Winter Consultation 2011/12

Introduction

1. This document sets out our analysis and views for the coming winter. Previous outlook reports are published on our website[1]. The document is separated into two main sections, a review of last winter and a consultation on the outlook for the upcoming winter. At the end of each section there are consultation questions relating to Gas and Electricity, four consultation sections in total. National Grid would welcome feedback on these specific points and also welcomes industry and wider participant views on all points raised in this document. All consultation questions and other views should be sent to energy.operations@uk.ngrid.com by Friday 19th August 2011.

Industry Feedback

2. We continually seek feedback on our outlook reports to increase their usefulness to the industry and to reflect changes when they become apparent. To feed back comments on our outlook reports please contact us at energy.operations@uk.ngrid.com.

Roles and Responsibilities

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

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5. National Grid has prepared this consultation document in good faith, and has endeavoured to prepare this consultation document in a manner which is, as far as reasonably possible, objective, using information collected and compiled by National Grid from users of the gas transportation and electricity transmission systems together with its own forecasts of the future development of those systems. While National Grid has not sought to mislead any person as to the contents of this consultation document,

[1] http://www.nationalgrid.com/uk/Electricity/SYS/outlook/.

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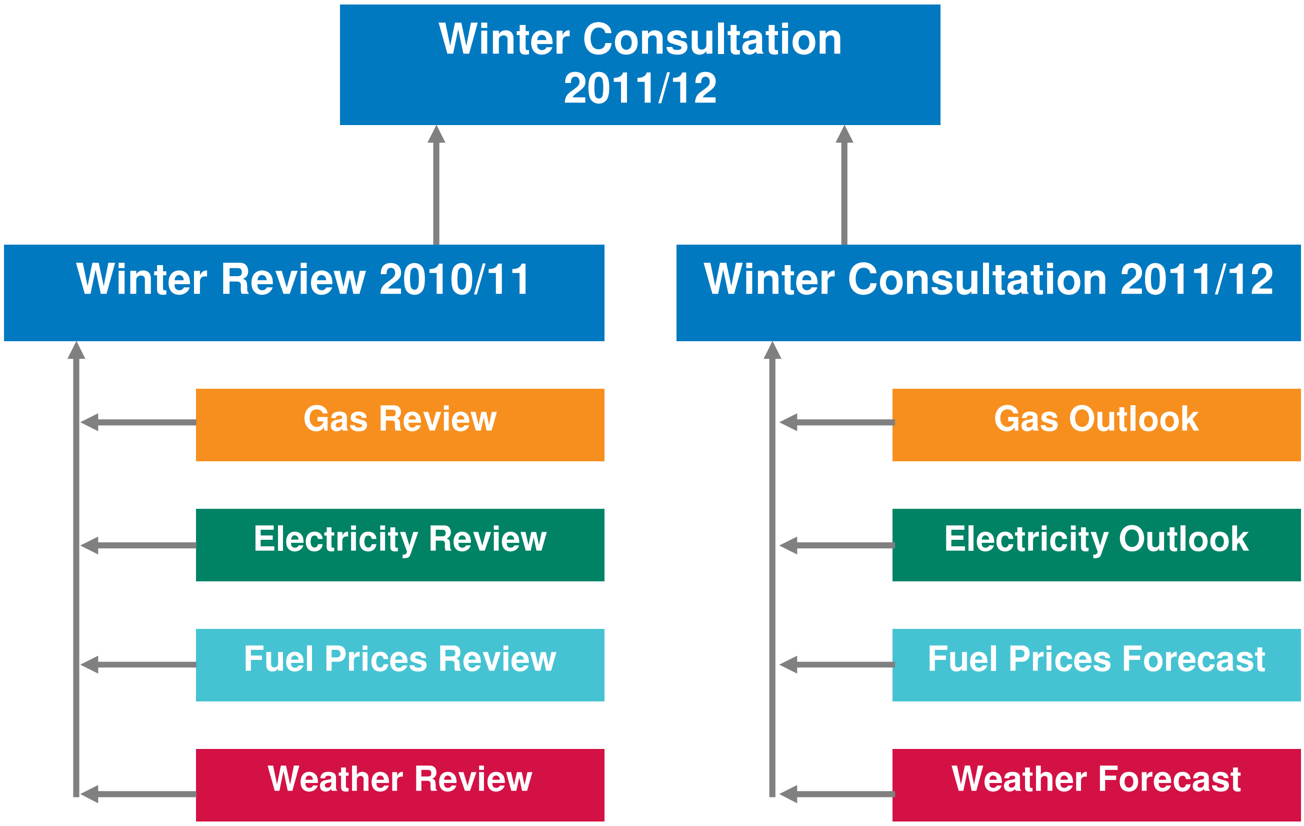
Overall Summary



Winter Review 2010/11 - Key Details

Weather

Coldest December on record but overall an ‘average’ winter due to other months being relatively ‘warm’

Fuel Prices

All energy prices increased during winter 2010/11, notably oil and gas.

As the relative increase in gas price was higher than that for coal, the economics within winter shifted from gas to coal as the preferred source of fuel for power generation

Gas

Highest demand 20th Dec 2010 (the 2nd highest)	465 mcm/d
2010/11 supply trends - lower UKCS, more LNG. Increased flexibility from non storage supplies	

Electricity

Peak demand 7th December 2010 at 17:30	59.7 GW
Actual generator availability at the peak	80%

Winter Outlook 2011/12 - Key Details

Weather	
Early weather forecast to be issued in Winter Outlook report in September / October 2011	
Fuel Prices	
Forward energy prices for next winter are broadly flat with the exception of some seasonality in gas prices. This strongly favours coal as the preferred source of fuel for power generation	
Gas	
Peak gas demand forecast (assumes low gas for power generation)	474 mcm/d
Little change in winter demand forecast for 2011/12 except for lower gas for power generation	
2011/12 supply forecasts – lower UKCS, more imports notably LNG	
Storage levels marginally lower, but should increase within winter when new facilities are commissioned	
2011/12 safety monitor requirements are similar to 2010/11	
Electricity	
Normal Demand Levels	58.1 GW
1 in 20 Demand Levels	59.7 GW
Generator Capacity	80.9 GW
Assumed Generation Availability (Not including Interconnectors)	63.8 GW
Forecast Surpluses based on normal demand	16%

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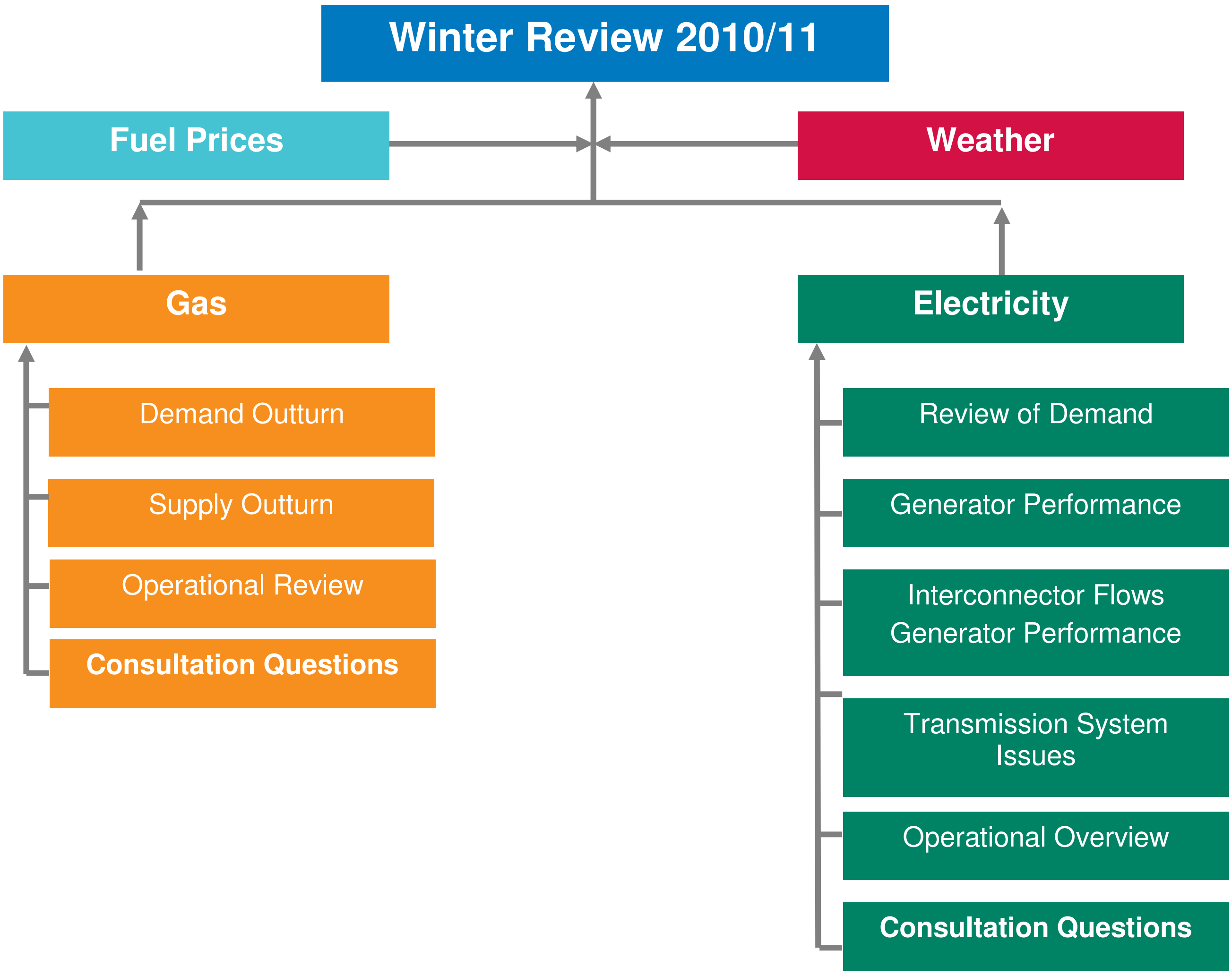
Winter Review 2010/11



Weather

7. Both cold and warm extremes were experienced during the 6 months from October 2010 to March 2011. The weather in October and early November fluctuated around seasonal normal but then temperatures dropped towards the end of November resulting in the coldest day in November and the coldest December on record. January saw a return to average conditions, February was the 4th warmest in the last 50 years and March the 12th warmest.

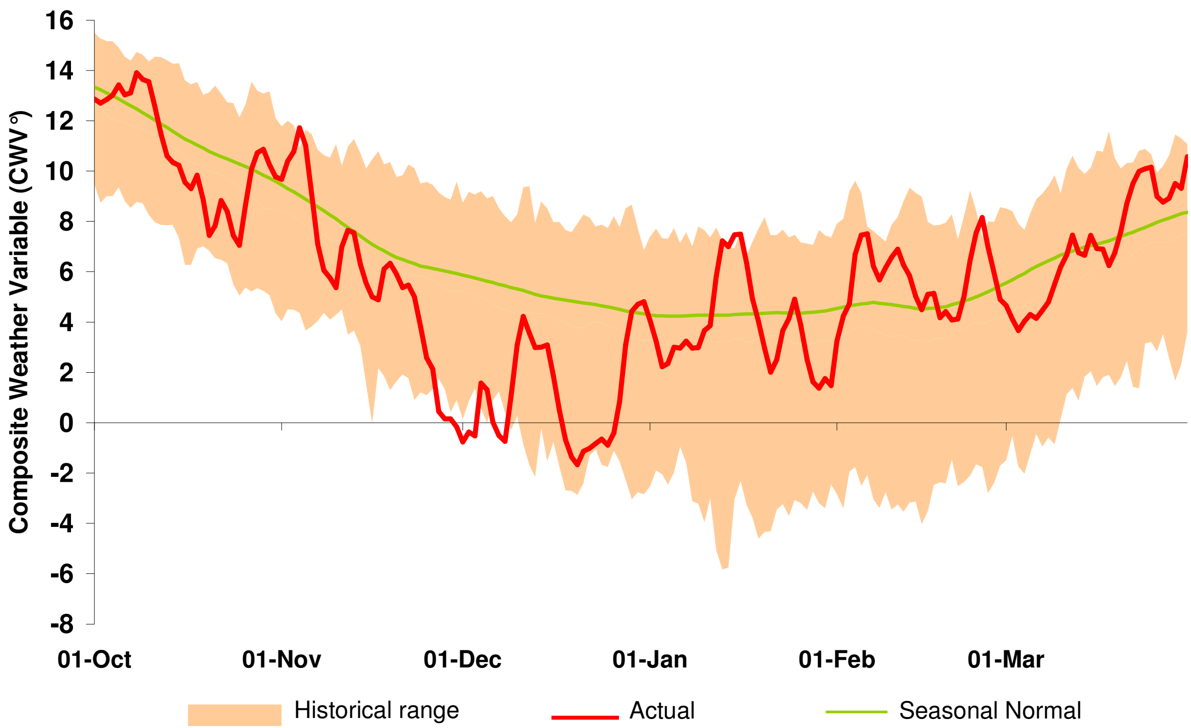
8. The 6 month period from October to March was average when compared to the last 83 winters. The coldest day was on December 20th with a severity of 1 in 3 cold.

9. For the 3 month mid-winter period from December to February, the severity was also average with the mild February offsetting the cold December.

10. In terms of recent winters, which have tended to be warmer, the October to March period was the coldest since 1995/96 being slightly colder than 2009/10.

11. Figure W1 compares the winter 2010/11 weather with the daily maximums and minimums since October 1928. The seasonal normal line has been adjusted for climate change and is not the average of the historical values.

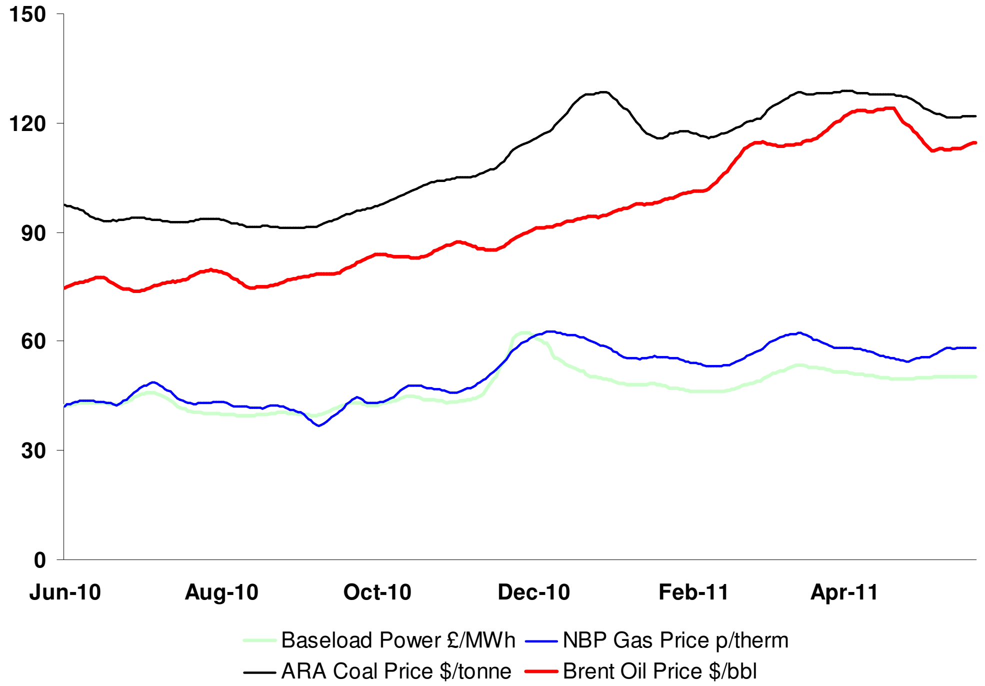
Figure W1 – Winter Composite Weather 2010/11



Fuel Prices

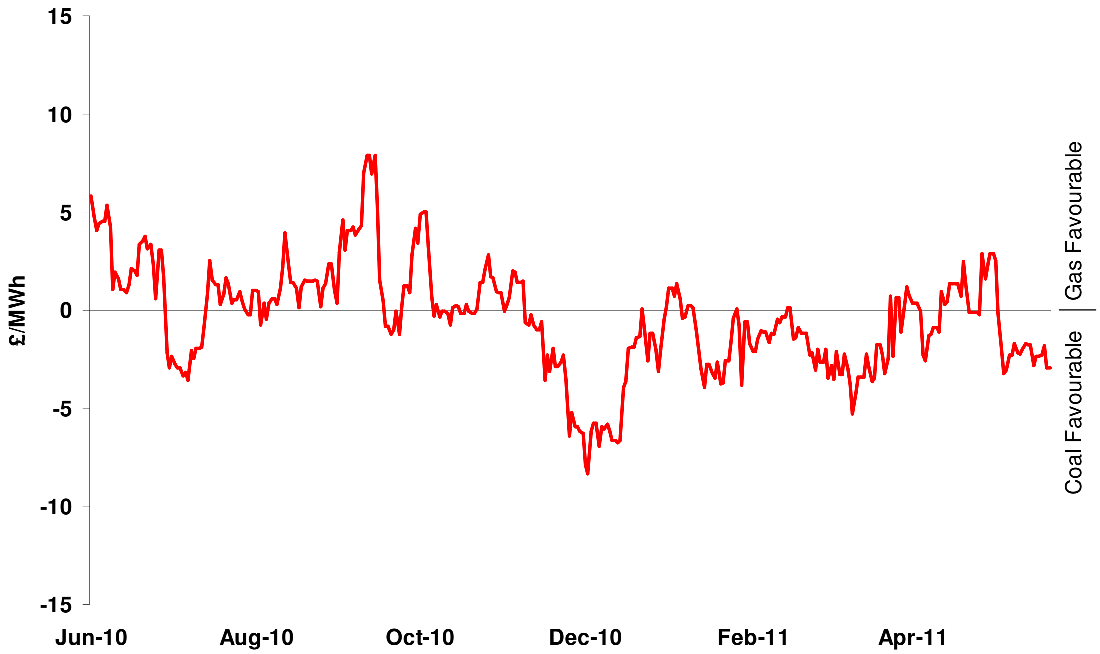
12. **Figure F1** shows energy prices for the 12 months prior to June 2011.

Figure F1 - Energy Prices since June 2010



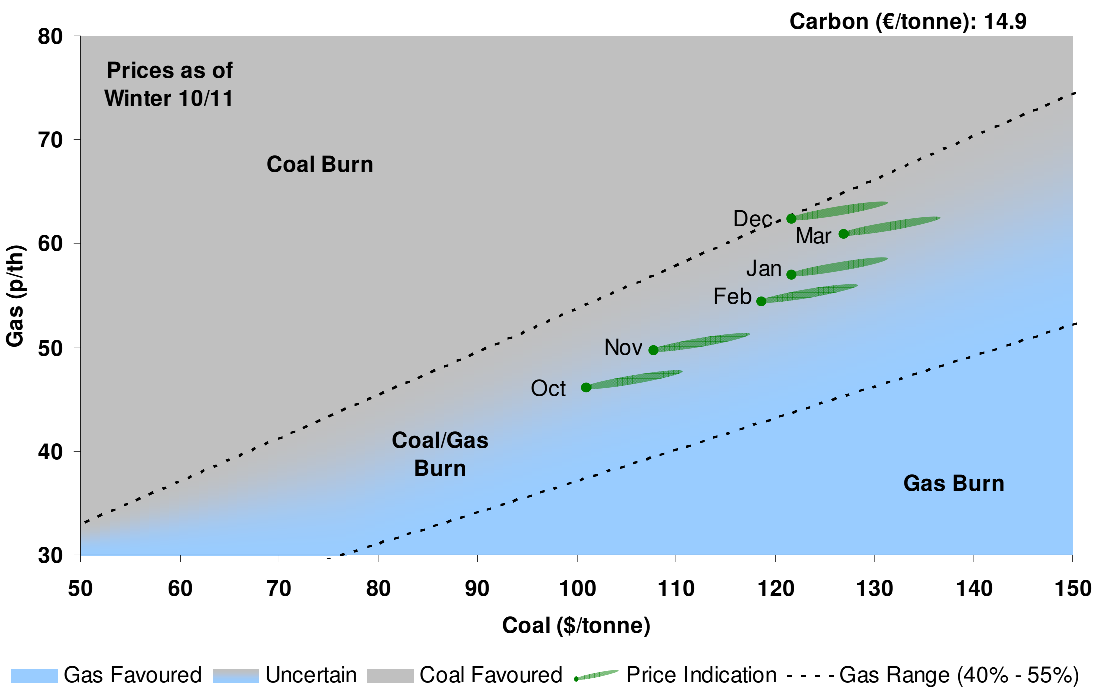
13. The chart shows that all energy prices have increased during the last year.
14. Oil remained in a range of $70-80 per barrel for some time before increasing from October 2010 due to views of economic growth leading to increasing demand and accelerated later by turmoil in the Middle East.
15. Coal prices have also increased due to views of the world economy and associated demand. The nuclear restrictions in Germany have also supported the price. As a consequence carbon prices have also increased.
16. UK gas prices increased from October and again in November when the UK experienced cold weather. Prices have remained relatively high since then due to indirect linkage to oil prices.
17. Electricity prices initially increased in line with the gas price, but have followed a lower trend since January as new power generation has made electricity margins more comfortable.
18. **Figure F2** shows the relative dark and spark spreads, showing whether gas or coal is favoured for electricity generation.

Figure F2 – Relative power generation economics (1)



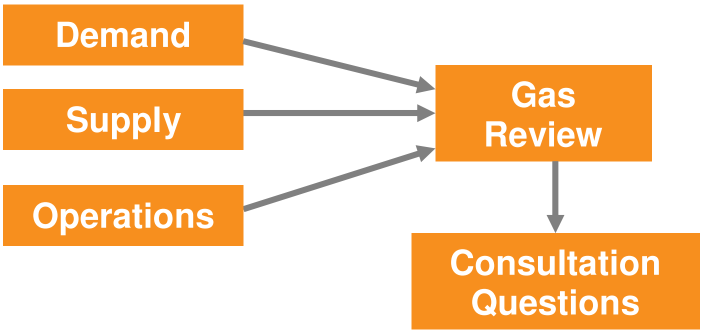
19. The relative increase in gas prices has been more than that for coal. This has slowly shifted the economics of power generation from gas to coal, however as shown in **Figure F3**, there are other factors to consider.

Figure F3 – Relative power generation economics (2)



20. **Figure F3** shows how prices of gas and coal have increased since October, however only during December and to a lesser extent March was there a strong bias for coal generation. The chart also highlights how differing station generating efficiencies make this far less clear, though not shown station ownership and the portfolio of energy players also influences the generation mix.

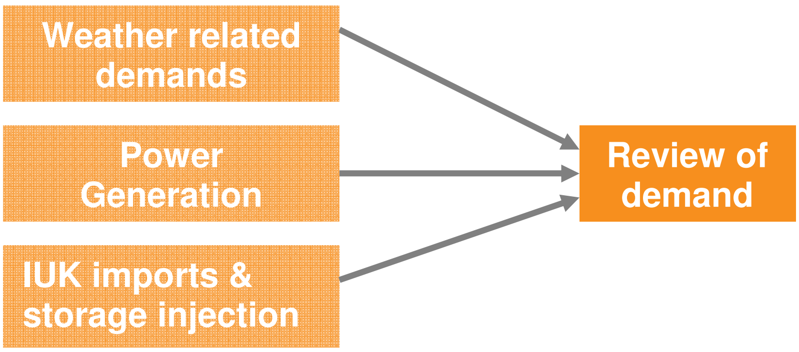
Gas



Overview

21. This section reviews winter 2010/11 in term of gas demand, supply and operational experiences.

Review of Demand

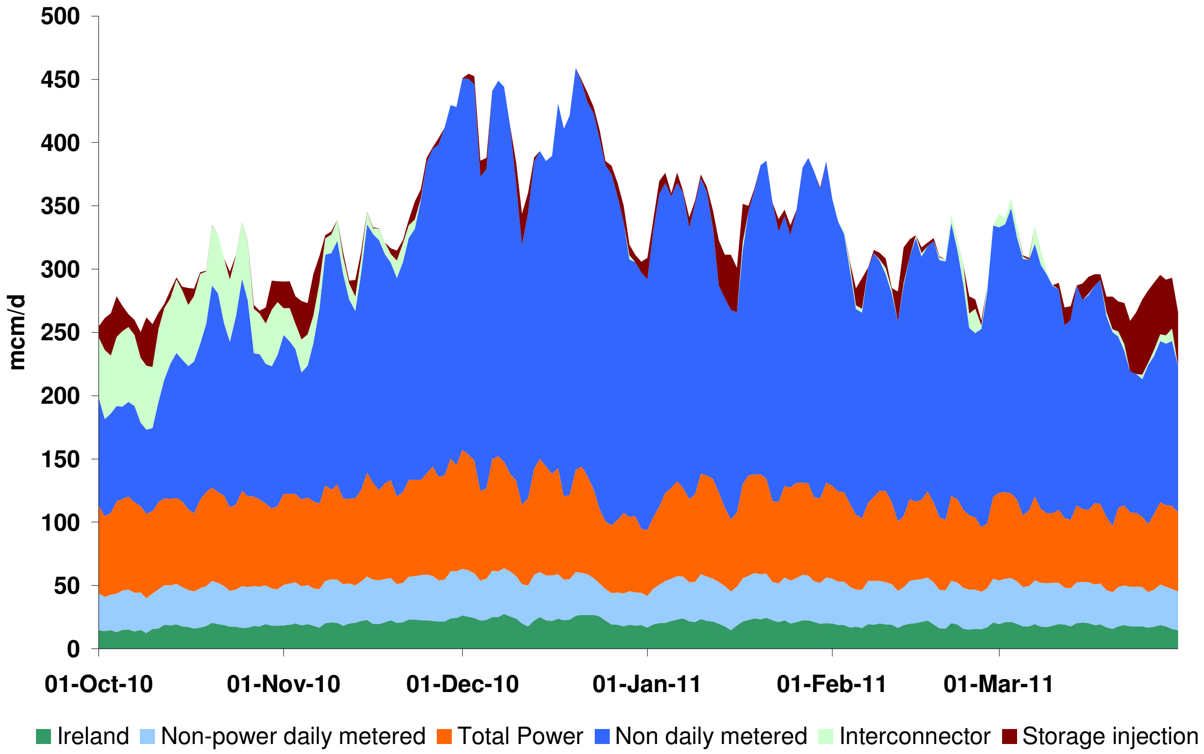


22. The highest demand day in winter 2010/11 was December 20th 2010. This was the second highest ever demand with exceptionally high NDM demand. Indeed, for the weather conditions experienced, the NDM demand was above our forecasts.

23. Like winter 2009/10, winter 2010/11 was accountable for many days of high demand, notably in December. Indeed, 9 of the highest 20 demand days occurred in December 2010, and in total 15 of these were during the 2010 calendar year.

24. **Figure G1** shows the gas demand for winter 2010/11.

Figure G1 - Winter Gas Demand 2010/11

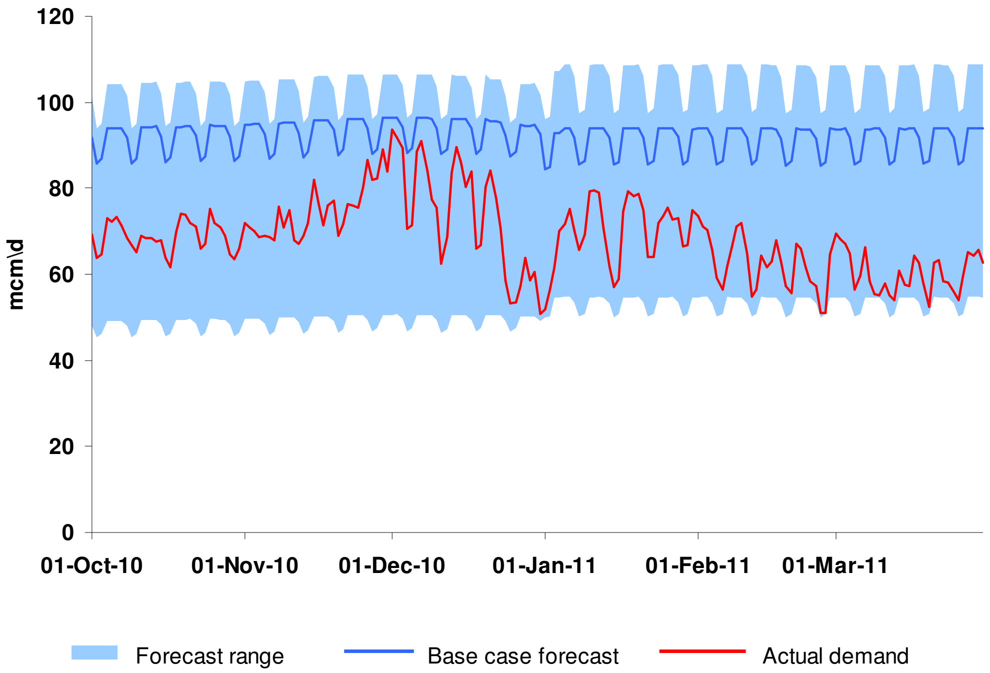


25. The chart clearly shows the influence of the cold weather from late November through December and the subsequent milder conditions thereafter.

26. Most of the increase in demand during the cold spell was in the NDM sector. IUK exports and storage injection were highest at the start and end of the winter filling in troughs in the demand when NDM demand was lower. There was also significant storage injection in the mid-winter troughs. For most other days storage injection was modest averaging just 2 mcm/d for demands above 400 mcm/d and 4 mcm/d for demands above 350 mcm/d.

27. **Figure G2** shows the power generation demand for winter 2010/11 together with the pre-winter base case forecast and high and low forecast ranges to reflect plausible generation merit orders depending on whether gas is base load or marginal generation.

Figure G2 - Winter Power Generation Demand 2010/11

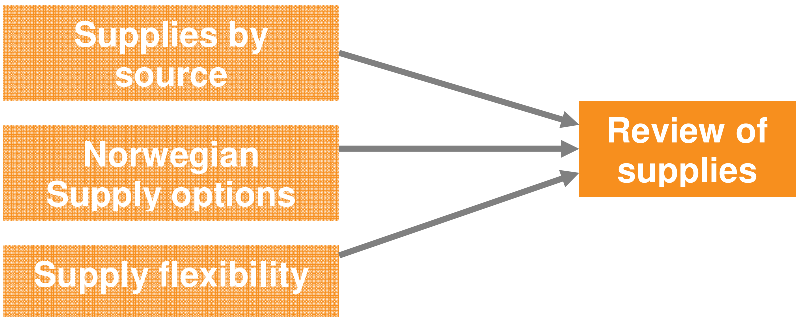


28. The chart shows that with the exception of the highest electricity demand days during December, power generation was lower than forecast with coal at near base load conditions for much of the winter. This was in contrast to the pre-winter forecasts that assumed a repeat of 2009/10 market conditions, namely that gas would be the primary source of fuel for power generation.

29. The shift to coal was a consequence of gas prices increasing from about 40 p/therm in early October to above 60 p/therm in December and remaining at near this level for the remainder of the winter. During the same period the cost of coal increased relatively less from about 90 to 120 $/tonne.

30. The review of gas supplies section shows the demand associated with IUK imports and storage injection in more detail.

Review of Supplies



31. **Table G1** summarises the make-up of gas supplies for winters 2008/09, 2009/10 and 2010/11 by supply source.

Table G1 – Winter Gas Supply by Source

	2008/09		2009/10		2010/11	
	bcm	%	bcm	%	bcm	%
UKCS	33.3	55%	28.0	44%	23.9	39%
Norway	17.8	29%	15.3	24%	15.2	25%
Continent	4.6	8%	6.1	10%	5.3	9%
LNG	1.6	3%	8.9	14%	13.0	21%
Storage	3.9	6%	4.7	7%	4.1	7%
Total	**61.1**		**63.0**		**61.5**	

32. For winter 2010/11 the table shows:

- Further decline in UKCS
- Comparable levels of imports from Norway and the Continent
- Considerable growth in LNG
- Less use of storage than in 2009/10

33. **Table G2** shows the make up of supplies for winters 2008/09, 2009/10 and 2010/11 by terminal.

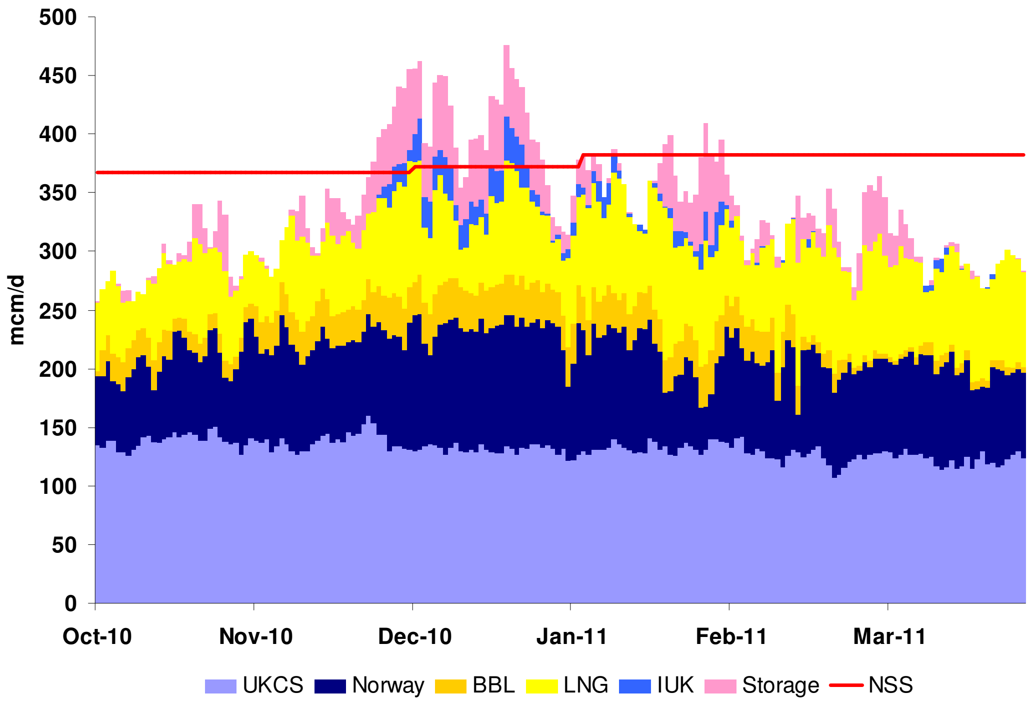
Table G2– Winter Gas Supply by Terminal

	2008/09		2009/10		2010/11	
	bcm	%	bcm	%	bcm	%
Bacton	13.9	23%	13.8	22%	12.6	20%
Barrow	2.1	3%	2.2	4%	2.1	3%
Grain	1.6	3%	2.5	4%	3.9	6%
Easington	15.1	25%	14.8	24%	14.8	24%
Milford H.	0.0	0%	6.4	10%	9.0	15%
Burton P.	0.1	0%	0.0	0%	0.2	0%
St Fergus	19.6	32%	14.6	23%	11.6	19%
Teesside	4.4	7%	4.3	7%	3.7	6%
Thed'pe	3.3	5%	3.0	5%	2.5	4%
Storage	1.1	2%	1.4	2%	1.2	2%
Total	**61.1**		**63.0**		**61.5**	

34. For winter 2010/11 the table shows similar flows at most terminals with the main exceptions being lower flows through St Fergus and higher flows through the Grain and Milford Haven LNG terminals.

35. **Figure G3** shows the gas supply by source for winter 2010/11, each of the supply sources is considered in turn in the following sub-sections.

Figure G3 – 2010/11 Supply Performance



36. The chart also shows the level of Non Storage Supply (NSS) as used in calculating the Gas Balancing Alert (GBA) trigger. This was increased from 367 mcm/d in early December to 372 mcm/d as a result of higher flows (notably LNG) during the first

period of high demand in late November / early December and again for similar reasons after the second period of high demand in mid December. For the demand days above 400 mcm/d, the average level of NSS was 378 mcm/d, this includes 2 days when Norwegian flows were significantly reduced due to upstream supply issues.

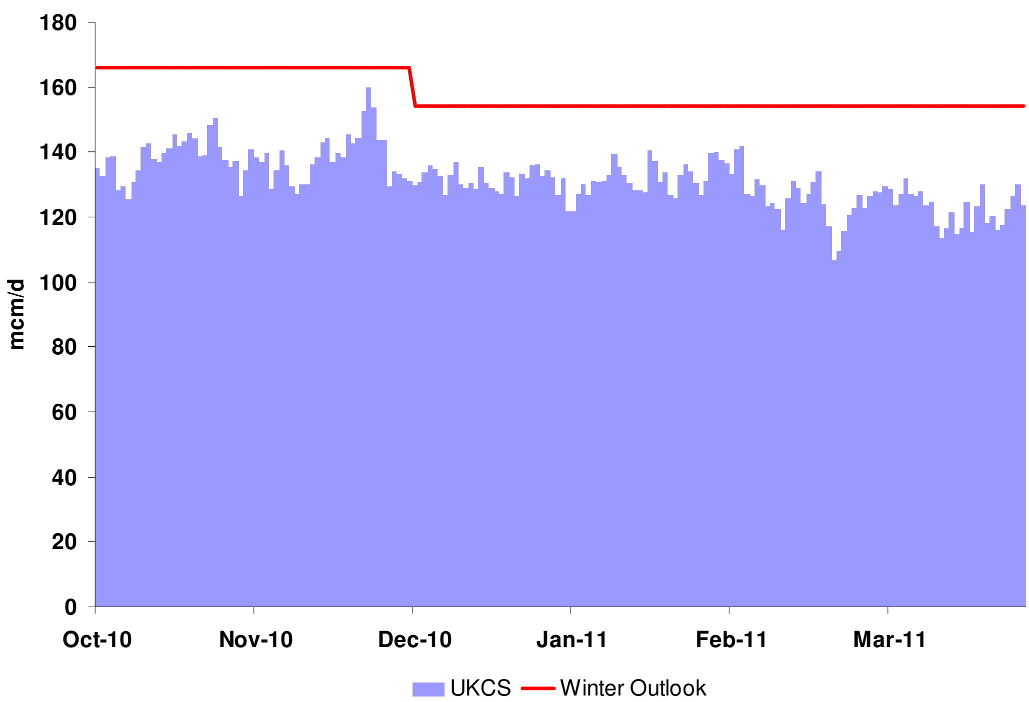
37. The highest day of supply was a record 477 mcm/d on 20th December, in aggregate there were 23 days of supply in excess of 400 mcm/d (32 in 2009/10) and 64 days in excess of 350 mcm/d (96 in 2009/10). Average demand for the highest 100 days of demand was 375 mcm/d, 16 mcm/d lower than in 2009/10.

UKCS Supplies

38. The forecast for UKCS supplies for winter 2010/11 was 184 mcm/d, for operational purposes 90% availability is assumed, resulting in a pre-winter operational forecast of 166 mcm/d.

39. **Figure G4** shows flows from the UKCS last winter and our operational forecast. This was subsequently reduced in early December to 154 mcm/d primarily due to long term field outages.

Figure G4 – 2010/11 UKCS Supplies



40. The chart shows that for most of the winter UKCS supplies were relatively steady but below our operational forecast. The possible reason why the levels of UKCS did not meet our operational forecast was that some high swing gas associated with Bacton Shell-Esso did not make a material contribution except during late November. This short term peak is clearly shown on the chart.

41. The profile for UKCS supplies also suggests some within winter decline with average October supplies of 138 mcm/d compared to just 123 mcm/d in March.

42. Average flows from the UKCS across the 6 month winter period were 132 mcm/d and for the 100 days of highest demand 133 mcm/d. **Table G3** shows the 2010/11 Winter Outlook peak forecast of UKCS supplies by terminal and the actual terminal supplies for the day of highest UKCS supplies (23rd November 2010) and the highest day for each terminal.

Table G3 – 2010/11 UKCS Supplies by Terminal

Peak (mcm/d)	Forecast	Actuals	
	Base Case	Highest UKCS	Highest Terminal
Bacton	60	56	58
Barrow	14	13	14
Burton Point	0	2	3
Easington	11	5	10
St Fergus[2]	58	50	52
Teesside	25	20	26
Theddlethorpe	16	13	15
Total	**184 (166)**	**160**	**178**

43. The table highlights that the day of highest UKCS supplies of 160 mcm/d was below the initial operational forecast of 166 mcm/d. This difference was due primarily to long term field outages (notably for St Fergus). A comparison of our 184 mcm/d forecast should be made against the aggregated highest terminal flows (178 mcm/d). This is well aligned to all terminals expect for St Fergus which is lower due to long term field outages.

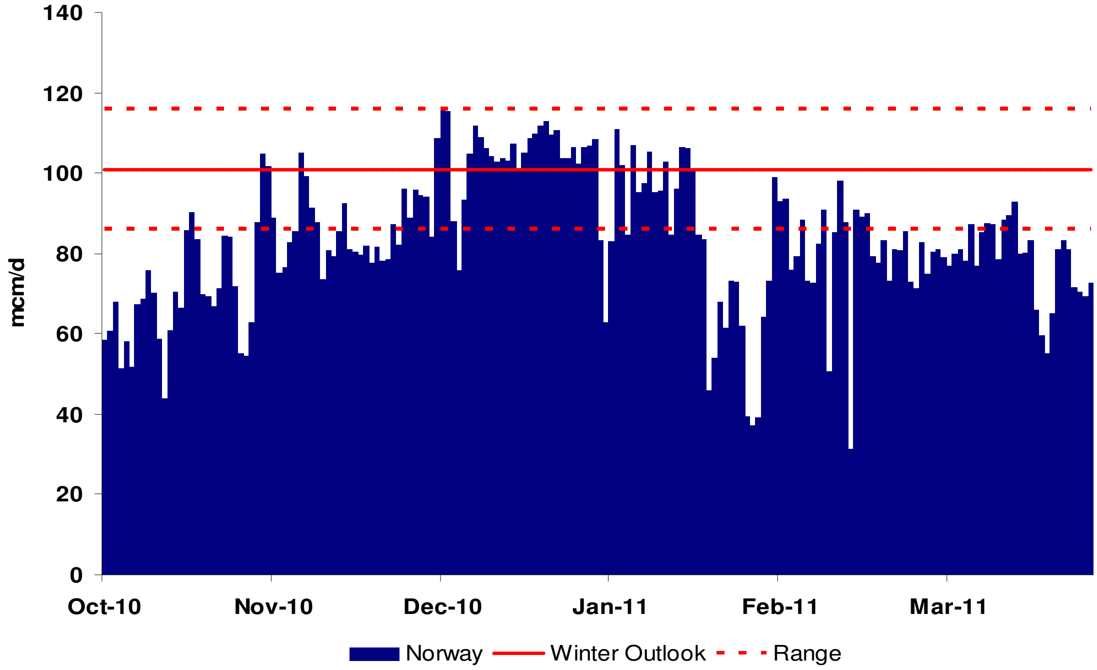
Norwegian Imports

44. Our forecasts for Norwegian imports to the UK for winter 2010/11 were subject to numerous uncertainties notably contractual obligations and transportation options regarding delivery to the Continent in Germany, France and Belgium. To capture this uncertainty a Central View of Norwegian flows to the UK (101 mcm/d) was produced within a range (93-116 mcm/d) based on high flows to the Continent (thus low UK flows) and low flows to the Continent (thus high UK flows).

45. **Figure G5** shows Norwegian flows through Langeled and our aggregated estimates for Norwegian imports to St Fergus through Vesterled, the Tampen Link and from Gjoa.

[2] Excludes estimates for Vesterled, Tampen and Gjoa

Figure G5 - 2010/11 Norwegian Imports to UK

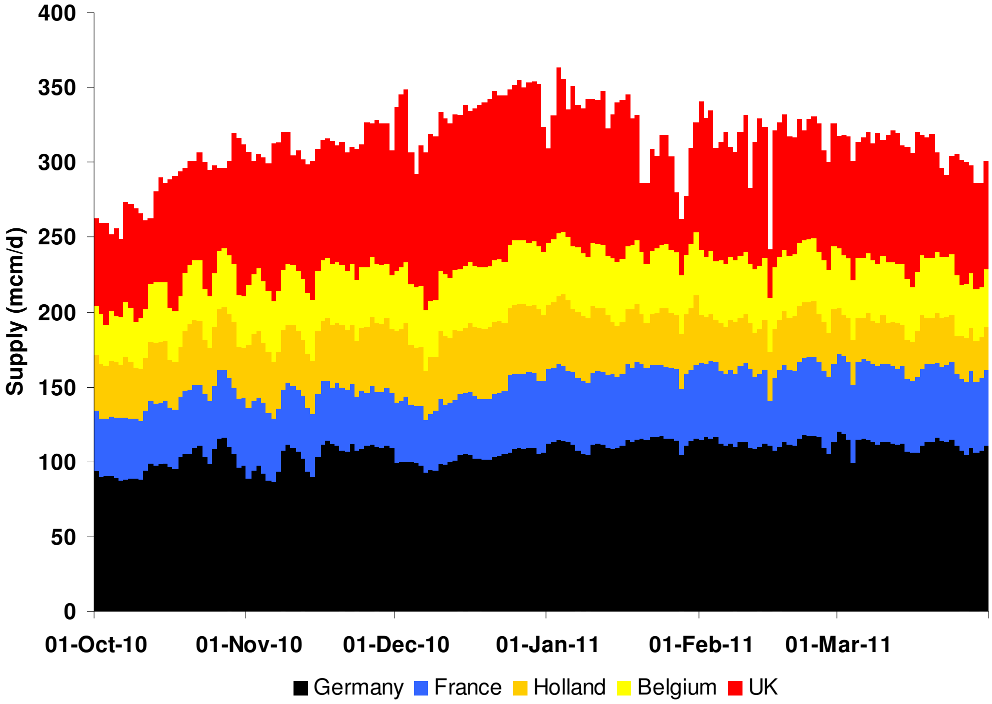


46. The chart shows that during the high demand periods, Norwegian flows were generally within our anticipated range. Average Norwegian flows across the 6 month winter period were 83 mcm/d within a range of 31-116 mcm/d. For the days of supply above 400 mcm/d average Norwegian flows were in line with our forecasts at 101 mcm/d.

47. As in winter 2009/10 Norwegian flows to the UK were at times reduced due to widely reported supply losses. As the chart shows, these were most noticeable in January rather than during the period of highest demands in December.

48. Besides the option to flow gas to the UK, Norwegian gas is also exported to Germany, France and Belgium. **Figure G6** shows our estimate of daily Norwegian exports to the UK and the Continent during winter 2010/11.

Figure G6 - 2010/11 Norwegian Exports to UK and the Continent



49. The chart shows some seasonality in Norwegian production. The average level of Norwegian production across the 6 month winter period was 318 mcm/d and 330 mcm/d for December to February. These flows are nearly identical to the pre-winter forecasts of 315 and 330 mcm/d respectively.

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

51. **Table G4** shows our estimate of winter Norwegian exports between 2008/09 and 2010/11.

Table G4 – Estimate of Norwegian Exports 2008/09 to 2010/11

(mcm/d)	Capacity 2010/11	Winter 2008/09	Winter 2009/10	Winter 2010/11	2010/11 Utilisation
Belgium	41	37	38	40	98%
France	52	47	46	46	88%
Germany[3]	151	121	138	147	97%
UK[4]	124	98	84	85	69%
Total	**368**	**302**	**306**	**318**	**86%**

[3] Includes flow to the Netherlands
[4] Capacity includes a proportion of FLAGS for Tampen

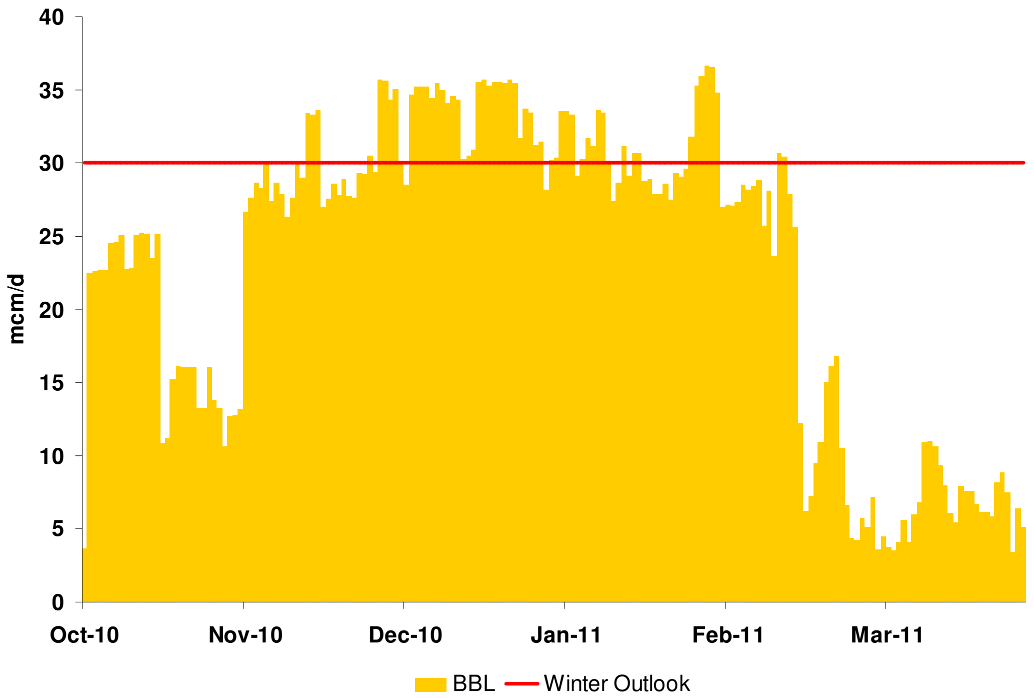
52. The table shows a further increase in Norwegian production last winter. Compared to last year, exports to Germany were higher. All the Continental pipelines operated at a high load factor (~90%) compared to below 70% for the UK.

53. The winter outlook forecast identified a range of possible flows from Norway to the UK. The resultant flows were aligned to the low range consistent with high deliveries to the Continent.

Continental Imports - BBL

54. **Figure G7** shows BBL flows for winter 2010/11. From November to mid February flows averaged 31 mcm/d, in line with our forecast of 30 mcm/d.

Figure G7 - 2010/11 BBL Imports to UK



55. During January BBL commenced their Interruptible Reverse Flow (IRF) capacity, i.e. non physical exports. The capacity increase of BBL to approximately 53[5] mcm/d was announced in April rather than as expected within winter.

Continental Imports – IUK

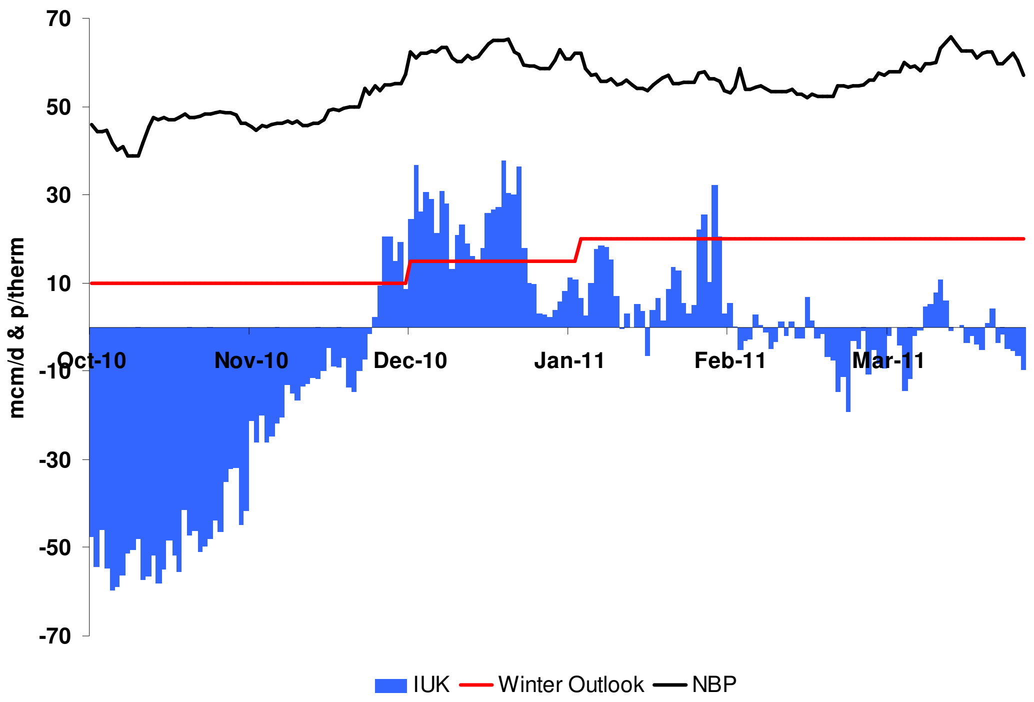
56. As in previous winters, IUK was forecast as the marginal source of non storage supply and would in terms of operation be similar to storage when UKCS and other imports could not meet demand with potential upper flows of 30 mcm/d. IUK flows were expected to be dependent on demand (price) and the availability of other supplies, notably other imports.

57. Figure G8 shows IUK import and exports flows for winter 2010/11. Whilst IUK was forecast to flow up to 30 mcm/d, a lower value was used in calculating the GBA

[5] Based on a CV of 39.6 MJ/m3 (standard)

trigger to account for supply options / uncertainties. As the winter progressed and IUK was seen to respond this value was increased.

Figure G8 - 2010/11 IUK Imports & Exports



58. In aggregate imports were 1.1 bcm and exports 2.1 bcm. Most exports were in October and November 2010. The highest flow for IUK imports was 38 mcm/d, for the days of demand above 400 mcm/d, IUK imports averaged 24 mcm/d.

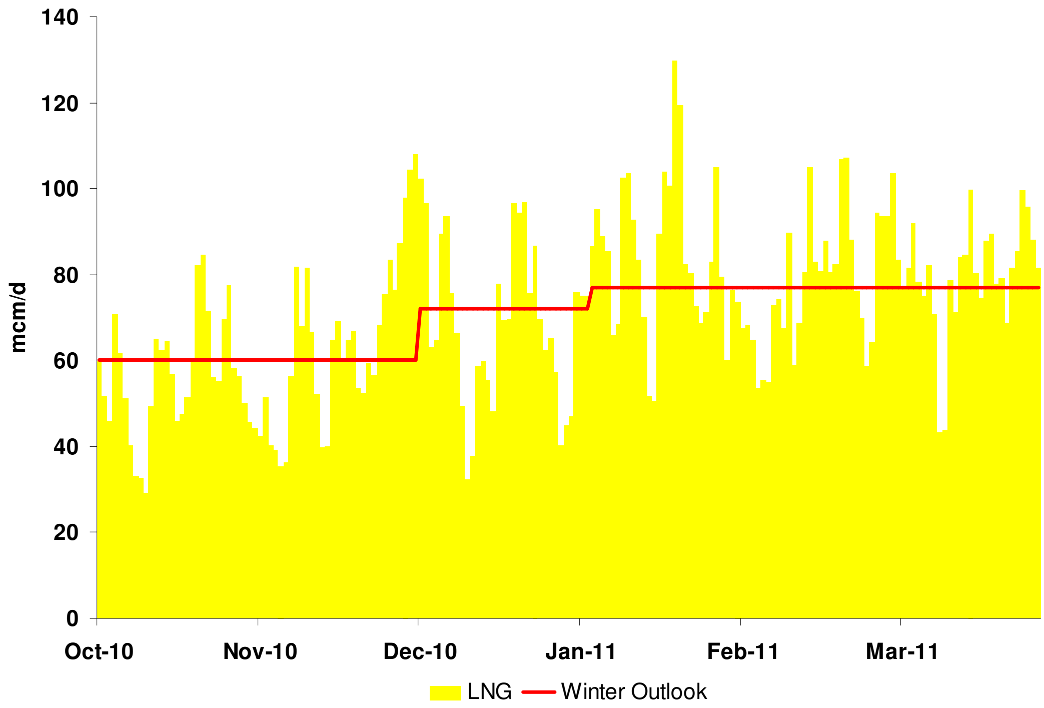
59. The chart for IUK shows that IUK responded to increased demand / gas price. This was noticeable from October to December when the net change of IUK was nearly 100 mcm/d i.e. from exporting 60 mcm/d to importing nearly 40 mcm/d. IUK also responded during the period of Norwegian supply losses in both January and February.

LNG Imports

60. The forecast for LNG imports for winter 2010/11 highlighted considerable uncertainties, hence an assumed base case forecast of 60 mcm/d within a range of 30 – 100 mcm/d.

61. **Figure G9** shows LNG imports through Grain, Milford Haven and the two LNG cargoes delivered through Teesside GasPort. Following high LNG flows during the high demands in late November and December we increased the operational forecast to 70 mcm/d in early December and 80 mcm/d in early January.

Figure G9 - 2010/11 LNG Imports



62. The chart shows considerable variation in day to day LNG flows ranging from approximately 30 to 130 mcm/d (included a contribution from Teesside GasPort) with an average flow of 72 mcm/d. For the days of demand above 400 mcm/d, the average flow was 88 mcm/d.

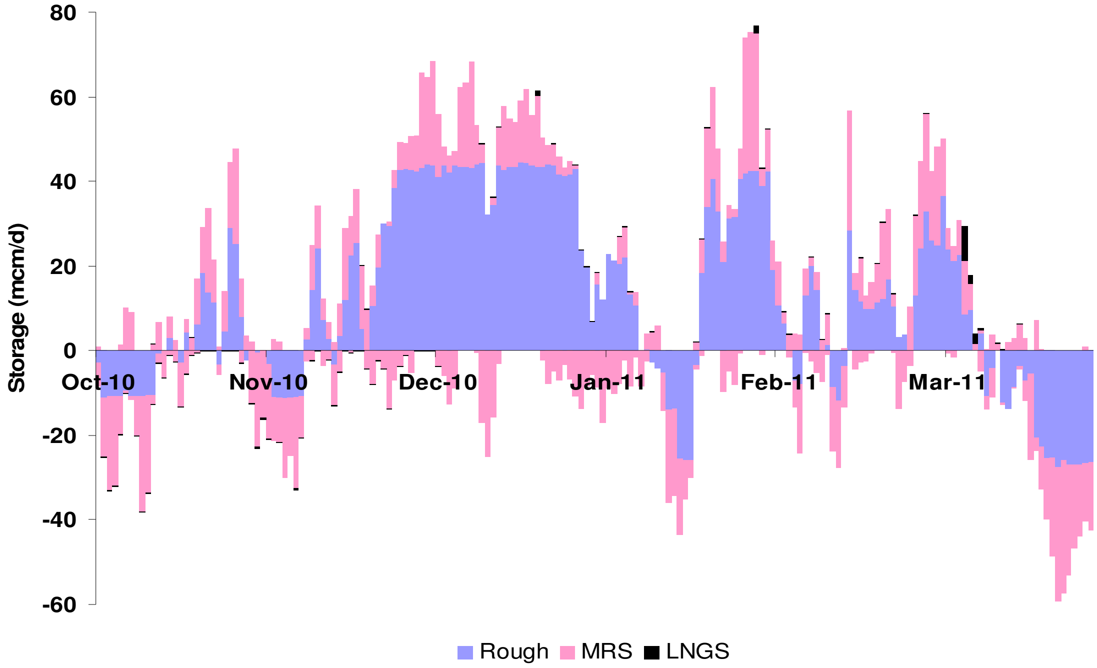
63. In aggregate total LNG imports were an estimated 13.0 bcm, of which 3.9 bcm was through Grain, 9.0 bcm through Milford Haven and an estimated 0.17 bcm through Teesside GasPort.

2010/11 Storage Performance

64. The forecast for storage for winter 2010/11 included no new storage facilities. Storage space was approximately 5% lower than for the previous winter primarily due to lower reported stocks in Rough. Storage deliverability was over 10% lower, this was primarily due to no commercial services from Glenmavis and to a lesser extent the outcome of an operational review of all storage sites. The loss of Glenmavis reduced ‘short range’ deliverability rather than a loss of endurance capability.

65. **Figure G10** shows storage withdrawals and injections over the winter in terms of Rough, MRS and LNG storage.

Figure G10 - 2010/11 Storage Withdrawals and Injection

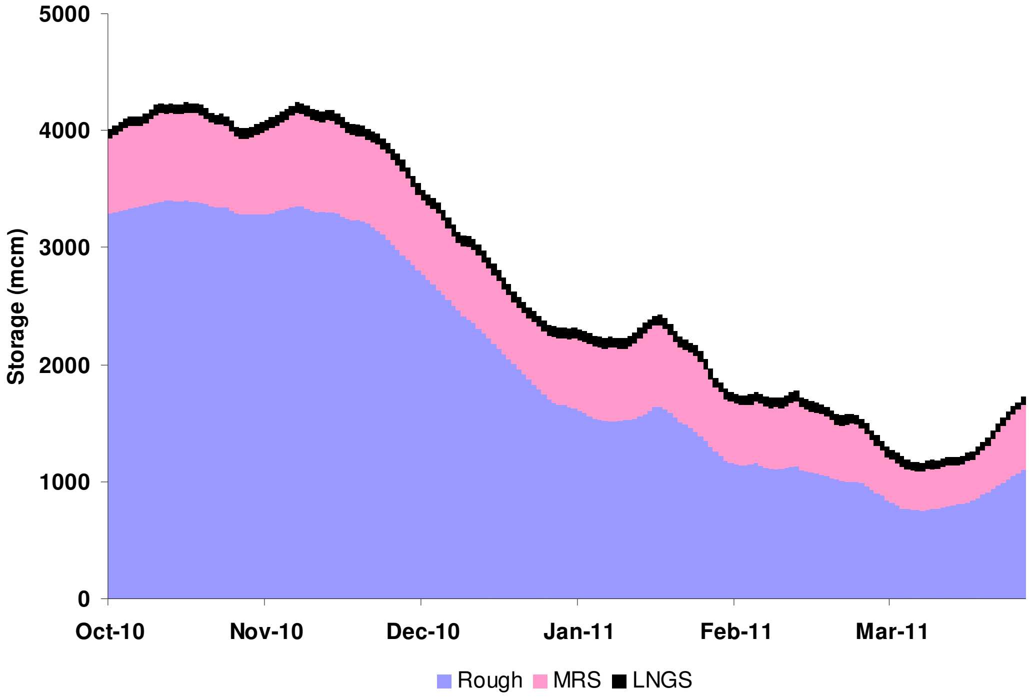


66. The chart shows:

- MRS withdrawals and injection throughout the winter including many days of both withdrawal and injection. For the 6 month winter period, aggregated MRS withdrawals were 1.2 bcm compared to 1.1 bcm injected.
- Rough was withdrawn extensively during the high demand period from late November through to late December. Thereafter lower demands mitigated withdrawals. During January over 0.1 bcm was injected into Rough.
- LNGS was little used throughout the winter period.
- The onset of mild weather in mid March brought about an early start to the ‘injection season’.

67. **Figure G11** shows the level of storage stocks through the winter.

Figure G11 - 2010/11 Storage Stocks

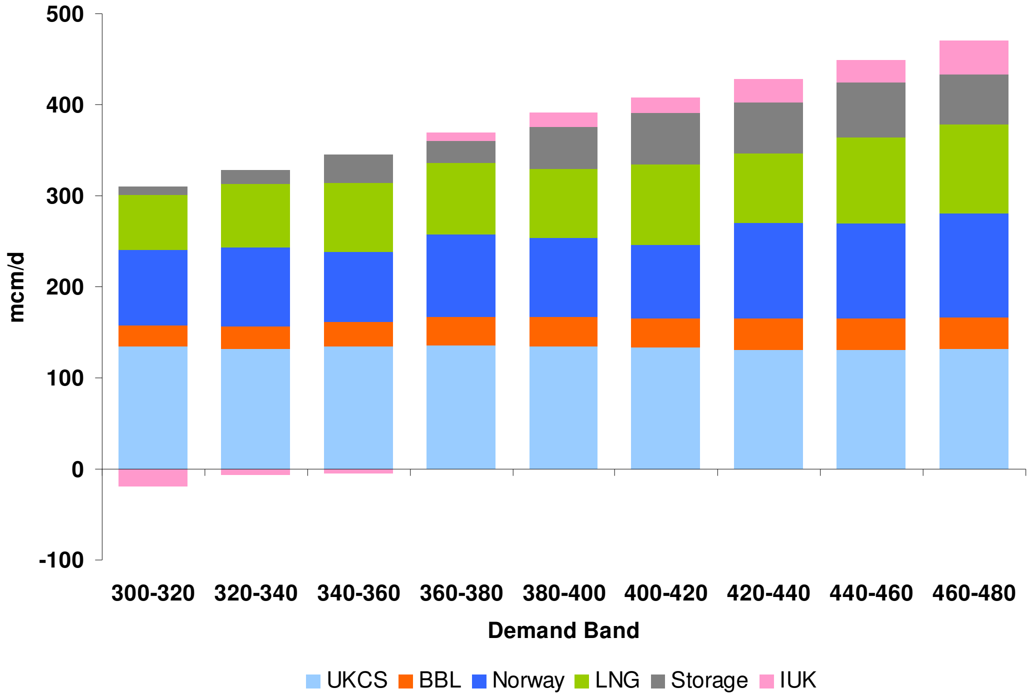


68. The chart shows appreciable decline in stock levels (notably Rough) during late November and December. By late December aggregated stock levels were at 50% with over 2/3rd of the principal winter period still to come. Post late December with milder weather the rate of storage decline eased to the extent that the lowest level of storage stocks was approximately 1.2 bcm compared to just 0.6 bcm the previous winter.

2010/11 Supply Flexibility

69. Historically storage and to a lesser extent IUK imports and some UKCS supplies have provided most of the necessary supply flexibility to meet variable demand. However the changing supply mix with increased reliance on imports has created a 'new order' on how supplies are utilised to meet high demands. This is demonstrated for winter 2010/11 in the following three charts, **Figure G12**, **Figure G13** and **Figure G14**

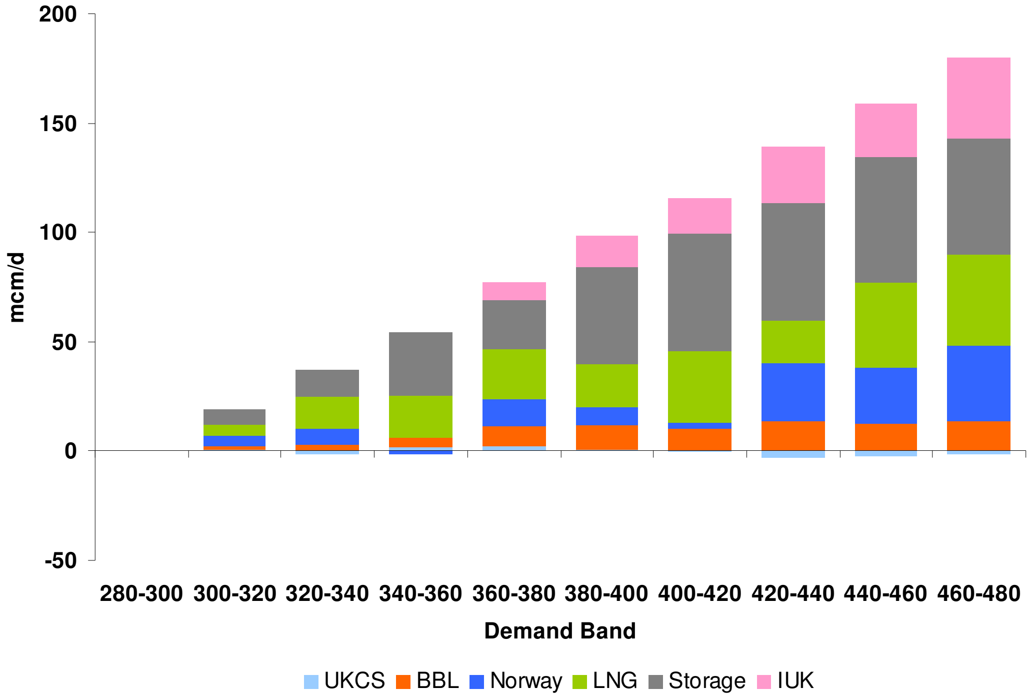
Figure G12 - Supply Make-up Winter 2010/11 (all demand)



70. The chart displays the make-up of supplies by supply type in demand bands of 20 mcm/d increments. As demand increases the chart shows:

- IUK shifting from exports to imports
- UKCS remaining flat (i.e. no swing or seasonality)
- Norway, BBL and LNG increasing (i.e. some swing or seasonality)
- Storage also increasing from a near zero start position

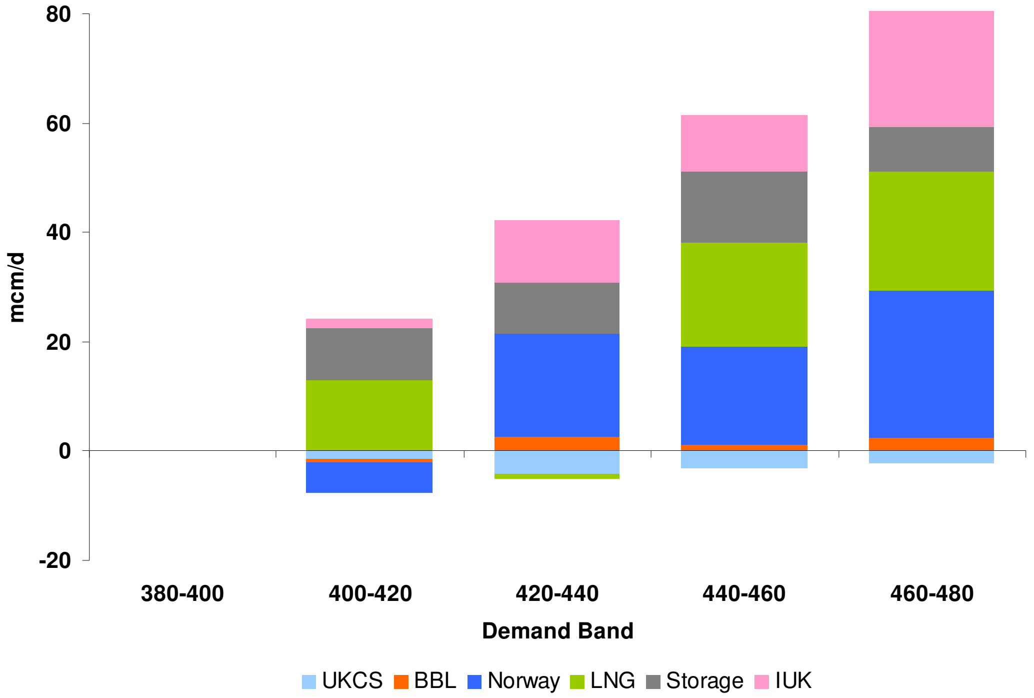
Figure G13 - Incremental Supplies Winter 2010/11 (demand above 300 mcm/d)



71. The chart displays the incremental make-up of supplies by supply type in demand bands of 20 mcm/d increments for demand above 300 mcm/d. This incremental approach identifies those supplies that are responsive / flexible. As demand increases the chart shows:

- No response from UKCS (indeed at the highest demands UKCS was marginally lower)
- Some response from BBL for demands above 360 mcm/d
- A variable response from Norway (the lower values are due to supply losses)
- Noticeable responses from LNG, storage and IUK
- On a % basis the supply response for demands above 300 mcm/d was met by: UKCS 0%, BBL 9%, Norway 14%, IUK 15%, LNG 25% and storage 38%

Figure G14 - Incremental Supplies Winter 2010/11 (demand above 400 mcm/d)



72. The chart displays the incremental make-up of supplies by supply type in demand bands of 20 mcm/d increments for demand above 400 mcm/d. This incremental approach identifies those supplies that are responsive / flexible. As demand increases the chart shows:

- No response from BBL or UKCS (indeed at the highest demands UKCS was marginally lower)
- A variable response from Norway (if Norway had not been subject to supply losses for lower demand bands the supply response from Norway would have been less)
- A noticeable response from IUK and LNG
- A limited response from storage. This was because storage was used extensively up to demands of 400 mcm/d and there was limited additional storage upside for any higher demands due to limited storage stocks and limited prospects of refilling such stocks within the winter
- On a % basis the supply response for demands above 400 mcm/d was met by: UKCS -6%, BBL 3%, Norway 30%, IUK 24%, LNG 27% and storage 21%

Operational Review

73. After a benign period through October and early November where demand remained at around the Seasonal Normal level, a prolonged period of colder weather began from around the 23rd of the month. High levels of demand were seen from then and throughout December due to the exceptionally colder weather with December 2010 being identified as the coldest on record. Five of the top ten highest daily demand figures of all time were recorded during December 2010. This presented a series of challenges on the NTS, requiring use of a wide variety of operational tools. However unlike the period of high demand in January 2010, supplies were generally consistent, with no significant supply losses coincident with the very cold days.

74. As the colder weather drove an increase in LDZ demand, IUK switched to imports, having been exporting from 1st March 2010. LNG imports increased, most notably at Isle of Grain, where high flow rates were seen prior to the start of commercial operations for Phase 3 on 3rd December.

75. On 19th December the forecast system demand was greater than the forecast system supply for the following gas day (20th December) and on that basis a Gas Balancing Alert (GBA) was issued. As a consequence a market response was seen in trading activity on an in-day and day-ahead basis and system balance was achieved with no direct System Operator actions.

76. On 20th December another GBA was issued for the 21st. A market response was again stimulated and at the start of the following gas day a significant upturn in supply nominations was evident.

77. The most notable feature of the winter was the very rapid early draw down of storage across all but facility types other than LNGS (Figure G11). This reduced stocks to a markedly lower level than for the previous year. By late December, storage stocks were reduced to about 50%, with two thirds of the winter still remaining. At the same time LNG importation terminal stocks also reached their lowest levels at below 300 mcm, this represented 25% of available tank space or about 3 days of supply. During this period storage was not operating as the last source of supply but as part of a flexible supply base. This reflects market confidence in the UK's supply diversity.

78. Towards the end of December there was a gradual improvement in the weather, this, when coupled with reduced demand during Christmas week, enabled a reduction in storage withdrawals and the opportunity for some injection to take place.

79. In January 2011, levels of demand returned to around the seasonal norm or seasonal warm levels as weather became milder following the end of the cold period in December. Supplies were generally consistent, although there were a number of notably high LNG importation totals and a number of supply losses affecting Norwegian supplies. Although these supply losses involved losses of greater than 25 mcm, no within-day GBAs were issued due to there being no expectation of significant end of day deficit. The storage stock levels began to stabilise and approach the levels seen last year as withdrawal rates reduced and storage injection took place during periods of lower demand.

80. Demand was at or around the seasonal warm level for most of February, increasing during the relatively colder period at the start of March. Supplies remained relatively

consistent, with the exception of a number of high LNG daily importation totals and two more Norwegian supply losses. By late February, storage stock levels were above the level seen in winter 2009/10.

81. Since 2009 there have been an ongoing series of significant changes to supply patterns. The commissioning and subsequent expansion of new LNG importation facilities has continued the shift away from the pattern of North-South flows that was prevalent when the majority of the NTS was designed and constructed.

82. As shown in **Table G5** for two comparable high demand days, the composition of UK gas supplies during winter 2010/11 has significantly altered when compared to 2002/3. The notable changes being less UKCS and significantly more imports.

Table G5 – Changing Supply Mix 2002/3 vs. 2010/11

	2002/3 8/1/2003	2010/11 21/12/2010
UKCS	341	132
Norway	19	113
Continent	13	66
LNG	0	94
Total NSS	**373**	**405**
Storage	79	50
Total	**450**	**456**

83. The diverse range of sources of supply, particularly following the rapid expansion of LNG importation capacity, has introduced new challenges in the day to day operation of the network.

84. For example the NTS was primarily designed to move gas from the North to the South. The geographical location of the primary LNG importation terminals in the south of the country, coupled to the ongoing reduction in UKCS supplies, presents operational challenges due to the limited capacity to move gas from South to North. This is highlighted by the fact that in 2011[6] LNG imports have exceeded combined UKCS and Norwegian supplies into St Fergus in all but 10 days.

85. Another example is the consequence of dynamic and diverse supply patterns enabled by the prevalence of very flexible supply sources. These include storage sites with fast fill capability (which are capable of both injection and withdrawal on the same gas day) and variable supplies notably from LNG, the Continent and on occasion Norway. To accommodate these supplies, more flexibility is required both by network operators and from assets, to deal with the wider variety of within day flow scenarios. The increasingly diverse and variable supply patterns are also responsible for an upward trend in linepack variations.

86. With further declines in the UKCS, increased import dependence and more flexible storage, these trends are expected to increase and will be compounded as more wind is added to the UK's generation fleet. This is because gas CCGTs are anticipated to provide cover for wind intermittency hence changes in the wind are expected to result in simultaneous gas demand and gas supply changes. Whilst

[6] Up to 12th June 2011

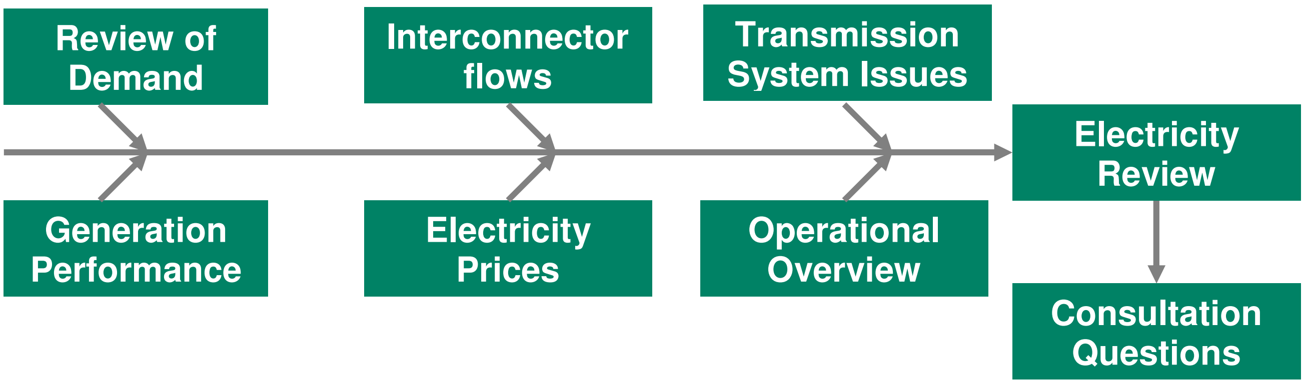
existing connected wind is about 5 GW and only results in day to day gas demand changes of about 11 mcm[7], the 2020 proposals for about 30 GW of wind could provide significant day to day gas demand changes of about 65 mcm. Such changes would be in addition to existing demand changes brought about primarily by temperatures.

[7] This assumes a day to day change of 50% of wind capacity, in the extreme higher day to day changes are possible

Consultation Questions - Gas - Review

Number	Question
GQ1.	The highest demand day resulted in NDM demand being above National Grid forecasts. Are there any possible reasons to explain this?
GQ2.	The relative economics of gas versus coal generation last winter were most favourable in terms of coal during December. During this month gas demand for power generation was relatively high. Are there any possible reasons to explain this?
GQ3.	National Grid 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 with the exception of some fields on long term outage and limited flows from some high swing gas associated with Bacton.
GQ4.	National Grid welcome views on our assessment, that Norwegian supplies were 'prioritised' towards the Continent both on a seasonal basis and during periods of supply loss.
GQ5.	IUK imports responded well last winter to UK demand / price with flows approaching 40 mcm/d. At higher demands / prices what additional flows could have been expected?
GQ6.	Last winter LNG imports in aggregate and at a terminal level varied considerably on a day to day basis. What are the possible drivers behind such variations?
GQ7.	Whilst Rough was subject to appreciable depletion during December, the aggregate level of MRS depletion was less noticeable. Are there any possible reasons behind this?
GQ8.	Our supply flexibility analysis highlighted that numerous sources in addition to storage provided flexibility. Do you agree with these sentiments and are there any reasons why the supply response from storage and UKCS was less noticeable at the highest demands?

Electricity

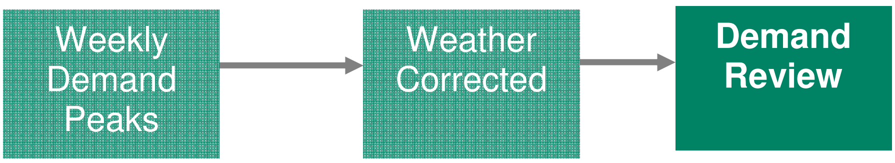


Overview

The section of the report reviews the last winter, 2010/11, for electricity and discusses some of the key learning points from the winter and assess the analysis from last years Winter Outlook Report.

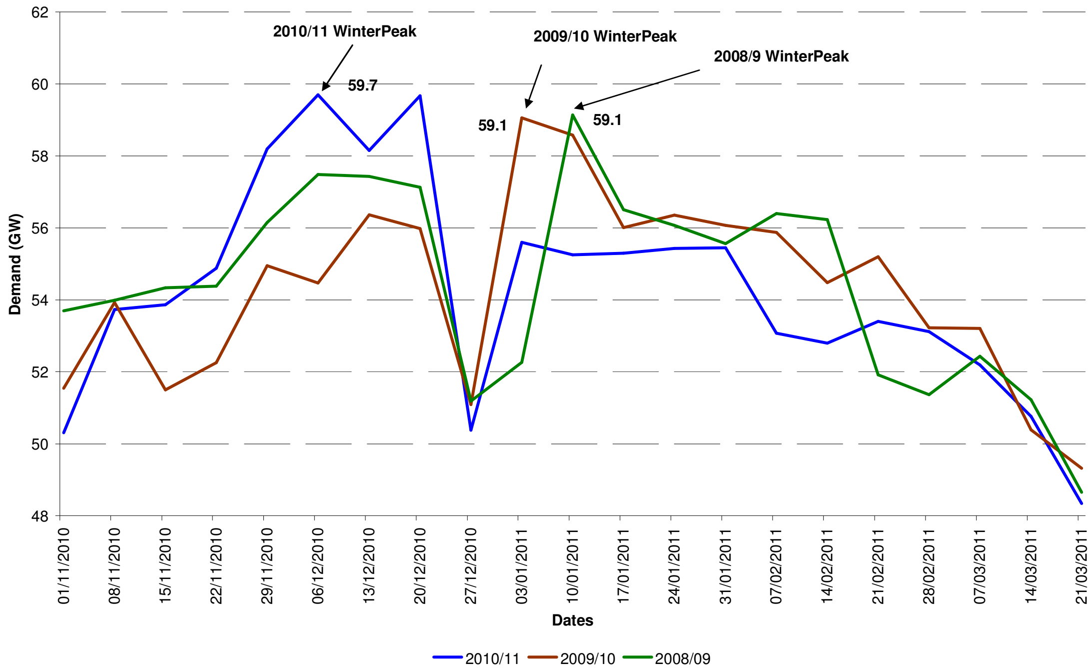
Review of Demand

87. Unless otherwise stated, demand discussed in this report excludes any exports to France, The Netherlands and Northern Ireland but does include station load and exports from the Transmission System to meet GB demand.



88. The highest electricity demand over the winter reached 59.7 GW for the half-hour ending at 17:30 on 7th December 2010. This compares to the highest demand of 59.1GW for the winters of 2008/09 and 2009/10. The last three years winter demands at a weekly resolution are shown in **Figure E1.**

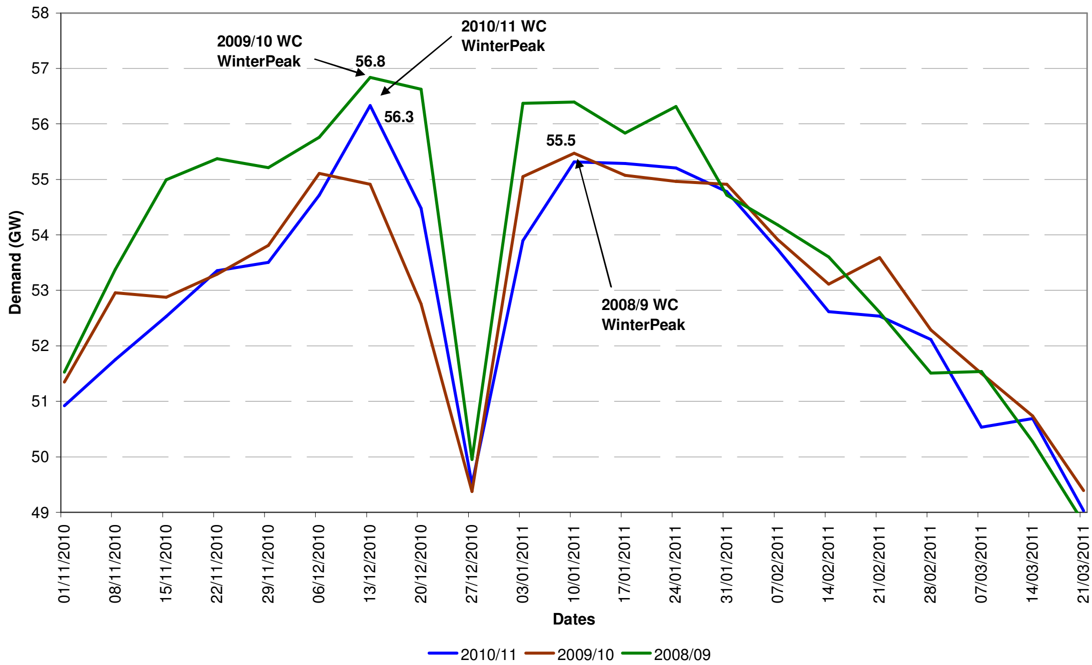
Figure E1 - Weekly Peak Demand for the last three winters



89. The forecast ACS demand from last years winter outlook report was 57.7 GW with a 1 in 20 peak demand forecast of 59.0 GW.

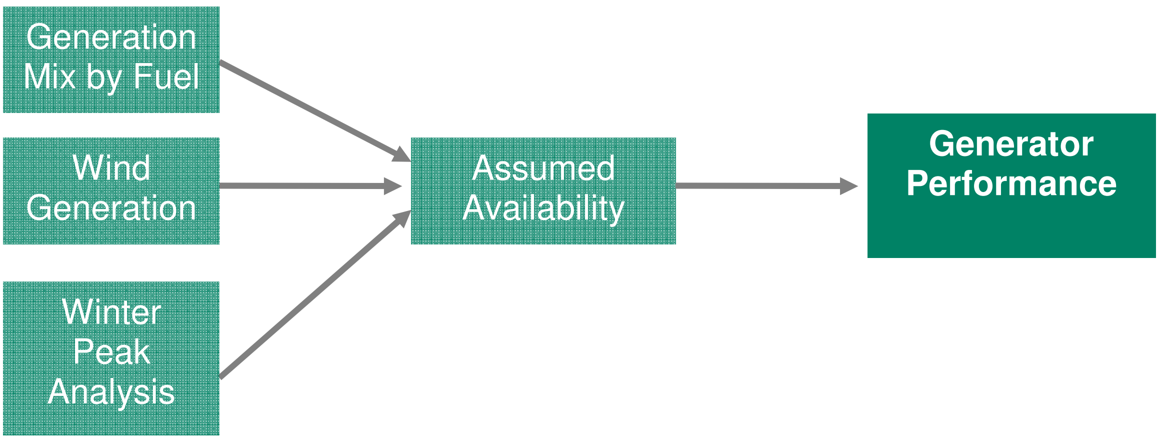
90. To understand the underlying demand trends for average weather conditions the out-turn demand for the last three winters have been weather corrected. This can be seen in **Figure E2**.

Figure E2 - Weather Corrected Weekly Peak Demand for Last Three Winters



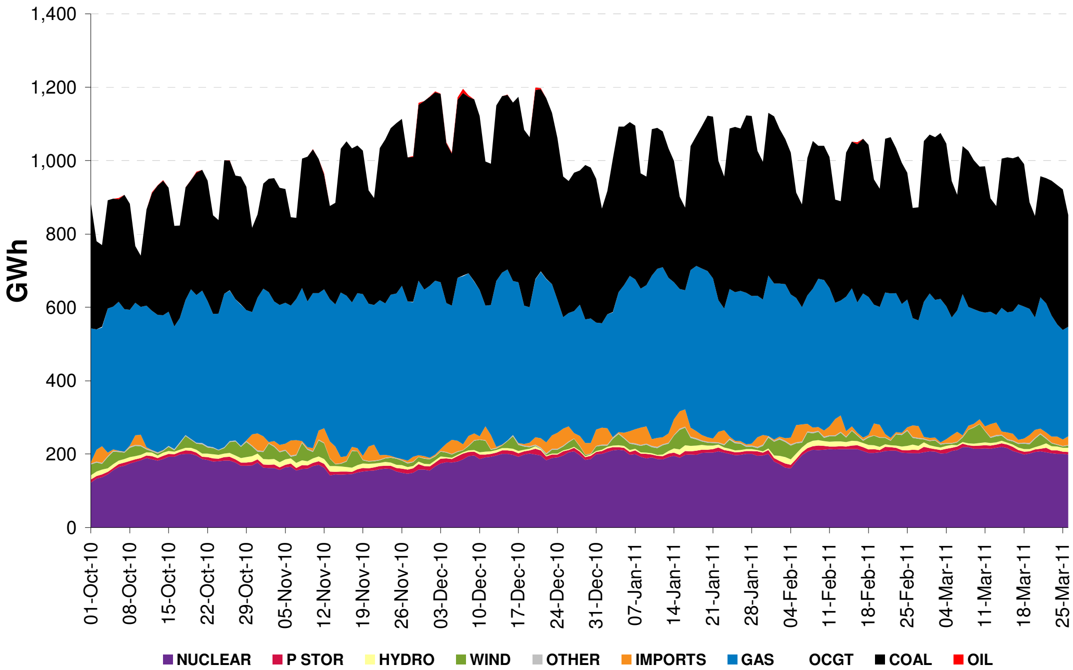
91. Although weather corrected, the size of the 2010/11 peak has most likely been affected by the ‘snow effect’ creating the exaggerated peak. The ‘snow effect’ is due to the extreme effect of the weather combined with a change in working habits i.e. the number of people unable to travel to work and staying at home and therefore using more energy.

Generator Performance



92. **Figure E3** shows the actual 2010/11 generation mix. Gas generation provided a greater proportion of the total generation than coal as the relative fuel price made gas the cheaper of the two fuels. A small amount of oil fired generation ran over the winter peaks compared to no oil running over the winter peak in 2009/10.

Figure E3 - 2010/11 Generation Mix by Fuel Type

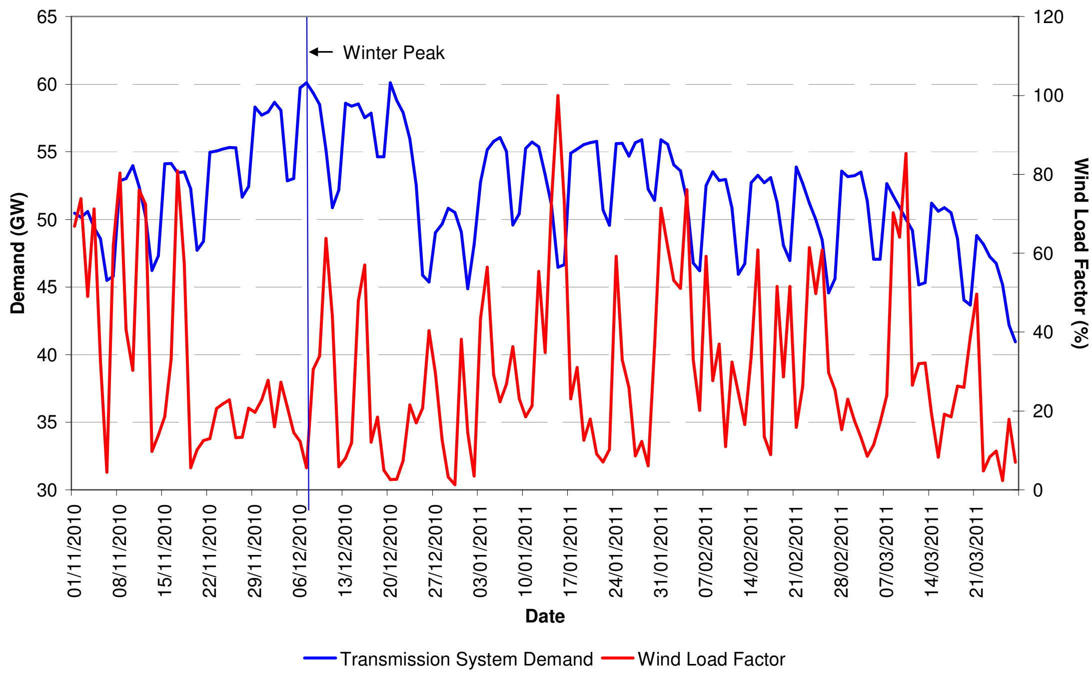


93. **Figure E4** shows a detailed view of the wind load factor during the winter. This data is based on the wind farms that are currently visible to National Grid through operational metering. These metered wind farms had a total capacity of approximately 2370 MW during the winter compared to 1575 MW last winter. This data gives an average load factor of 30.2% on the peaks over the period and a minimum of 1.3%.

94. The effect of wind on operation of the system is a key issue going forward. The uncertainty and intermittency of wind output requires strategies to ensure security of supply. Analysis of some of the effects of this going forward can be found in the recent National Grid publication - Operating the Electricity Transmission Networks in 2020[8]

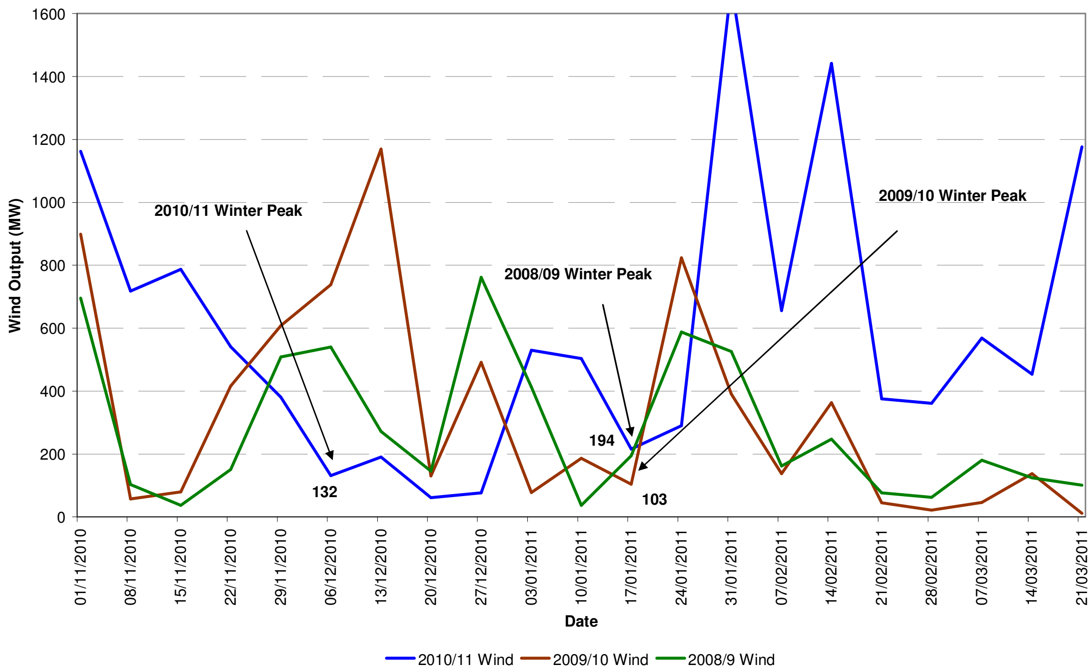
[8] http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/

Figure E4 - Daily Peak and Wind Generation Outturn



95. Looking at previous years, **Figure E5** the wind power output in MW can be seen for the past three years, also highlighted on the graph is the winter peak demand for each year. It can be seen from this chart that the wind output has been relatively low during the winter peak demands.

Figure E5 - Wind Generation at Weekly Demand Peak for the last 3 years



96. **Figure E6** gives a longer view of the wind output over the winter peak compared to installed capacity.

Figure E6 - Wind Generation compared to capacity for the last 5 years

97. **Table E1** gives a summary of wind power generation volumes as operationally metered by National Grid for the last five winters. The volume of wind power generation itself is not a key metric for system operation perspective but does provide an indicator of growth. In the same way as cold and warm winters have an effect on system operation windy and calm winters are likely to play a key part in system operation.

Table E1 - 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%
2010/11	2370	34%

98. Looking across the range of generation sources, the assumed availabilities from last years Winter Outlook Report are compared with the actual out-turn availabilities of the winter peak. This data is presented in **Table E2**.

99. For wind and hydro generation the basis of the 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. In both cases availability of input energy to the generation is often the limiting factor.

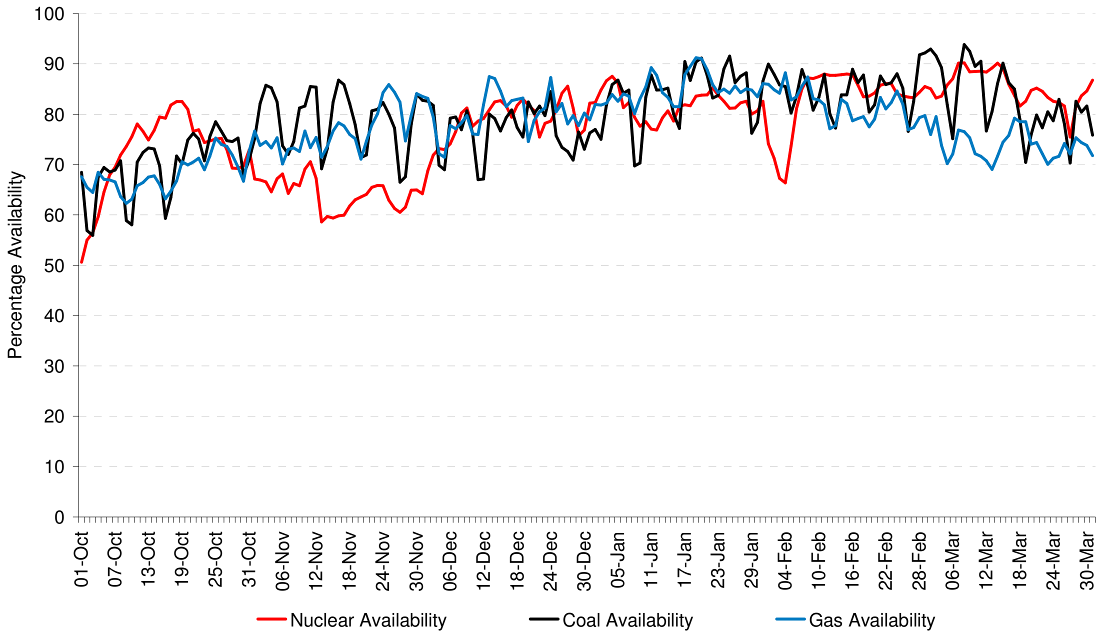
100. Overall there was 80% availability at the winter peak compared with an assumed availability of 85%. The differences can mainly be linked to a drop in coal availability and the French Interconnector importing 1 GW over the winter peak.

Table E2 - 2010/11 Assumed and Actual Availability of Generation Plant

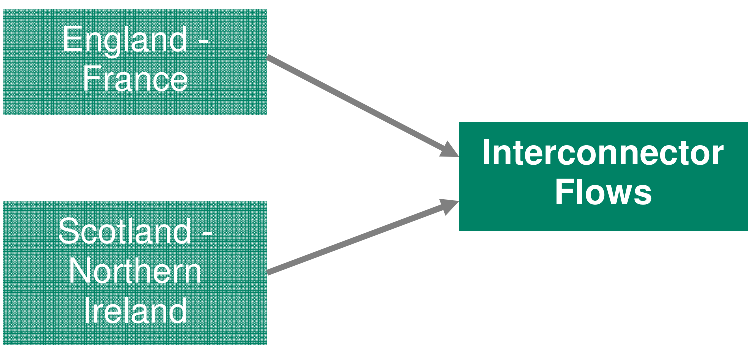
Power Station Type	Assumed Availability at Demand Peak (Central case)	Actual Availability at Demand Peak
Nuclear	75%	77%
French Interconnector	100%	50%
Hydro generation	60%	74%
Wind generation	10%	5%
Coal	90%	82%
Oil	80%	80%
Pumped storage	100%	100%
OCGT	90%	92%
CCGT	90%	86%
Overall	**85%**	**80%**

101. Looking at the main fuel types across the whole winter period **Figure E7** shows the availability of the Nuclear, Coal and Gas generation.

Figure E7 - 2010/11 Generation Availability by Main Fuel Types



Interconnector Flows

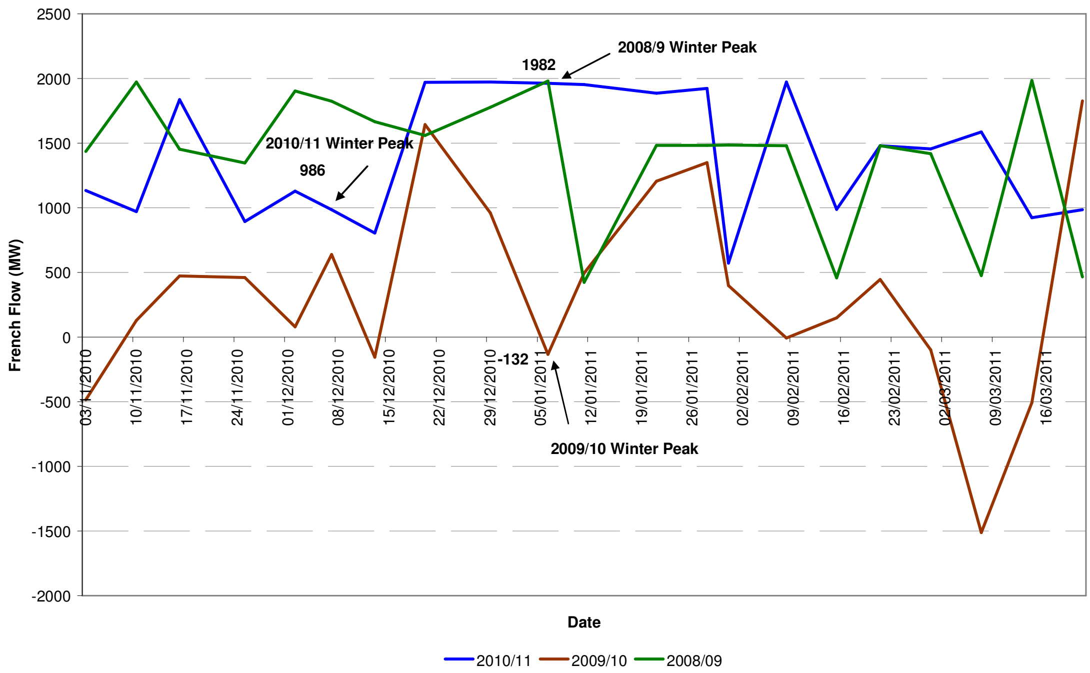


102. The interconnector to The Netherlands began full commercial operation on April 1st 2011, hence the flows on BritNed will not be considered for the review of Winter 2010/11 but will be considered in the Outlook for 2011/12.

IFA - England - France

103. The IFA can deliver up to 2GW in either direction. **Figure E8** shows the French interconnector actual flow for the last three winters at the GB weekly demand peak. It can be seen that the on average the level of import during the 2010/11 weekly peak was higher than previous years. The change to interconnector charging methodology was discussed in the 2010/11 Winter Outlook Report, such that interconnectors were no longer subject to Transmission Use of System Charges. It was expected that following the changes in charging the interconnector flow would be more closely linked to the price differential between the two markets.

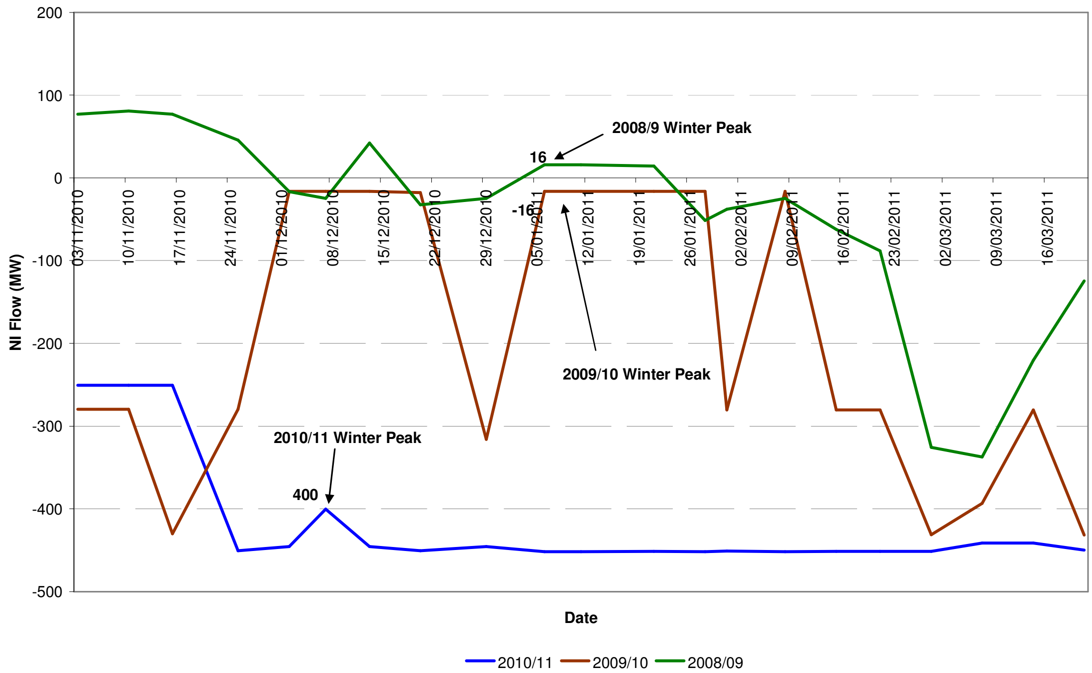
Figure E8 - French Interconnector Flow at Weekly GB Peak Demand



Moyle - Scotland to Northern Ireland

104. The Moyle interconnector can deliver up to 500 MW in either direction. The maximum flows on the interconnector are however reduced below this figure due to commercial restrictions. **Figure E9** shows the Moyle interconnector actual flow for the last three winters at the GB weekly demand peak. It can be seen that the on average the level of export during the 2010/11 weekly peak was not only higher than previous years but the flow across the whole winter was consistently at a high level of export in comparison to previous years. As mentioned above the change to the charging methodology is most likely responsible for this change in flow pattern.

Figure E9 - Northern Irish Interconnector at Weekly GB peak Demand

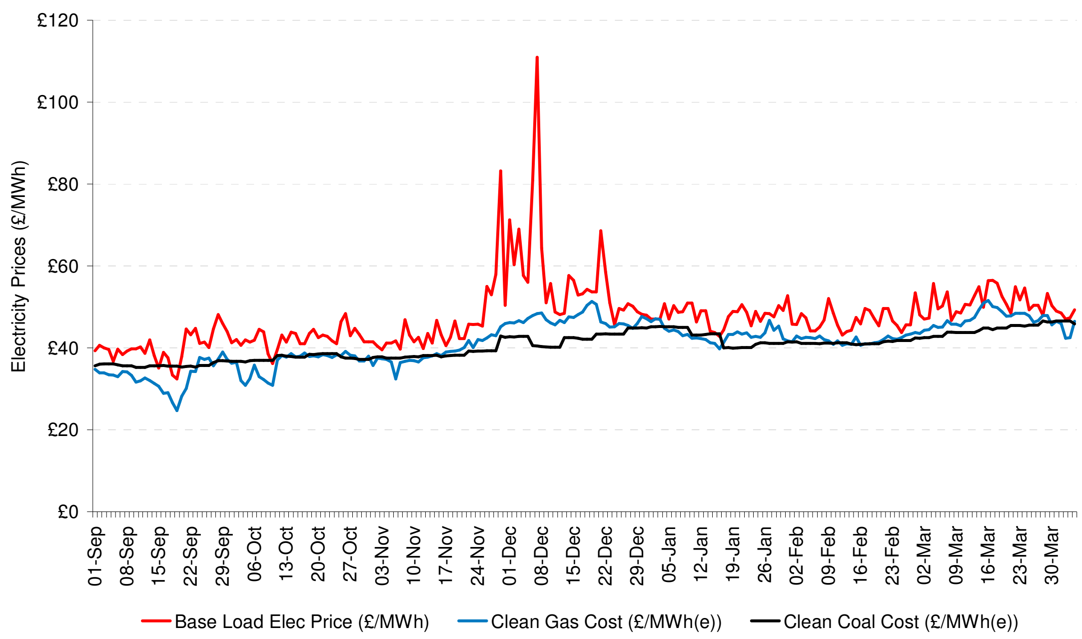


Electricity Prices

Electricity Prices

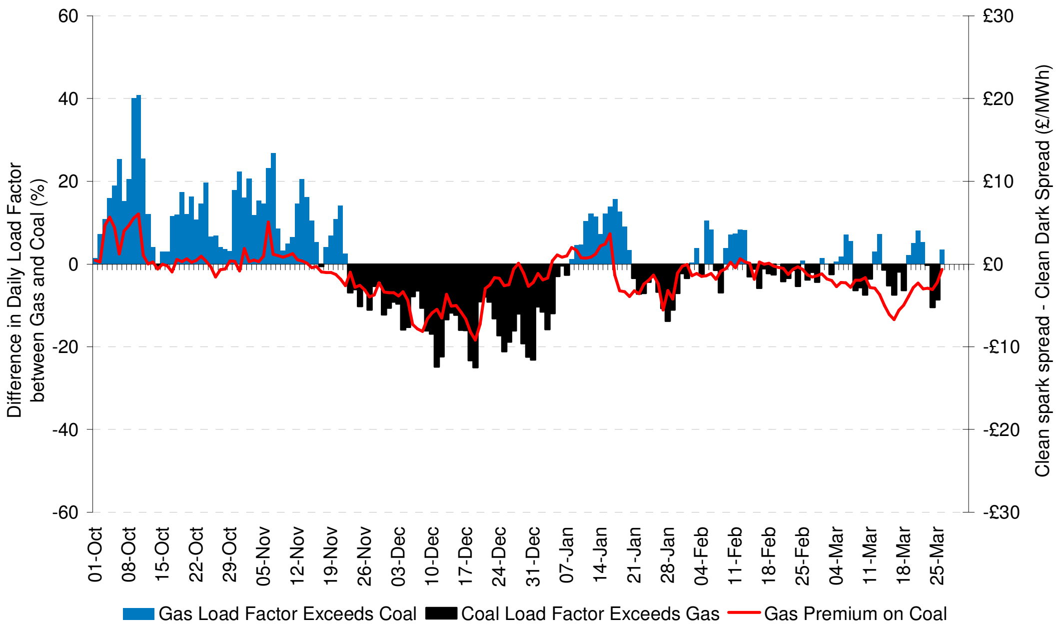
105. Day ahead baseload electricity prices were relatively stable throughout the winter, **Figure E10**. The price spike that can be seen during early December correlates with the coldest period of the winter and the highest demand days.

Figure E10 - 2010/11 Base Load Electricity Prices and Clean Gas/Coal Costs



106. Looking at the gas premium on coal in **Figure E11** it can be seen that during the cold spell at the end of November and the beginning of December the increased use of gas, mainly of Non-daily Metered demand, pushed the cost of gas generation higher than the cost of coal generation. During this time it can be seen that the baseload fuel source switched from Gas to Coal. This trend continued throughout the winter period with coal generation running as baseload rather than gas generation apart from a few occurrences when the gas premium on coal was positive.

Figure E11 - 2010/11 Difference between Daily Total Gas and Coal Generation



Operational Overview

Operational Overview

107. No system warnings were issued during the winter 2010/11 as a result of adequate generation margins throughout the winter. The last system warning was issued in January 2009.

Transmission System Issues

Transmission System Issues

108. Within the 2011 Summer Outlook Report[9] (Pages 29-33) there was analysis regarding the likelihood of reduction of wind output during minimum periods in order to be able to maintain the system Reserve Requirement.

109. Action was taken on wind earlier and more frequently than initially expected in order to maintain system security across constraint boundaries. During April and May a total of 19 GWh of actions were taken to reduce the output of wind farms, this is

[9] http://www.nationalgrid.com/uk/Electricity/SYS/sumOutlook/

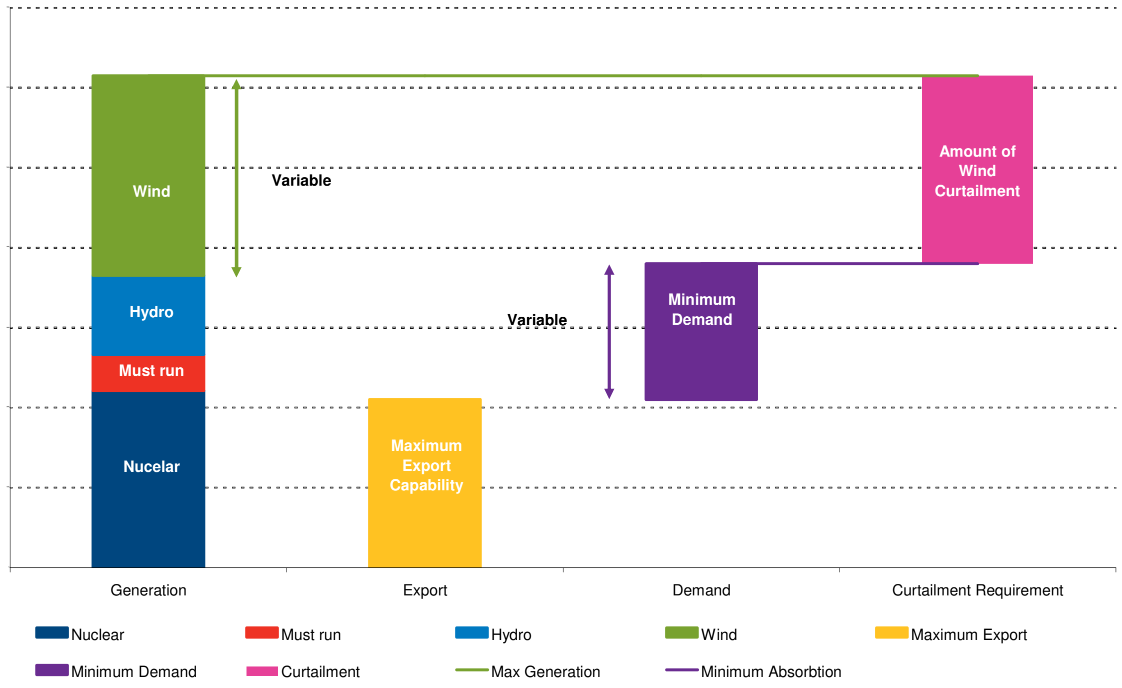
against 1470 GWh of metered wind output during the same period. Most occurrences of these actions occurred overnight in periods of low demand and high winds. The most significant event was on the wet and windy night of the 5th and 6th April where 3.8 GWh of actions were taken to reduce the output of the wind.

110. **Figure E12** shows the breakdown for the requirement for wind curtailment across a constraint boundary. For this example the Scotland to England boundary of the transmission system has been used.

- A boundary can be created to cover an area of the system where there will be an amount of generation and demand, in this example Scotland is the area inside the boundary.
- When the demand inside a boundary is equal to the generation inside a boundary the flow across the boundary is zero
- Any imbalance between the demand and generation inside a boundary will create a flow across the boundary.
- A boundary with a constraint will have a limit to the amount of flow across the boundary, normally dictated by the capacity of the transmission network. - A constraint boundary
- The Green line shows the Maximum expected Generation capacity during a minimum period. Hence the following fuel types are either expected to run or have the potential to run during a minimum:
  - Nuclear due to current inflexible nature
  - Must run generation required for system security
  - Hydro generation that will run in the event of a wet and windy period
  - Wind power as output will follow wind conditions
- The purple line is the Minimum Absorption Capability from the group and is made up from:
  - Maximum Export Capability (Yellow Box) which is the transmission capacity between Scotland and England - the constraint boundary in this example and;
  - Minimum Demand (Purple Box) within the group
- The difference between the two lines is the volume of generation that would have to be curtailed in order to maintain system security. In the event of a requirement to reduce generation inside the constraint group the most cost effective generation would be used, in these wet and windy events Wind and Hydro generation are normally the most cost effective and would be reduced first.

111. The analysis within the chart assumes the worst case scenario where by all generation units of all the fuel types are available and operational. It also includes a pessimistic value for the constraint from Scotland to England. In real terms these events coincide very rarely. There is also variability within the data.

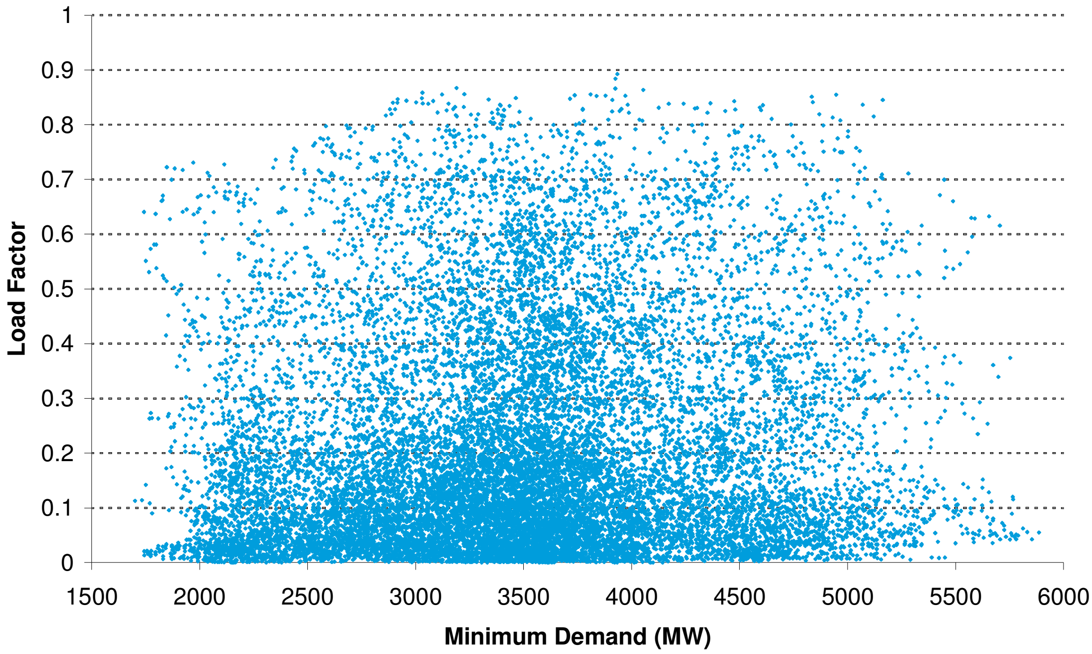
Figure E12 - Derivation of Wind Curtailment Requirement between Scotland and England



112. The wind power and minimum demand are the most volatile variables in this analysis and in **Figure E13** the half hourly levels for the Scottish demand and Scottish wind output have been plotted against each other. The data is for 2010 and is wind load factor rather than wind output due to the increasing value of wind capacity in Scotland during 2010.

113. The top left quarter of the data is the most significant area where there are low demands and high wind outputs. The transmission capacity from Scotland to England changed repeatedly during 2010 as pieces of equipment where taken out of service for either maintenance or upgrading, hence it would be inappropriate to mark the curtailment line on this data. The data is presented to give a picture of the likelihood of low demand and high wind output. Further analysis is given further in the document when looking at the potential for wind curtailment during the forthcoming winter.

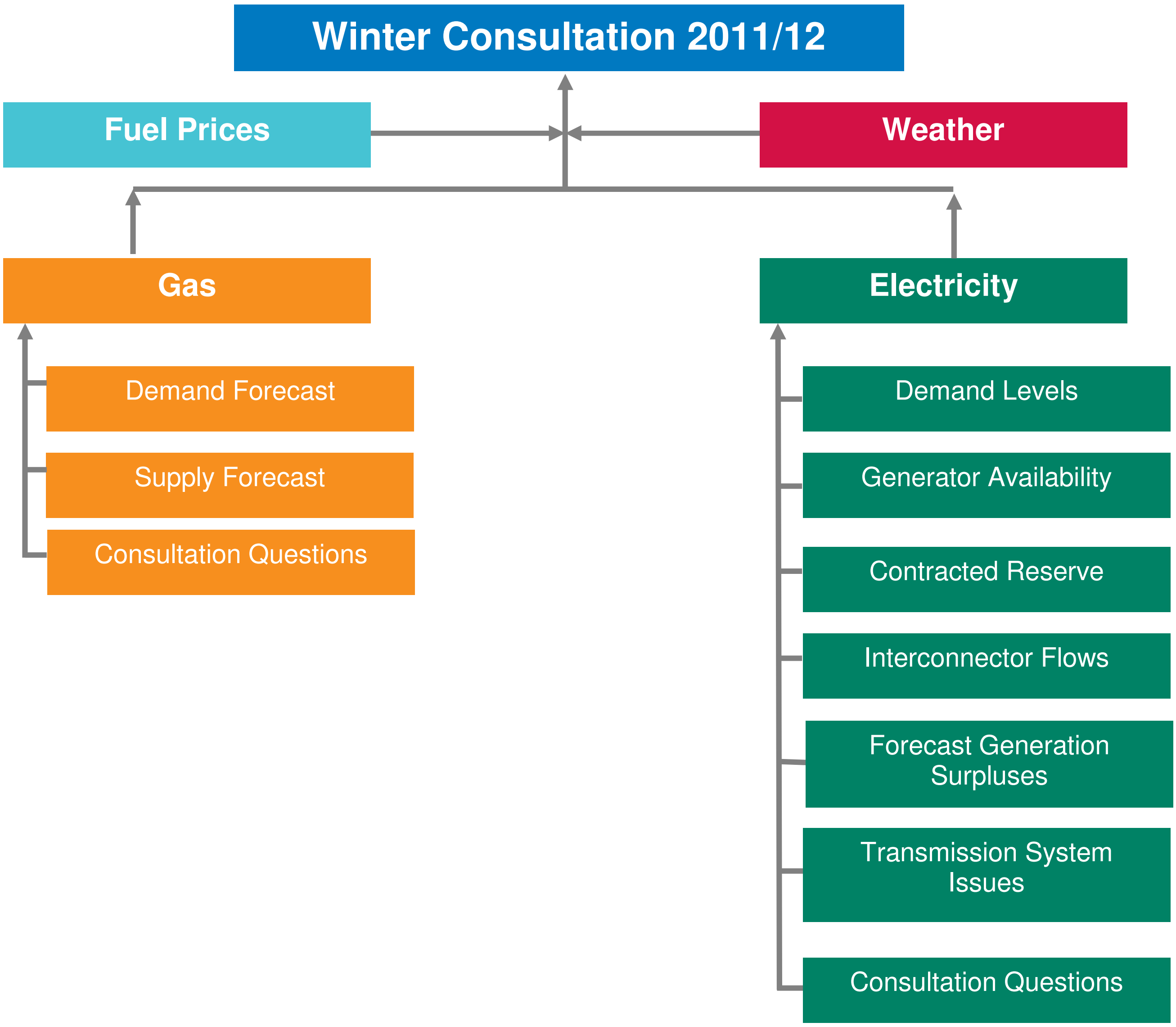
Figure E13 - Scottish Half hourly wind and demand levels for 2010



Consultation Questions - Electricity - Review

Number	Question
EQ1.	What further analysis of the winter peak would be useful for the winter consultation/outlook?
EQ2.	What other factors could be used in understanding the flows on interconnectors?
EQ3.	Are there any other fuel sources that require further analysis other than wind?
EQ4.	Is the description of the issues surround wind curtailment beneficial or is more detail and analysis required?

Winter Consultation 2011/12



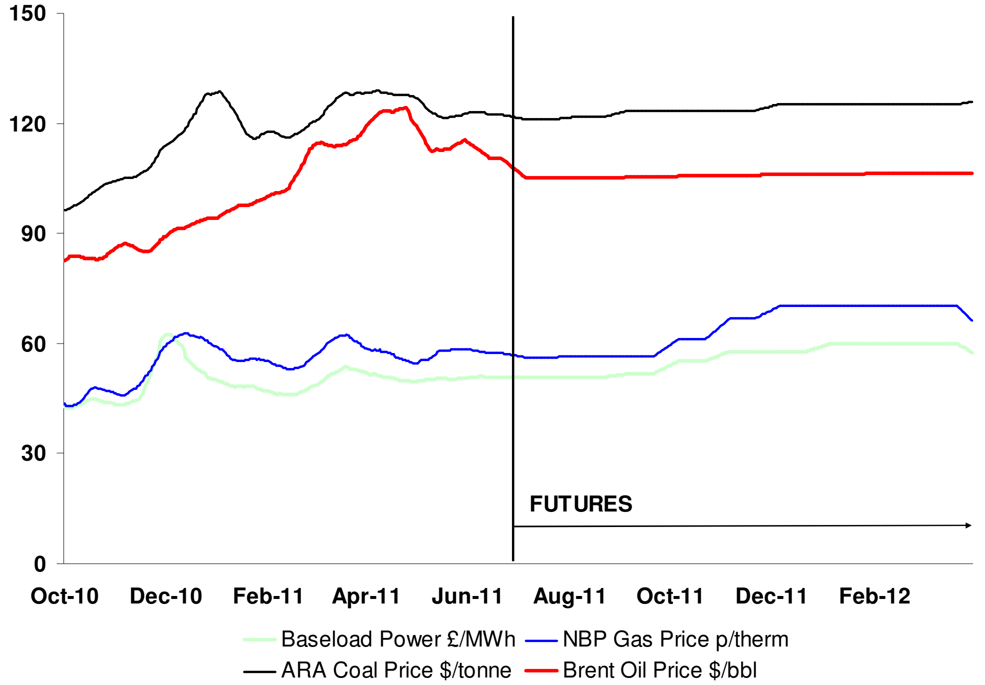
Weather

114. Any early weather forecast for winter 2011/12 will be issued in the Winter Outlook Report in September / October.

Fuel Prices

115. **Figure F4** shows historic energy prices and future prices as of 24th June 2011. These prices should reflect the markets view of energy related risks, such as tensions in North Africa and the Middle East, Japan's need for additional LNG and Germany's decision to close some nuclear plant.

Figure F4 - Historic and Future Energy Prices



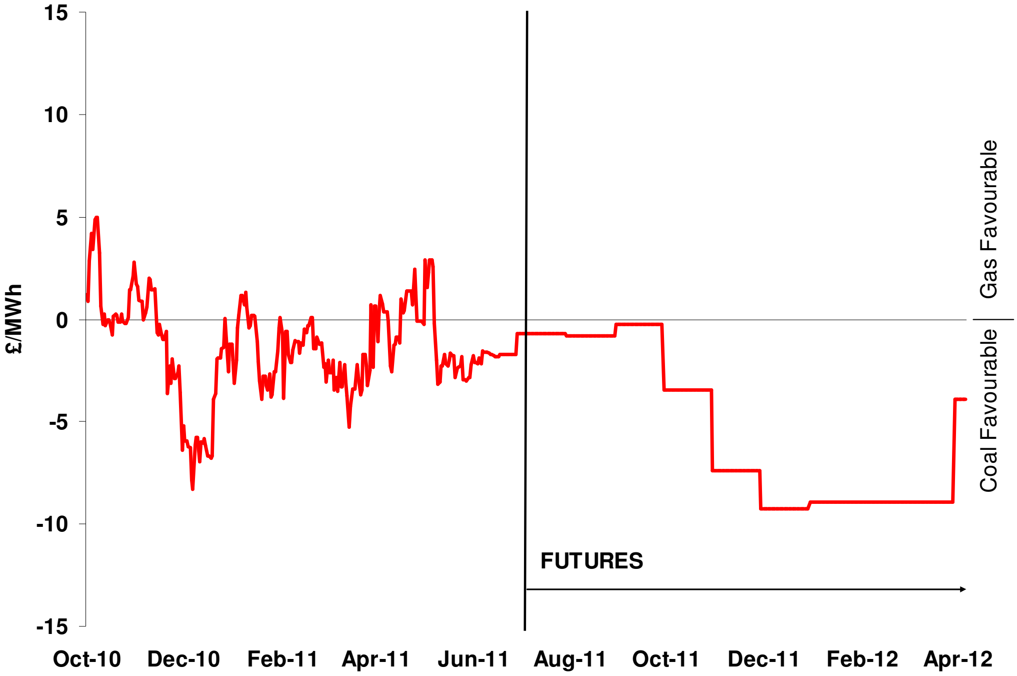
116. The forward gas price shows some seasonality with the highest price linked to oil indexed contracts, i.e. these currently provide a ceiling to the UK gas price. Other forward energy prices show less variation, though both power and coal show further increases.

117. Though not shown, forward US gas prices are typically only half those of European markets hence diversion of LNG cargoes to the US is not expected.

118. There are numerous factors that could affect the UK winter gas price, these include; changes to the oil price and other UK and Continental factors such as supply, demand, generation availability and storage levels.

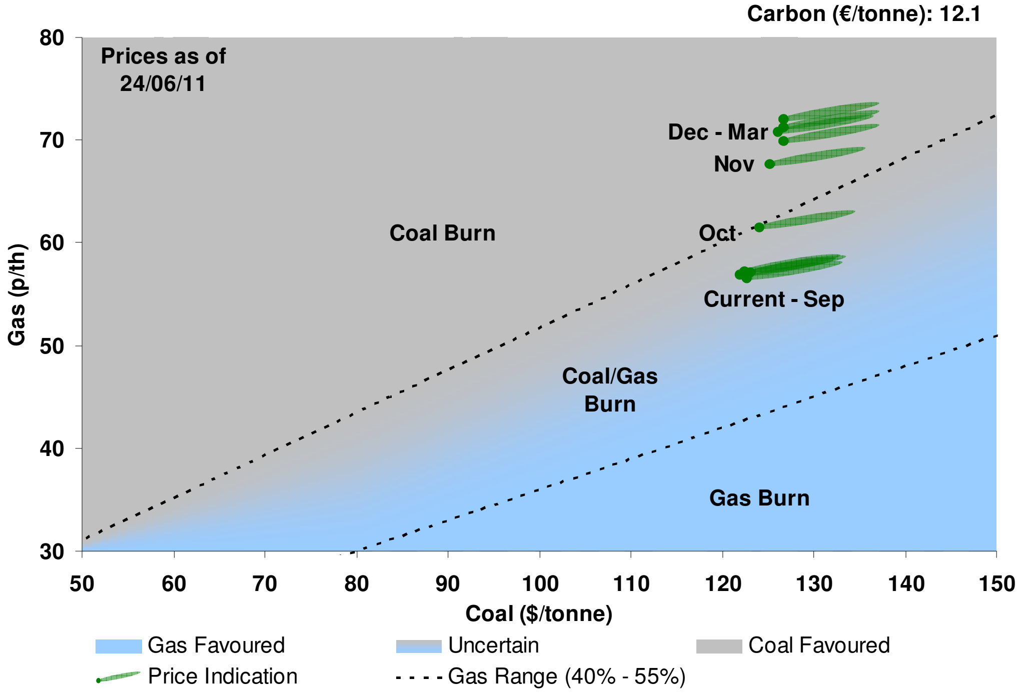
119. **Figure F5** shows the relative dark and spark spreads, showing whether gas or coal is favoured for electricity generation next winter.

Figure F5 – Relative power generation economics (1)



120. Recent reductions in the oil price have caused the gas forward prices to decrease, making the economics of gas and coal fired generation comparable through to October, thereafter, there is a strong shift towards burning coal in preference to gas. This is also shown in **Figure F6**.

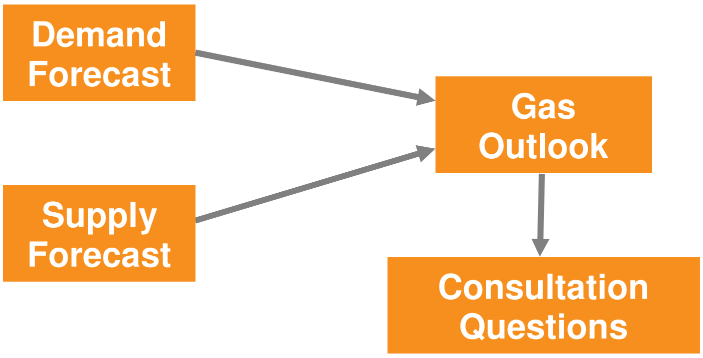
Figure F6 - Relative power generation economics (2)



121. Whilst the charts suggest that coal should be the favoured source of fuel for generation next winter other factors will part mitigate this. These include running hours for LCPD and generation portfolios.

122. For gas to become the preferred source of fuel for power generation next winter the gas price needs to fall by about 20 p/therm or there needs to be a further increase in the coal price by about $60/tonne.

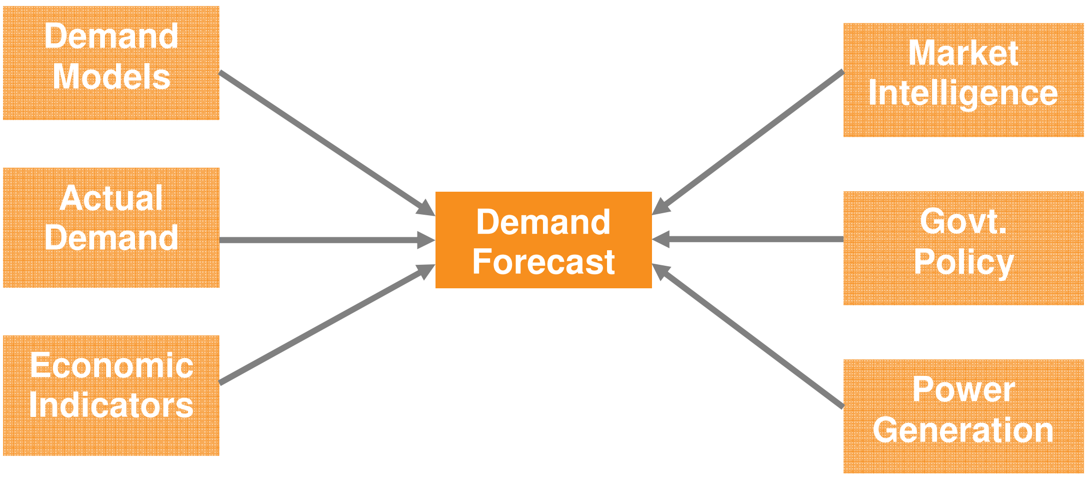
Gas



Overview

123. This chapter covers the gas supply-demand outlook for the forthcoming winter together with an update on the Safety Monitors and provision of new NTS capacity.

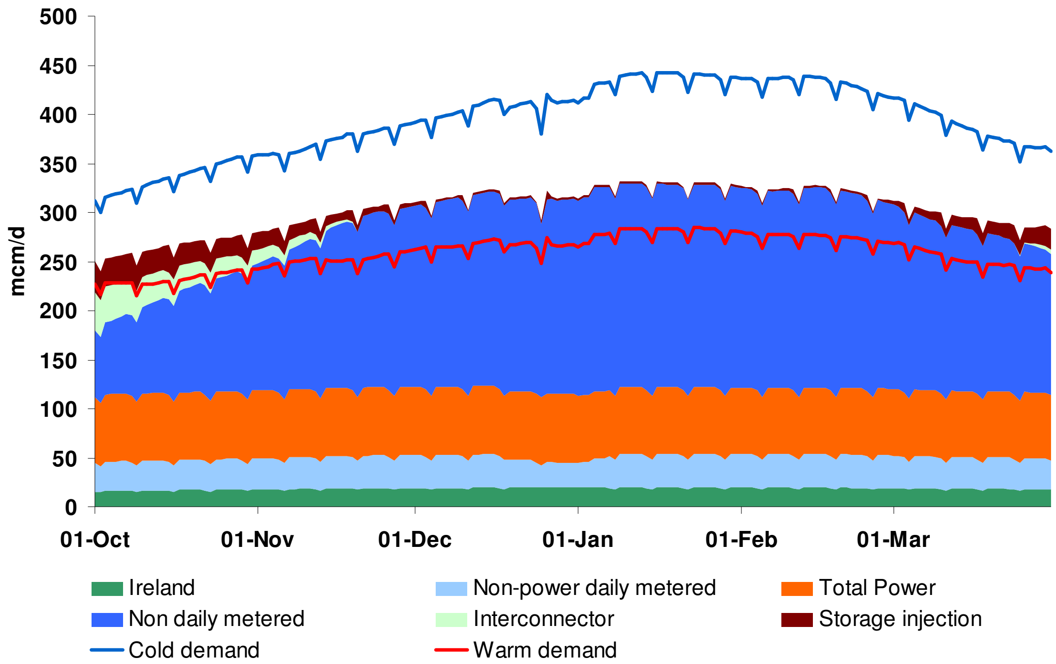
Demand Forecast



124. The 2011/12 winter demand forecast is slightly lower than the 2010/11 weather corrected demands. There is a drop in NDM demand due to higher gas prices and continued energy efficiency. Gas for power generation is forecast to be marginal generation in 2011/12 with demands similar to 2010/11. These are materially lower than the power generation demands in 2009/10.

125. **Figure G15** shows the forecast gas demand for winter 2011/12 based on seasonal normal demand. In addition lines to represent cold and warm demand are also shown. These lines represent the influence of weather rather than any demand changes associated with for example power generation economics.

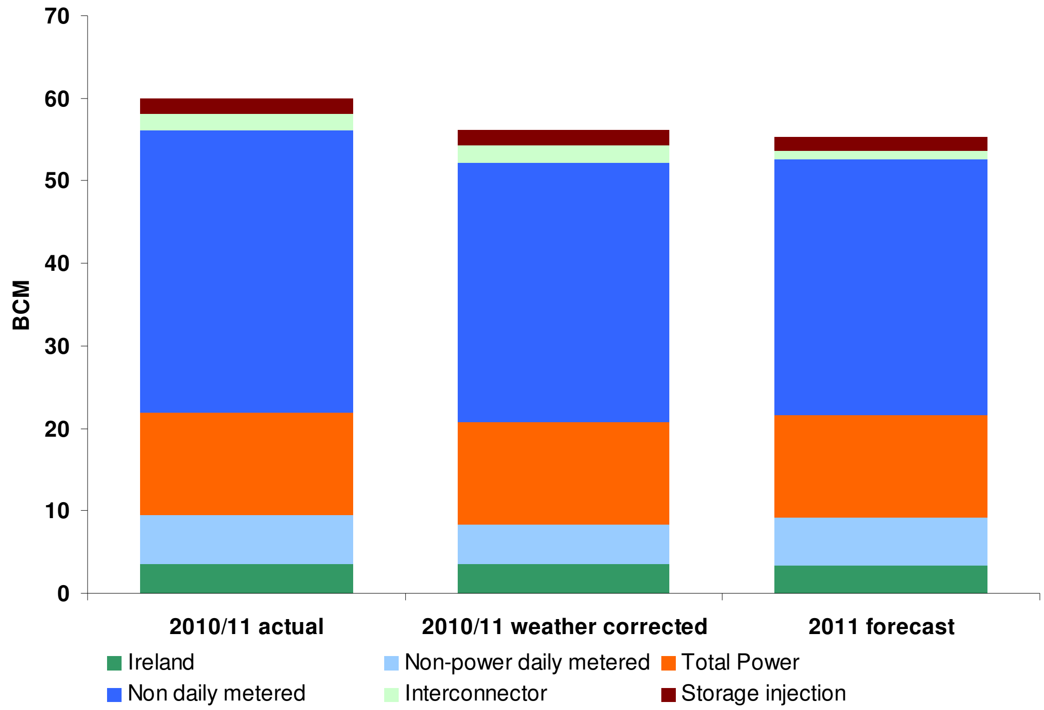
Figure G15 - Forecast Gas Demand Winter 2011/12



126. The chart shows seasonal normal demand peaking at about 330 mcm/d. In reality peak winter demands will be appreciably higher than this as for much of the winter temperatures can be expected to be colder than seasonal normal temperatures.

127. **Figure G16** shows the actual and weather corrected demand for last winter and also the forecast demand for winter 2011/12.

Figure G16 - Forecast Gas Demand October 2011 to March 2012



128. The chart shows:
    - The impact of weather correction on the 2010/11 NDM
    - Little difference between weather corrected 2010/11 and the winter forecast for 2011/12. The only noticeable difference being the forecasts for IUK exports. These are subject to considerable uncertainty

129. **Table G6** shows the historic actual and weather corrected demand for winters 2008/9 through to 2010/11 and the forecast for winter 2011/12.

Table G6 - Forecast Gas Demand- October to March 2011/12

October to March winter	2008/09		2009/10		2010/11		2011/12
bcm	actual	weather corrected	actual	weather corrected	actual	weather corrected	forecast
NDM	33.9	32.7	33.6	32.0	34.2	31.4	31.1
DM + Industrial	5.7	5.6	6.0	5.9	5.8	5.8[10]	5.8
Ireland	3.4	3.4	3.6	3.6	3.6	3.6	3.4
Total Power	13.2	13.2	16.6	16.6	12.5	12.4	12.4
Total demand	**56.8**	**55.5**	**60.5**	**58.9**	**56.6**	**53.7**	**53.1**
IUK export	3.0	3.0	1.1	1.1	2.1	2.1	1.0
Storage injection	1.4	1.4	1.2	1.2	1.8	1.8	1.7
GB Total	**61.2**	**59.9**	**62.8**	**61.2**	**60.5**	**57.6**	**55.7**

130. On a weather corrected basis, the table shows some decline (including the 2011/12 forecast) in NDM. DM + Industrial and Ireland show little change. The variation in demand for power generation highlights the changing economics of gas versus coal.

131. **Table G7** shows the daily average demand for last winter and the forecast demand for winter 2011/12. The table also shows the actual range of demand experienced last winter and a forecast range.

132. The low forecast range for weather sensitive loads is based on a very warm early October[11] day, Ireland, IUK and storage on historic data and power on our low gas scenario.

133. The high forecast range for weather sensitive loads is based on a very cold January day, Ireland on our peak day forecast, IUK and storage on historic data and power on our high gas scenario.

134. **Table G8** shows a similar table to G7 but is based on the mid winter months of December to February.

[10] Originally mis-reported at 4.8 bcm
[11] For the December to February range in Table 8, the very warm day applies to early December

Table G7 - Forecast Daily Gas Demand- October to March 2011/12

October to March winter	Daily average			Actual range		Forecast range	
mcm/d	2010/11 actual	2010/11 weather corrected	2011 forecast	2010/11 low	2010/11 high	2011/12 low	2011/12 high
NDM	188	173	170	66	318	35	340
DM + Industrial	32	32[12]	32	25	37	22	42
Ireland	20	20	18	12	28	12	32
Total Power	68	68	68	51	94	40	100
Total demand	311	295	290	176	465	140	510
IUK export	11	11	5	0	60	0	60
Storage injection	10	10	9	0	59	2	60
GB Total	**332**	**316**	**305**	**252**	**465**	**210**	**510**

Table G8 – Forecast Daily Gas Demand – December to February 2011/12

December to February winter	Daily average			Actual range		Forecast range	
mcm/d	2010/11 actual	2010/11 weather corrected	2011 forecast	2010/11 low	2010/11 high	2011/12 low	2011/12 high
NDM	225	206	199	145	318	125	340
DM + Industrial	32	32[13]	32	25	37	22	42
Ireland	21	21	19	15	28	15	32
Total Power	69	69	68	51	94	40	100
Total demand	350	330	321	251	465	238	510
IUK export	1	1	0	0	19	0	60
Storage injection	7	7	2	0	44	2	60
GB Total	**359**	**339**	**323**	**261**	**465**	**240**	**510**

135. The ranges in the tables highlight the considerable variation that exists for essentially all demand sectors even for the main winter months of December to February.

136. The 2011/12 high of 510 mcm/d is above the 120 diversified forecast (Table G9) as this assumes higher levels of power generation.

137. From October 2011 LDZ demand is firm only and NTS follows in October 2012. However, there is limited scope for interruption to reduce the total diversified peak day demand because the power generation forecast is towards the low forecast level and can be supplied by firm power stations. Irish gas demand tends to become more weather sensitive on very cold days raising the probability of a slight increase rather than decrease on a peak day.

[12] Originally mis-reported at 26 mcm/d
[13] Originally mis-reported at 27 mcm/d

138. **Figure G17** and **Table G9** show the highest day of demand in winter 2010/11 and the 1 in 20 peak day demand forecasts for winter 2011/12. The biggest difference in the demands is through the accounting methodology for power generation and to a lesser extent Ireland.

Figure G17 - 1 in 20 Peak Day Gas Demand 2011/12

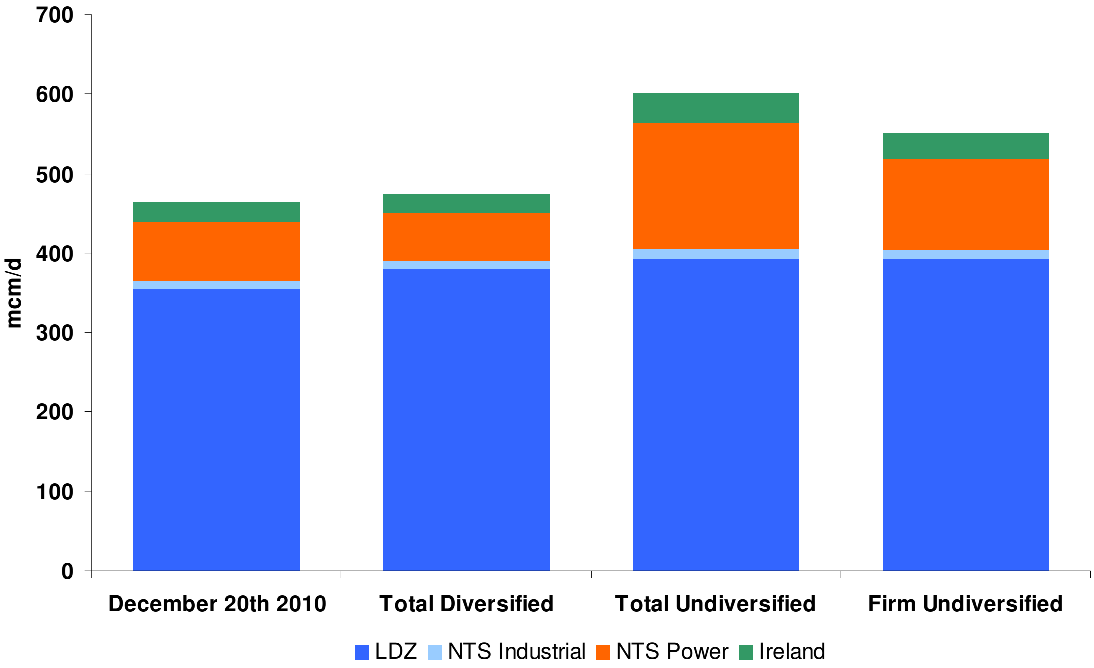


Table G9 – 1 in 20 Peak Day Gas Demand 2011/12[14]

Mcm/d	December 20th 2010	2011/12 forecast Total Diversified	Total Undiversified	Firm Undiversified
LDZ	356	381	392	392
NTS Industrial	9	8	14	12
NTS Power	74	62	158	115
Ireland	25	23	37	32
Total	**465**	**474**	**601**	**551**

139. Due to the price assumptions, the 1 in 20 diversified peak demand forecast assumes relatively low power generation. These are potentially very high as shown in the undiversified demand forecasts.

[14] Demand data can differ between different sources for a number of reasons including classification, CV and closeout date. Power generation classifications are: in G7 and G8 the LDZ connected power stations at Fife, Derwent, Shoreham, Barry, Severn Power and Fawley are included in the total power category but in G9 they are included in LDZ demand. Grangemouth and Winnington NTS offtakes are included in total power in G7 and G8 but NTS industrial in G9. Immingham and Shotton Paper are classified as NTS power stations for all 3 tables.

Supply Forecast

140. 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

141. For the purposes of this document, our initial assessment of UKCS supplies for winter 2011/12 is based primarily on industry feedback recently received from our 2011 TBE consultation. Table G10 compares our UKCS outturn from Winter 2010/11 and our initial view for 2011/12.

Table G9 - Preliminary 2011/12 UKCS Maximum Forecast by Terminal

Peak (mcm/d)	2010/11		2011/12
	Winter Outlook	Highest	Initial View
Bacton	60	58	49
Barrow	14	14	12
Burton Point	0	3	2
Easington	11	10	9
St Fergus[15]	58	52	46
Teesside	25	26	22
Theddlethorpe	16	15	13
Total	**184**	**178**	**153**
90% Operational Forecast	166		138

142. **Table G9** shows a provisional UKCS maximum supply forecast of 153 mcm/d for Winter 2011/12. This represents a 17% decline against the equivalent forecast for Winter 2010/11. In previous years reported declines have been typically between 5% and 10%. The decline in 2011/12 is forecast to be greater due to:

- General field decline
- An assumption that Rhum (~5 mcm/d) will not be flowing due to EU sanctions
- An end to various swing contracts

[15] Excludes estimates for Vesterled and Tampen

- A limited number of new fields forecast to come on-stream over the 2011/12 winter.

143. For the purposes of supply-demand analysis and for security planning, a lower operational forecast of UKCS is used. For this purpose an availability of 90% is used, resulting in a UKCS planning assumption for next winter of 138 mcm/d.

144. **Table G10** details how the 2011/12 UKCS forecast is derived.

Table G10 – Derivation of 2011/12 UKCS Maximum Forecast

	mcm/d
2010/11 Highest	**184**
Forecast decline from existing fields	-44
Forecast production increase from existing fields	+5
Forecast production increase from new fields	+8
2011/12 Winter Forecast	**153**
2011/12 90% Operational Forecast	**138**

Norwegian Imports

145. Norwegian imports to the UK flow through two dedicated import pipelines; Langeled to Easington and Vesterled to St Fergus and two additional offshore connections; Gjoa and the Tampen Link, both to the UKCS FLAGS pipeline to St Fergus.

146. In order to forecast Norwegian flows to the UK for next winter an estimate of total Norwegian production is made. Based primarily on historical flows Norwegian flows to the Continent are then forecast with flows to the UK determined UK by difference. Table G4 shows our estimates of average Norwegian exports to the Continent and UK since 2008/09. Our estimate of Norwegian production for next winter is approximately 2% higher at 320 mcm/d.

147. Due to the potential variation in Continental flows, a range of Norwegian flows to the UK is calculated based on observed load factors to each of the Continental countries that receive Norwegian supplies. For winter 2011/12 our preliminary forecast of Norwegian supplies to the UK is 95 mcm/d within a range from 83 to 118 mcm/d.

148. **Table G11** shows the forecast range of Norwegian exports for winter 2011/12. Also shown is a higher estimate of Norwegian flows for the mid winter period to account for supply seasonality. The lower 95 mcm/d flow for the UK has initially been used in security analyses such as the GBA trigger and the Safety Monitors.

Table G11 – Winter 2011/12 Estimates of Norwegian Exports

(mcm/d)	High flows to Continent	Low flows to Continent	Central	Central (mid winter)
Belgium	40	35	38	40
France	50	45	47	49
Germany	147	122	140	143
UK	83	118	95	103
Total	**320**	**320**	**320**	**335**

Continental Imports

149. Last winter, we again observed relatively stable flows through BBL but IUK was significantly more responsive to UK demand / price.

150. For BBL commercial arrangements for interruptible non physical reverse flow (i.e. non-physical exports) are now in operation. This may result in BBL flows becoming more responsive to the UK and possibly Continental market needs. The increase in BBL capacity from approximately 40 to 50 mcm/d may also increase opportunities to export more to the UK.

151. For planning purposes our preliminary forecast for BBL for next winter flows is 30 mcm/d, this is the same as last years forecast and that experienced last winter.

152. Last winter we observed IUK imports broadly responding to numerous factors, these included:

- Gas price
- UK demand
- Availability or rather non-availability of other non-storage supplies
- Storage flows / stocks

153. Graphical plots of IUK flows vs. these parameters show general trends rather than exact relationships due to the numerous factors at play.

154. For next winter these relationships are anticipated to generally hold true again with IUK importing when the UK has a market need for additional supplies above those supplied by most but not all other sources.

155. Our forecast for IUK imports next winter is to typically commence imports when demand exceeds the aggregate of all other non storage supplies. Based on the range of other supplies the resultant demand range is at about 300-400 mcm/d. Under certain conditions, for example low storage stocks, high UK gas prices, or supply losses then IUK could be expected to import at lower demands. Conversely, if storage stocks were high, UK gas prices low or supply availability was above expectations then IUK could be expected to import at higher demands.

156. Maximum IUK flows are forecast based on the average peak for the past two winters at about 40 mcm/d. However for security planning a lower value of 20 mcm/d will initially be used until there is evidence of higher flows.

LNG Imports

157. Last winter as shown in **Figure G9** the UK received record levels of LNG imports. Recent LNG deliveries have continued this trend despite concerns that Japan's needs for more LNG could reduce UK imports.

158. The market conditions for LNG flows to the UK remain favourable with UK gas winter 2011/12 prices much higher than those in the US. Spain may also continue its trend of lower LNG imports due to a combination of the economy, more pipeline imports and legislation to increase coal burn for power generation.

159. Issues that could reduce LNG imports next winter include more LNG to Japan and the possibility that the Gate LNG terminal in the Netherlands becomes a competitor for 'Europe bound' LNG.

160. On a global basis more LNG production is expected in 2011 (full production from Qatar, new production in Australia and Algeria (Pluto and Skikda)) is expected in 2012. Demand is expected to continue to increase in existing and new markets.

161. To manage the supply uncertainty surrounding LNG a wide range is again considered, namely from 50 to 120 mcm/d, with an average winter flow of 80 mcm/d. This is 20 mcm/d higher than last years initial forecast and 21% above the average LNG flow last winter. The range therefore identifies periods of both low flow and high flow from Grain and both Milford Haven facilities. Flows of LNG imports through Teesside GasPort provide a further upside to our range.

162. Due to the delayed construction of the Tirley pressure reduction installation (PRI) the entry capacity at Milford Haven remains restricted to 750 GWh/d (approximately 68 mcm/d).

Storage

163. For next winter further storage capacity is expected to become available from the Aldbrough storage facility and through Holford a new storage facility in the Cheshire area. In addition further space is expected at Hole House Farm[16].

164. Existing storage capacity has been reduced through the closure of Partington whilst no NTS shipper stock will be available at Glenmavis.

165. In aggregate storage deliverability for next winter at 1088 GWh/d is slightly lower than last year's figure of 1189 GWh/d. This is mainly down to the closure of Partington, but should increase when Holford is commissioned. This is expected to add a further 88 GWh/d and will further increase in winter 2012/13.

166. In aggregate storage space for next winter is also slightly lower, this is primarily due to a lower declared value for Rough space. For previous winters, Rough space has been increased during the refilling period.

167. **Table G12** shows our assumed levels of storage space and deliverability for next winter. Currently[17] Rough is filled to about 86%, MRS is filled to around 69%, and

[16] The increased space at Hole House Farm is from the transformation of salt caverns at Hill Top Farm. Dedicated facilities at Hill Top Farm are expected in the future.
[17] As of 29 June 2011.

Avonmouth to about 85%. This is ahead of the position for this time last year; most storage is expected to be filled before it is required next winter.

Table G12 – Assumed 2011/12 storage capacities and deliverability levels[18]

	Space (GWh)	Refill Rate (GWh/d)	Deliverability (GWh/d)	Deliverability (mcm/d)	Duration[19] (Days)
Short (LNG)[20]	517	3	143	13	3.6
Medium (MRS)	8674	390	469	43	19[21]
Long (Rough)	35580	240	476	43	75
Total	**44771**	**632**	**1088**	**99**	
Total 2010/11	48181	617	1189	108	

Preliminary View of Supplies Winter 2011/12

168. In the previous sub-sections we have outlined the basis for the assumptions incorporated into our analysis. **Table G13** summarises the supply range and our Base Case, and compares these with the 2010/11 forecasts[22] and actual flows. We should stress that these 2011/12 ranges and Base Case should be regarded as provisional with the primary purpose of fostering discussion and comment.

Table G13 – Preliminary View of Non Storage Supplies Winter 2011/12

(mcm/d)	2010/11 Range	2010/11 Top 100	2009/10 Highest	2011/12 Range	2010/11 Base Case
UKCS	166	133	160	138	138
Norway	86 – 116	88	116	83 – 118	95
BBL	30	28	37	30	30
IUK	30 – 0	10	38	40 – 0	20[23]
LNG Imports	30 – 100	79	130	50 – 120	80
Total	342 – 412	338	415[24]	311 – 406	363
Total inc. Storage				**411 - 506**	**463**

[18] This table represents our operational assumptions and is based on proven performance. Reported deliverabilities may be different to 'name plate' capacities. Space includes 763 GWh Operating Margins, excludes Holford. Holford space and deliverability will be included when operational
[19] Duration based on Space / Deliverability, excludes within winter refill
[20] Commercial services offered by LNGS for 2010/11
[21] 19 days represents an average. Actual range of specific sites is far greater
[22] Forecast range represents our pre-winter assessment, not any subsequent revisions
[23] IUK shown as 20 mcm/d but assumed to import more at high demands
[24] 415 mcm/d represents the highest daily supply of non storage supplies, this is much lower than the aggregated supply types (481 mcm/d)

169. Based on the supply assumptions detailed in the previous supply sections, **Table G13** 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.

Preliminary Safety and Firm Monitors

170. The safety monitor was 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.

171. The safety monitor defines the level of storage that must be maintained through the winter period. The focus of the safety monitor 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.

172. The firm gas monitor represents the storage level required to support Uniform Network Code defined firm demand in a severe winter. The firm gas monitor is published solely for the purpose of providing further information to the market.

173. This section on the safety and firm monitors is consistent with the industry note we issued on 9 June 2011 as required under the Uniform Network Code (Q5.2.1).

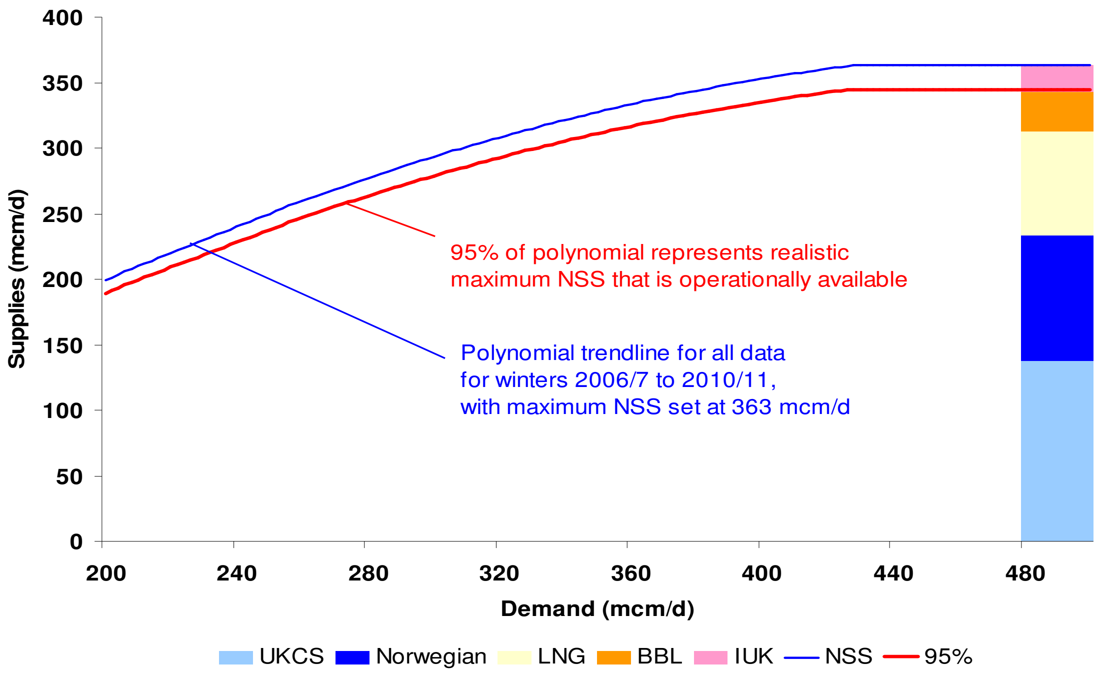
174. UNC Modification Proposal 0090: Revised DN Interruption Arrangements (Mod 0090) was directed for implementation on 1st April 2008. From October 2011 the majority of DN sites will be considered firm for transportation purposes. This has an impact on the 2011/12 safety and firm monitor in that additional DN demand is now no longer contracted for interruption by the Transporter and therefore under the methodology for calculating the monitor levels there is an increase in the number of "firm" loads.

175. 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 2011/12 safety monitors was 363 mcm/d. This is identical to the preliminary view of NSS in Table G13. Our final view of supplies for next winter will be detailed in our Winter Outlook Report document to be published in October: these levels will be used as the basis for setting the final safety monitor level by October 1st.

176. 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. Analysis of previous winters data shows that assuming an availability of 95% captures typically 95% of all data points, with those that are still below often the result of short term supply losses.

177. By applying a value of 95% to the aggregated total of NSS, the value of NSS used in determining the 2011/12 safety monitors is reduced from 363 to 345 mcm/d. The resulting relationship of NSS against demand is shown in **Figure G18**.

Figure G18 - Maximum NSS assumptions and NSS v demand relationship



178. The relationship of NSS vs. demand for the last five years provides the shape (not the values) for the basis for the NSS vs. demand relationship for calculating the 2011/12 Safety Monitor.

179. Table G12 shows our storage assumptions for winter 2011/12.

180. The demand background used for the analysis in this section is our demand forecasts for 2011/12 that we produced in June 2011. These are slightly lower than our 2010/11 forecasts produced in May 2010. With the overall supply position expected to be similar to that experienced last winter, the slightly lower levels of forecast demand should marginally decrease the safety monitor level for next winter. However the impact of slightly reduced demands has been offset by increased protected by isolation requirements, due to Mod 0090.

181. **Table G14** shows the total safety monitor space requirement on the basis of the assumptions outlined above.

Table G14 – Total Safety Monitor Space Requirement

	Total storage capacity (GWh)	Space requirement (GWh)	Space requirement %
Total	**44781**	**1337**	**3.0%**

182. 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.

183. As stated previously, the firm gas monitor is published solely for the purpose of providing further information to the market. The firm monitor illustrates the indicative level of gas that would need to be held in storage to supply all "firm" demand in a 1 in 50 winter. The analysis uses the same prudent demand and supply assumptions as used for the calculation of the safety monitor. Not surprisingly, Mod 0090 has had an impact on the Firm Monitor as DN load is now considered "firm".

184. **Table G15** shows the indicative total level of storage required for the Firm Monitor in a 1 in 50 winter. The total space requirement to support all firm load is 32612 GWh, i.e. approximately three quarters of total storage capacity of 44781 GWh (compared to approximately a third last winter). The increase is due to the impact of Mod 0090 where the majority of DN demand is effectively reclassified as firm. As detailed previously, there is little change in the supply or demand position from last winter hence the change is essentially academic rather than one that suggests a change in the level of security.

Table G15 – Firm Monitor Space Requirement

	Total storage capacity (GWh)	Space requirement (GWh)	Space requirement %
Total	**44781**	**32612**	**72.8%**

185. Modification Proposal 0195AV: Enduring NTS Exit Capacity Arrangements (Mod 0195) was directed for implementation on April 2009. From October 2012 this will also have an impact on the 2012/13 Safety and Firm Monitors in that additional NTS demand will also be considered as "firm".

186. National Grid held a Gas Operational Forum "Live Meeting" commencing on Friday 17th June to discuss the Firm Monitor methodology, the implications of a Firm Monitor set at 72.8% of storage space (and potentially considerably higher in 2012/13) and whether the current calculation of the Firm Monitor continues to meet the needs of customers.

187. Further discussions are expected at future Gas Transmission Working Groups and the Operational Forum meetings.

Winter 2011/12 Update on provision of new NTS capacity

188. Emissions related works - Work continues on the new 35MW electric drive compressor unit at Kirriemuir and the two 24MW units at St Fergus as part of National Grid's drive to reduce compressor station emissions. The new units are anticipated to operational during 2012.

189. Storage - A new pipeline is currently being constructed to provide additional capacity for the Hill Top Farm storage facility in Cheshire. The 3km x 900mm pipeline will be constructed from Warmingham to tie in to an above ground installation at Wheelock. The pipeline is anticipated to operational by late summer 2011.

190. South Wales expansion project - This project is part of the overall investment strategy to provide the capacity to transport gas from the two LNG importation terminals at Milford Haven.

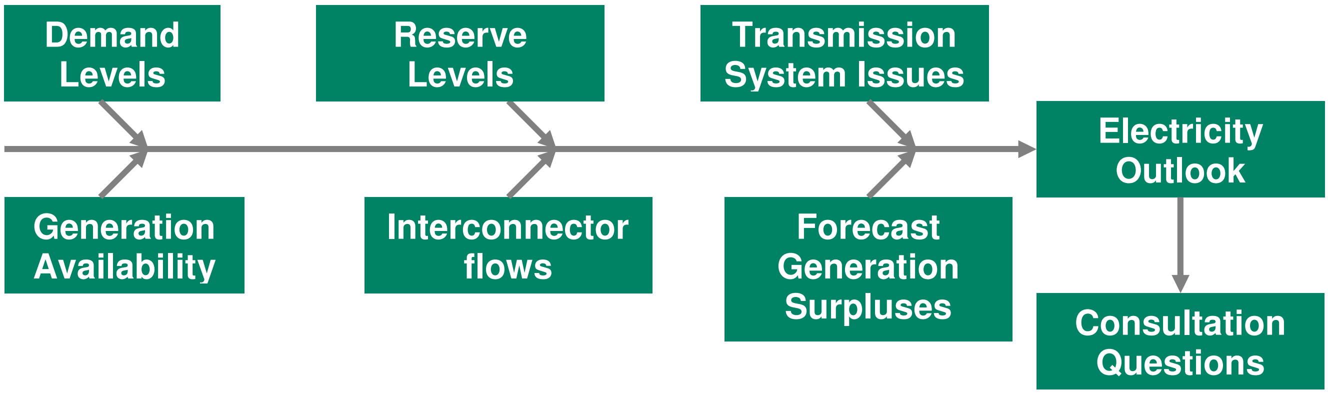
191. Preparatory works have commenced for the construction of the Pressure Reduction Installation (PRI) at Tirley in Gloucestershire. On completion for winter 2012/13 this will alleviate the existing force majeure capacity restriction and increase Milford Haven entry capacity to the 950 GWh/d release obligation.

192. New Exit Connections - During 2011, there will be a number of new connections to the NTS, including a network offtake point at Burnhervie on Feeder 13 between St Fergus & Aberdeen and a connection for a storage facility at Stublach in Cheshire.

Consultation Questions - Gas - Outlook

Number	Question
GQ9.	Oil indexed prices appear to provide a ceiling for UK winter gas prices. Do you agree with this? What sets the UK floor price?
GQ10.	Forward UK gas prices are currently displaying some seasonality with summer / winter price differentials of about 10 - 15 p/therm. Are these differentials sufficient to develop more UK storage?
GQ11.	The relative economics of gas versus coal generation for next winter strongly favour coal. What factors may result in a higher gas burn?
GQ12.	On a seasonal basis, NDM demand is forecast to again decline next winter. What are the possible factors behind this ongoing decline?
GQ13.	Do you support our view of lower UKCS supplies next winter and could the upstream tax regime changes affect production?
GQ14.	Our Norwegian forecast for next winter is based on marginally higher Norwegian production and some bias of Norwegian flows to the Continent. Do you support this view or have an alternative opinion?
GQ15.	What assumptions should be made for levels of imported gas through BBL for next winter, will the increase in capacity or the introduction of non physical reverse flow have a material impact?
GQ16.	For next winter will IUK again be a marginal source of supply more akin to storage?
GQ17.	What assumptions should be made for levels of imported LNG to the UK for next winter? Will additional imports to Japan or the start-up of the Gate facility in the Netherlands impact UK imports or will increased LNG production and low USA gas prices ensure good supply?
GQ18.	European gas supplies could be boosted by the commencement of Nord Stream but could also be impacted by tensions in North Africa and the Middle East. What planning assumptions should we consider to accommodate these uncertainties?

Electricity

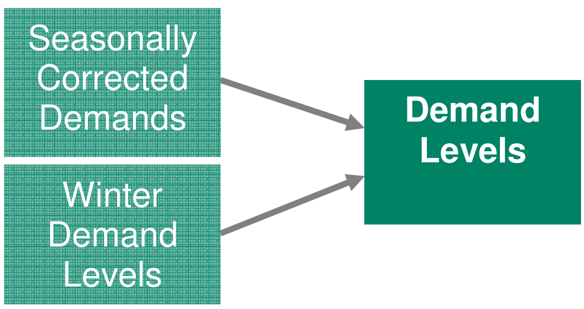


Overview

193. This section sets out the current forecast for the winter 2011/12.

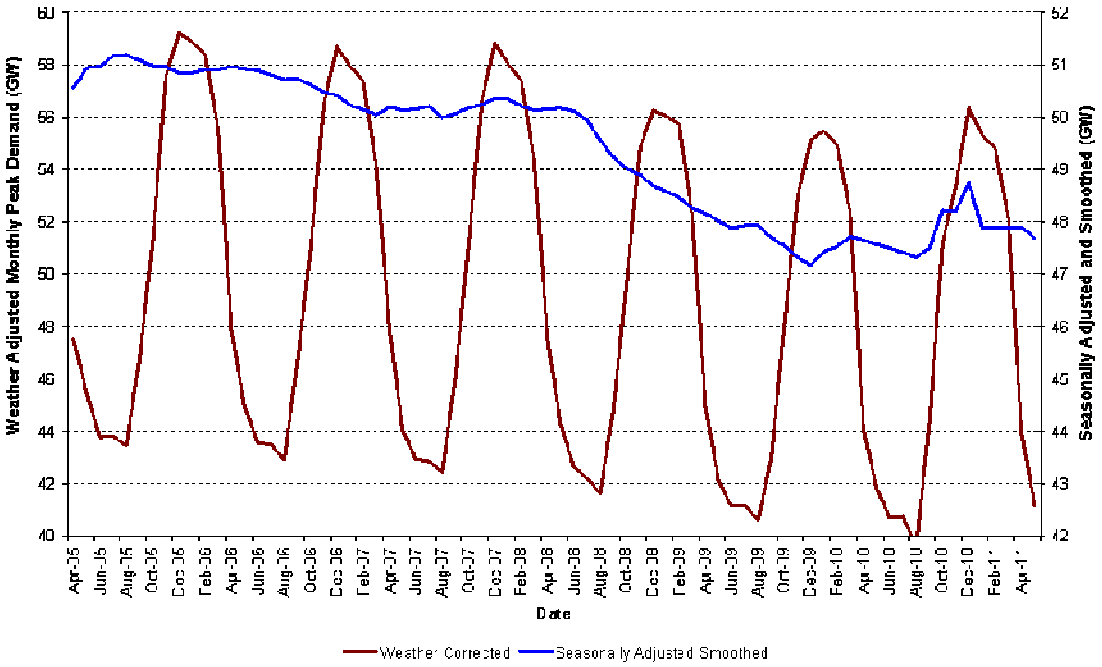
Demand Levels

194. Unless otherwise stated, demand discussed in this report excludes any exports to France, The Netherlands and Northern Ireland but does includes station load and exports from the Transmission System to meet GB demand.



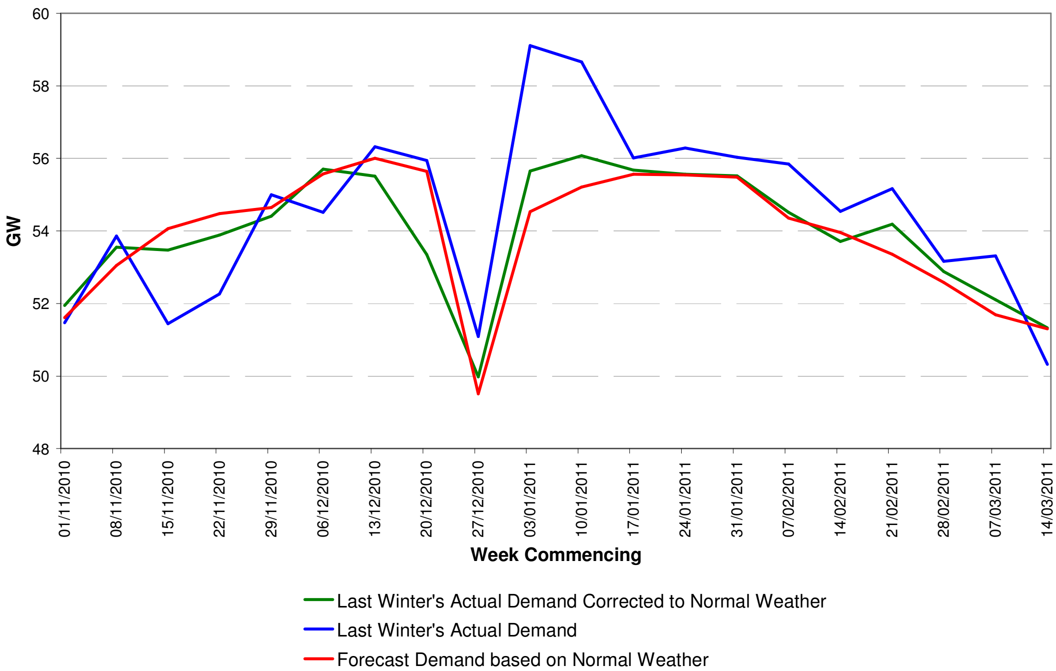
195. Previous demand level forecasts for the winter have been based around the assumed growth/decline in consumption relative to previous years. Following the decline that occurred during the economic downturn there has been a small amount of growth as shown in the weather and seasonally corrected demand level. **Figure E14** shows the weather and seasonally corrected demand levels for the last six years. The effect of the economic downturn can be clearly seen. The sharp rise in the demand during the winter of 2010/11 can be attributed to the ‘snow effect’ as discussed on page 36.

Figure E14 - Smoother Weather and Seasonally Corrected Normal Demand



196. **Figure E15** shows the previous years actual demand, weather corrected demand and the demand forecast for the upcoming winter. The most current forecast at any time is given on the **BRMS**[25].

Figure E15 - Previous years outturn and forecast for 2011/12



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[25] www.bmreports.com

197. The normal demand peak forecast for winter 2011/12 is currently at 58.1 GW. This is compared to the forecast last year of 57.7 GW and the outturn of 59.7 GW.

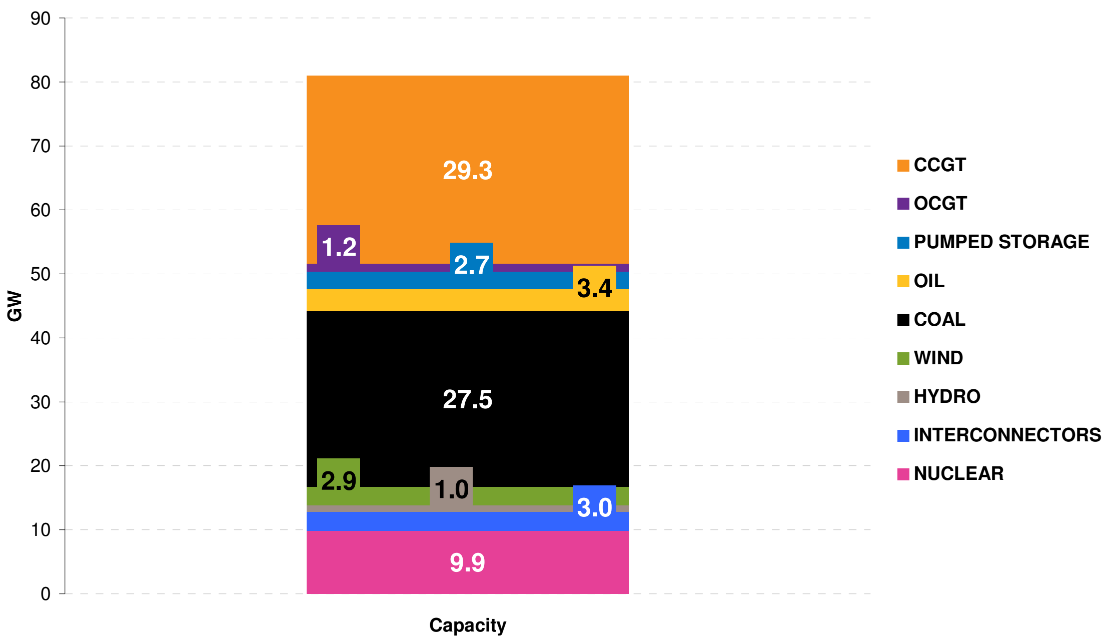
198. 1 in 20 conditions are a particular combination of weather elements which give rise to a level of peak demand within a Financial Year which has a 5% chance of being exceeded as a result of weather variation alone. The 1 in 20 demand peak is forecast to be 59.3 GW

Generator Availability

Generation Capacity

199. 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 2011 is 80.9 GW. A breakdown of this capacity is shown in **Figure E16**. The Operational Capacity figure from the summer outlook report was also 80.9 GW. There has been small variations in oil, coal and nuclear. Overall the operational view of capacity for the forthcoming winter is currently very similar to that of the Summer Outlook Report.

Figure E16 - Generation Capacity Operational View 2011/12



Generation Availability Assumptions

200. **Table E3** shows the assumed losses based on previous winters losses, including; breakdowns, shortfalls and any reduction in primary energy source such as wind and water. This data is then used in the forecast generation surpluses on page 77.

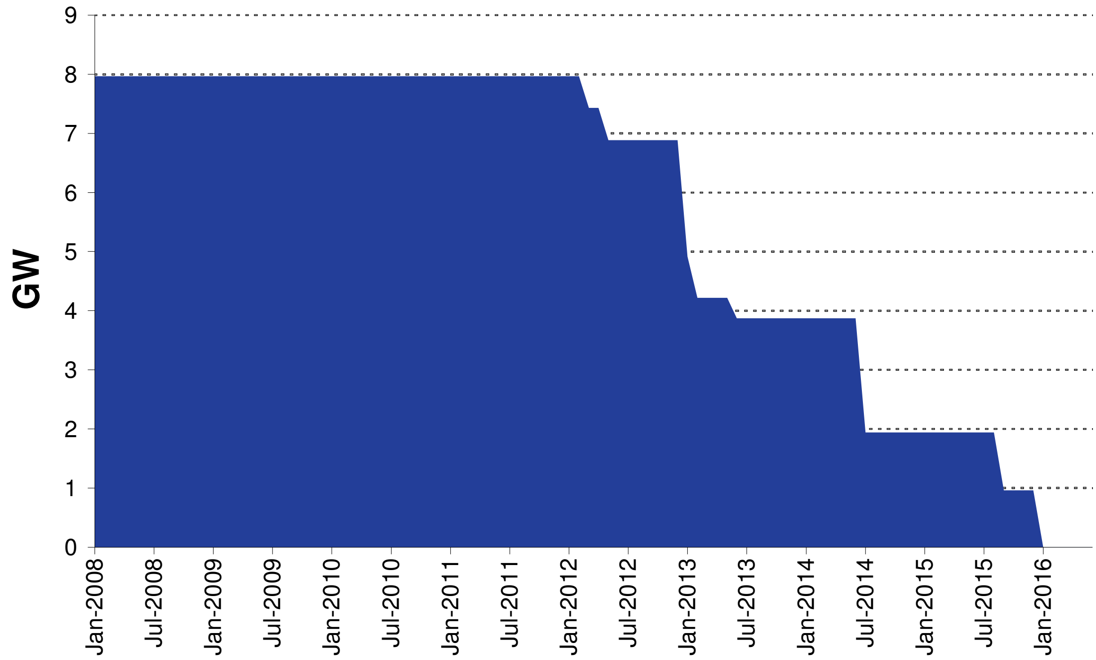
Table E3 - Assumed Losses of Generation Availability for Winter 2011/12

Power Station Type	Assumed losses
Nuclear	17%
Interconnectors	0%
Hydro generation	30%
Wind generation	92%
Coal	14%
Oil	30%
Pumped storage	4%
OCGT	2%
CCGT	11%
Total	**16%**

Generation Side Risks

201. Issues related to the limited hours under LCPD for opted out plant are unlikely to affect this winter but are likely to affect the following winter. LCPD opted out plant has 20,000 hours allowed operation until December 2015. At current observation rates of utilisation of the allowed hours, there is an implication of early closure of some units. The latest view of National Grid, based on running patterns to date projected forward for opted out coal units is shown in **Figure E17**.

Figure E17 - Indicative Total Generation Capacity For LCPD Coal Opted Out Plants



Merit Order

202. The focus of this report is for meeting electricity demand and less attention is given to which types of generation are likely to be at base load, two-shifting or marginal. This issue is determined to a large degree by the market and therefore is subject to some uncertainty as market prices for winter changes over time.

203. As discussed on page 54 forward prices suggest that coal fired power generation could be the base load plant from November through to March.

Reserve Levels

Reserve Levels

204. 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.

205. There is an additional reserve requirement to meet wind generation output uncertainty. This reserve held by National Grid specifically to manage the additional variability brought about by wind generation output being lower than expected. Its value varies based upon a function of the expected wind output through each period

of the day and the requirement is also met from both synchronized and non-synchronised sources.

206. National Grid procures 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. 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.

207. For winter 2011/12, the present level of contracted STOR reserve is approximately 1.65GW, over 1.05 GW from BM participants and nearly 0.6 GW from non-BM generating plant and demand reduction (of which, about 0.3 GW is unlikely to be available over the winter darkness peak).

208. Prior to the winter, there will be two further STOR tender rounds covering services for the winter 2011/12 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[26]

209. National Grid expects to contract more STOR to provide reserve service over the winter. Last winter 2.7 GW of STOR was contracted over the darkness peak period 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 to 20 winter peak demands last year was only about 1.75GW.

210. 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. 0.8GW of this 1.5GW reserve requirement has already been contracted, with 0.3GW from demand-side providers.

211. National Grid continues to have Maximum Generation contracts in place for Winter 2011/12, which provides 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.

Interconnector Flows

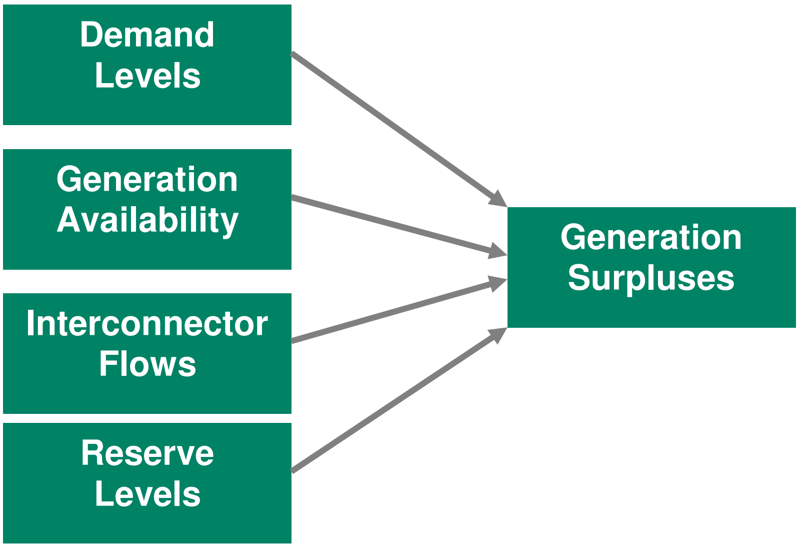
Interconnector Flows

212. There is uncertainty around the interconnector flows going forward. As in previous reports it is expected that the interconnector flows will follow the price differentials between the different markets. Germany's recent decision to close almost 16 GW of

[26] http://www.nationalgrid.com/uk/Electricity/Balancing/services/reserveservices/STOR/.

nuclear plant immediately and put in place a phased closure of all nuclear plant by 2022 is expected to have impacts during this winter. The forecasts of price differential between markets for the upcoming winter are not suitable to be able to create an accurate forecast of flows for the upcoming winter. Hence a detailed and up to date forecast will be included in the final winter outlook report.

Forecast Generations Surpluses



213. This sections looks at the amount of Generation Surplus available through the main scenarios of interest. Each chart has an amount of demand (green bars) the required operational reserve (orange bars). The solid line is the generation availability with 3GW of imports and then the dotted line includes 3GW of exports.

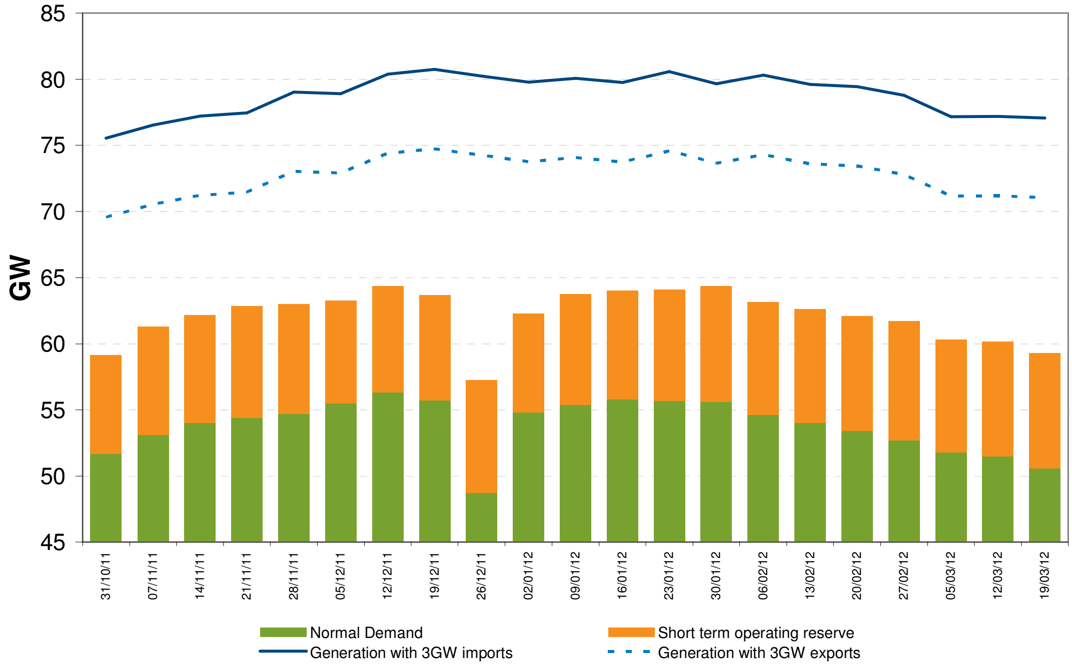
214. The normal demand is based on average weather conditions, where as the 1 in 20 demand is for a winter with severe weather that would only be expected in 1 winter out of 20.

215. The declared generation availability is the currently declared availability which is declared to National Grid through the requirements of Operational Code 2 section of the Grid Code. The assumed generation is derived from the assumptions set-out on page 73 and the declared generation availability.

216. The Moyle interconnector flow is not considered in the margin analysis as any export will allow for a greater amount of generation in Scotland. It can be seen from previous winters that Moyle generally exports during the winter.

217. **Figure E18** shows, Normal Demand and the declared generation availability. This chart shows that there is adequate margin under optimum declared conditions.

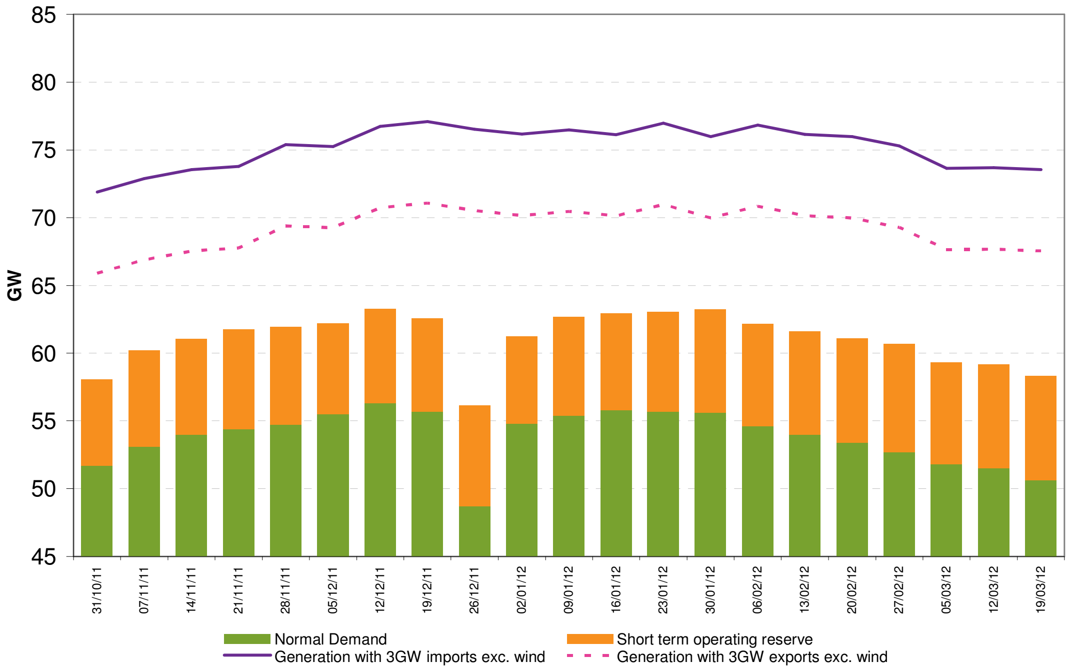
Figure E18 - Normal Demand and Notified Generation Availability



218. From this chart it is also possible to calculate the minimum generation surplus which is 16%. The surplus is the amount of generation available above the amount required to meet the demand and reserve requirements. It is represented as a percentage of the total available generation.

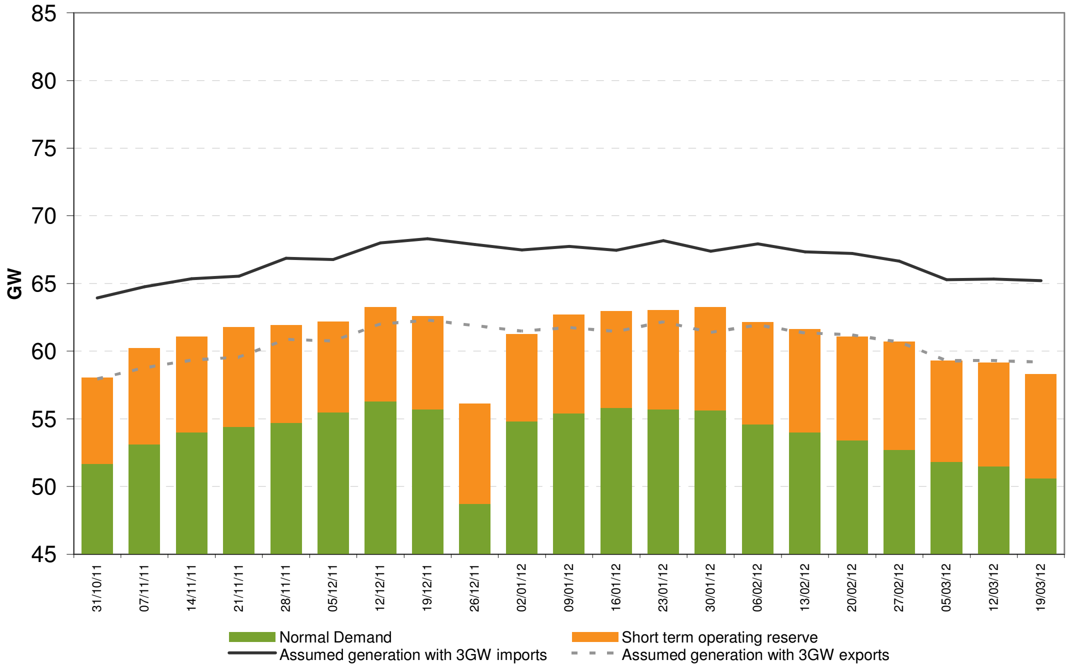
219. **Figure E19** shows, Normal Demand and the declared generation availability excluding wind. This shows that there is adequate margin without wind generation available under optimum declared availability.

Figure E19 - Normal Demand and Notified Generation Availability Excluding Wind



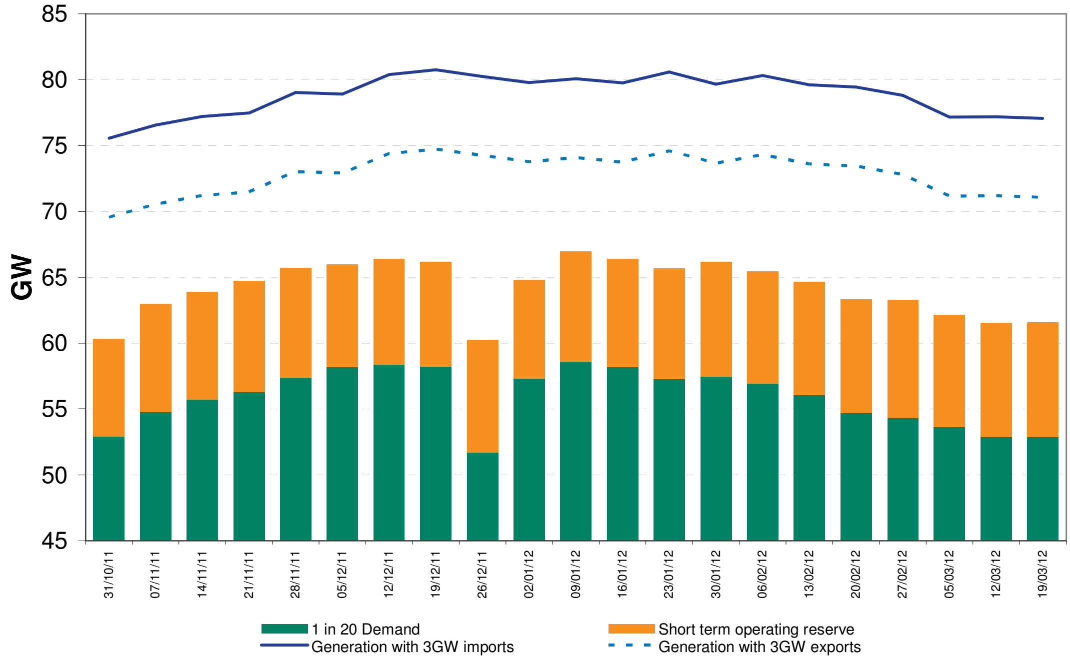
220. **Figure E20** shows, Normal Demand and the assumed generation availability. This chart shows that with 3 GW of exports there would be some erosion of the short term operating reserve. In a scenario where erosion of short term operating reserve was possible system warnings would be issued ahead of time as usual and it would then be expected that the market would respond accordingly.

Figure E20 - Normal Demand and Assumed Generation Availability[27]



221. **Figure E21** shows, 1 in 20 Demand and the declared generation availability, and again shows adequate margins.

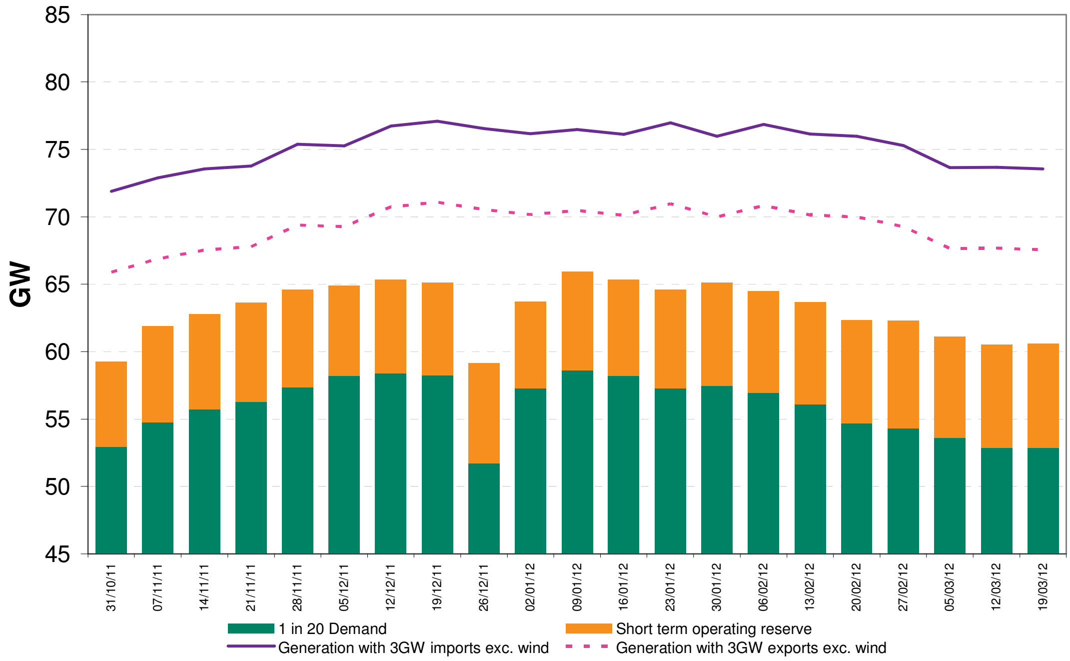
Figure E21 - 1 in 20 Demands and Notified Generation Availability



[27] For definition of Assumed Generation Availability please see paragraph 216

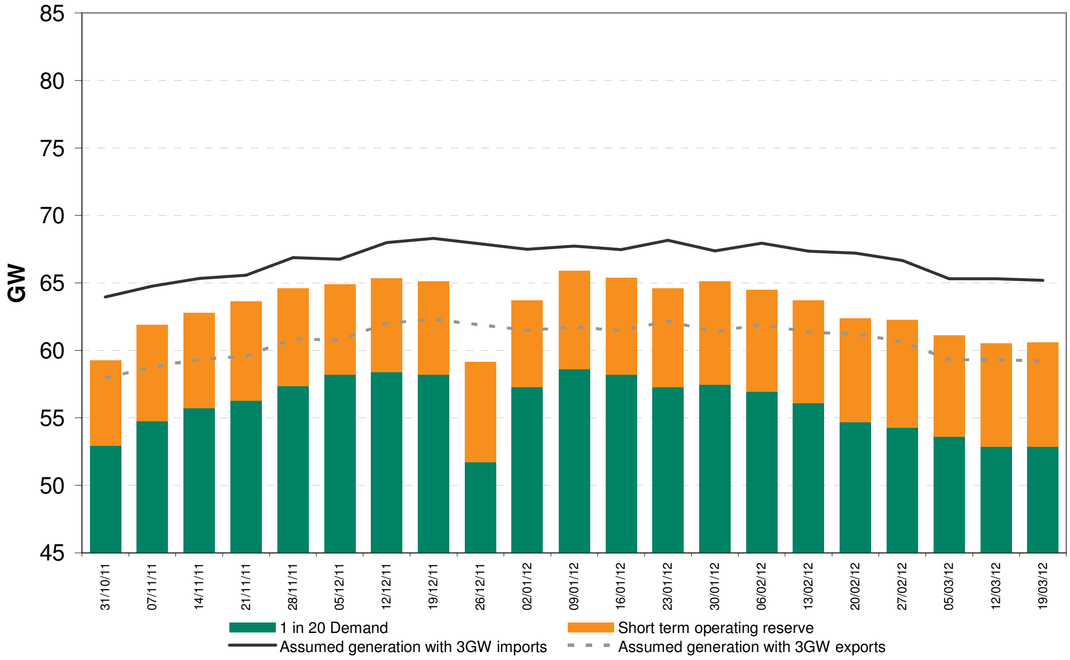
222. **Figure E22** shows, 1 in 20 Demand and the declared generation availability excluding wind with adequate margins available.

Figure E22 - 1 in 20 Demands and Notified Generation Availability Excluding Wind



223. **Figure E23** shows, 1 in 20 Demand and the assumed generation availability, where there is system margin under import conditions and again the possibility of erosion of system margin during export conditions. As mentioned previously system warnings would be issued ahead of time in this scenario and it would be expected that the market would respond accordingly.

Figure E23 - 1 in 20 Demands and Assumed Generation Availability



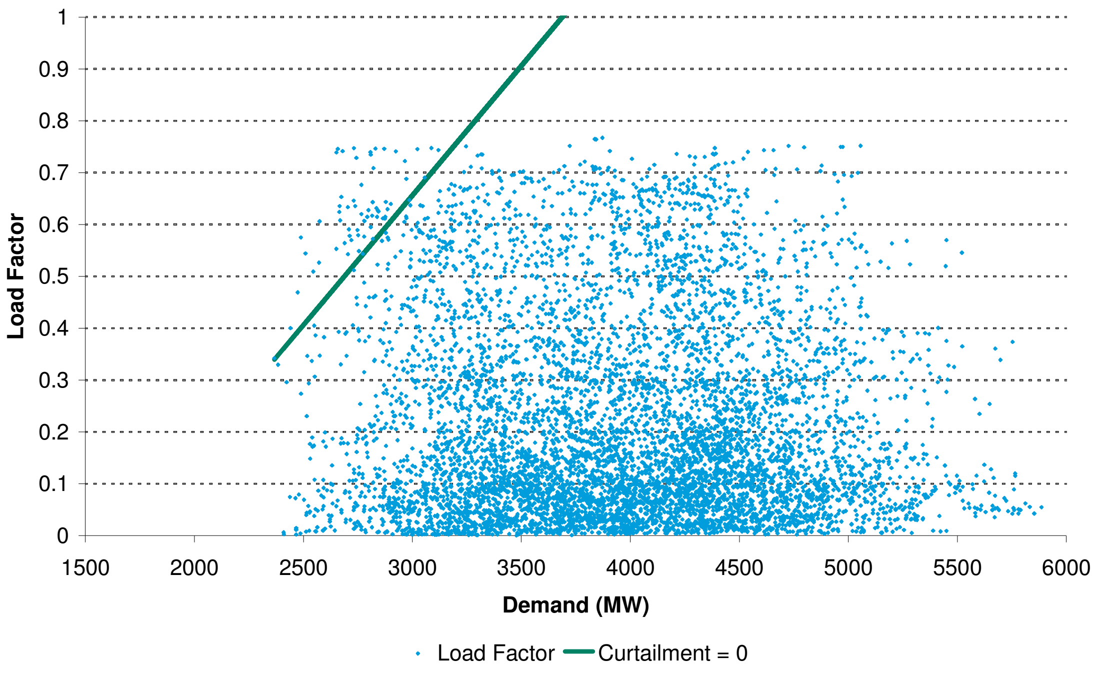
Transmission System Issues

Transmission System Issues

224. Following on from the actions taken on wind to secure the transmission system during the spring and the discussion on page 47, **Figure E24** shows a reduced data set - winter 2010 - and now includes a curtailment line. In the worst case scenario of maximum availability of generation and wet and windy conditions the points above the curtailment line are where actions would have been required. There are approximately 60 points above the line representing 30 hours where actions would have been required last winter. This data includes a fixed value for the constraint boundary between Scotland and England and also includes a fixed capacity for Scottish wind generation of 2 GW

225. Further forecasting of the likelihood of this occurring will be given in the Final Winter Outlook.

Figure E24 - Scottish Half hourly wind and demand levels for winter 2010 and curtailment line



Consultation Questions - Electricity - Outlook

226. National Grid would welcome comments on anything contained in the consultation report. In particular comments on the following questions would be most welcome

Number	Question
EQ5.	What is your current expected growth in demand levels?
EQ6.	What are the differences (if any) between National Grid's Generation Capacity and your forecast generation capacity, please include details of any generation plant that is mothballed state.
EQ7.	What other methods could be used for understanding the short-term unavailability of Generation Plant other than using historic performance data?
EQ8.	What other factors should be taken into consideration when approaching generation availability over the winter?
EQ9.	What additional Generation maybe placed into a mothballed state that will affect generation availability for the winter?
EQ10.	What load factor would you apply to intermittent generation - i.e. wind for consideration over the winter peak?
EQ11.	What is your expectations regarding the interaction between the French and Dutch Interconnectors?
EQ12.	What is your expected flow and direction of the French and Dutch Interconnectors?
EQ13.	What other specific scenarios of either demand or generation availability should be added to the analysis in the final report and which scenarios do you think would be most credible?
EQ14.	What further analysis, detail and scenario work would be beneficial around the transmission system issues?
EQ15.	Looking at the overall document - which sections provide the most value and which provide little value to your analysis?