Winter Outlook Report 2009/10

Outlook for winter 2009/10

Introduction

1. This document, the final report, sets out our analysis and views for the coming winter (October 2009 to March 2010), and reflects responses received through the consultation process. Ofgem plans to hold a seminar for industry parties on 14th October 2009 in London. The preliminary winter report and previous year final reports are published on our website at http://www.nationalgrid.com/uk/Electricity/SYS/outlook/.

Industry Feedback

2. We would like to thank the organisations that responded to the consultation. In all five responses were received, which we have reviewed and reflected in our final report. Whilst the formal consultation process has now closed, we continually seek feedback on our outlook reports to increase their usefulness to the industry and to reflect all changes in trends when they become apparent. To feedback comments on our outlook report please contact us at energy.operations@uk.ngrid.com.

Roles and Responsibilities

3. The competitive gas and electricity markets in Great Britain have developed substantially in recent years and have successfully established separate roles and responsibilities for the various market participants. In summary, the provision of gas and electricity to meet consumer demands and contracting for capacity in networks is the responsibility of suppliers and shippers. National Grid has two main responsibilities: first, as the primary transporter, for ensuring there is adequate and reliable network capacity to meet anticipated transportation requirements; second, as system operator of the transmission networks, for the residual balancing activity in both gas and electricity. The structure of the markets and the monitoring of companies' conduct within it are the responsibility of Ofgem, whilst the Department for Energy and Climate Change (DECC) has a role in setting the regulatory framework for the market.

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5. National Grid has prepared this consultation document in good faith, and has endeavoured to prepare this consultation document in a manner which is, as far as reasonably possible, objective, using information collected and compiled by National Grid from users of the gas transportation and electricity transmission systems together with its own forecasts of the future development of those systems. While National Grid has not sought to mislead any person as to the contents of this consultation document, readers of this document should rely on their own information (and not on the information contained in this document) when determining their respective commercial positions. National Grid accepts no liability for any loss or damage incurred as a result of relying upon or using the information contained in this document.

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Summary

Winter 2009/10 Outlook – Gas

7. At the end of September the Met Office issued its early indications for winter 2009/10. They report 'near or above average temperatures over much of Europe including the UK, but there is still a 1 in 7 chance of a cold winter'.
8. Fuel price futures show a small increase in both the oil and coal price with gas also increasing albeit from a relatively low starting position. The seasonal increase in the gas price is not as high as in recent winters, resulting in little to choose between coal and gas for base load power generation. For our demand forecast we assume coal is base load as any increase in wholesale gas prices during periods of high gas demand or tight supply, it is likely that coal will be favoured over gas.
9. Current US gas prices for the winter are now similar to those in Europe providing limited incentives to deliver spot LNG cargoes to Europe in preference to the US. Beyond winter 2009/10, UK and US gas prices are more aligned to the oil price. With summer 2010 prices comparable to winter 2009/10 prices there may be less incentive to flow from storage compared to previous winters.
10. Forecast demands for winter 2009/10 are 2.5% lower than weather corrected actual demands in 2008/9. This is due to the further reductions in NDM demand and our assumption for lower gas consumption in power stations due to a combination of lower electricity demand and expected higher availability of non gas fired power generation. If gas prices remain low then gas demand for power generation could be typically 20 mcm/d higher.
11. Our forecast for UKCS supplies for winter 2009/10 is approximately 6% lower with UKCS expected to make up typically 50% of non storage supplies.
12. For winter 2009/10, LNG imports provide us with the biggest supply uncertainty. Whilst potential LNG flows could exceed 100 mcm/d we expect flows will for most of the time be much lower than this. For consultation purposes we assumed a provisional range of 10-60 mcm/d with average flows of 30 mcm/d. Due to feedback and the frequency of summer cargoes, we have revised upwards our average flow to 40 mcm/d. Compared to previous winters there continues to be reasons to be more optimistic about LNG deliveries to the UK. This is primarily due to a combination of increased LNG production and the global recession.
13. From Norway we now anticipate similar levels of imports to last winter, with the potential for higher deliveries to the Continent at the expense of the UK. For BBL we now anticipate slightly lower flows than last winter reflecting the increased 'commercial' behaviour we have witnessed over the past year. For IUK we again expect flows to respond to market needs but due to a combination of lower UK demands and possibly more LNG, anticipate that the threshold for IUK imports may be at relatively high UK demands.
14. Our preliminary view of non storage gas supplies for winter 2009/10 remains at between 336-386 mcm/d, with a base case view of 343 mcm/d. This is comparable to last winter's level, with further upside potential from LNG and IUK imports.

15. With similar levels of non storage supply and lower levels of demand, our preliminary assessment of storage requirements for the Safety Monitors for winter 2009/10 is lower at approximately 100 mcm of storage space and 60 mcm/d of storage deliverability.

16. For winter 2009/10 we have made numerous changes to the Safety Monitor determination process replacing three storage types with a single storage type. We have also made a commitment to improve market information relating to Safety Monitor levels and the short term supply demand position. Some of these changes have been captured in a UNC Modification Proposal. Whilst this will not change the monitor requirements we believe the changes will enable the market to operate more effectively, as there will be greater clarity regarding the necessary Safety Monitor space and deliverability requirements and how these assumptions proceed into setting the Gas Balancing Alert (GBA) trigger.

Winter 2009/10 Outlook – Electricity

17. For winter 2009/10, based on the information available for this final report, the surplus generation availability above expected electricity demand continues to be materially more comfortable than we have seen in recent years. There also remains some potential upside in generation availability which is dependant upon the anticipated commissioning of several new large CCGT power stations and new wind power generation.

18. Under our normal demand scenario and base case generation availability, generation surpluses are comfortable. Under a 1 in 20 demand scenario which might be expected in a very cold winter, generation surpluses are still considered adequate at this stage.

19. Based on data submitted by Generators, our expectation of operational generation capability is 77.0 GW at the start of winter. Allowing for anticipated generation performance issues, such as planned and unplanned outages, based on historical performance we would expect this to deliver an availability of 66.1 GW.

20. The forecast Average Cold Spell (ACS) peak demand for winter 2009/10 at 57.4 GW is below last year's outturn peak demand, adjusted for ACS conditions. Last winter saw significant reductions in demand as a result of the economic recession. In winter 2009/10 we anticipate a further reduction in peak demand. This is supported at present by our operational demand forecasting models for which underlying demands are now stabilising. Clearly in a time of significant economic uncertainty, demand forecasting has become more challenging and we place greater emphasis for winter 2009/10 upon revisions to our latest view which will be published on www.bmreports.com as winter progresses.

21. Using installed generation capacity relative to ACS peak demand yields a plant margin of 34%, including any potential imports from France. The more representative estimate of actual likely generation availability at the winter peak of 66.1 GW yields an expected operational margin at the winter demand peak of 15%.

Contents

Section A
Outlook for Winter 2009/10

<u>Gas</u>

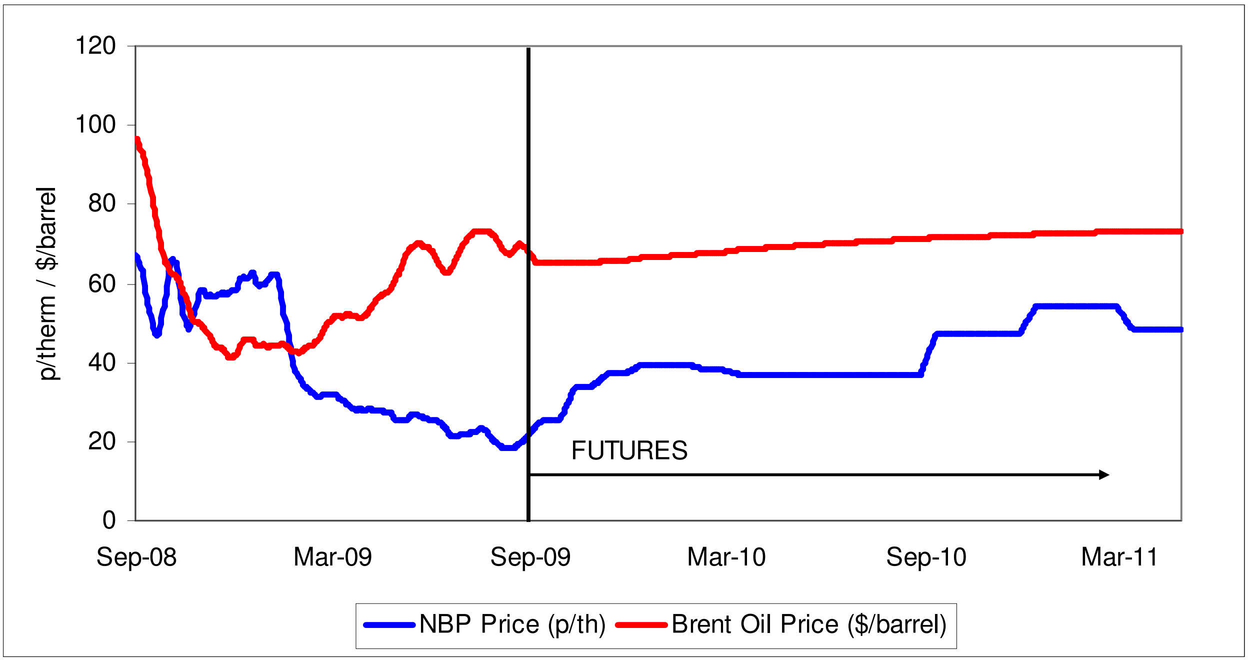
Met Office Weather Forecast

22. At the end of September the Met Office issued its early indications for winter 2009/10[1]. They report that 'preliminary indications continue to suggest that winter temperatures are likely to be near or above average over much of Europe including the UK. Winter 2009/10 is likely to be milder than last year for the UK, but there is still a 1 in 7 chance of a cold winter'.

2009/10 Fuel Prices

23. Figure A.1 shows the historical and forward UK oil and gas prices as of early September 2009. The oil price has been increasing since March, principally because of views of economic recovery.

Figure A.1 – Historic and Future Oil and Gas Prices



24. Historically the wholesale gas price has been strongly linked to the oil price, due to high interconnectivity with the Continent where long term gas contract prices tend to be indexed to oil. There is a lag on this linkage thought to be around 6 months. Additionally the UK winter gas price usually has a risk premium associated with it,

[1] http://www.metoffice.gov.uk/science/creating/monthsahead/seasonal/2009/winter.html

although this year this does not seem to be the case when comparing winter prices with the following summer.

25. The global recession has caused demand reductions in world energy demand. As a result, there has been a large amount of spare LNG available to spot markets. A lot of this gas has been delivered to the LNG facilities at Isle of Grain and Milford Haven. This extra gas, along with existing supplies and reduced demand, has seen daily gas prices fall significantly. Daily prices this summer have averaged 26 p/therm (up to Sept 7th) compared to 60 p/therm last summer. The market expects this trend to continue over the winter months with the winter price falling over the last few months. In the last six months (up to Sept 8th) winter 2009/10 price has fallen from about 50 p/therm to below 35 p/therm, a decrease of over 30%.

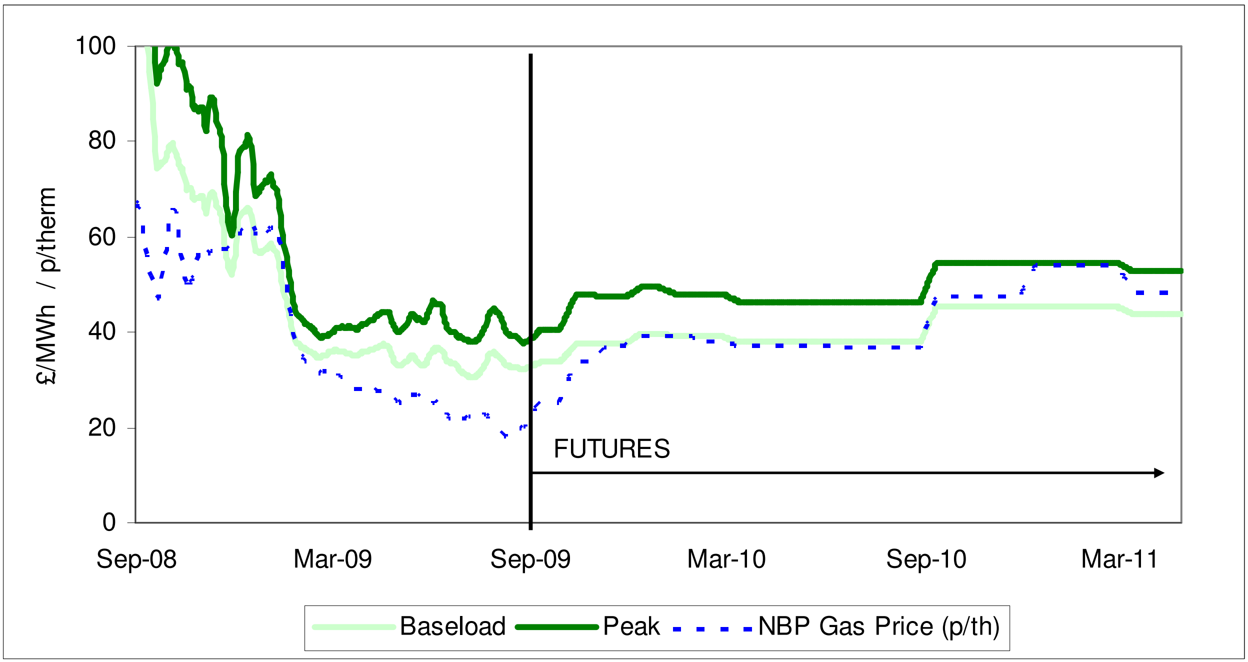
26. Should the lower wholesale gas prices result in lower end consumer prices, this may have an impact on the level of demand in winter 2009/10, especially if this combines with colder weather and an upturn in the economic outlook.

27. Beyond winter 2009/10, UK gas prices are influenced more by the oil price. This results in a Summer 2010 price that is very close to the winter 2009/10 price. At times recently, Summer 2010 has been trading higher than winter 2009/10. This has other implications for the winter and could for example provide an incentive to flow lower volumes from storage.

28. The availability of LNG imports is a critical factor in the supply / demand balance and therefore has an impact on the wholesale gas price. The current high availability of LNG is due to reductions in global gas demand combined with new production capacity. If global gas demand returns, the amount of LNG that comes to the UK could reduce as other countries with contracts for LNG take precedent. Alternatively the contractual position regarding take or pay may still result in surplus LNG being available for spot markets such as the UK, indeed a higher UK gas price could even attract additional cargoes.

29. Figure A2 shows the historical and forward UK wholesale baseload and peak power prices as of early September 2009, together with the NBP gas price. Historically, there is usually a strong correlation between the gas and power prices and only when there have been demand or supply issues specific to the power market has there been any noticeable deviation away from this trend. This occurred for a few months over summer 2008, mainly due to significant nuclear generation plant outages. This summer, daily power prices have again been higher relative to the gas price, due to a combination of factors. These include; the extra supply sources from LNG in the gas market and slightly tighter plant margins for power generation due to more generator outages than historically seen. This has led to coal becoming the marginal fuel for generation which in turn has led to the coal price becoming more influential in the power price. As the coal price has increased, this has fed into the power price.

Figure A.2 – Historic and Forward Power and Gas Prices



30. In the forward power markets, the usual seasonality in the gas price is not fully reflected. Forward baseload power prices for winter 2009/10 are typically £35-40 per MWh.

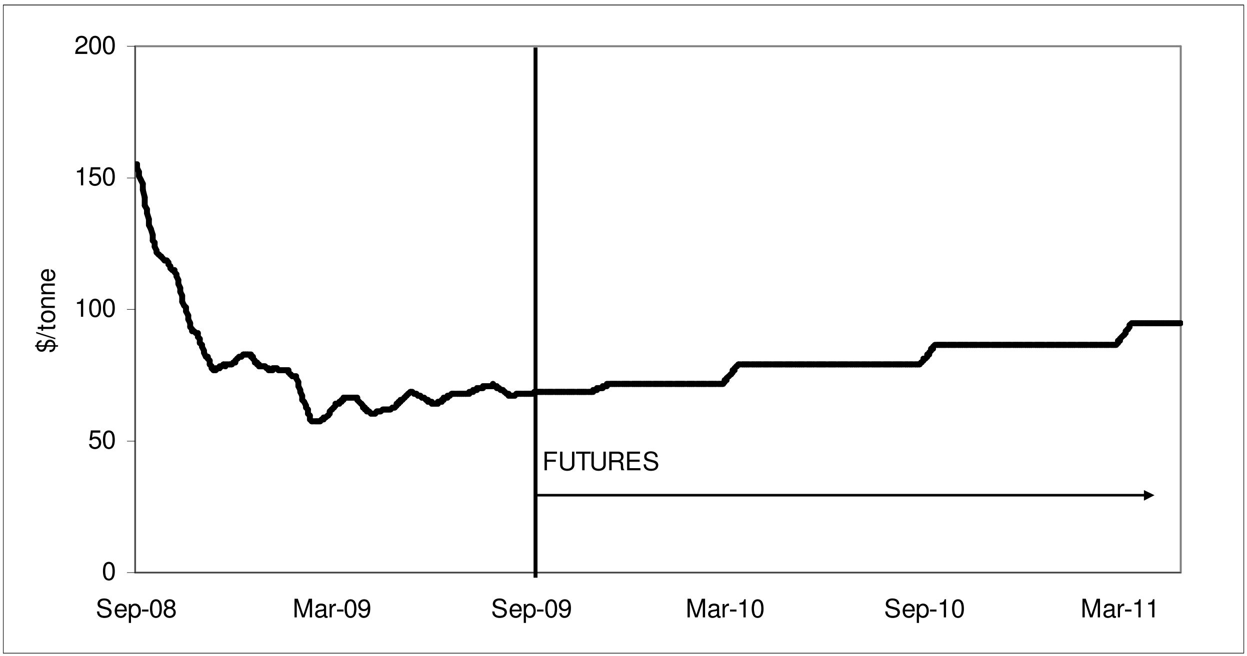
31. The coal price has to some extent been mirrored by movements in the price of oil, as they have many of the same drivers. The most notable driver for forward prices of both oil and coal being views of the global economic recovery.

32. Coal, however, has its own supply chain and demand requirements and specific price drivers relating to these, particularly demand from India and China. These have fluctuated in the last few months due to levels of Chinese stock piles and the return of Chinese coal mines to production after long closures for safety concerns; and in India due to the effects of the recent typhoon season and the continuing underlying increases in domestic coal demand.

33. The coal price peaked in July 2008 at over $224/tonne, driven by strong global demand, particularly in China and India, coupled with a shortage of available capacity and freight. Since then, the economic downturn has restricted demand particularly from China and India, two of the main importers of coal, and the main global manufacturers of goods. This has in turn caused the price to drop to the April 2009 low of just under $60/tonne. Since then the economy has started to recover, and demand has increased accordingly. The forward prices, as with oil, reflect the views of slow steady economic recovery. Figure A.3 shows the ARA CIF coal price[2]

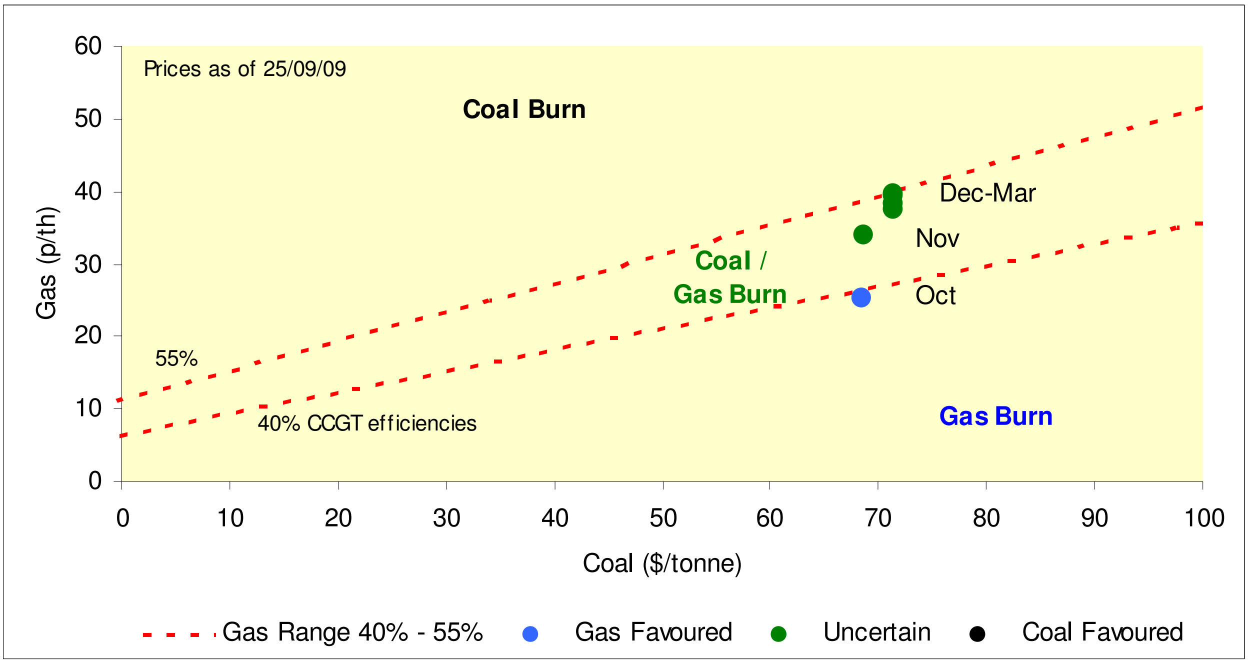
[2] Amsterdam Rotterdam Antwerp (cost insurance freight)

Figure A.3 – Historic and Forward Coal Prices



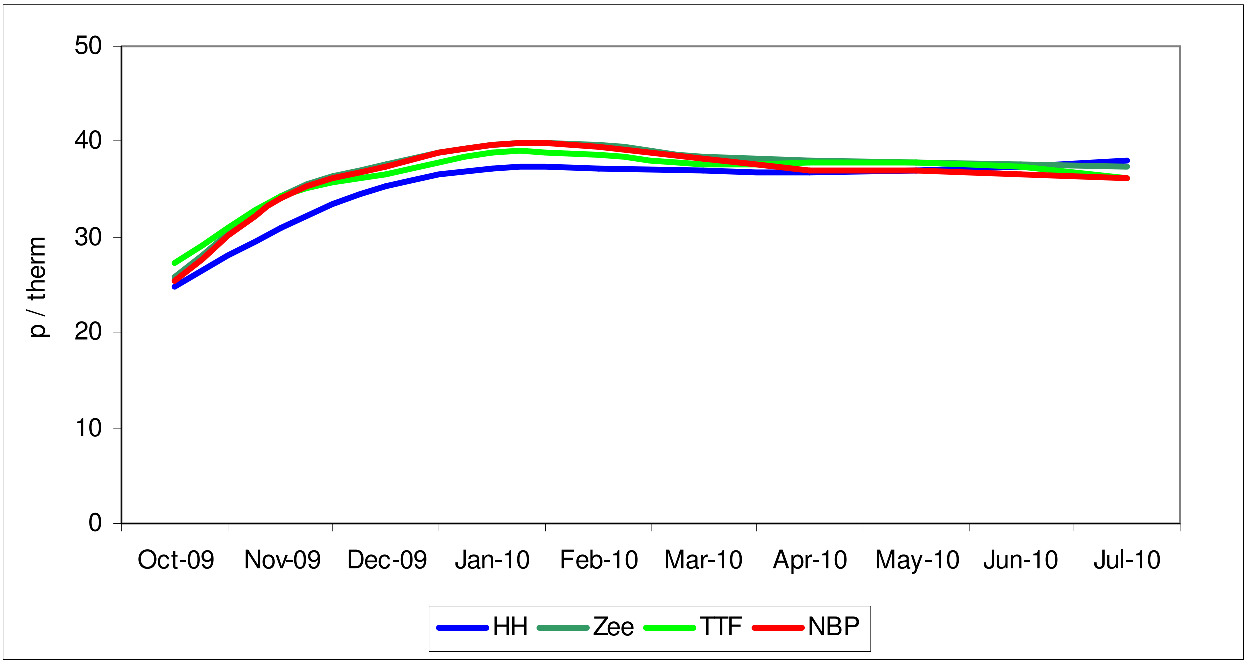
34. The relatively low price of gas since March 2009 has meant that gas has been favoured over coal for power generation throughout summer 2009. However, during winter 2009/10 the picture as shown in Figure A.4 becomes less clear. Low gas prices in October mean that gas fired generation remains favoured, but increases in gas price for November to March mean that whether gas or coal is favoured for power generation depends largely on individual station's efficiencies. The November to March prices on average slightly favour coal, however energy price fluctuations (particularly gas price as it is more prone to short term correction) closer to the day of delivery are more likely to have an effect on the fuels used for power generation. Any periods of very high gas demands or a tight supply demand balance are likely to result in an increase in wholesale gas prices. Under these conditions it is likely that coal will become base load for power generation with a corresponding reduction in gas demand for power generation.

Figure A.4 – Winter 2009/10 Gas vs Coal Generation



35. Figure A.5 shows the forward gas prices as of late September 2009, for European markets (NBP, Zeebrugge, TTF) and for the US (Henry Hub). Unlike previous winters, the NBP is not at a slight premium to the other Continental markets. The premium of the NBP over Henry Hub has reduced significantly recently to about 2-3 p/therm through to January before attaining parity post March. In terms of spot LNG cargoes this provides limited incentives to deliver LNG to Europe in preference to the United States.

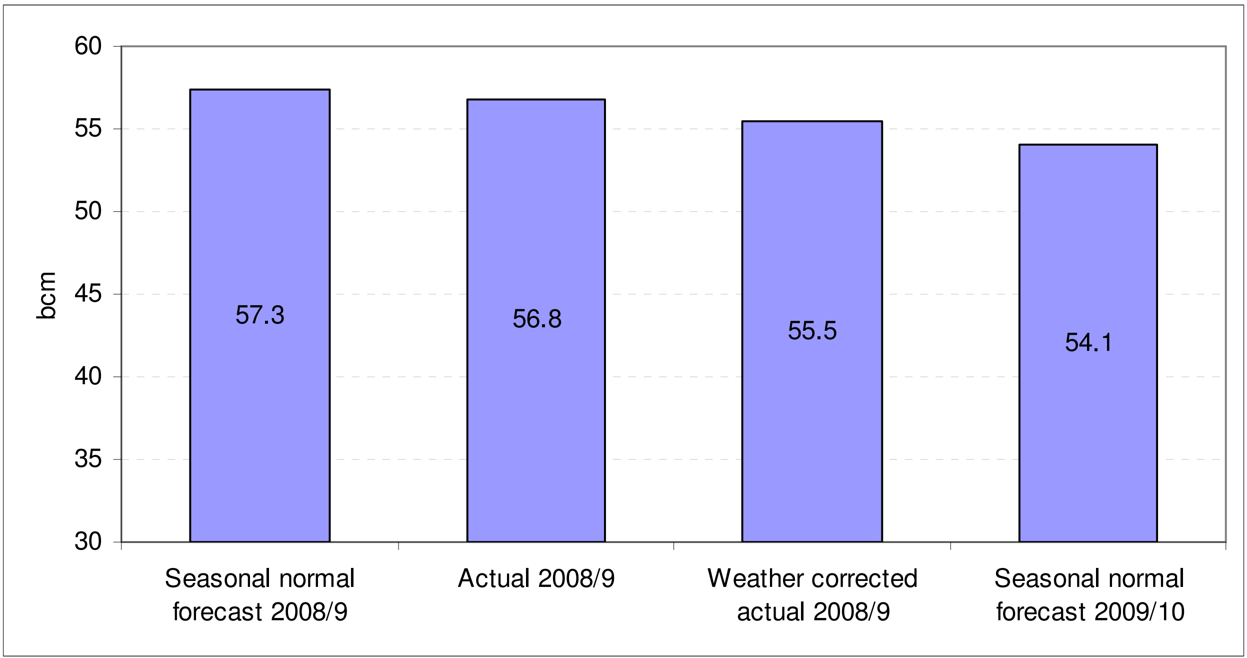
Figure A.5 - Forward Prices for Europe and US



Gas Demand Forecast 2009/10

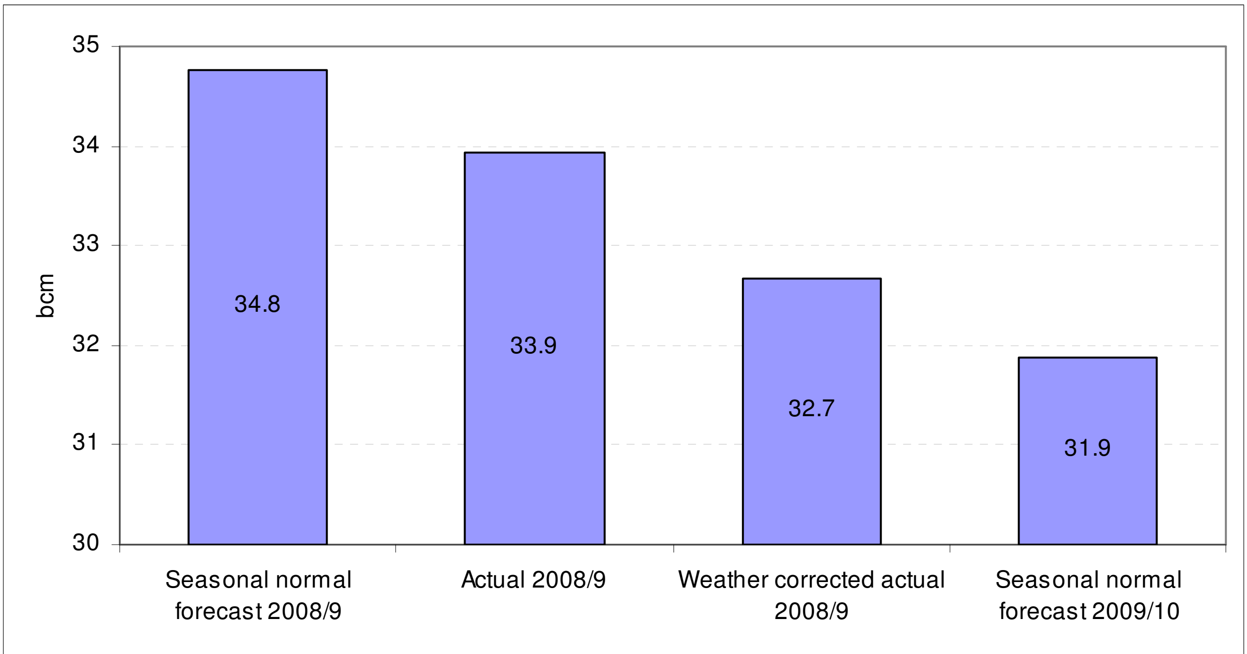
36. Figure A.6 compares the 2009 total forecast for winter 2009/10 with the actual, weather corrected and 2008 forecast demands for winter 2008/9. The new forecast is 4.8% lower than the actual and 2.5% lower than the weather corrected demands in winter 2008/9. This year's forecast is in the context of a severe recession. GDP is expected to contract by about 4% in 2009 and to grow only modestly in 2010 (source: Experian). The reasons for this reduced demand forecast are outlined in the subsequent sections.

Figure A.6 – Total Winter Demand



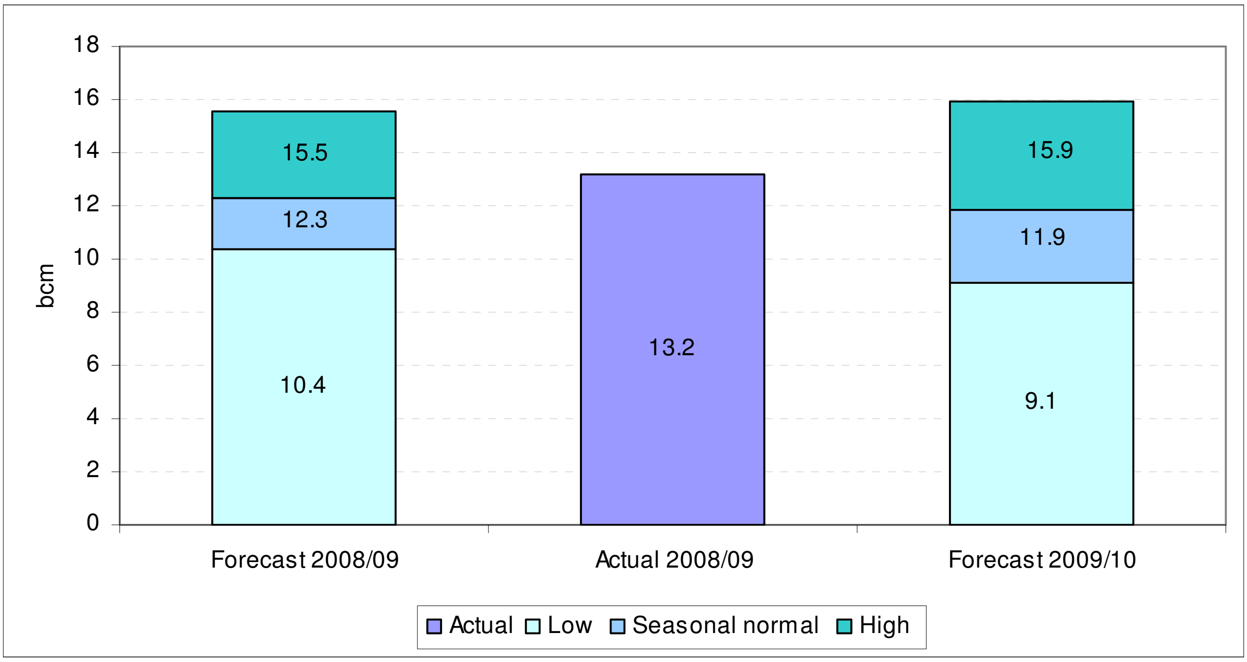
37. Figure A.7 compares the 2009 NDM forecast for 2009/10 with the actual, weather corrected and 2008 forecast demands for 2008/9. The NDM forecast for 2009/10 is 5.9% lower than actual demand in the 2008/9 winter and 2.4% lower than weather corrected demand reflecting the continued trend for lower NDM brought about by the recession and efficiency measures driven by higher consumer fuel prices.

Figure A.7 – NDM Winter Demand



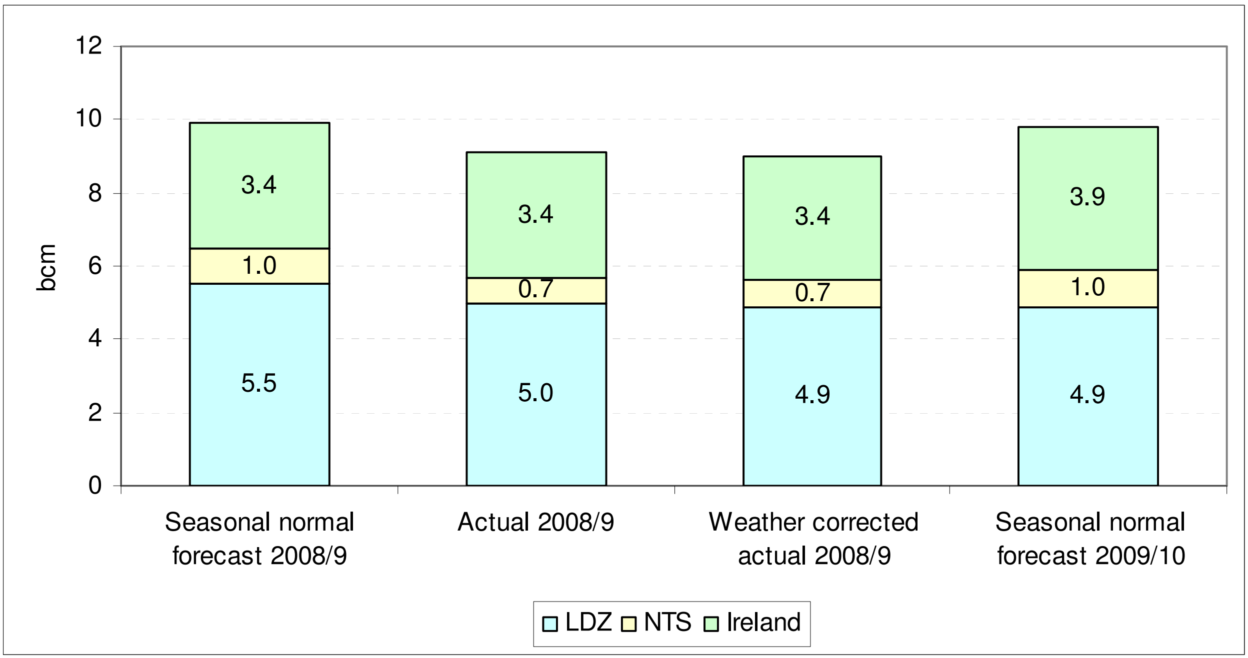
38. Figure A.8 compares the 2009 power generation forecast for 2009/10 with the actual and 2008 forecast demands for 2008/9. Increases in both gas and non-gas generation capacity has created a wider range of potential gas demand for power generation. In our business as usual demand forecast, coal is predicted to be base load during the winter with gas providing marginal generation. Lower electricity demands due to the recession and higher non-gas generation result in a gas forecast 3.3% lower than the forecast for 2008/9 and 9.8% lower than the actual demand in the 2008/9 winter. The development of high and low cases for power generation demand attempt to account for alternative demand patterns in the winter. For example, continued high deliveries of LNG, coupled with a warm winter and low demand for gas in other market sectors could result in a sustained period of lower wholesale gas prices and a switch to gas as base load generation.

Figure A.8 – Power Generation Winter Demand



39. Figure A.9 compares the 2009 DM forecast for 2009/10 with the actual, weather corrected and 2008 forecast demands for 2008/9. The DM forecast is broken down into the three major components of LDZ daily metered (DM) demand, NTS non power and exports to Ireland.

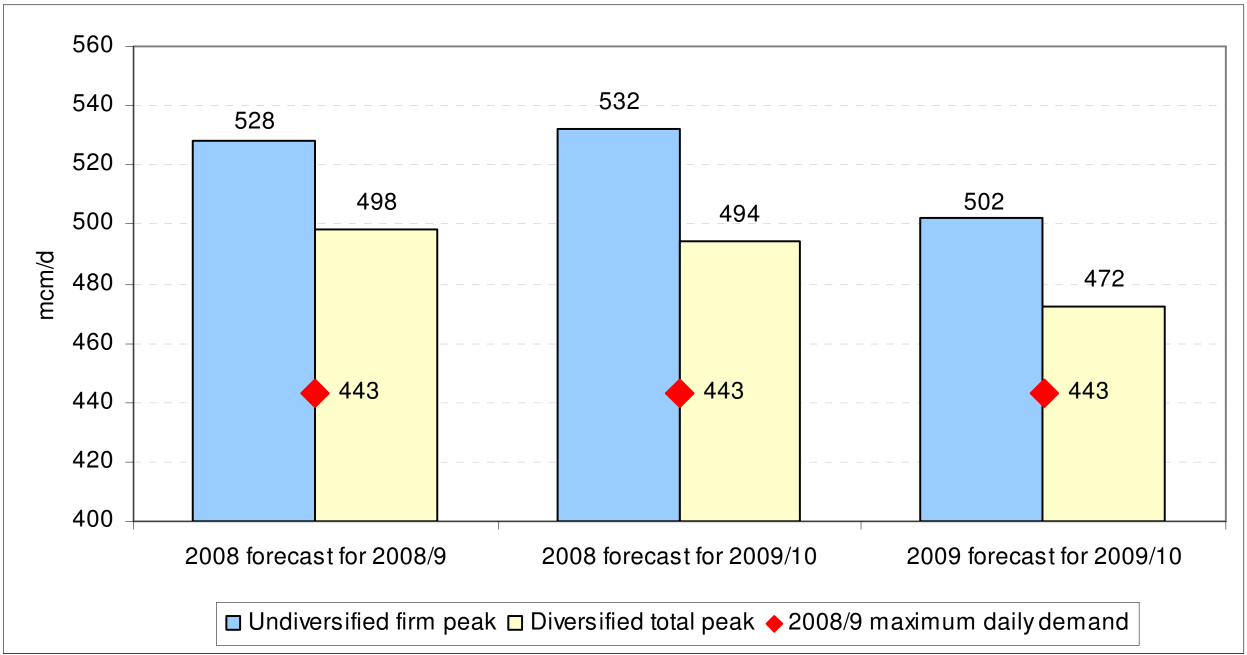
Figure A.9 – DM Winter Demand



40. The chart shows that LDZ DM demand is expected to be similar to the weather corrected demand in 2008/9. Exports to Ireland are predicted to increase due to new power station demand in Eire and a further albeit modest decrease in indigenous production. The two large NTS industrial demands that significantly reduced consumption in winter 2008/9 have returned to historical levels of demand. At current gas prices these are not expected to reduce consumption again this winter.

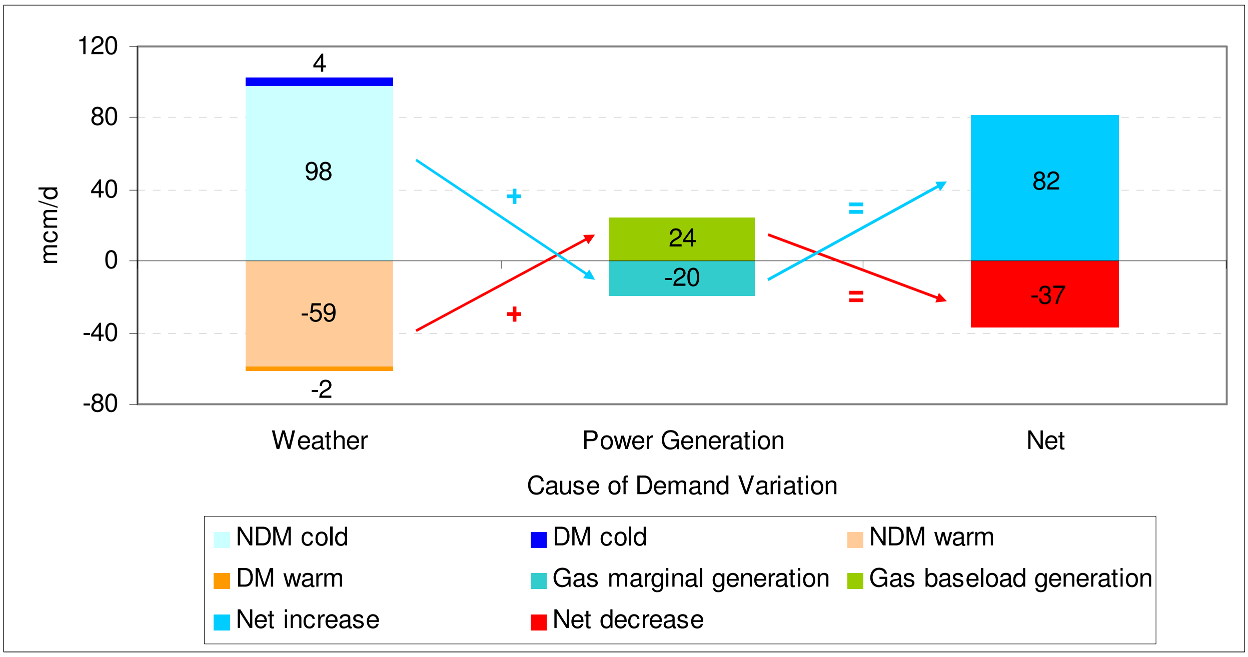
41. Figure A.10 shows that the peak day demand forecast for 2009/10 winter is 4.9% lower than 2008/9, in line with the forecast drop in total demand for the winter. The chart shows both our forecast for undiversified firm demand (used for capacity planning) and our forecast for diversified demand (used for operational planning).

Figure A.10 – Peak Demand Forecast



42. Figure A.11 shows the main causes of variation in UK daily gas demand. The biggest sensitivity is the impact of weather on NDM demands. Very cold weather relative to seasonal normal conditions could result in a demand increase of up to 100 mcm/day whilst warm weather could result in demand being as much as 60 mcm/day lower. Besides the weather, power generation gas demand may also be much higher or lower depending on the relative costs of generating using different fuels and the availability of alternative fuels. The 2009 forecasts assume that during the winter coal will be marginally cheaper than gas.

Figure A.11 – Variation in daily demand



43. The chart shows that under cold conditions the impact of higher NDM demand is forecast to be partly offset by a reduction in power generation due to the assumption that colder conditions and hence higher demands will result in an increase in the gas price. Alternatively warm conditions could result in an increase in power generation due to the assumed conditions of lower gas demand and gas prices.

44. Forward prices are currently indicating little to choose between gas and coal. If gas was to be the preferred source of generation this would lead to higher demand than in the seasonal normal forecasts. Under these conditions with very cold weather the higher NDM demand for gas is likely to lead to higher gas prices, with coal becoming the cheaper fuel. Power generation therefore mitigates the impacts of extreme weather on weather sensitive gas demand as shown in the net variation from seasonal normal forecasts.

2009/10 Gas Supply Forecast

45. The following sections examine each of the potential (non-storage) gas supply sources in turn: UKCS, assessment of European markets, imports from Norway, imports through IUK and BBL and LNG imports. These sections are followed by storage, an assessment of winter security and 2009/10 Safety Monitors and GBA.

UKCS gas supplies

46. The data in our June document provided an initial view of UKCS supplies based on our 2009 TBE forecasts and our most recent data regarding new UKCS developments.

47. Recent flow data and additional market intelligence has enabled us to reassess our forecast and form a final view of the peak UKCS supplies, shown in Table A.1 below. Our forecasts for Bacton, Burton Point and St Fergus remain the same. Our forecasts for Barrow, Easington, Teesside and have changed slightly due to our assessment of recent flows.

Table A.1 – UKCS Peak Terminal Supply Forecast

Peak (mcm/d)	2008/9		2009/10		
	Final Winter Outlook 08/9	Highest	Initial View	Final View	Changes
Bacton	66	66	65	65	
Barrow	17	18	15	16	+1
Easington	13	14	12	11	-1
Burton Point	1	4	1	1	
St Fergus[3]	78	80	70	70	
Teesside	23	30	25	24	-1
Theddlethorpe	18	21	15	16	+1
Total	**216**	**233**	**203**	**203**	
90% Planning Assumption	194		183	183	

48. As observed in 2008/9 and in previous years, it is probable that our final view of UKCS supplies may be exceeded at the individual terminal level due to daily diversity effects but our aggregated forecast is designed to account for these effects.

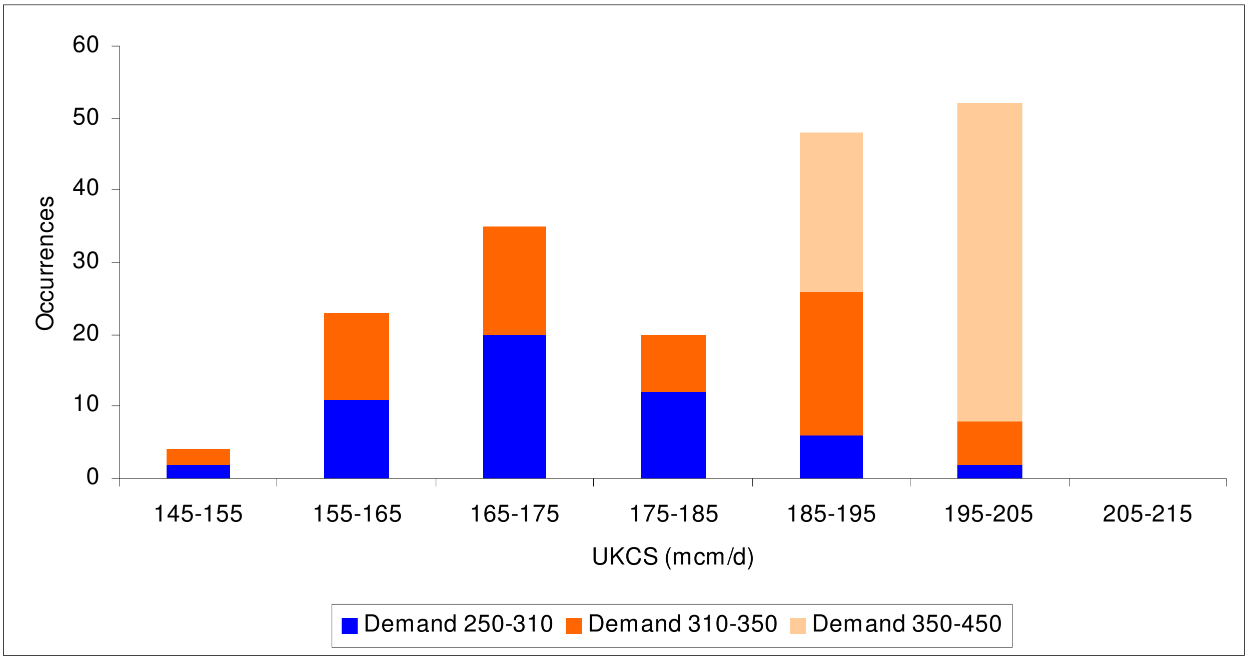
49. The net result of these changes is that our final view of UKCS supplies for Winter 2009/10 remains unchanged. Taking into account decline from existing fields and additional production from new fields, our year on year peak forecast is 6% or 13 mcm/d lower than that for 2008/9. In previous years, we have reported year-on-year decline around 10%, but in 2009/10 we anticipate more flows through Teesside due to changes in how the local gas power station sources its gas.

[3] Excludes estimates for Vesterled and Tampen

50. As in previous years it is appropriate to assume a level of UKCS supply below the maximum forecast when assessing the overall supply outlook, particularly when assessing supply-demand levels and Safety Monitor levels. The chosen level should reflect the level of delivered UKCS gas that we might expect on average during a prolonged cold spell. Last winter, we observed relatively consistent availability as detailed in the following analysis

51. Figure A.12 shows the range of UKCS flows into the UK last winter as a distribution. Data from the winter months (October – March) have been split into three ~60 day groups commensurate with the lowest demands 250-310 mcm/d, mid demands 310-350 mcm/d and higher demands 350-450mcm/d.

Figure A.12 – Distribution of UKCS flows in Winter 2008/9



52. The chart shows a high concentration of UKCS supplies between 185 and 205 mcm/d (approximately 85%-95% availability). Most of these occurrences were commensurate with higher demands. For the nine days of demand above 400 mcm/d, average flows were 201 mcm/d, this was 93% of our winter forecast of 216 mcm/d. For demands above 350 mcm/d, all flows were in the 85%-95% range.

53. Whilst we acknowledge that UKCS availability could be lower under more severe conditions, we propose to retain an assumed availability rate of 90% for high demand conditions (typically when demand exceeds 400 mcm/d). This results in a winter forecast of 183 mcm/d. Most consultation feedback from previous years has supported this approach.

54. We acknowledge that some within winter decline of UKCS supplies will occur. However, our starting position represents typical rather than maximum winter availability, also we have adopted a prudent approach for the assessment of peak and new UKCS supplies.

55. As highlighted above there is some scope for upside or downside against our final view of UKCS, for example:

- Lower offshore availability as a result of demanding weather conditions
- Increased risk of plant failure due to aging assets
- Higher than anticipated production decline due to increased annual production
- Higher or lower than anticipated production from new fields
- The development of new fields that on commencement of production have rapid decline

Europe

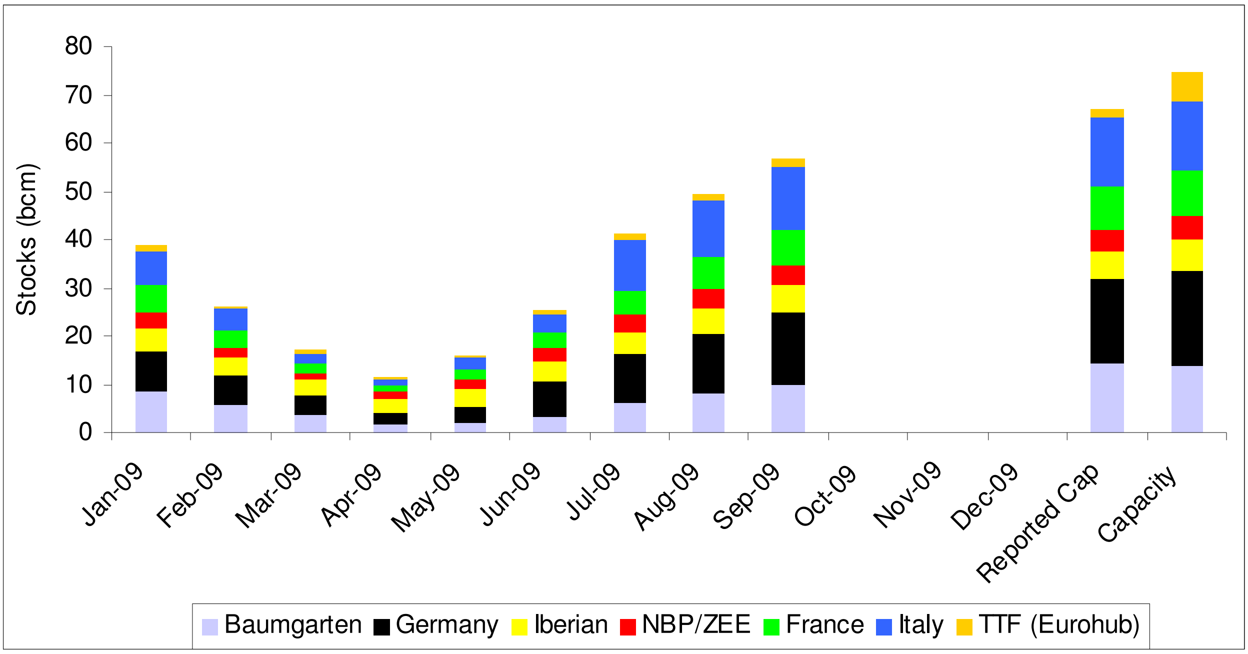
56. Despite more information now being published by European gas agencies it continues to remain difficult to provide a comprehensive overview of the European gas market, in terms of supply and demand winter analysis for both winters past and future analysis.

57. There are a number of areas where we are able to obtain complete, or near complete data, and these include Norwegian exports to the UK and Continent, LNG deliveries to Europe and Continental storage sites stocks.

58. Figure A.13 shows storage capacities and storage stock levels for storage across Europe from data extracted from the Gas Infrastructure Europe website[4]. While this does not represent all the storage sites it is now believed that over 86% of the total capacity in the region is now reported.

[4] http://transparency.gie.eu.com/ Storage stocks declared at the start of each month

Figure A.13 – European Storage Capacity and Storage Levels

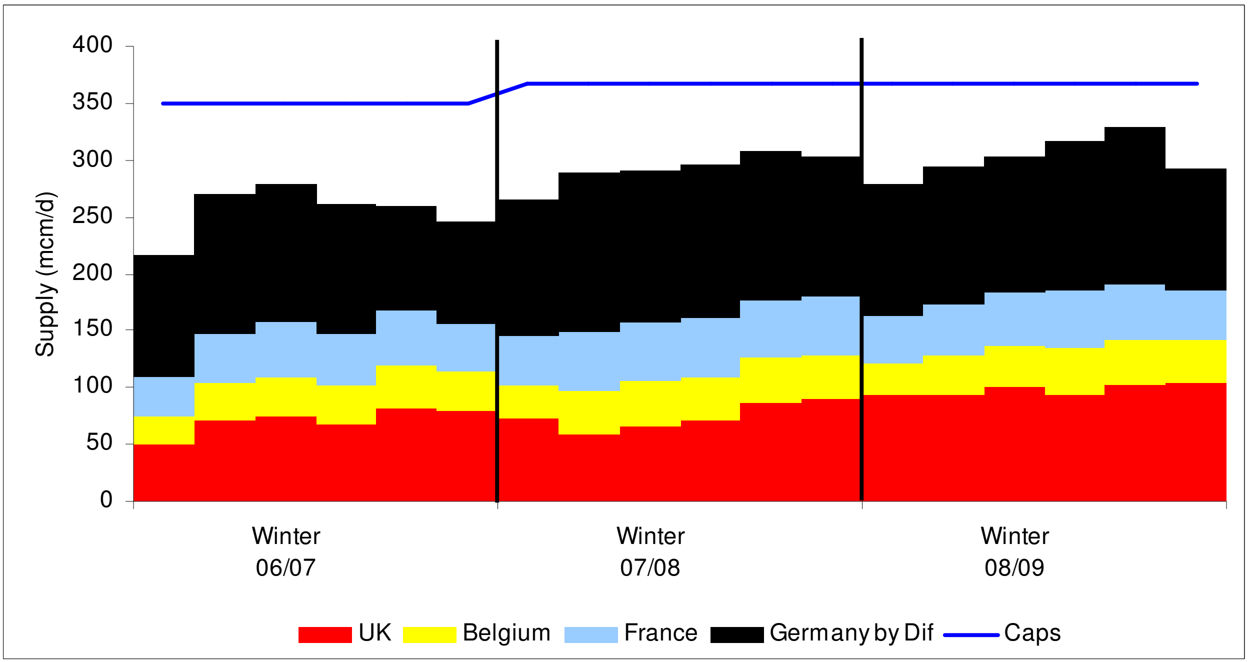


59. The figure shows reported European storage capacity and reported storage stock levels by 3 specific countries and 4 aggregated areas. Current reported stock levels are over 84% full and expected to be near completely filled for the start of the winter. It should be noted that as the number of sites reporting increased significantly over the year it is not possible for a direct comparison to last year.

Norway

60. Figure A.14 shows an estimate of average Norwegian monthly exports to Europe during the previous 3 winters (Oct-Mar), the data is based on the available daily flow information for Norwegian imports to France, Belgium and UK, monthly production data from the Norwegian Petroleum Directorate (NPD) with Norwegian imports to Germany determined by difference.

Figure A.14 – Estimate of Norwegian Exports by Destination



61. The chart shows further increases in Norwegian production with the UK receiving higher winter imports compared to the previous two years. The two key drivers behind this were decreased demand on the Continent leading to turn downs of contracted volumes and increased Norwegian production, notably from the Ormen Lange field.

62. In contrast to previous years, the flows to Germany increased over the winter in 2008/9, the main driver for this is likely the oil-indexed contract price which fell from January onwards. Though not shown, Norwegian exports to Germany actually peaked in July 2009, this was coincidental with our view of the lowest contracted price.

63. Table A.2 highlights winter volumes and load factors of gas delivered from Norway to Europe for the past two winters. The table highlights that despite increased production, deliveries to continental Europe fell, with the UK importing over 4 bcm more. For winter 2009/10 there remains scope for more gas to be delivered to Continental markets at the expense of the UK.

Table A.2 – Norwegian exports and load factors to European markets

Country	Winter 07/8 (bcm)	Winter 08/9 (bcm)	Annual Capacity (bcm)	Winter 07/8 Load Factor	Winter 08/9 Load Factor
Belgium	6.8	6.6	15	91%	89%
France	9.1	8.4	19	96%	89%
Germany	23.9	22.2	55	86%	81%
UK	13.6	17.8	45	60%	79%
Total	**53.4**	**55**	**134**	**80%**	**82%**
Daily Average (mcm/d)	292	302			
Monthly Range (mcm/d)	266-310	279-330			

64. For winter 2009/10 our assumptions for Norwegian production include:

- A slight decline across many of the currently producing fields, similar to the 2% observed last year
- Higher availability from Kvitebjørn
- Troll to produce at similar levels to last year
- Ormen Lange to continue to ramp up throughout the winter towards 65-70 mcm/d
- The start up of numerous smaller fields

65. In aggregate, our forecast for Norwegian production for winter 2009/10 is 58.1 bcm or a winter average of 319 mcm/d. This compares with 55 bcm last winter.

66. Using our model of the Norwegian offshore system along with our field production forecasts and the experience of previous winters we have developed a Base Case and range of flows to the Continent with flows to the UK determined by difference. This approach of assuming that the UK is the marginal destination for Norwegian exports was broadly supported by the feedback we received through the consultation process.

67. Figure A.15 and Table A.3 show our Norwegian forecast. Our Base Case has flows to the Continent increasing from last winter to levels similar to those seen in 2007/8. For the UK we forecast an average flow of 100 mcm/d, this is a slight increase from the average flow experienced last winter of 98 mcm/d but lower than the June forecast of 105 mcm/d. This small reduction reflects both operational experience this summer where the UK has received increased volumes of LNG imports and feedback through the consultation process.

Figure A.15 - Forecast Norwegian Exports by destination

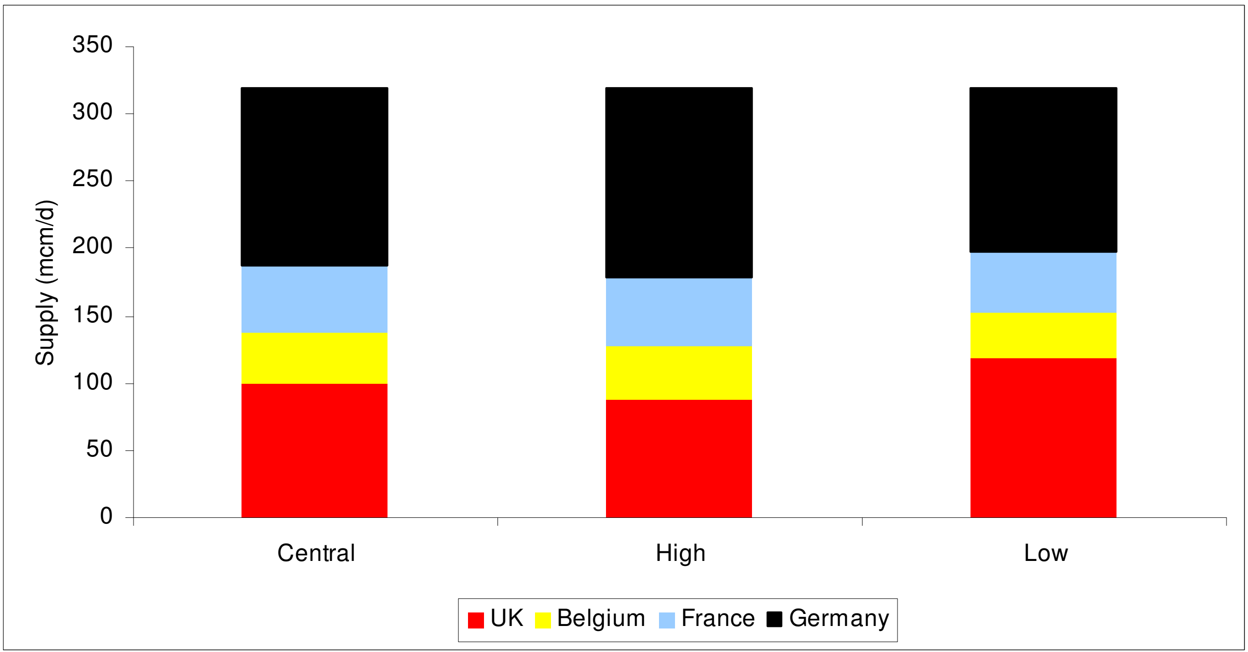
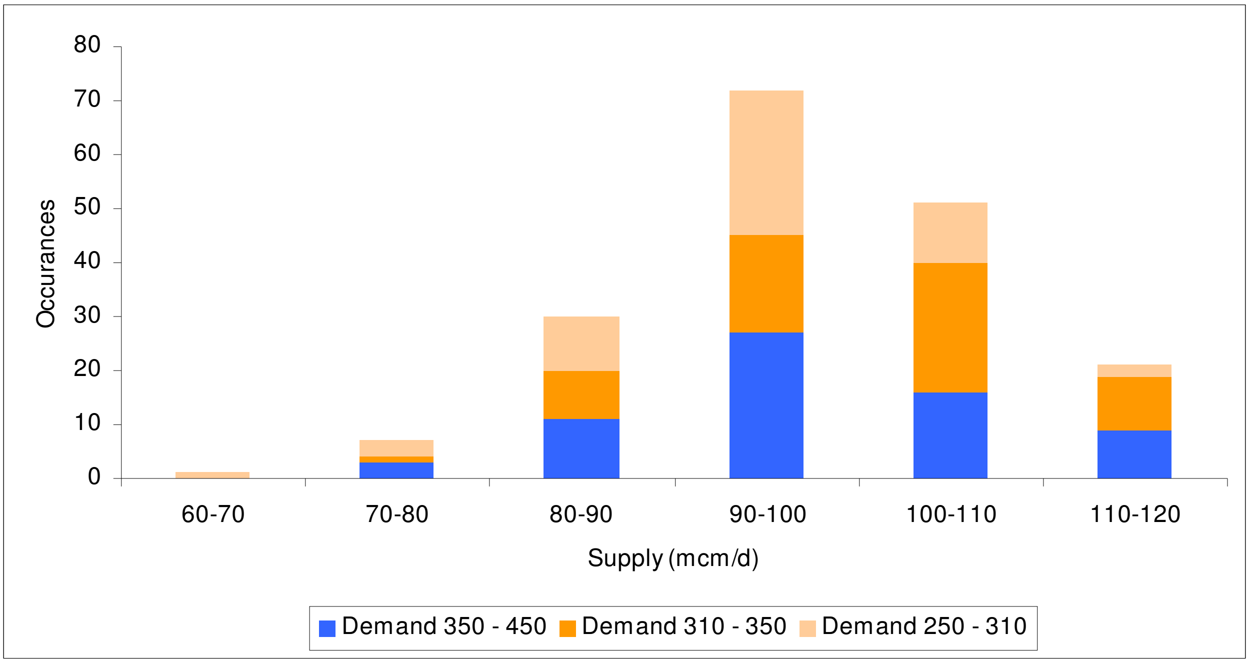


Table A.3 – Norwegian Forecast for Winter 2009/10

(mcm/d)	Winter 2008/9	Central	High	Low	Capacity
Belgium	37	38	39	35	41
France	47	50	52	45	52
Germany	121	131	140	121	151
UK	98	100	88	118	123
Total	**302**	**319**	**319**	**319**	**367**

68. The table shows the Base Case and high / low range for Norwegian exports, these represent average flows and do not capture the anticipated variations in flows. These are expected to be even greater than the high / low range as highlighted in Figure A.16 which shows the range of Norwegian flows to the UK last winter expressed as a distribution. To make an assessment relative to demand, the daily flows from the 6 months of data are split into three equal (~60 day) groups commensurate with the lowest demands 250-310 mcm/d, mid demands 310-350 mcm/d and high demands 350-450 mcm/d.

Figure A. 16 – Distribution of Norwegian flows to UK in winter 2008/9



69. The chart shows a range (68-114 mcm/d) of flows from Norway to the UK across the 6 month winter period. The range of flows were similar across all demands as were the average flows which were 95 mcm/d at lower demands, 100 mcm/d in the mid range and 97 mcm/d at higher demands.

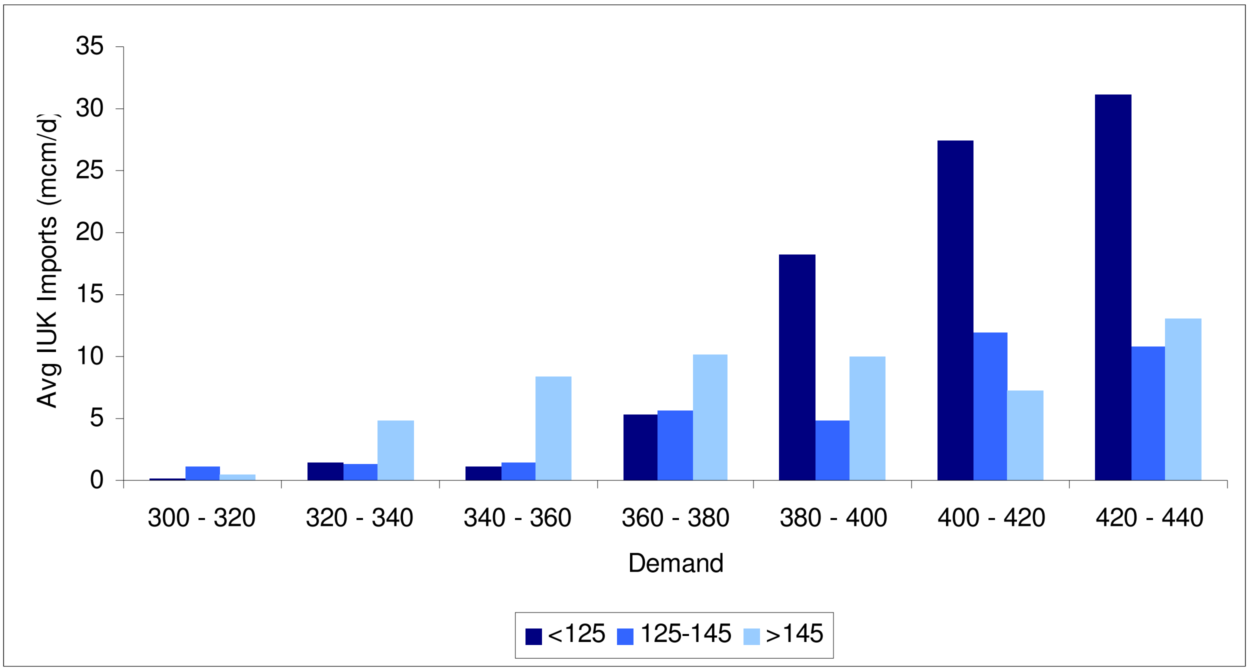
70. While increased Norwegian production may reduce the range of flows we would expect over the winter, there remain numerous factors including Continental supplies / demand (hence weather), storage stock levels, contractual flexibility / commitments and Norwegian offshore production that could result in a greater variation than seen last winter. So while we are forecasting a range (88 -118 mcm/d) for average Norwegian flows to the UK, we are also highlighting the expectation of greater ranges of Norwegian flows on a day to day basis.

IUK

71. Figure A.17 shows IUK imports for winter's 2006/7 to 2008/9 at differing levels of all other imports (Norway, BBL & LNG). This relatively recent time period was chosen to reflect the increased availability of import infrastructure. The chart shows IUK flows (y-axis) against demand (x-axis) in the context of low [5] levels of other imports (less than 125 mcm/d), mid levels of other imports (125-145 mcm/d) and high levels of other imports (greater than 145 mcm/d).

[5] There are about 150 data points in the 'low' and 'mid ' categories and about 100 in the 'high'

Figure A.17 – IUK Import Flows 2006/7 – 2008/9

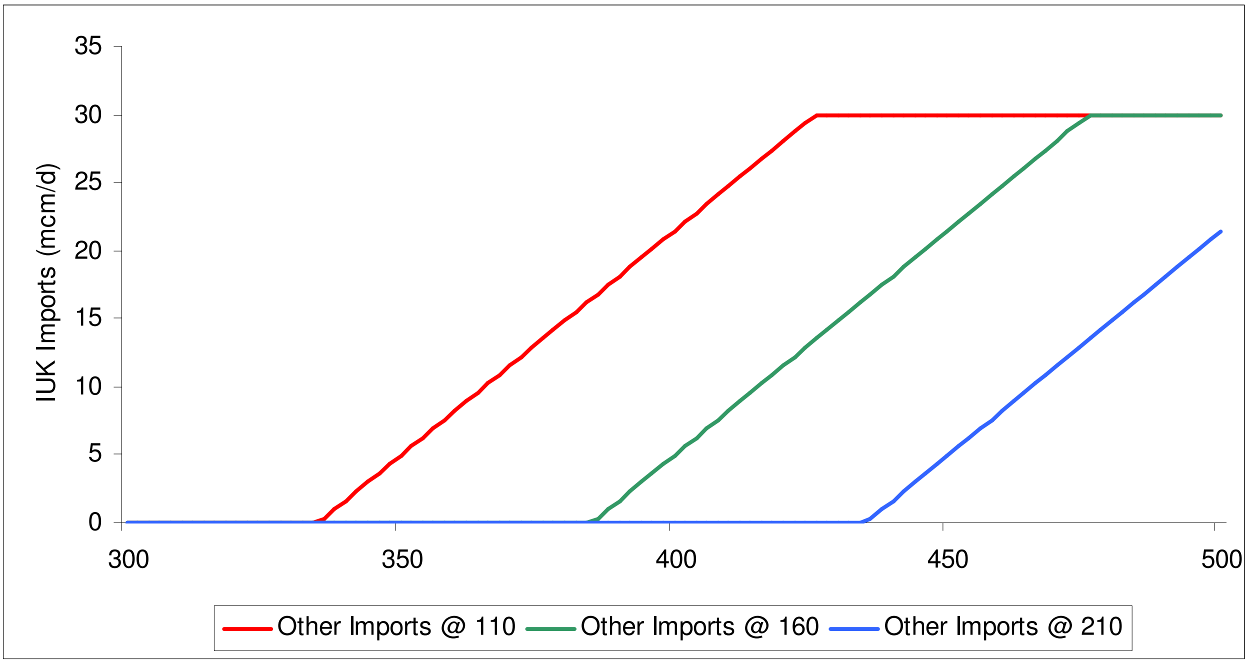


72. The chart clearly shows a general increase in IUK imports as demand increases, however the magnitude of the increase is dependant on other sources of imported gas. Indeed, for mid and high levels of other imports, the average flow of IUK imports at demands in excess of 400 mcm/d is only about 10 mcm/d.

73. For winter 2009/10, we again assume that IUK will respond to UK / Continental price differentials and operate as a marginal source of supply similar to storage when UKCS and other imports have not met demand. Hence if other imports are relatively low we would expect higher UK gas prices and the possibility of modest IUK imports, conversely if the UK is well supplied with other imports (notably LNG and Norway) we would expect lower UK prices and the prospects of IUK at float or exporting unless UK demand was relatively high.

74. Figure A.18 shows our forecast for IUK imports based on 183 mcm/d UKCS, 42 mcm/d of storage and a range of other import flows based around our Base Case of 160 mcm/d (100 mcm/d Norway, 40 mcm/d LNG and 20 mcm/d BBL) with a range of +/- 50 mcm/d. The chart shows that for low levels of other imports, IUK could commence importing at demands as low as 340 mcm/d, whilst for a well supplied UK not until demands were as high as 440 mcm/d. The relatively high threshold for IUK imports in a well supplied UK market highlights that IUK could again be at float or predominately in export mode in winter 2009/10.

Figure A.18 – IUK Import flows



75. Our assumptions for IUK imports for winter 2009/10 assumes an upper flow of just 30 mcm/d, though we acknowledge this could potentially be much higher. In addition, we believe that it remains prudent to consider lower IUK supply availability through to January due to uncertainties over the release of Continental storage that may be held back for Continental markets.

76. Table A.4 shows the make-up of supplies for the 20 days of highest demand for winters 2005/6 to 2008/9. These 20 days of highest demand were selected as this relates to average demands of approximately 400 mcm/d, which is commensurate with cold rather than very cold conditions.

Table A.4 – Supply make-up for highest 20 demand days, Winters 2005/6 – 2008/9

(mcm/d)	2005/6	2006/7	2007/8	2008/9
UKCS	265	208	211	198
Norway	29	84	84	97
BBL		24	36	29
LNG	12	12	3	18
Total NSS[6] (excl IUK)	**305**	**329**	**335**	**341**
IUK	35	18	12	3
Total NSS	**341**	**347**	**347**	**344**
Storage	45	46	54	63
Supply = Demand	**386**	**392**	**401**	**407**

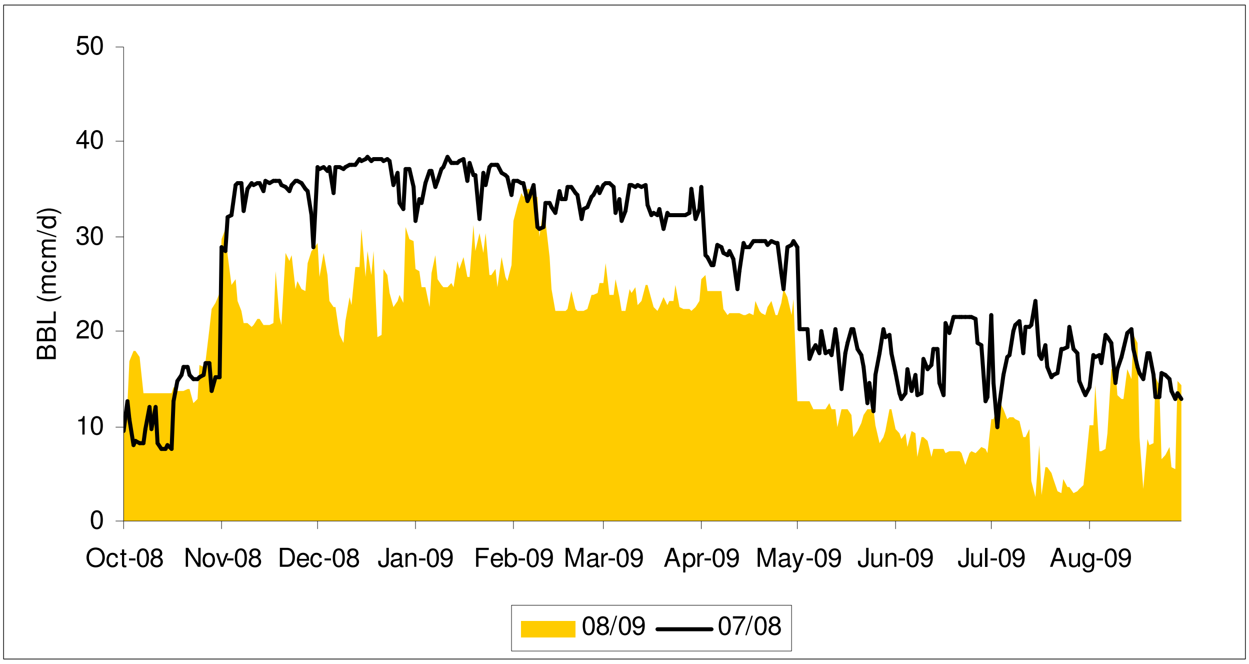
[6] NSS = Non Storage Supply

77. The table shows comparable demands for the four winters analysed though the trend in demands is upwards. The decline in UKCS has been more than offset by higher imports, notably from Norway. The table also reinforces the previous view that IUK is more responsive to the overall supply / demand balance, hence the relatively stable level of non storage supply including IUK imports. The relatively high flows of storage (notably last winter) highlight the key role storage plays in meeting high levels of demand.

BBL

78. For winter 2009/10 there remains the possibility that new commercial arrangements may be in place for interruptible non physical reverse flow (i.e. non-physical exports). Even if these arrangements are not in place we believe it is prudent to assume that BBL flows will continue to be more sensitive to the UK and possibly Continental market needs as highlighted in Figure A.19.

Figure A.19 BBL Import flows



79. The above chart shows that BBL flows over the last year have been lower than those in 2007/8, hence like IUK, BBL has possibly responded to increased availability of other imports notably Norway and LNG. In addition, BBL flows last year showed greater variation than seen previously, again possibly a sign of increased commercial behaviour. For winter 2009/10 we have revised our forecast down from the June level of 25 mcm/d to 20 mcm/d. Though we acknowledge the potential for much higher flows should the market conditions here and on the Continent allow.

80. In terms of physical operation for BBL, our understanding is that all three compressors will be available in the relatively near future.

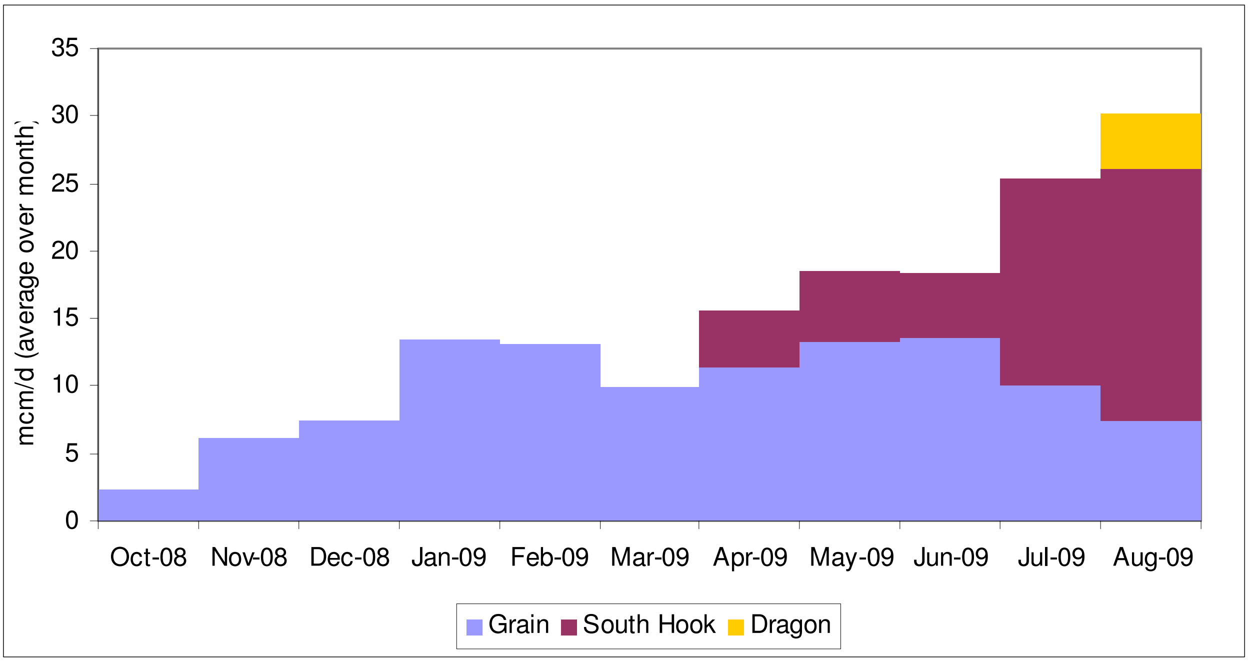
LNG Imports

81. During the summer months the NTS received its first LNG cargoes from Milford Haven. Initially from South Hook in April and then from Dragon in August. Whilst Dragon declared commercial operations from September, South Hook is still under going commissioning and has not yet declared the commencement of commercial operations.

82. The combination of greater availability of LNG through new liquefaction production, reduced global demand, together with the start up of two new UK terminals has seen the highest ever levels of LNG imports to the UK this summer.

83. LNG imports for gas year 2008/9 are likely to be around 6 bcm. Flows averaged about 10 mcm/d for the winter period and over 20 mcm/d for the summer period (Apr to end August). Figure A.20 shows monthly LNG imports through the UK's three LNG terminals.

Figure A.20 LNG Import Flows



84. The three largest world consumers (Japan, South Korea and Spain) have seen a year on year reduction in LNG imports of between 7% and 11% in the first half of 2009 in comparison with 2008. This is equivalent to a reduction in LNG deliveries of about 9 bcm.

85. France the second biggest European importer after Spain has seen a 4% increase in imports for the first half of 2008. The US which saw a fall in imports in 2008 compared to 2007 (falling from 22 bcm to 10 bcm), has seen increased import levels in 2009 with 8 bcm imported in the first half of the year. The 2008 import figure for the US however was the lowest value since 2002.

86. For winter 2009/10 as shown in Figure A.5, US forward gas prices are about 2-3 p/therm lower than prices in the UK and Continent. When additional shipping costs are factored in this provides limited incentives to send US bound cargoes to the UK and possibly Zeebrugge rather than the US. However, the prices still favour the UK over US for LNG produced in both North Africa and the Middle East. In terms of Far East markets, whilst some recovery in demand is expected, there is unlikely to be additional contracting of LNG as seen in previous winters

87. For winter 2009/10 there will be three operational LNG terminals in the UK; Grain (Phase 1 & 2), South Hook Phase 1 and Dragon Phase 1 as well as the possibility of LNG ship to shore transfers through Teesside GasPort. The reported base load capacity of the three terminals is approximately 83 mcm/d and could reach 112 mcm/d should South Hook Phase 2 be completed by the end of the winter.

88. With Grain and both Milford Haven LNG facilities now in commercial operation (or very nearly there) the uncertainties associated with LNG imports are now flow related rather than due to operational availability. Our preliminary forecast for average flows of LNG imports in June had a Base Case of 30 mcm/d within a range of 10-60 mcm/d. Since then, the Milford Haven facilities have both become operational and flowed on occasion up to 20% of total UK demand despite relatively low gas prices of about 20 p/therm. Consequently we have increased our Base Case view of LNG imports for winter 2009/10 from 30 to 40 mcm/d. Whilst we continue to assume that the average flow will be within a range of 10-60 mcm/d, as with other import sources where capacity far exceeds our view of supplies there remains the possibility of higher average flows and much higher day to day variations. The increase in our LNG import forecast also reflects feedback we have received during consultation.

Final View of Non-Storage Supplies

89. In the Winter Consultation report published in June, we provided a range of non storage supplies for winter 2009/10 and a Base Case. As detailed previously we received industry feedback to suggest the possibility of higher LNG flows. Our analysis supports this as does further inspection that suggests other imports may be sensitive to other increases in non storage supply. Hence whilst we have increased our view of LNG imports we have reduced our forecasts for imports through BBL and Norway.

90. Table A.5 shows our resultant ranges for non storage supply for winter 2009/10 and our revised Base Case. This level of non storage supply will be used for the initial setting of the Safety Monitors and GBA trigger level.

Table A.5 - Non-Storage Supplies for Winter 2009/10

(mcm/d)	Consultation Range	Consultation Base Case	Low Range	Base Case	High Range
UKCS	183	183	183	183	183
Norway	88 – 118	105	88	100	118
BBL	25	25	20	20	20
IUK	30 – 0	0	30	0[7]	0
LNG	10 – 60	30	10	40	60
Total	**336 – 386**	**343**	**331**	**343**	**381**

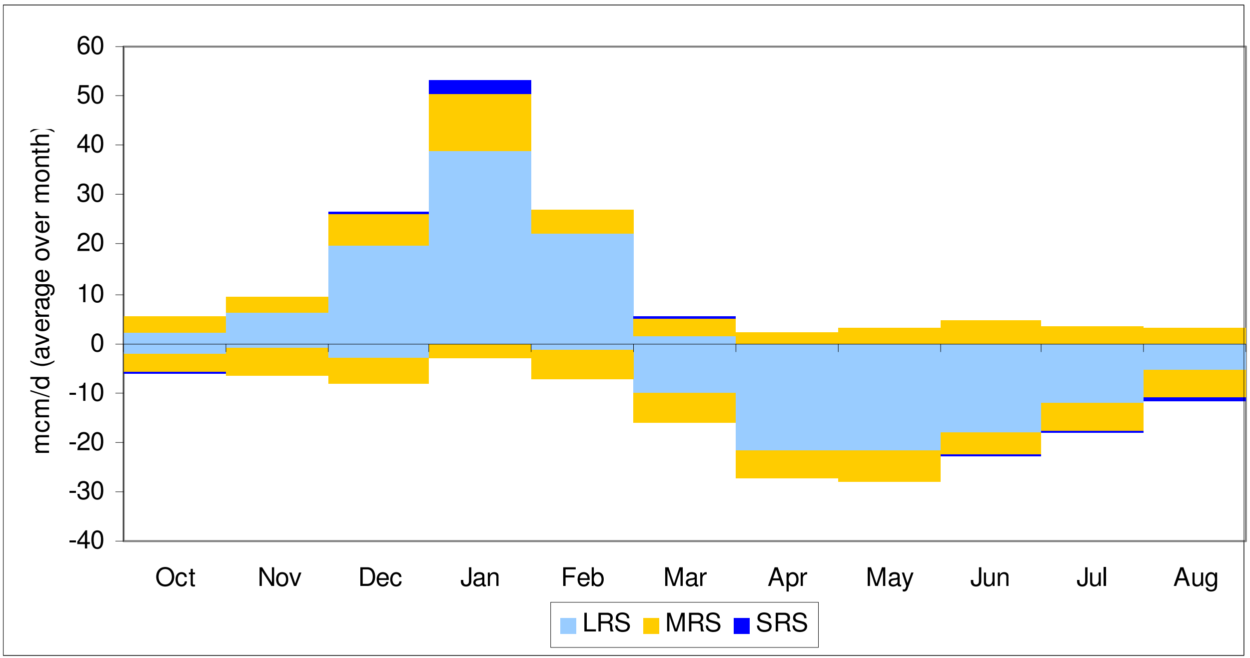
91. Note, IUK is assumed to increase as a consequence of tighter supply conditions (i.e. reacting to an increase in UK gas price). Hence the low case has higher IUK imports than the high case. For our Base Case we only assume IUK imports when demand approaches 390 mcm/d, for conditions where the level of NSS is lower we assume higher IUK imports commencing at lower levels of demand on the basis that IUK flows are price dependent and for tighter supply conditions prices should be higher.
92. BBL though shown as 20 mcm/d for low and high ranges may also respond to flow higher for tighter supply conditions (i.e. reacting to an increase in UK gas price).

Storage

93. Figure A.21 shows the storage injection / withdrawal for all storage sites for gas year 2008/9 broken down in terms of storage facility type. The highest monthly withdrawals were in January where flows averaged 53 mcm/d, the highest daily withdrawal was 95 mcm/d on 7th January 2009. The highest monthly injections were in May where flows averaged 28 mcm/d, the highest daily injection was 42 mcm/d on 12th April 2009.

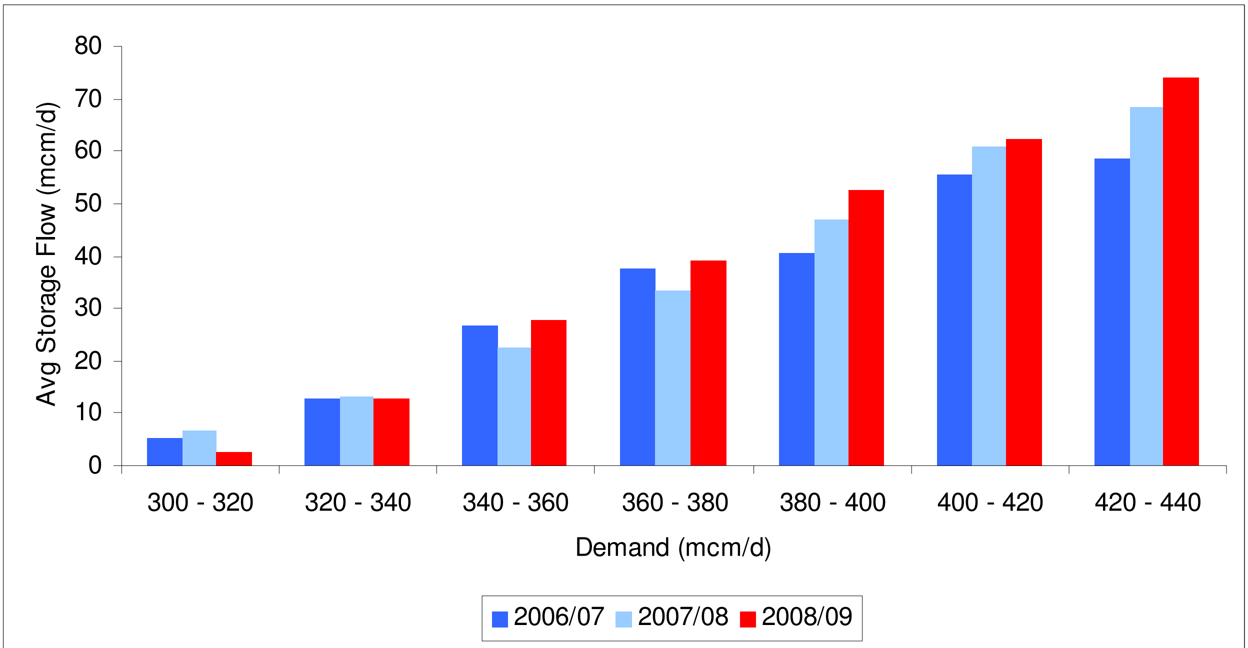
[7] IUK shown as zero but assumed to import as demands exceed 385 mcm/d

Figure A.21 Storage flows



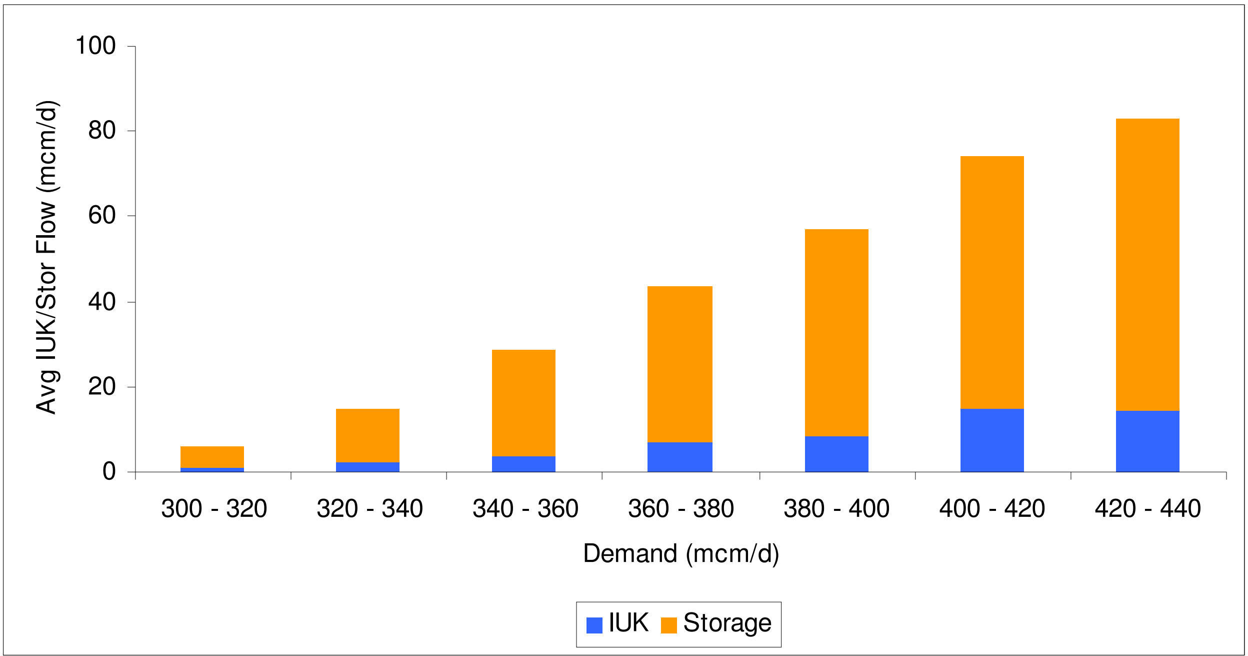
94. Figure A.22 shows average storage flows for the last three winters (2006/7 to 2008/9) expressed in terms of demand increments of 20 mcm/d. The chart clearly shows the increasing use of storage for higher demands with storage use commencing when demands exceed about 300 mcm/d.

Figure A.22 - Average storage flows 2006/7 – 2008/9



95. Figure A.23 shows the relationship between storage use and IUK imports for demands above 300 mcm/d. The bars represent the average flows of storage and IUK imports for winters 2006/7 to 2008/9 as shown in Figures A.22 and A.17. The chart shows aggregated storage volumes at about 4 times higher than IUK imports. IUK imports also appear to be less responsive to increased demand when demand exceeds 400 mcm/d. The average level of IUK imports for demand above 400 mcm/d at 14 mcm/d is broadly consistent with our central view for IUK for winter 2009/10.

Figure A.23 - Average IUK and Storage flows 2006/7 – 2008/9



96. National Grid LNG Storage undertook a business review during 2008/9, this resulted in the decision to reduce capacity at Partington from 4 LNG tanks down to 2 tanks and the closure of the Dynevor Arms LNG facility.

97. The Aldbrough storage facility will be operationally available for winter 2009/10, although the site is not yet fully completed, to the end of August the facility has delivered a maximum daily flow of 4.4 mcm/d into the NTS although higher flows have been delivered for shorter time periods.

98. Table A.6 shows our assumed levels of storage space and deliverability for winter 2009/10, this includes some flows from Aldbrough and the reductions arising from lower LNG storage levels.

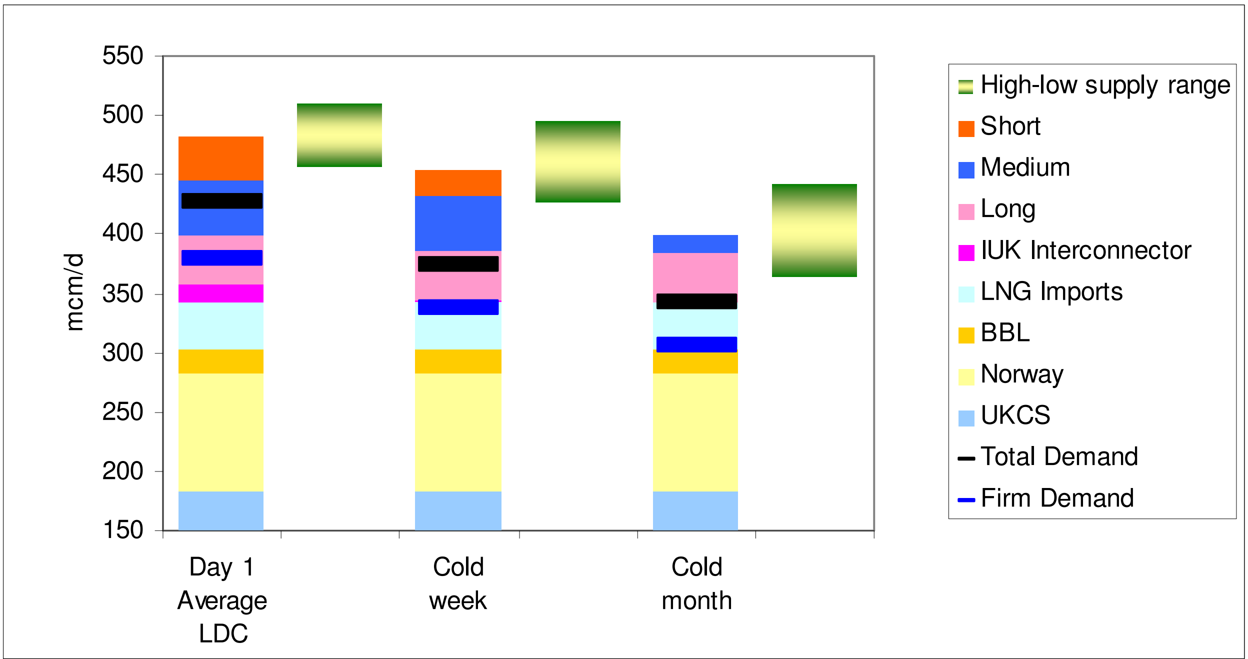
Table A.6 – Assumed 2009/10 storage capacities and deliverability levels

	Space (GWh)	Deliverability (GWh/d)	Deliverability (mcm/d)	Days at full rate
Short (LNG)	1970	390	36	5
Medium (MRS)	10086	515	47	20[8]
Long (Rough)	38750	455	41	85
Total	**50806**	**1360**	**124**	**n/a**

Winter Security Assessment

99. Figure A.24 shows our traditional cold spell analysis for average demand conditions, with total and firm demand for the coldest day of an average winter, a cold week within an average winter and a cold month within an average winter. The temperatures associated with these conditions are typically -2℃ for the cold day, 1℃ for the cold week and 3℃ for the cold month. The levels of demand are matched to our base case view of supplies. Also shown on the chart is the high-low supply range from Table A.5.

Figure A.24 – Cold spell analysis for 2009/10, for average conditions



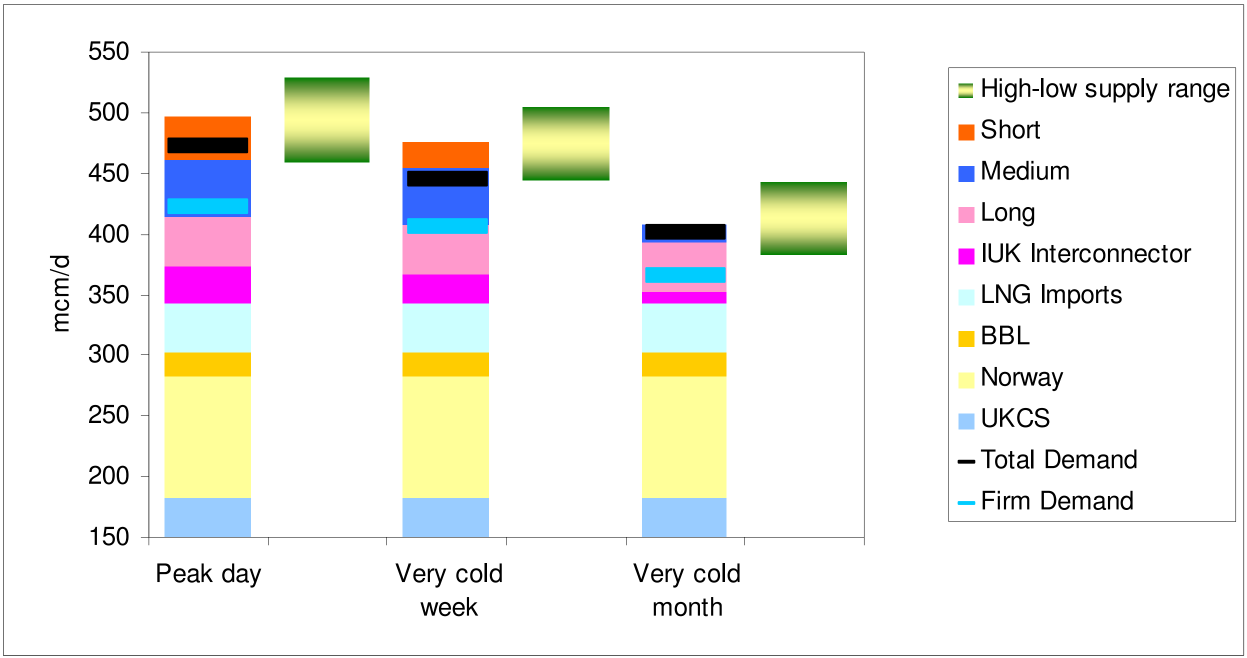
100. The analysis shows that for average conditions, with no unforeseen supply losses, sufficient supplies should be available to meet all demand for a cold day, a cold week and a cold month. Indeed our Base Case supply assumptions suggest that

the position is improved from winter 2008/9. This is due to a combination of factors, primarily a material reduction in our demand forecasts due to the economic recession, but also an increase in our Base Case non storage supply assumptions.

101. It should be noted that the average demand conditions reported in the above analysis are based on our 17 year data set of weather. This data set represents a warmer set of conditions compared to our 80 year data set. Even so, most recent winters have been even warmer than this.

102. Figure A.25 shows our cold spell analysis for severe9 demand conditions, with total and firm demand for the peak day[10] (1 in 20), a very cold week within a severe winter and a very cold month within a severe winter. The temperatures associated with these conditions are typically -5℃ for the peak day, -3℃ for the cold week and -1℃ for the cold month. The levels of demand are matched to our Base Case view of supplies. Also shown on the chart is the high-low supply range from Table A.5.

Figure A.25 - Cold spell analysis for 2009/10, for severe conditions



103. The analysis shows that for severe conditions, with no unforeseen supply losses, sufficient supplies could (subject to storage availability) be available to meet all demand for a peak day, a very cold week and a very cold month. For a peak day and a very cold week there is very high reliance on storage whilst a very cold month would require sustained flows from non storage supplies and available storage.

[9] Severe conditions are based on 1 in 50 demand conditions. For security analysis we use diversified demands

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

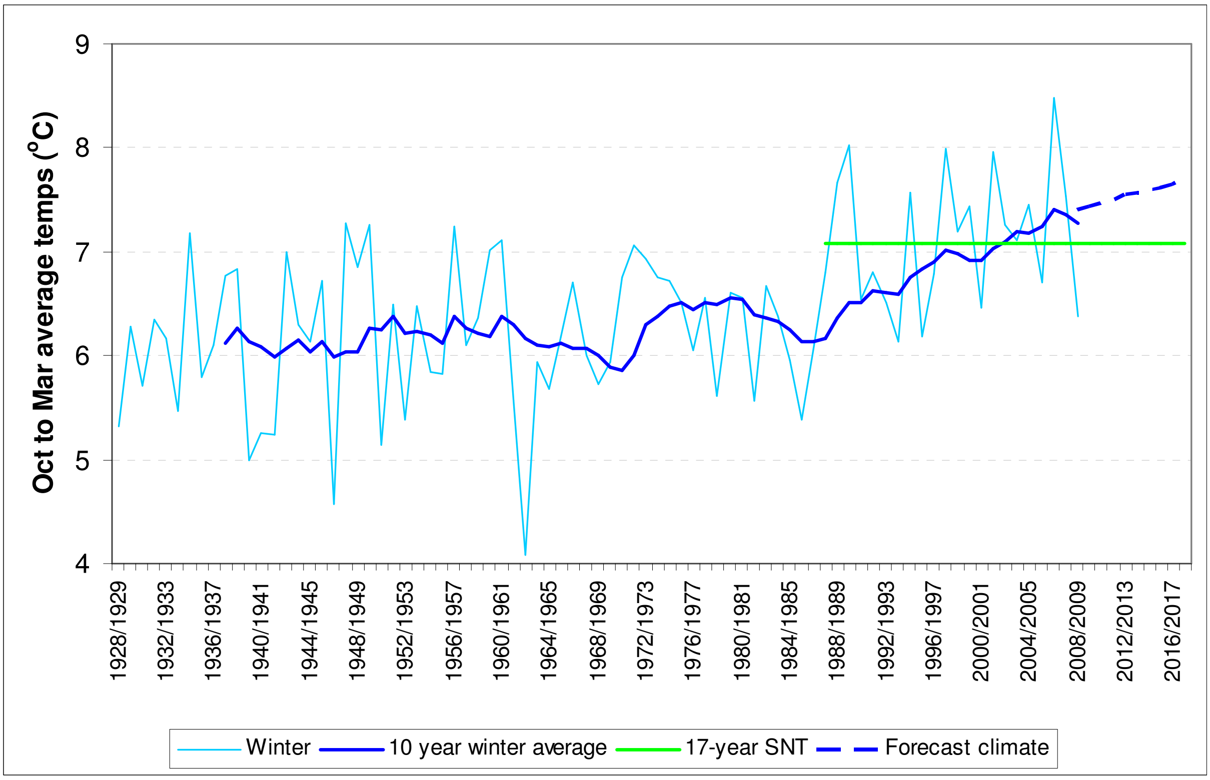
104. The analysis illustrates for our Base Case view of supplies, for a 1 in 20 peak day with average temperatures across the country around -5 ºC, there is sufficient supply availability to meet firm and interruptible demand. For the lower supply availability as denoted in the high-low supply range or if storage was depleted, there is the possibility that not all demand could be met, and hence a demand response would be required. Any interruption would be expected to be from shippers rather than National Grid as we would only interrupt for capacity purposes. For most circumstances there should be no requirement for any firm demand response

105. For our Base Case view of supplies for a very cold week and very cold month analyses, all demand could be met with our Base Case supply assumptions, although the very cold month shows a tighter supply / demand position. If supplies were closer to the lower end of our high-low supply range or if storage was depleted, there would be a requirement for a demand side response, albeit no firm demand response for most circumstances. For higher supply availability as denoted in the high-low supply range there is the possibility to meet all demand.

106. With the recent trend of warmer winters there is the possibility that our 1 in 50 basis for severe conditions based on the last 80 years of weather data is now less relevant than for previous security analyses. We have been working with the Met Office and other energy companies to explore this. Currently we are not in a position to use new measures for winter severity, however as shown in the following chart there are growing reasons to consider alternative measures.

107. Figure A.26 shows average October – March temperatures for the past 81 years. The chart also shows a forecast based on a 30 year moving average.

Figure A.26 – Average Winter temperatures from 1928/9 to 2008/9



108. The chart clearly shows the trend of warmer winters since the mid 1980s. Historically a 2℃ variation from the average temperature could create 1 in 50 type conditions. Based on the average temperature of recent winters, the reduction in temperature now required to create 1 in 50 type conditions is a reduction of about 3.5℃.

109. As the 1 in 50 basis for severe conditions may be less appropriate for our security analyses, we have developed an alternative approach. This approach has a number of key elements:

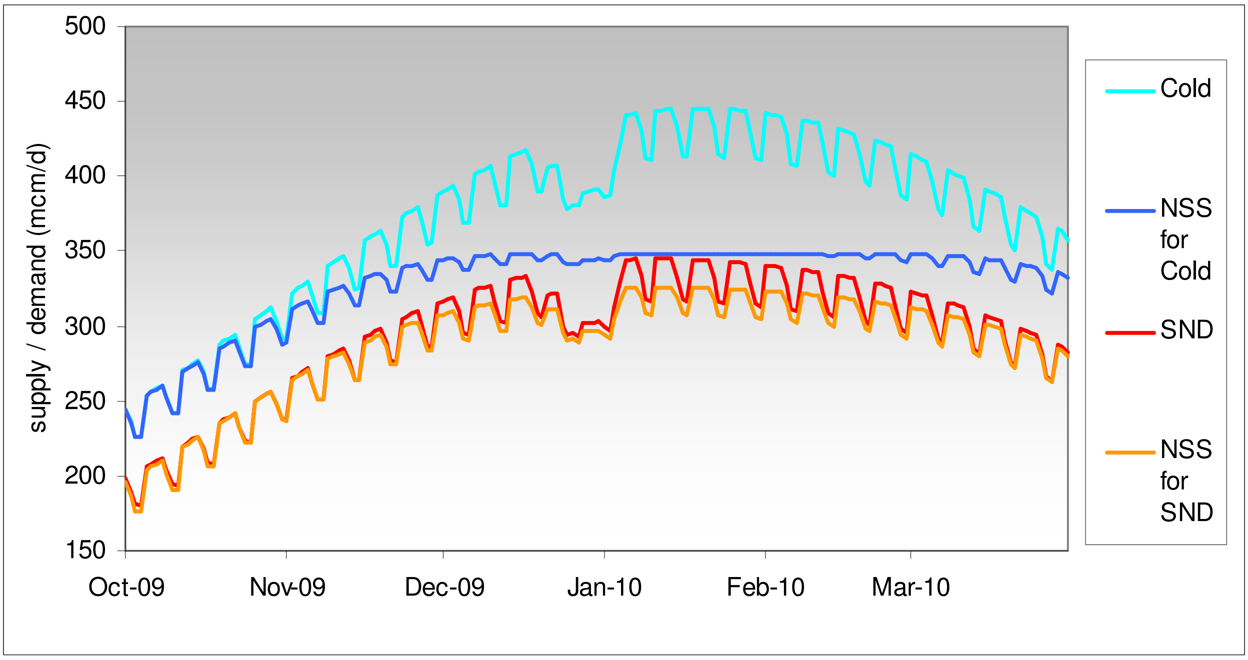
- Use of the seasonal normal demand (SND) curve, with the addition of a period of cold weather, representative of an observed cold spell that has been seen within the last 25 years. This enables a date-based approach
- Use of variable rather than a linear assumption for non-storage supply, to give a more realistic view of a winter-long supply demand match

110. This approach does not produce a security analysis based upon a long, sustained cold winter, rather one based upon a relatively average winter that includes a period of colder weather, a scenario that may provide a more representative basis for security analysis. This is not to say 1 in 50 conditions could not be experienced, but they do represent a very low probability event.

111. Most security type analyses tend to use a uniform single value for either each non storage supply (NSS) component or aggregated NSS. In reality, supplies will vary, and are likely to increase as demands rise. By analysing historic supply and demand data, it is possible to calculate, for any given level of demand, an expected

level of each NSS component or an aggregated level of NSS. This relationship is shown in Figure A.27 for our Base Case supply assumptions for winter 2009/10 against SND and cold[11] conditions.

Figure A.27 – Base Case supply assumptions for SND and Cold conditions

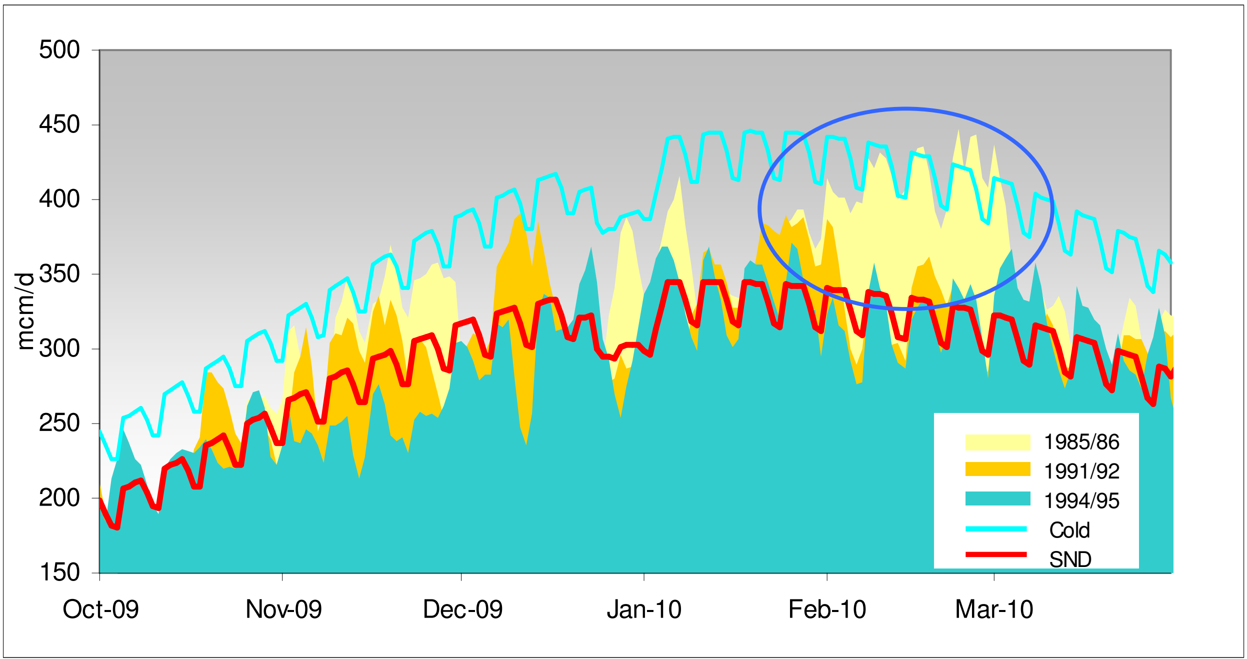


112. The chart shows that the level of NSS increases with increasing demand. For seasonal normal demand, NSS levels peak at roughly 325 mcm/d, whereas for cold conditions NSS reaches nearly 350 mcm/d. In reality there is a range of about +/- 10 mcm/d for 90% of the time around the Base Case level of supply. All demand above the level of NSS must be met by either storage or a demand response.

113. The SND curve shows a maximum demand of roughly 350 mcm/d, which is not reflective of the highest levels of demand that are likely to be seen within either an average or colder winter. The SND curve does not reflect the wide range of variation in demand that is possible across the winter. This is illustrated in Figure A.28 for three winters.

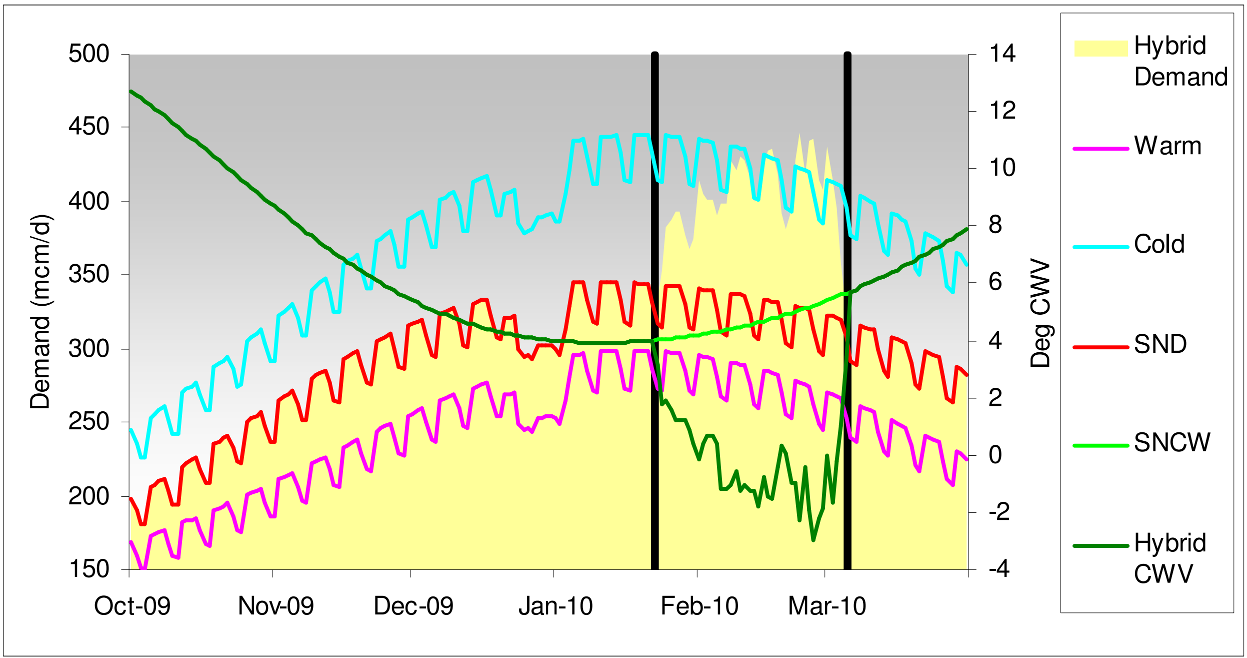
[11] Cold conditions are shown as a moving 7 day profile (smoothed) of 1 in 20 conditions. (Note the 1 in 20 peak day would be higher than 'cold' as it represents a winter peak day rather than a weekly assessment)

Figure A.28 – 2009/10 Seasonal Normal Demand, 1985/86, 1991/92, 1994/95



114. The chart shows the SND and Cold curve and the levels of demand that would be experienced if we saw a repeat of the weather patterns of three relatively recent winters. Not surprisingly, the winter profiles show significant variation. 1985/86 shows a sustained period of high demands throughout February. 1985/86 is the most recent winter that shows such a sustained period of high demands brought about by cold weather. Hence one potential scenario for winter 2009/10 is demands at seasonal normal levels except for a period of high demands as seen in February for winter 1985/86. Figure A.29 shows such a "hybrid" winter.

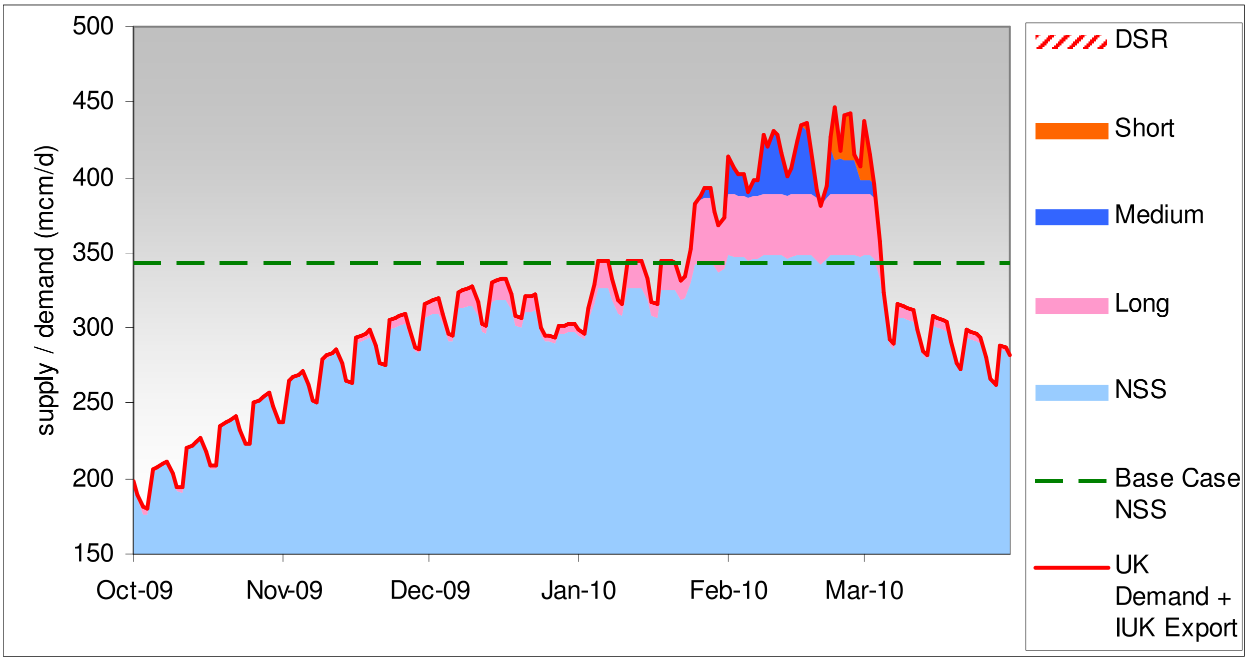
Figure A.29 – Hybrid winter



115. The chart shows the hybrid CWV profile and subsequent demand profile created by combining CWVs from winter 1985/86 for the period 23 January to 6 March, with seasonal normal composite weather (SNCW). For the period 23 January to 6 March CWVs are on average nearly 5 degrees lower than seasonal normal, producing demands at times comparable to those shown on the cold curve. This approach produces a demand profile that represents a credible scenario for a relatively challenging winter.

116. Figure A.30 shows a supply demand match using the hybrid winter demand profile and variable NSS.

Figure A.30 - Hybrid winter demand profile and variable NSS



117. There are a number of points to note from this analysis:

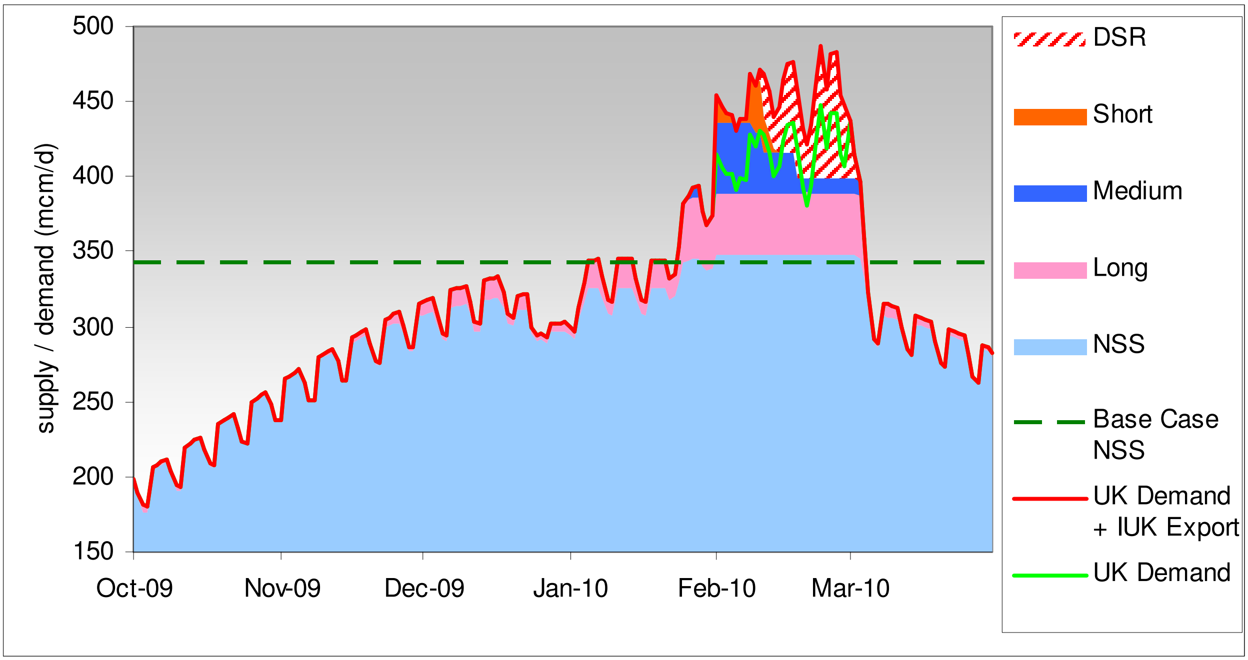
- All demand can be met by our assumed level of supply
- NSS level assumption of 343 mcm/d is marginally exceeded during February at high demand levels
- Use of Long storage commences at relatively low demand levels and early in the winter.
- There is significant use of Medium and Short storage with several sites depleted during February
- As demands are assumed at SND prior to the 'cold period', storage depletion could be understated

Russia - Ukraine

118. The following scenario shown in Figure A.31 assumes exports via IUK at 40[12] mcm/d for the whole of February. This is assumed to be the result of a cessation in Russian gas flows via Ukraine. This is coincident with the cold weather period previously described. Under these conditions, the Continental gas price needs to be higher than the UK gas price.

[12] During the January 2009 Russia / Ukraine dispute, IUK exports averaged just over 30 mcm/d with a peak just above 50 mcm/d

Figure A.31 - Hybrid winter demand profile and variable NSS with 40 mcm/d exports via IUK during February



119. Once again there are a number of points of interest from this analysis:

- IUK exports of 40 mcm/d throughout February raise total demands for a number of days to over 450 mcm/d and in some cases approaching 500 mcm/d.
- Under such conditions a significant Demand Side Response (DSR) would be expected as prices would be expected to rise, indeed, any price rise could also reduce IUK exports
- In the analysis the high demands result in all Short storage being depleted and most of the Medium sites also being depleted. This leads to a requirement for a further DSR as total supply deliverability is reduced to roughly 400 mcm/d by mid-February

120. It should be stressed that this is a low probability scenario, comprising of cold weather in the UK and coincidental high IUK exports driven by the loss of Russian gas flows across Ukraine. However it illustrates vulnerability to external events and highlights that with depletion of Short and most Medium storage, the total availability of supply is typically only 400 mcm/d.

Safety Monitors

121. On 31 May 2009, we published our preliminary view of initial Safety Monitor levels for 2009/10 as required under the Uniform Network Code (Q5.2.1).

122. It is our responsibility to keep the monitors under review (both ahead of and throughout the winter) and to make adjustments if it is appropriate to do so on the basis of the information available to us. In doing so, we must recognise that the purpose of the Safety Monitors is to ensure an adequate pressure can be

maintained in the network at all times and thereby protecting public safety. It is therefore appropriate that we adopt a prudent approach to setting the Safety Monitor levels.

123. Our latest Safety Monitor calculations incorporate our Base Case supply assumptions shown in Table A.5.

124. Table A.7 shows that the total non-storage supply assumption of 343 mcm/d used for calculating the 2009/10 Safety Monitors is 7 mcm/d higher than the equivalent figure used in setting the 2008/9 Safety Monitors.

Table A.7– Comparison of 2007/8 and 2009/10 Safety Monitor non-storage supply assumptions (mcm/d)

Non-storage supply type	2008/9 Safety Monitor	2009/10 Safety Monitor
UKCS	195	183
Norway	81	100
IUK	20[13]	0[14]
BBL	30	20
LNG	10	40
Total	**336**	**343**

125. This year we have made a number of changes to the Safety Monitor methodology, to improve security of supply whilst at the same time facilitating improved transparency and enhanced information provision to the market. It is important to note that these changes have not affected the overall Safety Monitor space requirement. The revisions to the Safety Monitor methodology sought to;

126. Treat all storage types equitably, by grouping all storage types/facilities together such that there is only one aggregated monitor for space. Hence operational storage space is apportioned equitably across all storage sites, including those with high cycling rates, rather than apportioning over the historically determined three storage types, Long, Medium and Short range storage.

127. Retain the prevailing determination of storage space requirements but make the deliverability requirement more visible. Hence there is one space Safety Monitor and one deliverability Safety Monitor. This should provide greater clarity for market participants and operational decision making.

[13] IUK was assumed to increase as a consequence of tighter supply conditions, reacting to an increase in UK gas price. IUK was also assumed to flow below forecast unless demand was well in excess of aggregated non-storage supplies.

[14] IUK assumed at zero for 2009/10 Safety Monitor

128. The resulting Safety Monitor levels for winter 2009/10 are detailed below. These are lower than the 2008/9 Safety Monitors. This is primarily due to the lower demand assumptions and to a lesser extent higher supply assumptions.

- 2009/10 Assumed storage space = 4959715 GWh
- 2009/10 Safety Monitor space = 1127 GWh (2.3%) 2008/9 = 10.1%
- 2009/10 Safety Monitor deliverability = 639 GWh/d

129. Safety Monitor levels and the associated winter profiles (i.e. how the monitors reduce later in the winter) will be published on or before 1 October 2009.

Gas Balancing Alert (GBA)

130. The changes to the storage classification for the Safety Monitor affects the setting of the GBA threshold or trigger. Previously this was set on the total level of non storage supply and addition of each storage facility type (Long, Medium & Short) containing stock at a minimum of two days full deliverability. The shift to include all storage in the Safety Monitor assessment, enables every storage facility (subject to two days deliverability) to be now included in the GBA trigger. Hence the GBA will now be far more responsive (and visible) to actual storage stock levels for all storage sites. This should result in subsequent changes to the GBA trigger being more gradual (both up and down as storage is refilled) rather than occasional large movements reflecting the loss of a storage facility type.

131. Further clarity should also exist as the same supply assumptions will apply to both the Safety Monitors and GBA trigger. As the following section details these relationships should become far more visible through our plans to provide improved market information (see also Section on Market Information Provision).

132. During winter 2009/10, we will provide enhanced winter feedback to the industry regarding supply assumptions and resulting changes to Safety Monitors by means of our website. Previously, during the winter National Grid has published its Winter Outlook supply forecast, a five day NTS demand forecast, storage stock levels, storage deliverability and Safety Monitor levels. Whilst all this information was on our website, the setting of the GBA and potential actions arising to protect Safety Monitor stocks were not particularly visible.

133. For winter 2009/10 we will be providing through our website a new platform showing a five day ahead view of the supply/demand balance, historic and forward projections of storage use and how these levels relate to the Safety Monitor requirements and the setting of the GBA trigger. Ofgem approved a UNC Modification Proposal (mod 257) to align information relating to both the GBA Trigger and Safety Monitor information on 25th September 2009.

134. The combination of improved information, greater clarity of the remaining storage position together with the alignment between the GBA and Safety Monitor should assist market participants and enhance security of supply.

[15] Excludes Operating Margins space booking for 2009/10.

Winter 2009/10 Update on Provision of new NTS Capacity

135. Compared to recent years 2009/10 will see significantly fewer construction projects on the NTS. Although several new sites, both entry and exit, are due to commission during the 2009/10 gas year the majority of the associated capacity expansion projects have already been completed.

136. Ongoing work to facilitate the expected increase in supplies from the Milford Haven LNG Importation terminals will include projects at Cilfrew and Treadow, as well as modifications and a replacement unit at Churchover multijunction.

Milford Haven LNG Terminals - New & Modified Pressure Reduction Stations.

137. This project is part of the overall investment strategy to provide capacity to transport gas from the new LNG importation terminals at Milford Haven, following auction signals for Milford Haven capacity received in the 2004 September and December LTSEC auctions.

138. The new Feeder 28 connecting Milford Haven to the NTS is fully commissioned. The commissioning of Felindre Compressor Station will follow the full commissioning of the new entry points and a further Pressure Reduction Station at Tirley.

139. The physical connections for South Hook and Dragon LNG Importation Terminals were completed last year. Dragon has subsequently declared commercial operations whilst South Hook despite high relatively flows has yet to declare the same operational status.

The references in the tables below relate to the map shown as Figure A.32.

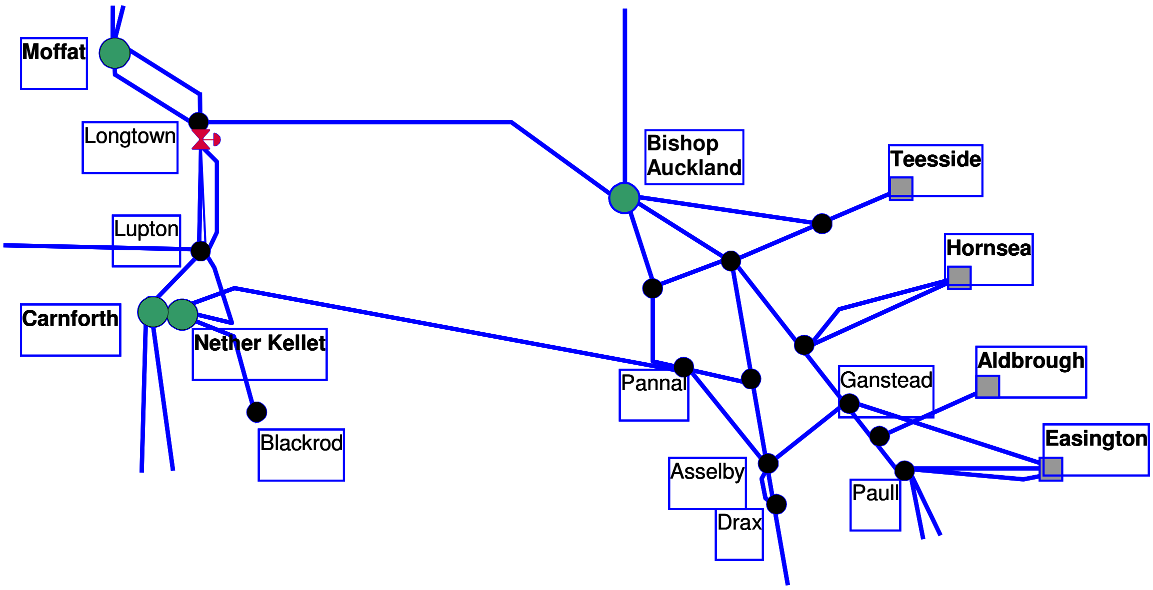
Table A.8 – Project Phases Table For Works in Figure A.32

Phases

Ref	Project	Scope
A	Churchover MJ modifications & replacement unit	Additional Unit and multi-junction modifications
B	Felindre Compressor Station	Commissioning
C	Cilfrew PRS	Commissioning
D	Tirley PRS	Under review awaiting planning consent

East Coast Entry Capacity

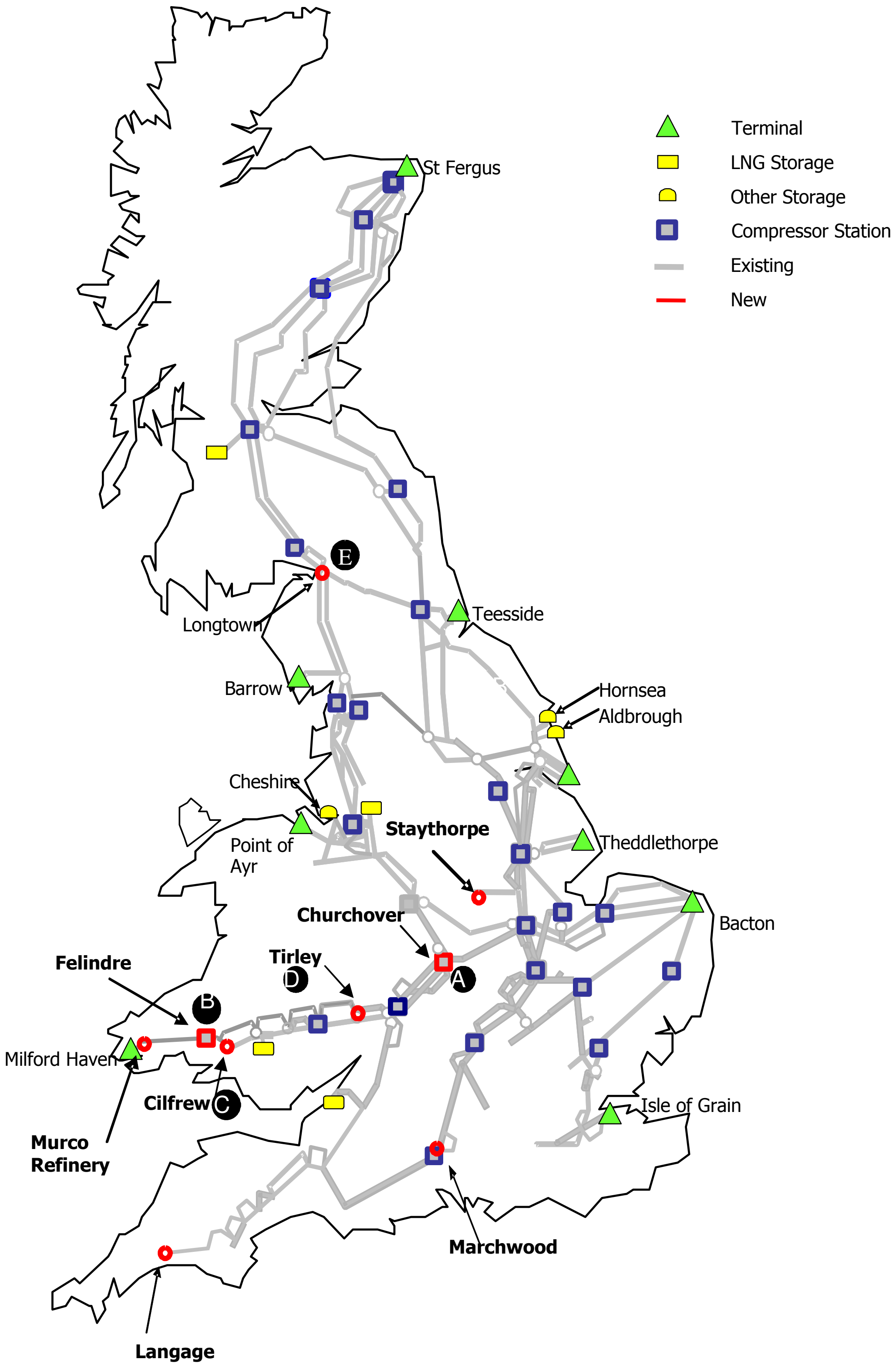
140. Following significant investment in providing new East Coast entry capacity in 2006, 2007 and 2008 (2008 marking the completion of the Trans Pennine link from Easington to Carnforth), 2009 will see the commissioning of the Longtown flow control valve, which will provide National Grid with increased control flexibility. The timing of this commissioning is dependant on sufficient flows through the station.



Phases

Ref	Project	Scope
E	Longtown Regulator	Commissioning new flow control valve

Figure A.32 – NTS Construction Projects Due for Delivery in Winter 2009/10



New Exit Connections

141. During the gas year 2009/10, it is expected that both Langage and Marchwood power stations and Aldbrough storage will become fully operational, after having connected to the NTS and taking limited commissioning gas last year. New connections to Staythorpe Power Station and Murco Oil Refinery at Milford Haven are also expected to be completed with first gas flows in 2009/10.

LNG Storage

142. Dynevor Arms LNG has been decommissioned and Partington, Avonmouth and Glenmavis LNG have re-declared their deliverability, shown in the table below. The total deliverability in 2009/10 for LNG Storage will be 35.9 mcm/d compared to 48.5 mcm/d last year.

Table A.9 – LNG Storage Site Deliverability for Winter 2008/9 compared with Winter 2009/10

Site	2008/9 Deliverability	2009/10 Deliverability
Partington LNG	20.3 mcm/d	14.2 mcm/d
Avonmouth LNG	14.4 mcm/d	13.2 mcm/d
Glenmavis LNG	9.3 mcm/d	8.5 mcm/d
Dynevor Arms LNG	4.5 mcm/d	N/A

Market Information Provision

143. National Grid's Gas Market Reporting pages at nationalgrid.com/uk/Gas/Data/ continue to grow and accommodate real time developments on the NTS. As physical and regime changes occur, the industry will see these developments incorporated into the existing suite of reports and data items. Explanatory news items will accompany any updates.

144. Winter 2009/10 will see the second phase release of our Gas Market Information System. Changes and improvements will include a more resilient platform, functional enhancements, data rationalisation and the delivery of new or revised information provision requirements. Some older, preformatted reports will cease to be published and will be replaced instead by searchable data items which users can download and interrogate in their own systems. Full details of the changes can be found in our Supplementary Help pages: http://www.nationalgrid.com/uk/Gas/Data/help

145. Information on the supply / demand forecast, storage stock levels and proximity to Safety Monitor and GBA trigger levels have been consolidated and can be found in a single place (from 1st October) at: http://www.nationalgrid.com/uk/Gas/Data/GBA/

146. Users can also subscribe to receive notification via email or text that news items have been published on our Information Provision pages by signing up at this address: http://www.nationalgrid.com/uk/Gas/Data/subscribe

Electricity

Electricity Demand Levels for 2009/10 – Great Britain

147. Our updated Great Britain Average Cold Spell (ACS)[16] winter peak demand forecast for the coming winter is 57.4GW. This is a 0.6GW reduction on 58.0GW ACS demand outturn of last year. Within the 2009/10 ACS demand forecast, a 0.2GW reduction has been made for the closure of Anglesey Aluminium, which is a large energy user expected to have ceased production by the time of winter peak 2009/10[17].

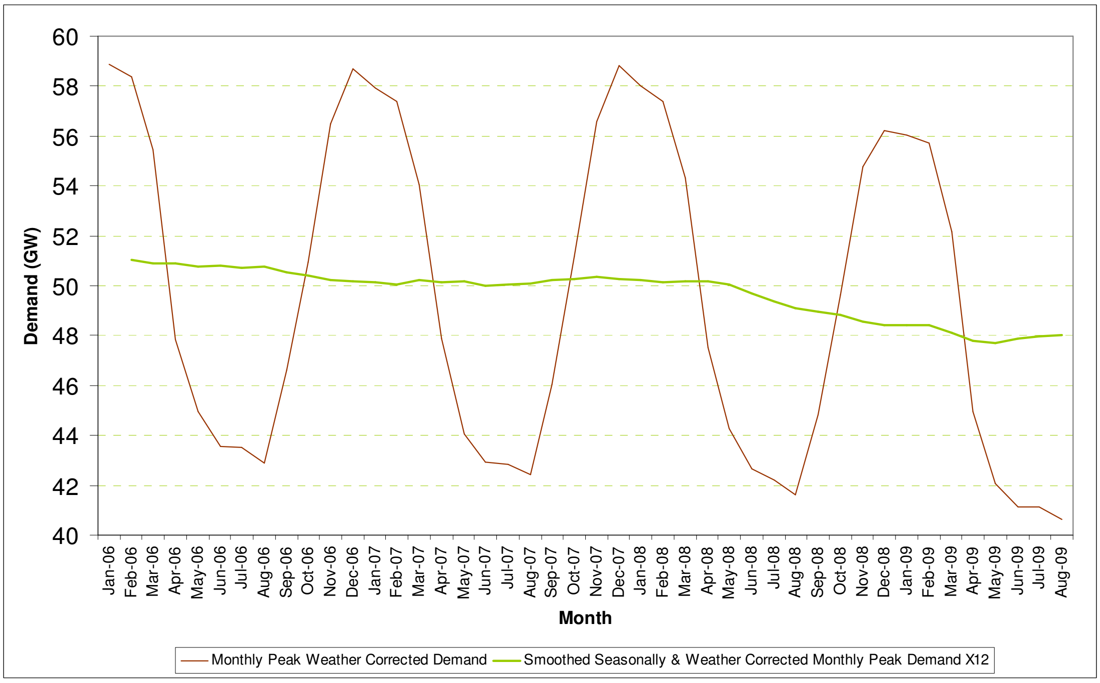
148. In 2008/9, we saw a 2.3GW lower ACS demand outturn than in 2007/8. This represents a 3.8% reduction on ACS demand levels. Although this drop was mainly due to the change in the economic climate, other contributing factors included embedded generation growth and energy conservation. We have analysed the change in monthly peak demand for the period from January 2006 to August 2009, which can be seen in Figure A.33. From the figure it can be seen that the reduction in peak demands started to appear in mid-summer 2008 and accelerated from late summer. The decline continued into 2009, resulting in a further underlying reduction in peak demands during the first half of 2009. The most recent trend appearing through the summer 2009 period is that the decline appears to have stabilised. We flagged this apparent stabilisation in energy patterns in our June consultation report. The stabilisation is subject to uncertainty as, whilst we have selected the most appropriate analytical approach (seasonal adjustment and smoothing of weather corrected data), it is still a relatively short term observed trend, which requires further experience of outturn demand levels to confirm it.

149. The decline for the pre recession period is due to a combination of factors as we acknowledge above. These include the growth in generation embedded in distribution networks, response to high energy prices and more efficient use of energy. The high energy price driver is likely to have softened marginally in effect as electricity prices have fallen. Having noted this though, the reduced prices do not seem yet to have fed through to all end consumers yet. Environmental drivers continue though to have effect with a continued high level of public awareness of the environmental benefits of reducing energy use. We have limited visibility of changes in the amount of embedded generation connected at distribution voltages through which to determine if a change in trend has taken place so for this driver it is difficult to take a clear view.

150. The uncertain timing and pace of economic recovery can not be accurately predicted, but through the continual monitoring of weather and seasonally corrected demand trends, we will continue to review our demand forecasts published on www.bmreports.com. The recession leading to demand uncertainty is one of the key issues being highlighted in this report.

[16] Annual Average Cold Spell (ACS) Conditions are a particular combination of weather elements which gives rise to a level of peak Demand within a Financial Year which has a 50% chance of being exceeded as a result of weather variation alone.
[17] See for public information source http://news.bbc.co.uk/1/hi/wales/north_west/8264673.stm

Figure A.33 – Smoothed Weather and Seasonally Corrected Normal Demand



151. The 1 in 20[18] peak demand forecast for 2009/10 is 59.4GW. The 1 in 20 demand peak represents our high demand scenario and to put this in context relate to temperatures of -2.7 Celsius at 1700. These demand figures relate to GB demand only and do not include any flows to France or Northern Ireland across interconnectors.

152. We have not presented a 1 in 50 cold level demand scenario as this is unlikely to occur based on recent history. The ten warmest years on record have occurred since 1997. Global temperatures for 2000-2008 now stand almost 0.2 ℃ warmer than the average for the decade 1990–1999[19]. The Met office has recently published its outlook of temperatures for winter. The Met office notes temperatures are likely to be near or above average over much of Europe including the UK. Winter 2009/10 is likely to be milder than last year for the UK, but there is still a 1 in 7 chance of a cold winter[20].

153. The Normal demand Peak forecast for Winter 2009/10 is currently at 56.2GW and is revised as we get closer to the time as part of our normal forecasting activities. Our most current forecast at any given time is given at www.bmreports.com. Normal demand is the demand that we expect to occur based normal weather conditions. The normal weather conditions are calculated from an average over a 30 year period on a weekly basis. Normal demand is also the basis on which the published generation surpluses are calculated as published on www.bmreports.com.

154. The French Interconnector has traditionally imported during the system peak demand period. Generally we believe it is appropriate to continue to treat the

[18] 1 in 20 Conditions are a particular combination of weather elements which gives rise to a level of peak Demand within a Financial Year which has a 5% chance of being exceeded as a result of weather variation alone.
[19] Source Met Office:http://www.metoffice.gov.uk/corporate/pressoffice/2008/pr20081216.html
20 See http://www.metoffice.gov.uk/science/creating/monthsahead/seasonal/2009/winter.html

interconnector with France as a source of generation rather than a demand at winter peak times. The recent trend for the Northern Ireland (NI) Interconnection was either exporting to GB at a lower level than historically observed or more consistent with longer term observations to be importing to NI at a low level. Because of the uncertainty of actual interconnector transfers on a daily basis, we have made the assumption that both interconnectors at system peak will be at float throughout this outlook analysis unless explicitly stated otherwise, and readers of the analysis here can overlay their best assumptions if different on demand (Interconnector exports) or generation availability (Interconnector imports). For the French interconnector we have summarised the relative price differentials between markets in paragraph 168 and 169.

155. We estimate that around 0.8-1.3GW of demand management is observed at times of peak demand in the winter of 2008/9 as consumers responded to high electricity prices at times of peak demand. When forecasting demand we assume this level of demand response will continue and we have recognised this in our peak demand forecasts. For 2009/10 we have assumed 1GW of demand side response in our demand forecasts for ACS and 1 in 20 conditions. Demand side response is not factored into our normal weather demand forecasts, as we do not expect significant demand side response under normal weather conditions.

156. We have considered the impact of a national pandemic in the UK for meeting electricity demands over winter to come. National Grid along with the wider energy industry, Government and industry Regulator has been planning for an event like this for many years. Generators have made contingency plans to keep plant available and operating to manage the risk to generation availability levels, although the exact impact of a pandemic is still uncertain. If a pandemic does occur in the UK during the winter, we expect the largest proportionate impact to be a reduction in demand relative to any impact on generation availability given the industry plans in place. As this report is concerned with the ability to meet peak demand, providing contingency processes function as anticipated, there is a low residual risk to electricity security of supply in this scenario.

Notified Generation Availability 2009/10

157. Based on the observed output of power stations, National Grid's current operational view of generation capacity anticipated to be available for the start of winter 2009 is 77.0 GW. This is an increase of 100 MW since May due to three new wind farms becoming operational and visible to National Grid's metering system. A breakdown of this capacity is shown in Figure A.34[21].

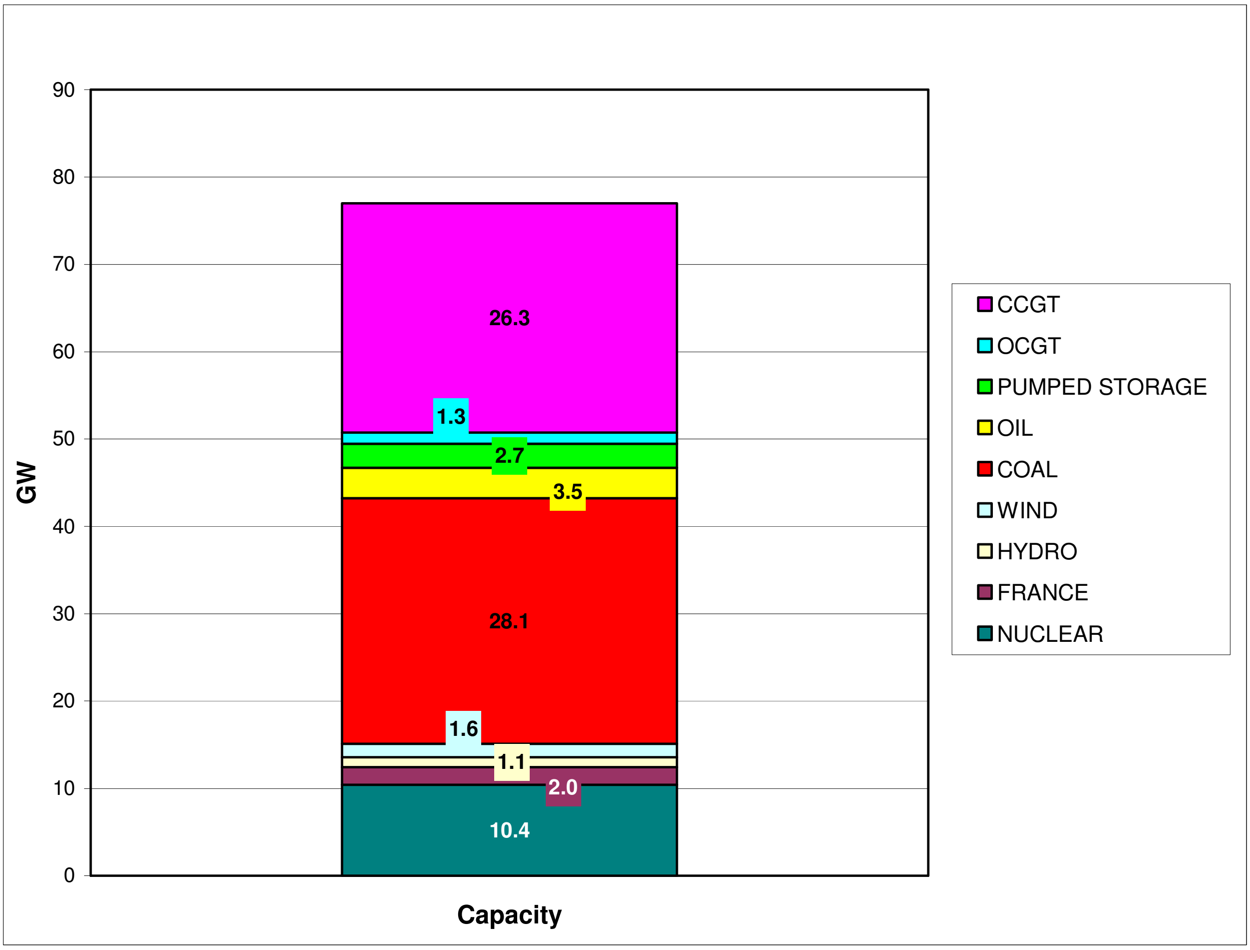
158. Some generation capability upside exists in the form of Langage (0.9GW), Immingham Phase 2 (0.5 GW) and Staythorpe C (1.7 GW) which could be entering full commercial operations at some point during the winter to come. Also we expect to see an additional 200MW of wind generation becoming visible to National Grid over the course of the winter, although this additional capacity has a degree of

[21] Charts similar to Figure A.33 are presented in our outlook reports available on our website http://www.nationalgrid.com/uk/Electricity/SYS/outlook/ which enables identification of changes over longer periods to be analysed.

uncertainty attached to it. Recent labour relations issues between companies and their contractors working on large engineering projects, including power stations could impact on the timing of realisation of the generation upside noted here.

159. Our end of winter 2009/10 operational view of generation could total up to 80.3 GW, dependant on how the build phase and commissioning of new CCGT's progresses and the rate at which new wind generation is being connected.

Figure A.34 – Generation Capacity Operational View 2009/10



Generation Availability Assumptions 2009/10

160. We have reviewed our forward looking availability assumptions based on last winter and they have proved generally robust at the aggregate level. Nuclear performance over last winter's demand peak was in historical terms very low, though we believe this level of performance is unlikely to be repeated to a similar extent. Over the summer we have reviewed our assumed availabilities for hydro and OCGT and made some minor changes in both these generation types. As both generation types are small, and the changes were to increase hydro availability and reduce OCGT availability, there has been negligible overall impact to total assumed generation availability. We have not received any views that significantly differ from

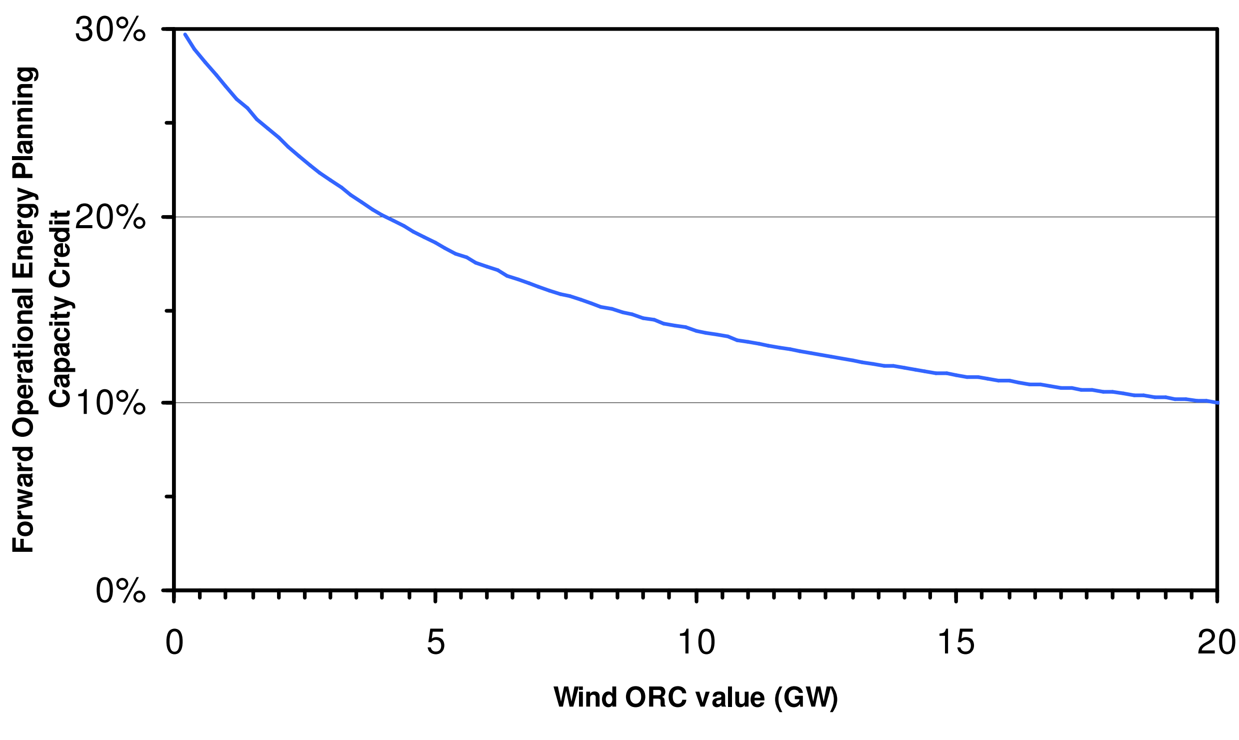
these assumptions through the consultation process, though some respondents identified the uncertainty around wind power's contribution to meeting peak demands. Based on this feedback, our low generation scenario includes a zero output from wind generation assumption.

161. We have continued working with Edinburgh University over the last year to assist us in developing an operational assumption for a capacity credit for wind, in line with our security of supply obligations for meeting the peak winter demand. As a result of this research, a paper was presented in July 2009[22] to Cigre/IEEE along with others covering a range of industry research efforts into identifying an operational capacity credit approach and value. The operational energy planning capacity credit value of 27% we have reached through our research has been used in our base case for winter 2009/10, but we note that the capacity credit exceeds recently observed contributions from wind at times of peak demand, so further work is planned in this area to better understand this outcome.

162. Figure A.35 shows the capacity credit curve for the coming winter's ACS peak forecast and base case generation availability assumptions for non-wind generation types. The modelling approach is to calculate how much extra demand a volume of wind power generation can support, giving us a capacity credit figure, whilst maintaining the same level of risk to meeting total energy demand in line with our security of supply standards. Our approach is underpinned by operational GB data for the actual wind farms output so well grounded in the specifics for our capacity and behaviour of wind farms. The research undertaken gives a full curve, illustrating how the operational energy planning wind capacity credit quickly declines with increasing levels of installed wind generation capacity, before the rate of decline with increased capacity tails off.

22 The paper will be published later this year by P.E. Olmos Aguirre, C.J. Dent Member, IEEE, G.P. Harrison and J.W. Bialek, 'Realistic calculation of wind generation capacity credits',. It was presented at the Cigre/IEEE PES Symposium on 'Integration of Wide-Scale Renewable Resources into the Power Delivery System', Calgary, July 2009. See http://www.cigre.org/userfiles/symposia/CALGARY%20TECHNICAL_PROGRAM_V2.pdf

Figure A.35 – Forward Operational Energy Planning Wind Capacity Credit



163. Hydro generation, mainly small generation, some of which is run of river, has an assumed load factor of 80%. This compares with observed load factors of 78%, 83% and 80% at the time of the winter peak demand for the last three years. OCGT's have an assumed availability of 80% in line with last winter's outturn availability of 77%.

164. Table A.10 shows our assumed generation availabilities for each class of plant (assumed load factors for wind and hydro) at the time of winter demand peak for 2009/10. Assumed load factors are used for wind and hydro generation in table A.10, instead of availability, as in both cases generation is limited by the volume of the primary energy source.

Table A.10 – Generation Availability Assumptions Made For Winter 2009/10

Power Station Type	Full Metered Capacity (GW)	Assumed Availability	Assumed Availability (GW)
Nuclear	10.4	80%	8.4
French Interconnector	2.0	100%	2.0
Hydro generation	1.1	80%	0.9
Wind generation	1.6	27%	0.4
Coal	28.1	85%	23.9
Oil	3.5	95%	3.3
Pumped storage	2.7	95%	2.6
OCGT	1.3	80%	1.0
CCGT	26.3	90%	23.6
Total	**77.0**		**66.1**
Overall availability		**86%**	

Mothballed Generation Capacity

165. The amount of plant that is long term mothballed has increased slightly to 1.25 GW from last year's level. We do not expect any other plant to be mothballed for winter 2009/10, and no additional plant has been mothballed during the summer. We do not expect any of the currently mothballed generation plant to become available for winter 2009/10.

Generation Side Risks

166. We have not identified a specific risk area such as for nuclear generation late returns from outage which existed last winter. Generation capability risks appear lower and more generic for the coming winter. Type faults/generic safety issues can arise occasionally or key power station mechanical plant may fail from time to time. Capacity restrictions through these kinds of risks and issues are only potentially onerous if they happen to coincide with periods of relatively high demands and they are low probability events.

167. Recent history has shown that wind power output at the time of the winter peak can be very low. The winter peak normally occurs when temperatures are low and this often results from anti-cyclonic conditions that also mean very little wind. High pressure normally extends over a large area and this could mean there would be very little wind generation in Western Europe. This in turn would reduce the amount of power available to flow from France to Britain. As a result, a low case generation scenario has been constructed on the basis of discounting wind power output to zero and allowing for the French interconnector to be at float rather than importing from France. Details of this scenario are shown further on in the report.

French Interconnector Flows for Winter 2009/10

168. The French interconnector is the largest interconnector between the GB and a neighbouring system so we tend to focus on it for energy planning purposes. In the GB market the scale of output or transfer over interconnectors is determined through market mechanisms. This means that a best view of likely transfers is established through looking at market price differentials between the GB and French markets. These prices change over time, so any view of relative forward prices between markets needs to be regularly reviewed. We are able in this report to give a summary of current France-GB power price differentials.

169. Current price differentials[23] between the UK and France are showing a premium of £11/MWh to France over the Baseload period (23:00 to 23:00) and a premium of £19/MWh to France over the Peak period (07:00 to 19:00). This is a large differential indicating high levels of export from the GB to French market over winter to come. History shows us that there is always a split between the morning period (07:00 to 15:00), where the flow over winter can be upto 2000MW to France, and the afternoon period (15:00 to 19:00) where the flow to France is reduced. This is because the prices are normally higher in the UK for the Darkness Peak, whereas they are (relatively speaking) more evenly priced across the French day. In addition to this, market participants will normally look to avoid exporting from the UK on a Triad[24] day as the financial repercussions of this are significant.

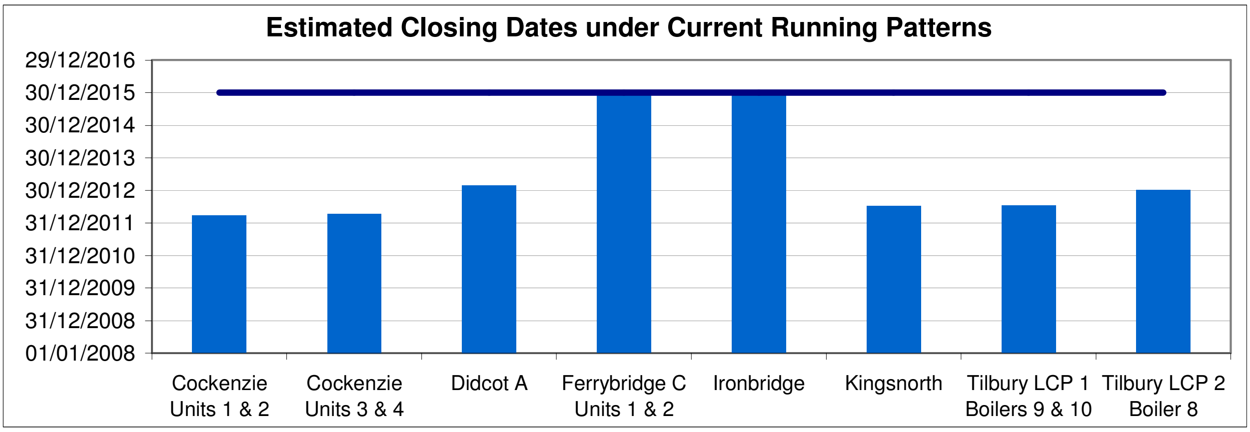
LCPD Summary for Winter

170. Issues related to the limited hours under LCPD for opted out plant are unlikely to affect winter 2009/10, but could be relevant for winter 2012/13 and certainly for the following winter based on historic operation patterns. LCPD Opted out plant has 20,000 hours allowed operation until December 2015. At the current observed rates of utilisation of the allowed hours there is an implication of early closure at some power stations. Our latest view of early closure, given running patterns to date projected forward for opted out coal stations is shown in Figure A.36. The first generation anticipated to utilise its hours is Cockenzie in May 2012. We have not shown opted out oil stations in this chart due to their current low number of running hours relative to their 20,000 hours allowance.

[23] As at mid September 2009.

[24] See http://www.nationalgrid.com/NR/rdonlyres/9F27FB81-711A-44E0-9476-2456945E08B0/33061/Triadcalculationmethodology.pdf for a high level view of how Triad charges work.

Figure A.36 – Indicative LCPD Coal Opt Out Plant Closing Dates



Contracted Reserve

171. In order to achieve the demand-supply balance, National Grid procures reserve services from either generation or demand side providers to be able to deal with actual demand being greater than forecast demand and to cover last minute plant breakdowns. This requirement is met from both synchronized and non-synchronized sources

172. We procure the non-synchronized requirement from a range of service providers which include both Balancing Mechanism (BM) participants, and non-BM participants. This requirement is called Short Term Operating Reserve (STOR) and is procured on an open market tender basis that runs three times per year.

173. National Grid encourages greater participation in the provision of reserve and engages with potential providers to tailor the service to meet their specific technical requirements.

174. For winter 2009/10, the total level of contracted STOR reserve is approximately 2.5 GW, over 1.7 GW from BM participants and nearly 0.8 GW from non-BM generating plant and demand reduction.

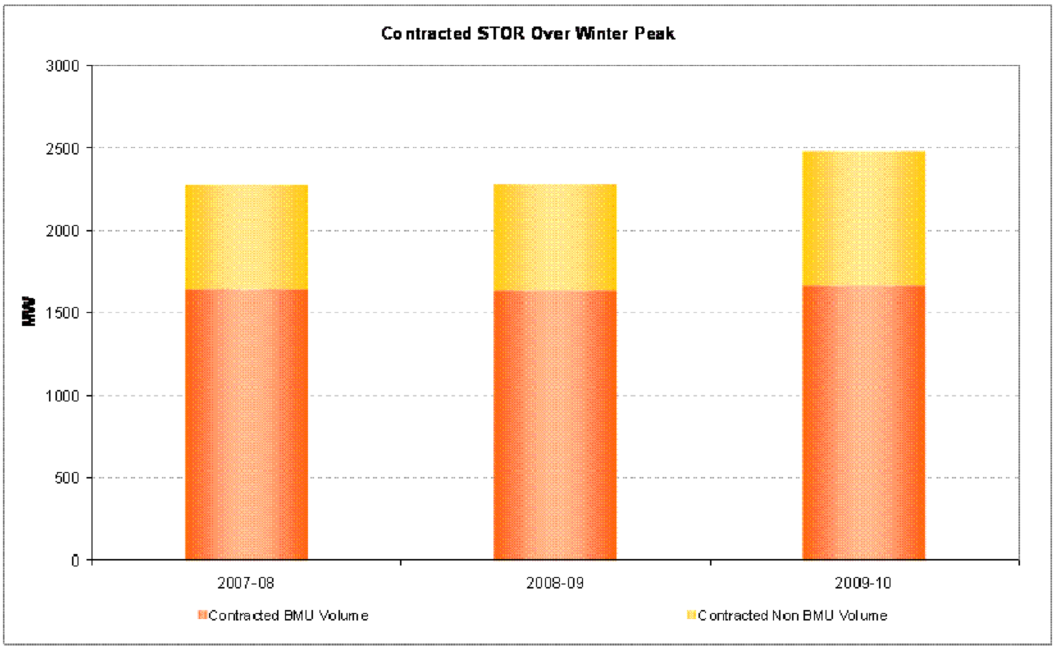
175. Figure A.37 shows the contracted STOR for the winter peak over the last 3 years. Further information regarding the STOR service can be found on our website http://www.nationalgrid.com/uk/Electricity/Balancing/services/reserveservices/STOR/.

176. In addition to STOR, there is a continual requirement to provide frequency response on the system. This can be either contracted ahead of time or created on synchronized sources within the BM. If all response holding was created in the BM, then approximately 1.5GW of reserve would be required to meet the necessary response requirement. 1GW of this 1.5GW reserve requirement has already been contracted, with 0.2GW from demand-side providers.

177. National Grid continues to have Maximum Generation contracts in place for Winter 2009/10, which provide potential access to 1 GW of extra generation in emergency situations. This is a non-firm emergency service and generation

operating under these conditions normally has a significantly reduced reactive power capability (which in turn can have a significant impact on transmission system security) Hence, it is not included in any of our generation capability and plant margin analysis. This service was available pre-NETA and similarly was never included in margin analysis

Figure A.37 - Contracted STOR for Winter Peak 2009/10



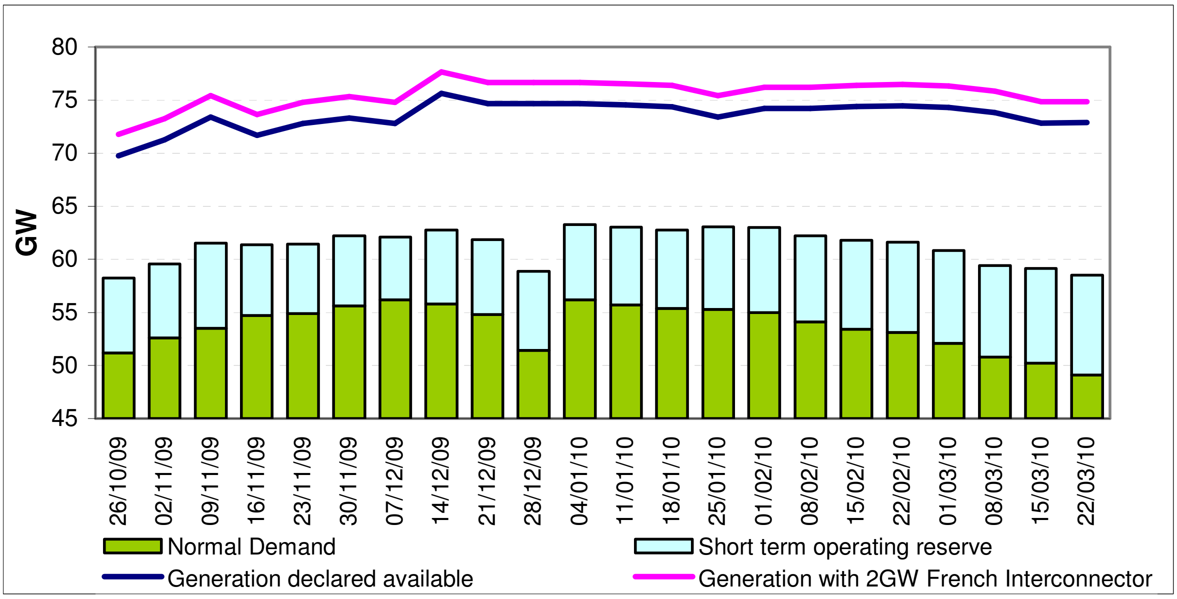
Forecast Generation Surpluses 2009/10

178. Figure A.38 shows the position for the coming winter with demand based on normal weather. The generation available is the availability declared to National Grid by the generators under Operating Code 2 of the Grid Code, and reflects planned unavailability, but has no allowance for unplanned generator unavailability.

179. Work has been going on all summer on the Scottish Interconnectors as part of the upgrading scheme, which has restricted the amount of power that can flow from Scotland to England. The work is not due to be completed until 3 weeks after clock change and the constraint on power flows will therefore continue until then. The short term operating reserve requirements make allowance for this and the higher levels are included in the charts below.

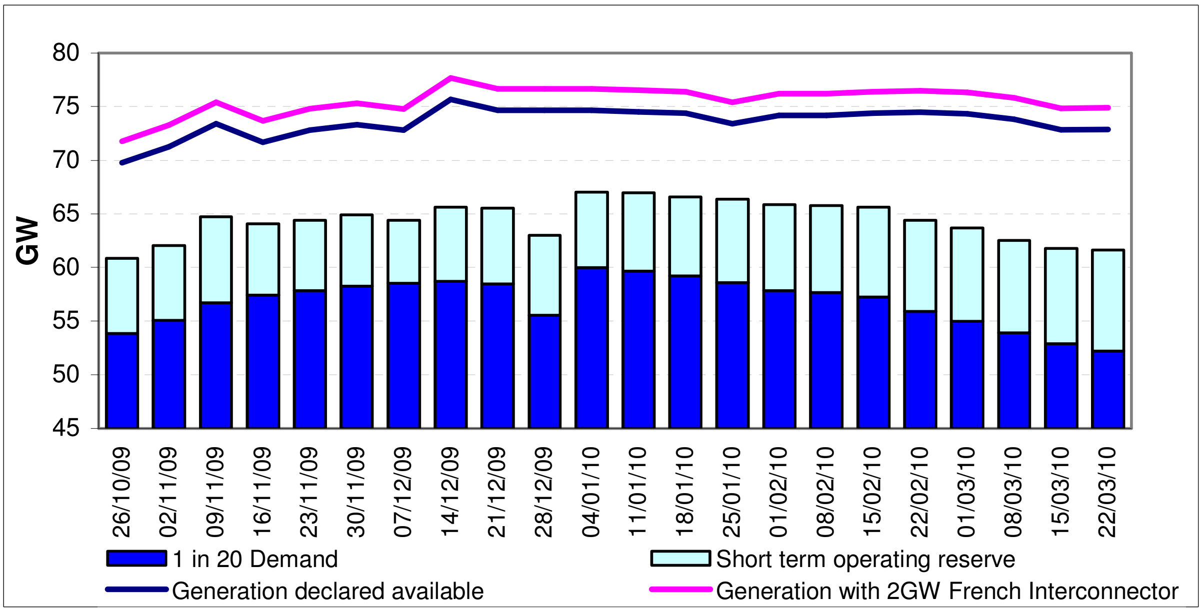
180. Demand in Figure A.38 is based on no interconnector exports to France and Ireland in line with our base assumptions at the time of the daily peak. As the figure shows based on normal demands and notified availability there is sufficient generation to meet demand and our short term operating reserve requirements comfortably, even without imports from the French interconnector.

Figure A.38 - Normal Demand and Notified Generation Availability



181. Figure A.39 shows the position for the coming winter with demand at 1 in 20 levels. This shows there is sufficient generation to meet a 1 in 20 demand and our short term operating reserve requirements comfortably.

Figure A.39 - 1 in 20 Demands and Notified Generation Availability

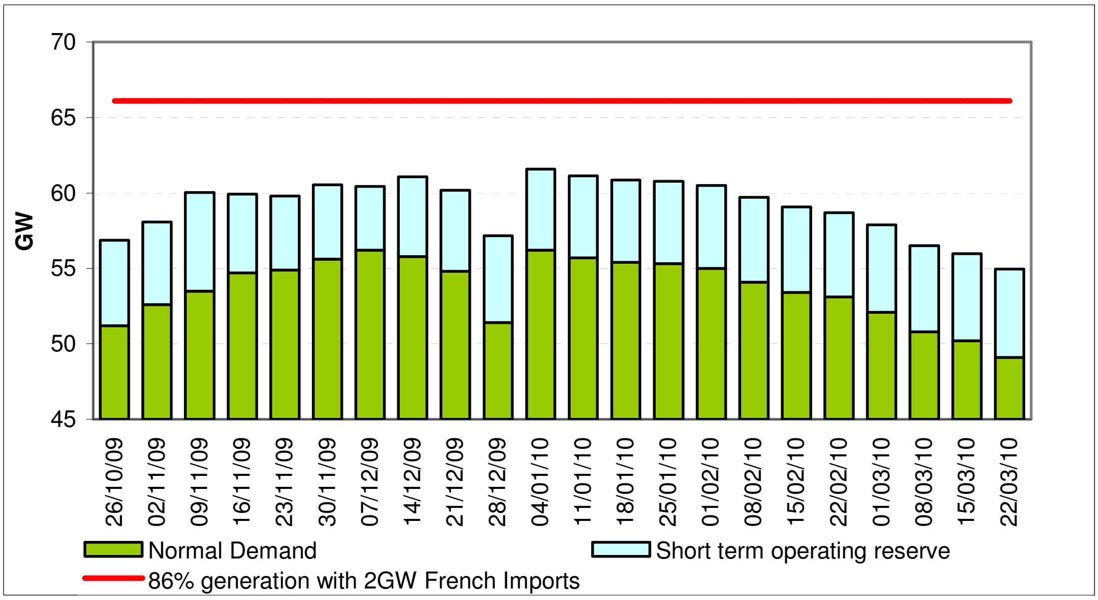


182. Figures A.40 and A.41 use generation availability as declared to National Grid by the generators under Operating Code 2 of the Grid Code, which reflects planned

unavailability, but has no allowance for unplanned generator unavailability. We have outlined our assumptions earlier in this report for the levels of actual generation availability we expect at the time of demand peak, which use historic availability achieved over historic demand peaks to indicate the combined effect of both planned and unplanned unavailability.

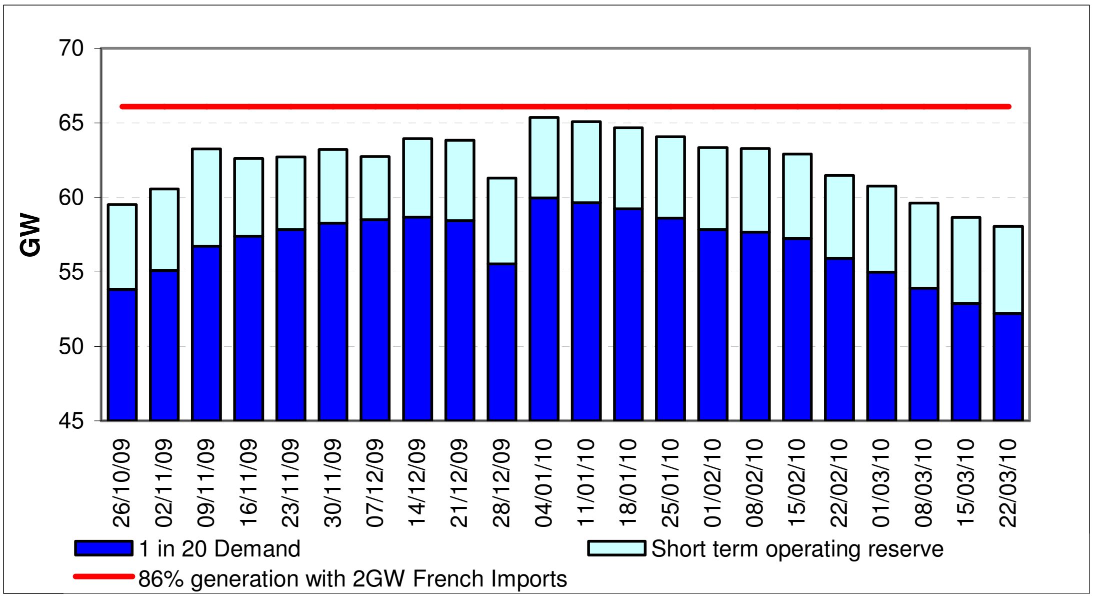
183. Figure A.40 shows normal demand plus short term operating reserve and our assumed availability of generation which is 86% of our operational view of generation capability plus 2GW of import from France. The chart shows there is sufficient generation to meet demand and our short term operating reserve requirements comfortably. Commissioning plant has been excluded from the short term operating reserve in Figures A.40 and A.41 for consistency with the 86% assumed generation availability line which also excludes commissioning plant.

Figure A.40 - Normal Demand and Assumed Generation Availability



184. Figure A.41 compares our assumed level of generation availability with the 1 in 20 demand level scenario. The chart shows there is again sufficient generation to meet demand and our short term operating reserve requirements.

Figure A.41 - 1 in 20 and Assumed Generation Availability



Low Generation Availability Scenario

185. This section of the report looks at how the generation surpluses would be affected by the scenario of zero wind and the French Interconnector at float as discussed earlier in the report. French interconnector at float is a reasonable assumption for the peak of winter electricity demands. It is possible though, that on some relatively high demand days that the interconnector could be exporting to France for some periods. If this were the case than GB demands would be increased by the amount of the export.

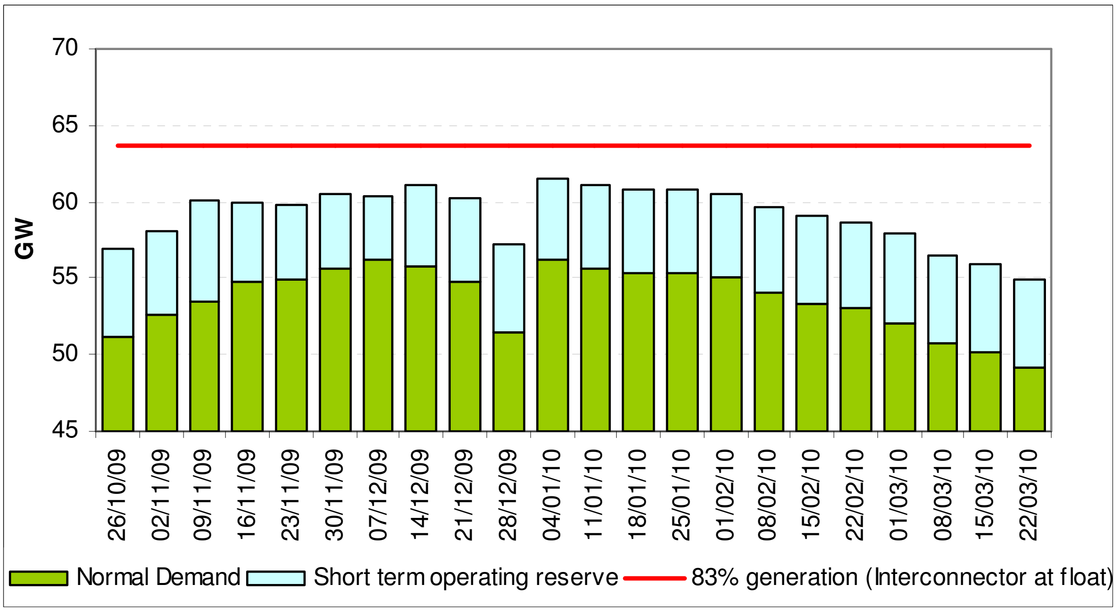
186. This scenario reduces the overall availability of generation plant from 86% to 83% as shown in Table A.11.

Table A.11 – Low Case Generation Availability Assumptions Made For Winter 2009/10

Power Station Type	Full Metered Capacity (GW)	Assumed Availability	Assumed Availability (GW)
Nuclear	10.4	80%	8.4
French Interconnector	2.0	0%	0.0
Hydro generation	1.1	80%	0.9
Wind generation	1.6	0%	0.0
Coal	28.1	85%	23.9
Oil	3.5	95%	3.3
Pumped storage	2.7	95%	2.6
OCGT	1.3	80%	1.0
CCGT	26.3	90%	23.6
Total	**77.0**		**63.7**
Overall availability		**83%**	

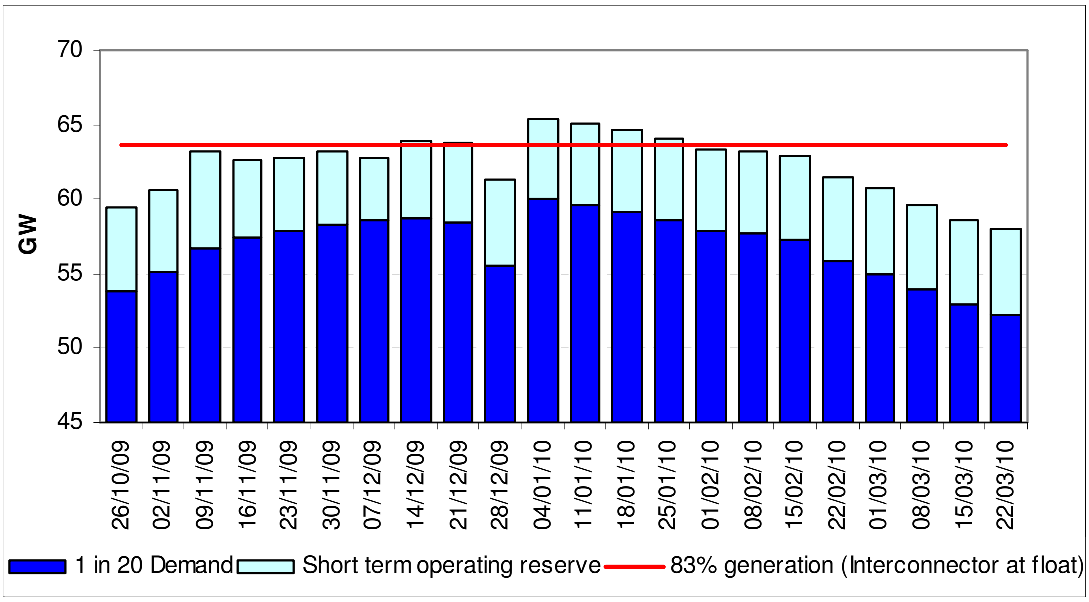
187. Figure A.42 shows that under this scenario there would be sufficient generation to meet demand and our short term operating reserve requirements comfortably.

Figure A.42 – Normal Demand and Low Generation Availability Scenario



188. Figure A.43 shows that if demands reached 1 in 20 levels in a low generation scenario with the French Interconnector at float there would be a slightly higher than normal risk of not being able to meet demand in January due to a small erosion of reserve levels. Under these circumstances some system warnings are likely to be issued. The likelihood is that demand would still be met in all but relatively high extremes of plant loss given our underlying assumptions.

Figure A.43 - 1 in 20 Demand and Low Generation Availability Scenario



Generation Merit Order 2009/10

189. We have focussed on the outlook for meeting electricity demand and are less concerned with which types of generation are likely to be base load, two-shifting and marginal. This issue is determined by the market and therefore is subject to significant uncertainty as market prices for winter change over time.

190. The current forward prices for fuel and carbon for the winter to come indicate gas fired generation will be cheaper than coal until November from which point for the remainder of the winter coal generation is preferred over gas. This suggests that the CCGTs are likely to run at base load at the start of the winter but do more load-following and two-shifting over the main part of the winter. Gas demand, discussed in the earlier part of this report is directly effected by the choice of fuel for the power sector, so there is informative analysis in detail in that part of the report[25].

[25] See Fuel Price analysis and commentary right at the start of section A of this report.

Section B
Gas/Electricity Interaction

Power Generation Gas Demand

191. This section is to investigate the relief that the electricity market can provide to the gas system when there is pressure on the gas supply whilst still meeting the projected electricity demand. This relief can be provided by the use of gas storage, gas fired power stations switching to running on distillate or power sector demand response through generation mix changes.

192. As is shown in this section of the report, with the base case assumptions described earlier in this report, it proves possible to meet gas demands, even if we had the coldest winter in recent history. The second scenario tested in this section is our low generation availability scenario with no wind generation, float on electricity interconnectors and 2GW electricity exported to France from 7am to 3pm. This is then combined with a low gas supplies availability scenario of a reduction of the non-storage gas supply by 40 mcm. This 40 mcm reduction could be caused by the loss of a major supply source such as Rough or increased exports through the Interconnector caused for example by a repeat of the Russia / Ukraine dispute. This showed there are no problems in an average winter, but a cold winter will require some non-power demand response as there would be little relief available from the power market. This low generation and low gas supplies case results in a need for gas demand side response only after a period of a consistent run of very cold days.

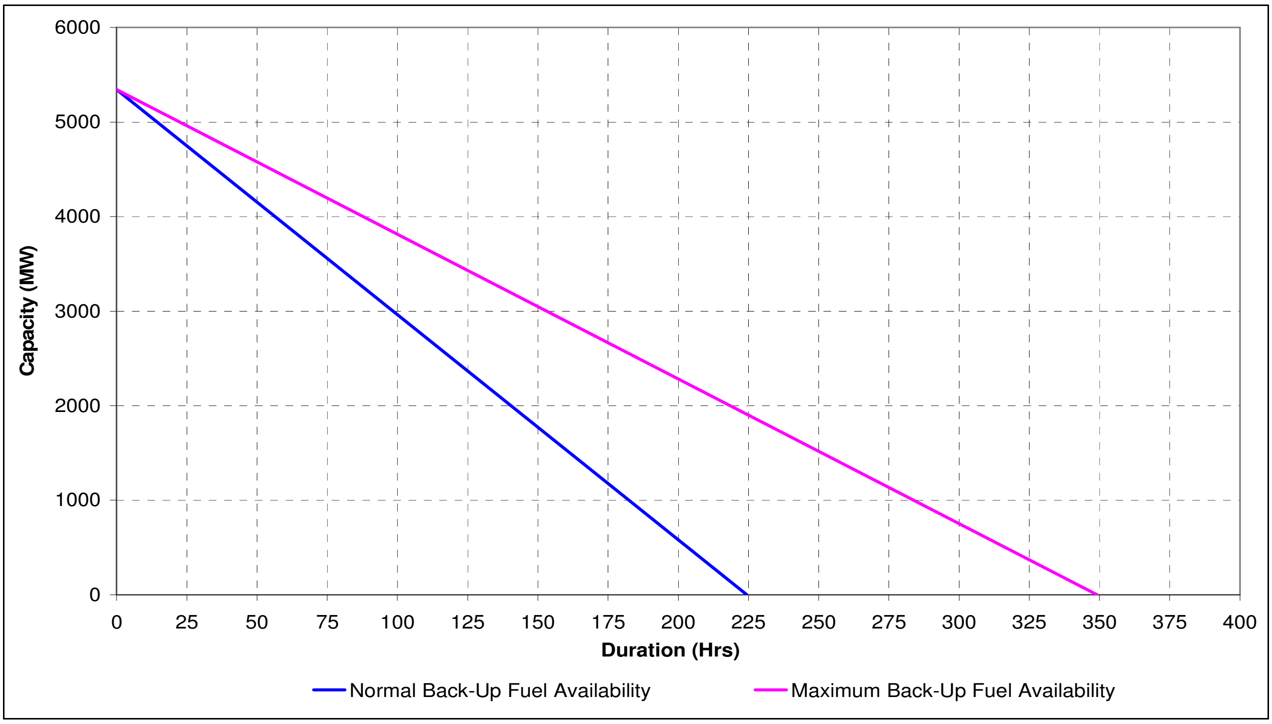
Power Stations with Alternative Fuels

193. Under the terms of the Grid Code, generating companies provide us with information on their capacity to generate using back up fuel. Using the data received, we estimate 5.3 GW have the capability to run on distillate which is slightly lower than last year's estimation of 5.4 GW. Out of the total 5.3 GW having back-up fuel generation capability, more than half have interruptible gas transportation arrangements.

194. Figure B.1 shows our estimation in a load duration curve form, of the decay of generation capacity available from distillate with time. The data has been aggregated and smoothed to protect the commercial positions of the individual generators. The two lines show the available generation capacity from starting points of normal fuel stocks and maximum fuel stocks, and assuming individual units generating at full load when running on distillate. Note, however, that this graph is not intended to suggest that all generators with back up fuel capability would run continuously on back up fuel supplies for several days or at full distillate running load. In reality different generators would adopt different commercial strategies. We currently assume that most of this capacity would only run on back up fuel over the peak demand periods, though its also equally likely that generators could run off peak on distillate. Our assumption is made because we have not seen any real experience of how power stations that run on distillate operate in recent history and a range of outcomes are possible. The key consideration is the amount

of gas demand from power stations that can be displaced within the gas day should this become necessary so timing in the electricity day is less critical. The curves below also assume no restocking of distillate. Restocking may be possible for some stations over the period they are running on distillate.

Figure B.1 – Power Load Duration Curves for Back Up Fuel Supplies



195. We have converted the MW electricity generation capability into a total of between 110 mcm to 175 mcm gas equivalent that can be displaced using distillate generation capability. This is shown in figure B.2 by way of load duration curves. Figure B.3 shows the mcm/d equivalent levels of distillate fired power generation for last winter and other winters for reference. In 2008/9, there was an estimated total of less than 1.0 mcm equivalent distillate use around system peak days, but we believe around 10 mcm/d is possible for a relatively few days. As we haven't observed much switching to distillate since winter 2005/6, there is some underlying risk that if switching is needed, there may be some unforeseen operational issues.

Figure B.2 – Gas Volume Equivalent Load Duration Curves for Back Up Fuel Supplies

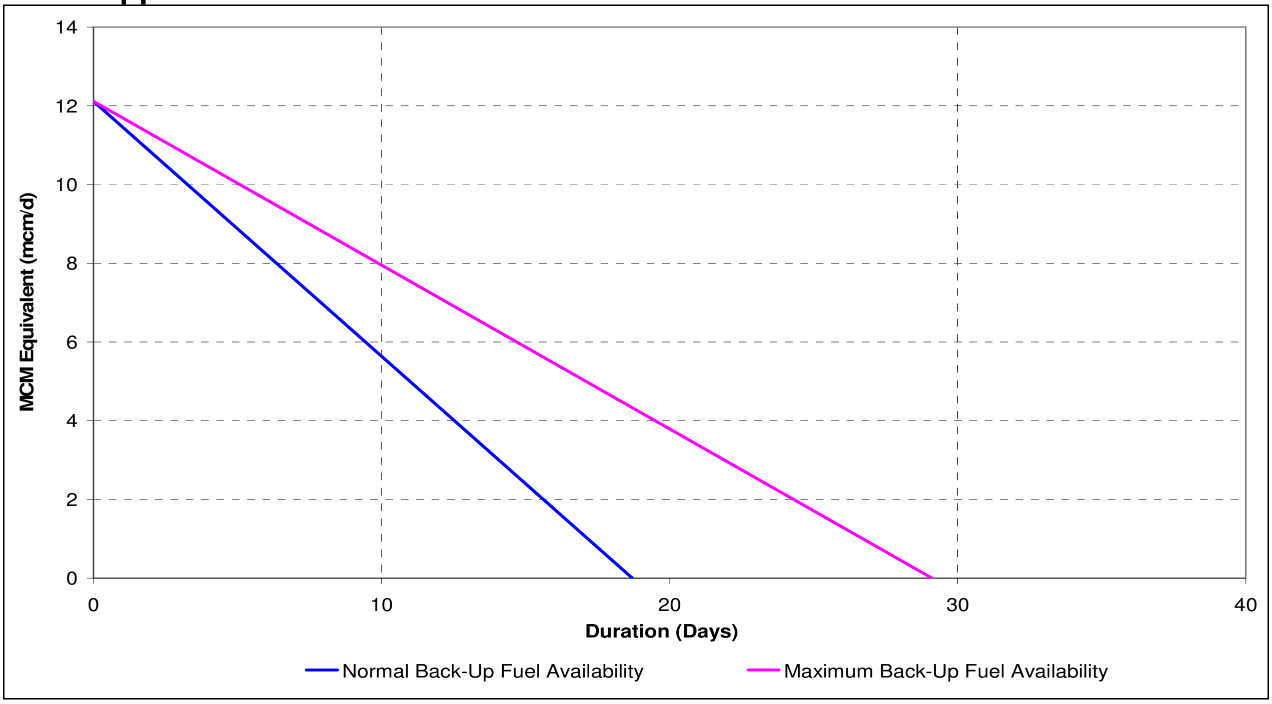
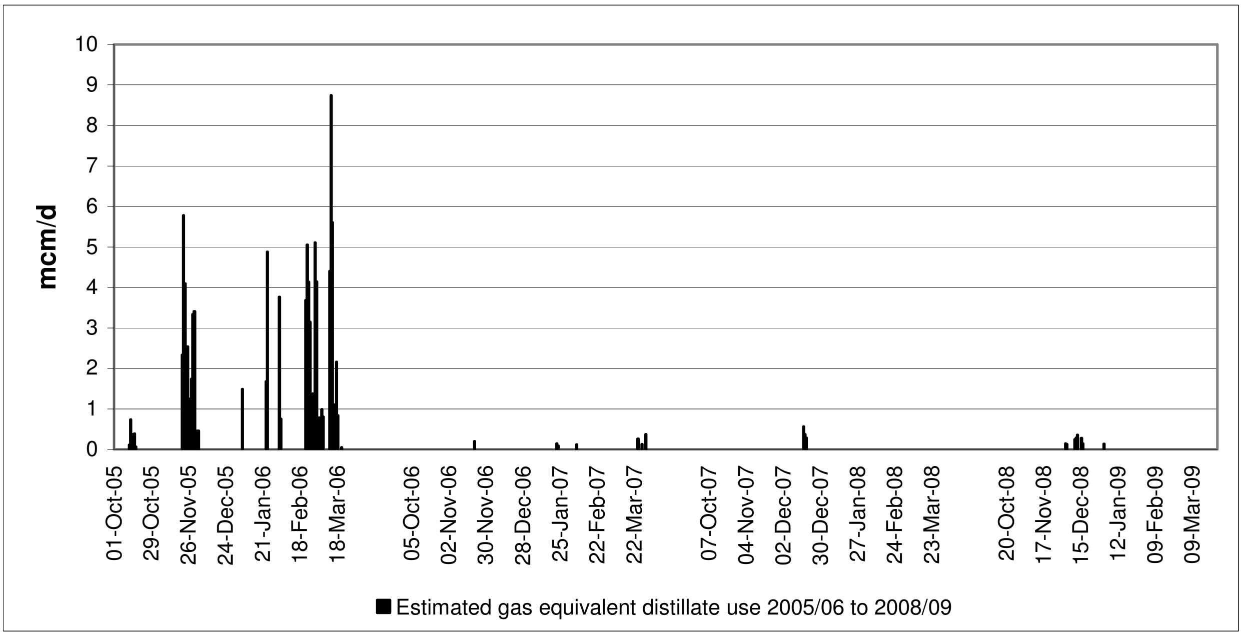


Figure B.3 – Estimated Historic Distillate Use in Term of mcm/d Relief to Gas Demand



Potential for Gas Demand-Side Response from Gas Fired Generation

196. We continue to expect that gas-fired power stations have the potential to respond to market price signals, decreasing their gas consumption when the cost of generating from other fuels is lower than the price of burning gas. We see this effect already in

action in the market in normal circumstances as the generation emphasis moves between generation types in response to economic signals. In tight gas market conditions we therefore expect high levels of generation running from other fuel types.

Analysis of potential CCGT gas demand response

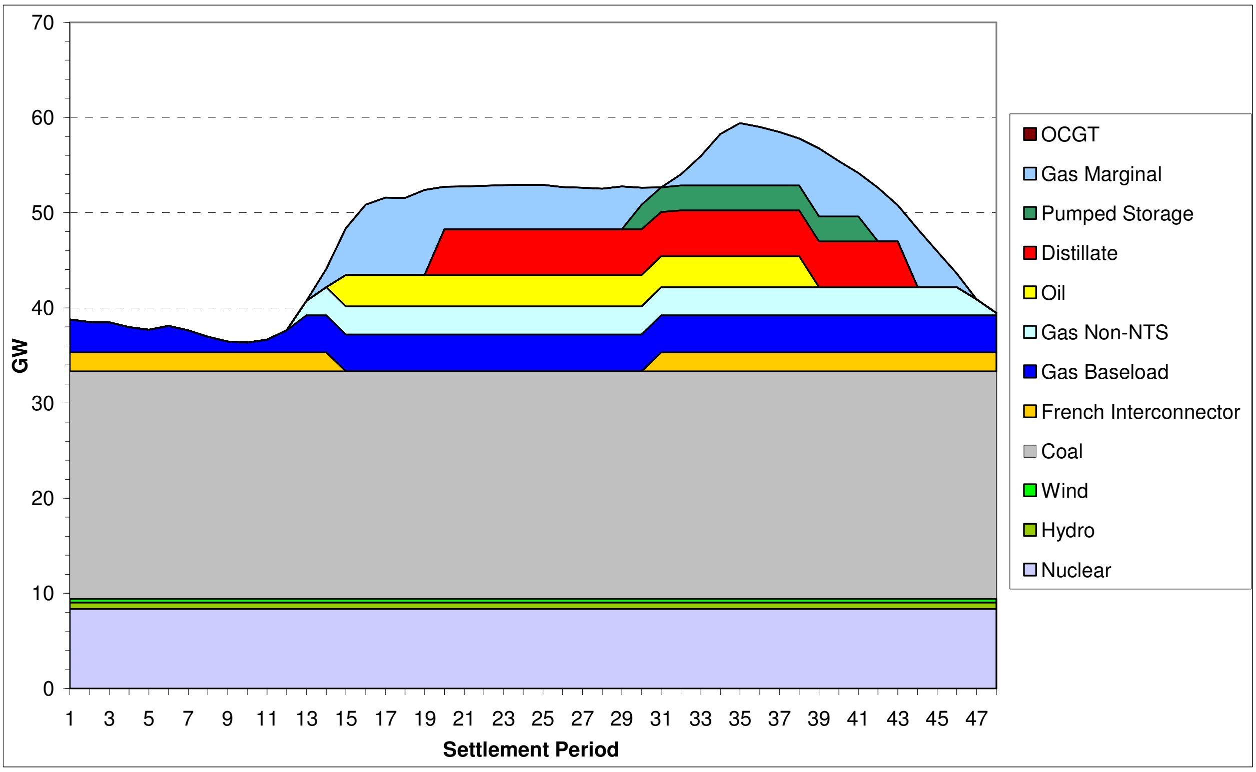
197. We have modelled the amount of relief that gas power stations switching to distillate could provide to the gas market. Using the assumption that distillate capable gas power stations ran for 12 hours per day gives at least 10 mcm/d of gas relief for up to 4 days based on normal and full distillate stocks. The charts here assume no restocking of distillate which we expect would take place as stocks are depleted over a number of days.

Table B.1 – Assumed plant availability factors for demand-side response analysis

Power Station Type	Full Metered Capacity (GW)	Assumed Availability	Assumed Availability (GW)	Model Assumptions Summary
Nuclear	10.4	80%	8.4	Baseload
French Interconnector	2.0	100%	2.0	Baseload, except 7 am to 3pm weekdays
Hydro	1.1	80%	0.9	Baseload
Wind	1.6	27%	0.4	Baseload
Gas Baseload	4.3	90%	3.9	Baseload
Gas Non-NTS	3.3	90%	3.0	Baseload
Coal	28.1	85%	23.9	Baseload
Oil	3.4	95%	3.3	12 hours over peak
Pumped Storage	2.7	95%	2.6	6 hours over peak
Distillate	5.3	90%	4.8	175 hours
Gas Marginal	13.3	90%	12.0	Marginal plant
OCGT	1.3	80%	1.0	Low merit, run occasionally
Total	**77.0**		66.1	
Average availability		**86%**		

198. Figure B.4 illustrates how electricity demand could be met on a typical cold day in a severe winter, consistent with the modeling assumptions described in table B.1. It shows approximately 23.9 GW of coal-fired generation throughout the day, gas as the marginal fuel across the day and distillate used for 12 hours around the peak demand period.

Figure B.4 – Potential generation profile – 1 in 20 cold winter weekday



199. The ability of the markets to operate in a manner consistent with our assumptions remains largely untested given the succession of mild winters experienced in recent years, which has necessitated only a low requirement for gas demand-side response. In particular, the ability of the electricity market to switch to a significantly reduced gas demand will be entirely dependant on the price signals triggering the appropriate response.

200. The most significant use of distillate occurred in the winter of 2005/6 of up to 9 mcm/d. This analytically derived daily use of distillate corresponds well to a relatively high utilisation of the daily capability we believe there exists across the CCGT generation fleet. We empirically link the basis of Figures B.2 (technical capability to burn distillate) and B.3 (analysed distillate use) which reflect two different approaches to assessing capability giving some comfort in the assessment of power sector relief to the gas market.

201. We continue to believe that the switch to distillate would occur based on a gas price signal but there may be practical issues about how much switching would actually take place.

Winter Scenarios for Gas/Power interaction

202. Two scenarios have been simulated. The first is the base case assumptions described earlier in this report. Table B.2 shows the gas supply assumptions used in the base case gas/electricity interaction modeling. Gas supplies comprising UK continental shelf, LNG imports, Norwegian imports and BBL imports adds up to 343

mcm/d. Gas demands in excess of 343 mcm/d are allocated 20% IUK and 80% storage, broadly in line with Figure A.22. IUK imports are capped at 30 mcm/d.

Table B.2 – Gas supply for demand-side response analysis

Source of Supply	mcm/d
UKCS	183
Norway	100
LNG	40
BBL	20
IUK	0 - 30
Long duration storage (Rough)	42
Medium duration storage (MRS)	47
Short duration storage (LNG)	35

203. Table B.3 shows the total demand response required for the base case scenario in an average, cold and severe winter. The cold and severe winters are 1 in 10 and 1 in 50 conditions based on the last 81 years with no adjustment for climate change. The average winter is based on the 17 years from October 1987 to September 2004. The potential CCGT figure shows the amount of required demand side response that could potentially be provided by the power generation sector. There are no problems with the base case scenario with only a small amount of demand response required from the power sector in a severe year.

Table B. 3 – Potential CCGT demand response (bcm), base case generation, base case gas supply

	Average	Cold	Severe
Required	0.0	0.0	0.4
Potential CCGT	0.0	0.0	0.4
Deficit	0.0	0.0	0.0

204. The second scenario reduces both the non-gas generation and gas supply. There is no wind generation, no electricity imports and 2GW electricity exported from 7am to 3pm. Non-storage gas supply is reduced by 40 mcm/d which could be caused by the loss of a major supply source such as Rough or increased exports through the interconnector caused by a closure of the Russia/Ukraine pipeline. Table B.4 illustrates the impact of these changes. There are no problems in an average winter but a cold winter will require some non-power demand response.

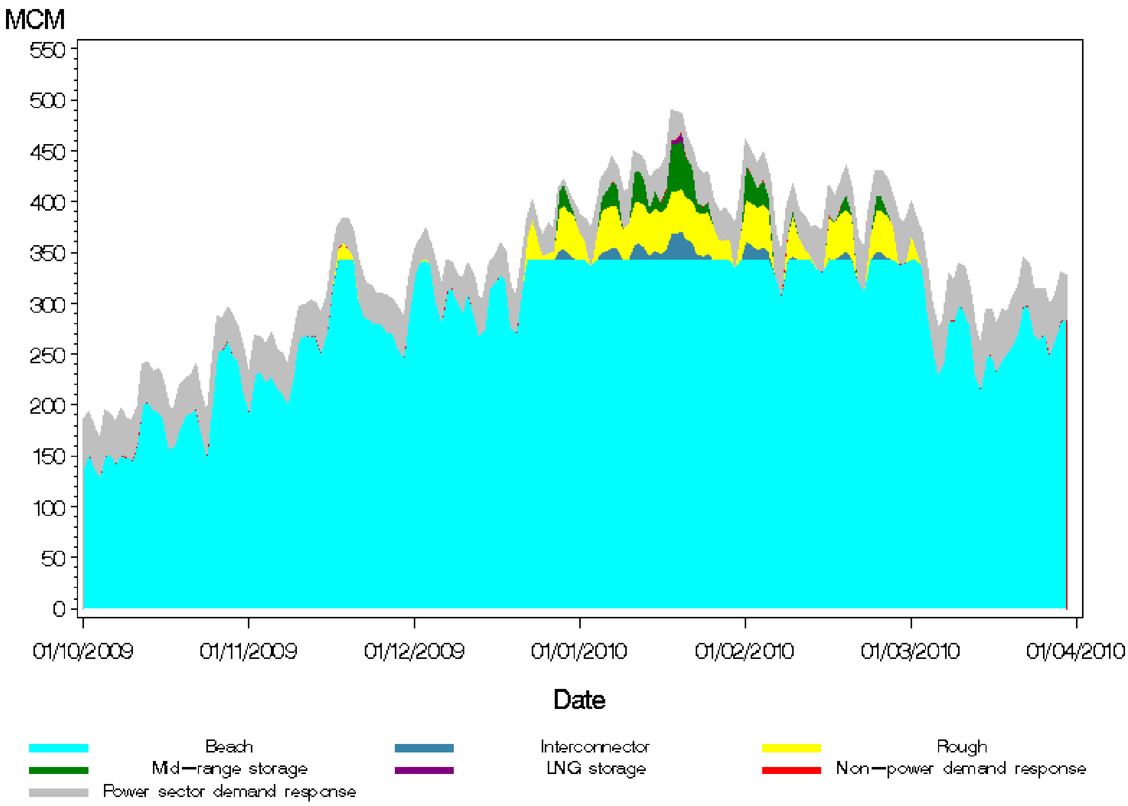
Table B. 4 – Potential CCGT demand response (bcm), low generation, low supply

	Average	Cold	Severe
Required	0.0	1.5	3.2
Potential CCGT	0.0	1.0	1.6
Deficit	0.0	0.5	1.6

205. The information in these tables is processed from simulations[26] of what the demand would be if historical weather was repeated. The following graphs are from a selection of these simulations. The model does not allow for refilling of mid-range storage or distillate stocks, however during the worst winters there would be little opportunity because of the consistently high demands. This analysis keeps the same ranking order throughout the winter resulting in CCGT demand response at low levels of demand as well as on high demand days. At low levels of gas demand this demand response is unlikely to occur because there should be plenty of gas to satisfy all demands.

206. Figure B.5 shows the base case scenario for 1962/3 weather, the coldest winter in recent history. Beach gas includes UKCS, Norwegian imports, LNG imports and BBL. Figure B.5 shows that even a winter as cold as 1962/3 would not be a problem.

Figure B. 5 – Theoretical gas supply build-up, base case, 1962/3 winter

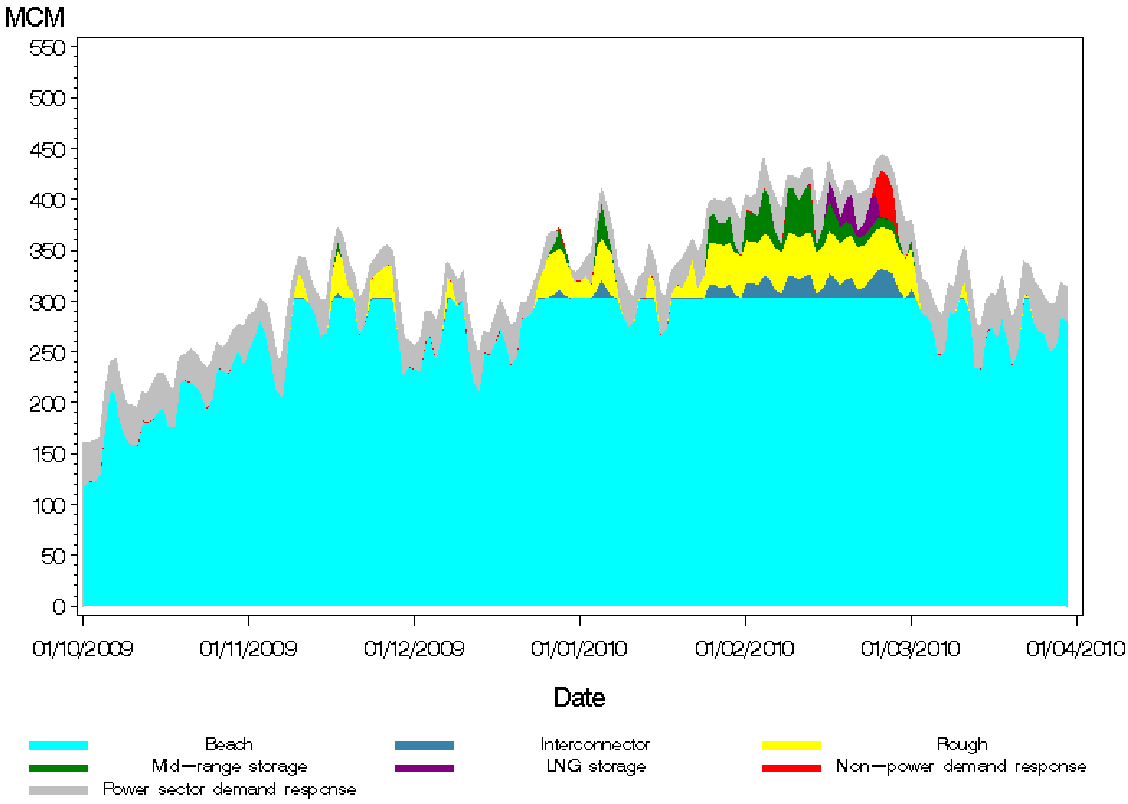


207. The low generation, low supply case is less able to cope with a cold winter. 1985/6, the coldest winter since 1962/3, was 1 in 12 cold but it ended with the second coldest February in the last 81 years. Figure B.6 shows the impact of 1985/6 weather. It shows that it is the number of cold days that would cause a problem, if 1985/6 weather was to be repeated, with most of the mid-range storage and all of the LNG storage used up.

[26] For more information see paragraph 7.1 of the Demand Forecasting Methodology Document: http://www.nationalgrid.com/uk/Gas/OperationalInfo/operationaldocuments/Gas+Demand+and+Supply+Forecasting+Methodology/

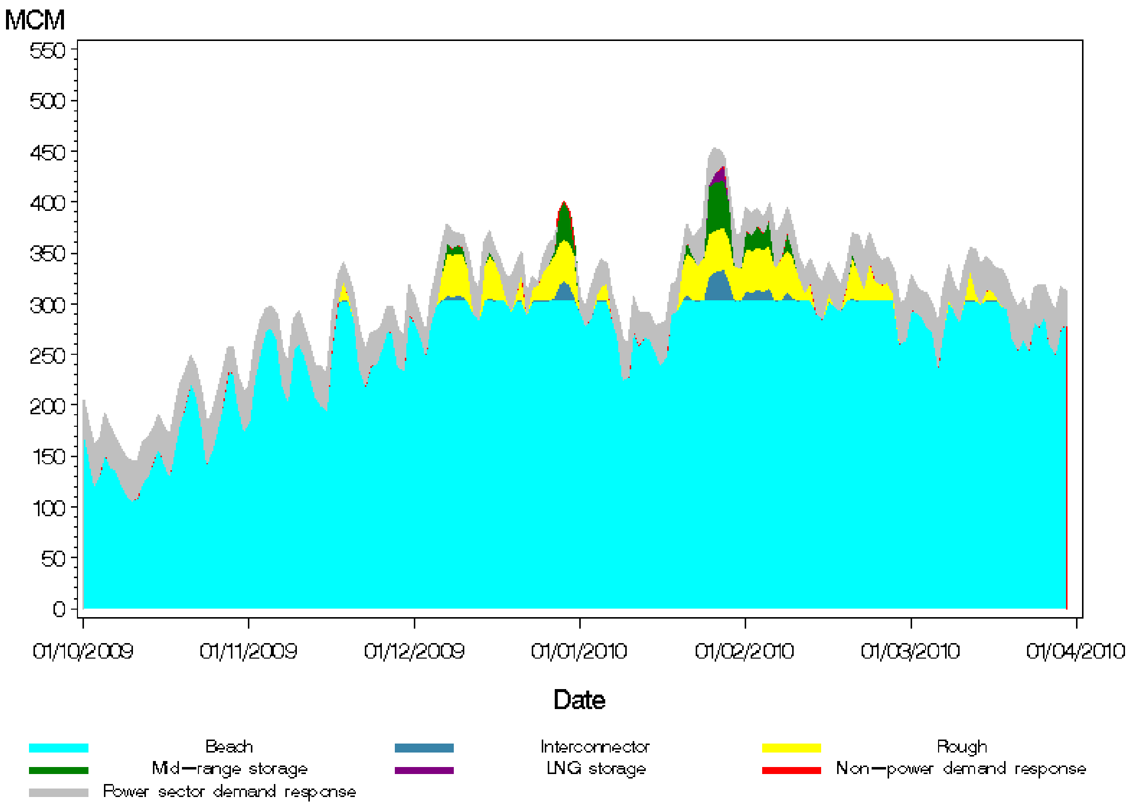
There is very little relief available from the power market. The non-power demand response area shown in red is the amount of demand that cannot be supplied under the central supply case. This demand reduction would be expected to be managed by shippers not National Grid. This demand reduction includes shipper interruption and self interruption due to high prices. It is likely to occur from the first days of high demand, which, when combined with refilling of mid-range storage during the milder weather in mid-January, would allow the use of LNG and mid-range storage to continue for longer.

Figure B. 6 – Theoretical gas supply build-up, low generation, low supply, 1985/6 winter



208. Figure B.7 shows that for a less extreme cold winter even the low generation, low supply scenario will be able to cope. 1995/6 was the coldest December to February in the last 20 years. The 1995/6 winter was 1 in 3 cold, based on data for the last 81 winters.

Figure B. 7 – Theoretical gas supply build-up, low generation, low supply, 1995/6 winter



Section C
Industry Framework Developments Relevant for Security of Supply

Introduction

209. National Grid remains committed to the development of commercial arrangements that encourage timely and appropriate market responses to secure energy supply-demand balances. This chapter reflects ongoing industry discussions, the detail of which can be found on our website or the relevant industry code administrators' website.

Gas

Entry Capacity Substitution

210. Ofgem introduced an obligation for National Grid to undertake Entry Capacity Substitution. Under this obligation National Grid will seek to substitute unsold Non-incremental obligated Entry Capacity to other entry points where Incremental obligated Entry Capacity is required to be released.

211. In order to meet the aims of this obligation regular workshops have taken place with the Industry. In May 2009 an Informal Consultation commenced to consider three potential solutions, followed by a further workshop in July 2009. A Formal Consultation on the proposed Methodology Statement which is based on the use of "retainers" commenced in August 2009. The proposed Methodology Statement can be found on our web site http://www.nationalgrid.com/uk/Gas/Charges/statements/

212. The proposed Methodology Statement will be issued to the Authority on 7th September 2009 and an Impact Assessment will be undertaken. If approved, Entry Capacity Substitution will be implemented on 01 March 2010

Exit Reform

213. Current arrangements allow Users to secure capacity until 30 September 2012.

214. Enduring NTS offtake arrangements allowing Users to secure capacity from 01 October 2012 onwards have now been implemented.

215. Applications can be made as follows:

- Users can apply for Enduring capacity in the Annual July Application Window or via an Ad-hoc process.
- Developers can apply for Enduring capacity via the ARCA process.
- Annual, Daily and Offpeak capacity can also be obtained in the Enduring regime.
- Further detail on Exit Reform can be found on a dedicated section of our website www.nationalgrid.com/uk/Gas/OperationalInfo/endureeexitcap/

Exit Capacity Substitution

216. Ofgem introduced an obligation for National Grid to undertake Exit Capacity Substitution. Exit Capacity Substitution would only apply to capacity from 1 October 2012 onwards i.e. the enduring period.

217. Regular workshops will be held with the Industry to discuss the most appropriate way to introduce this obligation. National Grid will publish a timetable in December 2009 for future Exit Capacity Substitution workshops.

218. National Grid has a licence obligation to submit an Exit Capacity Substitution Methodology Statement to the Authority by 4 January 2011, if approved implementation will be from the July 2011 application window.

Amendment to QSEC and AMSEC Auction timetables

219. On 29 May 2009 Ofgem approved Modification Proposal 230AV which moves the QSEC Auction from September to March each year. This will be implemented on 01 January 2010. The modification retains the September 2009 QSEC before moving the QSEC to March on a permanent basis. It is also retains the AMSEC auction in February with a shortened transaction period from the current 2 years to 18 months. This results in Incremental NTS Entry Capacity being released from 1 October at the start of the winter period when flows increase.

Force Majeure

220. National Grid raised Modification Proposal 0262 in August 2009. This Proposal seeks to address the impact of Force Majeure on Users, at either an ASEP or NTS Exit point. Currently where Force Majeure is called National Grid is relieved from its UNC requirement to make payment for any delay or failure in the performance of its obligation. This modification proposes that Users registered as holding firm capacity at the relevant ASEP or NTS Exit Point will receive a rebate. Ofgem is now considering this proposal.

Revision of the UNC Gas Balancing Alert (GBA) Trigger /Safety Monitor

221. In May 2009, National Grid NTS, issued proposed revisions in the use and publication of the Safety Monitor methodology whereby a single aggregated figure would be utilised, covering all storage facilities with two or more days of deliverability, rather than multiple monitor levels covering each different Storage Facility Type (short, medium and long range storage).

222. Following this in July 2009, National Grid NTS has raised UNC Modification Proposal 0257 ‘Revision of the Gas Balancing Alert Trigger /Safety Monitor’ to ensure that the prevailing GBA trigger calculation is modified to ensure that it

reflects the revised Storage Monitor methodology. Ofgem is now considering this proposal that if approved, would be implemented from 1st October 2009.

Review of the UNC Post-emergency Arrangements

223. In February 2009, National Grid initiated an industry review of the prevailing UNC post-emergency arrangements. The objective of the review was to consider primarily what UNC changes might be made to the post-emergency claims process that would improve the definition and give greater clarity in this area. It was anticipated that any such changes should provide confidence to shippers that they would be able to recover their costs for providing additional non-UKCS supplies and/or demand side reduction following a Network Gas Supply Emergency (Gas Deficit Emergency).

224. Following the conclusion of this review in June 2009, and, where appropriate, taking into consideration the consensus views of the industry, National Grid NTS has raised UNC Modification Proposal 0260 ‘Revision of the Post-emergency Claims Arrangements’ which is currently being considered by Ofgem.

<u>Electricity</u>

Balancing & Settlement Code (BSC) relevant proposals / issues

Electricity Market Information

225. The Authority approved BSC modification P226 for implementation on the 25th June 2009. P226 will enhance the visibility of key Large Combustion Plant Directive (LCPD) emission limit/allocations and operating hours data by publishing such data on the Balancing Mechanism Reporting System (BMRS). It is anticipated that increased visibility of LCPD data will allow market participates to make more informed economic decisions.

226. BSC modification P243 proposes to publish national forward generation availability (output useable) broken down by ‘fuel type’. It proposes to use the same eleven fuel type categories that are currently used for provision of the national outturn (last 5 minute and half-hourly averages) generation data. This proposal, if approved, will allow the market participants to compare the forecast and outturn generation data on a like-for-like basis, as well as providing indicative information on the future availability of different types of plant.

227. BSC modification P244 proposes to deliver BritNed outturn flow data to the BMRS which is scheduled to be commissioned in late 2010. This proposal, if approved, will ensure consistency with the existing BMRS generation data which is broken down by fuel type and separately shows the outturn data for the existing interconnectors to France and Ireland.

Incentives to balance

228. The Authority approved BSC modification P217 for implementation on the 5th November 2009. P217 will alter the calculation of the main electricity imbalance price by removing any premium associated with balancing services taken for the purpose of resolving transmission constraints. To achieve this, National Grid must

identify in real time, balancing services taken to resolve transmission constraints, and also provide balancing service adjustment data (BSAD) as individual trades. This modification will result in imbalance prices that more closely reflect the short term value of energy.

Black Start / Fuel Security Code (FSC) – Market Suspension/Recovery

229. National Grid raised two BSC modifications to improve the Black Start and FSC procedures and compensation arrangements, including the derivation of a single imbalance price, following a Black Start Period or FSC event. P231 provides greater granularity on market restoration processes, including clarity of roles and responsibilities of relevant parties, whilst P232 addresses post-event settlement processes, including the development of a price calculation methodology applicable to Black Start Periods and Fuel Security events. Ofgem approved both P231 and P232 in June 2009 for implementation in November 2009.

Following approval of P231 and P232, a BSC Procedure is currently being developed by the industry to provide more details on the processes for restoration of the market and post-event compensation arrangements.

Connection and Use of System Code (CUSC) – Relevant Proposals

Transmission Access Review

230. The 2008 Transmission Access Review[27] (TAR) set out the need for reform to grid access rules in order to support the connection of renewable and other low carbon generation by 2020 (and beyond). The TAR set out some principles that might underpin an efficient grid access regime.

231. As a response to the TAR (and to address all the TAR principles) National Grid established three industry working groups, under the CUSC framework to consider in a coordinated way the options for access reform and their wider impacts. Over the past twelve months, these working groups have developed a number of models for reform[28].

232. To ensure reforms are implemented in a manner and timeframe consistent with Government objectives on energy and climate change the Government has decided to intervene, using the powers taken in the Energy Act 2008. In line with this, the Department of Energy and Climate Change has published a consultation on 'Improving Grid Access'[29].

[27] Ofgem and BERR (2008): 'Transmission Access Review – Final Report', http://decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/access_review/access_review.aspx

[28] The proposals raised from these working groups are CAP161, CAP162, CAP163, CAP164, CAP165, CAP166 and CAP168, further information can be found at http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/

[29] http://decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx

CAP169: Provision of Reactive Power from Power Park Modules, Large Power Stations and Embedded Power Stations

233. CAP169 seeks to amend various sections of the CUSC to accommodate the provision of Reactive Power from Power Park Modules, introduce an appropriate Reactive Power Mandatory Services Agreement obligation for all categories of Large Power Stations and facilitate an appropriate payment mechanism for Reactive Power from restricted Embedded Power Stations. CAP169 was developed by Working Group, with 3 alternatives raised and considered. It requires corresponding changes to be made to the Grid Code. CAP169 will be reported back to the October 2009 CUSC Panel meeting and subsequently submitted to the Authority for decision.

CAP170: Category 5 System to Generator Operational Intertripping Scheme

234. CAP170 seeks to introduce a new category 5 System to Generator Operational Intertripping Scheme to cover intertrips capable of being armed with respect to a derogated non-compliant transmission boundary. It was raised by National Grid on the basis that at derogated non-compliant transmission boundaries the need to take action to manage constraints is more onerous than at compliant transmission boundaries. As such, the use of intertrips (assuming it is more economic than alternative Bid-Offer action to constrain generation pre-fault) is a necessity rather than an occasional tool in order to maximise flows across the derogated non-compliant transmission boundary. CAP170 was granted urgent status and proceeded straight to consultation by the company. CAP170 is currently with the Authority for decision, with the Authority having issued an Impact Assessment to consult on the proposal with the industry.

Grid Code relevant proposals / issues

235. On 27th May 2008, exceptional loss of generation led to the operation of the first stage of the national low frequency demand disconnection scheme. After an investigation by the Energy Emergency Executive Committee (E3C), two Working Groups were formed, one to investigate the effectiveness of the Low Frequency Demand Disconnection scheme and the other to assess the performance of embedded generation during the incident.

236. It was agreed at May 2008 Grid Code Review Panel (GCRP) to establish a joint Grid Code and BSSG (Balancing Service Standing Group) Working Group. The Working Group is tasked with reviewing the technical requirements and commercial mechanism applicable to the provision of frequency response, given the current generation mix and the anticipated changes in generation technologies.

BM System Replacement

237. National Grid has proposed the replacement of the Balancing Mechanism (BM) system with a global best-practice IT system using up to date technologies and a go live date of mid 2012. Last year National Grid consulted with the industry on the proposed BM replacement and the industry comments were fed into the System Requirements Specification. National Grid is currently evaluating the vendor responses, and the vendor evaluation process is likely to go into early 2010.

Implementation of a new Congestion Management System on the England-France Interconnector (IFA)

238. In order to comply with the Congestion Management Guidelines[30] National Grid Interconnector Limited (NGIL) and the French transmission system operator (RTE) have been developing a Capacity Management System (CMS) on the IFA. Implementation is currently planned for 1st October 2009. The key features of the new system will be Use it or Sell it (UIOSI) for long term capacity, Use it or Lose it (UIOLI) for day ahead capacity, five re-nomination points within day and two intraday auctions.

[30] The Congestion Management Guidelines, published in the Official Journal on 11 November 2006 (OJ L 312, 11.11.2006, p. 59-65), set the congestion management framework in the EU. They entered into force on 1 January 2007 and are annexed to Regulation (EC) 1228/2003 of the European Parliament and of the Council, of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity.