Winter Outlook Report 2008/9

Introduction

1. The competitive gas and electricity markets in the UK 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: (i) as the primary transporter, for ensuring there is adequate and reliable network capacity to meet anticipated transportation requirements; (ii) 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 Business Enterprise & Regulatory Reform (BERR) has a role in setting the regulatory framework for the market.

2. In recent years, National Grid has provided information to the participants in the gas and electricity markets by publishing an outlook for the winter ahead. This year, for the first time, we also provided a summer outlook report which examined supply and demand issues for this summer.

3. In conjunction with Ofgem, recognising that our sources of data are necessarily incomplete, we have conducted a consultation exercise designed both to help inform the industry and also to provide us with feedback to support the production of the winter outlook report. This Winter Consultation report was published on 10th June 2008. Ofgem also held a seminar on 10th September 2008 in London at which a number of industry representatives presented their views on the issues for this winter.

4. National Grid and Ofgem received responses to the Winter Consultation report from a number of market participants and these have been used to inform this updated Winter Outlook report. These responses were both helpful and informative, demonstrating the value of the consultation exercise.

5. The review of last winter was included in our consultation report and is not reproduced in this final report.

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cover both licensed entities, whereas in practice our activities and sharing of information are governed by the respective licences.

7. 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 2008/09 Outlook – Gas

9. Despite a recent fall in the oil price, all fuel price futures remain relatively high for next winter. The seasonal pricing of gas suggests coal will be the winter base load plant with gas fired generation as the marginal plant. UK and Continental gas prices are much higher than those in the US providing an incentive to deliver spot LNG cargoes to Europe in preference to the US. However as experienced last winter, the Far East may be again prepared to pay a premium to secure LNG cargoes.

10. Forecast demands for next winter are marginally lower than weather corrected actual demands in 2007/8. This is primarily due to an expectation of lower gas consumption for power generation due to completion of most retro-fitting flue gas desulphurisation (FGD) plant to existing coal-fired stations and high gas costs. There is also the possibility of a further turn down in domestic demand if consumer behaviour to higher gas prices continues.

11. Due to decline, our forecast for UKCS supplies for next winter is approximately 10% lower resulting in a need for increased imports. There is some uncertainty associated with all imports.

12. From Norway we anticipate similar production next winter compared to last winter as increased production from Ormen Lange is offset by the loss of Kvitebjorn. In terms of Norwegian imports to the UK, we expect that these will again be subject to Continental deliveries with the UK being the marginal source of supply. For BBL and IUK we expect similar performance to last winter though BBL (Dutch Interconnector) could be lower on account of new commercial arrangements for non physical reverse flow and our view for IUK (Belgian Interconnector) is now lower than in previous forecasts.

13. LNG imports again provide the biggest supply uncertainty with both Milford Haven and Grain Phase II facilities still to commission. Besides the uncertainty over the completion of new LNG terminals there is also the uncertainty as to whether the UK will attract LNG from competing markets, notably the Far East. Consequently our central view for LNG imports for next winter is relatively low with significant upside should either Grain Phase II or Milford Haven become operational.

14. Due to these supply uncertainties, our central view of non storage gas supplies for next winter is 336 mcm/d, within a range of 323 – 376 mcm/d. Storage volumes may be increased this winter if Aldbrough commences operation.

15. Our analysis of winter security highlights that market solutions may be required, such as demand-side response, should we experience a prolonged cold spell or any major loss of gas supply. This has been seen in previous winters.

16. Our assessment of storage requirements for the Safety Monitors based on our central view of supplies indicates that approximately 10% of all storage stocks are required at the beginning of the winter. As in previous winters, these levels will be subject to change based on the actual levels of supply we receive.

Winter 2008/09 Outlook – Electricity

17. For the electricity market in 2008/09, the notified generation background is broadly similar to that observed prior to the 2007/08 winter. Provided the electricity market continues to make plant available in response to the appropriate price signals, demand should be able to be met in full even in a harsh winter (i.e. 1 in 20 demand).

18. Demand should be met in all but the most extreme potential combinations of demand forecast error and generation unavailability.

19. Our current operational view of generation capacity anticipated to be available for the start of winter 2008 is 75.4GW giving a 25.4% plant margin.

20. Current forward prices for fuel and carbon for the coming winter indicate that coal-fired generation should be preferred to gas-fired generation. However, fuel prices may change as we approach the winter period and the impact of the large combustion plant directive (LCPD) may change the relative economics.

21. Generation availability is key to ensuring that there is adequate generation to meet demand. Nuclear stations at Heysham and Hartlepool are currently out of service for repairs. British Energy has stated that these units should return by Q3 2008/09 in time for the period when peak demands are likely to occur. However, there is always some risk that these units do not return as planned and we have considered this as an alternative scenario.

22. As the amount of wind generation as a proportion of the installed generation capacity increases, the capacity credit ascribed to a given installed capacity of wind generation becomes a key issue. Our analysis continues to indicate a mean load factor of 35% over the December and January evening periods when a peak demand is most likely, though this is highly variable.

23. There is scope for gas power stations to run on distillate fuel for several days providing, we estimate, between 110 and 180 mcm of gas equivalent output assuming no restocking of distillate.

24. 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.

Contents

Section A
Outlook for Winter 2008/09

Gas

2008/9 Fuel Prices

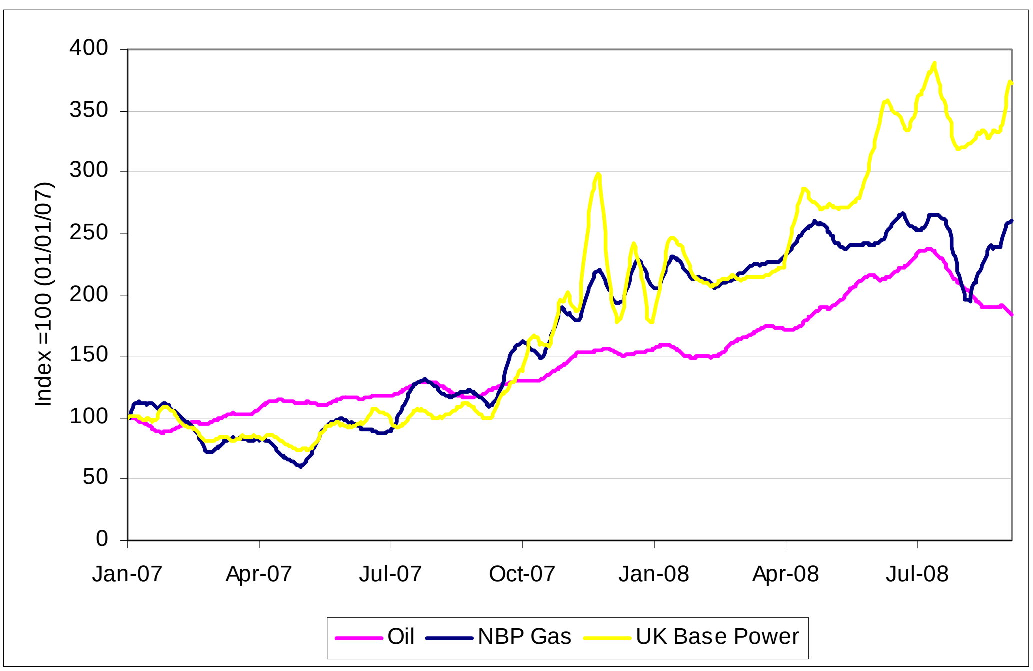
25. The past year has seen the oil price exert a greater influence over the UK gas price than in previous years, principally due to the continuing decline in North Sea gas production leading to the UK being more reliant upon imported gas. European gas contracts are predominantly indexed to the oil price, with the UK wholesale gas price becoming oil-indexed by association. This has seen NTS supply / demand fundamentals have less of an impact on the wholesale price.

26. Wholesale gas prices have generally tracked oil prices on an upward trend since May 2007, although there has been a recent fall in oil prices. The increase in oil prices has been largely driven by the relationship between global supply and demand. Increasing demand in places such as India and China has created a 'tight' market.

27. The increase in wholesale gas prices has in turn resulted in an increase in wholesale power prices, which are closely indexed to the gas price in the UK.

28. Figure A.1 shows the strong relationship between the oil price and wholesale gas and power prices in the UK.

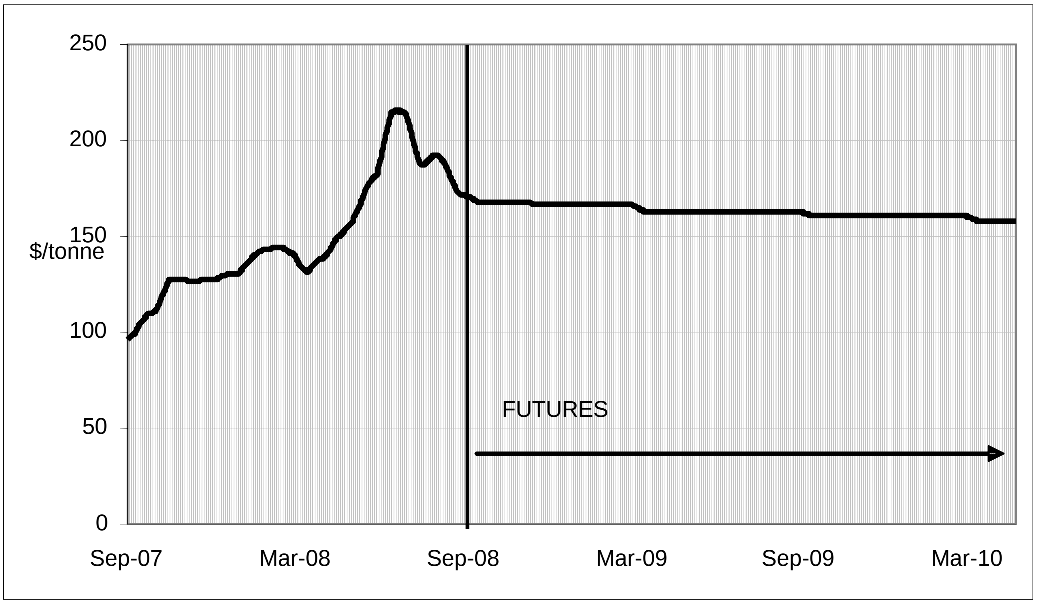
Figure A. 1 – Indexed energy prices since 2007



29. The strong oil, gas and power prices have been mirrored by significant increases in the price of coal, though like oil, coal prices have fallen recently. These increases have

been driven by strong global demand, particularly in China and India, coupled with a shortage of available freight. Figure A.2 shows the ARA CIF[1] coal price with forward prices reflecting the continuing strong demand, mainly driven by the growing number of power plants being commissioned across Asia.

Figure A. 2 – Historic and Future Coal Prices



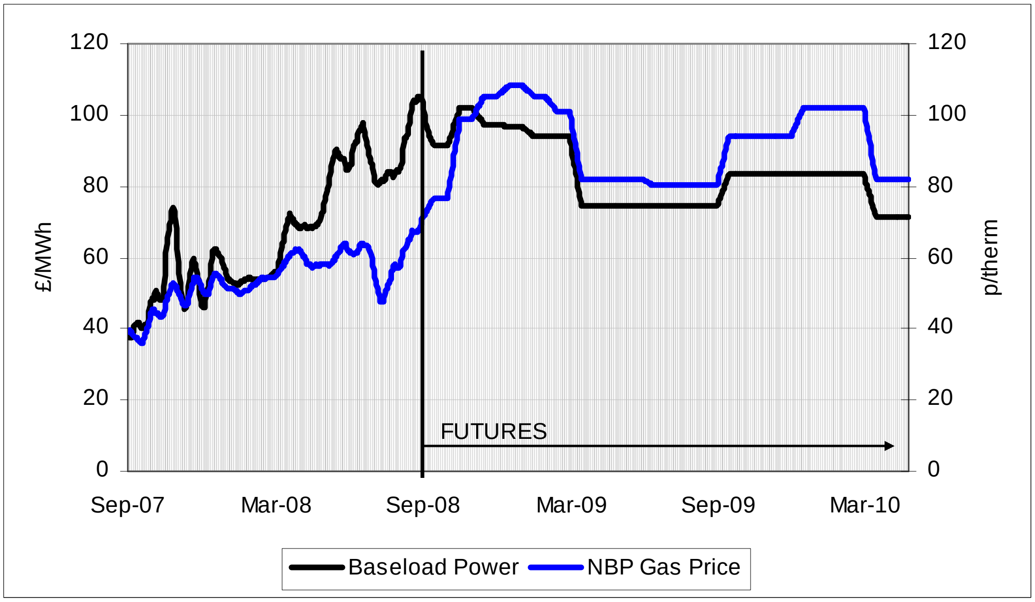
30. UK gas prices currently average 60p/therm for summer 2008, compared with 50p/therm for winter 2007/08. This puts into context the influence of the oil price on the gas price, which has more than offset the effect of reduced summer demands. A similar pattern has been seen in power markets, with base load power prices averaging £81/MWh during summer 2008, compared with £54/MWh in winter 2007/08.

31. Wholesale gas prices for winter 2008/09 are likely to be linked to oil prices with short-term corrections from this trend due to supply / demand fundamentals. This view was supported by feedback from our industry consultation.

32. Figure A.3 shows historic and future base load power and NBP gas prices.

[1] Amsterdam Rotterdam Antwerp Cost Insurance and Freight price. This price includes the cost of the goods, the freight or transport costs and also the cost of marine insurance.

Figure A. 3 - Historic and Future Gas and Power Prices (19/09/2008)



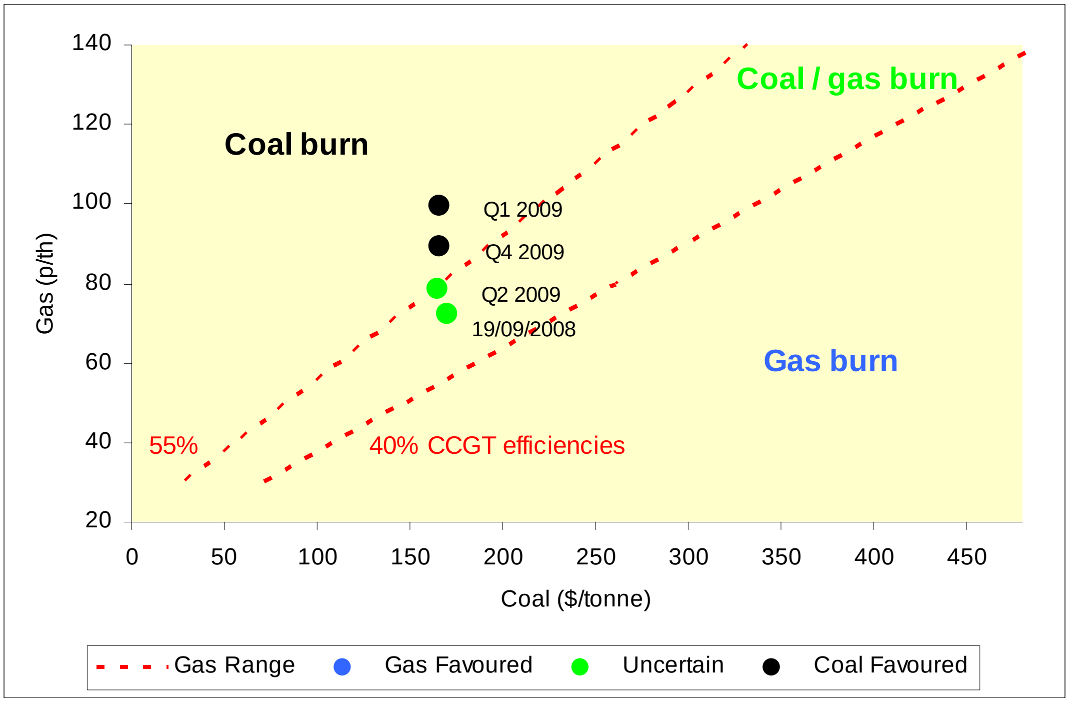
33. Current forward gas prices for winter 2008/09 are approximately £1/therm, with base load power prices at about £95/MWh. An element of risk is built into these prices, principally to account for possible colder weather and supply issues.

34. A loss of a significant source of gas supplies or a prolonged period of cold weather, particularly in the early part of the winter, may result in average prices pushing towards those indicated in the forward markets. In the event of a sustained outage at the wrong time, e.g. during a period of cold weather, then the resultant prices could be well above those in the current forward market.

35. Increased wholesale prices have resulted in significant increases in domestic gas and electricity charges. This may result in lower than forecast NDM demands, as observed in previous winters. Our forecast for NDM demand for winter 2008/09 did not assume the recent round of domestic price increases. Although this may reduce average consumption in this sector, it will not necessarily result in a reduction in 'peak' consumption.

36. Figure A.4 shows the preferred fuel for power generation at different price levels. A range of CCGT efficiencies is shown rather than a central assumption, with coal efficiency assumed to be 34% and the carbon price assumed to be €25/tonne. This suggests that coal would be burnt as the base load fuel for generation during the winter, based on the current forward curve. These prices are, of course, subject to change and the level of gas-fired generation can be influenced by other factors such as the operation of Large Combustion Plant Directive (LCPD) opted-out plant and nuclear plant availability, as witnessed last year.

Figure A. 4 – Gas v Coal Generation

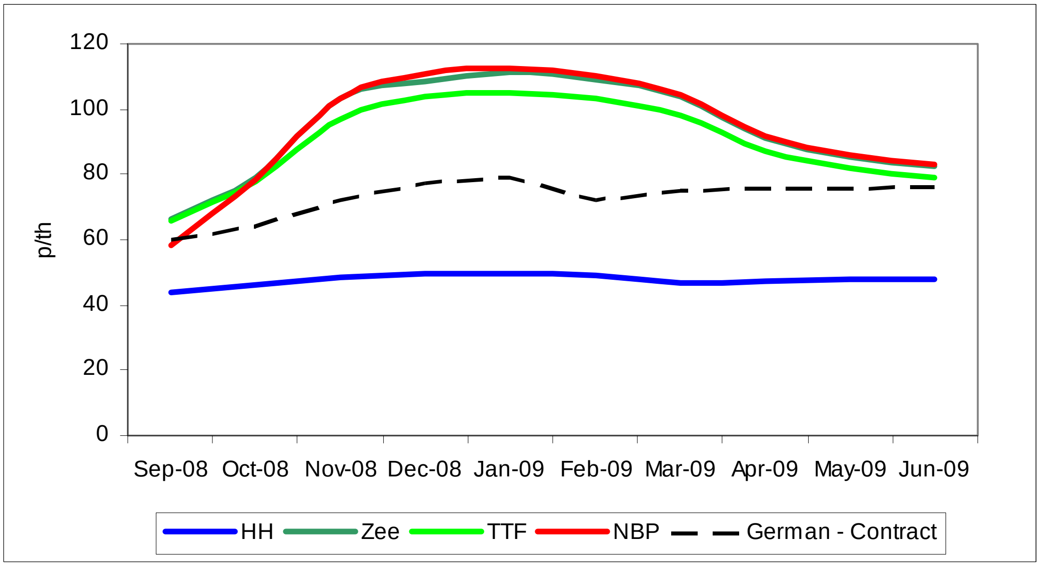


37. Figure A.5 shows the forward gas prices for European markets (NBP, TTF & Zeebrugge) and for the US (Henry Hub). As in previous winters, the NBP is at a slight premium to the other Continental markets. European winter prices are considerably higher than the Henry Hub price, with around a 60p/therm premium in the winter period. In terms of spot LNG cargoes this provides a considerable incentive to deliver LNG to Europe in preference to the United States.

38. However, the experience of winter 2007/08 suggests that prices in the Far East may exceed European levels if there is still a strong requirement for LNG, with Japan and South Korea expected to be prepared to pay a premium in order to secure LNG cargoes. Indeed, recent reports[2] suggest 120p/therm was paid for a recent LNG delivery to China.

[2] ICIS Heren Global LNG Markets (page 3) – 29th August 2008

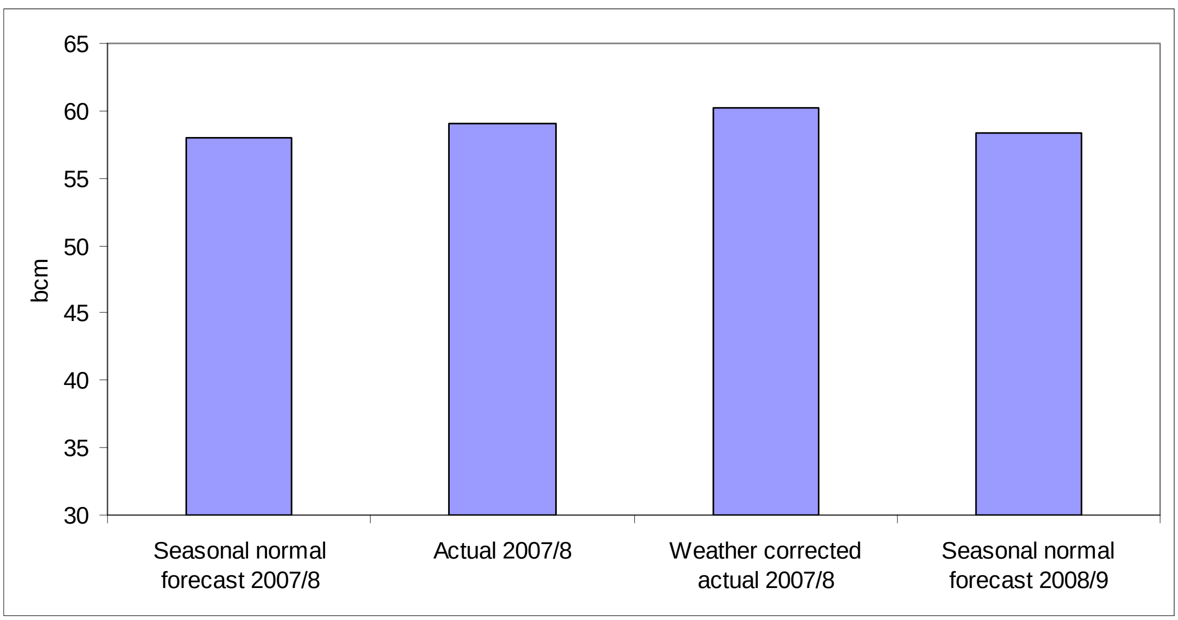
Figure A. 5 – Forward gas prices for Europe and the United States (Sept 2008)



Gas Demand Forecast 2008/09

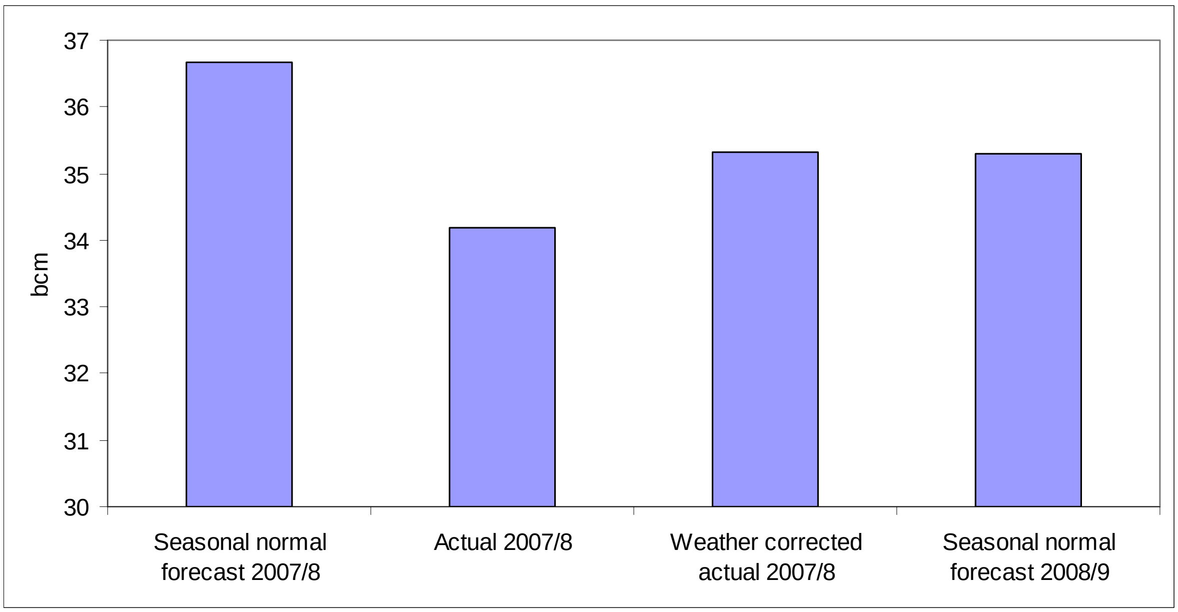
39. Figure A.6 compares the 2008 total forecast for winter 2008/9 with the actual, weather corrected and 2007 forecast demands for winter 2007/8. The new forecast is 1.3% lower than the actual and 3.3% lower than the weather corrected demands in winter 2007/8.

Figure A. 6 – Total Winter Demand



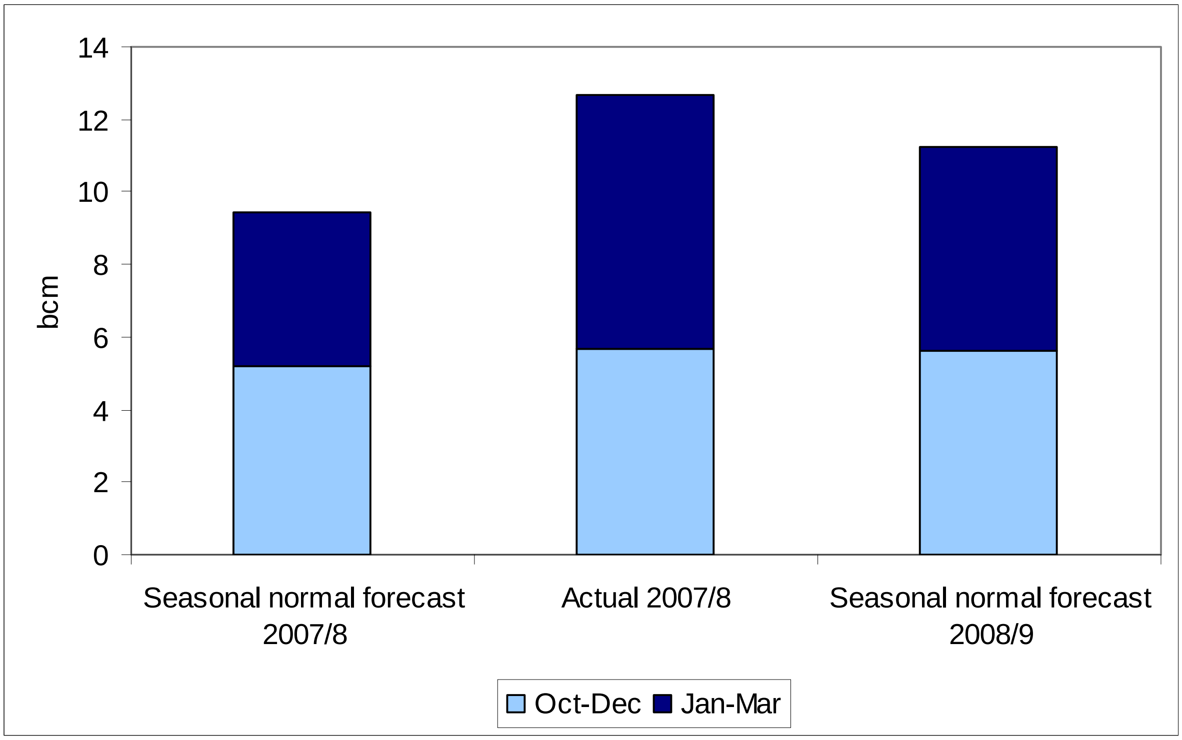
40. Figure A.7 compares the 2008 NDM forecast for 2008/9 with the actual, weather corrected and 2007 forecast demands for 2007/8. The NDM forecast for 2008/9 is almost identical to the weather corrected NDM demand in winter 2007/8. The feedback we received through the winter consultation believed that the trend for lower NDM brought about by high prices and efficiency measures would continue.

Figure A. 7– NDM Winter Demand



41. Figure A.8 compares the 2008 power generation forecast for 2008/9 with the actual and 2007 forecast demands for 2007/8. This graph illustrates the difference between early and late winter. The October to December forecast is very close to the actual power generation gas demand between October and December 2007. The forecast for January to March 2009 is higher than that forecast for the first 3 months of 2008 but lower than the demand that actually occurred.

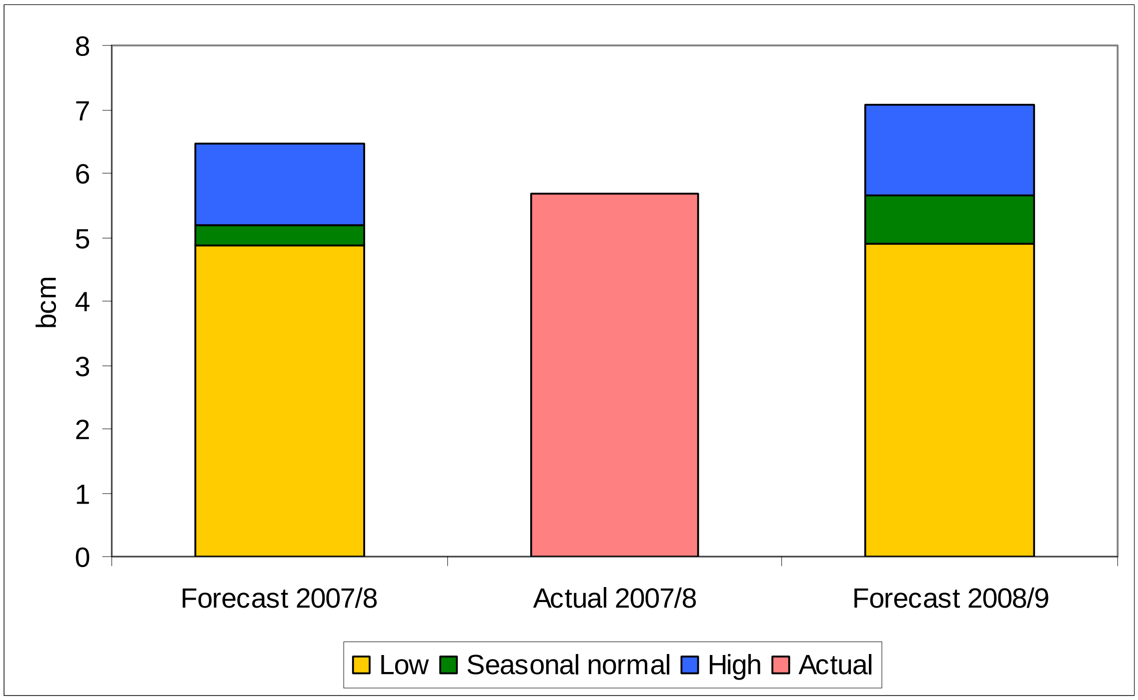
Figure A. 8 – Power Generation Winter Demand



42. Figure A.9 compares the October to December power generation figures in more detail. The low demand range is similar to the 2007/8 forecast. The seasonal normal[3] is 8.9% higher than the 2007/8 forecast due to the continuing impact of LCPD. The high level is 9.4% higher due to a number of factors including reduced output from nuclear power stations and increased take of gas from the NTS by directly connected power stations.

[3] Our seasonal normal forecast for power generation is our central or best view. Whilst there is no weather sensitivity in these demands, the ranking order used is dependent on weather and price assumptions derived from seasonal normal conditions

Figure A. 9 – October to December Power Generation Demand

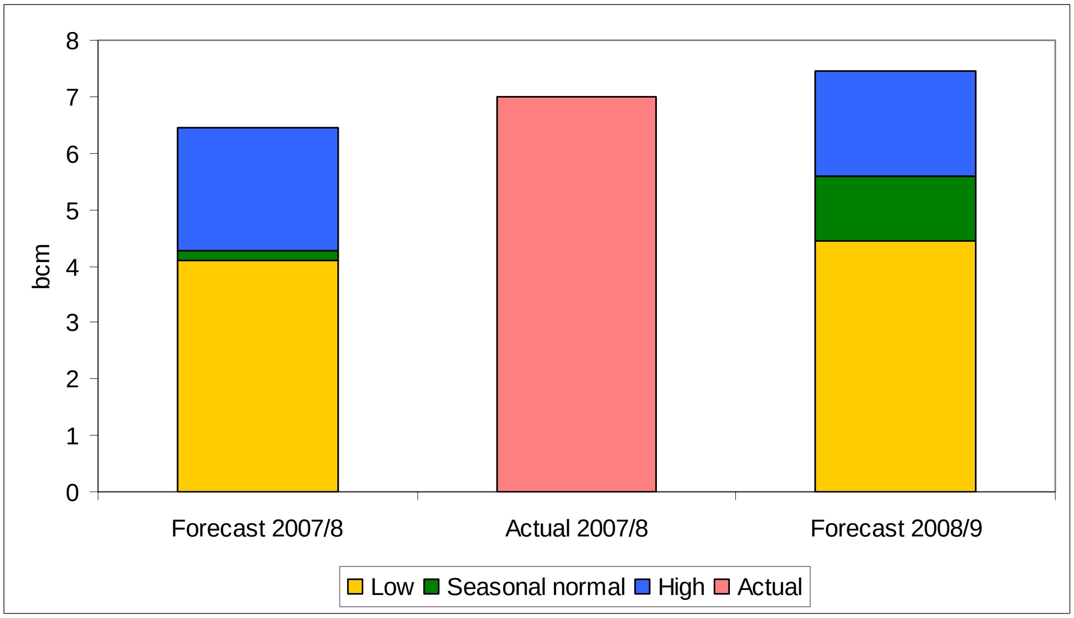


43. Figure A.10 compares the January to March power generation figures in more detail. The low demand range is marginally higher than the 2007/8 forecast. The seasonal normal is 30.8% higher than the 2007/8, whilst the high level is 15.7% higher.

44. The 2007 forecast assumed that coal would be base load resulting in the seasonal normal forecast for gas consumption being very close to the low level. One of the reasons for the high actual demand in January to March 2008 was the late fitting of Flue Gas Desulphurisation (FGD) plant to some of the coal power stations opting into the Large Combustion Plant Directive (LCPD) resulting in reduced output from these stations. The 2008/9 forecast assumes that all planned FGD installations will be completed by the coldest part of the winter. The LCPD will continue to limit the output of opted out coal power stations.

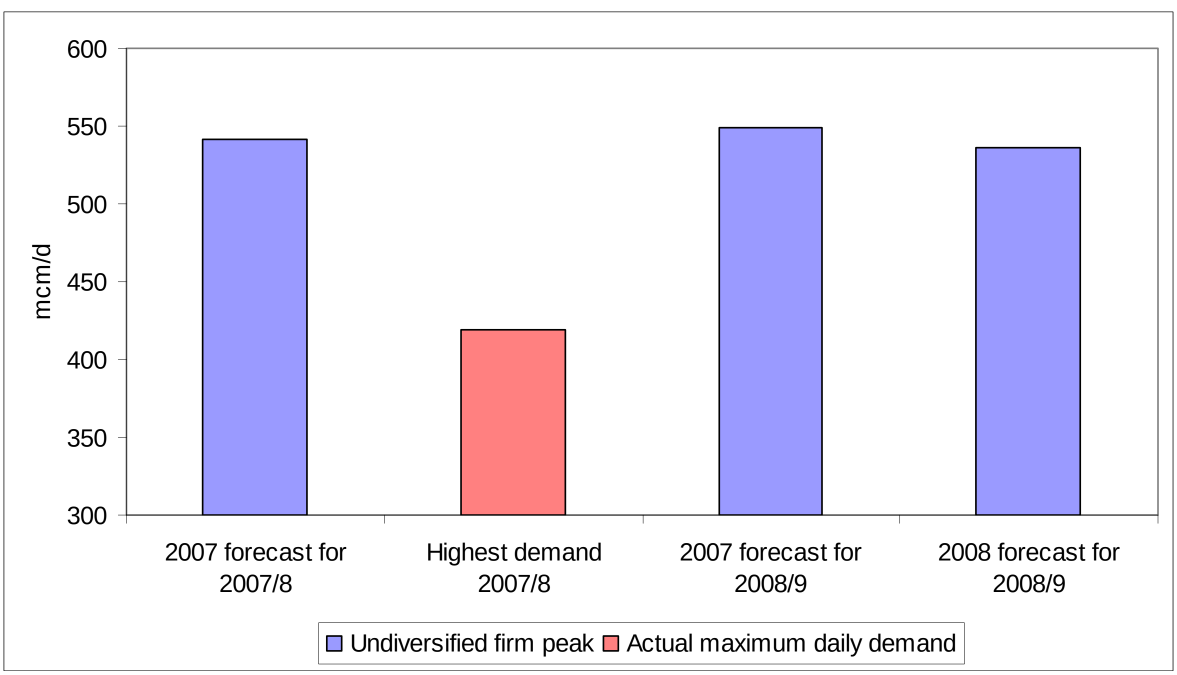
45. Current forward prices are indicating that coal burn should be more attractive relative to gas for winter 2008/9 resulting in a higher load factor for coal plant relative to 2007/8. The 2008/9 forecast also reflects the experience of the last two years, when gas use for power generation increased in the second half of the winter.

Figure A.10 – January to March Power Generation Demand



46. Figure A.11 shows that peak demand forecast for 2008/9 winter is marginally lower than the 2007 forecast for the 2007/8 winter, a small increase in power generation due to the commissioning of Langage CCGT power station being offset by a reduction in the LDZ firm peak day demand.

Figure A. 11– Peak Demand Forecast



2008/9 Non-Storage Gas Supply Forecast

47. 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 2008/9 Safety Monitors.

UKCS gas supplies

48. The analysis in our June document provided an initial view of UKCS supplies based on our 2008 TBE forecasts, combined with our experience last winter and our most up-to-date intelligence regarding new UKCS developments.

49. Following further analysis and receipt of additional market intelligence, we have re-assessed our UKCS forecast to form a final view of the maximum supply forecast by each terminal as shown in Table A.1. Our forecasts for Barrow, Easington, Burton Point and Teesside remain the same. Our forecast for Bacton is 1 mcm/d lower with production decline being offset by numerous relatively small new developments. Observed production decline at Theddlethorpe has led to a forecast 4 mcm/d lower than previously. At St Fergus, we have revised our forecast 5 mcm/d higher due to inclusion of several new field developments that more than offset production decline.

Table A. 1 – UKCS Maximum Terminal Supply Forecast

(mcm/d)	2007/8		2008/9	
	Base Case	Highest	Initial View	Final View
Bacton	76	65	67	66
Barrow	22	24	17	17
Easington	13	16	13	13
Burton Point	2	4	1	1
St Fergus	80	83	73	78
Teesside	24	26	23	23
Theddlethorpe	27	28	22	18
Total	244	246	216	216

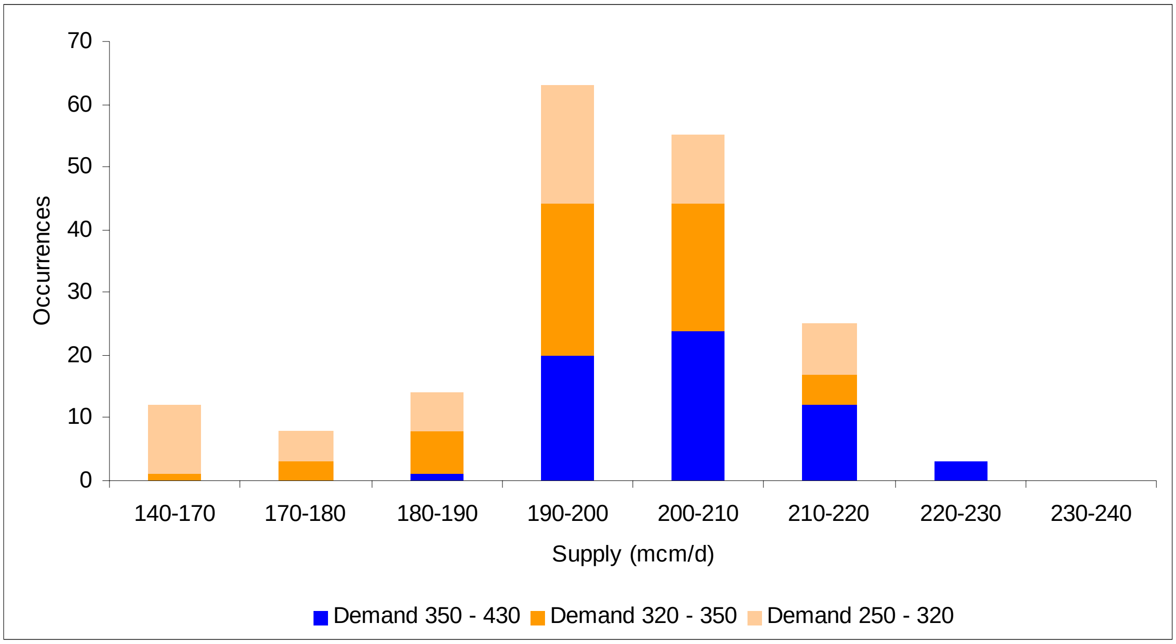
50. The net result of these changes is that our final view of UKCS supplies for Winter 2008/9 remains unchanged. Taking into account decline from existing fields and additional production from new fields, our year-on-year peak forecast is 9% or 28 mcm/d lower.

51. For the purposes of supply-demand analysis and safety monitor assessments, it is appropriate to assume a level of UKCS supply below the maximum forecast when calculating the supply outlook. The chosen level should reflect the level of delivered UKCS gas that we might expect on average in a prolonged cold spell. Last winter (excluding specific high swing supplies into Bacton and Barrow), we observed relatively consistent availability approaching 90% as detailed in the following analysis.

52. Figure A.12 shows the range of UKCS 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 (October-March) are split into three equal (~60 day) groups commensurate with the lowest demands 250-320 mcm/d, mid demands 320-350 mcm/d and high demands 350-430 mcm/d.

Figure A. 12 – Distribution of UKCS flows in winter 2007/8



53. The chart shows a concentration of UKCS supplies between 190 and 220 mcm/d (approximately 80-90% availability). For the 9 days of demand above 400 mcm/d the average % availability based on our pre winter maximum UKCS forecast of 244 mcm/d was 86%.

54. Whilst we acknowledge that UKCS availability could possibly be lower under more severe conditions, we propose to retain an assumed availability rate of 90% for high demand conditions (typically when demand exceed 400 mcm/d). This results in a winter forecast of 195 mcm/d. Most consultation feedback supported our approach in determining UKCS.

55. We acknowledge that we will probably observe some within winter decline of supplies from the UKCS. However, as our starting position represents typical rather than maximum winter availability and we have adopted a more prudent approach for new supplies expected to come on-stream during the winter we are not factoring in any additional within winter decline.

56. As highlighted above, there remains scope for downside or upside against our final view of UKCS, for example:

- Increased annual production from numerous UK fields (thus enhancing decline)
- the development of new fields that on commencement of production have a rapid decline
- lower offshore availability as a consequence of demanding weather conditions

- alternatively we may have higher flows as we have applied a cautious approach for the inclusion of new fields to reflect possible delays in commencement of production and a more cautious approach in calculating peak flows from annual production profiles

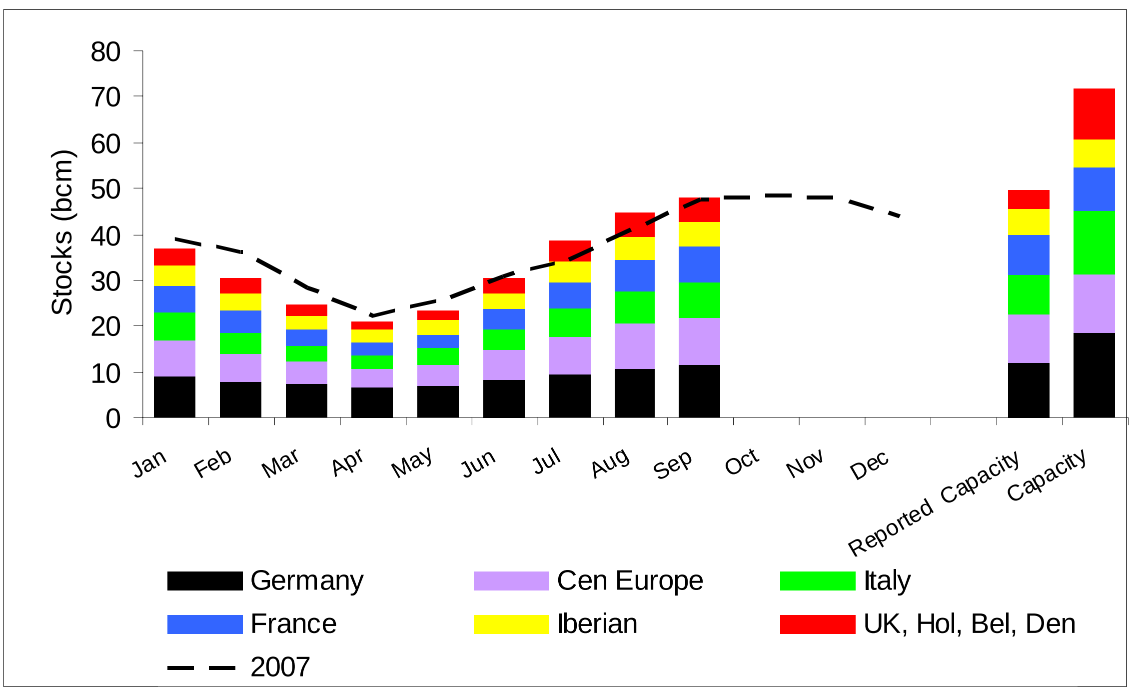
Europe

57. 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.

58. 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.

59. Figure A.13 shows storage capacities, storage stock levels and overall stock level as a percentage of capacity, for storage across Europe, with data extracted from the Gas Infrastructure Europe website[4]. It must be noted that this data is not representative of all storage sites but approximately 51 bcm of the 76 bcm believed to be contained in the area covered.

Figure A. 13 – European Storage Capacity and Storage Levels



60. The figure shows reported European storage capacity and reported storage stock levels by 4 specific countries and 2 aggregated areas. Current reported stock levels are

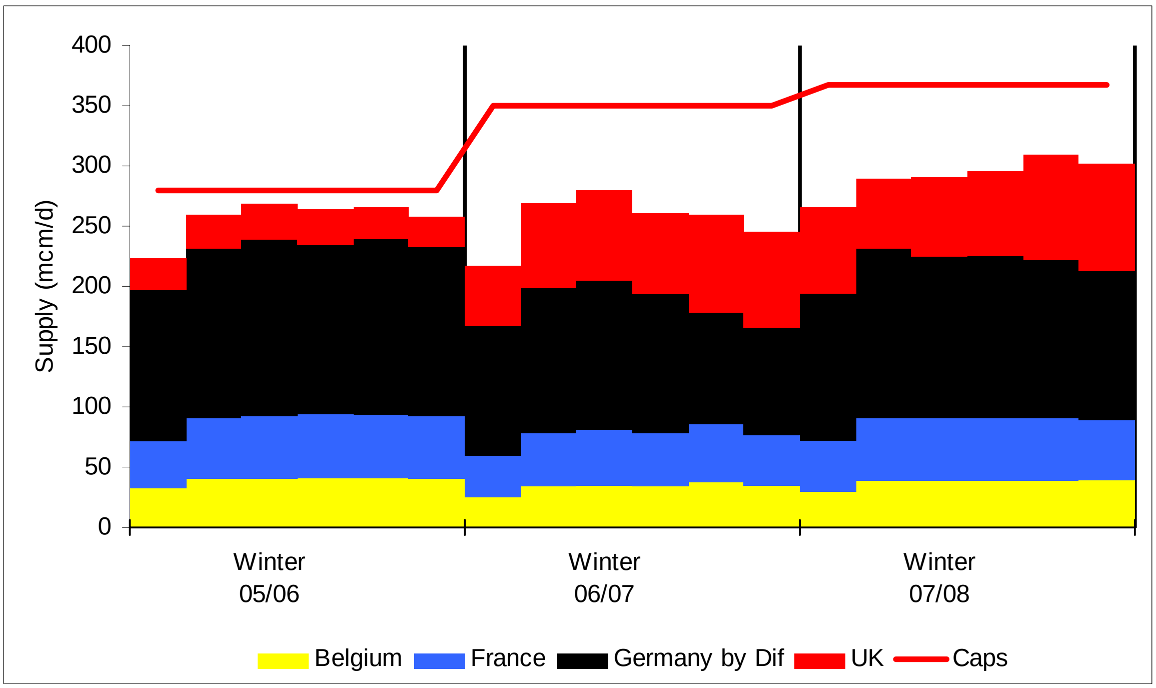
[4] http://transparency.gie.eu.com/

over 90% full and expected to be near completely filled for the start of the winter. The current level of all UK storage is approximately 96% full. The chart also shows that stocks were only partially depleted last winter (43% remaining) with a comparable usage and refill profile to that in 2007.

Norway

61. 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



62. The chart shows that while the capacity has increased over the last 3 winters with the addition of Langeled and the Tampen link overall flows have not increased at the same rate. The volumes to Continental markets (notably Germany) show notable variation from year to year, with the major factor behind this being the severity of the weather. This also highlights the flexibility in the supply contracts with Germany.

63. The chart also shows a trend (again notably for Germany) for a call on contractual volumes early on during the winter to preserve storage levels in case of colder weather later on.

64. Table A.2 highlights winter volumes and load factors of gas delivered from Norway to Europe for the past two winters. The table highlights increasing deliveries from Norway and high load factors to all markets except the UK. Hence, with no planned new export

pipelines from Norway and Norwegian deliveries expected over time to increase, much of the increase must therefore over time flow to the UK.

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

Country	Winter 06/07 (bcm)	Winter 07/08 (bcm)	Winter 06/07 Load Factor	Winter 07/08 Load Factor
Belgium	6.1	6.8	81%	91%
France	7.9	9.1	83%	96%
Germany	19.7	23.9	72%	86%
UK	12.8	13.6	67%	60%
Total	**46.5**	**53.4**	**73%**	**79%**
Daily Average (mcm/d)	**255**	**293**		
Monthly Range (mcm/d)	**217-280**	**266-310**		

65. On 20th August 2008 Statoil announced that a leak had been discovered on a pipeline between the platform at Kvitebjørn and Kollsnes, due to damage caused by a ship's anchor. It is not expected to re-open until Spring/Summer 2009. The consequence of the loss of the pipeline results in no gas exports from Kvitebjørn and Visund, a supply loss of around 17 mcm/d.

66. For winter 08/09 we expect further increased production from Ormen Lange as it ramps up towards 50 mcm/d, we also forecast some smaller increases in production from other fields notably Kristen, Åsgard and Oseberg. Taking this into account along with the Kvitebjørn loss, our forecast for Norwegian production for winter 2008/9 is 54 bcm or a winter average of 298 mcm/d. This compares with 53 bcm last winter, hence the loss of Kvitebjørn is broadly the same as the expected increase in flows from Ormen Lange.

67. Using our model of the Norwegian offshore system along with our field production forecasts and the experience of previous winters we have developed a central view and range of flows to the Continent with flows to the UK determined by difference. This is shown in Figure A.15 and Table A.3. Our central view has similar flows to the Continent to those seen last winter. As these assume relatively high Continental load factors we see more upside than downside in terms of flows to the UK. However, these may only materialise for a mild winter or if the Continent is well supplied from other sources.

68. Our 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.

Figure A. 15 - Forecast Norwegian Exports by destination

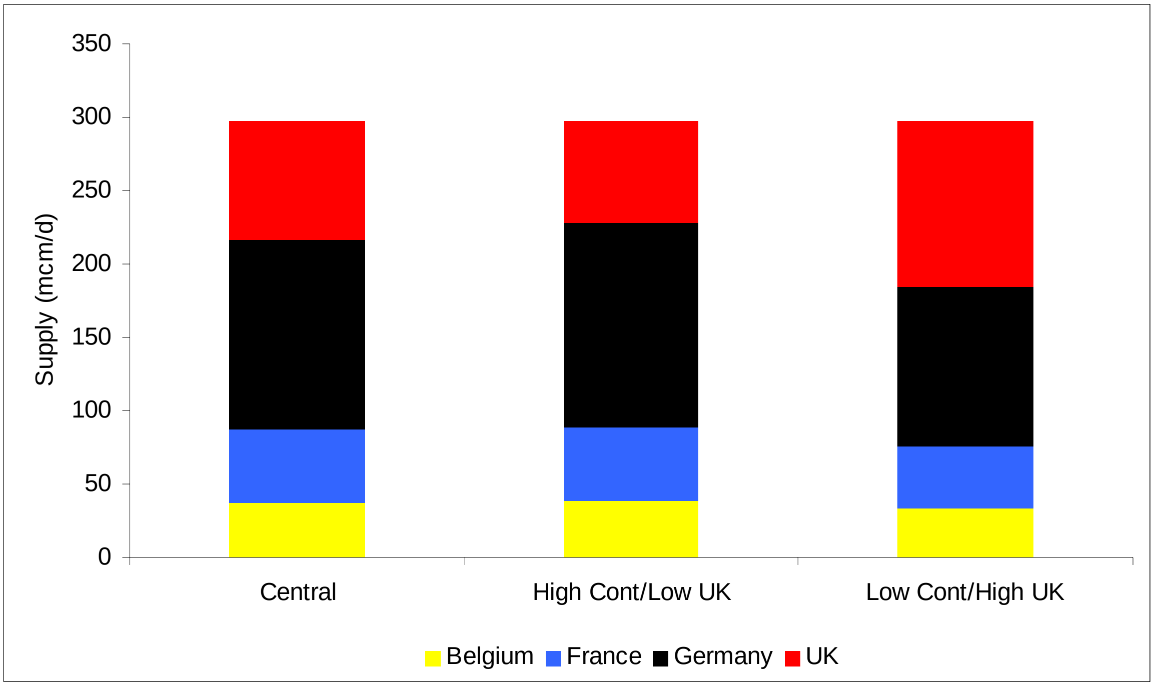


Table A. 3 – Norwegian Forecast for Winter 08/09

Country	Central	High Continent / Low UK	Low Continent / High UK	Capacity[5]
Belgium	37	39	33	41
France	50	50	43	52
Germany	130	139	109	151
UK	81	68	111	123
Total	**298**	**298**	**298**	**367**

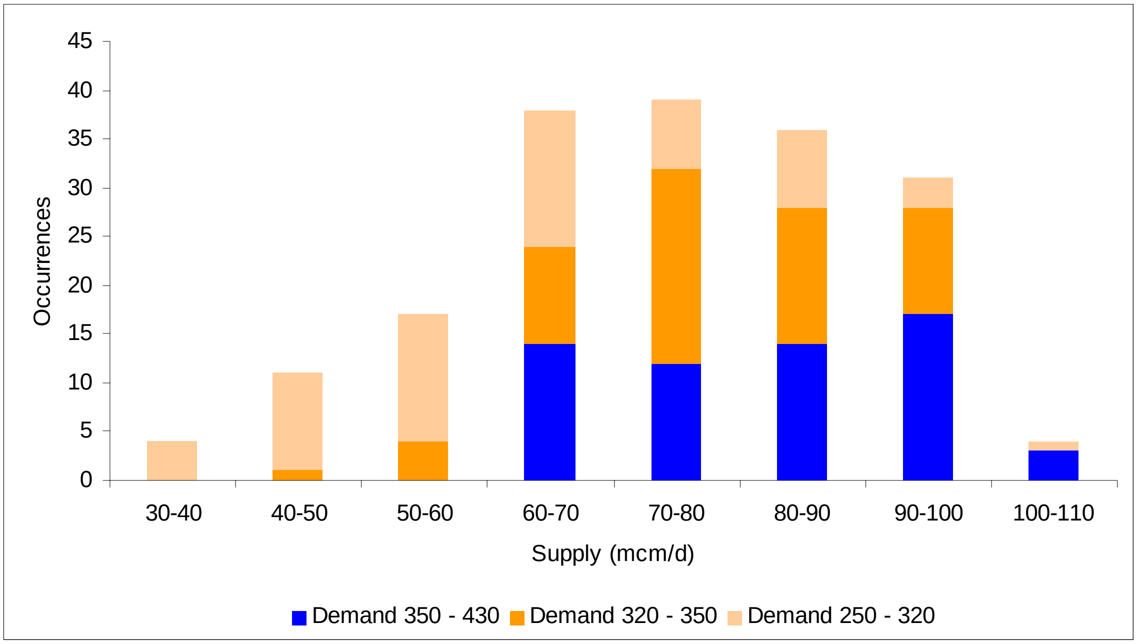
69. The table shows the central view and high / low range for Norwegian exports, these represent average flows and do not capture the anticipated variations in flows. The central view of flows to the UK of 81 mcm/d is approximately 10% higher than the average Norwegian flow experienced across all of last winter. The high / low range is between 68 and 111 mcm/d.

70. Figure A.16 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

[5] UK capacity includes Langeled, Vesterled and Tampen link capacity based on our assessment of the available capacity in FLAGS

demands 250-320 mcm/d, mid demands 320-350 mcm/d and high demands 350-430 mcm/d.

Figure A. 16 – Distribution of Norwegian flows to UK in winter 2007/8



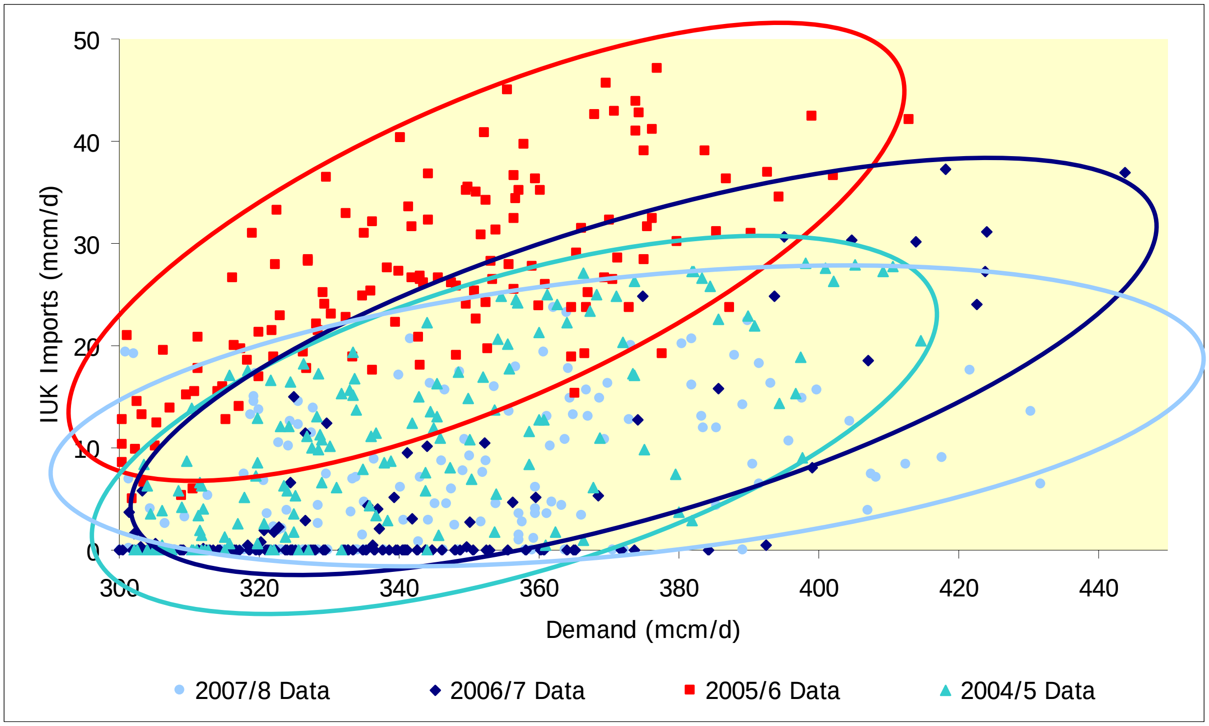
71. Figure A.16 shows a considerable range (30-106 mcm/d) of flows from Norway to the UK across the 6 month winter period. For higher demands the flows were generally higher (average flows of 81 mcm/d) and the range was tighter (62-106 mcm/d).

72. Hence not only are we forecasting a range (68 -111 mcm/d) of average Norwegian flows to the UK dependent primarily on the winter severity on the Continent and the impact of other supplies; we are also highlighting an even bigger range of Norwegian flows to the UK based on daily conditions. These are influenced by even more factors including Continental demand (hence weather), storage stock levels, availability of other Continental supplies, contractual flexibility / commitments and Norwegian offshore production.

IUK

73. Figure A.17 shows IUK imports for winter's 2004/5 to 2007/8. The chart shows a series of ellipses that capture most data points for each winter; three of these (2004/5, 2006/7 & 2007/8) are broadly similar though 2007/8 shows a lower response to higher demands. The exception is for the relatively 'tight' winter of 2005/6, this was also the winter that experienced the loss of Rough during February that resulted in at times even higher IUK imports.

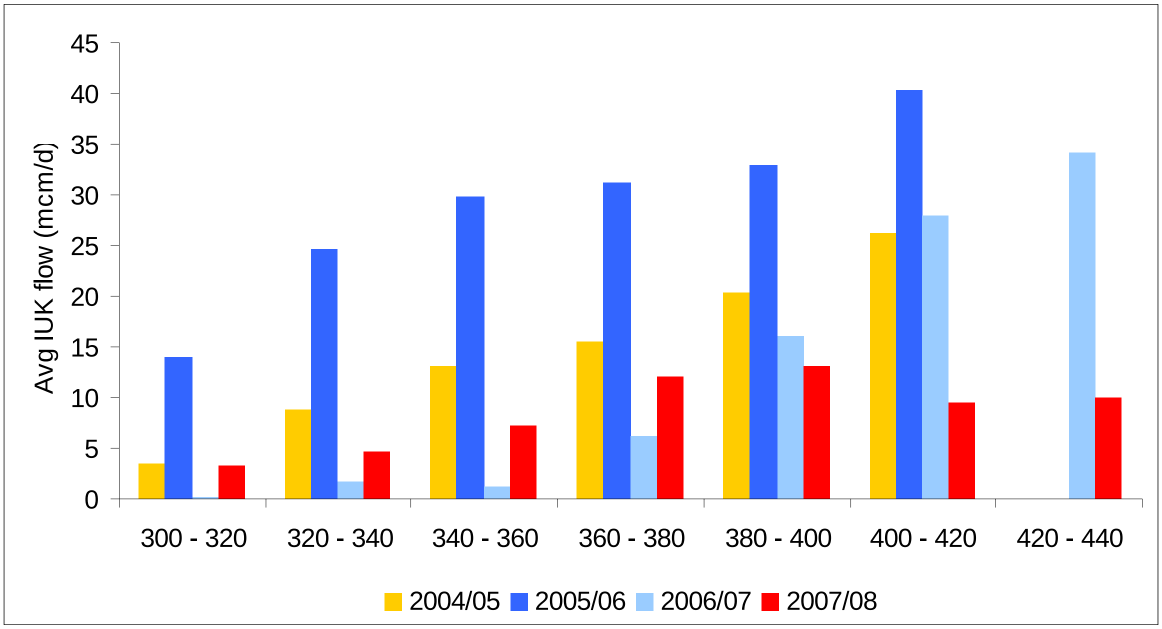
Figure A. 17 – IUK Import Flows 2004/5 – 2007/8



74. The chart shows a general trend that IUK imports increase with UK demand, however as shown by the depth of all the ellipses, there is a range of about +/- 15 mcm/d IUK flow around most levels of demand.

75. Figure A.18 shows the same data for IUK but the level of imports is expressed as an average flow for demand increments of 20 mcm/d.

Figure A.18 – Average IUK Import flows 2004/5 – 2007/8



76. The chart clearly shows higher IUK imports in winter 2005/6 compared to the other 3 winters. Whilst the chart also shows a general trend of increasing IUK imports against increasing demand, the data for 2007/8 shows no increase in imports for the highest levels of demand. On inspection for these days, the gas price was relatively high providing a driver for IUK imports, however the UK was well supplied with other imports, notably from Norway. For the four winters analysed, there has been 27 days with demands in excess of 400 mcm/d, for these days the average flow of IUK imports has been 23 mcm/d. For last winter for the 9 days of demand in excess of 400 mcm/d, the average flow of IUK imports was below 10 mcm/d.

77. For next winter, 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 imports from Norway or LNG are relatively healthy we would expect modest IUK imports, conversely higher IUK imports if Norwegian or LNG imports are low. In terms of an IUK forecast we would expect IUK to behave similar to the three ellipses that are shown close together, however based on the experience of last winter we are assuming for our central view an upper flow of just 20 mcm/d, though we acknowledge this could potentially be much higher. As stated previously we expect IUK imports to be dependent on the availability of other supplies, notably LNG and from Norway. 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.

78. Table A.4 shows the make-up of supplies for the 20 days of highest demand for winters 2004/5 to 2007/8. 20 days was selected as this relates to average demands of approximately 400 mcm/d, this is commensurate with cold rather than very cold conditions.

Table A. 4 – Supply make-up for highest 20 demand days, Winters 2004/5 – 2007/8

(mcm/d)	2004/5	2005/6	2006/7	2007/08
UKCS	283	265	208	211
Norway	28	29	84	84
BBL			24	36
LNG	0	12	12	3
Total NSS[6] (excl IUK)	**311**	**305**	**329**	**335**
IUK	21	35	18	12
Total NSS	**333**	**341**	**347**	**347**
Storage	62	45	46	54
Supply = Demand	**394**	**386**	**392**	**401**

79. The table shows comparable demands for the four winters analysed. The decline in UKCS has been more than offset by higher imports, notably from Norway and through BBL. The table also suggests that IUK is more responsive to the overall supply / demand balance, hence the level of non storage supply excluding IUK imports rather than levels of demand. The relatively high flows of storage highlight the key role storage plays in meeting high levels of demand.

80. Industry feedback from our consultation also highlighted what level of IUK flows could be relied on and that IUK flows could be expected to be higher when Continental supplies (storage) were secure for the remainder of the winter.

BBL

81. For next winter we have been working with BBL to develop new commercial arrangements for interruptible non physical reverse flow (i.e. non-physical exports). Whist these arrangements are still to be approved we believe it is prudent to assume that if implemented this could result in BBL flows that are more sensitive to the UK and possibly Continental market needs. Hence whilst we observed BBL flows at about 35 mcm/d for last winter we are assuming a marginally lower supply for our central view of 30 mcm/d for next winter.

82. In terms of physical operation, we anticipate that all compressors at Julianadorpe will be in operation, thus reducing the risk of any supply disruption.

83. At the recent Ofgem 2008 Winter Outlook Consultation Seminar, BBL Company presented a timeline of repairs to the damaged compressor showing that full compressor availability is expected by early November 2008.

LNG

84. For LNG imports to the UK for this winter there is still considerable uncertainty over the availability / sourcing of LNG and commissioning dates for the new facilities at both

[6] NSS = Non Storage Supply

Milford Haven and Grain. There is also the need to consider the time required for the commissioning of the facilities to become fully operable.

85. Global LNG imports are dominated (85% of total) by imports to the Far East, Spain, France and the US. Of these markets, there has been increases in deliveries to the Far East and Spain, similar levels of imports to France but a noticeable decline in imports to the US from 13.1 bcm in H1 2007 to just 4.8 bcm in H1 2008. This decline has been driven by a combination of higher prices in alternative markets (notably the Far East) and relatively low gas prices in the US caused by a surge in the supply of gas from unconventional sources.

86. For next winter as shown in Figure A.5, US forward gas prices are only about 50 p/therm, hence the trend of US LNG imports seeking alternative markets is expected to continue. This could include delivery to the UK, where the winter forward prices is currently priced at about £1/therm. Whilst UK gas prices are high, there is a belief that the Far East may again attract LNG at even higher prices or alternatively may have in advance contracted for further LNG deliveries on a short term basis. This is required to make up for increased demand for power generation partly caused by the large nuclear plant closure in Japan and delays to the commissioning of new LNG production facilities.

87. In terms of the new LNG importation facilities at Grain and Milford Haven there are still uncertainties regarding dates for commissioning, commencement of commercial operations and availability of LNG. Though press reports for Grain have suggested commissioning in Q4 2008 with a view to become operational for winter 2008/9 and reports for Milford also suggest operations during the winter we have assumed for our central view, LNG imports of just 10 mcm/d. In doing so we acknowledge there is some downside risk if little or no cargoes arrive but considerable upside if any of the new facilities become fully operational.

88. Industry feedback from our consultation also highlighted the considerable uncertainty relating to the delivery of LNG imports and the tightness of the global LNG market.

Final View of Non-Storage Supplies

89. In the Winter Consultation report published in June, we provided a Preliminary View of non storage volumes for Winter 2008/9. For supplies from Norway, IUK and LNG imports a range was quoted, to facilitate discussion and comment. Following the consultation, there is still considerable uncertainty regarding what levels of imports will materialise in Winter 2008/9, especially regarding Norwegian, IUK and LNG imports.

90. To promote debate and feedback from industry, in our first Winter Consultation document we deliberately set out a wide range of supplies for next winter. Whilst our latest views are still subject to considerable uncertainty we have produced a central view and a resulting high / low range as shown in Table A.5.

Table A. 5- Non-Storage Supplies for Winter 2008/9

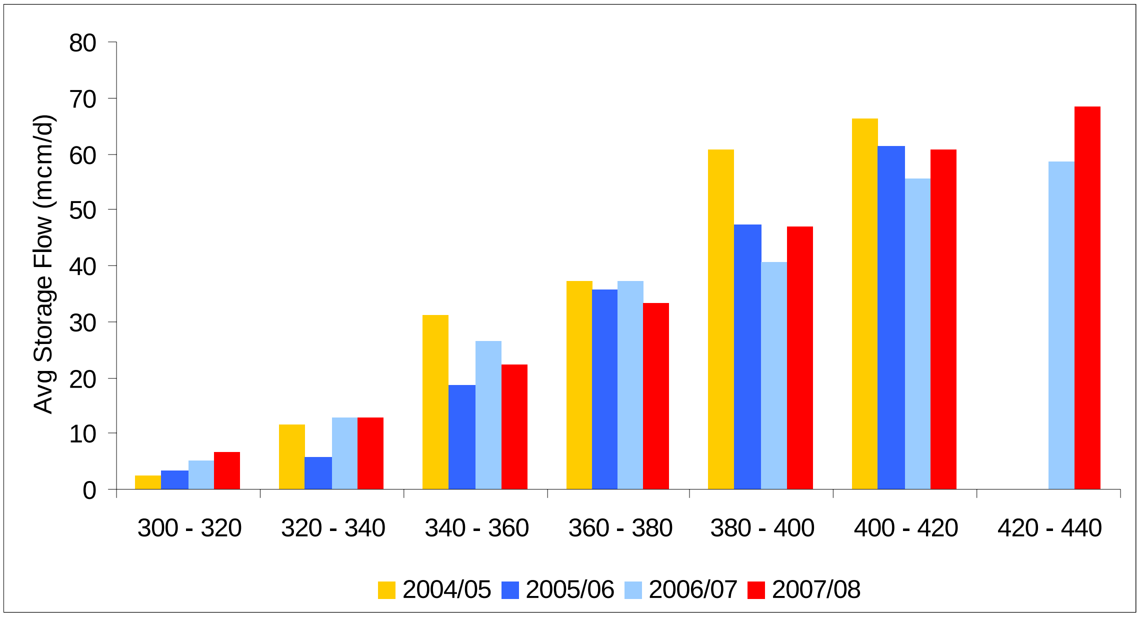
(mcm/d)	Consultn Forecast	Consultn Mid-range	Low Case	Central View	High Case
UKCS	194	194	195	195	195
Norway	80 – 115	98	68	81	111
BBL	30	30	30	30	30
IUK	0 – 50	25	30	20	10
LNG	0 – 83	42	0	10	30
Total	304 - 452	389	323	336	376

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. IUK is also assumed to flow below forecast unless demand is well in excess of aggregated non-storage supplies.

Storage

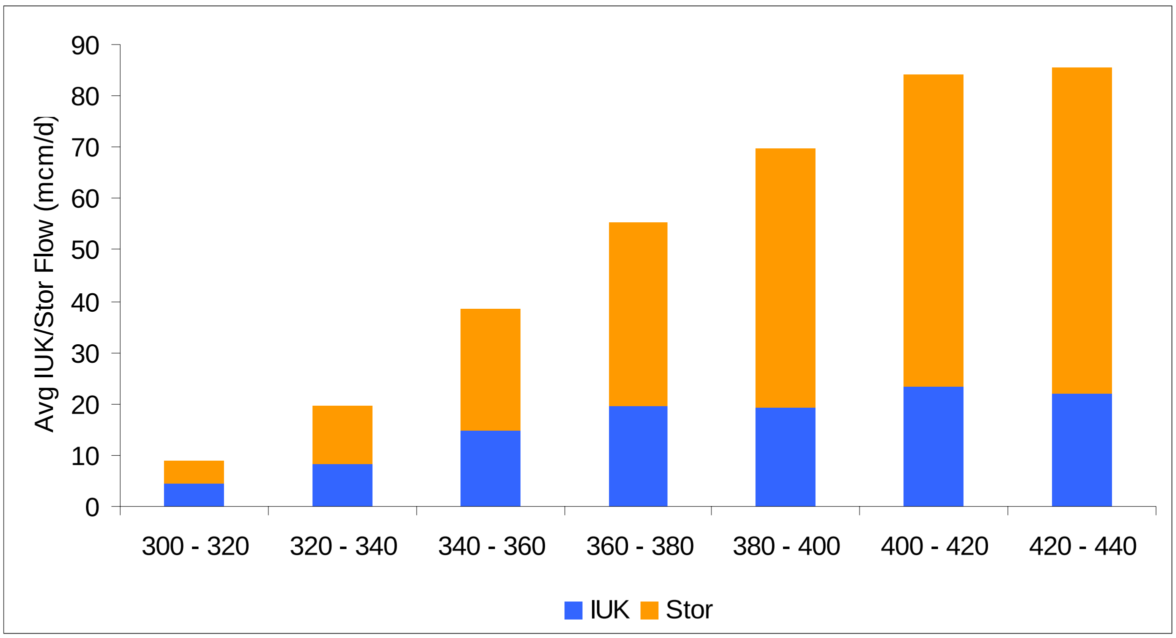
92. Figure A.19 shows average storage flows for the last four winters (2004/5 to 2007/8) expressed in terms of demand increments of 20 mcm/d. The chart clearly shows the increasing use of storage for higher demands with storage use commencing when demands exceed about 300 mcm/d.

Figure A. 19 - Average storage flows 2004/5 – 2007/8



93. Figure A.20 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 2004/5 to 2007/8 as shown in Figures A.18 and A.19. The chart shows aggregated storage volumes at about 3 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 21 mcm/d is broadly consistent with our central view for IUK for next winter.

Figure A. 20 - Average IUK and Storage flows 2004/5 – 2007/8



94. During next winter we expect the Aldbrough storage facility to become operational, though we are not expecting design flow rates until after 2008/9. Storage space at Hole House Farm is also expected to increase.

95. Table A.6 shows our assumed levels of storage space and deliverability for next winter, this includes some flows from Aldbrough.

Table A. 6 – Assumed 2008/9 storage capacities and deliverability levels

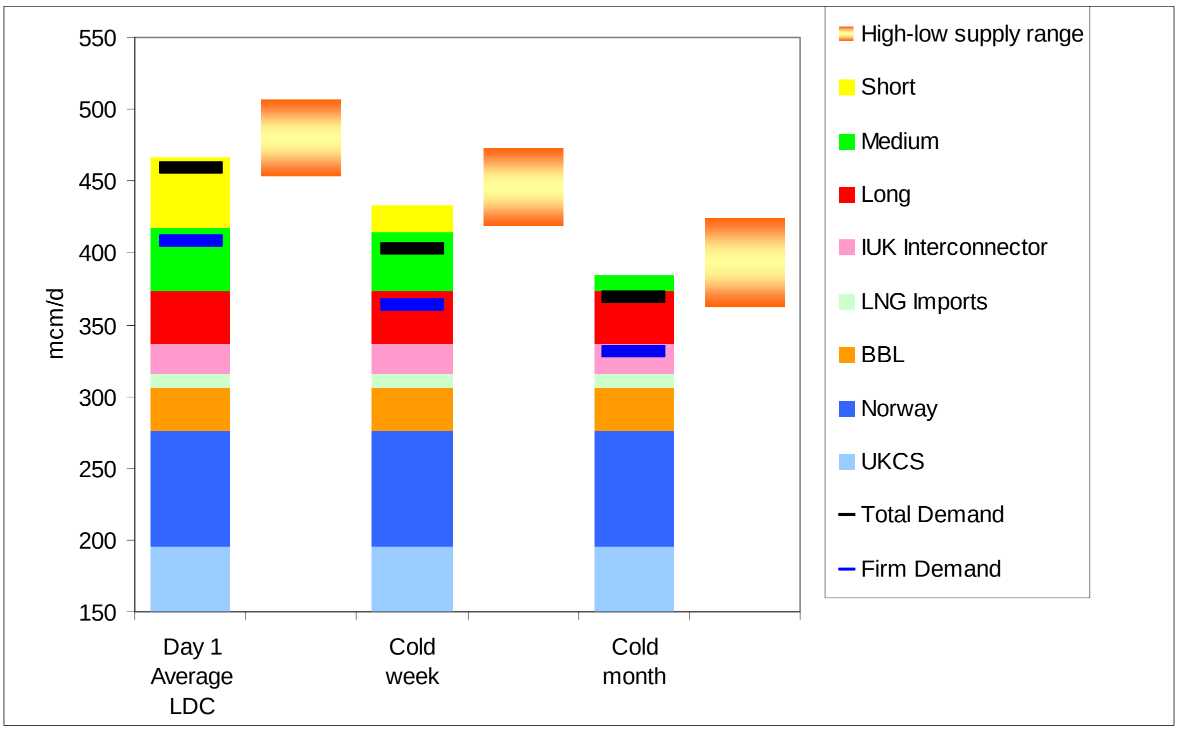
	Space (GWh)	Deliverability (GWh/d)	Deliverability (mcm/d)	Days at full rate
Short (LNG)	2202	526	49	4.2
Medium (MRS)	9826	530	49	18.5[7]
Long (Rough)	35545	455	42	78.1
Total	**47573**	**1511**	**140**	

[7] Weighted average duration

Winter Security Assessment

96. Figure A.21 shows our 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°C for the cold day, 1°C for the cold week and 3°C for the cold month. The levels of demand are matched to our central view of supplies. Also shown on the chart is the high-low supply range from Table A.5.

Figure A. 21 – Cold spell analysis for 2008/9, for average conditions



97. The analysis shows that for average conditions, sufficient supplies should be available to meet all demand for a cold day, a cold week and a cold month.

98. It should be noted that the average 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.

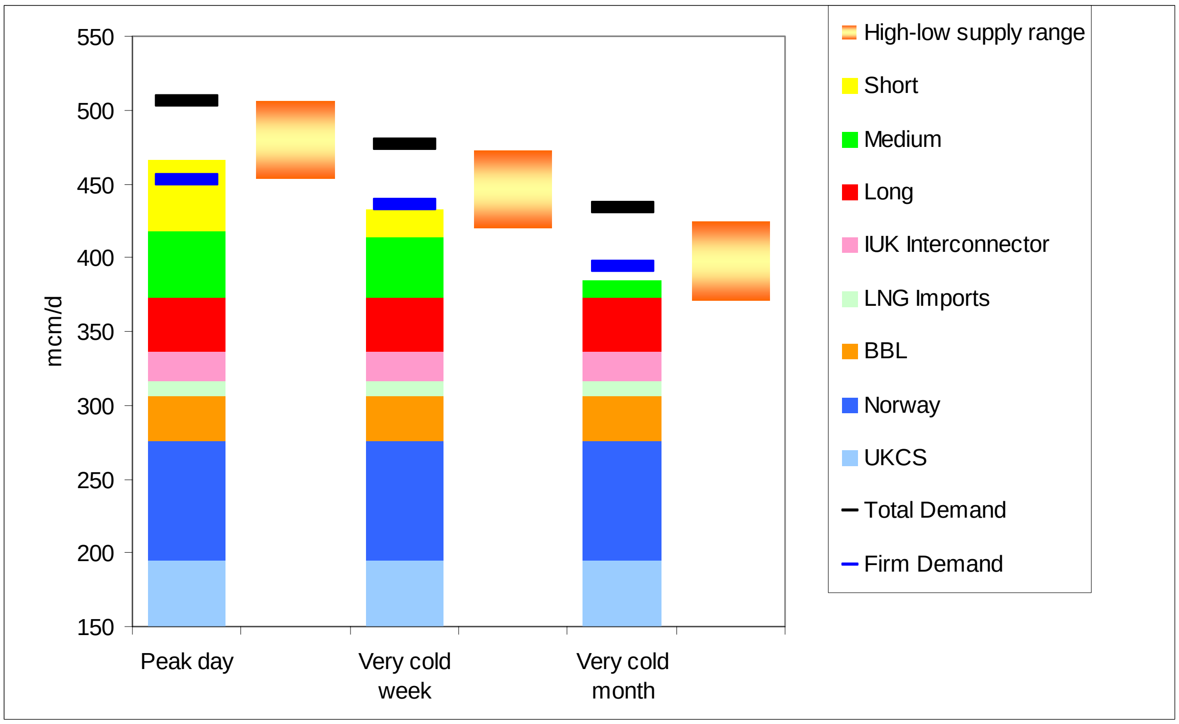
99. Figure A.22 shows our cold spell analysis for severe[8] demand conditions, with total and firm demand for the peak day[9] (1 in 20), a very cold week within a severe winter and

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

[9] Peak day conditions are based on 1 in 20 demand conditions. 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. For security analysis we use diversified demands

a very cold month within a severe winter. The temperatures associated with these conditions are typically -5°C for the peak day, -3°C for the cold week and -1°C for the cold month. The levels of demand are matched to our central view of supplies. Also shown on the chart is the high-low supply range from Table A.5.

Figure A. 22 - Cold spell analysis for 2008/9, for severe conditions



100. The analysis shows that all severe demand condition would be challenging in terms of meeting demand with the availability of supplies. This would be more pronounced for any prolonged cold spell.

101. The analysis illustrates for our central view of supplies, that for a 1 in 20 peak day with average temperatures across the country around -5 ºC, there is sufficient supply availability to meet firm demand, but a demand response roughly equivalent to nearly all interruptible demand 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 higher supply availability as denoted in the high-low supply range there is the possibility to meet most if not all demand.

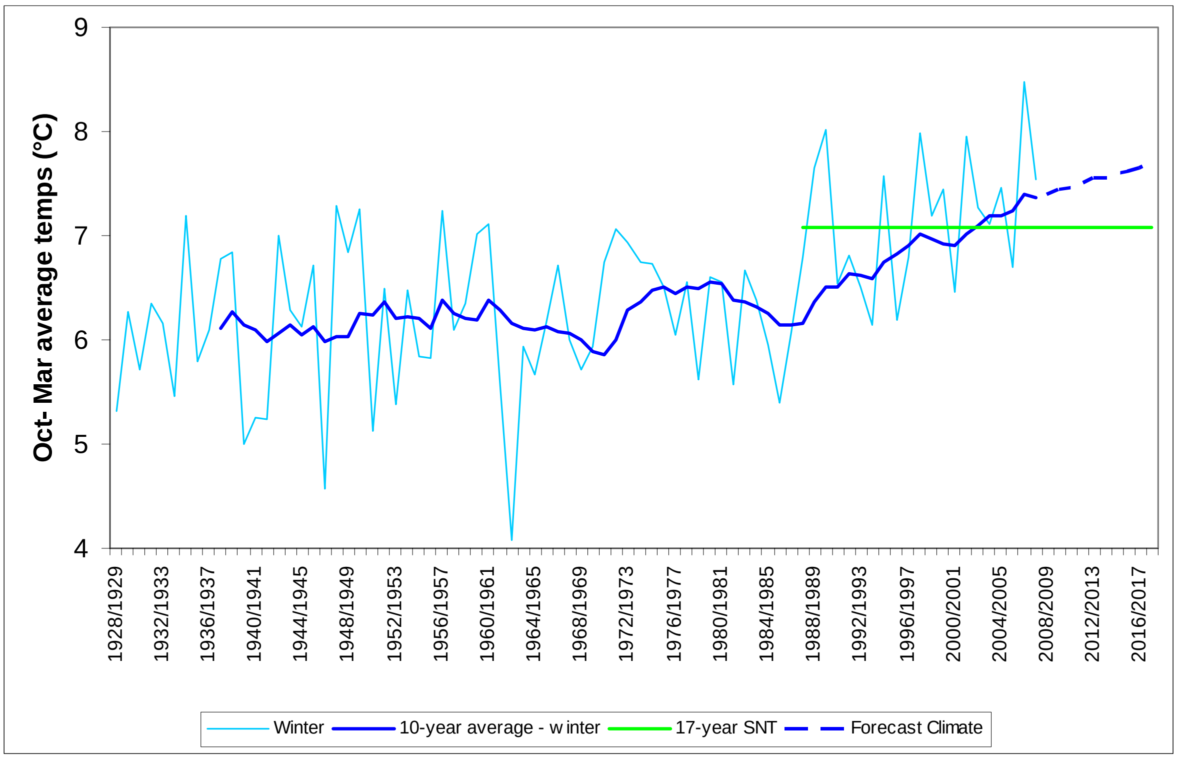
102. For our central view of supplies for a very cold week and very cold month analyses, a higher demand response would be required. This could include the possibility of some firm demand response. For higher supply availability as denoted in the high-low supply range there is the possibility to meet most demand though this becomes more testing for any prolonged period.

103. 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.

104. Figure A.23 shows average October – March temperatures for the past 80 years. The chart also shows a forecast based on a 30 year moving average

Figure A. 23 – Average Winter temperatures from 1928/9 to 2007/8



105. The chart clearly shows the trend of warmer winters since the mid 1980s. Historically a 2°C 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 reduction of about 3.5°C.

Safety Monitors

106. On 31 May 2008, we published our preliminary view of initial Safety Monitor levels for 2008/9 as required under the Uniform Network Code (Q5.2.1).

107. 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 protect public safety. It is therefore appropriate that we adopt a prudent approach to setting the Safety Monitor levels.

108. Our latest Safety Monitor calculations incorporate our Central View supply assumptions shown in Table A.5.

109. Table A.7 shows that the total non-storage supply assumption of 336 mcm/d used for calculating the 2008/9 Safety Monitors is 59 mcm/d lower than the equivalent figure used in setting the 2007/8 Safety Monitors.

Table A. 7 – Comparison of 2006/7 and 2007/8 Safety Monitor non-storage supply assumptions (mcm/d)

Non-storage supply type	2007/8 Safety Monitor	2008/9 Safety Monitor
UKCS	227	195
Norway	80	81
IUK	50[10]	20[11]
BBL	25	30
LNG	33	10
Supply risk	-20	0
Total	395	336

110. The resulting Safety Monitor levels shown in Table A.8 are above the 2007/8 monitors. This is primarily due to the lower non-storage supply assumptions.

Table A. 8 – 2008/9 Safety Monitor space requirement

Storage type	2007/8 Safety Monitor (%)	Assumed storage space (GWh)[12]	2008/9 Safety Monitor space (GWh	2008/9 Safety Monitor (%)
Long duration storage (Rough)	1.5%	35545	3917	**11.0%**
Medium duration storage (MRS)	0.0%	8251[13]	621	**7.5%**
Short duration storage (LNG)	0.0%	2058	102	**5.0%**
Total	1.2%	45854	4640	**10.1%**

10 Based on demands of 450 mcm/d or higher
11 IUK is assumed to increase as a consequence of tighter supply conditions, reacting to an increase in UK gas price. IUK is also assumed to flow below forecast unless demand is well in excess of aggregated non-storage supplies.
12 Excludes Operating Margins and Scottish Independent Undertakings
13 Excludes Aldbrough space

111. Safety Monitor levels and the associated winter profiles (i.e. how the monitors reduce later in the winter) were published on 1 October 2008.

112. During winter 2008/9, we will again provide winter feedback to the industry regarding supply assumptions and resulting changes to Safety Monitors by means of monthly updates via our Gas Operational Forum and our website.

Winter 2008/09 Update on Provision of new NTS Capacity

113. A significant construction programme has been undertaken to deliver large scale investment on the NTS for the 2008/9 gas year. These projects are driven by the need to provide capacity to accommodate new power station connections, to increase existing NTS capacity at entry and exit and to provide additional transportation capability. The references in the tables below relate to the map shown as Figure A.24.

Langage Power Station – Exit (Ottery to Langage)

114. This project allows the facilitation of a new 885MW CCGT power station at Langage, Devon, connecting at the South West extremity of the NTS. These projects have been completed and commissioned. Commissioning of the power station is expected to commence in December this year. The site is expected to begin commercial operation in 2009.

Table A. 9 - Langage Power Station - Exit

Ref	Project	Scope
A	Ottery St. Mary to Aylesbeare	10km x 600mm pipeline
B	Aylesbeare to Kenn	15km x 600mm pipeline
C	Kenn to Fishacre	Uprating of existing LTS assets to NTS standard
D	Fishacre to Lyneham	33km x 600mm pipeline

Marchwood Power Station – Exit (Barton Stacey to Lockerley)

115. This new pipeline provides capacity for a new 842MW CCGT power station at Marchwood connecting in to Feeder 7, near Lockerley. Commissioning of the pipeline is expected in autumn 2008. Commissioning of the power station is currently expected to commence this winter with full commercial operation anticipated in the summer of 2009.

Table A. 10 - Marchwood Power Station - Exit

Ref	Project	Scope
E	Barton Stacey to Lockerley	31km x 900mm pipeline

Milford Haven LNG Importation – Entry (New & Modified Compressor Stations)

116. This project is part of the overall investment strategy to provide capacity to transport gas from the new LNG importation terminals at Milford Haven. South Hook and Dragon LNG are indicating commercial operation in late 2008. The original signals for Milford Haven were received in September and December 2004 LTSEC auctions. The pipelines

associated with Milford Haven are fully commissioned. Commissioning of Felindre compressor station and ongoing modifications to Wormington are due in late 2008.

Table A. 11 - Milford Haven LNG Importation - Entry

Ref	Project	Scope
F	Wormington Compressor Station	Additional Unit and multi-junction modifications
G	Felindre Compressor Station	New Station

Isle of Grain LNG importation - Entry

117. This pipeline duplication is to provide additional capability to accommodate the 2nd phase expansion of the Isle of Grain LNG importation terminal. An auction signal was received in the September 2005 LTSEC. A further bid for Phase 3 capacity was made in September 2007. The pipeline is due for commissioning in Autumn 2008.

Table A. 12 - Isle of Grain LNG importation- Entry

Ref	Project	Scope
K	Isle of Grain to Gravesend	23.5km x 900mm

East Coast Entry Capacity

118. In response to entry auction signals, over the last 3 years National Grid has invested significantly in new East Coast entry capacity. This capacity has been delivered in stages since 2006, with 2008 marking the completion of the Trans Pennine link part of the project from Easington to Carnforth.

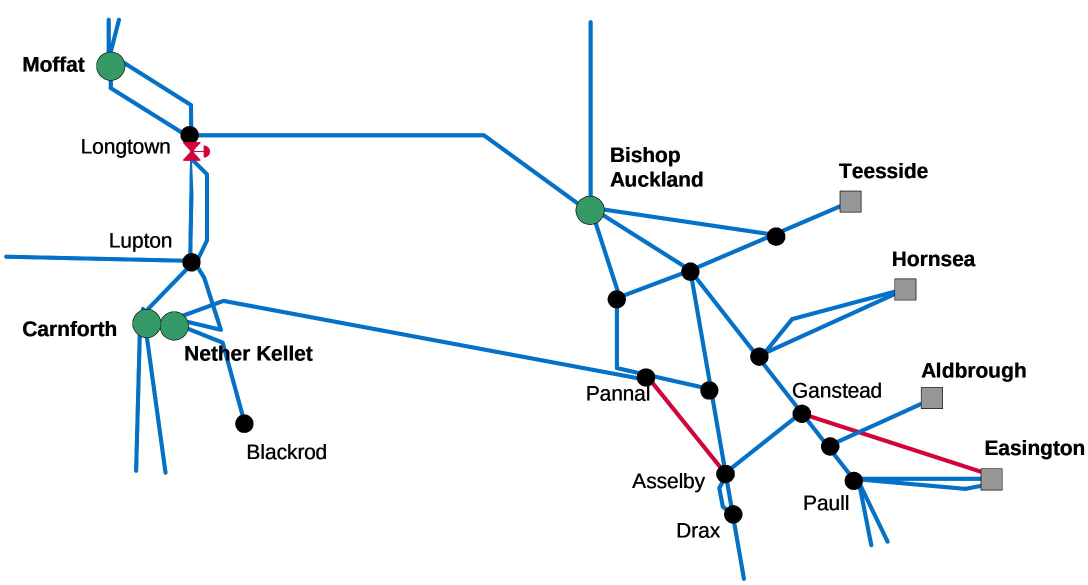
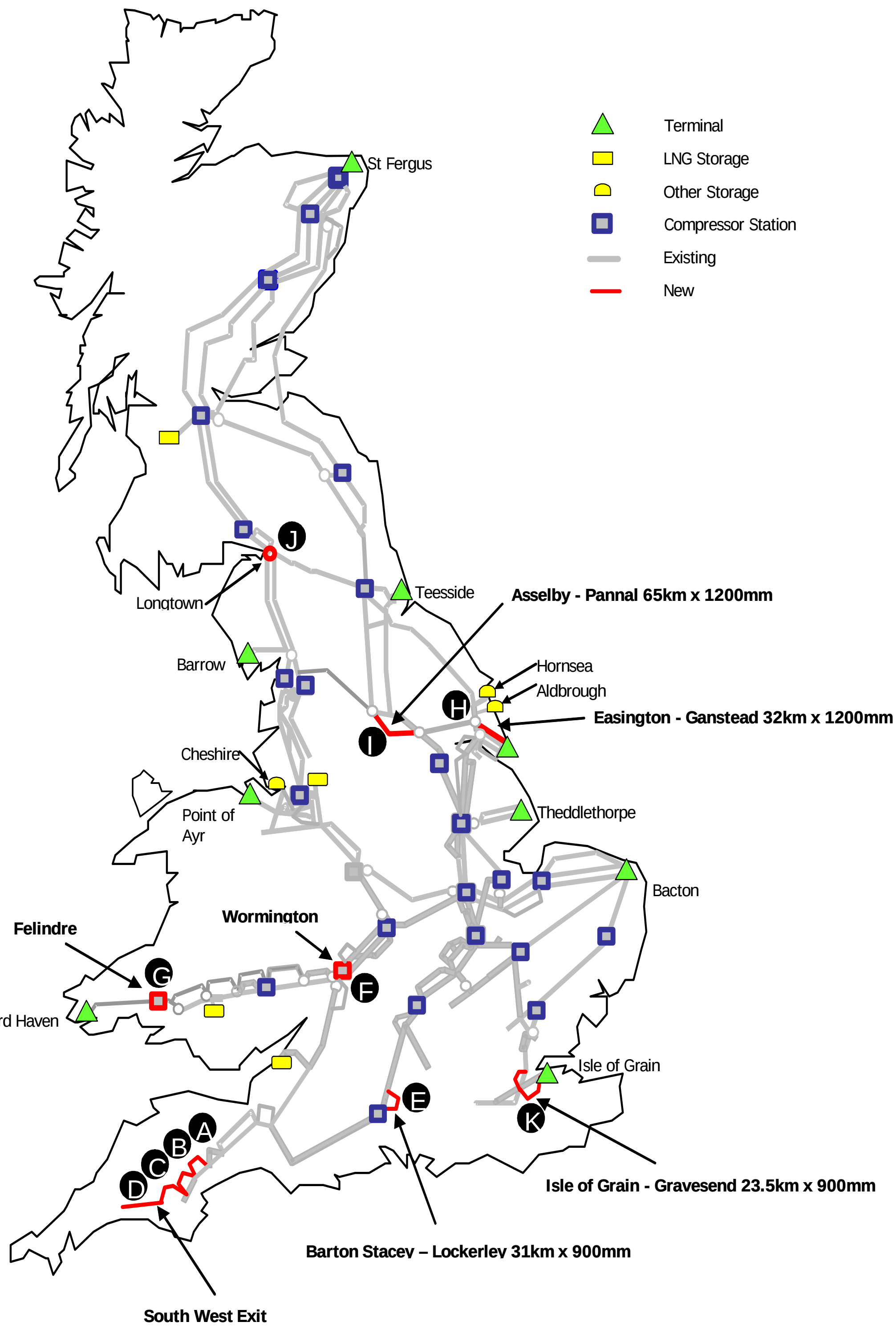


Table A. 13 – East Coast Entry Capacity

Ref	Project	Scope
H	Easington to Ganstead	32km x 1200mm pipeline
I	Asselby to Pannal	65km x 120mm pipeline
J	Longtown Regulator	Flow control

119. Further capacity products are available this winter to enable full use of this new capacity and these are described in more detail in the Section C.

Figure A. 24 – NTS Construction Projects Due for Delivery in Winter 2008/09



Electricity

Electricity Demand Forecast for 2008/09 – Great Britain

120. Our forward looking view of the peak demand level for the coming winter is unchanged between this final report and our preliminary report published in June 2008. Our Great Britain Average Cold Spell (ACS)[14] winter peak demand forecast for the coming winter is 59.9GW. This is a reduction of 0.4GW from the comparable 60.3GW ACS demand outturn of last year. The lower forecast is based on a combination of the observed decline in demand in recent years, the growth in embedded generation in distribution networks, the projected future higher energy prices, more efficient use of energy and likely slower economic growth. The 1 in 20[15] peak demand forecast is 60.9 GW. The 1 in 20 demand peak represents our high demand scenario. These demand figures relate to GB demand only and do not include any flows to France or Northern Ireland across the Moyle interconnector. Reflecting our assumption of an export to Northern Ireland of 0.3GW across the winter peak, the ACS peak demand forecast becomes 60.2GW and the 1 in 20 peak day demand forecast becomes 61.2 GW.

121. Around 0.8-1.3GW of demand management was observed at times of peak demand in the winter of 2007/08 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 2008/09 we have assumed 1GW of demand side response in our demand forecasts for ACS and 1 in 20 conditions.

122. We have reviewed our assumption of a 0.3GW export to the All Ireland market and believe that it remains prudent to make allowance in our base case for the capability under normal circumstances to provide this level of exports.

Notified Generation Availability 2008/09

123. The current operational view of generation capacity anticipated to be available for the start of winter 2008 is 75.4GW, giving a 25.4% plant margin. These figures differ from the longer term view published in the Seven Year Statement for the reasons outlined below.

124. The quoted plant margin for 2008/9 currently reported in the August 2008 update to the 2008 GB Seven Year Statement (SYS) is 28.0%, based on a Transmission Entry Capacity (TEC) contracted generation capacity of 79.6 GW. This includes the 2 GW import to GB of the GB-France Interconnector. The forecast demand in the SYS is 62.1GW, some 1.9GW higher than the forecast demand in this report, as the SYS reflects demand forecasts provided to National Grid by the Distribution Network Operators and does not take into account demand-side response.

[14] 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.
[15] 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.

125. Oldbury nuclear power station, which has a capacity of 0.5GW, is included in the 79.6GW capacity total and is due to de-commission on 31 December 2008 although it is hoping to extend its running.

126. The reduced nuclear output at Hinckley Point and Hunterston, announced by British Energy in 2007, continues and represents a loss of 0.8GW of capacity, not reflected in the 79.6 GW SYS figure.

127. Our assumptions on new generation commissioning dates are based on a range of information sources. It should be recognised that any commissioning dates may be subject to change and are often updated periodically by the operator. Langage (0.9GW) Marchwood (0.9 GW) and Immingham stage 2 (0.6GW) have contracted for TEC for 2008/9. Langage is expected to synchronise its first unit (0.45GW) during December and the second unit is expected online a month later, taking the potential capacity to 0.9GW. We then expect Langage will be under going commissioning and will not be fully available until this is completed, hence this is not included in our figures for generation availability. The two other stations are not expected to be available for winter 2008/09.

128. Whitelee wind farm near Glasgow has contracted for 0.3GW TEC for 2008/09 but currently has a capacity of around 0.1GW.

129. Wind continues to increase its share of the GB generation market, with approximately an additional 270MW of fully operational capacity visible to National Grid by the end of winter 2008-09, taking the total wind capacity to around 1.7GW. Our experience of wind generation is that its output is highly variable and difficult to forecast.

130. The latest view of TEC capacity available for the start of winter 2008 (1st October 2008) is therefore 76.2GW.

131. Glendoe Hydro at Fort Augustus, Scotland is expected to come online during the winter, initially having 51.5MW TEC but potentially increasing its output to around 100MW over the course of the following months.

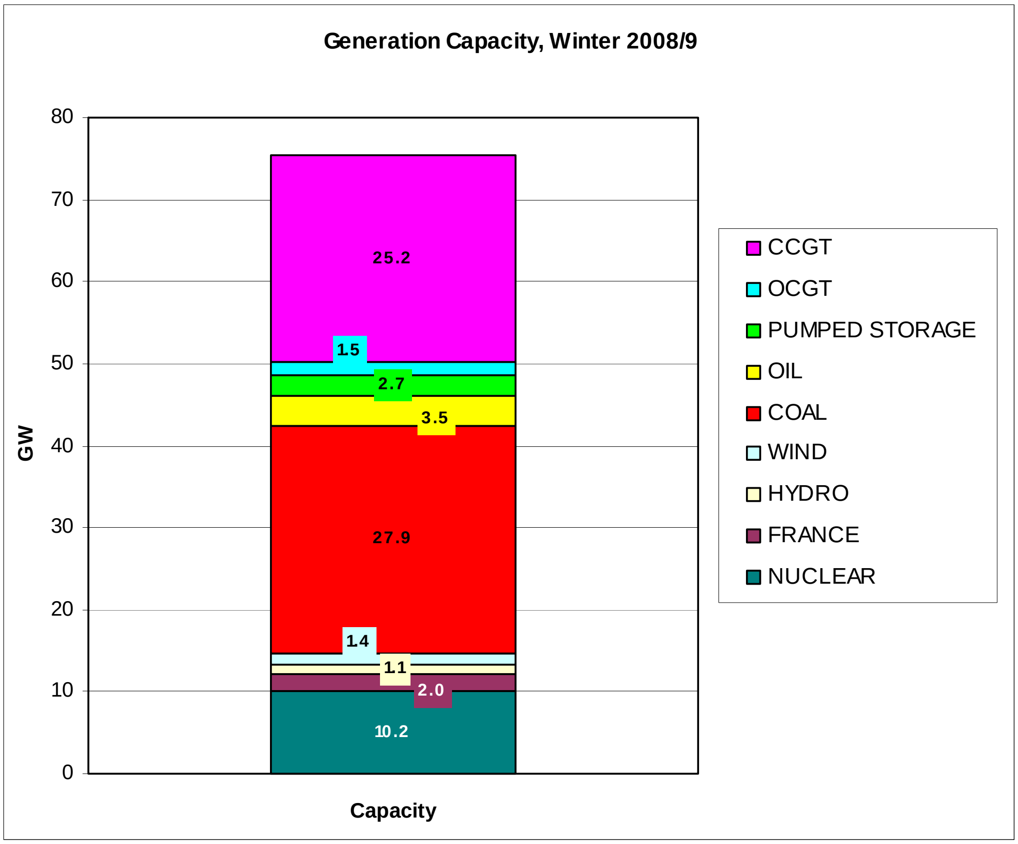
132. This headline plant margin as quoted in the SYS is a useful, broad indicator of the amount of generating plant on the system. At an operational level, we derive an alternative view of generation availability through observed generation output over a period of time, which can differ from the SYS.

133. Based on these observations, our current operational view of generation capacity anticipated to be available for the start of winter 2008 is 75.4GW. A broad breakdown of this capacity is shown in Figure A.25. In addition to this operational view of generation, we see potential upside in further wind generation capacity progressively becoming available during the course of the winter but a potential reduction due to the closure of Oldbury power station at the end of December.

134. In developing our operational view of available generation capacity, we undertook a detailed review of historic power station output for the preliminary winter outlook report. The main changes as a result of the review are to reduce our operational view of the capacity available from nuclear generation by 0.3GW and to reduce our operational view of coal generation by 0.3GW. We have increased our operational view of the output expected from open-cycle gas turbines (OCGTs) by 0.3GW which has been brought about by some units returning and the reclassification of some plant from CCGT to

OCGT, better reflecting its technical characteristics. This is reflected in an equal and opposite change in our operational view of the output of CCGT generation.

Figure A.25 – Generation Capacity Operational View, Winter 2008/09



Generation Availability

135. We have reviewed our forward looking availability assumptions based on recent experience and, whilst they have proved generally robust, we said we would review the assumed availability of wind and nuclear generation for winter 2008/09 over the summer. As part of our consultation we particularly invited views on the level of generation assumed availability to apply in this report.

Hydro Availability Assumptions

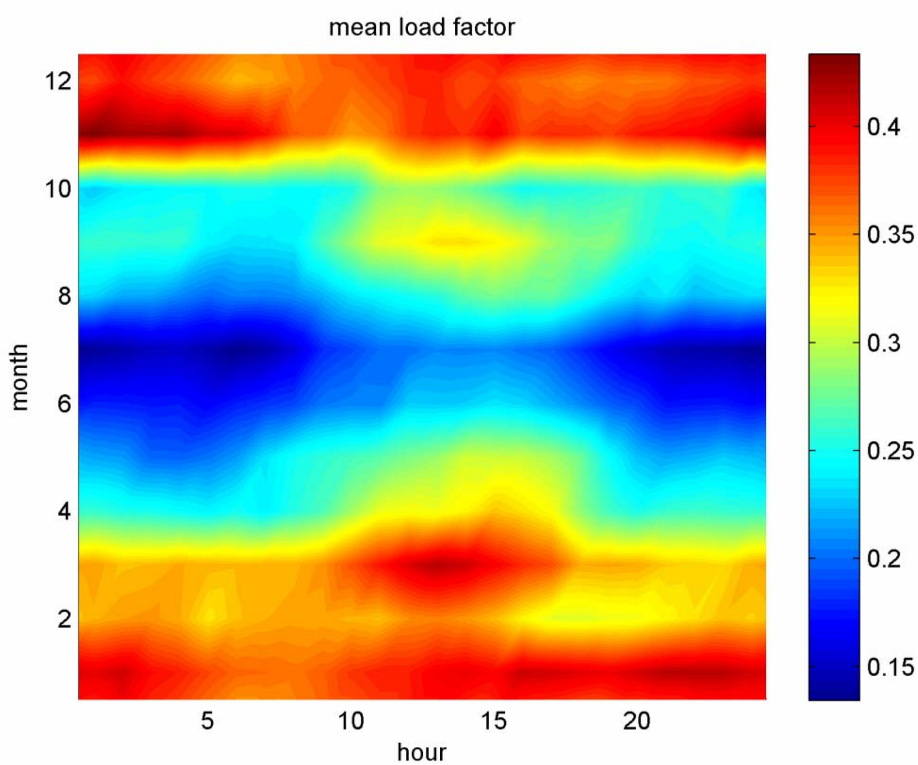
136. This has not changed since our preliminary report. Hydro generation, which here includes small generation that is run of river, has an assumed availability of 60% compared with an observed load factor of 73% at times of winter peak demand last year. 60% represents a prudent assumption to allow for risk that there is a water scarcity issue at the times of peak electricity demand. As hydro generation is relatively small and not forecast to significantly increase this has limited impact on the overall generation availability for winter 2008/09.

Wind Availability Assumptions

137. We have undertaken additional analysis of wind generation output probabilities at times of high demand. Our operational experience of wind generation shows we have seen load factors from zero to around 90% of installed capacity during the key part of the winter where demands are highest. In this final winter 2008/09 report we have included some further analysis that indicates the likelihood of a coincident demand peak with low wind output based on a model simulation using the data we have available. Our analysis shows that output from wind generation is not critical to meeting demand over the coming winter but this is based on number of assumptions for demand levels and that other types of generation are achieving the assumed levels of availability.

138. As the amount of wind generation as a proportion of the installed generation capacity increases, the capacity credit ascribed to a given installed capacity of wind generation becomes a key issue. Our overall conclusions have not changed as a result of our review and continue to point towards a base case mean load factor of 35% over the December and January evening periods when a peak demand is most likely. In response to the uncertainty of wind output we have used zero transmission connected wind output as an element of a scenario we have added to this report. Figure A.26 shows the mean load factor by time of day and month for the current wind generation that we operationally meter.

Figure A. 1226 - Wind – Daily and Monthly Mean Load Factors



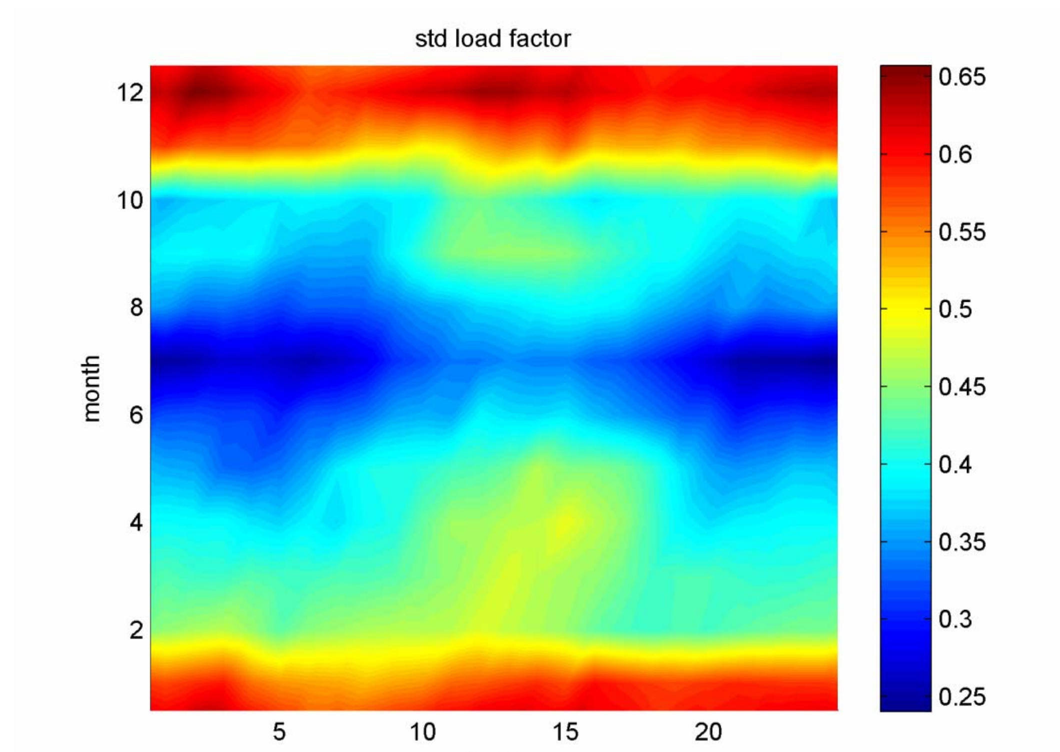
.

139. Our experience of the contribution of wind generation around the 2007/08 demand peak at 8% illustrates the issue of the intermittency of wind. We cannot depend with a high degree of confidence on a mean output contribution from wind generation at the time of demand peak. Particularly we have seen days in winter with high GB demands where there is very little generation from wind due to low winds and also days where wind generation output has been low due to too high winds, as turbines stop generating at higher wind speeds.

140. Figure A.27 below shows the standard deviation of wind output, from which it can be seen that the standard deviation of wind output increases to higher levels during the December and January period when we expect the peak demand is most likely to occur. The assumption to apply to wind generation contribution at the time of demand peak is one of the main uncertainties in our electricity sector analysis in this report.

141. Wind generation output is not normally distributed so the application of standard deviation of load factors only can be used as an indicator in a simple analysis of likely outputs. Looking at the distribution of load factors we see that it is credible to have load factors between zero and around 90% over winter peak demand periods.

Figure A. 27 - Wind – Standard Deviation of Load Factors



142. The additional analysis we have undertaken is to use our data of observed wind generation output with observed electricity demands and identify the probability distribution for coincident low levels of wind output and high levels of demand. We continue to treat our own analysis with some caution as a guide to future developments

of wind generation as it is based on a relatively limited data set for wind generation output (approximately 1½ years) and is representative of the type of wind generation we currently meter.

143. The result of our analysis is shown in the table here. The table for example shows that wind output is 0-1% of installed capacity on 39 hours of a year when demand is 90-100% of peak demand. We undertook this analysis to build on an OXERA[16] report in 2003 and a more recent Pöyry[17] report. We have identified further analysis we intend to undertake to particularly look at the impact of reduced embedded wind generation output which may be coincident with reduced transmission connected wind generation on our electricity demand from the transmission system.

Table A.14 – Wind : Daily and Monthly Mean Load Factors

		Wind output is % of installed capacity									
		0%-10%	10%-20%	20%-30%	30%-40%	40%-50%	50%-60%	60%-70%	70%-80%	80%-90%	90%-100%
Demand is % of annual maximum	0%-10%	0	0	0	0	0	0	0	0	0	0
	10%-20%	0	0	0	0	0	0	0	0	0	0
	20%-30%	0	0	0	0	0	0	0	0	0	0
	30%-40%	0	0	0	0	0	0	0	0	0	0
	40%-50%	430	225	145	86	54	29	27	16	4	0
	50%-60%	628	396	252	174	172	128	106	85	34	0
	60%-70%	699	469	325	258	206	170	132	122	62	3
	70%-80%	626	412	304	211	160	168	127	115	50	3
	80%-90%	188	166	142	92	79	89	80	73	42	3
	90%-100%	39	31	26	24	14	10	10	10	3	1

144. In terms of the outlook for 2008/09, with a relatively low level of wind generation in the overall generation mix, it is not yet critical to meeting demand even in our 1 in 20 demand levels scenario that we require a significant output from wind. Demand can still be met by other sources of generation and/or imports through the interconnector in the event of no wind generation output at the time of peak demand. Our work over the summer has though led us to conclude that there are challenges that we will face as GB system operator where wind generation is a large proportion of the generation fleet and that controllable flexible sources of generation or demand management need to be developed in parallel with a significant expansion of the wind generation capacity. We are already contributing to further investigation and identifying potential solutions to these issues through our engagement with the energy industry and government.

Nuclear Availability Assumptions

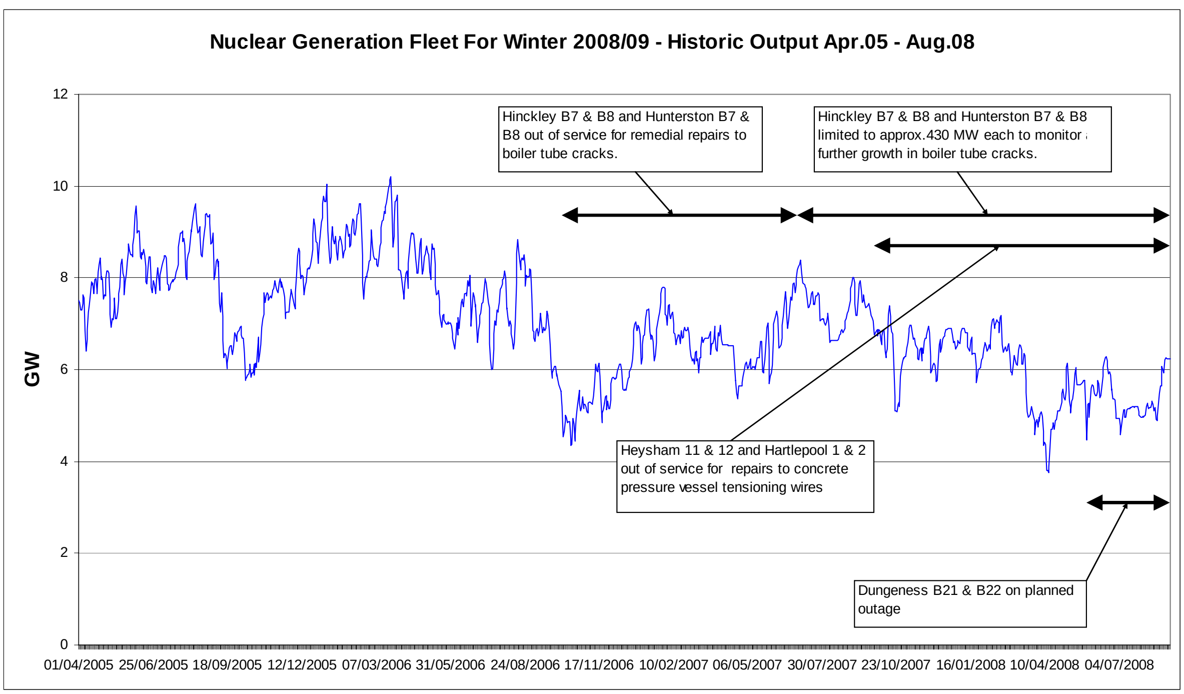
145. We have analysed forward looking data provided to us by nuclear power station operators for the coming winter 2008/09, which indicates a significantly higher level of availability for this type of generation than we have seen over recent winters. Based on this information, we have retained our 80% availability assumption. The level of certainty around the return for the winter of several nuclear power stations is a key sensitivity. Two large nuclear power stations at Heysham 1 and Hartlepool are currently out of service for repairs to concrete pressure vessel tensioning wires. British Energy has stated at their Q1 2008/09 results presentation on 13th August 2008[18] that these units should return by

[16] Oxera – The non-market value of generation technologies (2003), A report to BNFL.
[17] Pöyry – Implications of the UK meeting its 2020 renewable energy target (2008), A report to WWF-UK and Greenpeace UK.
[18] http://www.british-energy.com/documents/Results_Presentation_Q1_0809_FINAL.pdf

Q3 2008/09. This period of potential return includes December where our demand models expect a potential for the highest GB demands to occur. The extent to which these nuclear stations return from outage in time for the likely peak demand weeks in December/January is an area of potential sensitivity which we have reflected in an additional scenario added to the final winter outlook report.

146. We have analysed historic output of the subset of the stations included in the 10.2GW of nuclear power generation capability we foresee for winter 2008/09. The historic output from these stations over history from April 2005 has varied considerably and has been on a general decline. Statements by British Energy continue to point towards Heysham 1 and Hartlepool stations returning during Oct-December 2008. These returns occurring are included in our base assumption of 80% availability. If the returns do not occur then we expect nuclear availability across these 10.2GW of output to be lower and have illustrated the impact on overall generation availability in our additional scenario in this final 2008/09 winter outlook report where we replace our 80% availability assumption with a 65% availability assumption.

Figure A. 28 – Historic Nuclear Generation Output for winter 2008/09 installed capacity



England – France Interconnector Availability Assumptions

147. We expect that the French interconnector will be capable of exporting or importing 2GW of power over the winter[19]. We expect the direction of power transfer to be determined by relative market prices and have seen this as the key driver over recent history. It isn't proven how the French and GB market will interact in a situation where there is a coincident generation tightness and high demands and this remains a potential source of uncertainty. National Grid has an operational agreement with RTE, the French system operator which does provide us with further comfort that options are available for us as system operator in the unlikely event that power transfers are sub-optimal for ensuring GB security of supply. As an element of our new scenario added to this final winter 2008/09 outlook report we have illustrated a situation where the GB-France interconnector is at float (zero transfer in each direction).

Potential LCPD Impacts for winter 2008/09

148. We assume that environmental restrictions do not prevent coal generation from being available to the market or to National Grid in the event of high electricity demands over the coming winter. Most stations impacted by new emissions legislation under the Large Combustion Plant Directive (LCPD) are operating under scenarios as we expected, but with increased system operation costs incurred. In our longer term planning we did not expect the late fitting of Flue Gas Desulphurisation (FGD) at a number of coal power stations (Fiddlers/Ferrybridge 3+4/Rugeley) to continue towards the winter. As a result there continues to be some uncertainty as to when FGD will be commissioned and the timing of when the stations will be able to operate outside the relatively restrictive Section 5(1) derogation process. However, if National Grid has issued a system warning, such as a NISM, these stations are able to run without this counting towards their section 5(1) limited hours[20] to help ensure security of supply.

149. Some respondents to our consultation have highlighted more stringent environmental related restrictions such as limits on power station emissions. For example a reduced national annual limit for Sulphur Dioxide emissions that will apply to coal plant that has not fitted FGD which came into effect in 2008. In the case of Sulphur Dioxide emissions trades are possible within the national overall limits and have already taken place. The tighter limits on emissions are more likely to impact on the generation mix particularly in respect of the balance between gas and coal load factors rather than availability of stations to meet high demands and system peaks. This continues to be an area of uncertainty which we are monitoring.

150. We are supportive of further information transparency around environmental restrictions placed on large combustion plant as we believe this may aid efficient market operation.

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[19] There are no planned interconnector outages currently planned between October 2008 and March 2009. See http://www.nationalgrid.com/NR/rdonlyres/B3DEF0D1-FD27-4206-AE00-0F4CE0FF7126/24335/Outageprogramme200809rev100308.pdf

[20] Information is currently published on the Environment Agency website here http://www.environment-agency.gov.uk/business/444304/1765106/1765136/1765221/1765582/2025670/?version=1&lang=_e on those power stations running under LCPD Section 5(1) derogations.

Generation Availability Assumptions 2008/09

151. Our overall availability assumptions have not changed for this winter. However, in response to feedback received, we have reflected what we see as potential sensitivities and uncertainties in generation availability to illustrate the impact of no wind generation output, lower nuclear power output and float on the England to France Interconnector.

Table A. 15 – Generation Availability Assumptions Made For Winter 2008/09

Power Station Type	Full Metered Capacity (GW)	Assumed Availability	Assumed Availability (GW)
Nuclear	10.2	80%	8.2
French Interconnector	2.0	100%	2.0
Hydro generation	1.1	60%	0.6
Wind generation	1.4	35%	0.5
Coal	27.8	85%	23.7
Oil	3.5	95%	3.3
Pumped storage	2.7	95%	2.6
OCGT	1.5	95%	1.4
CCGT	25.2	90%	22.7
Total	**75.4**		**64.9**
Average availability		**86%**	

Mothballed Generation Capacity

152. We are aware of 1.0 GW of plant which is currently long term mothballed. We do not expect any other plant to be mothballed for winter 2008/09 and nor do we expect any of the mothballed generation plant to become available for this winter. Discussion with the operators of the long term mothballed generation capacity indicates that the time required for returning this plant could be in the region of two years.

Table A. 16 – Mothballed Capacity, Winter 2008/09

	Could Return within 6 months	Long Term Unavailable Plant
Generation capable of being returned within period (GW)	0	1.0

Contracted Reserve

153. In order to achieve a demand-supply balance, National Grid procures services from generation and demand side providers to be able to deal with actual demand being greater than forecast demand and plant breakdowns. This requirement is met from both synchronised and non-synchronised sources. We procure the non-synchronised

requirement from a range of service providers including Balancing Mechanism (BM) participants, non-BM generating plant and demand reduction. This requirement is called Short Term Operating Reserve (STOR) and is procured on an open market tender basis that runs three times per year.

154. 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.

155. For winter 2008/9, the expected total level of contracted STOR reserve is almost 2.3GW, over 1.6 GW from BM participants and nearly 0.7 GW from non-BM generating plant and demand reduction.

156. Prior to the winter, there will be a further STOR tender round, results of which will be published in late September covering services for the winter 2008/9 darkness peak. Communications regarding this will be through electricity operational fora and on our website.

157. 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 synchronised sources within the BM. If all response holding was created in the BM, then approximately 1.4GW of reserve would be required to meet the necessary response requirement. 1.2GW of this 1.4GW reserve requirement has already been contracted, with 0.5GW from demand-side providers.

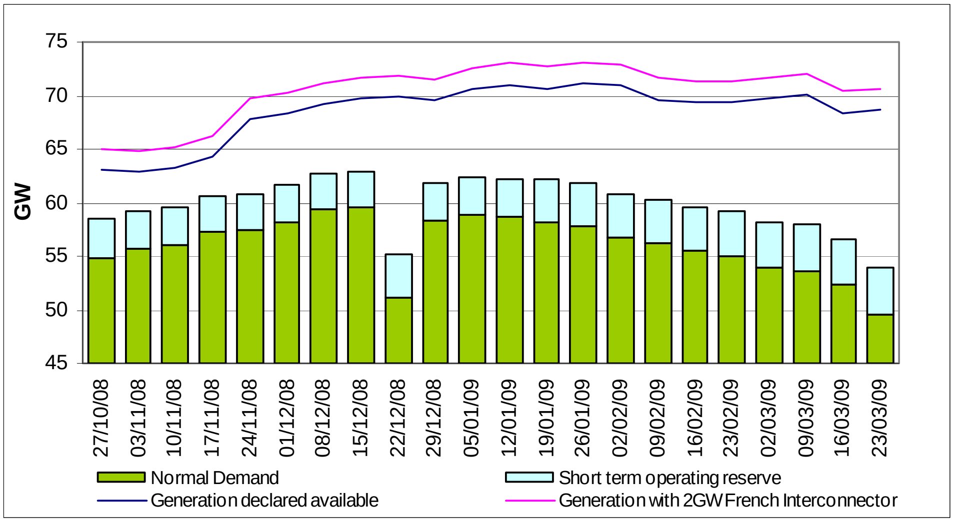
158. National Grid continues to have Maximum Generation contracts in place for winter 2008/9, which provide potential access to 1 GW of extra generation in emergency situations. This is a non-firm emergency service and generation operating under these conditions normally has a significantly reduced reactive power capability (which in turn can have a significant impact on transmission system security) Hence, it is not included in any of our margin analysis. This service was available pre-NETA and similarly was never included in margin analysis.

Forecast Position of Generation Surpluses for Winter 2008/09

159. Figure A.29 reflects a winter where weather and demand are at normal[21] levels for each week. The generation available is the availability declared to National Grid by the generators under the Grid Code Operating Code 2, and reflects planned unavailability, but has no allowance for unplanned generator unavailability. Demand in Figure A.29 includes a 0.3 GW export to Ireland and no exports to France. As the chart shows based on normal demands and notified availability there is sufficient generation to meet demand and our short term operating reserve requirements comfortably. Note that the generation availability makes no allowance for generation that may be ‘sterilised’ as consequence of transmission constraints.

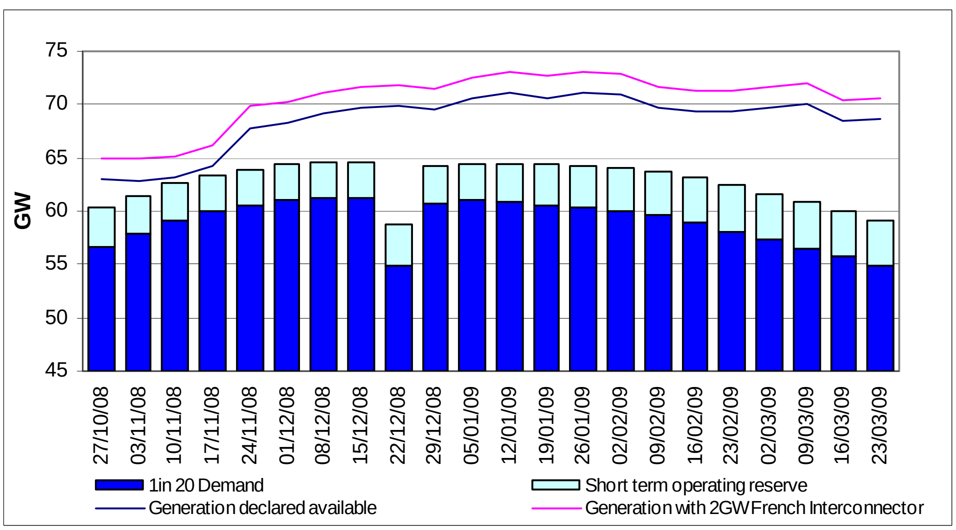
[21] Normal demand refers to demand we forecast based on 30 year average weather. This differs from ACS and 1 in 20 demands defined in footnotes to paragraph 33.

Figure A. 29 - Normal Demand and Notified Generation Availability



160. Figure A.30 reflects a winter where weather and demand are at 1 in 20 levels for each week. As the chart shows based on 1 in 20 demands and notified availability there is sufficient generation to meet demand and our short term operating reserve requirements comfortably.

Figure A. 30 - 1 in 20 Demand and Notified Generation Availability



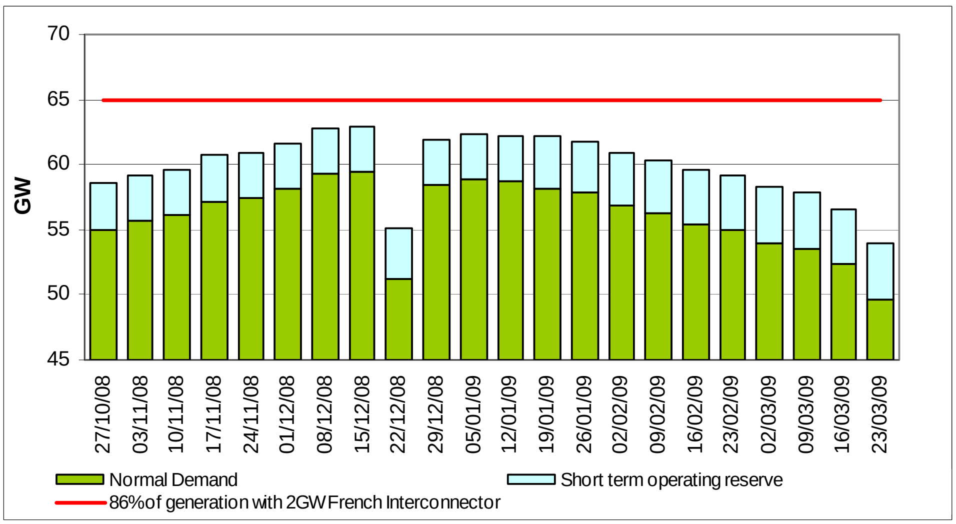
161. Figure A.29 and Figure A.30 use generation availability as declared[22] to National Grid by the generators under the Grid Code Operating Code 2, which reflects planned unavailability, but has no allowance for unplanned generator unavailability. We have

[22] This availability snapshot under OC2 was taken at end of August. Generators can change their availability submissions on a daily basis and often refine them as we approach closer to real time.

outlined our assumptions earlier in this report for the levels of actual generation availability we expect at the time of demand peak.

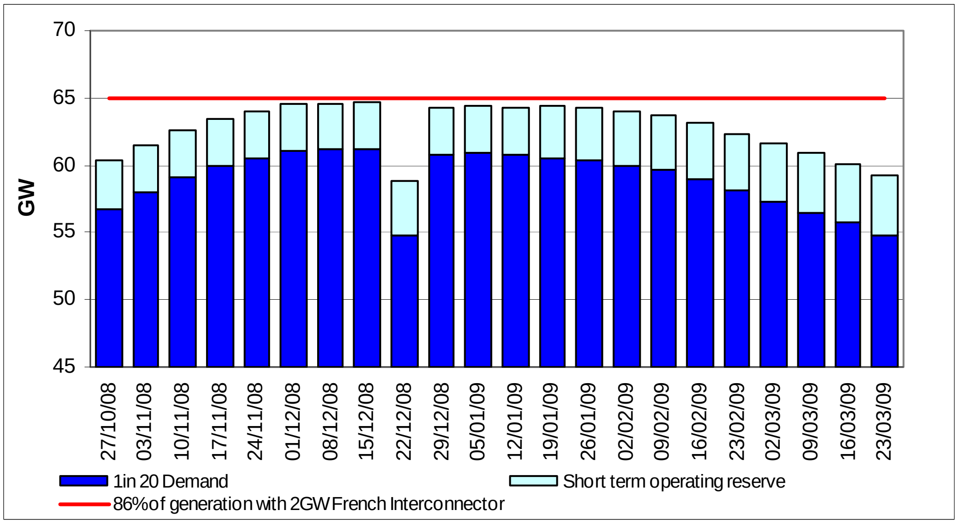
162. Figure A.31 shows our average weather condition driven demands (normal demand), plus our short term operating reserve and our assumed availability of generation which is 86% of our operational view of generation capability plus 2GW of import from France. The demand in the figure includes a 0.3GW export to Ireland. As the chart shows based on normal demands and using generation availability based on our assumptions there is sufficient generation to meet demand and our short term operating reserve requirements comfortably.

Figure A. 31 - Normal Demand and Assumed Generation Availability



163. Figure A.32 takes the 1 in 20 demand level scenario but uses our assumed level of generation availability. By using assumed levels of availability we are able to make an allowance for unplanned generator unavailability. We have continued to assume under the 1 in 20 demand scenario below that we export 0.3 GW to NI. Implicit in our analysis is that the French interconnector would transfer 2GW of power into the UK. However imports of power from France are not a condition of meeting demand. Figure A.32 shows that under our assumptions demand and our STOR can be met.

Figure A. 32 - 1 in 20 Demand and Assumed Generation Availability



Sensitivities For Different Availability Assumptions

164. Additionally in this version of the outlook report we have developed a scenario which illustrates the potential effect of some sensitivities around our base assumptions.

165. We have amended our base assumption for nuclear generation availability to 65% availability from the 10.2GW of capability and assumed a 0% contribution from wind generation. These scenarios lead to a revision of the 86% of output from the aggregate GB generation fleet to 83% of output as shown in Table A.17.

Table A. 17 – "Low" Generation Availability Assumptions Scenario For Winter 2008/09

Power Station Type	Full Metered Capacity (GW)	Assumed Availability	Assumed Availability (GW)
Nuclear	10.2	65%	6.6
French Interconnector	2.0	100%	2.0
Hydro generation	1.1	60%	0.6
Wind generation	1.4	0%	0.0
Coal	27.8	85%	23.7
Oil	3.5	95%	3.3
Pumped storage	2.7	95%	2.6
OCGT	1.5	95%	1.4
CCGT	25.2	90%	22.7
Total	**75.4**		**62.9**
Average availability		**83%**	

166. Figures A.33 and A.34 indicate that, even in the event that nuclear fleet performance is 65% of available output and wind output is zero coincident with the peak demand, electricity demand should still be met.

167. We believe that market mechanisms on the GB-France interconnector should result in imports to the UK at times of system stress or high demands. Where demand plus our short term operating reserve exceeds our generation scenario we would expect to be issuing some system warnings relating to erosion of short term operating reserve, but we would also expect to be able to meet demand in all but high scenarios of short term plant loss and demand forecast error.

Figure A. 33 - Normal Demand and "Low" Generation Availability Scenario

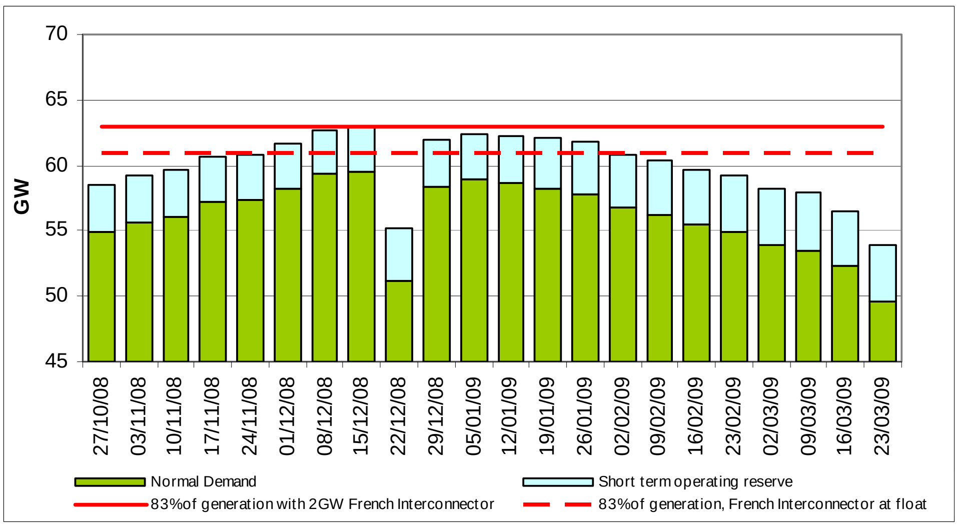
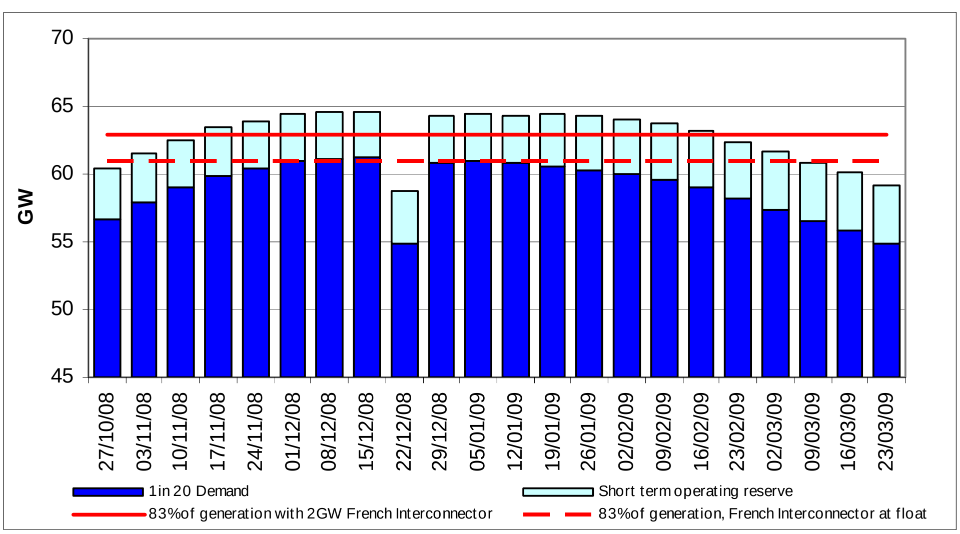


Figure A. 34 – 1 in 20 High Demand and "Low" Generation Availability Scenario



Generation Merit Order for Winter 2008/09

168. This report focuses on the outlook for meeting electricity demand and is less directly concerned from this perspective with generation merit order itself. Which power generation type contributes to meeting demand is determined to the greatest extent by the market. In terms of meeting gas demand, the relative utilisation of gas for power generation is a key factor. This is discussed in the gas section and gas power interaction sections of this report.

169. Forward prices for fuel and carbon continue to be subject to change, though coal has the economic advantage at present for the coming winter based on forward prices.

Market Information

170. National Grid provides a range of operational information which is available over public means on the internet[23]. For example we provide and Elexon publish regularly updated information of declared generation availability, electricity demands based on forecast weather and resulting generation plant surpluses as well as other information on an ongoing basis. A new feature of the BMReports website is a summary page[24] showing key operational electricity information in one place. The summary page will undergo some improvements in early November which will further improve market transparency aiding winter operations for 2008/09.

171. We will also produce winter to date reporting[25] on our website during the course of the winter at monthly intervals. This reporting will take a similar form to that first produced for the 2007/08 winter.

[23] www.bmreports.com

[24] http://www.bmreports.com/bsp/bsp_home.htm

[25] http://www.nationalgrid.com/uk/Electricity/Info/winterupdates/

Section B
Gas/Electricity Interaction

172. The Met Office[26] has predicted winter temperatures above the average for 1971-2000. There are no problems meeting demand in average weather conditions under any of the scenarios examined below.

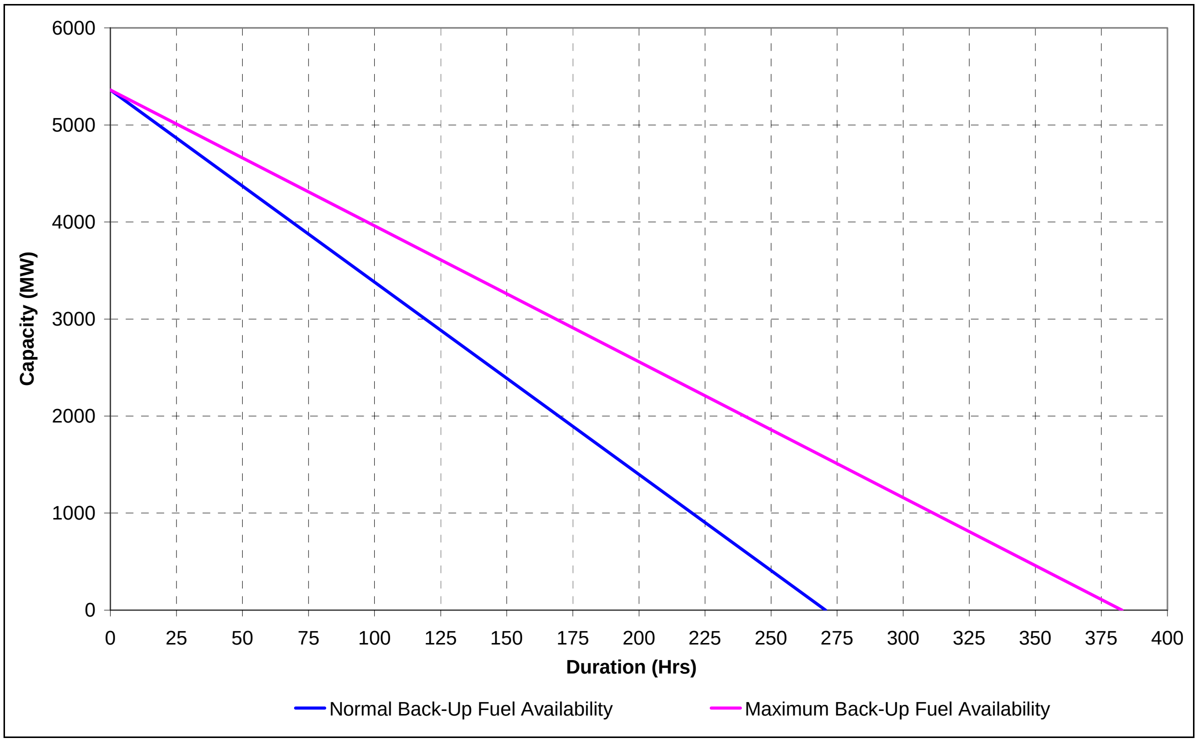
Power Stations with Alternative Fuels

173. From 1st January 2008, Directive 1999/32/EC on the Sulphur Content of Certain Liquid Fuels (SCCLF) which reduced the limits on the sulphur content of gas oil burnt in power stations to 0.1% by mass or less came into effect. Based on the response from our enquiries on backup fuel from a number of generating companies, this appears to have had little impact on the availability of back up fuel generating capacity in the coming winter. 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 5.4 GW have the capability to run on distillate which is higher than last year's estimation of 4.3 GW. Out of the total 5.4GW having back-up fuel generation capability, more than half have interruptible gas transportation arrangements.

174. Figure B.1 shows our estimation in a load duration curve form, showing 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 generation 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. This is 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 factor is the amount of gas demand from power stations that is displaced within the gas day. The curves below also assume no restocking of distillate which may be possible for some stations over the period they are running on distillate.

[26] Winter 2008/9 forecast issued 25 September 2008: http://www.metoffice.gov.uk/weather/seasonal/winter2008_9/

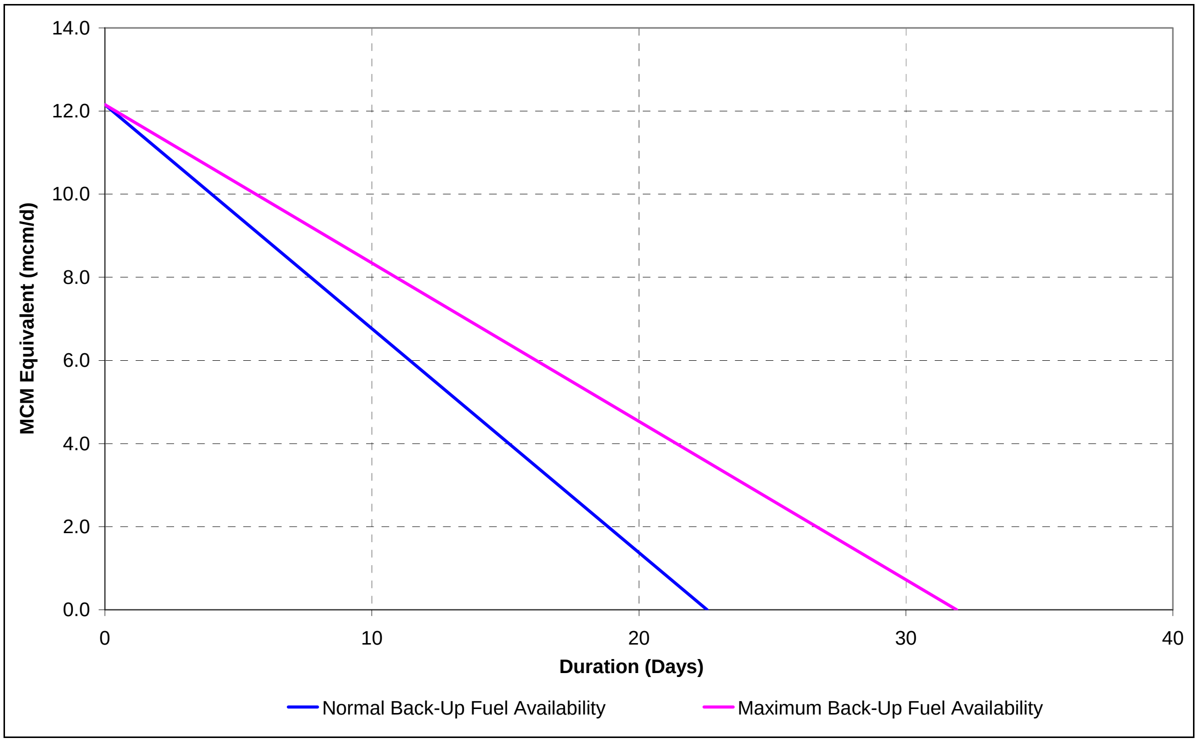
Figure B. 1 – Power Load Duration Curves for Back Up Fuel Supplies



175. In 2007/08, there was an estimated total of 1 mcm equivalent distillate use around system peak days. Based on the distillate back up fuel data from the generating companies for 2008/09, we estimate that a total of between 110 mcm to 180 mcm gas equivalent can be displaced using distillate generation capability.

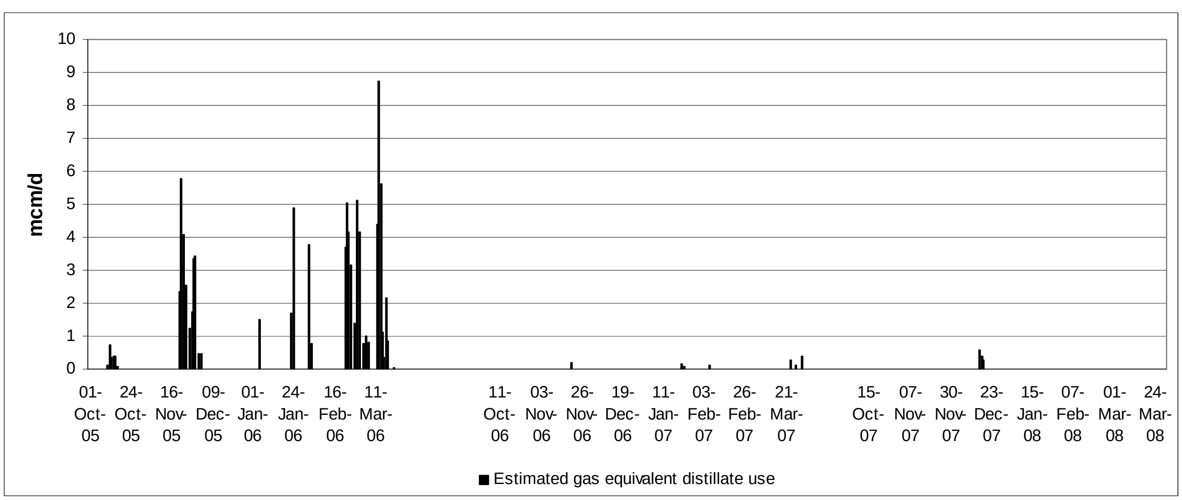
176. We have modeled the amount of relief that gas power stations switching to distillate could provide to the gas market. Using the assumption that distillate capable gas power stations ran for 12 hours per day gives at least 10 mcm/d of gas relief for upto 4 days based on normal and full distillate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

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



177. We have also estimated historic distillate use over previous winters. This shows very little use of distillate in the two most recent winters, but does show up to 9 mcm/d of relief and more normally 3-6 mcm/d.

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



Potential for Demand-Side Response from Gas Fired Generation

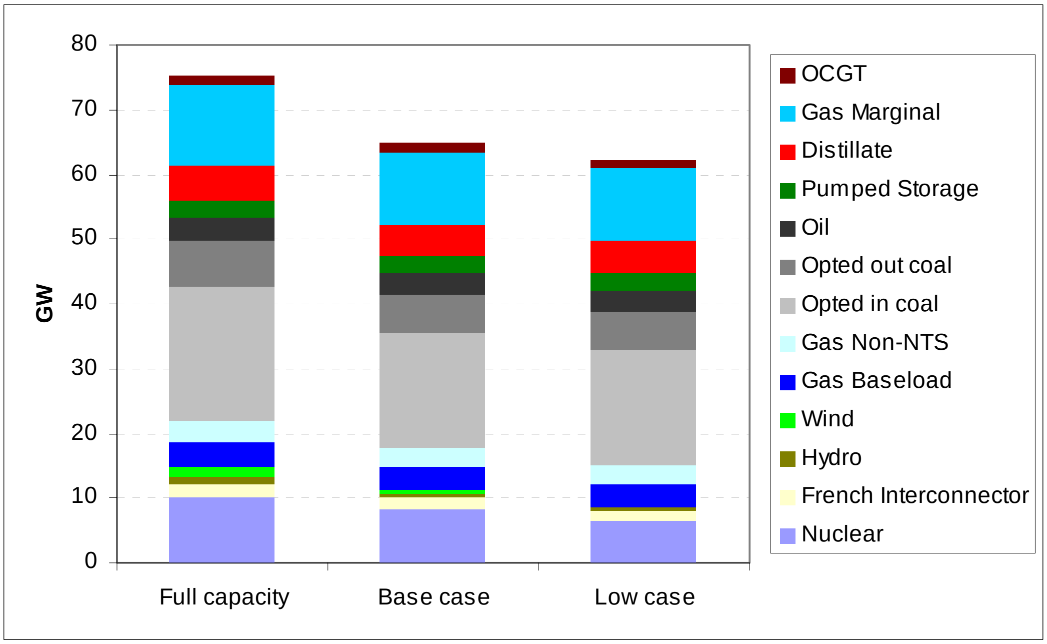
178. We continue to expect that gas-fired power stations have the potential to respond to market price signals, decreasing their gas consumption when the cost of generating from other fuels is lower than the price of burning gas. Our forecasts take account of the impact of LCPD on the generation from individual power stations. However, the demand response analysis assumes that it will become profitable for all coal plants, whether opted in or out, to generate ahead of marginal gas when demand response is required.

179. The generation capacities used for the demand-side response analysis are shown in Table B.1 and Figure B.4. Switching to distillate is assumed to occur on days when gas demand would require the use of LNG storage. The base case assumptions match the availability assumptions in Table A.15*.* The low case removes a further 2.6 GW from the nuclear, French interconnector and wind categories.

Table B. 1 – Generation ranking order for demand-side response analysis

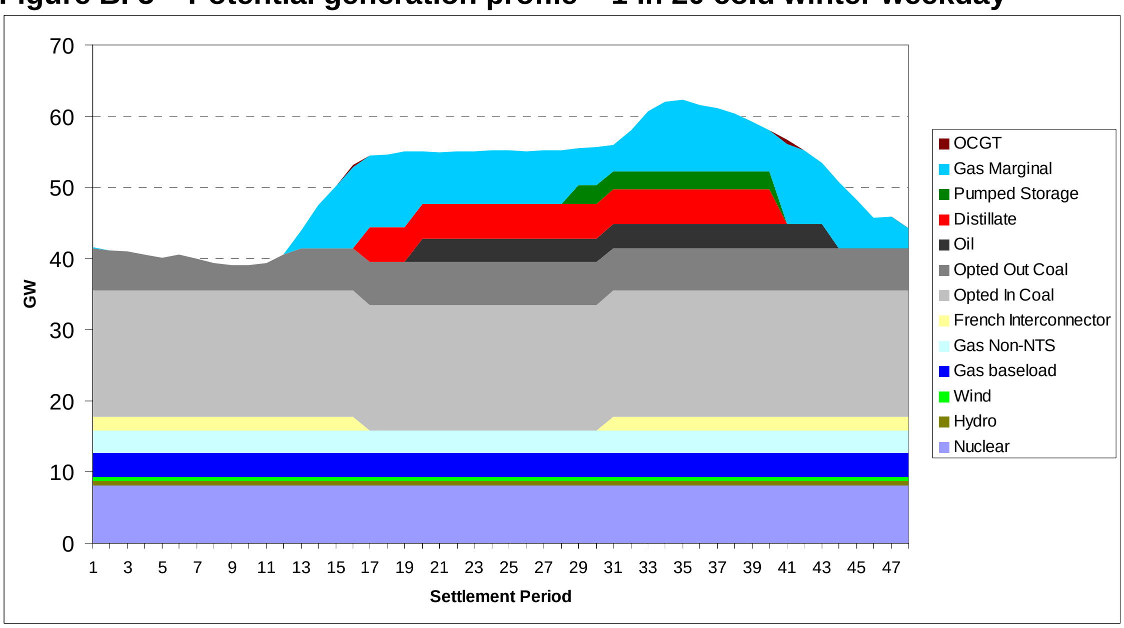
Power Station Type	Full Metered Capacity	Base case assumed availability		Low case assumed availability		Model Assumptions Summary
	GW	%	GW	%	GW	
Nuclear	10.2	80	8.2	65	6.6	Baseload
French Interconnector	2.0	100	2	75	1.5	Baseload, except 8 am to 3pm weekdays
Hydro	1.1	60	0.6	60	0.6	Baseload
Wind	1.4	35	0.5	0	0.0	Baseload
Gas Baseload	3.9	90	3.5	90	3.5	Baseload
Gas Non-NTS	3.3	90	3.0	90	3.0	Baseload
Coal	27.8	85	23.7	85	23.7	Baseload
Oil	3.5	95	3.3	95	3.3	12 hours over peak
Pumped Storage	2.7	95	2.6	95	2.6	6 hours over peak
Distillate	5.4	90	4.9	90	4.9	12 hours over peak
Gas Marginal	12.6	90	11.3	90	11.3	Marginal plant
OCGT	1.5	95	1.4	95	1.4	Low merit, run occasionally
TOTAL	75.4	86	65.0	83	62.4	

Figure B. 4– Generation order for demand-side response analysis



180. Figure B.5 illustrates how electricity demand could be met on a typical cold day in a severe winter, consistent with the modeling assumptions described above. It shows approximately 24 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.

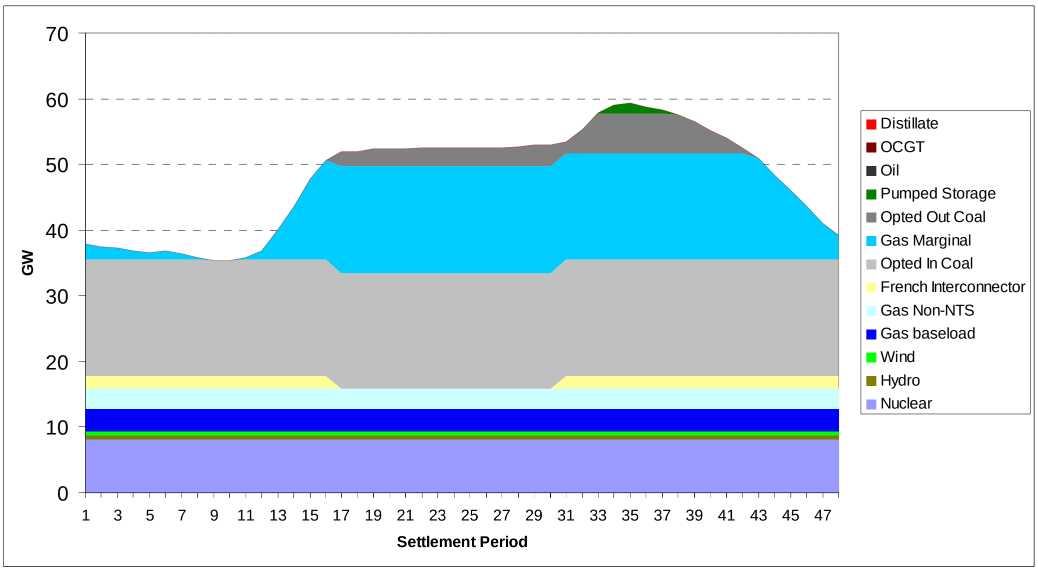
Figure B. 5 – Potential generation profile – 1 in 20 cold winter weekday



181. Figure B.6 illustrates a potential demand profile for a mid December weekday when there is no pressure for demand response. Marginal gas is shown in the ranking order

between opted in and opted out coal. Opted in coal generates for 24 hours, gas is at maximum generation for 14 hours and opted out coal for is required for 13 hours but only 3 at maximum levels. In practice the demarcation between fuels types will be less clear than this, with the efficiency of individual plants, location and generation portfolio of individual companies affecting the ranking order. The graph shows a small sliver of gas generation over night. When a gas power station is required it tends to run at full capacity with opted in coal reducing output to maintain the balance between supply and demand. Opted out coal power stations would also run at full capacity because the LCPD limit on running hours does not distinguish between full and partial generation.

Figure B. 6 – Potential generation profile – mid-December week day



182. 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.

183. There is scope for gas power stations to run on distillate fuel for several days providing, we estimate, between 110 and 180 mcm of gas equivalent output assuming no restocking of distillate.

184. Relatively mild winters without very high gas demands in the last two years mean that large scale switching from gas to distillate has not taken place. We have seen evidence of distillate use in the winter of 2005/06 of up to 9 mcm/day.

185. 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.

186. Table B.2 shows the gas supply assumptions used in the gas/electricity interaction modeling. Gas supplies comprising UK continental shelf, LNG imports, Norwegian imports and BBL imports adds up to 316 mcm. Gas demands in excess of 316 mcm are allocated 25% IUK and 75% storage. The base supply case assumes IUK imports are capped at 20 mcm, the high supply case caps IUK at 40 mcm.

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

Source of Supply	MCM
UKCS	195
Norway	81
LNG	10
BBL	30
IUK	20 (Central) 40 (High IUK)
Long duration storage (Rough)	42
Medium duration storage (MRS)	45
Short duration storage (LNG)	48

187. Tables B.3 to B.6 show the total demand response required for each scenario in an average, 1 in 10 cold and 1 in 50 cold winter. The 1 in 10 and 1 in 50 conditions are based on the last 80 years with no adjustment for climate change. The average winter is based on the 17 years from October 1987 to September 2004. In all 4 scenarios an average winter does not require any demand response, whilst a 1 in 50 winter requires a significant level of demand side response. The potential CCGT figure shows the amount of required demand side response that could potentially be provided by the power generation sector.

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

	Average	1 in 10	Severe
Required	0.0	1.3	3.0
Potential CCGT	0.0	1.0	1.9
Deficit	0.0	0.3	1.1

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

	Average	1 in 10	Severe
Required	0.0	1.3	3.0
Potential CCGT	0.0	0.7	1.4
Deficit	0.0	0.6	1.6

Table B. 5 – Potential CCGT demand response (bcm), base generation, high IUK supply

	Average	1 in 10	Severe
Required	0.0	0.4	1.3
Potential CCGT	0.0	0.4	0.9
Deficit	0.0	0.0	0.4

Table B. 6 – Potential CCGT demand response (bcm), Low generation, high IUK supply

	Average	1 in 10	Severe
Required	0.0	0.4	1.3
Potential CCGT	0.0	0.3	0.5
Deficit	0.0	0.1	0.8

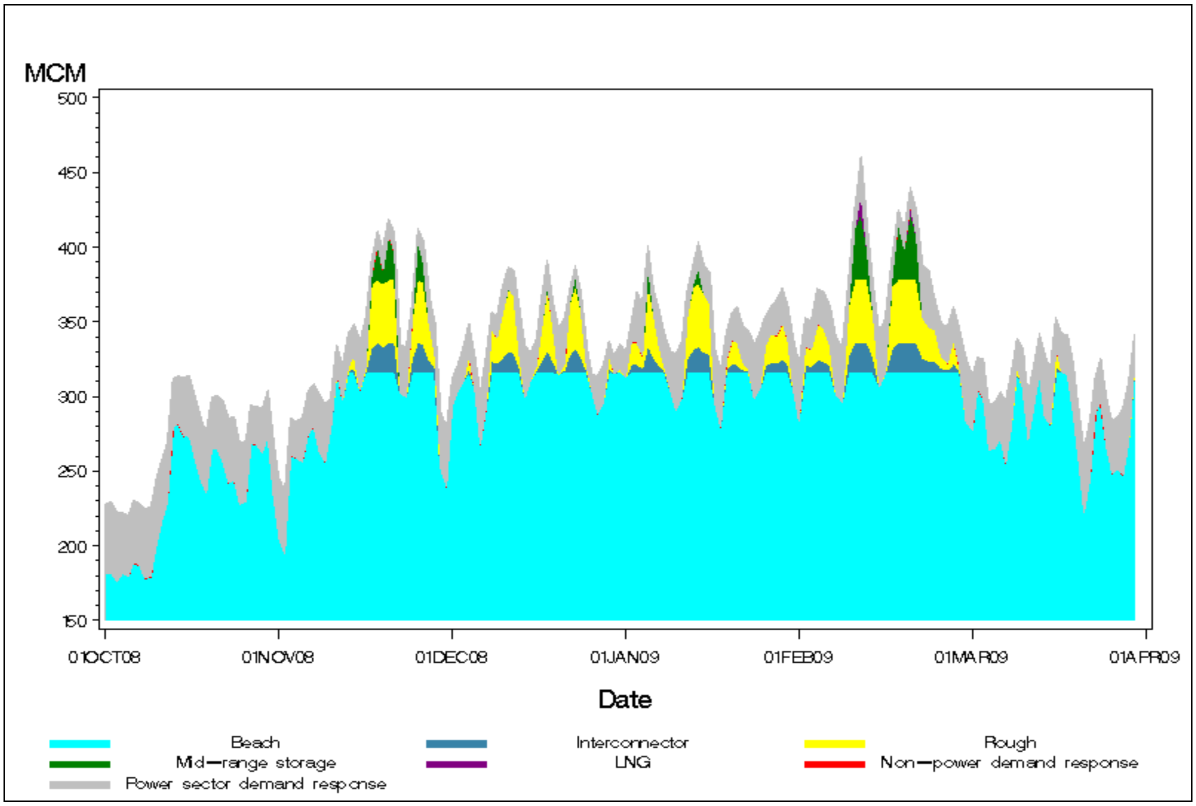
188. The information in these tables is processed from simulations[27] of what demand would be if historical weather was repeated. The following graphs are from a selection of these simulations. The model does not allow for refilling of mid-range storage or distillate stocks, however during the worst 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.

189. The worse case scenario of the 4 scenarios simulated is the low generation, central supply scenario. Figure B.7 shows this scenario for 1993/4 weather, the coldest winter in the last 20 years. Figure B.8 shows the impact of 1985/6 weather, the coldest winter since 1962/3.

190. Figure B.7 shows that 1993/4 weather would not be a problem. 1993/4 was the coldest winter in the last 20 years. The 1993/4 winter was 1 in 3 cold, based on data for the last 80 winters.

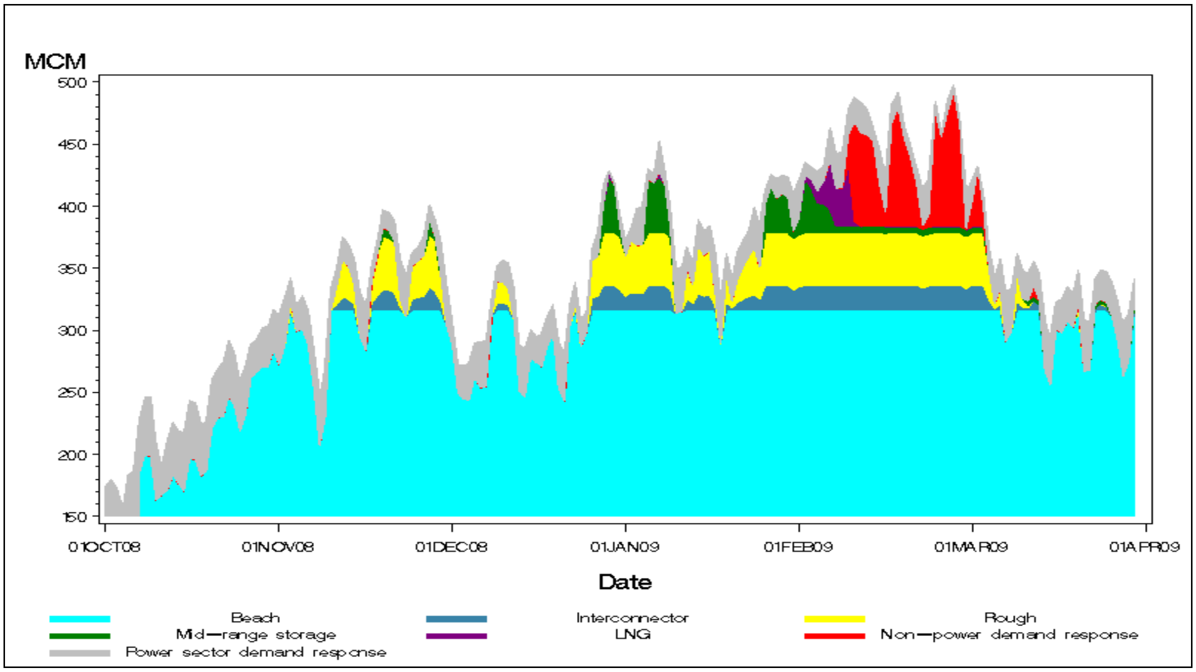
[27] For more information see paragraph 7.1 of the Demand Forecasting Methodology Document: http://www.nationalgrid.com/uk/Gas/OperationalInfo/operationaldocuments/Gas+Demand+and+Supply+Forecasting+Methodology/

Figure B. 7 – Theoretical gas supply build-up, low generation, central supply, 1993/4 winter



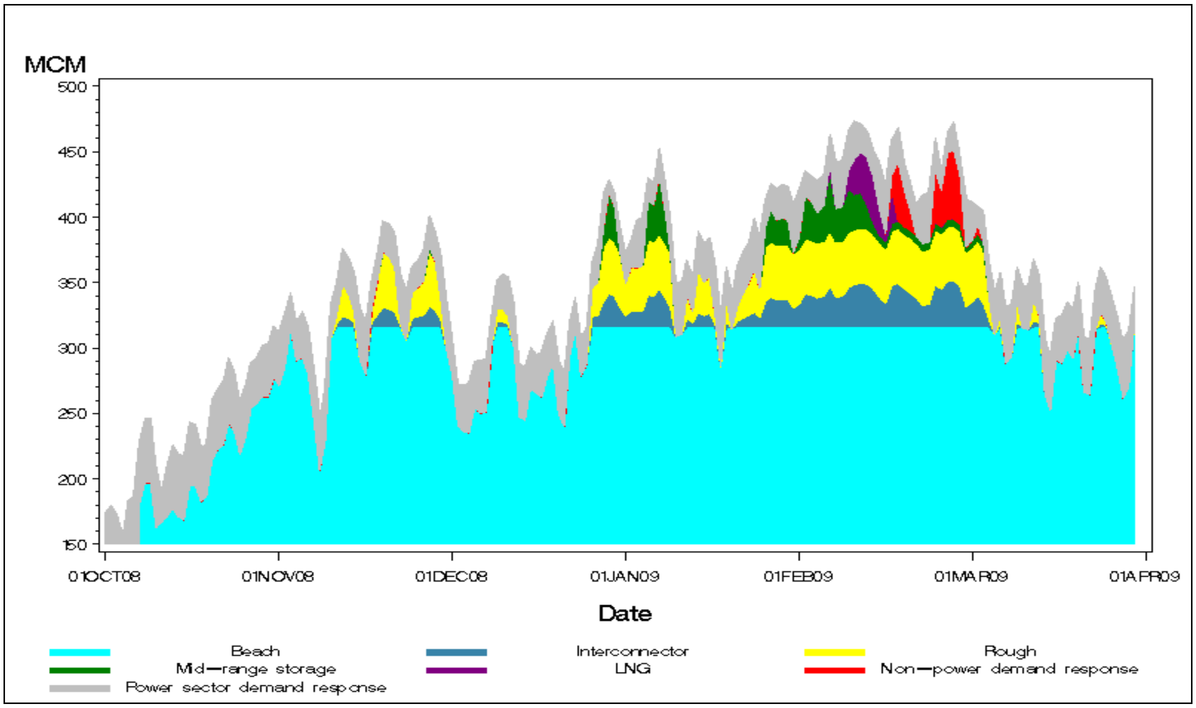
191. The low generation, central supply case is less able to cope with a cold winter. The1985/6 winter was 1 in 12 cold but it ended with the second coldest February in the last 80 years. Figure B.8 shows that it is the number of cold days that would cause a problem if 1985/6 weather was to be repeated with most of the mid-range storage and all of the LNG storage used up. 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. 8 – Theoretical gas supply build-up, low generation, central supply, 1985/6 winter



192. Figure B.9 shows an improved position with the high generation, high IUK supply scenario although some demand response is still required. There is considerable uncertainty as to how demand will react during a cold winter. Some respondents suggest that high prices will encourage greater energy conservation whilst others argue that customers will put a higher priority on comfort and thus increase demand.

Figure B. 9 – Theoretical gas supply build-up, base generation, high IUK supply, 1985/6 winter



Section C
Industry Framework Developments

193. 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 concerning such developments.

Gas Entry Capacity Transfers and Trading

194. National Grid makes available for sale entry capacity at the "obligated" level at each entry point in accordance with its GT licence. In addition National Grid has an obligation to facilitate the trade and transfer of obligated capacity between entry points. The key elements of the trade and transfer process are:

- The process is undertaken on a monthly basis, as part of the RMTTSEC auction, for the month ahead
- Shippers can bid for the obligated capacity at the existing ASEP before it is traded or transferred to another ASEP
- Shippers can surrender any unwanted capacity into the RMTTSEC
- Exchange rates are calculated once the bids for trades and transfers are known
- There is an exchange rate limit of 10:1

Discretionary Release of System Entry Capacity

195. On 22 August 2008 Ofgem approved UNC Modification Proposal 0216 which allows National Grid to release system entry capacity outside of the standard auction processes. It also provides a mechanism to sell capacity products with the ability to buy the capacity back at a predetermined price. National Grid has already utilized the new functionality provided by this Modification Proposal, to release additional firm capacity at Easington for October 2008 and to announce a further auction for the period November 08 to March 2009 at qualifying entry points within the Easington zone.

Entry Capacity Baselines Review

196. National Grid is obliged to release Firm Entry Capacity up to baseline levels which were set as part of the 2007-2012 Transmission Price Control Review (TPCR). Following the TPCR Ofgem conducted a specific review of baselines which resulted in an increase in baselines at certain entry points effective from July 2008. National Grid will therefore be offering for sale increased obligated levels of Entry capacity this winter supplemented by any non-obligated firm capacity and interruptible capacity that may be available.

Uniform Network Code - Information Provision

197. As part of its work within the European Gas Regional Initiative North West (GRI NW) National Grid has brought forward UNC Modification Proposal 0223 “Provision of day ahead Gas Flow Nomination Data at major Aggregated System Entry Points” aimed at publishing input gas flow nominations for all entry points delivering more than 10 MCMD. If this proposal is implemented this information will be published via the National Grid Information Exchange website on or before 18.00 D-1.

Balancing and Settlement Code (BSC) - Electricity Market Information

198. Following extensive industry consultation, National Grid has progressed two modifications on market information both of which focus on improving information transparency to the market. It is anticipated that greater information transparency would lead to better market signals to all market participants, thus allowing them to better manage their positions. This should ultimately result in a more efficient operation of the market.

199. P219 (‘consistency between forecast and outturn demand’) provides additional forecast/outturn demand data which allows a fuller comparison to be made between forecast and outturn demand. Since the additional data is provided across a range of timescales, the forecast/outturn data can be compared more easily across these timescales.

200. P220 (‘provision of new data items for improving market information’) provides additional operational data which includes a breakdown of generation by fuel type (both real-time and half hourly), forecast of wind generation, outturn temperatures and historical temperature trends, daily energy volume transmitted across the system and associated historical trends, and Short Term Operating Reserve (STOR) volumes instructed outside of the Balancing Mechanism.

201. Following Ofgem approval of P219 and P220 in April 2008, the modifications will become effective from 6 November 2008. The data provided under P219 and P220 (along with relevant existing data) will be published on a daily summary page on the BMRS; this daily summary page will be similar to the highly successful gas daily summary page.

202. P226 has recently been raised by Eon with the aim of improving the transparency and timeliness of market information about power stations whose operation has been affected by the Large Combustion Plant Directive which came into effect on 1st Jan 2008. This modification is currently being considered by a BSC working group but, in our view, is unlikely to result in any formal changes in time for winter 2008/09. We are actively engaged in the process of exploring the issues around information transparency for LCPD plant and believe that the modification process itself will raise awareness of where information is already published, particularly by the Environment Agency (EA).

Incentives to balance

203. There are currently two BSC modifications in train proposing changes to the way in which the electricity imbalance price is calculated. These are P211 “Main Imbalance Price based on an unconstrained schedule” and P217” Tagging Process and Calculation of Imbalance Prices”. Both aim to remove System Operator actions that the proposers consider are leading to price distortions and subsequently leading to market inefficiencies. However it is unlikely that either of these modifications will be implemented during winter 08/09

Connection and Use of System Code (CUSC) - Access to the Transmission System – CAP144, CAP148 and CAP149

204. CAP144 proposes to extend the provisions introduced by CAP048 (Firm Access and Temporary Physical Disconnection) to include the specific circumstances when a Generator is exporting but is required to disconnect from the Transmission System in an emergency via an Emergency Instruction (EI) issued by National Grid in Balancing Mechanism timescales in accordance with the Grid Code. Ofgem directed that this proposal be made. The proposal was implemented on the 27th of June 2008.

205. CAP148 seeks to prioritise the use of the GB Transmission System by renewable generators. Under the proposal, renewable generators would be given firm access to the GB Transmission System by a fixed date and be compensated to the extent they are constrained from exercising such right by the payment of a new category of Interruption Payment. This would be irrespective of whether or not any associated deep reinforcement works have been constructed and/or commissioned by such date. The Amendment Proposal achieves this by the introduction of Deemed Transmission Entry Capacity (“DTEC”). CAP148 is currently with Ofgem for Authority decision. Ofgem published an impact assessment in July and is minded to reject this proposal.

206. CAP149, Transmission Entry Capacity with restricted access rights (TEClite) seeks to amend the CUSC to formalize existing transmission access arrangements whereby some Users, through non-standard variations to their Bilateral Connection Agreement (BCA), have restricted access to the GB Transmission System. CAP149 has been approved and was implemented on 24th May 2008.

Transmission Access Review and Related Amendments

207. Following the publication of the Energy White Paper 2007, Ofgem and BERR led a wide reaching review of transmission access arrangements. This included short term developments consistent with the current framework.

208. The review included medium and longer term developments. This involved commercial issues such as proposed changes to the way in which generators get access to the transmission system (including the consideration of time limited short term derogations) and how existing capacity is allocated in the long term and closer to real time. The review also included technical issues such as whether the transmission system could be driven harder to achieve more transmission capacity, considering what incentives may be needed for the TOs to meet the 2020 challenges, commissioning a

2020 system study and a fundamental review of the SQSS. The review team provided GEMA and the Secretary of State with an interim report during January 2008 and a final report was published in June 2008.

209. In parallel with Ofgem and BERR's Transmission Access Review National Grid has consulted the industry regarding evolving the Transmission Access arrangements.

210. National Grid published the Transmission Access Standing Group Report in August 2007. The report discusses eight high-level access concepts, ranging from developments of the existing arrangements to more fundamental reforms. The outcome of this work, together with the work led by Ofgem and BERR has lead to the development of a suite of CUSC modifications presented at the April 2008 CUSC Panel, CAP161 to CAP166. The CUSC amendments and associated charging changes have been considered by three working groups. The working groups will be consulting on the developed amendments in autumn 2008. It should be noted that we do not anticipate any of the proposed CUSC amendments being implemented for winter 2008/09.

Market Information Provision

211. National Grid's market information pages on nationalgrid.com continue to grow and accommodate real time developments on the NTS. As physical and commercial changes occur, the industry will see these incorporated into the existing suite of reports and data items.

212. The second phase release of MIPI (MIPI2) is currently under development and is due for release in Q4 2009. Changes and improvements include the decommissioning of the IE3 platform, functional enhancements, data rationalisation and the provision of DN data post SOMSA exit.

213. National Grid is committed to the full and timely reporting of these developments and will therefore seek to inform the community via existing communication channels.