Winter Consultation Report 2008/9

A review of winter 2007/8 & preliminary outlook for winter 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 are conducting 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.
4. This document, the consultation report, sets out our preliminary analysis and views for the coming winter and poses a number of questions of market participants. Ofgem plans to hold a seminar for industry parties in early September in London following which the final report will be issued in week commencing 29th September 2008.
5. The deadline for responses to this consultation report is 12th September 2008. Responses should be e-mailed to energy.operations@uk.ngrid.com. Where requested, we will treat information provided to us on a confidential basis. However, respondents may send confidential information to Ofgem if they would prefer by e-mail to GB.markets@ofgem.gov.uk.

6. Unless specifically asked not to by respondents, we will share all responses received with Ofgem. Respondents shall request that their information is marked confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

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7. National Grid operates the electricity transmission network through its subsidiary National Grid Electricity Transmission plc and the gas transmission network through its subsidiary National Grid Gas plc. For the purpose of this report "National Grid" is used to cover both licensed entities, whereas in practice our activities and sharing of information are governed by the respective licences.
8. 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 Review 2007/08 – Gas

10. 2007/8 was another mild winter, the 6th warmest in our 80 year data set.
11. Overall gas demand outturned within our forecast's range. However we experienced higher gas burn for power generation, particularly from January 2008, due to a combination of problems with nuclear power stations, delays in fitting Flue Gas Desulphurisation (FGD) plant to existing coal stations, and higher coal and carbon prices.
12. Gas supplies were broadly in line with our forecasts. Though in decline, UKCS supplies made up 60% of demand. Norwegian supplies were marginally below our pre-winter forecast. At times the UK received a lower proportion of Norwegian production due to higher deliveries to the Continent.
13. BBL imports were a little above our forecast and, as expected, IUK behaved as the marginal source of non-storage supply responding to market conditions, though at higher demands IUK imports did not exceed 25 mcm/d.
14. Our concerns over the uncertainty around the timing of new LNG imports from Milford Haven were fully realised with Dragon and South Hook still to commission. Due to high gas prices in other markets, Grain received less LNG cargoes than the previous winter and no cargoes after January.

Winter Review 2007/08 – Electricity

15. The winter period we have focused on for the purpose of this outlook report is the period of November 2007 to March 2008
16. The highest electricity demand last winter was 60.6 GW for the half-hour ending 17:30 on Monday 17 December 2007. This compares to the highest demand of 58.1 GW and 60.0 GW for 2006/07 and 2005/06 respectively. These demands do not include any exports to France or Northern Ireland.
17. We estimate that around 0.8-1.3 GW of demand management occurred at the peak as large customers reduced demand to avoid Transmission Network Use of System Charges.
18. The winter peak demand was met by the market through its normal function together with our normal system operator balancing mechanism.
19. Generation output during winter 2007/08 can be characterised as having two distinct periods. Coal was used to generate more power than gas in late 2007 with this reversing in early 2008 with gas being used to generate more power than coal. This change was driven to a large part by relative fuel and carbon prices and the implementation of the Large Combustion Plant Directive (LCPD). These changes were managed within the current market mechanisms which give us confidence that we can expect the market to respond to fluctuations in demand and generation availability for the coming winter to ensure demand can be met.

Winter 2008/09 Outlook – Gas

20. All fuel price futures are currently 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 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.
21. Forecast demands for next winter are 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 retro-fitting FGD plant to existing coal-fired stations and high gas costs.
22. 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.
23. From Norway we anticipate higher UK imports as Ormen Lange production builds up, however we acknowledge the potential for higher deliveries to the Continent at the expense of the UK. For BBL and IUK we expect similar performance to last winter with IUK responding to market needs as the marginal source of non storage supply.
24. LNG imports provides the biggest supply uncertainty with both Milford Haven facilities still to commission and an expectation that Grain Phase 2 will also commission in time for next winter. 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.
25. Due to these considerable supply uncertainties, our preliminary view of non storage gas supplies for next winter is between approximately 300-450 mcm/d. This is much wider than for any previous winter. Ideally this consultation will reduce this uncertainty before next winter commences.
26. Our preliminary assessment of storage requirements for the Safety Monitors captures the supply uncertainty resulting in a wide range of storage requirements from essentially zero for a well supplied UK to 15% of all storage if imports are at the low end of expectations.

Winter 2008/09 Outlook – Electricity

27. 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).
28. Demand should still be met in all but the most extreme of potential combinations of demand forecast error and generation unavailability.

29. The current outlook for the coming winter for generation running patterns indicates that coal-fired generation is going to be preferred to gas-fired generation. Clearly the current forward looking view may change as we approach the winter period.

30. The level of certainty around the return for the winter of several nuclear power stations is a key sensitivity and the situation will be updated in our final Winter Outlook report.

31. 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.

32. 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.

33. 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
Experience of 2007/08

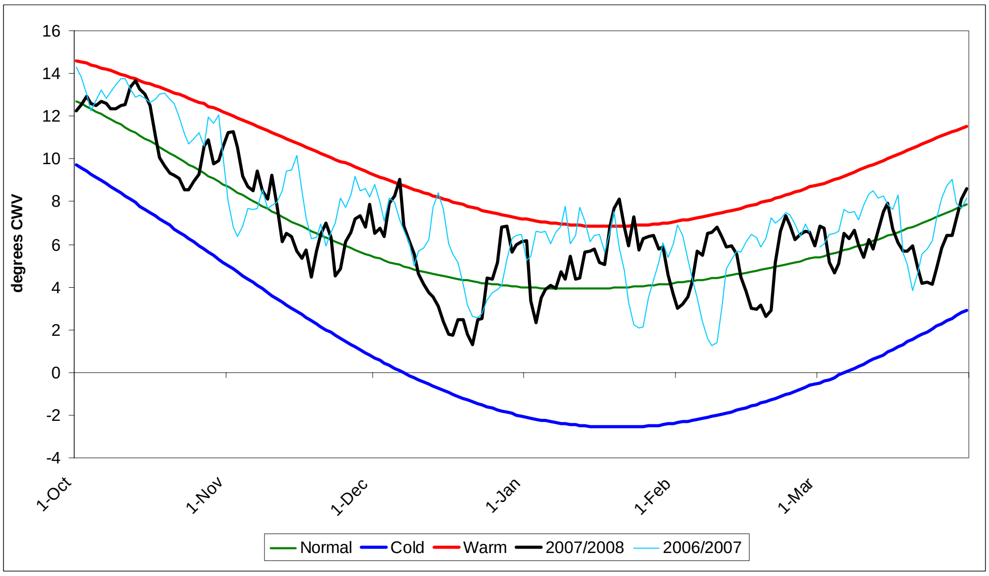
Weather

34. 2007/8 was another mild winter. For the period October 2007 to March 2008 the winter based on our 80 years of data was the 6th warmest recorded, in terms of severity the winter was 1 in 14 warm.

35. Figure A.1 illustrates the 2007/8 winter compared with the 2006/7 winter and warm, normal and cold conditions. The measure plotted in the graph is the Composite Weather Variable (CWV), which is calculated by combining temperatures and wind speeds and transforming them to produce a weather variable that is linearly related to non-daily metered gas demand.

36. The coldest day of the winter was December 21st 2007 with a national average temperature of 0.1°C (CWV of 1.3°).

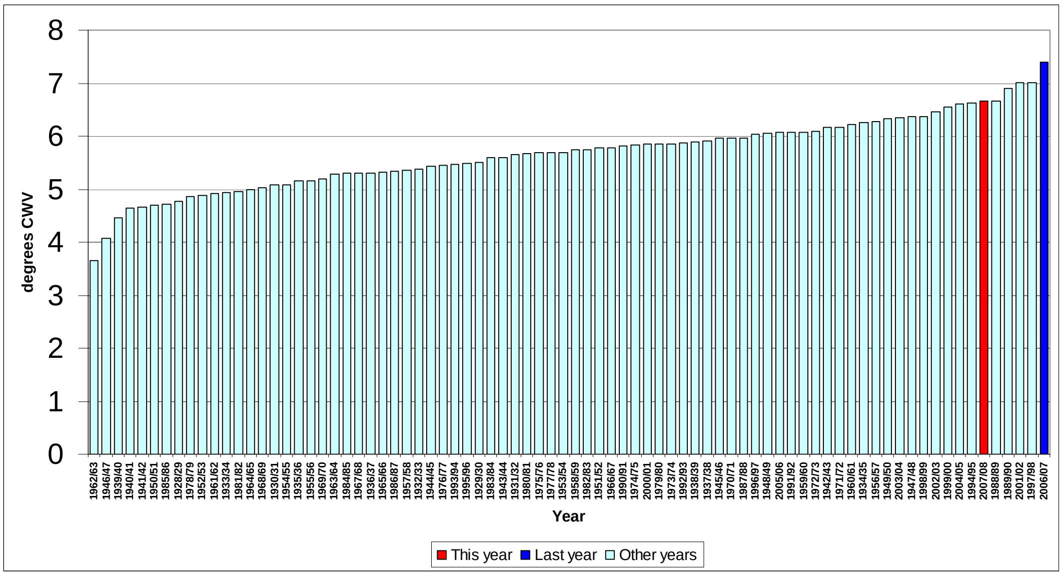
Figure A.1 – 2007/8 Winter Weather (CWV) Overview[1]



37. Figure A.2 compares the mean composite weather for the October to March period with previous winters.

[1] The cold and warm values are realistic daily ranges for each day of the winter. For further information please refer to http://www.nationalgrid.com/uk/Gas/OperationalInfo/operationaldocuments/Gas+Demand+and+Supply+Forecasting+Methodology/

Figure A.2 – Mean National Composite Weather for October to March



Gas

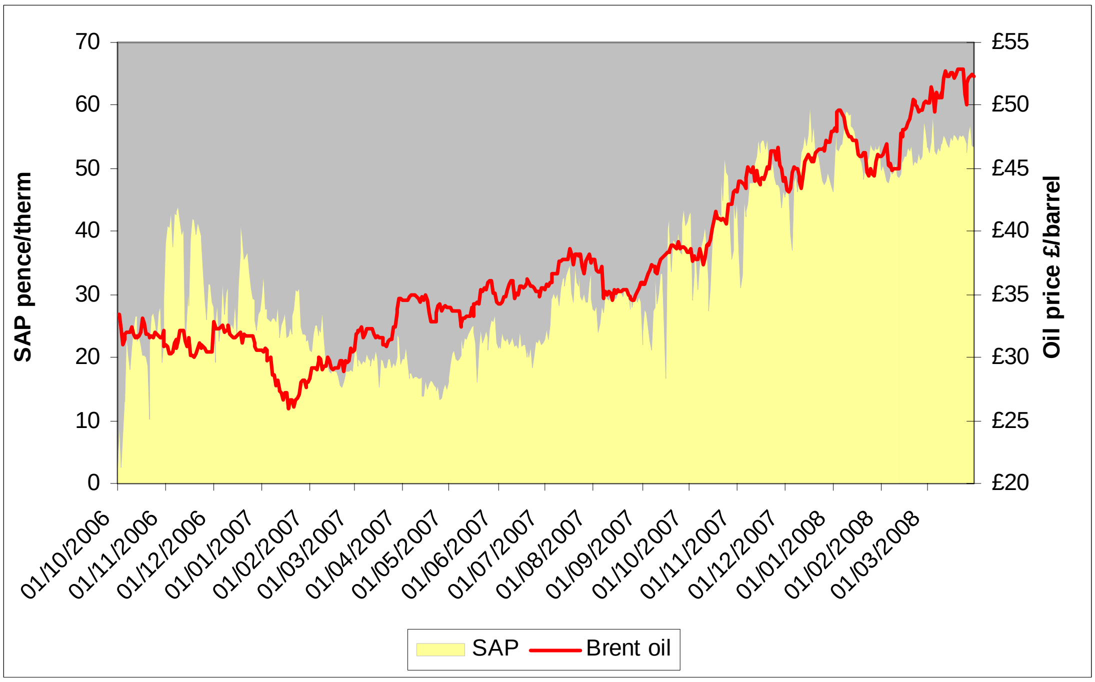
2007/8 Fuel Prices

38. The System Average Price (SAP) for gas reported by National Grid is very closely related to on the day NBP prices. Figure A.3 shows SAP and the Brent oil price for the period October 2006 to March 2008. SAP has risen steadily over the course of winter 2007/08 from around 30 p/therm in October 2007 to over 50 p/therm by the end of the winter period.

39. A number of reasons for this increase in SAP have been put forward, such as lower than expected Norwegian flows and the increasing oil price. As Figure A.3 indicates, the link between SAP and oil price has returned, principally due to the stronger link to Continental prices through increased import volumes.

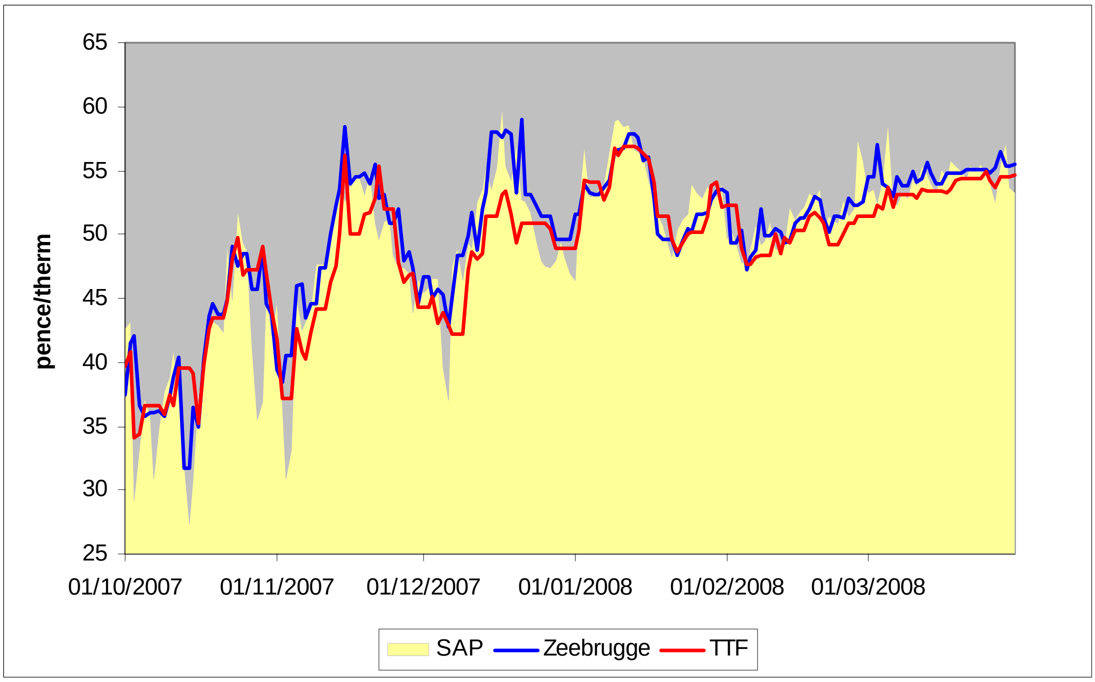
40. The trend seen last year when gas prices fell in the second half of the winter was not repeated this year, despite relatively mild weather and no significant disruptions to supply.

Figure A.3 – SAP and oil prices from October 2006



41. With the Dutch and Belgian gas markets linked to the UK via the BBL and IUK pipelines respectively, European prices at the Zeebrugge and TTF hubs have been consistent with UK prices as illustrated in Figure A.4.

Figure A.4 – UK and European Gas Prices

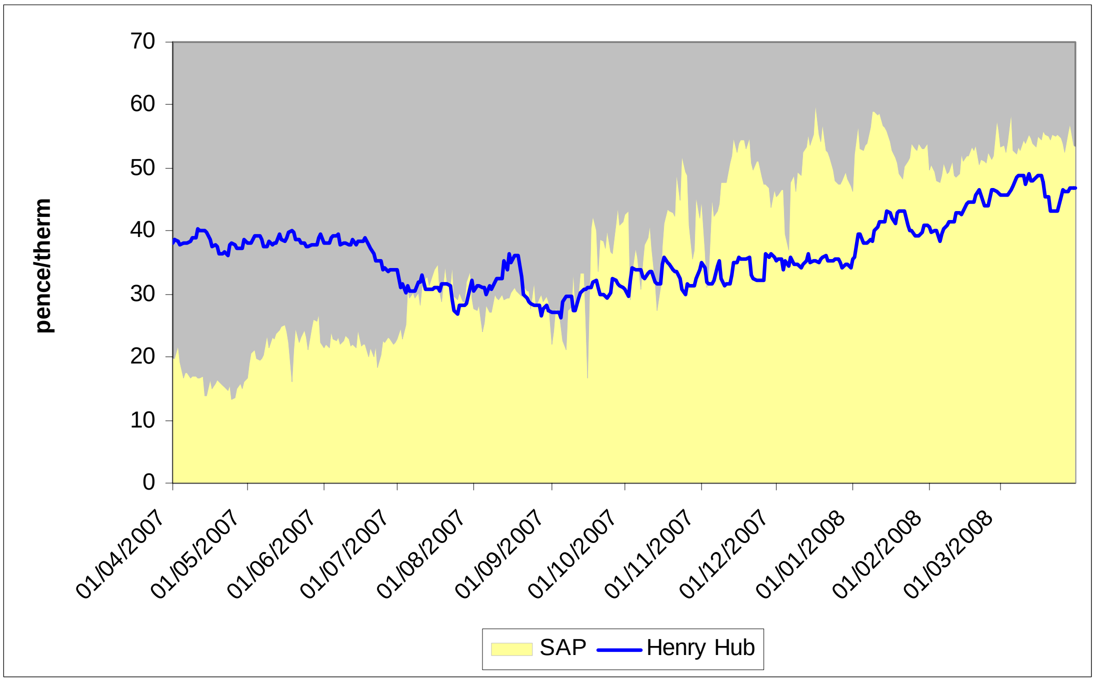


42. Figure A.5 compares SAP to the Henry Hub price in the United States. Although the Henry Hub price increased over the winter, the rise in SAP was even greater with

SAP being higher priced than Henry Hub for most of the winter. These conditions made the UK a more attractive destination for spot LNG cargoes than the United States.

43. Prices for spot LNG cargoes delivered to the Far East were reported to be above SAP and other Continental prices, with prices reaching 75 p/therm. This was sufficient for diversion of some LNG from the Atlantic basin to the Far East.

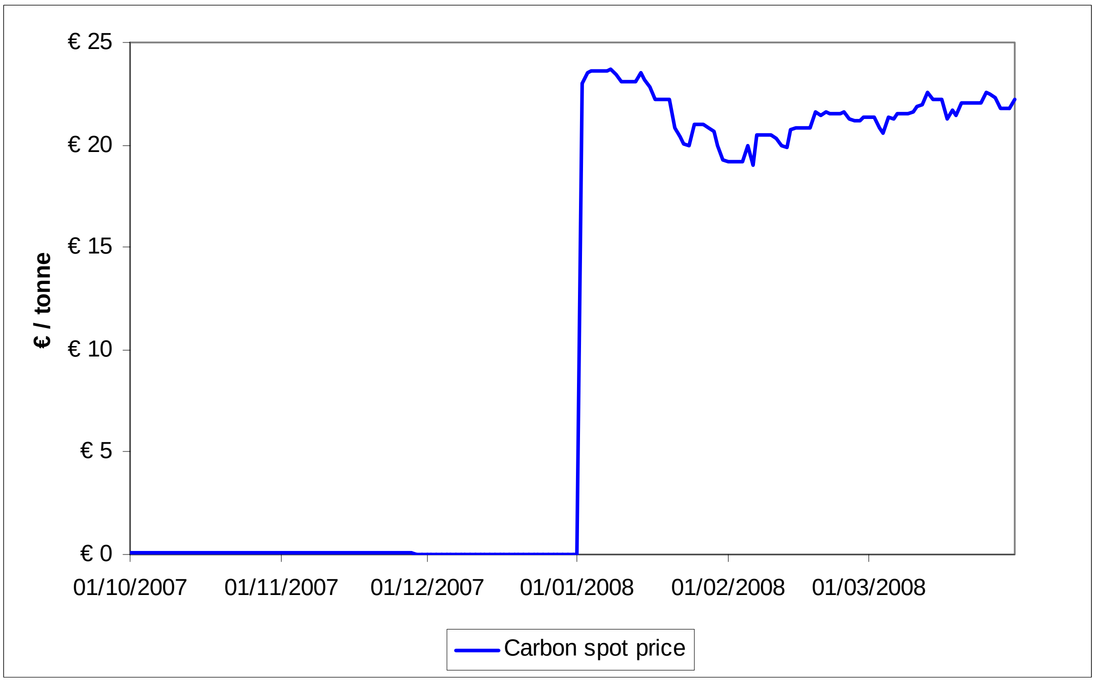
Figure A.5 – UK and Henry Hub Prices



44. Figure A.6 shows carbon prices for the winter. For the first half of the winter carbon was traded at less than €1 / tonne as credits issued in Phase I (2005-2007) of the EU ETS were over allocated at an EU level when compared with actual reported emissions. As credits could not be transferred into Phase II (2008-2012) of the scheme a surplus existed with little demand. The allocations for Phase II are lower than in Phase I and any surplus credits could potentially be carried over into Phase III (2013-2020). This has resulted in a carbon price of around €20 / tonne in the second half of this winter.

45. A higher carbon price benefits gas-fired generation when compared with coal-fired generation due to the higher carbon emissions associated with burning coal.

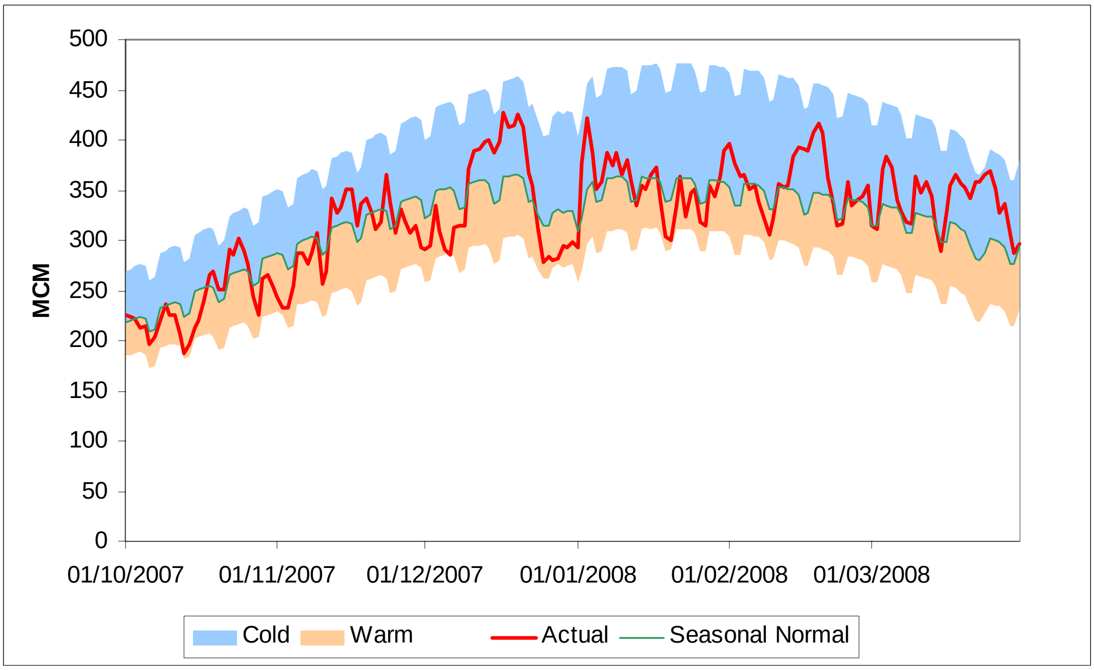
Figure A.6 – Carbon Prices



2007/8 Gas Demand

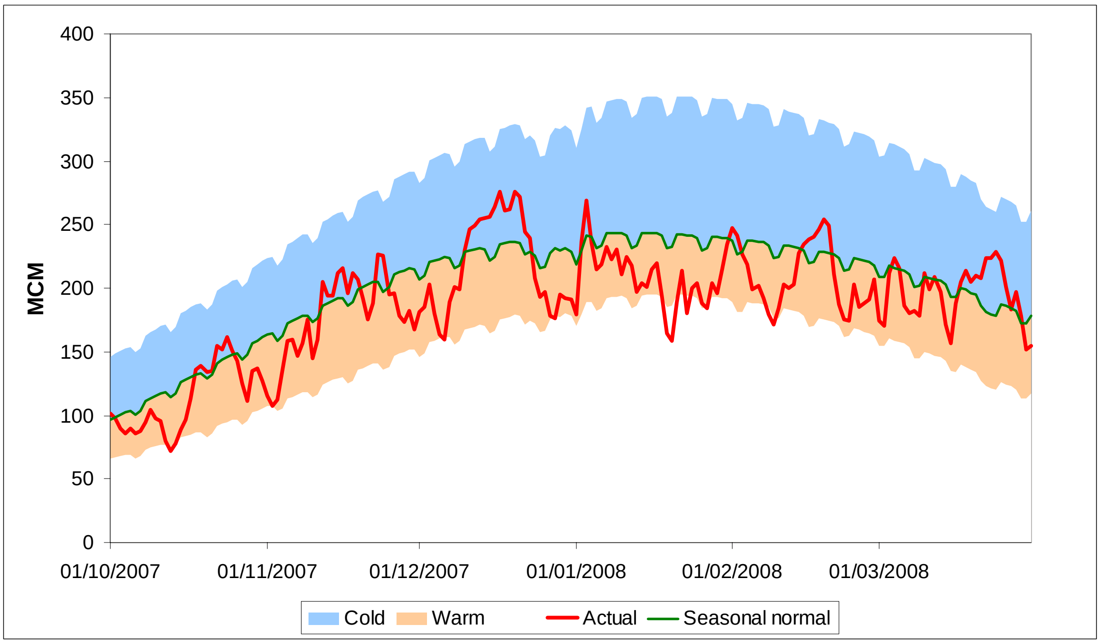
46. Figure A.7 compares total demand, excluding Interconnector exports and storage injection, with seasonal normal, cold and warm demand.

Figure A.7 – 2007/8 Seasonal and Actual Demands



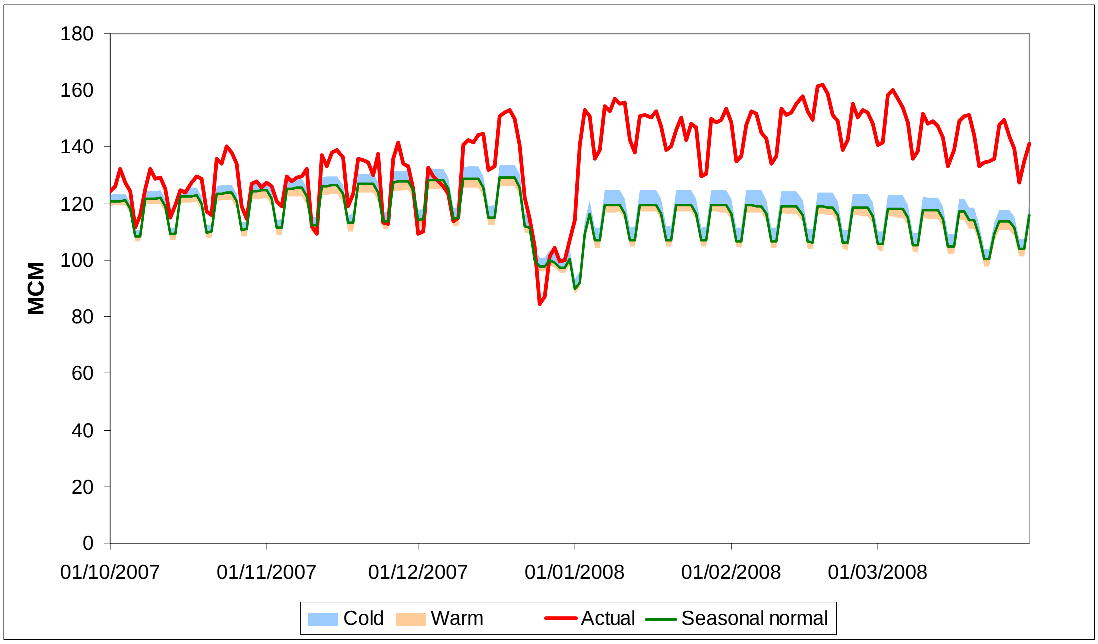
47. The actual demand exceeded seasonal normal for much of the winter, this would not normally be expected in a mild winter. Figure A.8 shows the same graph for the most weather sensitive load band, non-daily metered demand. This demand is as expected for the weather conditions experienced.

Figure A.8 – 2007/8 NDM Seasonal and Actual Demands



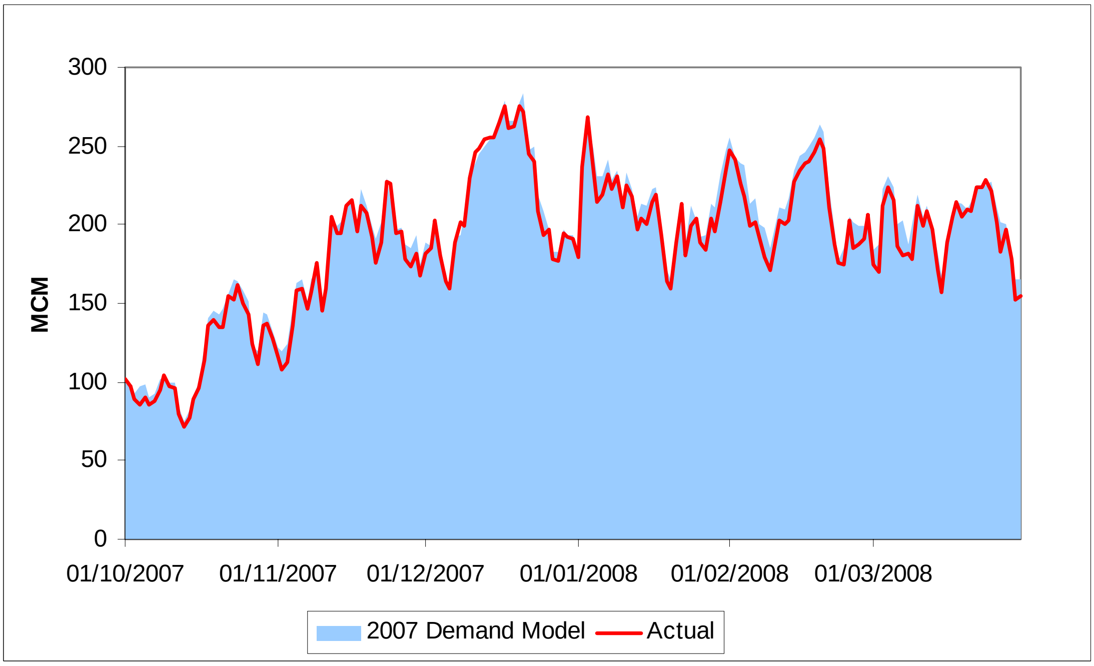
48. The discrepancy in actual demands is accounted for in the DM and NTS market sectors shown in Figure A.9. There is very little weather variation in demand in these market sectors as highlighted by the small difference between the cold and warm forecasts.

Figure A.9 – 2007/8 DM and NTS Seasonal and Actual Demands



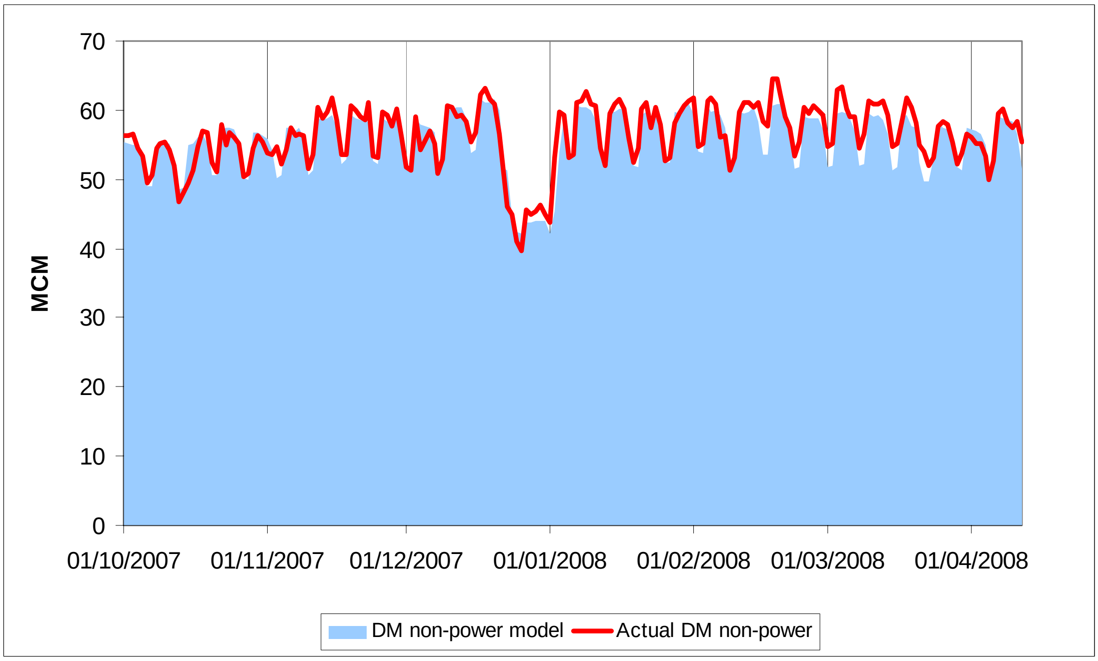
49. Figure A.10 compares actual NDM demand with the demand modelled from actual weather and the 2007 demand forecast model. The graph shows that actual demand was slightly below that predicted by the model by an average of 3%.

Figure A.10 – 2007/8 Actual NDM Demand



50. A similar graph for daily metered non-power demand (Figure A.11) shows that the actual demands were very close to the model values. This graph includes LDZ daily metered sites, NTS industrials and exports to Ireland and the Isle of Man.

Figure A.11 – 2007/8 Actual DM Non-power Demand



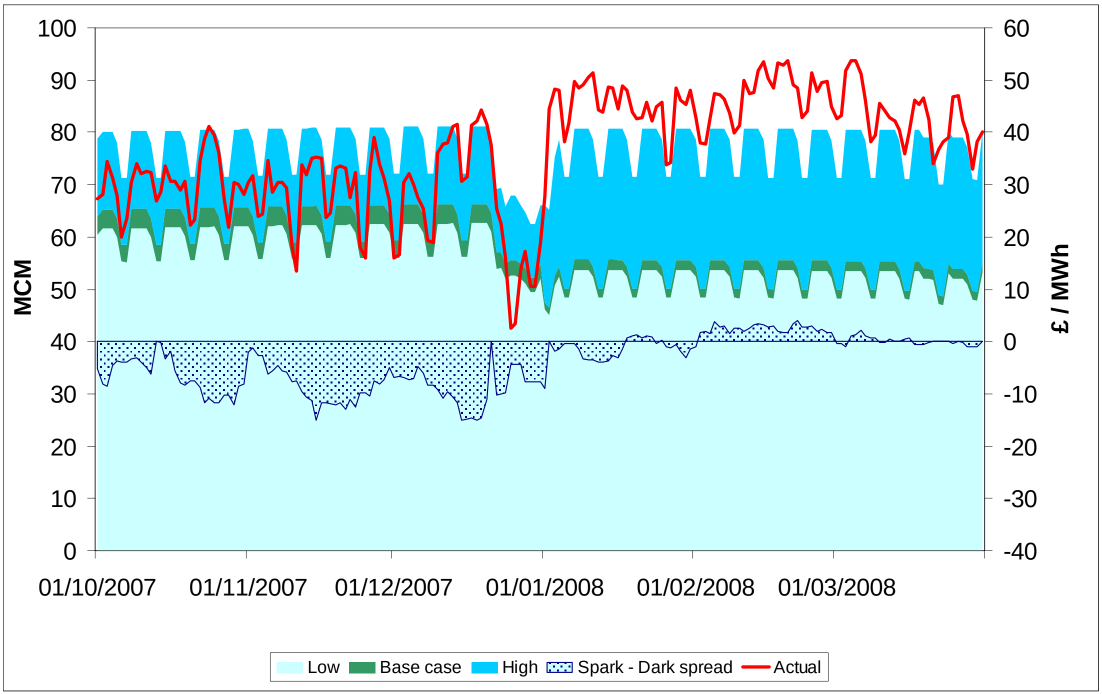
51. Figure A.12 shows actual power station demand compared to the 2007 forecast. Power generation forecasts are based on ranking orders for a three month period. The 2007/8 winter is split into two 3-month periods; from October to December and from January to March. The green area shows our seasonal normal forecast. This is the ranking order expected to prevail over the 3 month period. The high and low represent the range over which we expected power generation demand could vary in the 3 month period. The red line is the actual power generation gas demand.

52. The 2007 forecasts assumed that gas would be marginal generation during the winter and base load over the summer. For the first 3 months of the winter the forecasts were reasonably good with coal burn as expected being preferred to gas. The spark minus dark spread for this period shows this. The actual gas burn was higher than the base case forecast because gas, being the marginal fuel, replaced the generation lost from the Hartlepool and Heysham nuclear power stations.

53. The first 3 months of January shows that actual gas burn exceeded even the high forecast. This is due to the following reasons:

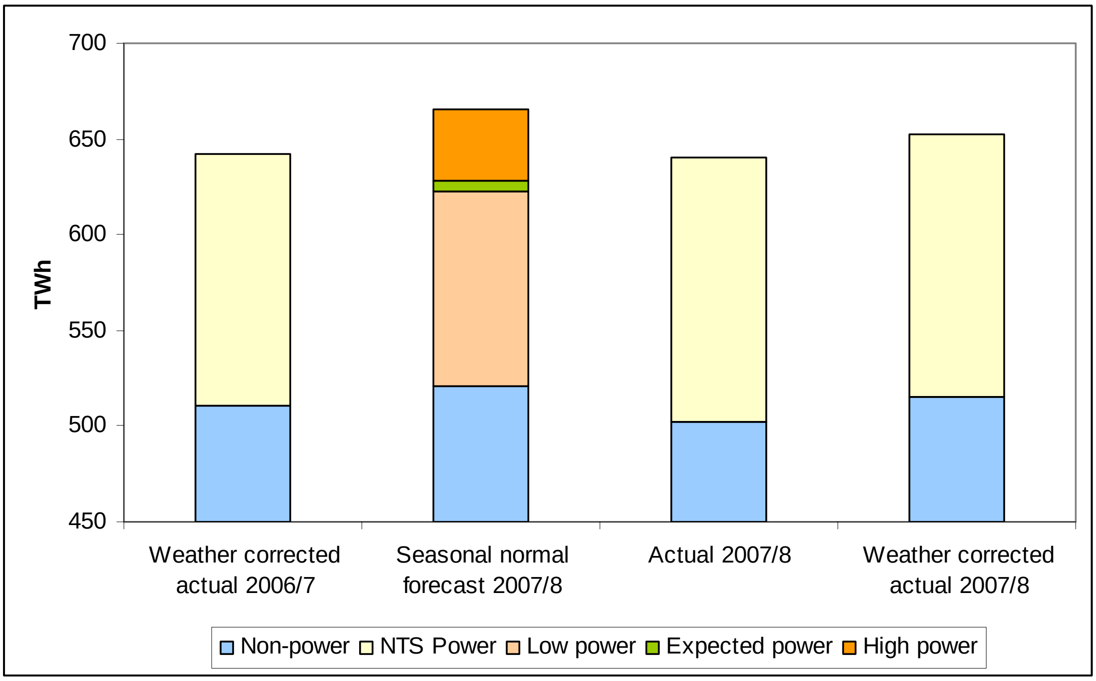
- continued problems with nuclear power stations
- delays in fitting flue gas desulphurisation (FGD) to some coal power stations so that they could comply with the large combustion plant directive (LCPD) effective from January 1st 2008
- the reduced profitability of coal compared to gas due to an increase in world coal prices
- the reduced profitability of coal compared to gas due to a higher carbon price as a result of phase 2 of the EU ETS which started on January 1st 2008
- mild weather
- power stations that have opted out of LCPD may have changed their operating strategy

Figure A.12 – 2007/8 Actual Power Station Demand



54. Figure A.13 compares the 2007/8 winter demand with weather corrected 2006/7 demand and forecast for 2007/8. Note the y-axis is offset to highlight relatively small differences.

Figure A.13 Total Winter Demand



55. The 2007/8 forecast was 2% below the 2006/7 weather corrected demand with the low and high power generation forecasts giving a range from 3% lower to 4% higher. The 2007/8 actual demand was very close to the 2006/7 weather corrected demand. The weather corrected 2007/8 demand was 2% higher.

2007/8 Gas Supply

56. Table A.1 summarises the make-up of gas supplies for winters 2006/7 and 2007/8 by supply source. The 2.9 bcm increase in demand was met primarily by an increase Continental supplies (notably BBL) and to a lesser extent Norway and storage. UKCS was marginally lower whilst LNG imports were approximately just 1/3rd of the previous winter.

Table A.1 – Gas Supply, Comparison of 2006/7 and 2007/8 by Source

	2006/7		2007/8	
	bcm	%	bcm	%
UKCS	37.0	64%	36.1	60%
Norway[2]	12.8	22%	13.6	22%
Continent	3.5	6%	6.7	11%
LNG	1.9	3%	0.7	1%
Storage	2.4	4%	3.5	6%
Total	**57.6**		**60.5**	

57. Table A.2 shows the make up of supplies for winters 2006/7 and 2007/8 by terminal. The 2.9 bcm increase in demand was met primarily by an increase into Bacton (BBL and specific high swing fields) and to a lesser extent Barrow (Morecambe) and Easington (Rough). Flows into Grain, St Fergus and Teesside were all lower.

Table A.2 – Gas Supply, Comparison of 2006/7 and 2007/8 by Terminal

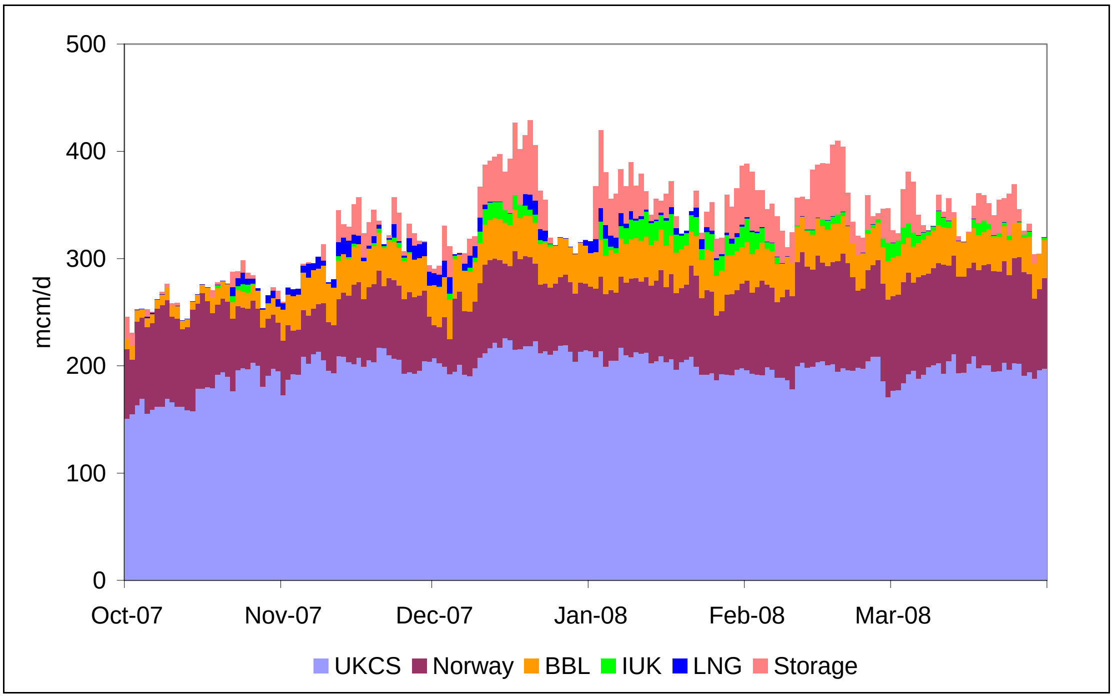
	2006/7		2007/8	
	bcm	%	bcm	%
Bacton	12.1	21%	15.8	26%
Barrow	1.7	3%	3.3	5%
Grain	1.9	3%	0.7	1%
Easington[3]	11.8	20%	12.8	21%
Point of Ayr	0.3	1%	0.2	0%
St Fergus	19.8	34%	18.9	31%
Teesside	4.8	8%	3.7	6%
Theddlethorpe	4.4	8%	4.3	7%
Other Storage	0.8	1%	0.8	1%
Total	**57.6**		**60.5**	

[2] Includes estimates for Vesterled and Tampen
[3] Includes Rough

58. Figure A.14 shows how the various gas supply sources were used in winter 2007/8 against seasonal normal demand. Each of these supply sources is considered in turn in the following sub-sections.

59. From early November onwards, the level of demand was for most days in the range of 300 to 400mcm/d. For this period, the average demand was nearly 350 mcm/d with 9 days of demand in excess of 400 mcm/d. Average demand for the highest 100 days of demand was 362 mcm/d.

Figure A.14 – 2007/8 Supply Performance



UKCS Supplies

60. Though we forecast that the UKCS is in decline by typically 5-10% annually, there was little change in aggregated production from the UKCS compared to last winter. This was primarily due to higher flows from specific high swing supplies into Bacton and Barrow compared to last winter.

61. Average flows from the UKCS across the 6 month winter period were 197 mcm/d and for the 100 days of highest demand 202 mcm/d. Table A.3 shows the 2007/8 Winter Consultation Base Case peak forecast of UKCS supplies by terminal and the actual terminal supplies for the day of highest UKCS supplies (15 December 2007) and the highest day for each terminal.

Table A.3 – 2007/8 UKCS Supplies by Terminal

Peak (mcm/d)	Forecast	Actuals	
	Base Case	Highest UKCS	Highest Terminal
Bacton	76	62	65
Barrow	22	22	24
Easington	13	14	16
Point of Ayr	2	2	4
St Fergus[4]	80	78	83
Teesside	24	24	26
Theddlethorpe	27	26	28
Total	**244 (220)**	**228**	**246**

62. The table highlights that the day of highest UKCS supplies of 228 mcm/d was below the forecast of 244 mcm/d. However when comparing against the highest day we need to apply a factor for UKCS supply availability. For operational planning, we currently assume 90%, hence the 244 mcm/d should be assessed as 220 mcm/d. Hence our operational forecast was marginally exceeded. On this basis and comparing with our highest daily forecast for each terminal, our UKCS Base Case appears robust with the exception of an under forecast for supplies into Bacton.

63. The flow profile of UKCS supplies across the winter suggests that most UKCS fields were producing at near maximum flow conditions for most of the winter period. From mid January onwards there is a small but noticeable decline in production.

Norwegian Imports

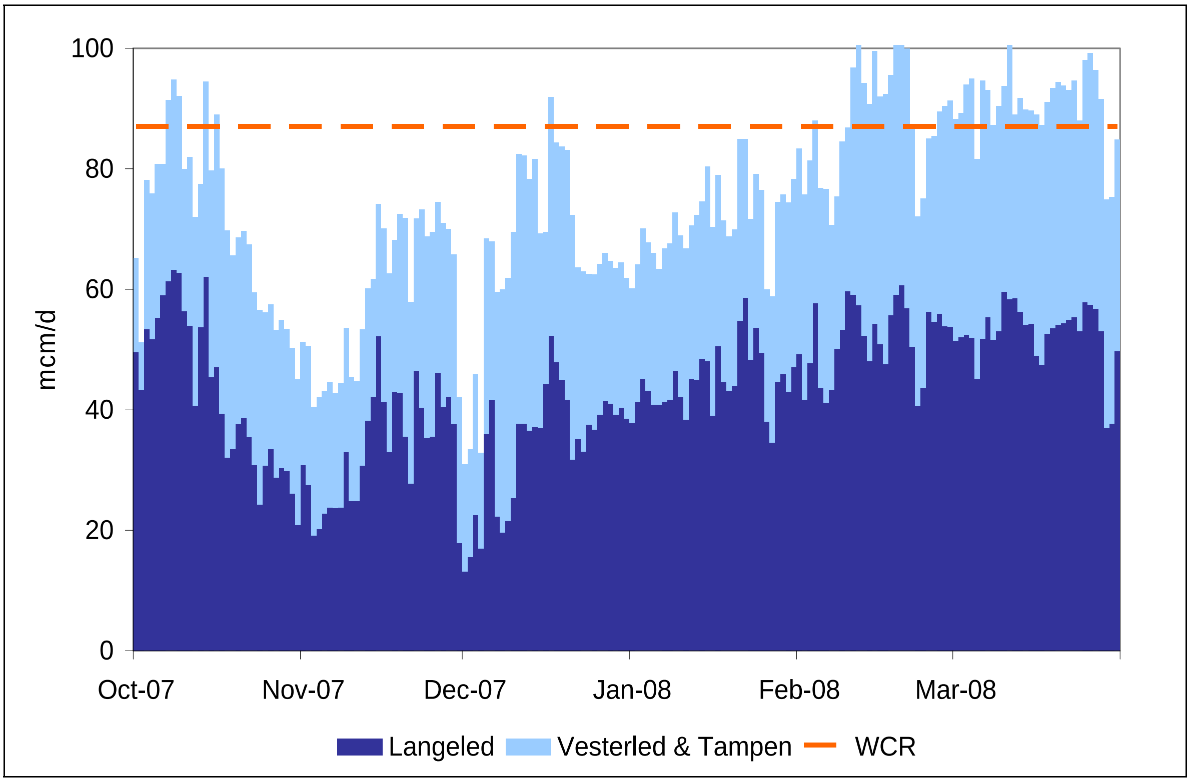
64. Our forecasts for Norwegian imports to the UK for winter 2007/8 were subject to numerous uncertainties including increased Norwegian production from Ormen Lange, contractual obligations and transportation options regarding delivery to the Continent in Germany, France and Belgium and completion of the third Norwegian / UK gas connection, namely the Tampen Link.

65. Our Base Case estimate for Norwegian flows was 87 mcm/d split approximately 37 mcm/d through Vesterled and Tampen and 50 mcm/d through Langeled.

66. Figure A.15 shows Norwegian flows through Langeled and our aggregated estimates for Norwegian imports to St Fergus through Vesterled and the Tampen Link. Average Norwegian flows across the 6 month winter period were 74 mcm/d and for the highest 100 days of demand 81 mcm/d; this was marginally below our 87 mcm/d forecast. Whilst our forecast flows for Norway were exceeded in October and in February and March, there were periods, notably in early November when only 40 mcm/d of gas was imported, as a result of increased Norwegian deliveries to the Continent.

[4] Excludes estimates for Vesterled and Tampen

Figure A.15 – 2007/8 Norwegian Imports to UK

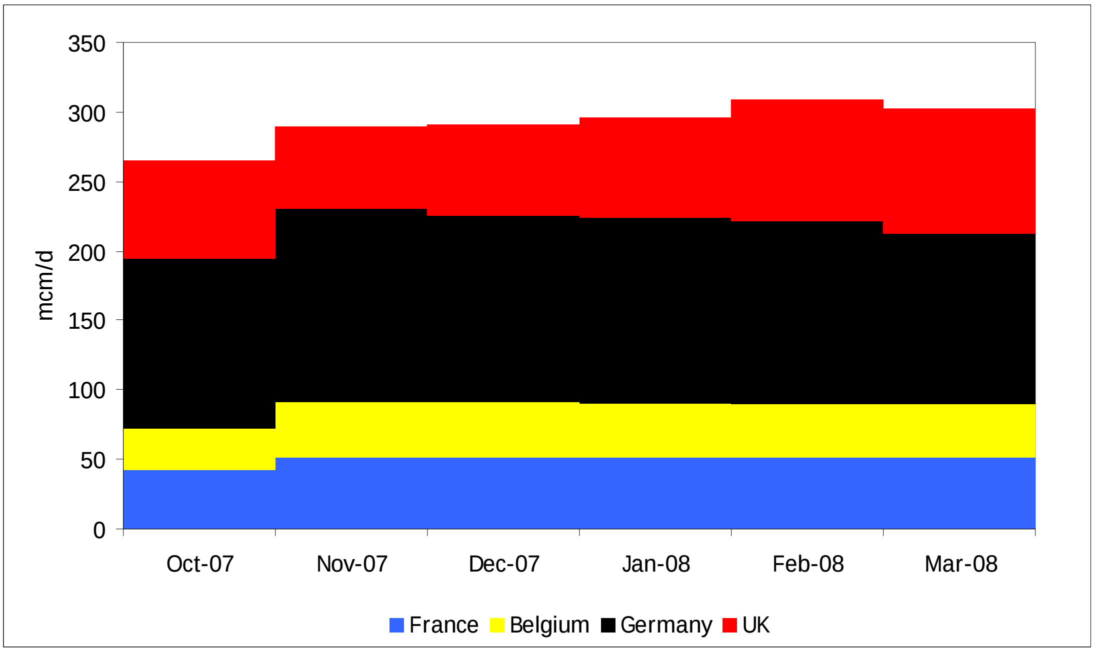


67. Besides the option to flow gas to the UK, Norwegian gas is also exported to Germany, France and Belgium. Publicly available flow data for Norwegian exports is incomplete. Norwegian production data is reported on a monthly basis by the Norwegian Petroleum Directorate (NPD), with import flows reported daily for Zeebrugge (Fluxys data), Dunkerque (GRTgaz data) and the UK[5]. Hence any assessment of Norwegian flows is limited to monthly type analyses with further need to estimate Norwegian own use gas, UK imports through Vesterled and Tampen and then assess German imports by difference.

68. Figure A.16 shows our estimate of monthly Norwegian exports to the UK and the Continent during winter 2007/8. The chart shows that Norwegian production tended to increase as the winter progressed and averaged nearly 300 mcm/d. The chart shows that supplies to the UK were squeezed during November as more supplies were delivered to the Continent, notably to Germany, probably due to contractual commitments.

[5] Langeled only

Figure A.16 – 2007/8 Norwegian Exports to UK and the Continent



69. Table A.4 shows our estimate of winter Norwegian exports between 2005/6 and 2007/8. The table shows a significant increase in Norwegian production for this winter. This is primarily due to commencement of flows from Ormen Lange but also due to the return of Kvitebjorn and increased flows from Troll. The table also shows considerable variation in volumes delivered to the Continent again possibly reflecting contractual flexibility and high rates of utilisation to all markets other than the UK.

Table A.4 – Estimate of Norwegian Exports 2005/6 to 2007/8

(mcm/d)	Capacity 2007/8	Winter 2005/06	Winter 2006/07	Winter 2007/08	2007/8 Utilisation
Belgium	41	39	33	37	91%
France	52	50	43	50	96%
Germany	151	140	108	130	86%
UK[6]	121	28	71	74	61%
Total	**365**	**257**	**255**	**292**	**78%**

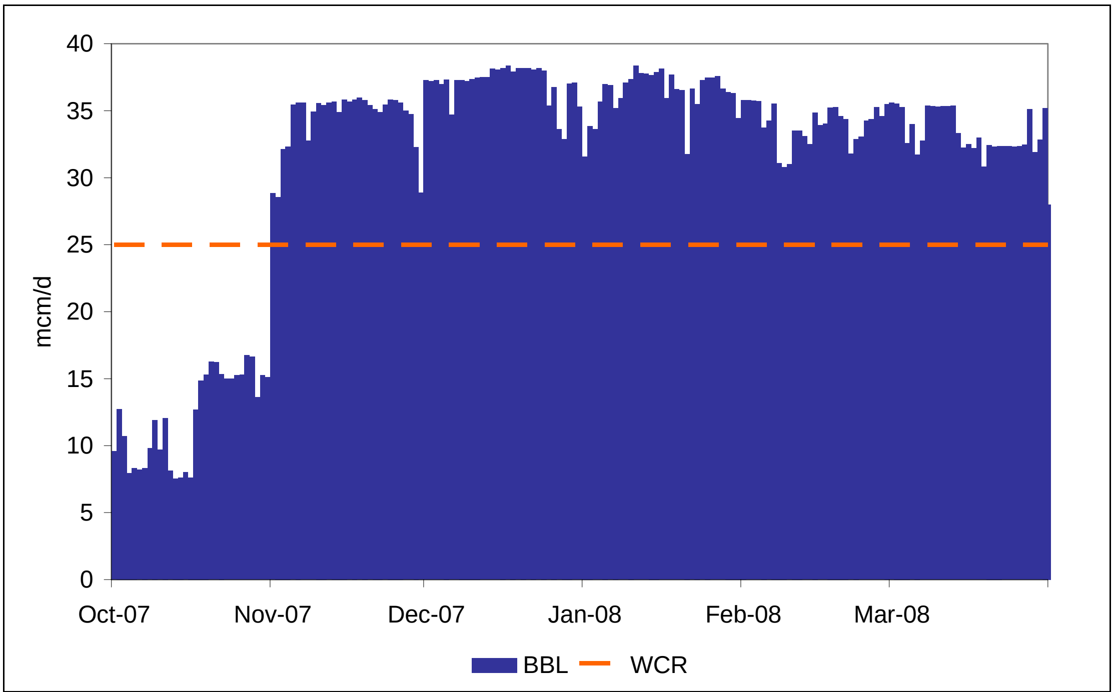
[6] Includes Tampen capacity assumed at 15 mcm/d, this will step up as FLAGS ullage increases

Continental Imports - BBL

70. For winter 2007/8 we forecast that BBL flows to the UK would be relatively stable at 25 mcm/d (based on winter flows of the Gasunie Centrica contract) but with the possibility of higher levels of imports.

71. Figure A.17 shows BBL flows for winter 2007/8. Flows for much of the winter period at about 35 mcm/d exceeded our pre-winter forecast by about 10 mcm/d suggesting additional shippers were utilising the BBL 40+ mcm/d capacity. As in the previous winter, BBL flows were not particularly sensitive to UK supply demand fundamentals and market prices.

Figure A.17 – 2007/8 BBL Imports to UK

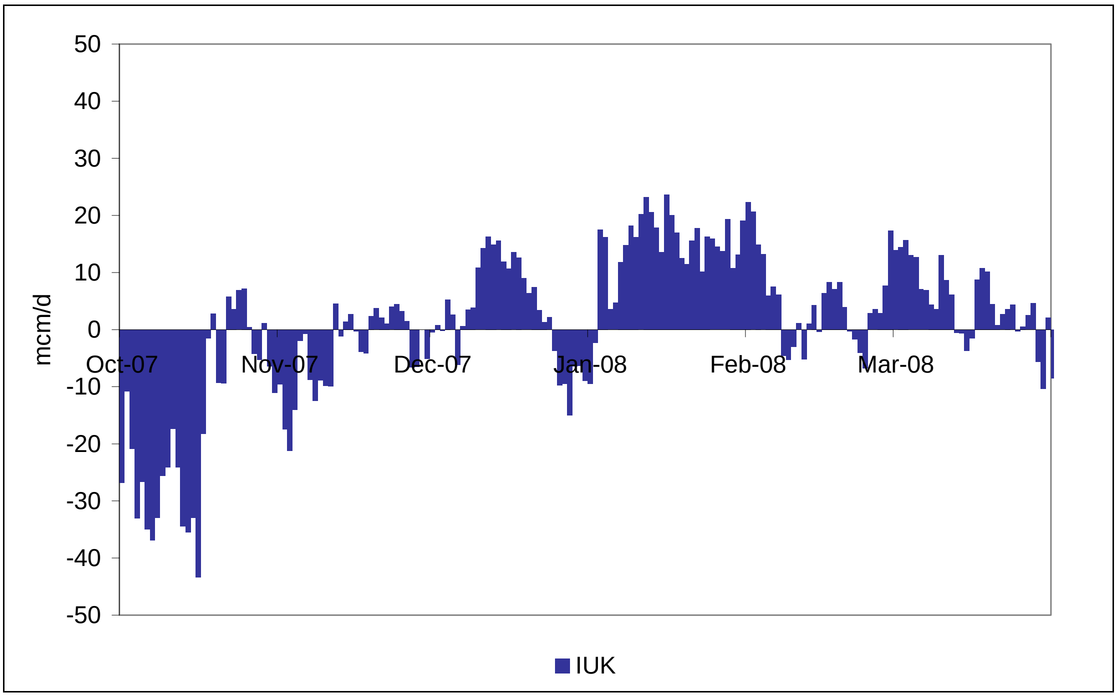


Continental Imports - IUK

72. For winter 2007/8 we forecast that IUK would operate as the marginal source of non storage supply responding to market differentials between the UK and Belgium. We also forecast that IUK would steadily increase import flows to the UK as demands increased, ultimately attaining imports of 50 mcm/d at UK demands of 450 mcm/d. We also suggested that imports post December could be higher than pre December if Continental storage stocks were healthy.

73. Figure A.18 shows IUK import and exports flows for winter 2007/8. In aggregate imports were 1.0 bcm and exports (mainly in October) 0.8 bcm. The highest flow for IUK imports was 24 mcm/d in mid January.

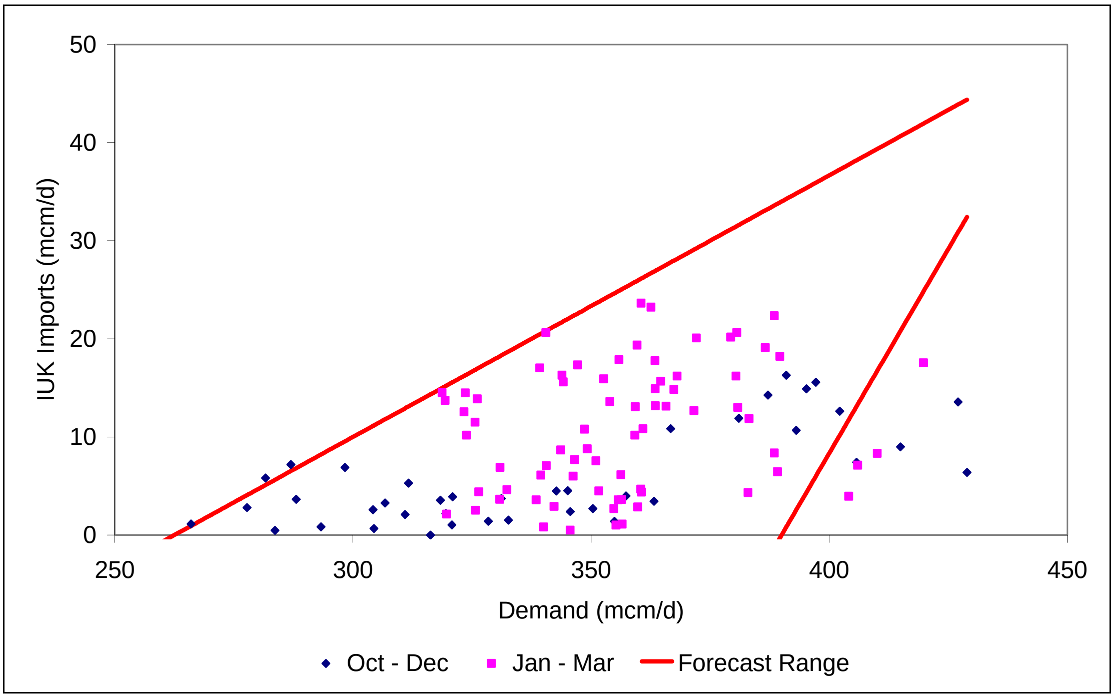
Figure A.18 – 2007/8 IUK Imports & Exports



74. Figure A.19 shows IUK imports against demand. The import flows are shown for the periods October to December and January to March. Also shown on the chart is our forecast range for IUK imports.

75. The chart shows a relatively wide range of import flows suggesting the IUK was responsive to market conditions. Most of the flows were inside our forecast range, however the exception here was for when demands were above 400 mcm/d. This suggests that higher imports through IUK may not of been forth coming if UK demand was to have been higher. Review of the two data sets suggests as expected, greater import availability post December.

Figure A.19 – 2007/8 IUK Imports vs Demand



LNG Imports

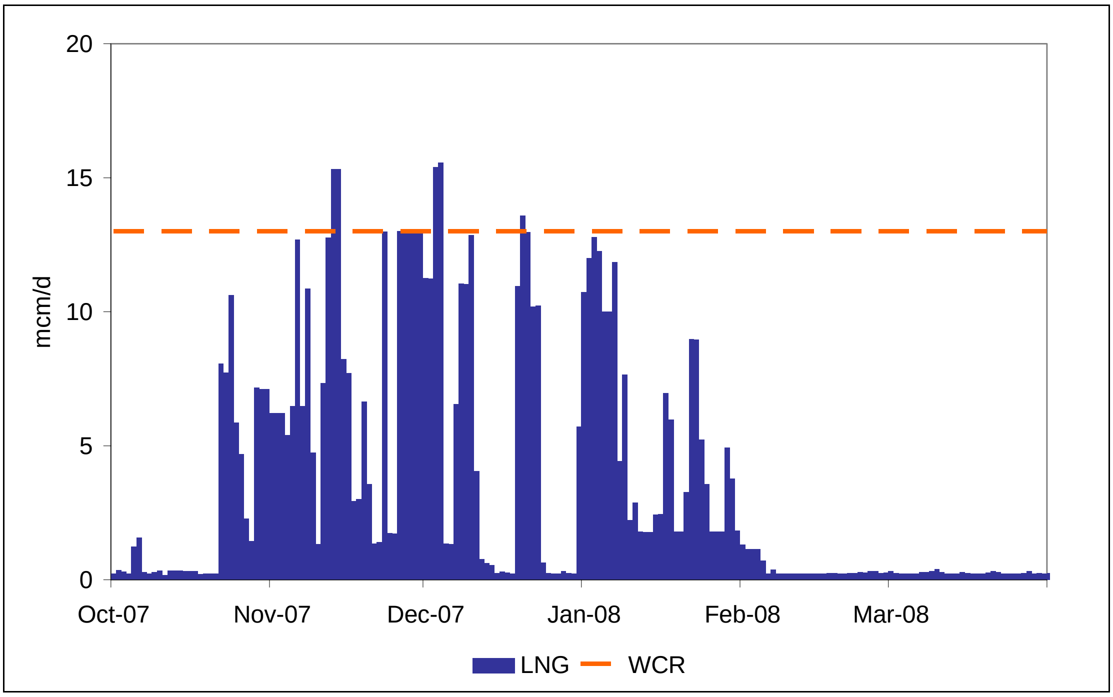
76. Our forecast for LNG imports for winter 2007/8 highlighted considerable uncertainties. These included possible delays in commissioning for both Milford Haven terminals, delivery of spot cargoes to Teesside GasPort and global market conditions impacting deliveries to Grain. In the absence of any consultation feedback or market information to suggest that Dragon LNG would be delayed beyond Q4 2007 we assumed an LNG forecast of 33 mcm/d made up of 20 mcm/d Dragon and 13 mcm/d Grain. To capture the uncertainty over Dragon, we included a supply risk of 20 mcm/d into our Safety Monitor assessment.

77. As the winter period commenced, our concerns over the commissioning timing for Dragon became apparent and we realised our supply risk for the Safety Monitors and informed the market through our monthly website updates in November. Hence from November our expectations of LNG imports were limited to 13 mcm/d through Grain and the possibility of occasional cargoes into Teesside GasPort.

78. Figure A.20 shows LNG imports through Grain. Compared to winter 2006/7 there were noticeably fewer cargoes delivered and no cargoes after January, hence whilst the 13 mcm/d forecast was met this was on an intermittent basis. Despite relatively high UK gas prices Teesside GasPort received no cargoes.

79. The general consensus behind the reduced number of LNG cargoes to Grain was the opportunity to sell LNG into higher priced markets, notably the Far East.

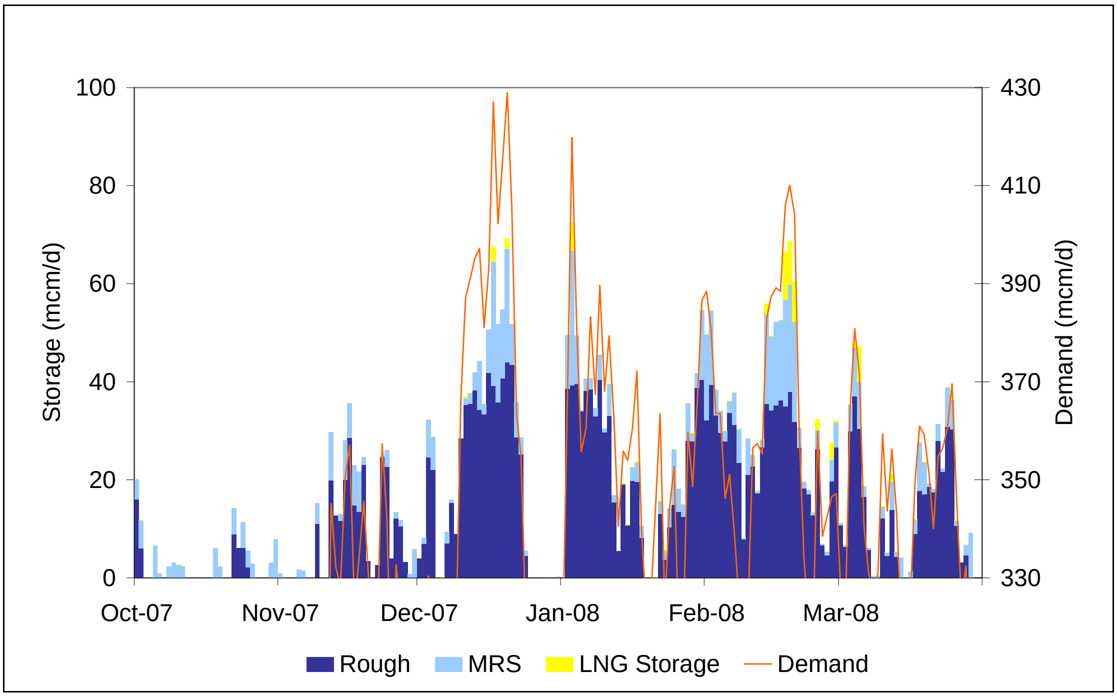
Figure A.20 – 2007/8 Grain LNG Imports



Storage Performance

80. Our forecast for storage for winter 2007/8 included the possibility of some flows from the Aldbrough salt cavity facility. This was expected to become partially operational during the winter. As with information for Dragon, we did not receive any consultation feedback or market information to suggest that Aldbrough would be delayed beyond Q4 2007. For the Safety Monitor assessment, we excluded Aldbrough from our forecasts.
81. Again as with Dragon, we received information in November indicating delays. We again informed the market through our monthly website updates.
82. Figure A.21 shows storage withdrawals over the winter in terms of Rough, MRS and LNG storage. The chart also shows demand on a similar albeit offset scale to highlight the close relationship between storage withdrawals and demand.

Figure A.21 – 2007/8 Storage Withdrawals



83. Table A.5 details storage space, storage withdrawals and storage injection during the winter. The table highlights the relatively high use of all storage types with the exception of LNG and relatively high levels of storage cycling that took place, notably for MRS sites.

Table A.5– 2007/8 Storage Utilisation

	Reported Space (mcm)	Withdrawal (mcm)	Injection (mcm)	Reported Deliv. (mcm/d)	Highest Deliv.[7] (mcm/d)
Rough	3300	2674	356	42	44
MRS[8]	771	726	665	36	28
LNG	259	62	40	49	14

[7] Aggregated by site
[8] Excludes Aldbrough

2007/8 Operational Overview

84. Over the course of any winter period National Grid NTS puts into action robust processes, procedures and strategies to aid in the safe, reliable and efficient operation of the NTS. This section is designed to provide an insight into the issues that impacted system operation last winter period and includes detail regarding some of the operational measures.

Bacton Fire

85. On 28th February a fire in a waste water treatment facility at the Shell Bacton Terminal caused the unplanned shutdown of the plant. This event caused an instantaneous reduction in NTS supply of around 30 mcm. To counter this we experienced a rapid response from storage withdrawal. This balanced the NTS without any need for us to undertake commercial and physical balancing actions.
86. Immediately after the incident came to light, prices on the OCM increased by around 25%. And by the end of the day SAP had increased by 10%. This had a knock on effect on the forward curve, with March forward prices trading 11% higher the next morning. However, it should be noted that at the same time as the Bacton incident day on day increases in the oil markets occurred, so the rise in gas price may not of been fully linked to Bacton.
87. On 3rd March flows through Shell Bacton returned. By the 5th March flows where again at high levels suggesting no lasting impact

Interruption

88. Winter 2007/8 required no transporter or emergency interruption to customers supplied directly from the NTS. There was some shipper interruption recorded at 3 NTS sites. National Grid has little insight into which sites may be interrupted by shippers and relies on their notification of interruption.

Network Infrastructure

89. National Grid NTS commissioned two major new pipelines last winter providing additional capacity and network flexibility in response to Long Term System Entry Capacity (LTSEC) auction signals.
90. A new 300km, 1200mm diameter pipeline capable of operating up to 94barg was commissioned from Gloucestershire to Milford Haven in South Wales. The pipeline was commissioned in 3 stages enabling Milford Haven to be connected from November. Filling the pipeline required 20mcm of additional NTS linepack.
91. Besides providing capacity for two new LNG importation terminals (still to be commissioned), the pipeline enables NTS pressures in South Wales to increase significantly, providing additional security on the winter's coldest days.
92. The principal section of the Trans Pennine pipeline was also commissioned through Lancashire and North Yorkshire during autumn 2007. This 95km, 1200mm

pipeline is designed to operate to 75barg and builds upon previous phases delivered in 2006 and that planned for summer 2008. It was designed to ensure that the NTS can better accommodate East coast entry and the changing dynamics of network flows.

Capacity Management

93. National Grid has been investing in the NTS to meet existing Easington Baseline capacity and in response to auctions signals for incremental capacity at Easington and Aldbrough. This investment programme will be completed by winter 2009/10.

94. To ensure firm entry rights can be honoured, interruption occurs when notified or anticipated inputs outstrip firm rights and/or NTS capability. Buy Backs are undertaken if it is necessary to bring aggregate daily firm holdings within the physical capability of the NTS to protect its integrity.

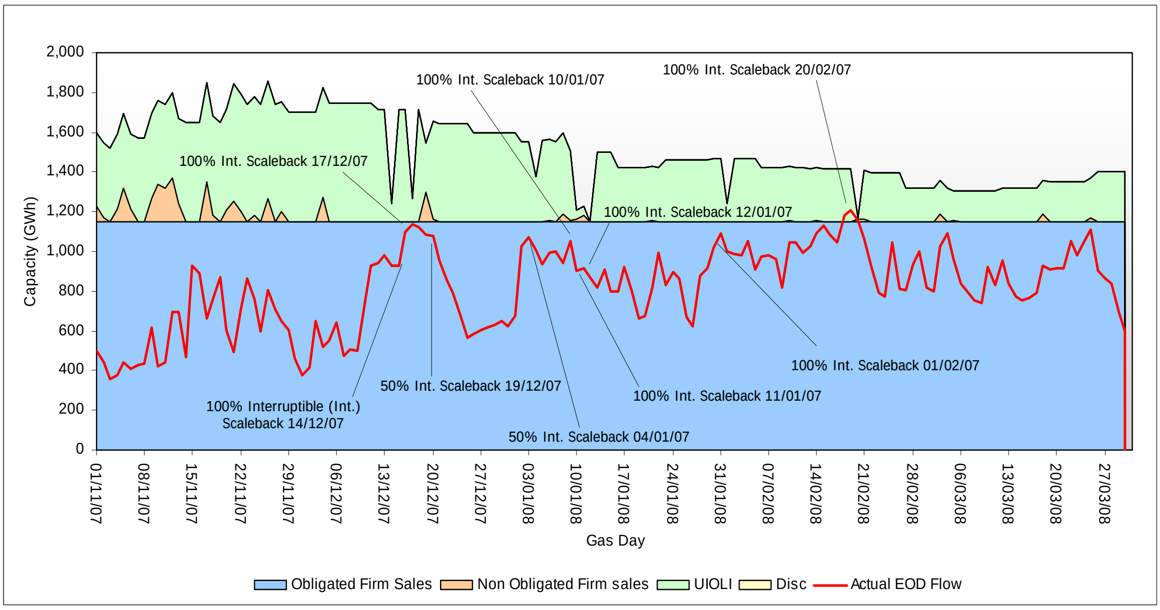
95. For winter 2007/8 it was necessary for us on 9 occasions to scale back interruptible rights on days of high East coast inputs. Of these 9 days, 7 were scalebacks of 100% interruptible capacity and 2 were just 50%.

96. Figure A.22 shows for Easington, the ASEP which experienced most scaleback activity last winter, capacity sold, actual flows and resulting scalebacks. Due to the highly dynamic nature of gas flow on the NTS these interruptible scalebacks were undertaken due to a number of interacting factors, including:

- high forecast and actual flows across East coast ASEPs, often above forecast ASEP capabilities
- uneven supply patterns within day, including significant deviation from the 1/24th supply rate criteria

97. The result of these was high operating pressures close to the ASEPs which required National Grid to take action to protect the physical integrity of the system.

Figure A.22 – Easington Capacity Sold and Flow Winter 2007/8



98. The equitable scaling back of interruptible capacity enabled National Grid to honour all firm entry capacity rights during the winter, avoided any entry capacity buy backs and protected the physical integrity of the system.

Transfer and Trades (T&T)

99. In September 2007 an interim solution was introduced as a result of UNC modification proposal 0169 to facilitate T&T of entry capacity for the months November 2007 to March 2008. There was a single, two-stage, stand alone auction by National Grid on 27th September and 10th October 2007. Capacity allocations resulting from the auction are shown in Table A.6 which shows the additional capacity allocated per ASEP through the T&T process.

Table A.6 – T&T Capacity Allocation

GWh	Nov	Dec	Jan	Feb	Mar
Barrow	2.0	2.0	2.0	2.0	-
Easington	85.4	85.8	85.8	85.8	85.8
Grain	42.3	-	-	-	-
Teesside	23.8	48.3	42.6	41.2	-

100. Table A.7 shows the resulting capacity level post T&T process. Firm capacity at Grain was lower than its Baseline due to capacity being transferred away.

Table A.7 – Resulting Entry Capacity Post T&T

GWh	Nov pre T&T	Nov	Dec	Jan	Feb	Mar
Barrow	309.1	309.1	309.1	309.1	309.1	309.1
Easington	1062.0	1147.4	1147.8	1147.8	1147.8	1147.8
Grain	175.0	44.0	1.7	1.7	1.7	1.7
Teesside	361.3	385.1	409.6	403.9	402.5	361.3

Discretionary release of Interruptible capacity

101. Under UNC Modification 159 National Grid has the option of releasing interruptible capacity at its discretion. This was intended to assist National Grid in maximising the capacity offered and utilised at an ASEP. Discretional release of interruptible capacity was introduced in support of interim T&T process.

102. A number of criteria need to be fulfilled before this interruptible capacity is released. Available capacity at an ASEP would need to be utilised prior to additional capacity being released. During winter 2007/8 a number of ASEPs qualified for discretional Interruptible capacity and much of this was purchased. Table A.8 shows the maximum amount of additional discretional interruptible capacity released per ASEP through the winter.

Table A.8 – Maximum Release of Additional Discretional Interruptible Capacity

GWh	Nov	Dec	Jan	Feb	Mar
Barrow	55.0	58.9	58.9	57.1	60.6
Hatfield	0.0	6.1	6.3	6.7	7.3
Grain	210.0	253.6	260.1	260.3	0.0
Teesside	94.8	0.0	0.0	0.0	0.0
Thed'pe	120.3	0.0	0.0	0.0	0.0

Questions for consultation

We would welcome comments on all aspects of this section, and in particular on the following:

QA1. We welcome views on the contributing factors behind the 3% reduction in NDM demand and are these likely to be permanent?

QA2. What proportion of this reduction in weather corrected gas demand is due to short-term actions such as turning down the thermostat and what proportion is due to long-term efficiency measures such as loft insulation and condensing boilers?

QA3. We welcome views on our assessment of UKCS supplies and in particular our view that for the majority of the winter most UKCS supplies were operating at or near maximum flow.

QA4. We welcome views on our assessment, that at times during the winter Norwegian supplies were prioritised to Continental markets at the expense of flows to the UK

QA5. We welcome views on the drivers behind increased BBL flows

QA6. We welcome views on our suggestions:

a) that IUK was responsive to market conditions

b) that IUK has increased import availability post December

c) that IUK may not have imported significantly more at higher UK demands

QA7. Were global gas markets responsible for lower LNG import flows or were there any other mitigating factors?

QA8. What were the key drivers behind storage use this winter?

QA9. Under conditions of increased demand, would storage cycling be so prominent?

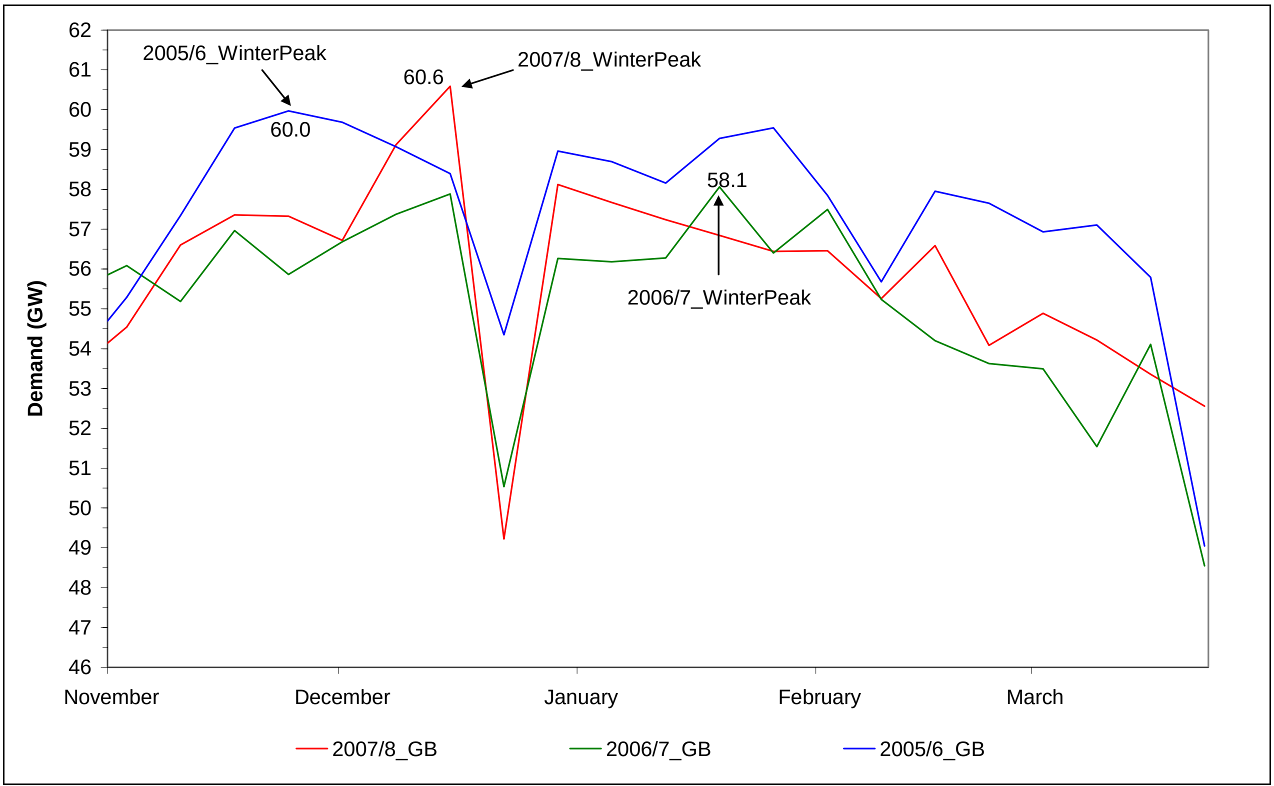
Electricity

Electricity Demand

103. Unless otherwise stated, demand discussed in this report excludes any exports to France and Northern Ireland. There is discussion of exports to France and Northern Ireland later in this section.

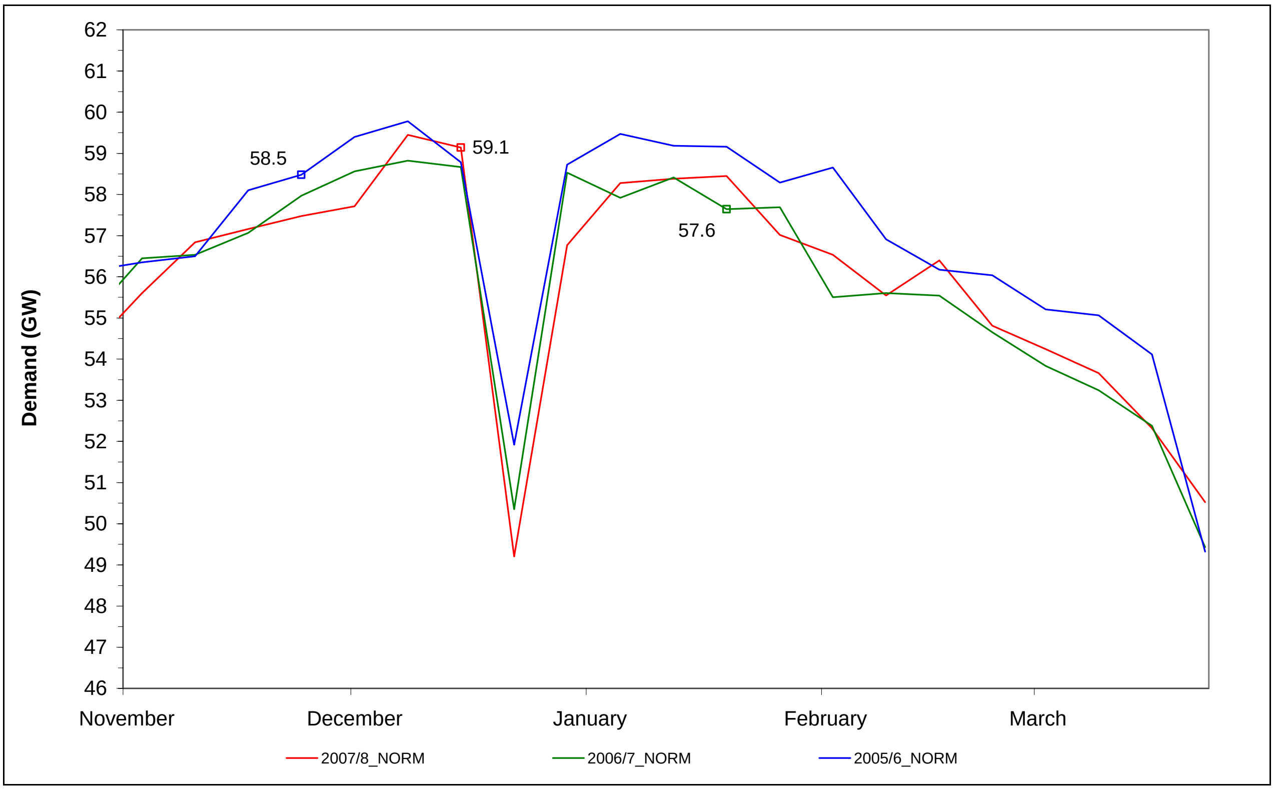
104. The highest electricity demand over the winter reached 60.6GW for the half-hour ending 17:30 on 17th December 2007. This compares to the highest demand of 58.1GW and 60.0GW over winter 2006/07 and 2005/06 respectively. This is shown in Figure A.23.

Figure A.23 – Weekly Peak Demand for the Last Three Winters



105. We correct outturn demands for weather to observe underlying demand trends under average weather conditions, based on a 30 year average. Figure A.24 below shows normalised weekly peak demands for 2007/08 (red), 2006/07 (green) and 2005/06 (blue) for comparison.

Figure A.24 – Weather Corrected Weekly Peak Demand for Last Three Winters

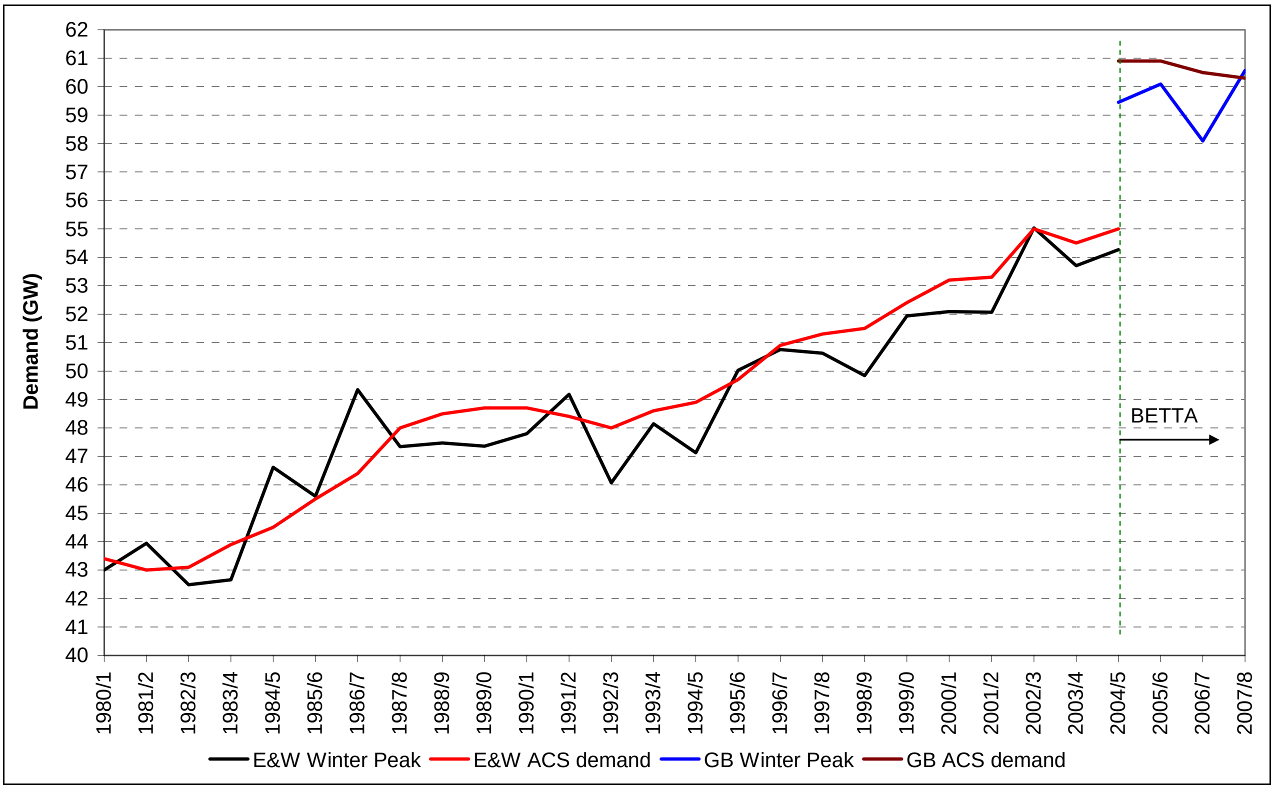


106. Weather corrected weekly peak demand indicated that winter peaks would have happened two weeks before Christmas for the last three winters had the weather been normal for the time of year. The actual peak demand of 60.6 GW for 2007/08 experienced during a pre-Christmas cold snap corrected to normal weather conditions was 59.1 GW. The actual weather corrected peak demands for winter 2006/07and 2005/06 were 57.6GW and 58.5GW respectively. The graph suggests that the underlying demands in 2007/08 and 2006/07 were generally lower than in 2005/06.

107. At the actual demand peak we estimate there was around 0.8-1.3 GW of demand management as large customers reduced demand to avoid Transmission Use of System Charges.

108. Figure A.25 shows the highest winter actual demand and outturn demand corrected to average cold spell (ACS) conditions from 1980 until 2007/08 winter. The graph includes both E&W and GB values for 2004/5 for easy comparison post-BETTA. The graph also indicates a successive decline in ACS corrected demand for the last three winters. We believe the lack of year on year peak demand growth recently observed is due to a combination of factors including the growth in generation embedded in distribution networks, high energy prices and more efficient use of energy.

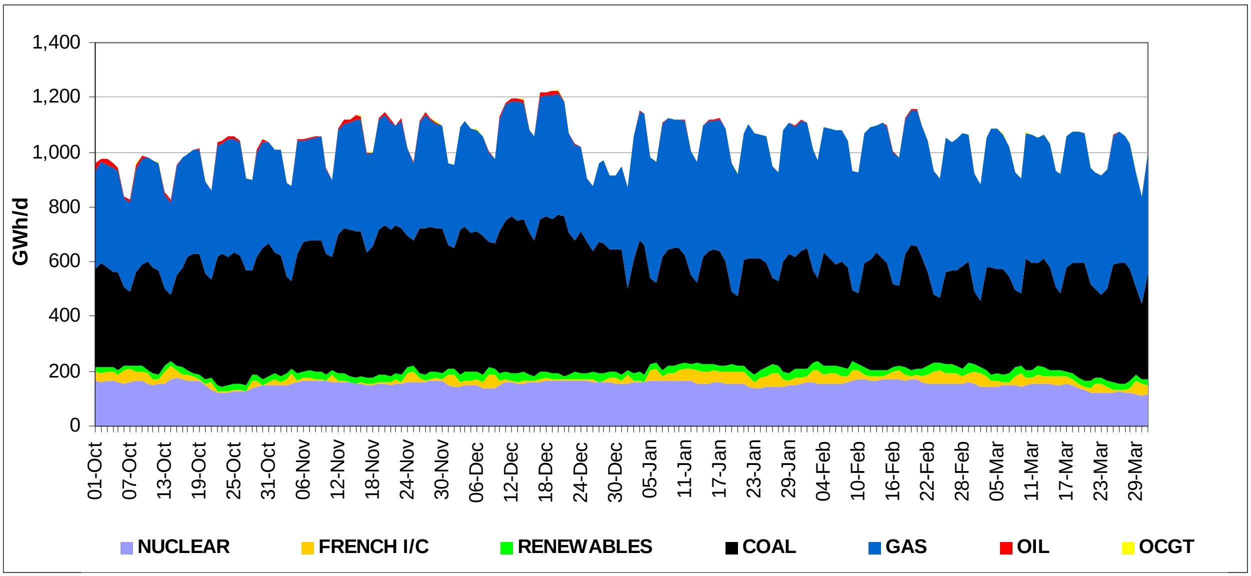
Figure A.25 – Winter Peak Demand Outturns



Electricity Generation Capacity

109. Figure A.26 shows the actual 2007/08 generation mix. Winter can be characterised as one with two main periods where coal was used to generate more power than gas in late 2007 with this reversing in early 2008 with gas being used to generate more power than coal. The reasons for this are discussed elsewhere in this report. We also saw more power provided to the GB market by the GB-France interconnector in the first part of 2008 compared with the final period of 2007. In line with our assumptions and expectations, oil was the marginal generation for the winter periods of highest electricity demand and played its part in meeting demand over the last two working weeks of December 2007.

Figure A.26 – 2007/08 Generation Mix by Fuel Type



110. Our assumed availabilities by generation fuel type and the actual availability at the winter demand peak are shown in the table below. The outturn availabilities we saw are broadly in line with our winter outlook assumptions with the exception of wind and nuclear generation.

111. The actual availability at demand peak in table A.9 for wind is the load factor during the winter demand peak period. More wind generation capacity was available but was not generating due to insufficient wind. Wind generation output by its very nature is intermittent and difficult to forecast.

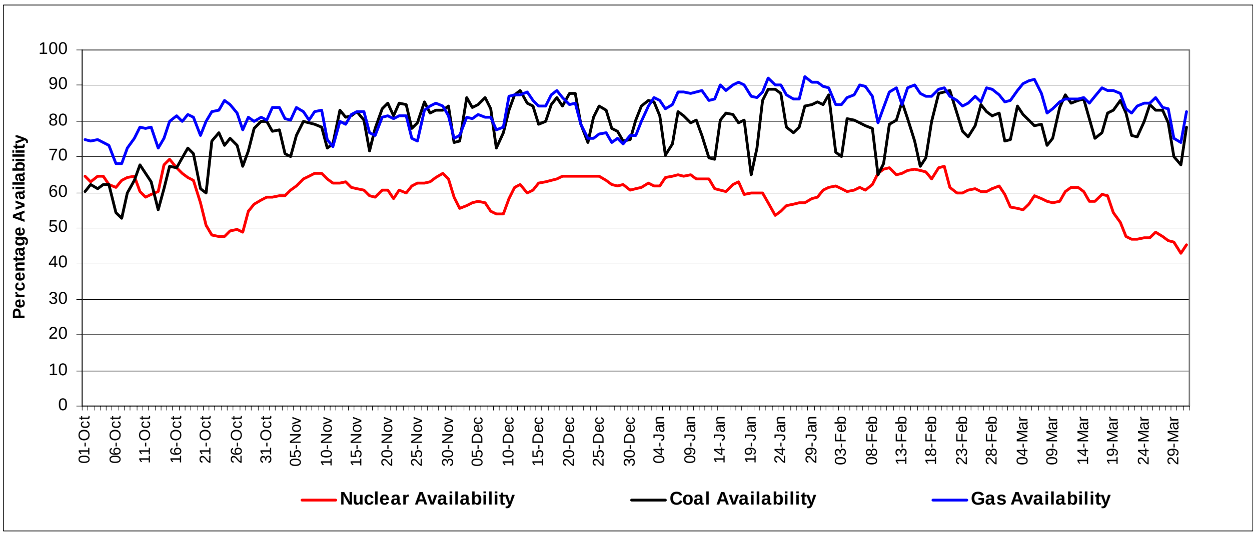
112. For nuclear power stations we saw four large units (two units at each of Hartlepool and Heysham) taken out of service due to technical issues. We did not anticipate these outages taking place when looking ahead to winter 2007/08.

Table A.9 – 2007/08 Generation Assumed and Actual Availability

Power Station Type	Assumed Availability at Demand Peak	Actual Availability at Demand Peak
Nuclear	80%	63%
French Interconnector	100%	100%
Hydro generation	60%	73%
Wind generation	35%	8%
Coal	85%	87%
Oil	95%	92%
Pumped storage	100%	98%
OCGT	95%	92%
CCGT	90%	90%

113. The outturn availabilities over the course of the winter by main fuel type are shown in Figure A.27. The availabilities across the winter period indicate that availabilities are related to day of week and to the level of demand itself, as would be expected as generators take the opportunity to make units unavailable for commercial or technical reasons, such as maintenance. Availability is also influenced by which source of fuel is more economic, as the more marginal fuel is less likely to be available. We expect to see the highest levels of availability during the darkness peak evening demand period of the day in winter. When demands are significantly lower than those expected at the winter peak, for example in the early period of winter (see October in Figure A.27), we see lower availabilities and it is normal to have some power stations on planned maintenance in October. We also see a small number of generation outages at times during the winter.

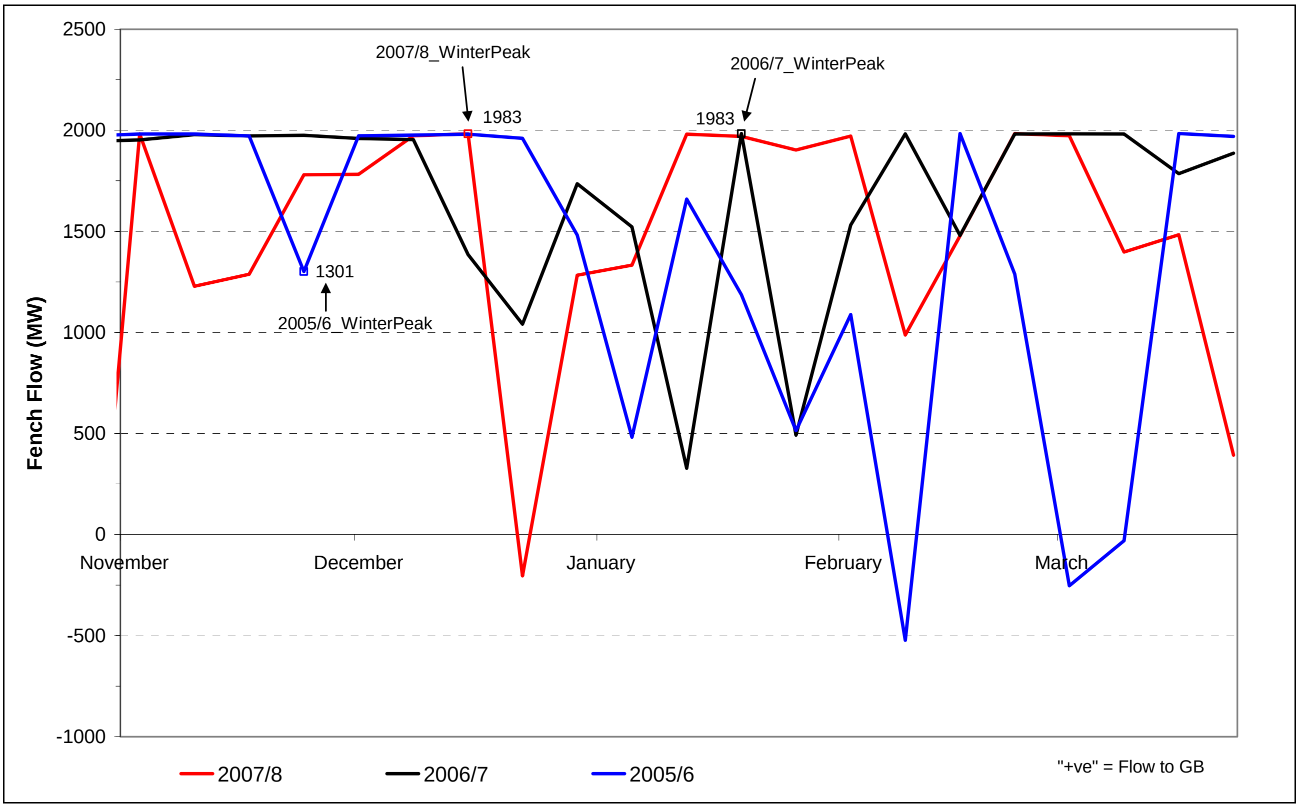
Figure A.27 – Generation Availability by Main Fuel Types



Interconnector Flows

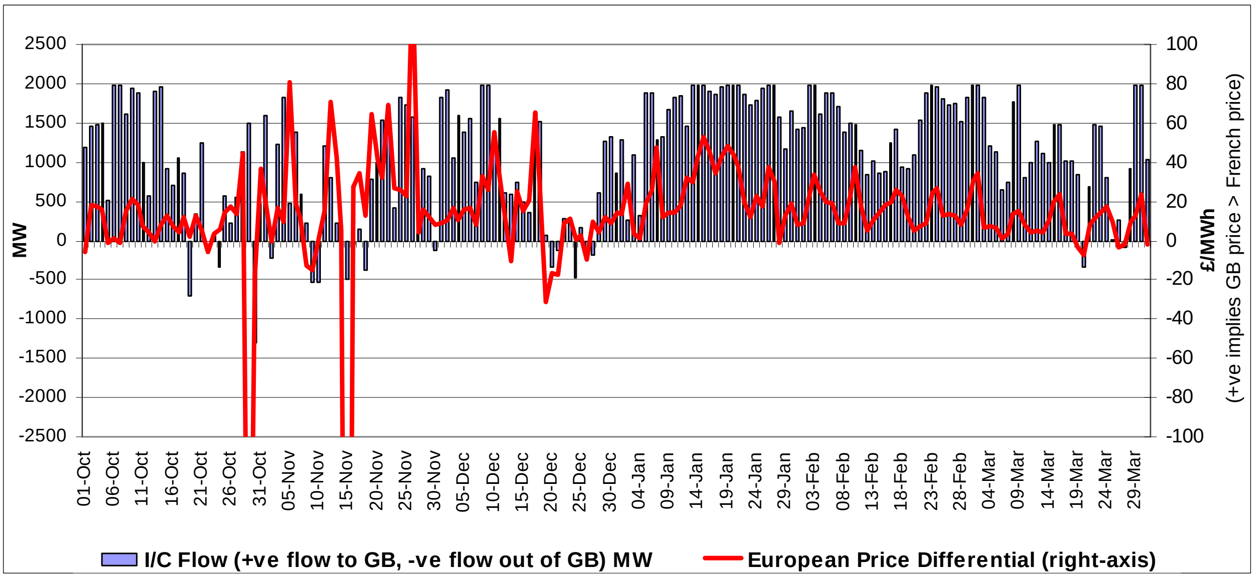
114. The GB market currently has two electricity interconnectors, one to France and one to Northern Ireland. The GB-France interconnector can deliver up to 2 GW in either direction. Figure A.28 shows French interconnector actual flow for the last three winters at GB weekly peak.

Figure A.28 – French Interconnector Flow at Weekly Peak Demand



115. For winter 2007/08 we have analysed the flow over the period of peak GB demand and the correlation of this direction of flow with relative GB and French power price market differentials. This is shown in Figure A.29. The chart shows that the price differential between GB and France was the key driver of interconnector transfers. Note the figure below shows the average transfer amount between 3pm and 7pm whereas the chart above shows the weekly spot peak transfer amount.

Figure A.29 – French Interconnector Transfers and European Price Differentials



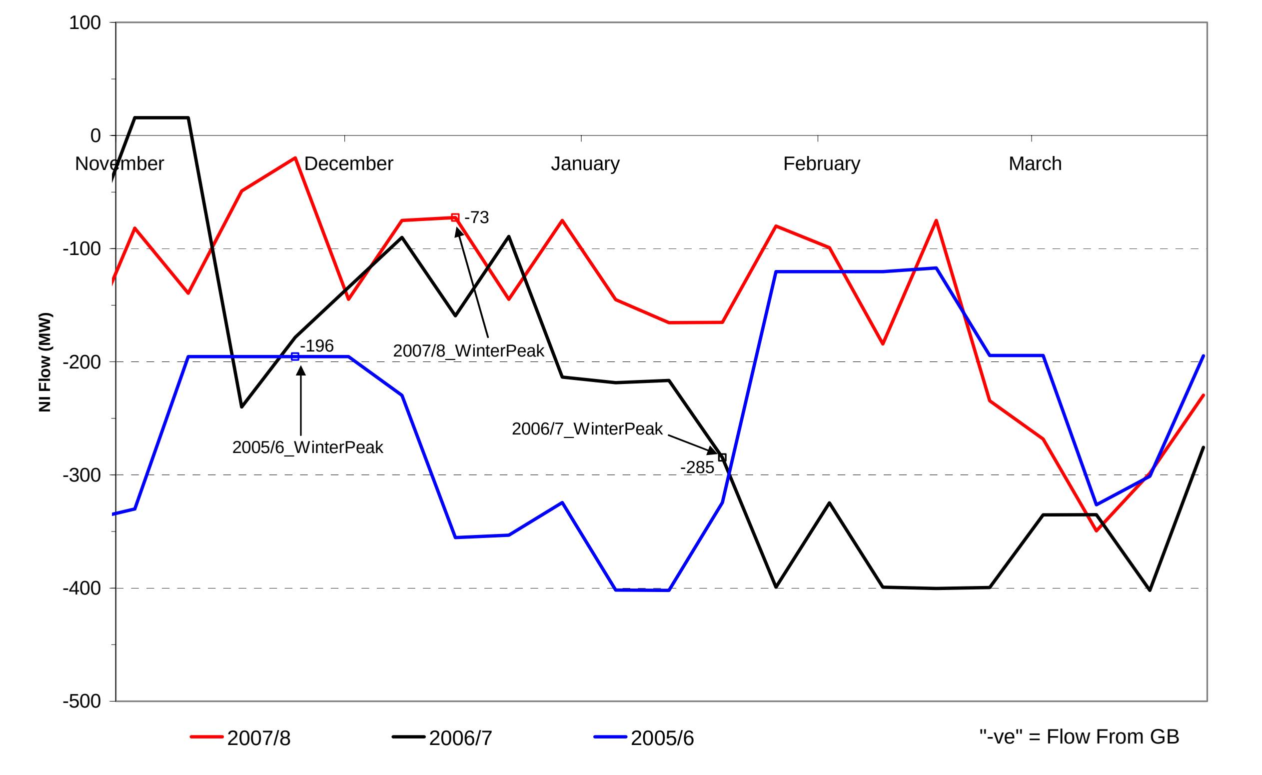
116. At the time of peak GB demand on 17th December 2007 the interconnector was importing 2.0 GW into the GB market. In general over the daily GB demand peak over winter the interconnector has brought power into the GB market from France. During the high demand weeks in mid December 2007 we did see some days where demand was high and the interconnector was exporting a small amount of power from GB to France. A particular feature of the GB transmission charging regime called Triad[9] charging, tends to work to reinforce market signals not to export power to France at the time of GB Triad demand peak. However, due to the complexities of determining the days upon which Triad demand are measured, there may be instances where the market incorrectly predicts the Triad days and we see small exports to France at time of GB peak demand.

117. The interconnector between GB and Northern Ireland (NI) and is smaller and tends to predominantly export power from GB to NI. This interconnector can physically flow 500 MW to NI and 250 MW to GB, though Transmission Entry Capacity (TEC) contractually limits the flow to GB to 80 MW.

118. Historically, across the winter there has been an export from GB to NI of around 100-400 MW, as illustrated by Figure A.30.

[9] See our website at http://www.nationalgrid.com/NR/rdonlyres/BC5D87D0-4682-4C56-9375-7B932A1BD726/24713/UoSCMI4R0FINALBSUoS.pdf for our charging methodology statement on page 27 for an explanation of Triads.

Figure A.30 – NI Interconnector Flow at Weekly Peak Demand for Last Three Winters

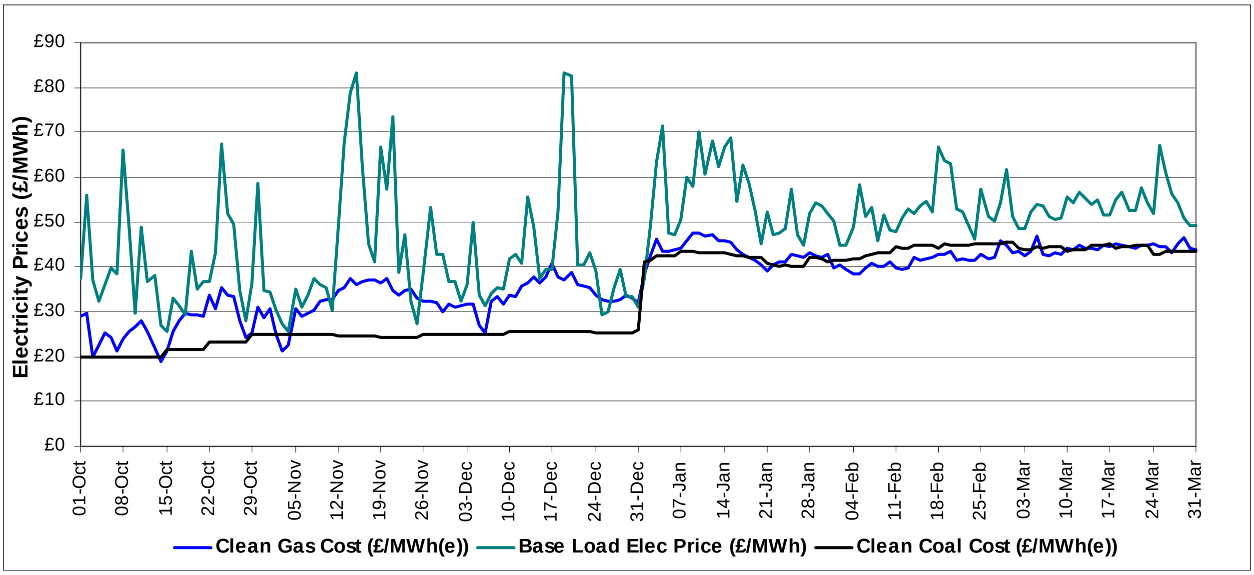


Prices and Merit Order

119. Within day baseload electricity prices were relatively volatile throughout the winter. In particular the baseload electricity price from October through to December had a high of 83.18 £/MWh on 19th December 2007 and a low of 18.93 £/MWh on 16th October 2007.

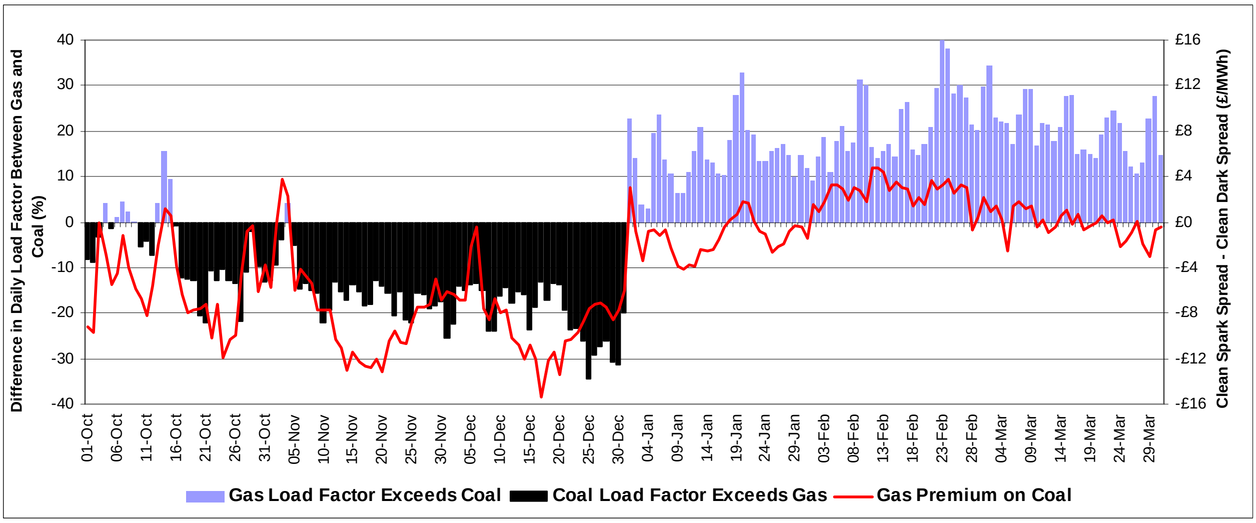
120. Carbon prices under the EU Emissions Trading Scheme (EU ETS) have been a key factor in determining the merit order of generation. Phase 1 of the EU ETS ended on 31st December 2007 and Phase 2 began on 1st January 2008. The fact that the allowances from phase 1 of the EU ETS could not be transferred to phase 2 led to a collapse in the price of carbon in the final quarter of 2007. Once the new phase 2 of the EU ETS began the effective carbon price increased again to something in the 20-25 €/tonne range. This fed into a step change in generation costs on 1st January 2008 compared to late 2007, which as coal is more carbon intensive affected this fuel type more. This change in carbon price appears to have fed into an increase in baseload electricity prices when one compares the final three months of 2007 with the first three months of 2008.

Figure A.31– Baseload Electricity Prices and Clean Gas/Coal Costs



121. Analysis of electricity clean spark and dark spreads shows the effects clearly. In the first three months of the winter coal established a price advantage in terms of dark spreads being more attractive than spark spreads. Spark and dark spreads in the first three months of 2008 were in a tighter range with less of a differential in the relative profit opportunity of gas or coal. Figure A.32 of price differential and load factor confirms that relative clean fuel costs impact the load factors of generation. Coal's more attractive dark spread in the last three months of 2007 saw high utilisation of coal generation, but then this advantage narrowed and we saw gas generation load factors then exceeding coal.

Figure A.32 – Baseload Electricity Prices and Clean Gas/Coal Costs



LCPD – Early Operational Observations

122. The Large Combustion Plant Directive (LCPD), which came into force on 1st January 2008, has clearly impacted the commercial regime of a number of power stations.

123. Restricted running hours of generating stations that have opted-out of the LCPD have impacted the availability of coal-fired stations. This has been managed by the market in terms of balancing generation and demand. The main impact on National Grid has been an increase in system operation costs as we have adapted our operational approach to the new circumstances. For example, some stations are seeking to synchronise and de-synchronise all their units within a single hour to optimize their allowed running hours. Some stations have also changed their operation from running baseload to generating at peak times. The response to LCPD appears to be specific to individual power stations and we believe reflects the economic opportunity cost of the range of operating conditions. It is still too early to draw firm conclusions on how the LCPD will affect power station operation going forward and we continue to review the impact of this regime change.

124. Some stations that had 'opted in' to LCPD (i.e had chosen to retro-fit Flue Gas Desulphurisation plant) were not fully compliant on 1st January 2008. Operational issues arising from this were managed successfully.

125. We have not encountered any security of supply related issues as a result of LCPD. We have seen that plant without FGD still makes itself available to the market and National Grid when commercial incentives are sufficient to do so. This leads us to conclude that, at times of system stress with high winter demands, that these stations would make themselves available.

Operational Overview

126. We experienced four[10] days where NISMs (Notice of insufficient margins) were issued during 2007/08. NISMs are our lowest level of "system warning". A NISM relates to an erosion of the level of contingency reserve we hold and does not indicate itself that demand cannot be met in real time. Contingency reserve requirements reduce as we approach real time due to lower uncertainty around demand levels and lower expectations of aggregate generation failures as we approach real time. In some cases NISMs can be cancelled as we approach real time. No High Risk Demand Reduction (HRDR), Demand Control Imminent (DCI) or Risk of System Disturbance (RSD) warnings were issued in 2007/08. System warnings[11] are a normal part of our operational interaction with the market and whilst we experienced four days where warnings were issued, there is no significant cause for concern.

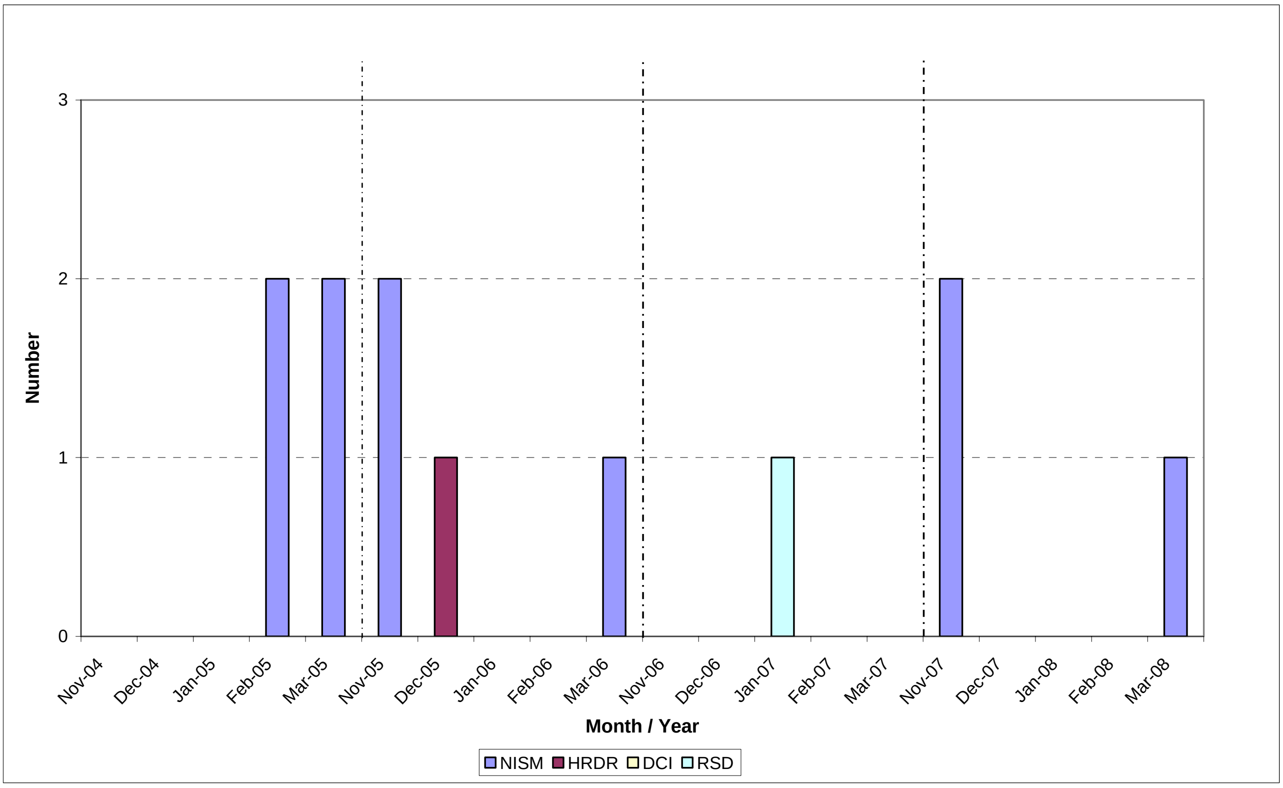
[10] The broad definition of winter (November to March) here to includes the NISM issued post clock change on 30th October 2007.
[11] System warnings can be found on http://www.bmreports.com/bsp/bsp_home.htm as the first item on the new summary page along with an outline explanation of warning types.

Table A.10 – System Warnings Summary for 2007/08

Date	Type	Shortfall MW	Shortfall from	Shortfall to
30/10/07 (not included in chart below)	NISM	300	16:00	19:30
14/11/07	NISM	1100	16:00	19:00
15/11/07	NISM	1900	16:00	20:00
13/03/08	NISM	1000	17:00	18:00

127. Figure A.33 shows the pattern of system warnings over the last 4 years and illustrates that winter 2007/08 was similar to previous winter experiences.

Figure A.33 – Historic Experience of System Warnings Issued



Questions for consultation

We would welcome comments on all aspects of this section, and in particular on the following:

QA10. Do you agree that the market's preference for power generation switching from coal fired generation before 1st January 2008 to gas fired generation for the rest of the winter was driven by the implementation of the LCPD and carbon price changes? Were there any other key factors?

QA11. Do you believe that the market reacted as expected to our system warnings when they were issued?

QA12. What actions were taken by the market to contribute towards meeting demand at times when we issued system warnings? Were there any limitations on any actions the market took at times of system warnings and what could or should be done to address any limitation, if identified?

QA13. Was sufficient key information available on the operational view of electricity demand and supply to enable market participants to be aware of electricity system balancing issues? Should additional key information be provided?

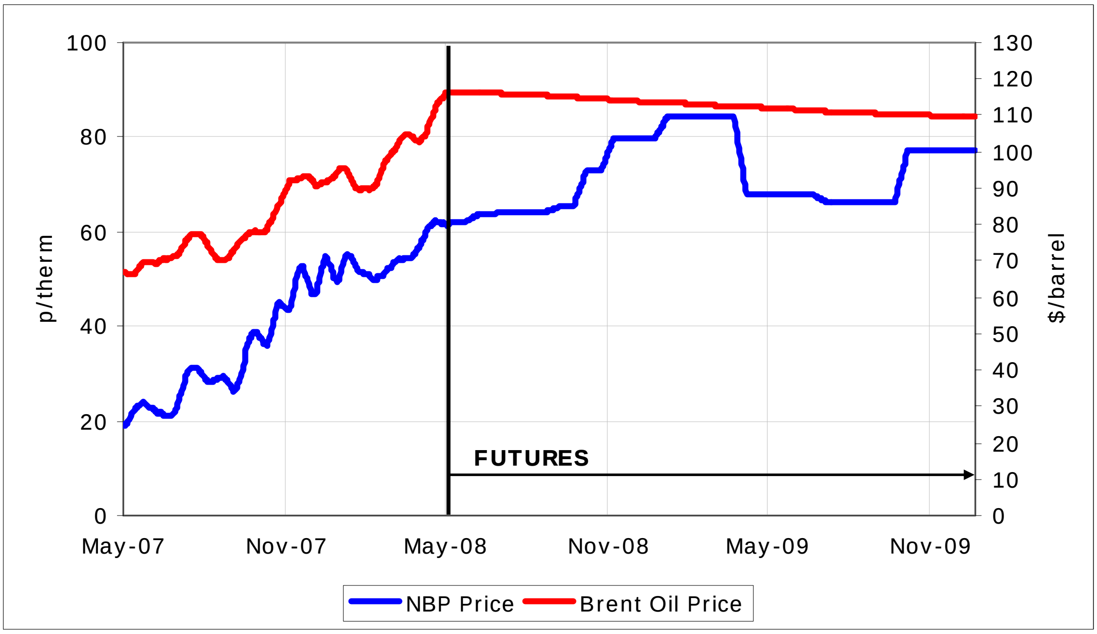
Section B
Outlook for 2008/09

Gas

2008/9 Fuel Prices

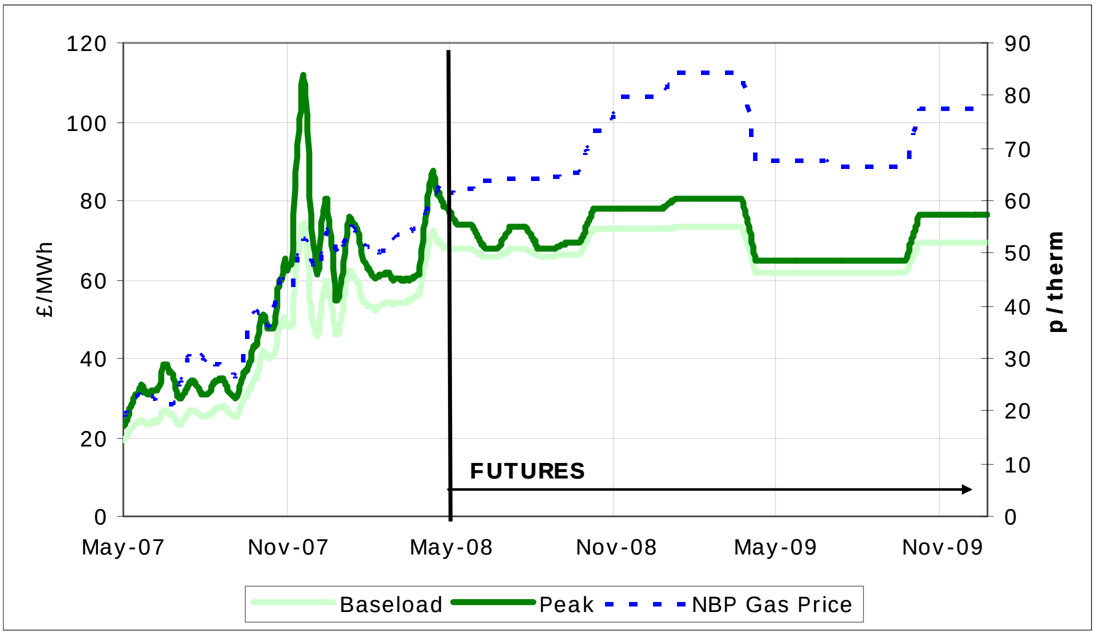
128. Figure B.1 shows the historical and forward UK oil and gas prices as of early May 2008. Historically there has been significant increases in both fuels with a belief that the rise in gas prices is strongly linked to oil. Forward markets show very high prices for both commodities. In addition, the forward NBP price for gas shows some winter seasonality with prices in excess of 80p/therm for next winter

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



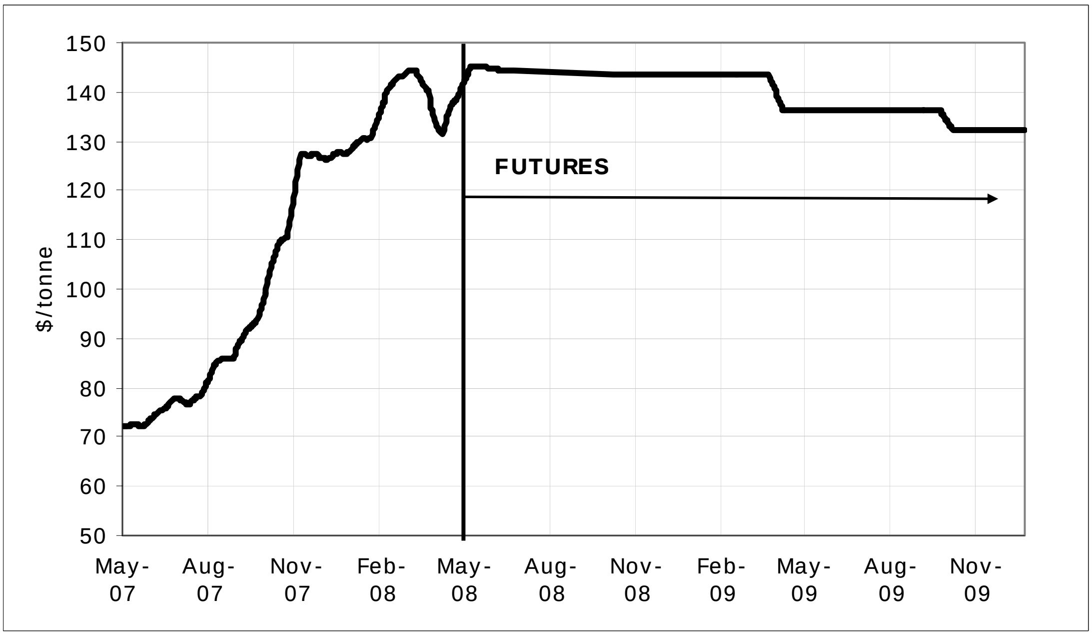
129. Figure B.2 shows the historical and forward UK wholesale baseload and peak power prices as of early May 2008, together with the NBP gas price. Historically, there is a strong correlation between the gas and power prices and only when there has been demand or supply issues specific to the power market has there been any deviation away from this trend. In the forward power markets, the seasonality in the gas price is not fully reflected. Forward baseload power prices for winter 2008/09 are typically £70-80/MWh.

Figure B.2 – Historic and Future Power and Gas Prices



130. The strong oil, gas and power prices have been mirrored by significant increases in the price of coal. These increases have been driven by strong global demand, particularly in China and India, coupled with a shortage of available freight. Figure B.3 shows the ARA CIF[12] coal price with forward prices reflecting the continuing strong demand, mainly driven by the growing number of power plants being commissioned across Asia.

Figure B.3 – Historic and Future Coal Prices

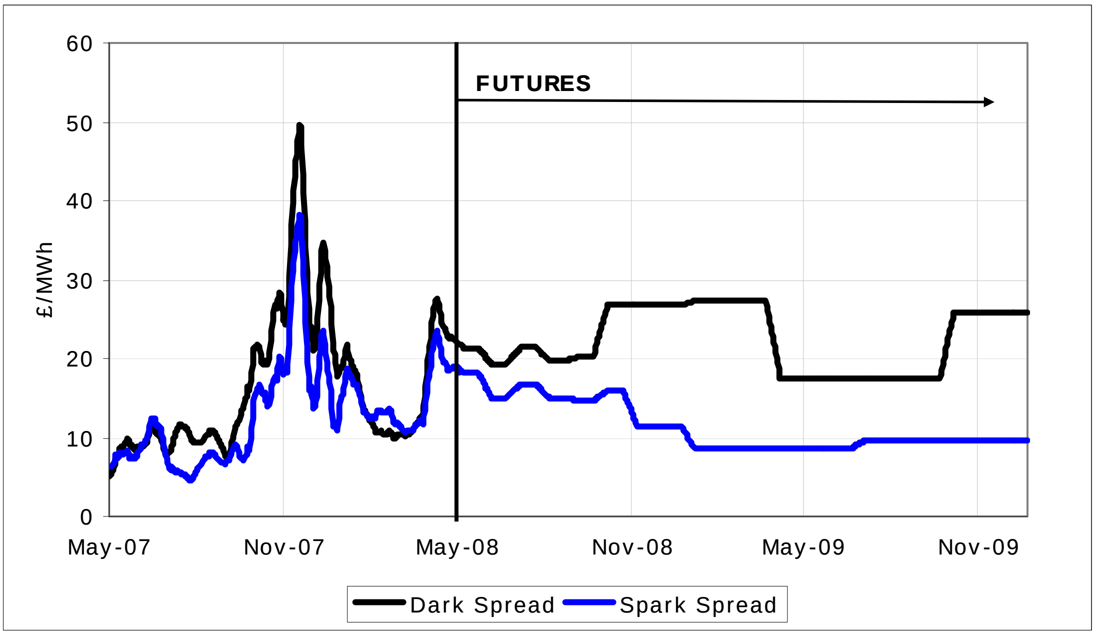


[12] Amsterdam Rotterdam Antwerp Cost Insurance and Freight price. This price includes the cost of the goods, the freight or transport costs and also the cost of marine insurance.

131. The current high gas price is now benefiting coal-fired power generation when compared with gas-fired generation in the UK. The forward curve shows a dark spread of over £20/MWh compared with a spark spread that falls to around £10/MWh in winter 2008/09. This is despite coal prices being at record highs, thus emphasising the strength of the current gas price.

132. These forward prices suggest that coal-fired generation will be the baseload plant over the coming year, with gas-fired generation as the marginal plant. Traditionally, gas has been the baseload plant during the summer months when the seasonal gas price has been lower, with coal the baseload plant during the winter. This pattern has not been seen during the past two years, with volatile energy prices resulting in the spark spread being higher than the dark spread for shorter periods, as illustrated in Figure B.4.

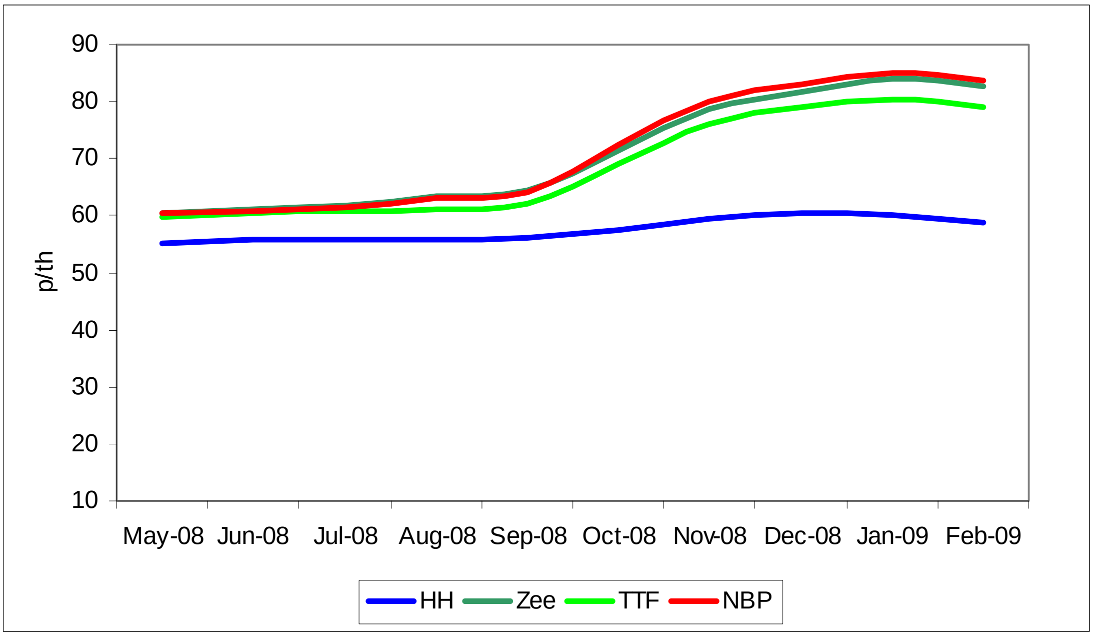
Figure B.4 – Historic and Dark and Spark Spreads



133. Figure B.5 shows the forward gas prices as of early May 2008, 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. Though Henry Hub prices are historically high, the European winter prices are approximately 20p/therm higher. In terms of spot LNG cargoes this provides a considerable incentive to deliver LNG to Europe in preference to the United States.

134. 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.

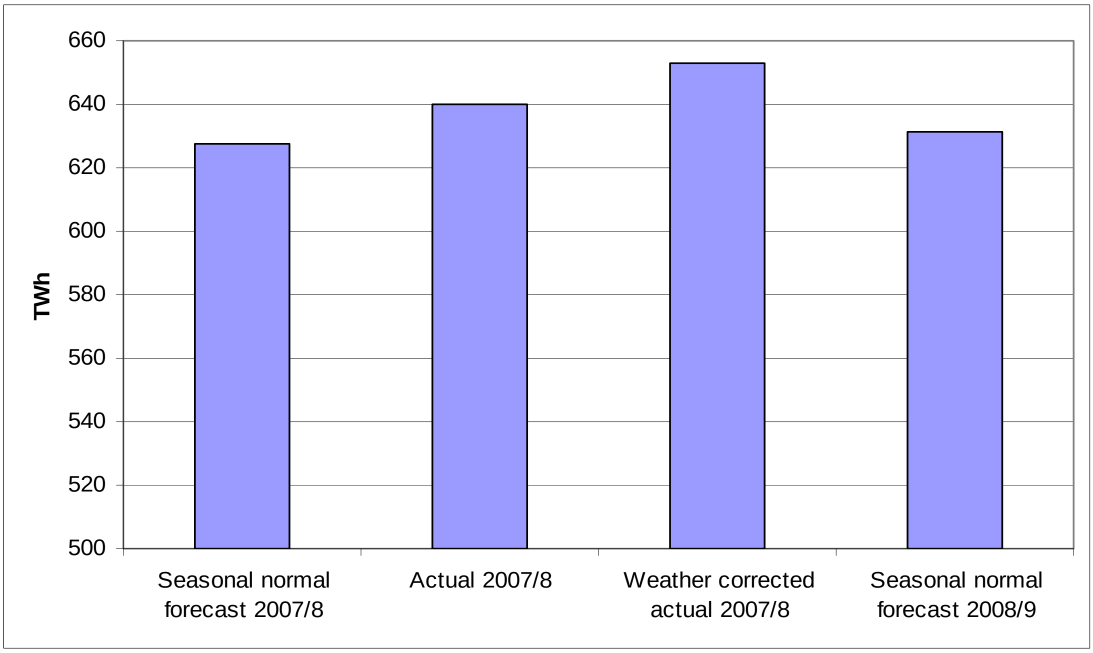
Figure B.5 - Forward Prices for Europe and US



Gas Demand Forecast 2008/09

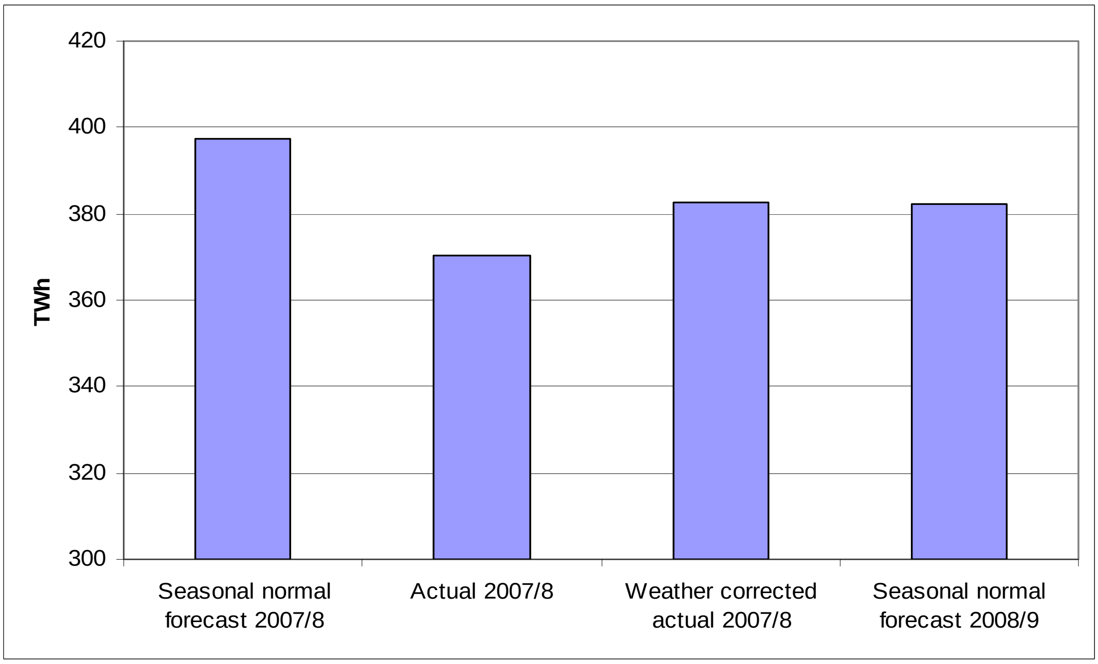
135. Figure B.6 compares the 2008 total forecast for winter 2008/9 with the actual, weather corrected and 2008 forecast demands for winter 2007/8. The new forecast is lower than both the actual and weather corrected demands in winter 2007/8.

Figure B.6 – Total Winter Demand



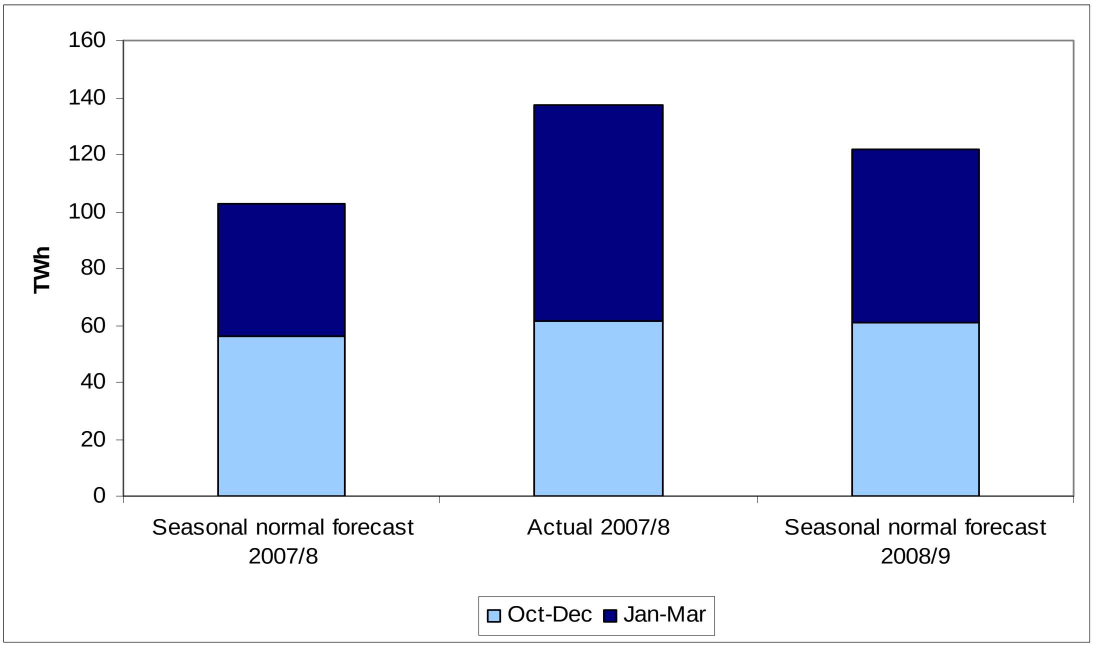
136. Figure B.7 compares the 2008 NDM forecast for 2008/9 with the actual, weather corrected and 2008 forecast demands for 2007/8. The NDM forecast for 2008/9 is almost identical to the weather corrected NDM demand in winter 2007/8.

Figure B.7 – NDM Winter Demand



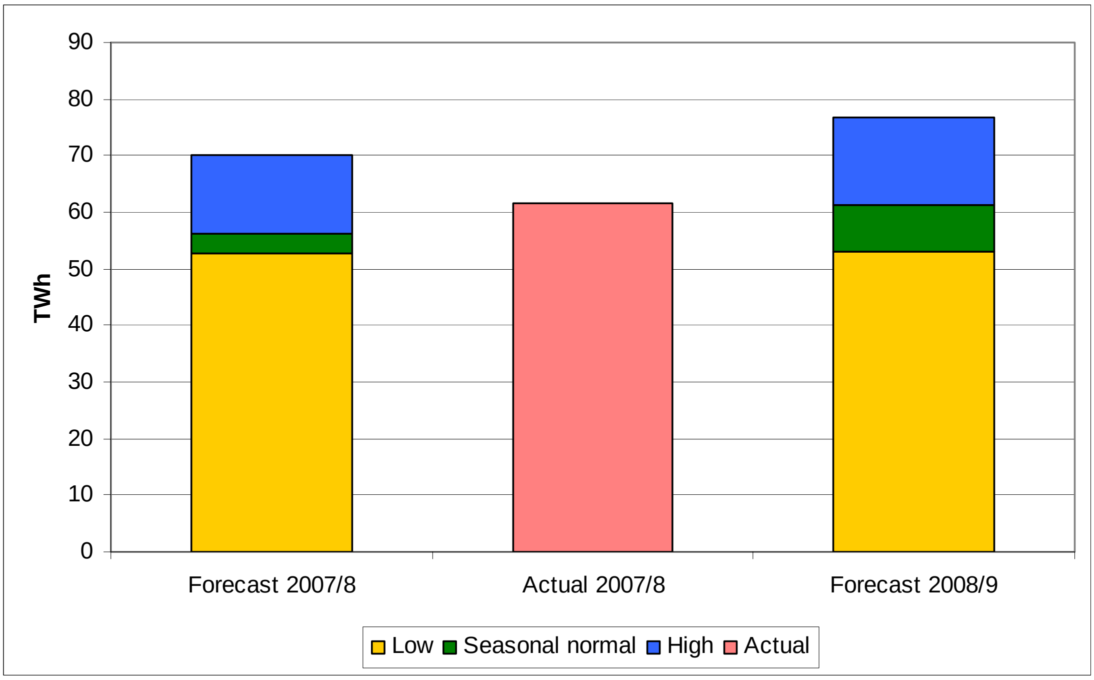
137. Figure B.8 compares the 2008 power generation forecast for 2008/9 with the actual, weather corrected and 2008 forecast demands for 2007/8. This graph illustrates the difference between early and late winter. The October to December forecast is very close to the actual power generation gas demand 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 B.8 – Power Generation Winter Demand



138. Figure B.9 compares the October to December power generation figures in more detail. The low demand range is similar to the 2007/8 forecast. The high level is 9% higher.

Figure B.9 – October to December Power Generation Demand

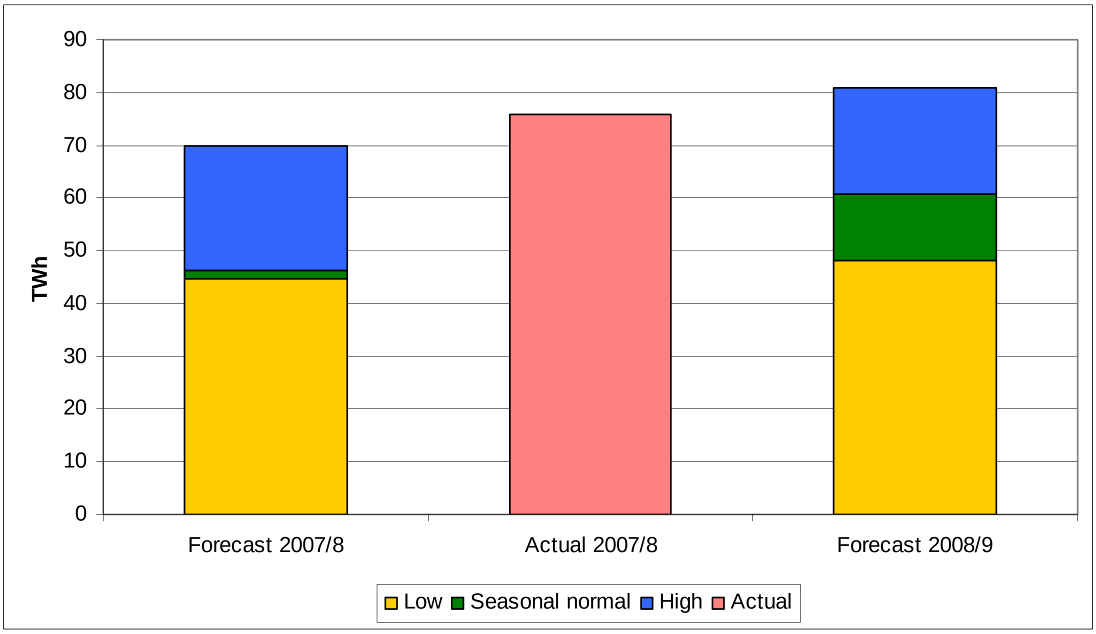


139. Higher base case and high scenario forecasts are due to a number of factors including reduced output from nuclear power stations compared with that assumed in the 2007/8 forecast, the potential for increased take of gas from the NTS by directly connected power stations and the commissioning of Langage and Marchwood stations during the 2008/9 winter.

140. Figure B.10 shows increases in the low, base case and high levels compared to 2007/8 for January to March power generation gas demand. The 2007 forecast assumed that coal would be base load resulting in the base case 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 FGD 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 FGD installations will be completed by the start of winter. The LCPD will continue to limit the output of opted out coal power stations.

141. 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, with a base case forecast closer to the mid point between the high and low forecasts.

Figure B.10 – January to March Power Generation Demand



2008/9 Gas Supply

142. This section examines each of the potential (non-storage) gas supply sources in turn: UKCS and imports from Norway, the Continent and LNG. We set out the main factors associated with these supply sources and seek views on their respective prospects, in particular on how the performance of the various supply sources might vary across the winter months.

143. As there is considerable uncertainty in the level of imported supplies for next winter, our initial view is appreciably influenced by our experience last winter. This should not be seen as a best view at this stage but a means for industry engagement and consultation.

UKCS Gas Supplies

144. For the purposes of this document, our initial assessment of UKCS supplies for winter 2008/9 is based primarily on industry feedback we have recently received from our 2008 TBE consultation. Table B.1 compares our forecasts of UKCS supplies for 2007/8 and our initial view for 2008/9.

Table B.1 - Preliminary 2008/9 UKCS Maximum Forecast by Terminal

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

145. Table B.1 shows a UKCS maximum supply forecast of 216 mcm/d. On completion of ongoing analysis we may update this forecast when we publish our annual 'Development of Investment Scenarios' paper in July.

146. The 2008/9 maximum UKCS supply forecast incorporates a year-on-year decline of 33 mcm/d from existing fields. This is partially offset by our forecast of new developments of approximately 5 mcm/d. Hence our net reduction in UKCS supplies is 28 mcm/d, approximately 11% lower than for last year.

[13] Excludes estimates for Vesterled and Tampen

147. The 11% year on year decline is greater than our previous reported declines of typically 5-10%. We attribute this to a combination of:

- increased annual production from numerous UK fields (thus enhancing decline)
- the development of new fields that on commencement of production have a rapid decline
- a cautious approach for inclusion of new fields to reflect possible delays in the commencement of production
- a more cautious approach to calculating a sustained level for peak winter production

148. For the purposes of supply-demand analysis and for security planning, we assume a level of UKCS supply below the maximum forecast. For this purpose we intend to continue to use an availability of 90%, resulting in an UKCS forecast for next winter of 194 mcm/d

149. There are many factors that may increase or in particular decrease our UKCS supply forecasts. These include:

- lower availability through poor weather conditions offshore;
- the late commissioning of new fields or delays in the resumption of production following maintenance outages, resulting in reduced supply availability early in the winter;
- within-winter decline of existing fields resulting in reduced supply availability later in the winter;
- though not observed last winter due to high gas prices, the possibility of lower production from high swing fields at Barrow and Bacton.

Norwegian Imports

150. Last winter we observed the commencement of flows from the Ormen Lange field into Langeled and deliveries to St Fergus via the Tampen Link to the FLAGS pipeline. Next winter we anticipate higher production from Ormen Lange.

151. In forecasting Norwegian flows to the UK for next winter we need to estimate Norwegian production and assess flows to the Continent. Table A.4 shows for the winter period our estimates of average Norwegian exports to the Continent and UK since 2005/6. Our estimate for Norwegian production for next winter is 310 mcm/d based primarily on further increases in production from Ormen Lange.

152. Table B.2 also highlights the variations in Norwegian flows to the Continent. On inspection of the capacity and actual flows there is evidence to suggest the potential for higher flows to Germany (if required) and lower flows to all destinations as occurred in 2006/7.

153. Table B.2 shows a possible range for Norwegian exports to the Continent based on 95% of the capacity for the maximum winter flow with the minimum flow based on actual flows for the mild winter of 2006/7. Resultant UK flows determined by difference range from 80 to 115 mcm/d.

Table B.2 – Winter 2008/9 Estimates of Norwegian Exports

(mcm/d)	Capacity	Minimum	Maximum
Belgium	41	33	39
France	52	43	49
Germany	151	108	144
UK (by difference)	121	115[14]	80
Total	**365**	299	310

Continental Imports

154. Last winter, we again observed relatively stable flows through BBL and flows through IUK that effectively responded to the UK's market need for gas, similar to a storage facility.

155. For next winter we are working with BBL to develop new commercial arrangements from September 1st for interruptible non physical reverse flow (i.e. non-physical exports). If implemented, this may result in BBL flows that could be more sensitive to the UK and possibly Continental market needs. We also anticipate that all compressors at Julianadorpe should be in operation, thus reducing the risk of any supply disruption from BBL.

156. Whilst we observed BBL flows about 35 mcm/d for last winter we believe it is prudent not assume flows above 30 mcm/d for next winter.

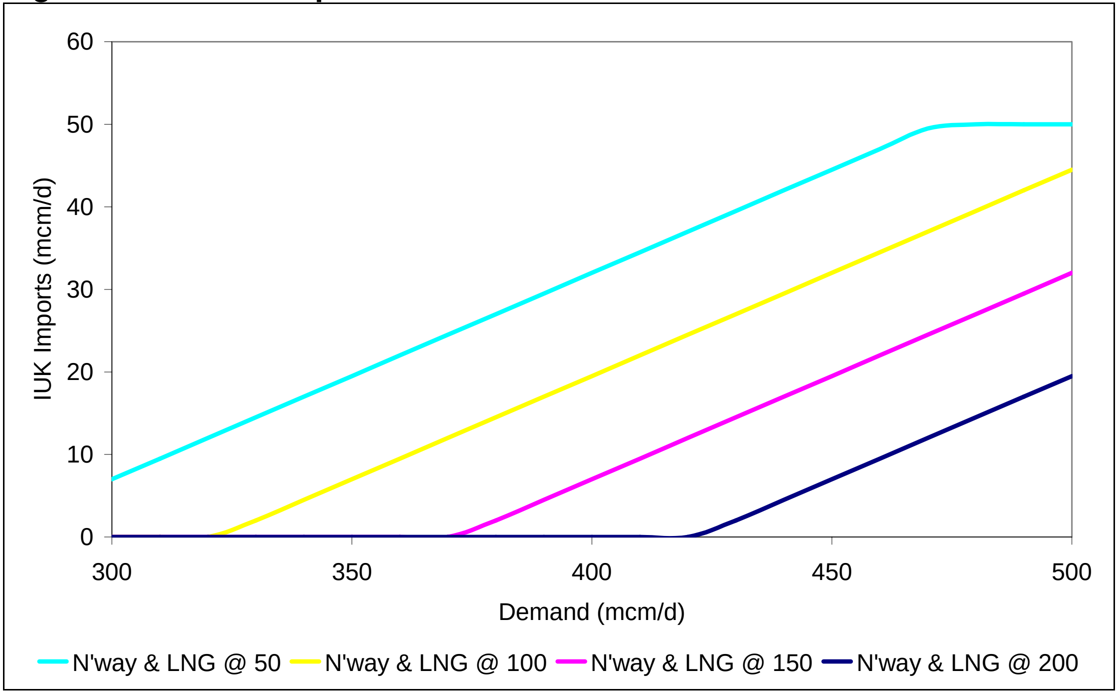
157. For IUK we are not aware of capacity enhancements to the Belgium and interconnecting networks. Last winter we observed IUK imports approaching 25 mcm/d, however we did not see any noticeable increase in IUK imports for days when the demand exceeded 400 mcm/d.

158. In previous winters IUK has behaved as a marginal source of supply when UKCS and other imports have not meet UK demand. We expect this trait to continue, with IUK and storage acting as the supply balancer to the meet UK 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.

159. Figure B.11 shows our forecast range for IUK imports based on 194 mcm/d UKCS, 30 mcm/d BBL and various combinations of Norwegian and LNG import flows from 50 to 200 mcm/d. The chart shows that for low levels of Norwegian and LNG imports, IUK could commence importing at demands as low as 300 mcm/d, whilst for a well supplied UK not until demand as high as 400 mcm/d.

[14] Capped at 95% of capacity

Figure B.11 – IUK Import flows



160. Though not shown on Figure B.11, we believe that it remains prudent to consider lower IUK supply availability up to December due to uncertainties over the release of Continental storage that may be held back for Continental markets. Based on last years experience, the difference was about 5 - 10 mcm/d.

LNG Imports

161. Last winter we only received LNG deliveries through Grain and due to global market opportunities to supply LNG to other markets, notably the Far East, there were less cargoes received than the previous winter.

162. For next winter we again have the prospect of additional deliveries through Milford Haven through two new terminals; South Hook and Dragon and additional volumes through Grain Phase 2.

163. A recent press article[15] reports that 'South Hook is expected to receive a first commissioning cargo around September in preparation for Winter 2008/09' and that 'the terminal is not expected to start full commercial operations (and thus be capable of delivering gas into the NTS) until December, when it is due to be handed over by engineering contractors to South Hook LNG'.

164. The capacity for South Hook Phase 1 is 10.5 bcm/year equivalent to a base load deliverability of 29 mcm/d.

165. Dragon is also believed to be commissioning in H2 2008, the capacity for Phase 1 is 6 bcm/year equivalent to a base load deliverability of 16 mcm/d.

[15] ICIS Heren European SpotGas Markets, 3rd June 2008, page 9

166. Grain Phase 2 is believed to be commissioning in Q4 2008, the capacity for Phase 2 is 9 bcm/year equivalent to a base load deliverability of 25 mcm/d.

167. All of these facilities will be capable at times of exceeding these base load deliverabilities. The capacity release obligation for Milford Haven for next winter is approximately 60 mcm/d, this increases to nearly 90 mcm/d from January 2009. The capacity release obligation for Grain for next winter is approximately 38 mcm/d.

168. Besides the uncertainty over when the Milford Haven and Grain Phase 2 LNG facilities will be commissioned, there is again market uncertainty over whether the UK will attract LNG next winter in preference to alternative markets; notably the Far East where buyers have been active in obtaining spot cargoes from the Atlantic Basin.

169. To manage the supply uncertainty surrounding LNG we are proposing at this stage of our winter consultation to consider a very wide range, namely from 0 to 83 mcm/d. This therefore assumes periods of zero flow and flows up to 45 mcm/d for the Milford Haven facilities and 38 mcm/d for Grain.

170. We acknowledge that flows as high as the capacity release obligation are theoretically possible at Milford Haven and Grain.

171. We also acknowledge that flows of LNG imports through Teesside GasPort are possible. These provide a further upside to our range.

Storage

172. 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.

173. Table B.3 shows our assumed levels of storage space and deliverability for next winter.

Table B.3 – 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
Long (Rough)	33300	455	42	73.2

Preliminary View of Supplies Winter 2008/9

174. In the previous sub-sections we have outlined the basis for the assumptions incorporated into our analysis. Table B.4 summarises the supply range, and compares these with the 2007/8 Base Case. We should stress that these 2008/9 ranges should be regarded as illustrative for the purpose of fostering discussion and comment.

Table B.4 – Preliminary View of Non Storage Supplies Winter 2008/9

(mcm/d)	2007/8 Base Case	2007/8 Top 100	2007/8 Highest	2008/9
UKCS	220	202	226	194
Norway	87	81	107	80 – 115
BBL	25	35	38	30
IUK	0 - 50	9	24	0 – 50
LNG Imports	13	4	16	0 – 83
Total	345 - 395	331	411	304 – 452
400 mcm/d demand day				328 – 400
450 mcm/d demand day				341 – 429

175. Based on the supply assumptions detailed in the previous supply sections, Table B.4 suggests that the non-storage supply availability for next winter is most uncertain and subject to deliveries of LNG imports and to a lesser extent Norwegian supplies. The availability of these supplies is expected to influence IUK imports.

Safety Monitors

176. Safety monitors were introduced in 2004 as a mechanism for ensuring that sufficient gas is held in storage at all times to underpin the safe operation of the gas transportation system.

177. The safety monitors define levels of storage that must be maintained through the winter period. The focus of the safety monitors is public safety rather than security of supply. It is a requirement of National Grid's safety case that we operate this monitor system and that we take action to ensure that storage stocks do not fall below the defined levels.

178. This section on safety monitors is consistent with the industry note we issued on 31 May 2008 as required under the Uniform Network Code (Q5.2.1).

179. The safety monitor requirement is highly dependent on the non-storage supply level. As there is considerable uncertainty regarding the make up and aggregate level of non-storage supplies, we have provided an outer range for the Safety Monitor levels for 2008/09, based on a high level of non-storage supplies and a low level of non-storage supplies.

180. High non-storage supply assumptions:

- 90% peak UKCS availability = 194 mcm/d
- High Norwegian supplies at 115 mcm/d
- BBL supplies at 30 mcm/d
- High LNG supplies at 83 mcm/d
- Total non-storage supplies excluding IUK = 422 mcm/d
- IUK and storage provide additional supplies to meet demand in the ratio 1:3

181. Low non-storage supply assumptions:

- 90% peak UKCS availability = 194 mcm/d
- Lower Norwegian supplies at 80 mcm/d
- BBL supplies at 30 mcm/d
- No LNG supplies
- Total non-storage supplies excluding IUK = 304 mcm/d
- IUK and storage provide additional supplies to meet demand in the ratio 1:3

182. The resultant safety monitor requirement for these two supply cases is summarised in Table B.5. As expected, the high and low assumptions for non-storage result in a wide range for the storage space levels.

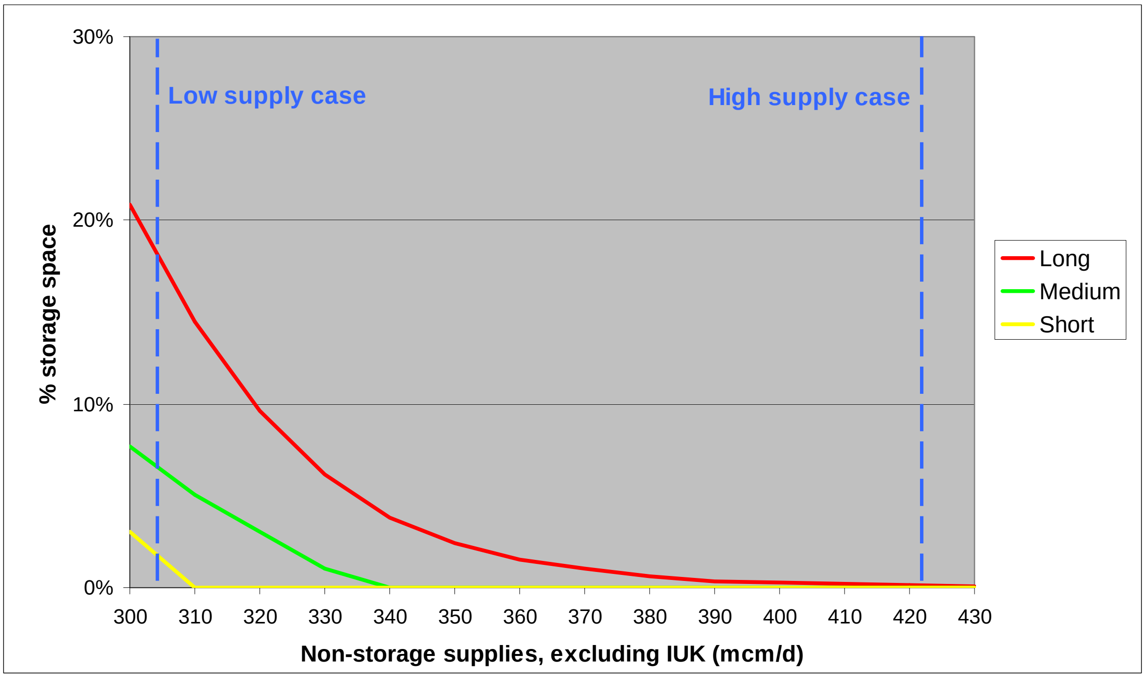
Table B.5 – Safety Monitor Storage Space Requirements

Storage type	Assumed storage space (GWh)[16]	High non-storage supply		Low non-storage supply	
		Space (GWh)	Space	Space (GWh)	Space
Long duration storage (Rough)	32845	40	0.1%	5872	17.9%
Medium duration storage (MRS)	8251	0	0%	525	6.4%
Short duration storage (LNG)	2058	0	0%	7	0.3%

183. Figure B.12 shows the potential range of the safety monitor storage space requirement for non-storage supply levels between the high and low supply cases.

[16] Excludes Operating Margins and Scottish Independent Undertakings

Figure B.12 – Safety Monitor Storage Space Range



184. It is our responsibility to keep the safety 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. Ideally the passage of time before next winter and the outcome of this consultation may provide further clarity on expected levels of supply for next winter.

Winter 2008/09 Update on Provision of new NTS Capacity

185. A significant construction programme is underway 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 connect new LNG imports and to provide additional transportation capability from existing entry terminals. The references in the tables below relate to the map shown as Figure B.13.

Table B6.a - 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

186. These projects are required to provide capacity for and facilitate a new 885MW CCGT power station at Langage connecting at the South West extremity of the NTS. These projects have been completed and commissioned. Commissioning of the power station is due for October 2008, and is expected to begin commercial operation in 2009.

Table B6.b - Marchwood Power Station - Exit

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

187. This pipeline is required to accommodate a new 842MW CCGT power station at Marchwood connecting in to Feeder 7, near Lockerley. Commissioning of the pipeline is expected in late summer 2008 and commissioning of the power station is currently expected over this winter with full commercial operation anticipated in the Summer of 2009.

Table B6.c - Milford Haven LNG Importation - Entry

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

188. These projects are part of the overall investment strategy to provide capacity to transport gas from the new LNG importation terminals at Milford Haven. Currently expectations are for delivering gas in 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, with approximately 70km of reinstatement works to complete. Commissioning of Felindre compressor station and the modifications to Wormington are due in Autumn 2008.

Table B6.d - East Coast- Entry

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

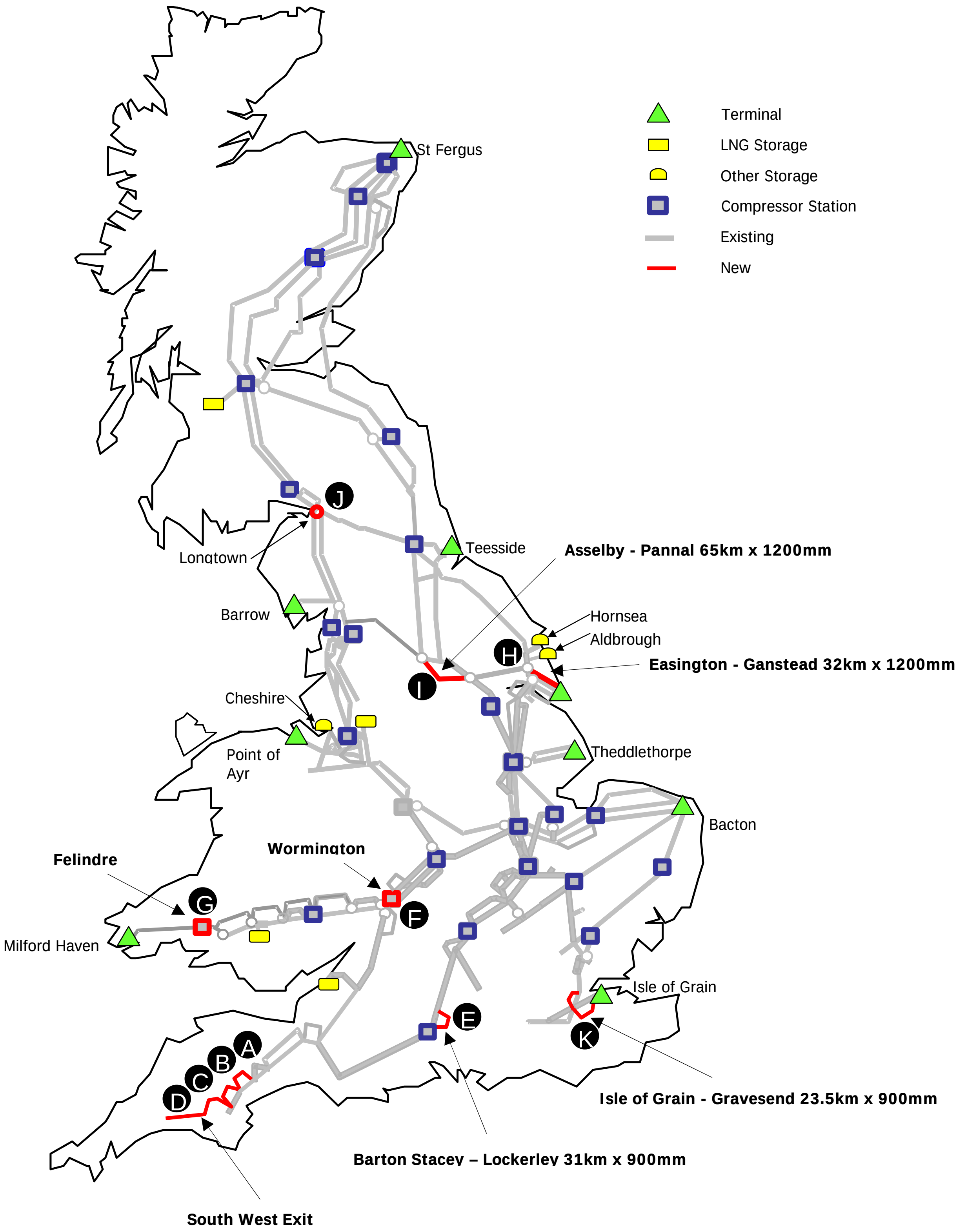
189. These projects are being installed to provide entry capacity on the East coast in response to entry auction signals and mark the completion of Trans-Pennine link from Easington to Carnforth. Asselby to Pannal has been commissioned. Easington to Ganstead and Longtown Regulator are expected to be commissioned in October 2008.

Table B6.e - Isle of Grain LNG importation- Entry

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

190. This is pipeline is to provide additional capability to accommodate the 2nd phase expansion of the Isle of Grain LNG 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 October 2008.

Figure B.13 – NTS Construction Projects 2008/09



Questions for consultation:

We would welcome comments on all aspects of this section, and in particular on the following:

QB1. When should we expect completion of all FGD installations?

QB2. Will there be a further reduction in NDM gas demand due to efficiency savings in winter 2008/9?

QB3. Will the NDM demand lost due to short-term actions return on a very cold winter's day?

QB4. What are the drivers behind the current strong UK gas price and what will be the key influences on the price in winter 2008/09?

QB5. Is there a 'floor' price in the UK that will need to be maintained in order to attract specific imports to meet demand?

QB6. What assumptions should be made over the maximum UKCS supply availability for 2008/9?

QB7. With imports expected to make up an even larger proportion of supplies, should we continue to assume that UKCS supplies (with the exception of some high swing fields) continue to underpin UK demand?

QB8. Do you agree with our high level view of Norwegian increased Norwegian production for next winter with resultant imports to the UK being dependent on Continental flows?

QB9. Should we include any other considerations in making our forecasts for Norwegian imports?

QB10. What assumptions should be made for levels of imported gas through BBL for winter 2008/9, and should we assume a uniform supply profile throughout the winter period?

QB11. What assumptions should be made for levels of imported gas through IUK for winter 2008/9, and specifically:

QB11a. Should we assume that the IUK will operate as a marginal source of supply when UKCS and other imports can not meet UK demand?

QB11b. Should we assume that the availability of gas through IUK will increase as the certainty regarding the availability of Continental storage to meet the remainder of the winter improves?

QB12. When should we expect commissioning of Dragon, South Hook and Grain Phase 2 and how long may these activities take before becoming fully operational?

QB13. What assumptions should be made for levels of imported LNG through Grain, Milford Haven and Teesside for winter 2008/9?

QB14. .We would welcome views on our assumed levels of storage space and deliverability?

QB15. We would welcome views on the extra storage space that could be made available through storage cycling?

QB16. We would welcome comments on our 2008/9 Preliminary View, and thoughts on how we can reduce or manage the resulting supply range

Electricity

Electricity Demand Levels for 2008/09 – Great Britain

191. Our Great Britain Average Cold Spell (ACS)[17] 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[18] 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.

192. As discussed in Section A, 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.

Notified Generation Availability 2008/09

193. The quoted plant margin for 2008/9 currently reported in the January 2008 update to the 2007 Seven Year Statement (SYS) is 26.8%, based on a Transmission Entry Capacity (TEC) contracted generation capacity of 79.4 GW. This includes the 2 GW import to GB of the GB-France Interconnector.

194. Oldbury nuclear power station, which has a capacity of 0.4GW, is due to de-commission on 31 December 2008 and is not included in the 79.4GW capacity total i.e. at the start of winter total capacity based on TEC is 79.8GW.

195. The reduced nuclear output at Hinkley Point and Hunterston, announced by British Energy in 2007, continues and represents a loss of 0.8 GW of capacity, not reflected in the 79.8GW SYS figure.

196. Langage (0.9GW) Marchwood (0.9GW) and Immingham stage 2 (0.6GW) have contracted for TEC for 2008/9. Langage is expected to begin commercial generation in January 2009 with the two other stations not expected to begin commercial operations before March 2009. These capacities are included in the

[17] 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.

[18] 1 in 20 Conditions are a particular combination of weather elements which gives rise to a level of peak Demand within a Financial Year which has a 5% chance of being exceeded as a result of weather variation alone.

total TEC capacity of 79.8GW referred to above but are not expected to be available at the start of winter.

197. Wind continues to increase its share of the GB generation market, with an additional 136MW of capacity coming online during summer 2008 and a further 150MW of fully operational capacity visible to National Grid by the end of winter 2008/09. Our experience of wind generation is that its output is highly variable and difficult to forecast.

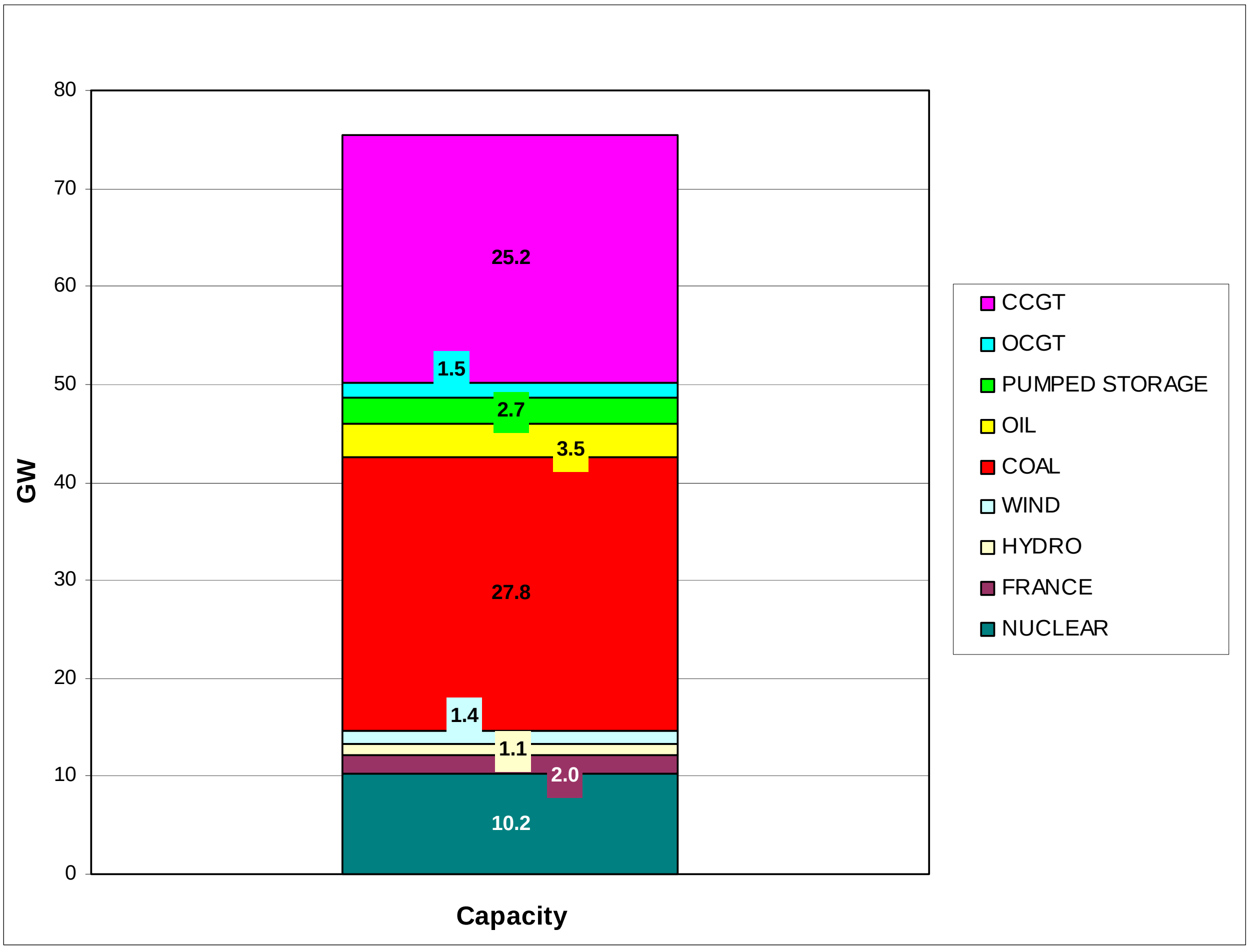
198. Therefore, the latest view of TEC-contracted generation capacity available for the start of winter 2008 (1st October 2008) is 76.7GW.

199. 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, generators provide us with more detailed information about their expected availability. We use this to derive an operational view of generation availability, which can differ from the SYS view for a variety of reasons including planned outages and operational restrictions on output.

200. Based on the observed output of power stations which may differ from the contracted TEC position, our current operational view of generation capacity anticipated to be available for the start of winter 2008 is 75.4GW. A breakdown of this capacity is shown in Figure B.14. In addition during the winter, we expect around 150MW of wind generation capacity will progressively become available, that Oldbury (0.4GW) nuclear power station will close on 31st December 2008 and that Langage (0.9GW) will be commissioned in January 2009. Therefore our end of winter 2008/09 operational view of generation is 76.1GW.

201. In developing our operational view of available generation capacity, we have recently undertaken a detailed review of historic power station output which has modified our view of the contributions from some fuel types relative to the view contained in the Summer Outlook report and last Winter's Outlook report. The main changes as a result of the review have been 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 0.3 GW 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, of course, is reflected in an equal and opposite change in our operational view of the output of CCGT generation.

Figure B.14 – Generation Capacity Operational View, Winter 2008/09



Generation Availability Assumptions 2008/09

202. We have reviewed our forward looking availability assumptions based on recent experience and, whilst they have proved generally robust, we plan to review the assumed availability of wind generation for winter 2008/09 over the summer. As part of our consultation we particularly invite views on the level of wind generation assumed availability to apply in this report applicable at the demand peak. 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.

203. 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% represent a prudent assumption to allow for risk that there is a water scarcity issue at the times of peak electricity demand. Unlike wind, hydro generation capacity is not forecast to increase significantly in capacity.

Table B.7 – Generation Availability Assumptions Made For Winter 2008/09

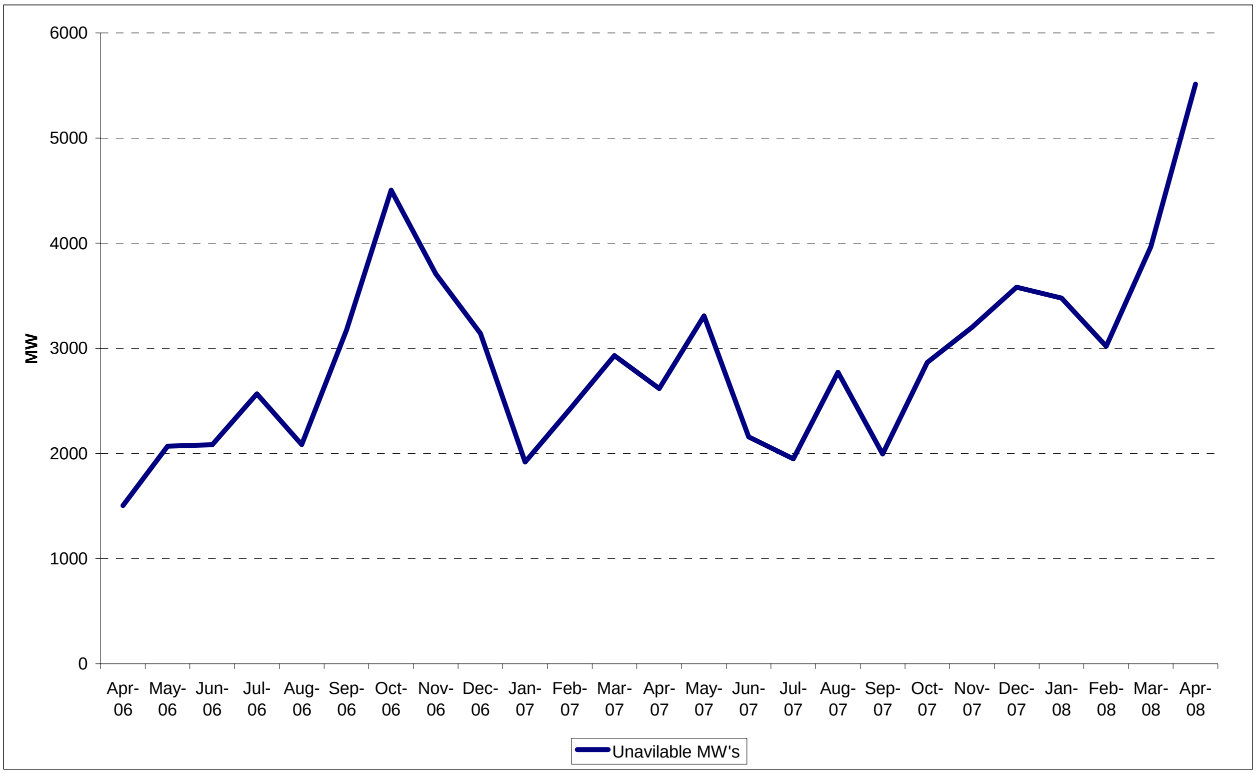
Power Station Type	Full Metered Capacity (GW)	Assumed Availability	Assumed Availability (GW)
Nuclear	10.2	80%	8.2
French Interconnector	2.0	100%	2.0
Hydro generation	1.1	60%	0.6
Wind generation	1.4	35%	0.5
Coal	27.8	85%	23.7
Oil	3.5	95%	3.3
Pumped storage	2.7	95%	2.6
OCGT	1.5	95%	1.4
CCGT	25.2	90%	22.7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

Nuclear Availability Assumptions

204. 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. This is explored in the following sections and the situation will be updated in our final Winter Outlook report.

205. We have analysed historic availability of nuclear power stations for the last three winters and present the results in the figure below. Unavailability has tended to be "lumpy" with a single issue impacting several units of a particular design simultaneously. A review of historic unavailability indicates that 80% availability is high relative to recently observed trends. However 80% availability is broadly consistent with actual availability levels achieved in winter 2005/06.

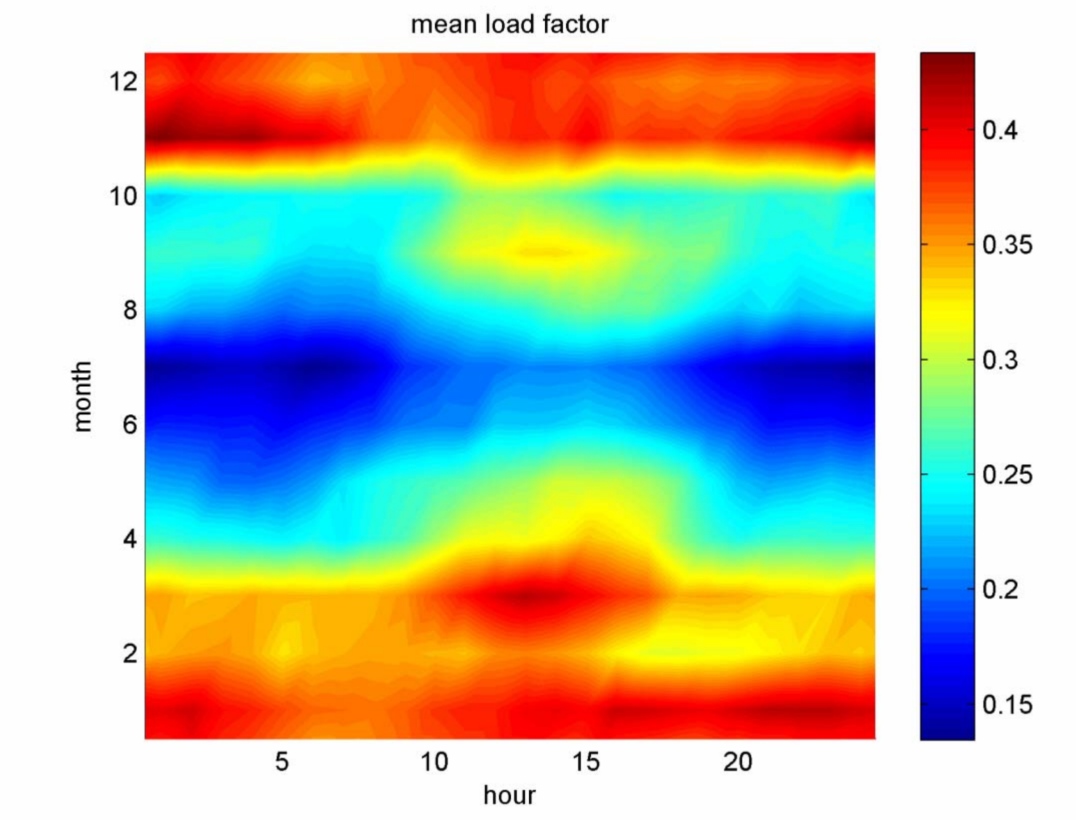
Figure B.15 – Historic Nuclear Generation Unavailability



Wind Availability Assumptions

206. 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. We have updated the analysis provided in our recent summer outlook report to base it upon a larger data set. Our overall conclusions have not changed as a result of our review and continue to point towards a mean load factor of 35% over the December and January evening periods when a peak demand is most likely. We have looked at the actual output of wind generation during the likely periods of a peak demand and found that historic load factors vary from zero to around 90% of installed capacity. Figure B.16 shows the mean load factor by time of day and month for the current wind generation that we operationally meter.

Figure B.16 - Wind – Daily and Monthly Mean Load Factors

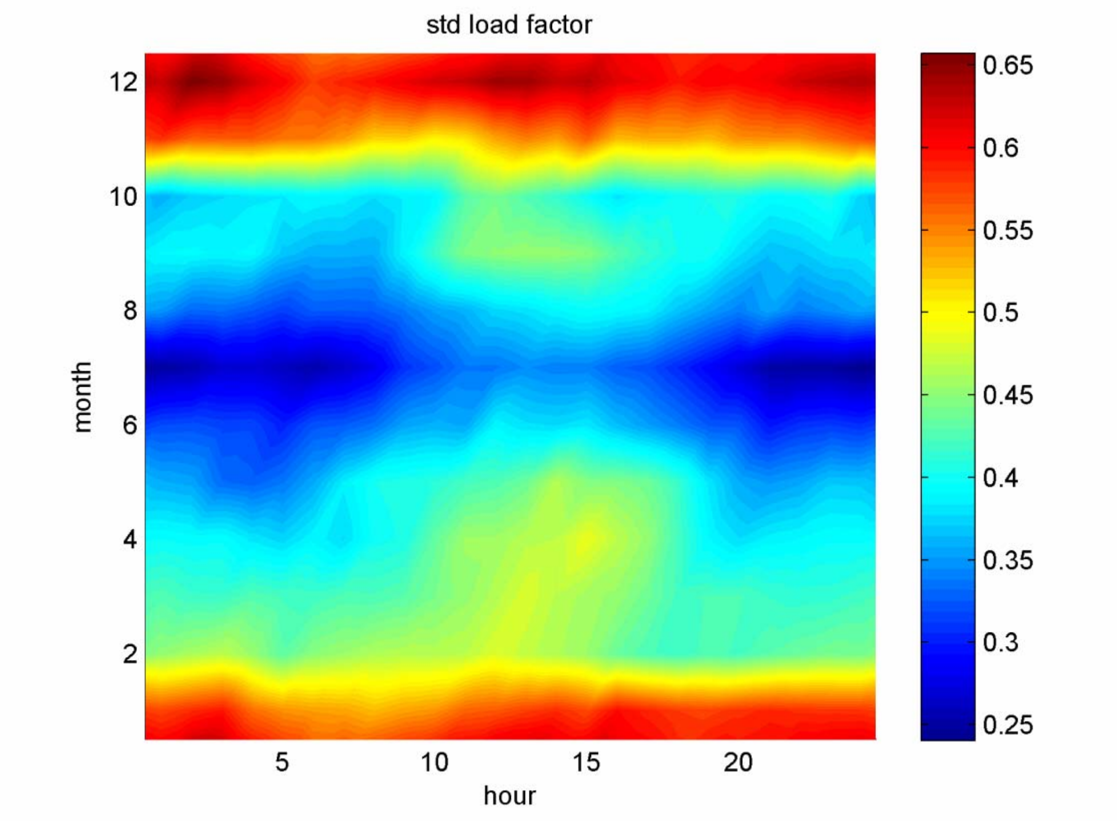


207. Our experience of the contribution of wind generation around the 2007/08 demand peak at 8% illustrates the issue of the intermittency of wind. We cannot depend with a high degree of confidence on a mean output contribution from wind generation at the time of demand peak. Particularly we have seen 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.

208. Figure B.17 below shows the standard deviation of wind output, from which it can be seen that the standard deviation of wind output increases to high 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.

209. Wind generation output is not normally distributed so the application of standard deviation of load factors can only 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 B.17 - Wind – Standard Deviation of Load Factors



210. 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 security of supply even in our 1 in 20 demand levels scenario. Demand can still be met by other sources of generation and/or imports through interconnectors in the event of no wind generation output at the time of peak demand.

211. We intend to undertake further analysis to inform the assumption we make for wind generation's contribution towards the peak demand over the course of the summer. We welcome input from stakeholders regarding this issue.

Mothballed Generation Capacity

212. 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 B.8 – 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

213. In order to achieve a demand-supply balance, National Grid procures services from either generation or 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.

214. 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.

215. For winter 2008/9, the current total level of contracted STOR reserve is almost 2.0 GW, over 1.6 GW from BM participants and 0.3 GW from non-BM generating plant and demand reduction.

216. Prior to the winter, there will be two further STOR tender rounds in June and August 2008 covering services for the winter 2008/9 darkness peak. Communications regarding this will be through electricity operational fora and on our website.

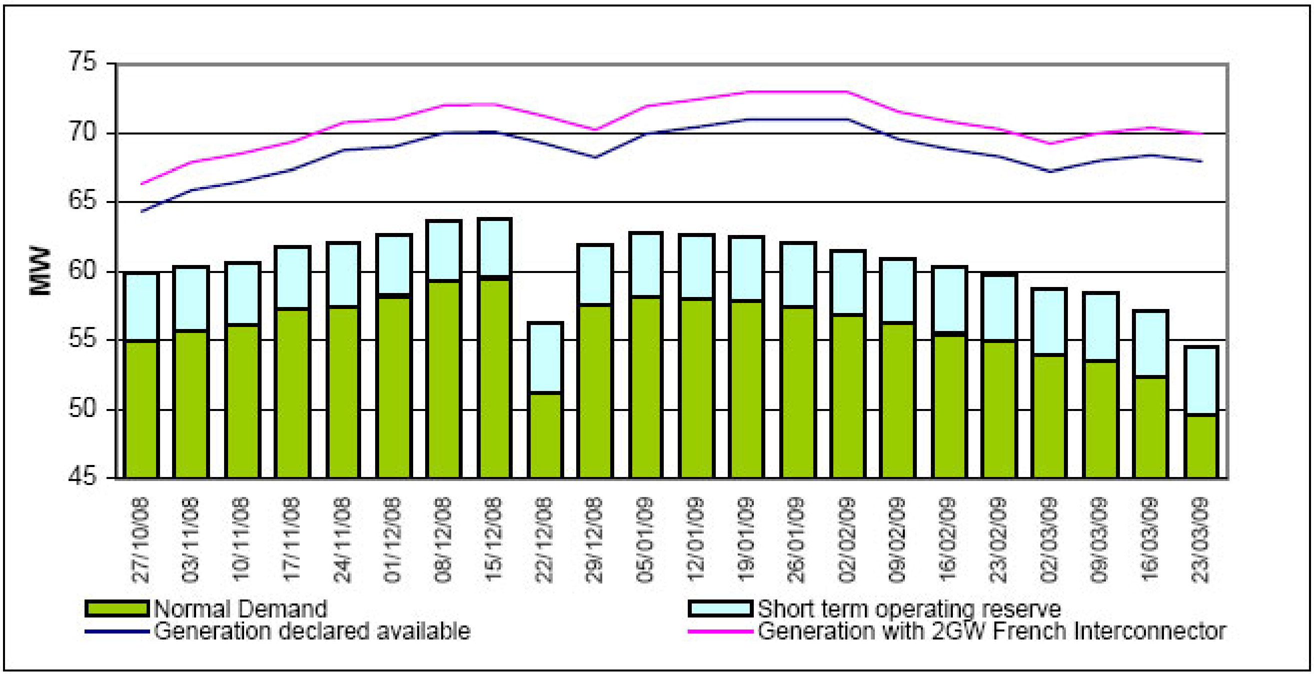
217. In addition to STOR, there is a continual requirement to provide frequency response on the system. This can be either contracted ahead of time or created on synchronised sources within the BM. If all response holding was created in the BM, then approximately 1.4GW of reserve would be required to meet the necessary response requirement. 0.9GW of this 1.4GW reserve requirement has already been contracted, with 0.6GW from demand-side providers.

218. 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

219. Figure B.18 reflects a winter where weather and demand are at normal[19] 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 B.18 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.

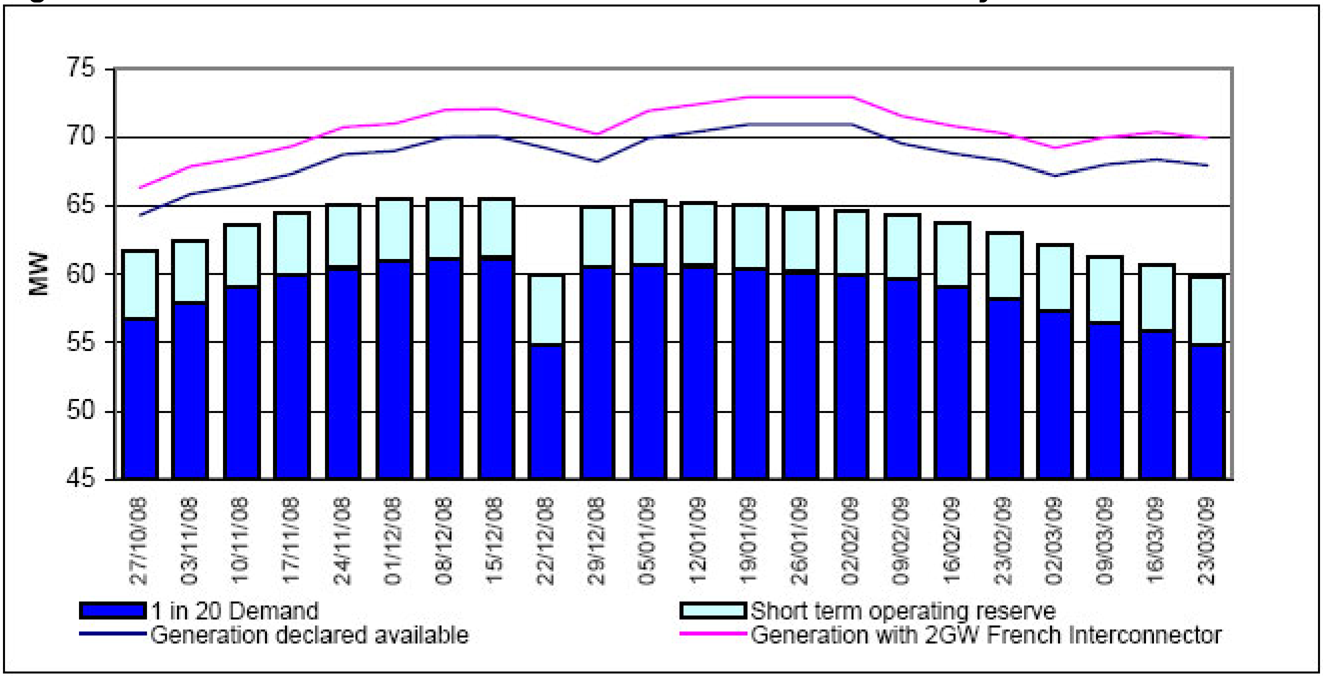
Figure B.18 - Normal Demand and Notified Generation Availability



220. Figure B.19 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.

[19] 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.

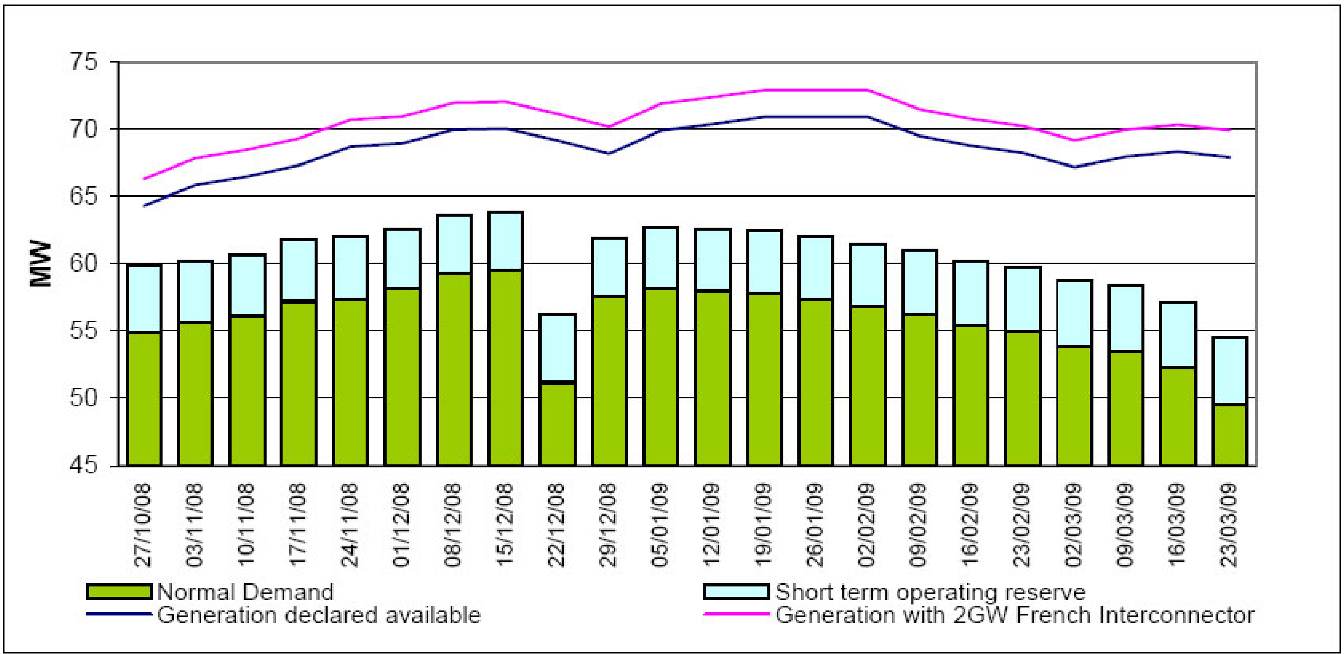
Figure B.19 - 1 in 20 Demand and Notified Generation Availability



221. Figure B.18 and Figure B.19 use generation availability as declared 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 outlined our assumptions earlier in this report for the levels of actual generation availability we expect at the time of demand peak.

222. Figure B.20 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 adequately.

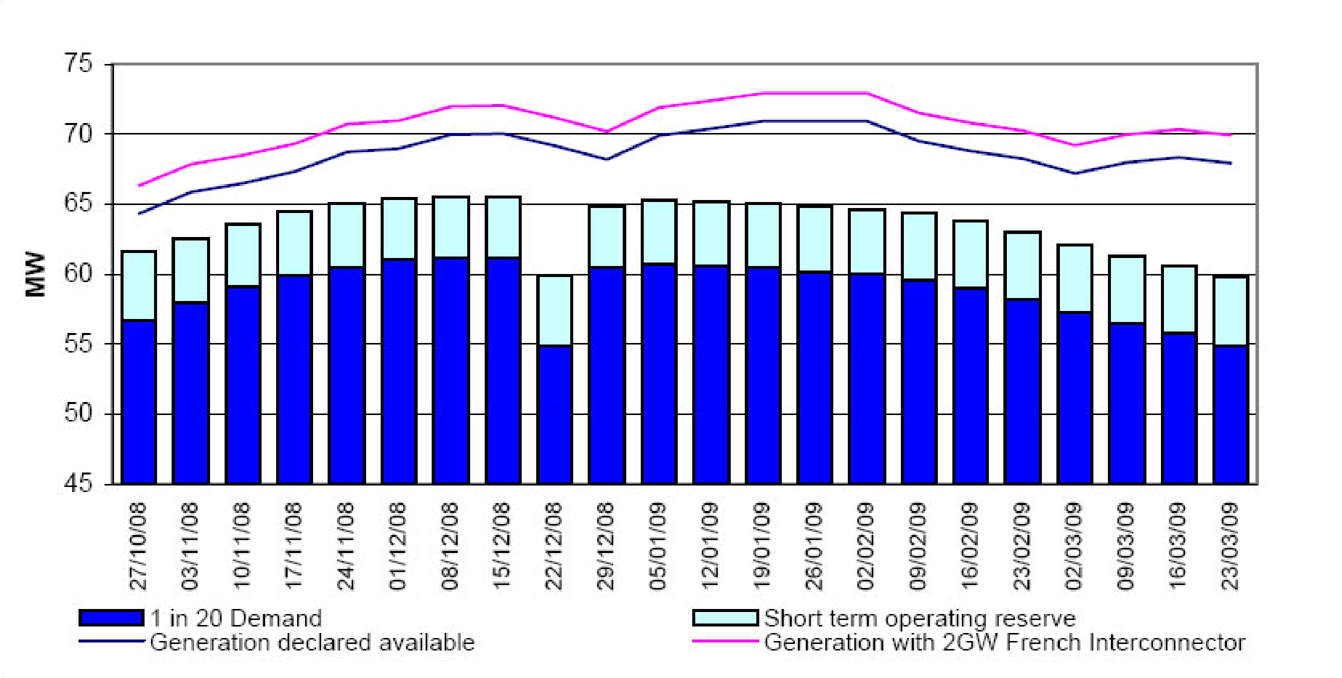
Figure B.20 Normal Demand and Assumed Generation Availability



223. Figure B.21 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. This figure shows that 1 in 20 demand levels can be met, but we would expect that our short term operating reserve requirement would very marginally be encroached upon if a 1 in 20 demand level occurred in any of nine weeks over the winter. 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 this is not a condition of meeting demand.

224. Where the 1 in 20 demand plus our short term operating reserve exceeds our 86% of generation including 2GW of French Interconnector, 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 extreme scenarios of short term plant loss and demand forecast error.

Figure B.21 - 1 in 20 and Assumed Generation Availability



Generation Merit Order for Winter 2008/09

225. 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.

226. Forward prices for fuel and carbon continue to be volatile, though coal has the economic advantage at present and is likely to the baseload fuel for the coming winter. We will update our analysis of fuel and carbon prices during the summer and include our findings in the final report to be published at the end of September.

Questions for Consultation

We would welcome comments on all aspects of this section, and in particular on the following:

QB17. The level and direction of flow of the electricity interconnector that might be expected given cold weather in both UK and Europe;

QB18. The appropriate capacity credit to apply to wind generation towards meeting a demand peak;

QB19. The level of availability to assume for nuclear generation for 2008/09;

QB20. The accuracy of our generation availability assumptions for all fuel types;

QB21. Our forecast of peak electricity demand, which we forecast to reduce, and the validity of the drivers we identify behind this demand reduction;

QB22. At times of demand peak is it realistic to assume that 300MW of transfer takes place to Northern Ireland?

QB23. How will generating plant that has 'opted-out' of the LCPD behave in the coming winter given their limited operating hours?

QB24. Has the introduction of the LCPD, and particularly the incentive for all generation units related to a relevant power station stack to be operating together, affected market participants ability to balance their demand and generation portfolios at times of high electricity demands?

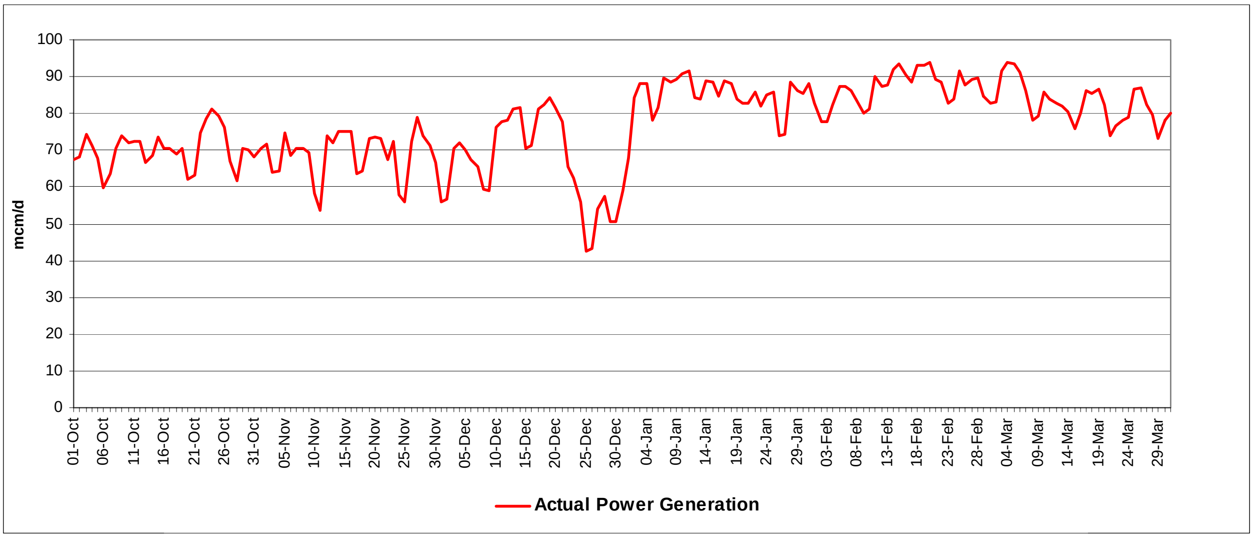
QB25. Are there any key drivers of generation availability that are changing for winter 2008/09?

Section C
Gas/Electricity Interaction

Power Generation Gas Demand – GB

227. Daily consumption from CCGTs had been fairly steady in the last three months of 2007 at around 75 mcm/d on peak demand days. From January 2008, the implementation of LCPD, carbon price changes and relative fuel costs had a large effect on the generation running regime as referred to elsewhere in this report. We saw an obvious switch to gas generation and as a result the jump in gas consumption by the power sector to over 90 mcm/d.

Figure C.1 – Gas Consumption for Power Generation



228. The maximum contractual power generation gas demand in GB for winter 2008/09 is shown in Table 10. These figures exclude smaller embedded power generators, typically Combined Heat and Power stations, which do not participate in the Balancing Mechanism.

Table C.1 – Maximum 2008/09 GB Power Generation Gas Demand

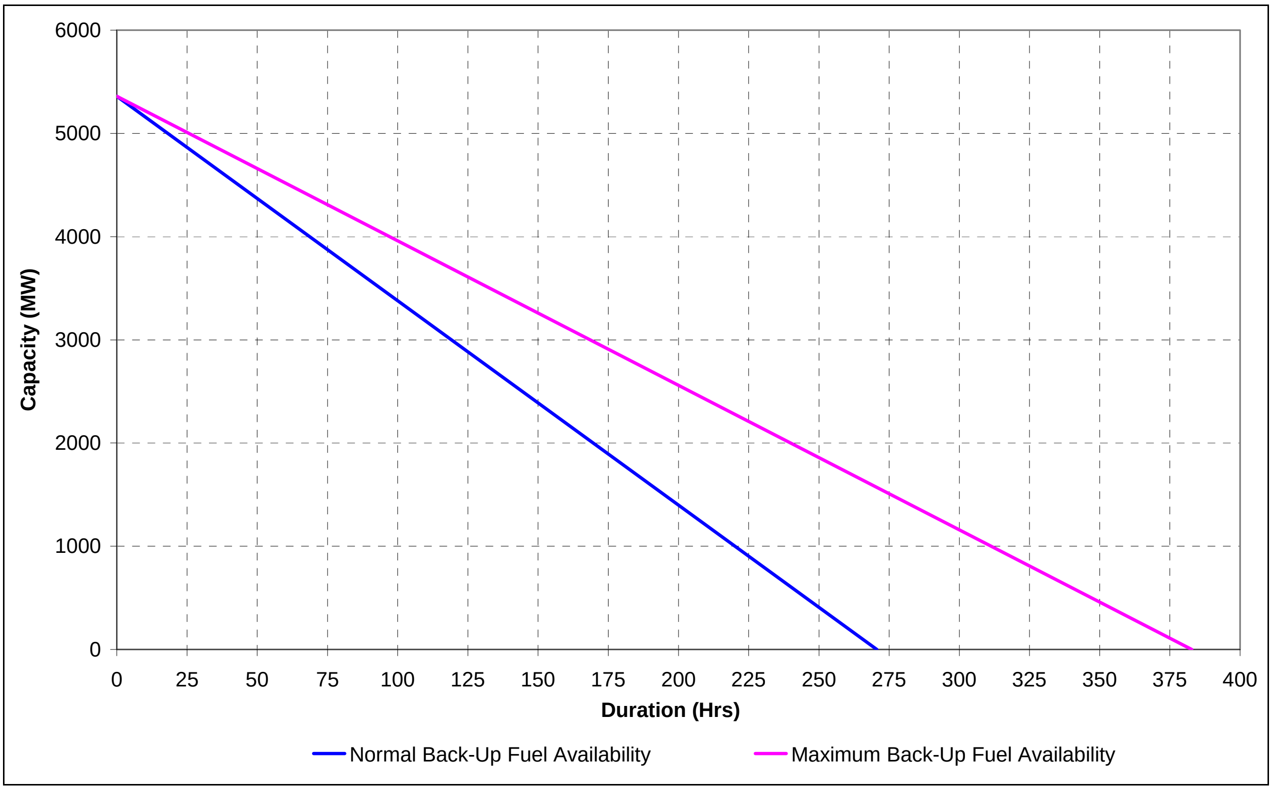
	Total mcm/d	Number of CCGTs	GW Capacity CCGT
NTS Connected	137.6	32	24.1
LDZ Connected	3.9	5	1.1
Total	**141.5**	**37**	**25.2**

Power Stations with Alternative Fuels

229. 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 5.4 GW having back-up fuel generation capability, more than of half of which have interruptible gas transportation arrangements.

230. Figure C.2 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 for.

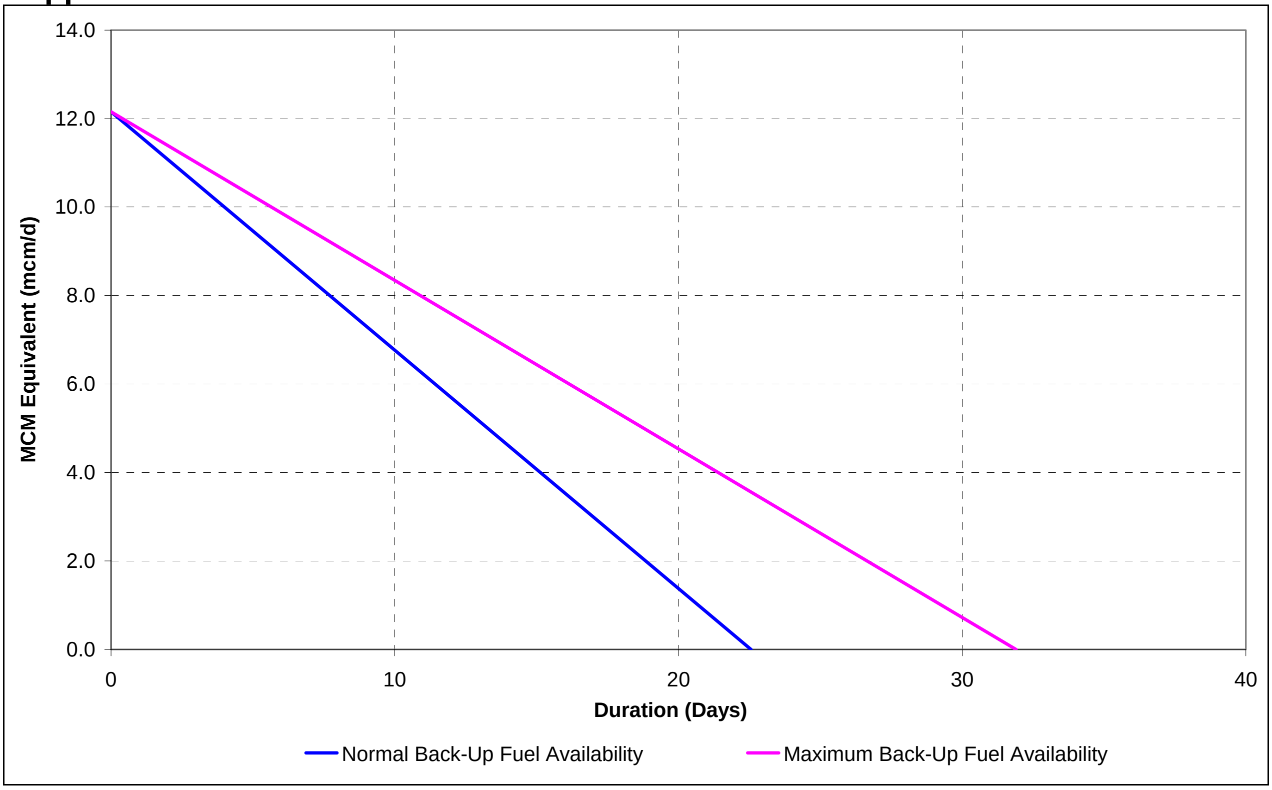
Figure C.2 – Power Load Duration Curves for Back Up Fuel Supplies



231. 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.

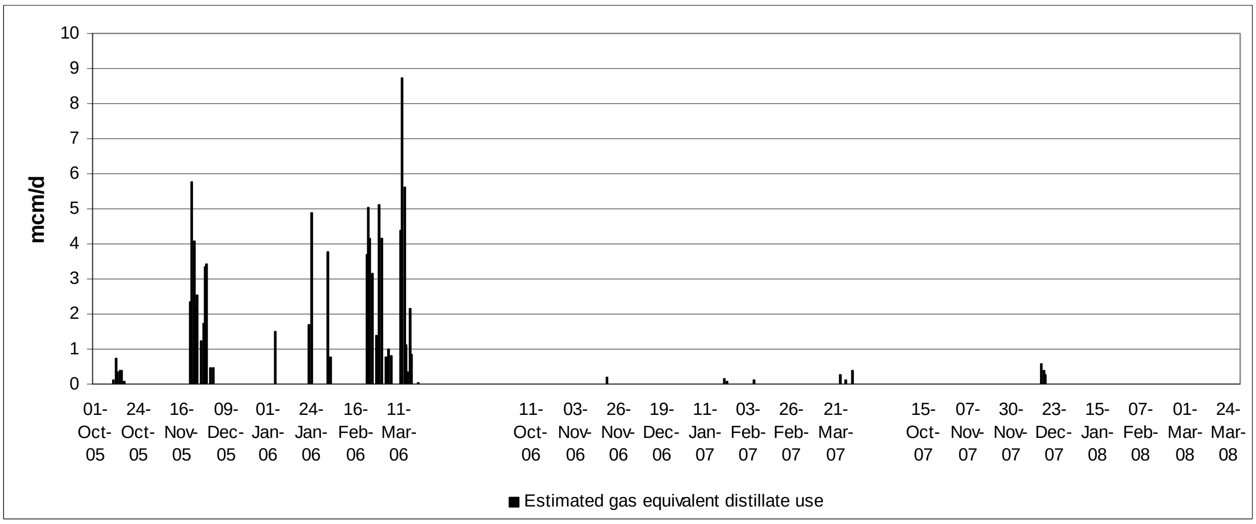
232. We have modeled the amount of relief that gas power stations switching to distillate could provide to the gas market. Using the assumption that distillate capable gas power stations ran for 12 hours per day gives at least 10 mcm/d of gas relief for upto 4 days based on normal and full distillate 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 C.3 – Gas Volume Equivalent Load Duration Curves for Back Up Fuel Supplies



233. 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 C.4 – Estimated Historic Distillate Use in Term of mcm/d Relief to Gas Demand



Potential for Demand-Side Response from Gas Fired Generation

234. 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.

Analysis of potential CCGT gas demand response

235. A number of respondents have previously identified practical issues that could limit the extent of any CCGT response. We welcome feedback through our consultation on these and related issues associated with gas power stations providing relief to the gas sector. Issues raised included:

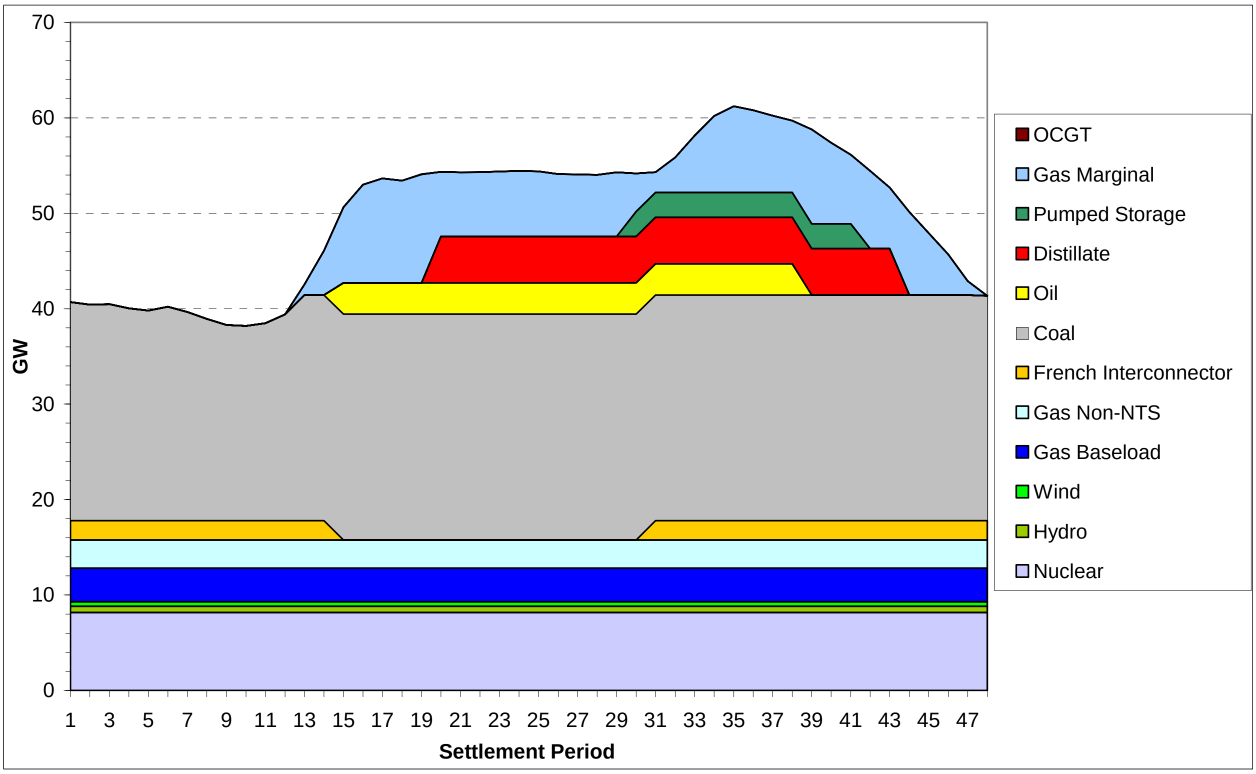
- Technical risks associated with frequent switching to/from and prolonged use of distillate;
- Limitations on the levels of switching to coal and oil as a result of environmental constraints and LCPD considerations;
- Ability to replenish stock may be difficult, especially in prolonged severe weather conditions and if stocks are delivered by road tankers;

Table C.2 – Assumed plant availability factors for demand-side response analysis

Power Station Type	Full Metered Capacity (GW)	Assumed Availability	Assumed Availability (GW)	Model Assumptions Summary
Nuclear	10.2	80%	8.2	Baseload
French Interconnector	2.0	100%	2.0	Baseload, except 8 am to 3pm weekdays
Hydro	1.1	60%	0.6	Baseload
Wind	1.4	35%	0.5	Baseload
Gas Baseload	3.9	90%	3.5	Baseload
Gas Non-NTS	3.3	90%	3.0	Baseload
Coal	27.8	85%	23.7	Baseload
Oil	3.5	95%	3.3	12 hours over peak
Pumped Storage	2.7	95%	2.6	6 hours over peak
Distillate	5.4	90%	4.9	180 hours
Gas Marginal	12.6	90%	11.3	Marginal plant
OCGT	1.4	95%	1.4	Low merit, run occasionally
Total	**75.4**		**64.9**	
Average availability		**86%**		

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



237. 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.

238. 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.

239. 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.

240. 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.

Questions for Consultation

We would welcome comments on all aspects of this section, and in particular on the following:

QC1. Our assumptions relating to the generation running order under very cold weather conditions;

QC2. The extent to which the electricity market prices will be able to achieve levels compared to gas prices such that they will determine that CCGTs will continue to burn gas at peak electricity demand periods;

QC3. The ability and willingness of CCGT generators to switch to distillate

QC4. Whether and for how long CCGTs will generate continuously on distillate back-up and any restrictions to the replenishment of distillate stocks;

QC5. The ability and willingness of generators to replace gas-fired generation by coal and oil fired generation;

QC6. The extent to which increased levels of fossil fuel generation could be used to displace gas-fired generation throughout a cold winter, including considerations of reliability, environmental constraints and fuel stocks;

QC7. Will the French interconnector operate as normal – i.e. transferring power to the market with greatest scarcity and highest price under very high demand days. Are there any particular issues associated with simultaneous power scarcity in both markets?

Section D
Industry Framework Developments

Introduction

241. 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

242. 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. For winter 07/08, National Grid implemented an interim trade and transfer mechanism. Based on the experience gained from the interim process, an enduring trade and transfer mechanism (UNC Modification 187A) and an associated methodology statement to calculate exchange rates were developed and subsequently approved by Ofgem.

243. The main changes introduced through the enduring mechanism are:

- The process is undertaken on a monthly basis, as part of the RMSEC 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 RMSEC
- Exchange rates are calculated once the bids for trades and transfers are known
- There is an exchange rate limit of 10:1

Potential Additional Capacity Release Mechanism

244. National Grid have raised UNC Modification 216 to enable the release of additional entry capacity for this winter outside of the normal auction processes. If this modification is approved this may result in the release of additional non obligated capacity at specific entry points, for example Easington.

Baseline Capacity Substitutions

245. National Grid is developing arrangements by which it may substitute unsold baseline capacity between entry points to avoid or minimise NTS investments required to meet incremental signals provided through long term entry auctions. This means that if baseline amounts are not purchased in the long term auctions, they may be used to meet requirements elsewhere and hence might not be available in subsequent annual and daily auctions. Users need to consider such

changes in developing their bidding strategies for future auctions. However it should be noted that this Obligation does not come into force until 6 April 2009.

Gas Market Information Provision

246. National Grid recognises the important role that timely and accurate information plays in the facilitation of the gas market. The Market Information Provision Initiative was rolled out in 2007 to improve the way in which we published data on the internet. The new system makes market information available for the first time as pure data as well as in report format via National Grid’s website. It also allows automatic downloads of key data as requested by users. This ongoing development enables users to download and manipulate data to meet their individual modelling and analysis requirements.

247. Ofgem directed the implementation of UNC Modification Proposal 104 “Storage Information at LNG Importation Facilities”, which requires National Grid Transmission to publish aggregate physical LNG stocks across all LNG importation facilities held at the end of the gas day. This facility was made available to the industry through National Grid’s website from 01 October 2007. Subsequently National Grid Transmission raised a Proposal to clarify that where only partial information is received from LNG importation facilities, potential misleading or incomplete information would not be published.

Amendment of IUK’s Network Entry Provisions

248. As part of an importation capacity expansion of the Bacton Interconnector that took place in 2007, an upgrade of Interconnector UK Ltd’s (IUK) fiscal metering system at Bacton was required. This upgrade, which was implemented in September 2007, required that some technical parameters of IUK’s Network Entry Provisions (NEPs) were amended to ensure that the physical and commercial boundaries remained aligned. This in turn enhanced the security of supply of the total system through facilitating increased flows from the Bacton terminal.

Electricity Market Information

249. Following extensive industry consultation, National Grid has progressed two modifications to the Balancing & Settlement Code (BSC) 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.

250. 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.

251. 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.

252. 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.

Incentives to balance

253. 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

Black Start – Market Suspension/Recovery

254. In the latter part of 2007 National Grid took part in a Government led Black Start Simulation. One conclusion of this exercise was the need for both National Grid and the market to map out and increase awareness of the process required to facilitate the subsequent recovery of the electricity market. To this end we have instigated a BSC issue group (Issue 32) and our expectation is that the conclusions drawn in this group will lead to subsequent BSC modification proposals. However it not clear whether any consequential modifications will be implemented during winter 08/09

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

255. CUSC Amendment Proposal (CAP)144 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 is minded to direct that this proposal be made. If approved, the amendment is expected to be implemented prior to winter 2008/09.

256. 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. CAP148 has a long lead time and, if approved, it would be at least three years before holders of DTEC connected to the system.

257. 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

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

259. The review will include medium and longer term developments for which primary or secondary legislation may be required. This will involve the definition and allocation of TEC, the way the transmission system is planned and operated, the way energy and system balancing is achieved and the governance arrangements. The review team provided GEMA and the Secretary of State with an interim report during January 2007 and a final report is expected during May 2008.

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

261. 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 led to the development of a suite of CUSC modifications presented at the April 2008 CUSC Panel, CAP1661 to CAP166. It should be noted that we do not anticipate any of the proposed CUSC amendments being implemented for winter 2008/09.

Grid Code

262. As part of the work to clarify Black Start arrangements within the codes, we have developed, with the industry, a Grid Code amendment which will clarify the OC9 (Contingency Planning) provisions which would be utilised in the event of a Total and Partial Shutdown of the GB Transmission System. The provisions cover National Grid's and Users' obligations at each of the recovery stages from a Total or

Partial Shutdown e.g. LJRP, Zonal Restoration, System Operational and Market Reconvened. It is anticipated that a decision will be made on the proposals and, if approved, implemented before winter 08/09.

System Operator to System Operator Service Changes

263. We are currently making some improvements to the way we operate our system operator to system operator (SO-SO) services between National Grid and RTE, the French transmission system operator. This work is part of the Balancing Workstream of the ERGEG[20] Electricity Regional Initiative. The SO-SO service allows us to trade with RTE for operational reasons and for reciprocal arrangements for RTE. The improvements expected to go live will provide for prices for SO-SO services to move from being a single price per day set day ahead to prices for each of six time blocks which can be revised intraday. This change is expected to go-live before Winter 2008/09 and may affect how each system operator uses the SO-SO service. We believe this improvement will increase efficiency in the European electricity market leading to more cost reflective pricing of services related to the time of day and evolving demand/supply balance issues in each market.

[20] ERGEG (http://www.energy-regulators.eu/portal/page/portal/EER_HOME) is an advisory group of national regulators established by the European Commission in 2003.