Transporting Britain's Energy 2009:

Development of Energy Scenarios

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Cover photograph: South Hook LNG terminal

TBE 2009 – Development of Energy Scenarios

Executive Summary

As part of our annual Transporting Britain's Energy (TBE) consultation process, the principal purpose of this document is to set out our latest projections for gas supply and demand over the next ten years. Historically we have also presented analysis for the development of the National Transmission System (NTS) that arises from the supply-demand outlook. Whilst this remains important and is outlined in this document, the changing forecasts of lower demands with little or no growth and completed or near completed import infrastructure means that the emphasis on new NTS investments has shifted to include alternative topics such as 2020 targets and security of supply. To reflect this we have changed the name of this publication from 'Development of NTS Investment Scenarios' to 'Development of Energy Scenarios'

The supply-demand position for next winter is discussed in our Winter 2009/10 Consultation documents[1] and related industry presentations, and is therefore outside the scope of this document.

As a consequence of high energy prices and a rapid decline in the UK economy, energy demand for both gas and electricity has fallen significantly. For the 2008/9 financial year, weather corrected gas demand in traditional Distribution Network (DN) market areas fell by 5%, the fourth consecutive year of decline. Over the same period electricity demand from National Grid's transmission system fell by 4%. As most of these falls were accounted for in the winter period, the recent year on year declines are noticeably higher.

Though energy prices have fallen from their exceptional highs in 2008, our longer term forecasts for most forms of energy and therefore end user prices remain relatively high. This combined with increased energy efficiency measures, higher carbon prices and government initiatives, results in DN gas demand forecasts that are essentially flat and these would show a decline if it was not for new power generation demand within the networks. Our forecasts for gas demand in the power generation sector are for modest increases as new CCGT plant replaces opt-out coal and ageing nuclear plant. Through to 2018/19 we forecast 13.6 GW of new CCGT plant to be connected to the NTS, of which 7.5 GW is under construction. These additions are lower than previously forecast due to lower electricity demand forecasts.

Our latest forecasts for gas exports to the Continent are higher due to an improved global supply position (notably LNG) arising through lower global demands. For Ireland we forecast lower exports due to the recession and the development of indigenous supplies.

Over the ten-year forecast period (includes 2009), total gas demand is projected to fall at a rate of around 0.25% per annum, with DN demand falling at 0.7% per annum and NTS demand forecast to grow at an average of 0.4% per annum. Around the base case forecast we have captured a range of demands based on numerous sensitivities; compared to last year the resultant ranges are greater reflecting increased uncertainty. On a peak basis we are forecasting some slight growth in demand as our methodology for determining peaks has detected no significant change in the weather sensitivity of demands despite lower annual throughputs.

[1] http://www.nationalgrid.com/uk/Gas/TYS/outlook/

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In addition to our ‘business as usual’ demand forecasts we continue to assess the impact of the EU’s two renewable targets that require:

1. 15% of the UK’s total energy (includes transportation) to come from renewables by 2020.

2. EU 20/20/20 vision - 20% of energy from renewable sources along with a 20% reduction in GHG emissions and 20% improvement in energy efficiency by 2020

Our scenarios to achieve these targets cover electricity, heat and transport. Whilst there are numerous ways of apportioning the relative contribution to the target across the three sectors, we have focussed on the strategic priorities of saving energy and electricity decarbonisation. Currently, these represent the most economic and efficient hierarchy of measures as no other sectors offer such short term potential combined with a mature and economic technology platform. Hence our reported scenario in this document for 15% of renewable energy is made up of 8% electricity (notably wind and biomass), 4% heat (contributions include, biomass, solar, heat pumps, hydro) and 3% transport (essentially biofuels).

Our forecasts for gas supply continue to be built on declining UKCS production and increasing import dependency. Our latest forecasts for UKCS decline are little changed than previously forecast but due to lower demands, the import requirement of 46% in 2010/11 and 69% at the end of our ten year planning period is now less than previously reported.

The UK’s requirement for increased quantities of imports has resulted in the construction or near completion of numerous import projects to supplement existing importation routes. Hence the UK is now well served in terms of both capacity and diversity of supply. Nevertheless, as we have observed at times and stated frequently, capacity does not necessarily mean any guarantee of physical flows.

As in previous years, there continues to be considerable uncertainty regarding the use of import infrastructure. In constructing our base case forecast this year we have changed our approach and developed a ‘core’ / ‘non- core’ concept where core represents what gas is likely to flow and non-core what gas may flow. Obviously with import capacity far exceeding import requirements, even this approach only part captures possible supply patterns. At a high level we forecast UKCS to continue to decline by typically 5-10% per year, Norway to be the dominant importer in the short to medium term, with LNG imports to steadily increase over time to comparable levels to Norway. For the Continent in the short term we anticipate lower imports than forecast previously as a well supplied UK (notably from LNG as a result of the global economic downturn) exports more gas to the Continent.

For investment planning and forecasting for peak conditions we include storage. Whilst some new storage facilities are under construction, most storage proposals have compared to last year’s development timescales slipped a further year due to uncertainties over the economy and gaining planning consents

In terms of assessing longer term security we have again analysed the loss of an import source, namely supplies from Norway, the Continent or LNG. Compared to last year the position look more secure due to the lower demands. Nevertheless, the loss of any import source with only modest levels of storage would provide challenging conditions, notably during the winter period.

Our latest investment cycle has just commenced and we are not yet in a position to identify potential network implications arising from our latest supply and demand forecasts. Whilst lower demands may have some impact on investment, the changing nature of supplies (notably LNG imports and new storage) and specific large loads (notably power stations) will ensure a need for further network reinforcement. On the supply side we continue to look for signals received through our LTSEC auctions to underpin network investment.

In addition to its primary role of establishing a long-term supply and demand picture for investment planning purposes, the TBE consultation process also provides a forum for debate on a range of related issues facing the gas industry. To support this, we have once again organised an industry seminar to coincide with the publication of this document. For this year's seminar, we have chosen a theme of "Demanding Times"; to reflect the changes arising from the global recession and how going forward the EU's renewable energy targets may be met.

We would welcome feedback on the issues raised by this paper, and in particular the supply-demand outlook, including our scenario's to meet the EU's 2020 targets. This feedback, together with signals received from entry capacity auctions, will assist us in our task of identifying appropriate energy scenarios and long-term developments to the NTS, and presenting plans that reflect these developments within our next Ten Year Statement, which we will publish towards the end of 2009. It would be helpful to receive comments by 14th August 2009.

Feedback should be directed by e-mail to:

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1. Introduction & Context

1.1 Introduction

This is the ninth year in which we have published a discussion document mid-way through our annual consultation process, known as Transporting Britain's Energy (TBE). It comes at the point at which we have produced updated gas supply and demand forecasts, using the information provided to us by many industry participants. This year we have changed the name of our publication from 'Development of NTS Investment Scenarios' to 'Development of Energy Scenarios' to reflect the broader scope of our forecasts and more settled nature of forecast demand and completed or near completed import infrastructure. As a consequence the future drivers for network investment are less obvious than in previous forecasts. That said, on the demand side there are numerous connections expected for new power stations and on the supply side numerous import and storage proposals, many of which will come to fruition. The changing nature of short term changes to both demand and supply is also leading to a need for increased flexibility and therefore potential investment.

The document's publication is timed to coincide with an open industry seminar (9th July 2009, One Great George Street, London). The theme of this year's seminar is "Demanding Times". This theme recognises the global recession and how this is impacting energy demand and availability of supply. In this report we also briefly consider the longer term renewable and environmental targets and scenarios on how these could be met.

The main components (and related timeline) of the annual TBE process can be defined as:

- Publication of a consultation agenda to set out the key industry and public policy issues that we believe should be considered within the consultation process (winter)
- Consultation meetings with industry stakeholders seeking views on forecasts, long term requirements, security of supply issues, demand uncertainties, market interactions and perceptions from winter experience (spring)
- Publication of this document, Development of Energy Scenarios, on the supply-demand outlook, including an update on meeting environmental targets and network investments (summer)
- Long Term System Entry Capacity (LTSEC) auctions (autumn 2009, spring 2010)
- Publication of the Ten Year Statement (winter)

The TBE consultation process has again proved to be a particularly valuable element of our forecasting process, with an excellent response to this year's questionnaires. Coupled with the information collected during our consultation meetings, this information has assisted with the development of many of the core assumptions. A summary of the responses to the Market Uncertainties Consultation Questionnaire will be found on our website alongside this document.

The remainder of this Section highlights the next steps in this consultation process, Sections 2 and 3, respectively, provide an overview of our latest demand and supply forecasts, with more detail provided in the Appendices. In support of our Planning Code obligations, we have again been more specific behind the assumptions we have used in generating our forecasts. Due to timing constraints and the impact of lower demands, we have not yet determined future network investments associated with our latest forecasts, hence Section 4 briefly describes the basis to our investment plans. Finally, Section 5 highlights the longer term security of supply considerations that arise from the present supply-demand outlook.

1.2 Issues for Consultation & Next Steps

We would welcome views and feedback on all aspects of this paper. Areas of particular interest are:

- Our conclusions in relation to the demand position up to 2018/19, and our view on to how demand may look if EU 2020 environmental targets are met
- Our view of supplies including our latest view of the prospects for UKCS production and provision of imports
- The approach that we are adopting this year to the identification of future NTS developments, namely the construction of a base case with supply ranges to derive potential investment requirements
- Issues regarding longer term security of supply arising from the increase in the level of imports associated with the decline of the UKCS.

We look forward to receiving feedback following the publication of this paper. This feedback, together with signals received from entry capacity auctions, will assist us in our task of identifying appropriate long-term developments to the NTS, and presenting plans that reflect these developments within the Ten Year Statement towards the end of 2009.

2. Gas Demand

2.1 Introduction

This section provides an overview of our latest gas demand forecasts, covering the impact of the recession on gas demand, our view on the economy, fuel prices and levels of energy efficiency going forward. Section 2.6 also has an overview of the work we have been developing in order to assess the impact on the gas and electricity transmission systems of meeting EU environmental targets. This section also gives some information on the indicative reinforcements needed to the electricity transmission system in order to meet these targets.

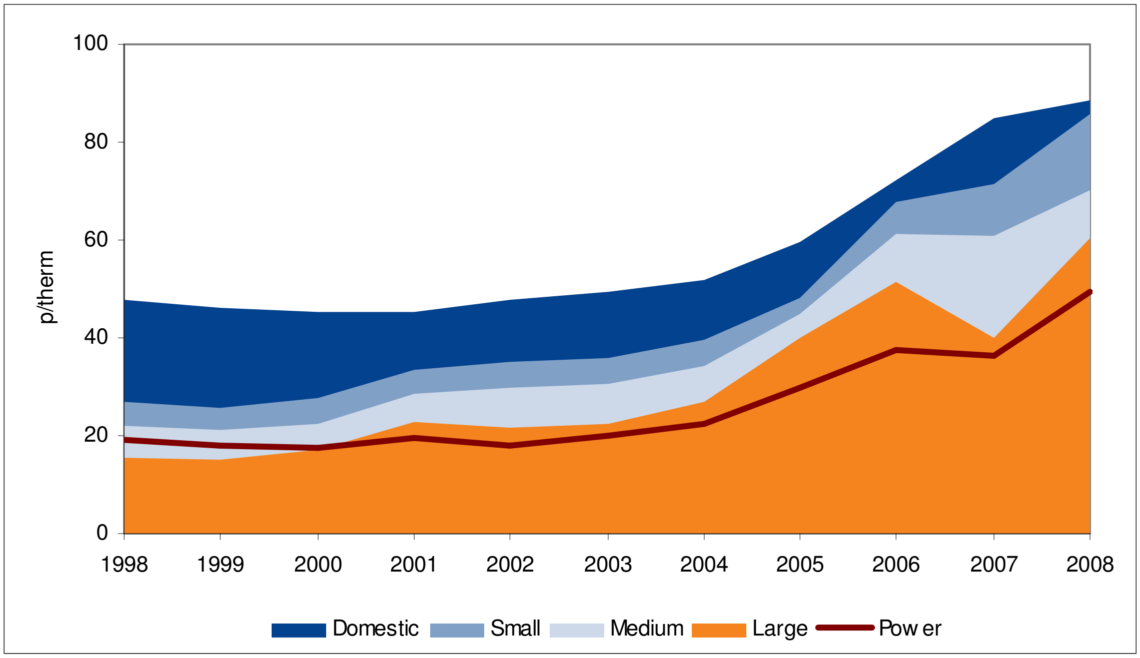
A more detailed view of the key assumptions underpinning these volumes can be found in Appendix 1.

2.2 Recent demand history and gas prices

The past year has seen unprecedented levels of volatility in both the energy markets and the world financial markets. This has seen end-user gas prices in the UK reach record levels (see Figure 1) and a rapid decline in the UK economy, resulting in a recession. The effect of the economic downturn on energy demand has been significant with a rapid decline in both electricity demand and gas demand, with the latter particularly concentrated in the traditional Distribution Network (DN) market sectors. Although this document focuses on gas, the level of electricity demand has an impact on gas-fired power generation demand. For the financial year 2008/9, weather-corrected electricity demand from National Grid's Transmission system fell by 4% when compared with the previous year. Weather corrected gas demand in the DN markets fell by 5% over the same period.

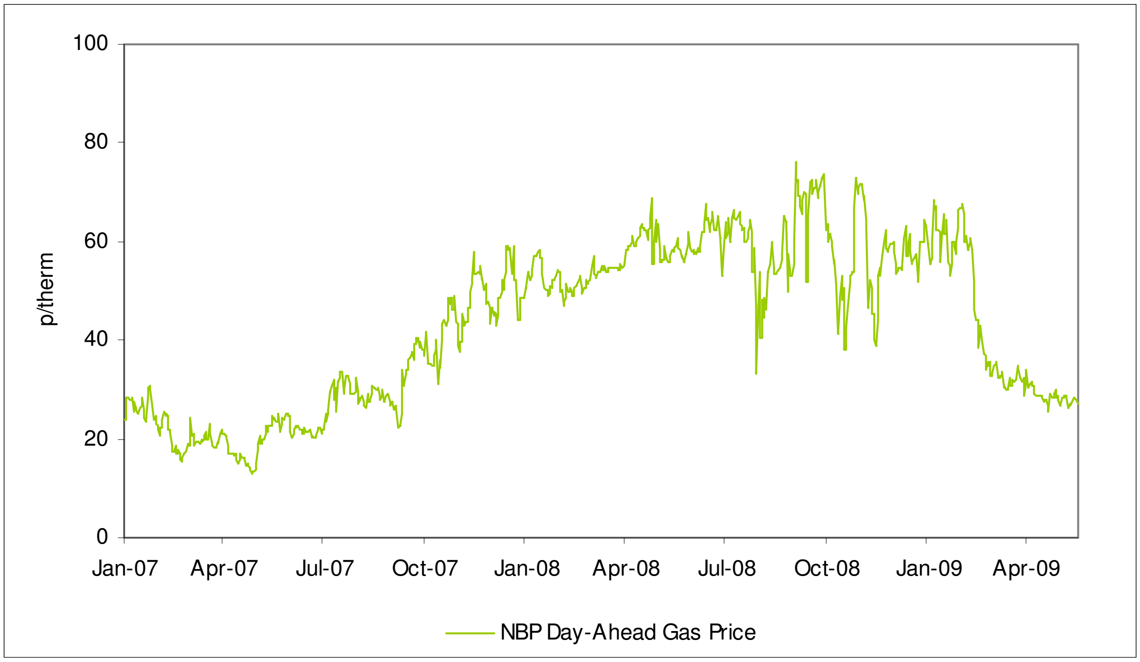
Weather-corrected consumption in the gas Distribution Networks (DNs) fell by around 1.6% in 2008 when compared with 2007, the fourth consecutive year of gas demand falling in these sectors. Between 2004 and 2008, weather-corrected gas demand fell by over 10% in the DNs. Almost all of the reduction in gas demand in 2008 occurred in the final four months of the year as the impact of the financial 'credit-crunch' and the increase in end-user fuel prices combined. This reduction in demand due to the ongoing recession has continued into 2009. Weather-corrected demand for the first five months of 2009 was 9.5% lower than for the corresponding period last year. The fall in DN demand has also been prevalent across all market sectors from domestic consumers to large industrial users.

Figure 1 – Average Annual End User Gas Prices by Sector
Source: DECC



The global nature of the economic crisis has resulted in a fall in energy prices from the record levels seen in the summer of 2008 and a subsequent reduction in end-user prices in early 2009, although this fall in end-user prices has not been significant when compared with the increases seen in recent years. Figure 2 shows the changes in wholesale gas prices since the beginning of 2007. NBP prices have tended to track the increase in the global oil price through to summer 2008. Wholesale prices in the UK maintained a level of around 60 p/therm in the early part of the winter, falling rapidly in the early part of 2009. Further commentary on gas prices can be found in Appendix 1.

Figure 2 – Wholesale Gas Prices
Source Heren



The steady increase in end-user prices over the past five years, coupled with government policies around energy efficiency and carbon emissions reductions, is thought to have changed consumer behaviour and stimulated energy efficiency improvements. Our analysis of the demand reduction in the domestic (0-73.2 MWh p.a.) gas sector suggests that a significant proportion of this fall is due to increased energy efficiency, with scope for further reductions into the future. Rising public awareness of their carbon footprint and the impact on global warming may also be affecting consumption.

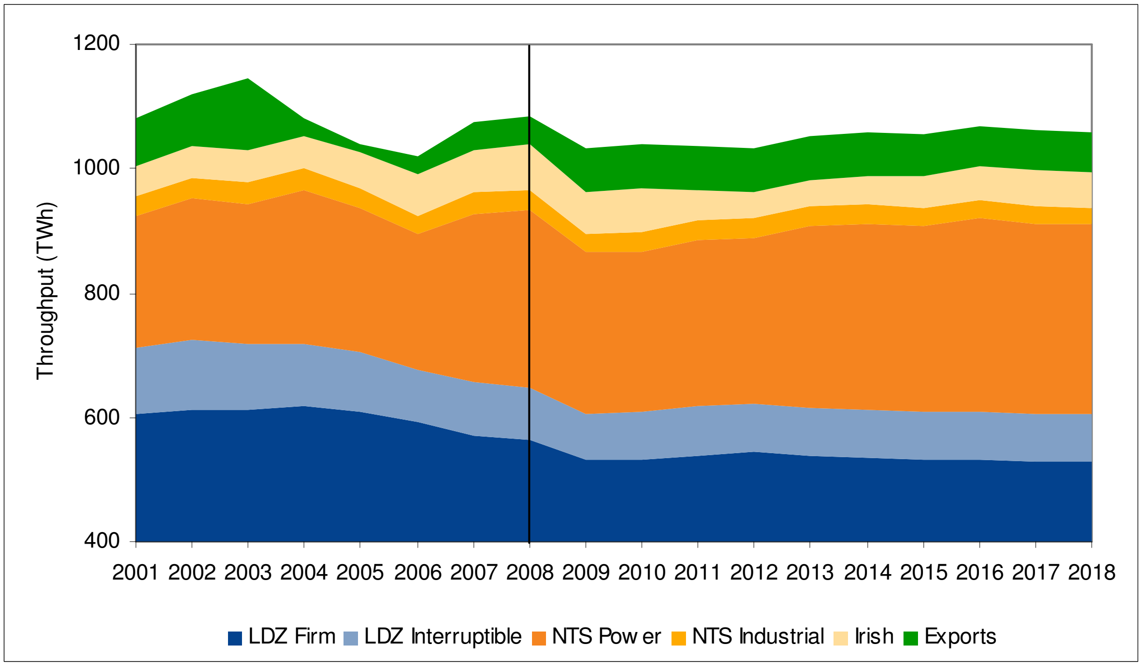
Gas demand in the power generation sector increased by over 6% in 2008. The very high coal prices in the summer of 2008 saw gas become a more competitive fuel for generation despite the corresponding high gas process. The delay in fitting FGD equipment to some of the opt-out LCPD coal plants and the continued problems with nuclear plant availability also contributed to gas' share of the generation mix rising. Power generation gas demand fell in the early part of 2009 as coal and carbon prices fell dramatically and electricity demand also fell due to the impact of the recession.

Exports to continental Europe have been above 4 bcm for the past two calendar years. These volumes have been driven by a combination of new UK import infrastructure and differences between the UK gas price and Continental contracted gas. Due to the global recession, there now appears to be increased availability of 'international' supplies for the UK; notably LNG and to a lesser extent Norway as Continental buyers take less gas or change their timing for receipt of gas due to pricing arrangements that are indexed to oil albeit lagged. For 2009 there is also a driver for higher exports to the Continent on account of increased depletion of Continental storage, partly as a result of the Russia / Ukraine dispute. Exports to Ireland increased again in 2008, with strong demand in the power generation sector outweighing falling demand in the traditional market sectors due to the recession.

2.3 2009 Annual Gas Demand Forecasts

Figure 3 shows both historical annual gas demands and our 2009 forecast. All demands shown are weather corrected. The history shows the continued fall in DN demand from 2004 and the increase in NTS demand over the past two years, driven largely by increased gas-fired power generation demand.

Figure 3 – Historical and Forecast Annual Gas Demand
Source: National Grid



Note: 1 bcm = 11 TWh at a CV of 39.6 MJ/m3

The most significant aspects of this year's forecast are the sharp reduction in demand in 2009 and the lower overall growth rates across the ten-year period. The impact of the recession in 2009 is evident. DN demand is forecast to fall by around 6.4% in 2009 due to the contracting UK economy. NTS demand is also predicted to fall, by around 2.3%, with lower power generation, industrial and Irish export demand being offset to some degree by greater exports to Continental Europe. Overall demand is therefore forecast to fall by just under 5% in 2009.

Our forecast for the economy is that we will begin to see a return to growth in mid 2010, with GDP levels returning to 2% from 2012 onwards. Coinciding with a reduction in end user fuel prices, this results in a small amount of growth in the DNs, although this is also driven by new power generation demand within the networks. Over the long term, however, the demand growth driven by the improving economic outlook and new housing completions is more than offset by the impact of rising end user gas prices and energy efficiency initiatives. These, coupled with increasing carbon prices and government policy, are forecast to result in increased levels of energy efficiency and renewable energy, thus reducing gas demand. The long term DN forecast is therefore that demand will fall over the ten-year forecast period.

After falling in 2009, gas demand in the power generation sector is forecast to increase in subsequent years as new CCGT plant connects to the NTS, replacing opt-out coal-fired generation and ageing nuclear plant. This results in gas' share of generation increasing. 13.6 GW of new CCGT plant is forecast to connect to the NTS by 2018/19, although at a slower build up rate than in previous forecasts due to our lower forecast of electricity demands increasing the forecast plant margin. 7.5 GW of CCGT plant is currently under construction, which may result in very high plant margins in the short-term. More detail on our power generation forecasts can be found in Appendix 1.

Exports to Europe are forecast to increase in the early part of the forecast due to lower GB demands and an improved global (LNG) supply position arising through lower demands. Though subject to considerable uncertainty, we forecast these exports to be maintained over the forecast period.

Exports to Ireland are forecast to fall in the short to medium term due to a combination of lower Irish demand due to the recession and the onset of new indigenous supplies. Exports are then predicted to increase as these indigenous volumes decline, thus increasing the level of exports, although not back to the level seen in 2008 due to a lower forecast of overall Irish demand.

Over the ten-year forecast period, gas demand is therefore projected to fall at a rate of around 0.25% per annum, with DN demand falling at 0.7% per annum and NTS demand forecast to grow at an average of 0.4% per annum.

2.4 Demand Sensitivities

Alongside our base case of demand a number of sensitivities have been developed to enable us to look at a range of potential demands in the future. Given the volatility seen in energy markets over the past eighteen months and the uncertainty over the length and severity of the current economic downturn, this work is especially relevant this year.

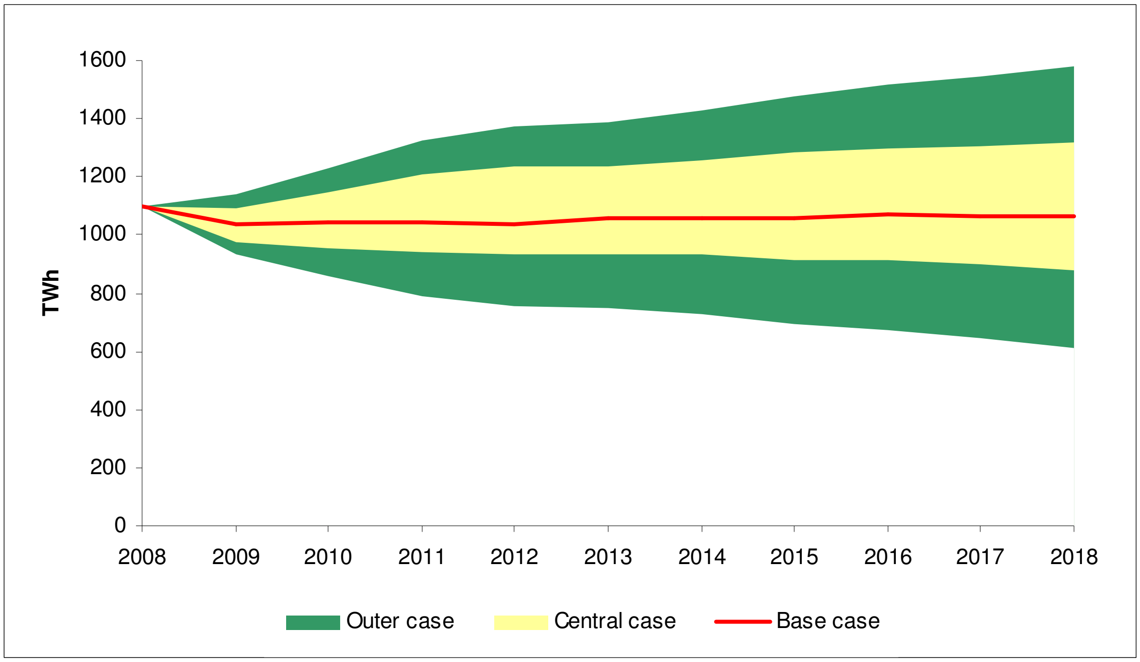
This work has been developed for the Energy Markets Outlook document which will be published by DECC and Ofgem later in the year. To give a flavour of the sensitivities assessed, cases were analysed for economic variables, fuel prices, energy conservation, power generation capacity and output, CHP capacity, warm weather and exports to both Ireland and the Continent. In this year's sensitivities we have also developed two 'recession cases' – one with a deep and long lasting recession and the other with a rapid economic recovery.

Figure 4 shows a possible range of gas demands around our base case forecast. The outer case assumes that all factors are acting independently and pushing gas demand in one direction, hence the extremely wide range. In practice these variables are not mutually exclusive and it is unlikely they would push gas in one direction. For example, it is possible that weaker fuel prices and weaker economic growth could coincide thus cancelling each other out to a certain degree, as far as the impact on demand is concerned. The central case takes this into account and gives a more probable band of demand levels.

This central band is noticeably wider in the short-term than last year. The volatile nature of energy markets in the recent past suggests this is a more prudent approach. This range also reflects the uncertainty still surrounding the length and depth of the recession and when will see a return to economic growth. Over the longer-term there is a little more scope for an upturn in demand in the sensitivities we have analysed, which reflects the level of this year's forecasts and the underlying assumptions behind them.

It should be noted that these sensitivities are indicative at present and will be finalised for publication in the Energy Markets Outlook document later this year.

Figure 4 – Sensitivities around Base Case Demand Forecast
Source: National Grid



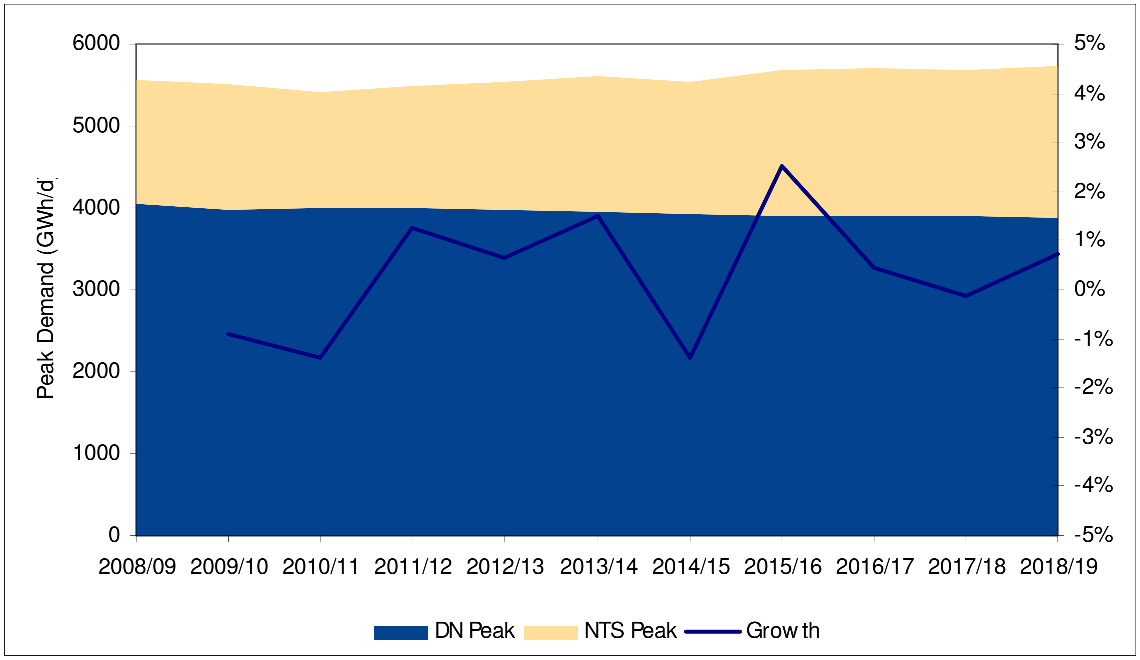
2.5 2009 Peak Gas Demand Forecasts

The reduced forecast in annual demand has resulted in a lower forecast of peak gas demand, a key driver for investment in transportation infrastructure. Peak demand is forecast to rise at 0.3% per annum over the forecast period, with NTS demand growing at 2.1% per annum and DN demand falling at 0.4% per annum. The 'spiky' nature of the growth rates is indicative of new CCGT loads connecting to the NTS.

The peak forecast is derived using our established weather / demand modelling methodology which has detected no significant change in the weather sensitivity of demand despite lower annual throughputs. Peak demand forecasts in the weather sensitive DN sectors therefore have a very similar profile to the annual forecasts.

Figure 5 shows our latest NTS and DN peak demand forecast. The DN forecasts should be seen as complementary to the DN exit requirements provided through the Offtake Capacity Statement (OCS). This chart does not take into account the move to 'universal firm' demand post 2011. We are currently in the process of assessing the potential impact of demand that is currently interruptible becoming firm and how that would alter our peak demand forecasts.

Figure 5 – Forecast Peak Gas Demand
Source: National Grid



A brief summary of the key forecast drivers and assumptions is listed below, with more detail on the process, assumptions and forecast outcome detailed in Appendix 1.

- Economic growth forecast to return in mid-2010 with GDP returning to 2% growth in 2012.
- End user prices rise over the forecast period following falls in the short-term.
- Energy efficiency measures forecast to reduce growth rates over the forecast period.
- Demand levels are forecast to fall in the Distribution Networks over the ten-year period, where previous forecasts have always shown some growth.
- 13.6 GW of new CCGT capacity forecast to connect over the ten-year period, mainly to replace closing coal and nuclear plants.
- Exports to continental Europe rise as GB demand falls, remaining at a near consistent level over the forecast period.
- Irish exports reduced by new indigenous supplies from 2011 onwards.

2.6 Long Term Energy & Environmental Targets

The UK Government has set two key environmental targets relating to renewable energy and green house gas emissions (GHGs):

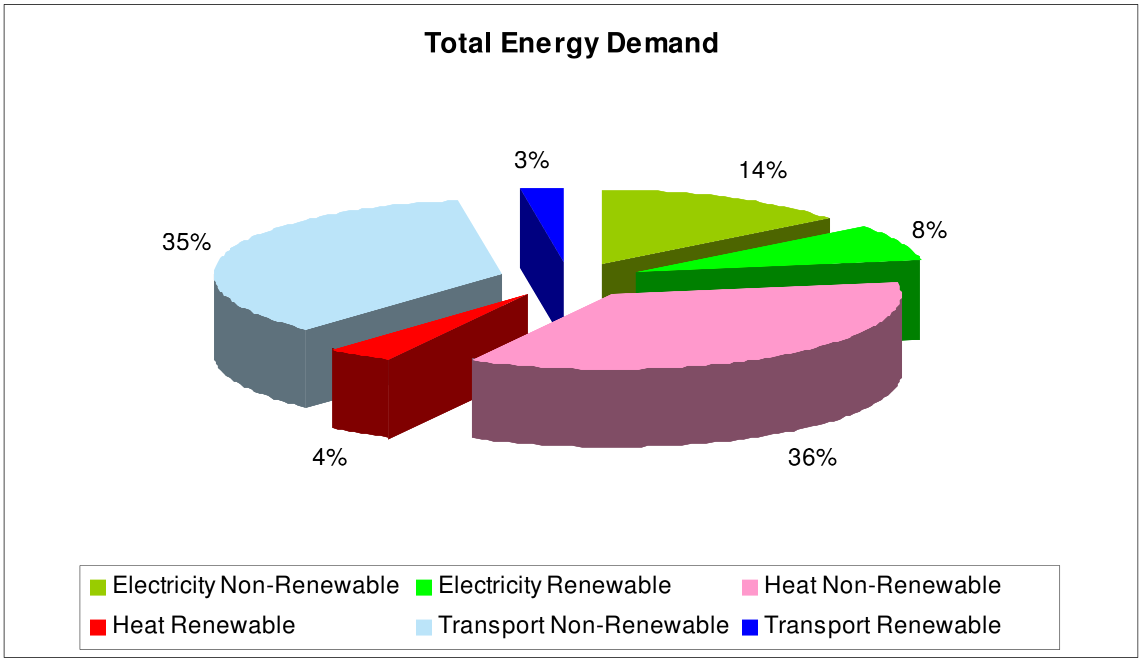
1. The first of these targets is part of the EU's integrated energy/climate change proposal that addresses the issues of energy supply and climate change and in doing so sets a target of 20% of European energy (including electricity, heat & transport) to come from renewable sources by 2020. The UK contribution to this target is 15% which is lower than the European wide average due to the UK's low starting point (2% compared to EU average of 9%); however, the UK has the largest increase of any country due to it's low starting point, economic strength and it's high potential for renewable generation i.e. significant wind, wave and tidal resource.

2. The second target, which follows the principles of the overall EU 20/20/20 vision (20% of energy from renewable sources along with a 20% reduction in GHG emissions and 20% improvement in energy efficiency by 2020) but goes even further, has been incorporated in the recent Climate Change Bill and sets a target of 80% reduction in GHGs from the 1990 levels by 2050.

Clearly the size of this challenge means significant changes in Government and regulatory policies coupled with increased incentives to help facilitate the construction of necessary infrastructure and maximise energy efficiency measures. These changes will need to ensure the access regime delivers the timely connection of new renewable sources of generation some of which may well need to be connected ahead of associated network reinforcement.

Our base case or "business as usual" forecast described in this document only reaches around half of the renewable sources required by 2020. Consequently, we have been developing a range of holistic energy scenarios to inform our understanding of the priorities across all sectors e.g. electricity, heat and transport. There is, of course, more than one way of apportioning the relative contribution to the target across the three sectors. In developing our energy scenario for 2020, we have focussed on the strategic priorities of saving energy and electricity decarbonisation, which represent the most economic and efficient hierarchy of measures as no other sectors offer such huge near term potential combined with a mature and economic technology platform. In both the heat and transport sectors, in which carbon mitigation technologies can be relatively expensive, we have suggested those solutions which seem to us to be appropriate and economic in their own context, for example, advocating the introduction of high efficiency boilers and insulation measures, rather than heat pumps, in much of the existing housing stock. The result of this analysis is reflected in Figure 6.

Figure 6 - Total Energy Demand in 2020
Source: National Grid

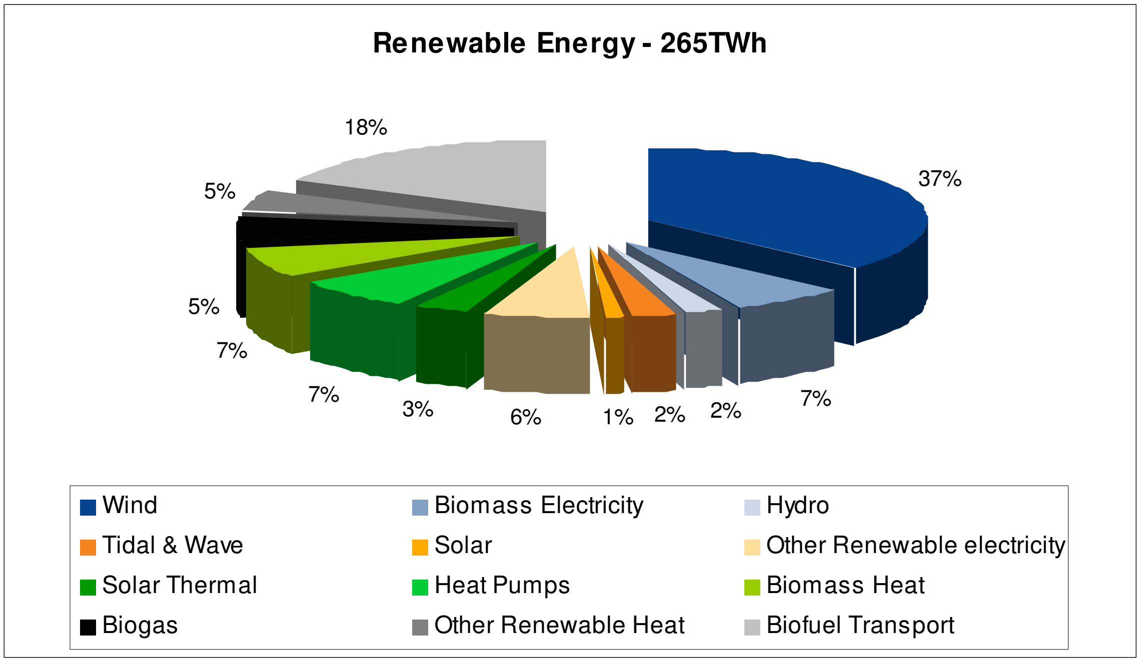


We have also assessed, at high-level, the plausibility of delivering the required volumes of different renewable energy technologies, by reviewing potential installation rates and the experience elsewhere around the world. The scenario is certainly plausible but achieving the required levels of different (and often emerging) technologies represents a significant challenge.

The scenario that we have developed assumes that the whole of our renewable energy target is met domestically. Moreover, it also assumes that the energy demand from international aviation and national navigation is included in the target. We note the comments in the Government's Renewable Energy Strategy (RES) document concerning the aviation sector's very limited ability to access renewable energy in the 2020 timescale. Of course, since this scenario was developed a number of changes to the elements of these targets have been agreed e.g. a limit to aviation demand and electric transport counting towards the biofuel target, not to mention the world wide recession. These developments will be incorporated into future updates to this scenario over the summer.

A breakdown of the contribution from the different renewable technologies in our scenario is shown in Figure 7.

Figure 7 – Breakdown of Renewable Energy in 2020
Source: National Grid



Under the EU's 2020 target, renewable electricity's share of overall electricity demand has to be in the range 34%-40%, assuming only some contribution from heat and transport, to achieve the overall renewable share of energy i.e. electricity has the largest burden. Our scenario assumes 36% of electricity will come from renewable sources (mostly wind and biomass) with heat providing 10% (mostly biomass and heat pumps) and transport 7% (biofuel). This compares to the RES levels of 32% for electricity, 14% for heat and 7% for transport.

Obviously there will be a number of alternative ways to deliver the target which will involve less renewable generation but these scenarios would require significant behavioural change to increase the renewables share of heat (e.g. heat pumps) and transport (e.g. biofuel and electric cars) along with high levels of energy efficiency. We are continuing to progress work which examines the potential for biogas injection into existing pipelines, and there may be greater potential for this than is reflected in the chart above.

Given the importance of natural gas in heating and clean power generation for many decades to come, we are also developing our view on how our gas network will evolve and considering the development of carbon networks. We will also continue to monitor the wholesale gas markets and facilitate industry understanding of the availability of gas in the coming decades.

2.7 Indicative Reinforcements to meet Environmental Targets

In June 2008, the Government published its consultation on a UK Renewable Energy Strategy. Following on from this, the Electricity Networks Strategy Group (ENSG), a cross industry group jointly chaired by the Department of Energy and Climate Change and Ofgem, asked the three electricity GB Transmission Licensees, National Grid, Scottish Hydro Electric Transmission and Scottish Power Transmission with the support of an Industry Working Group to take forward a study to:

1. Develop electricity generation and demand scenarios consistent with the EU target for 15% of the UK's energy to be produced from renewable sources by 2020 (as shown above)

2. Identify and evaluate a range of potential electricity transmission network solutions that would be required to accommodate these scenarios.

In March 2009, ENSG published a report 'Our Electricity Transmission Network: A Vision For 2020': http://www.ensg.gov.uk/assets/1696-01-ensg_vision2020.pdf which discharged the action placed on the Transmission Licensees. The reinforcements identified in this report are based on a range of scenarios that take account of the significant changes anticipated in the generation mix between now and 2020. In particular, the scenarios examined the potential transmission investments with the connection of large volumes of onshore and offshore wind generation required to meet the 2020 renewables target, whilst, at the same time, facilitating the connection of other essential new generation, such as new nuclear that will be needed to reduce carbon emissions and maintain continued security of supply.

The study concluded that, provided the identified reinforcements are taken forward in a timely manner, they can be delivered to required timescales. It should also be noted that the reinforcements identified in this report are designed to facilitate connection of a large volume of different types of generation in a given area, not dependent on a single generation project proceeding, and where the lead time for the combined transmission reinforcements in a given area would exceed the time taken to construct the generation, i.e. lack of transmission capacity would have a potential negative impact in meeting renewable targets and/or accommodating generation required to maintain continued security of supply.

The development of the potential reinforcements are phased to achieve a 2020 delivery date with the initial phase being delivered in 2015 based on the prospective growth of renewables in each region. It is recognised that there will continue to be a degree of uncertainty about the volume and timing of generation growth in any given area. It is therefore proposed to continue to monitor the development of the market and update the scenarios accordingly. The proposed transmission reinforcements will be developed in such a manner as to ensure that the options are maintained at minimum costs. By undertaking pre-construction engineering work, the delivery of each project can be positioned such that construction can be commenced when there is sufficient confidence that the proposed reinforcements will be required. This is the least regrets solution, i.e. the minimum commitment to secure the ability to deliver to required timescales.

Following Ofgem initial consultation phase on strategic investments, funds have been made available to undertake the 2009/10 pre-construction engineering for reinforcements identified by the study and these are being developed without requirements for user commitment. It is anticipated that Ofgem will undertake further consultation with regard establishing a regulatory framework which will facilitate taking forward the reinforcements identified by the report and any additional anticipatory reinforcement which may be required to facilitate the objectives identified in the report.

3. Supply Forecasts

3.1 Introduction

This section provides a brief overview of our latest gas supply forecasts out to 2018/19 and the key assumptions behind them. Appendix 2 provides greater detail. Besides conventional gas sources, we have for the first time assumed a small supply contribution from biogas based on a build-up profile to 1% of all supplies by 2020. There is much uncertainty over the contribution biogas and other non conventional gas sources (i.e. coal bed methane) could provide, hence we acknowledge that these flows could be less or considerably more, but their inclusion is a recognition of the role they could ultimately play.

The main purpose of our supply forecasts is to allow a picture of supply and demand to be created that can be used to assess potential NTS investments and determine other business requirements that are influenced by the pattern and availability of gas supplies. The supply-demand picture is clearly also relevant from the perspective of security of supply. The supply-demand position for next winter is discussed in our Winter 2009 Consultation documents, whilst Section 5 covers security of supply from a longer term perspective.

Our supply forecasts are developed through a combination of:

- TBE consultation
- supply intelligence including commercially available data
- market observations and assessment
- signals for entry capacity through the LTSEC auction - as a result of the last LTSEC auctions in September 2008 we released 90 GWh/d (~8 mcm/d) at Caythorpe from October 2011

Our supply-side analysis continues to be based on declining UKCS production and increasing import dependency. Whilst we have a surplus of import capacity, most of which is now either built or nearing completion, we face considerable uncertainty regarding where imports will be delivered and how much gas will flow. Last year we captured the supply uncertainty through a base case supply forecast with ranges around each of the supply sources. This was subsequently detailed in our 2008 Ten Year Statement and also reported in the 2008 EMO[2].

This year we have again developed a base case supply forecast and detailed the rational behind our methodology. Our base case should not be seen as a central case or necessarily a best view of future supplies but as a starting position to capture the ongoing uncertainty as to how import capacity may be utilised.

As in previous years we build our base case supply forecast around declining UKCS supplies and increasing levels of imports, the following sections detail our approach for the various components of gas supply. For each supply component we also determine a range of possibilities, these are not at the extreme limits but at realistic levels. These

[2] http://www.berr.gov.uk/energy/energymarketsoutlook/page41839.html

ranges are not reported in great detail but are shown in the entry capacity charts for each terminal in Section 4 and Appendix 2.

With lower forecast demands and high capacity from completed or near completed import projects from diverse sources of supply, there is considerable uncertainty as to how supply will meet demand. To capture this ongoing supply uncertainty, we have enhanced the approach previously used that prioritised or used a merit order of gas supplies. Namely, for each of the components or supply sources we have developed a 'core' / 'non- core' concept where core represents what gas is likely to flow and non-core what gas may flow. Obviously with import capacity far exceeding import requirements, even this approach only part captures possible supply patterns.

In the following sections that detail each of the supply sources in turn we have identified the basis for core gas and non-core gas. We have only been partially explicit as to how the non-core gas from the each of the supply sources has been allocated as this was achieved in part through an iterative basis. At a high level the allocation process is as follows:

1. Determination of annual demand
2. Determination of core and non-core gas from each supply source
3. Allocation of core gas to annual demand
4. By difference identify the annual supply shortfall to be made up from non-core gas sources
5. Due to excessive surplus of non-core, further review of non-core gas for each supply source i.e. move from capacity based apportionment to a derated[3] based availability
6. Finally we allocate the remaining supply shortfall to all non-core supply sources based on derated availability

3.2 UKCS Supplies

In constructing our base case gas supply forecast we consider UKCS supplies as the first supply component in terms of the make-up of our supply forecasts for numerous reasons:

- Since UKCS supplies were first developed in the late 1960's UKCS supplies have always under-pinned UK gas demand
- Though in decline the estimated 63.5 bcm of UKCS supplies[4] in 2008 made up 61% of all UK supplies[5]. This compares to 66.8 bcm in 2007 (67% of UK supplies)
- Most supplies from the UKCS are from fields currently in production, hence the marginal cost of supply is relatively low
- With the exception of limited volumes of UKCS gas that is piped direct to the Netherlands and potential options for exports through the Interconnector (IUK) at Bacton, the UK is the only option in terms of supply destination

[3] A derated basis relates to anticipated usage or application of load factors (see Section 3.3)
[4] Estimated UKCS supplies delivered to the NTS
[5] Aggregated supplies to NTS, includes storage

- With the exception of a few high swing fields, most UKCS supplies operate at a high load factor[6] to maximise production. A high load factor is usually commensurate with 'base load' operation. In 2008 the average load factor for all UKCS supplies was 80%, this was the highest of all supply components, the next highest being Norwegian imports at 64% based on observed peak flow and just 53% based on capacity
- Consequently all UKCS supplies are considered as 'core' with the exception being those high swing fields (typically less than 10%). The non-core component for UKCS is determined in the final allocation of the remaining shortfall after all other core gas sources are calculated

In constructing our long-term gas supply forecasts we continue to rely on information received through the long term auctions for entry capacity and information from market participants through our TBE consultation process. To ensure we consider other supply possibilities we supplement this data with information from commercial sources and trade journals. This year was the fourth year that we received most of the information regarding UKCS supplies through Oil and Gas UK, whereby Oil and Gas UK members released their data to Oil and Gas UK and under agreed terms we extracted a field specific data set. This data representing about 90% of UKCS fields was supplemented with additional commercial data to form the basis of our UKCS supply forecasts. Hence we believe our UKCS forecasts continue to closely reflect the view of upstream parties.

Based on the information provided to us, our latest forecast for UKCS annual production for next year (NTS deliveries in 2009/10) is 9% lower at 53 bcm than the equivalent forecast that we made in 2008. This is due to a combination of lower demand and a lower forecast for UKCS production next year. In aggregate for the 10 year planning period where our forecasts 'overlap' our latest UKCS annual forecasts are approximately 2% lower than those made in 2008, with lower forecasts being seen between 2008/09 through to 2010/11, then similar forecasts through to 2015/16 before they revert to being higher for the remainder of our 10 year planning period. Our current assumption for the commencement of West of Shetland production is 2014/15 a year later than forecast in 2008. Appendix 2 provides greater detail on the decline in annual UKCS production.

Figure 8 shows our latest forecast for UKCS annual production (delivered to NTS) shown as core and non-core and UK annual demand (includes exports to both Ireland and through IUK). Around the forecasts for UKCS annual production is a range commencing at +/ - 10% of our 2008/09 forecast and thereafter increasing by +/- 2% per year. Also shown on the chart is actual UKCS supplies and annual demand since 2000/01. The actual demand line has not been weather corrected. The % import line relates to NTS demand including both Irish and IUK exports, if these were excluded, the % for imports would be lower.

[6] % of average flow divided by peak flow

Figure 8 – UKCS Annual Supplies

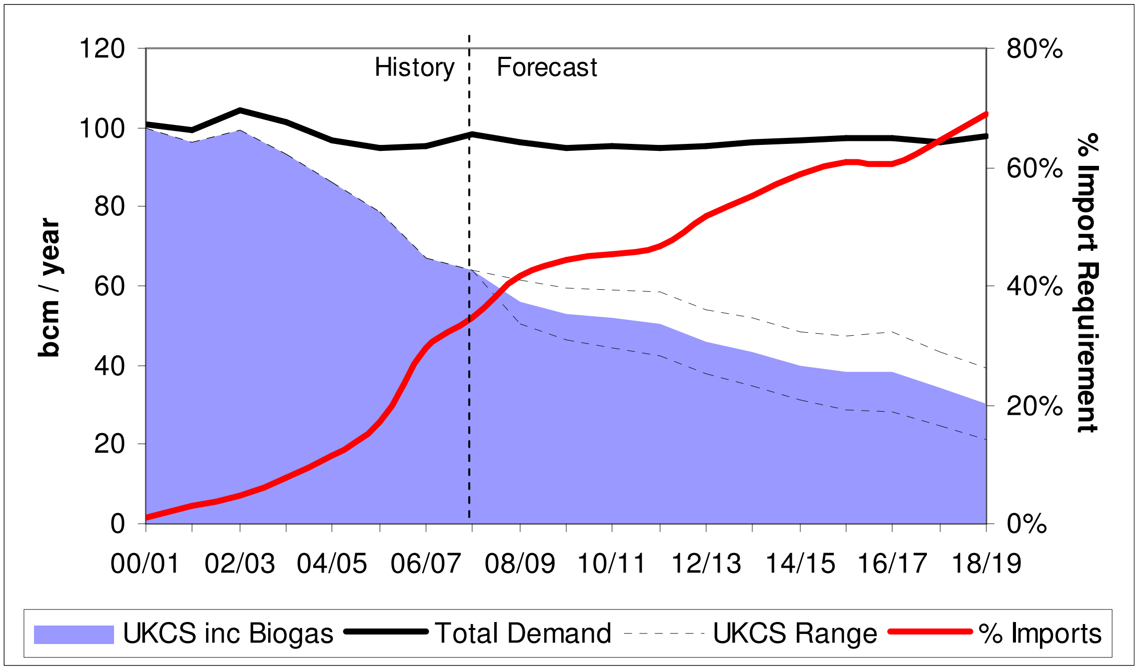


Figure 8 shows for our base case the UK's import dependency reaching 46% in 2010/11: this is marginally lower than the 47% we reported last year. The chart also shows UK import dependency reaching 69% at the end of our 10 year planning period in 2018/19. This is slightly lower than reported last year primarily due to lower demands. The range for import dependency based on uncertainties associated with future UKCS production is typically +/- 10% around our base case forecast.

The current basis for reporting import dependency includes exports to Ireland and the Continent in the measure of demand, if these demands were excluded, the UK's import dependency would be lower. The rapid increase in the import dependency line between 2006/07 and 2007/08 was due to a combination of events in 2006/07. Namely; low demands (not weather corrected) and high Norwegian imports as Continental buyers took less gas, this in turn depressed some UKCS production from high swing fields. This is a good example of where non-core supplies have been reduced.

Our latest forecast for UKCS peak production in 2009/10 is about 1% higher at 203 mcm/d than the equivalent forecast that we made in 2008.

Through the 10 year planning period our latest peak UKCS forecasts are generally higher than those made in 2008; this is more noticeable towards the end of our 10 year planning period. Again, Appendix 2 provides greater detail on the decline in peak UKCS production.

3.3 Imports

The declining production from the UKCS has resulted in a need for increasing quantities of imported gas. To fill this requirement, there has in a relatively short period been the construction or near completion of numerous import projects to supplement existing importation routes from Norway, the Continent and LNG. These projects, which are detailed in Appendix 2, include:

- first operational in 1978, the Frigg pipeline to St Fergus. This was modified in 2001 to accept further Norwegian supplies. Subsequently known as Vesterled, this pipeline has a 13.1 bcm/year capacity
- first operational in 1998, IUK import capacity has been upgraded through the construction of compression facilities at Zeebrugge in 2005/06 and 2006/07 with further expansion in 2007/08 to 26.9 bcm[7]
- completed in 2006/07 a 26.3 bcm/year capacity pipeline, known as Langeled, from the offshore Norwegian gas network to Easington. From 2007/08, this pipeline was linked to the Ormen Lange gas field via the onshore processing terminal at Nyhamna
- completed in 2007/08 an offshore pipeline, known as the Tampen Link between the Norwegian Continental Shelf and the FLAGS pipeline to St Fergus. This pipeline could ultimately be used to fill the ~10 bcm/year FLAGS pipeline as UKCS supplies into it decline
- completed in late 2006 and upgraded in 2007, a 15 bcm/year capacity pipeline, known as BBL, between Balgzand in the Netherlands and Bacton. From September 2008 there are plans to accept non physical reverse flows through netting off import nominations. Longer term BBL may be expanded for higher UK imports and possibly exports.
- LNG imports into Isle of Grain commenced in 2005, with an initial capacity of 4.7 bcm/year. This was expanded by 9.1 bcm/year in late 2008, and further expansion post 2010/11 by a further 6.9 bcm/year
- LNG imports into Teesside through Excelerate's on board gasification were commissioned in early 2007. Whilst not expected to be base load, the capacity of this facility is potentially 4.2 bcm/year
- LNG imports into two new facilities at Milford Haven were expected from 2007/08, these are now expected to be fully operational later this year. The initial combined capacity is 16.4 bcm/year, with plans to expand both facilities thereafter towards a potential capacity of 32.9 bcm/year
- other LNG imports projects yet to receive full planning consents include another Teesside project, Canvey Island, Anglesey, Barrow as well as at other UK ports
- currently there are limited other new pipeline projects that are being reported publicly

In aggregate, the existing and development plans for new import capacity is around 200 bcm per year. This far exceeds the UK's projected import requirements even at the end of our 10 year planning cycle. Rather than show the import capacity against the import

[7] Reported flow rates at standard conditions, reduce by ~5.5% for normal conditions

requirement we have 'de-rated' the import capacity to reflect operational experience and expectations of future use. For import pipelines (except IUK) connected to the UK we have assumed a de-rated annual capacity of 85%, this is broadly reflective of maximum utilisation rates than could be achieved when factors such as demand seasonality, lack of UK storage and operational outages are considered. For LNG and IUK imports we have assumed a de-rated annual capacity of 75% or 50% (operation & under construction or proposed) and 25% respectively. This may appear low but to date the highest annual load factor for IUK imports is just 22% in 2005/06, whilst for LNG imports through Grain Phase 1 just 57% also in 2005/06. Globally LNG regasification capacity exceeds production or liquefaction capacity by a ratio in excess of 2 to 1.

Figure 9 shows our view of import requirements against a back drop of de-rated capacity for existing import facilities (shown by supply type), import projects that are under construction (all LNG) and proposed import projects yet to be sanctioned (all LNG except for the possible further expansion of BBL). For the proposed import projects we have for illustrative purposes assumed development timescales consistent with the proposals.

Figure 9 – Import Requirement vs De-rated Import Capacity

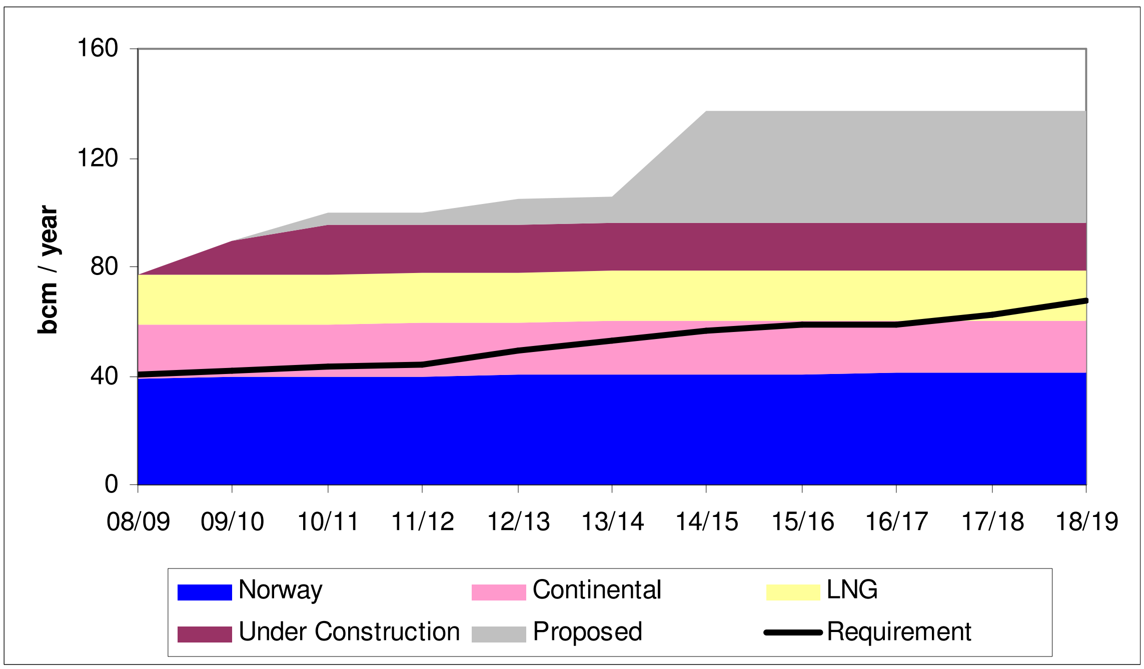


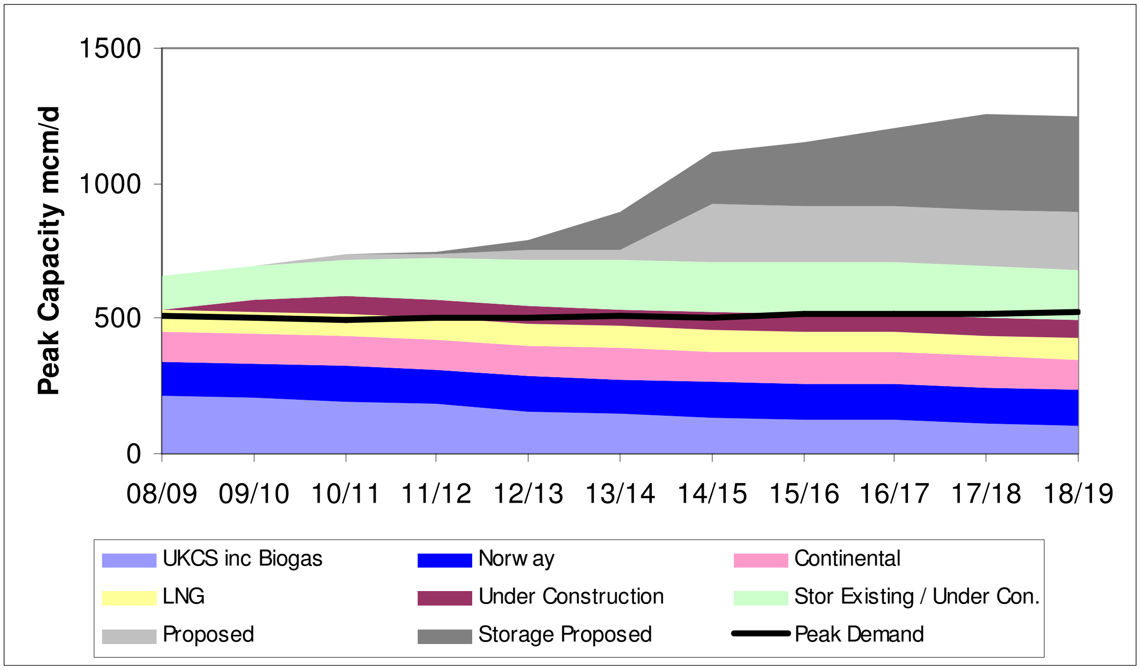
Figure 9 shows that the de-rated annual import capacity is just over 140 bcm, if the category of import proposals is excluded this falls to about 100 bcm. This is above our forecast import requirement at the end of our 10 year planning period. Hence without high export volumes to the Continent through IUK and possibly BBL, we believe that it remains unrealistic to expect that all of the proposed import projects will meet their proposed development timescales and delivery volumes. The inclusion of new proposed import projects in the 2009 base case are described in the subsequent import sections.

Figure 10 shows the peak position. As we have used our 1 in 20 peak day demand[8] we have not de-rated any of the supplies, hence all imports are shown at their maximum capacities. Besides the import components shown in Figure 9, the peak position also

[8] Undiversified demand

includes UKCS and storage. For the proposed import and storage projects we have for illustrative purposes assumed development timescales consistent with the proposals.

Figure 10 – Potential Peak Supply



The chart shows that the theoretical peak position is well covered; however the supply is almost certainly overstated due to the following reasons:

- inclusion of all proposed import and storage projects with development timescales consistent with proposals. In reality not all of these will proceed as reported
- reporting of capacity rather than peak forecasts
- reporting of UKCS at 100% load factor
- no consideration for any storage space / deliverability limitations

As the uncertainty associated with possible future peak supplies provides an inconclusive evaluation for longer term security, we have considered an alternative approach based around the loss of key import infrastructure to assess security. This is detailed in Section 5.

Norwegian Imports

The difference between annual demand and our annual forecast for UKCS production shown in Figure 8 determines our view of future import requirements. In our base case supply forecast Norway is the primary source of imports to make up this shortfall. This is broadly consistent with last years base case supply assumptions; however this year we have apportioned Norwegian supplies on a core and non-core basis.

Our basis for assuming Norway as the primary source of imports in our base case is based on a combination of:

- future expectations of Norwegian production
- Norwegian export capacity to UK and Continent
- proximity of UK and characteristics of UK market

As future Norwegian supplies to the UK are so important we have developed a high level Norwegian forecast by considering numerous concepts and sources of information, these include:

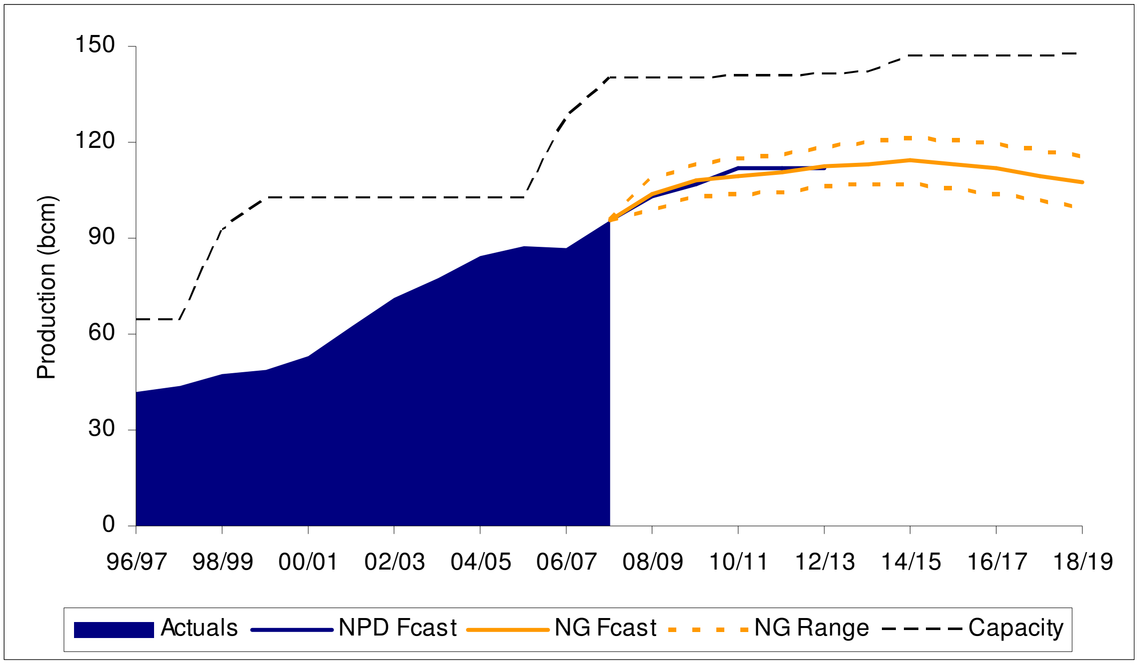
- historic performance, in terms of annual trends and seasonal variation
- capacity utilisation, in terms of historic load factors both nationally and seasonally
- system developments, in terms of new supplies, new infrastructure and its effect on overall capability and network flexibility
- other forecasts, including those from the Norwegian Petroleum Directorate (NPD) and from consultants
- remaining gas reserves, in terms of potential impact on long term production profiles

Norwegian gas production in 2008 was approximately 99 bcm, the Norwegian Ministry of Petroleum and Energy (NMPE) forecast production to increase to 103 bcm in 2009, 107 bcm in 2010 and potentially rising to 115-140 bcm by 2020. Our forecasts for future production from the Norwegian Continental Shelf (NCS) also assume further increases; however we have taken a more cautious build-up in production and assume production in 2020 is below 120 bcm. Whilst in theory production could be higher, primarily driven by higher volumes from Ormen Lange, developments within the Statfjord area and new discoveries in the Norwegian Sea, we believe that system capabilities and the application of realistic load factors may in the absence of new offshore Norwegian infrastructure limit production below the NMPE forecasts. Recent reports of a new discovery, the Gro field, in the Norwegian Sea suggest this field may be the largest Norwegian discovery since Ormen Lange with reserves between 10-100 bcm. Hence if / when developed, along with other potential discoveries in the area, this could materially increase future Norwegian production and / or extend Norwegian production beyond existing forecasts.

Our assessment of export pipelines from Norway to the Continent suggests that with the partial exception of flows to Germany, there is limited head room to flow significant additional volumes. Hence by inference, much of the increase in Norwegian production over the next few years is expected to flow to the UK. Of course, any new export pipeline would affect this assumption, but such a pipeline is unlikely to be operational within the next few years, and if constructed would be expected to build-up over a number of years.

Figure 11 shows our forecast for overall Norwegian production out to 2020, this includes Snohvit production and gas for the Norwegian domestic market, including power station and petrochemical applications. The chart also shows the NMPE forecast through to 2013, this forecast lies within the broader NMPE forecast range that shows a Norwegian production range of 115 to 140 bcm in 2020.

Figure 11 - Norwegian Annual Production



The chart shows our forecast of Norwegian production rising from current levels of about 100 bcm to approximately 110 bcm before posting a slight decline post 2015. Our chosen plateau level of 110 bcm represents about 80% of the current Norwegian export capacity (includes Tampen[9] and Snohvit[10]) of approximately 140 bcm. Also shown on the chart is a range for Norwegian flows based on +/- 5% at the start of the forecast period, increasing to +/- 10% in 2020. A load factor of 80% represents a relatively high load factor when seasonal demand and upstream outages are factored in. The slight decline we show post 2015 could be arrested through new developments such as the Gro field.

To determine Norwegian flows to the UK we make the following assumptions:

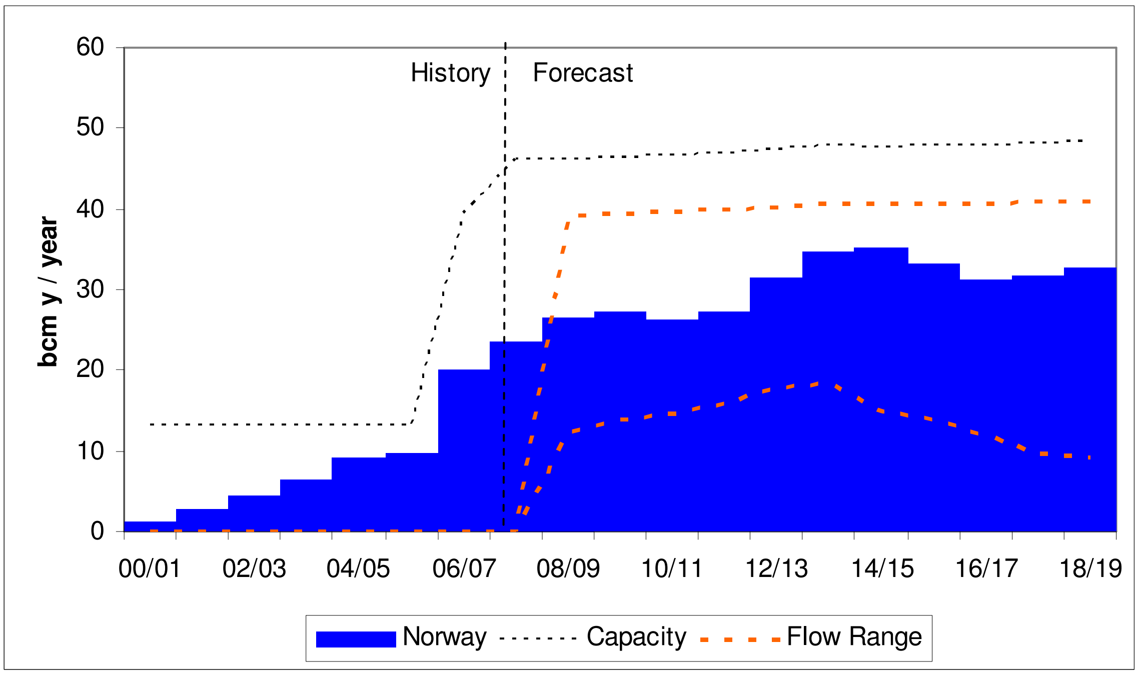
- during the forecast period no new major pipelines are built to either the UK or the Continent
- Norway prioritises gas supply to the Continent, hence flows to the UK are based on the difference between total Norwegian production and flows to the Continent
- Our basis for core Norwegian gas represents our lower estimate of Norwegian production (i.e. the lower range in Fig. 11) less maximum export volumes to the Continent. Hence this represent gas that 'must' be delivered to the UK
- For non-core Norwegian gas (before final allocation) we take the difference between maximum Norwegian production less minimum export volumes to the Continent less core UK exports
- for security planning we make the assumption that the loss of Norwegian production impacts the UK ahead of the Continent

[9] Adjusted for FLAGS ullage
[10] Snohvit capacity assumed at 5.7 bcm

- regarding UK entry locations for Norwegian flows we assume preference of flows through Langeled (capped at 85% load factor) rather than Vesterled and a modest increase in flows through Tampen as ullage in FLAGS becomes available

Figure 12 shows Norwegian imports to the UK since 2000/01 and post 2008/9 our base case forecasts for Norwegian flows to the UK, also shown is the capacity of Norwegian pipelines to the UK. The forecasts include both core and non-core gas, with core gas representing about 50% of Norwegian imports at the start of the forecast period and about 30% at the end. Around the forecast we have shown a range for Norwegian imports, the upper range is based on 85% of the capacity with the lower range based on the core gas, namely Norwegian gas that subject to aggregated Norwegian production levels being met, 'must' flow to the UK.

Figure 12 – Base Case Norwegian flow forecast to UK



The chart shows actual volumes delivered to the UK have increased from just over 1 bcm in 2000/1 to over 23 bcm in 2007/8. During this period Norwegian imports made up over 70% of total imports of 108 bcm.

The commencement of our forecast in 2008/9 shows further growth to about 27 bcm before levelling off until about 2012. Thereafter our forecast increases to 30 to 35 bcm due to higher Norwegian production and no commensurate increase in Continental export capacity. Thereafter we forecast a slight decline post 2015 due to higher Norwegian export capacity to the Continent (this is assumed through new compressors rather than a new pipeline).

In terms of meeting the total UK import requirement, the Norwegian contribution falls from approximately 65% in 2008/9 to 45% in 20018/19.

The range we show for Norwegian imports derived through our core / non-core concept to the UK is approximately +/- 10 bcm until about 2015, thereafter the downside increases due to uncertainties in Norwegian production and increases in Continental export capacity.

Remaining Import Requirement

Besides Norwegian imports there is also a need to consider Continental and LNG imports. Again we have applied a core / no-core concept in determining these flows. At a high level we continue to assume:

- modest changes to the way BBL operates, namely predominantly forward flows to the UK based on known contracts, but becoming more commercially driven
- IUK responding to market differentials between the UK and the Continent
- LNG imports growing over time to meet most of the growing import requirement

The next two sections consider Continental and LNG imports.

Continental Imports

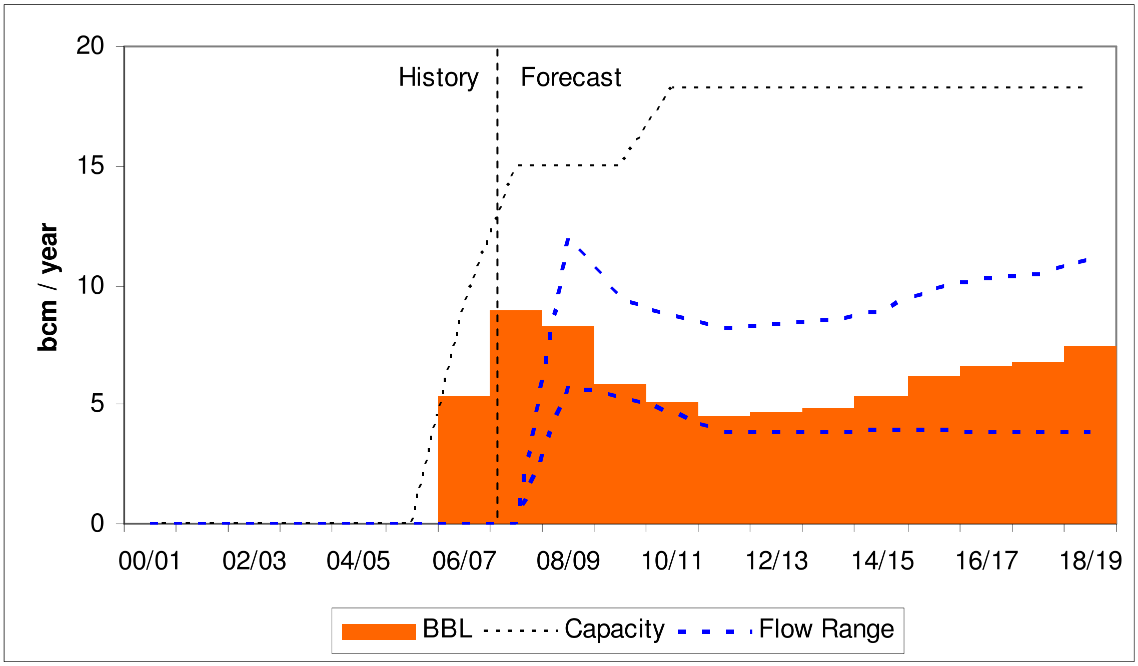
It must be stressed that there is considerable uncertainty over future flows through both BBL and IUK due to:

- options to flow gas to alternative markets
- market liberalisation and access to transmission pipelines and storage
- development of new commercial arrangements
- possible gas quality issues

In our base case supply forecast we assume that the current basis for imports through BBL will continue broadly unchanged. Namely that BBL will import at reported contracted rates but may in the short term become more responsive to market differentials between the UK and the Continent due to the commencement of non-physical reverse flows. Longer term as the UK's level of import dependency increases and there is a need for new or expanded import infrastructure, there is the possibility that BBL's capacity is further expanded. Alternatively there could be a new pipeline with the Continent to effectively link-up with the increase in gas transportation capacity to Europe from Russia through Nord Stream and to a lesser extent South Stream and other routes.

Figure 13 shows imports through BBL since 2006/7 and post 2008/9 our base case forecast for imports through BBL, also shown is the capacity of BBL. This is assumed to increases by 3 bcm in 2010/11 through additional compression (an approved project). The forecasts include both core and non-core gas, with core gas representing about 90% of BBL imports at the start of the forecast period and about 50% at the end. Around the forecast we have shown a range for BBL imports, the upper range is based on an upside to the forecasts of 3.65 bcm/year, equivalent to +10 mcm/d, with the lower range based on the core gas assumptions. Namely that BBL imports are reduced over the next few years due to increased commercial arrangements including non-physical reverse flows, to approximately half of the original import 8 bcm/year contract between Centrica and GasUnie.

Figure 13 – Base Case BBL flow forecasts



The chart shows our base case forecast for BBL declining through to 2011/12 due to increased commercial arrangements before slowly increasing due to a combination of an increase in the UK's import requirement and an improved supply position on the Continent. The latter is assumed to be brought about by the completion of new supply routes to the Continent from Russia and possibly elsewhere and improvements in terms of the market structure on the Continent.

For IUK we continue to make the assumption that IUK responds to market conditions tending to operate seasonally between a UK market with summer / winter price differentials against a Continental market that is predominately supplied through long term contracts that are also oil indexed. In a changed world of potential 'surplus' LNG imports (see LNG Imports section), to provide a driver for exports to the Continent, we make the assumption that IUK exports are higher than last year with lower levels of imports. Over time as the UK's level of import dependence increases we make the assumption that IUK gradually imports more though continues to be a net exporter and retain some measure of seasonality.

Figure 14 shows imports and exports through IUK since 2000/1 and post 2008/9 our base case forecast for IUK, also shown is the capacity of IUK for both imports and exports. Due to its commercial type behaviour, for IUK we assume no core gas. The contribution provided by the non-core component is based on:

- average observed flows (aggregated for both imports & exports) for the past 5 years (20 mcm/d)
- the import / export split for 2008/9 based on recent experience (i.e. predominately exports)
- an assumption that in the short term the UK will remain well supplied, thus maintaining predominately exports
- an assumption that in the longer term the UK will tend to import more from the Continent, thus slowly reducing exports
- modest changes in IUK imports / exports from one year to the next to limit both supply and demand volatility

Around the forecast we have shown a range for IUK imports. Both the upper and lower ranges are based on a tolerance of +/- 3.65 bcm/year, equivalent to +/-10 mcm/d.

Figure 14 – Base Case IUK flow forecasts

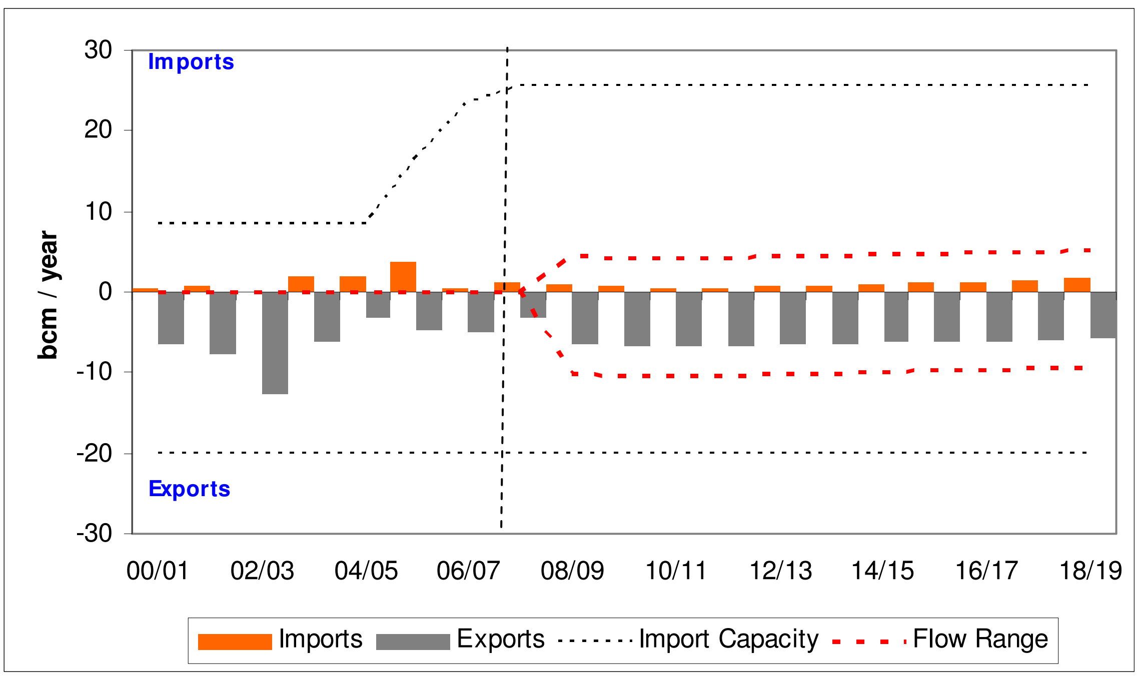


Figure 14 shows that historically IUK has since 2000/01 operated seasonally (both imports and exports) every year. With the exception of 2005/06, exports have exceeded imports. The seasonal nature of IUK flows has for most years resulted in modest utilisation of annual capacity. Our latest base case forecast shows a bias to exports though over time there is a gradual increase in imports. The range for our forecasts captures all historic flows with the exception of exports in 2002/3.

LNG Imports

Of all the supply components LNG imports provide the greatest level of supply uncertainty due to numerous factors:

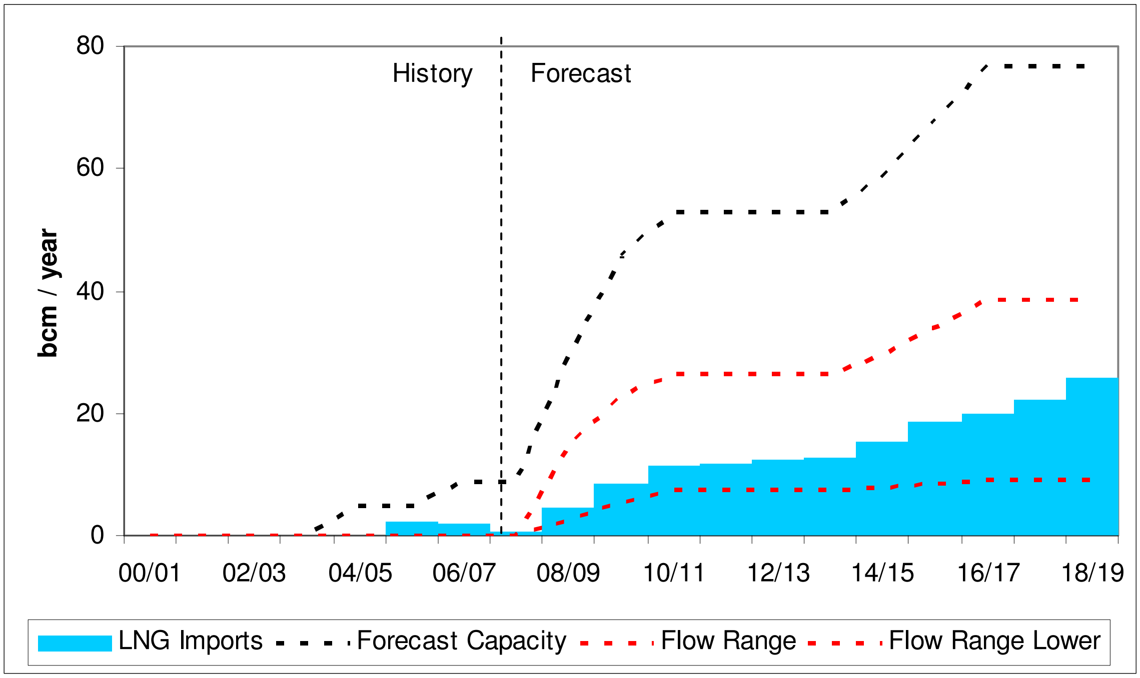
- limited operational experience to date
- global options to deliver gas to alternative (higher priced) markets
- an excess of global LNG re-gasification capacity over LNG production, thus providing destination options
- a view that most LNG imports to the UK may not be specifically contracted
- the prospect of greater LNG availability for 'traded' markets due to the global recession
- uncertainties regarding the commissioning dates of new import facilities and how such facilities will operate
- reported delays and increasing costs associated with the construction of LNG production facilities

As with the other supply components we have applied a core / non-core approach in determining our LNG import forecasts. The basis for determining these have not been based on a global LNG model but on operational experience to date and consideration of other metrics.

For core LNG imports we have made an assessment of LNG boil off and combined this with a load factor (12% of capacity) that represents average operational experience to date. For future plants that are either not yet constructed or may operate as merchant facilities we have applied a lower load factor. For non-core gas we have made the assumption that LNG imports could operate at a load factor as high as 50% of installed capacity. This may appear low but needs to be considered in the context of global utilisation rates for LNG terminals (below 50%) and the very high capacity of existing and future capacity of UK LNG terminals relative to import requirements. For example the capacity of existing LNG facilities and those under construction now exceed 50 bcm, with proposals for other LNG projects adding potentially a further 50+ bcm.

Figure 15 shows LNG imports since 2005/6 and post 2008/9 our base case forecast for LNG imports, also shown is our forecast capacity of LNG. The forecasts include both core and non-core gas, with core gas representing about 90% of LNG imports at the start of the forecast period and about 50% at the end. Around the forecast we have shown a range for LNG imports, the upper range is based on 50% of forecast capacity and the lower range based on the core gas assumptions detailed above.

Figure 15 – Base Case LNG flow forecasts

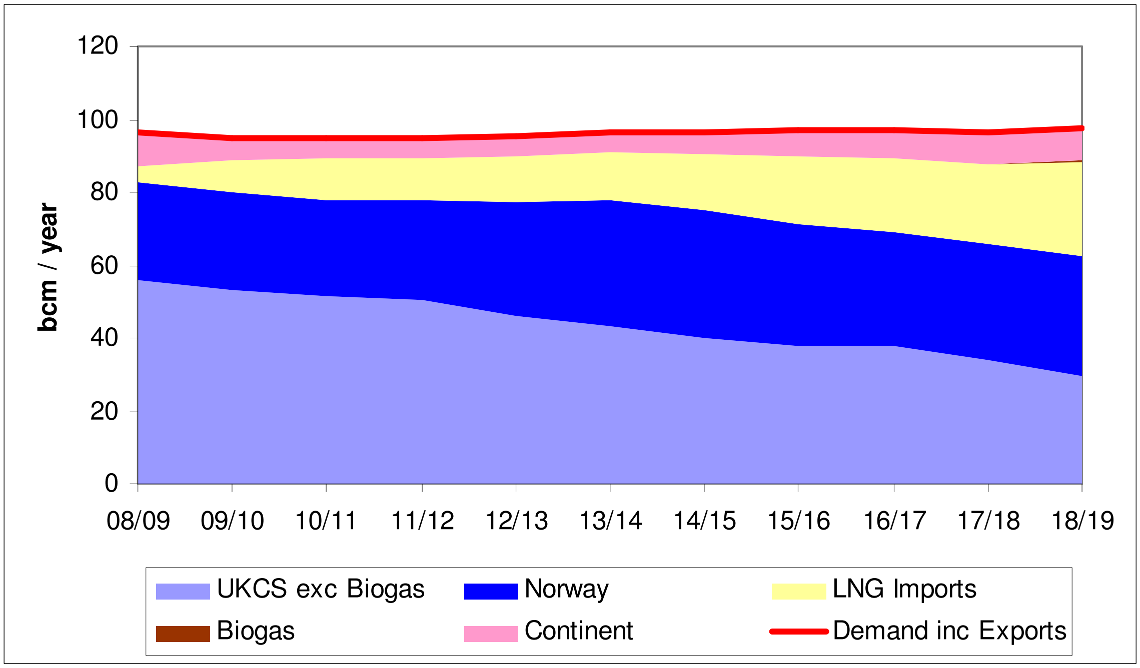


The chart shows a rapid expansion of LNG capacity from 2008/09 as Milford Haven and the expansion at Grain come on stream. We assume further LNG import capacity is brought on stream towards the end of our 10-year planning period. Our base case forecast shows a gradual build up of LNG with imports approaching 10 bcm in 2009/10 and exceeding 20 bcm in 2016/17. Though these forecasts are well below installed capacity they do represent a significant proportion of UK imports and a flow of 10 bcm per year relates to about 10 LNG cargoes per month (based on 135,000 m3 vessels). The uncertainty for future LNG imports is highlighted by the considerable range shown in the chart, the upper range only represents 50% of forecast capacity, hence much higher imports are theoretically possible. Whilst these high rates of delivery may not necessarily be achieved on an annual basis, high rates may occur for relatively short periods.

3.4 Base Case Annual Match

Figure 16 shows our resulting base case annual supply-demand match.

Figure 16 – Base Case Annual Supply



As described previously for each of the supply components in turn, the chart shows:

- little or no growth in annual demand
- a decline in UKCS production
- relatively high levels of Norwegian imports with only modest growth from current import levels
- a short term reduction in Continental imports before returning to nominal growth
- a phased build-up of LNG imports

3.5 Base Case Peak Match

Storage

For the peak position, we also need to include storage. As shown in Figure 17 and detailed in Appendix 2, there are numerous proposals for new storage in the UK. In aggregate the peak deliverability of all existing and proposed storage facilities[11] is now approximately 550 mcm/d, this compares with the current deliverability of nearly 130 mcm/d.

[11] This includes most press reported storage projects, in addition to these there are numerous other storage projects that are not yet fully defined or reported in the press

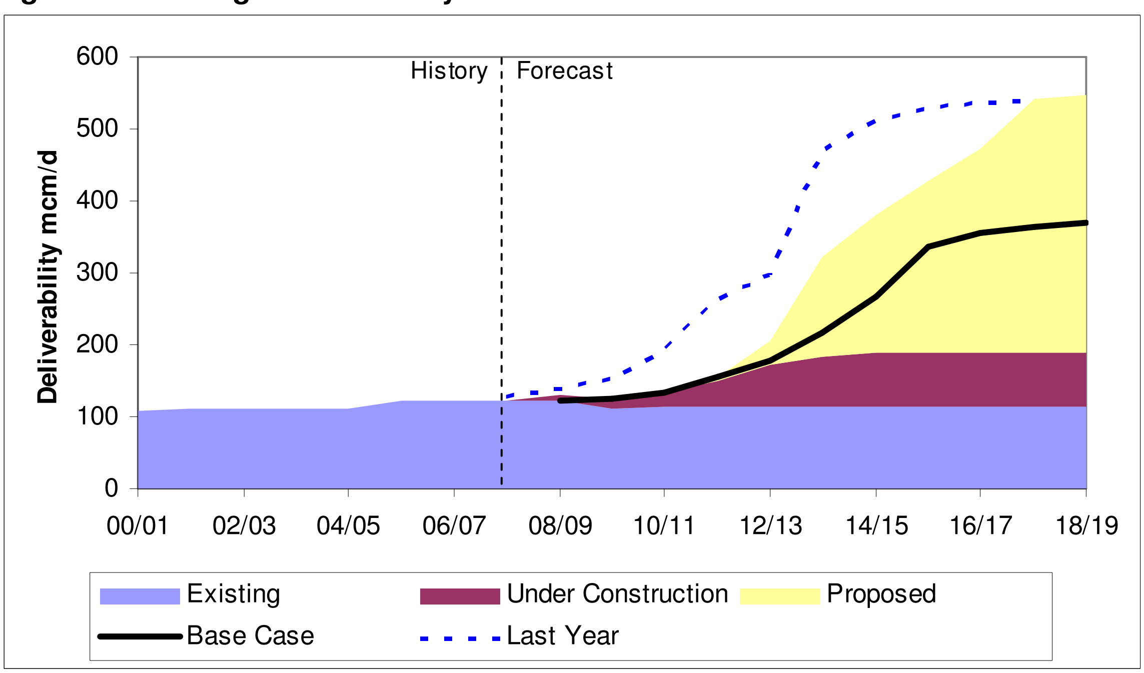
Inclusion of all storage proposals in our base case forecast is neither practical nor realistic for the following reasons:

- the history / track record of many UK storage developments has been one of slippage and deferral with relatively few new storage projects being completed over the past decade. The recent economic conditions have ensured that this trend has continued
- the absence of limited capacity signals from entry auctions for most of the proposed storage projects
- the difficulty in obtaining planning and other permits
- the sheer magnitude of the proposed storage facilities in the context of peak day demands at approximately 500 mcm/d

Hence for inclusion in our base case forecast we have included all storage facilities that are currently under construction and those that we believe are well advanced in terms of securing planning, financial backing and have commitments from major players. Even for these we may assume some slippage. For external reporting purposes, we are not explicit for any of the proposed storage facilities other than those that are under construction or have signalled entry capacity through the auctions. Hence our network plans can readily substitute one proposed storage facility with another.

Figure 17 shows storage deliverability in terms of existing facilities, those under construction and those proposed. For comparative purposes, last years aggregated storage deliverability is shown. The chart also shows storage deliverability since 2000/01 and our base case forecast. A similar chart for storage space is shown in Appendix 2.

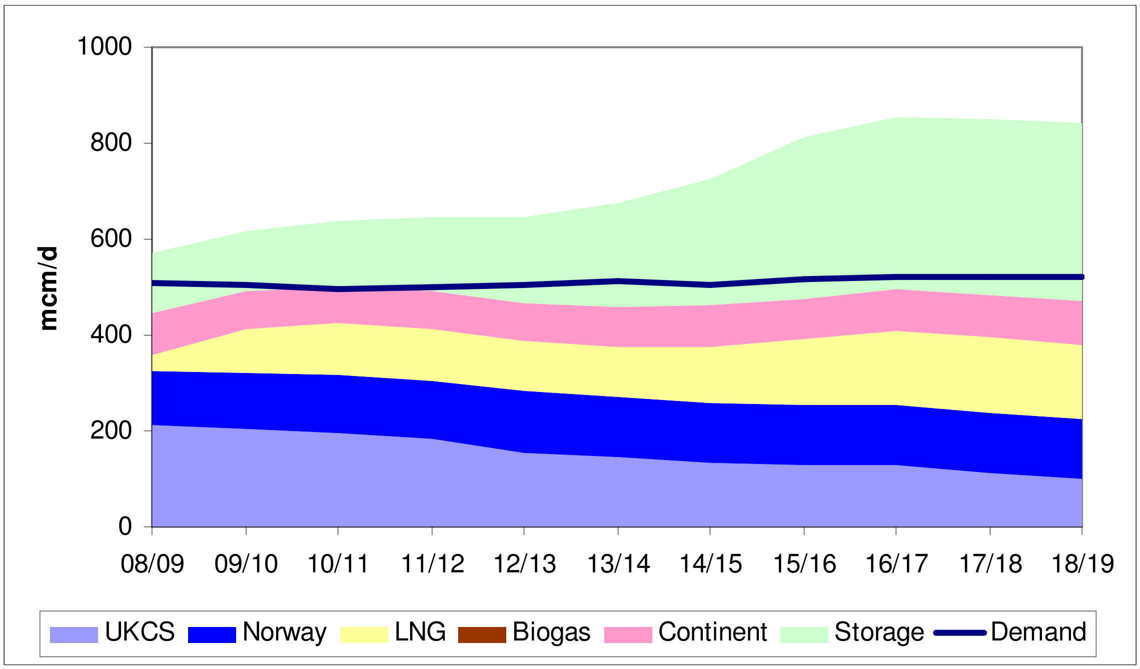
Figure 17 – Storage Deliverability



The chart shows that UK storage deliverability has changed little since 2000/01 despite two new facilities with a third facility now undergoing commissioning. This is due to the conversion of Grain to an LNG import facility and the recent closure of Dynevor. Storage projects under construction are planned to add 75 mcm/d deliverability, whilst other proposals in aggregate add a further 400 mcm/d. Our base case forecast captures all facilities under construction and approximately half of the other proposals. The chart also shows last year's aggregated storage position, this highlights that most storage projects have slipped a further year in terms of the developers proposals.

Figure 18 shows our resulting base case peak supply-demand match. The demand line is our 1 in 20 peak day demand. UKCS is shown at maximum deliverability; all imports are based on our best view of peak supplies rather than capacity. Storage deliverability is consistent with our base case forecast.

Figure 18 – Base Case Peak Supply



In terms of peak demand, the forecast shows a near static position. Throughout the ten-year planning period the forecast level of non-storage supply is above 400 mcm/d. For operational planning, as illustrated in this years Winter Consultation report we tend to use more rigorous assumptions for all non storage supply components. Over time, the peak position becomes increasingly well covered, but only through our assumptions of new storage developments. These are expected to play an increasingly import role in maintaining security as import dependency increases. Section 5 details an assessment of longer term security based on the loss of an imported gas source.

Appendix 2 details our base case peak flow forecasts and subsequent flow ranges for all major entry terminals. The charts also show the capacity we are obliged to release and a shaded area that represents the entry capacity as booked through the long term system entry (LTSEC) and monthly (AMSEC) auctions; these were last held in September 2008 (LTSEC) and March 2009 (AMSEC). For ease of conversion from energy to volume, all of these charts assume a CV of 39.6 MJ/m3 rather than using terminal-specific CV forecasts.

4. Investment Plans

The NTS investment planning process uses scenario analysis as a mechanism for managing uncertainty regarding new gas supplies. This technique ensures that a broad spectrum of potential investments is identified allowing initial feasibility studies to be undertaken where appropriate. These initial studies support the delivery of timely and efficient investment on the NTS as requirements are clarified, predominantly through the Long Term System Entry Capacity (LTSEC) auctions, and Offtake Capacity Statement (OCS) process for DN exit requirements.

A combination of high gas prices, recessionary effects and poor credit availability are lowering expectations of new connections at entry or exit to the NTS in the short and medium term. Any expectations of growth opportunities are primarily focused on the potential for new power stations and new storage facilities. The existing supplies and offtakes from the NTS will be well served through to the medium term by the recently completed investments in South Wales and in the Yorkshire area

Our investment planning cycle which is now underway focuses on the base case for supplies as per Section 3. The analysis undertaken will not be limited to supply scenarios and will consider other signals provided as part of the LTSEC auctions and exit requests. Sensitivities will be analysed to address continuing uncertainty surrounding the timing, location and volume of future supply sources.

The primary mechanism for shippers to provide us with signals of their future capacity requirements is through the long term auctions, which now form an integral part of our investment planning process. Hence the requirement for any additional projects into the future is subject to the relevant market signals being received and any approved projects are subject to an ongoing review following subsequent auctions.

The planning process will be further detailed in the Transmission Planning Code, as per the condition C11 of the Gas Transporters License.

Appendix 3 details current NTS planned projects whilst Appendix 4 shows a map of investments.

5. Security of Supply

This section highlights security of supply issues arising from the projected supply-demand position from a longer term perspective. Issues associated with next winter are discussed in our Winter 2009/10 Consultation document.

This analysis focuses on the effect of the loss of one type of imported gas source, and the potential impact on the remaining sources of imported gas. The analysis is presented in terms of the resultant load factors and a high level impact assessment. Whilst the assessment is based on the annual position, the analysis is also appropriate for winter / peak analysis as storage is assumed to make up most of the increase in demand for these conditions.

The starting point for this analysis is based on our 2009 base case annual supply demand match as shown in Figure 16; **however we have only included existing import projects and those under construction.** The following list details the key assumptions used in this assessment:

- The three sources of gas imports (Norwegian, Continental and LNG) are each, in turn, assumed to be zero, with the resultant supply shortfall made up by the two remaining import sources
- The resultant increase in supplies for each import is assumed to be equally split between the other two sources of supply
- As we are assessing annual supply, no attempt was made to model any additional flows from UKCS, or use of storage supplies. In practice, storage would be used, notably in the winter when demand is above the annual average
- Available capacity is limited to existing capacity and import projects under construction. Hence LNG imports are limited to Grain I, II & III, South Hook I & II, Dragon I and Teesport.
- The resultant load factors are shown as a minimum to maximum range, as well as highlighting the load factors resulting from the loss of each supply type
- The resultant load factors for Norwegian, Continental and LNG over the forecast period, are presented against a backdrop of green, amber and red load factor ranges, where:
    - **Green represents an acceptable level of security with sufficient capacity with only supply availability being potentially limiting**
    - **Amber represents a challenging level of security with a tightening of the supply position with potentially limiting supply availability and flexibility**
    - **Red represents a potential breach of security standards with the need to operate at near maximum capacity for sustained periods, thus a requirement for near continuous supply availability**

For the purposes of this analysis, BBL and IUK are assumed to respond in the same manner, for example a loss of 50 mcm/d Norwegian supply will be made up by 25 mcm/d from Continental (BBL and IUK) and 25 mcm/d from LNG supplies.

Figures 19 to 21 show the load factors for Norwegian, Continental and LNG over the forecast period.

Figure 19 – Norwegian load factor range for loss of other supplies

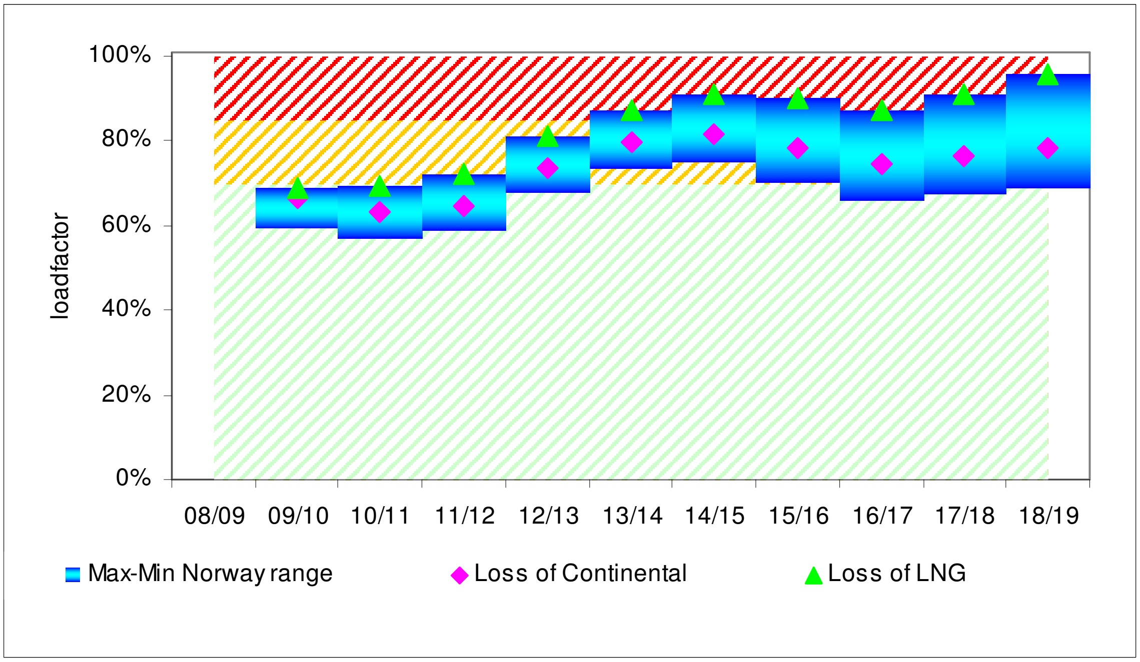


Figure 19 shows that for the loss of either LNG or Continental imports for the first few years of the forecast period there is a need for a relatively small increase in load factors for Norwegian flows. This is to be expected during this period as flows from the Continent or LNG are relatively modest. Thereafter the forecast shows a sustained increase in the range out to 2018/19, driven by the loss of significant volumes of LNG from the base case. The chart shows that after 2013/14 for a number of years even the minimum load factors are within the amber range (70%-85%), thus indicating more challenging conditions. In addition by 2013/14 the maximum load factors are within the red range (85%-100%) by 2013/14, an unrealistically high load factor for pipeline supplies, thus requiring near-continuous supply availability and system performance or alternatively a need for new import infrastructure or greater use of non Norwegian import infrastructure.

Figure 20 – Continental load factors for loss of other supplies

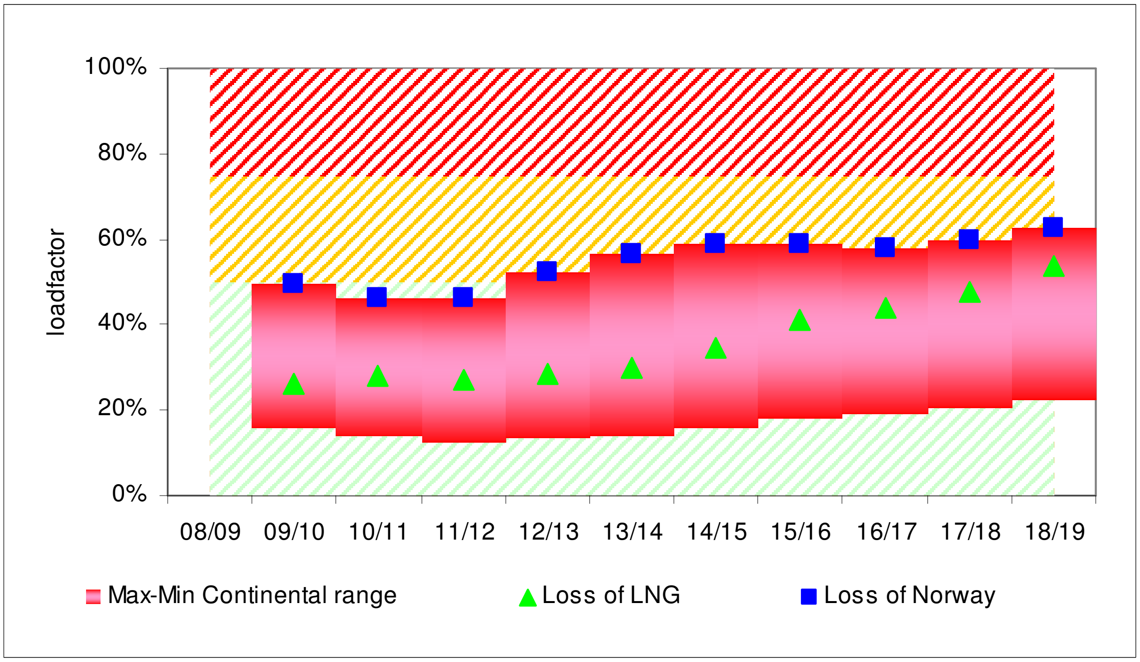


Figure 20 shows that there is a wide range in load factors for Continental flows resulting from the loss of other supplies. This is to be expected as our base case forecast for Continental flows are relatively low (typically 15% to 30% load factors), and hence the loss of either LNG or in particular Norwegian supplies triggers a significant increase in the requirement for higher Continental flows and hence an increase in load factors. Our analysis indicates that load factors steadily rise, with maximum load factors potentially exceeding 50% by 2012/13. A load factor for Continental imports of 50% needs to be put into the context of the need to source significant volumes of gas from the Continent and that the current bi-directional operation of IUK would probably be in UK import mode for most of the year.

Figure 21 – LNG load factors for loss of other supplies

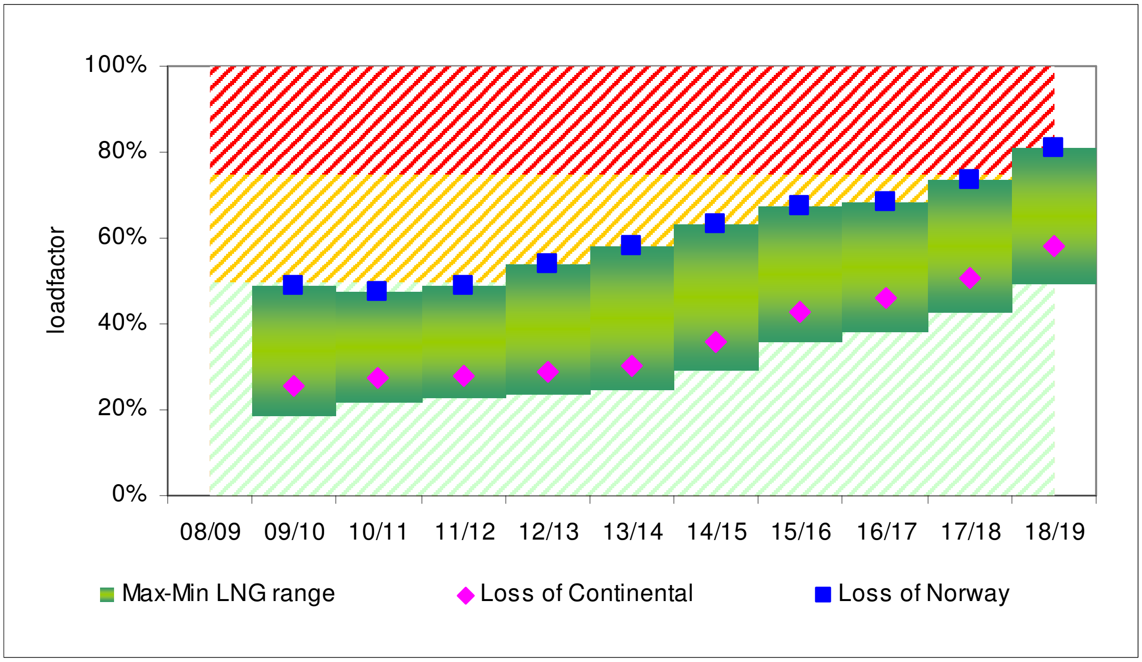


Figure 21 shows that there is a wide range in load factors for LNG flows resulting from the loss of other supplies (notably Norway). The assumption in this analysis of no new LNG facilities beyond those under construction results in a steady rise in LNG load factors throughout the period analysed. Load factors potentially above 50% could be experienced as early as 2012/13; whilst this may not appear challenging it could result in LNG imports above 25 bcm per year. This level of LNG imports is roughly equivalent to Spain's current LNG imports and would require standard LNG tankers (135,000 m3) to arrive at the UK at the rate of approximately one every day, or every other day if larger tankers were used.

Our supply loss analysis shows that in theory even the loss of one type of imported gas could be covered by additional supplies from other supply types at acceptable levels for the next two to three years. Thereafter the increasing level of import dependency means that a loss of one type of supply results in the need for significant flows from alternative import sources. With only modest levels of storage the loss of any import source would provide challenging conditions, notably in the winter period. Hence there is a continued need for new supply infrastructure in terms of new storage or for further imports.

We acknowledge that numerous proposals for new storage developments will also assist in maintaining supply if we were to experience a future loss or partial loss of imports; however as Figure 17 and Appendix 2 highlights, most new storage developments remain proposals without full planning consents rather than being constructed. Another issue to consider is the increased reliance of future power generation on CCGTs hence the potential impact on electricity supply as well as gas.

Appendix 1 - Gas Demand

A1.1 Gas Demand Forecast Process

Gas demand is influenced by a number of factors, each having a varying degree of influence. A key sensitivity is the gas price, but also the level of exports, which means assessing the European and Irish markets, the level of energy conservation, CCGT developments and the strength of the economy are all key factors considered when producing the forecast. This gives a flavour of some of the key forecast drivers, but is by no means an exhaustive list.

The process that is employed to develop the annual gas demands is based upon a combination of different techniques, including econometric modelling, assessment of increased energy efficiency, monitoring of information from the enquiries for new loads, analysis of the consumption of existing large demands and market analysis. Detailed analysis of certain market sectors – domestic, small commercial end users, large commercial end users, industrial consumers and power generation – is carried out. Each forecast is developed from a set of planning assumptions, which are discussed in more detail below.

The data used to support these assumptions and the subsequent forecasts is obtained from independent consultants and organisations as well as our Transporting Britain's Energy (TBE) consultation and a process of information exchange between the Distribution Network businesses and ourselves. This consultation process incorporates data-gathering questionnaires aimed at specific sectors of the industry (including consumers) and meetings with major industry demand-side stakeholders, such as power generators and gas shippers. The TBE consultation both informs, and helps us to validate, our forecast and planning assumptions. These planning assumptions are subject to routine review and update in the period between each forecast.

A1.2 Key Forecast Drivers and Assumptions

The following section outlines the key drivers affecting this year's forecast.

A1.2.1 Fuel Prices

A1.2.1.1 Fuel Price Trends

Fuel price forecasts are an important factor underpinning our gas demand and power generation forecasts. Historical trends, forward markets and the interaction between different fuel prices are all considered before consumer prices for different end-user sectors are developed. Forecasts from external specialist consultancies and feedback through the TBE consultation are also considered when producing our fuel price forecast.

The impact of fuel prices within different sectors can vary and the effect of other drivers is considered alongside our fuel price assumptions, particularly in our econometric modelling. This detailed econometric modelling enables us to take account of the impact of fuel prices within each demand sector.

The volatility in world energy markets and the global economy have resulted in some unusual patterns in wholesale gas prices during the past year. Summer NBP gas prices where higher than in the previous winter, despite the seasonality of GB gas demand. This increase in wholesale prices was principally driven by the corresponding increase in the price of oil. Continental gas prices are traditionally linked to the price of oil and the UK has become reliant on Continental imports (includes Norway) in order to meet demand due to the decline of the UKCS. Rising demand saw prices stabilise around the 50 p/therm mark during winter 2008/09, despite the oil price rapidly falling, as a semblance of seasonality returned to the NBP price. Colder weather in the early part of 2009 saw this price level maintained, until the combined effect of warmer weather, the end of the winter period and falling oil prices resulted in NBP prices falling to around 30 p/therm in March 2009.

Figure A1 shows NBP gas prices and Brent Oil prices since January 2007.

Figure A1 – Wholesale Gas & Oil Prices
Source: Heren

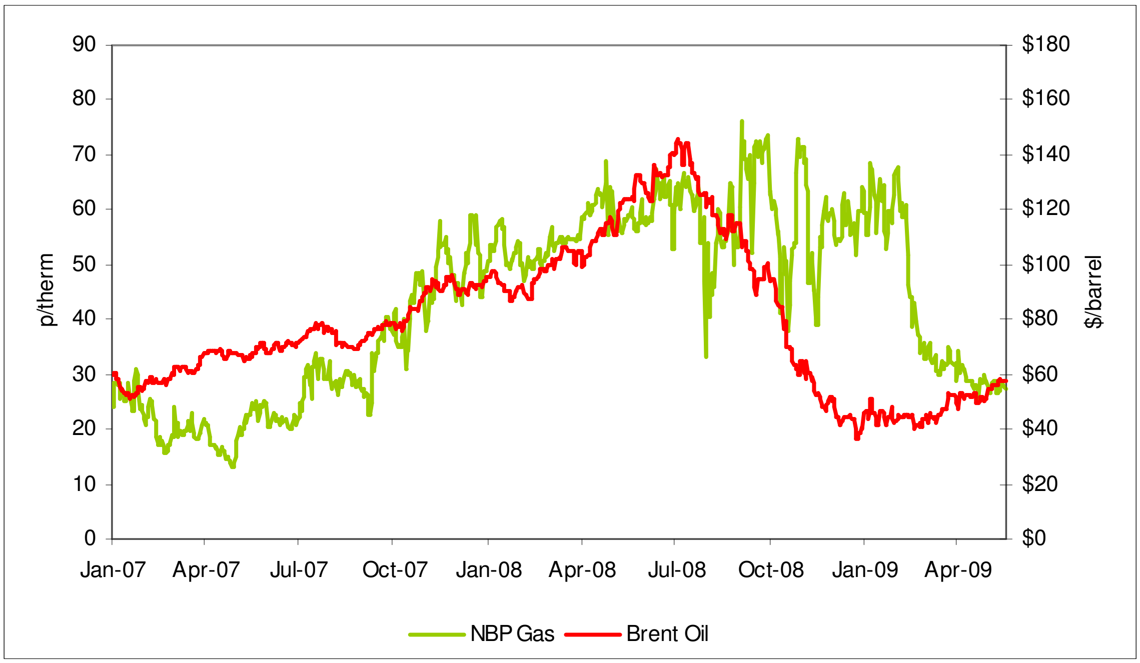
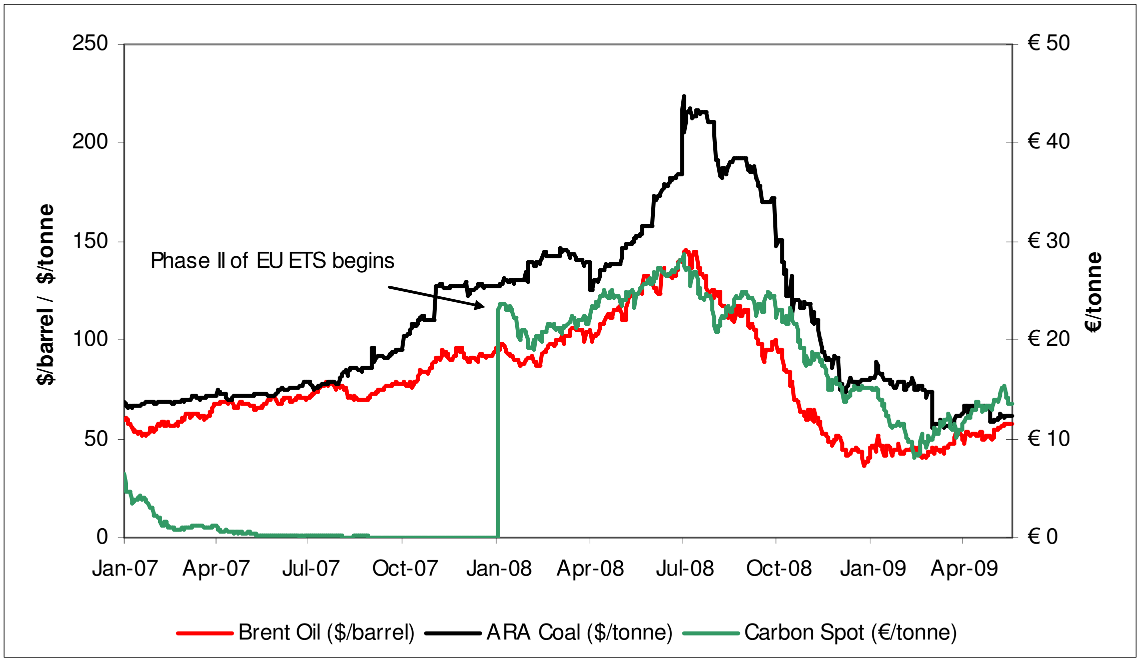


Figure A2 shows the Brent oil price with the ARA coal price and the EU ETS Phase II carbon price. Strong growth up to summer 2008 driven by increasing global demand for energy, particularly in places such as China and India can be seen in both the coal and oil prices. The impact of the 'credit crunch' and the implosion of financial markets resulting in a global recession and reduced energy demand then saw a dramatic fall in energy prices.

Figure A2 – Oil, Coal and Carbon Prices
Source: Heren



A1.2.1.2 Impact of Fuel Prices on Gas Demand

Wholesale price changes filter into all market sectors, from power generators through to domestic end-users. Although the wholesale price makes up a larger proportion of an industrial consumer's bill than a domestic consumer, domestic end-users have still seen significant energy price increases during the past six years.

After price reductions in the domestic sector in the early part of 2007, a round of price increases by the major suppliers in early 2008 was followed by further significant price increases in late summer 2008 after a long period of rising wholesale prices. The timing of these price increases combined with the beginning of the economic downturn has resulted in demand falling in this sector. Although there were a series of smaller-scale price reductions in early 2009 as wholesale prices fell, this did nothing to slow the falling demand.

The common theme with the end-user price rises in the past few years has been the unprecedented media coverage, which has seemingly heightened domestic users awareness of energy consumption. The period of increasing prices has coincided, not unsurprisingly, with falling DN demand. Reductions in domestic weather-corrected gas demand, by far the largest sector of DN demand, were seen for the first time in 2005 and have been followed by three further years of reductions.

DN consumption has decreased by 10% during the past four calendar years with further falls in the early part of 2009. As section 1.2.2 discusses, our analysis suggests that the vast majority of the fall in consumption in the domestic sector over this period is due to increased levels of energy efficiency. In the larger demand sectors the drive to reduce consumption in the face of higher fuel bills is also evident, with the recession also resulting in demand destruction, particularly in the energy intensive large firm and interruptible sectors.

Increasing fuel prices result in consumers taking action in order to reduce consumption. Our historical analysis and subsequent forecast assumes that the majority of this action is increased energy efficiency, with greater public awareness and government schemes accelerating this process.

A1.2.1.3 Fuel Price Forecasts

Our fuel price forecasts for the 2009 gas demand forecasts are based on outturn wholesale prices and end-user prices for 2008. Our approach to forecasting fuel prices is based on historical price movements, the relationship between end user prices and wholesale markets, the relationship between different fuel prices (e.g. gas and oil), consultation feedback, forward markets and the forecasts of specialist consultancies.

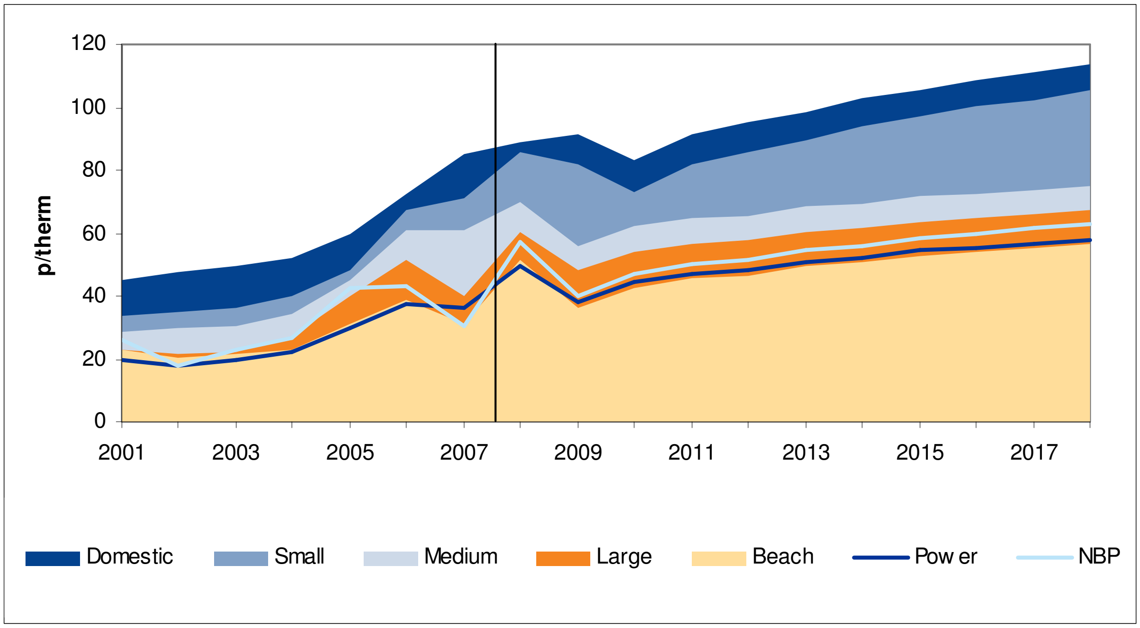
Given the evidently strong relationship between the oil price and the UK wholesale gas price, this link underpins our fuel price forecast. Our fuel price forecast projects a relatively strong oil price over the period following a period of relatively lower prices in the short-term.

Our forecast reflects the view that with a return to growth in the global economy, energy will return to being relatively costly when compared with the earlier part of this decade. The pressures of climate change, the likely premium placed on fossil fuels, probably in the shape of carbon prices or taxes, and political pressure to reduce energy demand and increase efficiency is likely to result in higher energy prices. Certainly the push towards the 2020 renewable and carbon targets is likely to result in an increase in end user prices.

As stated earlier, our forecast is based on the link between oil and wholesale gas prices remaining. Although a number of commentators have suggested that with increasing levels of LNG, the link could be broken, with NBP prices being possibly indexed more closely to US LNG prices (e.g. Henry Hub), we are currently viewing this as a sensitivity to our central case forecast. The average annual wholesale gas price forecast over the period is 55 p/therm, rising over the ten years.

The wholesale gas price results not only in an increase in end-user gas prices, but also in strong power prices. Figure A3 presents our forecast of end user gas prices, with a fall in end user prices in the short-term before a return to rising prices in the medium-term. The wholesale price is reflected in the larger end-user categories falling more promptly than in the domestic market, hence the lag in gas prices falling in the smaller sectors in 2010 as opposed to 2009.

Figure A3 - End user gas price forecast



The forecast for the coal price, which has a significant impact on our power generation models due to it generally being the competing fuel with gas, is that it will generally track the oil price (as shown in Figure A2). Over the longer term a reduction in the coal price is projected as coal demand falls in Europe. This is due to a forecast increase in the carbon price in Phase III of the EU ETS, as carbon credits begin to be fully auctioned rather than allocated, initially in the power generation sector, and the end of the period of operation for coal plants opting out of the LCPD. Operation of coal plants in the early part of the opt-out period under LCPD suggest that a number of these plants may use up their allocated hours of operation before the designated end date of December 2015, with the avoidance of higher carbon prices in Phase III of the EU ETS one of the possible reasons for this.

Our central case assumes that there will be a degree of seasonality to the NBP price resulting in gas-fired generation operating more as the base load plant in the summer when gas prices are lower, with coal operating more as the base load plant in the winter period.

A1.2.2 Energy Efficiency

Increased thermal efficiency is forecast to have a significant impact on DN demand over the course of the forecast period. Our forecast assumes that most of the impact of higher end-user prices is an increase in thermal efficiency. Our analysis of historical levels of energy efficiency, by looking at rates of boiler replacement, cavity wall installation and loft insulation for example, suggest that much of the fall in domestic demand has been driven by such measures being implemented. There is also scope for further improvements in the future, both with the further implementation of existing measures and newer technologies, such as smart meters.

Our forecast also takes into account the government drive towards zero-carbon homes by 2016. Our assumption is that new homes will use less energy over the forecast period as appliances and heating systems become more efficient. Certainly, new homes currently being built will almost always use less gas for water and heating than existing properties that may have been built up to one hundred years ago.

A1.2.3 Economic Factors

Our econometric models take into account a number of other factors when forecasting gas demand. Although fuel prices in each sector do have a significant impact, factors such as household disposable income, the number of new households forecast and commercial / manufacturing output are also modelled. Our models combine data from specialist independent consultancies with our own forecasts e.g. the fuel price forecasts described earlier.

The impact of the economic downturn is covered in Section 2.2, with demand falling rapidly due to the recession. Although some demand will return as the economy returns to growth, it is forecast that this will be at a much slower rate than the demand fell in the economic downturn. It is likely to be more energy efficient sources of demand that replace the demand that has been lost, possibly due to environmental pressures.

The forecast for economic growth over the next ten years is lower than in previous forecasts, with average economic growth reduced due to the current economic downturn. As stated earlier, our forecast is that we will begin to see a return to growth in mid 2010, with GDP levels returning to 2% from 2012 onwards.

The short-term economic outlook is probably the biggest uncertainty in or forecasts and as stated earlier we are looking at sensitivities around our base case to assess two 'recession cases' – one with a deep and long lasting recession and the other with a rapid economic recovery.

A1.2.4 Power Generation

Our power generation forecasts are supported by information received from TBE consultation feedback, customer enquiries, journals, press releases and other sources. A power generation background is developed based on known and potential station closures, and the connection of new generation capacity to replace this plant. The timing of these openings and closures is important when assessing how the power generation market will look over the next ten years and beyond, with the plant margin, the fuel mix, suppliers generation portfolios, government and environmental legislation all taken into account when developing the forecast.

This generation background is then used as a basis for our forecast of gas demand from power generation, with the fuel price forecast, particularly for gas and coal, the key factor in determining the likely operation of individual stations, alongside the age, efficiency and historic generation patterns of stations.

It should be noted that the power generation forecast is based on a 'business as usual' approach with no major changes to current known policy, regulatory framework or incentives assumed in the forecast.

The impact of the recession has been keenly felt with electricity demand falling rapidly during the course of the winter 2008/09 and future power generation projects being delayed due to the current economic climate and the lower demands.

The combination of lower forecast electricity demands and 7.5 GW of CCGT plant currently under construction is likely to result in very high plant margins in the next few years, certainly up until the closure of the LCPD opt-out plant. There is therefore the possibility of mothballed capacity, particularly between 2010 and 2014. This could be marginal oil and gas plant or even opt-out coal plant conserving some of their 20,000 hours for closer to 2015, although this would seem less likely.

The lower electricity demand forecast gives rise to much greater uncertainty from a plant-mix perspective, although it is less likely that there will be a 'generation crunch' around 2016 due to the loss of around 12 GW of oil and coal plant due to LCPD.

As alluded to earlier in this section, the cost of emissions under the EU ETS is likely to benefit gas over coal in the longer term, with carbon prices forecast to increase in Phase III of the scheme. The forecast broadly assumes that gas will be the base load fuel in the summer months, with coal operating more as base load during the winter months. The spark and dark spreads, which indicate the profit that can be made by burning either gas or coal for power generation, are forecast to be relatively close together, as has been borne out by recent history.

Among the key factors affecting the development of our generation background and thus the amount of new gas-fired generation forecast to be connected are the LCPD and further environmental legislation such as the Industrial Emissions Directive (IED), the EU ETS, the rate of development of renewable energy sources, and the future of nuclear generation in the UK. The following sections detail our forecasts for the major plant types in the generation background.

A1.2.4.1 Environmental legislation

The revised LCPD, which became effective from 1st January 2008 restricts the operation of fossil fuel-fired plants unless apparatus to restrict emissions are fitted. The early stages of the LCPD saw a handful of plants fail to fit the required apparatus in time, thus restricting their operation in 2008. LCPD opt-out plants are restricted to 20,000 hours of operation between 2008 and 2015. Our forecast assumes that the 12 GW of opt-out plant will begin to close from 2012 onwards. The operation of some of these plants in 2008 suggests the plant may close earlier than this forecast, however it is thought that the exceptional circumstances seen last year - high wholesale prices, low nuclear plant availability - have resulted in plant operating more than it necessarily may have done so under 'normal' conditions.

LCPD opt-in coal plant is forecast to begin to close towards the end of the next decade as the stations reach ages of 50+ years and further emissions restrictions impact on operation.

The proposed next phase of environmental constraints may have a significant effect on the future generation outlook. The proposed Industrial Emissions Directive (IED) will follow the Large Combustion Plant Directive in 2016. IED proposes to consolidate a number of environmental directives, one of which is the LCPD into a single directive. The final EU legislation is due to be finalised in Dec 2010 following the consultation process, but has seen many changes and developments.

The key points that would affect large combustion plants are as follows:

- Effective from 1st Jan 2016 – therefore IED would bite straight after the closure deadline for opted out plant under LCPD, possibly compounding the capacity crunch at that time;
- Further reduction in SO_2 and NOx limits for coal plant already captured under LCPD;
- Older gas-fired generation would be captured by the NOx legislation for the first time, with plant built pre-2002 no longer exempt (this would cover almost all the gas-fired generation currently operating in the UK). Older gas generation would struggle to comply with the limits being proposed without recourse to expensive abatement measures;
- Uncertainty around the emissions regime from 2016 onwards could delay generation investment decisions being made.

A number of amendments to IED are currently being considered under the Czech Presidency of the EU. The latest position would seem to be that the limited life period will be 20,000 hours operation until 2023 (similar operation and timeframe as current LCPD) although this has not been confirmed in a revised text at the time of writing.

A1.2.4.2 Capacity changes

As stated above, 12 GW of coal and oil plant is forecast to close by 2015 due to LCPD.

Nuclear capacity is expected to reduce by around 4.9 GW by the end of the forecast period. This is despite the forecast assuming that all the AGR nuclear stations are granted five year extensions beyond their existing planned closure dates, except where a longer extension has already been granted. A sensitivity to this forecast may be that the existing AGR plant continues to operate until they are re-planted. Our forecasts do not include any new nuclear plant in the ten-year period. Our forecast is that the first new nuclear plant connects in 2019/20.

Over the course of the next ten years, 13.6 GW of new CCGT plant capacity is predicted to make up the bulk of the shortfall caused by coal, nuclear and oil plant closures, with 7.5 GW of this capacity already under construction. Some of the existing gas stations are forecast to close over the forecast period, with this becoming more prevalent in the ten to fifteen year horizon due to the age of the stations and the impact of IED.

The government recently announced that between two and four coal plants will receive government funding to assist in the development of carbon capture and storage (CCS). At the point when CCS becomes a 'proven' technology then all coal plants – and possibly gas – will have to have CCS technology. Our understanding is that this would apply to existing and new plants.

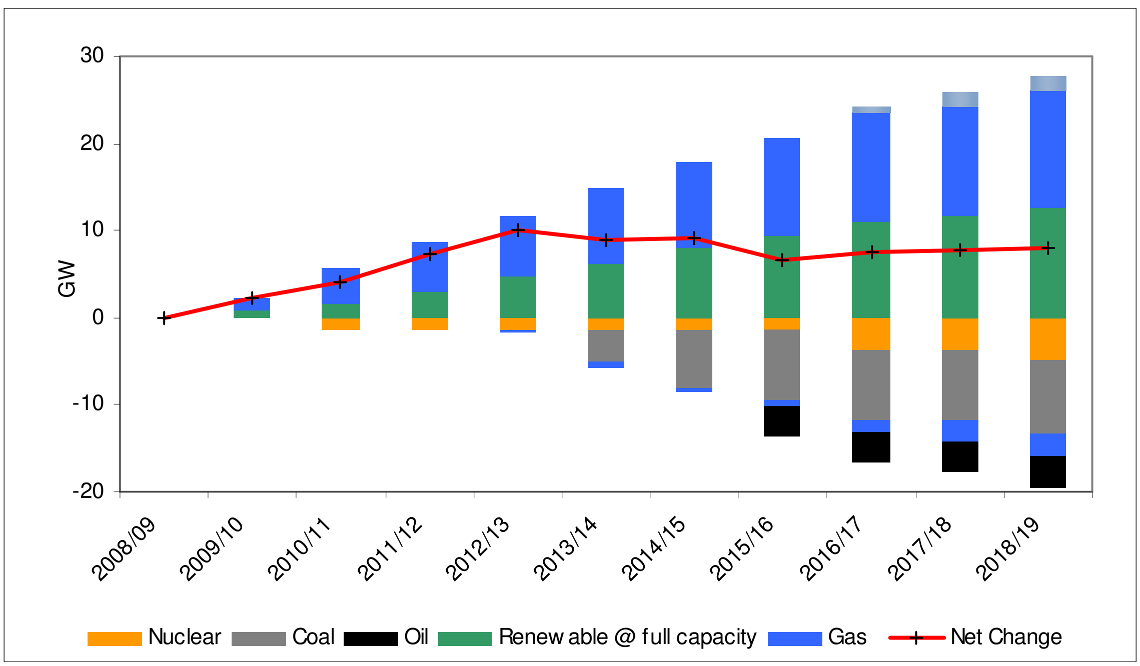
Our forecast assumes 3.2 GW of new 'clean coal' capacity during the next ten years, with the possibility of existing plant also receiving funding to retrofit CCS. The forecast assumes that existing opt-in coal plant begins to close from around 2020 due to age, further environmental constraints and the potential cost of retrofitting CCS.

The first transmission connected offshore wind farm is forecast to connect in early 2010. A number of recent announcements have been made about the 're-evaluation' of large renewables projects, with lower oil prices, lower electricity demand and the difficulty in obtaining credit all resulting in project delays. This has resulted in a lower level of renewable generation forecast to connect to the transmission system in the earlier part of the ten-year period, although our 'business as usual' view in 2020 is similar to last year. See section 2.5 for more detail.

14.5 GW of new renewable plant is forecast to be built by 2018/19 with most of this connected to the transmission system. The vast majority of this renewable capacity is forecast to be onshore and offshore wind generation, with some biomass plant also forecast to connect in the ten-year forecast period. This will result in around 16% of electricity supplied coming from renewable sources by 2018/19. This is a higher number than previously forecast, principally due to lower electricity demand forecasts resulting in the renewable generation output being a larger share of consumption.

Figure A4 shows the projected changes in generation fuel mix over the forecast period, highlighting the increase in gas' share of this market over this time frame.

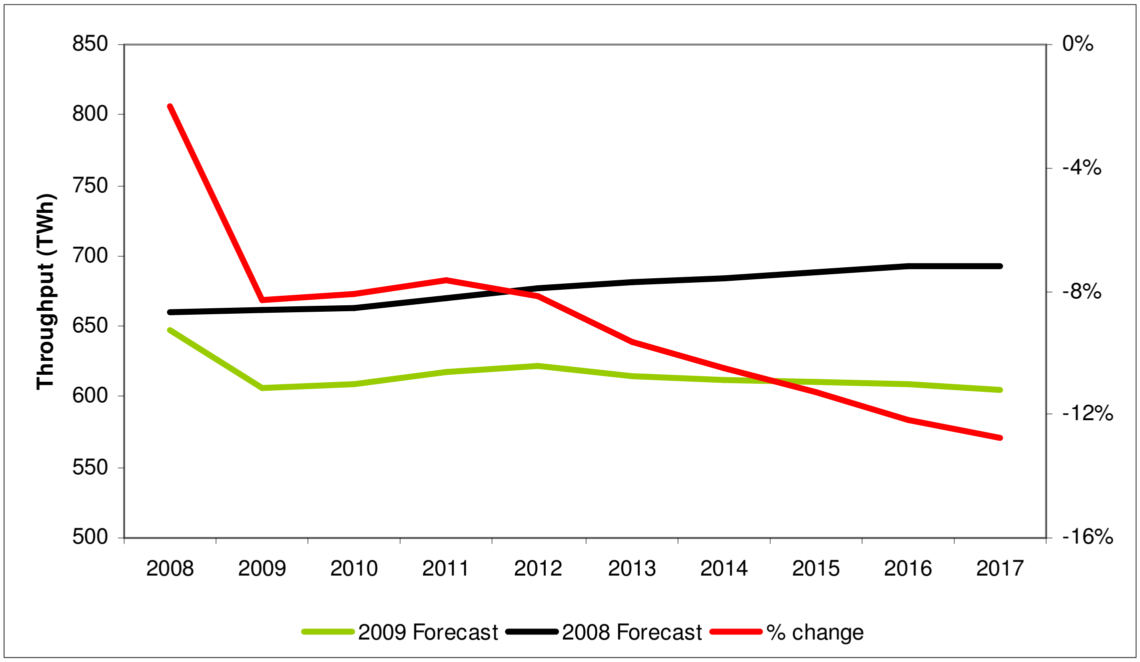
Figure A4 – Forecast Generation Capacity changes by fuel type.
Source: National Grid



A1.3 Forecast Comparisons

The following charts provide a comparison of the current forecasts with those appearing in the 2008 Ten Year Statement and serve to highlight how the assumptions detailed have impacted upon our demand forecasts.

Figure A5 – Comparison of Total DN Annual Throughput Forecasts
Source: National Grid



As Figure A5 shows the 2009 forecast of DN demand is significantly lower than in 2008. The vast majority of this difference is due to the impact of the recession, with the forecast for calendar year 2009 significantly lower than this time last year. The greater amounts of energy efficiency improvements included in the forecast, coupled with an overall weaker economy over the ten-year period results in the forecast being around 13% lower than last year in 2017.

Figure A6 – Comparison of Total System Annual Throughput Forecasts
Source: National Grid

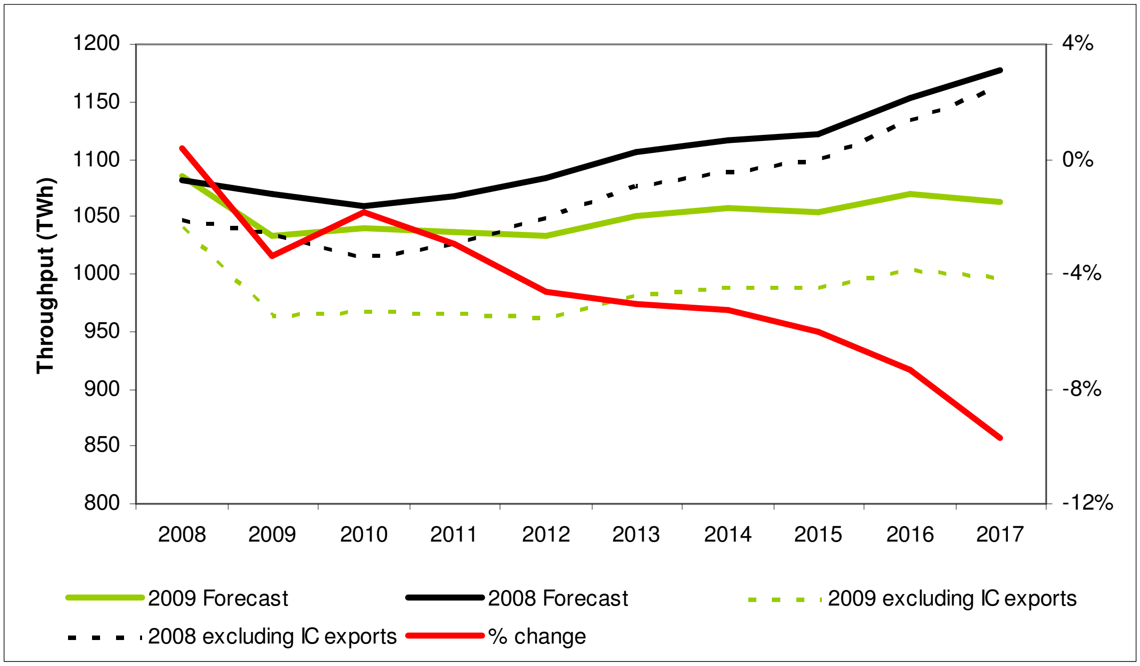


Figure A6 compares the 2009 forecast of total system demand with the 2008 forecast. The difference between the two forecasts is less marked in the short-term here due to the higher forecast for exports to the Continent counteracting the impact of the recession and reduced gas-fired power generation demand to some extent. The higher level of Continental exports does reduce the percentage difference between the two forecasts at a system level when compared to a DN level. Both forecasts are shown without these exports to highlight the effect this part of the forecast has.

Overall, the forecast demand through the NTS is almost 10% lower in 2017 than forecast in 2008 through a combination of lower demands in all sectors apart from Continental exports. The recession; slower economic growth rates over the period; greater energy efficiency improvements; lower electricity demand reducing power generation requirements; and lower exports to Ireland due to lower indigenous energy demand in Ireland all combine to give this significantly lower forecast.

Appendix 2- Supply

A2.1 Introduction

This appendix provides further details behind our latest forecasts of UKCS production and resultant terminal forecasts

A2.2. UKCS Annual Production

Our 2009 UKCS forecast is shown in detail in Figure A7 below. This year we are showing the UKCS forecast in greater detail due to uncertainties over the timing of new field developments.

'Producing' represents fields currently in production. 'Development' represents fields where production is anticipated to begin over the next two years. 'Appraisal' represents those fields either in early stages of development, or those which we believe may enter production within the forecast period. Many of the fields in this category were present in previous forecasts but recent economic conditions may contribute to a delay in the first gas production of these fields.

Information received indicates that first gas production from the West of Shetlands area is still planned to begin around 2014, although it is believed that a number of key final investment decisions are still to be made.

As in previous years, our forecast includes an assessment for UKCS 'upside'. This upside attempts to account for future gas production from fields that are currently unknown to us. This upside is determined by the analysis of reserves and production rates of fields which have recently, or are forecast to come into production. Expressed as an aggregated volume, our 2009 forecast of UKCS upside in the period shown is just 7 bcm. This is lower than our 2008 forecast of 13 bcm, largely due to inclusion of additional fields in the appraisal category

Figure A7 also includes a contribution from biogas, based on a growth profile of meeting 1% of UK gas supplies by 2020. National Grid and United Utilities have recently won funding from the UK government for a demonstration project near Manchester which could be operational by 2011. This technology has been utilised in Europe and North America and could contribute a noticeable part of the supply mix by 2020. Alternatively or in addition, the UK could also be producing coal-bed methane for grid injection before the end of our forecast period.

Figure A7 UKCS Annual Production

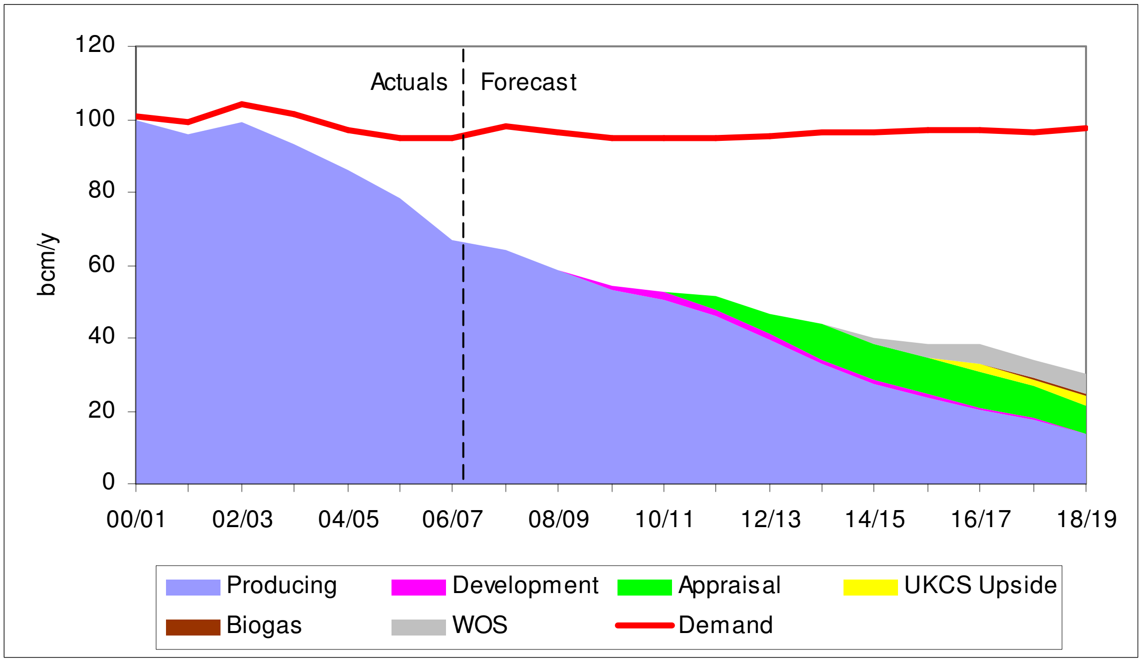


Figure A8 compares our latest UKCS forecast with that made in 2008. The 2009 forecast is lower in the first few years, due to forecast field decline and the potential suppression of production by low demands / prices / imported gas availability (caused by the current global recession). For the central part of the forecast they are similar and post 2016/17 the 2009 forecast is higher, due to our current assessment of potential West of Shetlands developments and a slightly modified approach to UKCS upside in 2009. Across the period where the forecasts overlap, forecast production is essentially the same at 482 bcm in 2008 and 480 bcm in 2009.

Figure A8 Comparison of National Grid forecasts for UKCS annual production

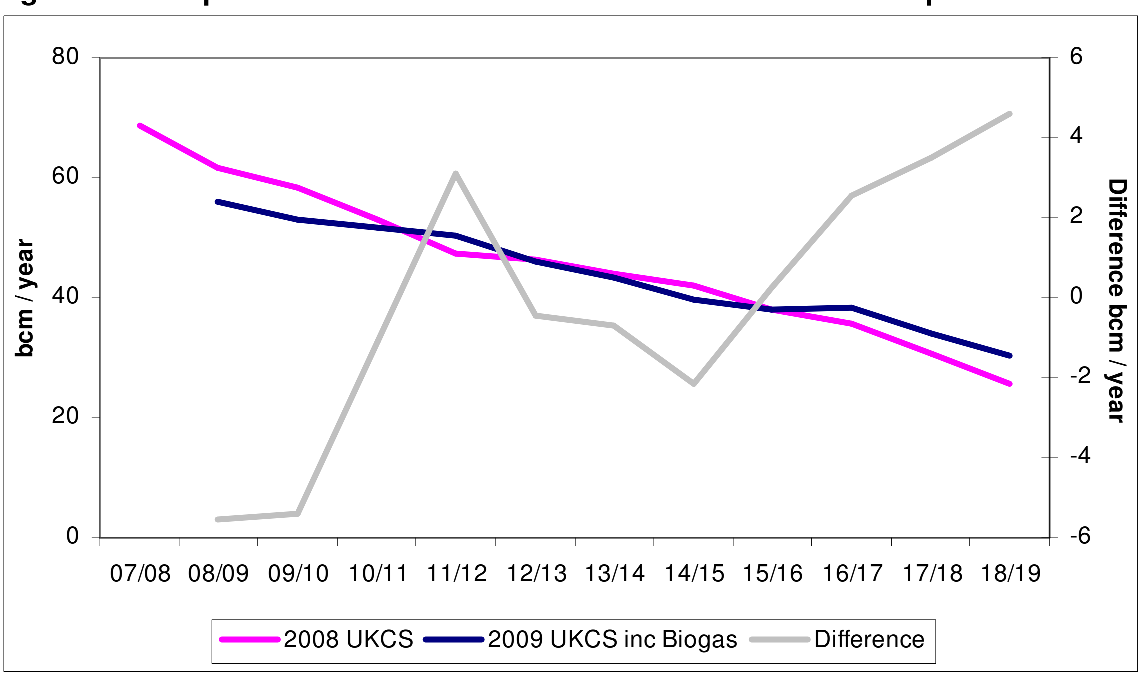
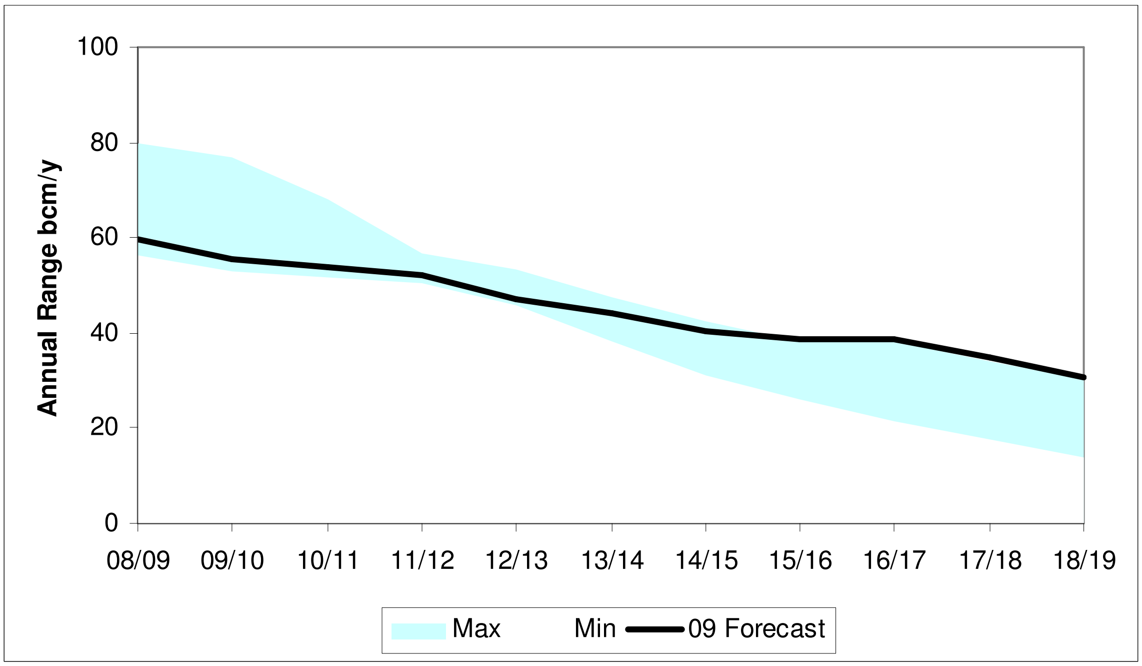


Figure A9 shows our latest UKCS supply forecast (gas supplied into National Grid's system only) compared against the range of data available to us. As in previous years, all forecasts show a significant decline in UKCS annual production from current levels of around 60 bcm. Our forecasts move from the lower end of the range to near the top at the end of the period due to our assumptions for UKCS upside and West of Shetlands production. Variations in forecasts can be attributed to a number of factors such as: variations in the definition of a gas supply year, whether gas is processed or consumed offshore, CV conversion rates and our UKCS upside assumptions.

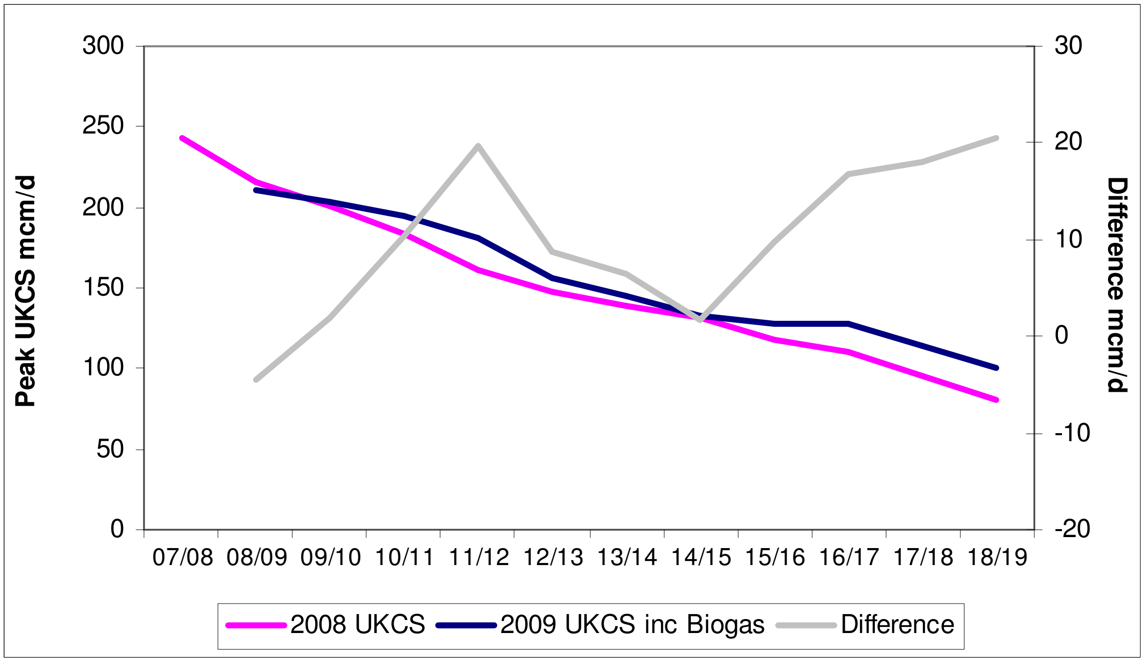
Figure A9 Comparison of forecasts for UKCS annual production



A2.3. Maximum UKCS Peak Supply Forecast

Figure A10 compares this years forecast for UKCS peak production with our previous forecast. From around 2010/11, our 2009 forecast is higher than that in 2008 due to updated information on new field developments. As mentioned earlier, in the latter part of our forecast, the 2009 forecast is higher due to potential West of Shetlands developments and a slightly modified UKCS upside methodology for 2009.

Figure A10 Comparison of National Grid forecasts for UKCS Peak production

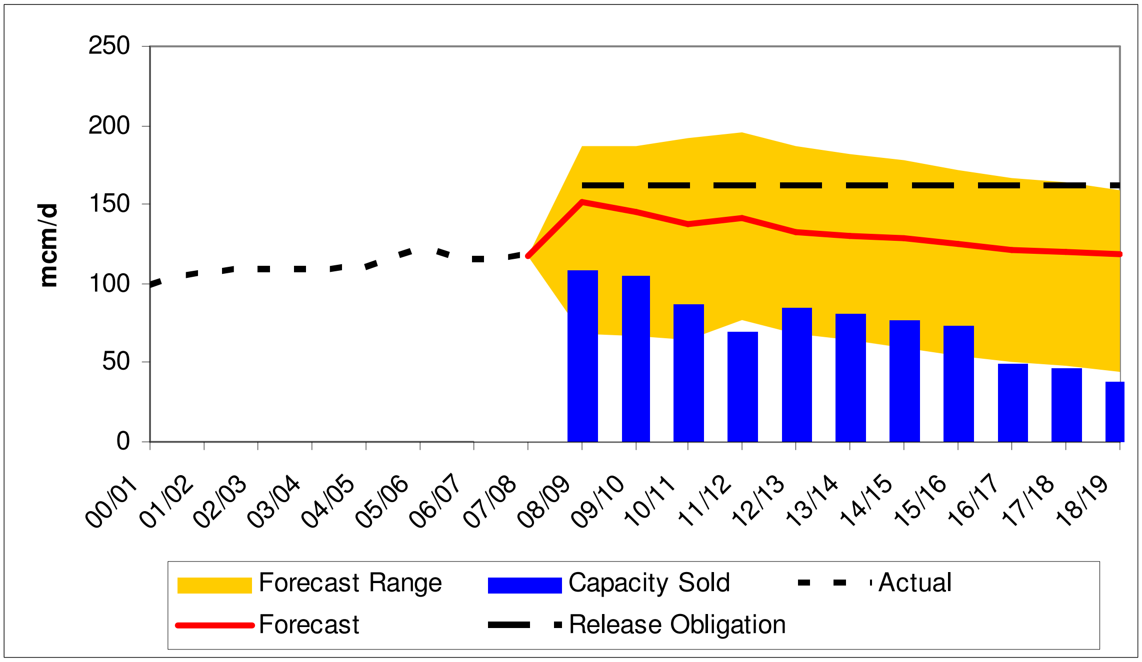


A2.4 Terminal Supply Forecasts

The following Figures A11 – A18 show our peak base case forecasts, forecast peak supply ranges and some historic maximum flows for each of the main entry terminals. As detailed previously the supply ranges are not necessarily extreme limits but have been determined through our forecasting process. The charts also show the entry capacity we are obliged to release[12] and the entry capacity booked through the LTSEC and AMSEC auctions as of June 2009. The last LTSEC auctions were held in September 2008 and last AMSEC auctions were held in March 2009 (AMSEC). Recently Ofgem approved UNC code modification 230AV, which stipulates that the next LTSEC auction will be in September 2009. The following LTSEC auctions will be held in March 2010, and in March of each year thereafter.

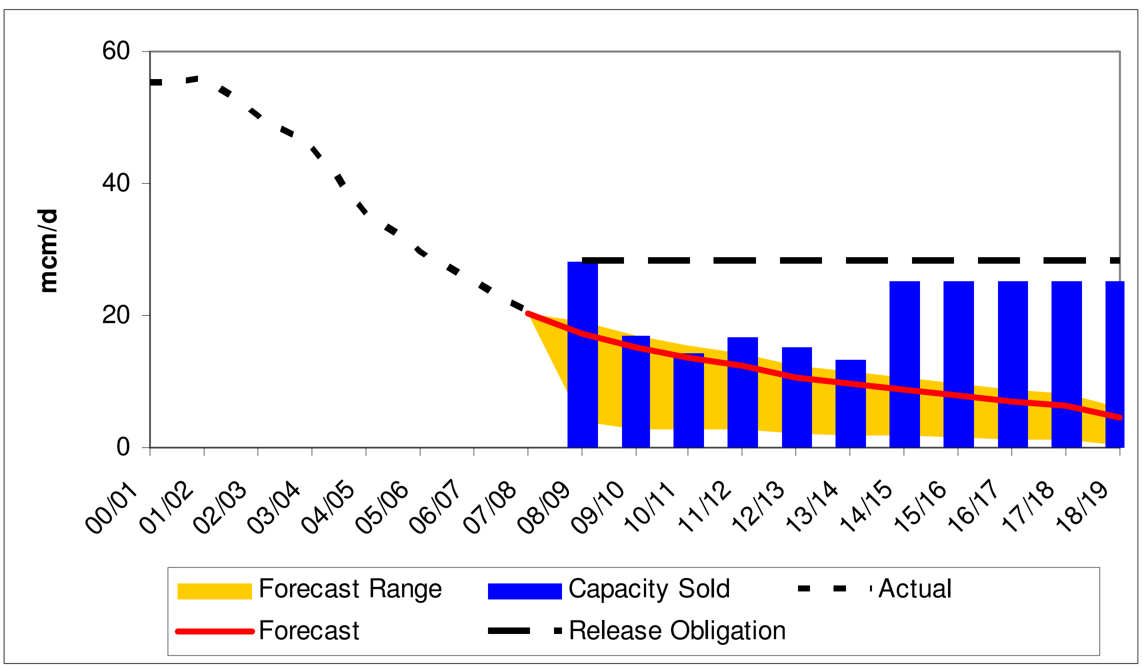
[12] The release obligation is the aggregate level of baseline capacity and released incremental capacity

Figure A11 – Bacton



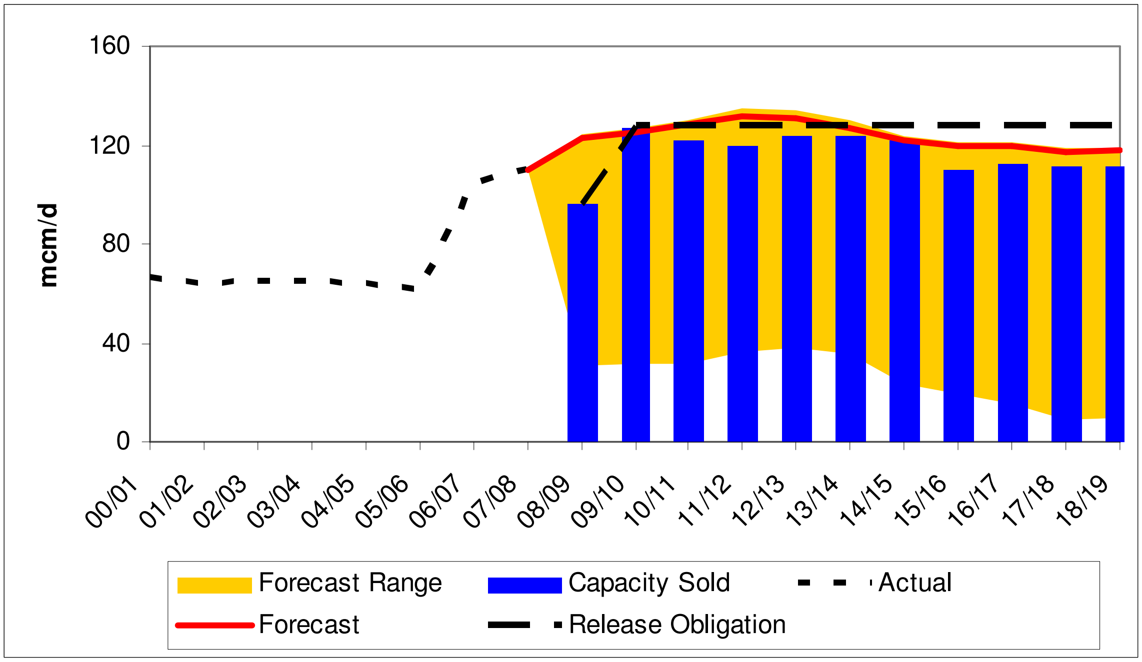
The Bacton forecasts for peak assume high IUK imports. For operational planning as reported in our June 2009 Winter Consultation document we use a much lower level for IUK imports. As in 2008, our 2009 Bacton forecast slowly declines due to falling UKCS production. The upper range includes import flows via IUK & BBL at import capacity are above the release obligation and above the amount of capacity sold to date. Although not shown in the ranges above, additional gas could also be delivered to Bacton if BBL is expanded or if Gazprom's Nord Stream project results in new import infrastructure or if any of the proposed Southern Basin offshore storage projects are developed.

Figure A12 – Barrow



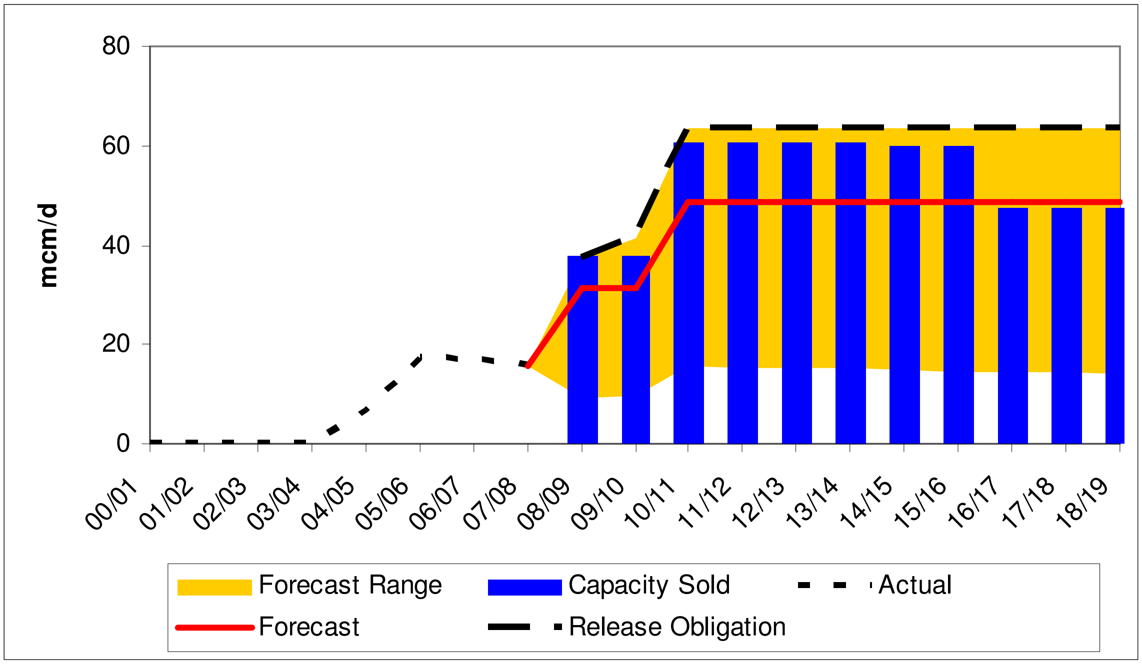
Consistent with previous forecasts, flows from Barrow fall due to declining UKCS production. Though not shown in our forecast above, Barrow flows could be increased significantly by a number of new storage proposals (Bains and Gateway), or Hoegh LNG's proposed Port Meridian facility.

Figure A13 – Easington



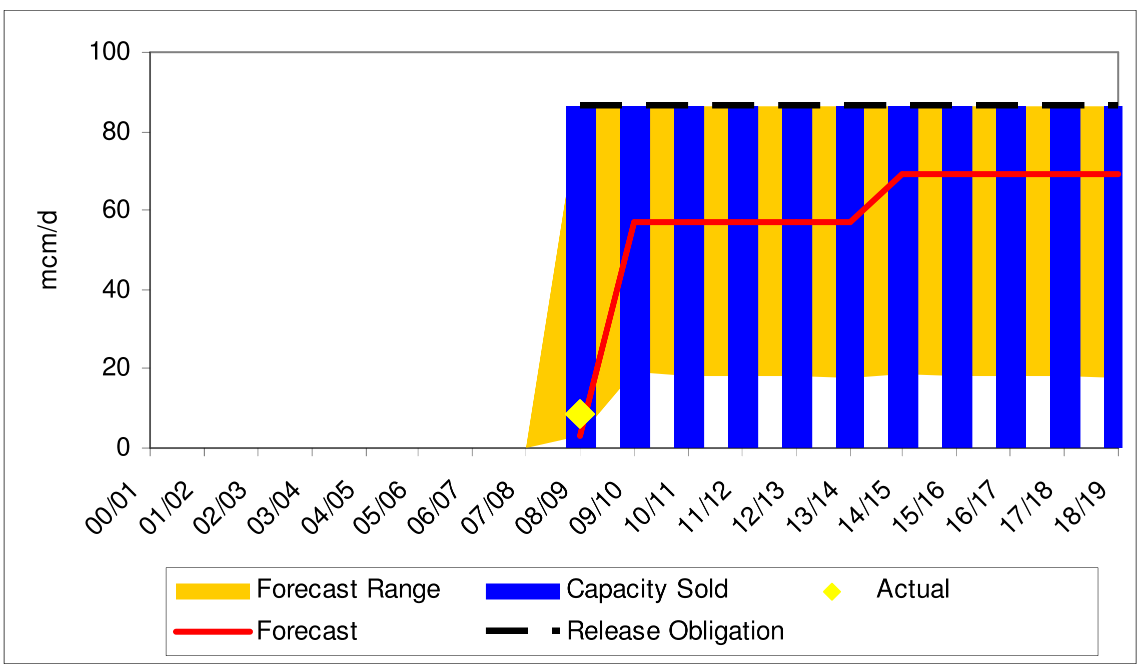
The Easington forecast shows that peak supplies could be marginally in excess of our release obligation over the next few years if there were to be coincidental flows of Langeled at its design capacity, full deliverability from Rough and higher UKCS as a result of new developments and blow down of some existing fields. The decline in UKCS post 2013/14 reduces our forecast below the release obligation.

Figure A14 – Isle of Grain



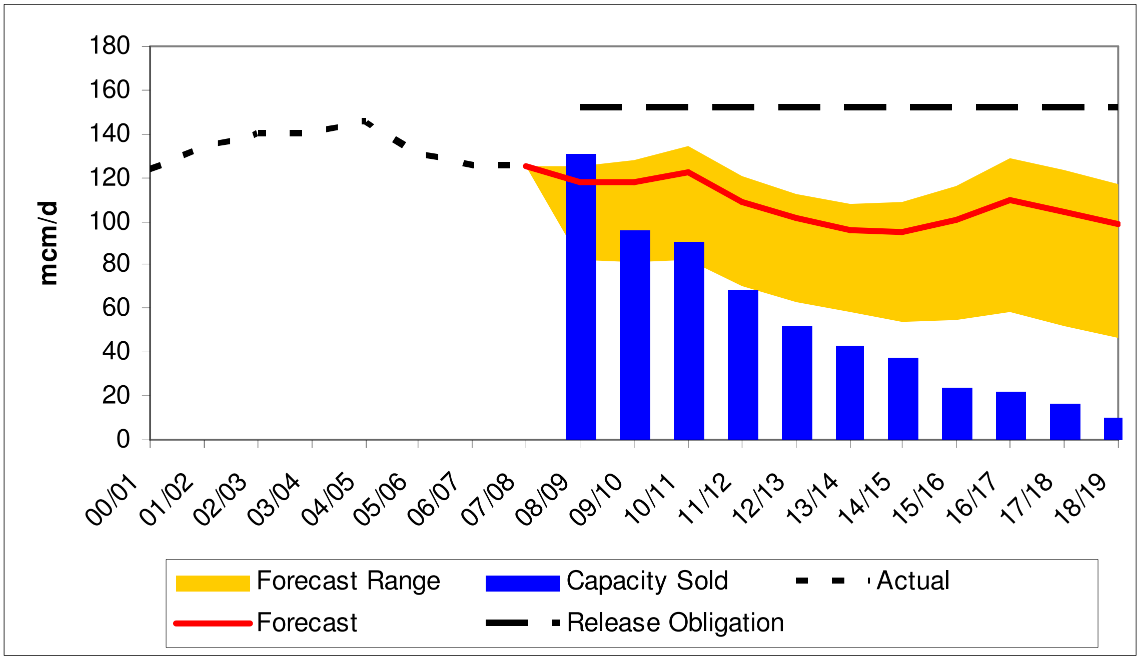
For the purposes of our base case, we currently assume that Grain LNG flows at 75% of installed and future import capacity at peak. It should be noted that there is much uncertainty associated with LNG imports and this is reflected in the forecast range for Grain.

Figure A15 – Milford Haven



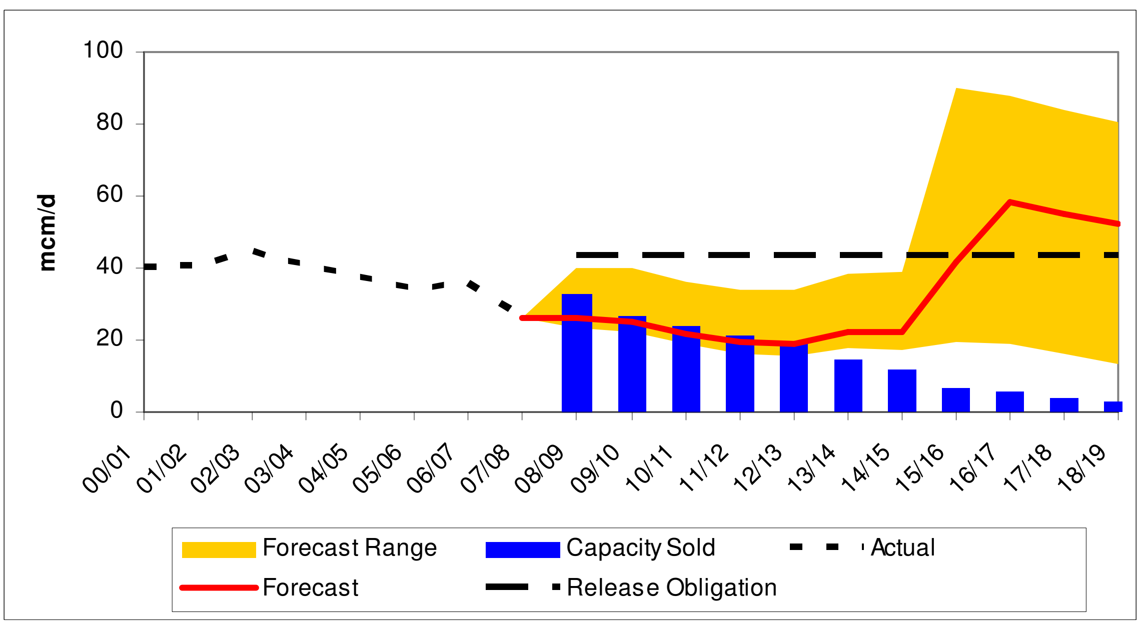
As with Grain, for the purposes of our base case we assume that the Milford Haven import terminals flow at 75% of installed and future import capacity at peak. Again, it should be noted that there is much uncertainty associated with LNG imports and this is reflected in the forecast range for Milford Haven.

Figure A16 – St Fergus



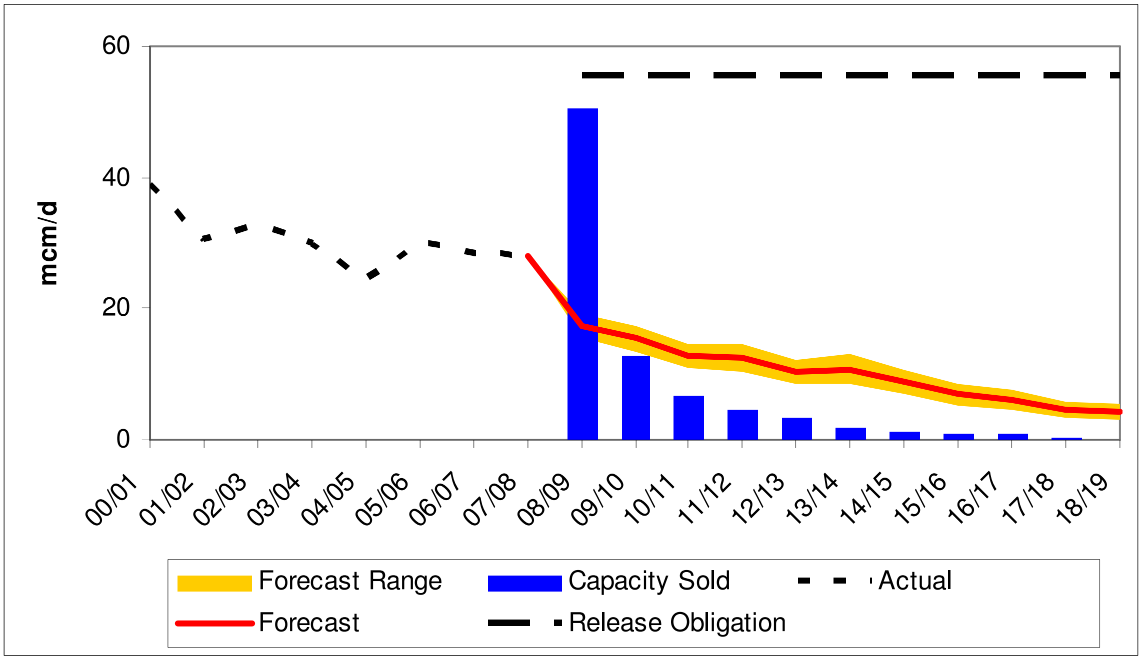
Our base case forecast for St Fergus marginally increases in the short term due to forecasts of higher flows via the Tampen link. Thereafter there is some decline before increasing again due to our assumptions regarding West of Shetlands developments.

Figure A17 – Teesside



For Teesside, our UKCS forecast drives the decline in our base case until 2013/14, when additional UKCS supplies are anticipated. Longer term a new LNG import facility may be constructed at Teesside. The range for Teesside captures the possibility of LNG imports through Teesport LNG.

Figure A18 – Theddlethorpe



The forecast for Theddlethorpe falls due to declining UKCS production. Though not shown, flows could be higher if the Saltfleetby storage project is developed.

A2.5 Imports

Table A1 details existing and near completed import projects.

Table A1 – Existing and near completed import projects

Import Project	Operator / Developer	Type	Location	Capacity (bcm/yr)
Interconnector	IUK	Pipe	Bacton	25.5
BBL Pipeline	BBL	Pipe	Bacton	~15
Langeled	Gassco	Pipe	Easington	25
Tampen*	Gassco	Pipe	St Fergus	10
Vesterled	Gassco	Pipe	St Fergus	13
South Hook 1	QP / ExxonMobil	LNG	Milford Haven	10.5
Dragon	BG / Petronas	LNG	Milford Haven	6
Isle of Grain Phase I & II	National Grid LNG	LNG	Isle of Grain	13.5
GasPort	Excelerate	LNG	Teesside	~4
			Total	123

Table A2 details under construction and proposed import projects.

Table A2 – Under construction and proposed import projects

Import Project	Developer	Type	Location	Date	Capacity (bcm/yr)	Status
South Hook 2	QP / ExxonMobil	LNG	Milford Haven	2009/10	10.5	Under construction
BBL Expansion	BBL	Pipe	Bacton	2010+	~3	Investment Decision taken
Isle of Grain 3	National Grid LNG	LNG	Isle of Grain	2010	7	Under construction
Dragon 2	BG / Petronas	LNG	Milford Haven	2013+	6	Planning received (1 tank)
ConocoPhillips	Partners	LNG	Teesside	2013+	7+	Planning received
Canvey LNG	Partners	LNG	Canvey Island	2013+	5.4+	Planning rejected possible resubmission
Port Meridian	Hoegh LNG	LNG	Barrow	2013	4	Planning granted
Other LNG	Various	LNG	n/a	2013+		Conceptual
			Total under construction inc proposed		17.5 (42+)	

A2.6 Storage Projects

In addition to the potential new import projects, a number of storage projects are also under consideration or development, which would help to meet peak demands. These include salt cavity developments and conversions of depleted onshore oil and gas fields.

Table A3 details existing and near completed storage projects.

Table A3 – Existing storage projects

Storage Project	Operator	Location	Space (~bcm)	Operational
Rough	Centrica Storage	Southern North Sea	3.3	1985
Hornsea	SSE Hornsea	Yorkshire	0.3	1979
Humbly Grove	Star Energy	Hampshire	0.3	2005/06
LNG Storage	National Grid LNG Storage	Various	0.3	1971-1983
Hatfield Moor	Scottish Power	Yorkshire	0.1	2000/01
Holehouse Farm	Energy Merchants Gas Storage	Cheshire	0.04	2001/02
		Total	4.34	

Table A4 details under development storage projects.

Table A4 – Under development storage projects

Storage Project	Developer	Location	Space (bcm)	Gas Year
Aldbrough[13]	SSE / Statoil	East Yorkshire	0.4	2008/09
Holford	E.ON	Cheshire	0.2	2011/12
Caythorpe	Centrica	East Yorkshire	0.2	2011/12
Stublach	Storengy UK Limited	Cheshire	0.4	2013/14
		Total	1.1	

Table A5 details storage projects with planning consents.

Table A5 – Storage projects with planning consents

Storage Project	Developer	Location	Space (~bcm)	Planning Granted	Status
Aldbrough II	SSE / Statoil	East Yorkshire	0.4	May-07	FID[14] not yet taken
Portland	Portland Gas Ltd	Dorset	1.0	Jul-07	FID not yet taken
Whitehill Farm	E.ON	Yorkshire	0.4	Oct-07	FID not yet taken
Gateway	Stag Energy	Offshore Barrow	1.5	Nov-08	FID not yet taken
Holehouse Farm	EDFT Storage	Cheshire	0.3	Mar-09	FID not yet taken
Bains	Centrica Storage	Offshore Barrow	0.6	Jun-09	FID not yet taken
		Total	4.2		

Table A6 details storage projects yet to receive planning consents.

Table A6 – Storage projects yet to receive for planning consents

Storage Project	Developer	Location	Space (~bcm)	Date Applied
King Street	NPL	Cheshire	0.2	Oct-07
Saltfleetby	Wingas	Lincolnshire	0.7	Oct-08
Fleetwood	Canatxx	Lancashire	1.0	Feb-09
		Total	1.9	

Table A7 details storage projects yet to submit planning consents.

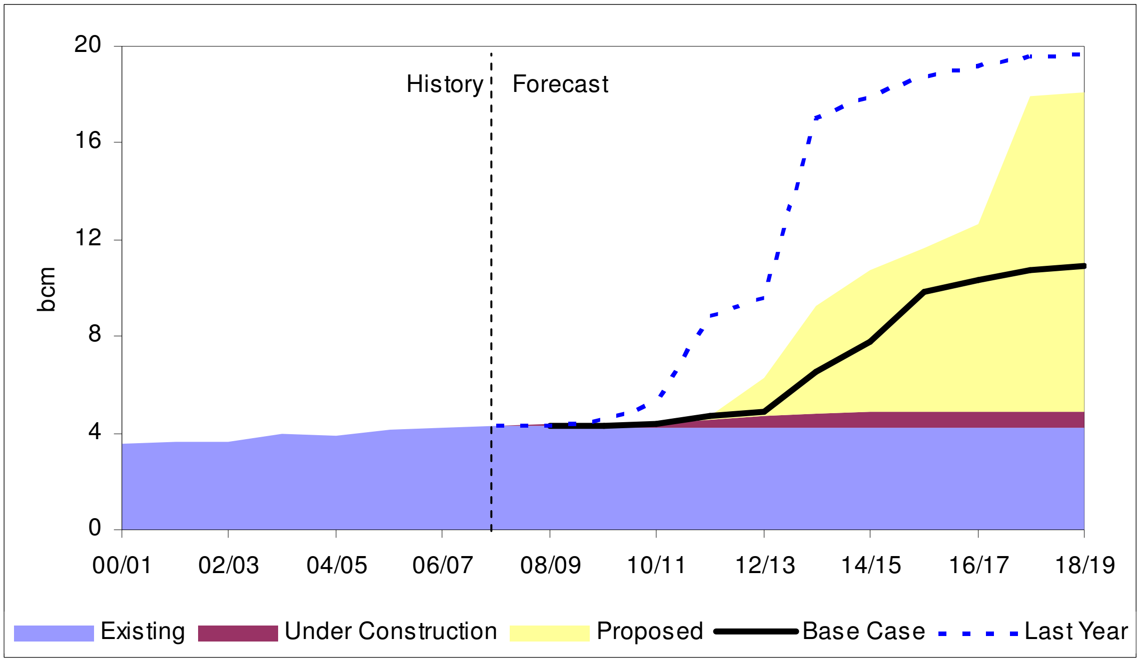
Table A7 – Storage projects yet to submit planning consents

Storage Project	Developer	Location	Space (~bcm)
Albury I	Star Energy	Surrey	0.2
Albury II	Star Energy	Surrey	0.4
Hewett	ENI	Offshore Bacton	4.0
Baird	Centrica	Offshore Bacton	1.7
Hatfield West	Scottish Power	Yorkshire	0.1
Gateway II	Stag Energy	Offshore Barrow	1.5
		Total	7.9

[13] Commercial operations commenced July 2009, space 0.06 bcm of planned 0.37 bcm
[14] FID – Final Investment Decision

Figure A19 shows storage space in terms of existing facilities, those under construction and those proposed. For comparative purposes, last years aggregated storage space is shown. The chart also shows storage space since 2000/01 and our base case forecast. A similar chart for storage deliverability is shown in Figure 17.

Figure A19 – Storage Space – Supply Scenarios



Appendix 3 – NTS Investment

NTS Planned Projects

The aim of the investment planning process is to ensure that investment is made in the most efficient manner possible to meet the overlapping drivers of growth, replacement and environmental efficiency.

The following tables highlight the approved and proposed NTS expansion projects over the next few years. The build dates indicate the construction season in which it is intended to commission the project.

Projects Approved for 2009 Construction

Project	Build	Scope
Churchover New Compressor	2009-10	15MW

Projects Approved for 2010 Construction

Project	Build	Scope
Easington to Paull	2010-11	26km x 1200mm
Cambridge Multijunction modifications	2010-11	Flexible Flow Configurations
Gilwern Offtake	2010-11	Uprating for Higher Presure
Wormington to Sapperton	2010-11	42km x 900mm

Projects Currently Planned for 2010 Onwards

Project	Scope
Sapperton to Easton Grey	19km x 900mm
Hole House Farm to Elworth	5km x 900mm

Projects Currently Under Review

Project	Scope
Warburton to Audley Pipeline	49km x 1200mm
Paull to Goxhill Pipeline	6km x 1200mm
Goxhill to Hatton Pipeline	63km x 1200mm

Appendix 4 – 2009 Investment Map