Winter Outlook 2012/13

Introduction

1. This document sets out our analysis and views for winter 2012/13. Previous outlook reports are published on our website[1]. The document is based upon the consultation published in July and the two responses received.

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@nationalgrid.com

Roles and Responsibilities

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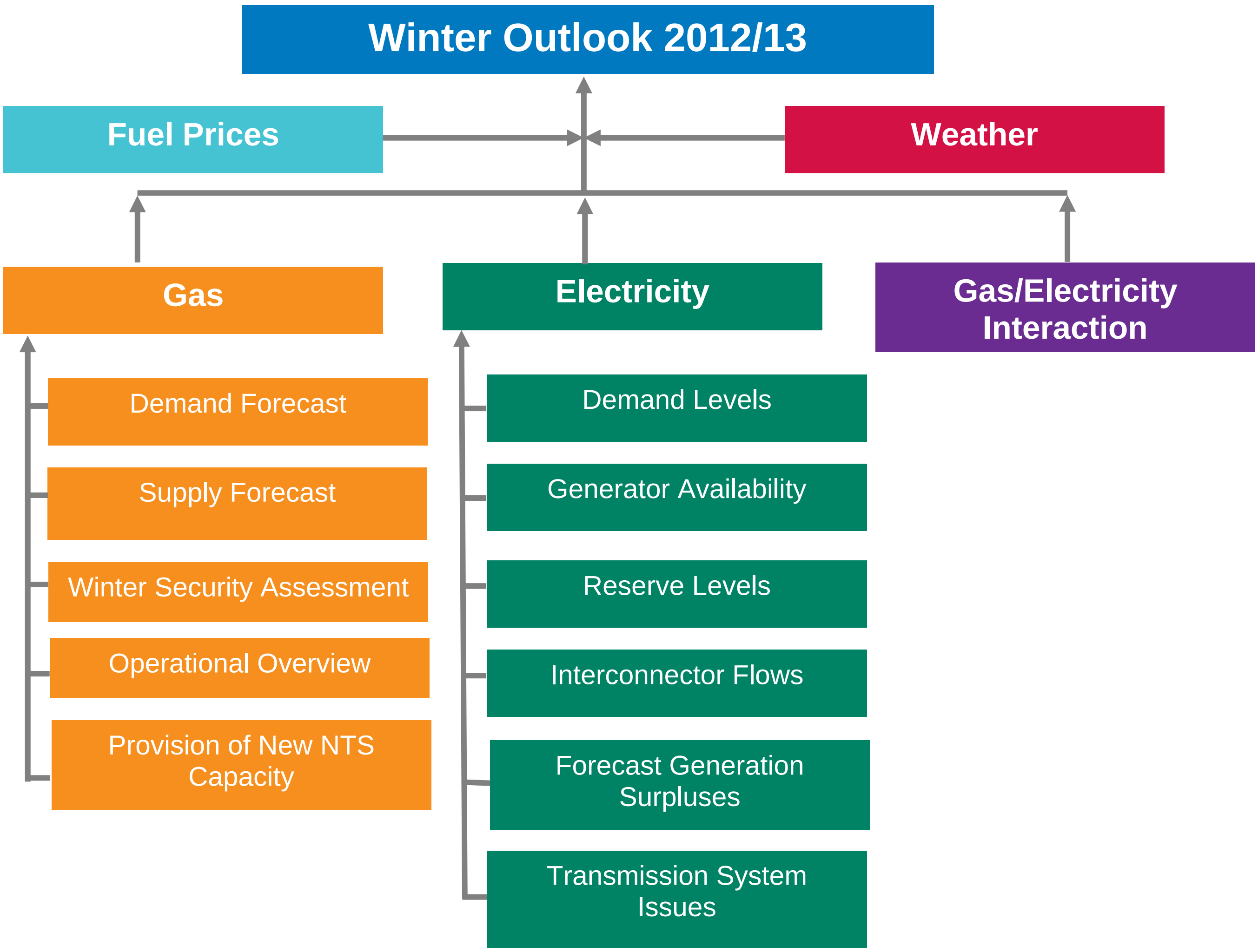
Winter Outlook 2012/13



Winter Outlook 2012/13 - Key Details

Fuel Prices	
Forward energy prices for winter 2012/13 strongly favour coal rather than gas as the preferred source of fuel for power generation	
Gas	
For security planning the 2012/13 peak gas demand forecast assumes a high level of gas demand for power generation as well as 1 in 20 cold weather conditions	516 mcm/d[2]
2012/13 supply forecasts – marginally lower than winter 2011/12, LNG again provides greatest uncertainty	411 mcm/d
2012/13 storage deliverability – higher than winter 2011/12, should increase further within winter when new facilities are commissioned	108 mcm/d
2012/13 Safety Monitor requirements higher than winter 2011/12 (1.5%)	4.6%
Electricity	
Normal demand levels forecast	55.9 GW
ACS demand levels forecast	57.0 GW
1 in 20 demand levels forecast	58.8 GW
Generator capacity	79.1 GW
Assumed generation availability (excl. Interconnectors) at winter peak	64.4 GW
Forecast surplus based on declared generation availability and normal demand (excl. Interconnectors):	
• at winter peak	19%
• minimum over winter	17%

[2] The peak day forecast of 516 mcm/d is a slight increase on the number shown in the Winter Consultation summary table. This increase is due to a revised figure for Moffat exports.

Contents

Weather

7. The Met Office has ceased publication of their long term winter weather forecast. The Met Office web site contains a short description of the weather up to 30 days ahead[3] and guidance for contingency planners up to 3 months ahead[4]. The latest 3 month outlook for October to December forecasts an increased risk of colder than average weather.

8. Last winter's weather illustrated the variability of winter weather. It was close to seasonal normal for the 3 months from December to February but the second warmest in National Grid's 84 year weather history for the 6 months from October to March. February 2012 was average for the whole month but this was split into cold weather for the first two weeks and warm weather for the last two weeks.

9. Early warning of severe weather can be obtained from month-ahead ensemble forecasts. The European Centre for Medium Range Weather Forecasts[5] specialises in producing these forecasts. Products based on them are available from a number of weather service providers. Fifty separate forecasts are produced showing the range of possibilities. The greater the number of forecasts showing the same outcome, the greater the possibility of that outcome.

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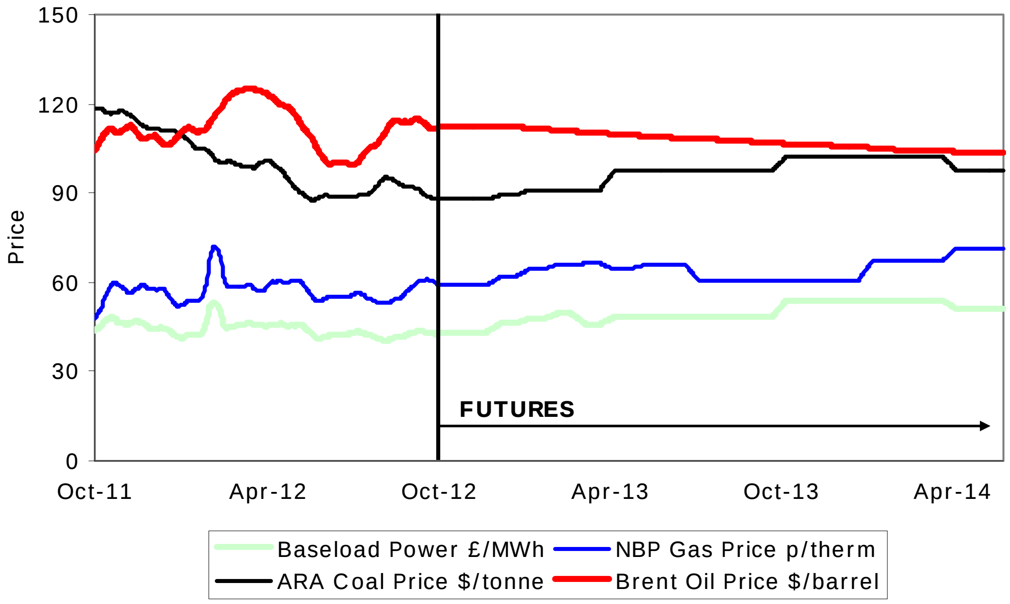
[3] (http://www.metoffice.gov.uk/public/weather/forecast/?tab=map&map=SignificantWeather)
[4] http://www.metoffice.gov.uk/publicsector/contingency-planners
[5] (ECMWF http://www.ecmwf.int/)

Fuel Prices

10. **Figure F1** shows historic energy prices for the 12 months prior to September 2012 and forward prices through to March 2014.

Figure F1 – Historic and forward energy prices[6]



11. The chart shows that gas, electricity and oil prices have been variable throughout the year, but overall have ended the year in a similar position as they started. Coal prices have declined throughout the year. The reasons behind this may be a combination of increased coal production in China and Indonesia and higher coal exports[7] from the US due to increased use of gas for power generation.

12. Forward prices for oil show a declining trend towards $100 per barrel. The forward trends for the other three fuel types show some increase.

13. Despite short term variations, UK gas prices have remained broadly flat rather than exhibit any seasonal variation. Forward prices for the next winter 2012/13 and 2013/14 again show a seasonal increase with mid winter prices at near parity with contracted gas at oil indexation.

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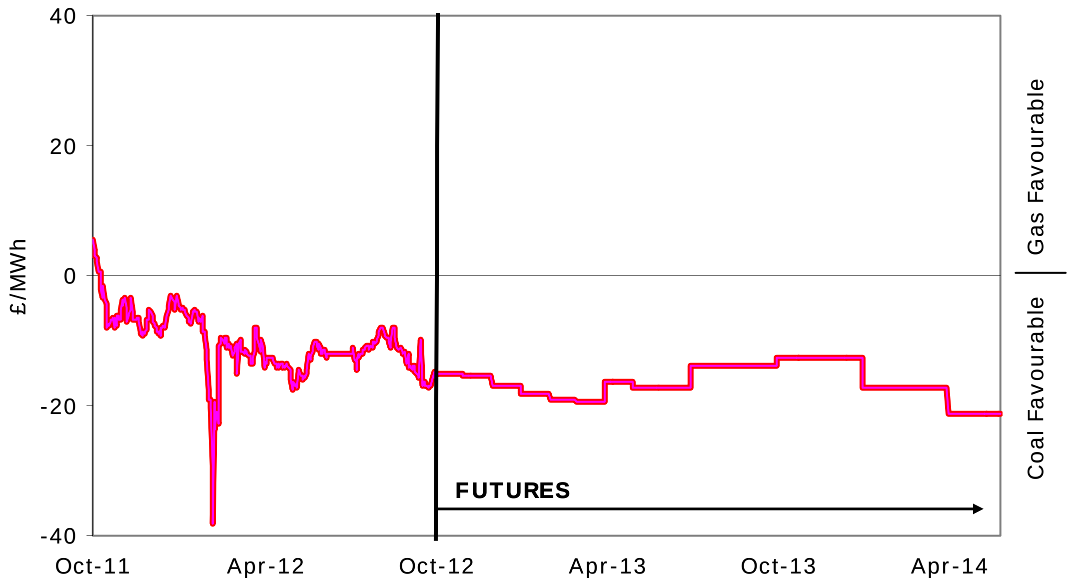
[6] Historic prices show a 1 week rolling average of spot prices
[7] BP Statistical Review of World Energy

14. Electricity prices have tended to follow the gas price, but have followed a lower trend over most of the past year, thus lowering the economics of gas fired power generation. Forward electricity prices show some seasonality, albeit not as pronounced as for gas.

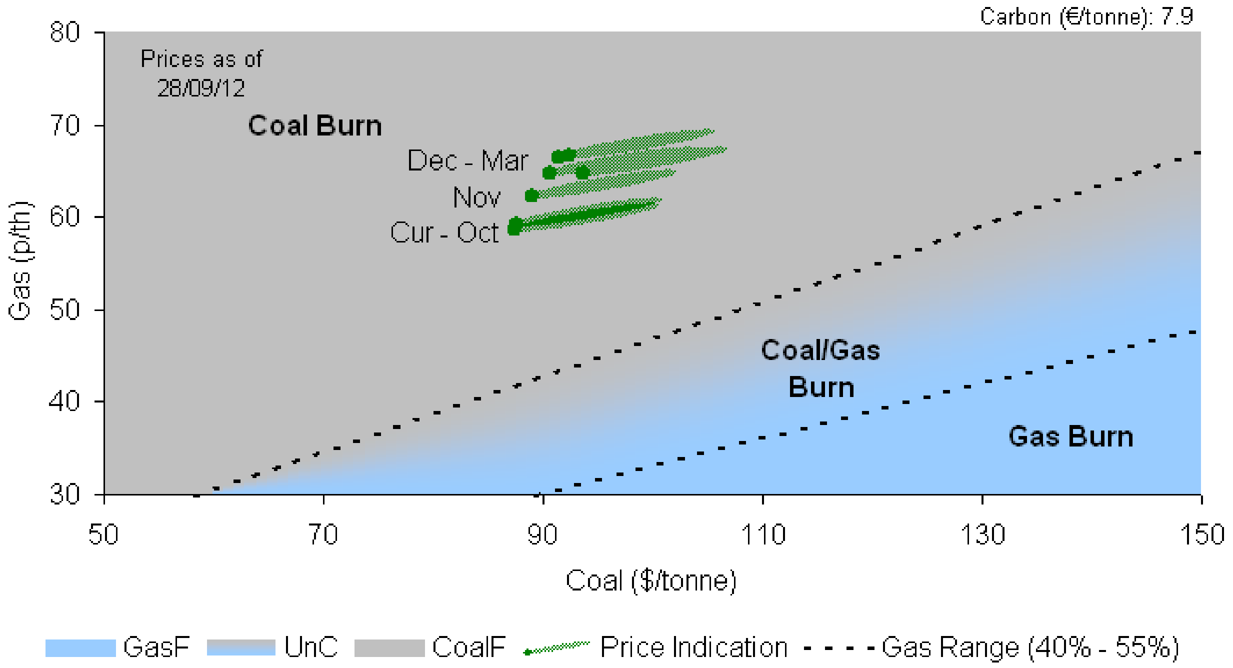
15. **Figure F2** shows the relative clean dark and clean spark spreads, showing whether gas or coal is favoured for electricity generation. These costs include the costs for carbon.

Figure F2 – Relative power generation economics (1)



16. For the majority of the previous year the relative prices have favoured coal over gas for power generation. The forward prices for winter 2012/13 suggest this is likely to continue with coal strongly favoured over gas. This is further supported in **Figure F3** where the economics are shown relative to fuel costs and power generating efficiencies. The spike in February 2012 corresponds to high UK gas prices as a result of very high prices and demand for Continental electricity and gas.

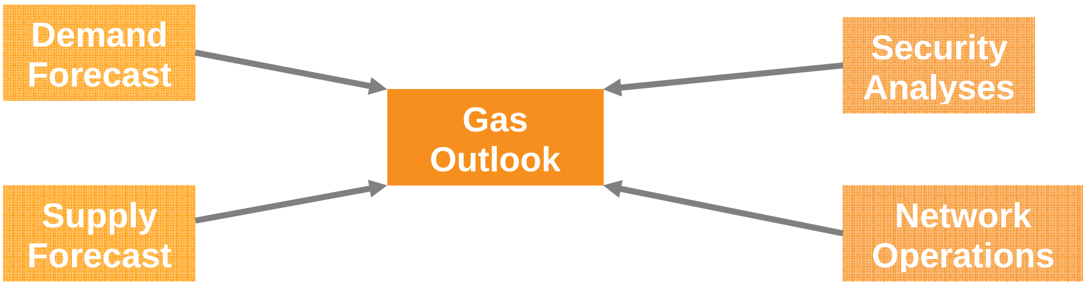
Figure F3 – Relative power generation economics (2)



17. The chart shows how the forward prices for winter 2012/13 strongly favour coal burn over gas. For gas and coal to be equitable the gas price for winter 2012/13 needs to fall by about 40% or around 30p/therm, alternatively there needs to be a further increase in the coal price by about $80/tonne.

18. Whilst the price of coal and gas are influential in terms of power generation, other factors such as running hours for LCPD, plant availability and generation portfolios will also influence fuel choice.

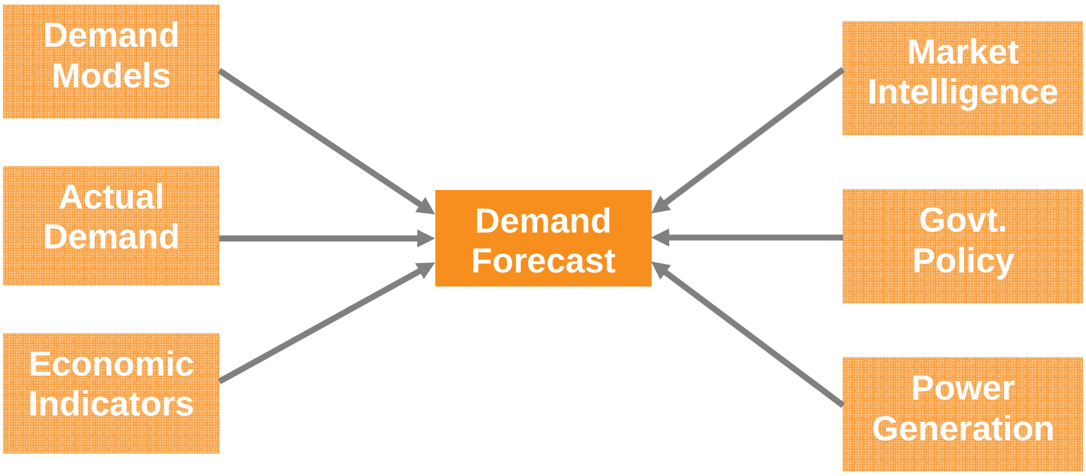
Gas



Overview

19. This chapter covers the gas supply-demand outlook for the winter 2012/13 together with an update on the Safety Monitors, an operational perspective and provision of new NTS capacity.

Demand Forecast

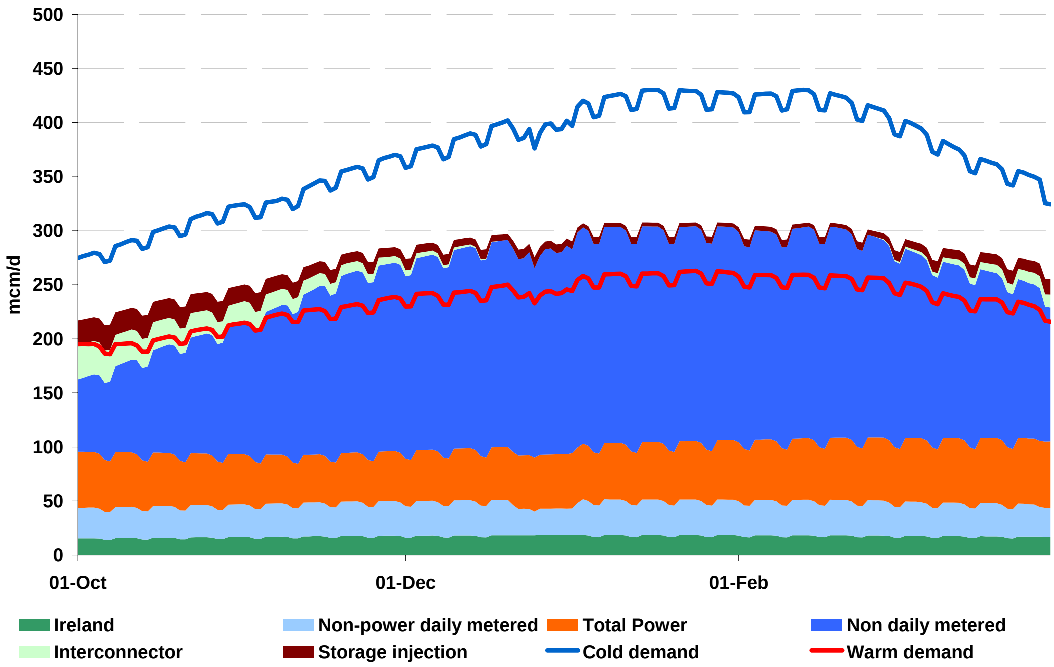


20. The demand forecasts presented in this document are essentially the same as those reported in the Winter Consultation.

21. The 2012/13 winter demand forecasts are similar to the 2011/12 weather corrected demands except for IUK exports and storage injection. Gas for power generation is forecast to be the marginal generation in 2012/13 with demands similar to 2011/12.

22. **Figure G1** shows the forecast gas demand profile for winter 2012/13 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 G1 - Forecast gas demand profile - winter 2012/13

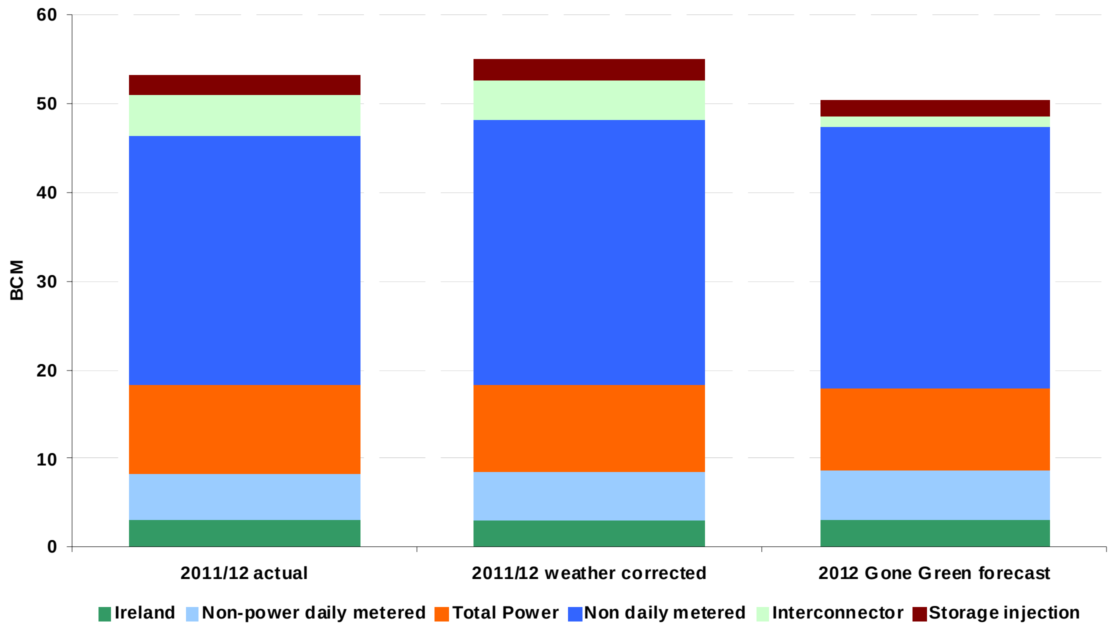


23. The chart shows seasonal normal demand peaking at about 300 mcm/d. In reality, peak winter demands will be appreciably higher than this, as for much of the winter, temperatures can be expected to be colder than seasonal normal temperatures.

24. **Figure G2** shows the actual and weather corrected demand[8] for last winter and also the 2012 Gone Green forecast demand for winter 2012/13. The 2012 Gone Green forecast is used rather than our 2012 Slow Progression forecast as Gone Green assumes gas as the marginal source for power generation whilst Slow Progression assumes gas at base load.

[8] Weather corrected demand removes the effect of weather on actual demand to produce the demand that would have occurred if the weather had been seasonal normal.

Figure G2 - Forecast total gas demand - October 2012 to March 2013



25. The chart shows:

- The impact of weather correction on the 2011/12 NDM demand
- Little difference between weather corrected 2011/12 and the winter forecast for 2012/13. The only noticeable difference being the forecasts for IUK exports and storage injection. These are subject to considerable uncertainty.

26. **Table G1** shows the historic actual and weather corrected demand for winters 2009/10 through to 2011/12 and the forecast for winter 2012/13.

Table G1 - Forecast total gas demand- October 2012 to March 2013

October to March winter	2009/10		2010/11		2011/12		2012/13
bcm	actual	weather corrected	actual	weather corrected	actual	weather corrected	forecast
NDM	33.6	32.0	34.2	31.4	28.2	29.9	29.4
DM + Industrial	6.0	5.9	5.8	5.8	5.3	5.3	5.5
Ireland	3.6	3.6	3.6	3.6	3.0	3.1	3.1
Total Power	16.6	16.6	12.5	12.4	9.9	9.9	9.3
Total demand	**60.5**	**58.9**	**56.6**	**53.7**	**46.7**	**48.4**	**47.7**
IUK export	1.1	1.1	2.1	2.1	4.4	4.4	1.4
Storage injection	1.2	1.2	1.8	1.8	2.3	2.3	1.8
GB Total	**62.8**	**61.2**	**60.5**	**57.6**	**53.5**	**55.2**	**50.9**

27. On a weather corrected basis, the table shows some decline in all sectors except IUK exports and storage injection. Power generation continues to fall due to fuel prices continuing to favour coal generation over gas.

28. **Table G2** shows the daily average demand for last winter and the forecast demand for winter 2012/13. The table also shows the actual range of demand experienced last winter and a forecast range.

29. The low forecast range for weather sensitive loads is based on a very warm early October[9] day, with Ireland, IUK and storage based on historic data and power on our low gas scenario.

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

Table G2 - Forecast daily gas demand - October 2012 to March 2013

October to March winter	Daily average			Actual range		Forecast range	
mcm/d	2011/12 actual	2011/12 weather corrected	2012 forecast	2011/12 low	2011/12 high	2012/13 low	2012/13 high
NDM	154	163	162	35[10]	277	35	344
DM + Industrial	29	29	30	19	35	19	45
Ireland	17	17	17	12	23	12	30
Total Power	54	54	51	35	81	35	95
Total demand	255	265	262	156	401	132	516
IUK export	24	24	8	2	58	0	60
Storage injection	13	13	9	0	60	0	60
GB Total[11]	**292**	**302**	**278**	**209**	**421**	**150**	**516**

31. **Table G3** shows a similar table to **Table G2** but is based on the mid-winter months of December to February.

[9] For the December to February range in Table G6, the very warm day applies to early December

[10] This demand occurred on 1st October 2011 which was an exceptionally warm Saturday with temperatures reaching almost 30°C in Kent.

[11] Totals may not add up due to diversity for example at low demand some IUK exports and storage injection would be expected

Table G3 – Forecast daily gas demand – December 2012 to February 2013

December to February winter	Daily average			Actual range		Forecast range	
mcm/d	2011/12 actual	2011/12 weather corrected	2012 forecast	2011/12 low	2011/12 high	2012/13 low	2012/13 high
NDM	195	196	190	130	277	125	344
DM + Industrial	30	30	31	19	35	19	45
Ireland	17	17	18	12	23	12	30
Total Power	51	51	52	35	71	35	95
Total demand	295	295	292	205	401	200	516
IUK export	15	15	1	2	28	0	30
Storage injection	10	10	2	0	45	0	45
GB Total	**320**	**320**	**295**	**238**	**421**	**235**	**516**

32. 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.

33. **Figure G3** and **Table G4** show the highest day of demand in winter 2010/11[12] and the 1 in 20 peak day demand[13] forecasts for winter 2012/13. The biggest difference in the demands is through the accounting methodology for power generation and to a lesser extent Ireland.

[12] December 20th 2010 was very close to the highest ever demand day of 465.46 mcm.
[13] Diversified demand is the demand that could be expected for the whole country on a very cold day. This is the definition normally used for 1 in 20 peak day demand. Undiversified demand is the sum of individual peak day forecasts for every LDZ and each NTS site. Obligated demand is the highest of baseline or sold capacity at each offtake.

Figure G3 - 1 in 20 peak day gas demand 2012/13

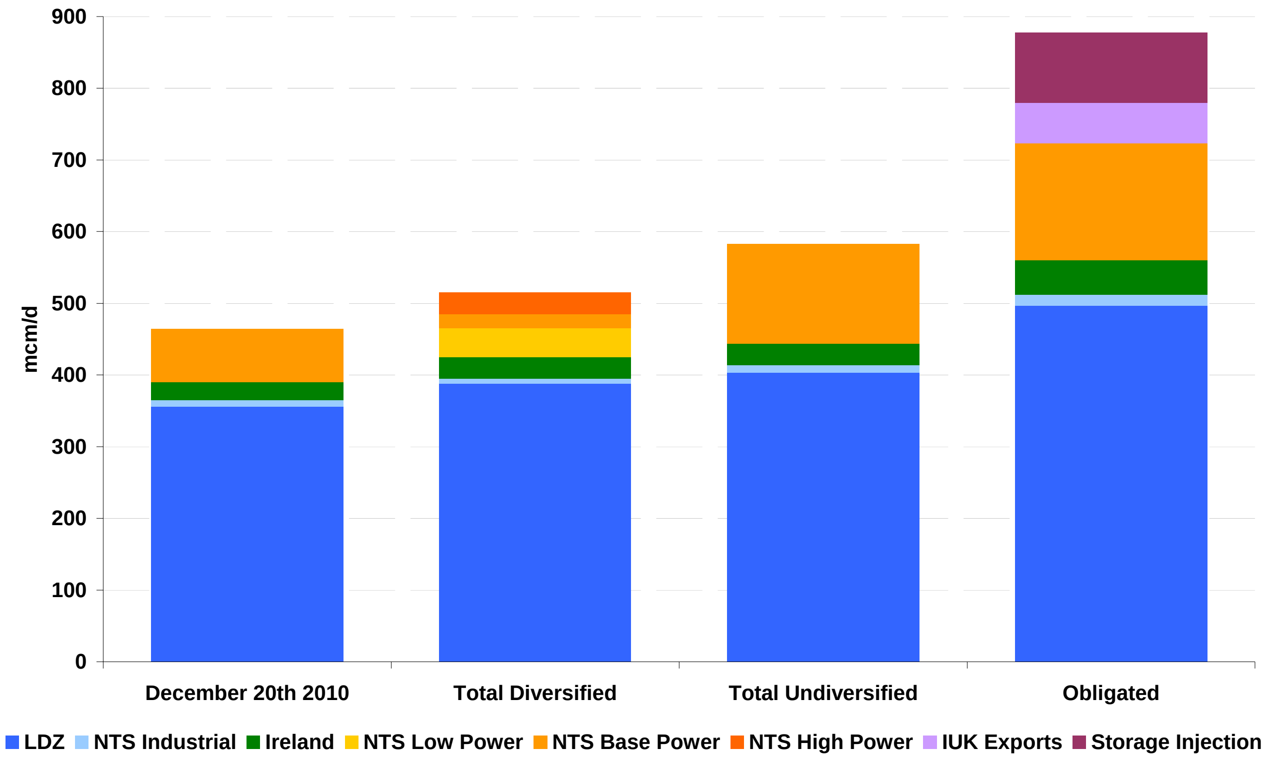


Table G4 – 1 in 20 peak day gas demand 2012/13[14]

	2012/13 Gone Green Forecast			
mcm/d	December 20th 2010	Total Diversified	Total Undiversified	Obligated
LDZ	356	388	403	497
NTS Industrial	9	7	11	15
Ireland	25	30[15]	30	48
NTS Power	74	90	139	163
IUK Exports	0	0	0	57
Storage Injection	0	0	0	98
Total	**465**	**516**	**583**	**878**

34. Due to the price assumptions, the Gone Green forecast for gas-fired power generation is relatively low. However for the 1 in 20 peak, the high case forecast for power

[14] Demand data can differ between different sources for a number of reasons including classification, CV and closeout date. Power generation classifications are: in tables G4 to G6 the LDZ connected power stations at Fife, Derwent, Shoreham, Barry, Severn Power and Fawley are included in the total power category but in G7 they are included in LDZ demand. Grangemouth and Winnington NTS offtakes are included in total power in G4 to G6 but NTS industrial in G7. Immingham and Shotton Paper are classified as NTS power stations for all 3 tables.

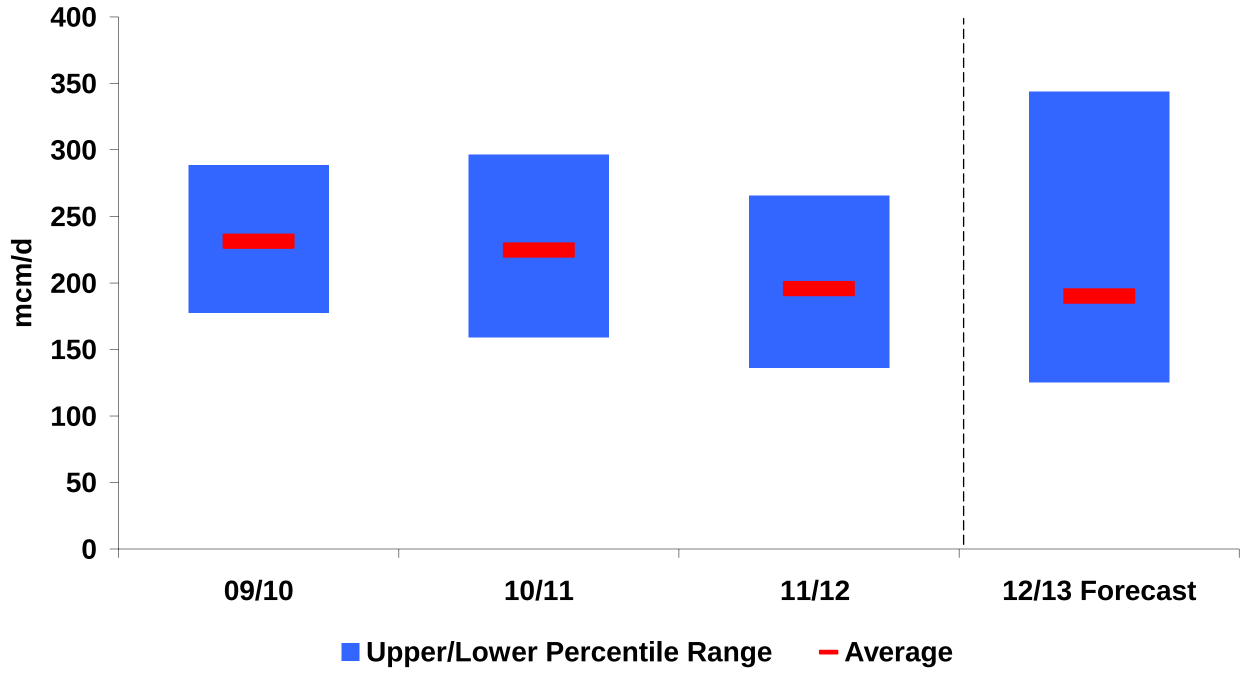
[15] The Ireland forecast has been increased from 22 in the Winter Consultation to 30 mcm. The original forecast did not adequately reflect the sharp upturn in demand in very cold weather.

generation is used to capture the possibility of increased demand. This is necessary for planning purposes and could materialise with lower availability of non-gas generation such as nuclear and wind and power exports to the Continent. For the 2012/13 Gone Green forecast, this increases the power generation component of the diversified peak day forecast by 30 mcm from 60 mcm to 90 mcm.

35. The Composite Weather Variable (CWV) formula to determine NDM peaks has recently been modified to adjust for the increase in demand in cold weather observed in the last 3 gas supply years. This adds 6% to the 2012/13 Gone Green LDZ peak demand forecast. This is partly offset by a 4% reduction in annual demand giving a net increase of 2% to the peak forecast.

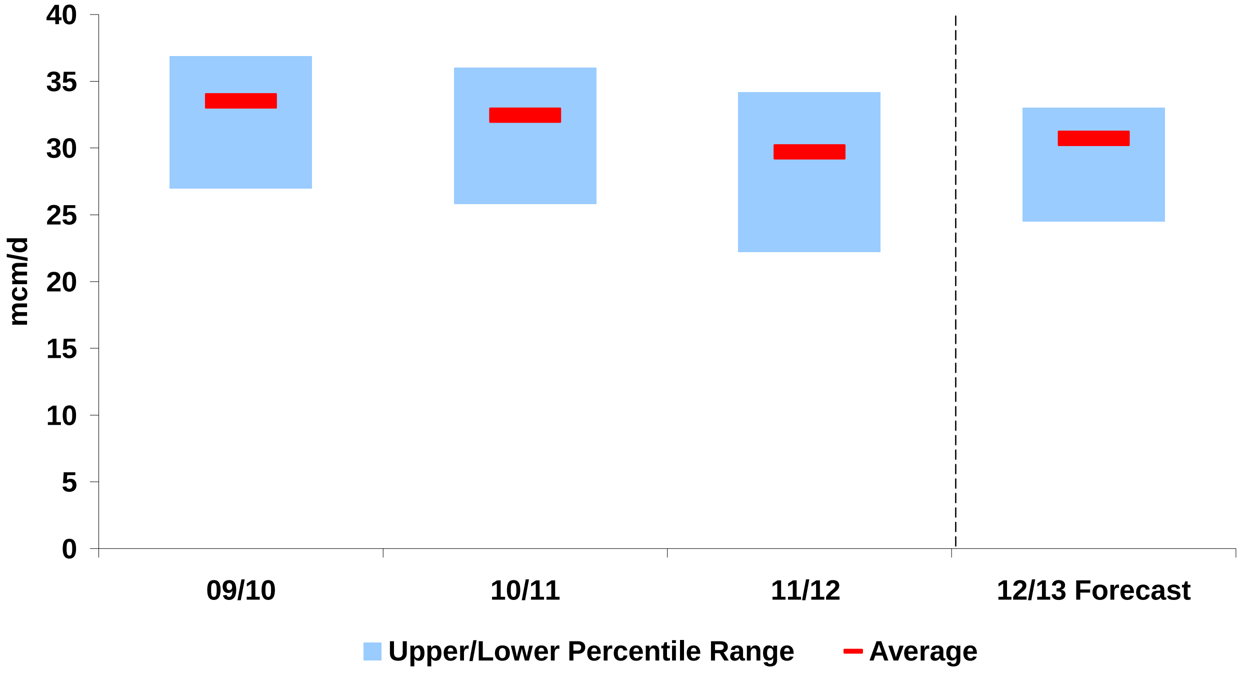
36. **Figures G4 to G7** show daily demand ranges for the 3 months from December to February for the last 3 winters compared to forecasts for December 2012 to February 2013. The historic data has not been weather corrected.

Figure G4 – NDM historic demand and 2012/13 forecast



37. The 2012/13 NDM average forecast is similar to 2011/12. The pronounced variation around this value is driven by the weather.

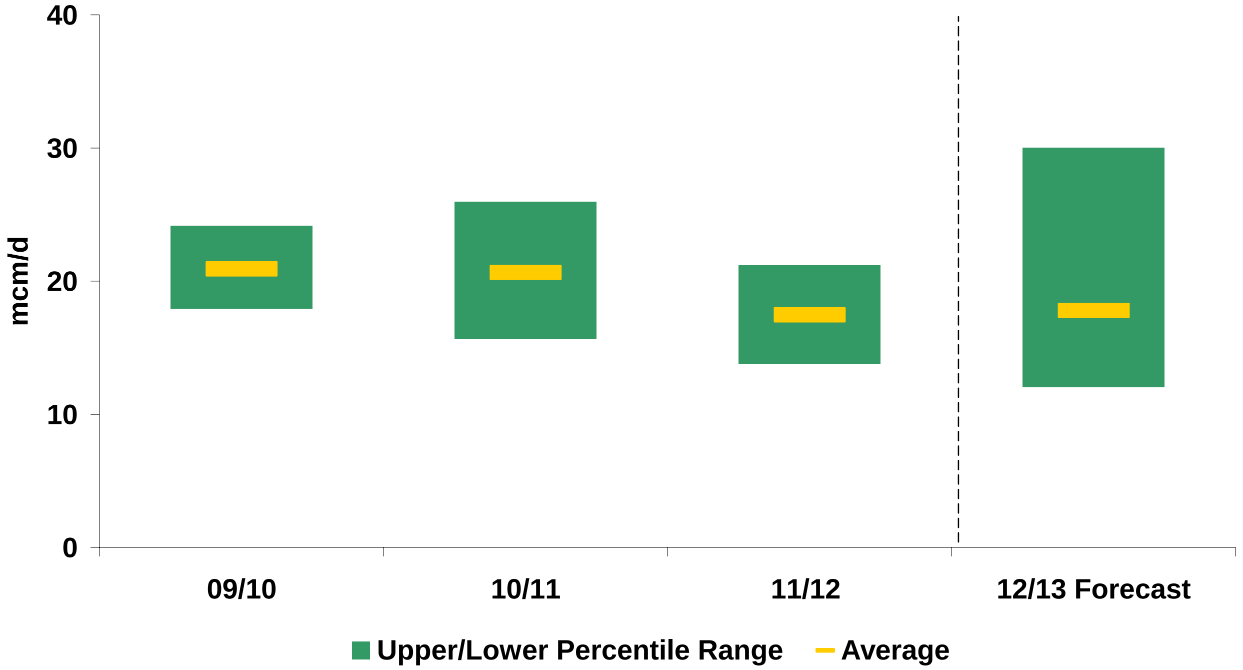
Figure G5 – Historic DM & industrial[16] demand and 2012/13 forecast



38. The non-power daily metered demand is expected to be similar to previous years.

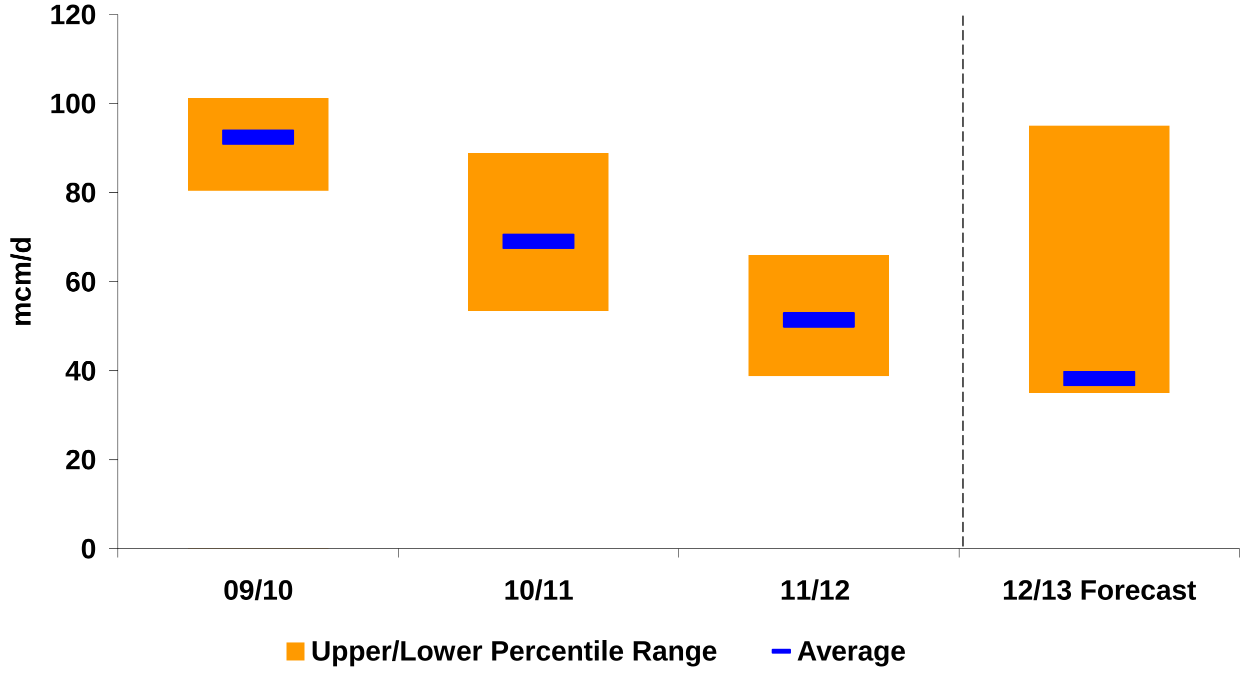
[16] Excludes power generation

Figure G6 – Historic Moffat exports and 2012/13 forecast



39. Exports through Moffat are predicted to be similar to last year although there is the potential for much higher exports should the need arise.

Figure G7 – Historic power generation demand and 2012/13 forecast



40. Power generation is expected to be lower than in 2011/12 but any shift towards favouring gas for power generation could increased demand towards 100 mcm/d.

Supply Forecast

41. This section briefly reviews the forecasts from last winter then 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 the winter. Our final view is influenced by our experience last winter and feedback through Future Energy Scenarios (FES) and Winter Consultations.

42. **Table G5** shows our 2011 Winter Outlook forecasts and various measures of non storage supply as experienced in winter 2011/12.

Table G5 – Winter 2011/12 non storage supplies by supply source

mcm/d	UKCS	Norway	BBL	IUK	LNG	Total
2011 Outlook Dec – Feb	119	96	30	8	80	333
Average Dec – Feb	111	102	28	0	44	285
2011 Outlook 400+ mcm/d	125	105	32	20	92	374
Highest day (each supply)	137	127	35	10	86	395
Highest day (total supplies)	106	113	29	0	79	327
Top 10	109	114	28	1	66	318
Top 100	113	103	25	0	49	290

43. The table shows two forecasts for non storage supply for last winter, namely forecasts for the coldest winter months (Dec – Feb) and for demand days above 400 mcm/d. Despite mild weather we did not change our forecasts during the winter as the forecasts were based on the possibility of higher demands.

44. The actual average forecast for Dec – Feb was just 285 mcm/d, by comparison winter 2010/11 was 334 mcm/d. In terms of the supply components used to meet this demand, the supply forecasts were all robust with the exception of LNG. For demand days above 400 mcm/d, the forecasts including those for LNG were good.

UKCS Gas Supplies

45. The data in the Winter Consultation provided an initial view of UKCS supplies based on 2012 FES forecasts and the most recent data regarding new UKCS developments. **Table G6** shows a final view of the UKCS supplies, these are little changed from the initial view.

Table G6 - 2012/13 UKCS maximum forecast by terminal

Peak (mcm/d)	2011/12		2012/13		
	Forecast	Outturn	Initial View	Final View	Changes
Bacton	51	53	38	38	
Barrow	11	11	9	10	+1
Burton Point	2	3	2	2	
Easington	9	10	14	14	
St Fergus[17]	41	42	38	38	
Teesside	20	20	25	25	
Theddlethorpe	13	12	11	11	
Total	**147**	**151**[18]	**137**	**138**	
90% Op. Forecast			123	124	

46. **Table G6** shows a provisional UKCS maximum supply forecast of 138 mcm/d for Winter 2012/13. This is 7% lower than the equivalent forecast for Winter 2011/12 and comparable to the highest flow of UKCS observed last winter of 137 mcm/d.

47. The forecast decline of 7% is typical of that observed in recent years. The decline would have been less as there are numerous new fields expected to come on stream during winter 2012/13, however these have been offset by our assumption of a limited contribution from Elgin Franklin.

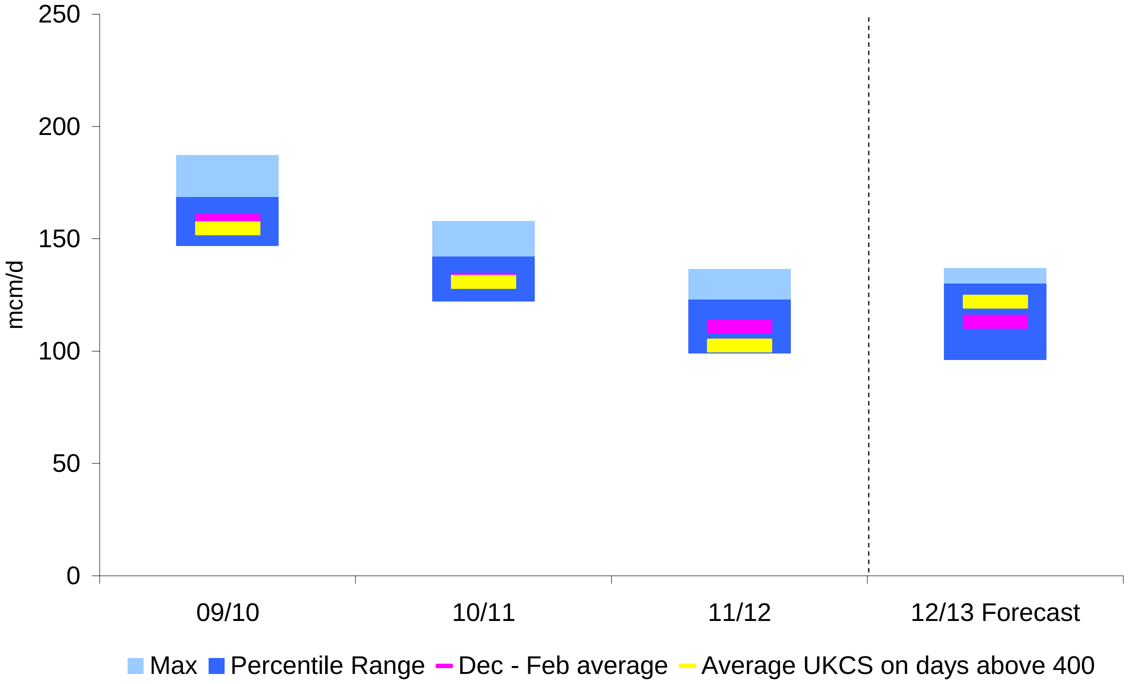
48. Our assessment of new UKCS developments coming on stream in 2012/13 total nearly 20 mcm/d, this is the highest in recent years. Most fields are expected to produce below 2 mcm/d, though Jasmine, Devenick, Clipper South and Breagh (over two years) exceed this.

49. 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 maximum UKCS planning assumption for winter 2012/13 of 122 mcm/d.

50. **Figure G8** shows historic UKCS flows for winters 2009/10 through to 2011/12, together with the winter forecast for 2012/13. The historic data is from the peak winter months of December to February, the range represents all but the highest and lowest 5% of flows i.e. the 5 – 95 percentile. Also shown is the average flow for all three months and the flows for all demand days when demand has exceeded 400 mcm/d.

[17] Excludes estimates for Vesterled and Tampen
[18] The outturn represents the highest day of flow at each terminal, in aggregate these exceed the highest daily UKCS flow in 2011/12 of 137 mcm/d

Figure G8 – UKCS historic flows and 2012/13 forecast



51. The chart shows very tight ranges for all winters, this illustrates the limited flexibility of UKCS supplies. The forecast for winter 2012/13 actually shows an increase compared to that observed last winter.

52. The 2012/13 forecast range for UKCS is shown as 96 to 137 mcm/d. The January to February winter average forecast is 113 mcm/d with a marginally higher forecast of 122 mcm/d for when demands exceed 400 mcm/d.

Norwegian Imports

53. 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.

54. In order to forecast Norwegian flows to the UK for winter 2012/13 an estimate of total Norwegian production is made. This estimate has not changed since the publication of the Winter Consultation.

55. The forecast for Norwegian production for winter 2012/13 is approximately 320 mcm/d. Flows to the UK are determined by difference from the net production and flow estimates for domestic use and flows to the Continent.

56. 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 2012/13 our forecast of Norwegian supplies to the UK is within a range from 70 to 115 mcm/d.

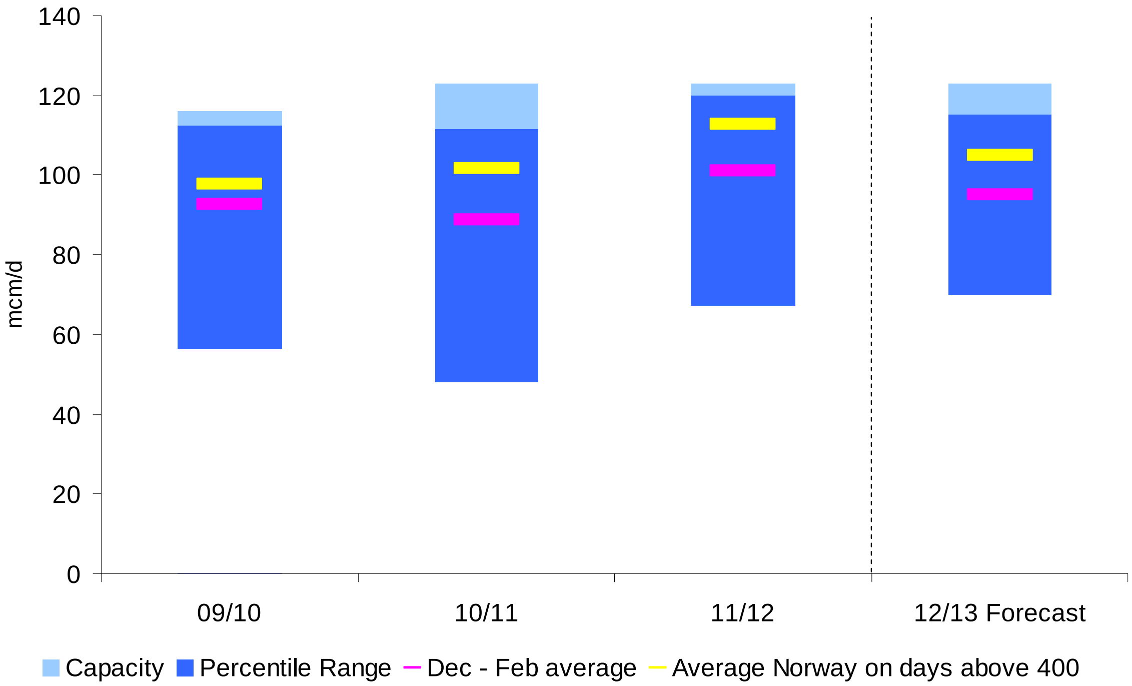
57. **Table G7** shows the forecast range of Norwegian exports for winter 2012/13. Also shown is a higher estimate of Norwegian flows for the mid-winter period to account for supply seasonality.

Table G7 – Winter 2012/13 estimates of Norwegian exports

(mcm/d)	High flows to Cont	Low flows to Cont	Central	Mid Winter	Capacity
Norway	*25*	*25*	*25*	*25*	
Belgium	40	35	37	40	41
France	50	45	48	50	52
Germany	135	100	120	130	151
UK	70	115	90	95	124
Total	**320**	**320**	**320**	**340**	**368**

58. **Figure G9** shows historic Norwegian flows for winters 2009/10 through to 2011/12, together with the winter forecast for 2012/13 and the capacity for Norwegian exports to the UK.

Figure G9 – Norwegian historic flows and 2012/13 forecast



59. The chart shows the impact of the supply losses in winters 2009/10 and 2010/11 with a tighter range for winter 2011/12. Last winter Norwegian imports to the UK increased for demands over 400 mcm/d exceeding our forecast of 105 mcm/d averaging 113 mcm/d.

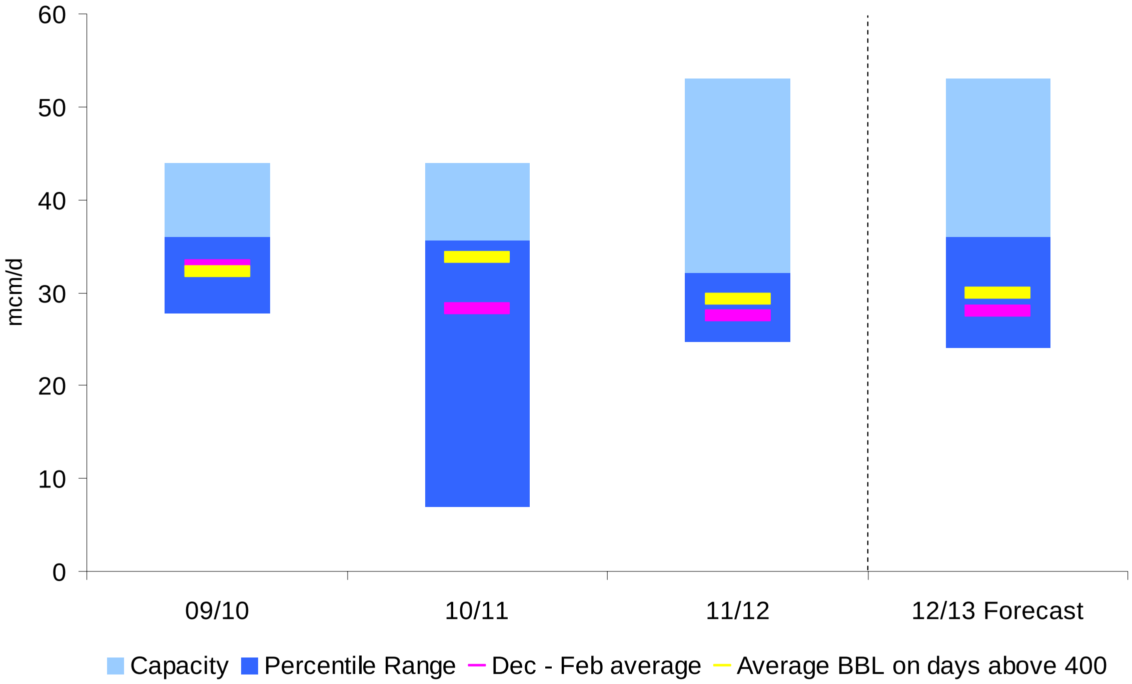
60. The 2012/13 forecast range for Norway is shown as 70 to 115 mcm/d. The December to February winter average forecast is 95 mcm/d with a higher forecast of 105 mcm/d for when demands exceed 400 mcm/d.

Continental Imports – BBL

61. Winter consultation feedback on BBL flows for winter 2012/13 was broadly supportive of similar flows to those experienced last winter, with relatively stable flows for most of the winter but showing increased responsiveness to Continental markets.

62. **Figure G10** shows historic BBL flows for winters 2009/10 through to 2011/12, together with the winter forecast for 2012/13 and the capacity for BBL.

Figure G10 – BBL historic flows and 2012/13 forecast



63. The chart shows that despite the increase in BBL capacity for last winter overall flows were lower than in previous winters. This was partly due to relatively low UK demands but also may have been due to increased use of the commercial reverse flows.

64. The 2012/13 forecast range for BBL is shown as 24 to 36 mcm/d. The January to February winter average forecast is 28 mcm/d with a marginally higher forecast of 30 mcm/d for when demands exceed 400 mcm/d.

Continental Imports – IUK

65. Winter Consultation feedback on the potential IUK imports was supportive of the view that IUK was a flexible / marginal source of supply responsive to market dynamics.

66. Last winter as in most previous winters, IUK imports responded to numerous factors, these included:

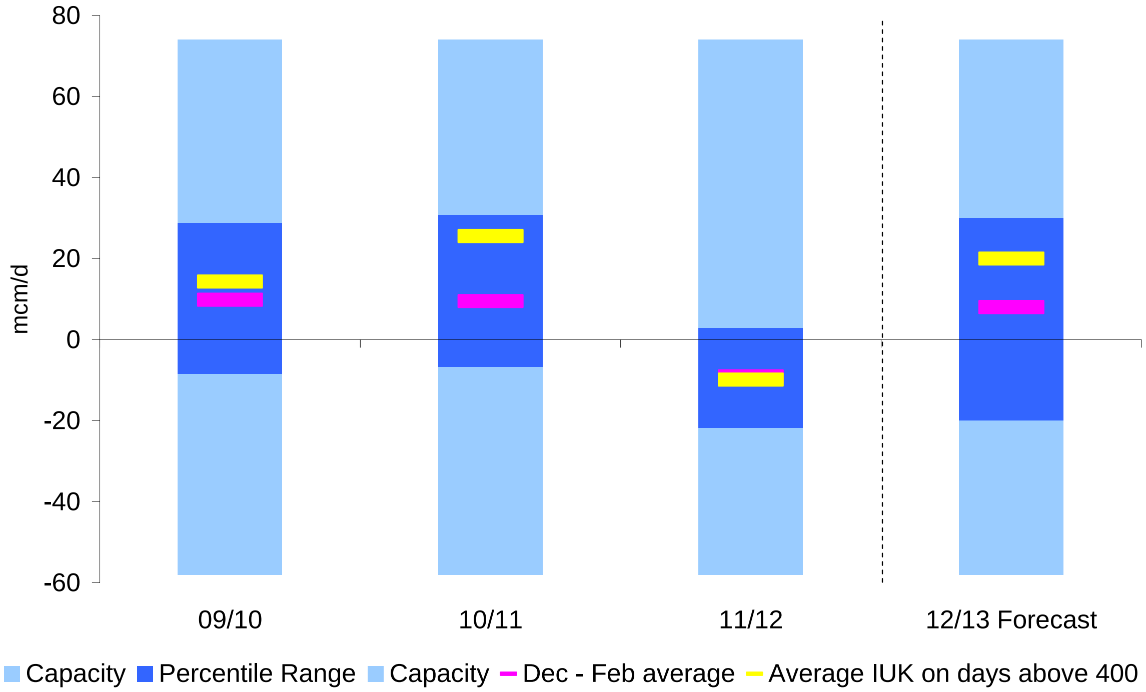
- Gas price
- UK demand
- Continental Demand

- Availability or rather non-availability of other non-storage supplies
- Storage flows / stocks

67. For winter 2012/13 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.

68. **Figure G11** shows historic IUK flows for winters 2009/10 through to 2011/12, together with the winter forecast for 2012/13 and the capacity for UK imports.

Figure G11 – IUK historic flows and 2012/13 forecast



69. The chart shows broad ranges for winters 2009/10 and 2010/11 from 0 to about 30 mcm/d. The upper range is much lower than the capacity of 74 mcm/d. Last winter IUK was in export mode for the majority of the winter with only 9 days of imports, this was largely due to the depressed demands associated with mild weather along with a well supplied UK market.

70. The 2012/13 forecast range for IUK imports is shown as 0 to 30 mcm/d. The December to February winter average forecast is just 8 mcm/d with a higher forecast of 20 mcm/d for when demands exceed 400 mcm/d.

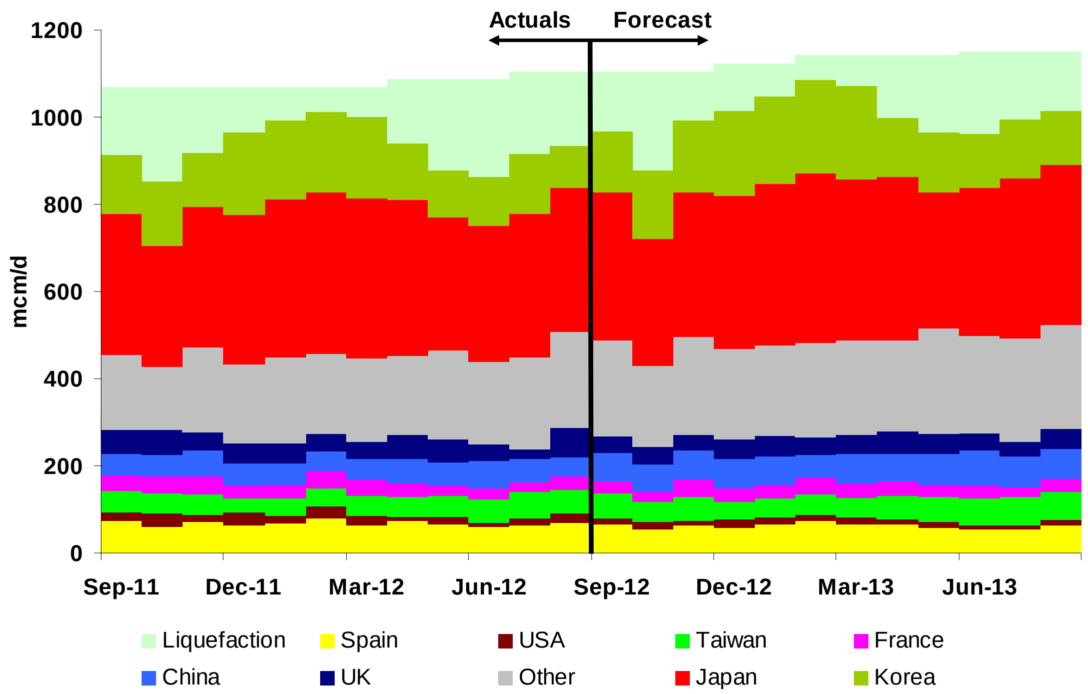
LNG Imports

71. Feedback from the Winter Consultation highlighted the continued uncertainty over LNG imports to the UK for winter 2012/13. Last winter the UK received lower levels of LNG than in winter 2010/11 and our view is that LNG imports will continued to remain suppressed due to high levels of LNG demand in the Far East, notably Japan.

72. **Figure G12** shows our internal analysis of LNG demand on a historic and forward basis, with liquefaction capacity shown in light green and global demand overlaid. The chart shows that despite additional LNG capacity brought on stream during 2012 the LNG market (on a global basis) may continue to remain tight over winter 2012/13.

Figure G12 – Global LNG supply / demand

Source: Lloyd's List, LNG Journal, National Grid

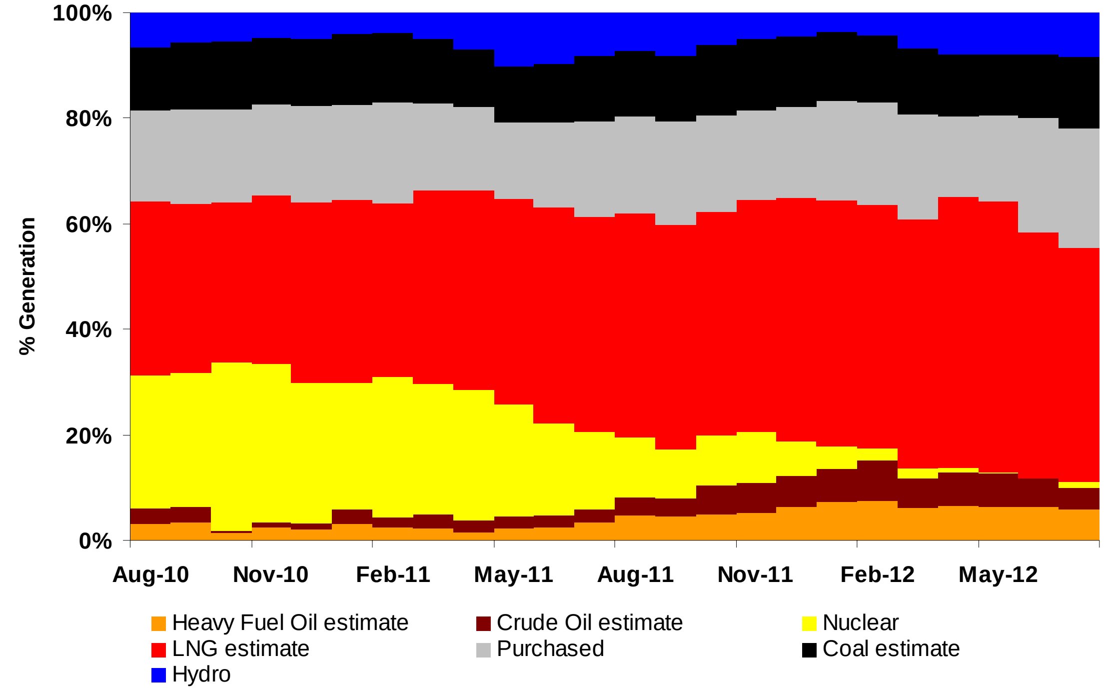


73. The chart shows an increase in LNG liquefaction capacity since last winter, with Australia's Pluto facility starting up last spring. The Angola project is expected before the end of 2012, while any new production in Algeria (Skikda / Arzew) may replace existing volumes rather than adding extra capacity.

74. In terms of LNG demand, the chart shows an overall year on year increase of around 5%, with Japan showing only modest growth as our analysis suggests that most CCGTs in Japan are running at high load factors. The growth in gas burn in the generation mix in Japan is shown in **Figure G13**.

Figure G13 – Estimated Japanese power generation mix

Source: Federation of Electrical Power Companies Japan (FEPC), National Grid



75. In July 2012, two Japanese nuclear power plants were restarted after all plants had previously been shutdown following the earthquake and tsunami in 2011.

76. The nuclear generation in July may have offset oil generation rather than LNG. We would expect this trend to continue with any more nuclear restarts offsetting oil generation before gas. However, further nuclear restarts remain uncertain and some reports state no more nuclear coming back online until next summer.

77. On a price basis, despite reports of some reductions, gas prices in Asian markets continue to be higher than those in Europe whilst US gas prices continue to be appreciably lower. In most instances traded LNG will tend to flow towards higher priced markets, however the cost of shipping and some need to maintain supply diversity should ensure that some LNG will continue to flow to the UK during winter 2013.

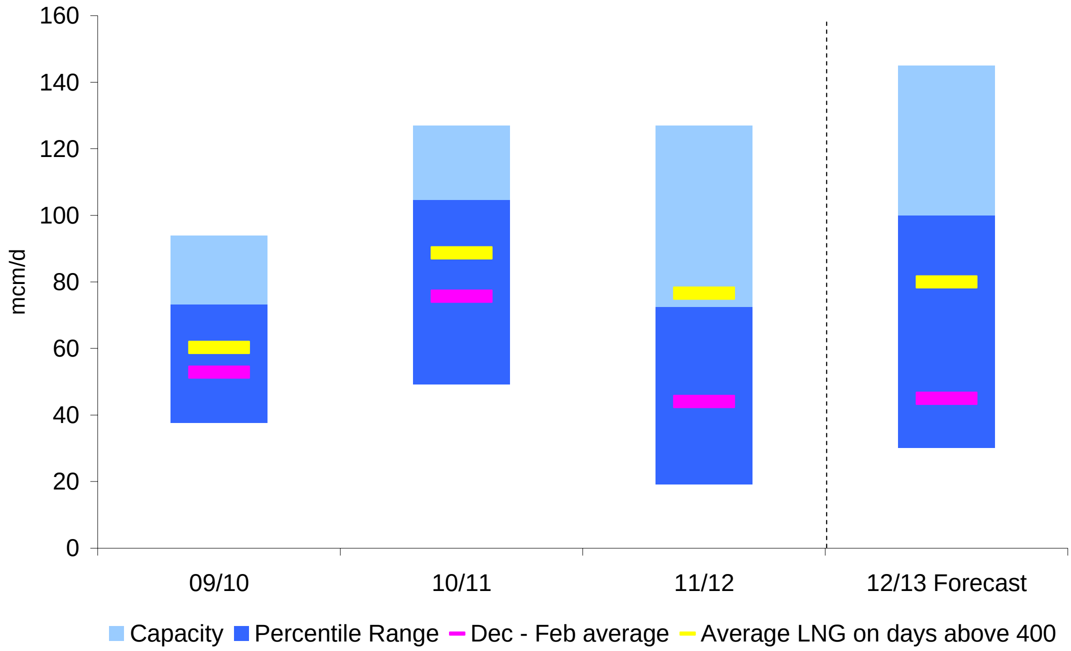
78. **Table G8** shows some factors which may support higher or lower LNG imports to the UK during winter 2012/13:

Table G8 – Factors affecting LNG imports to the UK

Higher LNG Imports	Lower LNG Imports
Increased overall global production	Commissioning delays to new facilities
Return of more nuclear generation in Japan	High global LNG demand, especially in the Far East
Potentially lower LNG demand in the US and Europe (Spain)	More LNG to nearby terminals Gate (Netherlands) or Zeebrugge (Belgium)
Increase in capacity at Milford Haven from ~68 to ~86 mcm/d (950 GWh/d).	Reduced production from existing facilities through for example unplanned maintenance or pipeline attack as in Yemen during August 2012
	Higher global LNG demand

79. **Figure G14** shows historic LNG imports for winters 2009/10 through to 2011/12 (ex. Teesport) together with the winter forecast for 2012/13. The historic data is from the peak winter months of December to February, the historic range represents all but the highest and lowest 5% of flows – i.e. the 5 – 95 percentile. Also shown is the average flow for the December to February periods and the average flows when demand exceeded 400 mcm/d.

Figure G14 – LNG historic flows and 2012/13 forecast



80. The chart highlights that LNG flows last winter were appreciably lower than in winter 2010/11. The chart also highlights how on the highest days of demand, there has been higher flows of LNG, including last winter.

81. Our forecasts for winter 2012/13 are primarily based on the experience from last winter. The forecasts also show a broad range of supplies to reflect the ongoing uncertainty in LNG supply.

82. In terms of LNG entry capacity, the Pressure Reduction Installation (PRI) at Tirley in Gloucestershire has now been commissioned, capacity at Milford Haven has now increased to 950 GWh/d.

83. Our LNG forecasts are based around flows through Milford Haven and Grain hence any flows of LNG imports through Teesside GasPort (about 11 mcm/d) provides an upside to the forecasts.

Storage

84. For winter 2012/13 extra storage capacity is expected to become available from the commissioning of Hill Top Farm.

85. In aggregate, storage deliverability for winter 2012/13 is 1186 GWh/d, which is slightly higher than last year's. This is mainly due to the start-up of Holford, and should increase further when Hill Top Farm is commissioned. This is expected to add a further 117 GWh/d and is expected to increase further in winter 2013/14.

86. In aggregate, storage space is higher than last winter due to an increased declaration for Rough, as well as extra space at Holford and Aldbrough. This should also increase with the start-up of Hill Top Farm.

87. **Table G9** shows our assumed levels of storage space and deliverability for winter 2012/13. Currently Rough is filled to around 98% and MRS to around 87%. This is broadly the same as last year, with most storage expected to be filled before the coldest winter months.

Table G9 – Assumed 2012/13 storage capacities and deliverability[19]

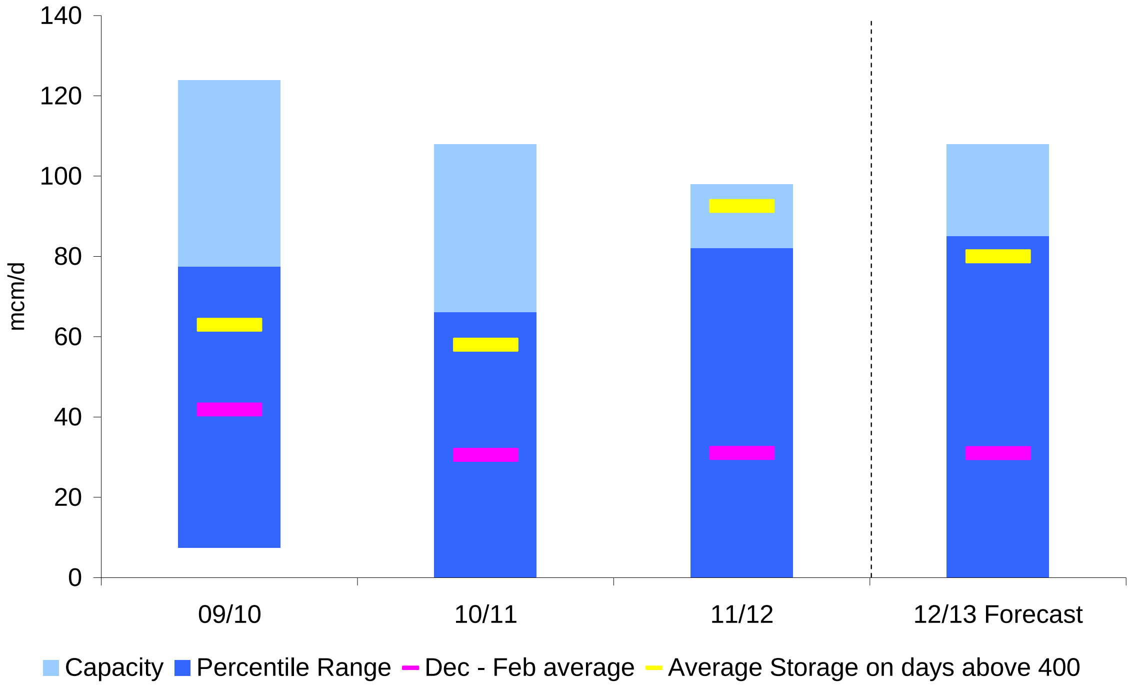
	Space (GWh)	Refill Rate (GWh/d)	Deliverability (GWh/d)	Deliverability (mcm/d)	Duration (Days)
Short (LNG)	300	2.5	143	13	2.1
Medium (MRS)	10665	608	558	51	19
Long (Rough)	40000	279	485	44	82
Total	**50965**	**889**	**1186**	**108**	
Total 2011/12	48944	632	1075	98	

88. As of early September, European storage has been filled to a slightly lower extent than the UK at 85% full. The reporting of European storage stocks[20] has further increased to 75.6 bcm of this, the UK's contribution is reported at 4.8 bcm.

[19] This table represents our operational assumptions and is based on proven performance. Reported deliverabilities may be different from 'name plate' capacities. Space includes 814GWh of Operating Margins and excludes Hill Top Farm, which will be added when operational. GWh to mcm conversions assumes a CV of 39.6 MJ/m^3.
[20] http://transparency.gie.eu.com/

89. **Figure G15** shows historic storage flows for winters 2009/10 through to 2011/12, together with the winter forecast for 2012/13 and changes to aggregated storage deliverability.

Figure G15 – Storage historic flows and 2012/13 forecast



90. The chart highlights many interesting features:

- An increase in storage deliverability for winter 2012/13 following recent declines (as reported in winter outlook publications)
- Across the winters relatively little change in the values for average flows
- The broad range of deliveries highlighting supply flexibility
- As to be expected, the higher level of supply at demands above 400 mcm/d (compared to the average for December to February) highlights the responsiveness of storage to higher demands. For last winter these were the highest on record due to the relatively few days of high demand

91. The forecast for winter 2012/13 is similar to last winter. The 2012/13 forecast range for storage is shown as 0 to 85 mcm/d. The December to February winter average forecast is 31 mcm/d with a higher forecast of 80 mcm/d for when demands exceed 400 mcm/d.

92. Flows from Hill Top Farm provide a further upside to the storage forecasts.

Final View of Supplies Winter 2012/13

93. The previous sub-sections outlined the basis for the assumptions incorporated into the forecasts. **Table G10** summarises the 2012/13 forecasts in terms of a supply range and our forecasts for December to February and for demands above 400 mcm/d. The table also compares these with the 2011/12 forecasts.

Table G10 – Final view of non storage supplies winter 2012/13

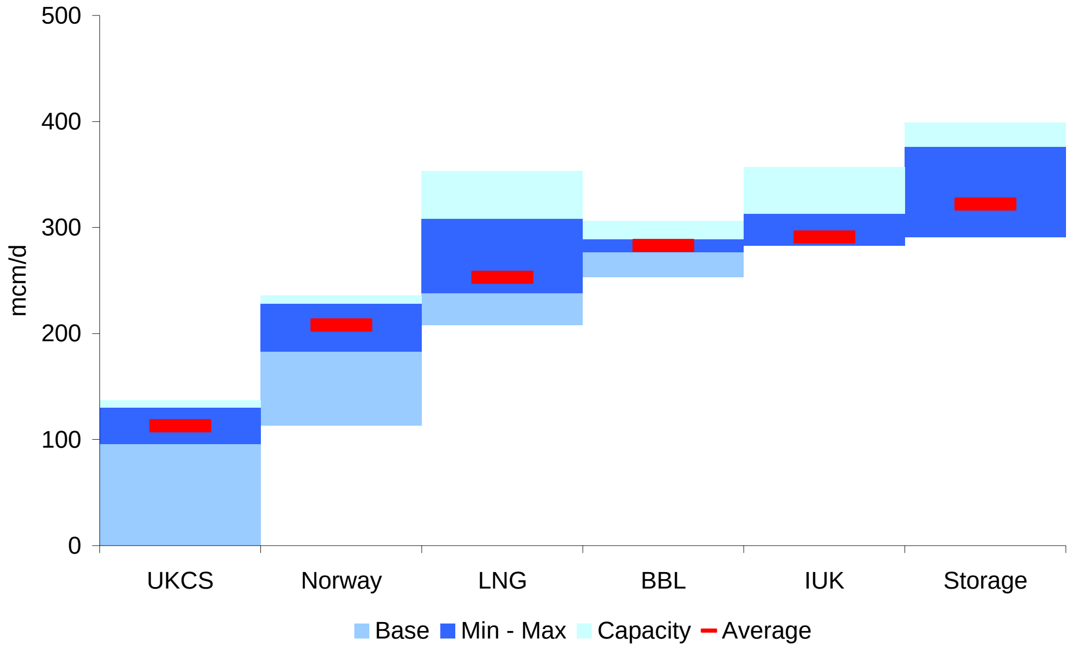
	2011/12		2012/13		
(mcm/d)	Range	400+	Range	Dec – Feb	400+[21]
UKCS	106 – 132	125	96 – 130	113	124
Norway	70 – 118	105	70 – 115	95	105
BBL	24 – 36	32	24 – 36	28	30
IUK	0 – 30	20	0 – 30	8	20
LNG Imports	50 – 110	92	30 – 100	45	80
Total	**250 – 426**	**374**	**220 – 411**	**289**	**359**
Storage[22]	2 – 74	65	0 – 108	31	80
Total inc. Storage	**252 - 500**	**439**	**220 - 519**	**320**	**439**

94. The table highlights some supply uncertainty in all components, notably for LNG, and to a lesser extent Norway and IUK. The supply forecasts for December to February and for when demands exceed 400 mcm/d form the basis for the initial setting of the GBA trigger level. As the winter progresses, all these values are subject to change based on operational performance and the expectation of the commercial availability of additional storage facilities.

95. **Figure G16** shows an assessment of average supplies for the December to February period as a supply stack. Each supply source is stacked at the level of the 'average' position. Theoretically each stack could commence at higher or lower positions.

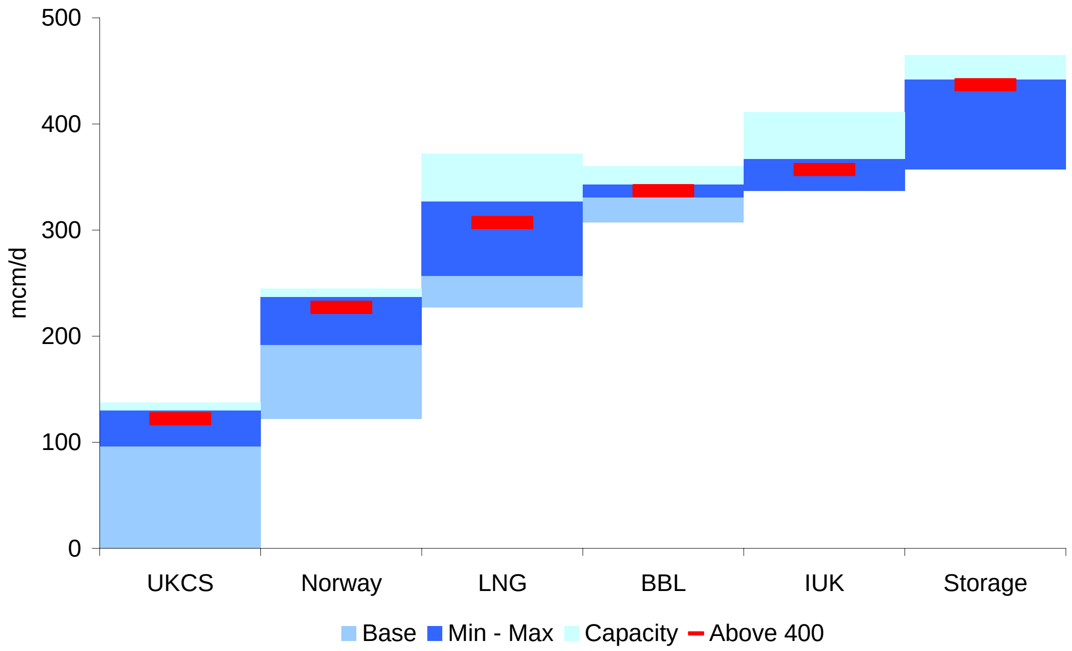
[21] The supply forecast for demands above 400 mcm/d represent typical flows for such demands, they do not represent a maximum
[22] Storage capacity is 108 mcm/d, lower values represent assessment of flows under stated conditions. Within winter this is expected to increase as new facilities are commissioned / proven

Figure G16 – Winter 2012/13 assessment for December to February



96. **Figure G17** shows an assessment of the supplies for when demand exceeds 400 mcm/d as a supply stack. Each supply source is stacked at the level of the '400 mcm/d' position. Theoretically each stack could commence at higher or lower positions to enable higher demands to be met.

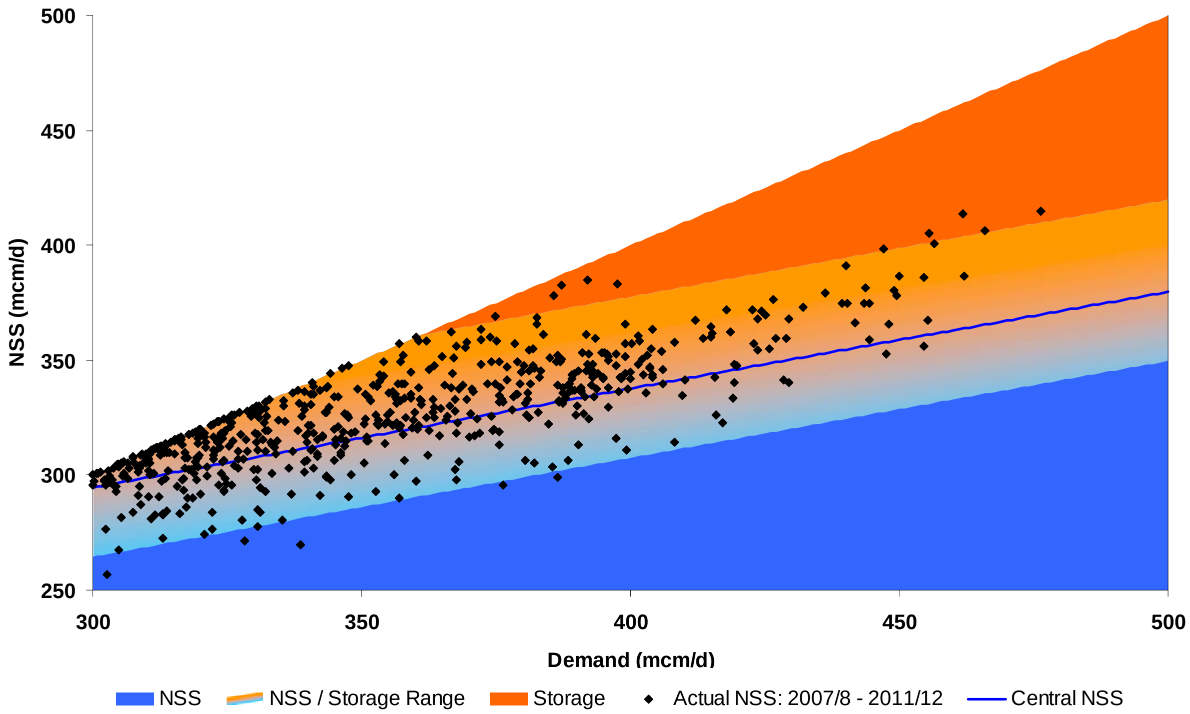
Figure G17 – Winter 2012/13 assessment for Demands above 400 mcm/d



Winter Security Assessment

97. **Figure G18** shows a simplified representation of how supply is forecast to meet demand in winter 2012/13. The data set to create this chart is from the past 5 winters with a weighting towards the most recent winters. The supply is broken down into three discreet areas, one of non storage supply (NSS), one of storage and an area in between where storage and NSS are both expected to contribute to some extent.

Figure G18 – Winter 2012/13 simplified representation of supply



98. The chart shows considerable variation in NSS, this is not surprising given the different winter conditions. In winter 2010/11, the level of NSS reached record levels in excess of 400 mcm/d as the headroom of capacity was utilised to a greater extent than in previous winters. Winter 2011/12 saw much lower demands with significantly lower NSS levels.

99. For winter 2012/13 there is considerable uncertainty regarding the level of individual supply components, most notably LNG. For the winter security assessment central view on NSS, we have used an NSS assumption based on a weighted rolling average of the last five years of NSS: this is shown by the blue line on chart above.

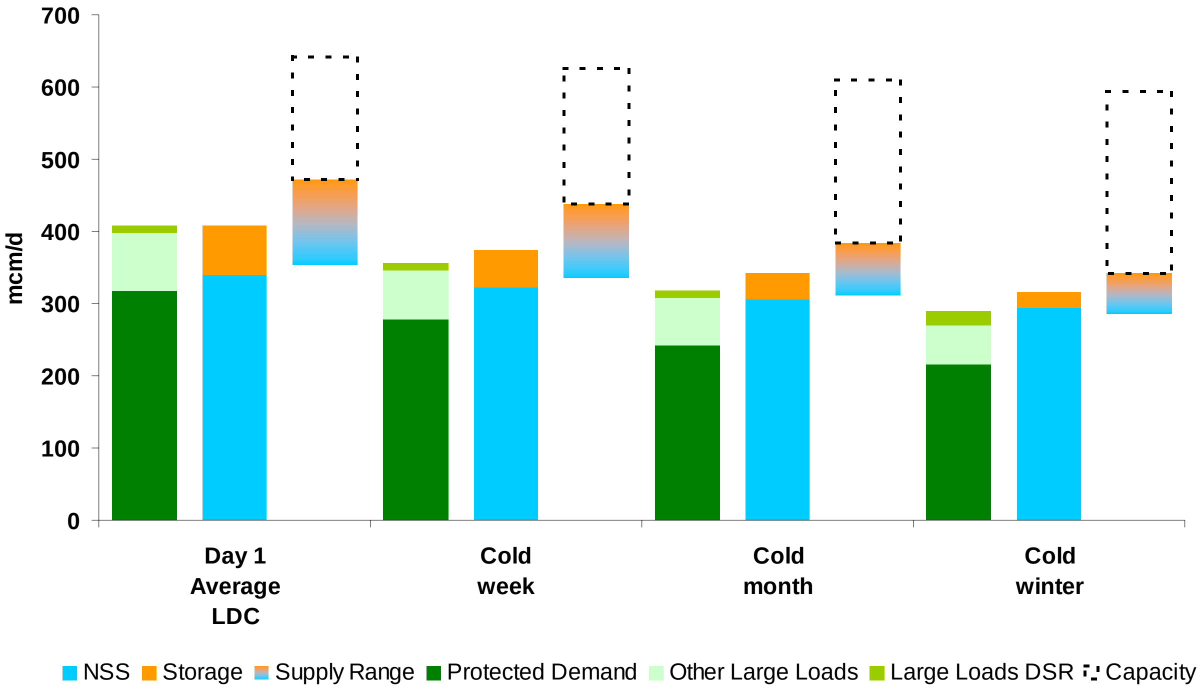
100. For the high and low NSS supply range for the winter security assessment, a range of an additional 40 mcm/d and a reduction of 30 mcm/d is assumed, as shown by the bottom of the orange area and the top of the blue area in the chart: this aligns well with the actual NSS supply range seen over the last five years.

101. For the safety monitor calculation, which has a focus on public safety, it is prudent to assume a level of NSS which will be available throughout the winter, notably at times of high demand, this is set at 95% of the blue line.

102. **Figure G19** shows a cold spell analysis for average demand conditions for 4 durations:

- The coldest day typically -2°C
- The coldest week of the winter at about 1°C
- The coldest month at about 3°C
- The coldest 3 months of the winter at about 5° C

Figure G19 – Cold spell analysis for average conditions



103. The chart shows 3 bars for each level of demand. The first bar shows demand as 3 components:

- Protected demand namely all loads protected by monitor in the Safety Monitor calculation. These demands include non daily metered (NDM), Ireland and priority customers
- Large loads that are not expected to respond to a short term increase in gas price. These are defined in the chart as ‘other large loads’
- Large loads that are expected to respond to a short term increase in the gas price and therefore provide a demand side response (DSR.) These are defined in the chart as ‘large loads DSR’

104. For all but the peak day (**Figure G20**) and cold winter (**Figures G19 & G20**), the DSR is shown as a range from 0 - 10 mcm/d, this is assumed to be primarily from large industrial loads. This is appreciably less than shown in previous years as little or no response is assumed from gas fired power stations as these are assumed as the marginal source of power generation rather than base load. Other generating

assumptions also limit the response, namely low wind (10%), relatively low nuclear availability (84%) and some electricity interconnector exports.

105. For the peak day a higher DSR of 0 – 30 mcm/d is shown as for the peak day the high case forecast for power generation is used to capture the possibility of increased demand. This is necessary for planning purposes and could materialise with lower availability of non-gas generation such as nuclear and wind and power exports to the Continent. Any DSR from power generation is not anticipated to significantly erode the power generation plant margin due to the within day profile of electricity demand i.e. gas plant could still be available for the within day electricity peak.

106. For a cold winter a higher DSR of 0 – 20 mcm/d is shown to reflect some increase in the DSR that may be possible away from the 'darkest' winter days when electricity demand tends to peak.

107. At certain times the DSR from gas fired power station may be higher, for example at weekends, away from the 'darkest' winter days and with higher availability of non gas generating plant. For each additional GW of non gas generating plant available, the DSR may increase by about 4.5 mcm/d. Though not shown an additional DSR for a limited time through use of distillate could be possible. Historically this was estimated at about 10 mcm/d but is anticipated to be less now due to a combination of closures / mothballing and operational factors.

108. The second bar represents supply shown as non storage supply (NSS) and storage as shown by the representation in **Figure G18** (central NSS line).

109. The third bar shows the range of supply for NSS (**Figure G18**) combined with an assessment of storage use. In addition this bar shows an estimate of the additional available capacity based primarily on import capacity and smaller contributions from UKCS and storage.

110. The wide range of the NSS and storage highlights the significant amount of supply flexibility that is available within the UK. Flexible supplies include storage, LNG imports, IUK and to a lesser extent Norway and BBL. The available capacity highlights there is further headroom to provide additional supplies if they are available.

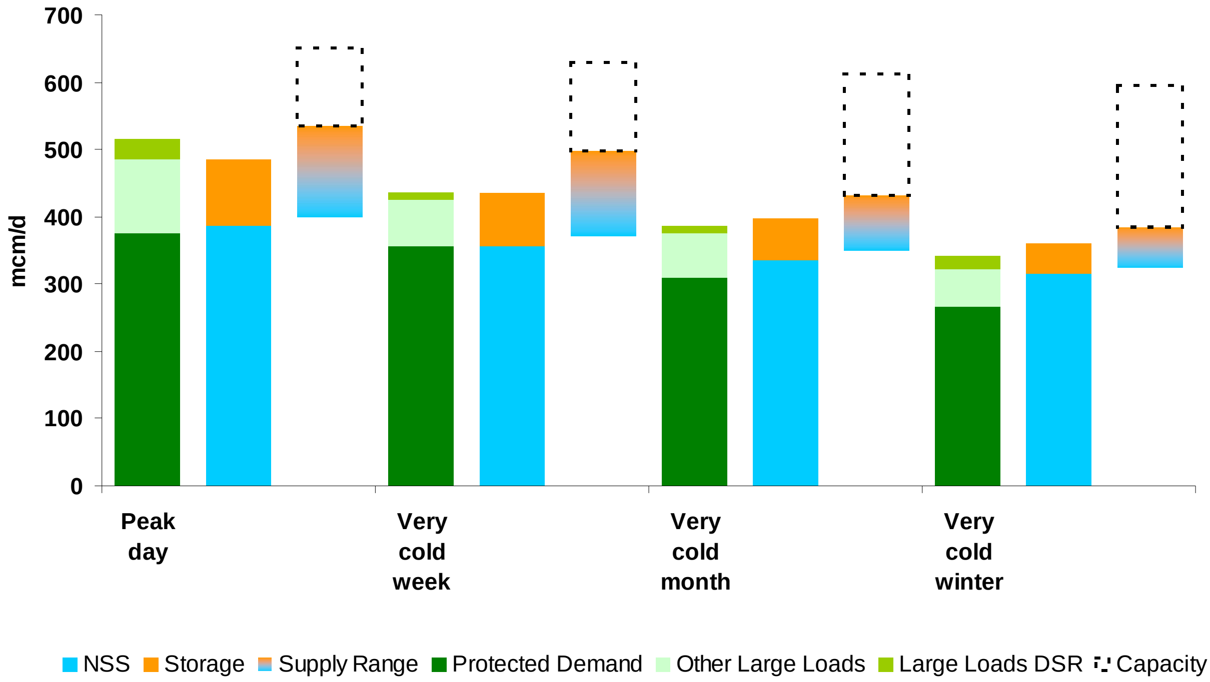
111. The analysis shows that for average conditions, all demand is met by central case supplies for all demand conditions evaluated.

112. Protected demand as defined in the Safety Monitors, is readily met by NSS for all demand conditions.

113. **Figure G20** shows a similar cold spell analysis for **severe**[23] demand conditions:

- The peak day[24] (1 in 20), typically -5°C, also assumes high case for power generation
- The coldest week of the winter at about -3°C
- The coldest month at about -1°C
- The coldest 3 months of the winter at about 1.5°C

Figure G20 - Cold spell analysis for severe conditions



114. Apart from a 30 mcm/d requirement for either additional NSS or storage or an equivalent demand side response for a peak day, all demand could be met by the central case supply assumptions for all demand conditions evaluated. The wide range of the NSS and storage at peak and the potential for a modest demand side response indicates that a requirement for 30 mcm/d should in principle, be achievable.

115. Protected demand is met by NSS for all demand conditions.

Supply loss analysis

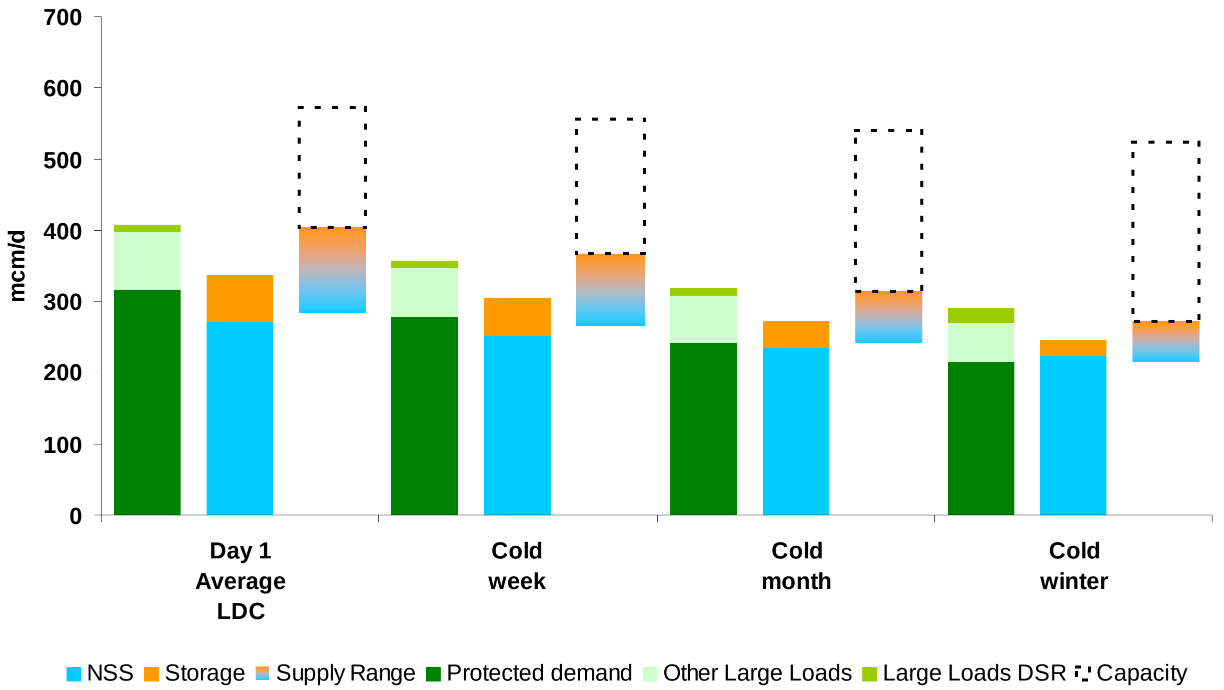
116. The analysis presented this year includes the impact of a 70 mcm/d supply loss within the cold spell analysis. The 70 mcm/d supply loss is shown as a reduction in

[23] Severe conditions are based on 1 in 50 demand conditions. For security analysis we use diversified demands.
[24] Peak day conditions are based on 1 in 20 demand conditions. A peak day does not always occur in a severe year. The coldest day in the last 80 years, January 13th 1987, was in a 1 in 3 cold winter.

NSS. The 70 mcm/d supply loss applies to the day, week, month and winter (3 month) periods, i.e. from a single day supply loss to a winter-long loss. A 70 mcm/d supply loss would be broadly consistent with the loss of the current largest source of imports, namely the Langeled pipeline or close to capacity of IUK.

117. **Figure G21** shows the cold spell analysis for average demand conditions and a 70 mcm/d supply loss.

Figure G21 – Cold spell analysis for avg. conditions and 70 mcm/d supply loss

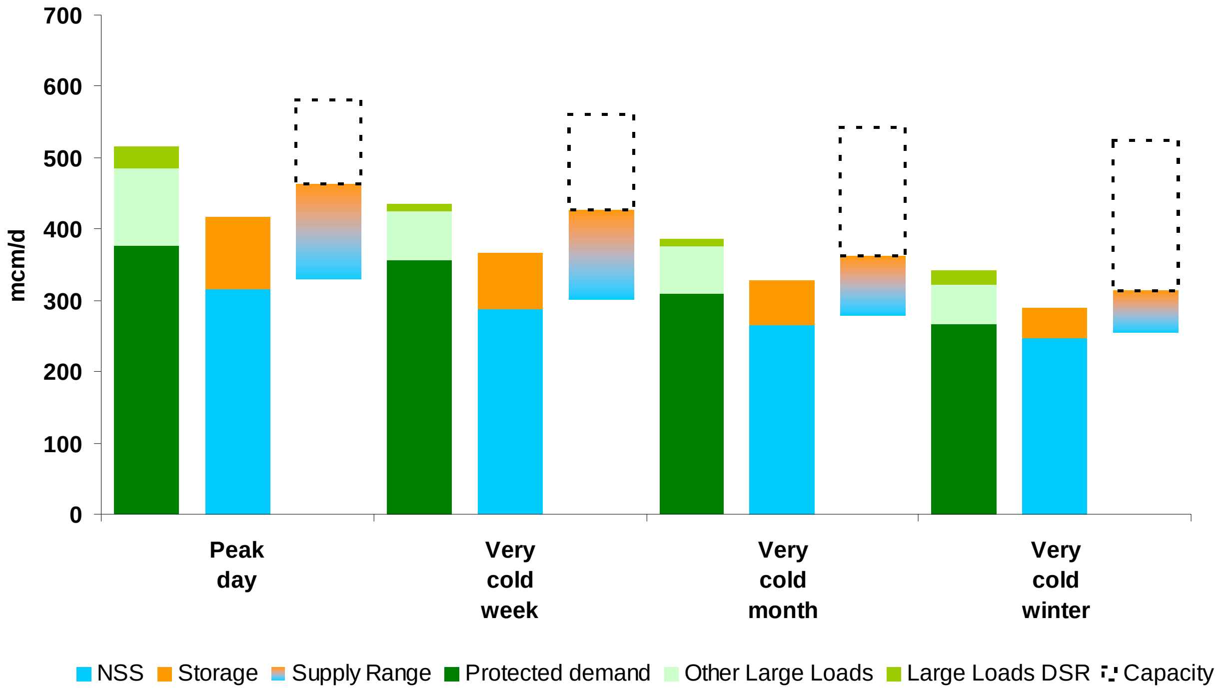


118. The resulting analysis shows a requirement for an increase in NSS and storage and potentially a demand side response, albeit for average conditions this may be modest.

119. Protected demand is met by central case NSS and storage for all demand conditions.

120. **Figure G22** shows the cold spell analysis for severe demand conditions and a 70 mcm/d supply loss.

Figure G22 – Cold spell analysis for sev. conditions and 70 mcm/d supply loss



121. As stated previously the peak day demand for 2012/13 of 516 mcm/d is much higher than that used in similar analysis last year due to an increase in the diversified peak day power generation forecast from 60 mcm/d to 90 mcm/d. This approach is considered necessary for network capacity considerations as there is a possibility of simultaneous high demand through extreme cold conditions and high gas demand for power generation.

122. For the peak day, the resulting analysis shows there is a requirement for an increase in NSS and storage and a demand side response. Even with these responses there may be a supply shortfall hence the remaining demand may not be met without a further demand response or further supplies from the available capacity.

123. With the utilisation of additional import capacity these findings are consistent with the UK's N-1 calculations where the UK's peak day demand can be met with the loss of any major supply. In the N-1 calculation all supplies are assumed at maximum import capacity rather than the lower levels assumed in these analyses. For example in the N-1 calculation, the combined potential flow from BBL and IUK is identified as 127 mcm/d compared to just 50 mcm/d or less in these analyses. This difference makes up the majority of the additional available capacity.

124. Protected demand is met by central case NSS and storage for all demand conditions.

Safety Monitors

125. On 2nd July 2012, the preliminary view of initial Safety Monitor levels was published for 2012/13 as required under the Uniform Network Code (Q5.2.1).

126. It is National Grid's responsibility to keep the monitor under review (both ahead of and throughout the winter) and to make adjustments if it is appropriate to do so. It

should be noted that the purpose of the Safety Monitors is to ensure an adequate pressure can be maintained in the network and thereby protecting public safety. It is therefore appropriate that a prudent approach is adopted in setting the Safety Monitor levels.

127. **Figure G18** shows the NSS versus demand assumption for winter 2012/13, based on an analysis of the last five winters. This continues the approach of using a variable NSS assumption which is demand dependent. This more accurately reflects the flexible supply options available within the UK. It is important that the assumed level of NSS used for calculating the Safety Monitors is available throughout the winter, notably at times of high demand. Hence in calculating the Safety Monitors, NSS at lower levels (95%) are used.

128. The current Safety Monitor methodology treats all storage types equitably, by grouping all storage types/facilities together such that there is only one aggregated monitor for space. Hence operational storage space is apportioned equitably across all storage sites, including those with high cycling rates.

129. There is one Safety Monitor for space and one Safety Monitor for deliverability. This provides greater clarity for market participants and operational decision making.

130. The resulting Safety Monitor levels for winter 2012/13 are detailed below. The combination of slightly lower NSS and higher levels of domestic demand (for cold conditions) are the primary drivers for the increase in the safety monitor requirement for next winter.

- 2012/13 Assumed storage space = 50965 GWh
- 2012/13 Safety Monitor space = 2359 GWh (4.6%), (2011/12 = 731 GWh)
- 2012/13 Safety Monitor deliverability = 672 GWh/d, (2011/12 = 518 GWh/d)

131. Safety Monitor levels and the associated winter profiles (i.e. how the monitors reduce later in the winter) will be published on or before 1st October 2012.

Operational Overview

Operational Challenges

132. The key operational challenges for winter 2012/13 continue to be around the set up and management of the National Transmission System (NTS) in an increasingly unpredictable supply and demand environment.

133. Supply sources have changed as UK Continental Shelf (UKCS) gas supplies have declined and imports increased. Total imports exceeded indigenous UKCS supplies for the first time in 2010/11.

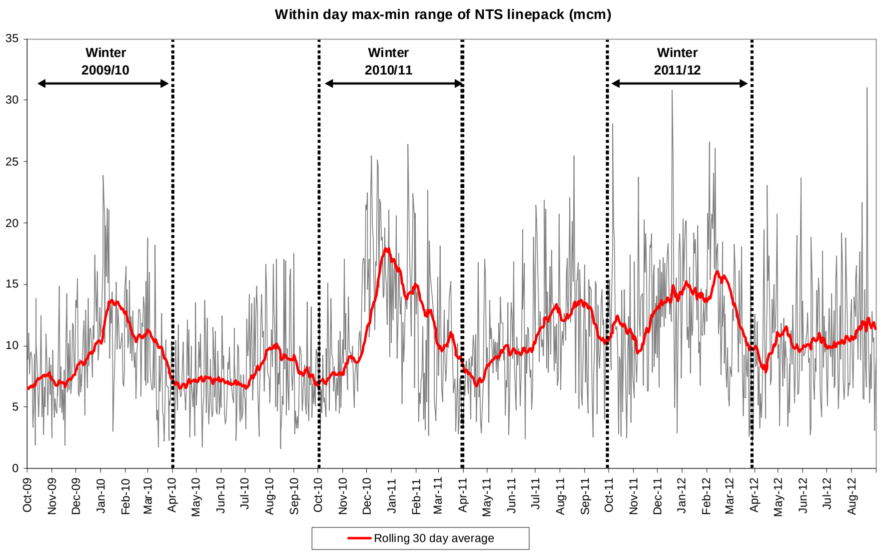
134. The re-distribution of UKCS and import sources, both in terms of flows and location, continues to drive a less predictable, more dynamic transmission operation with the requirement for more sophisticated physical and commercial planning. This assessment is necessary to meet statutory safety obligations for gas quality and pressure alongside the needs of our customers and wider market participants.

135. Comparison of the day to day capacity utilisation at terminals has highlighted a significant variation in supply to a far greater extent than we have traditionally

experienced for supplies that were predominately from the UKCS. These variations as shown in range charts (**Figures G8 – G11** and **G14 & G15**) are more noticeable for LNG, IUK, Norwegian imports and storage rather than for UKCS and BBL. These variations, have led to greater operational challenges, manifesting particularly with respect to the management of within day linepack and managing NTS pressures within safe and agreed operational tolerances.

136. **Figure G23** shows the magnitude of linepack variations over the past 3 years.

Figure G23 – NTS linepack variations 2009/10 – 2011/12



137. Large linepack reductions are caused when the demand from the network, exceeds the rate of supply entering the network. This usually occurs at the start of the gas day often as power demand increases (see **Figure G24**), supplies then tend to increase later on in the day, and as long as the rate of supplies is above demand, linepack recovers.

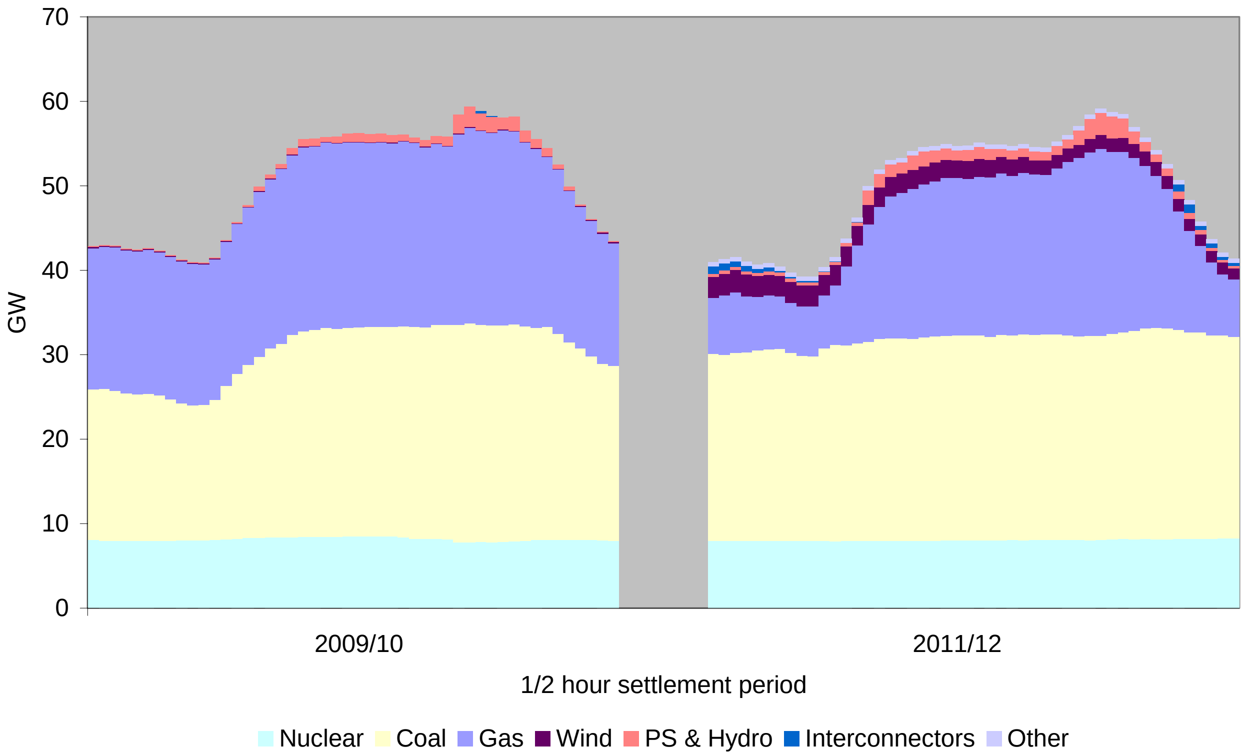
138. Large linepack variations increase the risk that commercial operations such as the release of discretionary capacity and meeting Offtake Capacity Statement (OCS) pressures are not met.

139. More importantly, linepack variations can impact physical safe control operations, for example by increasing the exposure to supply losses or impeding the capability of the network infrastructure to respond to such losses from other high rate ‘short notice’ facilities such as storage or other ‘flexible’ supplies.

140. There is also evidence of the market increasingly managing portfolios to balance at shorter periods and closer to end of day. Alongside the changes to the supply environment, the day to day demand volatility has also steadily increased over recent years. This has been driven by offtake profiles feeding the distribution networks and increasingly from gas fired power stations providing the within day electricity demand profile essentially from NTS linepack. This is illustrated in the following charts.

141. **Figure G24** shows the power generation sources (transmission) behind the daily electricity profiles for the two days of highest electricity demand for winters 2009/10 and 2011/12. These are shown for each ½ hour settlement period

Figure G24 – Power generation profiles for winter peaks 2009/10 & 2011/12



142. The chart shows, for both years, similar daily profiles of electricity demands and similar peaks of about 60 GW; however the power generation sources between the two years have some subtle and most important differences. Notably what sources of power generation provide the variation to meet the within day electricity demand profile.

143. The chart shows that in 2009/10 the within day variation or flexibility to meet the rapid changes in electricity demand in early morning and early evening was met by primarily coal (38%) and gas (35%) and a contribution from pumped storage and hydro (13%). For 2011/12 there is a material change with nearly all the within day flexibility being provided by gas (84%) rather than coal (4%). As in 2009/10 the contribution from pumped storage and hydro was 13%.

144. The values for 2011/12 actually exceed 100% as during the day the contribution from wind decreased from 2.6 to 1.3 GW providing a negative response in term of flexibility (-5%), hence the other sources of power generation had to provide additional flexibility to overcome the reduction in wind.

145. The primary reason why gas provided so much more flexibility in 2011/12 compared to 2009/10 is due to the relative fuel prices. In 2009/10 at the time (January 2010) of the highest electricity demand there was near parity in the spark spread and dark (both about £10/MWh), hence both fuels were competing on a similar basis. For

2011/12 (February 2012), there was a very strong bias towards coal burn over gas hence gas took the roll of the marginal source of generation. For the record, at the time of highest electricity demand in February 2012, the spark spread was around zero £/MWh and the dark spread as high as £30/MWh.

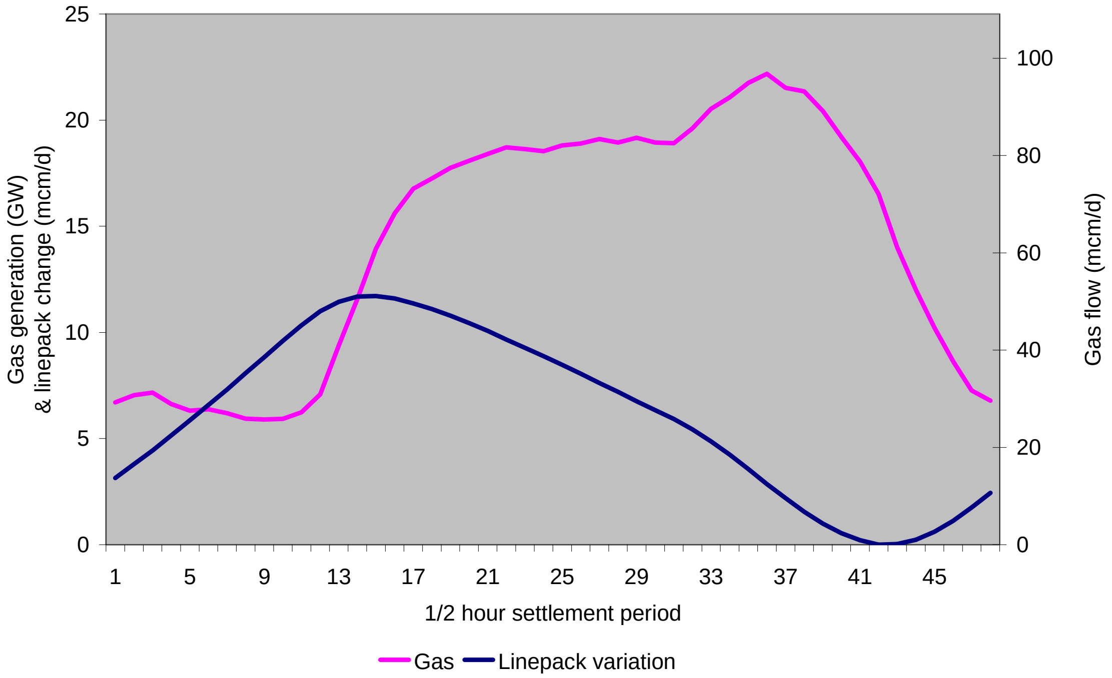
146. Another factor to identify with the gas profile in 2011/12 is the magnitude of the contribution of gas for the highest ½ hour at 22.2 GW. Across the day the average contribution was 14.3 GW and a lowest level of just 5.9 GW. The reported capacity of gas fired plant for winter 2011/12 was 30.5 GW, hence for the peak ½ hour, most (73%) of the gas generation capacity was used albeit with a tendency to meet only the periods of highest electricity demand.

147. The implications of most of the variable element of the daily electricity profile being supplied via gas are considerable:

- Despite being the marginal source of power generation most gas fired generation needs to be available at peak times to provide the electricity within day demand profile
- With gas as the marginal source of power generation, this profile is currently all provided via NTS linepack

148. **Figure G25** illustrates the implications for NTS linepack for last winter's highest day of electricity demand. As the entry profiles associated with variations in UK offtake demand are not consistent, NTS linepack provides essentially all of the flexibility to meet the daily changes in electricity demand.

Figure G25 – NTS linepack changes to meet 2011/12 peak generation profile



149. Across the day, the chart shows that the gas generation varied between about 6 and 22 GW, at an assumed generating efficiency of 50%, this equates to gas flows (on an equivalent daily basis) of from about 20 towards 100 mcm/d. The resulting maximum

within day change in linepack is approximately 12 mcm/d. This build up during the early hours of low electricity demand and falls away as electricity demand increases.

150. **Figure G23** shows linepack changes over the past 3 years, in 2012 the average daily variation has been typically 10-15 mcm/d within a broader range of 5-30 mcm/d. Hence the NTS linepack associated with providing most of the UK's within day electricity profile represents a significant portion of the total within day linepack variation.

151. For winter 2012/13 gas fired generation is expected to be the marginal source of power generation. Consequently gas is again expected to provide by far the largest contribution in terms of meeting the within day electricity profile, hence these trends of linepack variation are expected to continue.

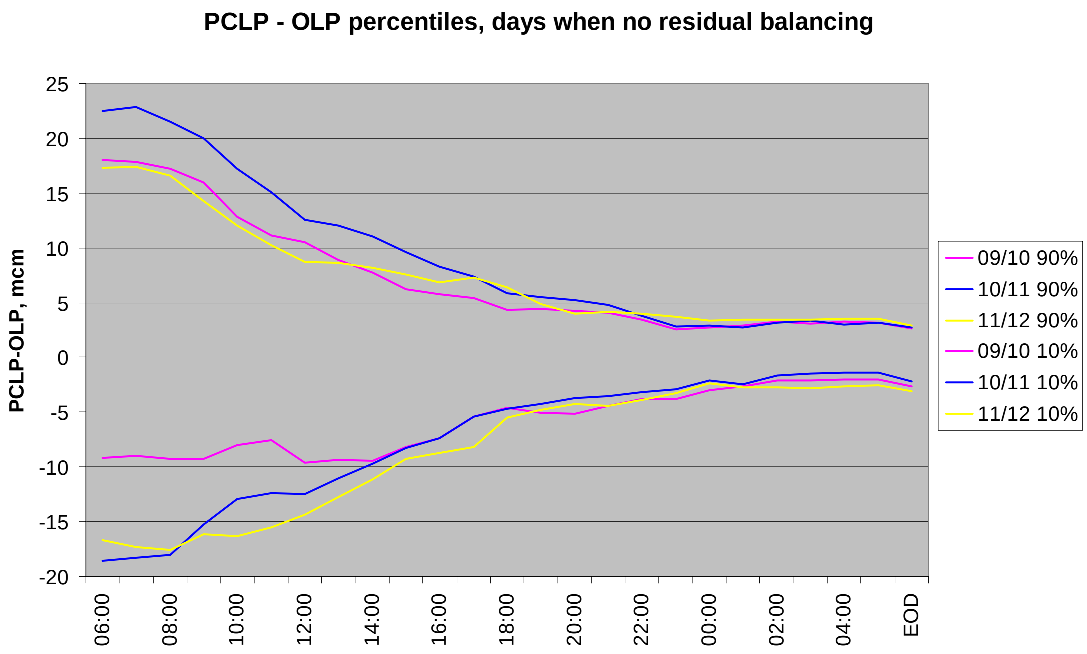
152. **Figure G24** shows that even now with modest levels of connected wind, variations in wind generation need to be accommodated, in the future with more wind, this will increase further. With gas fired power generation expected to provide cover for wind intermittency, there is an expectation of further obligations on NTS linepack.

153. Demand and supply volatility causes operational challenges and requires enhanced system operation capabilities and quick reconfiguration of the NTS to ensure gas supplies can be transported to the points of demand.

154. With shippers taking advantage of the increased capability for gas to be delivered (via LNG, storage etc) at short notice to meet balancing requirements, there has also been a notable trend towards later reconciliations of daily balance, with start of day offtake and flow notifications provided being less reflective of outturn flows.

155. This trend is highlighted in **Figure G26** in terms of Projected Closing Linepack (PCLP).

Figure G26 – Projected closing linepack (PCLP) changes

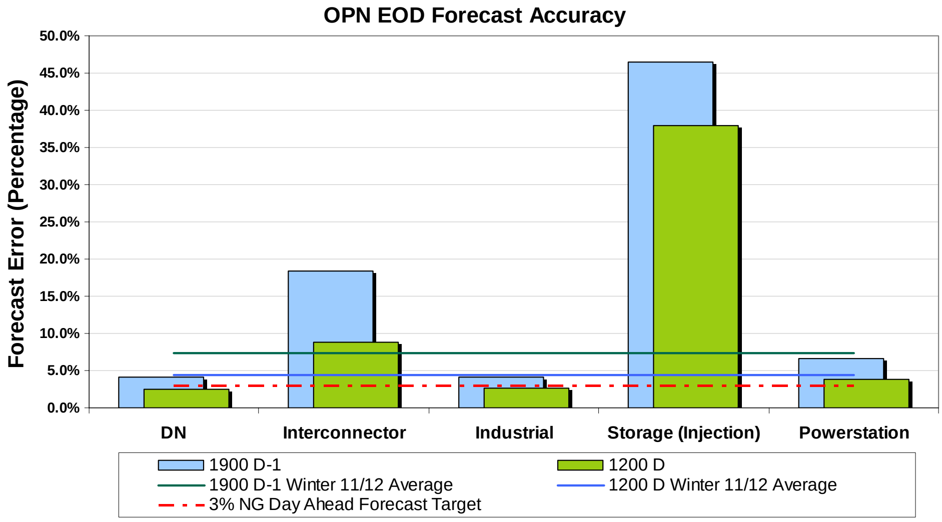


156. The chart shows (after removing days impacted by National Grid balancing actions) the underlying market imbalance at the start of the day and the time taken for the network to balance. Despite the low demands last winter, the trend has been increasing and on average the (PCLP) at the start of the gas day is around twice as far out of balance compared to ten years ago, and the time taken for the system to come into balance has also been increasing with PCLP Closing Linepack values not converging to similar levels until around midnight.

157. In order to manage the NTS safely and efficiently, it is essential that information provision to the system operator is timely and accurate, with market participants operating in accordance with the information they have submitted.

158. **Figure G27** shows the accuracy of the Offtake Profile Notification (OPN) versus End of Day (EOD) forecast.

Figure G27 – Forecast accuracy OPN vs EOD



159. The chart shows the average percentage error of forecasted demand by source. It compares the OPNs received by D-1 19:00 and by D 12:00 versus the actual end of day volume. In general terms the forecast error for last winter was an average of about 7.5% at D 12:00 and about 4.5% at D 19:00, this compares to a day ahead forecast target of just 3%. For storage injection and the Interconnector, the errors were much higher. Again this highlights the complexity in defining operating strategies based upon the information received.

160. In summary: the combination of fundamental changes to flow patterns of supply and demand on the NTS, within day supply and demand profiling and reduced accuracy of aggregate user notifications have all increased the operational challenges faced in managing the NTS.

Exit Reform

161. The Enduring NTS Exit Capacity Arrangements were introduced through UNC modification 0195AV in January of 2009. Following the introduction of new processes and systems for the longer term application and trading elements of the regime over

the last 3 years, October 2012 will see the full implementation of the Enduring NTS Exit Capacity Arrangements including the introduction of daily auctions and new commercial constraint management tools at exit points.

162. More general information regarding the Enduring NTS Exit Capacity Arrangements regime can be found on the National Grid website at http://www.nationalgrid.com/uk/Gas/OperationalInfo/excap/ or alternatively you can contact capacityauctions@uk.ngrid.com if you have any specific questions or concerns.

Gas Balancing Alert (GBA)

163. A review of the existing Gas Balancing Alert (GBA) arrangements has been completed under UNC modification 415. An Ofgem decision on MOD 415 is expected to be announced via the Joint Office of Gas Transporters in early October 2012. Should MOD 415 be approved National Grid will endeavour to implement the changes effective on gas day 1st November 2012.

164. The proposals submitted in UNC MOD 415 seek to change the existing GBA arrangements by introducing two new information provision products related to the NTS physical system balance, these are:

    1. Margins Notice (MN)
    2. Gas Deficit Warning (GDW)

165. More information on the changes proposed can be viewed on the Joint Office website under, Live Modifications 0415 – Revision of the Gas Balancing Alert Arrangements. http://www.gasgovernance.co.uk/0415

166. Ofgem's final decision will be communicated via the Joint Office of Gas Transporters. If the mod is approved, National Grid will undertake a separate set of communications to ensure the industry is fully aware of the new tools and the implementation date.

Market Information Provision

167. National Grid's Gas Operational Data details extensive data and real time information. As physical and regime changes occur, the industry will see these developments incorporated into the existing suite of reports and data items.

168. Changes to the Exit Capacity regime in October 2012 will result in a further release to enhance and improve the publication of NTS Exit Capacity information. Some older, preformatted reports will cease to be published and will be replaced instead by searchable data items which Users can download and interrogate in their own systems.

169. Information on the supply / demand forecast, storage & LNG Importation stock levels and GBA trigger levels (subject to Mod 415) can be found at: http://marketinformation.natgrid.co.uk/gas/frmPrevalingView.aspx

170. Information on the supply / demand forecast, storage stock levels, storage deliverability and GBA trigger levels (subject to Mod 415) have been consolidated at: http://www.nationalgrid.com/uk/Gas/Data/GBA/

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

Update on Provision of new NTS Capacity for Winter 2012/13

Emissions related works

172. Work continues on the new 35MW electric drive compressor unit at Kirriemuir, two units at St Fergus and one at Hatton. Kirriemuir is expected to be commissioned before the end of 2012 with Hatton and St Fergus following during the first or second quarters of 2013.

Storage

173. A new feeder has been constructed to provide additional capacity for the Hill Top Farm storage facility in Cheshire. The 3km x 900mm pipeline has been constructed from Warmingham to tie into an above ground installation at Wheelock. The feeder is now operational.

South Wales Expansion Project

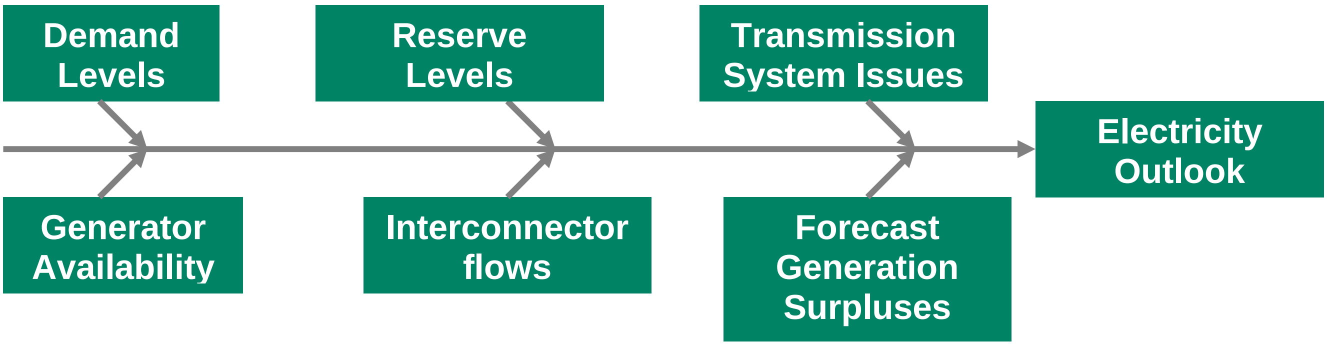
174. This project is part of the overall investment strategy to provide the capacity to transport gas from the two LNG importation terminals at Milford Haven.

175. The Pressure Reduction Installation (PRI) at Tirley in Gloucestershire has now been commissioned. The force majeure capacity restriction for Milford Haven entry capacity has now been lifted.

New Exit Connections

176. NTS exit connections to the NTS that have been commissioned include: a network offtake point at Burnhervie on Feeder 13 between St Fergus & Aberdeen, a connection for a salt cavern storage facility at Stublach in Cheshire and a ‘minimum offtake’ at Carrington

Electricity

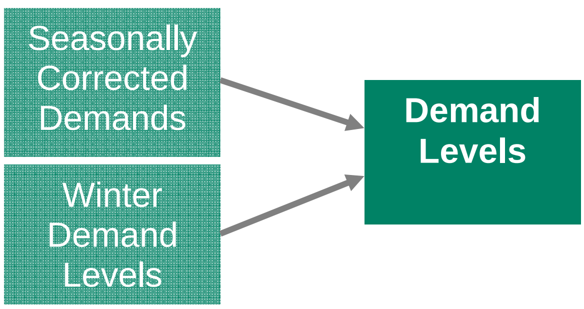


Overview

177. This chapter sets out the current electricity forecast for the winter 2012/13.

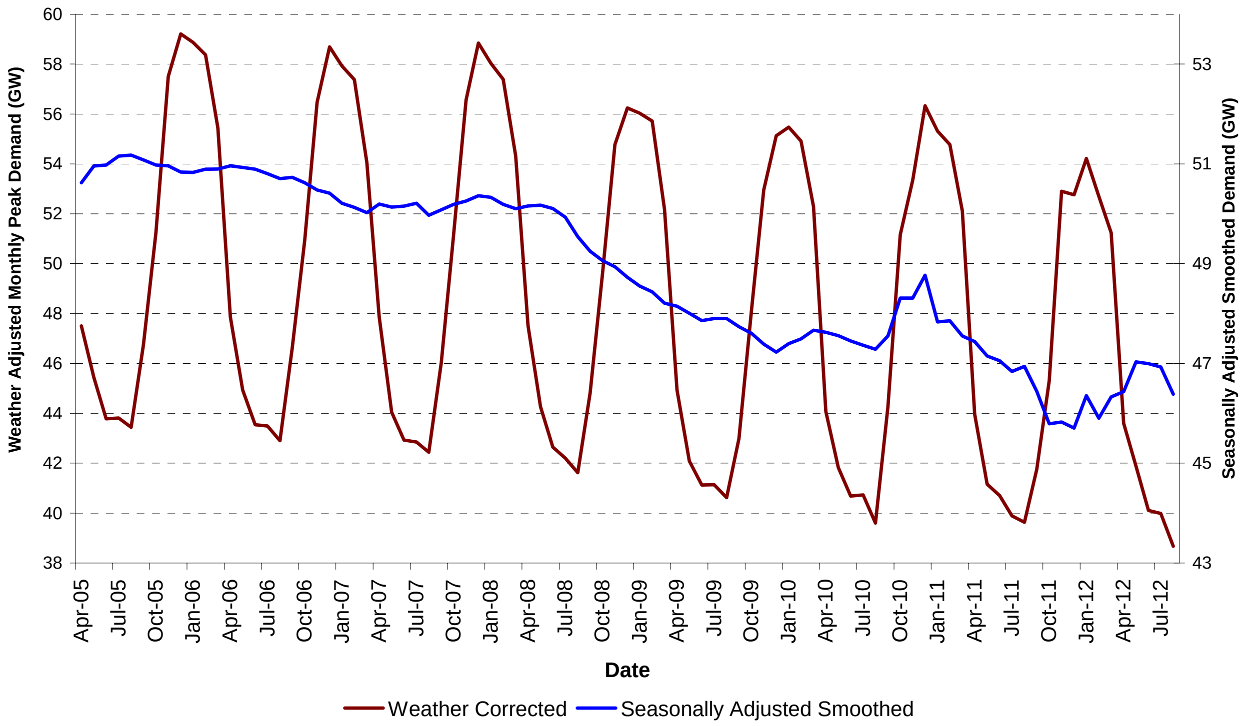
Demand Levels

178. Unless otherwise stated demand discussed in this report excludes any exports to France, The Netherlands and Ireland but does include station load.



179. **Figure E1** shows the weather corrected and seasonally adjusted demand levels for the last seven years. The economic downturns of October 2008 – November 2009 and September 2011 – March 2012 can clearly be seen. The sharp rise in the demand during the winter of 2010/11 is down to the limitations of the weather correction process in dealing with an exceptionally cold winter. There is some evidence of a recovery in demand from April – July 2012, which may be economic in nature. The drop for August 2012 may be connected to a decrease in activity over the Olympic period; but it is too early to be definitive. All this makes forecasts for the coming winter unusually difficult. The assumptions we have made imply that we believe the underlying demand levels will be between the levels seen before and after the downturn of September 2011 – March 2012.

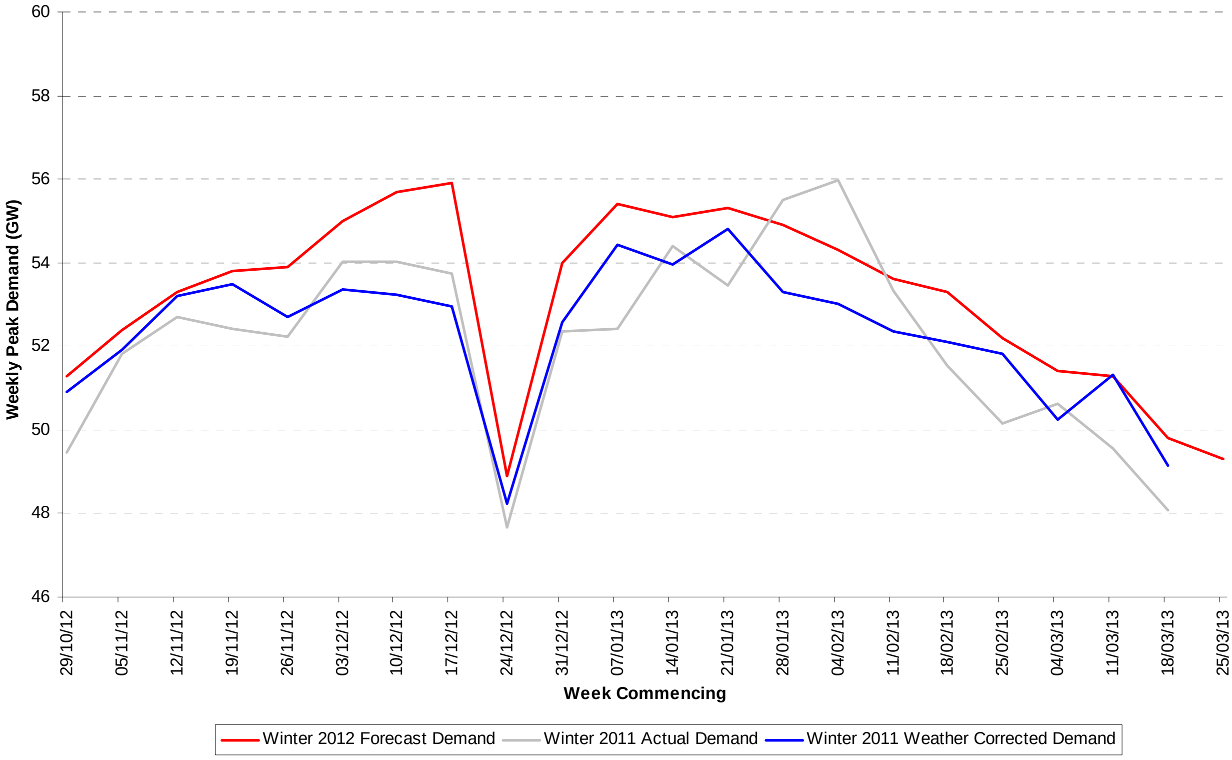
Figure E1 - Smoothed Weather and Seasonally Corrected Normal Demand



180. **Figure E2** shows the previous year's actual demand, weather corrected demand and the demand forecast for the upcoming winter. The most current forecast at any time is given on the **BMRS**[25]. It can be seen that the weather corrected forecast is typically higher than the weather corrected demands experienced last winter, particularly in the weeks leading up to Christmas. Some of this is due to our belief that underlying demand levels will have increased by about 0.6 GW since the last winter, an effect that we believe will be primarily economic, as discussed in the preceding paragraph. Another difference is that Christmas day this year falls in ESI week 52, rather than in ESI week 51. However the major factor explaining the difference was the high level of wind generation in these weeks last year. Embedded wind generation for which National Grid does not receive metering reduces the demand that has to be supplied by the transmission system. It is not possible to forecast how much of this unmetered wind generation there will be more than a few days ahead of time, and so, adopting a prudent approach, our long range forecasts assume zero wind generation.

[25] www.bmreports.com

Figure E2 - Previous years outturn and forecast for 2012/13



181. The weather corrected demand peak forecast is 55.9 GW compared to the weather corrected demand forecast from the Winter Consultation of 55.3 GW. The differences in the demand forecast between the consultation and this report are due to recent experiences of an increase in the seasonally corrected demands.

182. The Average Cold Spell demand peak forecast (ACS) is the yearly peak demand level that has a 50% chance of being exceeded in the forecast year. For winter 2012/13 the ACS is currently 57.0 GW. This is up from 56.9 GW at the time of the Winter Consultation.

183. 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 58.8 GW compared to the 58.7 GW in the Winter Consultation.

Embedded Wind Generation

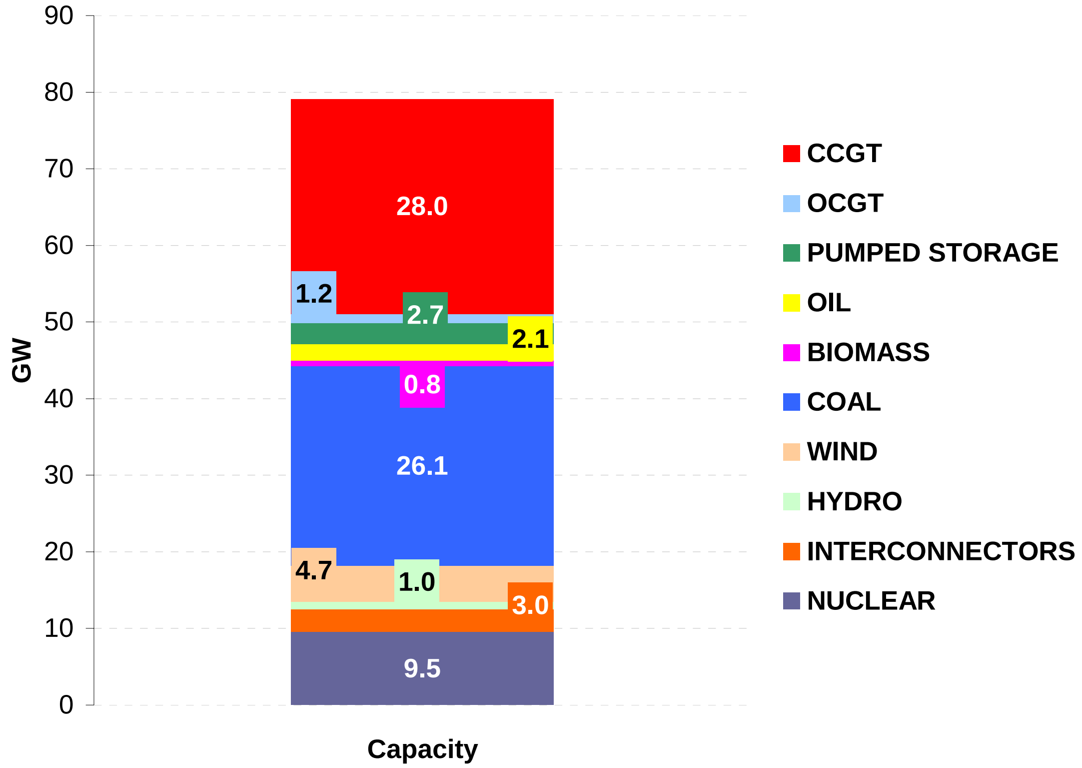
184. As discussed in Paragraph 180, there is an increasing volume of embedded wind for which National Grid receives no metering. This wind generation has the same effect as negative demand for the System Operator. National Grid forecasts an estimate of the national total of this unmetered wind generation for up to ten days ahead and uses this forecast to improve its shorter term forecasts for national electricity demand. For demand forecasts more than ten days out it is not possible to get a forecast for the wind strength, and hence demand forecasts are produced on the assumption that there will be no unmetered wind generation. More information will be provided through the Operational Forums and future Summer/Winter Outlook reports.

Generator Availability

Generation Capacity

185. Based on the observed output of power stations, National Grid's current operational view of generation capacity anticipated to be available at the start of winter 2012/13 is 79.1 GW, a reduction of 0.5 GW from the Winter Consultation figure of 79.6 GW. A breakdown of this capacity is shown in **Figure E3**.

Figure E3 - Generation Capacity Operational View 2012/13



186. The net reduction is due to a combination of gains and losses. Capacity has reduced due to the closure of the two oil fired units at Grain and the extension of the ongoing repairs at Shoreham but capacity has increased due to the commissioning of the last two units at Pembroke and more wind farm capacity coming on the system.

187. There will be a further reduction of 1 GW at the end of December due to the closure of Derwent and two units at Kingsnorth.

188. There is some potential upside due to the commissioning of West Burton B, re-commissioning of Glendoe and an expectation of higher output at Little Barford following the refurbishment work. In addition there will be another 0.5 GW of import capacity available once the East-West Interconnector is in commercial operation.

Generation Availability Assumptions

189. **Table E1** shows the assumed losses based on the average of previous winters, including breakdowns, shortfalls and an assumed level of primary energy source for wind and hydro. They do not allow for planned outages as these have already been accounted for in the notified availability. The assumed losses are applied to the notified availability and this data is then used in the calculation of forecast generation surpluses.

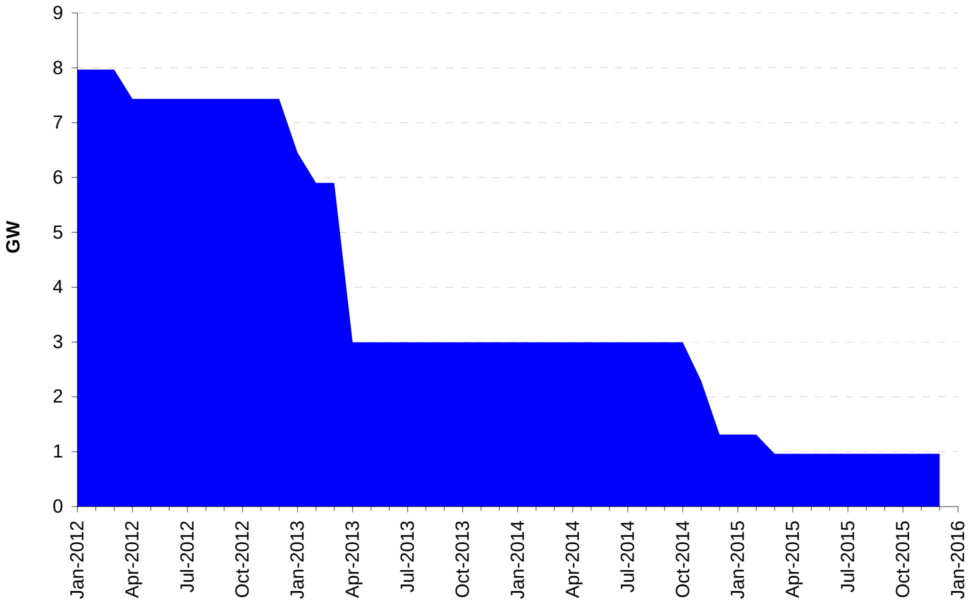
Table E1 - Assumed Losses of Generation Availability for Winter 2012/13

Power Station Type	Assumed losses
Nuclear	16%
Interconnectors	0%
Hydro generation	25%
Wind generation	90%
Coal + biomass	15%
Oil	15%
Pumped storage	2%
OCGT	6%
CCGT	13%
Total	**17%**

Effect of LCPD on Coal Generation Capacity

190. Plant opted out of the Large Combustion Plant Directive, LCPD, has 20,000 hours allowed operation until December 2015. The limited running hours will have an affect this winter with 0.5 GW already lost from Cockenzie and a further loss of 1 GW at the end of December due to the closure of two units at Kingsnorth. An additional 3.5 GW of plant will have been lost by the end of March 2013 due to the closure of Didcot A and the remaining units at Cockenzie and Kingsnorth. The latest view of estimated closure dates for opted out coal units is shown in **Figure E4**.

Figure E4 - Indicative Total Generation Capacity for LCPD Coal Opted Out Plants



Unavailable CCGT Generation

191. National Grid is aware of 4.2 GW of CCGT generation that has been declared unavailable for the winter 2012/13 for a variety of reasons. This includes Keadby, Medway, Peterborough, Roosecote, Teeside and Shoreham.

192. It is expected in the event of a change to market conditions such as lower gas prices, high levels of demand or large generation losses, some of this generation may become available to the market.

Reserve Levels

Reserve Levels

193. 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.

194. There is also an additional reserve requirement to meet wind generation output uncertainty. This reserve is 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 met from both synchronized sources and non-synchronized sources.

195. 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.

196. For winter 2012/13, the present level of contracted STOR is approximately 2.7 GW, approximately 1.6 GW is contracted from BM participants and 1.1 GW from non-BM generating plant and demand reduction (the non-BM participant capacity is unlikely to be available over the winter darkness peak).

197. Prior to the winter, there will be one further STOR tender round covering services for the winter 2012/13 darkness peak; the results of which will be published at the beginning of November. Communications regarding this will be through the Electricity Operational Forum and the National Grid website.[26]

198. National Grid expects to contract more STOR to provide reserve services over the winter. Last winter about 3.9 GW of STOR was contracted, but much of that was not available over weekday peak demands. Total availability at the time of the top 20 winter peak demands last winter was about 2.3 GW. This winter the expectation is to contract about 3.0 GW and allowing for seasonal influences and any one-off events, the amount of contracted STOR that will actually contribute to the operational reserve requirement at the winter 2012/13 darkness peak is expected to remain consistent with last winter's (2011/12).

199. 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 1.9 GW of reserve would be required to meet the necessary response requirement. 1 GW of this 1.9 GW reserve requirement has already been contracted, 0.14 GW of which has been contracted from demand-side providers.

200. National Grid continues to have Maximum Generation contracts in place for Winter 2012/13, 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 the generation capability and plant margin analysis calculations. This service was available pre-NETA and similarly was never included in margin analysis.

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

Interconnector Flows

Interconnector Flows

201. Interconnector flows are closely correlated with price spreads however there is a significant amount of uncertainty in both going forward. Curve prices on the continent seem more sensitive to fuel and emissions prices than in GB, with significant fluctuation in day ahead prices in Germany and France depending on the forecast renewable output.

202. The East-West Interconnector (EWIC) between Deeside (GB) and Woodland (IRE) is set to be commercially available by October with a capability of +/-0.5 GW, increasing total capability via interconnectors to 4 GW. IFA has a planned bipole outage in early October but otherwise all interconnectors are assumed fully available in this section.

203. The differential between GB power prices and European prices for the winter indicate imports to the GB market from Europe overnight and during the off-peak periods. The forecast flow over the peak periods appears much more uncertain; we are currently forecasting exports to the continent for the first few months of winter changing to a net float or import position over the latter half of the season.

204. The forecast flows for Q4 12 and Q1 13 are shown in **Table E2**, based on the forward prices for these periods.

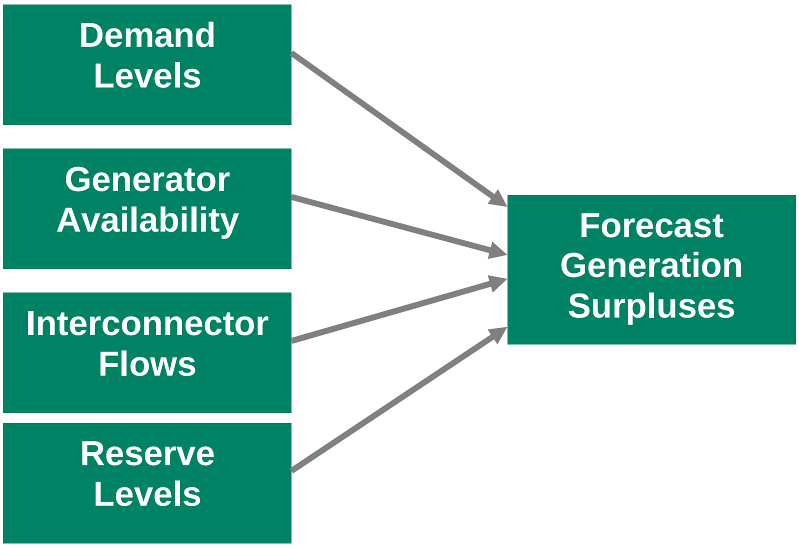
Table E2 – Forecast Weekday Interconnector Flows

Time (Oct-Dec)	Forecast Flow minimum (+ve to GB)	Forecast Flow maximum (+ve to GB)
07:00 – 19:00	-3 GW	-1 GW
19:00 – 23:00	-1 GW	+2 GW
23:00 – 07:00	+1 GW	+3 GW

Time (Jan-Mar)	Forecast Flow minimum (+ve to GB)	Forecast Flow maximum (+ve to GB)
07:00 – 19:00	-1.5 GW	+1.5 GW
19:00 – 23:00	-1 GW	+2 GW
23:00 – 07:00	+2 GW	+3 GW

205. Events in February 2012 highlighted the sensitivity of power prices to extreme weather conditions beyond the scope of any long-term forecasts. French baseload prices spiked to £160/MWh which resulted in a total export across all interconnectors of over 3 GW during a triad in the GB market on 8th February.

Forecast Generation Surpluses



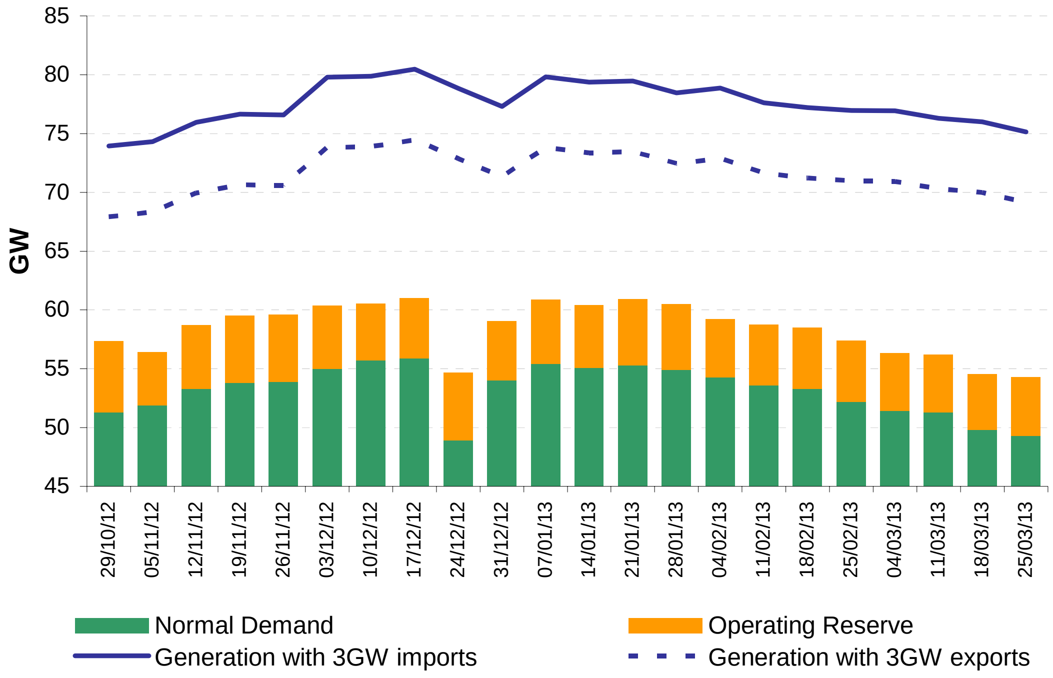
206. This section looks at the amount of Generation Surplus available in each of the main scenarios of interest. Each chart has an amount of demand (green bars) and the required operating reserve (orange bars). The solid line shows the generation availability with 3 GW of imports while the dotted line shows 3 GW of exports. (The East-West interconnector has not been included in this section as it has yet to be commissioned although it is likely to start commercial operation before the start of the winter).

207. 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.

208. 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.

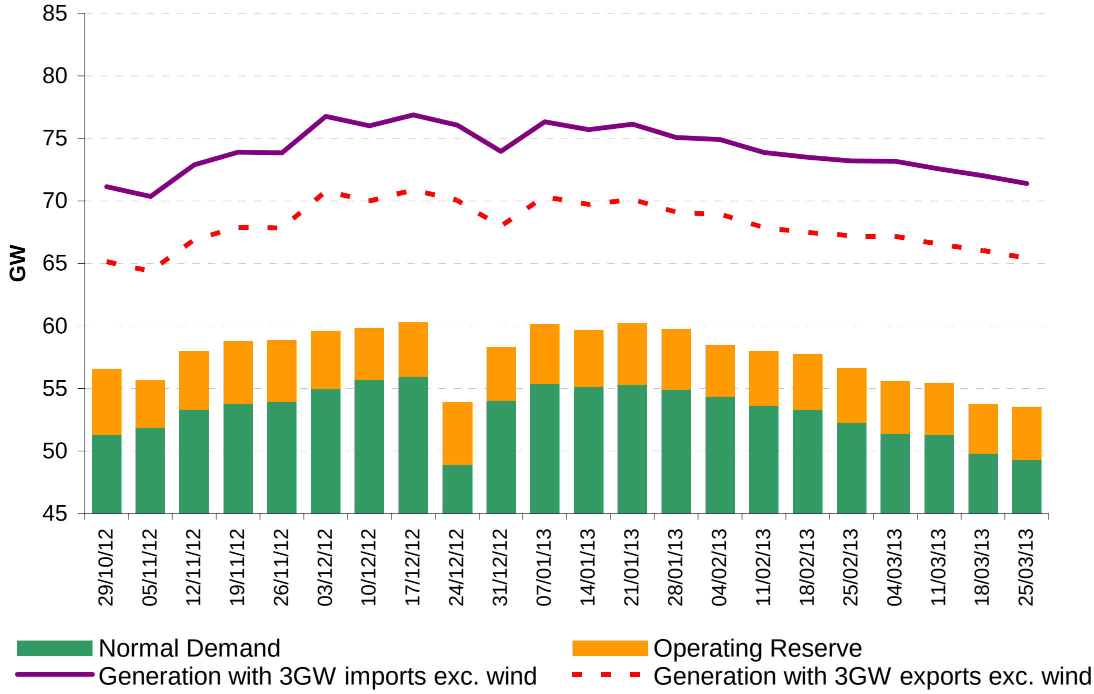
209. The declared generation availability is the currently declared availability which is submitted to National Grid by generating companies in accordance with Operational Code 2 of the Grid Code. The assumed generation availability is derived from the assumed losses set-out in **Table E1** and the declared generation availability.

Figure E5 - Normal Demand and Declared Generation Availability



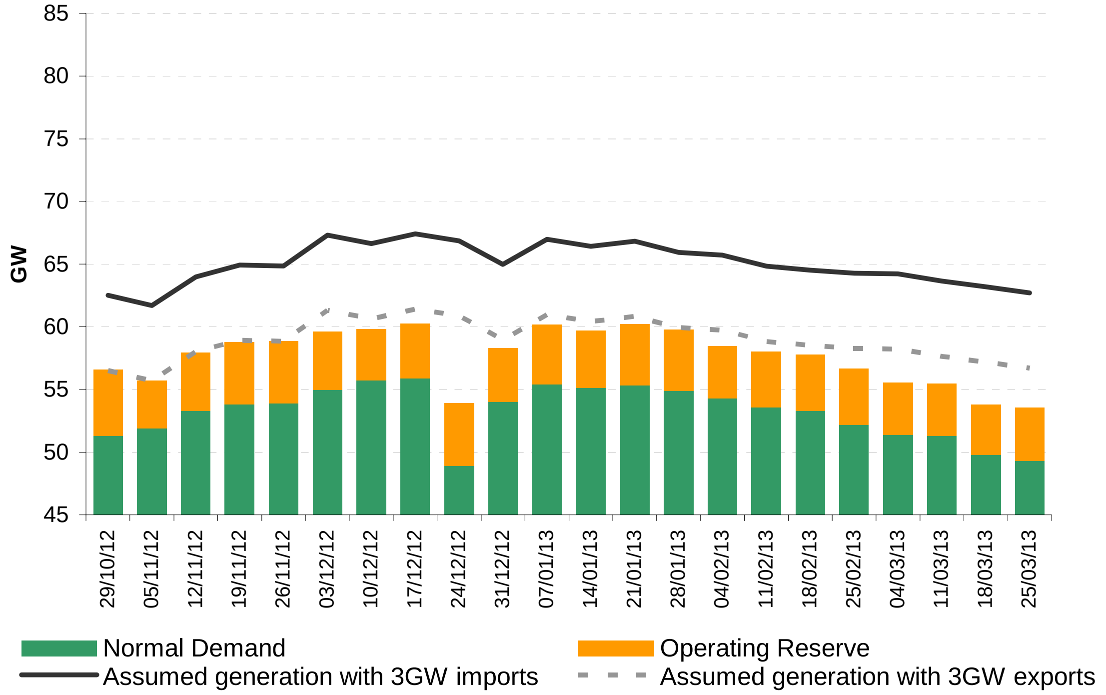
210. **Figure E5** shows Normal Demand and the declared generation availability. This chart shows that there is adequate margin under optimum declared conditions. From this chart it is also possible to calculate the minimum generation surplus which is 17% in the week commencing 26th November. The surplus is the amount of generation available above the amount required to meet the demand and operating reserve requirements. It is represented as a percentage of the total available generation with the interconnectors at float. The normal demand peak occurs in the week commencing 17th December where there is a surplus of 19%.

Figure E6 - Normal Demand and Declared Generation Availability Excluding Wind



211. **Figure E6** 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, although the minimum surplus on this basis drops to 13%, assuming the interconnectors are at float.

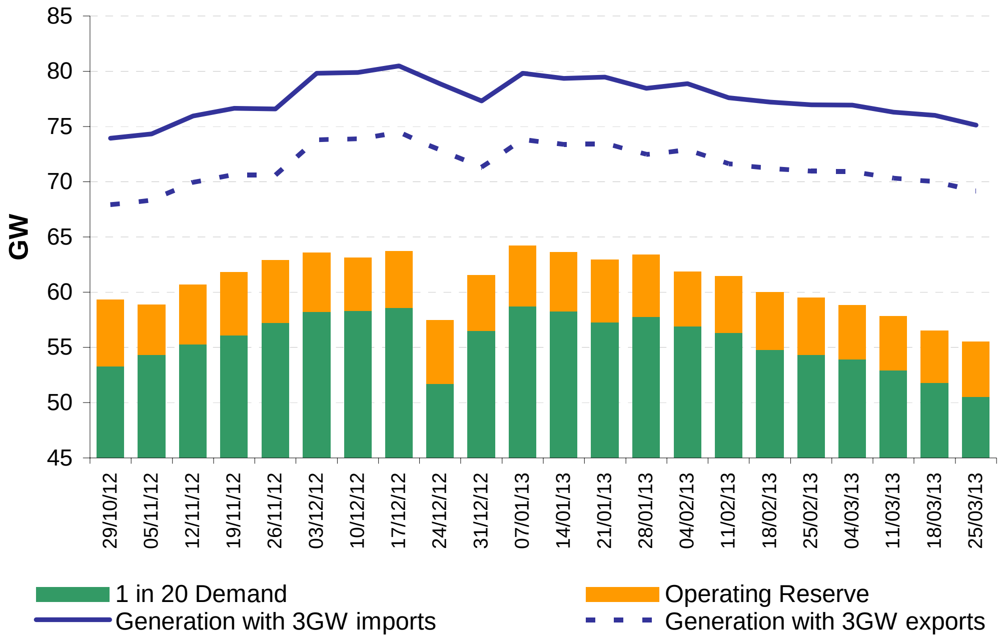
Figure E7 - Normal Demand and Assumed[27] Generation Availability



212. **Figure E7** shows Normal Demand and the assumed generation availability. The assumed generation availability is 64.4 GW at the time of the forecast peak demand (week commencing 17^{th} December) resulting in a surplus of 6%. The minimum surplus is 5% (week commencing 26th November). These surpluses are calculated assuming the interconnectors are at float. The chart shows that even with 3 GW of exports there would still be sufficient generation to meet demand and reserve.

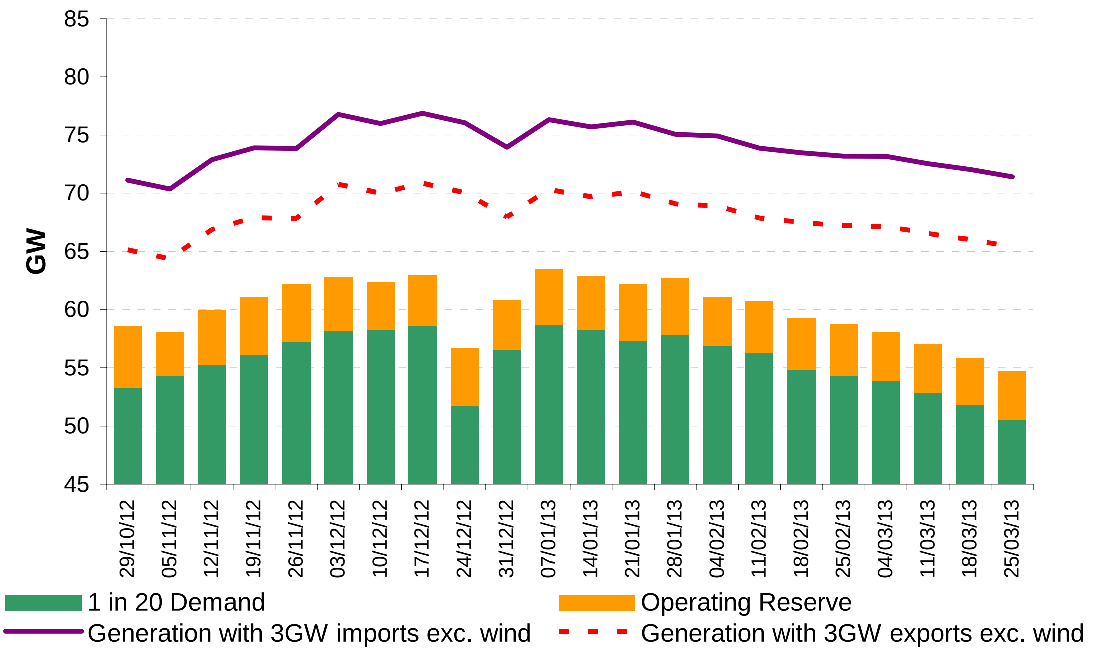
[27] For the definition of Assumed Generation Availability please see Table E1

Figure E8 - 1 in 20 Demands and Declared Generation Availability



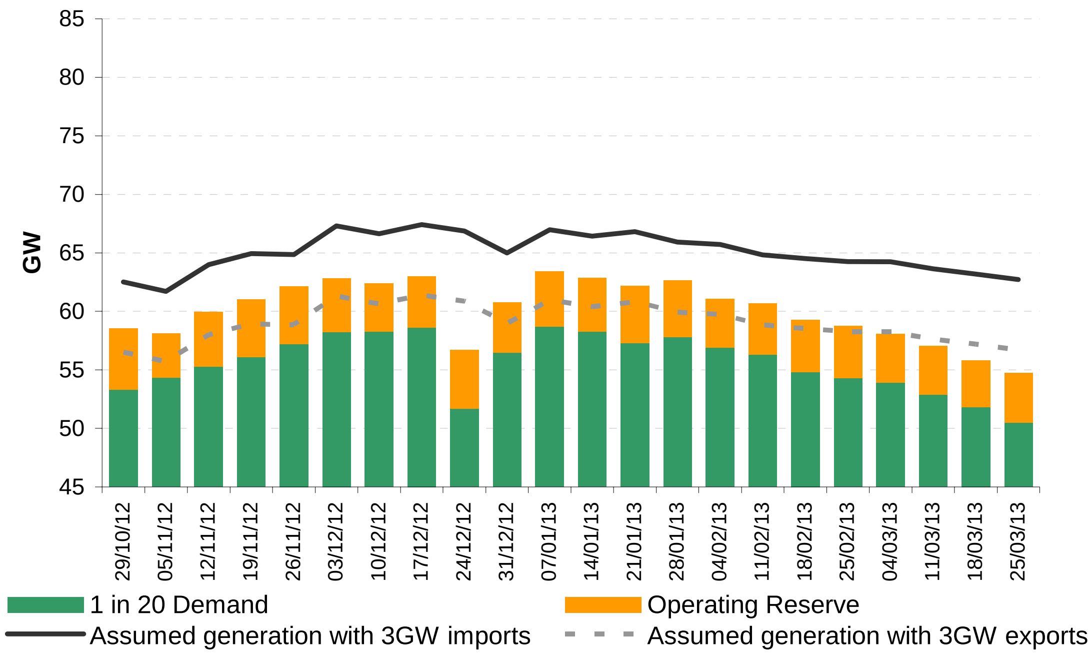
213. **Figure E8** shows 1 in 20 demands and the declared generation availability. In this scenario there are adequate margins.

Figure E9 - 1 in 20 Demands and Declared Generation Availability Excluding Wind



214. **Figure E9** shows 1 in 20 demands and the declared generation availability excluding wind. This indicates that there would be adequate margins available in this scenario.

Figure E10 - 1 in 20 Demands and Assumed Generation Availability



215. **Figure E10** shows 1 in 20 demands and the assumed generation availability. In this scenario there would be adequate system margin under import conditions but there would be an erosion of reserve during export conditions throughout most of the winter. If the interconnectors were assumed at float the least surplus would be -0.5% in the week commencing 26th November and the surplus for the 1 in 20 demand peak would be 0.8% in the week commencing 7th January.

216. In the event of a scenario with high demands due to unusually cold weather combined with low wind generation, with the stated assumptions full exports to the continent would result in reserve levels not being met. System warnings, such as the Notification of Insufficient System Margin, would be issued ahead of time to inform the market and to encourage an increase in available generation or reduction in demand. In addition, if necessary, trading may be undertaken on the interconnectors to reduce exports. However, as previously indicated, more plant is expected to become available as the winter progresses and it may be that some of the 4.2 GW of unavailable CCGT plant may be able to be returned to service if sufficient lead time was available.

Forecast Generation Surpluses – Key Risks

217. The key risks to the forecast surpluses being lower than forecast are:

- Normal demand being higher than forecast
- Weather being colder than 1 in 20
- Availability losses being higher than assumed

- Uncertain timing of LCPD plant closures
- An increase in the volume of mothballed plant.

218. The full range of interconnector flows from maximum import to maximum export has been covered in the forecasts with maximum exports being the most onerous case. However, the new East-West Interconnector going into commercial operation could increase the total export flow by another 0.5 GW.

219. Wind generation for the winter peak has been assumed to be 10% of the maximum but it could be lower. However, this would result in only a small reduction in the surplus.

220. There is a potential upside that could increase forecast surpluses and off set the downside risks, which is a higher total plant capacity than assumed due to the commissioning of new CCGT units at West Burton B.

221. Utilising interconnector capacity to reduce exports or increase imports through trading would provide a means of absorbing some of the reduction in surplus that might arise through any of the key risk areas identified.

Transmission System Issues

Transmission System Issues

222. Action was taken at various times during the last winter to reduce wind farm output in Scotland in order to maintain system security across constraint boundaries[28]. A total of 150 GWh of wind generation was curtailed in Scotland through a combination of option contracts, trading and bid acceptances. This was 2% of the Great Britain total of 7238 GWh of metered wind output during the same period.

223. **Figure E11** illustrates the requirement for wind curtailment across a constraint boundary. For this illustration the Scotland to England boundary of the transmission system has been used.

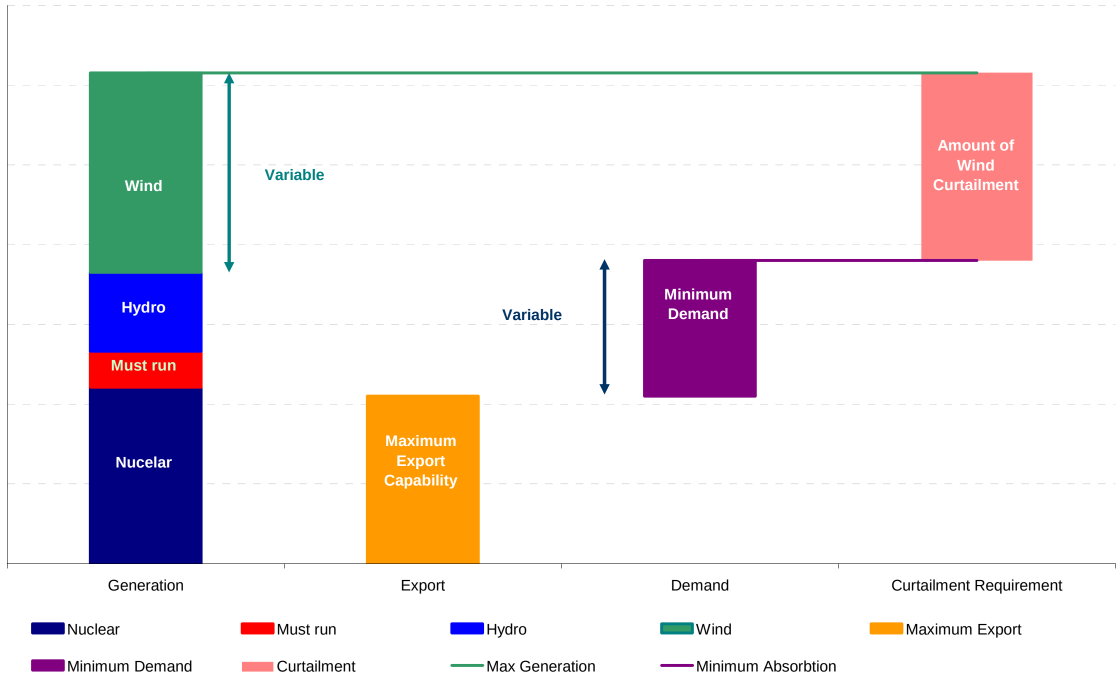
- A boundary can be created to cover an area of the system where there will be an amount of generation and demand, in this illustration Scotland is the area inside the boundary
- When the demand inside a boundary is equal to the generation inside a boundary the flow across the boundary is zero
- Any 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 secure capability of the transmission network. This is a constraint boundary

[28] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/Pages/ElectricityTransmissionPolicy.aspx

- The green line shows the Maximum Expected Generation capacity during a minimum demand period. 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 (Orange Box) which is the transmission capacity between Scotland and England - the constraint boundary in this illustration
    - 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 wet and windy events wind and hydro generation units become the most cost effective as those coal and gas units not required for system security will already have had their output reduced

224. **Figure E11** is for illustration purposes only and is not to scale.

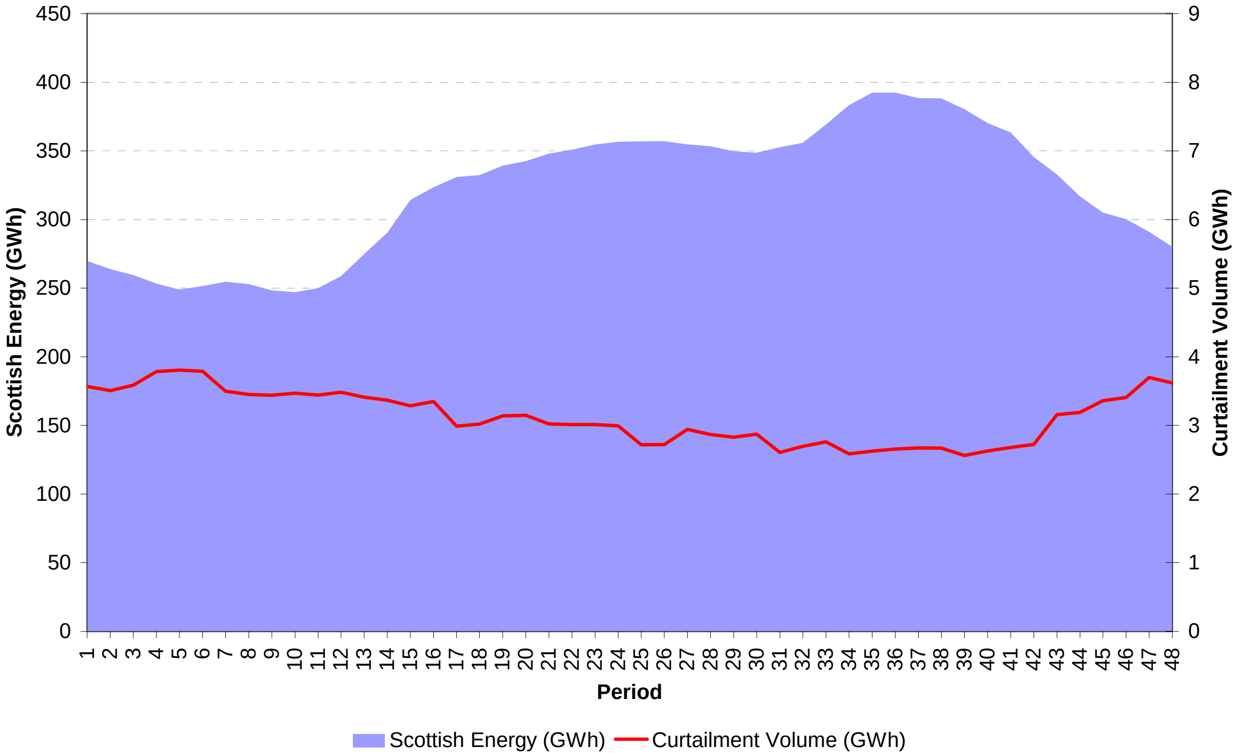
Figure E11 - Derivation of Wind Curtailment Requirement between Scotland and England



225. **Figure E12** shows the volume of wind curtailment against electrical energy consumed in Scotland for last winter by period of the day. It shows that the volume of

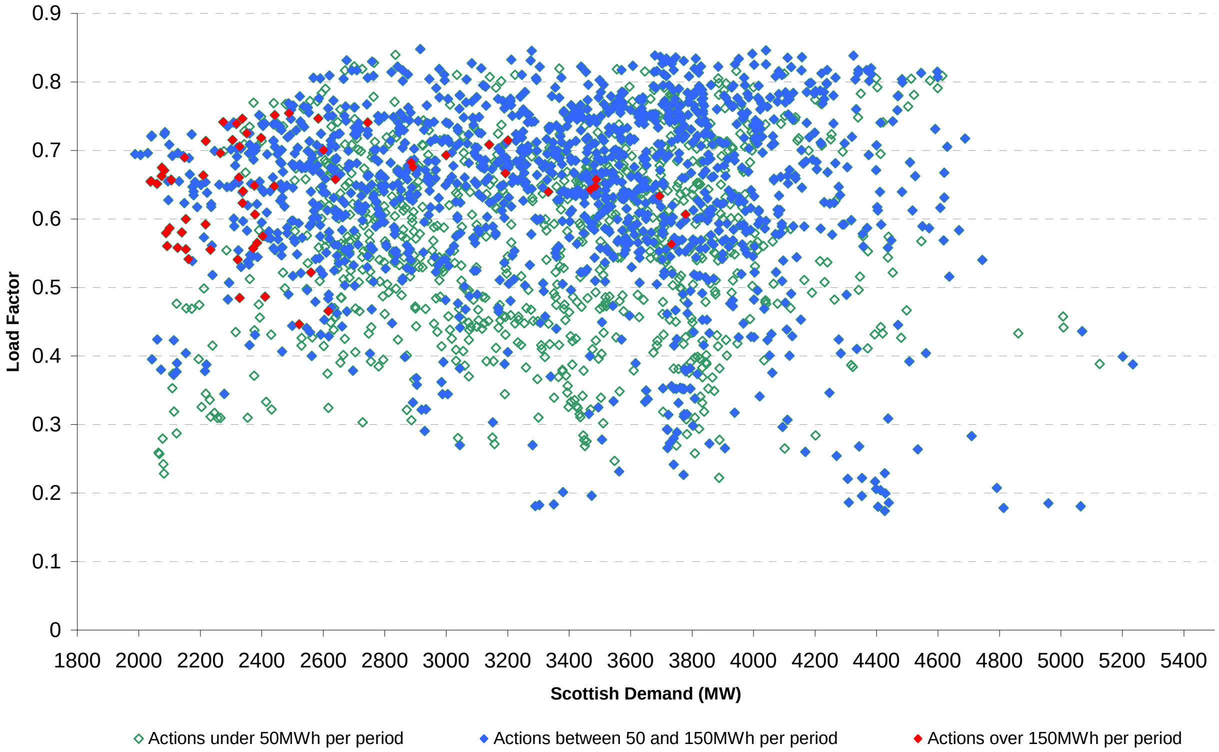
curtailment is higher overnight when the demand is lower but that curtailment is likely to occur throughout the day.

Figure E12 – Sum of Scottish Half Hourly Wind Curtailment Volumes together with Energy Supplied per Settlement Period for Winter 2011/12.



226. **Figure E13** shows settlement periods where wind curtailment actions have been taken plotted against Scottish demand and Scottish wind load factor for Winter 2011/12. It shows volume of actions in three categories: actions under 50MWh per settlement period, actions between 50 and 150MWh per settlement period and actions over 150MWh per settlement period. The largest actions (those over 150MWh per half hour) usually occur at higher wind levels and lower demands and most actions are taken when wind output is above 20% of capacity, however the spread of actions indicates transmission system capability is also an important factor.

Figure E13 - Scottish Half Hourly Wind and Demand Levels for Winter 2011/12 when Curtailment Actions were taken.



227. Forecasting the level of wind curtailment for the coming winter is dependant on actual wind strength, rainfall, transmission system capability, demand, generation availability and how these factors vary in relation to each other. Wind strength over the last winter was higher than average, however installed wind generation capacity has grown over the last year. Transmission system capability is forecast to be broadly similar to last year. Wind generator's capability to provide ancillary services has also been increasing over the last year, which, if it grows sufficiently, will reduce the need for conventional generators being required to run for system security. Against this backdrop National Grid's assumption is that it is likely that the amount of wind curtailment for this coming winter will be broadly similar to last winter's.

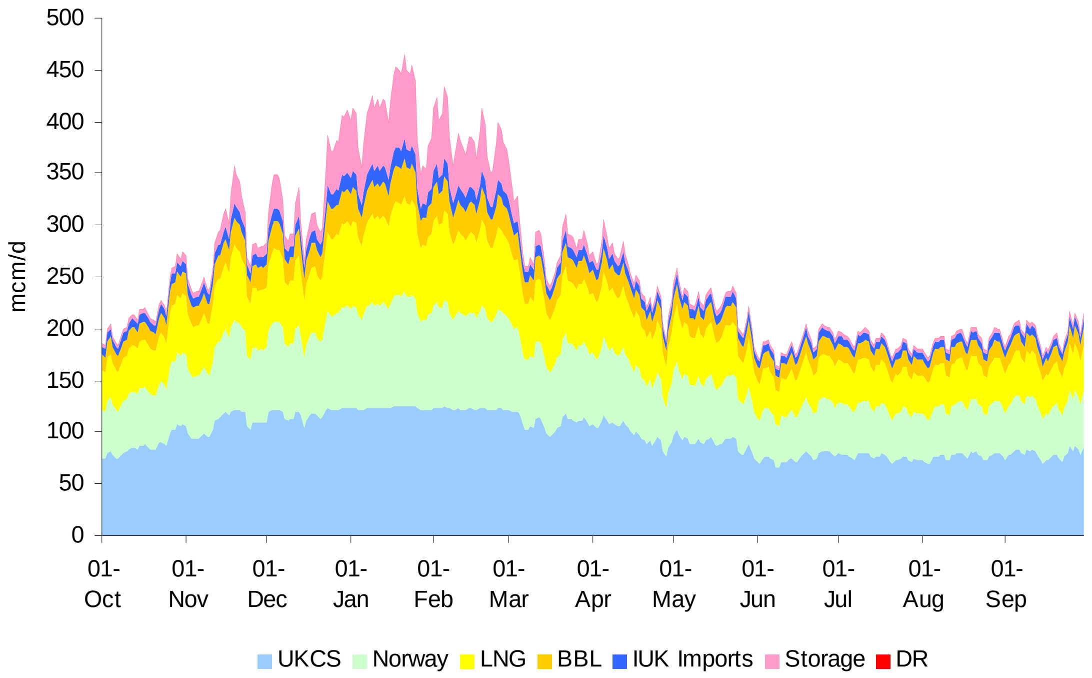
Gas/Electricity Interaction

228. This section evaluates the interaction between the electricity and gas markets.

229. With most gas power stations assumed as the marginal source for generation, the demand forecasts for gas power generation are at the lower end of the possible range. Consequently the potential for further demand side response (DSR) from power generation is limited and might only be achieved if, for example, the availability of other generating plant increases or if distillate were used in preference to gas.

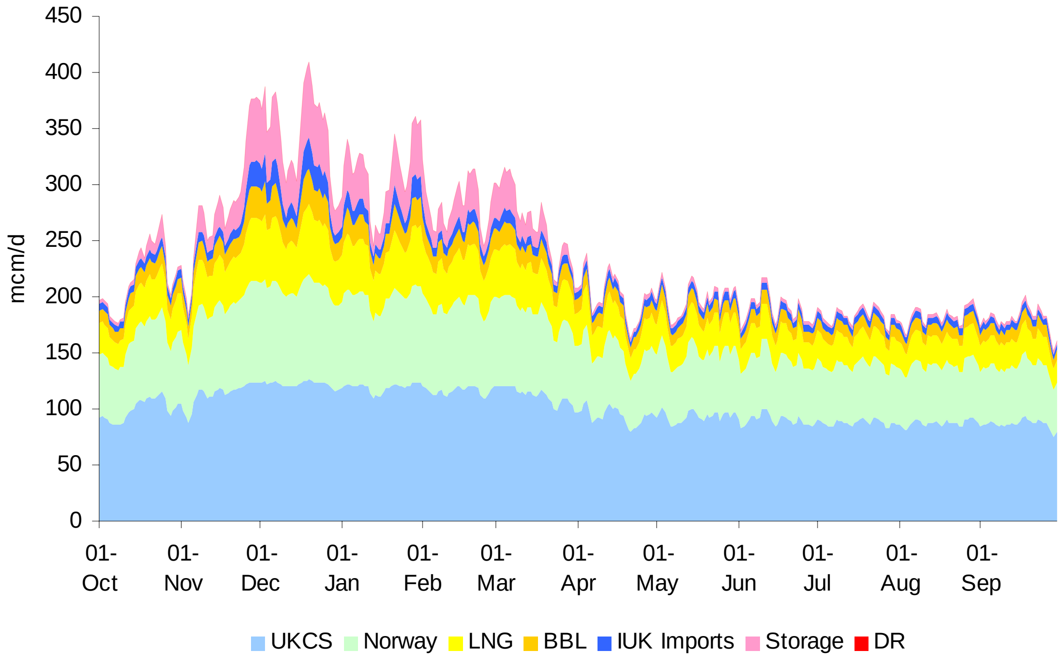
230. **Figure GE1** shows the impact of 1962/63[29] weather on 2012/13 gas demand. The low power generation demands mean that when the cold weather arrives there is plenty of gas storage to supply the increased weather sensitive demand. **Figure GE2** shows a similar graph for 2010/11 weather. This year was chosen as it was not only relatively recent but had the most cold days for 25 years.

Figure GE1 – 2012/13 gas demand at 1962/63 weather conditions



[29] 1962/3 was the coldest winter in the last 250 years.

Figure GE2 – 2012/13 gas demand at 2010/11 weather conditions



231. **Table GE1** summarises some of the impacts on gas demand for next winter. With gas as the assumed marginal source for power generation, the ability for the power market to provide extra relief for the gas market is limited because the gas demand forecasts already assume low levels of gas powered generation.

Table GE1 – Possible variation in daily gas demand from model assumptions

Cause	Impact on daily gas demand
Variation in LDZ gas demand from demand model estimate	+/- 15 mcm
Variation in NTS industrial demand from demand model estimate	+/-2 mcm. Demand response in 2005/6 was up to 4 mcm
Variation in Moffat exports from demand model estimate	+/- 4 mcm. Demand tends to increase above model estimate in very cold weather.
Wind generation 30% instead of 10%	4 mcm reduction
24 hour 4 GW electricity imports	18 mcm reduction (from float)
1 GW increase in non-gas generation	4.5 mcm reduction