Summer Outlook Report 2010

Executive Summary

1. This Summer Outlook Report is our third that gives a detailed insight into a range of issues that the electricity and gas industries may face during the summer months.

2. This report covers potential electricity and gas issues, such as demand-supply balance, how demand responds to high temperatures, and transmission issues.

3. We have continued with a less formal process than that undertaken for the Winter Consultation Report. We welcome feedback on our analysis and the contents of the Summer Outlook Report to help us to ensure that it meet the needs of the industry in the future.

Electricity

4. The outlook for the electricity market in summer 2010 currently shows higher plant surpluses than at the same point in time before summer last year. This means that the outlook for electricity security of supply for the coming summer appears comfortable, more so than at the same time last year. The issues with electricity security of supply over recent summers have either been caused by exceptional events, such as exceptionally high levels of near coincident generation losses (May 27th 2008), or a period of hot temperatures without sufficient timely market response, and are considered a rarity.

5. There are no market changes expected during the summer which we anticipate to materially impact security of supply. A key aspect of summer for electricity system operation is the outage programme on our transmission system. Again this summer, extensive works are anticipated to connect the large number of new generators coming onto our system and to replace some of our older transmission assets to ensure continued reliability.

6. On the demand side, our assessment suggests the impact of the recession on energy demand is still being felt, but is likely to be relatively unchanged between last summer and the coming summer. We have noted a continued impact on the summer minimum demand which has fallen significantly in percentage terms as a result the recession. This could feed into an increased need for us to take actions to reduce generation levels, particularly overnight.

7. The Summer Outlook Report sections referring to electricity security of supply are based on market metrics that are regularly updated. The most up to date market information on expected plant surpluses and demand levels is provided on the key electricity operational information platform called the “Balancing Mechanism Reporting Service” at

www.bmreports.com. This report is based on information available in Late March.

Gas

8. Summer demand levels for gas are typically half those experienced in the winter; we are confident that demand will be met in all but exceptional circumstances this summer. There is, however, considerable uncertainty regarding which sources of supply will be utilised to meet demand. This is further compounded by annual maintenance to upstream supply infrastructure, the need to refill storage and the interaction of global and Continental markets through LNG and Interconnector (IUK) flows respectively.

9. We forecast a range of demands for each of the summer months. Weather effects are most noticeable during April and May and late September, these are primarily limited to Non Daily Metered (NDM) demands. In aggregate, other demands are more stable through the summer though each demand component may at times be variable, notably power generation, storage injection and Interconnector (IUK) exports. Overall we forecast higher summer demand in 2010, primarily due to increased gas use for power generation, and to a lesser extent, through higher storage injection.

10. Together with NDM demand, gas demand for power generation makes up the largest two demand components. Current forward prices for coal and gas suggest that gas will be the preferred source for power generation this summer. The operational restrictions on some coal plant through the LCPD could further favour gas. Other factors such as changes to fuel prices, shipper generation portfolios and operational considerations will also influence the choice of fuel.

11. The gas supply position this summer should provide adequate cover for the anticipated level of demands. The exception to this could be a major loss of supply infrastructure or high levels of concurrent upstream maintenance. Under these conditions we would anticipate an increase in the gas price thus providing incentives to attract additional supplies including gas from storage or even a reduction in gas demand through price sensitive demands such as IUK exports or gas for power generation.

12. In terms of supply sources we anticipate further declines in gas from the UKCS being offset by additional imports notably from LNG where further increases in flows compared to last summer are expected.

13. Like last summer, there is again a relatively low level of NTS investment activity. This is reflected in our NTS maintenance plan that shows a high availability of entry capacity.

Industry Feedback

14. To help us improve the process for the Summer 2011 Outlook Report, we would appreciate any comments on this third report.

15. Comments should be e-mailed to energy.operations@uk.ngrid.com Where requested, we will treat information provided to us on a confidential basis. However, respondents may send confidential

information to Ofgem if they would prefer by e-mail to GB.markets@ofgem.gov.uk.

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

Roles and Responsibilities

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

Legal Notice

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

19. National Grid has prepared this document in good faith, and has endeavoured to prepare this document in a manner which is, as far as reasonably possible, objective, using information collected and compiled by National Grid from users of the gas transportation and electricity transmission systems together with its own forecasts of the future development of those systems. While National Grid has not sought to mislead any person as to the contents of this document, readers of this document should rely on their own information (and not on the information contained in this document) when determining their respective commercial positions. National Grid accepts no liability for any loss or damage incurred as a result of relying upon or using the information contained in this document.

Copyright

20. Any and all copyright and all other intellectual property rights contained in this consultation document belong to National Grid. To the extent that you re-use the consultation document, in its original form and without making any modifications or adaptations thereto, you must reproduce, clearly and prominently, the following copyright statement in your own documentation:

Contents

Chapter 1: Electricity

Introduction

21. This Chapter focuses on the electricity supply-demand outlook for the forthcoming summer. Whilst demand levels are typically only around two thirds of those experienced in the winter, there tends to be a high level of generation unavailability during the summer, as power stations are shut down for maintenance.

22. For the coming summer the Large Combustion Plant Directive (LCPD) combined with relative coal and gas fired generation economics could lead to some more marginal opted out coal power stations moving to a long notice to be available or being unavailable for periods. We saw some of this activity taking place last summer. As it is in response to market conditions we do not anticipate any issues if this were to reoccur in summer to come. Indeed with healthier margins than last summer and a number of new CCGT generators now becoming available there is greater scope for marginal coal fired generation to stand down for periods of time.

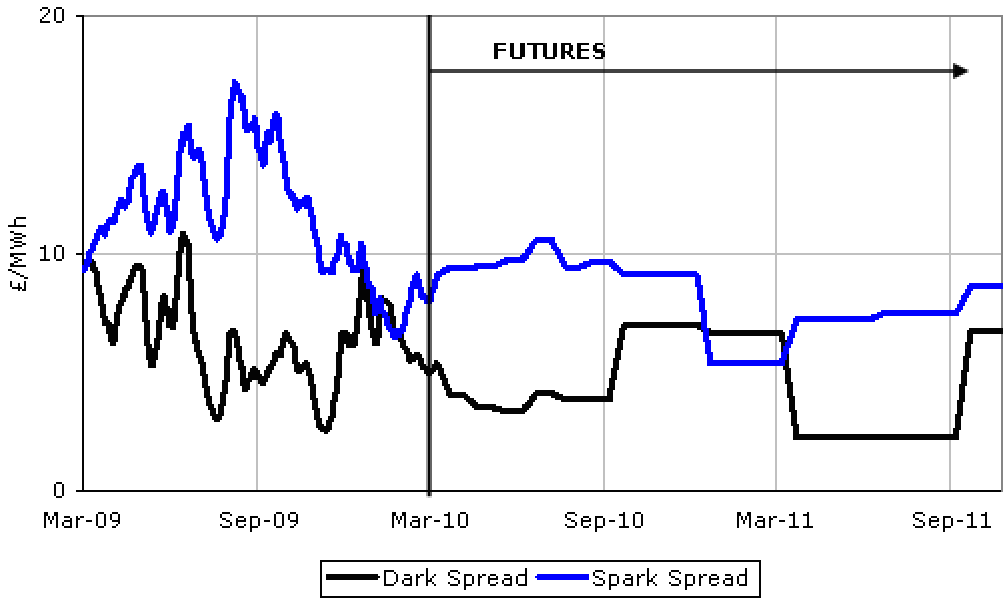
23. The economic recession has contributed to lower demands than would otherwise have been forecast for the coming summer. A key metric we focus on for gaining a perspective on energy security of supply is the remainder value of declared available generation minus our reserve requirements and minus demand, which we term surplus. Taken together, the increase in available generation capacity through new CCGT commissioning and lower demands are contributing to higher summer generation plant surpluses than last year.

24. Currently the forward looking surpluses for summer are comfortable, but of course this picture is likely to change as we approach real time.

25. On the generation availability side we foresee no issues under normal conditions given our assumption that the market responds to changes in demand by making generation available as required.

26. Electricity prices and fuel costs for coal and gas on a clean basis for summer 2010 (see Figure E1 and Appendix 1) show that gas is preferred to coal generation. We expect to see higher load factors from gas power stations during summer to come than coal where maintenance programmes allow.

Figure E1 – Comparison of Dark Spread and Clean Spark Spread

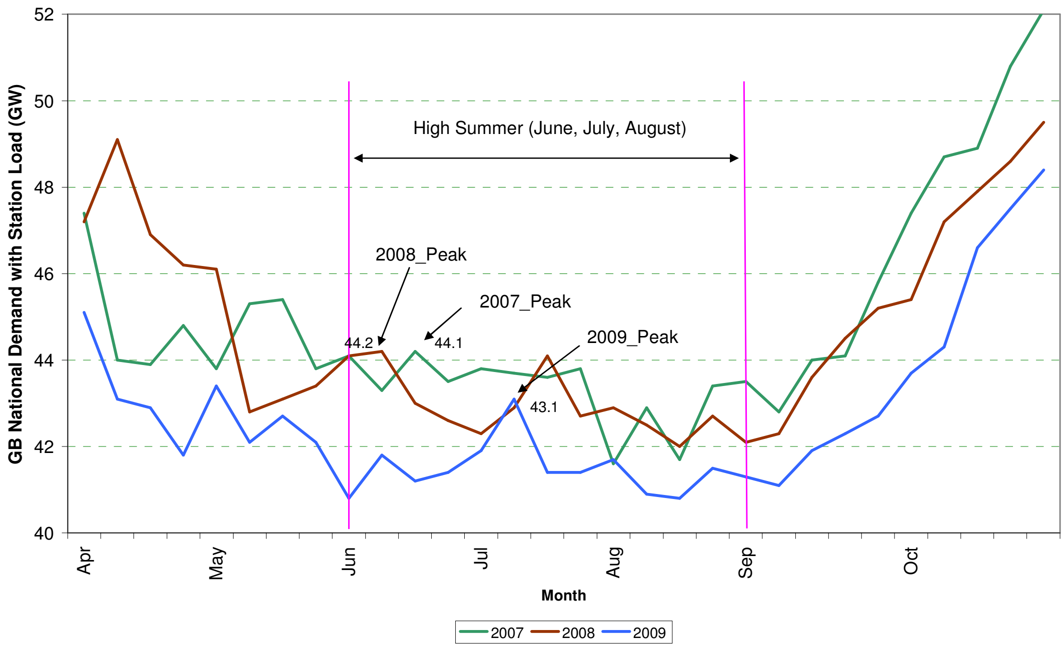


Historic Summer Electricity Demand

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

28. Figure E 2 shows the weekly peak demand for the last 3 summers. The graph highlights the lower demand during "high summer" months (June, July and August) when the weather is generally warmer and brighter. Furthermore, minimum demand generally occurred in late July or early August when many people are on holiday. The drop of the recession in 2009 is clearly visible with the demand peak being around 1.1GW less.

Figure E 2 – Weekly Peak Demand of Last 3 Summers



29. The UK mean temperature for last summer was 14.8 °C this was 0.7°C above the 1971-2000 average. Broken down this meant temperatures were 1.1 °C above average during June, 0.3 °C above during July and 0.7 °C above in August. The cloudy conditions in July and August meant that temperatures tended to be lower in the day and warmer at night relative to normal[1].

30. The UK summer rainfall was above normal, but the three months had contrasting patterns. June was drier than normal in most areas, with less than 30% of average rainfall in Cornwall and parts of south-east England. July was much wetter than normal, with over 200% of average rainfall having been widely experienced; for England and Wales it was the wettest July on record in a series back to 1914. In August the wettest weather was focused on western Scotland and Cumbria. Summer overall was wetter than normal in most areas, particularly the Scottish Borders, and parts of northern England and south Wales, with the drier exceptions being in East Anglia and south-east England.

31. Sudden, extreme rainfall events have previously occurred during summer periods. Where these caused issues during 2007 they were associated with the wettest June since met office records began in 1914. It's very unlikely that such events are repeated, and our preparedness is heightened since the 2007 incidents[2] which further reduces the risks. Other weather related events such as lightning strikes do from time to time impact our operation of the transmission system during summer. We have a proven track record of managing the effects

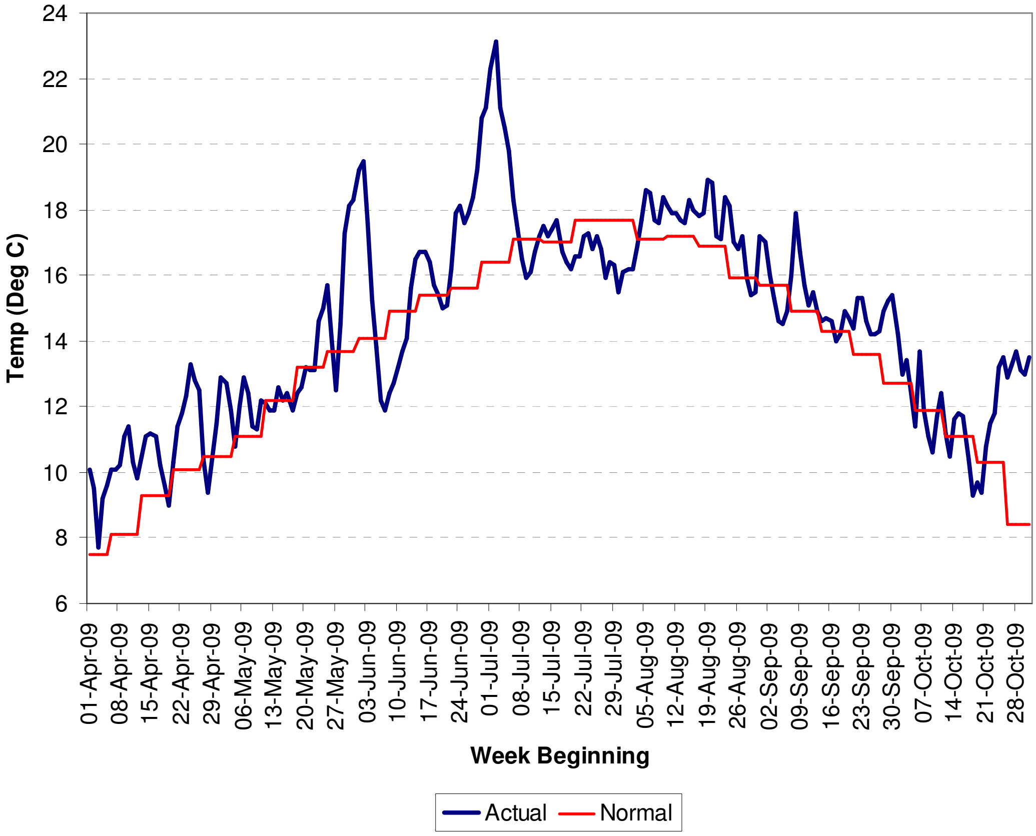
[1] Information for sections 29 and 30 comes from http://www.metoffice.com/climate/uk/2009/summer.html

[2] See http://www.nationalgrid.com/NR/rdonlyres/AADCC1E5-D360-41FD-ADC1-84AE4E165748/18859/The_Floods_01Aug07.pdf

of weather related events on meeting electricity demand as part of our business as usual operations. Therefore we are confident this places us in a strong position moving forward.

32. Figure E3 shows past summers average temperature for GB at 12:00hrs against a weekly 30 year average (normal weather). It can be seen that the peak demand of high summer shown in figure E2 corresponded with the hot spell in mid July.

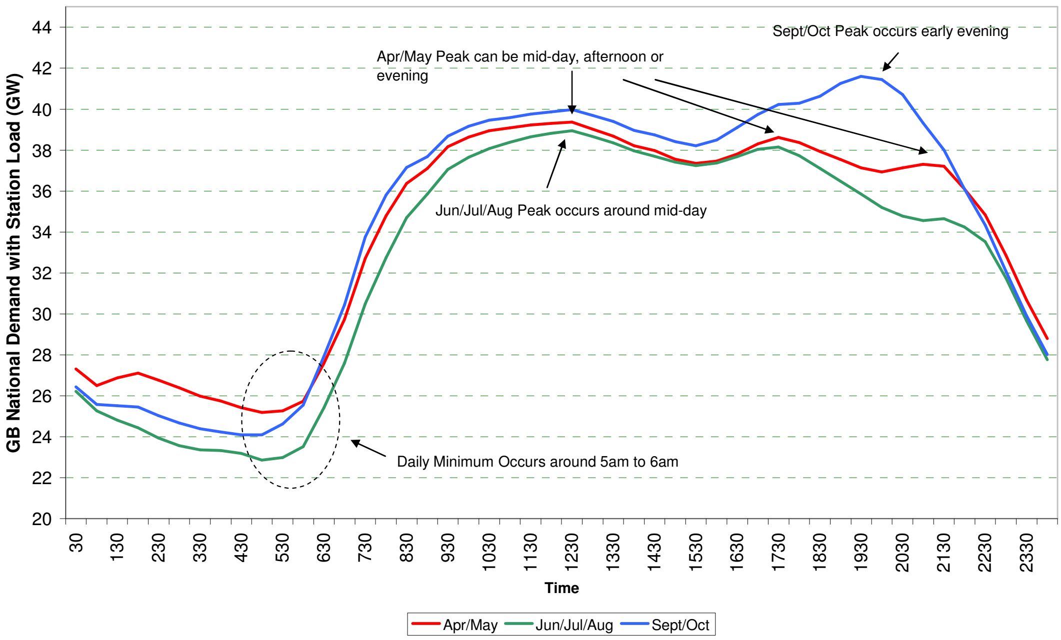
Figure E 3 – Mean Temperature for GB at 12:00hrs against a 30 year average.



33. Figure E 4 depicts the daily demand profile of summer months. In "high summer" months of June, July and August demand is reasonably flat across the working day (9:00 to 18:00), with a strong tendency to peak at midday. During April and May, demand is also reasonably flat across the working day, but there is a higher chance that demand will peak in the late afternoon, dependent upon the weather conditions. In the shoulder months of September and October the daily peak occurs in the evening, due to the effect of darker evenings increasing the lighting load. Daily minimum demand generally occurs around 5:00~6:00am.

34. In the coming summer, the football world cup could result in large TV pickups[3]. A key factor impacting the size of the TV pickups are the progress of the England team, though in any case a popular sporting event final will result in large changes in the profile of power demand. In 2002 we saw a TV pickup of 2.6GW at half time during a football match between Brazil and England. We routinely manage changes in electricity demand as part of our second by second balancing of electricity demand and supply and are therefore confident of being able to manage these effects on electricity demand during summer to come.

Figure E 4 – Half-Hourly Demand Profiles



Minimum Demands

35. The minimum demand is expected to occur on a Sunday around 5am to 6am in Mid July as per previous years shown in figure E5. The minimum demands of the year in summer have reduced by 2.3 GW in the last 2 years and 1.4GW from 2008 to 2009.

[3] See this factsheet for information on TV pickups and demand forecasting more generally. http://www.nationalgrid.com/NR/rdonlyres/1C4B1304-ED58-4631-8A84-3859FB8B4B38/17136/demand.pdf

Figure E 5 – Weekly minimum weather corrected demands

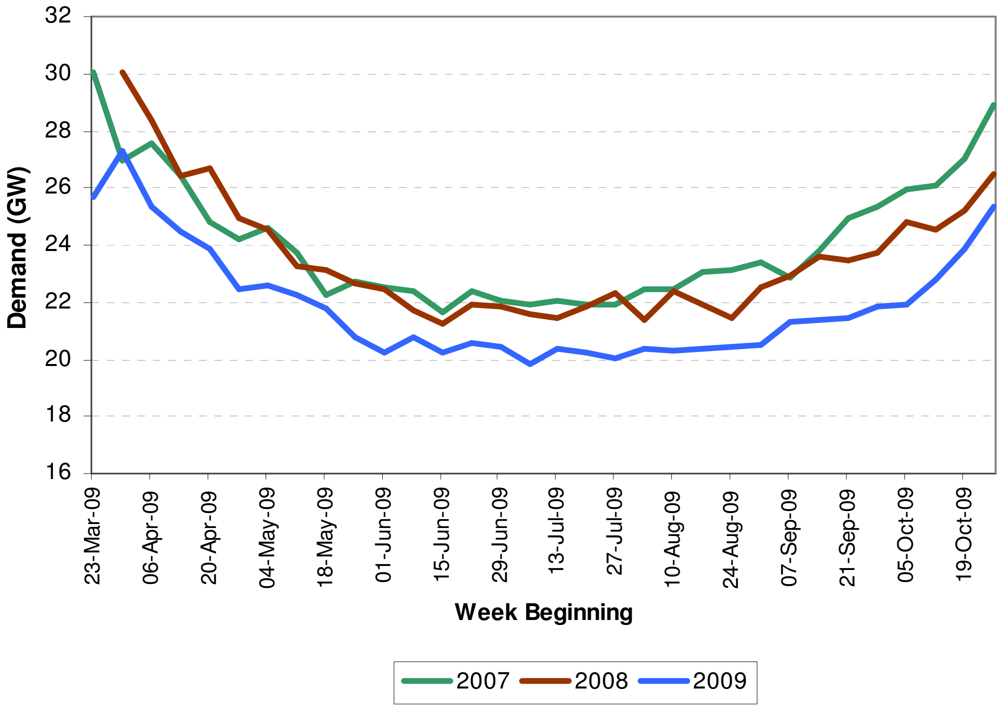


Table E 1 – Annual minimum weather corrected demands (MW)

GB Minimum Demands Including Station Load

Year		2005	2006	2007	2008	2009
Minimum Demand		22012	22535	22337	21492	20057
Date		03/07/2005	09/07/2006	29/07/2007	20/07/2008	02/08/2009
Time		05:30	05:30	06:00	05:30	06:00

36. To show how significant the drop is, in figure E6 are the last 10 years of England and Wales minimum demands. Our series of minimum demands is shown for England and Wales to enable us to provide a history going back before the BETTA market reform in April 2006.

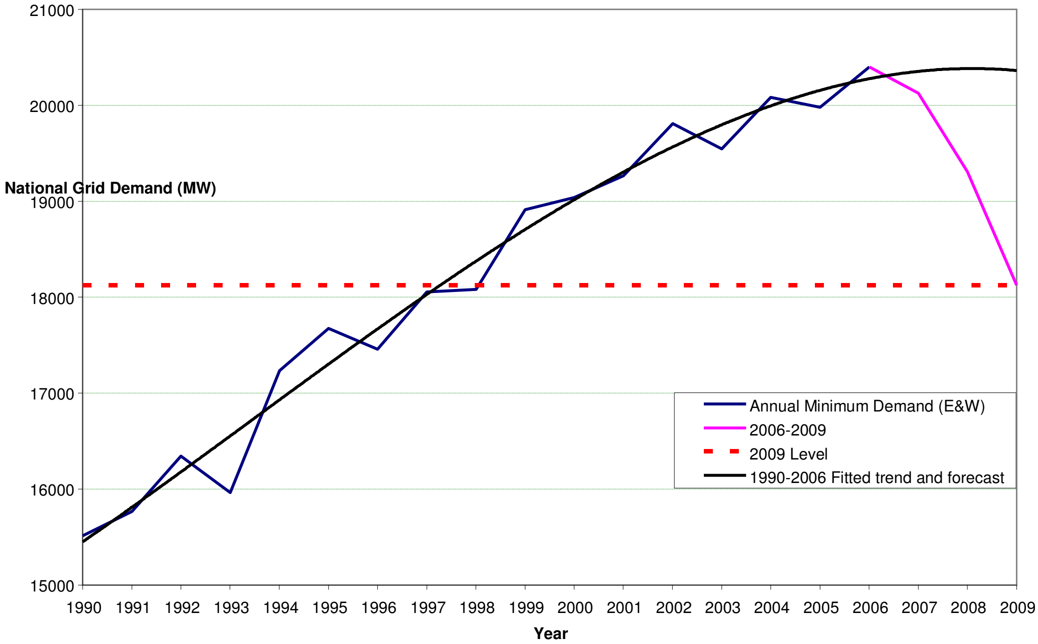
37. The drop in demand over the summer minimum from 2009/10 on 2008/09 is in contrast to the winter peak ACS[4] demand change that has only dropped 0.2GW from 2008/09 to 2009/10. The extent of any further decrease in minimum demand between summer 2009/10 and the summer to come is a key area of uncertainty for us that may impact on our operation of the power system, though clearly doesn't mean that electricity demand cannot be met.

38. Weather correction of the minimum is less important than with maximum demands as the temperature, wind speed and illumination have little or no effect. The minimum demand is potentially more strongly indicative of the economic situation because it represents the underlying reduction, including industrial shut downs. Winter peak demand trends and how the recession has impacted them are different because there is

[4] Annual Average Cold Spell (ACS) Conditions are a particular combination of weather elements which gives rise to a level of peak demand within a Financial Year which has a 50% chance of being exceeded as a result of weather variation alone.

much less holiday effect and heating is used in cold weather almost irrespective of economic conditions.

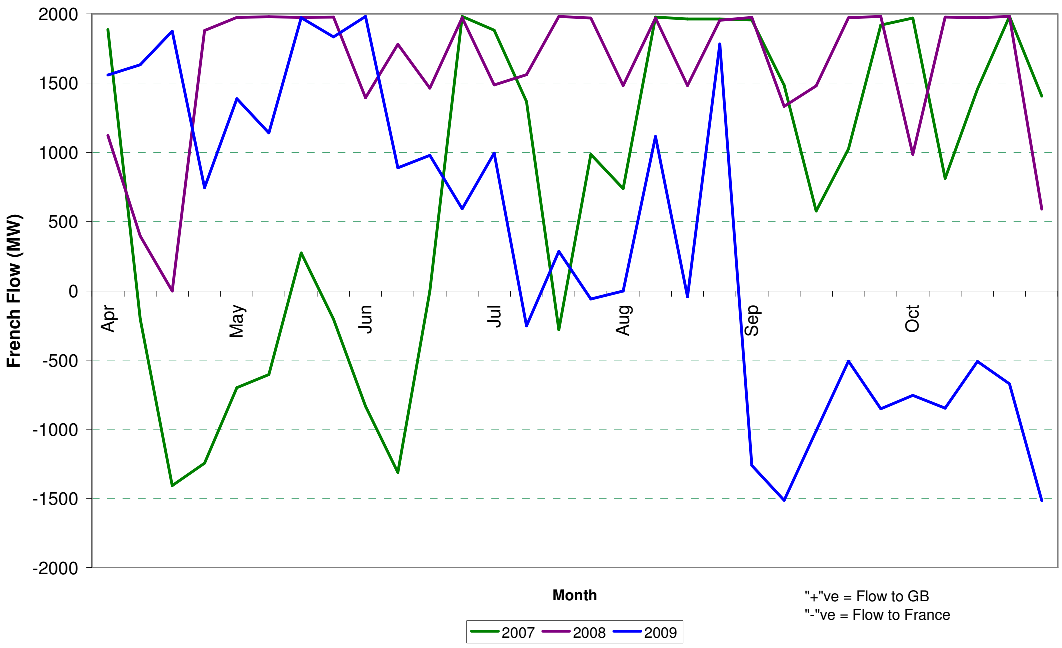
Figure E 6 – England and Wales minimum demands (MW)



Interconnector Exports to France

39. Historically, across the summer there has been a varying profile of import/export flows on the GB-France Interconnector across the day. Last summer there was a clear switch between importing to exporting towards the end of summer due to market signals influenced by the decrease in the value of sterling and increased margin tightness in France illustrated in Figure E 7. Interconnector flows are strongly correlated with the relative market prices with power flowing into the highest priced market. Detailed interconnector flow historic data are available on the National Grid website and close to real time information on www.bmreports.com.

Figure E 7 – French flows at time of TSD[5] Weekly Peak Demand



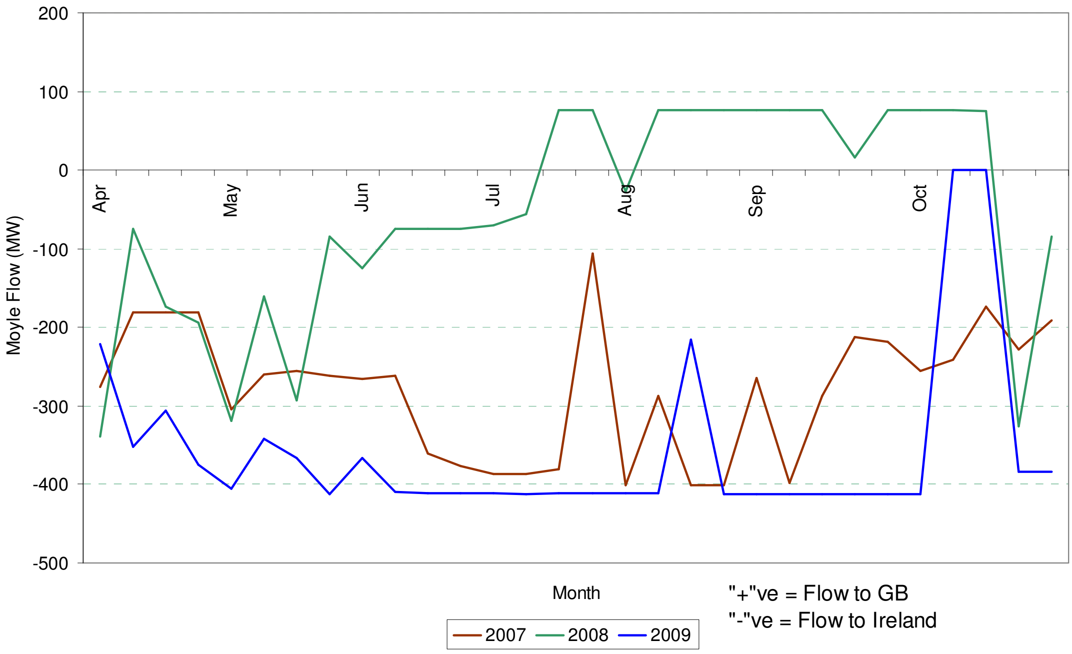
Interconnector Exports to Northern Ireland

40. The interconnector between GB and Northern Ireland (NI) can physically transfer up to 500 MW in either direction. Commercial or contractual limits, such as the amount of capacity auctioned or GB Transmission Entry Capacity (TEC) limit the physical flow seen. For example the interconnector has only 80 MW of TEC at the GB end.

41. Historically the pattern of summer flows between GB and Northern Ireland (NI) was mainly of GB as an exporter to NI of around 100-400 MW. Figure E 8 shows we have historically been exporting over demand peaks, but this pattern changed in 2008 with higher levels of import to GB occurring more frequently than recent prior years. The change in pattern in 2008 was mainly driven by relative market power prices making it attractive to import power into the GB market from NI. But the historic trend of the past of mainly importing returned last summer. Detailed historic interconnector flows are available on the National Grid website and real time flows are published on www.bmreports.com.

[5] Transmission System Demand is the value of demand including transmission losses, station transformer load, pumped storage demand and interconnector demand.

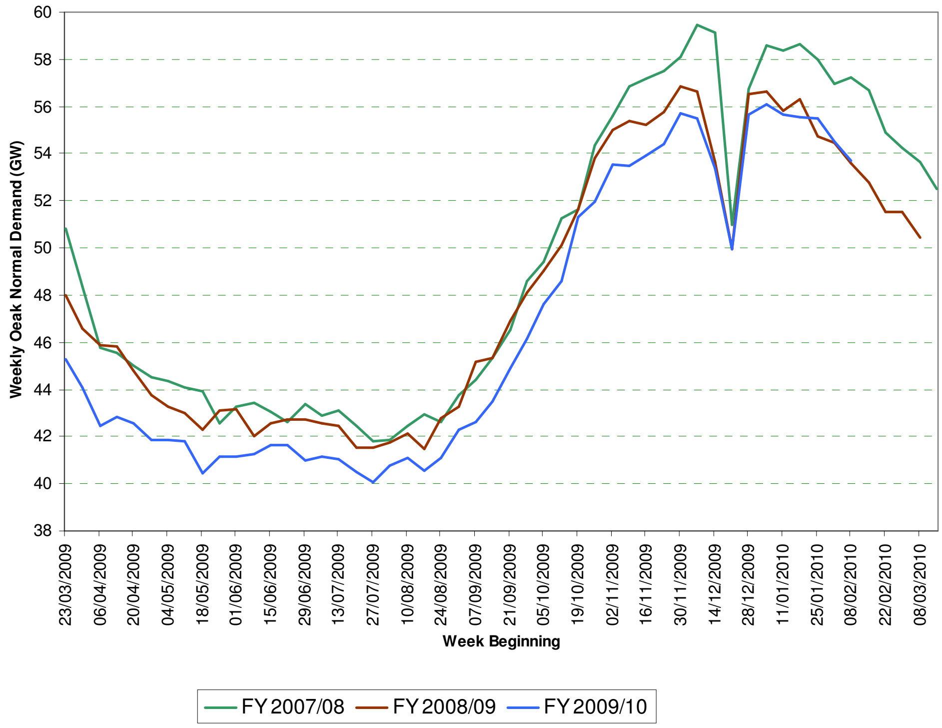
Figure E 8 – Moyle flows at time of TSD Weekly Peak Demand



Summer Demand Forecast 2010

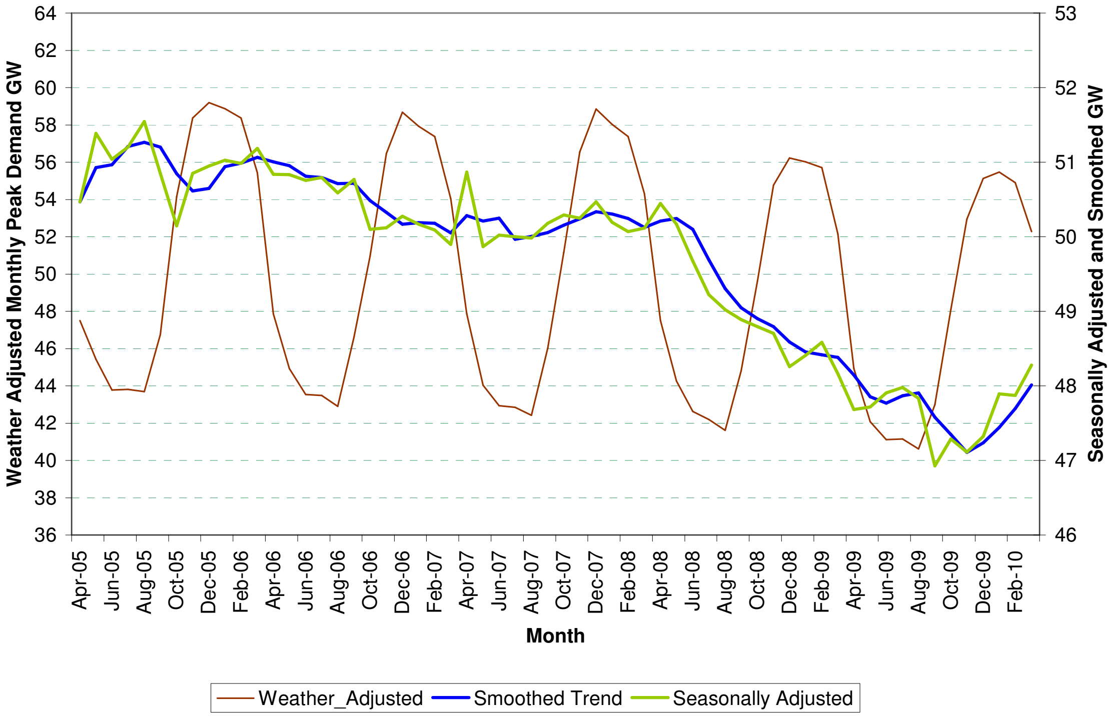
42. From late summer of 2008 we observed a sharp down turn in electricity peak demand compared to the previous year. Each year is shown in Figure E 9 which depicts the weather corrected weekly demand of the last 3 years. The average demand reduction was around 2 GW for the period from October 2008 to November 2009 compared to the year before. The reduced demand was consistent with the negative growth of the British economy recorded in the last two quarters of 2008 which continued in to 2009. The rate of demand reduction began to slow from late November 2009, narrowing the difference between the previous year and from January 2010, demand is in line with last year.

Figure E 9 – Weather Corrected Weekly Demand



43. Furthermore, the seasonally adjusted and weather corrected demand trend shown in Figure E 10 shows that, even before the recession, a reduction in electricity demand started to set in from 2005 due to price responses from consumers, energy efficiency measures and growth in embedded generation. However, there was a much sharper fall starting in summer 2008 as the recession took hold. There currently appears to be a stabilisation of demand at around last years levels so we have carried this though to our forecast of this years demand. There appears to have been an underlying increase in demand levels over the last three months, though we are cautious about if this will be sustained and also the extent of any increase in underlying demands going forward.

Figure E 10 – Seasonal and Weather corrected Monthly Peak Demand

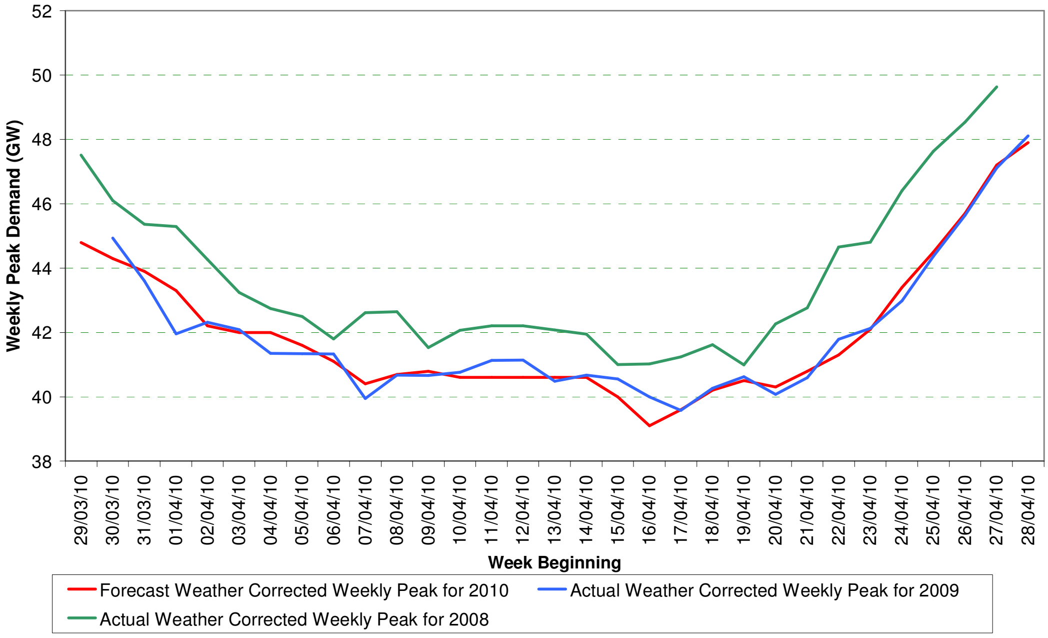


44. For the summer 2010 demand forecast there is a higher than normal degree of uncertainty. The economic forecasts from several different institutions suggest that the average GDP growth rate[6] in 2010 will be marginally positive. We have assumed that the recent demand drop already reflected will stabilise against that observed last summer. Figure E 11 shows the weather corrected weekly peak of summer 2008, 2009 at weekly average weather and the forecast of summer 2010 under the same average weather conditions. The forecast will continue to be updated as part of our normal process and will be published on the www.bmreports.com[7].

[6] http://www.hm-treasury.gov.uk/d/201001forcomp.pdf

[7] http://www.bmreports.com/bsp/BMRSSystemData.php?pT=WEEKFC

Figure E 11 – Summer 2010 Weekly Peak Forecast in comparison to Summer 2009 & 2008

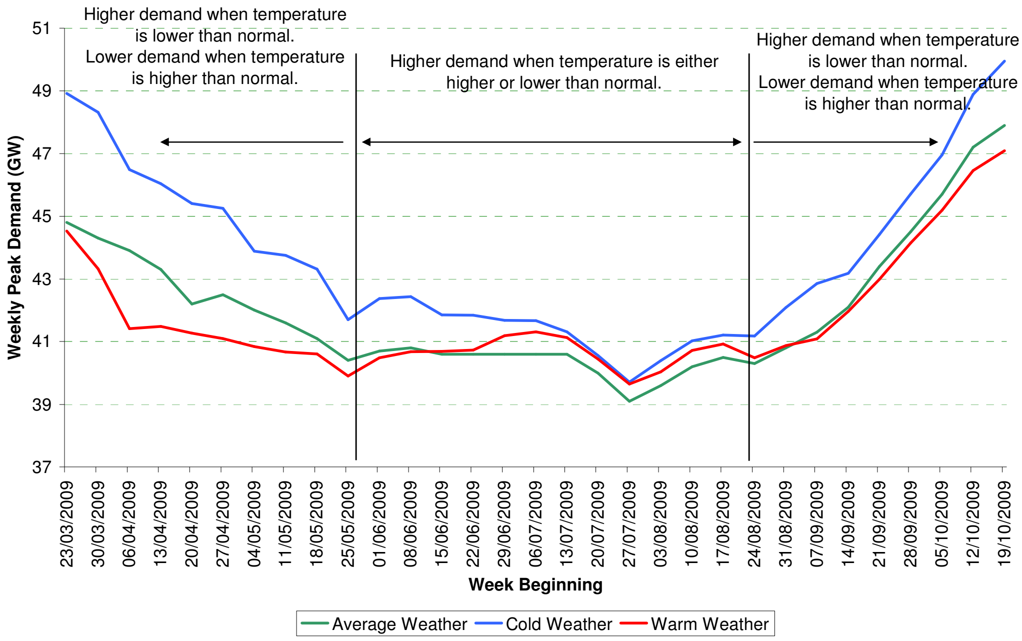


Demand Response to Weather Variation

45. Demand response to weather conditions varies over different years as demand characteristics change. Figure E12 depicts the relationship between summer demand and weather, at different times of the summer based on historic demand and weather data.

- Demand is generally higher when the temperatures are abnormally cold. This is the case between April and mid-June, and also in the late summer period from September.
- In mid-June to mid-August, the temperature is often close to the comfort temperature of 16-17 degrees. Either a fall or increase in temperature will cause demand to increase.

Figure E 12 – Electricity Demand under average, warm and cold conditions



46. In addition to assuming the underlying demand stabilization, we assume the Moyle and the GB-France interconnector are at “float” (no import or export). This compares with an average of 300MW export to Northern Ireland and import flow of 400MW from France over peak periods during summer 2009. This float assumption is made to enable readers of this report to apply their own best assumptions or scenarios to electricity interconnector behavior.

Generation Capacity

47. There has been a small increase in the operational view of generation capacity since we issued the Winter Outlook Final Report. Our operational view of generation capacity has risen from 77.0 GW to 78.3 GW. This is due to a combination of reductions and additions as detailed below. Some minor reductions in capabilities across the generation fleet have been noted.

48. Oldbury nuclear power station has been granted a further life extension so both units are still included in the operational capacity.

49. Two CCGT stations, Langage (0.9 GW) and Immingham Stage 2 (0.5 GW), have been commissioning over the winter and are expected to complete commissioning in the near future. Both have therefore been included in the operational capacity for this summer. Three further CCGT stations are expected to be commissioning over the next few months. These are Staythorpe (1.7 GW), Severn Power (0.9 GW) and Grain (1.2 GW). However, these three stations have not been included in the operational plant capacity as they will not be fully operational by the start of the summer.

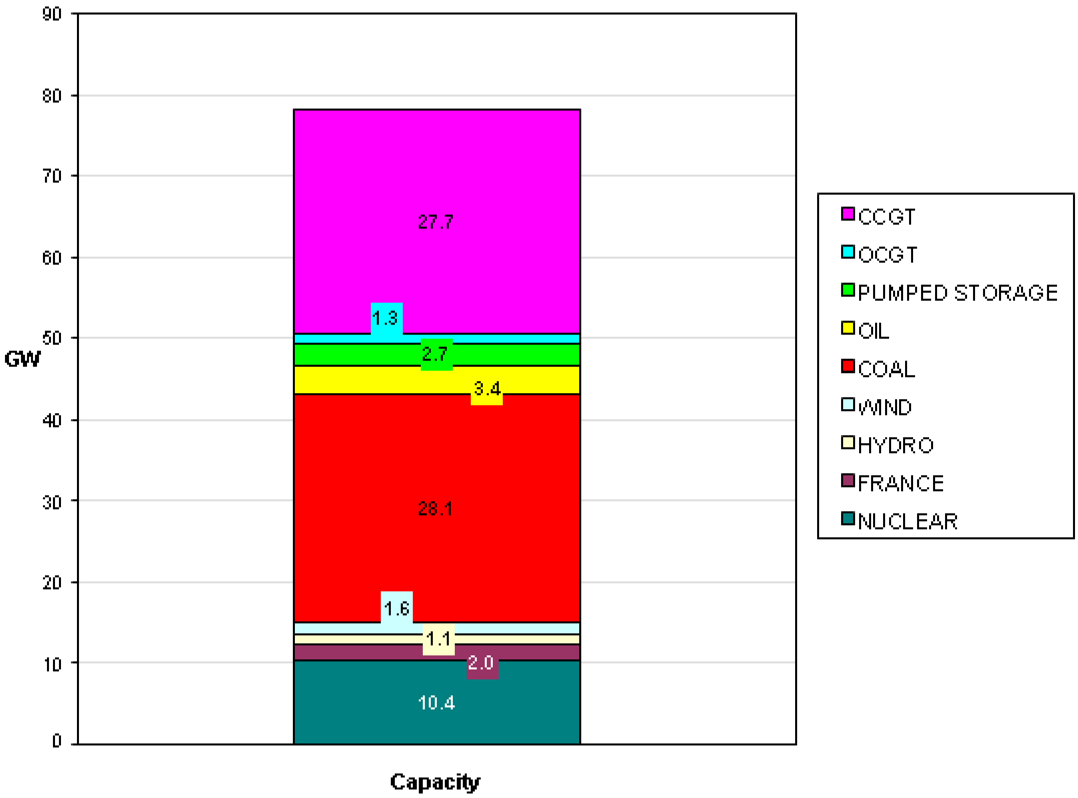
50. Wind continues to increase its share of the GB generation market and the amount of fully operational capacity visible to National Grid is now

1.6 GW. A further 300 MW is expected to come on line during the course of the next few months but this has not been included in the operational plant capacity as the wind farms will not be available to generate at full output by the start of the summer. Over the whole of summer and rest of the year, significantly more wind generation capacity could come on line though there is some uncertainty as to the rate at which this happens.

51. During the summer, wind generates on average around 20% of its maximum output, but output can vary between zero and full output over short periods of time. The published surpluses include wind farm availability based on submissions received or Operational Rated Capacity for non-submitting wind farms. By the end of the year it is planned to publish forecast Output Useable split by fuel type[8] to give an indication of how much the forecast surplus would be reduced during periods of low wind speed.

52. The changes outlined above give our current operational view of 78.1 GW of generation capacity that is anticipated to be available for the start of summer 2010. A breakdown of this capacity by fuel type is shown in Figure E 13.

Figure E 13 – Generation Capacity – Summer 2010



[8] We supported BSC Modification P243 that delivers this from November 2010. See http://www.elexon.co.uk/changeimplementation/ModificationProcess/modificationdocumentation/modProposalView.aspx?propID=268

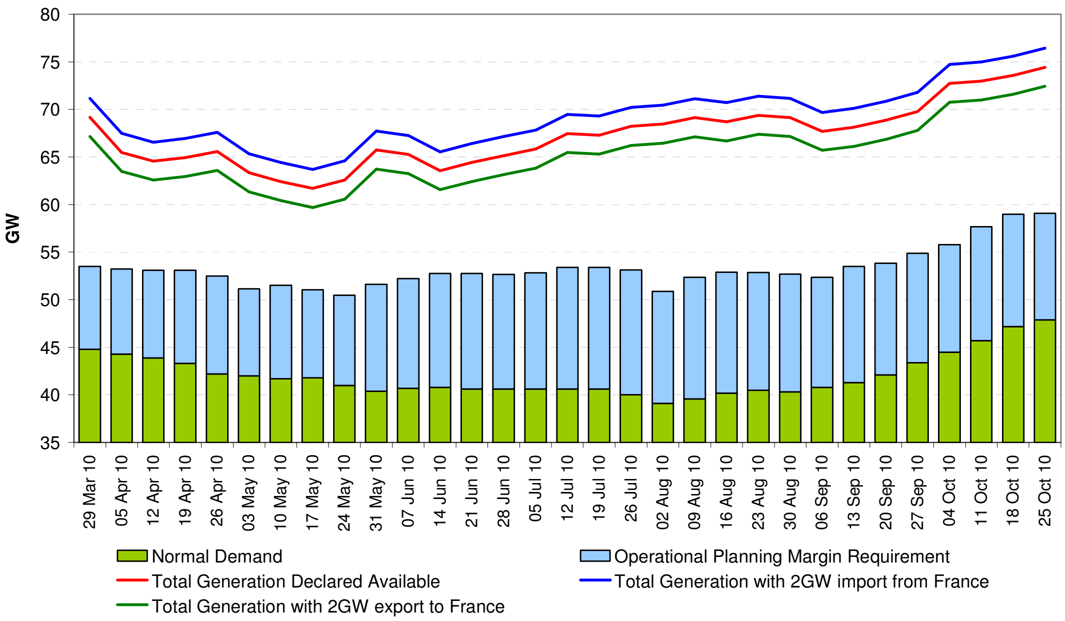
Generation Availability

53. As usual over the summer period there will be a significant generation outage programme that will reduce the amount of available generation plant. Generation surplus, which is the excess of generation availability over demand and reserve requirements, is published on www.bmreports.com.

54. At present there is a comfortable surplus for every week in the summer based on the current generation outage programme provided by the generators. Therefore no problems are expected in being able to meet demand over the summer.

55. Figure E 14 shows the normal demand levels and the generator availability declared to National Grid by Generators under Grid Code Operating Code 2 (OC2), both including and excluding 2 GW of import or export from the GB-France Interconnector[9]. As the interconnector between NI and GB is relatively small and over the summer tends to impact our amount of constrained generation in Scotland rather than our national surpluses, no adjustments have been made for imports or exports of electricity to and from NI.

Figure E 14 – Declared Generation Availability



56. Figure E 14 illustrates the position for this summer based on forecast normal demands, i.e. demands based on average weather conditions for each week. The chart shows weekly generation availability as declared by generators under the Grid Code. This reflects planned unavailability

[9] The French Interconnector comprises two pairs of 500MW circuits and has annual availability around 95-97%. Full availability is assumed at peak times although if an unplanned outage were to occur then availability could be reduced in increments of 500MW.

as currently notified by generators' outage plans, but does not include an allowance for unplanned losses of generation.

57. It is necessary to hold varying levels of reserve such that within-day there is adequate reserve to cover for short-term generator breakdown, demand forecast errors and other specific issues such as the effects of transmission system constraints or generator commissioning. This amounts to a requirement to discount up to 12 GW at the planning stage from the generation declared technically available. The allowance is shown in Figure E 14 as OPMR (Operational Planning Margin Requirement). More detailed breakdowns and explanation of OPMR categories are shown on our website[10].

58. The OPMR is normally higher in the summer than winter to take account of generation plant constrained by transmission outages, particularly on the Scotland to England transmission circuits.

59. For this summer, the OPMR requirement is increased further to allow for the uncertainty in the new CCGT plants that are due to be undergoing commissioning, but declared technically available. This adjustment to the OPMR reserve requirement in respect of commissioning plants is removed once they have proved to be operating reliably.

60. As can be seen in Figure E 14, with full exports from France the excess generation over average weekly peak demand would be in the range of 20-30 GW. However, this does not reflect the fact that actual power station availability tends to be considerably less than that declared 2-3 months ahead, and in an average summer there will be times when demand is up to 1.5 GW above normal when temperatures are either significantly above or below average.

61. It is expected that some LCPD (Large Combustion Plant Directive) opted out coal and oil fired generation plant will again go "summer cold" so that the affected units would only be available with long notice periods. Any such action is expected to be in response to a sufficiently large plant surplus but if the generation was required at some point, due to an erosion of the surplus, then it is assumed that generators would be able to respond in time to the appropriate market signals.

62. The planned summer outages for the two largest fuel types of generation, coal and gas, are shown in Figure E 15. This can be compared to the outages that were notified for last summer at the beginning of March 2009 shown in Figure E 16. This year there is forecasted to be less of an impact on generation margins from planned outages because there are less planned outages of coal and gas stations, and also because planned outages are more evenly profiled over this summer. This view is based upon submissions of generation outage plans provided to National Grid by operators. CCGT outages on average are reduced by 2% (60 MW) compared with 2009 and coal outages are down by an average of 23% (1400 MW). There is

[10] See http://www.nationalgrid.com/uk/Electricity/Data/reserve/ linking through particularly to "BMRS surplus" related data.

insufficient diversity of ownership in other generation fuel types to enable the analysis to be shown for them[11].

Figure E 15 – Planned outages by fuel type for 2010

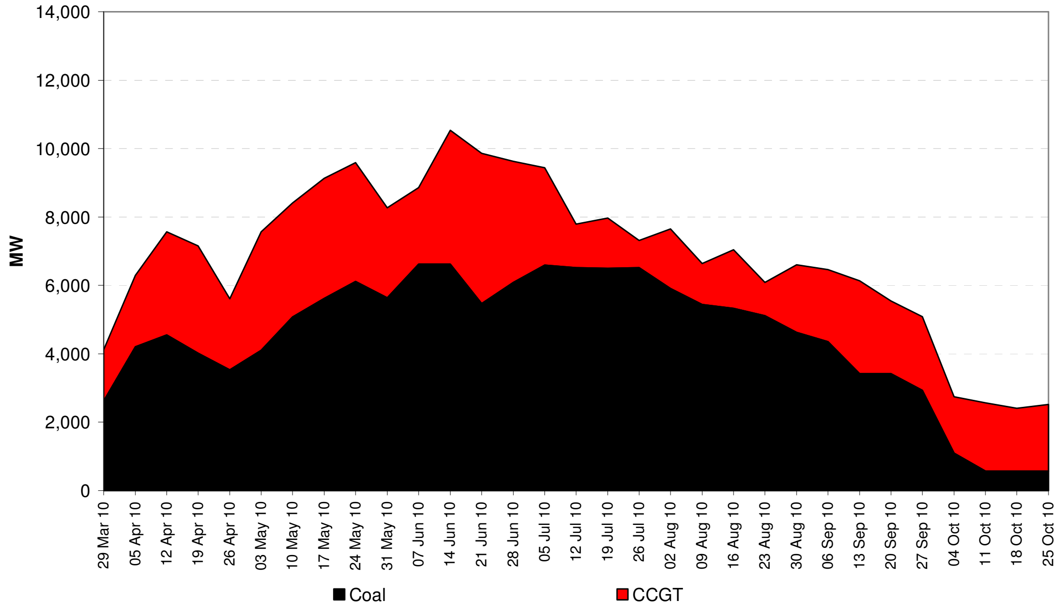
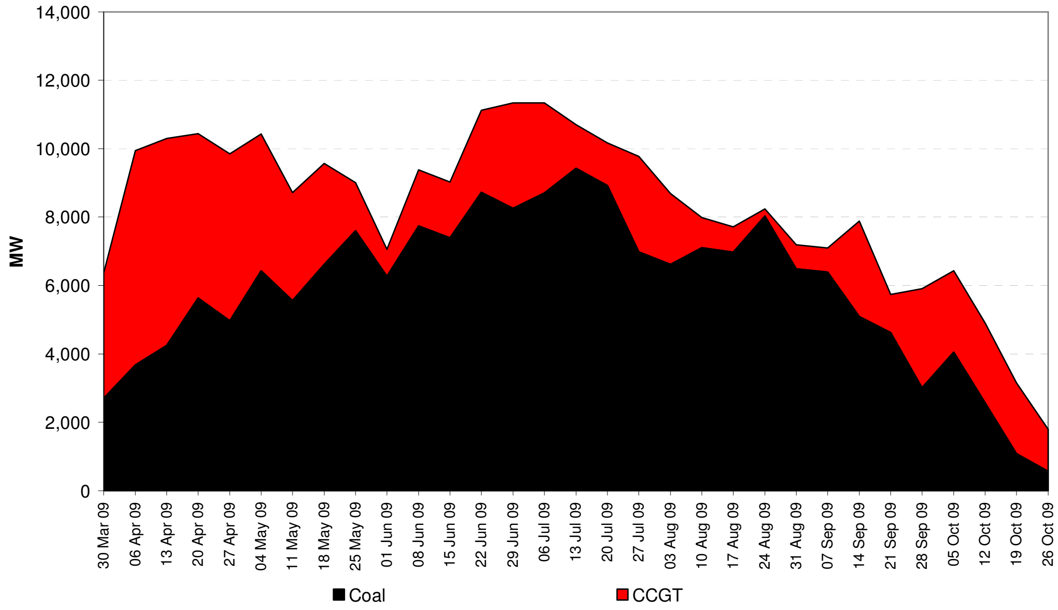


Figure E 16 – Planned outages by fuel type for 2009

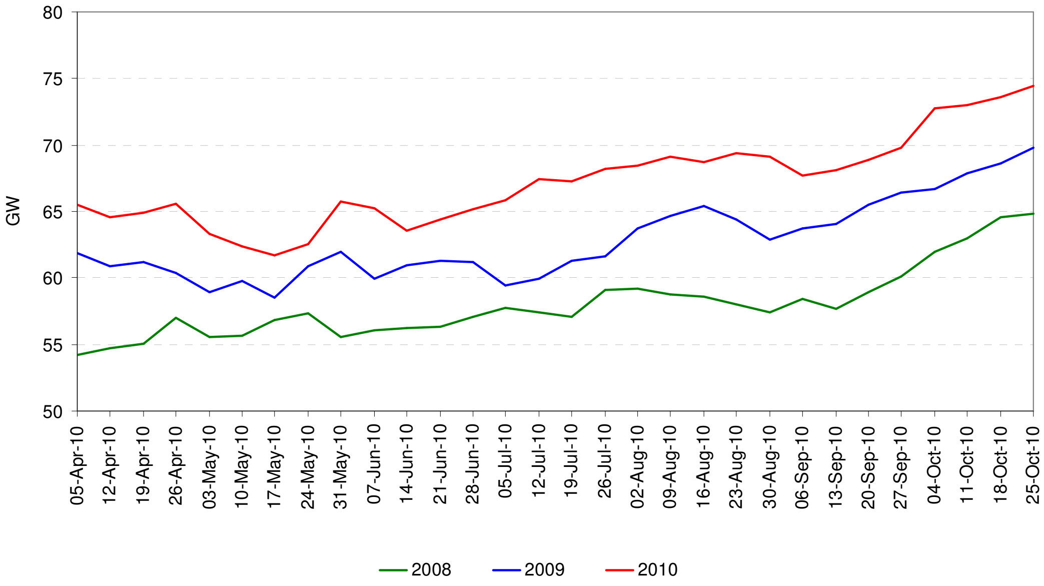


63. The current levels of notified availability are higher than the last 2 summers as illustrated in Figure E 17. This is due to improved nuclear

[11] BSC modification P243 will provide generator and by fuel type level of outage information. This information will be provided by National Grid to Elexon to be published on BMRS from November 2010.

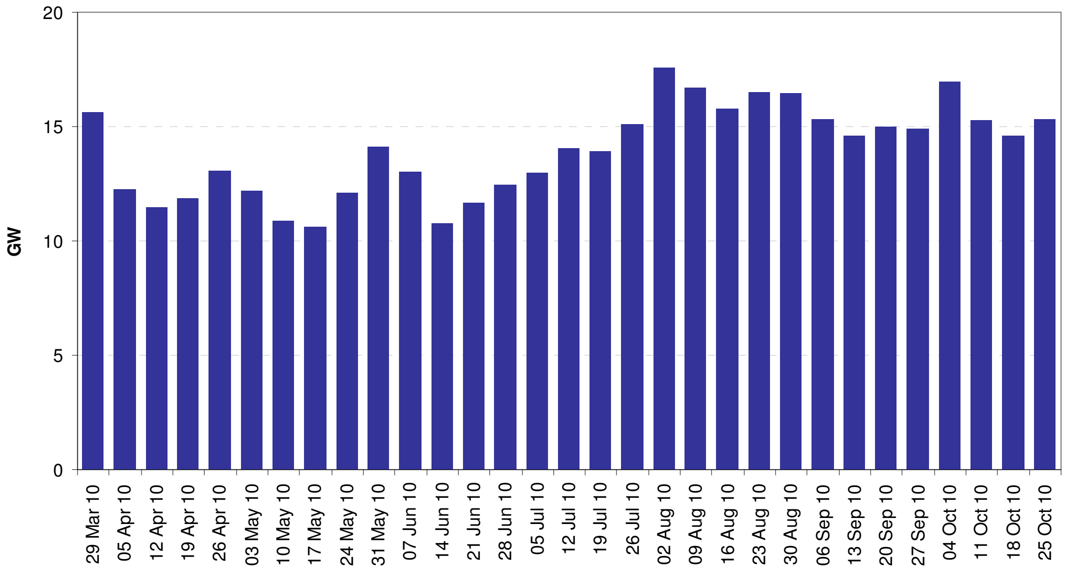
availability and new CCGT plants coming on stream. Note that in charts of availability the new CCGTs are treated as available, but in terms of calculating surpluses (shown in E14) they are discounted until they are commercially operational through their inclusion in OPMR. A total of 4.3 GW is currently in this category.

Figure E 17 – Declared Generation Availability for the last 3 summers



64. The current surpluses over the summer, calculated as the excess of available generation over forecast demand and reserve requirements, are shown in E18. The surpluses are based on the interconnectors between GB and France and between GB and Northern Ireland being at float i.e. zero power transfer.

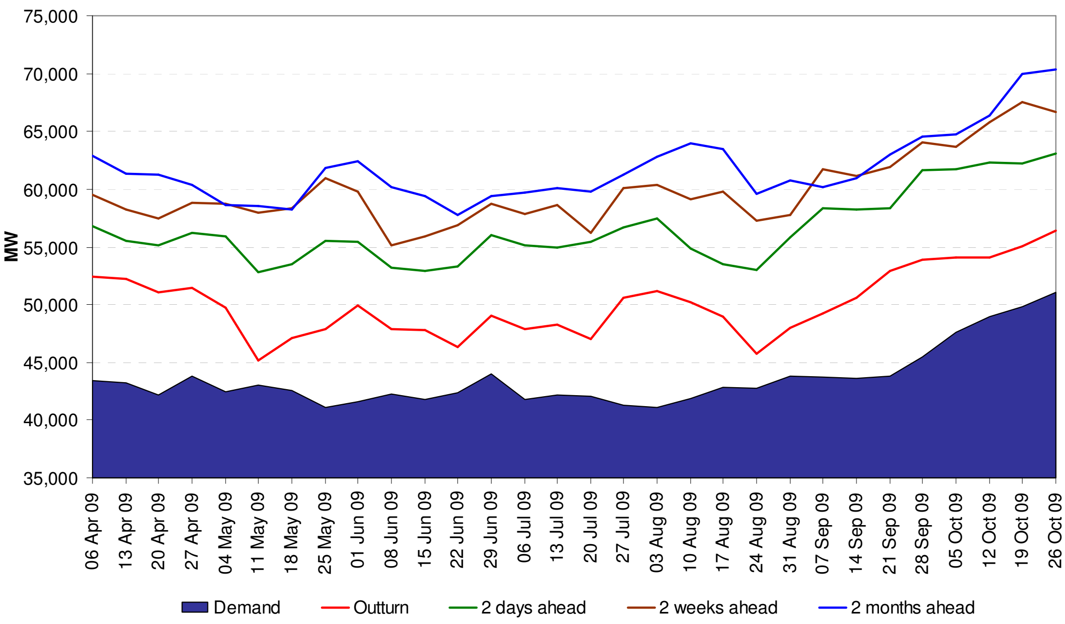
Figure E 18 – Generation Surplus



65. Outturn generation availability will be lower than that currently indicated due to new outages being planned, short term breakdowns and plant shortfalls.

66. Figure E 19 below shows the generation availability last summer at the time of the weekly peak demand as it evolved from 2 months ahead to real time. This shows that the outturn availability reduced by up to 15 GW compared to the position at 2 months ahead.

Figure E 19 – Changes to Generation Availability at the time of the Weekly Peak Demand for Summer 2009



(Outturn availability excludes interconnector imports and wind)

System Warnings

67. System warnings may occur at any time of the year. Recent experience shows they may be issued in high summer as occurred for 6 days between April and September inclusive during summer 2008. No system warnings were issued during summer 2009 [12]. System warnings during the summer have most often been associated with short term generation unavailability relative to demand and limited compensatory action by the market in making replacement generation available. System warnings are a useful tool for us to highlight a potential issue to stimulate market reaction where it hasn't already taken place to make additional generation plant available or additional demand side services.

Market Information

68. In response to industry requests, National Grid and Elexon have made some improvements to electricity operational information. A summary of key parameters, including demand, generation availability and surpluses are calculated by National Grid and are published on a rolling update basis on the Elexon BM Reports website[13].

69. This information helps to facilitate efficient market operation as it informs market participants of the expected levels of demand and therefore the

[12] Indeed no system warnings have been issued at all since 15th January 2009.
[13] See http://www.bmreports.com/bsp/bsp_home.htm for the electricity market summary page.

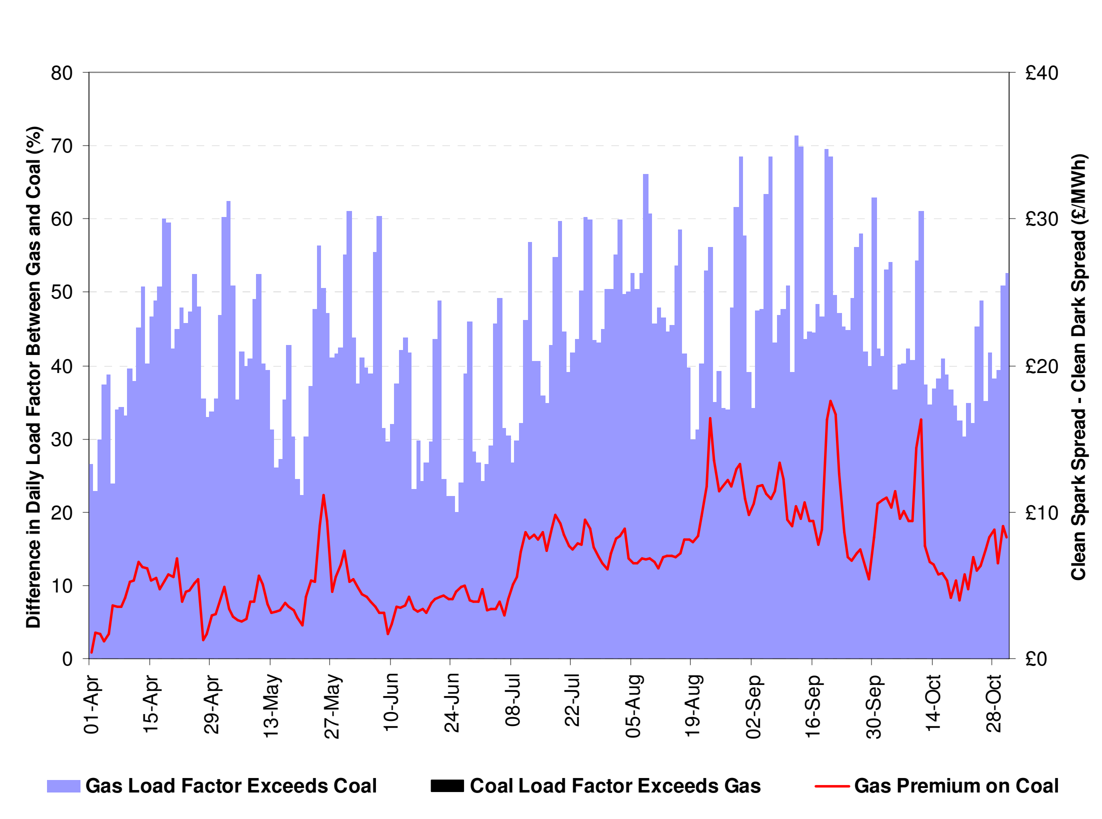
amount of generation they may need to contract with to meet their customers' demand.

70. We continue to proactively review the operational information we receive and also provide to the market to ensure that we are able to facilitate efficient market operation and safe, secure and efficient and economic power system operation. We have raised modification P244 and actively contributed to the working group for P243, both of which will further improve market information and go live in November 2010.

Merit Order

71. Figure E 20 shows the relationship between spark and dark spreads over summer 2009. It can be seen that throughout the summer the spark spread remained higher than the dark spread leading to a higher load factor for gas generation than coal.

Figure E 20 – 2009 Summer Coal and Gas Load Factors and Clean Spreads.



72. At current market prices for summer 2010 the clean spark spread shows a significant advantage over the clean dark spread (see appendix 1 and figure E1). This suggests gas fired generation will continue to run ahead of coal although fuel prices are very volatile and clearly this may change.

73. Forward prices for both peak and base load power are currently higher in France than GB over the summer as a whole so this suggests the French interconnector is likely to be exporting to France for much of the

summer. Interconnector transfer levels between markets are highly correlated with relative prices and often even vary within day.

Transmission System Issues

74. 2010 sees the continuation of major works to construct or rebuild major sections of the transmission system in Scotland and the North of England, to deliver additional transmission capacity to transport energy from new renewable generation (wind) in Scotland, as part of the Transmission Investment for Renewable Generation (TIRG) works.

75. As part of this project, major outages are required to upgrade the capacity of the transmission circuits that cross the Cheviot boundary. This is the third year of a three year project to upgrade the transmission capacity of the circuits crossing this boundary from 2.2 GW to 3.2 GW by 2011/12.

76. Additionally, significant outages are required for construction works within Eastern England and the southeast, primarily to facilitate generation connections.

77. The network outages to undertake the work will reduce the available transmission system capacity between Scotland and England, as well as between the North and South of England, and in the South East.

78. To manage the resulting constraint volumes, we will use a combination of (i) contracts to limit the output of certain power stations; (ii) arming of intertrips to automatically disconnect generation in the event of a transmission fault, (iii) actions on the day in the Balancing Mechanism, and (iv) trades or pre-gate balancing transactions (PGBTs) to resolve these constraints efficiently and effectively.

79. These transmission system reinforcements form part of a substantial development of the networks to accommodate new generation and to replace assets to ensure the continued reliable performance of the GB transmission system. Details of planned reinforcements are shown in National Grid's Seven Year Statement http://www.nationalgrid.com/uk/Electricity/SYS/

Chapter 2: Gas

Introduction

80. This Chapter focuses on the gas supply-demand outlook for the forthcoming summer. With summer demand levels typically half those experienced in the winter, we are confident that demand will be met in all but exceptional circumstances. There is, however, considerable uncertainty on how supply will be utilised to meet demand. This is further compounded by annual maintenance to upstream supply infrastructure, the need to refill storage and the interaction of global and Continental markets on LNG and Interconnector (IUK) flows respectively

81. In this Chapter we examine issues associated with gas demand and gas supply. These include a high level assessment of the economics of choice of fuel for power generation and the prospects for gas imports / exports. We also provide an assessment on how summer performance may be affected by operational maintenance and new infrastructure. Changes to the regulatory regime are detailed in Chapter 3.

Historical Summer Gas Demand

82. As in the winter, gas demand in the summer can be assessed in terms of weather sensitive demands (Non Daily Metered – NDM) and non weather sensitive demands. The latter includes Daily Metered (DM), exports to Ireland[14] and the Continent, power station demand and storage injection.

83. Due to the possibility of lower temperatures, weather has the biggest impact on summer gas demand during April, May and late September. April 2009 was the second warmest April on record whilst May was the 12th warmest and September the 9th warmest in the last 50 years. The impact of climate change has resulted in a general trend of warmer springs and earlier summers.

84. None of the summer demands reported in this paper are weather corrected as the need to correct for unseasonable weather in the summer is far less than for the winter.

85. Figure G1 shows the gas demand experienced in summer 2009 and Figure G2 shows the weather in terms of our Composite Weather Variable (CWV). This is broadly based on temperature.

[14] Some smaller DM loads are partially weather sensitive as are exports to Ireland

Figure G1 – Summer Gas Demand 2009

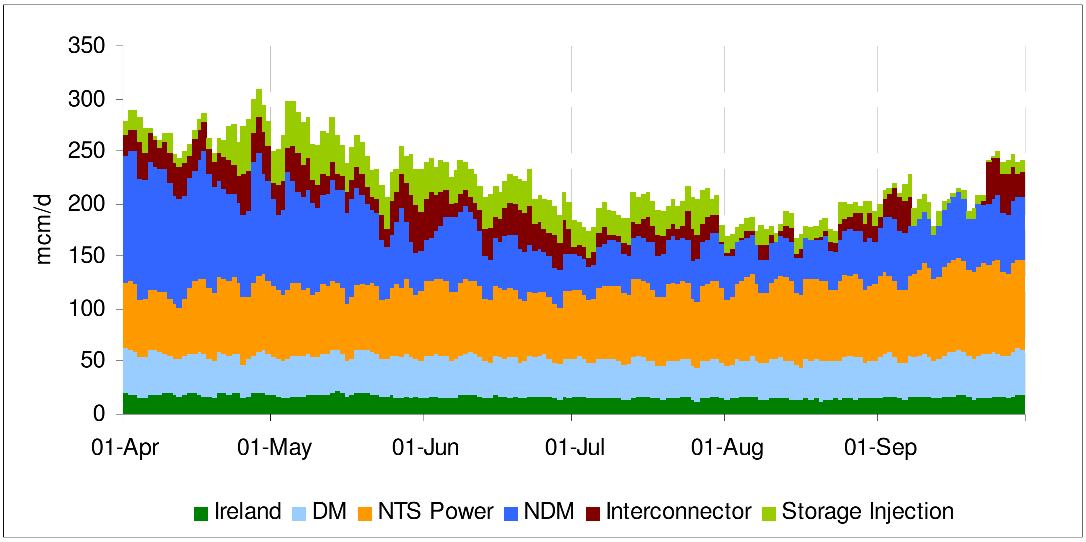
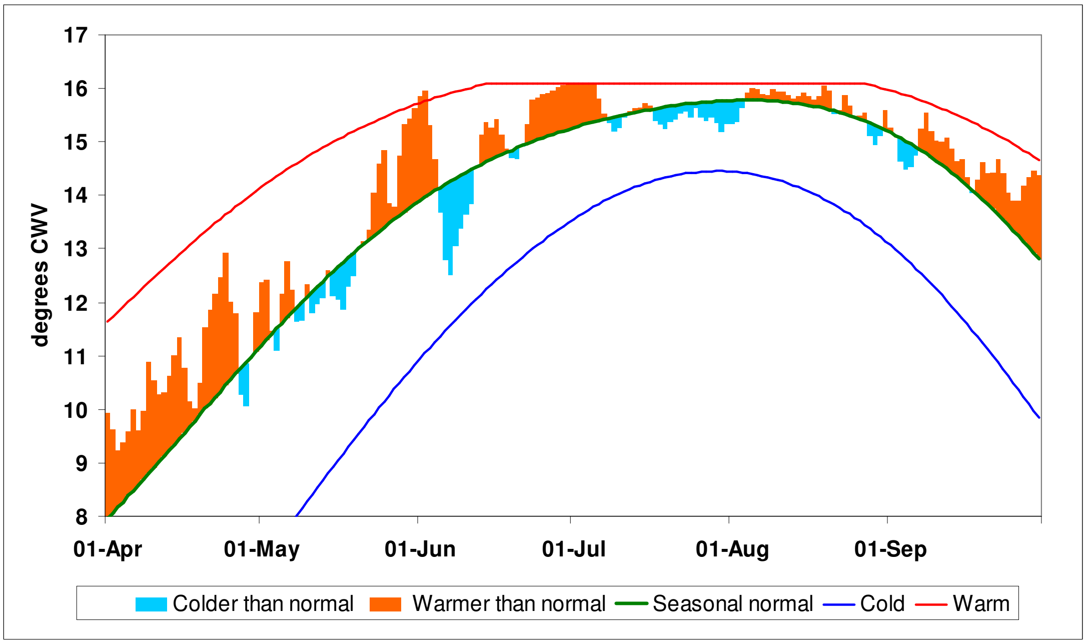


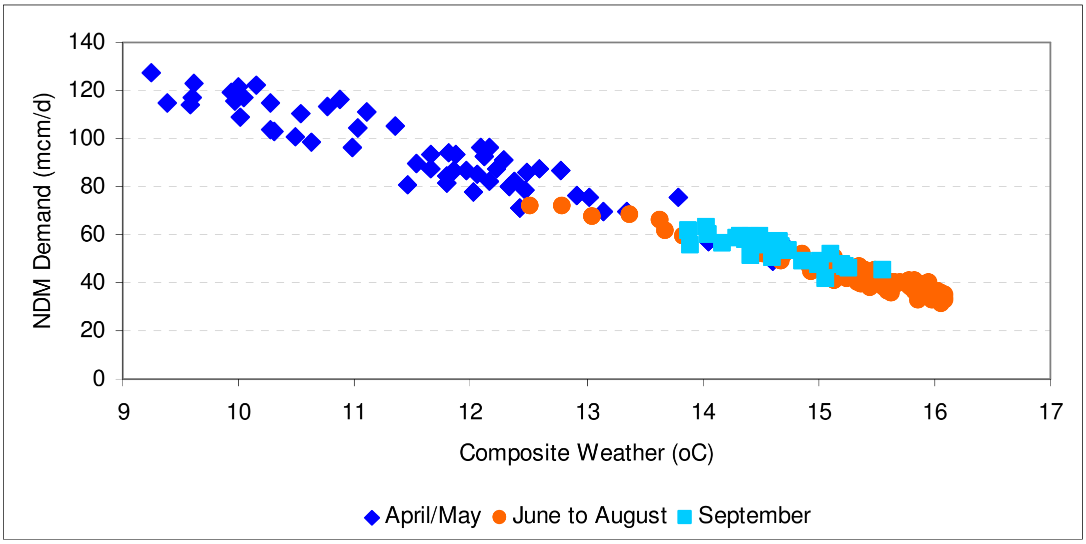
Figure G2 – Summer Composite Weather 2009



86. Figure G1 highlights relatively stable flows in terms of exports to Ireland and Daily Metered (DM) loads. NTS power generation demand increased over the summer as a consequence of a declining gas price. The Non Daily Metered (NDM) profile highlights the sensitivity to weather whilst storage injection and IUK exports are primarily determined by refill requirements and price differentials respectively.

87. Figure G3 shows the relationship between weather expressed in terms of a CWV and NDM demand for summer 2009.

Figure G3 – NDM 2009 Summer Demand



88. The NDM demand for summer 2009 is typical of most summers whereby gas demand can be considered in 3 separate periods; namely:

i) the late spring period of April and May when NDM gas demand is falling

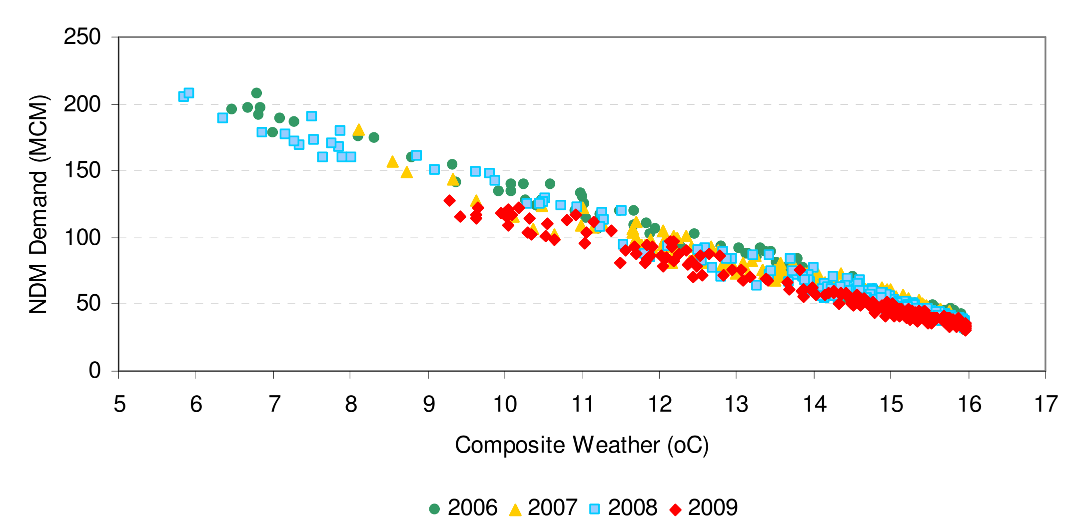
ii) the mid summer period from June to August when NDM demand is essentially flat for all but a few colder days, noticeably a cold week in early June following a very warm period at the end of May

iii) the increase in NDM gas demand at the end of summer in September as temperatures start to fall.

89. The NDM demands in summer 2009 were less weather sensitive than previous years as illustrated by Figure G4. There are numerous possibilities behind this and the reason is probably a combination of factors, such as:

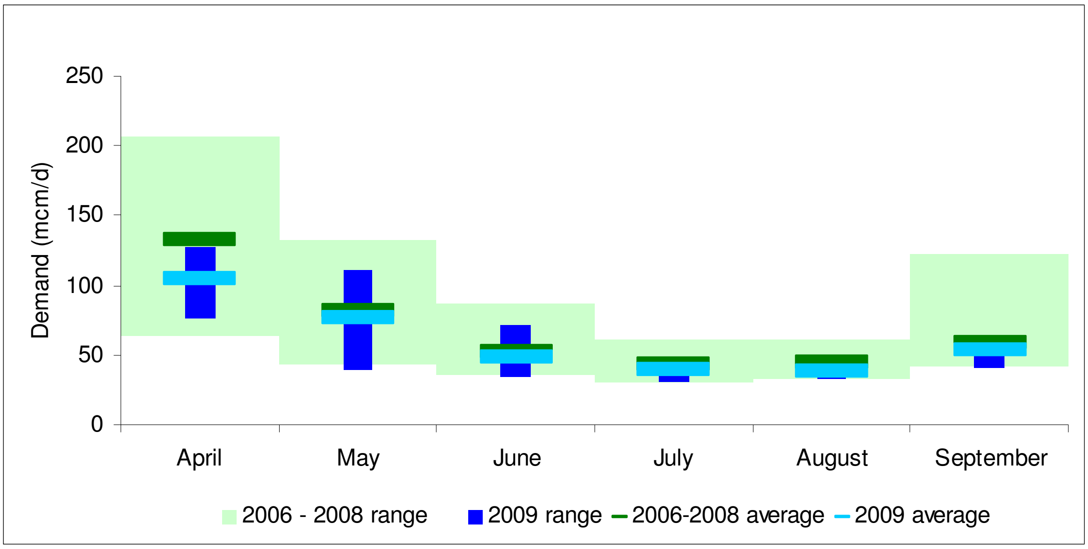
- Consumer behaviour arising from the warm April resulting in an early switch off of heating systems
- The ongoing effects of the recession
- Ongoing improvements in energy efficiencies of appliances, notably water heating systems

Figure G4 – NDM 2009 Summer Demand compared to 2006-2009



90. Figure G5 shows NDM summer demands between 2006 and 2008 in terms of minimum, average and maximum demands for each calendar month. Also shown explicitly is the same demand data for 2009.

Figure G5 – NDM Summer Demands (2006 – 2009)

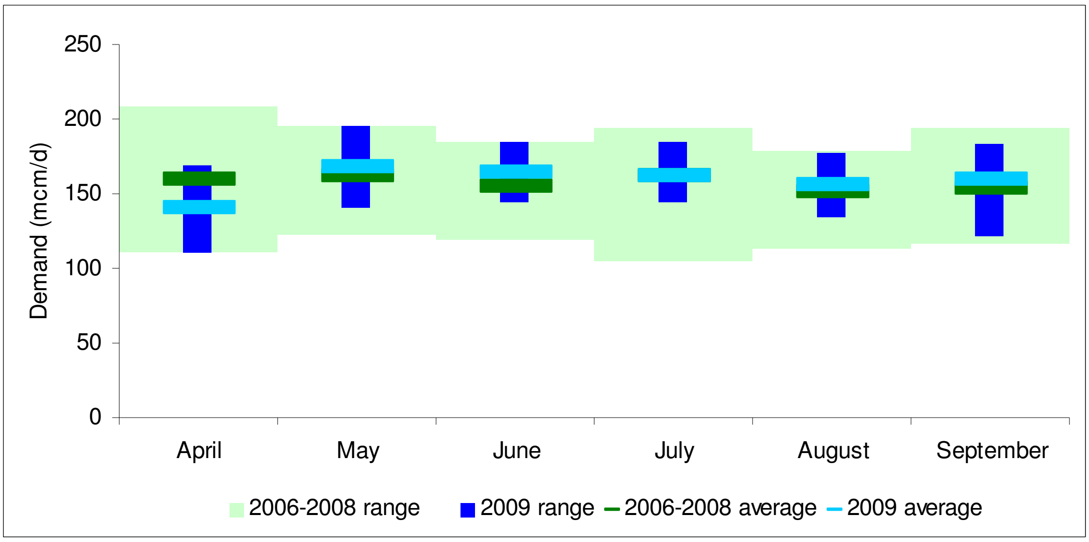


91. The chart highlights how much NDM demand variation can occur in the shoulder months (April, May & September) compared to the mid summer period. To put this into context, for the months of June, July and August the average 2009 NDM demand was 42 mcm/d, during this period the NDM demand was within a +/- 10 mcm/d range for 90% of the days.

92. In a similar manner, Figure G6 shows all other demands, namely the non weather sensitive demands of DM, exports, storage injection and power generation between 2006 and 2008 in terms of minimum,

average and maximum demands for each calendar month. Also shown explicitly is the same demand data for 2009

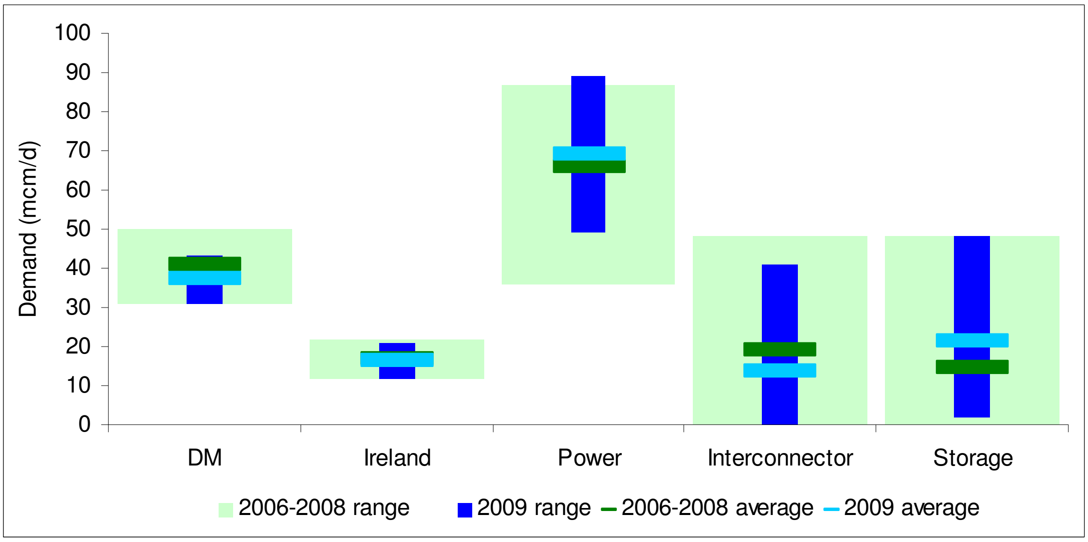
Figure G6 – DM, Export, Storage Injection & Power Generation Summer Demands (2006 – 2009)



93. Whilst the chart highlights the lack of weather sensitivity in these demands, it also shows the potential range of demands from about 100 to 200 mcm/d with an average of about 150 mcm/d. The data set for 2009 shows a tighter data set of demands with higher demands for much of the mid summer period, and lower demands in April.

94. This range of potential demands for each of these demand components is shown in Figure G7.

Figure G7 – Range of DM, Export & Power Generation Summer Demands (2006 – 2009)

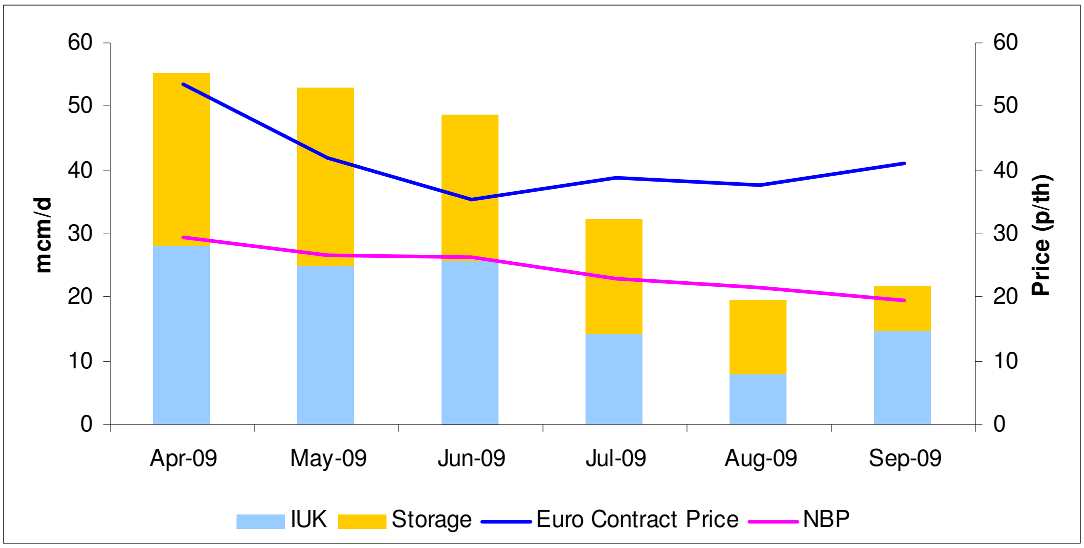


95. The chart highlights relatively modest variations in 2009 DM and Irish demand of just 12 and 9 mcm/d respectively. However, the variations for 2009 power generation and IUK exports were both 40 mcm and storage injection varied from 2 to 45 mcm/d.

96. Historically, the drivers behind the range for power generation have been plant maintenance and fuel costs whilst the range for IUK exports have been determined by price differentials and Continental demand for gas. This in turn has been influenced by supply contracts, demand to refill storage and access to transportation. Consequently, the range of non weather sensitive demands experienced of about 100 to 200 mcm/d could theoretically be much greater at about 80 to 230 mcm/d.

97. Figure G8 shows average monthly IUK exports and storage injection experienced in summer 2009. Also shown is average day ahead NBP prices and our estimate of a Continental contracted price based on a lagged oil price.

Figure G8 – IUK export and storage injection in summer 2009



98. The chart for 2009 highlights higher storage injection and IUK exports in the early part of the summer, often when demands were higher as were NBP prices. For storage this was probably a consequence of some facilities (notably Rough) injecting at higher rates during this period due to the lower pressures associated with depleted stocks. For IUK we believe less gas was exported after June due to increased deliveries of other supplies to the Continent including those directly from Norway.

99. Table G1 shows the total gas demand for April to September from 2006 to 2009 for NDM and all the demand components in Figure G7.

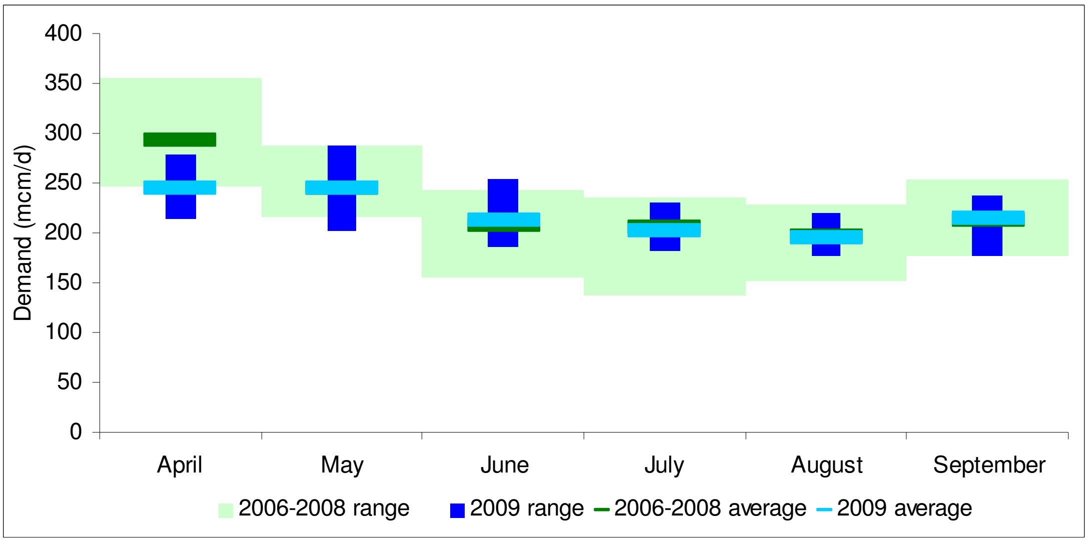
Table G1 – Summer Gas Demand (2006 – 2009)

(bcm)	NDM	DM	Ireland	Power	IUK	Storage	Total
2006	12.7	7.5	3.0	10.4	4.5	2.2	40.3
2007	12.3	7.4	3.1	12.7	3.4	2.2	41.1
2008	13.0	7.5	3.2	13.1	2.5	3.6	42.9
2009	11.0	6.9	3.0	12.7	2.5	3.9	40.0
Average	12.2	7.3	3.1	12.2	3.2	3.0	41.0
%	30%	18%	8%	30%	8%	7%	100%

100. Table G1 shows aggregated April to September demands of about 41 bcm. The general trends suggest a small decline in NDM and IUK exports and marginally higher use of gas for power generation and for storage refill. The fall in DM volumes in 2009 is largely due to the effects of the recession.

101. For completeness of charts, Figure G9 shows for summers 2006 to 2008, on a monthly basis minimum, average and maximum demands for each calendar month for total demands; namely the combination of NDM and the non weather sensitive demands. Also shown explicitly is the same demand data for 2009.

Figure G9 – Total Summer Demands (2006 – 2009)

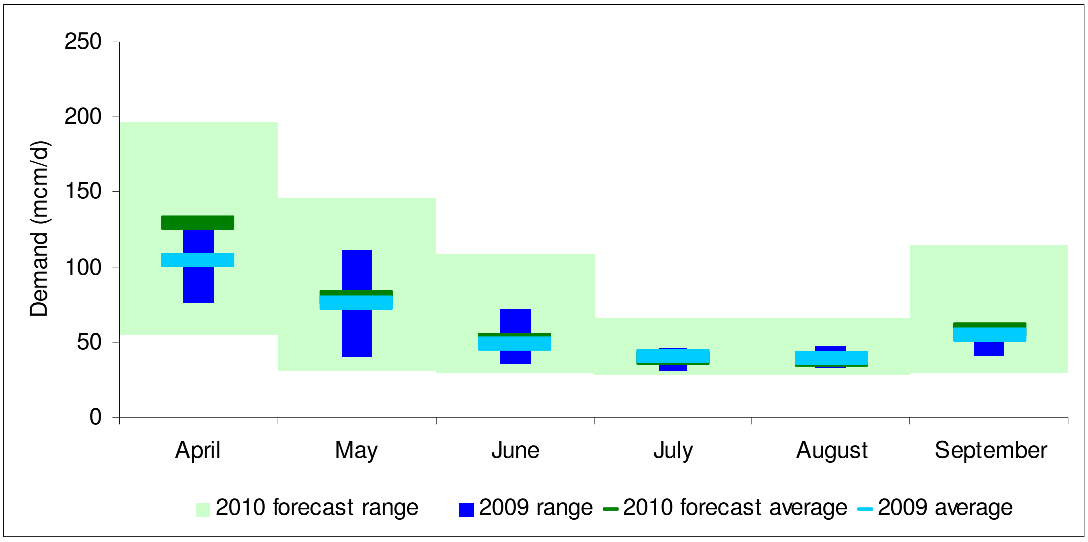


102. In terms of average demand, the chart again highlights the variation in demand for the shoulder months and the relatively stable demands for the mid summer period. For 2009 the affects of a warm April are clearly visible. Historically, there is considerable variation in terms of the range of demand, even during the mid summer period with average demands of typically 200 mcm/d there has been days of demand as high as 240 mcm/d and as low as 140 mcm/d. As detailed previously, these are primarily driven by IUK exports and power generation. By contrast, the demands experienced in mid summer 2009 tended to be in a much tighter range with most demand days within 180 to 220 mcm/d.

Forecast Summer 2010 Gas Demand

103. Figure G10 shows the monthly variation in forecast daily NDM demand based on the weather experienced in the last 20 years. Also shown is the actual variations experienced last summer. If our 81 year data set were used, the upper range would be higher.

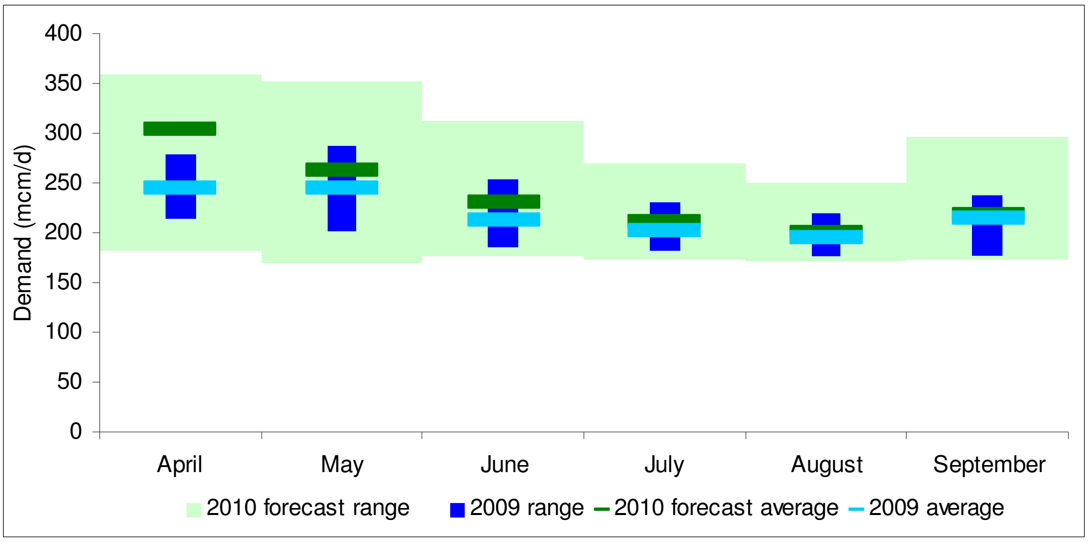
Figure G10 – NDM demand forecast for Summer 2010



104. Forecast demands this summer for Irish exports, NTS industrial loads and non-power daily metered LDZ demands are not expected to change much from those experienced last summer. The May 2009 power generation forecasts for 2010 are similar to the actual demands experienced in summer 2009. However, power generation demand has increased over the winter indicating that the summer 2010 demand levels could be up to 15 mcm/day higher than summer 2009.

105. Figure G11 shows our forecast for total summer demand for each month expressed as an average demand and a range. Also shown is the actual data for 2009.

Figure G11 – Total demand forecast for Summer 2010



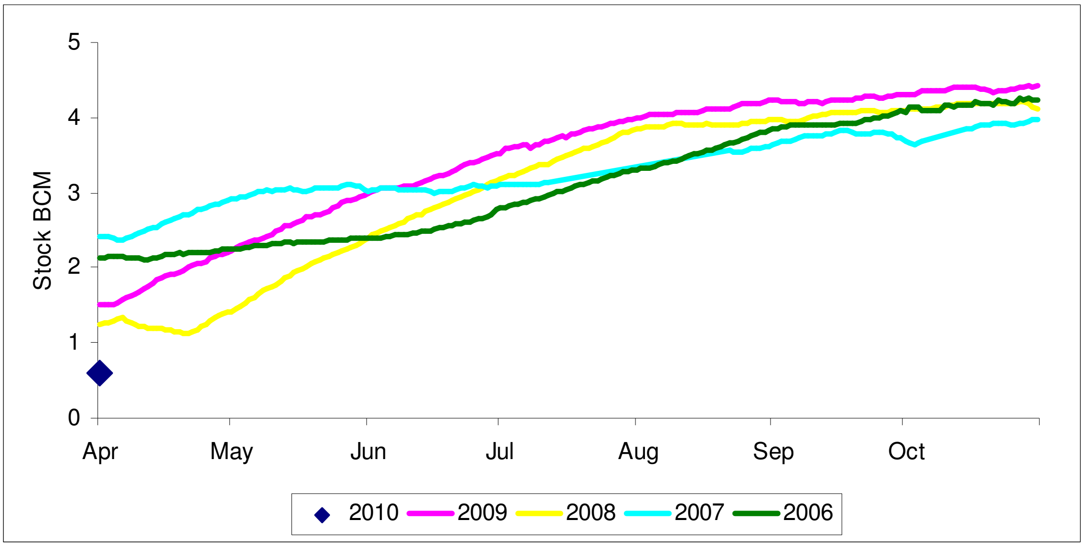
106. The total demand forecast is similar to last year though higher due to our assumption of increased gas demand for power generation and marginally higher storage injection.

107. IUK exports are assumed at similar levels to summer 2009, hence these could provide an upside or downside to the forecasts.

108. Due to increased storage use last winter and further build-up of operations at Aldbrough for next winter, forecast gas demand for storage injection this summer is marginally higher than experienced over the past 4 years (Figure G7). Depending on refill plans, the duration for storage injection could also be longer though this is not expected due to increased injection capabilities. In general, if NDM gas demand is higher than expected due to a colder spell of weather, with a corresponding increase in spot prices, we would expect to see less storage injection and possibly lower IUK exports.

109. Figure G12 shows the refilling of storage during the last four summers through aggregated storage stock levels. Despite variations in the need to refill by up to 1 bcm, storage stocks levels have been comparable by August. For 2010 injection, storage stocks are expected to be at relatively low levels as of April following considerable depletion through to mid March. For 2010 approximately 4 bcm of storage needs to be refilled. Historically over the past 4 years average summer filling rates have been about 15-20 mcm/d with maximum storage rates above 50 mcm/d. Hence with approximately 4 bcm to be refilled, the duration is expected to be between about 200 days, in time for next winter.

Figure G12 – Aggregated Storage Stocks 2006 - 2009



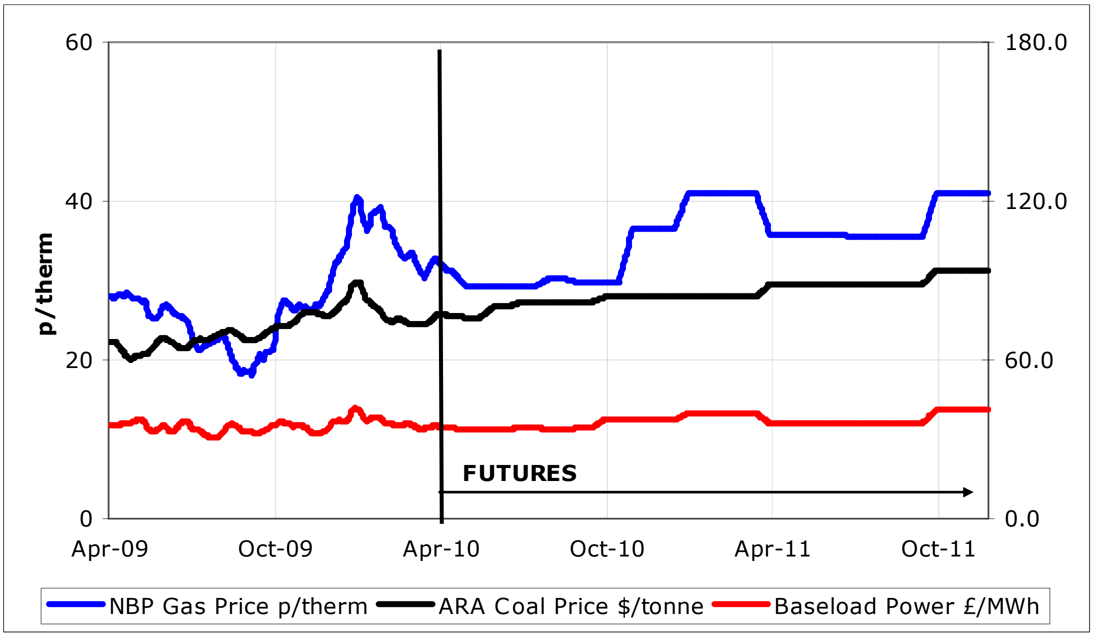
110. Forecasting gas demand for IUK exports this summer is, as in previous years, difficult. The price differentials between NBP and Zeebrugge (Figure G18) currently remain very small, tending to favour exports flows rather than imports. A factor that may again promote lower exports this summer as in 2009 is the possibility of contractual obligations from suppliers coupled with lower Continental demand due to the global recession. Compared to last winter Continental storage stocks are estimated to be more than 10 bcm higher than in 2009, hence this might therefore also result in lower IUK exports.

111. Assessment of the mid summer period (see Figures G1 and G7) reveal that power generation demand is the largest single demand component making up approximately one third of total summer gas demand.

112. The seasonality of the UK gas price has historically seen gas-fired power stations used for base load generation in the summer with coal used as the marginal source. The European Union Emissions Trading Scheme (EU ETS) reduces coal's competitive advantage when compared with gas due to higher associated carbon emissions. The Large Combustion Plant Directive (LCPD) which came into operation at the beginning of 2008 has also reduced coal demand to a certain degree as some UK plants can only generate for a limited number of hours between 2008 and 2015. Hence these plants are expected to operate more when electricity prices are higher in the winter months rather than the summer.

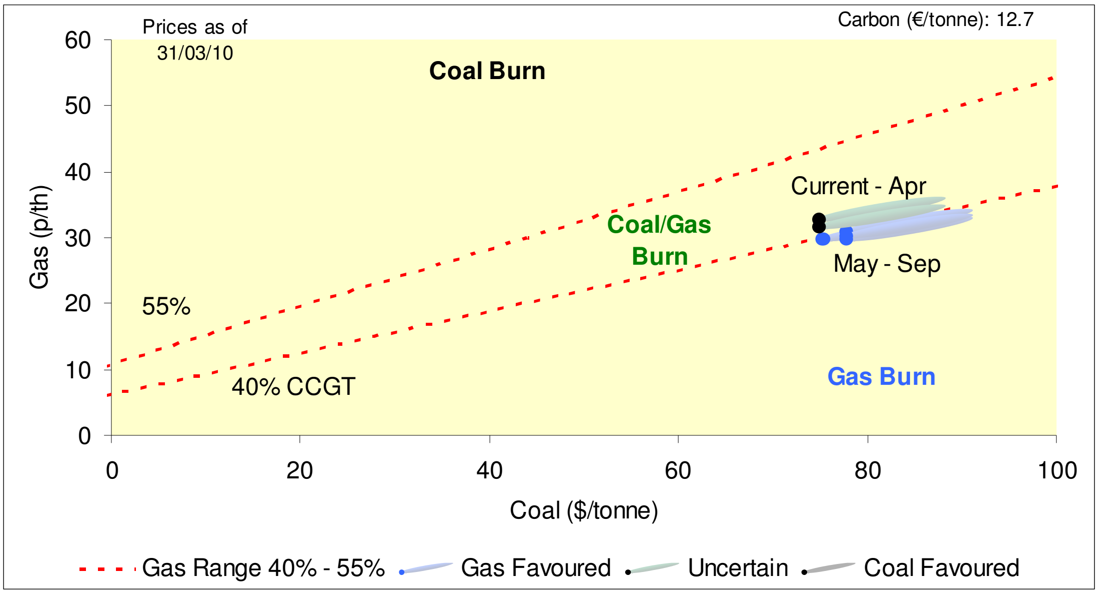
113. Figure G13 shows historic and forward gas, coal and power prices for coal, gas and base load power. The chart shows relatively stable power and coal prices with some seasonality in the historic and forward gas price.

Figure G13 – Historic and Future Fuel Prices



114. As discussed briefly in Chapter 1, the current forward prices of gas, coal, power and carbon suggest that gas is marginally the preferred choice between gas and coal in terms of the economics for power generation this summer. This is shown in Figure G14 in terms of a price plot of coal versus gas. The current and forward prices of about 30 p/therm for gas and 70 $/tonne for coal show very little variation until next winter when some seasonal pricing for gas returns.

Figure G14 – Coal versus Gas Generation Plot



115. In terms of the choice of fuel for power generation, the chart shows a band of generating uncertainty between the areas favouring coal or gas. This arises through assumed generation efficiencies of 40% and 55%. This band passes through the gas axis rather than the origin due to the carbon price (assumed at €12.7/tonne) impacting coal more than gas. The symbols for the fuel prices show ellipses to represent a range of possible transport costs for both fuels.

116. The volatility seen in fuel prices over the past twelve months should not be discounted and a relatively small change in either fuel or carbon prices will change the relative economics of gas and coal-fired generation. This highlights the need to consider a range of gas demands for power generation this summer.

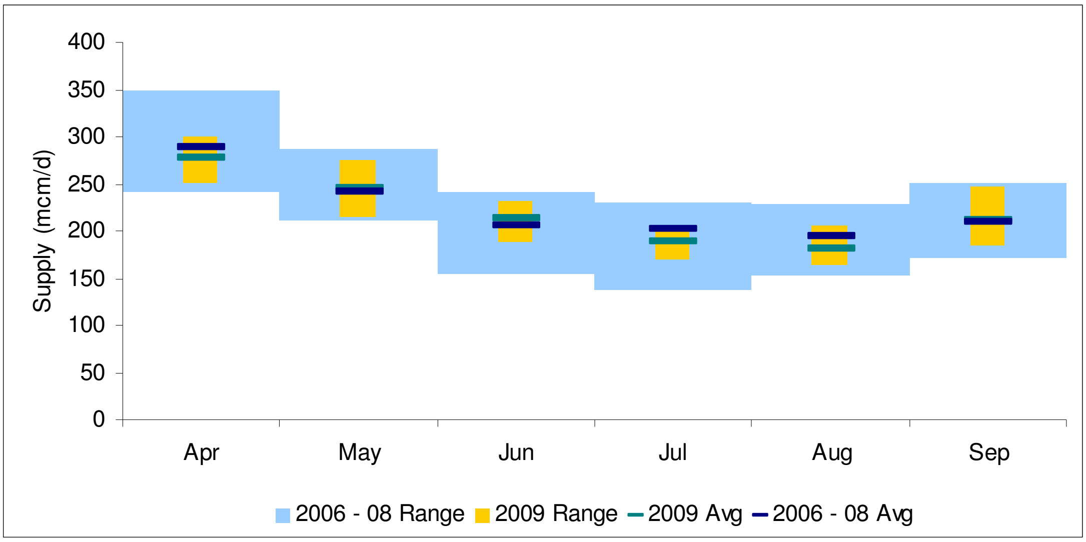
117. With gas expected to be the lowest cost option for power generation, gas demand is expected to be in the range 70-110 mcm/d. Conversely if coal were to be the lowest cost option for power generation, gas demand would be expected to be in the range 40-70 mcm/d.

118. Besides the decrease in demand for power generation through a higher gas price or lower coal gas price, IUK exports could also decrease if there was also a fall in Continental gas prices through for example surplus supply.

Historic Summer Gas Supply

119. Figure G15 shows aggregated gas supplies from April to September for all supply sources from 2006 through to 2008 in terms of minimum, average and maximum demands for each calendar month. Also shown explicitly is the range and average for 2009.

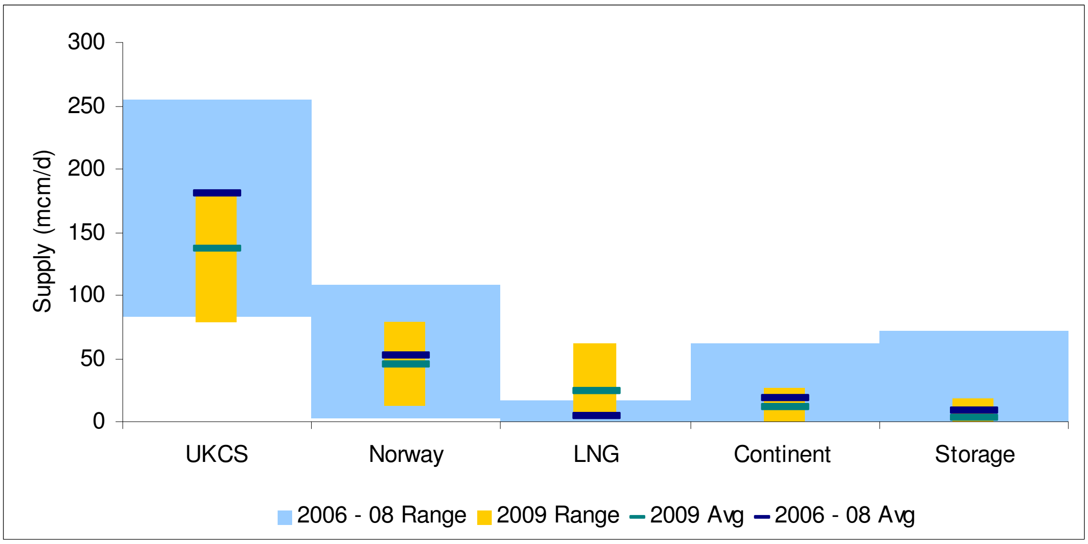
Figure G15 – Summer Supplies by Source (2006 – 2009)



120. As one would expect, the figure is similar but not identical to the total demand figure (Figure G9).

121. The range of supplies for April through to September for 2006 through to 2008 for each of the supply sources is shown in Figure G16. Also shown explicitly is the range and average for 2009.

Figure G16 – Range of Supply Sources (2006 – 2009)



122. The chart highlights considerable variations in all of the supply sources. Over the four year period minimum flows close to zero have been experienced for all supply sources except UKCS. Even if the mid-summer period is assessed the ranges remain considerable. The ranges for 2009 highlight the increase in LNG flows primarily at the expense of lower UKCS.

123. Table G2 shows the gas supply for April to September from 2006 to 2009 for each of the supply sources in Figure G16.

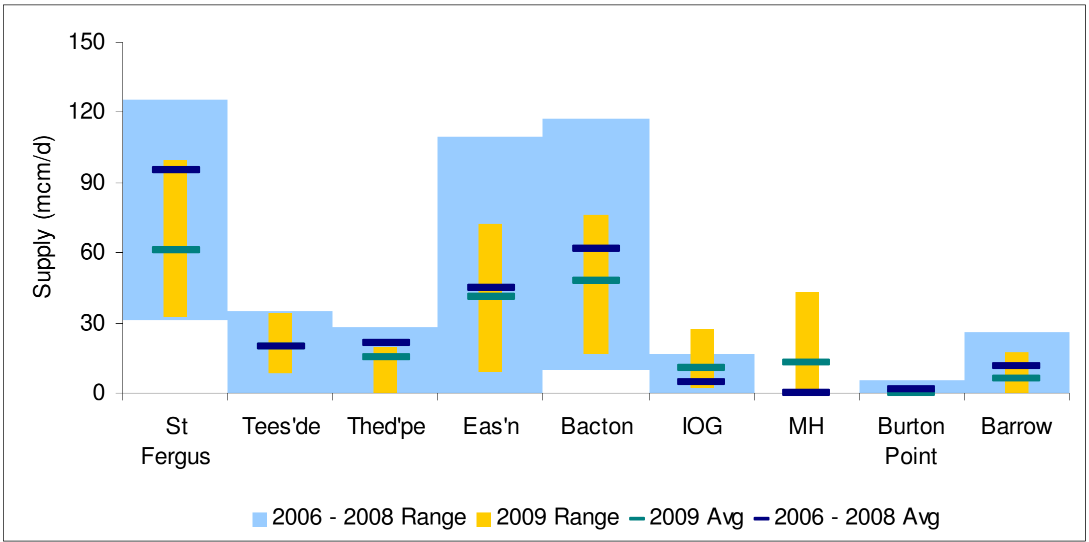
Table G2 – Summer Gas Supply by Source (2005 – 2008)

(bcm)	UKCS	Norway	LNG	Continent	Storage	Total
2006	33.3	4.7	1.3	0.2	0.4	39.7
2007	30	7.1	0.1	2.4	0.9	40.6
2008	28.3	9.8	0.2	3.6	0.7	42.5
2009	24.9	8.2	4.4	2.0	0.6	40.1
Average	29.1	7.4	1.5	2.0	0.7	40.8
2009%	62%	20%	11%	5%	2%	

124. Table G2 shows aggregated April to September supplies of about 41 bcm, these are not identical to the total demands in Table 2 due to shrinkage and CV variations. The data shows supplies dominated by deliveries from the UKCS, though year on year these have declined by on average 10% each year. Until 2009, most of the decline in UKCS has been offset through increased imports from Norway and to a lesser extent the Netherlands through BBL. In 2009 there was a surge of LNG imports, these not only met the decline in the UKCS but also compared to 2008 imports displaced some Norwegian supplies.

125. The range of supplies for April to September from 2006 through to 2008 for each terminal is shown in Figure G17. Also shown is the range and average for 2009.

Figure G17 – Summer Supplies by Terminal (2006 – 2009)



126. The chart highlights considerable variations at all of the supply terminals. Over the four year period, minimum flows of zero have been experienced at all supply terminals except St Fergus and Bacton. If the mid summer period is assessed the upper ranges are noticeably reduced for St Fergus, Easington and Bacton. The data for 2009 shows with the exception of the LNG receiving terminals of Grain and Milford Haven, lower flows at most terminals, notably St Fergus and Bacton.

127. Table G3 shows the gas supply for April to September from 2006 to 2009 for each of the supply terminals in Figure G17.

Table G3 – Summer Gas Supply by Terminal (2006 – 2009)

(bcm)	St F	Tee	The	Eas	Bac	IOG	M H	BuP	Bar	Storage	Total
2006	18.5	4.1	3.8	1.8	8.4	1.3	0	0.4	1	0.4	39.7
2007	15.4	2.3	3.6	6.6	9.3	0.1	0	0.2	2.1	0.9	40.6
2008	14.2	2.9	3.4	7.8	10.9	0.2	0	0.2	2.3	0.7	42.5
2009	11.2	3.6	2.8	7.5	8.7	2.0	2.4	0.0	1.2	0.6	40.0
Average	14.8	3.2	3.4	5.9	9.3	0.9	0.6	0.2	1.7	0.7	40.7
2009%	28%	9%	7%	19%	22%	5%	6%	0%	3%	2%	

128. Table G3 shows that on a volumetric basis, summer supplies have historically been dominated by deliveries from St Fergus and to a lesser extent Bacton and Easington. However, supplies from St Fergus have been in decline by about 10% every year and Easington has been higher since 2007 due to Norwegian gas being landed through Langeled. In 2009 there were some significant changes brought about by the surge of LNG imports with reductions at all other terminals with the exception of Teesside.

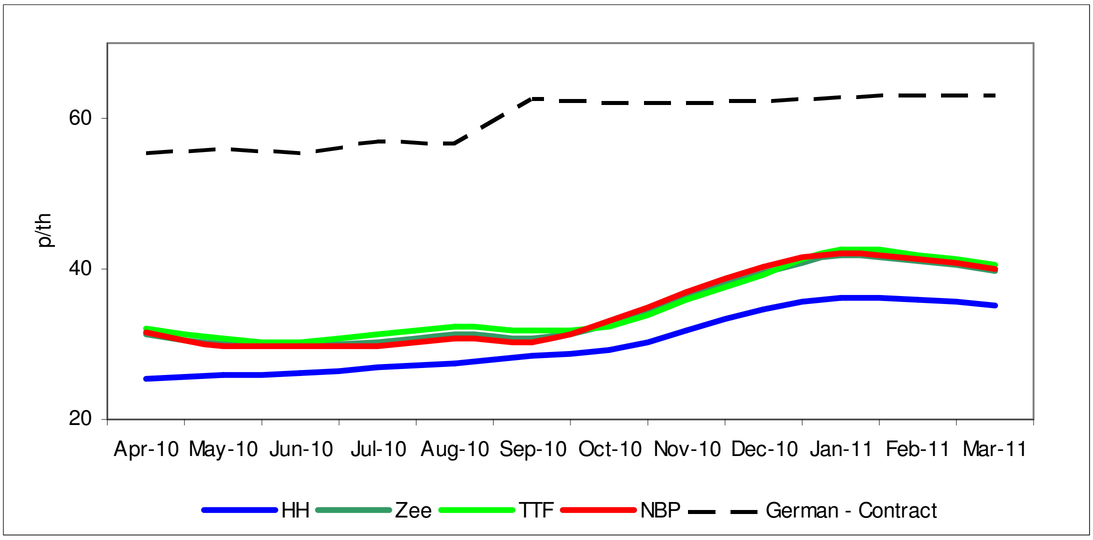
Forecast Summer 2010 Gas Supply

129. We expect that UKCS supplies will continue to be the largest source of supply this summer, however, we also expect UKCS supplies to continue to decline by 5–10% thus resulting in higher imports. To put a UKCS summer decline of 7.5% into context, this is equivalent to about 10 mcm/d.

130. There is considerable uncertainty over import flows to the UK this summer, notably the volume of LNG and whether these will displace other imports or reduce UKCS deliveries further. Factors impacting LNG deliveries to the UK include:

- The completion of commissioning for South Hook 2 at Milford Haven. This increases the import capacity from 10.5 to 21 bcm/year
- The possibility of increased availability of ‘summer’ LNG due to the commencement of new production sources and also from lower demand requirements in contracted markets due to the global recession and also in the US where the development of unconventional gas sources (notably shale) has reduced the anticipated demand for US gas imports
- Competition for LNG in the Atlantic basin. Currently as shown in Figure G18, there is a slight premium for the UK NBP over the US Henry Hub prices. This suggests that spot LNG may flow towards Europe rather than the US, however the transportation cost may continue to influence the final destination.
- The possibility that UK LNG terminals may be used to supply LNG to the Continent through IUK exports

Figure G18 – Forward Gas Prices (20th March 2010, sources Heren & Nymex)



131. Despite the UK being a net importer of gas on an annual basis since 2004, IUK has exported every summer. We anticipate this trend will continue this summer, though export volumes may somewhat tempered due to contractual take or pay obligations. With NBP and Continental markets priced so closely together as shown in Figure G18 it is difficult to see an obvious price driver unless comparison is made to our estimate of the German contract price.

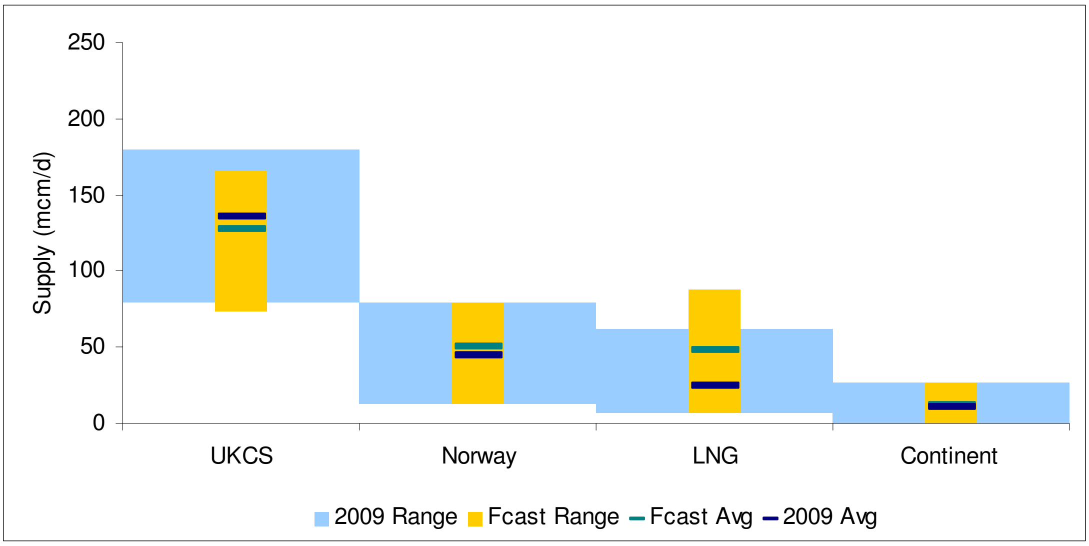
132. As in previous summers we would expect reduced IUK exports or even IUK imports if the UK gas price increased due to a supply shortfall.

133. For BBL we again expect some imports during the summer. As we have experienced over the past year or more, these may become more commercially driven, particularly if the proposed arrangements for non-physical exports are completed.

134. With Ormen Lange now at near full production we again expect significant Norwegian imports through a combination of Langeled, Vesterled and the Tampen Link. The economic slowdown on the Continent may also result in higher Norwegian imports to the UK due to flexibility in Continental contracts or prices. However, as stated previously Norwegian imports may be reduced if LNG imports continue to grow and / or UK gas prices decline further.

135. Figure G19 shows our forecast range of gas supply by supply source for this summer. Also shown is the actual supplies in summer 2009.

Figure G19 – 2010 Summer Forecast of Gas Supply by Source

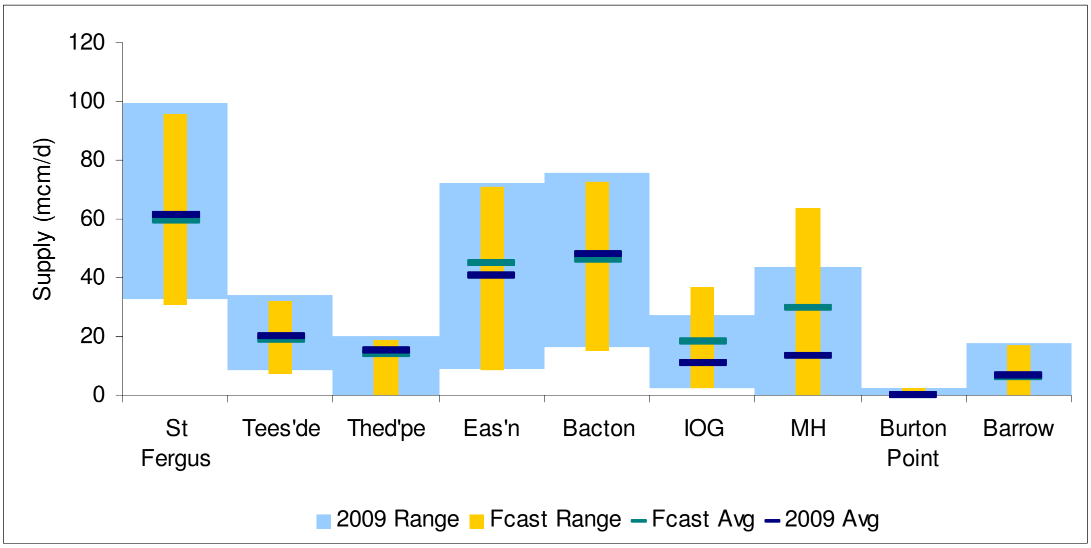


136. The chart shows considerable variation in all supply sources, notably for LNG. Forecasting summer flows is subject to considerable uncertainty as import capacity far exceeds demands and there are numerous competing factors that determine which supplies make-up the UK supply mix. Compared to summer 2009 we are forecasting similar average flows for all supply sources with the exception of LNG which is approximately 25 mcm/d higher at 48 mcm/d. Our average forecast for the UKCS is about 10 mcm/d lower representing a 7.5% year on year decline. For Norway and the Continent we forecast similar flows to summer 2009 though these are subject to much uncertainty. The ranges for all supply sources highlight the uncertainty associated with these forecasts.

137. The uncertainty over what supply sources will flow this summer feeds through to which entry terminals will receive gas. This uncertainty is further compounded by the fact that summer demand is typically only half that of winter demand. These factors should be taken into context for our forecast flows for this summer.

138. Figure G20 shows our terminal forecast for next summer expressed as a range for each terminal. Also shown are the actual supplies in Summer 2009. The forecasts have been derived through a combination of feedback through our annual TBE planning and analysis of historical data to determine the average flow and supply range. Obviously with so many permutations to make up demand, these forecasts should be considered indicative rather than explicit.

Figure G20 – 2010 Forecast of Summer Supplies by Terminal



139. The chart highlights considerable variations at all terminals. Following on from our gas sourcing assumptions, we forecast similar flows at most terminals, marginally higher flows into Easington and appreciably higher flows through the LNG receiving terminals at Grain and in particular Milford Haven. The high range for those flows experienced in 2009 and those forecast for 2010 again highlight the considerable uncertainty over these forecasts.

Summer 2010 NTS Maintenance Programme and Network Capacity Expansion

140. To ensure a high level of safety and reliability in operation, it is essential that a system of inspection and maintenance exists for assets associated with the transmission of natural gas. Effective maintenance is essential to minimise the safety and environmental risks caused by failure of pipelines and plant.

141. In accordance with National Grid's Gas Transporter Safety Case, maintenance activities shall comply at all times with any statutory or legislative requirements, in order to meet legal obligations. These practices are robustly designed and seek to minimise overall operating cost by increasing the useful life of pipelines and plant, reducing the risk of failure and reducing the risk of emergency repairs.

142. The NTS investments delivered last summer for capacity expansion for winter 2009/10 have provided additional capacity and network flexibility. These can be summarised as follows:-

- Completion of a new compressor unit at Wormington and ongoing works at a new site at Felindre in South Wales as part of the overall entry capacity project for the Milford Haven LNG importation terminal.
- Commissioning of the South Hook and Dragon LNG terminals.

143. This summer will see the completion of an additional compression unit at Churchover for the 2010/11 winter and further progression of additional electric units at St Fergus and Kirriemuir as part of the project to reduce compressor emissions.

144. 44km of 900mm pipeline is currently being progressed in the South West from Wormington to Sapperton for the 2010/11 winter, providing additional capacity to meet forecast demand growth in the South West.

145. Further reinforcement from Easington to Paull provides additional entry capacity on the east coast.

146. Further information on some of these and other expansion projects can be found at: http://www.nationalgrid.com/uk/Gas/Pipelines/

147. National Grid's maintenance plan includes the impact of network reinforcement, annual maintenance programme and supply outages. It can be found on the National Grid website at: http://www.nationalgrid.com/NR/rdonlyres/F2AD8307-E05D-42BA-8149-164FF2586C46/39532/AprilMaintenanceProgSummer2010Draftv1.pdf

148. The above document details Aggregated System Entry Points (ASEP) capacity for each month, based on Seasonal Normal Demand conditions for the period where scheduled maintenance has most impact on capability. The data has been generated by National Grid and assumes the particular ASEP is favoured at the expense of other terminals. Where no volume has been given, this indicates that the maintenance scheduled has no adverse effects on the ASEP capability.

149. The document also details maintenance work for each month and affected Exit Points.

Chapter 3: Commercial Regime Developments

150. National Grid remains committed to the development of commercial arrangements that encourage timely and appropriate market responses to secure energy supply-demand balances. This chapter reflects ongoing industry discussions concerning such developments in both electricity and gas.

Electricity:

Market Information Transparency

151. BSC modification P243 (effective from 4 November 2010) will provide more granular Output Usable data to the market by publishing this information at BM Unit level.

152. In anticipation of BritNed interconnector going live in late 2010 / early 2011, we raised BSC modification P244 to allow real-time and half-hourly publication of BritNed (and other future interconnector) flows. This modification (effective from 4 November 2010) will provide a more complete view of generation data and will ensure consistency with existing information.

153. In order to facilitate implementation P243 which requires publication of interconnector forward capability data, we raised a Grid Code modification F/09 which will enable Interconnector Owners to provide the required data under Grid Code in the same way that generators currently do.

Transmission Access Review

154. The 2008 Transmission Access Review (TAR) set out the need for reform to grid access rules in order to support the connection of renewable and other low carbon generation by 2020 (and beyond). The TAR set out some principles that might underpin an efficient grid access regime.

155. As a response to the TAR (and to address all the TAR principles) National Grid established three industry working groups under the CUSC framework to consider in a coordinated way the options for access reform and their wider impacts. Over a period of twelve months, these working groups developed a number of models for reform.

156. To ensure reforms are implemented in a manner and timeframe consistent with Government objectives on energy and climate change, the Government decided to intervene, using the powers taken in the Energy Act 2008. In line with this, in August 2008, the Department of Energy and Climate Change published a consultation on 'Improving Grid Access'.

CAP170: Category 5 System to Generator Operational Intertripping Scheme

157. CAP170 seeks to introduce a new Category 5 System to Generator Operational Intertripping Scheme to cover intertrips capable of being armed with respect to a derogated non-compliant transmission

boundary. It was raised by National Grid on the basis that at derogated non-compliant transmission boundaries the need to take action to manage constraints is more onerous than at compliant transmission boundaries. As such, the use of intertrips (assuming it is more economic than alternative Bid-Offer action to constrain generation pre-fault) is a necessity rather than an occasional tool in order to maximise flows across the derogated noncompliant transmission boundary.

158. CAP170 was granted urgent status and proceeded straight to wider industry consultation. The CAP170 Amendment Report was submitted to the Authority for decision in March 2009. Since then, the Authority has issued an Impact Assessment for consultation, followed by two further consultations; one focusing on an updated cost analysis and the second consulting on competition issues.

CAP169: Provision of Reactive Power from Power Park Modules, Large Power Stations and Embedded Power Stations

159. CAP169 sought to accommodate the provision of Reactive Power from Power Park Modules, introduce an appropriate Reactive Power Mandatory Services Agreement obligation for all categories of Large Power Stations and facilitate an appropriate payment mechanism for Reactive Power from restricted Embedded Power Stations. It also requires corresponding changes to be made to the Grid Code.

160. CAP169 was developed by Working Group, with 3 alternatives raised and considered. The Amendments Panel recommended that WGAA1 or WGAA2 be implemented. On 21st December 2009, the Authority directed that WGAA3 be implemented from 21st March 2010. WGAA3 introduces a zero payment where a third party restriction exists that prevents the generating unit from providing the service in accordance with an instruction from National Grid. In its decision letter, the Authority requested that the industry and National Grid undertake a further review of the issues raised by CAP169. National Grid will progress this through the CUSC Balancing Services Standing Group. For further information on this group, please see our website at:

http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/workingstandinggroups/bssg/index.htm

Developments to the interface between the System Operator and Transmission Owners

161. We undertook an informal consultation exercise in September 2009 to seek views on a range of potential approaches to enhancing the role of transmission companies within the existing SO/TO arrangements. The consultation looked at the timeliness of connections to the transmission networks and measures to contribute to the minimization of network constraint costs.

162. As a result of the consultation, work is being progressed to develop the outage planning and investment planning interfaces between the SO and TOs. This work will focus on the timing and extent of interaction; and on the required level of data exchange to support that interaction.

163. A number of broader incentive arrangements on TOs in relation to activities that influence network constraints were discussed. Respondents to the consultation suggested that, due to the likely complexity of such arrangements, it would be prudent for them to be considered as part of the next price control review.

Consultation A/10: Generator Grid Code Compliance

164. A/10 is intended to improved the transparency and consistency of the process of ensuring generators connecting to the transmission system comply with the Grid Code connection conditions. The proposals standardise and codify the process into the Grid Code. The Consultation closes in May 2010.

165. Grid Code Consultation A/10 was developed by an industry Working Group and was published on 1st February 2010. Consequential code changes are required to the DCUSA, Distribution Code and CUSC and the respective change control processes have been initiated in parallel. These consequential changes relate to Licence Exempt Embedded Medium Power Stations (LEEMPS) who are not directly connected to the transmission system but are still required to undergo the compliance process.

Gas:

Entry Credit Arrangements

166. Modification Proposal 0246 “Quarterly NTS Entry Capacity User Commitment” was raised by National Grid Gas NTS as a consequence of discussions within Review Group 0221 and is currently with Ofgem for direction. Proposal 0246, if implemented, would remove, what the Review Group agreed was, an inappropriate length of time between Shipper Users being allocated capacity in a QSEC auction and them committing financially to the capacity acquired. The proposal would also enhance the current regime by removing the ability for Users to defer their Quarterly NTS Entry Capacity commitments.

167. EDF Energy (0246A) and British Gas Trading (0246B) have raised alternative Modification Proposals. All three proposals were submitted to Ofgem in May 2009 and a decision is expected early this year. Implementation of any of these proposals would lead to changes to the credit security arrangements related to QSEC Capacity holdings, which would in turn affect the operation of future QSEC auctions.

Exit Credit Arrangements

168. The aforementioned ability for Shipper Users to currently defer their Entry Capacity commitment also applies at NTS Exit Points. National Grid Gas NTS raised Modification Proposal 0261 “Annual NTS Exit (Flat) Capacity Credit Arrangements” to remove this current ability for the User’s to defer their Annual NTS Exit (Flat) Capacity. This proposal was approved by Ofgem in December 2009 and implemented on 1st January 2010.

Introduction of Enduring NTS exit capacity arrangements

169. On 19 January 2009 Ofgem approved UNC Modification Proposal 0195AV with effect from 01 April 2009 which introduces Enduring NTS

offtake arrangements from 01 October 2012. Current arrangements allow Users to secure capacity until 30 September 2012.

170. As part of these arrangements

- Users can apply for Enduring Annual NTS Exit (Flat) Capacity in the Annual July Application Window or via an Ad-hoc process
- Developers can apply for Enduring Annual NTS Exit (Flat) Capacity via the ARCA process.
- A standard 4 year User Commitment is applied to Enduring Annual NTS Exit (Flat) Capacity requested from 01 April 2009 (subject to the Exit Capacity Release Methodology)
- Annual, Daily and Offpeak capacity can also be procured before the start of the Enduring regime.
- For further detail please refer to a dedicated exit reform section of our website www.nationalgrid.com/uk/Gas/OperationalInfo/endureexitcap/

171. The initialisation processes and the first July application window has been held successfully, with Users being informed of both their initialised quantities and their allocated quantities of Enduring Annual NTS Exit (Flat) Capacity.

172. Modification Proposals 0263 and 0276 were raised to enable the partial assignment of Enduring Annual NTS Exit (Flat) Capacity and Annual NTS Exit (Flat) Capacity. Modification Proposal 0276 has been directed for implementation by the Authority, with an implementation date yet to be determined.

173. Four other Exit Modification Proposals have been raised;

- Modification Proposal 0287 – Change System Capacity Transfers Notification Time Limit from 04.00 hours to 03.00 hours
- Modification Proposal 0288 – Facilitating the Reduction of Enduring Annual NTS Exit (Flat) Capacity by a value less than 100,000kWh
- Modification Proposal 0289 – To determine the amount of Annual NTS Exit (Flat) Capacity to be released when the quantity of unsold NTS Exit Capacity fluctuates within the Gas Year
- Modification Proposal 0290 – To facilitate the release of Additional NTS Exit (Flat) Capacity at National Grid NTS's discretion

Substitution

174. As part of Transmission Price Control 4 Ofgem introduced an obligation on National Grid NTS to undertake both Entry and Exit Capacity Substitution and Exit Capacity Revision Methodology.

175. Under the Entry obligation National Grid NTS will seek to substitute unsold non-incremental obligated Entry Capacity to other entry points where Incremental obligated Entry Capacity is required to be released

following successful capacity bids in the QSEC auction satisfying the test defined in the Incremental Entry Capacity Release Methodology.

176. During 2009 National Grid NTS consulted with the Industry and Ofgem to identify the most appropriate way to introduce Entry Capacity Substitution. The Entry Capacity Substitution Methodology Statement and associated Modification Proposal (0265) and Charging Methodology changes were implemented by Ofgem on the 17th December 2009. The Entry Capacity Substitution Methodology applies from the March 2010 Quarterly System Entry Capacity (QSEC) Auctions.

177. National Grid NTS has a licence obligation to submit an Exit Capacity Substitution Methodology Statement and an Exit Capacity Revision Methodology Statement to the Authority by 4th January 2011. Workshops are currently being held with the industry to discuss the most appropriate way to introduce this obligation. National Grid NTS published a timetable in December 2009 detailing future NTS Exit Capacity Substitution workshops.

System Flexibility

178. Changes in supply and offtake behaviours driven by regime developments and types of connectees may generate volatility in gas flows and hence require a more flexible system to ensure that the customers' needs are met. Examples of these include:

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

179. The magnitude and materiality of these developments is uncertain, however, National Grid NTS is keen to investigate and identify the potential for increased service requirements before they occur so that it can act to accommodate such requirements. To this end we have been discussing with the industry what data / information should be analysed, what timescales should be monitored for trends and what trends would identify/predict a change in this area. These indicators of the use of system flexibility will be reported to the industry on an ongoing basis through the Operational Forum meetings. An Ofgem consultation on system flexibility is also expected this year.

Amendment to QSEC and AMSEC Auction timetables

180. Modification 0230AV was implemented by the Authority in May 2009, with effect from 1st January 2010. National Grid NTS held a QSEC auction in September 2009 and held a QSEC in March 2010 and will hold a QSEC between the 1st March and 31st March each year. The AMSEC auction will continue to be held between 1st February and 29th February (inclusive) but the capacity period offered for release in the AMSEC auction has been amended to an 18 month period.

Transmission Charging

181. One of the key areas for review has been the methodology by which NTS Exit capacity prices will be determined, with changes having been implemented in March 2009 for the setting of NTS Exit (Flat) Capacity charges from 1st October 2012 post exit reform. Changes have also been made from 2009 in regard to the setting of constrained LNG credits, the source of supply and demand data used for calculating both entry and exit prices, and the minimum reserve prices applied in the long term entry capacity auctions.

182. During 2009, National Grid NTS has launched a fundamental review of entry charging principles. This is in response to growing industry concern about the increasing rate of the TO entry commodity charge. A charging methodology proposal, GCM19 - "Removal of NTS Daily Entry Capacity Reserve Price Discounts", has been raised to remove the zero price within day clearing auction and the 33% day-ahead discount. In conjunction with GCM19 National Grid NTS has also raised Modification Proposal 0284 – Removal of the Zero Auction Reserve Price for Within-day Daily NTS Entry Capacity (WDDSEC) to remove the zero reserve price from the Uniform Network Code (UNC). Modification Proposal 0285 – "Use it or Lose it" (UIOLI) Interruptible Capacity only be released when firm entry capacity is at least 90% sold out has also been raised in conjunction with this process, to reduce the amount of NTS Entry Capacity available at a zero price

Flow Weighted Average Calorific Value (FWACV)

183. The UK's move toward greater diversity of supplies and the development of new types of supplies may lead to a greater propensity for CV capping effects through the current application of The Gas (Calculation of Thermal Energy) Regulations 1996 (as amended in 1997), thereby potentially resulting in increased levels of energy that cannot be billed to end consumers. In April 2009 National Grid Gas NTS raised UNC Review Proposal 0251 "Review of the Determination of Daily Calorific Values" in order to:

- review the existing Flow Weighted Average CV and CV shrinkage arrangements;
- consider the issues which impact on the accuracy of the FWACV methodology when comparing actual energy delivered to the system against that which is billed to gas consumers;
- develop potential solutions to resolve any issues identified;
- if necessary, explore the process for amendment to the Regulations; and
- develop relevant amendments to the Regulations and UNC to deliver any proposed changes to the current arrangements

184. Management of low CV supplies such as bio methane has been the main topic of discussion within the Review Group. The Review Group has now completed its work and submitted the final Review Group Report to the UNC Modification Panel in January 2010.

Appendix I – Forward Prices[15]

1) GB Power Prices

£/MWh	Month Ahead (April)	Quarter 2 2010	Quarter 3 2010	Summer 2010	Winter 2010/11
Baseload	33.65	33.65	34.10	33.90	38.85
Peaks	38.35	38.60	39.30	38.95	43.90
Off-Peaks	31.04	30.90	31.21	31.09	36.04

2) Gas Prices (assuming 49.13% efficient plant)

NBP	Month Ahead (April)	Quarter 2 2010	Quarter 3 2010	Summer 2010	Winter 2010/11
p/therm	31.45	30.75	30.75	30.70	39.65
£/MWh e	21.84	21.36	21.36	21.32	27.54

3) Exchange Rates

	£ to €	£ to $
	0.8996	0.6675

4) Coal Prices (assuming 36% efficient plant)

ARAcif	Month Ahead (April)	Quarter 2 2010	Quarter 3 2010	Summer 2010	Winter 2010/11
$/tonne	73.00	74.18	75.90	77.70	83.40
£/MWh e	19.42	19.73	20.19	20.67	22.19

5) Carbon Prices

	€/metric tonne	£/MWh e Gas	£/MWh e Coal	£/MWh e Oil
2010	12.90	4.76	10.91	9.98
2011	13.30	4.91	11.25	10.29
2012	14.00	5.16	11.84	10.83

6) Clean Spark Spreads

£/MWh e	Month Ahead (April)	Quarter 2 2010	Quarter 3 2010	Summer 2010	Winter 2010/11
Baseload	7.05	7.54	7.99	7.82	6.48
Peaks	11.75	12.49	13.19	12.87	11.53
Off-Peaks	4.44	4.79	5.10	5.01	3.68

7) Clean Dark Spreads

£/MWh e	Month Ahead (April)	Quarter 2 2010	Quarter 3 2010	Summer 2010	Winter 2010/11
Baseload	3.32	3.01	3.00	2.32	5.59

[15] Analysis based on prices as at 31st March 2010.

Peaks	8.02	7.96	8.20	7.37	10.64
Off-Peaks	0.71	0.26	0.11	-0.48	2.78

8) Clean Fuel Spreads (+ve = Gas higher in Merit than coal)

£/MWh e	Month Ahead (April)	Quarter 2 2010	Quarter 3 2010	Summer 2010	Winter 2010/11
Spread	3.73	4.53	4.99	5.50	0.89

9) French Power Prices

£/MWh	Month Ahead (April)	Quarter 2 2010	Quarter 3 2010	Summer 2010	Winter 2010/11
Baseload	34.72	32.93	34.63	33.78	0.00
Peaks	42.28	41.16	45.79	43.48	0.00
Off-Peaks	30.53	28.35	28.44	28.39	0.00

10) GB vs French Spreads

	Month Ahead (April)	Quarter 2 2010	Quarter 3 2010	Summer 2010	Winter 2010/11
Baseload	-1.07	0.72	-0.53	0.12	38.85
Peaks	-3.93	-2.56	-6.49	-4.53	43.90
Off-Peaks	0.51	2.55	2.77	2.70	36.04