m. This investment would need to be recovered by the generator so we would expect to see some price impact in either gas prices or electricity prices; however, the average impact to consumers would be very thinly spread and therefore negligible in p/therm or p/kWh terms.

5.5.3 Strategic storage

The strategic storage policy requires the provision of dedicated storage quantities that are procured and controlled by Government and used only in specific predefined circumstances.

Due to the relatively low volumes of potential unserved energy implied by the analyses in Section 4, we specify this policy option to provide sufficient storage capacity to prevent all unserved energy loss. We therefore consider that a facility (or part of a facility) with a capacity of approximately 0.5bcm with adequate deliverability of around 25mcm/d. There are numerous potential candidate projects with known capacity, performance characteristics and costs that might provide such storage capacity.

We have considered a number of ways of implementing this policy – via direct government investment and control, or through placing an obligation on a third party, such as National Grid. However, the choice of approaches would not materially effect any high-level assessment of its costs and benefits, so, for simplicity, we have assumed that this policy option is implemented via direct government investment and control.

Following any decision to implement this policy option, HM Government would need to identify and progress the necessary legal changes and procurement processes, for which we expect they would need specific legal advice.

Part of the legal change would be to identify both the framework for exercising the use of the facility and the entity with that power, e.g. Ofgem/GEMA, the Health and Safety Executive or the National Emergency Coordinator. That framework and entity would also need to establish the precise physical conditions under which the facility could be used, e.g. at demand levels in excess of say 95% of the forecast NTS 1 in 20 peak day where there is a supply failure of greater than say 50mcm/d, and how this fits in with the Emergency procedures. We assume that it would be provided to the market at a set price, reviewed from time to time based on the value of lost load – the analysis in this document implies a price between £2/therm and £5/therm would be appropriate. The gas would be released via the OCM, which would set the cash-out price and provide a strong incentive to bring gas into the market below this price.

5.5.3.1 Selection criteria

This policy option meets the criteria of providing sufficient volumes and having a clear responsibility for delivery, but may potentially have the consequence of distorting the market value of commercial storage and inhibiting the development of such commercial storage, creating a moral hazard.

This option has the benefit of adding extra volumes of storage to the market, enabling it to meet low probability/high impact events. However, the additional volumes would not be available for commercial use. Selecting underground storage rather than LNG tanks, or tankers offshore, which were also considered, has the benefit of providing physical gas located in GB which would not be impacted by external political influences.

It is likely that this option would take several years to build and to deliver security benefits. Defining the arrangements for its deployment might be complex, especially considering how it might interface with existing market mechanisms such as the emergency cash-out arrangements. We anticipate that it could garner some industry support; however, we think that many market participants would be sceptical. This policy option would probably require primary legislation.

Other factors that need to be considered include the costs, financing, and any cost recovery mechanisms (through taxes or a small levy on transportation charges or gas bills), as well as whether and how much the moral hazard might distort the commercial market, which are considered below.

5.5.3.2 Evaluation

An examination of a 0.5bcm facility to prevent the lowest probability of unserved energy volume, would suggest a capital cost of over £0.5bn (based on the recent cost estimates for the proposed Baird facility). We have assumed a cost of between £400m and £600m for such a facility. The financing of the investment might be expected to cost between £22m and £33m per annum (based on 3.5% discount rate over 30 years), which does not compare favourably against the potential benefits – the expected value of unserved energy – as estimated in Section 4.3.3.2, of £7.8m to £10m per annum[42]. We therefore conclude that investing in strategic storage would be uneconomic.

Whilst this policy option contemplates that the gas would be released to the market at a set price thereby forming a price cap, we would not expect strategic storage to affect normal market prices which are much lower than this. Therefore, day-to-day volatility, weekend/weekday differentials, seasonality, the relationship to oil prices and the absolute levels of gas prices would remain unaffected so should therefore not impact the investment made by the commercial sector.

5.5.4 Supplier stocking obligation

This policy option places an obligation on each gas supplier to hold sufficient supplies to cover a certain level or proportion of its firm supply. It can be seen as an alternative way of introducing strategic storage by removing volumes of commercial storage from the market, so increasing the incentives to introduce more new commercial storage. The loss of existing commercial storage might be expected to increase seasonal spreads and volatility of prices, thus creating a greater incentive for new investment.

The obligated volumes would be based on the impact of system failure and an objective to mitigate unserved energy. This policy option assumes the same volumes (and therefore maximum benefits) as the strategic storage option, above, and would therefore place an obligation on each supplier to hold 0.5% of their supply obligations in storage.

Implementation would first need to definitively establish if there were any necessary legal changes. We consider that Ofgem already have the necessary powers to introduce these obligations to gas supply licences, and as such we consider that this would be the simplest route to implementation. In this situation Ofgem would also be in the best position to police and audit the obligation. Ofgem may also be responsible for setting the obligatory stocking levels; these might change over time, depending on the perceived risk of a supply shortfall and may be zero for some years. In this case Ofgem would need to indicate future years' obligation requirements, in order for shippers/developers to have time to develop more storage facilities.

5.5.4.1 Selection criteria

This option could be implemented reasonably quickly, as obligations could be discharged through the use of existing infrastructure, although the incentives to build new storage to compensate for the ring fencing of the existing storage would take some time to work through. The determination of the obligatory stocking levels might be complex, especially if they change from year to year.

Shippers and suppliers could be expected to argue against compulsory obligations, and primary legislation might be required.

In addition to those considered for strategic storage above, this option would more than likely have an unintended consequence of increasing the barrier to entry for small players. This could be overcome by some form of exemption or less onerous obligation for small or new players.

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42 Note that the cost of unserved energy in any one year would be an order of magnitude higher, but when combined with the probabilities it results in these expected values.

5.5.4.2 Evaluation

We consider that similar benefits could accrue from this option than as for the strategic storage option – we consider that there is maximum benefits of preventing all unserved energy – i.e. £7.8m (based on 2010) and £10m (based on 2025) per annum. However, we consider that there might be risks to the benefits associated with this policy option, in comparison to strategic storage, (e.g. supplier non-compliance) and therefore consider it prudent to introduce a lower bound to the benefits of £4m per annum.

As the market-led investment (driven as a consequence of sterilising commercial storage) would take a number of years to materialise, we expect that investment costs would be lower in net-present terms. Downward pressure on costs could also be introduced through innovation. We have estimated that the resulting investment costs would be in the region of £500m to £300m in net-present terms.

5.5.5 Top-up support

Top-up is a method initially developed at the start of the Network Code in 1996. The transmission system operator would analyse the potential gap between forecasted supplies and severe demand and procure sufficient supplies/storage to fill the gap from market participants. Costs were then smeared across shippers through transportation charges. This method was set up because British Gas plc was not convinced that the rest of the market would deliver gas in severe conditions since the GB market was isolated and the market rules were relatively new and untested in relation to security of supply.

Top-up was phased out around 2004 by Ofgem because it was felt that the market should be able to provide under suppliers' 1-in-50 obligations.

Reintroducing some form of top-up support would have a similar objective to the strategic storage and stocking obligation options, but instead introduces a market based auction process to deliver the cover, which should provide the most efficient combination of storage and demand side response. This has the benefit over stocking obligations that the costs can be socialised across all suppliers as well as being more flexible in the volumes required over time.

To satisfy the obligations for new facilities to be developed on time, the national provider would need to analyse the market conditions and supply availability for a number of years ahead to give time for new facilities to be built and any shortfall identified against a severe demand level can be filled through an auction process. The auction can be for different tranches of security of supply volumes as some might be required for a longer period of time and others might be for a small period whilst new infrastructure is being developed.

5.5.5.1 Selection criteria

This option could be implemented relatively quickly, as the framework for top-up arrangements has already existed in the UNC, although details of the regime might require some industry development. Monopoly regulation issues might make this a complex option, and we expect that industry support would depend on the resolution of such detail. It is unlikely that this option would require primary legislation to enact; however, implementation would need to comply with the relevant European legislation (e.g. 2003/55/EC).

This option has the advantage of using commercial providers, can be open to various providers and may facilitate DSR. However, there will be barriers to overcome such as defining an acceptable cost smearing mechanism and ensuring compatibility with the gas balancing mechanism and normal cash-out arrangements. These were major considerations during the removal of the previous top-up arrangements in 2004.

5.5.5.2 Evaluation

We consider that the same benefits would accrue from this option than as for the strategic storage option, i.e. a maximum of £7.8m (based on 2010) to £10m (based on 2025) per annum. However, we consider it likely that the actual benefit is less than this figure: the gas transporter will have the ability to tailor each year's top-up requirements to the prevailing conditions and may face regulatory incentives to be conservative in its estimates. The actual benefit that would be realised by this policy option would therefore be lower than that suggested by the maximum, and we consider it prudent to introduce a lower bound to the benefits of £3m per annum.

Investment driven by the increase in storage capacity bookings would take a number of years to materialise, and therefore we expect that investment costs would be lower in net-present terms (as they are incurred later in the appraisal period). Downward pressure on costs could also be introduced through innovation, and we consider that this policy option would be complimentary to the existing operating margins regime, presenting possible further savings. We have estimated that the resulting investment costs would be in the region of £400m to £200m in net-present terms.

5.6 Policy options cost/benefit comparisons

From the above considerations we have constructed the approximate costs and benefits included in Table 27 below. The table captures the observations of:

- reduced cost of expected demand loss – the expected average saving made due to lower probabilities and/or volumes of unserved energy;
- NPV of reduced cost of expected demand loss – capturing any changes to the asset base of the gas industry that are likely to be recovered through long-run marginal cost pricing in the market between 2010 and 2025;
- other benefits – other benefits that might occur (not quantified);
- implementation costs – the administrative costs of implementing the particular policy option;
- investment costs – as would be driven directly or indirectly as a result of the policy option and be required as an upfront investment;
- risks – any risks that have not been quantified and included in the above; and
- the net benefits or costs.

Table 27 – Cost/benefit comparisons (2008 prices)

			Policy Option				
			Restore I&C interruptible volume levels	Minimum distillate obligation	Strategic storage	Stocking obligation	Top-up support
			+ 26mcm/d	+ 24 mcm/d	500mcm & 25mcm/d	0.5% supply obligation in storage	Auction to meet 1 in 50
Assumptions	Discount rate		3.50%	3.50%	3.50%	3.50%	3.50%
	Appraisal period (years)		30	30	30	30	30
Benefits	Reduced cost of expected demand loss (£m in 2010, £m in 2025)	High	4.18 , 5.45	2.34 , 3.05	7.8 , 10	7.8 , 10	7.8 , 10
		Low	4.18 , 5.45	2.34 , 3.05	7.8 , 10	4.0 , 4.0	3.0 , 3.0
	NPV of reduced cost of expected demand loss (£m)	High	95.5	53.3	175.7	175.7	175.7
		Low	95.5	53.3	175.7	73.6	55.2
		Other	Qualitative	Electrical security and gas price hedge			
Costs (£m)	Implementation	High	0	0	-3	0	0
		Low	-1	-1	-5	-1	-1
	Investment	High	-50	-40	-400	-300	-200
		Low	-125	-100	-600	-500	-400
Risks			Regulatory intervention	Barrier to entry in electricity market	Moral hazard	Moral hazard, barrier to entry	Moral hazard
	Net benefits (costs) (£m)	**High**	**45**	**13**	**-227**	**-124**	**-24**
		Low	**-31**	**-48**	**-429**	**-427**	**-246**

5.7 Policy option conclusions

Existing policies such as the 2020 energy efficiency and renewables targets are already delivering significant security of supply benefits, primarily through reducing gas demand into the future. As UKCS supplies decline, importation facilities that are already constructed or committed are available to meet demand – gas will flow subject to price signals, which is enabled through the liberal nature of the gas market. We therefore conclude that the existing policies are positively contributing to the security of the GB gas market.

Our modelling indicates that, given the volume and diversity of supplies, the risk of a supply shortfall and unserved energy occurring is 1 in 19 years with 2010 supply and demand assumptions and 1 in 15 years with 2025 assumptions, which include very little additional supply and storage capacity compared to what we have now. We calculate that the amount of unserved energy would be relatively small in these events and could be covered completely by an additional 500mcm of storage over and above that already committed with deliverability of around 25mcm/d.

Further improvements to security of supply might be found from two broad areas: long-term, large volume strategic facilities designed to provide significant volumes over a longer period; and shorter-term, rapidly available facilities designed to overcome periods of short term stress. We have examined 24 potential policy options targeted at improving security of supply.

The major policy of HM Government directly investing in strategic gas storage would be expensive and does not, based on the analysis in this report, provide sufficient benefit in improving security of supply to justify its costs.

Of all the policy options examined, two options perhaps warrant further consideration:

- restoring I&C interruptible volumes to historic levels and so utilising the capability of them using alternatives to their gas supply; and

- introducing new obligations on some or all large gas-fired power generators to install and maintain backup fuel facilities and to keep and maintain backup fuel stocks.

Of these two policy options, restoring I&C interruptible volumes to historic levels, whilst there would be various regulatory issues in implementing, would have the effect of halving any risk of unserved energy.

We also believe that introducing new obligations on existing and/or new CCGTs would have some challenges: there are potentially significant unintended consequences the mitigation of which might lead to complexity; and it might prove much more difficult to gain support from industry. We note that existing market mechanisms in the electricity market provide some incentive to invest in alternative fuel capability, and would urge that caution is applied to any market changes (gas or electricity) which might decrease these small incentives. We also consider that introducing an involuntary obligation on CCGTs might increase the perception of regulatory risk and increase barriers in the electricity industry.

However, recognising the significant contribution to gas security of supply provided by CCGTs, should the levels of cover be reduced, either by the decommissioning of backup facilities at existing stations, or insufficient capacity being built at new sites, policy makers will need to consider whether there is a requirement to introduce new obligations to install and maintain backup distillate facilities and stocks.

Given that all the potential commercial storage facilities being considered are larger than the potential shortfall that emerges from our analysis, a number of influences – the improvements in the planning process, the tax allowances on cushion gas already in place and the potential increase in volatility from CCGT demand following the introduction of more wind generation – should provide incentives for at least one of the projects to go ahead, making the need for the other options unnecessary.

We therefore recommend that no new major policies are introduced in an attempt to increase the security of the GB gas market.

ANNEX A – MODELLING

Pöyry has approached the study in two ways, a deterministic scenario approach and a probabilistic approach. This annex describes the two models, Pegasus and Prometheus, that Pöyry has developed to carry out this work.

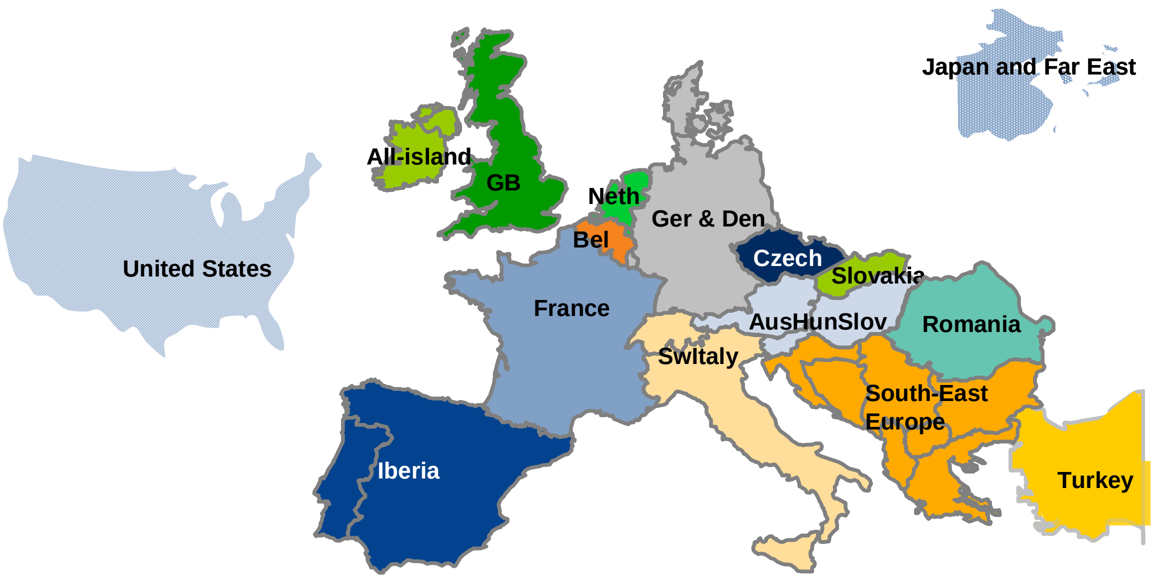
A.1 Pegasus

Pöyry forecasts the price of gas in a variety of zones worldwide using the pan-European and US gas model, Pegasus ('Pan-European GAS + US'). The model examines the interaction of supply and demand on a daily basis in GB, Continental NW Europe (NWE), Spain, the US, Italy, SE Europe and the Far East. Examining daily demand and supply across these markets gives a high degree of resolution, allowing the model to examine weekday/weekend differences, flows of the Interconnectors and gas flows in and out of storage in detail.

A.1.1 Detailed description

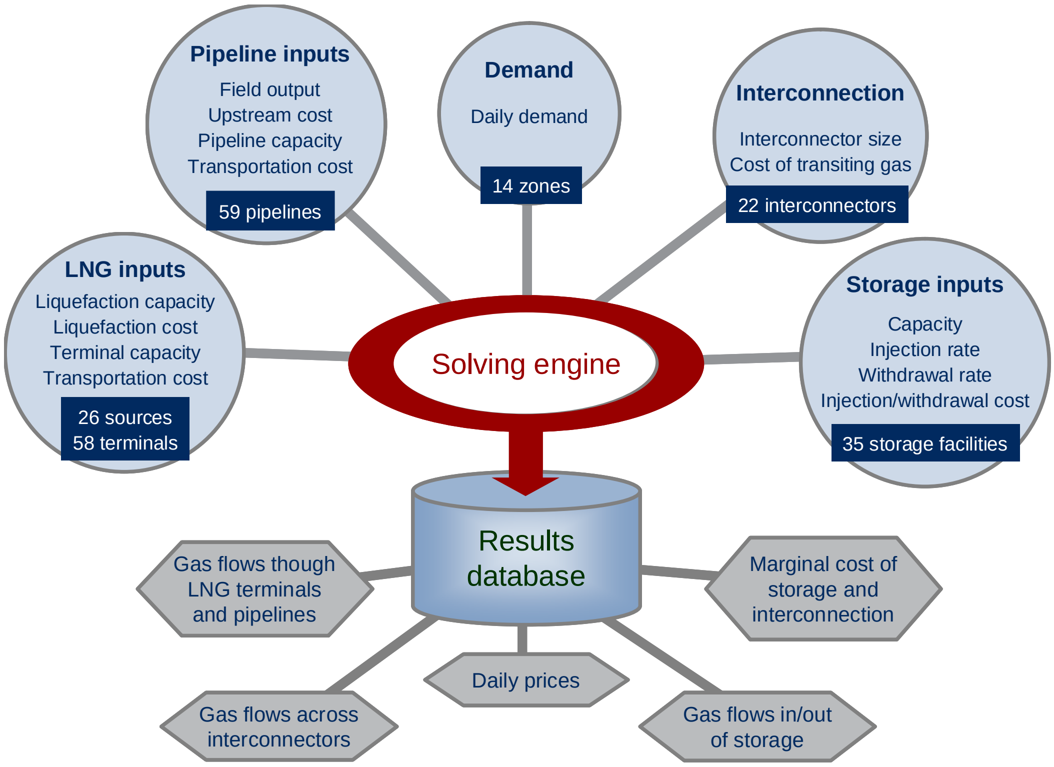
Pegasus itself is comprised of a series of modules. The main solving module is based in XPressMP, a powerful Linear Programming (LP) package, which optimises to find a least-cost solution to supply gas to these 17 zones over a gas year. The solution is subject to a series of constraints, such as pipeline or LNG terminal sizes, interconnector capacities and storage injection/withdrawal restrictions.

Figure 44 – Geographic coverage of Pegasus



The solving module takes input files generated by a series of Excel/VBA modules, which allow a variety of scenarios to be created by changing variables such as supply, demand, costs, storage and interconnectors. The outputs from the model, such as prices and flows of gas, are sent to a database to allow easy extraction of data at either a daily, monthly or annual resolution, as shown in Figure 45.

Figure 45 – Structure of Pegasus



A.1.2 Interconnection and storage

Interconnection through between zones is a key part of the modelling in Pegasus. For example, the BBL and IUK interconnectors between GB and Continental European markets are important given the influence of oil-indexed long-term contracts. The optimisation algorithm in Pegasus minimises the cost of supplying gas to all market zones, subject to both the capacity and the cost of transiting gas across the interconnectors. This tends to lead to imports into GB during winter to supply the peaky GB winter demand, and exports from GB during summer. These patterns naturally change over time with differing assumptions on gas cost and new import projects and their location. The daily resolution in the model means that during the shoulder months, the interconnectors 'flip-flop' back and forth between import and export – exactly as we have seen historically. Interconnection between each of the demand zones is also modelled in the same manner.

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

We also model European and US storage in three generic types – depleted field, salt cavern and LNG. This lower level of detail is sufficient for other countries storage due to the non-commercial nature and opaqueness of use of much of the storage facilities.

A.1.3 LNG modelling

To model LNG accurately, gas is split into 'LNG sources' (e.g. Qatar, Oman, Nigeria) and 'LNG terminals' (e.g. Isle of Grain, Dragon, South Hook). Subject to known contractual constraints, LNG cargoes can be 'delivered' from any source to any LNG terminal. As a result, LNG cargoes can be delivered to different destinations depending on which market is most profitable for a particular cargo – for example, LNG will deliver preferentially to Montoir or Zeebrugge when prices are higher in NW Europe than in GB. Thus the NW European market can be linked to GB market not just through the interconnectors but also via LNG arbitrage. Furthermore, the interaction with the US, Italy and Spain means that all markets can become linked together via LNG and pipelines.

The cost of LNG transportation takes into account the distance between the points where gas is delivered, along with assumptions on oil price (for fuel costs), and reductions in shipping costs.

A.1.4 Gas cost

Pegasus can model worlds where oil-indexation or gas-on-gas competition is the major driving forces in the market. For oil-indexed contracts, either LNG or pipeline, although specific oil-indexed contracts can be added to any given route, given the confidential nature of most contracts, generic oil-indexation contracts reflecting knowledge of the likely market where gas is delivered are typically used.

For worlds where gas-on-gas competition becomes a major driver of price formation, Pöyry assesses the long-run marginal cost of different gas supplies and transportation costs to model the prices that gas could be delivered to market.

A.1.5 Demand forecasts and profiles

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

Our daily gas demand profiles reflect the known factors in the market, including weekend and weekday differentials, Christmas and summer shutdowns, and winter demand peaks due to space heating or summer peaks due to CCGT loads for air conditioning.

A.2 Prometheus

Pöyry has developed the 'Prometheus' model for examining the effects of unexpected and/or extreme events on the GB gas market. At its core, Prometheus uses the same optimisation criteria as our deterministic gas model, Pegasus; however, Prometheus is notably different in two ways. Firstly, it includes a stochastic model of the GB gas market that captures the likelihood and magnitude of a variety of natural, technical and political events. Secondly, to avoid a massive computation problem, we have simplified the level of interconnection by decreasing the number of zones from 17 in the deterministic modelling to four in the stochastic modelling.

In effect, Prometheus models a simple four-zone Atlantic gas market, and drives thousands of scenarios though the Pegasus engine.

This section sets out some of the detailed assumptions used within the Prometheus model.

A.2.1 Demand variation

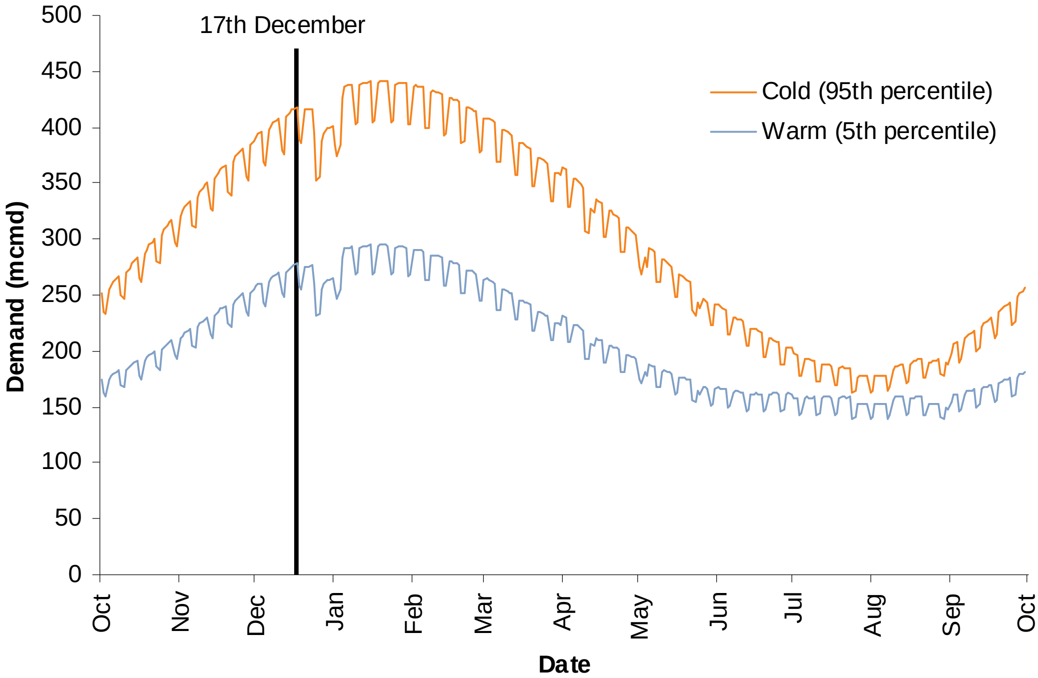
We have modelled demand variations to replicate the daily weather severity considerations of National Grid Gas plc (NGG), who regularly publishes daily demand forecasts based on seasonal normal, warm and cold weather profiles. The warm and cold profiles are stated by NGG as being at 1 in 20 weekly values, and are based on the Gumbel-Jenkinson distribution[43].

We have used the Average and Severe annual demand forecasts, as described in Section 2.6.1. Within Prometheus, we apply these as 50th and 98th percentiles of the Gumbel-Jenkinson distribution to generate a range of annual demand figures. Figure 46 below shows the cold and warm profiles used in the model (corrected for weekend/weekday).

Figure 47 shows the Gumbel-Jenkinson distribution for a sample day –17 December 2010 – with the 5th, 50th, 95th and 98th percentiles highlighted.

This distribution is then used to scale each iteration of the daily demands (generated by their distributions). Sample annual demands at daily resolution, representing particular average and high samples, are presented in date order in Figure 48, and as a duration curve in Figure 49.

Figure 46 – GB Demand profiles



[43] The Gumbel-Jenkinson distribution, also known as the extreme values distribution, is a probability distribution specifically constructed to enable the examination of extreme events.

Figure 47 – GB Demand distribution for 17th December 2010

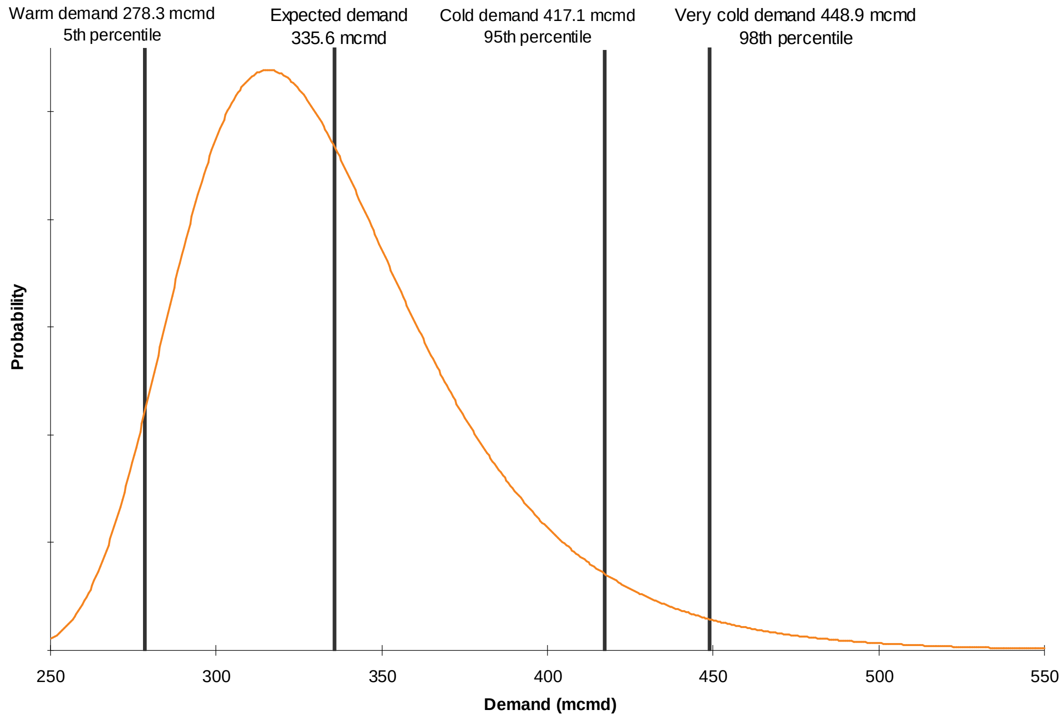


Figure 48 – Sample daily demand tracks (2010)

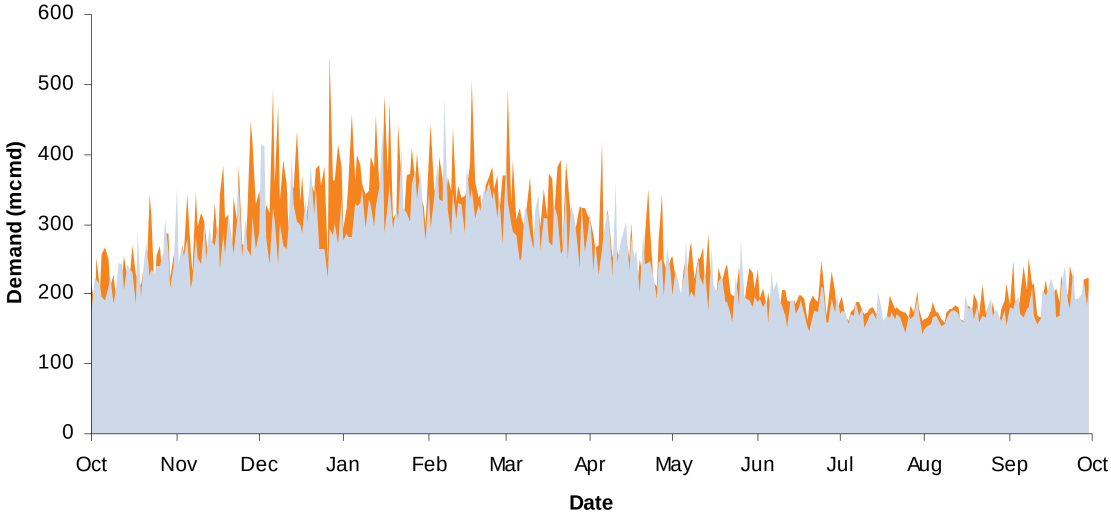
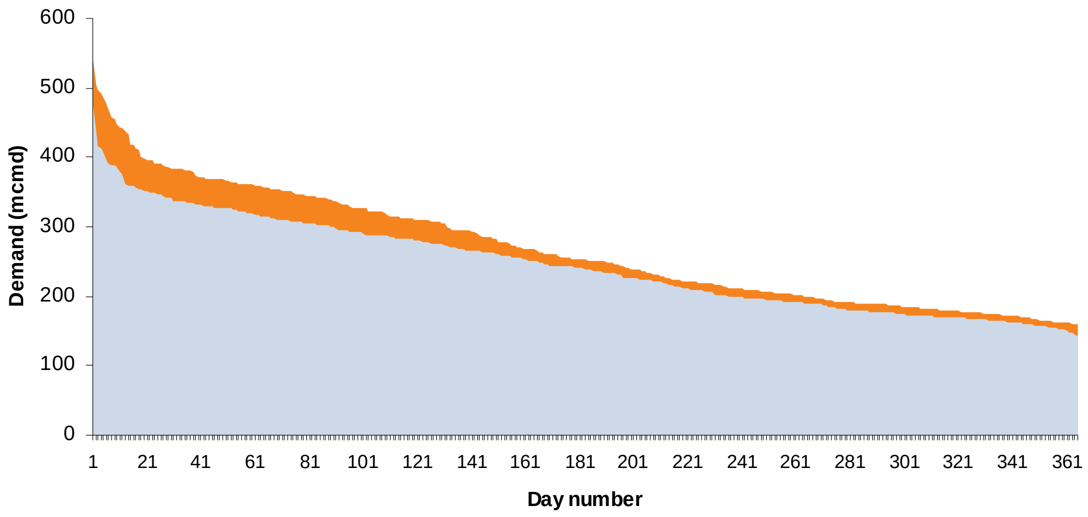


Figure 49 – Sample load duration curves (2010)



A.2.2 Oil

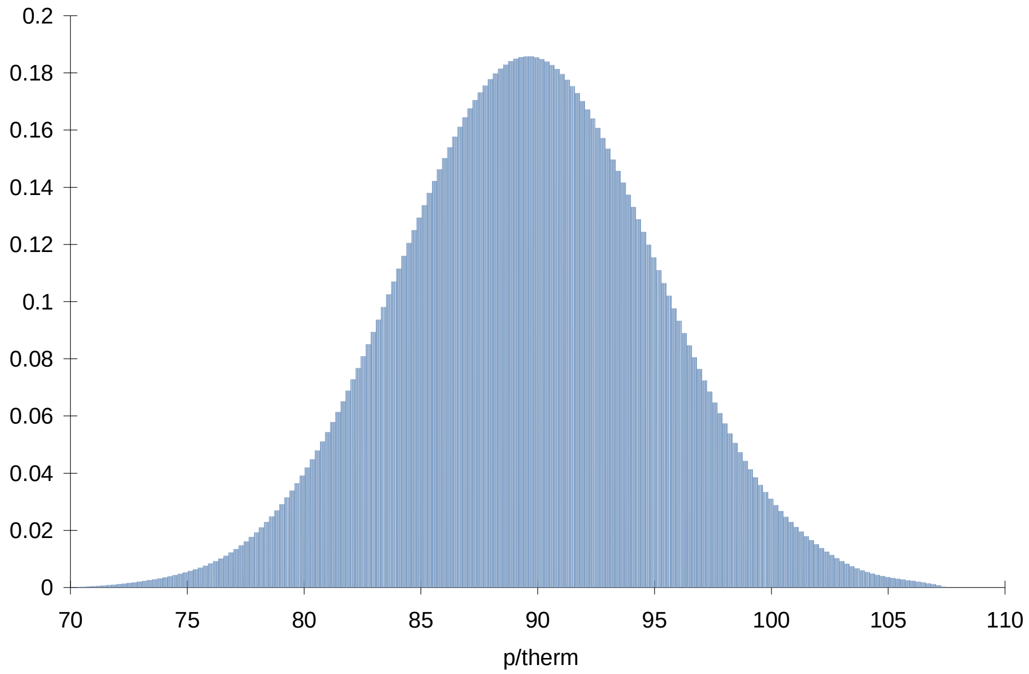
The historical variation of oil prices is very large. We expect that, if we were to accommodate such historical variation within the Prometheus model meaningful results regarding security and resilience to other factors might be obscured. We have therefore constrained the consideration of oil prices to be uniformly distributed within the bounds of +/- $20/bbl. The oil price distribution is used within the model to drive the pricing of oil-indexed take-or-pay contracts within the supply curve.

A.2.3 Other supply curve influences

For the purposes of the probabilistic modelling used within Prometheus, we have allowed for a small uncertainty in the long-run and short-run marginal cost assumptions by assuming they are normally distributed with 95th and 5th percentiles at +/- 10%.

We have applied a similar modest uncertainty for CCGT distillate response and other demand response, demonstrated in Figure 50 below. For values of lost load that have been determined by examining GVA we have assumed that these levels are fixed.

Figure 50 – Distribution of gas prices for switching to distillate



A.2.4 Sampling methodology

Prometheus uses a Latin Hypercube approach to sampling from the input distributions. This ensures that an appropriate combination of values is sampled from each distribution, such that the 'tails' of resulting distributions can be analysed more effectively. Were a more traditional Monte Carlo approach to be adopted there would be no guarantee that extreme values would be sampled, and therefore resultant statistics, especially those driven by rare events, could be misleading.

A.2.5 Other impacts

Pegasus models the availability of gas supply to GB on a global basis: that is to say gas supply by pipeline is available from Europe, and LNG supplies are available to be diverted from Europe or the US markets. One consequence of this interconnectedness is that events in markets outside GB could potentially have an impact on the GB market.

The biggest single event that has been identified would be for severe winter weather in the US to increase US demand for gas and potentially divert LNG cargos away from GB. At the very least this is likely to raise the price of gas in the GB market.

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ANNEX B – OTHER ASSUMPTIONS AND PÖYRY'S CENTRAL SCENARIO

B.1 Other assumptions

B.1.1 Oil Prices

We have used DECC's 2009 price assumptions for Brent crude, as presented in Table 28.

Table 28 – Brent oil price assumptions (US$/bbl, Real 2008)

	Central
2010	70.00
2015	75.00
2020	80.00
2025	85.00

Source: DECC

B.1.2 Exchange rate assumptions

Similarly, we have used DECC 2009 exchange rate assumptions, as shown in Table 29.

Table 29 – Nominal exchange rates

	€/US$	£/US$	€/£
2010	1.35	1.46	0.92
2015	1.39	1.60	0.87
2020	1.39	1.60	0.87
2025	1.39	1.60	0.87

Source: DECC

B.1.3 Government policy assumptions

For all our scenarios, we assume that the government introduces no additional measures, other than those it has already instigated, such as: renewables, energy efficiency and carbon targets for 2020, support for transparent third party access to pipelines across Europe, improved strategic planning application process, compliance with the large combustion plant directive and introduction of smart meters.

In this 'do nothing' world, the commercial market is left to operate without any interference beyond the existing regulatory regime.

B.1.4 Costing and revenue recovery assumptions

Pöyry maintains a database of costs associated with all investments in and the operations of physical infrastructure with the information coming from published figures and from data provided by clients across Europe. These include the capital costs, annual operating costs, and refilling costs where appropriate. These are then projected to give a long-run marginal cost ('LRMC') figure for each facility and transport route, which is then used by Pegasus in identifying the least cost supply to meet demand.

We also maintain a record of publicly available details of long-term contracts, which are also used in the model to set prices along certain routes based on oil indexation. Price levels in the receiving markets are then set by the marginal sources, whether it is the LRMCs or oil-index contracts, depending on the take-or-pay commitments, available uncommitted supplies and transportation capacity.

B.2 Pöyry's central demand scenario

This scenario uses Pöyry GB gas demand growth assumptions from our latest ILEX Energy report 'Study of the GB Gas Market', with updated prices January 2009. A full list of the ILEX Energy reports available across Europe is given in Annex E.

In general this sees European demand (I&C and residential) rising and new projects come on in a timely manner to meet new demand. Some LNG comes to Europe, but in the medium-term new competition from LNG is limited. Russia continues to provide the lion's share of European imports, but there is some success in Caspian states' marketing activities, and some pipeline import competition begins to develop, but despite sustained development of hubs and trading, prices remain dominated by oil-indexed contracts across Europe. There is some seasonality due to trading (which minimises take-or-pay) and storage costs.

B.2.1 GB demand projections

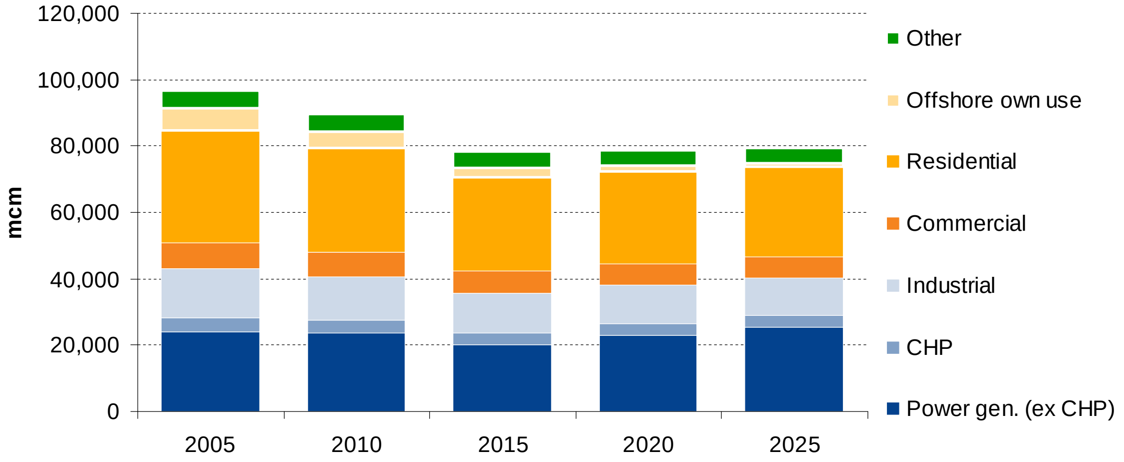
Pöyry use percentage growth rates to project I&C and residential demand. Across Europe we have used growth rates from the EC's 'European Energy and Transport – Trends to 2030' as a guide, and to model the impact of the current recession we have further reduced growth estimates in 2009 and 2010. CHP, and other categories of gas use, follow the same trend as I&C and residential, while offshore own use declines in line with UKCS production. The growth rates are shown in Table 30.

Table 30 – Growth factors for GB

	2010-15	2015-20	2020-25
CHP	0.5%	-0.5%	0.3%
Industrial	0.5%	-0.5%	0.3%
Commercial	0.5%	-0.5%	0.3%
Residential	0.5%	-0.5%	0.3%
Offshore own use	-8.0%	-8.0%	-8.0%
Other	0.5%	-0.5%	0.3%

So GB demand projections using Pöyry's GB gas demand growth assumptions, which are also reflective of partly meeting the 2020 renewables targets, is shown in Figure 51.

Figure 51 – GB demand projections



B.2.2 Power generation

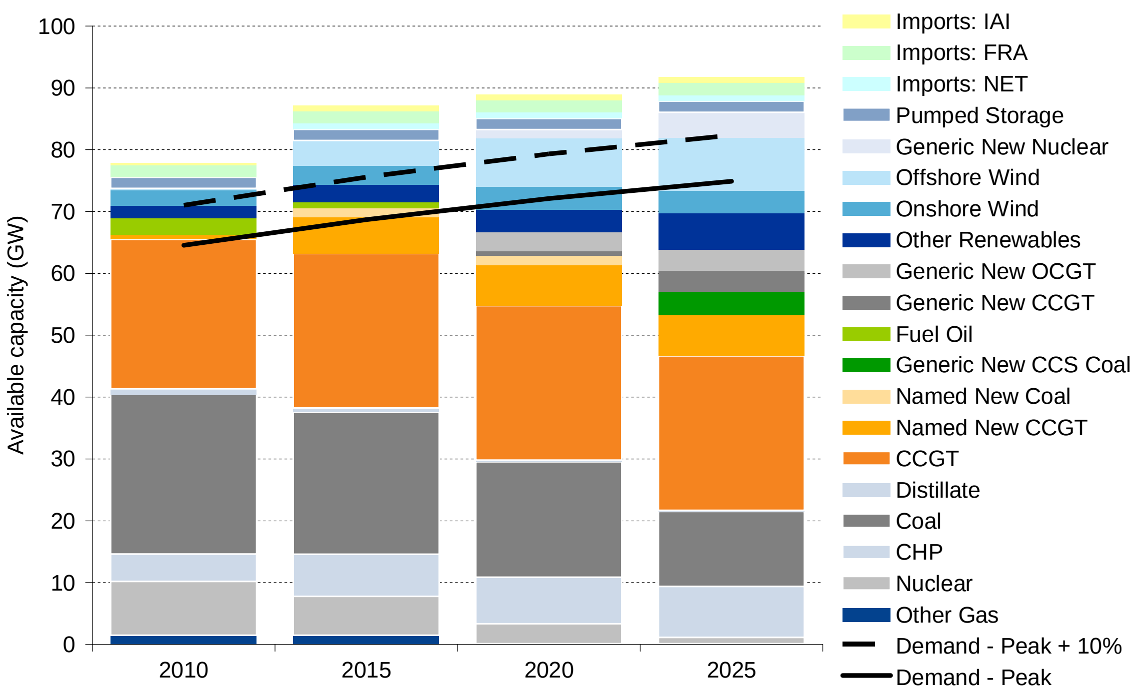
Demand for gas in large-scale power generation is taken from Pöyry's electricity model EurECA as used in the ILEX Energy report 'Projections of the Price of Wholesale Electricity in Great Britain' February 2009 edition. The gas prices from Pegasus are iterated through EurECA to provide consistent gas demand from power generation figures.

In the electricity central scenario we assumed carbon prices slowly rise upwards until they reach a long-term (Phase III) price of €25/ tCO_2 in 2013 and in Phase IV they rise further, driven by the economics of CCS coal, and reach €40/ tCO_2 by 2030. We assume coal prices (in 2008 money) in 2010 of £2.85/GJ decreasing to £2.56/GJ, excluding any delivery cost from the entry point to the power station, as this cost changes on a plant-by-plant basis. On average, for inland coal plants in GB we assume a delivery cost of £0.35/GJ and £0.26/GJ for coastal plants.

Electricity demand is based on average growth and reflects National Grid's central view of the future from their Seven Year Statement from 2009 to 2015. Beyond 2015, we use demand growth projections based on the 'European Trends in Energy and Transport, Trends 2007–2030', which presents projections of growth in electricity. The rate of growth subsides from National Grid levels in 2015 to 0.5% p.a. by 2030. Peak electricity demand is projected using the system load factor projections by National Grid, with the system load factor then held constant after 2015.

Figure 52 shows the generation mix within GB, which includes 17.6GW of new build by 2020 of which 8.7GW is CCGT, 1.7GW is CCGT CHP, 1.6GW is coal, 1.6GW is nuclear and 3.2GW is OCGT (reflecting the peak requirements from the intermittent nature of the new renewable generation).

Figure 52 – Generation mix within the GB market (GW)



B.2.3 Renewables assumptions

These have been based on the ILEX Energy report 'The Value of Renewable Electricity in the UK' with January 2009 prices. Pöyry consider the 2020 renewables targets to be quite firm, but there is some uncertainty regarding the ability for Member States to meet these very ambitious commitments.

We have used our model EuRenO to determine the mix and level of renewables generation up to 2020, assuming that Member States meet a certain proportion of the gap between their business as usual position (renewables deployment under current policy) and the production needed to meet their target. For GB, our Pöyry central scenario assumes this to be at 50% of the gap between the RES and that required to deliver full renewable energy target for 2020. This also assumes 50% of the 10% transport target is achieved. Figure 53 details Pöyry's assumptions for renewable new build within GB to meet 50% of the Directive. We assume full compliance with the 2020 directive by 2030, which means that mature technologies will largely be built by 2020, and more expensive technologies built between 2020 and 2030. Figure 54 details the incremental amounts of generation needed in order for GB to meet the 2020 targets.

Figure 53 – Assumed renewable new build within Pöyry central case for GB

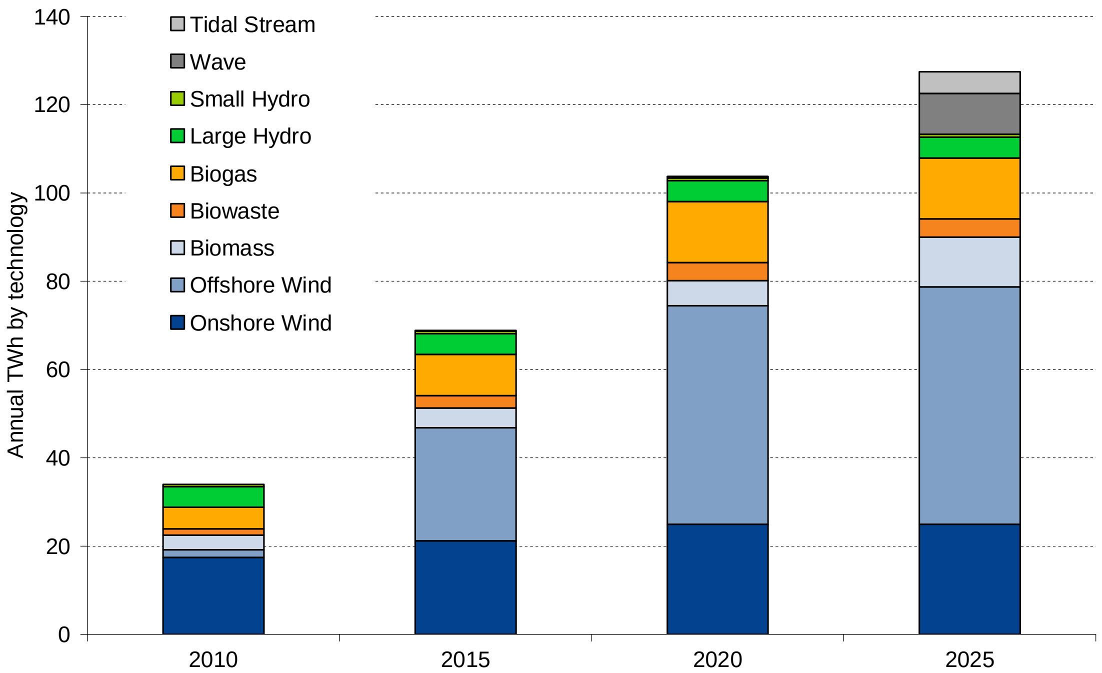
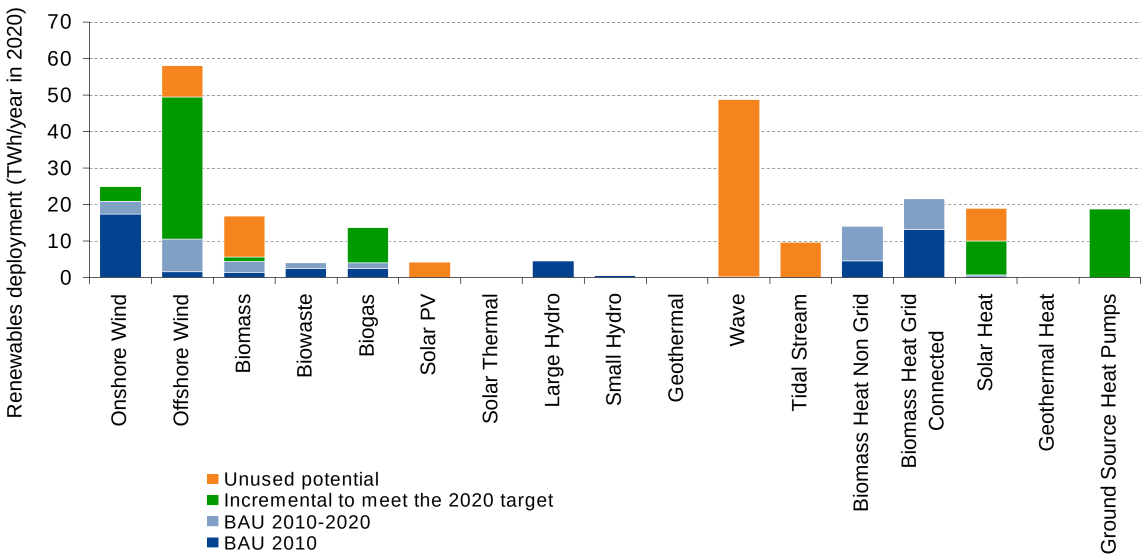


Figure 54 – Amount needed to meet the 2020 target



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ANNEX C – GAS SECURITY OF SUPPLY STANDARDS ACROSS EUROPE

Country	Gas Storage Capacity 2006 (mcm)	Gas Storage Deliverability (mcm/day)	Total Gas Consumption 2006 (mcm)	Access Type	Security of Supply Standard	Relevant Statistic	Gas in Storage used for SoS as % of Total Storage
	Source: GSE & Pöyry						
Austria	4230	49	8,909	nTPA	The Austrian transmission system is divided into 3 areas, each under the control of an Independent System Operator, one of whom is appointed Regional Control Leader (RCL). The RCL co-ordinates across the entire transmission system, and alerts the relevant government ministry in case of a supply crisis. The ministry then imposes instructions to the relevant system parties (producers, transporters, storage operators and end users) to alleviate the supply crisis. There is no explicit storage monitoring.		
Belgium	684	23	16,465	rTPA	The TSO, Fluxys, has a mandated public service obligation (PSO) to be able to supply all uninterruptible customers in the case of severe temperatures that would occur based on the winter of 1962/3 or 5 consecutive days with temperature < -11ºC. For this purpose Fluxys maintains reserved "strategic storage" (gas and capacity), which are charged to users through transmission tariffs.	Uninterruptible customer volume at 1962/3 winter severity or 5 days with temp < -11ºC	

Country	Gas Storage Capacity 2006 (mcm)	Gas Storage Deliverability (mcm/day)	Total Gas Consumption 2006 (mcm)	Access Type	Security of Supply Standard	Relevant Statistic	Gas in Storage used for SoS as % of Total Storage
	Source: GSE & Pöyry						
Bulgaria	350	3.3	3,578	No TPA	Similar arrangement to Belgium and Denmark whereby the TSO has an obligation to acquire storage capacity and gas to meet a PSO related to customer demand under defined temperature scenarios.		
Croatia	550		2,785	No TPA	Backup HFO and LFO stocks made available to industrial users in emergency and regular stocks from public utilities, as defined by government regulation. Storage capacity comprises 0.55bcm and 4.8mcm/d.		
Czech Republic	2321	36	9,325	nTPA	Similar arrangement to Belgium and Denmark whereby the TSO has an obligation to acquire storage capacity and gas to meet a PSO related to customer demand under defined temperature scenarios.		
Denmark	1001	16	5,933	nTPA	TSO is obliged to procure storage capacity to meet demand of non-interruptible customers at 60-days at normal winter temps, 3-days at -14ºC (equivalent to 1 in 50 peak day). Shippers required to keep a certain % of gas storage during winter months. Shippers are required to procure sufficient storage capacity to meet demands of non-interruptible customers	60-days firm at normal winter temps, 3-days at -14 ºC (equivalent to 1 in 50 peak day)	

Country	Gas Storage Capacity 2006 (mcm)	Gas Storage Deliverability (mcm/day)	Total Gas Consumption 2006 (mcm)	Access Type	Security of Supply Standard	Relevant Statistic	Gas in Storage used for SoS as % of Total Storage
	Source: GSE & Pöyry						
France	12255	266	44,644	nTPA	Shippers supplying domestic & public interest customers are required to withstand a loss of main supply for a 6-month period under normal weather conditions, to ensure supplies for both a 1-in-50 winter and an extremely cold period – a 3-day 1-in-50 period. Ensure availability to alternative sources (storage, short-term contracts, LNG, etc.)	1-in-50 winter and 1-in-50 3-day period.	85% of their capacity rights in store
Germany	19993	331	102,990	nTPA	Suppliers have a legal requirement to take reasonable steps as prudent operators to ensure security of supply for their customers under normal and exceptional conditions, with severe penalties for failure. This obligation is discharged via contracts with TSOs and storage operators/providers.	None	None

Country	Gas Storage Capacity 2006 (mcm)	Gas Storage Deliverability (mcm/day)	Total Gas Consumption 2006 (mcm)	Access Type	Security of Supply Standard	Relevant Statistic	Gas in Storage used for SoS as % of Total Storage
	Source: GSE & Pöyry						
Hungary	3720	51	14,202	rTPA	Both concepts of PSO storage (currently 76% of total storage is reserved for this purpose) and strategic storage (in 2008, 5% of storage or 0.2 bcm). It is planned that the strategic storage volume will be increased to 1.2 bcm by January 2010, with daily withdrawal capacity of 20 mcm available for at least 45 consecutive days (corresponding to the average winter residential demand). The Hungarian government is planning for the strategic storage to be operated by an association established specifically for this purpose comprising all the major industry players, who will pay a fee based on their system throughput. The use of the strategic storage is authorised by the government based on notification by the TSO or energy ministry.	Total strategic deliverability of 20 mcm/d. Total PSO storage of 76% total storage (2.82 bcm in 2008)	0.2 bcm (5% of 2008 total storage) – increasing to 1.2 bcm in January 2010
Italy	14335	253	84,484	rTPA	Approx 40% of storage is reserved for Strategic Storage, whose release is controlled by the ministry. Additionally there is a legal obligation on each importer to maintain 10% of its import requirements in storage (minimum quantity specified by Ministry for Industry each year). Also there a number of short-term measures.		~40% of storage reserved for strategic storage

Country	Gas Storage Capacity 2006 (mcm)	Gas Storage Deliverability (mcm/day)	Total Gas Consumption 2006 (mcm)	Access Type	Security of Supply Standard	Relevant Statistic	Gas in Storage used for SoS as % of Total Storage
	Source: GSE & Pöyry						
Netherlands	5078	177	47,804	nTPA	Shippers must have contracts in place to meet demand of small customers down to -9ºC. The TSO, GTS, is required to protect supplies to small customers during extremely cold winters. It procures storage gas to meet their increased demand when temperatures drop below -9ºC (down to -17ºC). Shippers pay for the above arrangements through a PSO tariff.	Required storage volume down to -17ºC t	Required storage volume is temperature dependent
Poland	1,575	34	16,336	No TPA	As from 2012, parties importing gas into Poland will be obliged to keep 30 days worth of their average daily import in store. This total obligatory storage must be stored in facilities which allow the total export of the gas to the system within 40 days. The regulator oversees the volumes and costs of this storage. The TSO must ensure that the storage utilises technically acceptable facilities (as defined in law).	30 days worth of average daily imports	Average daily imports = 25 mcm 30 x 25 = 750 mcm (45% of total storage)

Country	Gas Storage Capacity 2006 (mcm)	Gas Storage Deliverability (mcm/day)	Total Gas Consumption 2006 (mcm)	Access Type	Security of Supply Standard	Relevant Statistic	Gas in Storage used for SoS as % of Total Storage
	Source: GSE & Pöyry						
Slovakia	2750	34	6,575	nTPA	Recent change to the law (February 2009) provides the Slovakian government with new powers to preferentially access both gas fields and storage facilities that may be exporting gas to foreign countries, during the period of an emergency. The law requires that the main gas supplier (SPP) must maintain gas storage reserves to cover 30 days of average national daily demand during the period October to March. The regulator will also now regulate the prices of storage by setting them in comparison to EU storage prices. The government has also established a framework for fining parties who breach supply security standards (fines in the range €170K to €1.7m).	30 days of average daily national demand (Oct-Mar period)	30 days average national demand (Oct-Mar period) = 800 mcm (29% of total storage)
Spain	4140	172	32,889	rTPA	Shippers cannot source >60% of portfolio from any one country. Shippers to gas distributors must maintain 35-days supply	35 days non-power sector demand	Non-power sector demand = 21 bcm 35 days demand = 2.014 bcm (49% of total storage)

Country	Gas Storage Capacity 2006 (mcm)	Gas Storage Deliverability (mcm/day)	Total Gas Consumption 2006 (mcm)	Access Type	Security of Supply Standard	Relevant Statistic	Gas in Storage used for SoS as % of Total Storage
	Source: GSE & Pöyry						
Turkey	3035		31,183	rTPA	Legal obligation on each importer to maintain 10% of its import requirements in storage for a period of 5 years	10 % of import volume	2006 imports = 30.741 bcm 10% imports = 3.074 bcm => 100% available storage
GB	4364	96	94,469	nTPA	Minimum level of storage required to ensure safe operation of system, shippers cannot reduce storage below Monitor level. Shipper licence obligation to contract for sufficient gas to meet domestic portfolio demand during a 1-in-50 Winter. Difficult to enforce – shippers are deemed compliant if they sign up to Network Code and have access to NBP.	Safety monitor for 1-in-50 winter	

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ANNEX D – POLICY OPTION DETAILED REVIEW

D.1 Physical gas storage

Strategic storage	This is the provision of dedicated storage quantities that are controlled by Government and used only in specific predefined circumstances. The strategic storage could be either newly built via central funding or through an obligation on a central body, such as NGG, to contract for such services. Strategic storage is generally thought to be long-range or mid-range storage, which gives a steady output for a sustained period of supply shortage. These measures are used explicitly in Italy and Hungary. It appears that in these two countries there is a certain amount of discretion by the Ministries regarding when to trigger the use of strategic storage, but they seem to depend on physical system constraints, rather than price. The investment costs would be £100m's, but the volume that could be provided could be significant.
Timeframe for implementation	We estimate that it would take at least five years to implement a new strategic store, so would not be implementable quickly.
Speed of response at time of need	Potentially a quick speed of response to cover any potential shortfall in supply, depending on whether there are rules put in place to trigger its use or whether it is at the Government's discretion.
Complexity	Defining the rules for when it would be used could be problematic. The rules would need to consider what type of events would be included, and how it might interface with market mechanisms such as a gas balancing alert, and post-market emergency arrangements. We would suggest that it perhaps could be included as part of the Emergency procedures, to avoid unduly influencing normal market operation. Alternatively, the principle of auctioning the gas in store to the market could be adopted, although this, too, might be complex.
Potential volume	This option has the obvious benefit of being sized to provide sufficient and reliable volumes. However, once built it might be difficult to increase the volume.
Potential deliverability	Depending on the site chosen, facilities could be sized to provide sufficient deliverability to cover significant events.
Control	This facility would be under Government control, either under the rules established or by its discretion.
Reliability	Design specifications could be designed to ensure that the infrastructure is reliable. Unless there were capacity constraints at the delivery location (long-term firm NTS entry capacity bookings would prevent this), overall reliability should be relatively good.

Legality	Primary legislation would probably be needed, although there is a possibility to make use of regulations under Section 2(2) of the European Communities Act, based on the requirements of 2004/67/EC (security of gas supply directive).
Industry support	Many industry participants would be concerned that it might be used to cover short-term price spikes rather than genuine provision of strategic storage in an extreme supply shortage, or for political reasons to keep energy prices low to consumers. The EU, some Governments and regulators have promoted this as the best option to provide secure and reliable supplies in the case of a supply crisis.
Barriers addressed	Government/socialised funding overcomes many of the storage investment barriers for private companies.
Unintended consequences	Many parties and previous reports show the danger of unintended consequences of preventing new commercial storage being developed because the presence of strategic storage volumes removes any incentive to invest. This policy option has the potential to significantly distort the value of other storage/flexibility assets, but it may also affect the market price on days of system stress. This is a general problem for all the physical storage options (including top-up), leading to a moral hazard. Resolving such a moral hazard would require the Strategic Storage to be an absolute last resort. If in the future others develop commercial storage or demand decreases, it could become a stranded asset. If the excess capacity is sold into the market then this could raise issues of subsidies.

Extra strategic LNG tanks

Although strategic storage is normally considered as underground storage that gives both a deliverability and volume dimension, LNG storage can also be considered for strategic storage to provide a short duration supply to support a system that has run into difficulties. This can be in the form of the LNG peak shaving facilities, (some of which NGG is in the process of decommissioning), or building additional tanks at one or more of the LNG import terminals .

Gas would be regasified and released into the market upon instruction from Government.

The cost of the tanks and the gas in store could either be borne by the Treasury or through a fixed element on the transportation charges. Revenues of the LNG released could accrue to the Treasury or be used to offset the transportation charges. The investment cost would be in the region of £10m's.

Timeframe for implementation	Finding the space at existing facilities may be problematic and this may need to be carried out in conjunction with a planned expansion programme. Alternatively, it could be done alongside a new development. We therefore consider that this policy option would take a relatively long time to have an effect.

Speed of response at time of need	This option has potentially a quick speed of response, and might deliver gas to the NTS within a few hours.
Complexity	Defining the rules for when it can be used, or any auction mechanism and the interaction with the market would be complex.
Potential volume	The ability to meet supply disruption throughout a winter period would depend on the number of tanks that would be procured. Notionally, it may only cover a relatively few days.
Potential deliverability	This option might provide significant deliverability, limited primarily by the regasification and/or NTS entry capability, however the regasification capability might present a constraint if shared with normal commercial use.
Control	This facility would be under Government control, either under the rules established or by its discretion.
Reliability	Design specifications could be designed to ensure that the infrastructure is reliable. Unless there were capacity constraints at the delivery location (long-term firm NTS entry capacity bookings would prevent this), overall reliability should be relatively good.
Legality	If provision was done by the Government, primary legislation would be needed for the smearing of costs. The smearing of costs might be regarded as a tax, in which case it would need to be constructed in a way that complied with EU tax law. Also not clear whether a licence would be needed if the Government enters into arrangements with NGG. If provision was done by NGG, it is anticipated that this could be achieved through existing arrangements or licence modifications, otherwise primary legislation would be needed to make the changes. If the provision goes beyond what can be described as balancing or activities relating to transmission, there might be a need to comply with the unbundling requirements of 2003/55/EC.
Industry support	Many industry participants would also be concerned that it might be used to cover short-term price spikes rather than genuine provision of strategic storage in an extreme supply shortage.
Barriers addressed	Developing extra tanks to store LNG addresses the barriers for investing in peak shaving, as there are little commercial incentives to develop these. It will not address barriers for developing longer-range storage such as salt caverns.
Unintended consequences	The incentives to invest in new storage of a similar type will be diminished. Moral hazard, as discussed above. Potentially a stranded asset, but less impact than a major underground gas storage.

Strategic LNG offshore	Effectively a temporary strategic storage, the Government could procure (or oblige a central body such as NGG to procure) one or more tankers of LNG at the start of each winter and keep it/them offshore ready for immediate supply delivery, or for sale into the market after the worst of the winter had subsided. This option was used by Spain in 2003/04 and 2005/06. It depends on spare berthing and onshore tank capacity being available. The process for releasing it into the market would probably be by auction to market participants, who could then feed it into the OCM. The costs of tanker rental would be borne by the Treasury and the revenues from the sale would offset this. As it is temporary it will have lower capital cost, but higher variable cost, so would be cheaper in the short-term, but not as a long-term measure. Chartering a tanker would be a few £m per winter (based on current rates) plus the difference in value of the cargo from when it is purchased to when it is sold.
Timeframe for implementation	Provision of an LNG tanker kept offshore has the advantage of such a decision only being made on a year by year basis and so avoids having to commit significant sums into a long-term strategic gas provision.
Speed of response at time of need	A tanker moored in a suitable location offshore could move to an available LNG terminal in less than a day.
Complexity	We assume the Government would have some discretion over how many and when to procure, based on set guidelines and when to auction off at the end of the perceived gap had disappeared. The use would depend on there being an available spare slot at a terminal and TPA arrangements in place at the terminal.
Potential volume	The volumes can be adjusted on a year by year basis, sometimes nothing, sometimes 2 or 3 tankers, depending on the perceived risks. The volume available would not provide security towards a supply disruption lasting more than a few days. Given a supply shortage, we would expect commercial tankers to arrive within a few days.
Potential deliverability	Deliverability would be limited by the regasification capacity at the LNG terminal. In the event that LNG terminals were inputting as much as they could in such a situation, there would be no additional deliverability.
Control Mechanism	This facility would be under Government control, either under the guidelines established or by its discretion
Reliability	Unless there were no spare delivery slots, the reliability would be relatively good.
Legality	It is not clear whether a licence would be needed if the Government enters into arrangements with NGG and it would need to comply with procurement rules, although there is some flexibility in cases of urgency.
Industry support	May be acceptable as a short-term measure in specific circumstances, but many industry participants would also be concerned that it might influence the market if it was used when there was particularly low risk of failure.

Barriers addressed	Temporary strategic LNG storage addresses the barriers for investing in peak shaving, as there are little commercial incentives to develop these. It will not address barriers for developing longer-range storage such as salt caverns.
Unintended consequences	An auction process means that shippers to other countries could purchase the cargo and it does not end up in GB. If this was adopted by a number of Governments, tying up a number of tankers for a few months in the winter would put a strain on LNG transportation and unduly influences the price of LNG.
Minimum stocking obligation	This option is used by a number of countries, including Belgium, France, Italy and Spain, whereby each supplier has an obligation to hold sufficient supplies to cover a specified number of days or a proportion of its firm supply, as noted in Annex C. This option has the advantage that it can be applied to existing infrastructure and the obligations varied over time (both within year and from year to year) as the potential risk of supply failure varies. The obligation puts the onus on suppliers to ensure they have enough coverage in physical storage stocks in the market, putting an incentive on them to build more storage, either to meet their obligations or to meet their regular requirements for flexibility. This option is also used in the oil markets (although we note that stocks can also be held in the Netherlands rather than in GB). The capital costs would be much less under this option, but indirect costs would be borne by the market.
Timeframe for implementation	As this option puts an obligation on shippers to utilise existing storage facilities there is no physical construction, so this option could be implemented reasonably quickly. However, fast implementation might sterilise existing storage capacity causing a price impact. The time to develop the associated replacement storage capacity would be at least 5 years or so. It might therefore be more appropriate to assume a relatively long lead time for this option, so that shippers/developers can factor in the reduced availability of commercial storage in their investment decisions.
Speed of response at time of need	Response time would be within a few hours, depending on the notice periods required at the facilities.
Complexity	Establishing the minimum levels for number days and volume and how this varies according to risk may become complex. If this were simplified by fixing the levels for a number of years, there could be more or less available than desired. Establishing the mechanism for enabling the use of stocks might be complex, although European precedence would indicate that complexities would not be insurmountable.
Potential volume	Varying the volumes means that the appropriate amounts would be held in reserve. However, it does not affect the total storage volumes available to the market in the short term, as mentioned above.

Potential deliverability	Potentially relatively high, depending on the release mechanism(s) adopted.
Control Mechanism	Controlled by Ofgem under the shipper licence obligations.
Reliability	Potentially relatively high, depending on the release mechanism(s) adopted. As the shippers have some discretion regarding how they procure the storage capacity, there should be more diversity of entry points compared to a single strategic storage facility.
Legality	It is expected that primary legislation would probably be needed, although there is a possibility to utilise regulations under Section 2(2) of the European Communities Act, based on the requirements of 2004/67/EC (security of gas supply directive).
Industry support	Shippers would be against compulsory obligations, and might be expected to argue that the market would supply the most efficient solution.
Barriers addressed	Sterilising existing storage capacity is likely to increase seasonal spreads and volatility, which increases the value of storage. This would assist proposed projects in getting over their investment hurdles, although planning and other barriers would still remain.
Unintended consequences	It could be argued that the value of storage would increase in the short-term as the available capacity for regular commercial flexibility would be diminished. Consequently seasonal spreads would be widened and volatility would increase, not just at NBP, but across Europe. There is the cost of monitoring, but it puts the emphasis on suppliers to provide a form of supply obligation and linked explicitly to firm portfolios so may incentivise innovative interruptible deals to reduce exposure.
Top-Up contracts – long-term and medium-term	This is a method initially developed at the start of the Network Code in 1996 whereby, having analysed the potential gap between forecasted supplies and severe demand, the transmission system operator procures from market participants' sufficient supplies/storage to fill the gap. Costs are then smeared across market participants through transportation charges. This method was set up because the GB market was isolated and the market rules were relatively new and untested in relation to security of supply. Top-up was phased out around 2004 by Ofgem because it was felt that the market should be able to provide under suppliers' 1-in-50 obligations. Prior attempts to phase it out in 1998 were blocked by the Health and Safety Executive.
Timeframe for implementation	Top-up contracts have the advantage of being relatively quick and easy to establish, given that the principles are already established, although the exact rules governing the amount to be procured and any auction process would take some time to develop and seek industry agreement.

Speed of response at time of need	Responses times can be within a few hours, depending on the notice periods at the various facilities.
Complexity	The tender process should be relatively straightforward, but there are a number of regulatory issues around the way in which the gap is defined, the options are valued and how they are paid for, e.g. through the balancing neutrality mechanism.
Potential volume	The volumes can be defined annually so are flexible relative to the perceived risks.
Potential deliverability	Deliverability can also be defined annually and appropriately to the perceived risks.
Control	This would be controlled by NGG, under the supervision of Ofgem.
Reliability	It was proven to be reliable in the period in which it operated, but there were no major outages in that time.
Legality	This would need to comply with 2003/55/EC in how costs are charged and as regards the activities that TSOs can carry out. Since it is a re-introduction of a previous regime it could be covered through a licence obligation.
Industry support	There was some support for the Top-Up mechanism when it was in place, but its reintroduction into a mature and liquid market is unlikely to receive much support.
Barriers addressed	Although not as strict as a stocking obligation, this would also have the effect of sterilising existing storage capacity or demand side response from other commercial arrangements. This is likely to increase seasonal spreads and volatility, which may increase the value of storage and would assist proposed projects in getting over their investment hurdles, although planning and other barriers would still remain.
Unintended consequences	As was noted in 2004, it gives NGG other balancing options in addition to the OCM, which can distort the cash-out mechanism. The mechanism, in effect, gives NGG a series of commercially valuable options. There would therefore need to be incentives on NGG to minimise costs to industry. It may give an unfair revenue advantage to existing facilities.

Storage capacity buyer of last resort	Also part of the arrangements at the start of Network Code, this was an obligation on the TSO to buy any unsold storage capacity at a relatively low reserve price. The TSO would then utilise as much of the storage capacity as it thought was needed to bridge the potential gap between contracted supplies and severe demand – in the form of its own top-up gas. This policy could be reintroduced to help underwrite potential storage projects, especially where it is considered that TPA exemptions should not apply.
Timeframe for implementation	As above for top-up.
Speed of response at time of need	This is based on NGG having its own gas in storage facilities that are not fully utilised, so could be implemented within a year.
Complexity	There are as number of regulatory issues that would need to be addressed, e.g. how the gap is defined, the prices that should be paid and the cost recovery mechanisms.
Potential volume	This option would only deliver if there is spare capacity, otherwise it would have no immediate effect although could enable NGG to provide investment signals.
Potential deliverability	As above
Control	This would be controlled by NGG, under the supervision of Ofgem.
Reliability	It was proven to be reliable in the period in which it operated, but there were no major outages in that time. In the last few years of its operation, storage was fully booked so it was not available.
Legality	This would need to comply with 2003/55/EC in how costs are charged and as regards the activities that TSOs can carry out. Since it is a re-introduction of a previous regime it could be covered through a licence obligation.
Industry support	We consider that there would be a mix of support from industry.
Barriers addressed	Does not necessarily address many of the investment barriers, as all costs are not covered by the low guaranteed revenues for the developer. However, it could provide a basis for limiting the downside risk of investing and therefore lowering financial hurdle rates.
Unintended consequences	This would effectively give NGG the ability to provide its own Top-Up, and could lead to a distortion of the OCM and imbalance charges. There would need to be incentives on NGG to minimise costs to industry. It may be seen to give an unfair revenue advantage to facilities with TPA, depending on the rules around usage. However, if profits increase it should be possible to encourage more investment

Capacity mechanism for gas	Rather than an placing a direct obligation on suppliers/shippers, this option provides an additional payment to shippers for making specific supplies available to the market. These supplies may include, for example: a supply contract from a UKCS production facility; stored gas with the appropriate withdrawal rights; and tested/active DSR contracts (capturing any backup facilities). The pricing mechanism could be tailored to incentivise different types of supply, (e.g. as it might be considered more reliable, stored gas might be rewarded more than smaller DSR contracts), and could reference OCM or imbalance charges to ensure the incentive remains. Such a mechanism might add significant costs to shippers (which might be asymmetrically distributed, depending on portfolios and positions). These costs might be under- or over-recovered through the capacity mechanism depending on both its design and day-to-day environmental factors, which might be expected to affect wholesale prices.
Timeframe for implementation	This option might require significant legal changes and would require significant regulatory consultation. We therefore consider that this would take a few years to be implemented.
Speed of response at time of need	Theoretically, this should be available instantly, as it is based on incentivising shippers to permanently have locational bids on the OCM.
Complexity	The potential complexity of this option rules it out on its own. Firstly, it is impossible to establish how much undelivered gas (including gas in Norway, Netherlands and Belgium) was actually available. Secondly, gas balancing and trading functions at a daily resolution and rely on a degree of flexibility in the system to accommodate instantaneous imbalance (this enables self-dispatch by shippers/suppliers) – a compatible capacity mechanism would need careful design to capture within-day security risks. Capacity mechanisms can (and do) work in electricity markets because the dispatch of generation is undertaken by the transporter, not by the supplier, (the transporter must keep the system in balance instantaneously). There is far greater certainty over availability through incentives built into the bidding mechanism, and proven/evidenced maximum generation capacities.
Potential volume	This may not provide any more volume than is already available, given the existing capacity margin, shown in Figure 35.
Potential deliverability	Depends on the detail of the mechanism.
Control	This would be controlled by Ofgem under the shipper and/or transporter licences.
Reliability	Relying on shippers to always have a volume on the OCM would be questionable in severe circumstances.
Legality	Primary legislation might be needed and State aid approval might be required, depending on the exact nature and design of the mechanism.

Industry support	This option is unlikely to gain industry support as the entry shippers may benefit at the expense of the exit shippers.
Barriers addressed	Depending on the incentives and the design of the mechanism, this would may address some of the barriers, e.g. by providing a more secure stream of revenue to storage facilities.
Unintended consequences	Any mechanism is likely to create opportunities for gaming, particularly on days when the bids are mot likely to be called. The mechanism would redistribute cash flows within the industry away from the wholesale pricing mechanism, which may effect liquidity and commercial market signals to provide new capacity. At worst, a capacity mechanism could destroy many of the benefits of free-trade within the market.

D.2 Backup fuels for power generation

Minimum distillate storage requirement	This is a mandate that CCGTs must hold sufficient distillate to cover a predetermined number of days, or volume, of generation. The additional cost of this would come from a central source, either Government funded or from a levy on the other CCGTs, through the electricity market, or through the gas market arrangements. Using distillate as an alternative to natural gas is already a commercial option to those CCGT power stations that have the capability, but since it is used so little and the reform to the exit arrangements are discouraging, significant volumes of capability may be decommissioned in the near future. Implementing this policy quickly may prevent the loss of this capacity. Distillate backup can also used for black-start – the mechanism to power-up the electricity network. The incentive placed on CCGTs is stronger than the Top-Up or other DSR-type options, which are dependent on a contractual chain, and are subject to generators' willingness to provide.
Timeframe for implementation	Relatively quickly, as it can be implemented under existing legislation.
Speed of response at time of need	At a few hours' notice, although it has the potential to be instantaneously available.
Complexity	Cost recovery mechanisms could be particularly complex.
Potential volume	Setting a minimum distillate requirement would provide volume in the short-term but may have restocking limitations.
Potential peak	Depending on the number of CCGTs operating at the time, it could represent a reasonable amount of daily volume, although when there are few CCGTs operating there is lower volume available.

Control	Monitoring the stock obligations would be the responsibility of Ofgem. Decisions on when to switch to distillate would be made by the individual generators, based on price.
Reliability	Unused backup facilities can fall into disrepair – annual maintenance and testing would be required, potentially increasing costs.
Legality	Powers to put such a requirement in place already exist under s.34 and 35 of the Electricity Act 1989. There may be environmental limits at certain sites that further limit volumes available.
Industry support	Depending on the cost recovery mechanism, might be supported by the main dual-market utilities and independent generators, however it might be seen as unnecessary. Gas and electricity transporters might be negative.
Barriers addressed	Payments for holding backup would override the lack of incentives to invest in such facilities.
Unintended consequences	Restocking large volumes of replacement distillate could put strain on the distillate distribution chain, as the stock of barges and road/rail tankers does not have the spare capacity to maintain flows for more than a few days without affecting the distribution of heating oil and distillate. Identifying measures to improve the distillate supply chain might ensure gas security during a severe supply disruption, as explained in Section 2.8, although this would increase the costs of this option. If it is an obligation on new facilities it will have possible impacts on new power generation investment through marginally higher costs and lower efficiencies. If existing sites are not obliged to build tanks (many would be physically unable due to land and technology issues) it could lead to distortions in the market. If this option is applied to existing or committed power generation it might be seen as being interventionist which increases the perception of regulatory risk and increases the barriers to entry in the electricity market.
Coal plant post LCPD	The amount of coal-fired generation will decrease dramatically in 2015, as part of the obligations under the large combustion plant directive (LCPD). This proposal is to keep some of these coal stations to enable coal to run instead of CCGTs when needed for gas security. This would have a number of impacts, including environmental. It is not clear where the cost of keeping the plant available would come from.
Timeframe for implementation	There would be a large number of legislative and regulatory hurdles to get over before implementing in 2015.
Speed of response at time of need	Potentially within a few hours.
Complexity	The cost allocation/recovery mechanism would be extremely complex as it would need to operate via the electricity market.

Potential volume	A greater overall volume of energy can be stored more cheaply as coal than as oil, but environmental limits may affect this.
Potential peak	Reasonable, though capped by both CCGT and post-LCPD coal capacities.
Control Mechanism	Monitoring the stock obligations and administering the payments mechanism would probably be the responsibility of Ofgem. Decisions on when to switch to coal-fired generation would probably be made by the individual generators based on price (though depending on cost allocation/recovery mechanisms, and subject to limits imposed by the Environment Agency.
Reliability	Coal plant have been an established part of the GB's generation mix for a number of years, with proven technology and established maintenance schedules.
Legality	Using coal plants that have opted-out under the LCPD after 2015, or before then once the generating stations have exceeded their 20,000 operational hours limit, is not an option under the LCPD directive. There might be an opportunity to try to get some flexibility into the new directive which is to replace the LCPD, but this indefinite. Planning to retain non-LCPD plant for use in severe supply disruptions would risk challenges in advance that the Government was planning to breach the directive (especially from opted-in plant that has subsequently invested and could otherwise capture upside during times of gas market stress). The LCPD is enforced by the Environment Agency, but it may be possible to override this in emergencies.
Industry support	Players without a financial position are unlikely to support this option, due to its complexities (particularly considering its effectiveness and the chain of command).
Barriers addressed	Would provide peak and annual capacity to meet extreme demands, utilising existing facilities.
Unintended consequences	Extending the life of coal plant will conflict with policy options designed to meet emissions targets and achieve the 2020 obligations. There could be significant market distortions within and between gas and electricity markets.
Capacity mechanism for Power	By providing a payment mechanism specifically for non-gas-fired generation capacity this should provide sufficient incentive to generators to arrange for enough distillate stocks or other forms of generation to be made available and to keep generating through a gas supply outage.
Timeframe for implementation	A large number of regulatory hurdles to get over before implementing, so likely to be a number of years.

Speed of response at time of need	Potentially within a few hours.
Complexity	The cost allocation/recovery methodology would probably need to be complex if it were to support the gas industry.
Potential volume	Dependant on level of payments.
Potential peak volume	Dependant on level of payments.
Control Mechanism	Monitoring the availability and administering the payments mechanism would probably be the responsibility of NGG under the guidance of Ofgem. Decisions on when to switch to other types of generation would be made by the individual generators, based on price, and subject to limits imposed by the Environment Agency.
Reliability	Disuse of backup facilities could potentially have a negative impact on reliability as delays to maintenance occur. Additional costs will have to be borne by customers.
Legality	It is anticipated that primary legislation would be needed and any concerns regarding State aid would have to be addressed.
Industry support	Creating a support mechanism in the electricity industry would probably receive a mixed reception. In theory it should lower the risk for generators, but this might encourage new entry and therefore be strategically unpopular with exiting market players. Creating a mechanism to specifically support the gas security of supply would likewise receive a mixed reception, although might depend more on portfolio and position. We would expect the gas industry to be at best neutral or at worst sceptical. We would expect it to be argued that the value of gas security ought to be built into the gas price, and that investment in generation to provide a capacity margin should take such a gas price into consideration.
Barriers addressed	Payments for holding backup would override the lack of incentives to invest in and maintain facilities.
Unintended consequences	Re-introducing a capacity mechanism into the power market may mean that additional power station capacity is retained on the electricity grid to cater for increased levels of intermittent generation e.g. wind power. This could have the benefit to gas security of supply in a scenario of severe disruption, as it would be less dependent on continued power from CCGTs running on distillate over a longer period of time. Such a regime would first have to be justified to meet electricity security of supply concerns before any secondary benefit to natural gas could be considered.

D.3 Demand side response (DSR)

Restore I&C interruptible volumes to historic levels

End users and shippers are currently able to agree contracts where the end user agrees to interrupt its gas supply in return for a fee or discount. However, there has been limited bids and transporter contracts under the new Mod 90 auctions. The transporters are reinforcing their pipeline networks to remove transportation constraints so there will be fewer interruptible customers going forward and there is the risk that I&C sites decommission the backup facilities.

However, Mod 90 has not fully taken into account the demand side insurance contribution provided under the historical I&C interruptible contract. This policy option would be to encourage I&C Interruption to remain at historic levels by:

(i) Introducing an auction to provide a demand side insurance incentive that shippers, on behalf of I&C sites as the UNC prevents a direct interaction, which is independent of the transporters' needs for capacity constraint interruption;

(ii) The level of required volumes would be set for a fixed period, say 5 years, by the SO based on its forecast severe annual and peak supply and demand position.

(iii) Encouraging end users to maintain their backup supplies and enter into contracts with shippers to provide the DSR capacity;

Logically, there should already be an incentive on end users to enter into these arrangements as these would be amongst the first consumers to be interrupted if there was an emergency, for which they would receive very limited recompense. However, the current perception that the market has sufficient supplies available to it means that this occurrence is perceived as very rare, so the incentive is negligible. In addition, as discussed above the implementation of exit reform has removed the small incentive to maintain backup capabilities.

In Italy in 2005/06 suppliers were given targets for having a minimum amount of their portfolios on interruptible contracts. This application was impractical, as the emergency regulation was introduced at short notice and there was not an even spread of interruptible customers between shippers.

Timeframe for implementation

A NUC modification would need to be raised to establish the auction process and once approved the SO would need to hold an auction and notify successful bidders. Such a process would take in the order of one year to implement.

Speed of response at time of need

If the contracts and mechanisms are robust, the response could be within a few hours.

Complexity

Setting up the auction rules and administering the process is not simple but should not be that much harder than the entry and exit capacity auctions. Agreement to the process of defining the required volumes will need both industry and regulatory oversight.

Potential volume

Potentially a return to the historic levels of 36mcm/d.

Potential peak	As above
Control	The controls would be largely market based, though there would be some discretion to influence the level of volumes required.
Reliability	Simply encouraging industrial users to maintain backup facilities will not necessarily provide the required response, as their focus is generally on their own markets, not the gas markets. This also maintains the ability of the transporter to take direct control of offtake facilities (i.e. the transporter can isolate the load where there is failure to interrupt).
Legality	Promoting DSR contracts with suppliers is possible now with no legislation needed. Introducing a new demand side insurance auction process will need careful handling through the UNC modification process.
Industry support	There is potentially a high level of industry support.
Barriers addressed	This would aid in meeting demand in extreme times without the need for new peak facilities, say via replacement LNG storage.
Unintended consequences	Increasing the cost for industry for backup facilities that are rarely used.
End users to bid directly into the OCM	This option is designed to facilitate or force direct participation in the OCM by consumers. Whilst in theory, consumers should be able to participate in the market indirectly through contracting with shippers, in practice it is difficult for consumers and shippers to agree terms. This option would require a change to the licence regime to allow or oblige non-shippers access to the OCM, so that they can directly offer their flexibility to turn down at any time, and not be forced to contract through their shipper. In this way the customer could respond to price movements in real time and offer its value, which might vary over time.
Timeframe for implementation	We estimate that this option would require approximately one year to implement the necessary regulatory and licence changes. If primary legislation is required this process could take longer.
Speed of response at time of need	Potentially within a few hours.
Complexity	More complex to implement than shipper to end user DSR contracts as the end user would do the bidding and the shipper would be liable for any imbalance.

Potential volume	There will be concerns on how much volume would actually be made available when it is required and whether sufficient volume would be available for a long-period of supply disruption. Obliging customers above a certain scale to bid in would be a better way of ensuring a volume of DSR is available – although it is likely to be at prices approaching VOLL.
Potential peak	This could theoretically be fairly high, especially if consumers are obliged to bid.
Control Mechanism	Market based, overseen by Ofgem.
Reliability	We expect reliability would be fairly low.
Legality	An exception to the existing requirement for a shipper licence will be required though changes to the current regulations. Primary legislation might be required to overcome any problems of direct contracting between gas transporters and consumers.
Industry support	We consider this option unlikely to find much industry support (based on previous consultations), and the take-up from industrial users is likely to be small given the infrequent number of occasions they are likely to be used.
Barriers addressed	Competitive barriers to entry, as well as removing the barrier to larger end users.
Unintended consequences	Non-compliance with any accepted OCM bid would impact shippers, who would have to pay any imbalance penalties. This could result in legal action. There is a risk that consumers misunderstand their own VOLL, and bid into the OCM at a significant discount to their VOLL, causing direct and potentially indirect losses to the UK economy.
Additional information provision to end users to prompt DSR	Based on the desire for some end users to participate more directly, an alternative to direct bidding on the OCM to improve end users' interaction with the market, live price information from the OCM can be fed to end users to encourage DSR actions through their shippers. In times of potential tight supply, alerts can be sent by email/text/fax to trigger some sort of action. Ideally it should be implemented alongside the drive for more DSR contracts.
Timeframe for implementation	Changes to the APX rules and procedures may take a few months to implement.
Speed of response at time of need	Uncertain, but could be implemented alongside a drive for voluntary DSR contracts which may crystallise the procedures.
Complexity	Relatively simple.

Potential volume	Provision of the price information only will not be sufficient to ensure that gas volumes are available when required.
Potential peak	Uncertain.
Control	Control would be through Ofgem.
Reliability	Implemented on its own this is likely to prove to be very unreliable, but the option could be implemented alongside a drive for voluntary DSR contracts which may crystallise the procedures.
Legality	This can be achieved through existing arrangements.
Industry support	The industry would probably be largely in support, and it reflects a growing trend within the industry to improve transparency.
Barriers addressed	Would improve the current speed of response, if implemented correctly.
Unintended consequences	We do not consider that there would be any unintended consequences with this policy option.
Crisis price incentives on firm market	This process would target smaller users into DSR by the application of a price levy or tax in times of stress. A portion of the revenues raised would have to be recycled to the fuel poor, to minimise impact on the most vulnerable. To be implemented fully it would require the majority of customers in the country to have smart meters. Without smart meters, it would rely on profiling and estimated readings.
Timeframe for implementation	The implementation timetable for smart metering is 10 years, so may not be properly effective until then.
Speed of response at time of need	Smart meters should allow the changes to be implemented technically in a few hours; however, the Government decision process to implement an across the board temporary tax rise may take a little longer. The speed at which millions of consumers then modify their thermostats would probably be over a number of days, if at all.
Complexity	The process could be relatively simple to implement, but would also depend on how the money raised is allocated. If it were based on estimates or profiles it would be significantly more complicated for the suppliers to implement.
Potential volume	If all households turned down their room thermostats by a couple of degrees, it could lower demand quite significantly. However, the number that would actually act is very uncertain.
Potential peak volume	Peak reductions would be less certain than volume reductions.
Control	Government control, with implementation through the suppliers.
Reliability	Not reliable

Legality	Powers to set prices in times of emergency exist under s.2 of the Energy Act 1976. But if the funds raised by the levy go to the Treasury then this would be a tax. As such it is normal for this to be done through a Finance Act. The tax would need to comply with EU tax law, such as the Energy Products Directive.
Industry support	Would enable providers to more effectively target users.
Barriers addressed	Provides a way for firm customers to respond to pricing signals when the system is stressed.
Unintended consequences	Could be introduced without smart metering, but it is likely to have more adverse consequences if based on estimated use/profiles.

D.4 Other direct security policies

Supplier obligation	Similar to the stocking obligation, above, this option is a regulatory/licence obligation to say suppliers must meet a gas security of supply metric, but can meet it from a variety of sources, including long-term contracts, storage and DSR. It could be strengthened by the implementation of a penalty should shippers fail to deliver when required, which would be equivalent to a second tier imbalance price. It should be noted that shippers in neighbouring countries might have yet stronger imbalance incentives, which would mean that in a crisis they would have a greater incentive to balance in those countries rather than GB.
Timeframe for implementation	Poor, if obligation is onerous; possibly good given future capacity availability.
Speed of response at time of need	Little difference to at present
Complexity	Defining what would supplies would count to the obligation would be complex (especially as the GB is a net importer). This option might be very difficult to enforce, as has been evidenced with the existing 1-in-50 obligation.
Potential volume	Potentially quite high, as there will be no restrictions for meeting supply, provided the incentives are at a sufficient level.
Potential peak volume	As above.
Control	Probably monitored under shipper licences by Ofgem, but the market would be free to contract as it saw fit.
Reliability	May not give any greater reliability than at present.
Legality	It would be a variation to the licences, and may require changes to the Gas Act.

Industry support	We consider it very unlikely that this would attract support from the industry.
Barriers Addressed	This would force a decrease in suppliers' risk.
Unintended consequences	The option may reduce traded spot gas, driving suppliers to long-term contracts in order to demonstrate compliance with the incentive.
Security obligation certificate	Similar to ROCs, SOCs are set to achieve the required security of supply level, with a recycle process. These can then be traded and provide a price signal to encourage provision of more supplies/storage, if required. This is effectively a means of enforcing/monitoring a supply obligation.
Timeframe for implementation	Poor as would require significant new legislation.
Speed of response at time of need	Poor as it reduces transporters' ability to balance
Complexity	Resolving what would count to a SOC would be problematic as having capacity doesn't mean gas will flow and buying from spot markets is not the same as having a long-term take-or-pay contract. There are also big issues on buy-out prices and recycling terms.
Potential volume	Potentially high.
Potential peak	Potentially high.
Control	Probably monitored under shipper licences by Ofgem, but the market would be free to contract as it saw fit.
Reliability	May not give any greater reliability than at present.
Legality	Can expect implementation to be similar to the process for ROCs, so would need significant primary legislation and possibly State aid approval.
Industry support	Possibly limited, due to complexity, and may inhibit transporters' ability to physically balance.
Barriers addressed	This would force a decrease in suppliers' risk.
Unintended consequences	Again this may have the un-intended consequence of reducing traded volumes in the spot market, potentially limiting competition between suppliers and acting as a significant barrier to entry for any new entrants.

D.5 Fiscal incentives

Grants, allowances, loans, etc.	To overcome some of the financial/economic barriers related to investing in commercial storage projects, the Government could provide grants or incentives to help the financial viability of an important project that would add significantly to the country's security of gas supply. Other countries, such as Poland provide significant incentives in such circumstances. This option may be required if significant incentives are provided to holders of depleted gas fields to use them for carbon capture & storage ('CCS') projects, even if their geology is better suited to use as a gas storage facility.
Timeframe for implementation	Probably a long time frame given the legal issues.
Speed of response at time of need	Dependent on the selected facilities.
Complexity	Would depend on the nature of the proposed grant, allowance or loan and how access to the funds would be applied for and allocated.
Potential volume	This option may not bring forward sufficient volume unless it made a significant change to a project's expected rate of return.
Potential peak	Dependent on the selected facilities.
Control	Government.
Reliability	Dependent on the selected facilities, though possibly very high.
Legality	Making this change would be difficult . Funding over a period of more than 2 years and of more than £1.5 million would require primary legislation. State aid approval would be needed and it is uncertain that such approval would be forthcoming.
Industry support	Potential support from parties looking to invest in new facilities. However, existing parties may have concerns about unfair treatment.
Barriers addressed	Would remove economic disincentives to invest in new facilities.
Unintended consequences	It could also have the un-intended consequence of providing a financial incentive that brings forward too much gas storage, making both existing and future facilities commercially unviable.

Cushion gas capital allowance

Many parties are highlighting that cushion gas is a significant cost in developing a new facility. Treating this as other capital expenditures would improve the project economics and so remove a perceived major barrier to development of new storage facilities. Current position is also not aided by project financiers assuming that the cushion gas has no terminal value in the free cash flow value calculations.

On 22 April 2009 clarification was given to a recent decision made by HM Revenue & Customs which confirmed that cushion gas would be eligible for plant and machinery capital allowances. This decision will reduce the capital costs in developing depleted field storage facilities in particular.

D.6 Indirect policies and regulatory incentives

Set out below are a number of other policies and initiatives that are applicable for consideration for improving security of supply. Some of these are already underway and we have already assumed in our modelling that they will, to some extent, be achieved in the timescales being considered in this project.

Energy efficiency to significantly reduce demand

Reducing demand through energy efficiency will improve security of supply by lowering demand. Various policies, including the 2020 targets and other initiatives, are already being developed to reduce the carbon intensity of consumer demand, which has the effect of reducing predicted gas demand.

Our base demand scenario already includes this.

Smart meters

The introduction of smart meters will support the above initiatives by allowing all consumers to better understand their actual consumption and support them in making decisions to reduce consumption, especially at times of high prices. This will especially be the case for electricity consumption which in turn will feed into how much gas is required in power generation.

Smart meters will take a long-time to implement across all 20 million users but have the potential to deliver significant volume reductions. However, the smart meters will not necessarily mean that end consumers react to pricing signals, especially during a severe winter scenario.

There is also the unintended consequence that this could adversely impact the fuel poor and those members of society who are more vulnerable to reductions in space heating.

Improvements to the planning process

Many facilities have been held up by the planning process in GB and reforms to speed up the process could accelerate the development of storage facilities. Reforms to the planning arrangements have been implemented recently, however it is not yet clear that these changes will make a significant difference.

More interconnection with & within the EU

This proposes that higher levels of pipeline integration between countries would allow gas to more easily flow to where the supply/demand balance is most needed. It also means each country doesn't have to individually provide storage capacity to meet its own worst case supply scenario. Continued pressure to liberalise and provide easy access and price transparency across the EU will improve the gas security of all countries, including GB.

Various projects have already been identified and the proposed EU stimulus package contains support for various interconnection projects to improve gas interconnections. In particular it provides support to address gas security of supply issues in central and south-eastern Europe, where flows were particularly restricted in the January 2009 Russian / Ukrainian gas supply dispute, and to further improve the diversity of supplies across Europe. The UK is not deemed a priority area, as it has a good diversity of supplies and interconnection with the Continent and Ireland.

Our modelling assumes no constraints within countries, but is limited to the stated interconnection limits, except where financially confirmed projects are to be introduced.

If there was to be a new Government funding mechanism for interconnection projects it is likely that it would be for a period of more than 2 years and of more than £1.5 million, so primary legislation would be required. There would also be State aid issues. Projects within UK waters would also need various environmental consents.

TPA exemptions

The second EU gas directive required that all pipeline, LNG terminal and storage facilities should provide open access to shippers, except in certain circumstances where new facilities can be granted exemptions.

A TPA exemption allows storage developers to contract with one or more shippers who would underwrite the investment through long-term contracts, thus reducing the cost of capital.

Blanket TPA exemption introduces inefficiencies into the market: suppliers are not able to fully access flexibility tools and therefore invest for themselves. Blanket TPA exemption is one of the reasons why the US and Germany developed significant levels of storage in the 1980s and 90s, when there was little interconnection and little or no TPA.

Full TPA arrangements should ensure the most efficient allocation of storage capacity, however it may introduce risks that become a barrier to investment. TPA exemption of individual facilities can help to overcome this barrier, but introduces the potential for market inefficiency and over-investment.

Gas quality

GB has a narrower range for gas quality (specifically Wobbe) than its near neighbours on the Continent. It therefore obliges producers and importers to process the gas before it enters the system so that it falls within the specification. This specifically affects LNG importers and, to a lesser extent, Norwegian imports. Reforms to the gas quality specifications are not due until 2020, but this may become an increasing issue if we are to rely on imports from the Continent at short notice, as the average Wobbe increases due to increased LNG and Russian gas via Nordstream reaching the Netherlands and Belgium. DECC may therefore want to consider a review earlier than the current timetable.

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ANNEX E – ILEX ENERGY REPORTS

Pöyry Energy Consulting produces the renowned ILEX Energy Reports. ILEX Energy Reports provide detailed descriptions of European energy markets coupled with market-leading price projections for wholesale electricity, gas, carbon and green certificates. ILEX Energy Reports and price projections are currently available for the:

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  - Belgium
  - Bulgaria
  - Cyprus
  - Central East Europe
  - France
  - Germany
  - Great Britain
  - Greece
  - Ireland
  - Italy
  - the Netherlands
  - Poland
  - Romania
  - Russia
  - South East Europe
  - Spain
  - Switzerland
  - Turkey
- renewables markets in:
  - Ireland
  - Italy
  - Poland
  - Romania
  - Spain & Portugal
  - United Kingdom
- the biofuels market in Europe.

ILEX Energy Reports are produced by Pöyry Energy Consulting, formerly known as ILEX Energy Consulting.

In addition to ILEX Energy Reports, Pöyry also produces a number of other reports, including electricity reports for Norway, Sweden and Finland, a renewables report for Sweden, and a report of the EU Emissions Trading Scheme with carbon price projections.

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