nationalgrid

Winter Consultation Report 2010/11

A review of winter 2009/10 & preliminary outlook for winter 2010/11

Introduction

1. This document, the consultation report, sets out our preliminary analysis and views for the coming winter and presents a number of questions to 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 4th October 2010. This report and the final report will be published on our website at http://www.nationalgrid.com/uk/Electricity/SYS/outlook/.

2. The report also covers a review of last winters experience and we share a review of our assumptions for last winter in the light of the actual winter events. This review is an important part of planning for next winter through learning from our recent experience. The consultation aspect of this report gives other stakeholders a route to share their insights and perspectives.

Industry Feedback

3. As this is a consultation report we are also seeking industry feedback. The deadline for responses to this consultation report is **4pm**, **23rd August 2010**.

4. Responses should be e-mailed to energy.operations@uk.ngrid.com. It helps us to consider your responses to this report if you address specific questions we raise where appropriate as well as provide more general feedback on your views of the winter to come. Where requested, we will treat information provided to us on a confidential basis. Alternatively, respondents may send confidential information to Ofgem if they would prefer by e-mail to GB.markets@ofgem.gov.uk.

5. Unless specifically asked not to by respondents, we will share all feedback received with Ofgem. Respondents can 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.

Roles and Responsibilities

6. The competitive gas and electricity markets in Great Britain have developed substantially in recent years and have successfully established separate roles and responsibilities for the various market participants. In summary, the provision of gas to meet consumer demands is the responsibility of shippers. Shippers are

required to book National Transmission System (NTS) entry capacity to be able to flow gas into the NTS. At present exit capacity is booked by Shippers. Any exit capacity booked from the 01st October 2012 will be booked by Shippers for their NTS sites and Gas Distribution Network Operators. Both exit capacity processes (i.e current and future) enable gas to be offtaken from the NTS. For electricity network capacity requirements, those for demand are derived from Distribution Network Operator submissions to National Grid under Grid Code. For generation entry capacity, generators contract with National Grid to secure Transmission Entry Capacity. National Grid has two main responsibilities: first, as the primary transporter, for ensuring reliable network capacity is provided in line with transmission licence requirements; second, as system operator of the transmission networks, for the residual balancing activity in both gas and electricity. The structure of the markets and the monitoring of companies' conduct within it are the responsibility of Ofgem, whilst the Department for Energy and Climate Change (DECC) has a role in setting the regulatory framework for the market..

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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 2009/10 – Gas

10. The 2009/10 winter started and ended with very warm weather, sandwiching a very cold spell from mid-December to mid March. The net result was an average winter for the 6 month period from October to March. The weather severity for the 3 month period from December to February was 1 in 5 cold, indeed the coldest in terms of average temperatures since 1978/79. The 2009/10 coldest day based on temperature was on 7th January, with a national average temperature of -3.3°C (CWV of -1.7).
11. Total weather corrected demand in winter 2009/10 was 6% higher than in winter 2008/09. This was not a return to pre-recession demands but primarily due to an increase in gas demand for power generation. A record demand of 465 mcm/d was set on 8th January.
12. Gas supplies were broadly in line with our pre-winter forecasts. For the first time winter imports exceeded UKCS supplies. Compared to 2008/09, UKCS supplies were 16% lower and made up 44% of demand.
13. Compared to 2008/09 imports from Norway were 2.5 bcm lower and from the Continent (BBL and IUK) 1.5 bcm higher. The big increase in imports came through LNG with regular cargoes from Grain and for the first time during a winter, through both terminals at Milford Haven. Total LNG imports increased from 1.6 bcm in 2008/09 to 8.9 bcm, this represented 14% of all supplies.
14. Total storage use across the winter was a record 4.7 bcm, this included appreciable storage cycling at some of the more flexible facilities.
15. During the high demand days in early January, National Grid declared four Gas Balancing Alerts (GBA) on account of within day supply losses. A GBA is a mechanism to provide additional gas through more supplies or alternatively through a demand response. On all four occasions the market responded to supply gas from additional sources, notably the Interconnector(IUK) and from storage.

Winter Review 2009/10 – Electricity

16. Peak demand in 2009/10 and periods of high demand through the winter were comfortably met with available generation. This is illustrated by the very low levels of running of oil fired generation through winter, which traditionally runs at times of relative power scarcity. No system warnings were issued during the winter.
17. In terms of generation availability we saw a small contribution from wind generation at the time of the demand peak, underlining the need to discount the technical availability of intermittent generation types. We also experienced a lower than expected contribution from nuclear generation coincident with the time of the peak demand. For both of these fuel types we go on in the report to reduce our expectation of their contribution to meeting demand compared to last years report,

but we also increase the contribution of other generation types based on better than expected performance.

18. When supply issues occurred for gas around the periods where GBA's were issued we saw the generation mix change in response, with increases in coal fired generation tending to meet the higher demands in the cold snap. Essentially we saw market mechanisms that hadn't been tested in potential gas supply issues work well in terms of the impact we saw on electricity generation.

19. The highest electricity demand over the winter reached 59.1GW for the half-hour ending 17:30 on 7th January 2010. This compares to the highest demand of 60.6GW and 59.1GW over winter 2007/08 and 2008/09 respectively.

Winter 2010/11 Outlook – Gas

20. Fuel price futures show an increase in the oil and coal price with gas also increasing albeit retaining a seasonal profile. The current mid winter price of gas suggests coal may be the winter base load plant with gas fired generation as the marginal plant. However, as we have observed changes in the fuel prices for the past two winters which has lead to gas being used for base load generation, our current forecast assumes this will happen again and gas, rather than coal, is forecast to be base load. UK and Continental gas prices are very close and are now appreciably higher than those in the US providing an incentive to deliver spot LNG cargoes to Europe in preference to the US. For Asia LNG demand has started to recover, but not to the detriment of expected UK LNG deliveries.

21. Forecast demands for next winter are very similar to the weather corrected actual demands in 2009/10. The key sensitivity here is the use of gas for power generation.

22. Due to declining reserves, our forecast for UKCS supplies for next winter is approximately 9% lower with UKCS expected to make up typically 45% of non storage supplies.

23. From Norway we anticipate marginally higher UK imports as Norway's offshore production continues to increase notably through the development of Gjøa field which will flow to St Fergus. We again acknowledge the potential for contractual deliveries to the Continent rather than the UK. For BBL we expect similar performance to last winter, for IUK we again expect flows to respond to market needs.

24. The biggest supply uncertainty for next winter is LNG where capacity is further increased through the recent commissioning of South Hook Phase II and the expectation of commissioning of Grain Phase III within winter. When completed, LNG import capacity for next winter could exceed 140 mcm/d. For consultation purposes we have assumed a provisional range of 30-100 mcm/d with average flows of 60 mcm/d. As with last winter there are reasons to be more optimistic about LNG deliveries to the UK due to a combination of: increased LNG production, limited recovery of global demand and relatively high European gas prices.

25. Our preliminary view of non storage gas supplies for next winter is between 342-412 mcm/d, with a base case view of 367 mcm/d. This is comparable to last winter's actual level of non storage supply, with further upside potential from LNG and possibly IUK imports.

26. Our preliminary assessment of storage requirements for the Safety Monitors for next winter is 2.3% of total storage space. This is comparable to last winter's assessment.

Winter 2010/11 Outlook – Electricity

27. For next winter, based on the information available at this stage, the surplus generation above expected electricity demand is comfortable with a similar generation surplus as we saw at this point for last winter. A combination of softer demands compared to before the recession and stable generation capability are underlying the current outlook. Several new CCGT power stations have completed commissioning and further CCGT stations are anticipated to start or have begun commissioning between now and winter. Those CCGT's currently commissioning remain as an upside in our analysis should they prove available in time to contribute to meeting winter demands. In addition we expect to see increases in wind power generation capability taking place.

28. Our expectation of operational generation capability is 77.1GW at the start of winter, which we calculate delivers a 66.2 GW expected availability allowing for generation performance issues.

29. The Average Cold Spell (ACS) peak demand for winter to come of 57.6 GW is not materially different to last years outturn peak demand adjusted for ACS conditions.

30. Using installed generation capacity relative to ACS peak demand yields a plant margin of 34%. The more representative estimate of actual likely generation availability at the winter peak of 66.2 GW yields an operational capacity headroom at the winter demand peak of 15%.

31. Setting the ACS demand forecast along side the generation availability figures currently show comfortable surpluses of electricity generation over demand for the winter to come. In this report we show that it should be possible to adequately meet even our 1 in 20 probability demands plus our short term operating reserve requirements.

32. We reforecast electricity demand on a regular basis and expect to update our demand expectations over the summer for the winter to come. These updates will be reflected in the final winter outlook report. We also regularly receive generation availability information from operators and this report takes a snap shot in time based on the information we have at this point. Key information such as generation surpluses and demand forecasts are reviewed and updated for changes on a weekly basis and published on www.bmreports.com. Readers of this consultation report may also find it useful to obtain updates of key metrics on a regular basis from bmreports. We are working with Elexon to deliver greater transparency of

generation availability through the implementation of BSC modification P243[1] which will go live in November 2010. This modification will make generator outage plans more transparent in year ahead to 2 day ahead timescales.

33. There remains some uncertainty about how economic factors will drive demand going forward. We have seen underlying electricity demand levels returning to similar levels as those of the previous year (May 2010 levels compared with May 2009) and have reflected this observation in our forecasts going forward. We will update our forecasts specifically in the final report to reflect the latest demand levels and trends at that time.

Contents

[1] See the Elexon website for more information on P243.
http://www.elexon.co.uk/changeimplementation/findachange/modproposal_details.aspx?propid=268

Section A

Experience of 2009/10

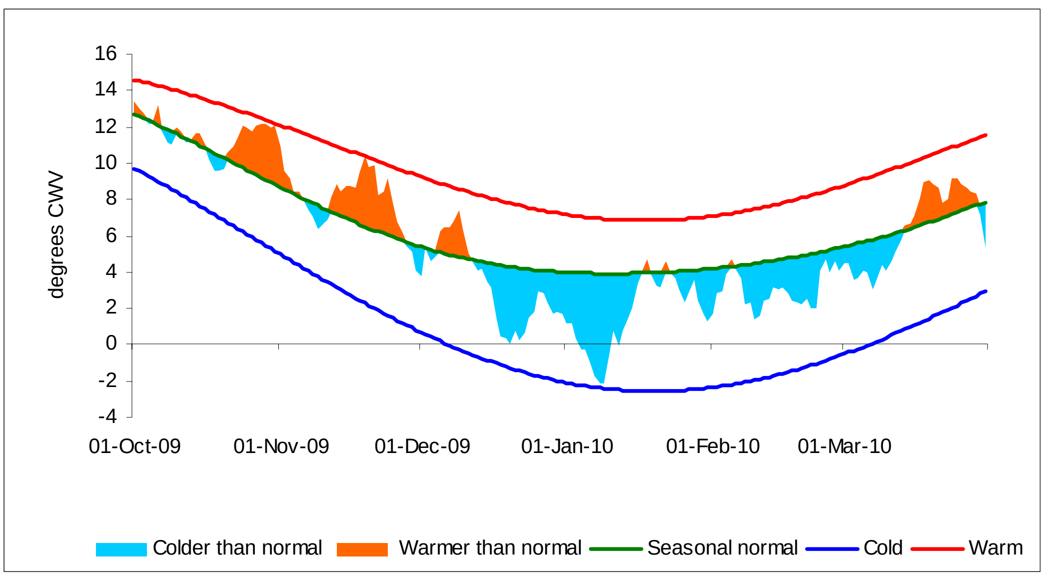
Weather

34. The 2009/10 winter started and ended with very warm weather, sandwiching a very cold spell from mid-December to mid March. The net result was an average winter for the 6 month period from October to March[2]. The weather severity for the 3 month period from December to February was 1 in 5 cold, indeed the coldest in terms of average temperatures since 1978/79.

35. The 2009/10 coldest day was 1 in 3 cold. The coldest day based on composite weather (CWV) was January 9th with a national average CWV of -2.1° (average temperature of -1.1°C). The coldest day based on average temperature was January 7th with an average temperature of -3.3 °C (-1.7° CWV)[3].

36. Figure A.1 illustrates the 2009/10 winter compared with 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 correlating them to produce a weather variable that is linearly related to non-daily metered gas demand.

Figure A.1 – 2009/10 Winter Weather (CWV) Overview[4]



[2] These weather severities are based on the 82 winters starting from October 1928.
[3] The CWV formula includes a proportion of previous days' temperatures so the coldest CWV tends to be later than the coldest temperature
[4] The cold and warm values are realistic daily ranges for each day of the winter. For further information: http://www.nationalgrid.com/uk/Gas/OperationalInfo/operationaldocuments/Gas+Demand+and+Supply+Forecasting+Methodology/

37. The chart above clearly illustrates the relatively warm conditions through to mid December and the relatively cold conditions from then through to mid March.

38. Figure A.2 compares the mean temperature for the December to February period with previous winters. Figure A.3 shows the average temperature for each October to March. Through rising temperatures since the mid 1960's it illustrates the impact of climate change in recent years. Although the 2009/10 winter was close to the long term average it was much colder than many recent winters and colder than seasonal normal weather adjusted for climate change[5].

Figure A.2 – Average temperatures for December to February since 1928

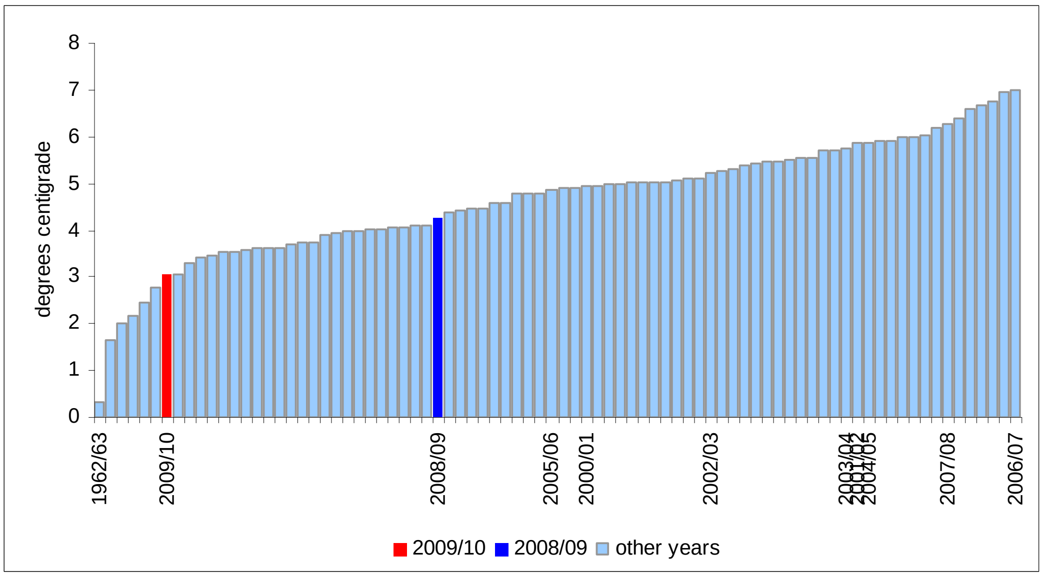
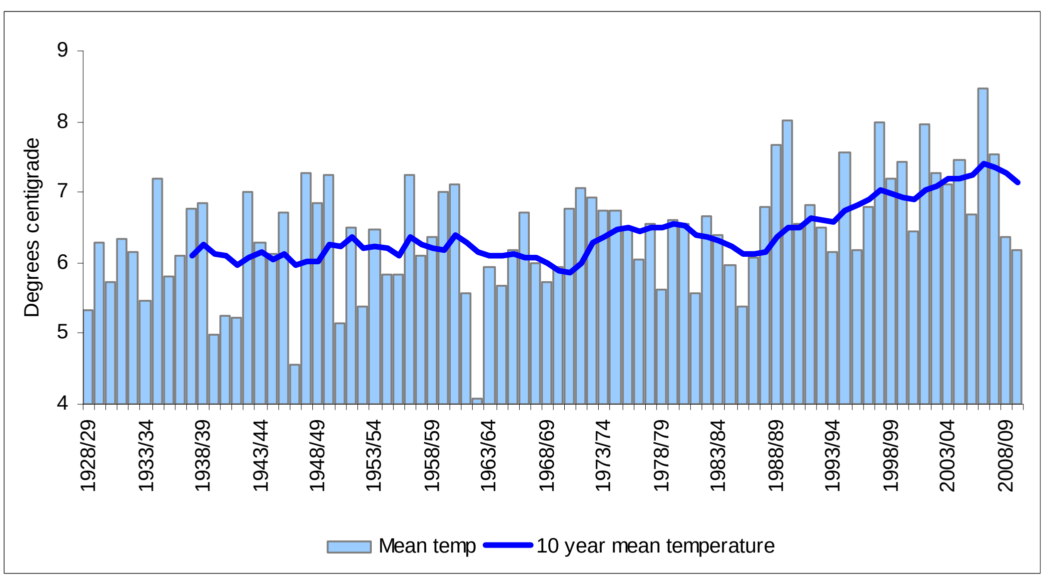


Figure A.3 – Average temperatures for October to March since 1928



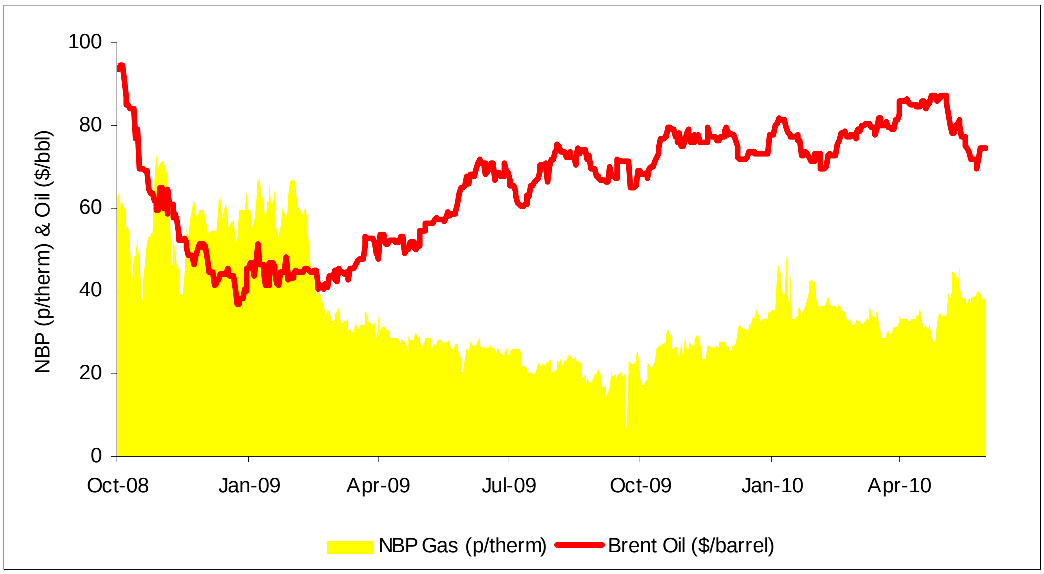
[5] Seasonal normal demand is based on the weather between October 1987 and September 2004

Gas

2009/10 Fuel Prices

39. Figure A.4 shows the day ahead UK National Balancing Point (NBP) price for day ahead gas and the day ahead Brent oil price for the period October 2008 to May 2010. The within day System Average Price (SAP) reported by National Grid generally follows the NBP with the exception when National Grid has to buy or sell relatively large volumes on the day for balancing purposes.

Figure A.4 – SAP and oil prices from October 2008



40. The NBP generally remained relatively low and stable for Winter 2009/10, especially considering the severity of winter experienced in the UK. Average NBP for winter 2009/10 was 31 p/th, the highest NBP price was below 50 p/therm. Within day SAP peaked at 64 p/th on 9th January, the third highest demand day, a day when a Gas Balancing Alert (GBA) was issued due to a major within day supply loss.

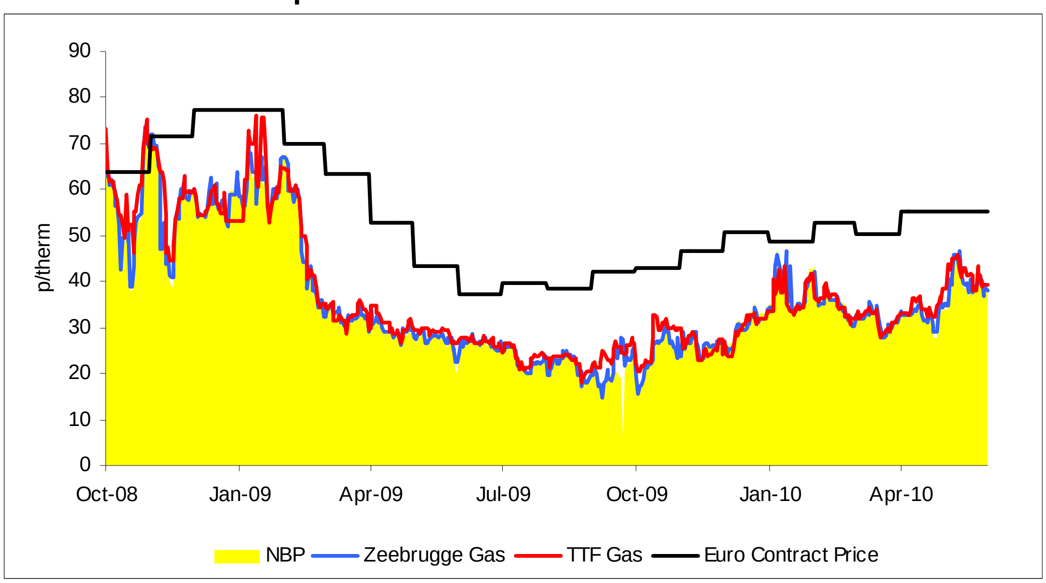
41. Despite the winter's cold weather and high demands, the supply position was relatively favourable, because of the arrival of significant volumes of LNG and at times IUK imports. This helped keep prices relatively low, considering the demands experienced. The winter period had 9 of the highest 15 demand days ever experienced by National Grid. In addition, National Grid issued 4 Gas Balancing Alerts (GBAs), for short term within day supply losses, which the market addressed well within the gas day. The highest gas demand was 465 mcm/d, over 20 mcm/d higher than for the previous winter. Due to plentiful supplies on this day, National Grid had to sell gas to balance the system.

42. Surprisingly, since the winter, prices have not fallen but increased. For January to March 2010, NBP averaged 36 p/th whereas May 2010 was close to an average of 40 p/th and recent June prices are now well above 40 p/th comparable to the highest prices seen during the winter. This may be due to many reasons, such as higher than expected demands from the Continent or some supply disruptions from Norway, but the price impact relative to the level of demand suggests there are other market sentiments working.

43. Oil prices have been generally rising slowly since the start of 2009 (Figure A.4), principally linked to views of economic recovery and increased demand, notably from China. The reductions in May 2010 were also due to less favourable views of the economy. Changes in the oil prices have had little or no effect on the UK gas price in recent months with oil indexation reduced as increased indigenous production of unconventional gas in the US has resulted in greater levels of LNG supply to alternative markets.

44. 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 broadly consistent with UK prices as illustrated in Figure A.5. The chart also shows our estimate of gas that is subject to long term contracts and linked to the price of oil through oil indexation. The chart shows a higher price for contracted gas over NBP of about 10 – 20 p/therm. During the high demand in January this premium was significantly reduced to a nominal level.

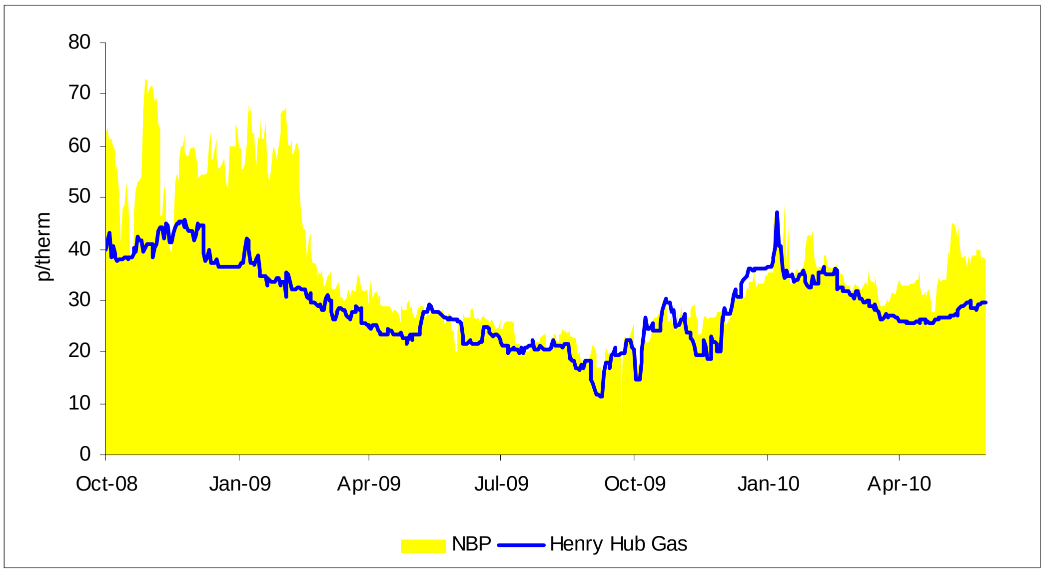
Figure A.5 – UK and European Gas Prices



45. Figure A.6 compares SAP to the Henry Hub price in the United States. The Henry Hub price decreased in line with the fall in oil price drops post July 2008, whereas the seasonal effect and the oil price lag for Continental contracts meant the NBP fell later in mid February 2009. Since then increasing US domestic (non conventional) gas production combined with increasing volumes of LNG production has resulted

in favourable supply conditions on both sides of the Atlantic. With the possibility to ship LNG to either markets, the UK and US gas prices have been more closely linked. Since winter 2009/10 the US and UK gas prices have again started to diverge with European markets becoming relatively more expensive than the US again.

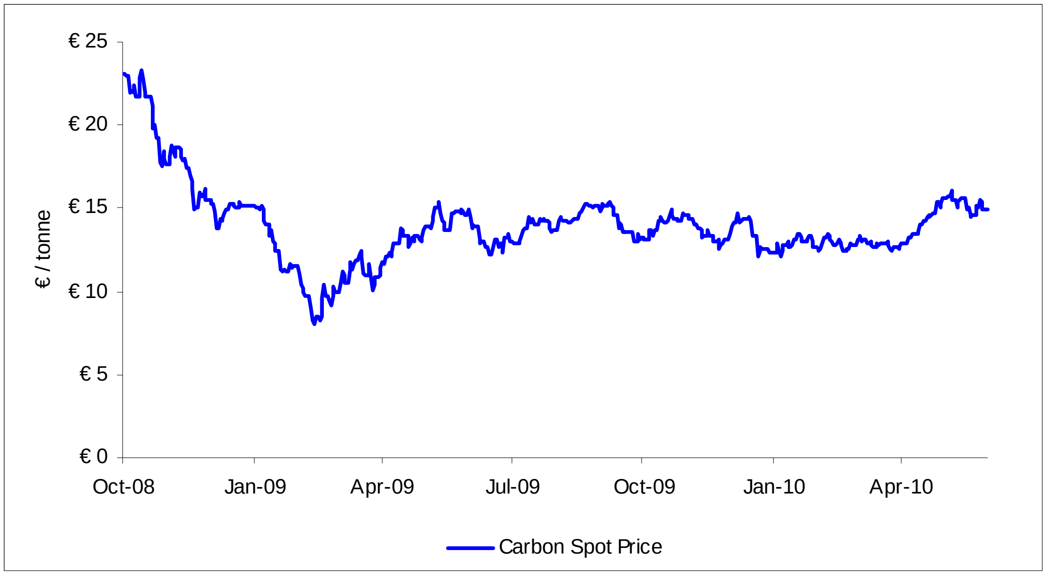
Figure A.6 – UK and Henry Hub Prices



46. Figure A.7 shows carbon prices since October 2008. Carbon prices initially fell to below €10/tonne, before some correction and have now been relatively stable since early 2009. How energy demand recovers as the world economy improves is a key sensitivity as to how the price will change, along with whether the European Union (EU) will adopt a tougher EU ETS cap on emissions (which it would do if the EU adopted a 30% GHG emissions reduction target by 2020.

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

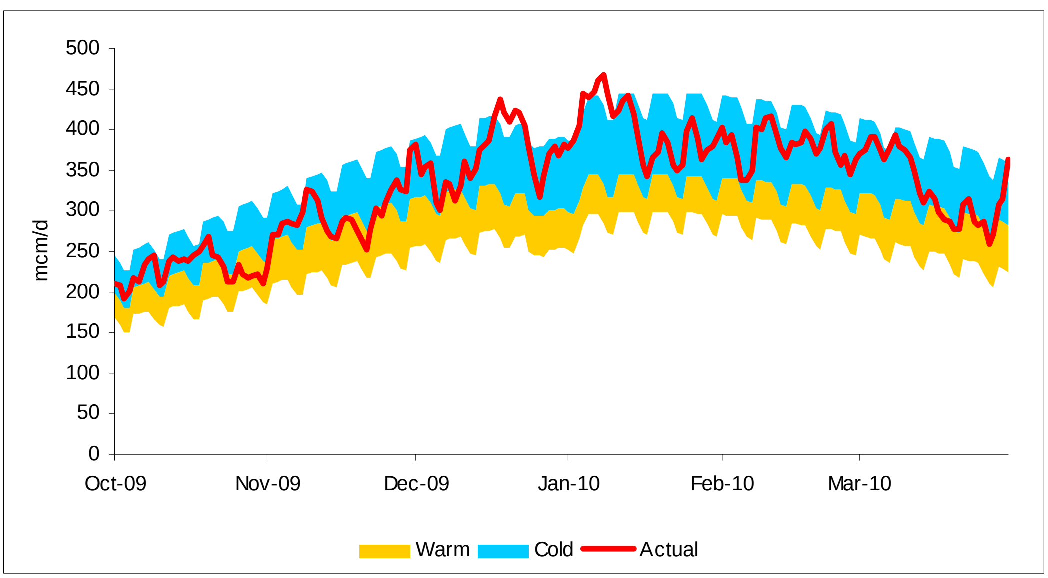
Figure A.7 – Carbon Prices[6]



2009/10 Gas Demand

48. Figure A.8 compares total demand, excluding Interconnector exports and storage injection, with seasonal normal, cold and warm demand.

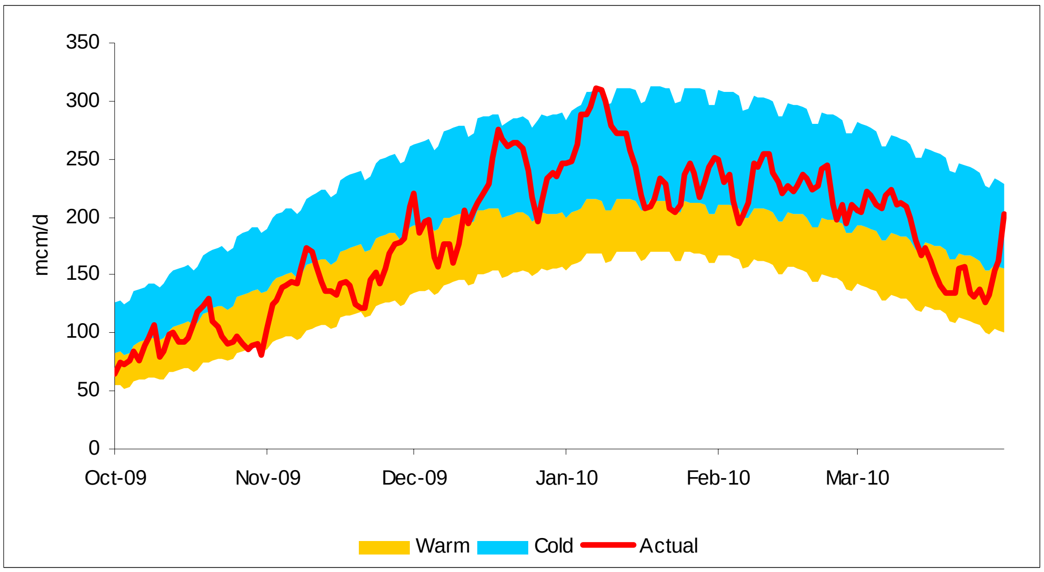
Figure A.8 – 2009/10 Seasonal and Actual Demands



[6] EU ETS Allowance prices (EUAs) are the currency used in the European Union Emissions Trading System (EU ETS), the mechanism for capping carbon emissions across the European power and industrial sectors.

49. The chart shows that actual demand was generally within the cold forecast band with a bias towards higher demands. On 8th January a record demand of 465 mcm/d was set. The high demand levels were not all due to the cold weather because before mid-December and after mid-March the weather was seasonally warm. Figure A.9 shows the same graph for the most weather sensitive load band, non-daily metered demand (NDM). NDM demand reflected the pattern of the weather shown in Figure A.1.

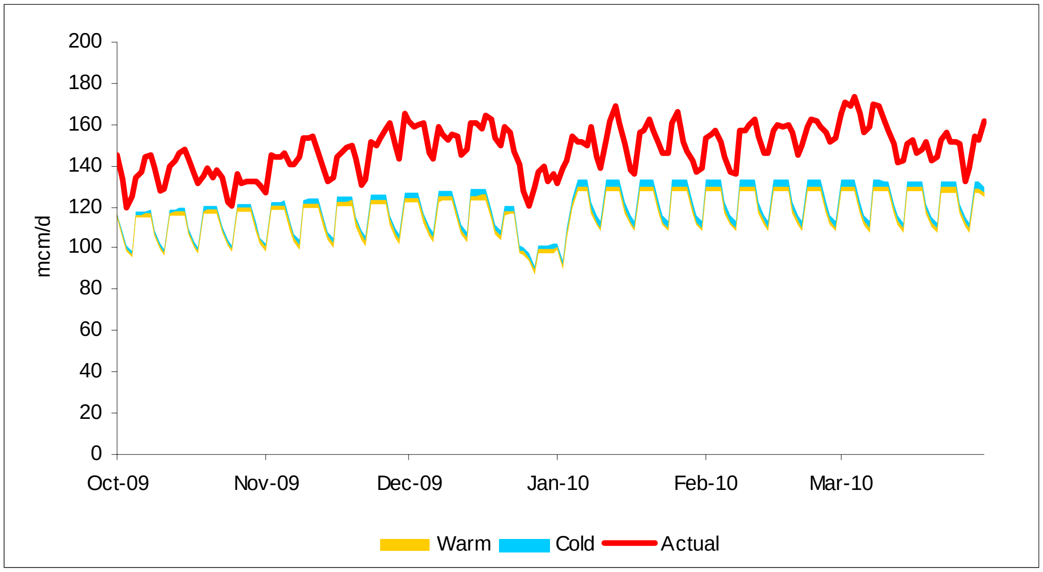
Figure A.9 – 2009/10 NDM Seasonal and Actual Demands



50. The chart shows that NDM demand was low during the warm weather at the start of the winter and higher during the very cold weather in early January. In recent years there has been a trend for NDM demand to become more weather sensitive, particularly at lower temperatures.

51. Figure A.10 shows some significant increases in DM and NTS demand compared to our forecast. There is very little weather variation in demand in these market sectors as highlighted by the small difference between the cold and warm forecasts.

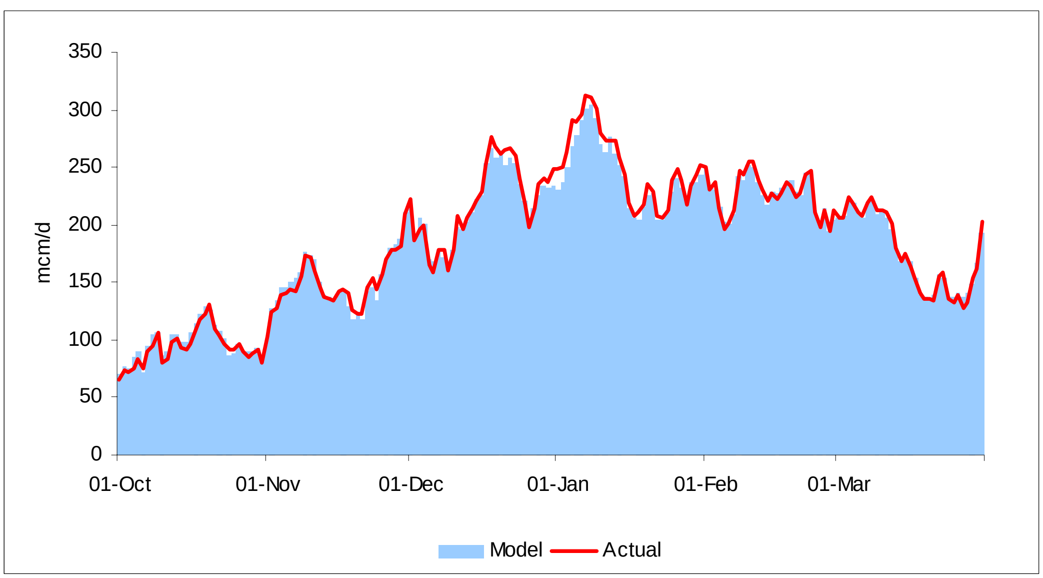
Figure A.10 – 2009/10 DM and NTS Seasonal and Actual Demands[7]



52. As detailed in the following sections, this difference was primarily caused by an increase in gas fired power generation.

53. Figure A.11 compares actual NDM demand with the demand modeled from actual weather and the 2009 demand forecast model. The graph shows that actual demand was close to the predicted level throughout the winter with slight over forecasting at the start of the winter and a bias towards under forecasts during periods of high demand.

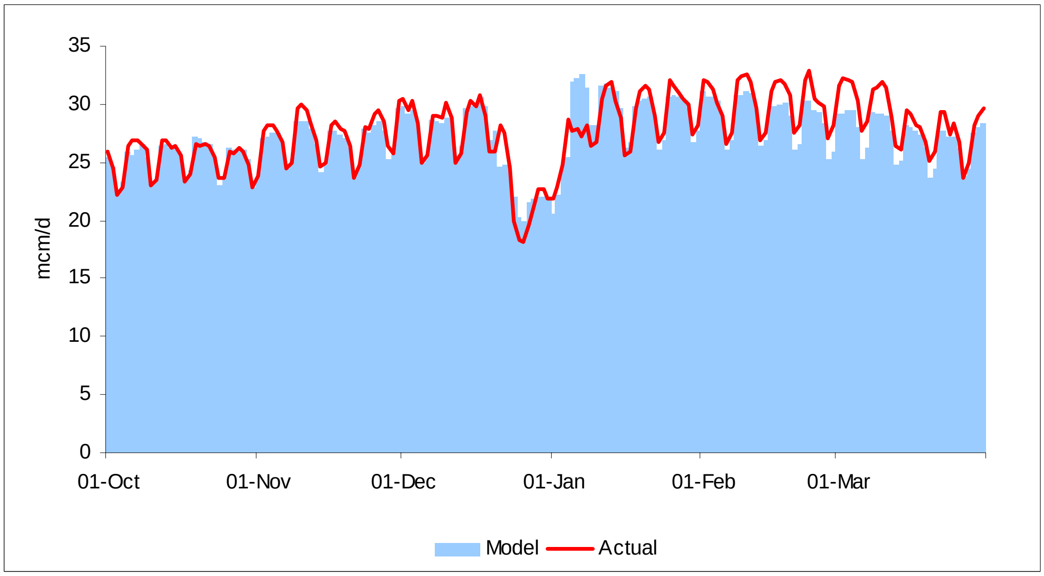
Figure A.11 – 2009/10 Actual NDM Demand



[7] Excludes IUK exports and storage injection

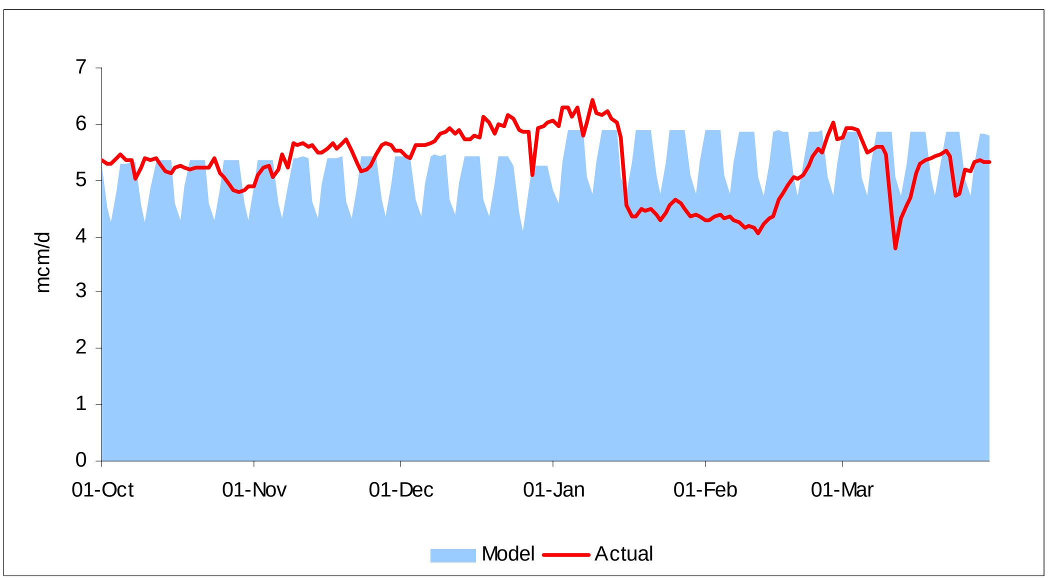
54. A similar graph for LDZ daily metered non-power demand (Figure A.12) shows that the actual demands were very close to the model values in the first half of the winter followed by a strong increase for the second half. The impact of the cold week just after Christmas can clearly be seen with actual demand approximately 5 mcm/d below expected levels.

Figure A.12 – 2009/10 Actual LDZ DM Non-power Demand



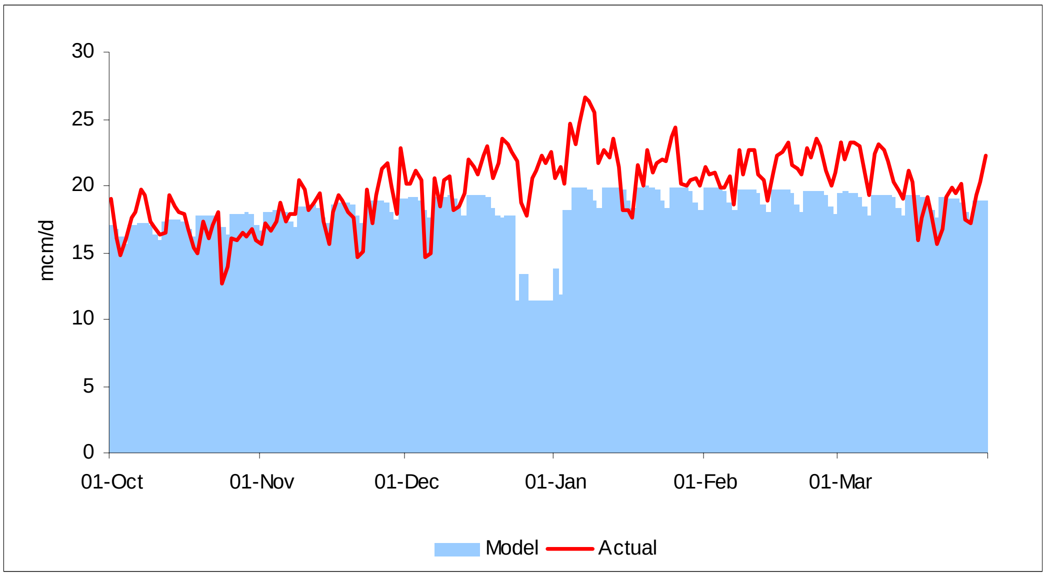
55. Figure A.13 shows the same information for the NTS Industrial market sector. The chart shows the reduction in demand due to a single large load undergoing maintenance in mid January.

Figure A.13 – 2009/10 Actual NTS Industrial Demand



56. Figure A.14 shows that exports to Ireland were close to forecast levels for the first half of the winter but increased during the cold weather.

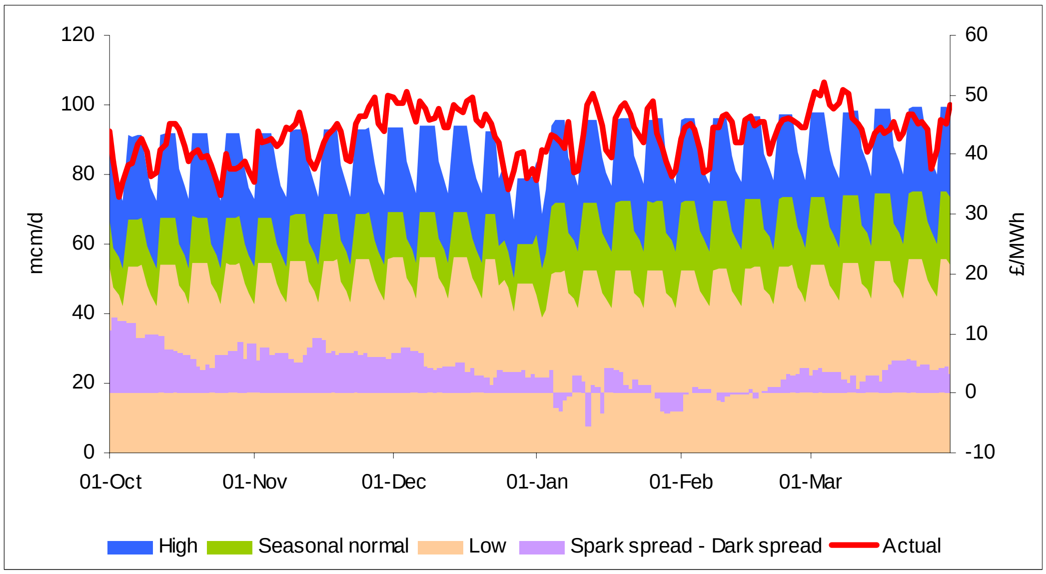
Figure A.14 – 2009/10 Actual NTS Exports to Ireland



57. Figure A.15 shows actual power station demand compared to the 2009 forecast. Power generation forecasts are based on ranking orders for a three month period. The 2009/10 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.

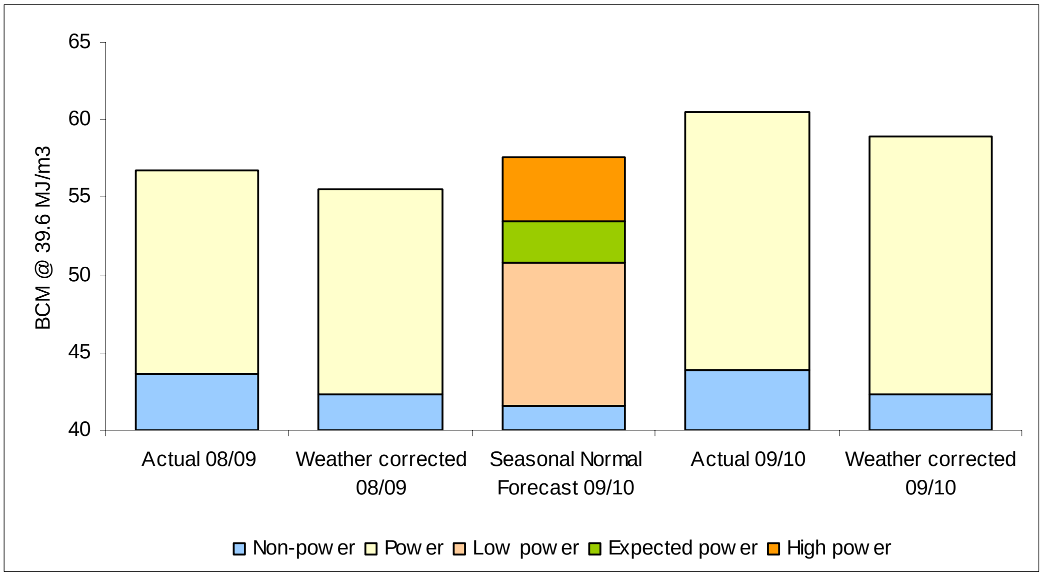
58. The 2009 forecasts assumed that gas would be marginal generation during the winter and base load over the summer. However fuel prices shifted in favour of gas generation for most of the winter resulting in gas demand for power generation at or just above the high level for the entire winter, hence the variation to the forecast in Figure A.10.

Figure A.15 – 2009/10 Actual Power Station Demand



59. Figure A.16 compares the 2009/10 actual, forecast and weather corrected winter demand with 2008/09 actual demand. Note the y-axis is offset to highlight relatively small differences. The non-power weather corrected demand for 2009/10 was very similar to 2008/09; power generation demand was 26% higher, total weather corrected demand was 6% higher.

Figure A.16 Total Winter Demand



2009/10 Gas Supply

60. Table A.1 summarises the make-up of gas supplies for winters 2007/08, 2008/09 and 2009/10 by supply source. The table shows that actual supply / demand (i.e. non weather corrected) for winter 2009/10 was higher than in the previous two winters. Compared to the previous winter there was a decline (~16%) in UKCS supplies to 28.0 bcm. For the first time, imports at 30.3 bcm exceeded UKCS supplies. Most of the increase in imports was due to significantly more LNG through both Milford Haven and Grain. Compared to winter 2008/09, imports from Norway were 9% lower whilst imports from the Continent and use of storage were higher.

Table A.1 – Gas Supply, Comparison of 2007/08, 2008/09 and 2009/10 by Source

	2007/08		2008/09		2009/10	
	bcm	%	bcm	%	bcm	%
UKCS	36.0	60%	33.3	55%	28.0	44%
Norway[8]	13.7	23%	17.8	29%	15.3	24%
Continent	6.7	11%	4.6	8%	6.1	10%
LNG	0.7	1%	1.6	3%	8.9	14%
Storage	3.5	6%	3.9	6%	4.7	7%
Total	60.5		61.1		63.0	

[8] Includes estimates for Vesterled and Tampen

61. Table A.2 shows the make up of supplies for winters 2007/08, 2008/09 and 2009/10 by terminal. For winter 2009/10 supplies through Bacton, Barrow, Teesside and Theddlethorpe were all similar to the previous winter. By contrast supplies through St Fergus were 26% lower due to a combination of lower supplies from Norway and lower production from the UKCS. The notable increase in terminal supplies was through Milford Haven and to a lesser extent Grain and storage.

Table A.2 – Gas Supply, Comparison of 2007/8 and 2009/10 by Terminal

	2007/08		2008/09		2009/10	
	bcm	%	bcm	%	bcm	%
Bacton	15.8	26%	13.9	23%	13.8	22%
Barrow	3.3	5%	2.1	3%	2.2	4%
Grain	0.7	1%	1.6	3%	2.5	4%
Easington[9]	12.8	21%	15.1	25%	14.8	24%
Milford Haven	0.0	0%	0.0	0%	6.4	10%
Point of Ayr	0.2	0%	0.1	0%	0.0	0%
St Fergus	18.9	0.31	19.6	0.32	14.6	23%
Teesside	3.7	0.06	4.4	0.07	4.3	7%
Thed'pe	4.3	0.07	3.3	0.05	3.0	5%
Storage[10]	0.8	0.01	1.1	0.02	1.4	2%
Total	60.5		61.1		63.0	

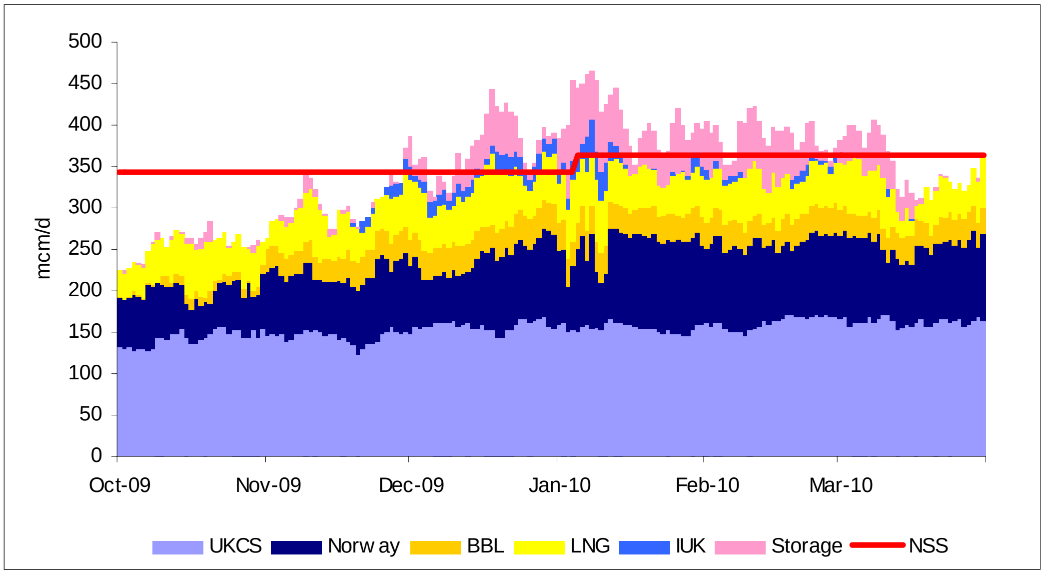
62. Figure A.17 shows how the various gas supply sources were used in winter 2009/10 against actual demand. Each of these supply sources is considered in turn in the following sub-sections.

63. The highest day of supply was a record 466 mcm/d on 8th January, in aggregate there were 32 days of supply in excess of 400 mcm/d (just 9 in 2008/9) and 96 days in excess of 350 mcm/d (67 in 2008/9). Average demand for the highest 100 days of demand was 391 mcm/d, 26 mcm/d higher than in 2008/9.

64. The chart also shows our Winter Outlook forecast for non storage supplies (NSS). This was increased from 343 mcm/d in early January to 363 mcm/d as a result of higher flows of NSS during period of high demand post mid December. For the demand days above 400 mcm/d, the average level of NSS was 360 mcm/d. This includes the period in early January when supplies from Norway were reduced. During these days other NSS increased deliveries (notably IUK and LNG) and the average level of NSS was maintained above 360 mcm/d.

[9] Includes Rough
[10] Excludes Rough

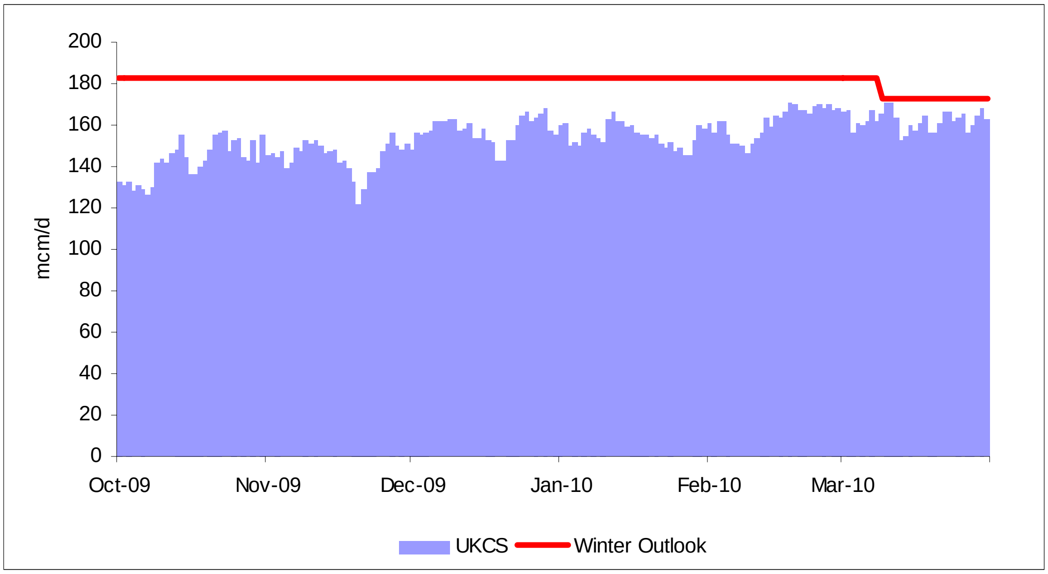
Figure A.17 – 2009/10 Supply Performance



UKCS Supplies

65. Our aggregated forecast for UKCS supplies for winter 2009/10 was 203 mcm/d, this was 9% lower than our forecast for the previous winter. For operational purposes we assume 90% availability for UKCS supplies, resulting in a pre-winter operational forecast of 183 mcm/d, this forecast was also used in setting the Safety Monitors. Figure A.18 shows flows from the UKCS last winter and our operational forecast. This was subsequently reduced in early March to 173 mcm/d as it became more apparent that a specific field that was included in the forecast would probably not flow for the remainder of the winter.

Figure A.18 – 2009/10 UKCS Supplies



66. The chart shows that for most of the winter UKCS supplies were relatively steady but below our pre-winter operational forecast. As the winter progressed there was some increase in UKCS flows as some fields that were on long term outages returned to production.

67. We believe that the main reason why the levels of UKCS did not meet our pre-winter operational forecast was that some high swing gas associated with Bacton Shell-Esso did not make a material contribution possibly because prices were not sufficiently high.

68. Average flows from the UKCS across the 6 month winter period were 154 mcm/d and for the 100 days of highest demand 159 mcm/d. Table A.3 shows the 2009/10 Winter Consultation Base Case peak forecast of UKCS supplies by terminal and the actual terminal supplies for the day of highest UKCS supplies (18th February 2010) and the highest day for each terminal.

Table A.3 – 2009/10 UKCS Supplies by Terminal

Peak (mcm/d)	Forecast	Actuals	
	Base Case	Highest UKCS	Highest Terminal
Bacton	65	42	51
Barrow	18	17	18
Easington	11	10	10
Point of Ayr	1	0	3
St Fergus[11]	70	61	65
Teesside	24	26	29
Theddlethorpe	16	16	19
Total	**203 (183)**	**171**	**194**

69. The table highlights that the day of highest UKCS supplies of 171 mcm/d was below the operational forecast of 183 mcm/d. This difference was due to lower flows from the high swing gas associated with Bacton Shell-Esso. A comparison of our 203 mcm/d forecast should be made against the aggregated highest terminal flows (194 mcm/d). This is well aligned to all terminals expect Bacton due to reasons detailed previously and to a lesser extent due to some field outages at St Fergus.

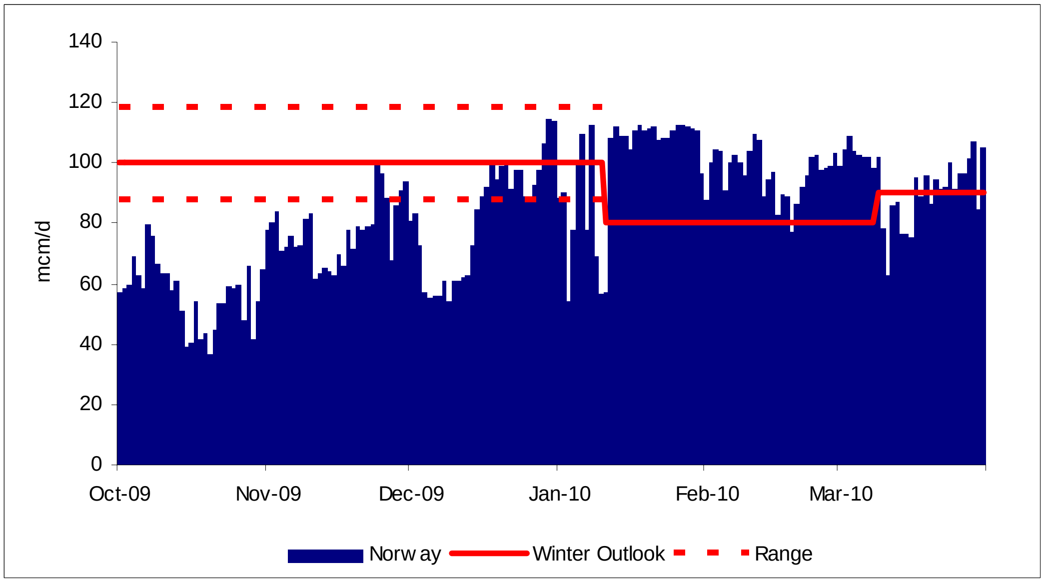
Norwegian Imports

70. Our forecasts for Norwegian imports to the UK for winter 2009/10 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. To capture this uncertainty we produced a Central View of Norwegian flows to the UK (100 mcm/d) and a range (88-118 mcm/d) based on high flows to the Continent (thus low UK flows) and low flows to the Continent (thus high UK flows).

71. Figure A.19 shows Norwegian flows through Langeled and our aggregated estimates for Norwegian imports to St Fergus through Vesterled and the Tampen Link.

[11] Excludes estimates for Vesterled and Tampen

Figure A.19 – 2009/10 Norwegian Imports to UK



72. The chart shows that post mid December (after the mild start to the winter) Norwegian flows were generally within our anticipated range. Average Norwegian flows across the 6 month winter period were 84 mcm/d within a range of 37-115 mcm/d. For the 100 days of highest demand average Norwegian flows were 96 mcm/d within a range of 54-115 mcm/d.

73. Whilst the average flows from Norway were broadly in line with our forecasts, the lower ranger highlights that on occasion Norwegian flows to the UK were reduced due to widely reported supply losses. As a consequence in early January we reduced our forecast from 100 to 80 mcm/d. Following a period of sustained performance we subsequently revised our forecast up to 90 mcm/d in early March.

74. 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 representing about 90% of daily import flows is now available from Zeebrugge (Fluxys data), Dunkerque (GRTgaz data), some of the flows entering Germany at Emden and Dornum and the UK[12]. In addition, Norwegian production data is reported on a monthly basis by the Norwegian Petroleum Directorate (NPD).

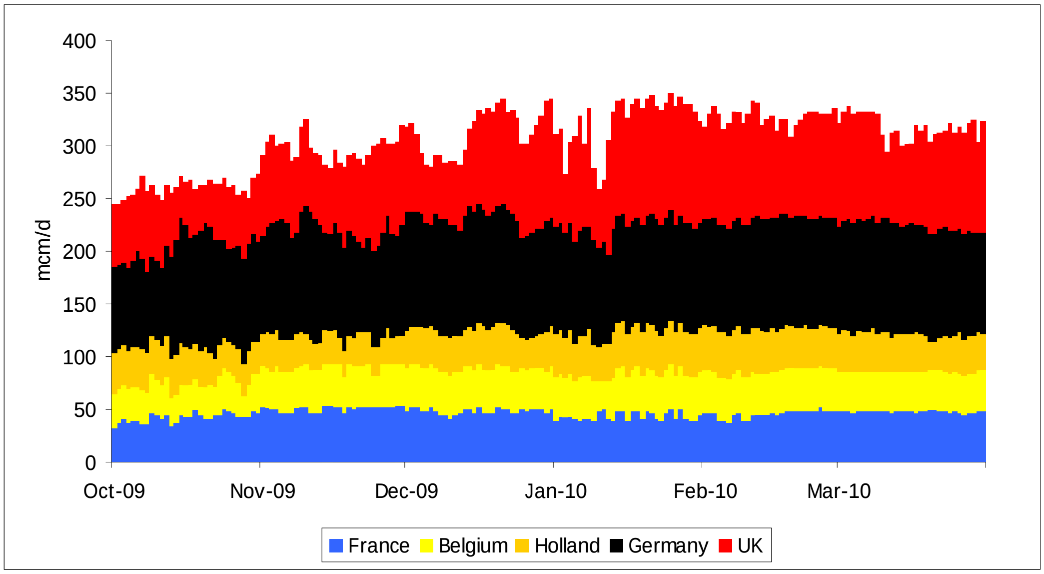
75. Figure A.20 shows our estimate of daily Norwegian exports to the UK and the Continent during winter 2009/10. The chart shows that Norwegian production tended to increase as the winter progressed before leveling off post December. Our estimate for average flows for the 6 month winter period was 287 mcm/d, for the 3 month mid winter period from December to February this increased to 304 mcm/d, essentially the same as our Winter Consultation forecast of 302 mcm/d.

76. The chart clearly shows that when the Norwegian production suffered supply losses in early January most of the flow reduction was experienced in the UK rather than

[12] Langeled only

the Continent. This was probably as a consequence of contractual commitments with flows to the UK having a lower priority than those to the Continent.

Figure A.20 – 2009/10 Norwegian Exports to UK and the Continent



77. Table A.4 shows our estimate of winter Norwegian exports between 2007/08 and 2009/10. The table shows a further increase in Norwegian production last winter, this was primarily due to higher flows from Ormen Lange. Compared to last year exports to Germany were higher and for the UK they were lower. All the Continental pipelines operated at a high load factor (~90%) compared to below 70% for the UK.

Table A.4 – Estimate of Norwegian Exports 2007/08 to 2009/10

(mcm/d)	Capacity 2009/10	Winter 2007/08	Winter 2008/09	Winter 2009/10	2009/10 Utilisation
Belgium	41	37	37	38	93%
France	52	50	47	46	89%
Germany[13]	151	130	121	138	91%
UK[14]	124	74	98	84	68%
Total	**368**	**292**	**302**	**306**	**83%**

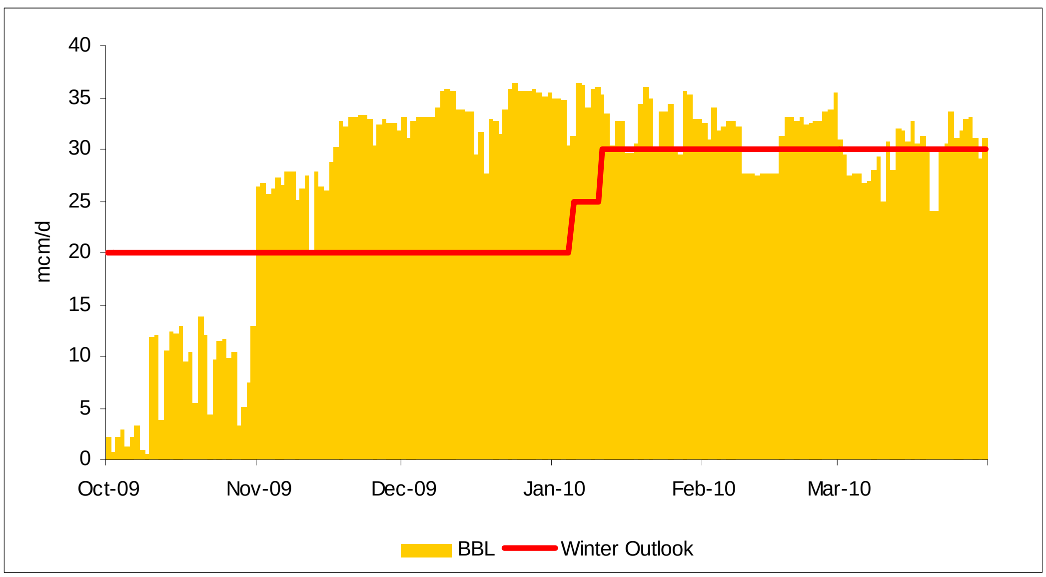
[13] Includes flow to the Netherlands
[14] Capacity includes a proportion of FLAGS for Tampen

Continental Imports - BBL

78. For winter 2009/10 we initially forecast that BBL flows to the UK would be 20 mcm/d. This was based primarily on winter flows for 2008/09 and the possibility that arrangements for non physical reverse flow could be in place to take advantage of a forward price for NBP gas that was below that of oil indexed gas, hence reduce BBL imports below the reported Centrica contract.

79. Figure A.21 shows BBL flows for winter 2009/10. From mid November onwards flows averaged 32 mcm/d, consequently in early January we increased our forecast to 30 mcm/d. Flows at these levels were realised for the remainder of the winter with limited variation when compared with other supply sources.

Figure A.21 – 2009/10 BBL Imports to UK

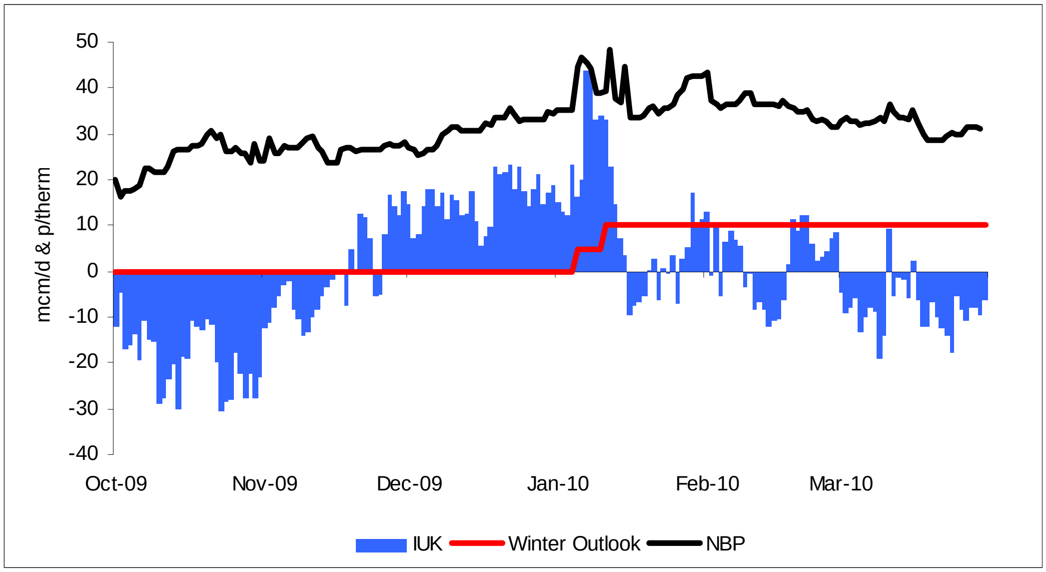


Continental Imports - IUK

80. For winter 2009/10 we forecast that IUK would operate as the marginal source of supply similar to storage when UKCS and other imports could not meet demand. For IUK we assumed zero / export flows for demands below 385 mcm/d and imports up to 30 mcm/d for higher demands. We stressed that IUK flows would be dependent on demand (price) and the availability of other supplies, notably other imports. For the Safety Monitor calculations we initially assumed zero imports, this was subsequently increased in early January to 10 mcm/d.

81. Figure A.22 shows IUK import and exports flows for winter 2009/10. In aggregate imports were 1.1 bcm and exports 1.1 bcm. The highest flow for IUK imports was 44 mcm/d in early January. For the highest 100 days of demand, IUK imports averaged 9 mcm/d, this was in line with revised assumptions.

Figure A.22 – 2009/10 IUK Imports & Exports



82. The chart for IUK shows that IUK responded to a series of conditions / events:

- During the period from October through to the start of December, IUK exports gradually declined as UK demand and NBP prices generally increased. During this period the UK gas price was below the Continental contract price of about 60 p/therm.
- From mid December to mid January with high UK demand and higher NBP prices, IUK imported at about 10 mcm/d. During this period UK gas prices increased but remained below the Continental contract price.
- During early January when UK demand was very high and supply losses from Norway occurred IUK imports peaked at over 40 mcm/d. During this period UK gas prices approached the Continental contract price.
- From mid January to late February IUK oscillated between imports and exports.
- During March as the UK gas price fell, IUK moved to predominately export mode.

83. The above conditions indicate that IUK imported to the UK for much of last winter despite the UK gas price being below the Continental contract price. The reason for this is believed to be due to surplus gas as a result of:

- Lower demand for gas on the Continent due to the recession
- Take or pay commitments, hence export to UK rather than pay for gas not consumed
- A slow start to the winter, hence plentiful Continental storage available

LNG Imports

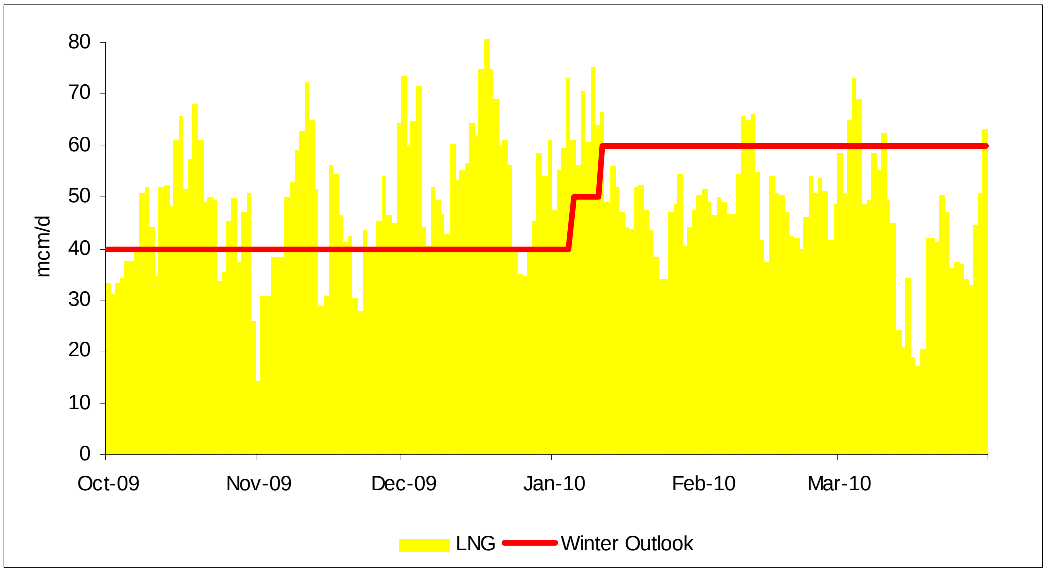
84. Our forecast for LNG imports for winter 2009/10 highlighted considerable uncertainties, most of these provided an upside rather than a downside in terms of increased LNG deliveries:

- Reduced demand in the largest LNG consuming nations, including those in Asia
- Low US LNG imports due to development of unconventional gas sources
- UK gas prices above those in the US
- Further increases in LNG production
- The possibility that South Hook II could be commissioned within winter

85. Consequently our preliminary winter forecast for LNG imports assumed flows of 40 mcm/d within a range of 10-60 mcm/d, with the distinct possibility of even higher flows.

86. Figure A.23 shows LNG imports through both Grain and Milford, also shown is the initial forecast and the subsequent revision to 60 mcm/d in early January. With hindsight a revision to 50 mcm/d would have been more appropriate.

Figure A.23 – 2009/10 LNG Imports



87. The chart shows considerable variation in day to day LNG flows ranging from 14 to 85 mcm/d with an average flow of 49 mcm/d. For the 100 days of highest demand the average flow was 55 mcm/d.

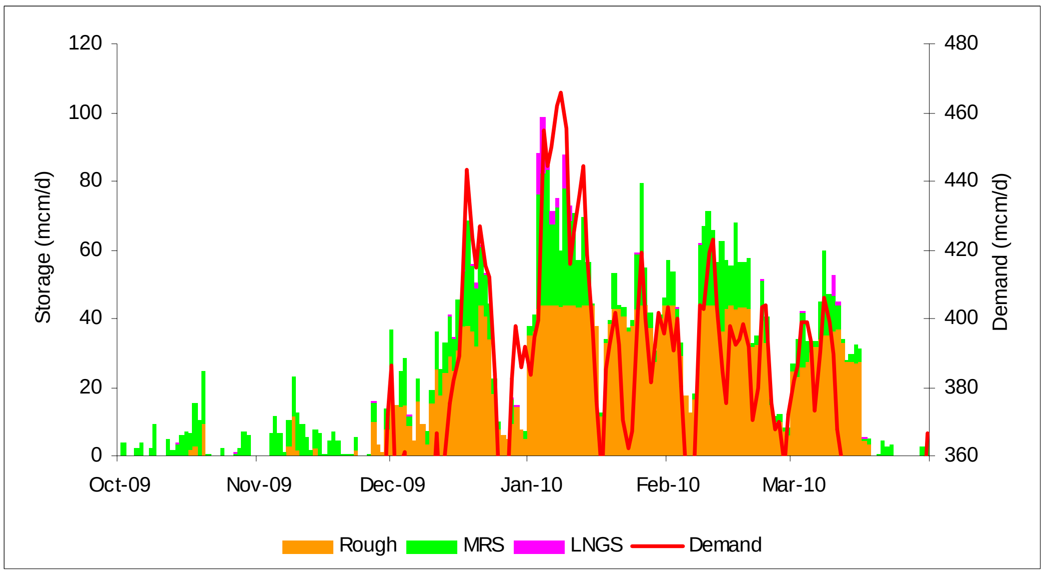
88. In aggregate total LNG imports were 8.9 bcm, of which 2.5 bcm was through Grain and 6.4 bcm through Milford Haven. There were no ship to shore transfers of LNG through Teesside GasPort.

2009/10 Storage Performance

89. Our forecast for storage for winter 2009/10 included flows from the Aldbrough salt cavity facility. This facility became operational during the previous summer, though not at full capacity.

90. Figure A.24 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 (based on our January forecast for non storage supplies) to highlight the close relationship between storage withdrawals and demand.

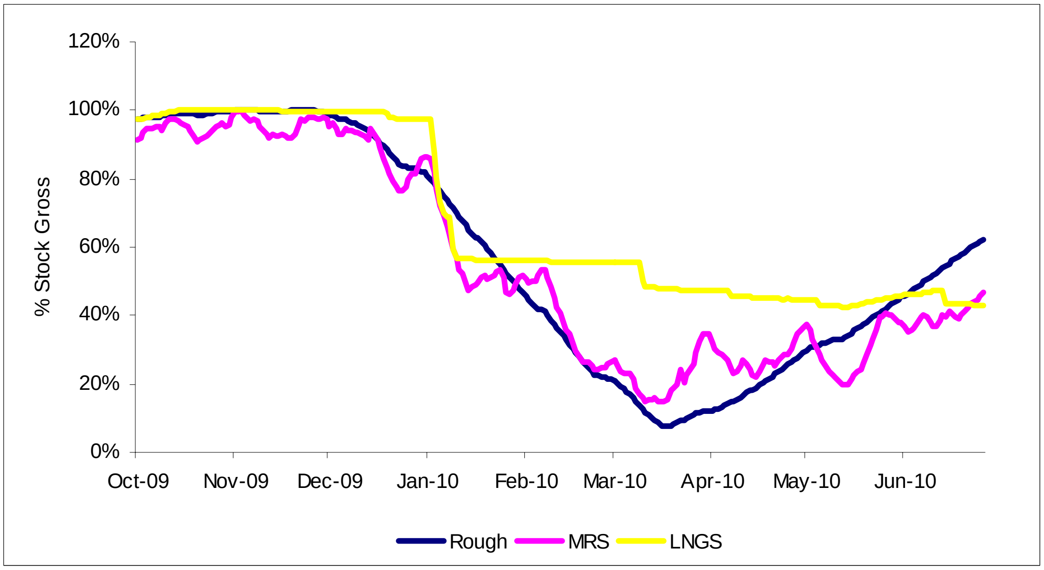
Figure A.24 – 2009/10 Storage Withdrawals



91. The chart shows limited storage use before mid December, thereafter considerable use including some 'cycling' through storage that had been injected within winter during periods of lower demand. In aggregate total storage use was 4.7 bcm, including 3.3 bcm from Rough (93% of pre winter stock), 1.3 bcm from MRS (145%) and LNGS 0.07 bcm (40%)

92. Figure A.25 highlights the decay of storage stocks, notably Rough and MRS as a consequence of relatively high use post mid December and the rapid depletion of LNGS in early January. The decay is shown as a % of storage stocks (based on highest stocks recorded less Operating Margins). What the chart does not show is the near complete depletion of certain storage facilities at times of high withdrawal, these were subsequently refilled within winter.

Figure A.25 – 2009/10 Storage Stocks



93. 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 including LNGS. The table also shows high levels of storage cycling, notably for MRS sites where the within winter injection represented 94% of the initial reported space. This represents the level of within winter 'cycling', for certain MRS sites the level of cycling was appreciably higher. Rough is also shown to have relatively high levels of injection however none of this occurred during the key winter months of December to February compared to 367 mcm injection for MRS.

Table A.5 – 2009/10 Storage Utilisation

	Reported Space (mcm)	Withdrawal (mcm)	Injection (mcm)	Reported Deliv. (mcm/d)	Highest Deliv.[15] (mcm/d)
Rough	3523	3285	295	41	44
MRS	917	1329	862	47	39
LNGS	179	71	23	36	17

[15] Aggregated by site

2009/10 Operational Overview

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

95. During the spring/summer of 2009, a review of the experience of the winter 2008/09 was undertaken. This led to the production of a revised safety monitor methodology, a UNC modification (257) and, following industry involvement, provision of more information to the market.

96. For winter 2009/10 a new platform was provided through the nationalgrid.com website[16], showing a five day ahead view of the supply/demand balance, historic and forward projections of storage use and how these levels related to the Safety Monitor requirements and the setting of the Gas Balancing Alert (GBA) trigger.

Winter 2009/10 Operational Experience

97. This year, there have been some significant changes to both supply and demand patterns. The commissioning of new LNG Importation facilities caused a significant shift from traditional North-South flows to a more diverse range of supply patterns. There was also an increasing prevalence of storage sites which have fast fill capability, leading to a change in storage site behaviour such that both injection and withdrawal are seen on the same gas day on many occasions. The same is true for IUK flows. This increase in dynamics between supply and demand patterns is leading to more challenges in the day to day operation of the network, with more flexibility required both by network operators and from assets, to deal with the wider variety of within day scenarios.

98. The first two weeks in January presented a series of challenges on the NTS, requiring use of a wide variety of operational tools. The following section describes the circumstances under which these tools were required.

99. On the first working day back from the Christmas/New Year break, the forecast gas demand was around 440 mcm/d, with cold weather forecast for the rest of the week over the whole of the UK. Against a background of a previous record demand of 449 mcm/d, this was always going to be a challenging day, and at the start of the day supply nominations were exceeded by demand nominations by a considerable amount.

100. Just after 10 a.m., information was received that there was a significant loss of supplies, leading to a projected deficit at the end of the day of over 60 mcm/d. A response team was set up to provide support to the control room. Key concerns were:

- Although there was sufficient capacity on the network to facilitate upturn in supplies from a variety of supply sources, there was no guarantee that the supplies would arrive; and even if they did arrive

[16] http://www.nationalgrid.com/uk/Gas/Data/GBA/

    - There was no guarantee that supplies would arrive in a timely enough manner to allow network pressure to be maintained;
    - There was limited time to set up the network to deal with the gas from a new supply pattern;
- In addition to the UK, Norwegian gas also supplies the Continent, and there was the unknown potential of a knock on effect of Norwegian disruption on imports from the interconnectors with both Belgium and Holland;
- Lack of formal communication channels with suppliers beyond our shores limited our ability to make fully informed decisions

101. After careful consideration of the options, the team made the decision to call a within day Gas Balancing Alert (GBA)[17]. This is a message sent out via email, on the nationalgrid.com website and to dedicated handsets which all shippers have, and is a mechanism to let all market participants know that there is potentially an issue with the supply/demand balance, and for them to review their portfolios and take appropriate action if possible. A within day GBA Alert has never been issued before; the criteria for issuing one was:

- that there has been a within day supply loss of 25 mcm/d or more
- and that National Grid has a reasonable expectation that there would be an end of day imbalance between supply and demand

102. With both these criteria met, National grid issued a GBA.

103. Over the next few hours, a market response was seen in terms of supply nominations, but it was 16:00 before physical supplies into the network finally exceeded demand being taken off the network. Significant upturns in supplies were seen from IUK and LNG importation terminals, demonstrating the value of having these diverse supply sources.

104. Over the following seven days, a further three GBAs were issued due to similar combination of circumstances. In addition, local issues on the network required use of locational Operating Margins, followed by Transporter Interruption and locational actions by National Grid. A new record demand day was also experienced.

105. This was a challenging time for the operational teams, but the value of having a portfolio of operational tools was clearly demonstrated, and they proved to be fit for purpose in dealing with the combination of issues that arose. Over the next few weeks and months, further unconnected events occurred and although there were no further Gas Balancing Alerts issued, the variety of operational issues experienced reinforced the need to have contingency plans both for the physical network, but also for the people involved in dealing with the incidents.

106. One of the lessons learned from these events was that there was limited communication with Norway during the supply disruption. Since that time, a new operational protocol has been introduced between the System Operators, and this has successfully been used during subsequent operational incidents.

[17] See subsequent sections for more details on GBA

Gas Balancing Alerts

107. The GBA is a signal to the market that demand-side reduction and/or additional supplies may be required to avoid the risk of entering into a Network Gas Supply Emergency. The UNC defines the circumstances under which a Gas Balancing Alert shall be issued as follows

- A GBA will be issued when the Forecast Total System Demand for the Gas Flow Day in question is greater than or equal to the Forecast Total System Supply for such Gas Flow Day
- National Grid may issue (by means of publication on its website) a Gas Balancing Alert where during a Gas Flow Day, an incident is notified to National Grid NTS that would (in the reasonable opinion of National Grid) reduce the Forecast Total System Supply for that Gas Flow Day by at least 25 mcm/d and the remaining Forecast Total System Supply for that Gas Flow Day is less than or equal to the Forecast Total System Demand (known as a "within day GBA").

Interruption

108. During winter 2009/10 It was necessary to interrupt one customer supplied directly from the NTS on a single occasion. This interruption was limited to the interruptible flows for a single site from 12:00 AM on 6th January until 15:00 on 7th January 2010, totaling 21,967,200 KWh (2 mcm). No other Transporter or emergency interruption to customers supplied directly from the NTS was required.
109. At times during the winter we understand that a number of Network Sensitive Loads were interrupted within the Local Distribution Zones and that between the 8th and 10th of January 2010 other interruptible loads within Distribution Networks were also interrupted.
110. Depending on the contract with the consumer, gas suppliers or shippers may also interrupt for their own reasons. This could be for supply/demand purposes or other commercial reasons. Although it is possible that shippers may call interruption at NTS sites, National Grid has little visibility of this and relies on notification of interruption from shippers.

Locational Trades

111. National Grid NTS may use locational energy buys and sells via the On the day commodity market (OCM) for capacity management where they are considered as the most economic actions to take compared with alternative actions, such as entry capacity buyback.
112. During Winter 2009/10 it was necessary for National Grid to utilise locational energy trades on the 6th January 2010. This involved the utilisation of locational energy trades to manage a Transportation Constraint within an area of the NTS[18].

[18] Although locational trades were used on only one occasion between 1/10/09 and 31/3/10, note that locational trades were also utilised on 1st April and 16th April 2010

Operating Margins Gas

113. National Grid purchases Operating Margins (OM) gas on an annual basis in line with both the requirements of Section K of the UNC and obligations described in the National Grid Safety Case (the Safety Case).

114. Primarily, OM Gas can be used in the immediate period following operational stresses such as supply failure as a result of a failure offshore, unanticipated demand changes or unexpected pipeline and/or plant unavailability. OM is used to maintain system pressures in the period before other balancing measures become effective. OM can also be used to support system pressures on the gas day in the event of a compressor trip, pipe break, or other failure or damage to transmission plant.

115. During Winter 2009/10 it was necessary for National Grid to utilise Operating Margins gas for locational reasons on the 6th January 2010.

Capacity Management

116. To ensure firm entry rights can be honoured, scaling back of interruptible rights occurs when notified or anticipated inputs outstrip firm rights and/or NTS capability. Constraint management actions, including buybacks, are undertaken if it is necessary to bring down the aggregate daily flows to within the physical capability of the NTS to protect its integrity. Following a scale back of interruptible rights, if system conditions return to normal National Grid has the scope to restore any previously scaled back interruptible capacity.

- For Winter 2009/10 it was necessary to scale back 100% of interruptible capacity for one day in January 2010 at Milford Haven ASEP. The interruptible capacity was not restored as system conditions were unfavourable. No further scale backs occurred at any entry points within the Winter 2009/10 period.
- As detailed above, during Winter 2009/10 it was necessary for National Grid to utilise locational energy trades on one occasion, to manage a Transportation Constraint within an area of the NTS
- No Capacity Buy Backs were incurred by National Grid during the Winter 2009/10 period at any ASEP

Transfer and Trades (T&T)

117. In April 2008 UNC MOD 187a “Alterations to the RMSEC Auction to Accommodate Transfer and Trade of Capacity between ASEPs” was approved by Ofgem with effect from 1st of June 2008. The modification introduced an enduring Transfer and Trade regime to facilitate the trade and transfer of firm capacity at and across ASEPs on a monthly basis.

118. For the winter period 2009/10 all bids received were allocated via surrendered or unsold capacity (trades). Therefore the firm release obligations at all ASEPs over

the winter period October 2009 – March 2010 were not altered as no capacity transfers between ASEPs were required.

Discretionary Release of Firm Capacity

119. In 2008 UNC MOD 216 was approved by Ofgem to enable National Grid to release firm capacity outside of the normal auction mechanisms by holding Discretionary System Entry Capacity (DRSEC) auctions as and when required.

120. For winter 2009/10 only one DRSEC auction was held, where National Grid envisaged making Discretionary System Entry Capacity available at a number of ASEPs. The quantity of firm capacity released via the DRSEC in response to User demand is detailed in Table A.6.

Table A.6 - Quantities of Discretionary Firm Entry Capacity sold

GWh/d	Month	Baseline	Non Obligated
AV	Oct-09 – Mar-10	0.0	0.0
EA	Oct-09 – Mar-10	0.0	0.0
GR	Oct-09 – Mar-10	0.0	0.0
HH	Oct-09 – Mar-10	0.0	0.0
HM	Oct-09 – Mar-10	0.0	0.0
IG	Oct-09	43.6	26.4
IG	Nov-09	43.6	26.4
IG	Dec-09	43.6	26.4
IG	Jan-10	43.6	26.4
IG	Feb-10	43.6	26.4
IG	Mar-10	43.6	26.4

Discretionary Release of Interruptible Capacity

121. 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.

122. 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. Table A.7 shows the maximum amount of additional discretional interruptible capacity released during winter 2009/10.

Table A.7 – Maximum Release of Additional Discretional Interruptible Capacity

GWh/d	Oct	Nov	Dec	Jan	Feb	Mar
Easington	0	0	190.4	377.4	519.4	470.8

Quarterly System Entry Capacity

123. UNC Modification 230AV “Amendment to the QSEC and AMSEC Auction Timetables” was approved by Ofgem on the 1st January 2010. The modification changed the definition of the capacity year thus allowing National Grid to release long-term system entry capacity from October instead of April in order to align the start of the release period with the gas year. This ensures that Incremental NTS Entry Capacity is released from the start of the winter period, when flows increase and when the capacity is needed most by Users.

124. The first QSEC auction with the newly modified timescales was held on 15th March 2010 and under the new modification rules the QSEC auction will continue to be held each March going forward.

125. For the first time, incremental capacity bids received in the March QSEC auction were satisfied via substitution of unsold Baseline Entry capacity from a neighbouring ASEP. The processes for negating potential network investment via substitution of Baseline Entry Capacity are detailed in the Entry Capacity Substitution Methodology Statement as was approved by Ofgem on 7th December 2009.

Capacity Retainer Window

126. The Entry Capacity Substitution methodology statement approved by the Authority on 7th December 2009 introduces the concept of a “retainer”. A retainer can be taken out by any Shipper in respect of any Aggregate System Entry Point (“ASEP”) in order to exclude the retained capacity from the possibility of being substituted to another ASEP. This provides Shippers with a lower (possibly zero) cost alternative to buying capacity if the Shipper is not in a position to make a full commitment. The Authority approved UNC modification proposal 0265: “Creation of a NTS Entry Capacity Retention Charge within the Uniform Network Code” and it was implemented on 18th December 2009. This modification enabled National Grid to make available entry capacity retainers, at ASEPs where capacity was not already sold out, in advance of the March 2010 QSEC auction.

127. The retainer window was open for two days on 25th and 27th January 2010. The following retainers were obtained.

Table A.8 – Capacity Retainers Granted

Retainers granted			
ASEPs	Gas Year	Retained Quantity (kWh/day)	Retention Charge (p/kWh/day)
Theddlethorpe	Y+4 Oct 2013 to Sept 2014	97,830,000	0.2922

128. As a result of the retainer at Theddlethorpe, an additional 97.83 GWh/day in excess of the sold quantity was excluded from substitution. The Shipper(s) taking the retainer will be refunded the retainer charge if they, or another Shipper,

subsequently obtains capacity for the period October 2013 to September 2014. Precise details of the application of refunds for retainer charges are provided in the ECS methodology statement.

Network Infrastructure

129. No new infrastructure was constructed during the 2009/10 gas year.

130. Decommissioning activities are progressing at the Bathgate and Scunthorpe compressor stations with both now being isolated from the NTS.

131. Two projects associated with the Milford Haven LNG Terminals were progressed during the 2009/10 gas year – Churchover multi-junction modifications were completed and Cilfrew pressure reduction station is now operational.

132. A number of new connections including to Langage, Marchwood, Staythorpe Power Stations, the Murco Oil Refinery at Milford Haven and the Aldbrough storage site all completed with first gas flows in 2009/10.

Questions for consultation

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

QA1. We welcome views on our assessment of gas demand and in particular whether gas demand for power generation would have been materially lower if gas prices were to have been higher?

QA2. We welcome views on our observation that during the highest demands in early January, NDM demand exceeded our forecast. What were the possible reasons behind this increase?

QA3. Is consumer behaviour still responding to high prices and the credit crunch or a long term response to climate change?

QA4. 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.

QA5. We welcome views on our assessment, that during periods of supply loss, Norwegian flows were prioritised towards Continental markets

QA6. We welcome views on the drivers behind IUK and BBL flows, notably the response of IUK during the periods of high UK demand, when the UK gas price was still below our assessment of the Continental contract price.

QA7. What were the drivers behind the surge in LNG imports?

QA8. We welcome view on the depletion of storage and the within winter cycling.

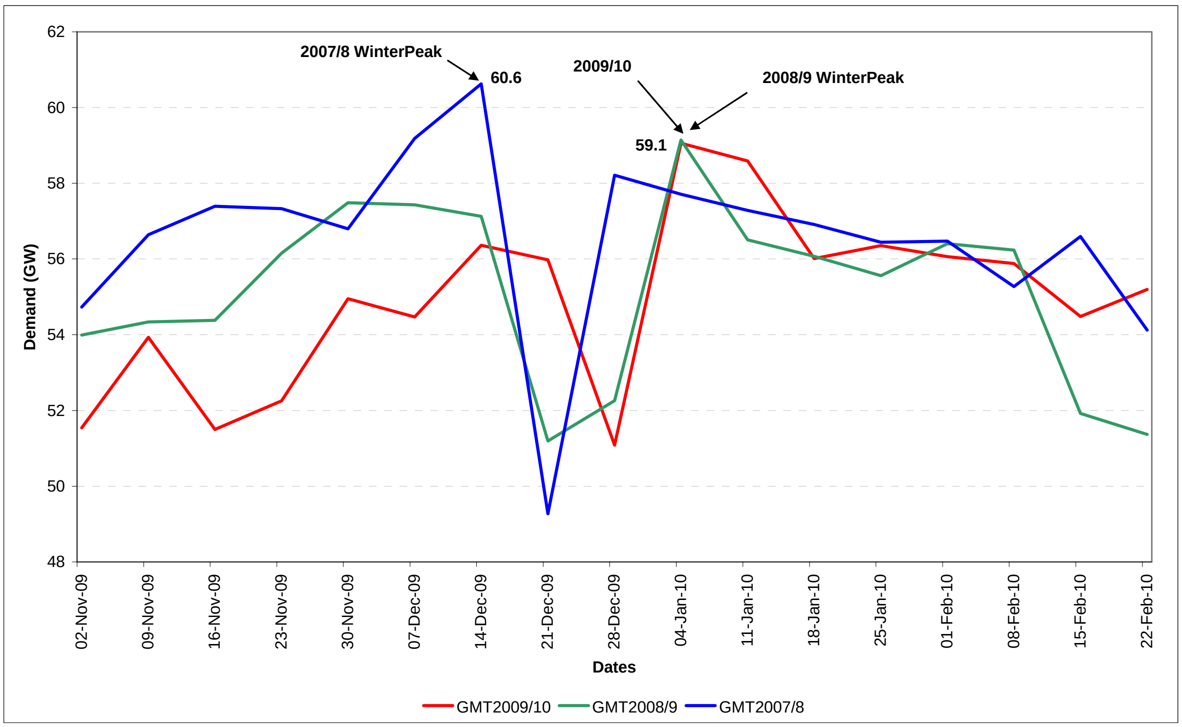
Electricity

2009/10 Electricity Demand

133. Unless otherwise stated, demand discussed in this report excludes any exports to France and Northern Ireland but includes station load and exports from the transmission system to meet indigenous GB demand. This is the same as IO14_DEM stream in the data published on our website[19] that we calculate and publish monthly using Elexon generation data. There is separate discussion of exports to France and Northern Ireland later in this section to inform the adoption of assumptions for interconnector behaviour during the winter to come.

134. The highest electricity demand over the winter reached 59.1GW for the half-hour ending 17:30 on 7th January 2010. This compares to the highest demand of 60.6GW and 59.1GW over winter 2007/08 and 2008/09 respectively. This is shown in Figure A.26.

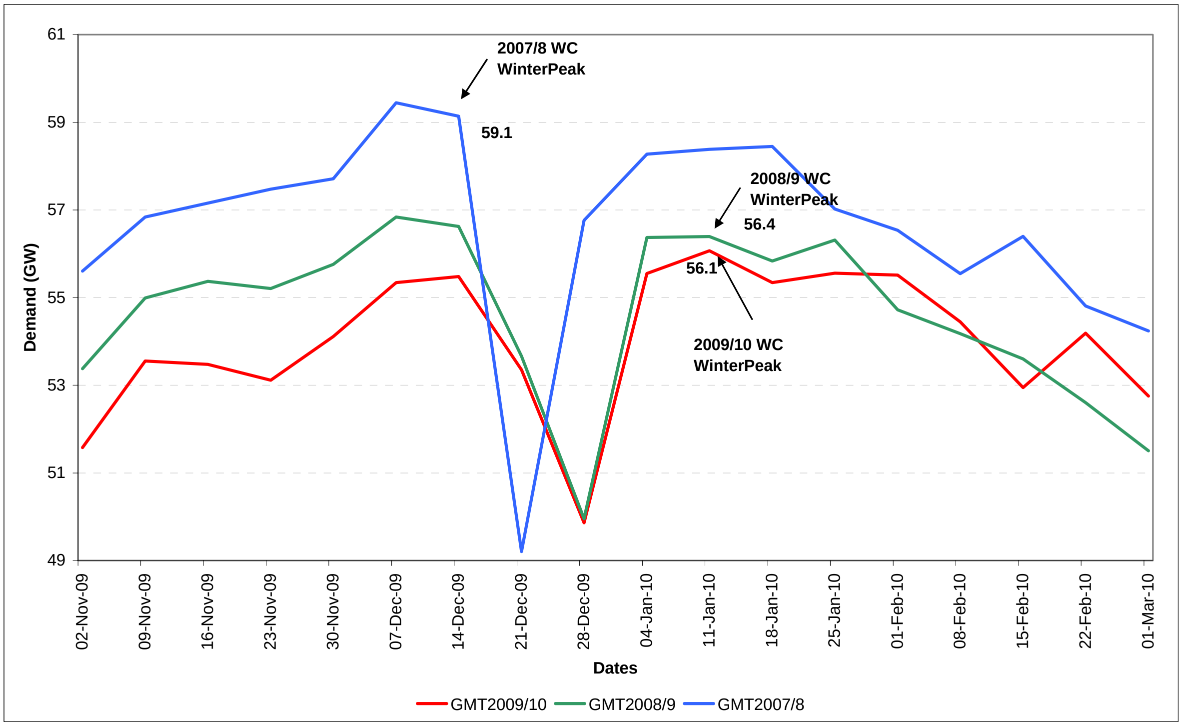
Figure A.26 – Weekly Peak Demand for the Last Three Winters



135. We have corrected outturn demands for weather to observe underlying demand trends under average weather conditions (based on a 30 year average). Figure A.27 below shows normalised weekly peak demands for 2009/10 (red), 2008/9 (green) and 2007/8 (blue) for comparison on a date aligned basis.

[19] http://www.nationalgrid.com/uk/Electricity/Data/Demand+Data/

Figure A.27 – Weather Corrected Weekly Peak Demand for Last Three Winters



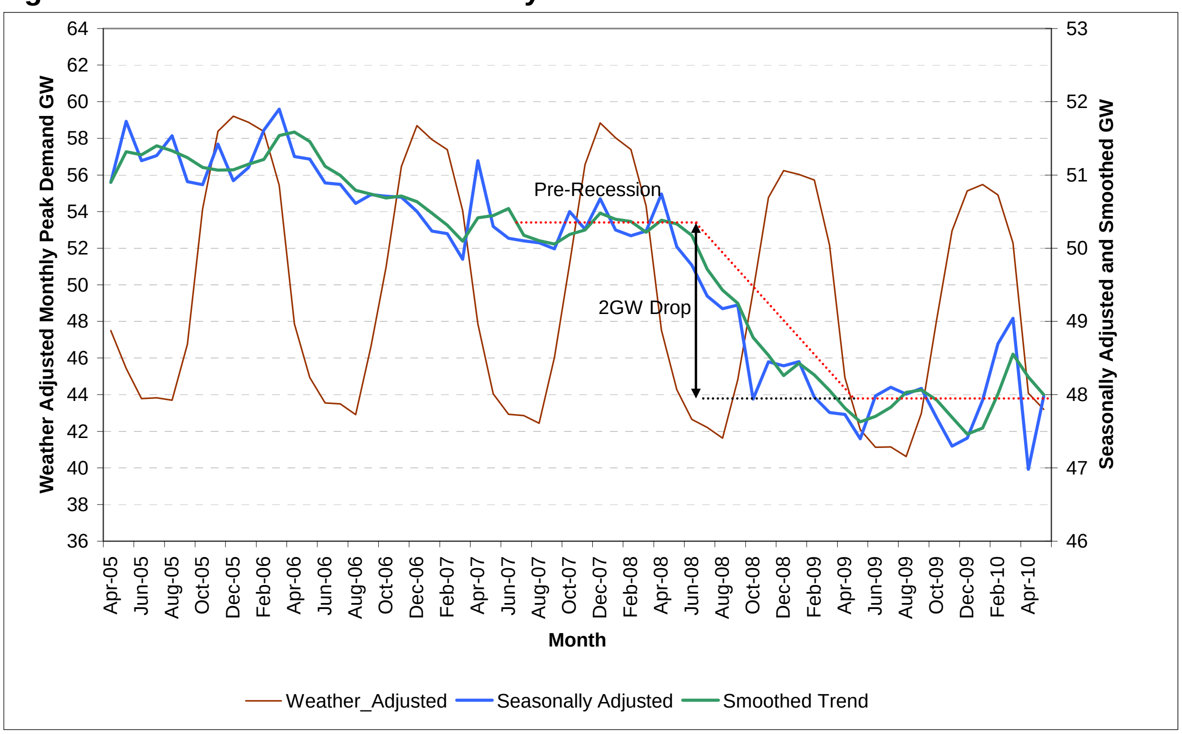
136. Weather corrected weekly peak demand indicated that this year's winter peak would have occurred one week later had the weather been normal for that time of the year. We believe that although weather corrected there may have been a "snow effect" that we cannot accurately correct due to the extreme nature of the weather events. The "snow effect" may be characterised by people not being able to get to work, leading to domestic electricity use in addition to close to normal business use which could have lead to a higher demand peak. For the previous two years the winter peak would have happened two weeks before Christmas had the weather been normal for the time of year. The actual outturn peak demand of 59.1 GW for 2009/10, experienced on the 7th of January during a cold snap was 55.6 GW, when corrected to normal weather conditions. This is lower than the actual outturn weather corrected peak demand of 56.1GW shown in the figure which occurred on the 11th of January. This was probably due to customer demand management actions this year on the actual demand peak day of the 7th of January being greater than the 11th causing the weather corrected demand to be higher on this day. Weather Corrected demands for winter 2007/08 and 2008/09 were 59.1GW and 56.4 GW respectively. The graph shows that the underlying demand in 2008/09 and 2009/10 were similar but still much lower than the 2007/08. The demand reduction was 2.0GW on average at each weekly peak except Christmas and New Year weeks due to non-alignment of bank holidays.

137. At the actual outturn demand peak we estimate that there was around 0.6-0.8GW of demand management as large customers reduced demand to avoid Transmission Use of System Charges. The amount of demand side response is difficult to

measure so we estimate it through looking at demand profiles on very high demand days. It is likely that the current economic slowdown had an impact on the amount of demand side management, as a number of end-users we believe undertake this type of action have either reduced their demand or have ceased production, either temporarily or permanently.

138. Figure A.28 shows the seasonally adjusted demand trend over the last 5 years. Weekly weather corrected monthly peak electricity demand started to decline in parallel with the reduction in energy use from April 2008 reaching a low in April and November 2009 where a 2.5GW decrease against the previous year was observed. Over the last four months, there appears to be a trend of growth back up to this time last years level, which is around 2GW lower than prerecession. We have carried this fixed level forward in our forecasts as there is some uncertainty in projected growth.

Figure A.28 – Weather and Seasonally Corrected Demand

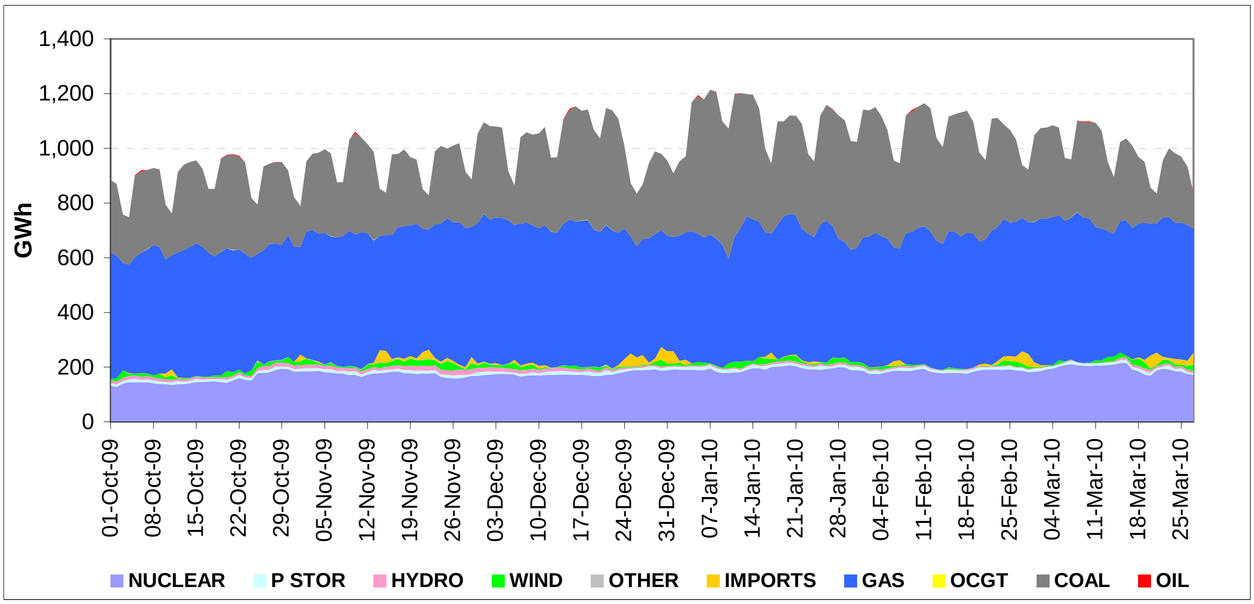


2009/10 Electricity Generation Capacity

139. Figure A.29 shows the actual 2009/10 generation mix. Gas fired generation provided a greater proportion of the total generation than coal as the relative fuel prices made gas the cheaper of the two fuels. The only exception to this was for a few days during the cold snap in early January when gas prices rose high enough to prioritise use of coal. Oil fired generation was much reduced compared to the previous winter and no oil plant ran over the winter peak. However it was needed to

maintain margins on a small number of days. Imports from France on the interconnector were also much reduced compared to the previous winter and the interconnector was exporting slightly at the time of the winter peak. This situation was a result of higher prices in France, which in turn was due to the unusually low availability of the French nuclear fleet.

Figure A.29 – 2009/10 Generation Mix by Fuel Type



140. A more detailed view of the amount of electricity generated by wind is shown in Figure A.30. This data is based on the wind farms that are currently visible to National Grid through operational metering. These wind farms have a total capacity of approximately 1586 MW. The output varied between 3 MW and 1586 MW with an average of 435 MW. This gives an average load factor of 27% over the period. From a security of energy supply perspective the key issue is the uncertainty and variability of output and the average load factor is of limited use. What can be observed from the data below is two periods of low wind output over several days in early November 2009 and early January 2010. Both of these periods were relatively cold for the time of year and coincided with relatively high electricity demands.

141. Figure A.31highlights that at the times of peak electricity demand over the last three successive winters wind power output has been relatively low compared with average load factors. Because of this issue we have undertaken further work with Durham University to identify a capacity credit approach using a risk based methodology which we outline in Appendix 1. The capacity credit approach has been developed into a more general power system security of supply. We are seeking comments on the usefulness of the approach for which the end result is a risk value for confidence that demand can be met in full for a given mix of generation types and an ACS demand level.

Figure A.30 – 2009/10 Daily Peak and Wind Generation

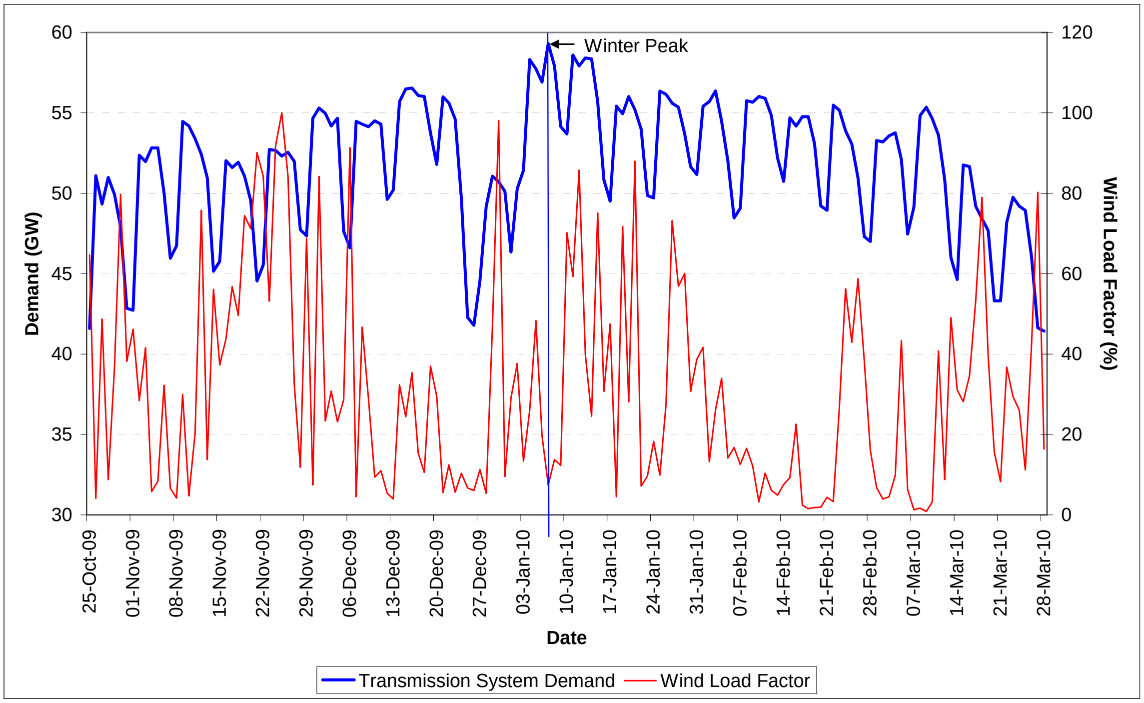
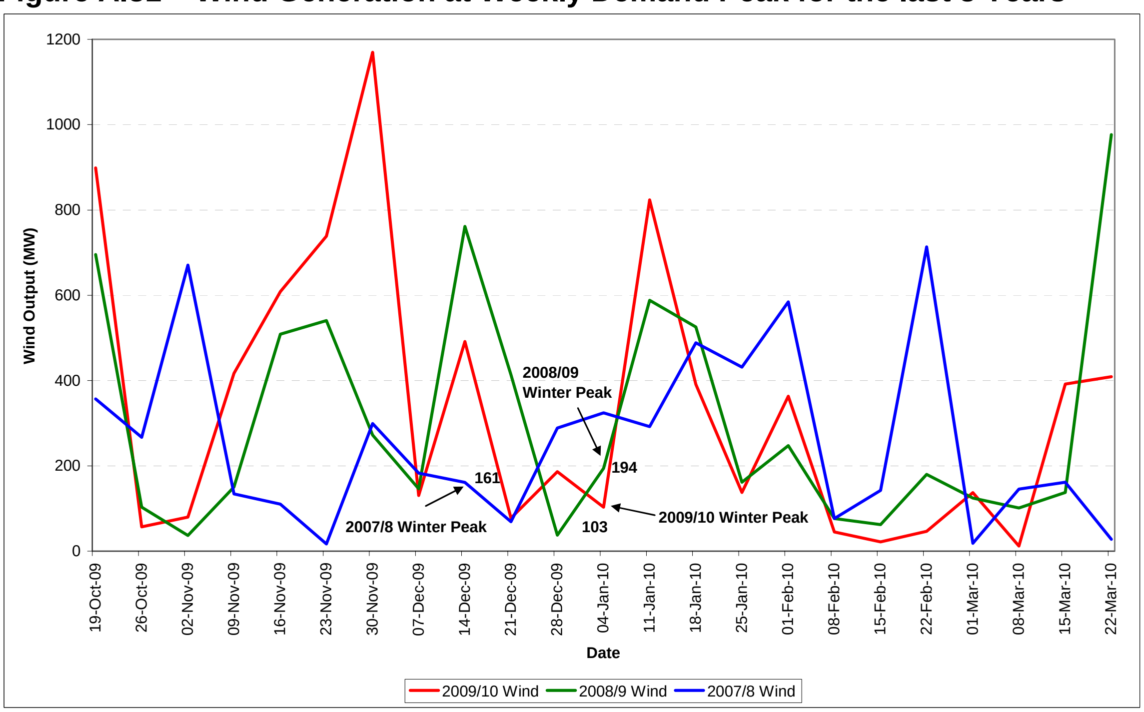


Figure A.31 – Wind Generation at Weekly Demand Peak for the last 3 Years



142. Table A.9 gives a summary of wind power generation volumes as operationally metered by National Grid for the last four winters. The volume of wind power generation itself is not particularly a key metric for us from a system operation perspective itself, but here it is a useful indicator of the growth in the impact of wind power with its inherent uncertainty and volatility. This illustrates what is becoming more of a feature for us in managing electricity security of supply. In the same way as we see relatively cold or warm years we clearly also see relatively windy or still years which along with the installed wind generation capacity are the key influences of the annual energy output.

143. Table A.9 Wind Generation Volumes Over Recent winters

	Wind Generation GWh	% increase on prior year
2006/7	1031	
2007/8	1097	6%
2008/9	1549	41%
2009/10	1575	2%

144. We have also reviewed our assumed availabilities against the actual availabilities for each type of generation at the winter demand peak that we had assumed for last winter. Table A.10 shows the results of this analysis against the central and low cases we adopted for last winter.

145. The overall plant availability turned out to be 87% at the time of the winter peak, which was one percentage point higher than the central case scenario. However, the outturn availability for nuclear at 75% was lower than expected. The lower availability was contributed to by Dungeness Power Station where both units were not available during the winter peak. This also coincided with low load re-fuelling at two other AGR units. The lower nuclear availability was balanced out by higher availability on the coal plant, pumped storage and the OCGTs. The coal plant achieved an availability of 92% instead of the assumed 85%. Gas fired generation availability out-turned close to forecast at 91%. Wind generation output was only 7% at the time of the winter peak. Hydro generation was also lower than expected due to lower than average rainfall. The oil fired plant was only 73% available due to a long term outage on one unit and another unit declared unavailable.

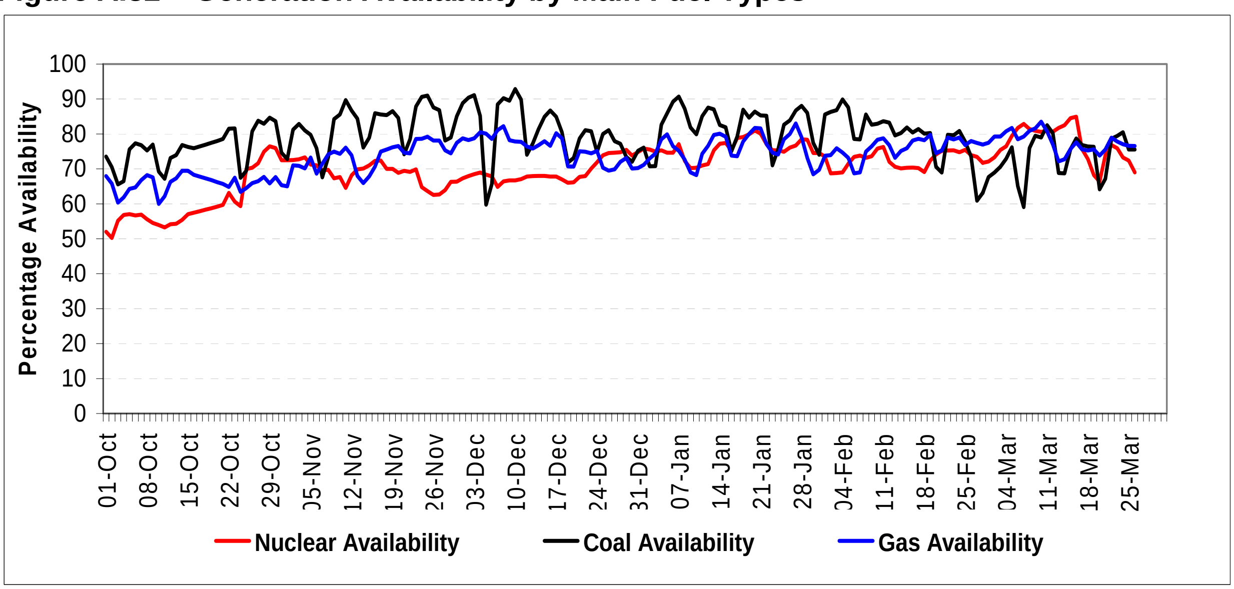
146. Note that for wind and hydro generation in table A.10 that the basis of assumed availability is different to that for other fuel types as it is actual load factor at the time of the demand peak and not technical declared availability as in both cases availability of input energy to the generation is a more limiting factor. In turbine availability terms we expect that wind turbine technical availability was in the high ninety percentage level range, but this has very little significance if the wind is not at a speed where they can generate at full output.

Table A.10 – 2009/10 Assumed and Actual Availability of Generation Plant

Power Station Type	Assumed Availability at Demand Peak (Central case)	Assumed Availability at Demand Peak (Low case)	Actual Availability at Demand Peak
Nuclear	80%	80%	75%
French Interconnector	100%	0%	100%
Hydro generation	80%	80%	59%
Wind generation	27%	0%	7%
Coal	85%	85%	92%
Oil	95%	95%	73%
Pumped storage	95%	95%	100%
OCGT	80%	80%	91%
CCGT	90%	90%	91%
Overall	86%	83%	87%

147. The outturn availabilities over the course of the winter by main fuel type are shown in Figure A.32. These can be compared with the availabilities at the winter peak shown above. The chart shows that plant availability remained reasonably consistent across the winter period. The nuclear availability was slightly lower for the first half of the winter but picked up by the middle of January, slightly too late for the winter peak.

Figure A.32 – Generation Availability by Main Fuel Types

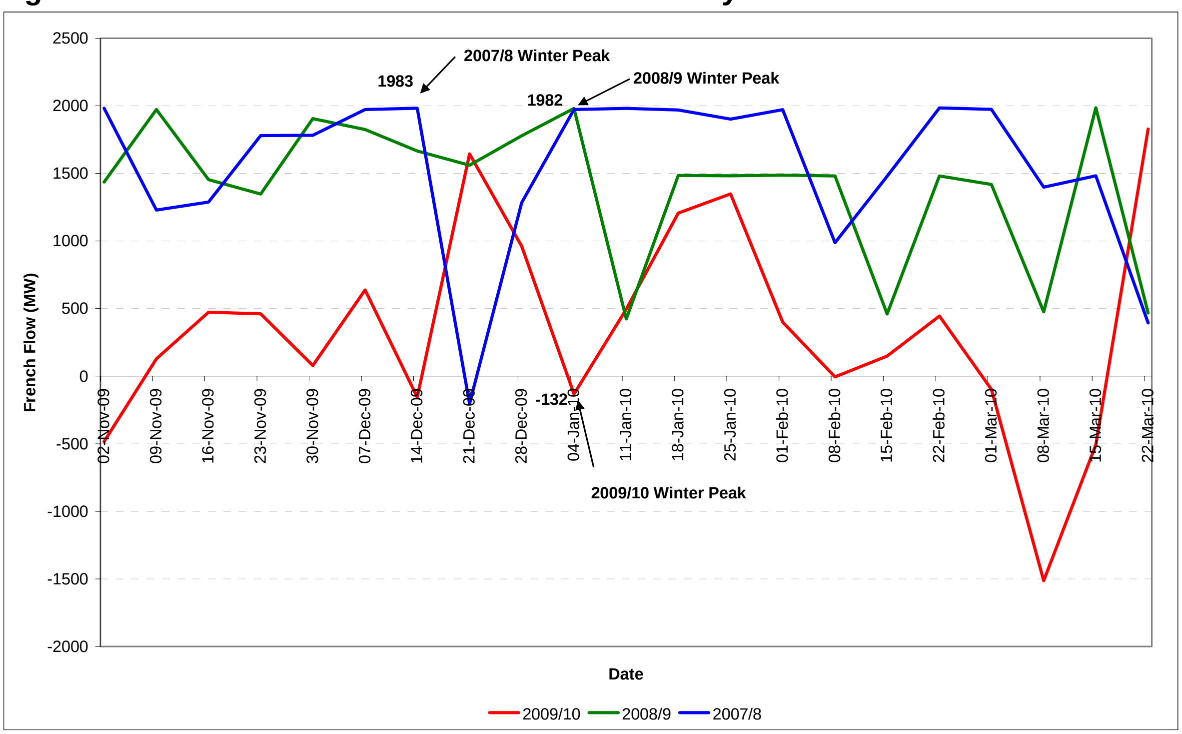


2009/10 Interconnector Flows

148. The GB market currently has two electricity interconnectors: one to France and one to Northern Ireland.

149. The GB-France interconnector can deliver up to 2 GW in either direction. Figure A.33 shows French interconnector actual flow for the last three winters at GB weekly demand peak. The graph indicates that the import level from France in the two previous years during system peak demand half hours were very similar, at close to full import. But for this years winter peak there was an export of 132MW. Under the GB TRIAD charging structure we assume float on the interconnector at times of high demand as exporting over a TRIAD peak will be relatively expensive for the party(s) exporting. Because of the strong pricing signal to be at float we expect that exports to France at times of GB demand peak are unlikely to repeat.

Figure A.33 – French Interconnector Flow at Weekly Peak Demand

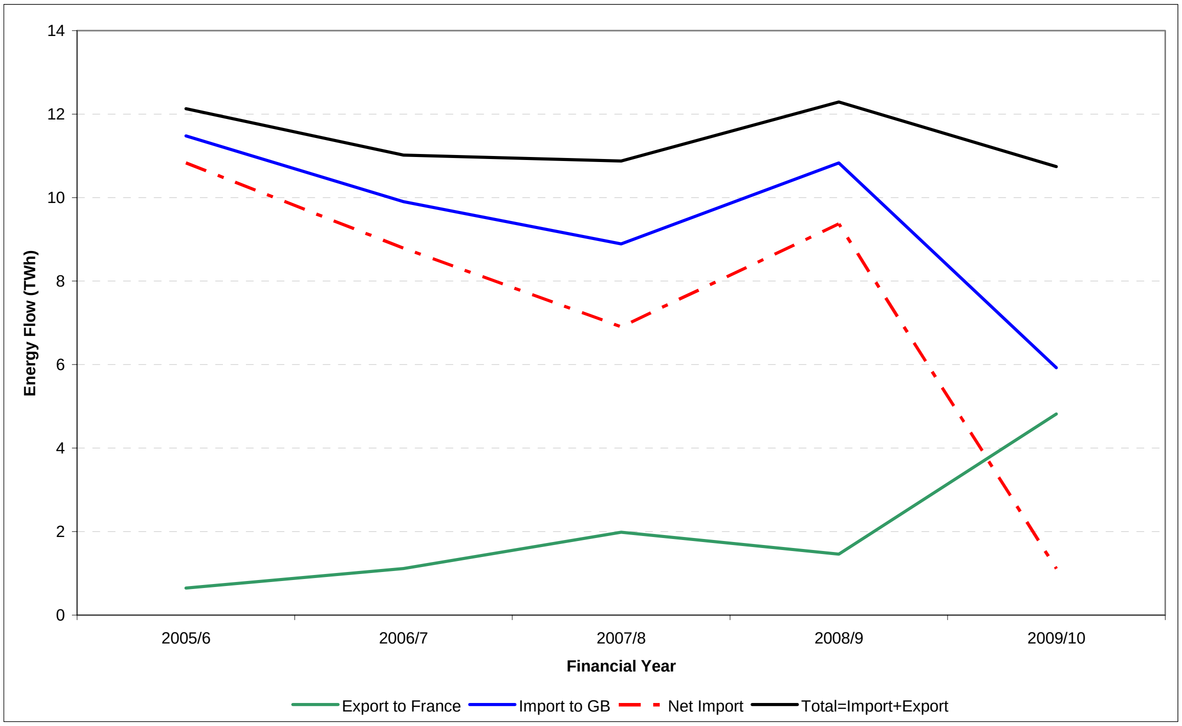


150. We have also analysed the overall import/export situation for the interconnector. Figure A.34 gives a summary of the annual import/export energy exchange between France and GB since BETTA, including both natural market flows and actions taken by National Grid as system operator. Our actions impacting interconnector flow are relatively small in terms of overall energy so do not materially affect the market trends observed. The net import from France has

reduced since BETTA. The main driver for direction of transfer of power is of course relative GB and France power prices.

151. We made some improvements to the cost reflectivity of the pricing of system operator to system operator services prior to winter 2009/10[20]. These changes went live as planned and, have in our view, delivered the cost reflectivity benefits we anticipated.

Figure A.34 – French Interconnector Annual Import/Export GWh since BETTA



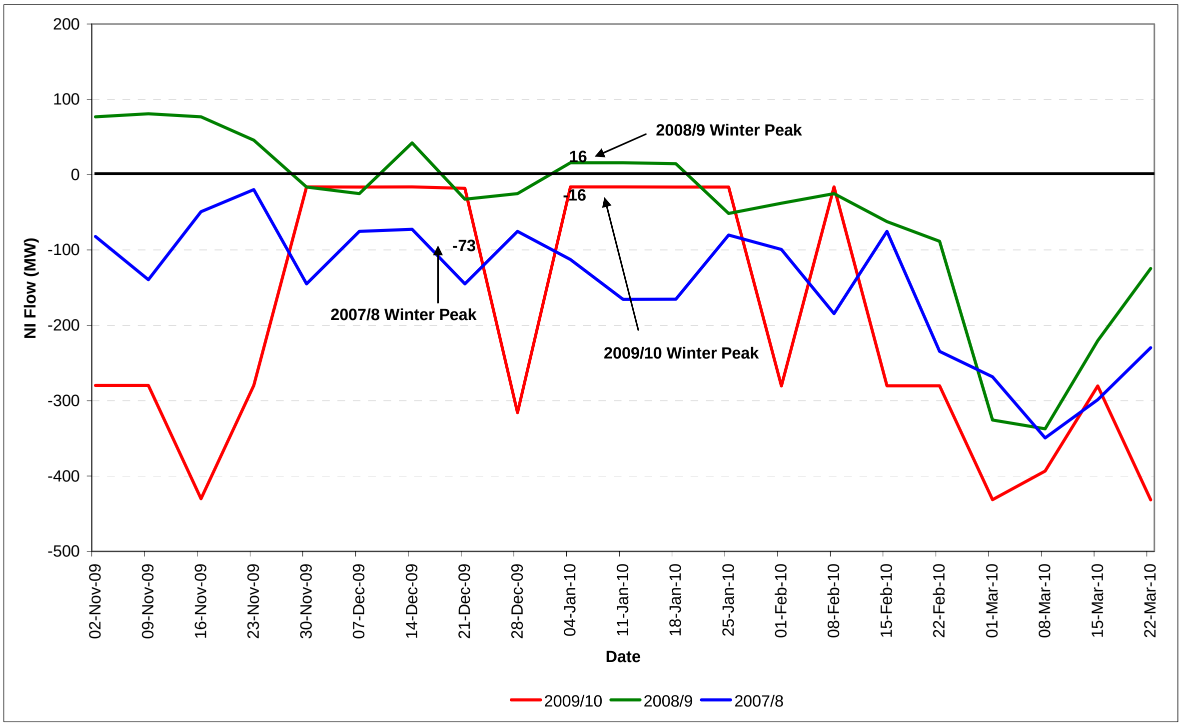
152. For 2009/10 we have analysed the flow over the period of weekly peak GB demand and the relationship between this and GB to France power price differentials. As expected, during periods of power having a higher value in the GB market relative to France, we continue to see that power flows into the GB market. More generally, due to the rate of exchange this year we have seen a change in power flow with an increase in the export to France.

153. The interconnector between GB and Northern Ireland (NI) is smaller than that between GB and France and has tended to predominantly export power from GB to NI, though this seems to have changed last year. The Moyle interconnector can physically flow 500 MW to NI and 500 MW to GB, though Transmission Entry Capacity (TEC) contractually limits the flow to GB to 80 MW whilst the flow to Ireland can be up to the technical capability.

[20] See http://www.nationalgrid.com/NR/rdonlyres/ABA52106-0F74-402F-AF40-A88BBB9DB6A7/32187/Forum_Update_Newsletter_Feb2009.pdf for a fuller explanation.

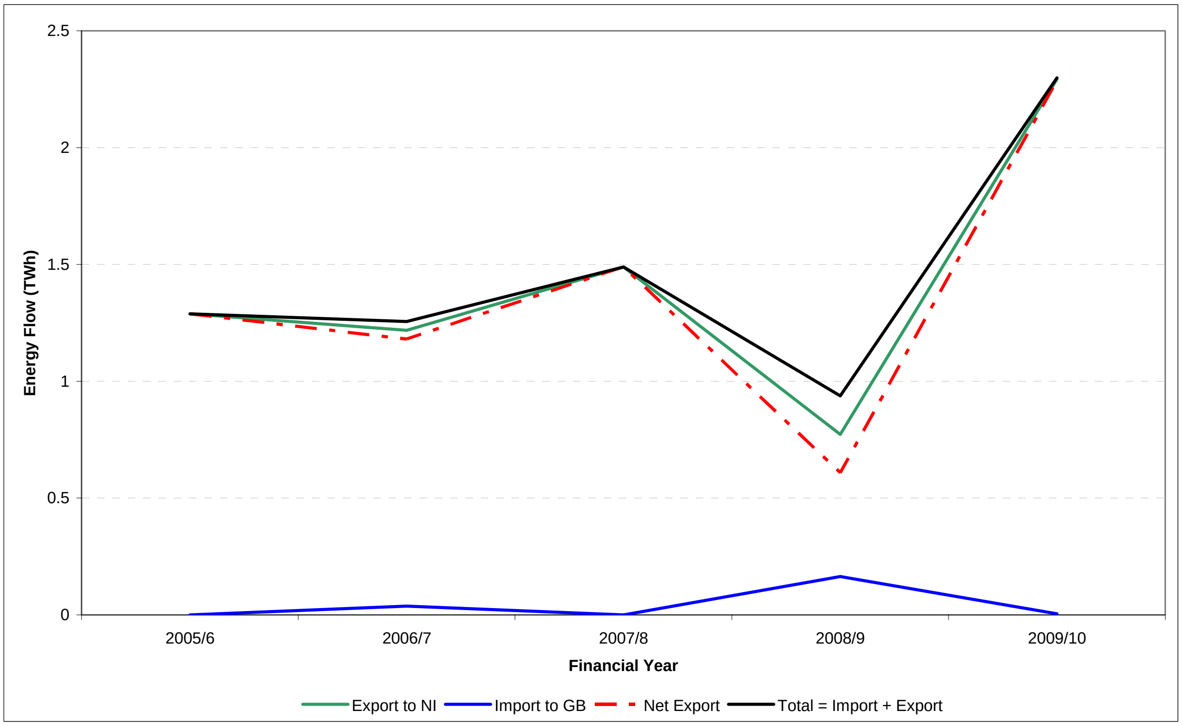
154. Historically, across the winter there has been an export from GB to NI of around 60-400 MW. Figure A.35 shows the interconnector statues at peak demands.

Figure A.35 – NI Interconnector Flow at Weekly Peak Demand for Last Three Winters



155. We examined the overall import/export situation for the Moyle interconnector. Figure A.36 gives a summary of the annual import/export energy exchange between Northern Ireland and GB since BETTA. The export from GB to NI had substantially reduced last year while the import substantially increased. The total energy volume was also significantly lower last year as a result. We had assumed for last winter that NI may require exports from GB at times of peak demand which tend to be correlated for both systems.

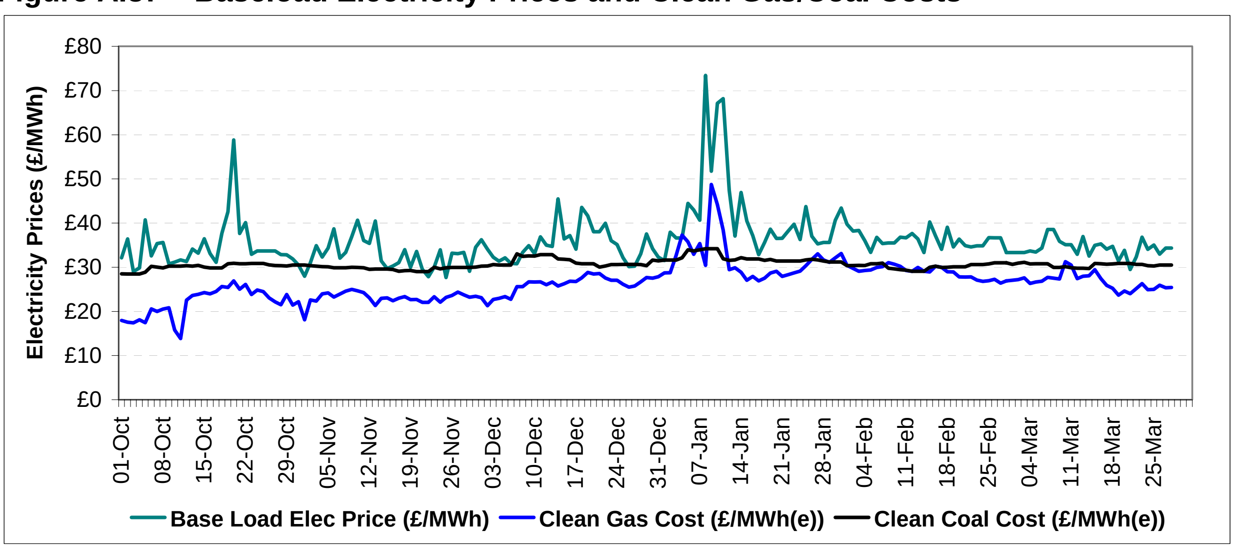
Figure A.36– NI Interconnector Annual Import/Export Energy since BETTA



2009/10 Prices and Merit Order

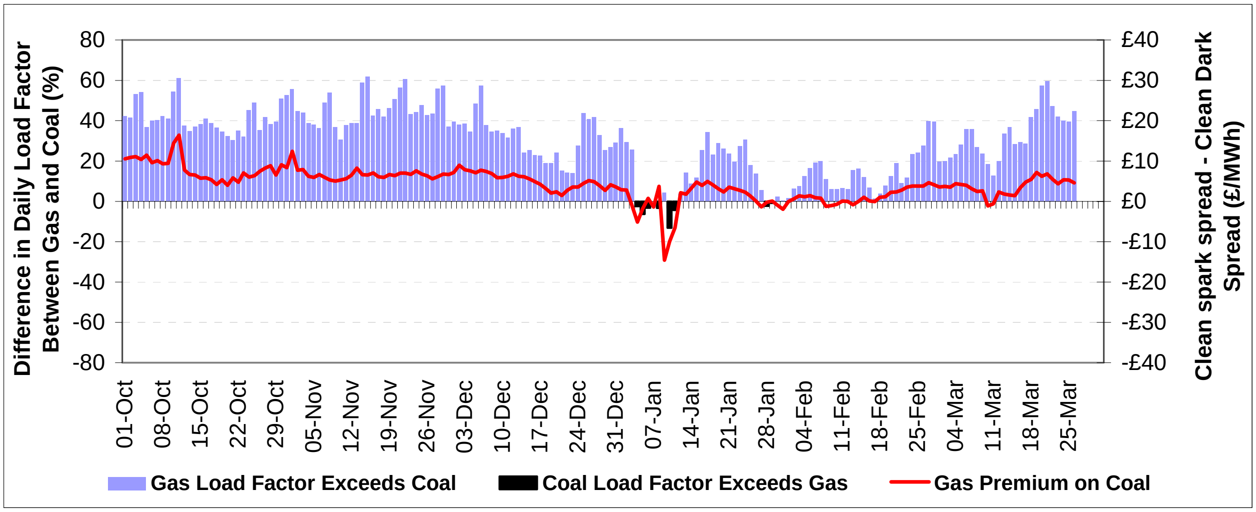
156. Day ahead baseload electricity prices were relatively stable throughout the winter as can be observed in Figure A.37 below. The price spike for base load power in January corresponded with the period of higher demands caused by the cold weather and an increase in gas prices.

Figure A.37 – Baseload Electricity Prices and Clean Gas/Coal Costs



157. Figure A.38 shows that for the core of winter, gas maintained an economic advantage over coal and therefore ran at a higher load factor than coal fired stations. The only exception was the cold period in early January when higher gas prices made clean coal generation costs lower than clean gas generation costs, resulting in an increased output from coal relative to gas fired generation.

Figure A.38 – Baseload Electricity Prices and Clean Gas/Coal Costs



Operational Overview

158. We did not issue any system warnings during winter 2009/10 as a result of healthy generation margins throughout the winter. The last system warning was issued in January 2009. This is the first winter since the BETTA market reform when no system warnings were issued and reflects the improved generation margins we currently see.

Questions for consultation

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

QA9. Do you believe that electricity demand side response capability has materially reduced due to the economic slowdown? Are you able to quantify this impact with supporting information and relate it to an overall GB estimate of end user demand response and share this with National Grid?

QA10. Do you believe demands will return in due course to pre-recession levels or to what extent do you expect them to recover? When might this recovery be expected to have taken place?

QA11. Do you identify other significant factors driving interconnector behaviour in addition to technical availability and relative energy prices between interconnector markets? Is recent interconnector behaviour with higher exports and lower imports to France/Northern Ireland likely to continue this coming winter?

QA12. How did the electricity generation market react to the GBA's issued by National Grid? Can you provide any insight as to the ease/difficulty of the switching from gas to coal fired generation?

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? If you believe additional key information should be provided please outline what other information would assist the market and outline the scale of potential benefit.

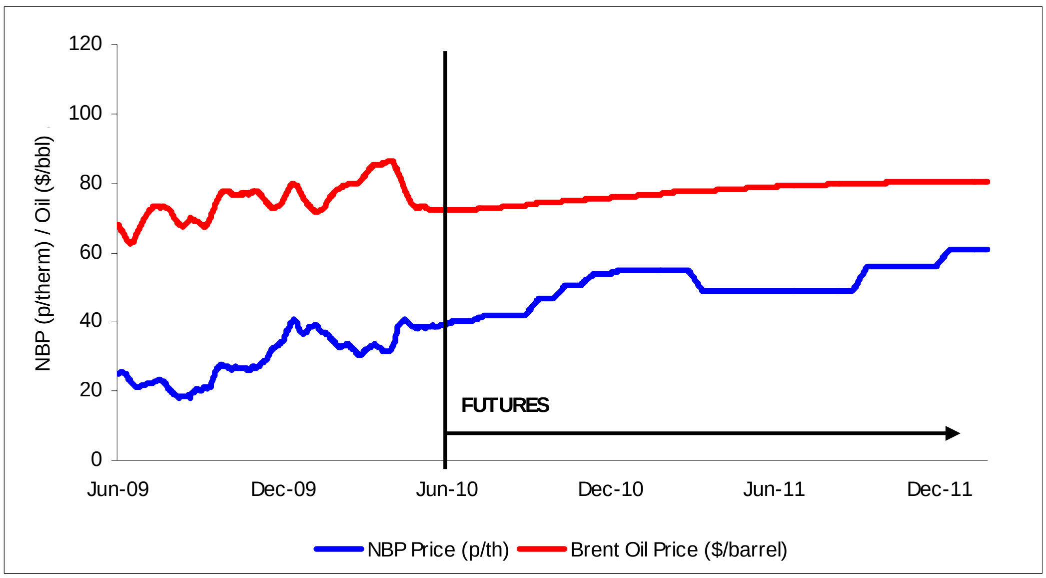
Section B
Outlook for 2010/11

Gas

2010/11 Fuel Prices

159. Figure B.1 shows the historical and forward UK oil and gas prices as of mid Jun 2010. The forward oil price is slowly increasing with time due to views of economic recovery. Historically the UK gas price has been strongly linked to the oil price with a lag of around 6 months, due to high interconnectivity with the Continent whose long term gas contract prices are oil linked. On top of this there is a seasonal risk premium for winter month's UK gas price reflecting supply / demand fundamentals.

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



160. Since the recession, the extra worldwide LNG available due to significant reductions in world demand and increased LNG production, has meant the oil linkage for non contracted gas has been broken. Over the last few months the relationship between oil and gas has become even more disparate, corroborating the view that this linkage may remain broken at least for the short term.

161. Most industry participants believe oil linkage will re-establish, although probably to a lesser extent, once the world economy improves. Views of when this will happen vary generally between 2012 and 2015. In theory as the economy recovers, demand will increase and LNG will return to its (non UK) long term contracted customers. Under these conditions the UK may again become more to European prices based on oil indexed contracts. There are many factors that are may affect this scenario, though:

- Demand may not return to pre recession levels
- US production of unconventional gas may continue despite low US gas prices
- LNG production may continue to increase

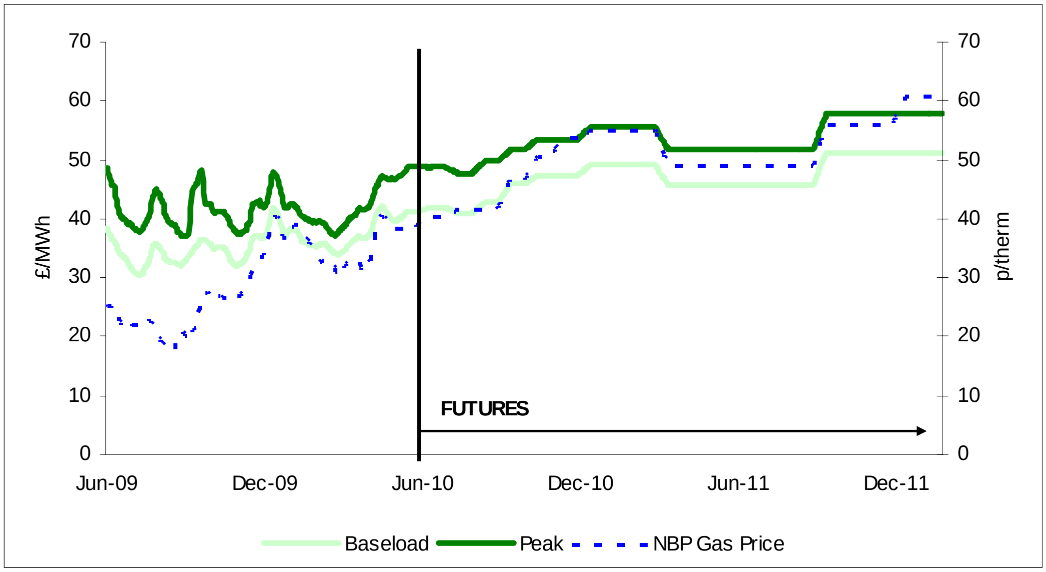
162. Hence the UK could still have considerable LNG available even after contracted customers take their requirements.

163. Press reports also state European gas contracts are becoming less oil linked. Whether oil linkage returns is not too relevant to the coming winter prices as full linkage will not return immediately and the historic lag means that it would be unlikely to have an effect on winter 2010/11 gas prices anyway.

164. The main factors affecting the gas price for this winter are supply, demand, risk and sentiment in the gas markets. The forward prices for the winter are moving based on the near term (prompt) markets. In the last few months Norwegian flow uncertainty relating to unplanned outages before their maintenance outage period have reduced confidence in supplies. Some market commentators believe the effect of this has been exaggerated by certain market players. This seems valid as the daily prices are now notably higher than last winter during the summer season of lower demands. This could indicate the possibility of a correction downwards in gas price over the coming months, which could follow through to the winter prices. However, markets are notoriously difficult to predict.

165. Figure B.2 shows the historical and forward UK wholesale baseload and peak power prices as of early June 2010, together with the NBP gas price. Historically, there is usually 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. This occurred for a few months over summer 2009, mainly due to significant gas price reductions meaning all gas fired generation available was already being used, where further switching to gas was not possible. So any further reductions in gas price could not be reflected in power prices, especially as it was the outage season, for generators. In the forward power markets, the seasonality in the gas price is not fully reflected, due to the ability of generation to switch to coal. Forward baseload power prices for winter 2010/11 are typically £45 to £50/MWh.

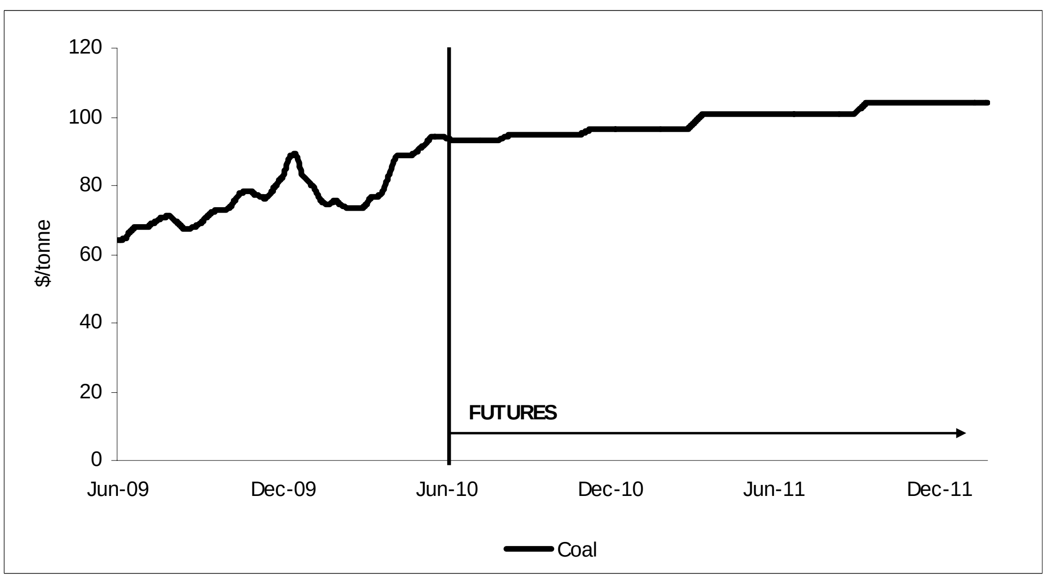
Figure B.2 – Historic and Future Power and Gas Prices



166. Coal prices have tended to reflect movements in the price of oil. The are some differences between markets due to differences in the supply chain, however similar demand fundamentals have meant they generally have similar movements. The rises in forward coal prices, as with oil, reflect the view of slow steady economic recovery and increased demand notably from China.

167. Figure B.3 shows the ARA CIF coal price for history and futures.

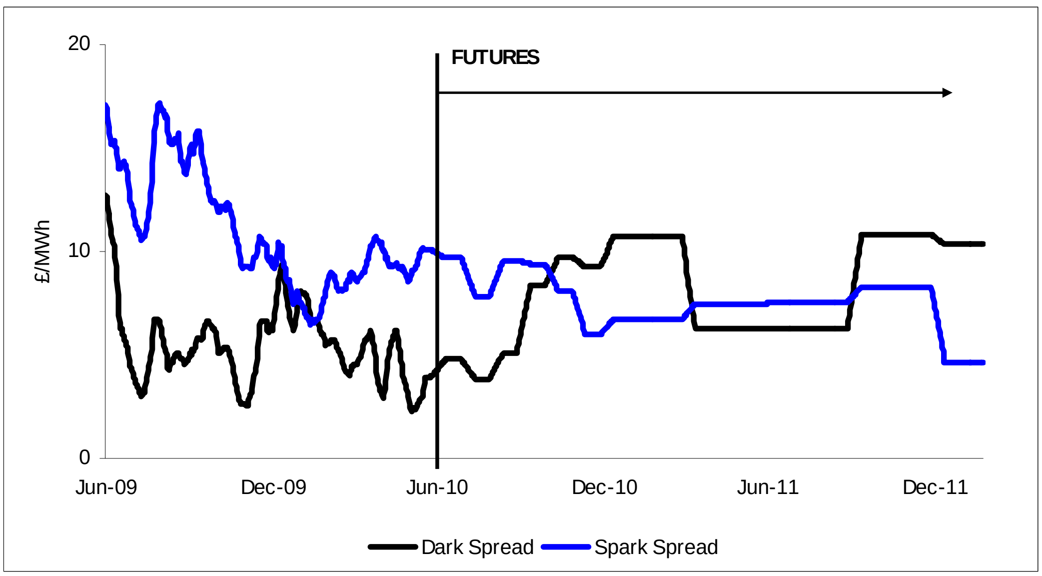
Figure B.3 – Historic and Future Coal Prices



168. The current low gas price, combined with the impacts of the carbon price is benefiting gas-fired power generation when compared with coal fired generation in the UK for the remainder of the summer. For the next two winters as shown in Figure B.4, forward prices suggest that coal fired generation becomes the more attractive of the two, with gas slightly favoured for next summer.

169. The forward curve shows a dark spread of £8-11 /MWh compared with a spark spread that falls to around £6/MWh in winter 2010/11.

Figure B.4 – Historic and Dark and Spark Spreads

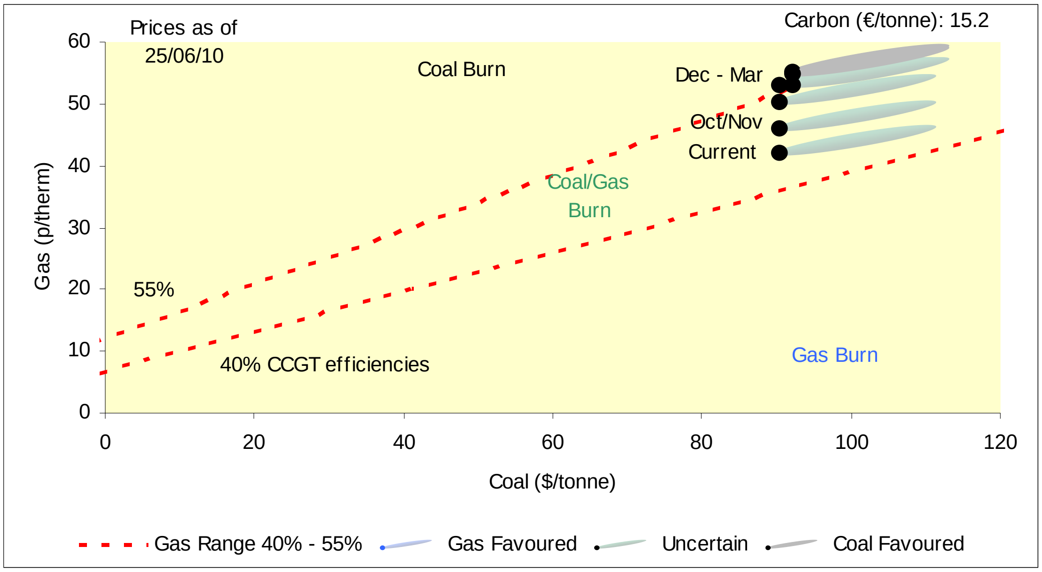


170. These forward prices suggest that coal-fired generation could be the baseload plant over the coming winter, with gas-fired generation as the marginal load. Historically this been position at this time of year due to the seasonality of gas and electricity prices. However, for the past two winters we have seen fuel price changes that mean that gas is relatively more preferable to coal, meaning that gas fired generation has often been Baseload during the winter. Consequently our current forecast for power generation for next winter has gas as base load rather than coal. This assumption will be revisited for our final Winter Outlook report in October.

171. Figure B.5 shows an alternative means of identifying the fuel for power generation for next winter. The chart shows forward prices for coal and gas against a backdrop the preferred source of fuel, this in turn is based on CCGT efficiency and carbon price. The ellipses on the chart reflect relative transportation costs. Current prices suggest little to choose between gas and coal burn with CCGT efficiencies being a major factor in terms of operational economics. As future coal prices show only a modest increase compared to the bigger increase in gas prices, the bias for next winter for all but the most efficient of CCGTs moves towards coal. For gas to become base load again for next winter, the gas price needs to fall by about 10 p/therm or there needs to be a further increase in the coal price by about $20/tonne.

Other factors such as running hours for LCPD and generation portfolios will also influence fuel choice.

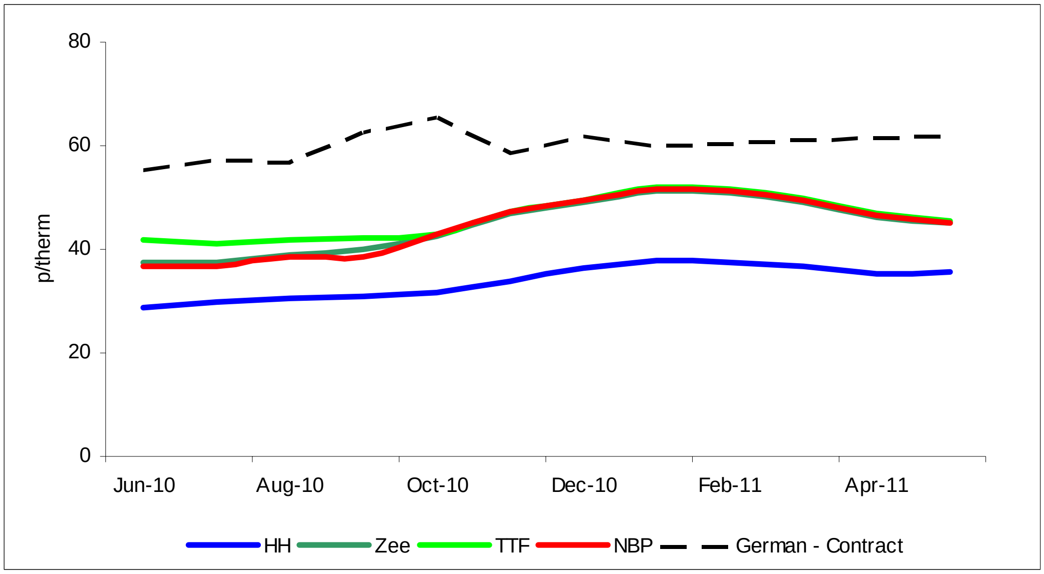
Figure B.5 – Winter 20010/11 – Gas vs Coal Generation



172. Figure B.6 shows the forward gas prices as of late May 2010, for European markets (NBP, Zeebrugge, TTF), for the US (Henry Hub) and our estimate of oil indexed contracts. All the European Markets are closely linked. Henry Hub prices are significantly lower than the European Markets throughout the forward curve. In terms of spot LNG cargoes this provides a considerable incentive to deliver LNG to Europe in preference to the United States.

173. Through the forecast period, the market prices are below our estimate of oil indexed contracts, though the differential is lower for the next winter period.

Figure B.6 - Forward Prices for Europe and US

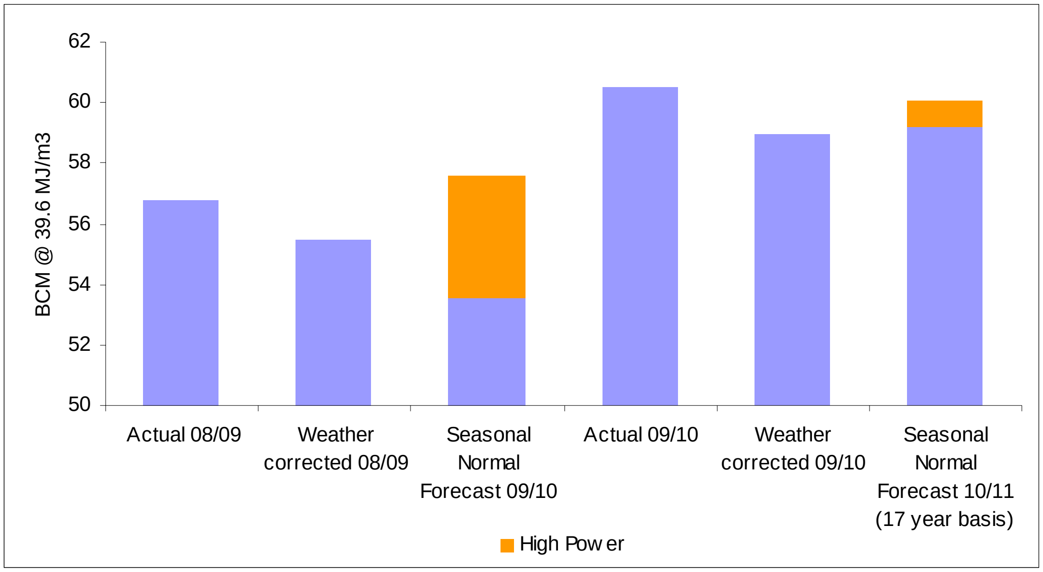


*There is some interpretation on the prices shown, due to data aggregation from months and quarterly trading.

2010/11 Gas Demand Forecast

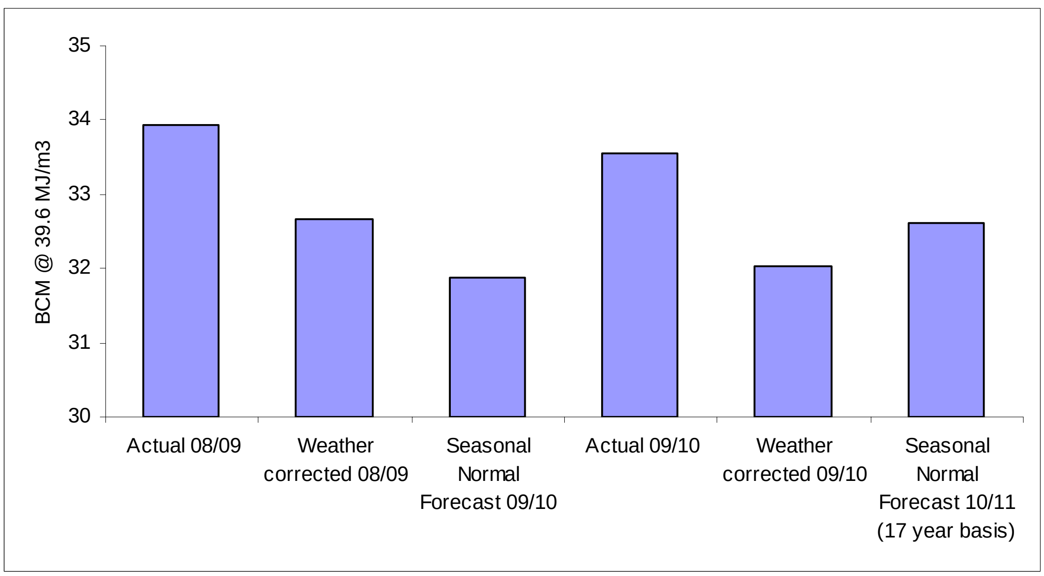
174. Figure B.7 shows that the total winter forecast for 2010/11 is similar to the weather corrected demand in the 2009/10 winter but 11% higher than the forecast for 2009/10. Most of this increase can be attributed to the change in power generation demand. For the 2010/11 winter gas is expected to remain as the preferred fuel with coal as the marginal fuel.

Figure B.7 – Total Winter Demand



175. The NDM forecast for 2010/11 is 2% higher than the weather corrected NDM demand in winter 2009/10 but similar to the weather corrected demand for 2008/09 as shown in Figure B.8.

Figure B.8 – NDM Winter Demand



176. Though subject to some uncertainty as described earlier, gas is assumed to be the base load fuel for power generation for the 2010/11 winter. Figure B.9 shows the 2010 gas-fired generation forecast for 2010/11 to be almost 40% higher than the 'expected' forecast for 2009/10 which assumed coal would be base load

generation. The commissioning of several new CCGTs has contributed to this higher forecast and the increase to the high power scenario.

Figure B.9 – Power Generation Winter Demand

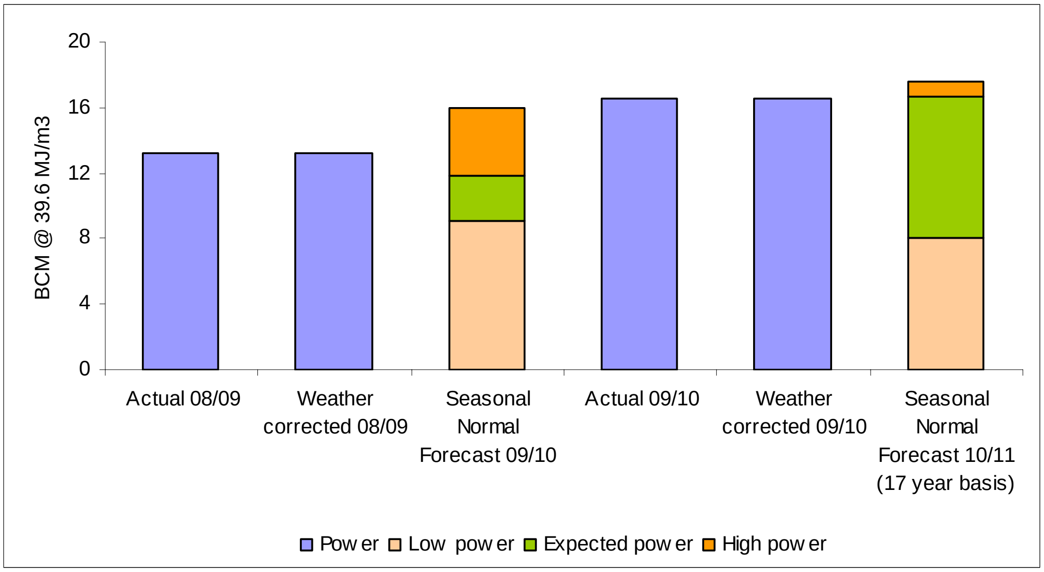
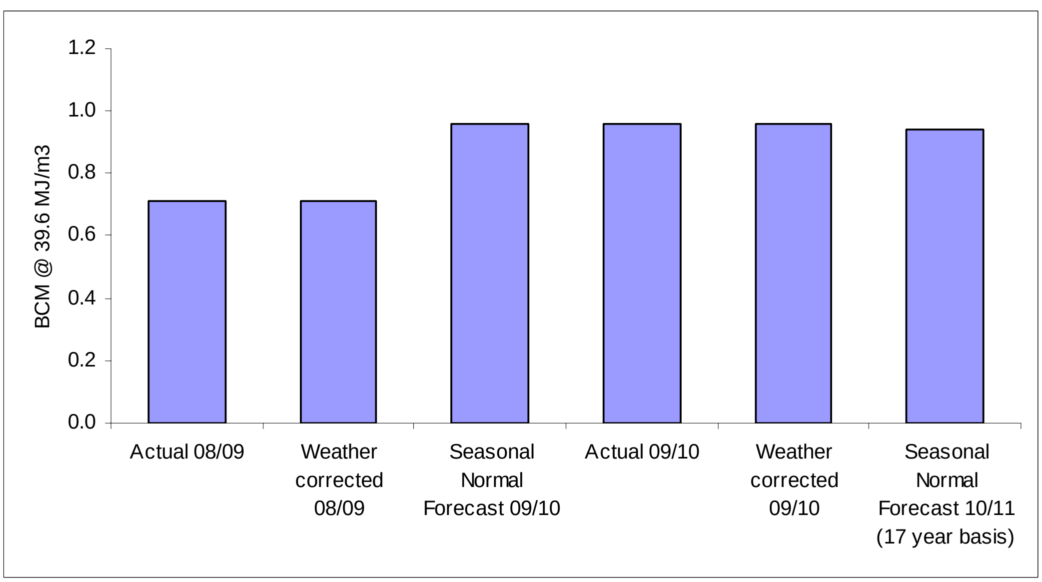


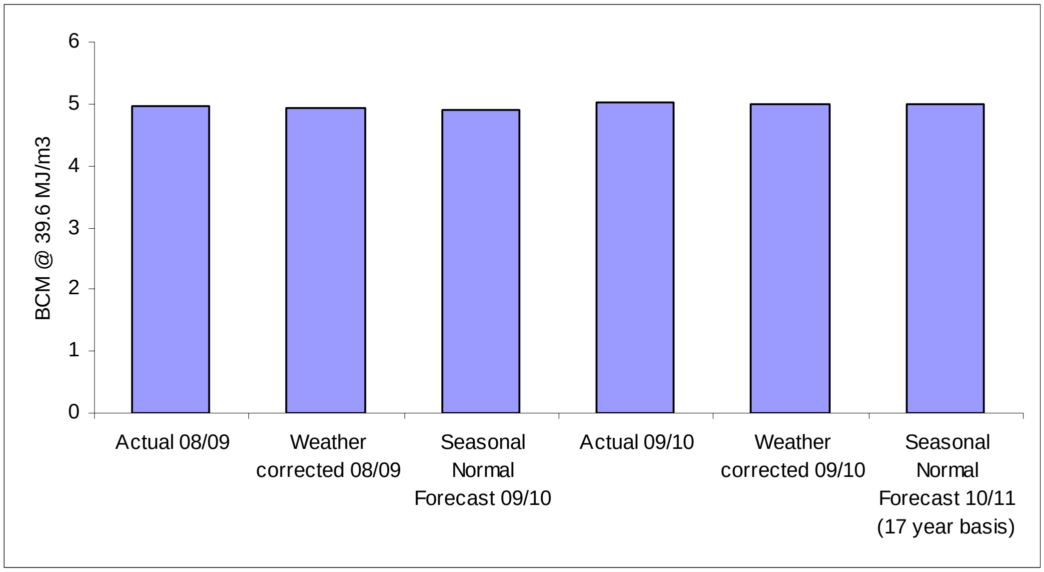
Figure B.10 shows that NTS industrial demand is forecast to be at a similar level to 2009/10.

Figure B.10 – NTS Industrial Winter Demand



177. Non-power daily metered demand is also forecast to remain at similar levels to 2009/10, as illustrated by Figure B.11.

Figure B.11 – Non-power LDZ Daily Metered Winter Demand



2010/11 Gas Supply

178. This section examines each of the potential (non-storage) gas supply sources in turn: UKCS and imports from Norway, the Continent and LNG. As in previous winters, there is considerable uncertainty in both the source and the level of imported supplies for next winter; our initial view is appreciably influenced by our experience last winter and feedback through our TBE consultation. This should not be seen as a definitive view at this stage but a means for industry engagement and consultation.

UKCS Gas Supplies

179. For the purposes of this document, our initial assessment of UKCS supplies for winter 2010/11 is based primarily on industry feedback we have recently received from our 2010 TBE consultation. Table B.1 compares our UKCS outturn from Winter 2009/10 and our initial view for 2010/11.

Table B.1 - Preliminary 2010/11 UKCS Maximum Forecast by Terminal

Peak (mcm/d)	2009/10		2010/11
	Final Winter Outlook 09/10	Highest	Initial View
Bacton	65	51	59
Barrow	16	18	15
Burton Point	1	3	0
Easington	11	10	13
St Fergus[21]	70	65	56
Teesside	24	29	25
Theddlethorpe	16	19	16
Total	203	194	184
90% Operational Forecast	183		166

180. UKCS supplies performed well over the winter 2009/10, broadly in line with our forecast with the exception that some high swing gas associated with Bacton Shell-Esso did not make a material contribution and to a lesser extent extended field outages at St Fergus.

181. Table B.1 shows a provisional UKCS maximum supply forecast of 184 mcm/d for Winter 2010/11. This figure may be updated pending completion of ongoing analysis and receipt of more data and feedback: Any revisions are expected to be incorporated into our annual 'Development of Energy Scenarios' paper in July, or in the final Winter Outlook report due to be published in October.

182. Our Winter 2010/11 figure of 184 mcm/d represents a 9% decline against the Winter 2009/10 figure of 203 mcm/d. In previous years we have reported declines typically between 5% and 10%.

183. For the purposes of supply-demand analysis and for security planning, we assume an operational forecast of UKCS supply below the maximum forecast. For this purpose we intend to continue to use an availability of 90%, resulting in a UKCS planning assumption for next winter of 166 mcm/d.

Table B.2 – Derivation of 2010/11 UKCS Maximum Forecast

	mcm/d
2009/10 Winter Forecast	**203**
Forecast Decline from existing fields	-30
Forecast production increase from existing fields	+4
Forecast production increase from new fields	+7
2010/11 Winter Forecast	**184**
2010/11 90% Operational Forecast	**166**

[21] Excludes estimates for Vesterled and Tampen

184. UKCS peak production from current fields is forecast to fall by 30 mcm/d between winter 2009/10 and winter 2010/11. Offsetting this fall is an increase in production due to come from new fields (~7 mcm/d) and an increase from existing fields.

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

- An increased tendency for producing fields to maintain production all year round rather than "preserving" gas for the winter. This has the effect of accelerating field decline
- Lower availability through poor weather conditions offshore
- The late commissioning of new production or delays in the resumption of production following maintenance outages may result in reduced supply availability early in the winter
- Within-winter decline of existing fields resulting in reduced supply availability later in the winter

Norwegian Imports

186. This winter we expect Ormen Lange to produce similar levels to last year as it is now close to its plateau production of 70 mcm/d, Troll production was comparatively low last year and we expect this to increase slightly as European demand returns. The Gjøa field is due to begin production in October 2010, all the gas from Gjøa will flow to St Fergus via a new offshore pipeline from the field and then through the FLAGS pipeline. The addition of Gjøa with an expected flowrate rate of 10 mcm/d, represents an upside to last year's Norwegian production forecast.

187. In order to forecast Norwegian flows to the UK for next winter we estimate total Norwegian production and assess flows to the Continent and determine flows to the UK by difference. Table A.4 shows our estimates of average Norwegian exports to the Continent and UK since 2007/08. Our estimate of Norwegian production for next winter is approximately 3% higher at 315 mcm/d.

188. Due to the potential variation in Continental flows we have created a range around the central case to highlight the resulting variations in flows to the UK. For the central case we have assumed similar Continental flows to last year, with economic growth being offset by lower weather related demand. The upper and lower ranges around the central case are based on the range (over the last 4 years) of observed load factors to each of the Continental countries that receive Norwegian supplies.

189. Based on our winter Norwegian production estimate of 315 mcm/d, Table B.3 shows a central case 10 mcm/d higher than last winter at 94 mcm/d within a range from 81 to 115 mcm/d. The range highlights an upside to the forecast if Continental supplies are lower than expected and a downside if they are higher.

Table B.3 – Winter 2010/11 Estimates of Norwegian Exports

(mcm/d)	Central	High flows to Continent	Low flows to Continent
Belgium	38	39	35
France	47	52	45
Germany	136	143	120
UK	94	81	115
Total	**315**	**315**	**315**

190. Figure A.20 shows for the October to March period some seasonality in Norwegian flows to the UK, and to a lesser extent the Continent. Last winter flows during October to the UK averaged 56 mcm/d compared to 100 mcm/d in January. Consequently, in addition to a 6 month winter forecast we have created a 3 month winter forecast (December to February) to reflect the anticipated delivery of higher Norwegian flows during the coldest winter months. This forecast is shown in Table B.4.

Table B.4 – Mid Winter 2010/11 Estimates of Norwegian Exports

(mcm/d)	Central	High flows to Continent	Low flows to Continent
Belgium	40	41	39
France	49	52	45
Germany	140	151	130
UK	101	86	116
Total	**330**	**330**	**330**

Continental Imports

191. Last winter, we again observed relatively stable flows through BBL but IUK was significantly more variable, with aggregated exports matching imports. Day to day flow variations for IUK were at times greater than 20 mcm/d.

192. For BBL we anticipate that commercial arrangements for interruptible non physical reverse flow (i.e. non-physical exports) should be in operation. This may result in BBL flows becoming more sensitive to the UK and possibly Continental market needs. We also acknowledge that the increase in BBL capacity from approximately 40 to 50 mcm/d may increase opportunities to export more to the UK.

193. For planning purposes our preliminary forecast for BBL for next winter flows is 30 mcm/d. This is based primarily on flows experienced last winter.

194. Last winter we observed similar volumes of IUK imports and exports of about 1.1 bcm. As shown in Figure A.17 and A.22, IUK imports broadly followed UK demand and price. IUK was also responsive to UK needs particularly during the highest

demands and when there were supply losses in early January. The highest IUK imports exceeded 40 mcm/d. By volume approximately 50% of IUK imports occurred when demand exceeded 400 mcm/d. The relationship of IUK flows against demand was very similar to the aggregated flows of all MRS and LNGS.

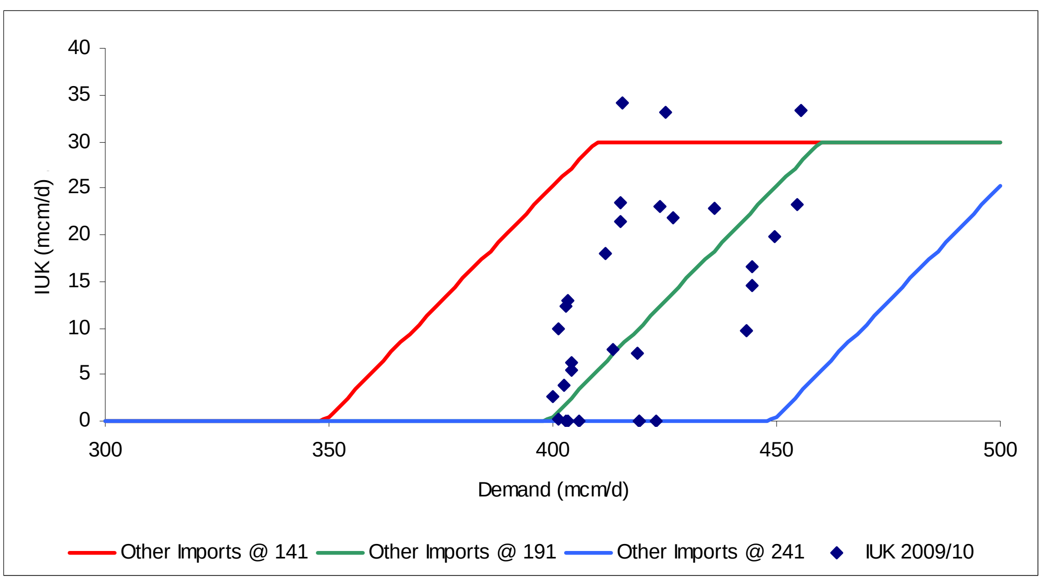
195. In most winters IUK has behaved as a marginal source of supply when UKCS and other imports have not met UK demand. We again expect this behaviour to continue, with MRS, LNGS and IUK acting as the supply balancer to the meet UK demand. Hence if imports from Norway or LNG are relatively high we would again expect little or no IUK imports, conversely higher IUK imports if Norwegian or LNG imports are low.

196. Figure B.12 shows our forecast for IUK imports based on 166 mcm/d UKCS, 42 mcm/d from Rough and a range of other imports based around our central case of 191 mcm/d (101 mcm/d Norway, 30 mcm/d BBL & 60 mcm/d LNG) with a range of +/- 50 mcm/d. The chart shows that for low levels of other imports, IUK could commence importing at demands as low as 350 mcm/d, whilst for a well supplied UK not until demands were as high as 450 mcm/d. Hence in a well supplied UK market, IUK could again be in export mode for low demands next winter.

197. For reference, the chart also shows IUK imports last winter for all demands above 400 mcm/d.

198. Though IUK can import up to about 70 mcm/d, we have assumed for security planning (not capacity planning) a maximum import level of 30 mcm/d. Of course this arbitrary level could be exceeded if market conditions were favourable.

Figure B.12 – IUK Import flows



199. Though not shown on Figure B.12, 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.

LNG Imports

200. Winter 2009/10 was the first winter for both Milford Haven LNG terminals and the first 'full' winter for Grain II. This increased the UK's import capacity for LNG from 8.5 bcm[22] to 34 bcm (~93 mcm/d capacity). Due to the increase in LNG terminal capacity and favourable supply conditions there was a step change in LNG imports from the previous winter from 1.6 to 8.5 bcm.

201. For next winter there is additional capacity through South Hook Phase II (commissioned Q2 2010) and the Grain Phase III (expected to be commissioned in Q4 2010). In aggregate this will bring UK LNG import capacity to in excess of 50 bcm/year (includes Teesside GasPort). This equates to potential daily flows in excess of 143 mcm/d.

202. The market conditions for LNG flows to the UK remain favourable with UK gas winter 2010/11 prices much higher than those in the US and global supply demand position for LNG that should not restrict LNG imports to the UK.

203. To manage the supply uncertainty surrounding LNG we are proposing at this stage of our winter consultation to consider a wide range but below the nameplate capacity, namely from 30 to 100 mcm/d, with an average winter flow of 60 mcm/d. This therefore identifies periods of both low flow and high flow from Grain and both Milford Haven facilities. We acknowledge that flows could be much higher than these but 100 mcm/d for the upper range and 60 mcm/d for average flows does represent an approximate 20% increase in LNG imports from the winter 2009/10.

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

Storage

205. For next winter we expect further capacity to become available from the Aldbrough storage facility and the possibility of further increases at Hole House Farm. In aggregate storage deliverability is little changed from last year's 1360 GWh/d.

206. Table B.5 shows our assumed levels of storage space and deliverability for next winter. Figure A.25 also shows storage refill up to late June 2010. Currently Rough is filled to about 60% with less than 50% for MRS and LNGS. Whilst this is down on the position for this time last year, most storage is expected to be filled before it is required next winter.

[22] Includes ~4 bcm for Teesside GasPort

Table B.5 – Assumed 2010/11 storage capacities and deliverability levels[23]

	Space (GWh)	Refill Rate (GWh/d)	Deliverability (GWh/d)	Deliverability (mcm/d)	Duration[24]
Short (LNG)[25]	1240	2.6	390	36	3
Medium (MRS)	10786	371	609	55	20[26]
Long (Rough)	38750	240	455	42	85
Total	50776	617	1454	132	35

Preliminary View of Supplies Winter 2010/11

207. In the previous sub-sections we have outlined the basis for the assumptions incorporated into our analysis. Table B.6 summarises the supply range and our Base Case, and compares these with the 2009/10 forecasts[27] and actual flows. We should stress that these 2010/11 ranges and Base Case should be regarded as provisional with the primary purpose of fostering discussion and comment.

Table B.6 – Preliminary View of Non Storage Supplies Winter 2010/11

(mcm/d)	2009/10 Range	2009/10 Top 100	2009/10 Highest	2010/11 Range	2010/11 Base Case
UKCS	183	159	171	166	166
Norway	88 – 118	96	115	86 – 116	101
BBL	25	32	36	30	30
IUK	30 - 0	9	44	30 – 0	10[28]
LNG Imports	10 - 60	55	85	30 – 100	60
Total	336 - 386	351	406[29]	342 – 412	367

208. Based on the supply assumptions detailed in the previous supply sections, Table B.6 suggests that the non-storage supply availability for next winter is again uncertain, notably in terms of deliveries of LNG imports and to a lesser extent Norwegian supplies. The availability of each of these supplies is expected to influence IUK imports.

[23] Includes 1208 GWh Operating Margins
[24] Duration based on Space / Deliverability, excludes within winter refill
[25] Commercial services offered by LNGS for 2010/11
[26] 20 days represents an average. Actual range is far greater
[27] Forecast range represents our pre-winter assessment, not any subsequent revisions
[28] IUK shown as 10 mcm/d but assumed to import more at very high demands
[29] 406 mcm/d represents the highest aggregate daily supply of non storage supplies

Safety Monitors

209. 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.

210. 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.

211. This section on safety monitors is consistent with the industry note we issued on 1 June 2010 as required under the Uniform Network Code (Q5.2.1).

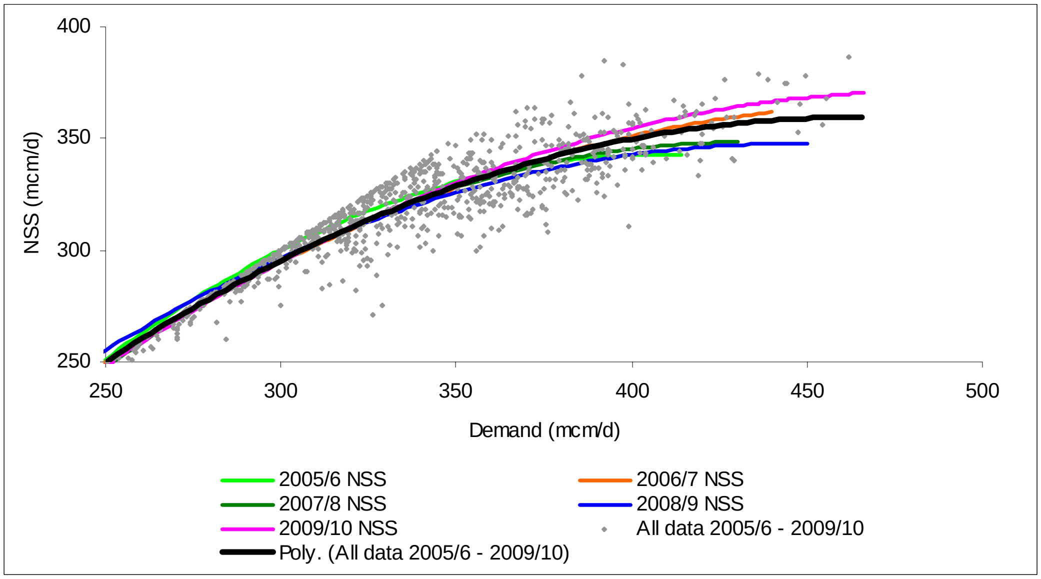
212. Following winter 2008/9, we reviewed the safety monitor methodology and made a number of revisions to the calculation of the monitor and enhancements to the dissemination of safety monitor information throughout the winter. We believe that these changes have:

- Improved information provision to the market with respect to safety monitor requirements
- Enabled the market to operate more effectively through greater clarity regarding the necessary safety monitor space and deliverability requirements
- Enhanced Security of Supply and the market's ability to plan and thereby efficiently deal with supply "shocks"

213. It should be noted that these changes did not increase the total safety monitor storage requirement. Following winter 2009/10 we have made a further revision to the safety monitor calculation methodology and also provided additional information to the marketplace with respect to the potential impact of a supply shock.

214. The safety monitor space requirement is highly dependant on the non storage supply (NSS) level. Previously, the safety monitor methodology assumed a single figure for NSS which applies for all days within the winter, i.e. the value of NSS is independent of demand. In reality NSS levels increase with increasing demand. This can be seen in Figure B.13, which shows trend lines for NSS versus demand for winters 2005/6 to 2009/10. An aggregated trend line for all five winters worth of data is also shown.

Figure B.13 – NSS v demand relationship for winters 2005/6 to 2009/10



215. The chart shows the relationship of NSS vs demand where NSS tend to equal demand for demands below 300 mcm/d thereafter NSS increases at a lower rate (due to use of storage) towards an asymptotic value. It is proposed that the shape (not the values) of the aggregated trend line forms the basis for the NSS versus demand relationship for calculating the 2010/11 safety monitor.

216. This approach, whilst not having a significant impact on the overall level of the safety monitor does have a number of benefits:

- It represents a more realistic approach to the relationship between supply (NSS) and demand
- Within winter monitoring of actual NSS levels will enable us to determine whether the NSS v demand relationship used within the safety monitor calculation methodology is fit for purpose. If it is found not to be, it can be revised based on the latest information, it also enables us to test our supply assumptions before we experience high winter demands.

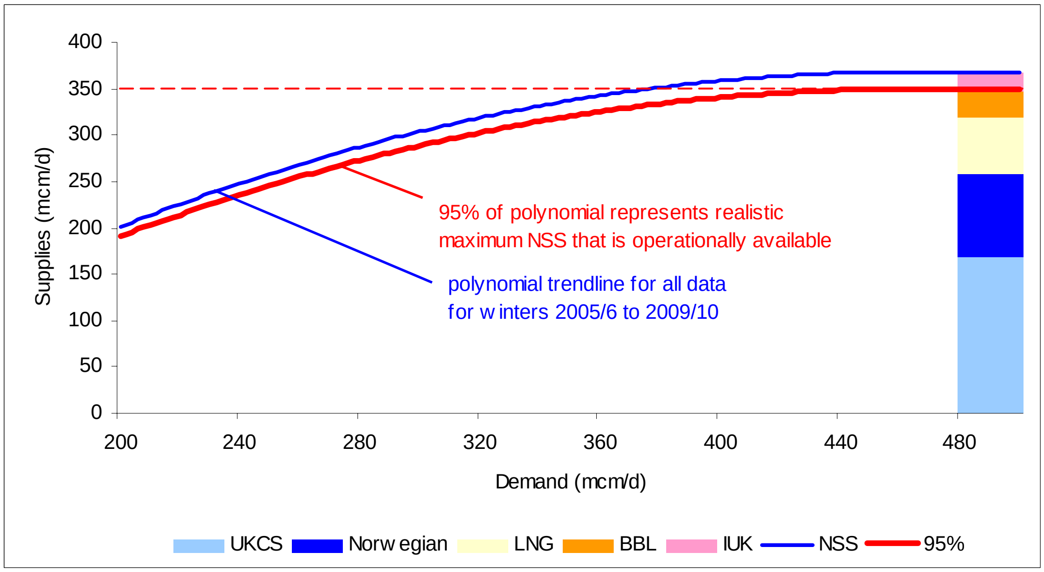
217. There is considerable uncertainty regarding the make up and aggregate level of non storage supplies. The aggregate supply position is expected to be similar to that experienced last winter. However there is movement in the forecasts for the individual supply components. The aggregated level of NSS used in calculating the safety monitors was 368 mcm/d. This is close but not identical to the preliminary view of NSS in Table B.6 (367 mcm/d) as the safety monitor requirement was determined in May and our current view of supplies has marginally changed. Our final view of supplies for next winter will be detailed in our Winter Outlook document to be published in October, these levels will be used as the basis of setting the final safety monitor levels by October 1st.

218. The focus of the safety monitors is public safety and hence it is prudent to ensure that the assumed level of NSS will be available throughout the winter, notably at

times of high demand. Figure B.13 highlights the range of data points around the best fit trend lines. To capture most data points the trend line needs to be reduced. On analysis of previous winters lowering the trend line to 95% captures typically 95% of all data points, with those that are still below often reflected by short term supply losses as experienced on occasion last winter.

219. By applying a value of 95% to the aggregated total of NSS, the value of NSS used in determining the 2010/11 safety monitors was reduced from 368 to 350 mcm/d. The resulting relationship of NSS against demand is shown in Figure B.14.

Figure B.14 – 2010/11 Non storage supply assumptions v demand relationship



220. Table B.4 shows our storage assumptions for winter 2010/11.

221. The demand background used for the analysis in this section is our demand forecasts for 2010/11 that we produced in May 2010. These are slightly higher than our 2009/10 forecasts produced in May 2009. With the overall supply position expected to be similar to that experienced last winter, the slightly higher levels of forecast demand have marginally increased the safety monitor levels for next winter. These are summarised in Table B.7.

Table B.7 – Total Safety Monitor Space Requirement

	Total storage capacity (GWh)	Space requirement (GWh)	Space requirement %
Total	**50776**	**1163**	**2.3%**

222. It is our responsibility to keep the safety monitor 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.

223. As the safety monitor requirement is so heavily dependent on NSS levels, any significant sustained supply shock will result in a significant increase in the safety monitor requirement. This year in an effort to provide the market place with some additional information regarding the potential impact of a supply shock, we intend to publish, for information only, an indicative safety monitor requirement for a NSS with a sustained 50 mcm/d supply loss. It must be stressed that the 50 mcm/d supply shock safety monitor will be published for information only, just as the firm monitor is. However this additional monitor does reflect the consequences of increased storage requirements should a sustained supply loss materialise.

LNG Storage

224. In December 2009 National Grid Storage announced a further strategic review of its LNG Storage business. This resulted in an announcement in May 2010 that further commercial storage services would not be offered beyond the current year at Glenmavis and Partington. Avonmouth LNG services are still under consideration, with, as a minimum, sufficient storage space being made available in 2011/12 for customers to carry over unused stock from 2010/11. OM (Operating Margins) and SIU (Scottish Independent Undertakings) services will continue from all three facilities.

Winter 2010/11 Update on Provision of new NTS Capacity

225. The references in the following tables of projects relate to the map shown as Figure B.15.

East Coast Entry Capacity

226. Following significant investment in providing new East Coast entry capacity in recent years, construction of the Easington to Paull pipeline is due to commence, this will provide increased entry capacity in the Easington area.

Projects

Ref	Project	Scope
A	Easington to Paull	26km x 1200mm

South West Exit Capacity

227. To meet demand requirements in the south west area the Wormington to Sapperton pipeline is due to completed in 2010, this will provide increased exit capacity in the South West.

Projects

Ref	Project	Scope
B	Wormington to Sapperton	44km x 900mm

Emissions related works

228. Two electric drive projects to reduce compressor station emissions are planned for completion in 2010/11.

Projects

Ref	Project	Scope
C	Kirriemuir	New 35MW VSD electric unit
D	St Fergus	Two new 24MW VSD electric units

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

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

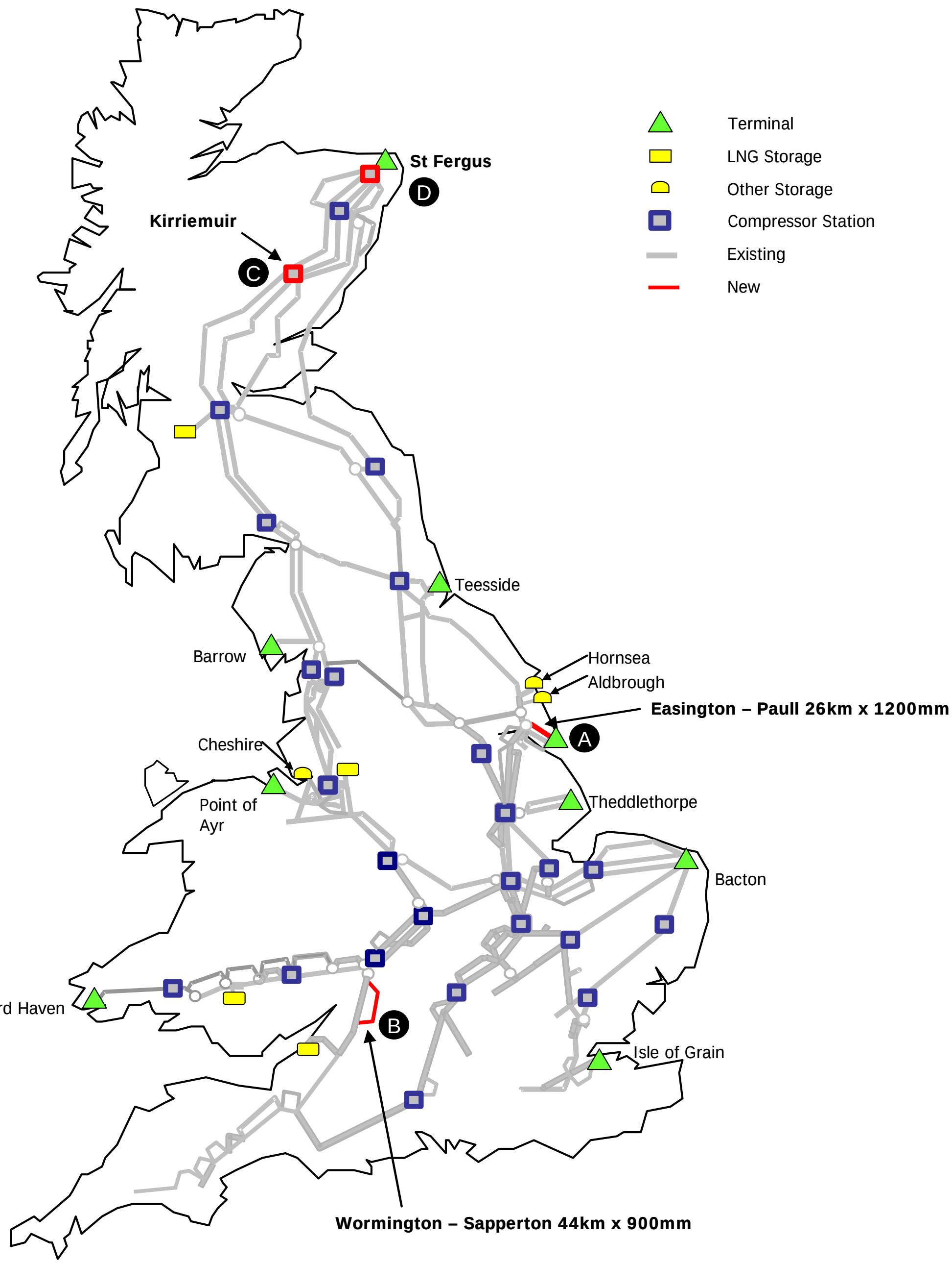
230. Both the South Hook and Dragon LNG importation terminals commenced commercial operation during summer 2009.

231. Work to facilitate entry flows from the Milford Haven LNG Importation terminals continues, including a planned replacement unit at Churchover compressor station.

New Exit Connections

232. During the gas year 2010/11, it is expected that new power stations, including Grain CHP, will become operational.

Figure B.15 – NTS Capacity Projects



Questions for consultation:

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

QB1. What drivers may influences the gas price in winter 2010/11? What factors may set floor and ceiling prices?

QB2. Are we right to currently assume that gas will baseload for power generation or should we follow the forward prices that suggest coal will baseload?

QB3. Do you agree with our high level view of lower UKCS supplies and marginally higher Norwegian imports to the UK albeit dependent on Continental flows?

QB4. What assumptions should be made for levels of imported gas through BBL and IUK for winter 2010/11?

QB5. What assumptions should be made for levels of imported LNG through Grain, Milford Haven and Teesside for winter 2010/11?

QB6. We would welcome comments on our 2010/11 Preliminary View, and thoughts on how we can reduce or manage the resulting supply range.

QB7. We would also welcome comments on our changes to the Safety Monitor determination.

Electricity

Electricity Demand Levels for 2010/11

233. Last year, saw a 0.2GW lower ACS demand outturn than the year before. This represents a 0.3% reduction from the year before but 2.3GW lower than winter 2008/09. The demand drop started to appear in mid-summer 2009 and accelerated from late summer. The decline in demand continued into 2009 but the most recent trend as indicated in the Figure B.16 is that there is now a stabilisation linked with the economy stabilising and returning to some growth.

234. Our Great Britain Average Cold Spell (ACS)[30] winter peak demand forecast for the coming winter is 57.6GW. This is 0.2GW less than the 57.8GW ACS demand outturn of last year, assuming the electricity demand decline caused by current economic crisis was essentially reflected in the existing demand drop observed to date.

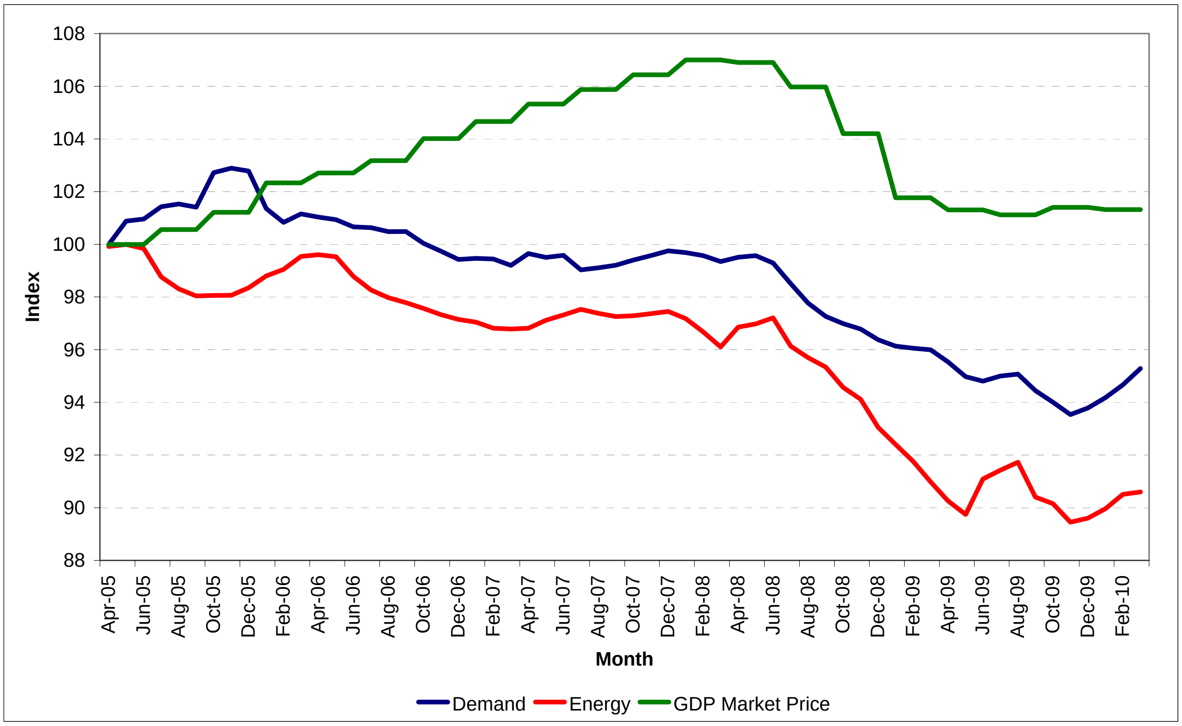
235. We have created and analysed an index of demand, energy and quarterly figures of GDP Market Prices[31] from April 2005 to date shown in Figure B.16. Pre recession, energy use was at a peak in April 2005 and began a slow decline, as stated earlier caused by embedded generation growth, energy conservation and fuel price increases. The weather corrected demand peak, which hit a high in winter 2005, has also been generally reducing at a very slow rate since this high point. In April 2005 the economy was growing based on the GDP market price index and hit a peak in March 2008. From this point on the recession took hold and the demand and energy levels show a clear reduction at this point and tracked this down until its stabilisation around June 2009 with a slight increase in GDP market price for last quarter of 2009, marking the end of the recession. It can be seen that the recession had a greater impact on energy use than demand levels. The stabilisation in demand and energy has aligned with the stabilisation in the economy. Continued stable levels of economic activity is the view we are taking forward in our forecasts, but these will be reviewed at regular intervals as we have more information. Particularly the pace and timing of any recovery remains a key uncertainty for our winter 2010/11 demand predictions.

236. In addition to the economic activity related driver of demand, the pre recession factors which have been gradually reducing demand continue to take effect. Such as; how much growth in embedded generation in distribution networks, more efficient use of energy and energy price awareness amongst consumers mitigate increased demand through economic activity further complicates the overall picture. We continue to review our forecast as our normal work process and publish regular updates on www.bmreports.com.

[30] 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.

[31] http://www.statistics.gov.uk/CCI/nugget.asp?ID=192&Pos=6&ColRank=1&Rank=144

Figure B.16 – Index of demand, energy and quarterly GDP market prices



237. The 1 in 20[32] peak demand forecast is 59.0GW. 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 interconnectors.

238. In Section A, we also estimated around 0.5-0.8GW of demand management observed at times of peak demand in the winter of 2009/10 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 2010/11 we have assumed 0.5GW of demand side response in our demand forecasts for ACS and 1 in 20 conditions. The reduction in the demand side response is based upon observed closures of large industrial demand users.

Notified Generation Availability 2010/11

239. Based on the observed output of power stations, National Grid's current operational view of generation capacity anticipated to be available for the start of winter 2010 is 77.1 GW. A breakdown of this capacity is shown in Figure B.17.

240. We could see around 300 MW of wind generation capacity progressively become available between now and the start of winter. This generation is currently being built and we have limited operational transparency of the firmness of progression of

[32] 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.

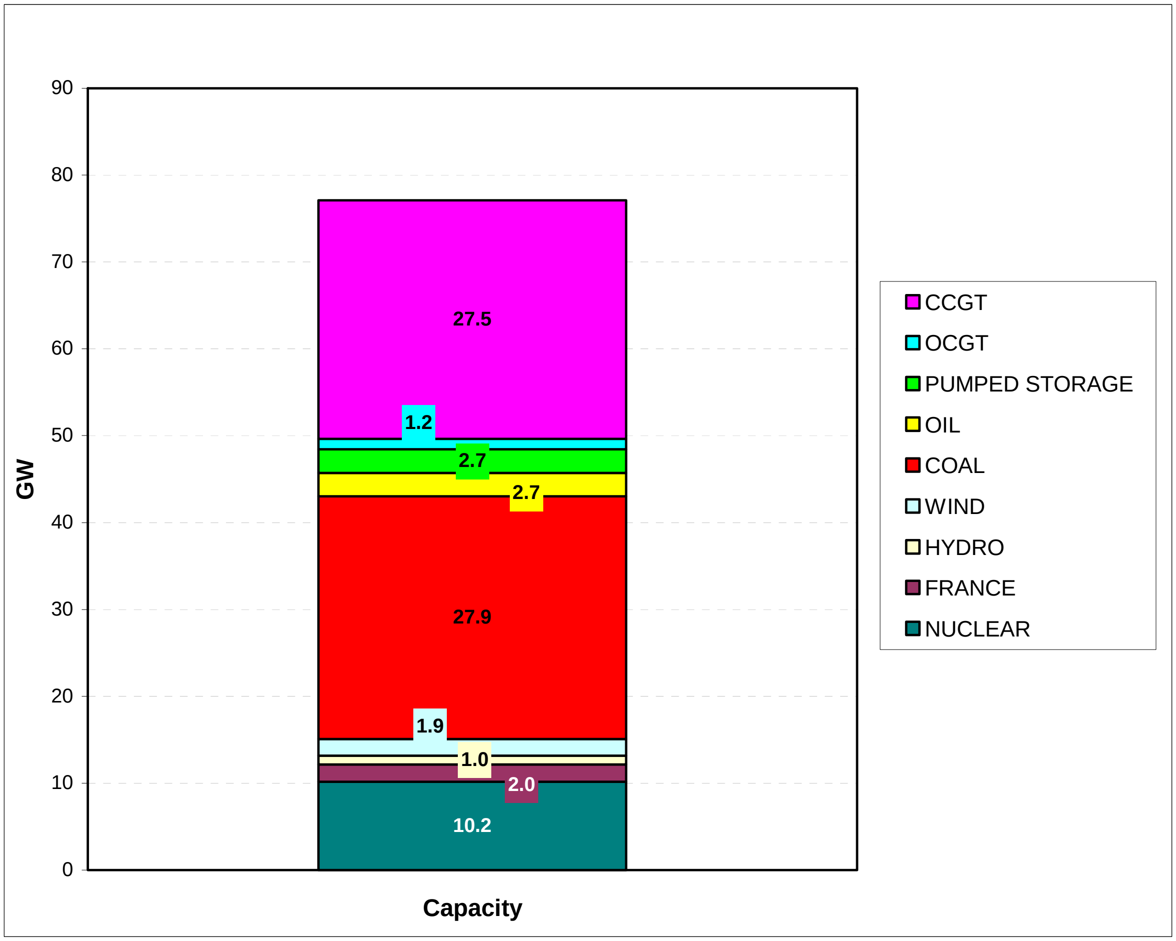
this generation towards operation, so it has not been included in the winter starting figure.

241. Some generation capability upside exists in the form of the new CCGTs currently undergoing commissioning or due to begin commissioning over the summer. These are Staythorpe (1700 MW), Severn Power (850 MW), Grain Units 6, 7 and 8 (1200 GW) and West Burton B (1300 MW). These stations are expected to enter full commercial operations at some point between now and the end of the winter to come. Also we expect to see additional wind generation progressively becoming available over the course of the winter. None of these are included in our winter 2010 starting generation figure.

242. Our end of winter 2010/11 operational view of generation could therefore total up to 82.5 GW, dependant on how the build phase and commissioning of the new CCGT's progresses and the rate at which new wind generation is being developed.

243. The total Operational Realisable Capacity (ORC) at 77.1 GW for winter to come has decreased from the summer outlook position due to one of the oil fired units not being available this winter, a new long term restriction at one of the nuclear units, the planned closure of one of the units at Oldbury and the latest assessment of the maximum operational capacity of the existing plant.

Figure B.17 – Generation Capacity Operational View 2010/11



Generation Availability Assumptions 2010/11

244. A lower availability of 75% has been assumed for nuclear plant as the nuclear fleet struggled to reach 80% last winter. However, the coal plant has been assigned a higher availability of 90% as it regularly achieved this and reached 92% at the time of the last winter peak. The assumed availability for CCGT plant has been left at 90% but oil has been dropped to 80% on the basis that one oil unit will remain withdrawn over the coming winter. An availability of 100% has been assumed for pumped storage generation in line with the outturn for the last two winters and the assumed availability for the OCGT plant has been increased to 90% after achieving 91% last winter. Hydro generation, which here includes small generation that is run of river, has been assigned a conservative assumed availability of 60%. This compares with an observed load factor of 59% at the time of the winter peak demand last year, 90% in 2008/09 and 73% in 2007/08. As far as wind is concerned, the assumption has been reduced to 10% as the winter peak usually occurs when temperatures are very low with little wind. A period of low

temperatures usually results from a high pressure system, which means low wind speeds.

245. Table B.8 therefore shows our assumed generation availabilities at the time of winter demand peak for 2010/11. The overall availability assumption results in a figure of 86%, which is close to last year's outturn.

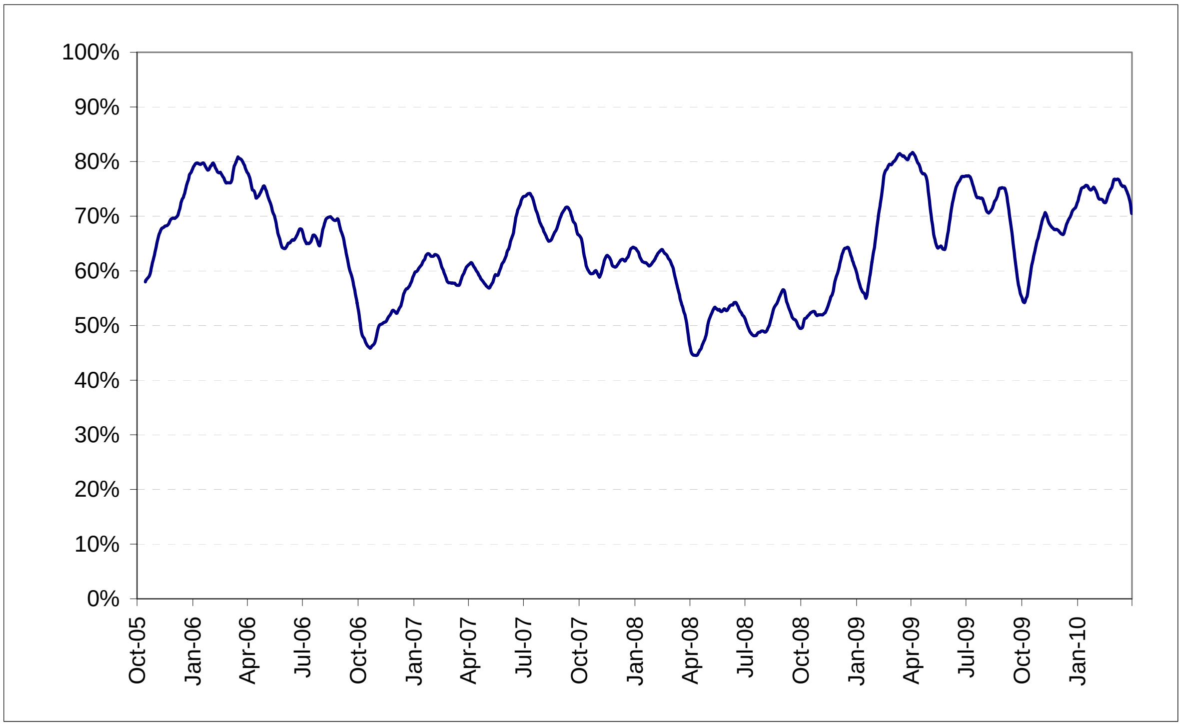
Table B.8 – Generation Availability Assumptions Made For Winter 2010/11

Power Station Type	Full Metered Capacity (GW)	Assumed Availability	Assumed Availability (GW)
Nuclear	10.2	75%	7.6
French Interconnector	2.0	100%	2.0
Hydro generation	1.0	60%	0.6
Wind generation	1.9	10%	0.2
Coal	27.9	90%	25.1
Oil	2.7	80%	2.2
Pumped storage	2.7	100%	2.7
OCGT	1.2	90%	1.1
CCGT	27.5	90%	24.7
Total	**77.1**		**66.2**
Overall availability		**86%**	

Nuclear Availability Assumptions

246. One area of potential uncertainty is the performance of the nuclear generation fleet. We have analysed historic availability of nuclear power stations for the last four winters shown in Figure B.18. Availability was lower than normal over the 2008/09 winter due to technical issues impacting several units of a particular design simultaneously. By the end of last winter nuclear availability returned to 80% for the first time since the winter of 2005/06. However, nuclear availability has failed to reach 80% since then so an availability of 75% has been assumed for the coming winter.

Figure B.18 – Historic Nuclear Generation Availability



Interconnector Availability Assumptions

247. As discussed in Section A, the French Interconnector was traditionally importing during the system peak demand period until this year but we still believe it is appropriate to continue to treat the interconnector with France as a source of generation or at float rather than a demand at peak times. The recent trend for the Northern Ireland Interconnection was either exporting to GB at a lower level than historically observed or more consistent with longer term observations to be importing to NI at a low level. We have therefore made the assumption that both interconnectors at system peak will be at float and readers of the analysis here can overlay their best assumptions if different on demand or generation availability. We have though assumed that relative market prices would make power available from France in line with historic experience.

248. During winter 2010/11 we expect the new Britned[33] interconnector between the Netherlands and GB to start commissioning. As this interconnector is still in it's build phase, in common with new generation we have not included it's potential affect on the demand and generation balance this winter. During Britneds commissioning programme we discuss the level and direction of transfers. In extreme circumstances we have the capability to request a float transfer if necessary for GB energy needs during the commissioning phase.

33 See http://www.britned.com/Pages/default.aspx for more information.

249. Britned are indicating commercial go-live by April 2011, which suggests their operations start after the period of high winter demands in December in January. The charging regime around TRIAD's that incentivises users of interconnectors not to be exporting at peak demand times will also apply to Britned, which indicates that should it be operating for the time of winter peak demand in 2010/11 that it will be likely to be importing to the GB market or at float.

Wind Capacity Credit

250. We have continued our work over the last year to assist us in developing an operational assumption for a capacity credit for wind in line with our security of supply obligations for meeting the peak winter demand. We initially undertook this work with Edinburgh University though now it continues with Durham University due to the movement of our lead researcher to Durham.

251. Whilst this work is ongoing we have reviewed the historic load factors of wind power generation and propose a 10% capacity credit figure for the winter to come. This reflects the levels of output we have seen at demand peaks, so average load factors over an entire winter will normally be significantly higher. The results of our latest phase of work on wind power capacity credits and system adequacy is contained in Appendix 1 to this report on which we invite comment and seek expressions of interest in a workshop.

Mothballed Generation Capacity

252. The amount of plant that is long term mothballed remains at 1.25 GW. We do not expect any other plant to be mothballed for winter 2010/11, though with new CCGT plant commissioning and continuing low demands as a result of the economic slowdown the possibility of some additional mothballing should not be completely ruled out. We do not expect any of the currently mothballed generation plant to become available for this winter.

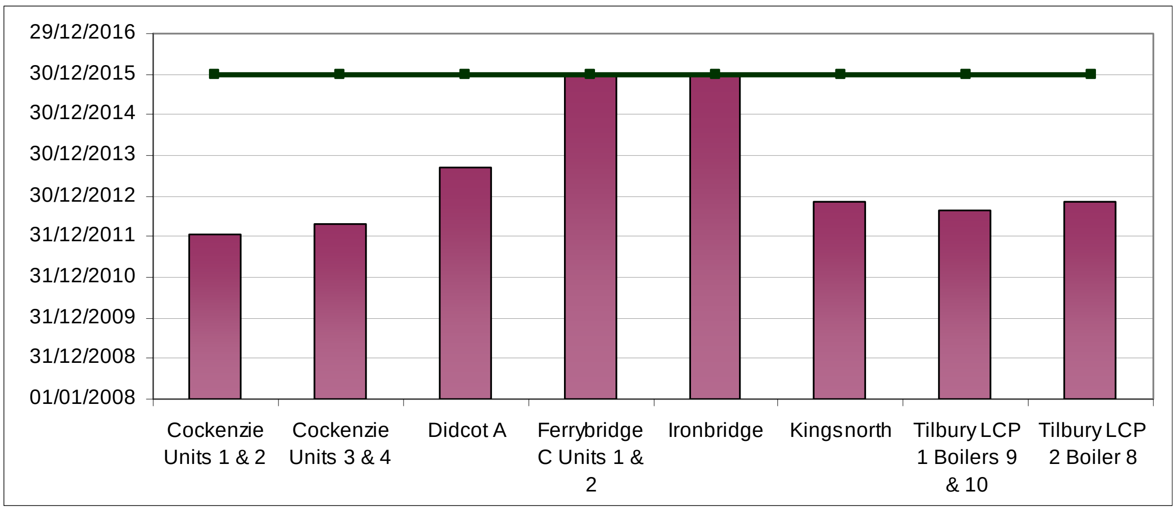
Generation Side Risks

253. For the coming winter we are not proposing at this stage to provide a "low case" generation scenario because we have not identified a specific risk area. Type faults/generic safety issues can arise occasionally or key power station mechanical plant may fail from time to time. Capacity restrictions through these kinds of risks and issues are only potentially onerous if they happen to coincide with periods of relatively high demands and they are low probability events.

254. Recent history has shown that during peak demand, the demand contribution from wind power could be low. If wind power output is discounted to zero over the winter demand peak, available generation reduces by 200 MW (10% of 1.9 GW capacity). Hence in the current environment the impact of no wind is of low materiality for this winter.

255. Issues related to the limited hours under LCPD for opted out plant are unlikely to affect this winter, but could be relevant for next winter and certainly for the following winter based on historic operation patterns. LCPD Opted out plant has 20,000 hours allowed operation until December 2015. At the current observed rates of utilisation of the allowed hours there is an implication of early closure at some power stations. Our latest view of early closing, given running patterns to date projected forward for opted out coal stations is shown in Figure B.19. We have not shown opted out oil stations in this chart due to their current low number of running hours relative to their 20,000 hours allowance.

Figure B.19 – Indicative LCPD Coal Opt Out Plant Closing Dates



Contracted Reserve

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

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

258. 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.

259. For winter 2010/11, our level of contracted STOR reserve is approximately 1.8GW, over 1.5 GW from BM participants and nearly 0.3 GW from non-BM generating plant and demand reduction.

260. Prior to the winter, there will be two further STOR tender rounds covering services for the winter 2010/11 darkness peak; the results of which will be published at the end of August and mid November. Communications regarding this will be through electricity operational forums and on our website http://www.nationalgrid.com/uk/Electricity/Balancing/services/reserveservices/STOR/.

261. National Grid expects to contract more STOR to provide reserve service over the winter. Last winter we contracted 2.7 GW of STOR in all, but much of that was not available over weekday peak demands and dependent on providers contracted position or availability. Total availability at the time of the winter peak last year was about 1.9GW.

262. In addition to STOR, there is a continual requirement to provide frequency response on the system. This can be either contracted ahead of time or created on synchronized sources within the BM. If all response holding was created in the BM, then approximately 1.5GW of reserve would be required to meet the necessary response requirement. 0.7GW of this 1.5GW reserve requirement has already been contracted, with 0.2GW from demand-side providers.

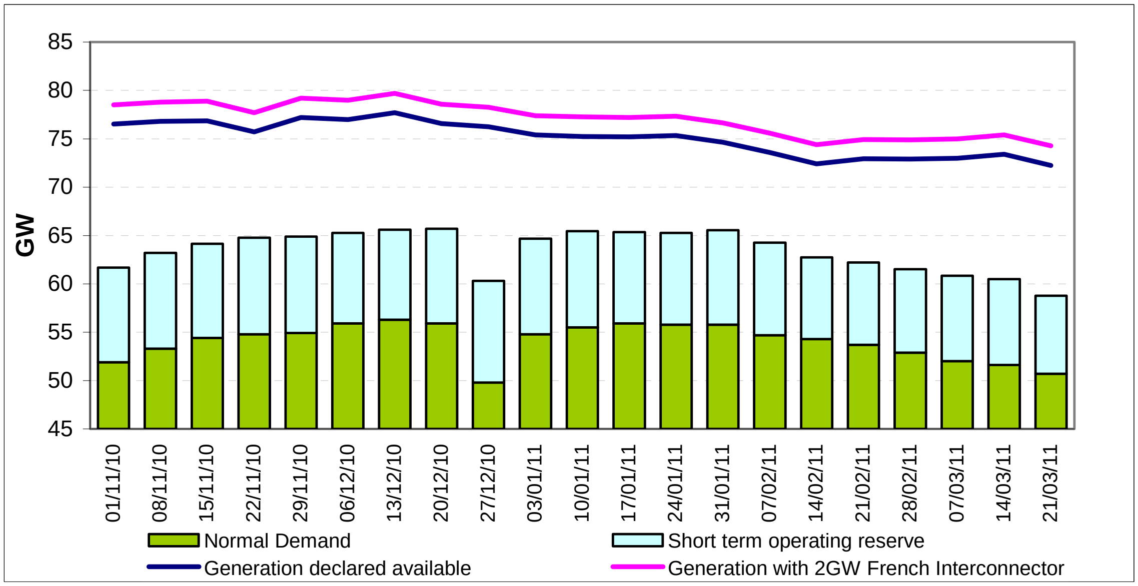
263. National Grid continues to have Maximum Generation contracts in place for Winter 2010/11, which provide potential access to 1 GW of extra generation in emergency situations. This is a non-firm emergency service and generation operating under these conditions normally has a significantly reduced reactive power capability (which in turn can have a significant impact on transmission system security). Hence, it is not included in any of our generation capability and plant margin analysis. This service was available pre-NETA and similarly was never included in margin analysis.

Forecast Generation Surpluses 2010/11

264. Figure B.20 shows forecast normal demand (i.e. assuming average weather). The generation available is the availability declared to National Grid by the generators under Operating Code 2 of the Grid Code, and reflects planned unavailability, but has no allowance for unplanned generator unavailability.

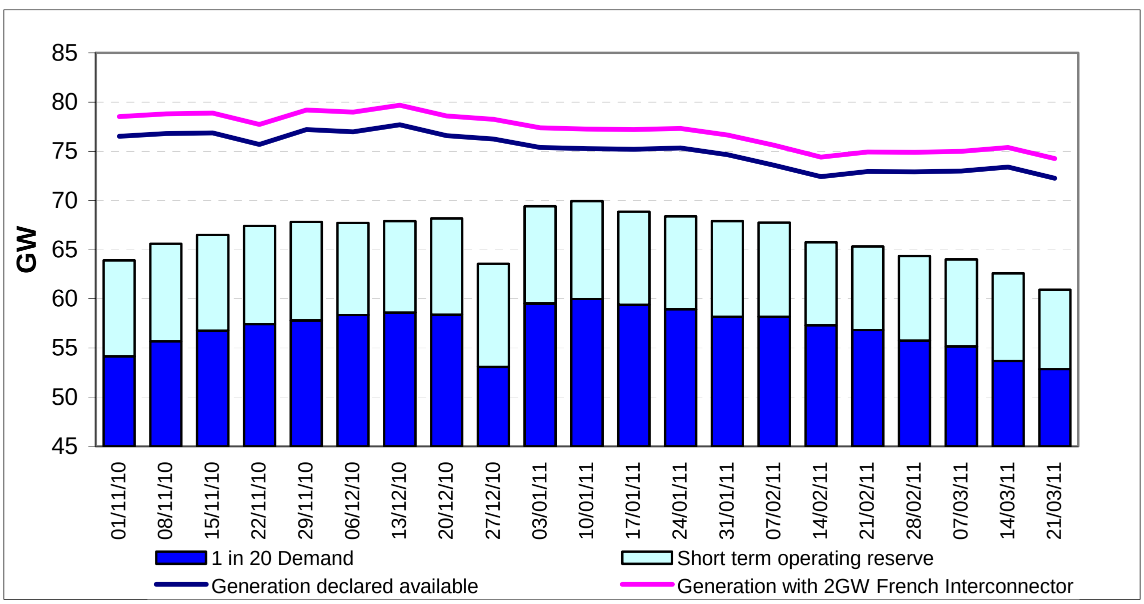
265. Demand in Figure B.20 is based on no interconnector exports to France and Ireland in line with our base assumptions at the time of the daily peak. As the figure shows based on normal demands and notified availability there is sufficient generation to meet demand and our short term operating reserve requirements comfortably, even without imports from the French interconnector.

Figure B.20 - Normal Demand and Notified Generation Availability



266. Figure B.21 shows the notified availability compared to demands based on 1 in 20 weather for each week. The chart shows there would still be sufficient generation to meet demand and our short term operating reserve requirements comfortably.

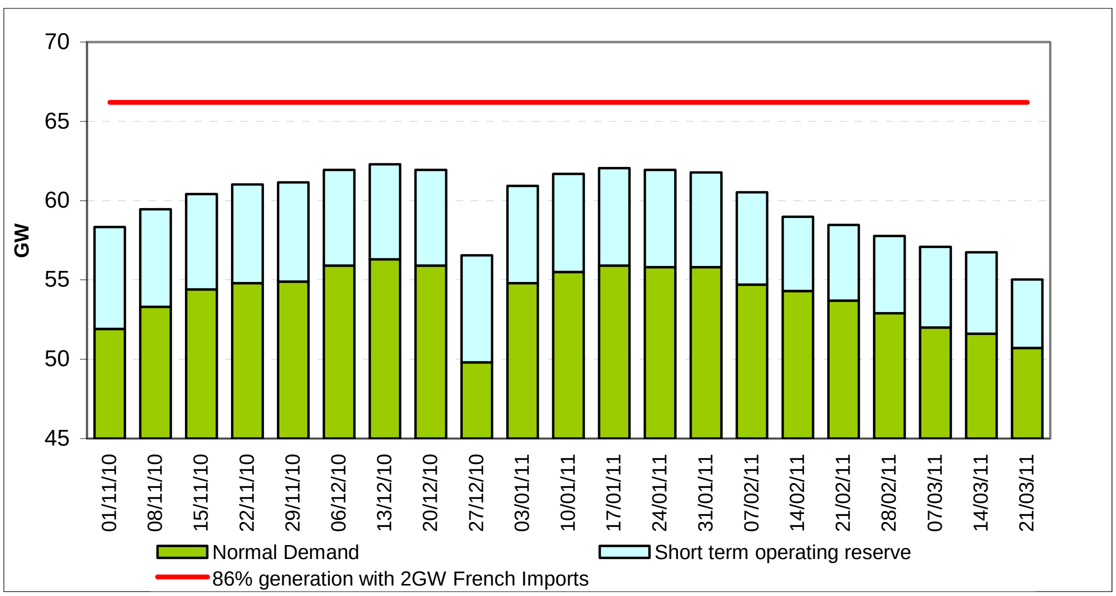
Figure B.21 - 1 in 20 Demand and Notified Generation Availability



267. Figure B.20 and Figure B.21 use generation availability as declared to National Grid by the generators under Operating Code 2 of the Grid Code, which reflects planned unavailability, but has no allowance for unplanned generator unavailability. We have outlined our assumptions earlier in this report for the levels of actual generation availability we expect at the time of demand peak, which use historic availability achieved over historic demand peaks to indicate the combined effect of both planned and unplanned unavailability.

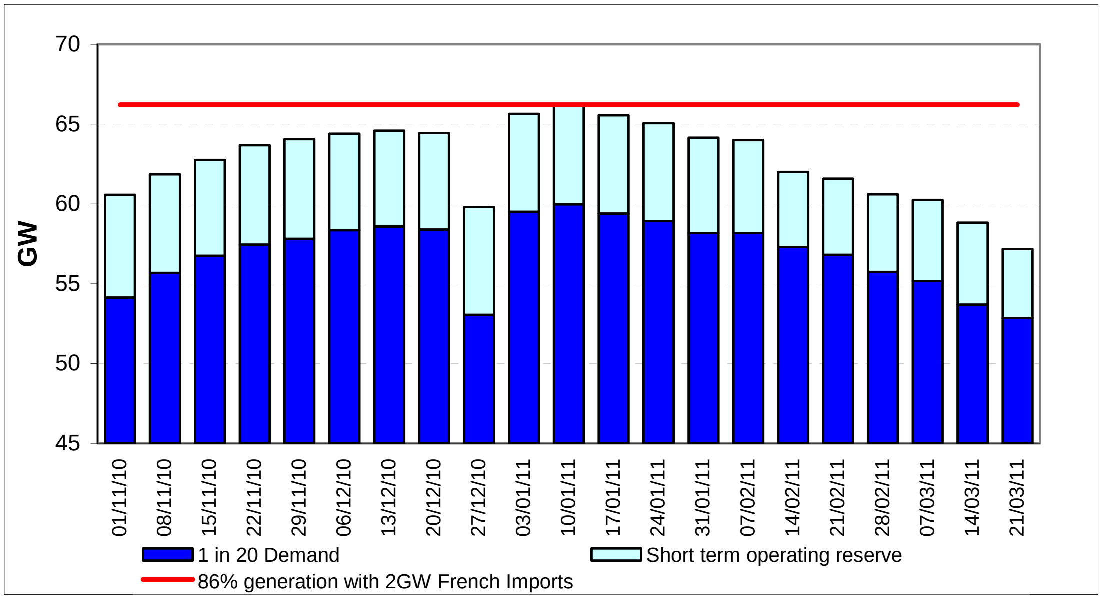
268. Figure B.22 shows our average weather condition driven demands (normal demand), plus our short term operating reserve and our assumed availability of generation which is 86% of our operational view of generation capability plus 2GW of import from France. As the chart shows based on normal demands and using generation availability based on these assumptions there is sufficient generation to meet demand and our short term operating reserve requirements comfortably.

Figure B.22. Normal Demand and Assumed Generation Availability



269. Figure B.23 takes the 1 in 20 demand level scenario but uses our assumed level of generation availability which as above allows for unplanned unavailability. This figure shows that 1 in 20 demand levels plus our short term operating reserve requirements could still be met.

Figure B.23 - 1 in 20 and Assumed Generation Availability



270. For the winter to come we do not propose developing specific scenarios to cover an increase in electricity demand. If economic recovery were to be a material driver going forward we expect it's impact to still be of low materiality by the time of the likely winter peak demands in December 2010 or January 2011. We are seeking views on what stakeholders foresee as credible scenarios we should present in our final outlook report either on the demand or generation aspect. Should responses to our consultation seek scenarios to be presented or if we observe a material trend in demand or a generation issue arises, we will then reflect this in the final outlook report.

Generation Merit Order 2010/11

271. This report section focuses on the outlook for meeting electricity demand and is less directly concerned from this perspective with the generation merit order itself. Which power generation type contributes to meeting demand is determined to the greatest extent by the market and therefore is subject to significant uncertainty as market prices for winter change over time.

272. The accepted guide for future winter prices and the power generation merit order are the current forward prices for fuel and carbon. We need to note the caveat that the relative economics of gas and coal can change significantly before winter arrives. At this stage, based on forward prices prevailing at the start of June for winter 2010/11 there is a small commercial advantage for generating power from coal compared with gas. We will update our analysis of fuel and carbon prices during the summer and include our findings in the final winter outlook report. For the purposes of analysing gas demand for winter 2010/11, we have made the assumption that gas is preferred to coal for power generation in winter to come. This ensures the credible but high gas demand scenario is presented as a way to manage the market uncertainty of fuel and carbon prices.

Questions for Consultation

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

QB8. The level and direction of flow of the electricity interconnector(s) that might be expected given cold weather in both UK and Europe and in particular how commercial operation of Britned will look during winter if anticipated to be different to other interconnectors;

QB9. The appropriate capacity credit to apply to wind generation towards meeting a demand peak (also see QB16-20 on the related appendix);

QB10. The accuracy of our generation availability assumptions for all fuel types and particularly comments on the likely reliability of nuclear power generation going forward;

QB11. Our forecast of peak electricity demand and insights into demand trends going forward. Do you believe demands will return in due course to pre-recession levels or to what extent do you expect them to recover? When might this recovery be expected to have taken place;

QB12. Will any additional generation be placed into a mothballed state that will affect generation availability for winter 2010/11?

QB13. When do you expect that new CCGT's will become available over this coming summer/winter?

QB14. Are there any key drivers of generation availability that are changing for winter 2010/11?

QB15. Should any specific scenarios of either demand or generation availability be added to the analysis in the final report and what scenarios do you think most credible?

We welcome comments on the approach to assessing operational risk and capacity credit assessment for wind going forward outlined in **Appendix 1** to this report. In particular feedback on the following aspects is sought: -

QB16. Do you feel that a new approach to assessing the security of supply risk is merited to assess security of supply risk when intermittent generation types are a significant proportion of the GB generation fleet?

QB17. Do you have any thoughts or comments on the approach outlined?

QB18. Is the illustration of the concept through using our "gone green" scenario a useful way to demonstrate the approach?

QB19. Is the concept of "Equivalent De-rated Capacity (EDC)" a useful way of measuring how a given installed wind generation fleet contributes to security of supply?

QB20. Are you interested in participating in a specific workshop in late September 2010 to explain the methodology further and our conclusions to date?

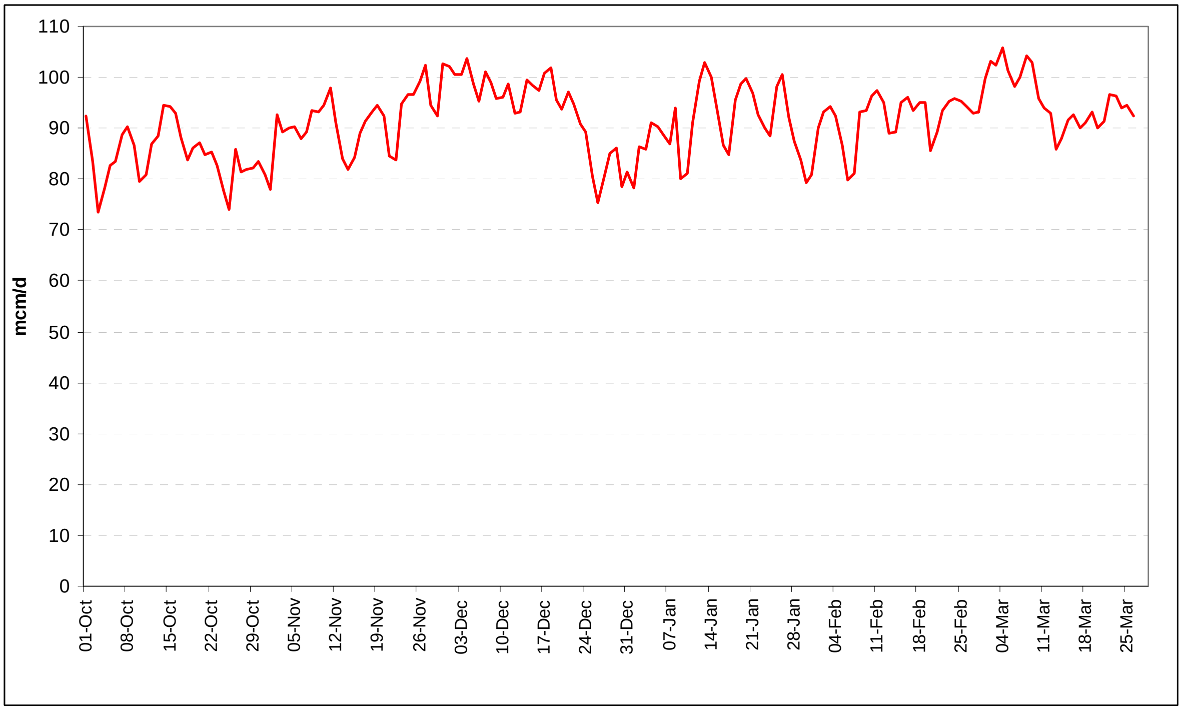
Section C

Gas/Electricity Interaction

Power Generation Gas Demand

273. Daily gas consumption from CCGTs varied over last winter with an early winter low of 73mcm/d and a late winter high of 107mcm/d. Significant use of gas for power generation was a feature across the winter as the general profitability of gas fired generation over coal prevailed for almost every day. The period in early January where Gas Balancing Alerts (GBA's) were issued caused some gas fired power generation to be substituted by coal, but even then significant gas burn for power generation continued.

Figure C.1 – Gas Consumption for Power Generation



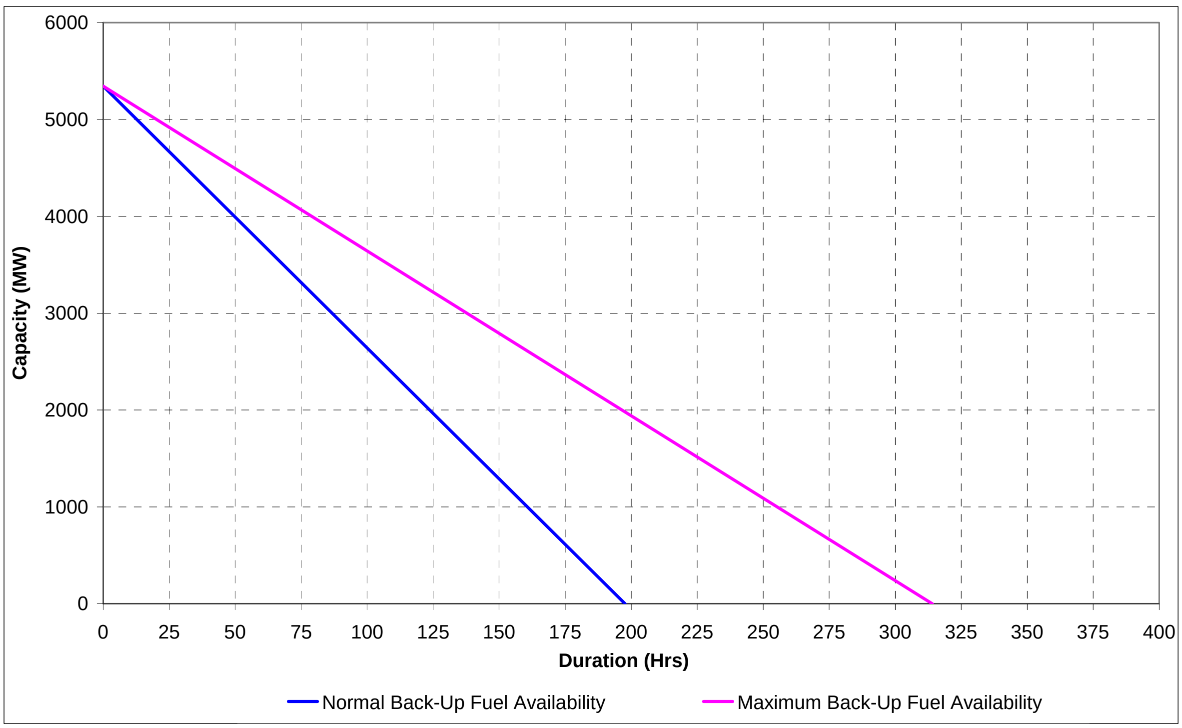
Power Stations with Alternative Fuels

274. 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 continue to estimate 5.3 GW have the capability to run on distillate Out of the total 5.3 GW having back-up fuel generation capability, more than half of them have interruptible gas transportation arrangements.

275. 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. Replies to our enquiries to stations with back-up generation capability, indicated that back up fuel stock has reduced slightly compared to last year leading

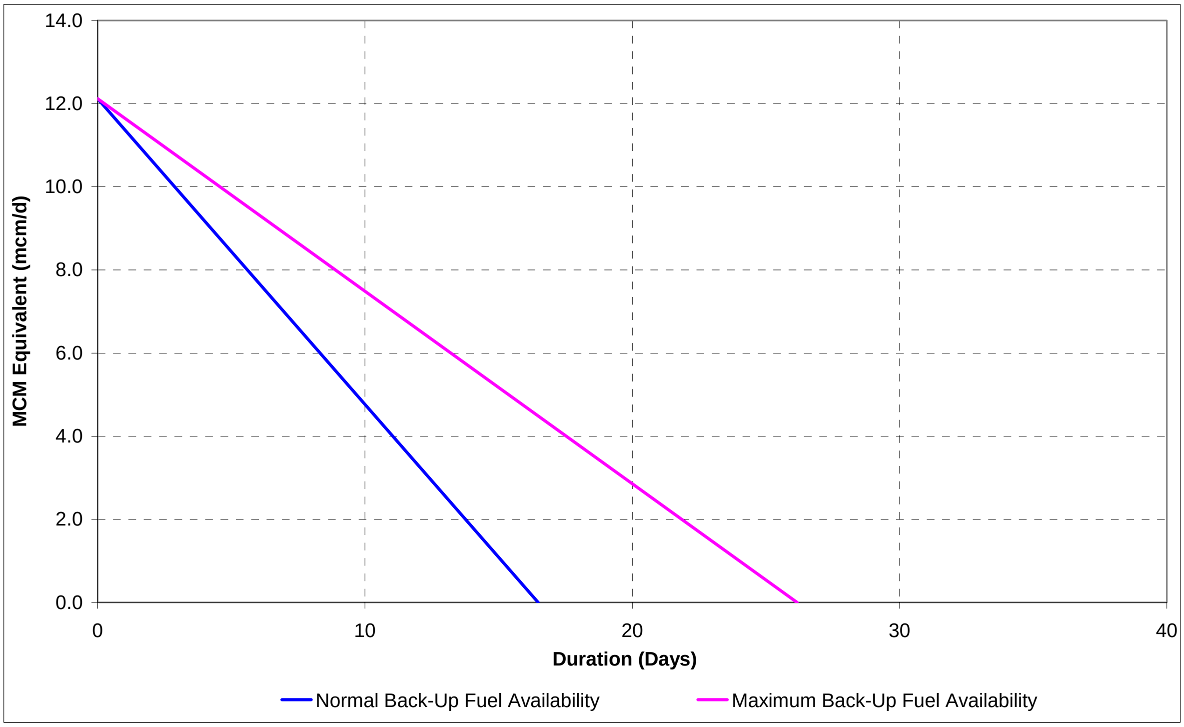
to a 27hrs reduction in the running duration. The two lines show the available generation capacity from starting points of normal fuel stocks and maximum fuel stocks, and assuming individual units generating at full load when running on distillate. Note, however, that this graph is not intended to suggest that all generators with back up fuel capability would run continuously on back up fuel supplies for several days or at full distillate running load. In reality different generators would adopt different commercial strategies. We currently assume that most of this capacity would only run on back up fuel for part of the gas day and that this would be during the offpeak electricity demand periods. The curves below also assume no restocking of distillate which may be possible for some stations over the period they are running on distillate.

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



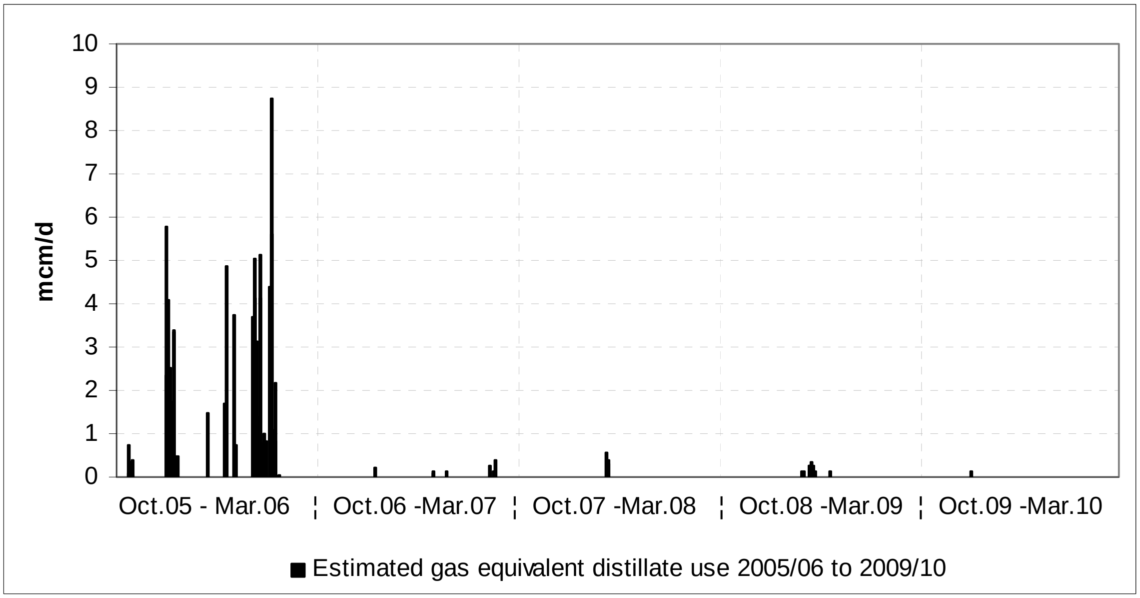
276. Based on the distillate back up fuel data from the generating companies for 2010/11, we estimate that a total of between 92 mcm to 145 mcm gas equivalent can be displaced using distillate generation capability. This is shown in figure C.3.

Figure C.3 – Gas Volume Equivalent Load Duration Curves for Back Up Fuel Supplies



277. We have also estimated historic distillate use in mcm/d equivalent over previous winters as shown in Figure C.4. This shows very little use of distillate in the last four winters, but up to 9 mcm/d of relief has been seen in the past. In 2009/10, it appeared that no distillate was used around system peak days.

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



Potential for Demand-Side Response from Gas Fired Generation

278. We continue to expect that gas-fired power stations have the potential to respond to market price signals, decreasing their gas consumption when the cost of generating from other fuels is lower than the price of burning gas. We see this effect already in action in the market in normal circumstances as the generation emphasis moves between generation types in response to economic signals.

Analysis of potential CCGT gas demand response

279. 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.

280. In this consultation report we have provided an overview of the status of distillate fuel stocks at gas power stations able to use the fuel instead of gas. As we've seen limited use of distillate and our experience of the period of high gas demands in winter 2009/10 was limited distillate use we are not presenting further analysis in

this report. Should it become apparent that the gas supply or generation availability issues are less comfortable we will present extended analysis in the final report.

Questions for Consultation

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

QC1. We've believe that gas power making extensive use of distillate has been very limited since winter 2005/06. Our assessment of stocks shows a relatively static position on last year. We welcome views on the likelihood of a situation where distillate use becomes significant and views on what the triggers to use distillate are. To assist us in our analysis we welcome views on the market scenarios we could model.

Please also comment upon: -

QC2. The ability and willingness of CCGT generators to switch to distillate;

QC3. Whether and for how long CCGTs will generate continuously on distillate back-up and any restrictions to the replenishment of distillate stocks;

QC4. The ability and willingness of generators to replace gas-fired generation by coal and oil fired generation;

QC5. The extent to which increased levels of other fossil fuel generation could be used to displace gas-fired generation throughout a cold winter, including considerations of reliability, environmental constraints and fuel stocks;

Section D
Industry Framework Developments

Gas

Modification Proposal 0260 - Revision of the UNC Post-emergency Arrangements

281. Following an industry review of the UNC post-emergency arrangements during 2009, National Grid NTS raised Modification Proposal 0260 *"Revision of the Post-emergency Claims Arrangements"* which was subsequently approved by Ofgem and implemented on 1st November 2009.

282. The implementation of Modification Proposal 0260 has improved the gas security of supply in the event of a Gas Deficit Emergency as Users that are able to provide additional non-UKCS gas supplies and/or demand-side reduction now have increased confidence of receiving an appropriate level of financial recompense; and the incentives on shippers to avoid being short in an emergency have been sharpened.

National Grid Gas NTS Licence: Special Condition C27 – Balancing Arrangements

283. In April 2010, National Grid NTS consented to a new Special Condition C27. This new Condition requires National Grid NTS, in conjunction with the industry to:

- Review the default cash out values that were introduced into the UNC in 2000 with a view to updating the existing values from April 2011[34].
- Develop an NTS Linepack product and if considered appropriate, implement such a Linepack product from October 2011.

284. National Grid NTS has subsequently initiated *UNC Review Group 0291 C27 – Balancing Arrangements* in order to facilitate industry discussion and development of both elements of its C27 obligations. Review Group 0291 commenced in May 2010 and it is anticipated to conclude in August/ September 2010 with its final recommendations being made following this to the UNC Modification Panel. Modification Proposals arriving from the Review Group are therefore likely to be consulted upon during Q4 2010.

Facilitation of 3rd party connected NTS Storage

285. There are several offshore storage facilities being cited for development that are likely to be indirectly connected to the NTS. These 3rd party connected NTS storage

[34] See Special Condition C27(3): "The licensee shall use reasonable endeavours to introduce updated values of the "System Marginal Buy Price" as such term is defined in Section F 1.2.1(a)(i) of the licensee's network code as at 1 April 2010 and the "System Marginal Sell Price" as such term is defined in Section F 1.2.1(b)(i) of the licensee's network code as at 1 April 2010, by 1 April 2011 in consultation with shippers and other interested parties."

facilities are not currently recognised within the commercial and operational arrangements.

286. In conjunction with the Gas Storage Operators Group (GSOG), National Grid Transmission has been assessing the implications that the introduction of NTS non-directly connected storage facilities might have on those existing arrangements, for example, the UNC and Storage Connection Agreements.

287. National Grid is mindful of DECC's recent implementation of the Gas Offshore Storage & Gas Unloading Licensing regime and we have agreed to support GSOG in its development of a UNC Modification Proposal (and associated agreements) that will seek to recognise these 3rd party connected NTS storage facilities.

System Flexibility 2010/11

288. Changes in supply and offtake behaviours driven by regime developments and types of connectees may potentially cause greater volatility in gas flows and hence require a more flexible system to accommodate them. Examples of these include:

- increased wind powered electricity generation to support renewable targets,
- flexible offtake profiles,
- increased LNG importation, and
- evolving interconnector, storage and supply behaviour

289. The magnitude and materiality of these developments is uncertain, however, as a prudent operator National Grid Transmission is keen to investigate the potential impact of these changes before they occur so that customer requirements can be met. Last year, together with the industry, we considered what data / information should be analysed, what timescales should be monitored for trends and what trends would indicate a need to respond. This led to the development of a set of data indicators that National Grid Transmission will monitor and report to the industry periodically through the Gas Operational Forum.

Entry Credit Arrangements 2010/11

290. Modification Proposal 0246 "Quarterly NTS Entry Capacity User Commitment" was raised by National Grid Gas NTS as a consequence of discussions within Review Group 0221. EDF Energy (0246A) and British Gas Trading (0246B) raised alternative Modification Proposals and all three proposals were submitted to Ofgem in May 2009.

291. On 3 June 2010 Ofgem decided to reject all three proposals but the Authority agreed that Shippers should not be able to defer security commitments without any consequence (an aspect of all 3 proposals) and have indicated that they would welcome a further proposal to address this specific issue.

System Flexibility 2010/11

292. This year, in addition to monitoring the indicators already established, we will be investigating additional indicators that can inform our understanding of NTS usage patterns.

Exit Capacity Substitution and Exit Capacity Revision

293. At the last PCR Ofgem introduced obligations for National Grid NTS to undertake Exit Capacity Substitution and Exit Capacity Revision. Exit Capacity Substitution and Revision would only apply to Exit Capacity from the 1st of October 2012 onwards i.e. the enduring exit period.

294. Four workshops have been held with the industry in early 2010 thus far, to discuss the most appropriate way to introduce these obligations. National Grid NTS has published the workshop presentations and minutes on its website. An informal industry consultation is planned for July 2010 prior to the formal consultation on the proposed methodologies in November.

295. The implementation of these obligations has been delayed such that National Grid NTS now has a licence obligation to submit its proposed Exit Capacity Substitution and Exit Capacity Revision Methodology Statements to the Authority by 4 January 2011.

Entry Capacity Substitution

296. At the last PCR Ofgem introduced an obligation for National Grid NTS to undertake Entry Capacity Substitution. Under this license obligation National Grid NTS seeks to substitute unsold Non-Incremental Obligated Entry Capacity from entry points (donor entry points) to other entry points (recipient entry points) where Incremental Obligated Entry Capacity is required to be released in accordance with the Incremental Entry Capacity Release methodology statement. Where substitution is applied this will result in the available capacity being reduced at the donor entry point and the amount of investment required to satisfy the incremental capacity release being lower than would be the case without substitution.

297. National Grid NTS's proposed entry capacity substitution methodology, associated UNC Mod proposal 265 and Charging Methodology GCM18 were approved/implemented by the Authority in December 2009 and first applicable to the March 2010 QSEC auction and associated processes .

298. As stated above, Modification Proposal 265 “Retainer” process was implemented by Ofgem in December 2009. This proposal introduced the concept of a “Retainer” process to allow Users an economic alternative to the purchase of substitutable entry capacity in order to protect unsold non-incremental obligated Entry Capacity from being substituted away. The first retainer process was held in January 2010

299. Reports on the outcome of both the application of entry capacity substitution and the retainer process held in 2010 can be found on National Grid's website: http://marketinformation.natgrid.co.uk/Gas/CapacityReports.aspx

Amendment to QSEC and AMSEC Auction timetables

300. On 29 May 2009 Ofgem approved Modification Proposal 230AV which moved the QSEC Auction from September to March each year which results in Incremental NTS Entry Capacity being released from 1 October at the start of the winter period when flows increase. The modification also retained the AMSEC auction in February with a shortened transaction period from the current 2 years to 18 months.

301. In 2010 the first QSEC and AMSEC auctions were run according to the new timescales as defined in UNC Modification Proposal 230AV.

Exit Reform

302. Transitional exit arrangements allow Users to purchase exit capacity with a latest effective date of the 30th September 2012.

303. In January 2009 the Enduring NTS offtake arrangements were implemented effective from April 1st 2009. The initialisation processes and first July increase applications and reduction notices for Enduring Exit (Flat) Capacity have been held offline successfully in 2009, with Users being informed of both their initialised quantities and their allocated quantities of Enduring Annual NTS Exit (Flat) Capacity for October 2012 onwards.

304. The first phase of the Gemini Exit Reform system has gone live and this will allow Users to carry out certain enduring activities online during the July 2010 application window. Phase 1 functionality allows:

- Online Application for Enduring Exit (Flat) Capacity (July 2010 process)
- Online Notice of reduction of Enduring Exit (Flat) Capacity (July 2010 process)
- Online Application for Annual Exit (Flat) Capacity (July 2010 process)
- Ad-Hoc / ARCA Enduring Exit (Flat) Capacity applications

305. Additional Enduring Exit functionality will be introduced through future phased releases of the Gemini Exit Reform system.

306. Enduring Exit Applications can be made as follows:

- Users can apply for Enduring capacity in the Annual July Application Window or via an Ad-hoc process
- Developers can apply for Enduring capacity via the ARCA process.
- Annual, Daily and Offpeak capacity can also be obtained in the Enduring regime

307. Further detail on Exit Reform can be found on a dedicated section of our website: http://www.nationalgrid.com/uk/Gas/OperationalInfo/endureexitcap/

308. A number of UNC modifications have been raised to enhance the Enduring Exit regime. Details of these can be found on the joint office website: www.gasgovernance.co.uk

Entry Charging Review

309. During 2009, National Grid NTS launched a fundamental review of entry charging principles. This was in response to growing industry concern about the increasing rate of the TO entry commodity charge. In 2009 National Grid NTS started to analyse the existing and potential future entry capacity procurement and has continued to develop charging proposals with the industry in 2010.

310. An initial outcome of the review has resulted in the development of a charging consultation and the subsequent development of two UNC mod proposals, namely:

- Charging consultation GCM19
- UNC Modification 0284 - Removal of the Zero Auction Reserve Price for Within-day Daily NTS Entry Capacity (WDDSEC)
- UNC Modification 0285 -"Use it or lose it"(UIOLI) Interruptible Capacity only to be released when there is at most 10% unsold firm entry capacity

311. An impact assessment is due to be issued by Ofgem with regards to the bulleted points above.

Exit charges

312. A key area developed in 2009 was the methodology by which NTS Exit Capacity prices will be determined with changes having been implemented in March 2009 for the setting of NTS Exit (Flat) Capacity charges from 1st October 2012 post exit reform.

Electricity

Balancing & Settlement Code relevant proposals / issues

Electricity Market Information

313. BSC modification P243 was approved by the Authority on the 20th January 2010 and will be implemented on the 4th November 2010. P243 will provide a more detailed forecast of generator availability, by publishing Output Usable data broken down by 'fuel types' on the Balancing Mechanism Reporting System (BRMS). It is anticipated that greater transparency on plant availability is likely to better facilitate price discovery and market competition.

Transmission Losses

314. The final report for BSC modification P229 was issued to the Authority on the 12th March 2010 for decision. P229 seeks to change the Transmission Losses arrangements in the BSC so a Transmission loss Factor (TLF) for each BSC

Season is calculated for each TLF Zone (Currently TLF = 0). Under P229 TLF Zones would be created based on 14 Grid Supply Point (GSP) groups, with historical data used to annually calculate each TLF per BSC Season per TLF Zone. This modification is with the Authority for decision. If agreed, the modification will be implemented 12 - 18 months after the Authority decision.

Grid Code relevant proposals / issues

Consultation A/10: Generator Grid Code Compliance

315. Grid Code Amendment Consultation, A/10, intends to improve the transparency and consistency of the process of ensuring generators connecting to the transmission system comply with the Grid Code connection conditions. The proposals standardise and codify the process into the Grid Code. The Grid Code Consultation closed on 18th June 2010. Implementation of the new compliance processes are currently expected to be applied to generators connecting from 2012 onwards.

316. Consequential code changes have been identified as being required to the Distribution Code and CUSC. A Distribution Code Consultation was published on the 15th June 2010 and a corresponding CUSC Amendment Proposal was raised at the March 2010 CUSC Panel, with a Working Group Consultation expected to be published shortly. Previously a code change had also been anticipated for the Distribution Connection and Use of System Agreement (DCUSA), although this is no longer thought to be required. These consequential changes relate to Licence Exempt Embedded Medium Power Stations (LEEMPS) who are not directly connected to the transmission system but are still required to undergo the compliance process.

Connection and Use of System Code (CUSC) relevant proposals / issues - CAP148, CAP167, CAP170, CAP181 and CAP182

317. *CUSC Amendment Proposal (CAP) 148* 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 has a long lead time and, if approved, it would be at least three years before holders of DTEC connected to the system. CAP148 is currently with the Authority for decision. Ofgem issued an Impact Assessment in July 2008 setting out the Authority's minded-to decision to reject each of the CAP148 variants. A further consultation was issued in April 2009 which considered the impact of the Authority's change in statutory duties, particularly the elevation of the sustainable development duty, following the commencement of the Energy Act 2008.

318. *CAP167*, Definition of a threshold(s) associated with a request for a Statement of Works, seeks to amend the CUSC to provide definitive clarification in the assessment of whether a small embedded power station development (or the aggregate effect of multiple projects) has a significant impact on the GB

transmission system. This clarification is provided by way of MW threshold(s), which are derived based on transparent criteria for determining whether there could be a significant impact, which determine whether a DNO is required to request a Statement of Works. CAP167 is currently with the Authority for decision.

319. The Authorities process for CAP 148 and CAP167 (and similarly for the Transmission Access Review related CUSC Amendment Proposals) is under review in the light of DECC's consultations on Transmission Access as further detailed below.

320. *CAP170* seeks to introduce a new category 5 System to Generator Operational Intertripping Scheme to cover intertrips capable of being armed with respect to a derogated non-compliant transmission boundary. It was raised by National Grid on the basis that at derogated non-compliant transmission boundaries the need to take action to manage constraints is more onerous than at compliant transmission boundaries. As such, the use of intertrips (assuming it is more economic than alternative Bid-Offer action to constrain generation pre-fault) is a necessity rather than an occasional tool in order to maximise flows across the derogated non-compliant transmission boundary. CAP170 was granted urgent status and proceeded straight to consultation by the company. CAP170 is currently with the Authority for decision, with the Authority having issued an initial Impact Assessment in May 2009. In July 2009 the Authority published a further consultation on National Grid's updated costs savings forecast, with respect to CAP170, for the period 2009/10, followed by a further consultation in January 2010 on the competition issues relevant to CAP170. The Authority is continuing to consider this proposal and currently expect to issue a decision in Q2/Q3 2010.

321. *CAP181* has been raised as a consequential change to the Grid Consultation A/10 (Compliance). A/10 seeks to formalise a compliance process within the Grid Code for all new generators to improve consistency and visibility of the existing process. If implemented, CAP181 Original seeks to amend the CUSC to ensure that the exiting industry position on limiting liabilities is retained; the specific changes required are:

a) CUSC Parties, including National Grid, would waive the right to claim directly against a Licence Exemptible Embedded Medium Power Stations (LEEMPS) for breach of the Distribution Code;

b) CUSC Parties would instead pursue a claim against the Distribution Network Operator to whose system the LEEMPS is connected, who in turn would claim against the LEEMPS or DCCS for physical damages under the DCUSA

c) Any claim by CUSC parties would be limited to a maximum of £1million, in line whether terms of the DUCSA (in force at the data of raising this Amendment Proposal.

322. *CAP182* - Provision of Frequency response from Direct Current (DC) Converters, was raised after an industry review of the suitability of the current CUSC arrangements reflecting the Grid Code requirement for DC converter stations to provide mandatory frequency response. The Interconnector Frequency Response

Working Group concluded that a number of changes were required to facilitate the provision and settlement of the mandatory ancillary service of frequency response from DC Converters. There are a number of references to apparatus providing the frequency response service within the CUSC, however these reference do not currently include DC Converters. CAP181 seeks to include DC Converters into all the relevant references within the CUSC and the Mandatory Service Agreement to ensure that there equitable arrangements with all providers of mandatory frequency response.

Transmission Access Review

323. Transmission access has proved to be a major barrier to new generation, due to a historic 'invest then connect' system, under which new plants had to join the access 'queue' on a first come, first served basis, and wait for all relevant reinforcement of the wider network to be completed before they could join the network and start generating. This led to an extensive queue of prospective new projects, with some plants offered connection dates as late as 2025.

324. In order to address this problem, the Government and Ofgem published a report of the Transmission Access Review (TAR) in June 2008, which set out the need to reform grid access rules to support the connection of new renewable and other generation.

325. Following the publication of the TAR, the industry and Ofgem worked intensively through a series of working groups to consider options for improving grid access. During this process it became clear that the industry process would not be able to agree a solution in time to ensure enduring rules are in place to help meet the wider goals of meeting carbon reduction targets. The Government took powers in the Energy Act 2008 to enable it to intervene if necessary, and in July 2009, following recommendations from Ofgem and industry representatives, the Secretary of State for Energy and Climate Change announced that he would use those powers to reform grid access.

326. DECC have since carried out two consultations on the future of the access arrangements to the GB transmission system. They have indicated and consulted on licence and code drafting to introduce a 'Connect and Manage' regime with enhanced User Commitment. Connect and Manage is where new users gain access to the system when a minimum amount of local works have been completed. The direct consequence of this early access is likely to be increased system constraints. The cost associated with these is expected to be shared across all users through existing BSUoS non locational arrangements. The existing incentives on the System Operator will continue to ensure these incremental costs are and minimised.

327. The revised regime is largely a formalisation of the current process that National Grid has been operating through Interim Connect and Manage since Spring 2009. However there are a number of changes to definitions that seek to add certainty and may result in earlier connection, particularly those around local works required prior to connection. It is also proposed to change the derogation process to self derogation rather than with Ofgem. Users Commitment is also changing through the formalisation if interim connect and manage. The notice period which connected

Generation parties are required to give National Grid for a reduction in Transmission Entry Capacity, TEC. Currently this is 5 days notice, but under the DECC proposals this will be extended to 1 year and 5 days notice. The DECC User Commitment proposals do not impact on the liabilities for pre commissioning generation.

BM System Replacement

328. Grid has proposed to replace the Balancing Mechanism (BM) system with a global best-practice IT system using up to date technologies and a go live date in 2013. Communication with stakeholders continues with updates provided through our Operational Forums as well as other routes. A second consultation is planned during the summer to gain further industry input into the project to ensure we continue to meet our customer needs.

Implementation of a new Cross Border Balancing on the England-France Interconnector (IFA)

329. National Grid and the French transmission system operator (RTE) are implementing further improvements to the Cross Border Balancing (CBB) tools between France and GB markets. The new CBB arrangements will provide increased flexibility for both RTE and National Grid and represent a key step in improved market coupling between France and GB. These changes go live in November 2010. The key features of the new arrangements for system to system operator trades are the introduction of hourly prices for hourly energy blocks. As energy will be priced in hourly blocks and called off close to the actual hour of delivery, the prices in future are going to be more reflective of the prevailing system conditions in France and GB. We also requested a longer notice/duration service be implemented and requested the inclusion of a 2hr duration CBB product with a 2hr lead time in addition to the 1hr product, to enable NGET to continue utilising the CBB arrangements for broader system balancing purposes and avoid commitment of alternative more costly actions. We have agreed an "extension solution" to the 1hr product initially developed with RTE, allowing the acquiring TSO to secure a 2hr delivery. If the service volume is not available for the second hour then the delivering TSO will deliver energy through the "extension" service and settle at a pre-agreed Excess Energy Price. This solution will be in place until April 2012. Any extension of these arrangements beyond this date would require a common agreement between Ofgem, CRE, National Grid and RTE

Appendix 1

Winter Outlook appendix: 'Generation adequacy assessment with high wind penetrations'

Introduction

1. This section of the report has been developed by Dr Chris Dent[35] from Durham University. Dr Dent is working with us to develop an approach suitable for the future with an expectation of high penetrations of wind power or other intermittent generation types that allows us to assess energy security of supply. This work has developed over the summer to focus on a whole power system risk level assessment for our capability to meet demand with a given generation mix and anticipated demand level.

2. The capacity of wind generation connected to the GB power system is increasing rapidly. As a consequence, when generation adequacy assessments are made, it is necessary to quantify wind's contribution to securing demand; this will become increasingly important once a substantial proportion of coal-fired plant retires due to the Large Combustion Plant Directive (LCPD).

3. We believe that wind generation does indeed make a contribution to supporting peak demand. However, because its statistical availability properties are very different to those of conventional plant, its contribution is limited, and must be assessed in a different way from that of conventional plant.

4. This Appendix describes our proposed approach in operational planning assessments to the twin issues of
   - quantifying wind's contribution to securing demand, and
   - assessing generation adequacy in systems with substantial wind penetrations

   Both the calculation structure (which provides direct continuity with the 'assumed availability' approach from previous Winter Outlooks), and the important data issues (in particular ongoing work to provide more detailed treatment of embedded wind) will be described.

5. This Appendix uses National Grid's Gone Green scenario to illustrate the EDC approach. The 2010/11 plant margin is forecast to be very healthy, and so use of 'Gone Green' provides a more instructive demonstration of how EDC quantifies demand security when the generation adequacy risk is more substantial. As always with such scenario analyses, the risk results should be interpreted as the consequences of that scenario's assumptions, rather than a prediction of the absolute risk level in future winters.

[35] See http://www.dur.ac.uk/ecs/engineering/staff/rastaff/?id=7876 for more information about Dr Dent's related work areas in the field.

6. We welcome comments from industry stakeholders on the proposed approach, before we further develop a risk-based approach for Winter Outlooks in future years, when we could be placing a degree of reliance on wind's contribution to supporting annual peak demand.

Data Utilised

7. Demand
   - A consistent GB time series for Initial Demand Out-turn (INDO) is available back to April 2001 on National Grid's website[36].
   - The winter station load of 600 MW must be added to winter INDO values to obtain the load met by GB transmission-connected generation.

8. Wind output
   - The wind data used in this report is from Poyry Consulting's 'Impact of Intermittency' project[37].
   - Allows construction of synthetic historic wind output time series, based on wind speeds from 2000-08, and any projected wind generation fleet.
   - Provides coverage of both onshore and offshore wind.
   - We believe this is currently the best GB wind resource dataset available; however, it has limitations, particularly in that it is based on records from meteorological stations rather than actual wind farm locations.
   - Projected installed wind capacities shown in Table A.1; we assume that of the onshore capacities, 3000 MW, 4500 MW and 6000 MW are distribution-connected in 2010, 2015 and 2020 respectively. The current projected installed capacity for winter 2010/11 is smaller than that projected in the 2009 Gone Green scenario as presently implemented in the Poyry database; this scenario is therefore used to illustrate the proposed methodology, rather than projecting an absolute value of risk for the next few years.

Table W.1: Installed MW wind capacity scenarios for 2010, 2015 and 2020.

Year	*Onshore*	*Offshore*	*Total*
2010	5735	410	6145
2015	10434	4107	14541
2020	14241	18458	32699

9. Average Cold Spell (ACS) peak demand
   - To compare demand levels between years, each historic demand record is expressed as a percentage of that winter's out-turn ACS peak demand

[36] http://www.nationalgrid.com/uk/Electricity/Data/Demand+Data/
[37] Public summary and methodology available from http://www.ilexenergy.com/?t=7_9Archive2009#PublicIntermittency

- Historic demand time series can then be scaled to the ACS peak demand level projected for the winter being studied.

10. Treatment of embedded wind generation
    - Embedded (distribution-connected) wind generation is mostly not metered by National Grid, and is visible only through its effect of lowering transmission-metered demand.
    - There are two options for the treatment of distributed wind:
      (a) Do not include the embedded wind generation in risk calculations, i.e. do not adjust historic demands to account for embedded wind, and only consider transmission-connected wind in risk calculations.
      (b) Add estimates for embedded wind output to historic demands, and treat transmission and distribution connected wind on an equal basis in risk calculations.
    - (a) is used in this year's Winter Outlook including this Appendix, because a detailed assessment of the embedded wind output is not yet available.
    - (b) is the superior approach if sufficient information on embedded wind is available, as it treats all wind on an equal basis and makes demand data from different historic years directly comparable.

11. Conventional generation availability
    - A standard Capacity Outage Probability Table calculation[38] is used
      - The available capacity from each conventional unit is assumed to be either zero or its operationally rated capacity.
      - The unit availability probabilities are the 'assumed availabilities' from the Winter Outlook.
      - For a given combination of units available/unavailable, the total available capacity is the sum of capacities of the available units, except that the output of a few stations is capped at our estimate of their Operational Realisable Capabilities.

12. Definition of system adequacy
    - The system is deemed adequate if there is sufficient generation available to meet demand *plus* response to cover the largest credible loss of infeed.
    - The largest loss is presently Sizewell B nuclear power station, which has capacity 1320 MW, implying a response requirement of 1 GW.

Wind Data Visualisation

13. Before performing risk calculations to quantify wind's contribution to securing demand, important insights can be derived from analysis of the wind and demand data.

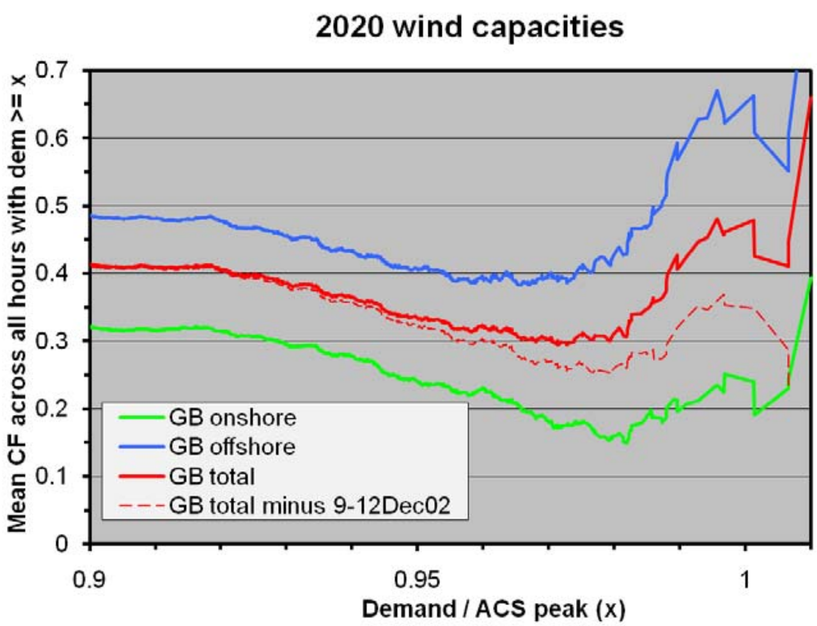
14. Fig. W.1 visualises the Great Britain wind resource at times of very high demand, based on the historic wind data and the projected installed wind capacity from 2020.

[38] R. Billinton and R.N. Allan, Reliability Evaluation of Power Systems, Springer, 1996.

Demand d is plotted on the x-axis, and y-axis shows the average wind capacity factor across all hours where demand is greater than d. This satisfies the two key requirements for a visualisation of the wind resource near peak demand, namely data aggregation to reveal trends in the data, and focus on times highest demand.

15. The graph clearly shows that the quality of the onshore wind resource deteriorates very significantly between about 93% and 97% of ACS peak demand (the onshore capacity factors from the Poyry dataset using 2010 and 2020 installed wind capacities are quite similar.) Further analysis shows that this picture of the wind resource is robust against withdrawal of any one year's data up to about 98% of ACS peak, apart from a specific issue with 9-12 December 2002.

Fig. W.1. Visualisation of GB's wind resource at times of high demand, for projected 2020 installed wind generation.



16. These four days produced both extremely high demands, and also an average onshore wind load factor across GB of around 50%. Within the seven years of data used here, these four days are anomalous; there are no other equivalent periods in the dataset. These days' critical effect on the visualisation of the resource at annual peak may be observed using the additional data series in Fig. A.1, from which they are withdrawn. Without further years of data, it is impossible to say whether this was a 1 in 2 year event which happened not to occur more than once in this 7 year period, a truly anomalous 1 in 100 year event, or somewhere in between.

17. The graph also shows that offshore wind resource is of higher quality at all demand levels (which is well known), and that it deteriorates much less than onshore at the highest demands. Any assessments of the offshore wind resource must however come with the caveat that there is very limited operational experience both in GB and

abroad, and what experience there is comes from near-offshore wind. While the onshore wind data in the Poyry dataset is broadly consistent with operational experience, we have been unable to make a similar verification for offshore wind in terms of resource and mechanical availability.

System Risk Calculations

Hindcast Calculations

18. The approach used in the risk calculations presented is to simulate (e.g.) 7 versions of winter 2010-11 using directly historic wind and demand time series from years 2002-8; this approach is commonly called hindcast. The wind output for each historic year is based on that year's weather records, and 2010-11's projected installed wind capacity. As there is a strong statistical dependence between wind availability and demand at times of high demand, 7 years of data may be used for only 7 future simulated years of demand/wind, not 7x7=49.

19. The key benefits of this approach when compared to probabilistic wind models are
    - ease of use;
    - naturally provides a robust treatment of the statistical relationship between wind availability and demand.
20. The main disadvantages are
    - short duration of simulation might provide limited opportunities for explorations of variability in outcomes;
    - no exploration of combinations of events which did not occur in the historic data used.
21. Balancing these arguments, we believe that hindcast is at present the most robust approach available for generation adequacy risk calculation, particularly in modelling the statistical relationship between demand and wind generation availability.

Risk indices: LOLP and LOLE

22. At any time *t*, the Loss Of Load Probability (LOLP) is the probability that demand exceeds available generating capacity:

$$[LOLP]_t = p(d_t \geq X_t + w_t),$$

where d_t is the demand, w_t is the available wind capacity, and X_t (which is explicitly treated as a random variable) is the available conventional generating capacity. As described earlier, for our purpose the demand is taken to include the response requirement.

23. If the demand and wind time series are hourly resolution (the Poyry wind data is hourly; the present demand series used takes the higher demand from the two settlement periods in each hour), then the Loss Of Load Expectation (LOLE) in hours per year over n_y years of study is

$$[LOLE] = \frac{1}{n_y} \sum_t [LOLP]_t \ .$$

24. The LOLE, i.e. the average number of hours of supply shortage per year, is commonly used as a generation adequacy metric in system planning or operational planning.

‘Whole-winter’ Indices and Choice of Conventional Plant Model

25. The assumption of independence between the availability of different conventional units is reasonable at times of high demand, where the market incentivises generating companies to make as much plant as possible available.

26. Operating margin could conceivably be thin during the maintenance season. However, due to the possibility of flexing maintenance schedules when margin is tight outside the peak season, we assume that the generation adequacy risk is dominated by the highest demands in winter.

27. Generation adequacy assessments in GB have usually looked at the time of winter peak itself, rather than the whole winter. The simple and robust hindcast approach for wind and demand modelling reflects the reality that the whole winter risk is not entirely concentrated at peak.

Effective Plant Margin With Wind Generation

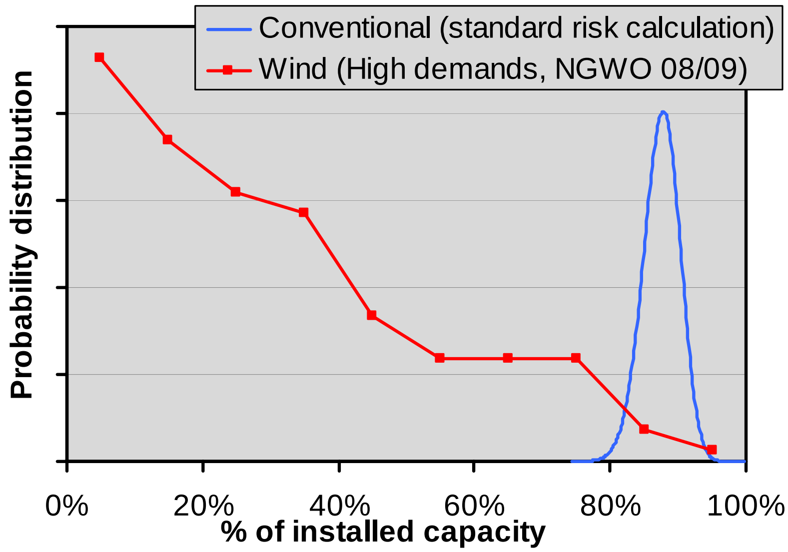
Dependence of Conventional Plant Distribution on Installed Capacity

28. In GB, the probability distribution obtained for available conventional capacity is approximately Gaussian near its mean, with the tails decaying slightly less rapidly than those of a Gaussian (see Fig. W.2 for a comparison with a typical distribution for available wind capacity).

29. If the installed conventional capacity changes, one option is to reconstruct the distribution based on a list of conventional unit capacities for the new scenario.

30. An alternative approach, used here, is to evaluate the conventional plant distribution for 2010, and then shift its mean to the mean availability of the changed conventional generation fleet. The width of the distribution should be scaled in proportion to the square root of the mean, as for independent units the standard deviations add as square-root-sum-of-squares, and the number of units is approximately proportional to the total installed capacity. This implicitly assumes that while the mean and standard deviation of the distribution change as the installed capacity and plant mix changes, its shape does not.

Fig. W.2. Comparison between typical distributions for available conventional and wind capacity[39].



31. This approach will be used for two purposes, described later:
    - Calculation of the conventional capacity equivalent to a generation fleet which includes both wind and conventional plant, in a manner consistent with our previous 'assumed availability' scaling approach;
    - Derivation of conventional plant distributions for future years, without having to specify future projected generation fleets unit-by-unit.

Wind Capacity Credits

32. Inclusion of wind generation within the 'assumed availability' approach used in the Winter Outlook requires the wind fleet to be assigned a capacity credit, which quantifies its contribution to supporting demand relative to that of the installed conventional plant. In this report, the sum of conventional capacities scaled by assumed availabilities will be referred to as 'de-rated capacity'; this terminology is widespread, including related work in Ofgem's Project Discovery[40].

33. A wide variety of wind generation capacity credit calculation methods are in use worldwide. The most common is probably Effective Load Carrying Capability (ELCC), the additional demand which the wind generation can support without increasing the system risk level[41]. Because of this variety of capacity credit approaches, there can

39 The wind series is based on data for hours within 10% of ACS peak demand, published in the 2008/09 Winter Outlook. The y-axis scales for the two plots are not directly comparable, as the wind visualisation is discrete, whereas the conventional distribution is regarded as continuous.

40 Ofgem used a flat 15% scaling factor for wind capacity, as opposed to our more detailed risk-based approach.

41 For a discussion of different approaches to capacity credit calculation, including ELCC, see C.J. Dent, B. Hasche, A. Keane and J.W. Bialek, 'Application of wind generation capacity credits in the Great Britain and Ireland systems', Cigre Paris Session 2010.

be no one definitive definition; the concept of capacity credit is thus an indicative quantity, used to visualise wind's contribution to securing demand.

34. One simple approach to capacity credit calculation is to use a low percentile of the probability distribution for available wind capacity at time of peak demand. This however is not explicitly grounded in the level of system risk, and moreover there is a good intuitive reason why the capacity credit as a percentage of installed wind capacity should depend on the installed capacity.

35. At low wind penetrations, the possibility of having zero aggregate capacity available from the wind fleet is not fundamentally different from the situation with the same capacity of conventional generation; the capacity credit for wind is then closely related to the mean available capacity, as it is for conventional plant.

36. For higher volumes of conventional plant, the probability of near-zero available capacity becomes vanishingly small. However, as the available capacity of a system's wind fleet is determined primarily by the weather, it is possible for near-zero capacity to be available from even a very large volume of installed wind generation. As a consequence, for high wind penetrations the capacity credit of the wind fleet should be somewhat lower than the mean available capacity.

Quantifying Adequacy: Equivalent De-rated Capacity

37. Loss of Load Expectation, calculated as described above, can be used as the metric which quantifies the generation adequacy risk faced by the system in a given winter scenario (a scenario being defined an ACS peak demand level, and the wind and conventional generation fleets). However, LOLE does not provide continuity with previous studies such as past Winter Outlooks and National Grid's 'Operating in 2020' Consultation[42], and is less transparent in its ability to reveal the drivers behind risk modelling results.

38. We therefore propose using a new measure, 'Equivalent Derated Capacity' (EDC)[43]. This is calculated for a given winter scenario as follows:
- Evaluate the risk measure in the given scenario, including both the wind and conventional generation.
- The EDC of the combined wind and conventional fleet is the de-rated conventional capacity which gives this same risk (without any wind generation). The available capacity distribution for this increased conventional fleet is obtained by rescaling as described above.

[42] http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/
[43] This is related to the Equivalent Firm Capacity and Equivalent Conventional Power Plant approaches described in M Amelin, 'Comparison of Capacity Credit Calculation Methods for Conventional Power Plants and Wind Power' IEEE Trans. Power Syst., vol. 24, no. 2, pp. 685-691. The key innovations in EDC are: (a) consideration of imperfectly reliable conventional units without assuming a single unrealistically large single test unit, (b) taking as the starting point the system with wind, rather than that without wind, and (c) direct continuity with National Grid's previous approach.

The EDC (capacity credit) of the wind fleet is the difference between this EDC for the wind and conventional plant together, and the de-rated capacity of the conventional fleet. The de-rated margin is the margin of total EDC over ACS peak demand.

39. EDC is therefore consistent with the assumed availability approach used in previous reports; alternative capacity credit calculation approaches such as ELCC would not provide this natural consistency. We thus conclude that EDC provides the clearest means of communicating the system adequacy risk in reports such as the Winter Outlook.

Example results: National Grid's 'Gone Green' scenario

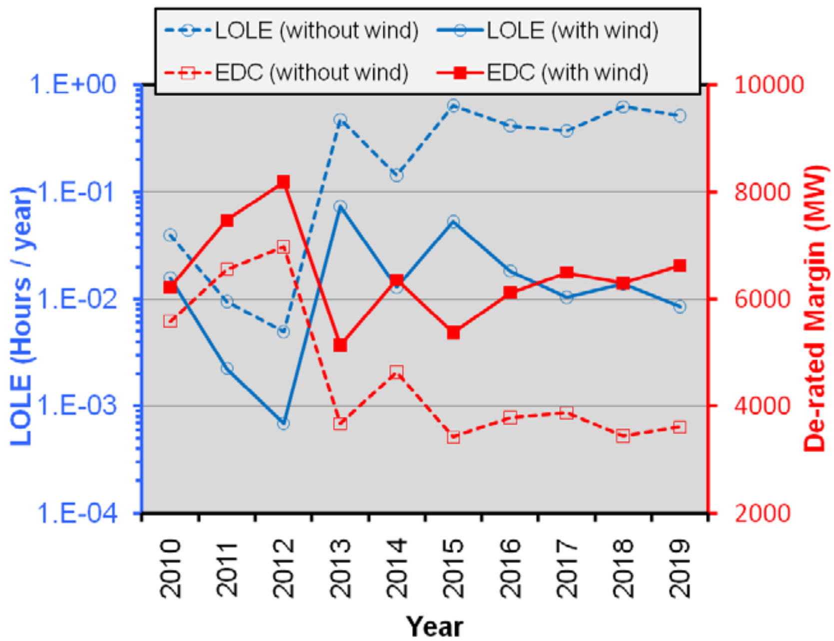
Data Used

40. For years 2010, 2015 and 2020, the National Grid / Poyry scenarios for installed wind generating capacity are used. Wind capacities and load factors for the intervening years are obtained by linear interpolation.

41. The conventional plant capacities for each year are taken from National Grid's 'Gone Green' scenario. The probability distribution for available conventional capacity in later winters are obtained by rescaling that for 2010 to give the 'gone green' assumed availability, as described above; the future 'assumed availability' scaling factors for the various technologies are the same as those used in recent Winter Outlooks. ACS peak demand is assumed to remain constant at 60 GW.

Results: De-rated Margin

Fig. W.3. LOLE and Effective Margin for future years in National Grid's 'Gone Green' scenario[44].



42. LOLE and EDC results for the Gone Green scenario are displayed in Fig. W.3. The dashed red curve shows the de-rated conventional capacity. National Grid's past experience shows that a de-rated margin of 5 GW is satisfactory in an all-conventional system. The dashed red curve shows that within the risk calculation used this is equivalent to LOLE of about 0.1 hours / year.

43. Over the next few years, the plant margin is forecast to increase further from an already healthy level due to commissioning of new CCGT plant. In this scenario, the main effect of large coal plant retiring due to the Large Combustion Plant Directive is seen between 2012 and 2013, when the de-rated conventional capacity drops by about 3 GW; it then remains constant to within 1 GW until 2019 (beyond 2013, regarding the Gone Green scenario as a forecast becomes progressively less robust, due to greater uncertainty over what plant will commission or retire.)

44. When the projected future wind generation is added to the risk calculation, the risk level decreases (as expected), or equivalently the de-rated margin increases. The major change in 2012-13 is still present, but the increase in risk is now to a level which has historically been regarded as comfortable. Post-2013, depending on one's perspective either the wind generation is ensuring that the de-rated plant margin

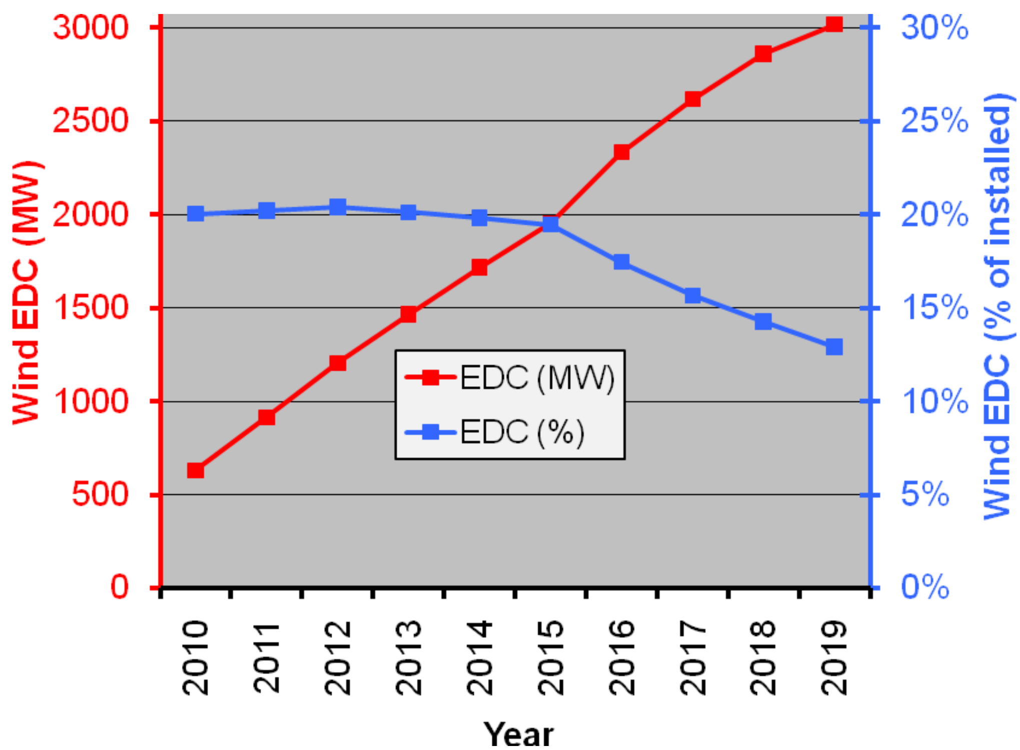
[44] This should be interpreted as specifically as an analysis of generation adequacy in the Gone Green scenario, rather than as a prediction of the plant margin which will be realised in the next decade.

remains healthy, or alternatively considerable reliance is being placed on wind's limited contribution to securing demand.

45. The graph also shows that the EDC metric tracks the LOLE very closely, with 1 GW of effective margin being roughly equivalent to a factor of 10 in LOLE.

Results: Capacity Credit of Wind

Fig W.4: EDC-based capacity credit of wind generation in the Gone Green scenario.



46. The EDC of the wind generation (i.e. the increase in EDC on addition of the wind generation) is plotted in Fig. W.4. Over the 10 years plotted, the GW EDC of the wind (the capacity credit of the wind generation) increases linearly with time, and slightly sub-linearly with installed capacity.

47. This is due to two competing effects. If the same load factor time series applied as the wind capacity is increased, then percentage capacity credit would decrease as the capacity increases. However, over the years an increasing proportion of the wind generation is offshore, giving an increasing quality of wind resource.

48. These competing effects explain the figure in further detail. Up to 2015, the initial exploitation of the offshore resource occurs, giving rapidly increasing average load factors. However, from 2015 there is already a substantial proportion of far-offshore wind, and therefore the improvement in average load factors slows down. As a consequence, the effect on the capacity credit of improving average wind resource quality diminishes, and the percentage capacity credit falls from just over 20% to around 13%.

Conclusions

49. We have presented a new approach, 'Equivalent De-rated Capacity' (EDC), for including wind generation in plant margin calculations. Unlike other capacity credit approaches, EDC provides natural continuity with the 'assumed availability' approach in previous Winter Outlooks.

50. EDC results are presented in the main body of this year's report using the actual transmission-connected conventional units and actual transmission-metered wind generation for winter 2010/11.

51. This Appendix has used National Grid's Gone Green scenario to illustrate the EDC approach. The 2010/11 plant margin is forecast to be very healthy, and so use of 'Gone Green' provides a more instructive demonstration of how EDC quantifies demand security when the generation adequacy risk is more substantial. As always with such scenario analyses, the risk results should be interpreted as the consequences of that scenario's assumptions, rather than a prediction of the absolute risk level in future winters.

52. Future work will include consideration of how to include distributed wind in the risk assessment, which would treat transmission-connected and distributed wind on an equal basis, and allow direct comparison of previous years' demand data. Looking further ahead, it will be necessary to model in more detail how increased demand response will help secure peak demand.