nationalgrid

Summer Outlook Report 2008

Executive Summary

1. Building on the success of the Winter Consultation Report process, National Grid has agreed to provide a detailed report into a range of issues that the electricity and gas industries may face during the summer months, May to September.
2. This report covers potential electricity and gas issues, such as demand-supply balance, how demand responds to high temperatures, European interactions and transmission issues.
3. Though we are undertaking 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 meets the needs of the industry.

Electricity

4. The outlook for the electricity market in summer 2008 appears broadly similar to that observed prior to summer 2007, albeit the introduction of the Large Combustion Plant Directive (LCPD) has introduced a new level of complexity. Provided the electricity market continues to make plant available in response to the appropriate price signals, demand should be able to be met in full.
5. Last summer the operation of the electricity market was characterised in July and August by coal fired generation displacing gas fired generation, with gas providing the marginal capacity. Current electricity, fuel and carbon prices for summer 2008 indicate that coal fired generation has a marginal competitive advantage and that coal should be the preferred fuel for baseload generation. Relatively small changes in fuel or carbon prices will impact significantly on the preferred fuel for generation with a consequential impact on the merit order and gas demand. Additionally, the Large Combustion Plant Directive may impact upon the running regimes of coal-fired generation.
6. The traditional focus has been on meeting the electricity demand at winter peak. Installed generation capacity does mean that summer demands can be met but this relies upon the market as a whole responding to changes in demand through the course of the summer, for instance through a hot spell where demands may increase. This may require some generation outages to be re-timed depending on the actual demands and generation already available. Market information on expected plant surpluses and demand levels is provided on both www.bmreports.com and www.nationalgrid.com .

Gas

7. Like electricity, the outlook for the gas market in 2008 appears broadly similar to that observed in recent summers. Other than non-daily metered demand which will continue to be weather dependent, there are increased uncertainties regarding most other market sectors.

8. As highlighted above, there is considerable uncertainty in the use of gas for power generation. Although coal-fired generation is currently more attractive for this summer, the lowest cost option for power generation could readily switch from coal to gas and vice-versa. The use of gas for power generation is also influenced by gas prices on the spot market. As in previous summers, exports through IUK are also difficult to assess, with drivers suggesting increased exports (slightly higher need for Continental storage refill) and other factors suggesting lower exports (small price differentials).

9. On the supply side, though in decline, we expect the UKCS to be the largest source of summer supply. We also expect increased imports from Norway as Ormen Lange continues to be brought on stream

10. LNG imports are not expected to be materially higher than for last summer, the exception to this being the possibility of commissioning cargoes at Milford Haven for both South Hook and Dragon.

11. In terms of supply terminals we anticipate considerable variation at all locations. However we do not expect this to be affected by either our maintenance programme or our network capacity expansion.

Roles and Responsibilities

12. 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 Business Enterprise & Regulatory Reform (BERR) has a role in setting the regulatory framework for the market.

Legal Notice

13. 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.

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

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Chapter 1: Electricity

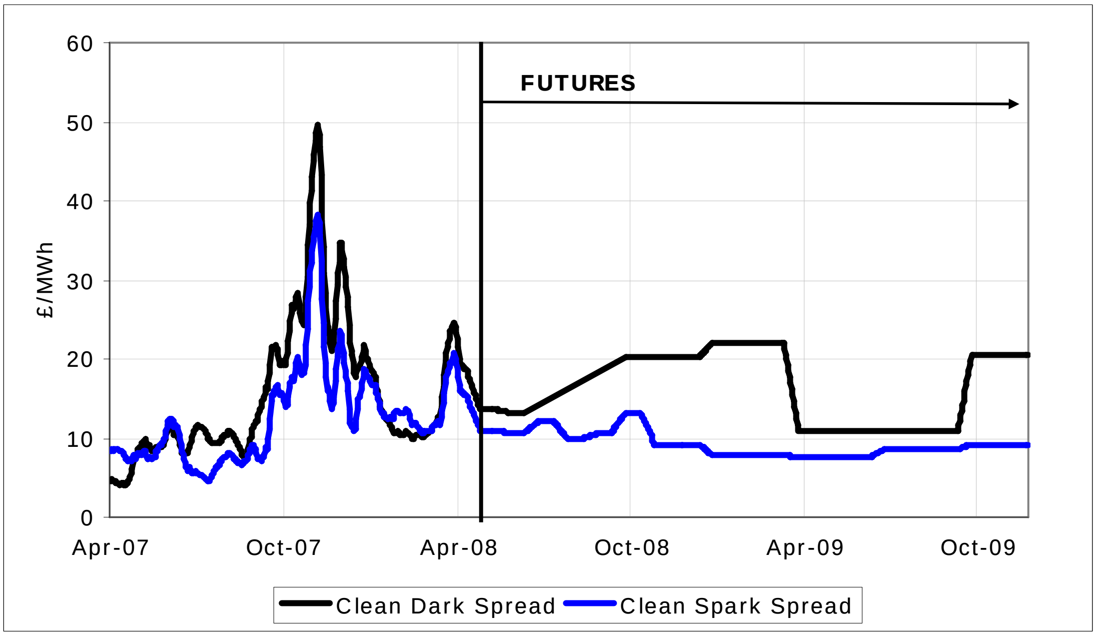
Introduction

16. 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. The introduction of the Large Combustion Plant Directive (LCPD), on 1 January 2008, which limits the running-hours of certain coal and oil stations, introduced a further degree of uncertainty when assessing the supply-demand balance for the forthcoming summer.

17. In this Chapter we examine issues associated with electricity demand, plant availability, the expected merit order, the uncertainty resulting from LCPD, the interactions with European markets and transmission outages and constraints.

18. Electricity prices and fuel costs for coal and gas for summer 2008 (see Figure 1.1) indicate that, at the moment, the clean spark spread for coal-fired generation is more attractive than that for gas, indicating that coal should be the preferred fuel for baseload generation this summer. This may change with relative movements in fuel prices and carbon prices, which are very volatile, and with prices for gas on the spot market. Additionally, the Large Combustion Plant Directive may impact upon the running regimes of coal-fired generation.

Figure 1.1 – Comparison of Dark Spread and Clean Spark Spread

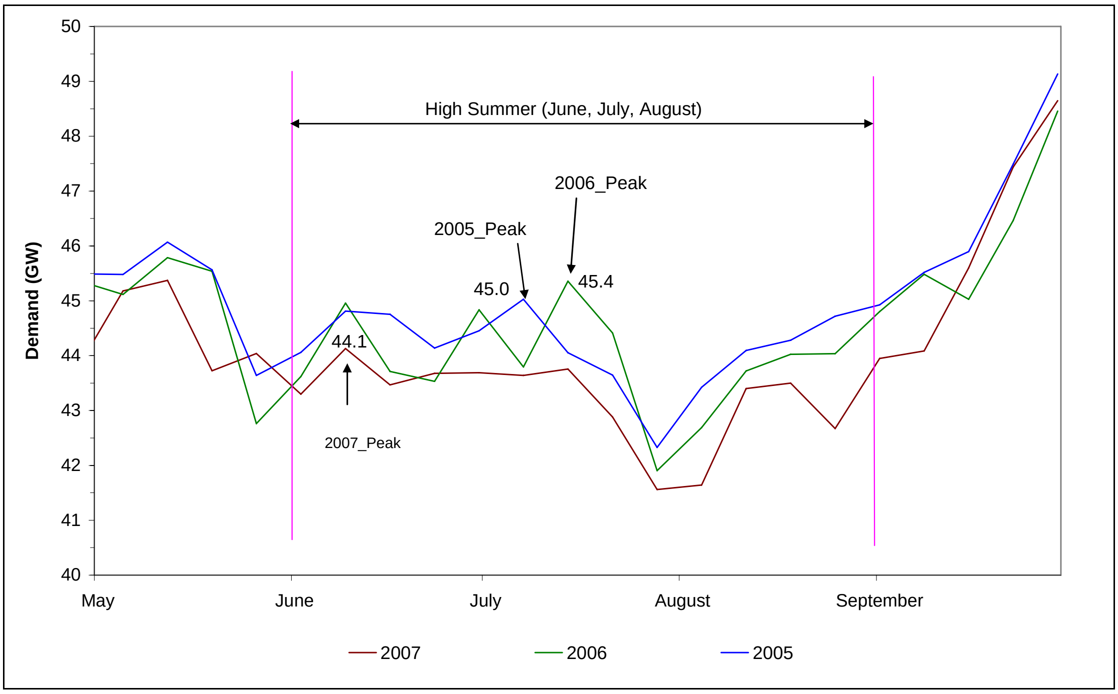


Electricity Demand

19. For summer 2008, we assume no growth in underlying demand from 2007. This is broadly consistent with the experience of the last couple of summers when fluctuations in the weather are accounted for. Last summer saw a small decrease in the peak demand but it is too early to determine yet whether this is part of a trend. 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.

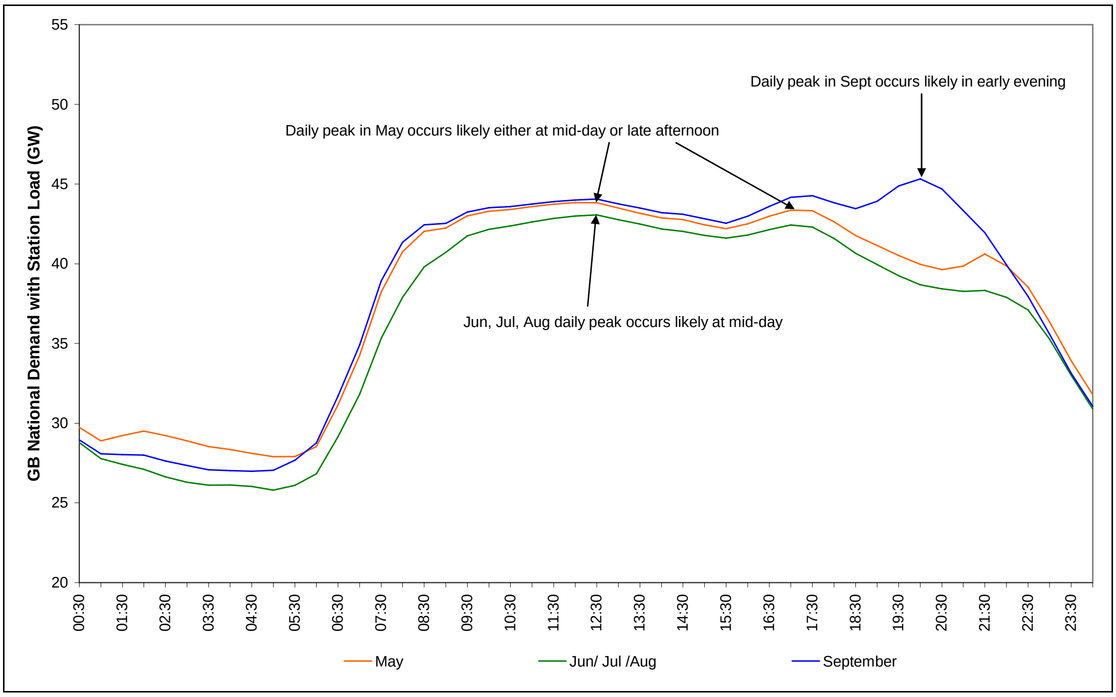
20. Figure 1.2 shows the weekly peak demand for the last 3 summers, and highlights the fact that demand is typically higher in May and September than in July and August when many people are on holiday.

Figure 1.2 – Weekly Peak Demand



21. We identify a period of "high summer" in the months of June, July and August, where demand is reasonably flat across the working day (9:00 to 18:00), but with a strong tendency to peak at midday. During May, demand is also reasonably flat across the working day, but there is a higher chance demand will peak in the late afternoon, dependent upon the weather conditions. In September, the daily peak occurs in the evening, due to the effect of darker evenings increasing the lighting load.

Figure 1.3 – Half-Hourly Demand Profiles



Demand Response to Temperature

22. To forecast demand, National Grid use a concept of effective temperature[1], which takes into account temperatures over preceding periods to reflect the lag impact between temperature changes and demand changes.

23. Figure 1.4 illustrates the spread of temperatures on the weekly peak day over the last 5 summers. In addition historic midday effective temperatures under average, warm and cold conditions are illustrated. On a weekly basis, the temperature has a 12% chance of exceeding the warm temperature, and a 12% chance of being below the cold temperature.

24. Figure 1.5 illustrates effective temperatures over the last 5 years and under historic average, warm, and cold conditions at 17:00. Effective temperatures at 17:00 are typically 2 degrees warmer than at midday, but on extremely hot days this temperature differential can increase.

25. Effective outturn temperatures in the last five years at midday have risen as high as 24 degrees and at 17:00 have risen to a peak of 29 degrees. During high summer in the last five years, we have experienced warmer than our "warm" reference effective temperatures in the summer on a number of occasions, whilst we have experienced few occasions colder than our "cold" reference temperatures.

[1] Effective temperature (TE) is a variable that is used in National Grid to estimate the variation of demand in relation to temperature change. TE (measured in degrees Celsius) is the average of a moving average temperature T0 and the TE of 24 hours before. Studies on the daily peak demand of the last three summer indicates that:

- in May and September, daily demand peak was linked to TE at 17:00
- in June, July and August, daily demand peak was linked to TE at 12:00 mid-day

Figure 1.4 – Effective Temperatures at Midday

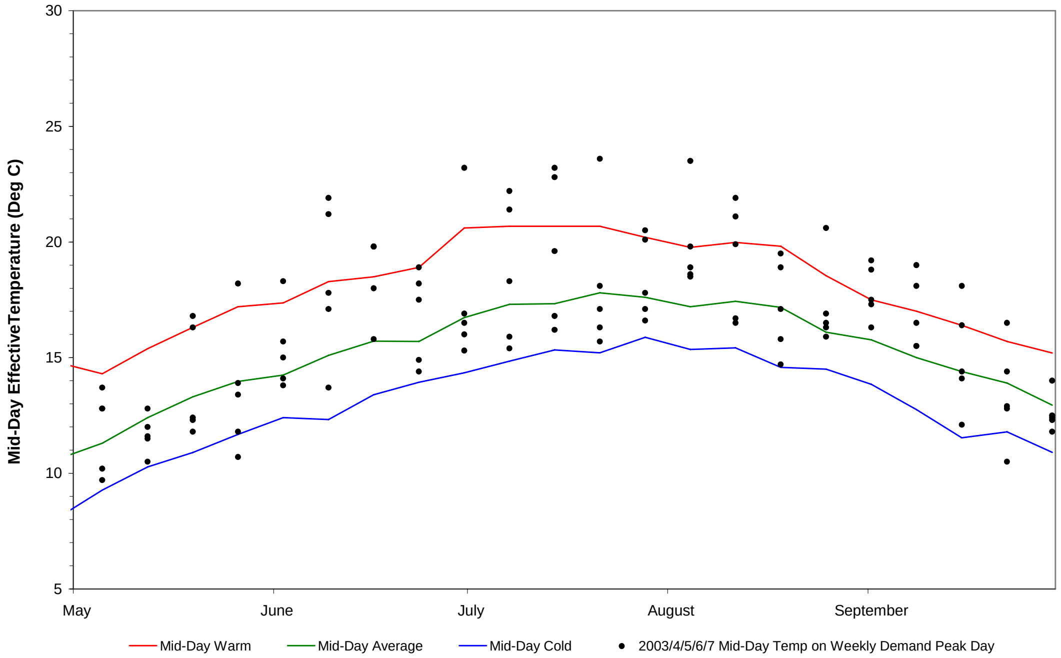
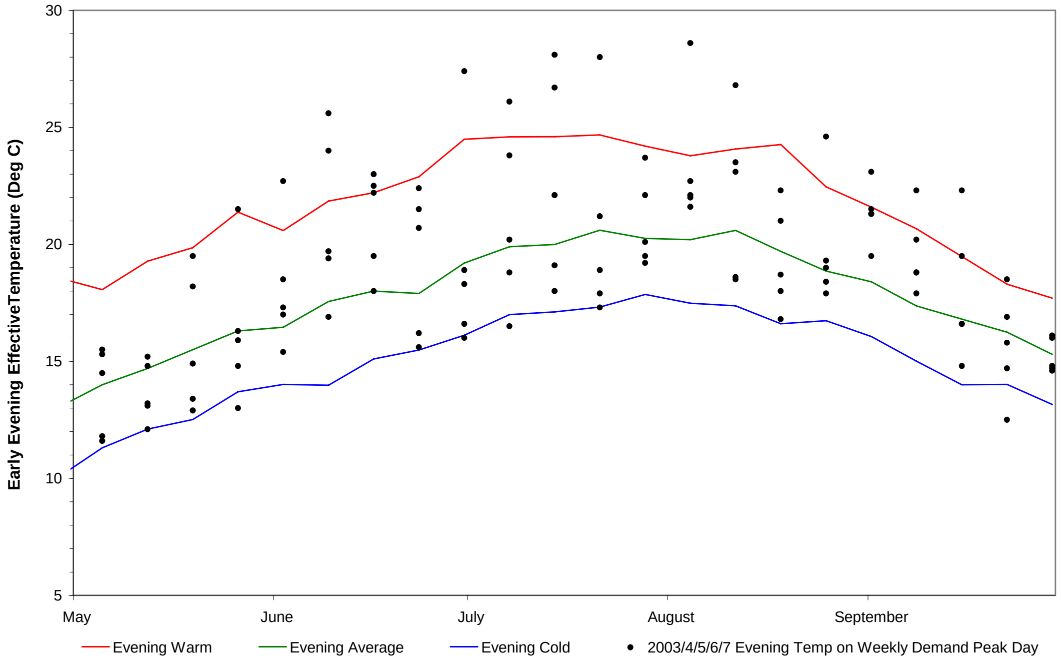


Figure 1.5 – Effective Temperature at 17:00

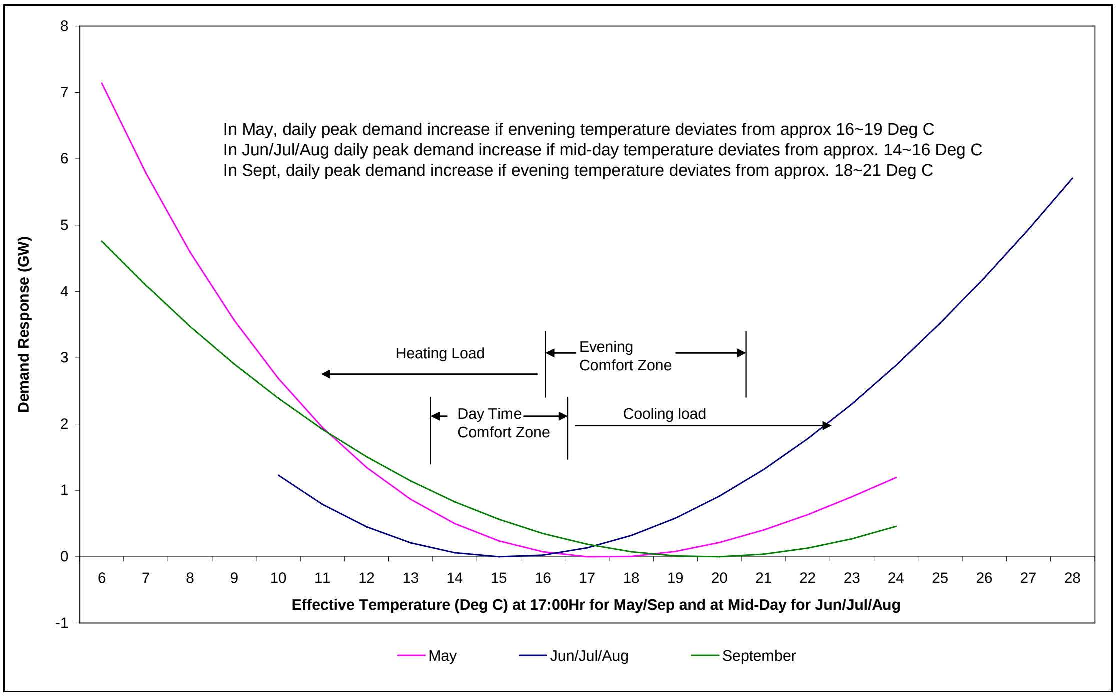


26. During the summer, the relationship between electricity demand and temperature is not as simple as during the winter when demand for electricity increases as the temperature falls. As illustrated by Figure 1.6, whilst demand does increase as temperatures fall, this is only true when temperatures are below the "comfort temperature" of around 16-17 degrees. At temperatures higher than this, demand actually increases when temperatures rise, due to the extra cooling demand.

27. Over recent years, National Grid has witnessed an increasing response to higher temperatures, which we attribute to the increased use of air conditioning and electric fans.

28. The relationship between demand and temperature also varies with the time of year itself, and so we present three curves for the relationship between temperature and electricity demand.

Figure 1.6 – Demand and Temperature Relationship



29. Table 1.1 shows the response of demand to temperature for the peak demand period for high summer, May and September.

Table 1.1 – Demand Response to Temperature

	Increase in Demand[2]
Increase in temperature – June, July, August	~200-300 MW per 1 degree
Decrease in temperature – May	~300-400 MW per 1 degree
Decrease in temperature – September	~250-350 MW per 1 degree

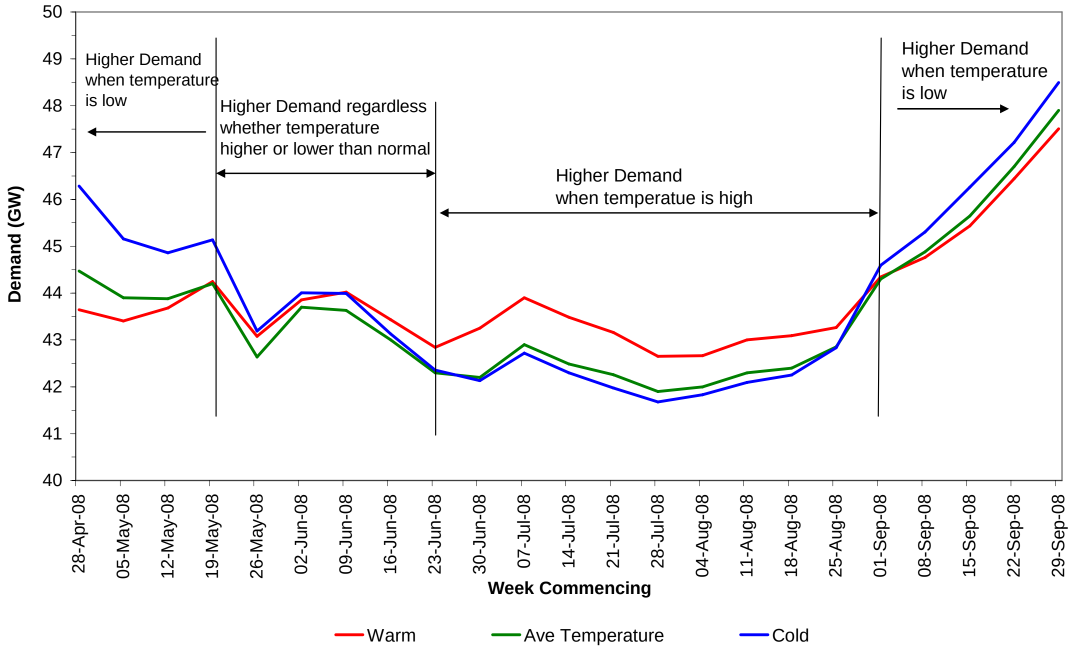
30. Figure 1.7 shows our modeled demand for 2008 under different temperature scenarios. We have assumed no growth in underlying demand from that experienced in summer 2007.

[2] The demand response figures are for changes in temperature around the monthly average.

31. Reflecting the relatively complex relationship between temperature and demand, at different times of the summer, demand is high when the temperatures are abnormally cold, and at other times of the summer demand is high only when the temperature is abnormally high:

- In May, demand rises when the temperature drops
- In late May and June, the temperature is often close to the comfort temperature of 16-17 degrees, and so either a fall or increase in temperature will cause demand to increase.
- During July and August, when temperatures are typically above the comfort temperature, demand rises with an increase in temperature.
- In September demand increases when the temperature drops.

Figure 1.7 – Electricity Demand under average, warm and cold conditions



32. The volatility of summer demand is lower than in the winter, due mainly to a lower demand response to temperature. Over recent years, we have seen during the high summer periods of June-August demand on the particularly hot days being around 2 GW higher than normal. In the winter, on days when temperature is significantly colder than normal, demand can be over 3-4 GW higher than normal.

Interconnector Exports to France

33. Historically, across the summer there has been a varying profile of flows on the GB-France Interconnector during the daytime periods (07:00 to 19:00). The Interconnector's flows varied across the day, on occasions exporting to France in the morning before reversing direction to flow to the GB for the evening peak. This is generally consistent with GB-France price differentials, as illustrated in Figure 1.9.

Figure 1.8 – French flows at time of Weekly Peak Demand

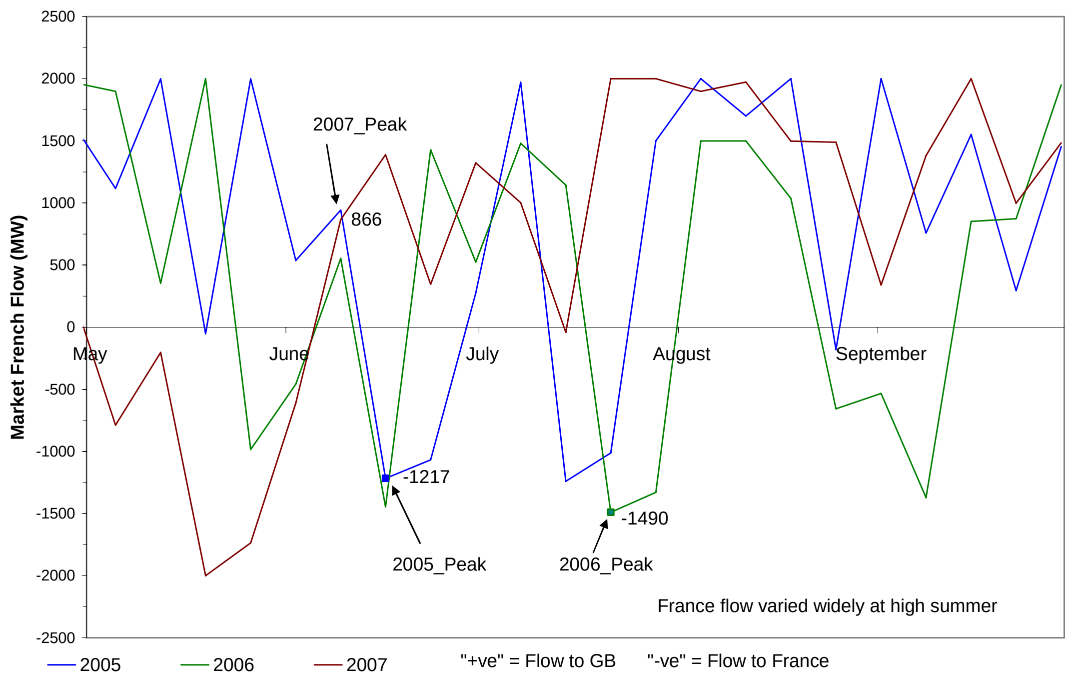
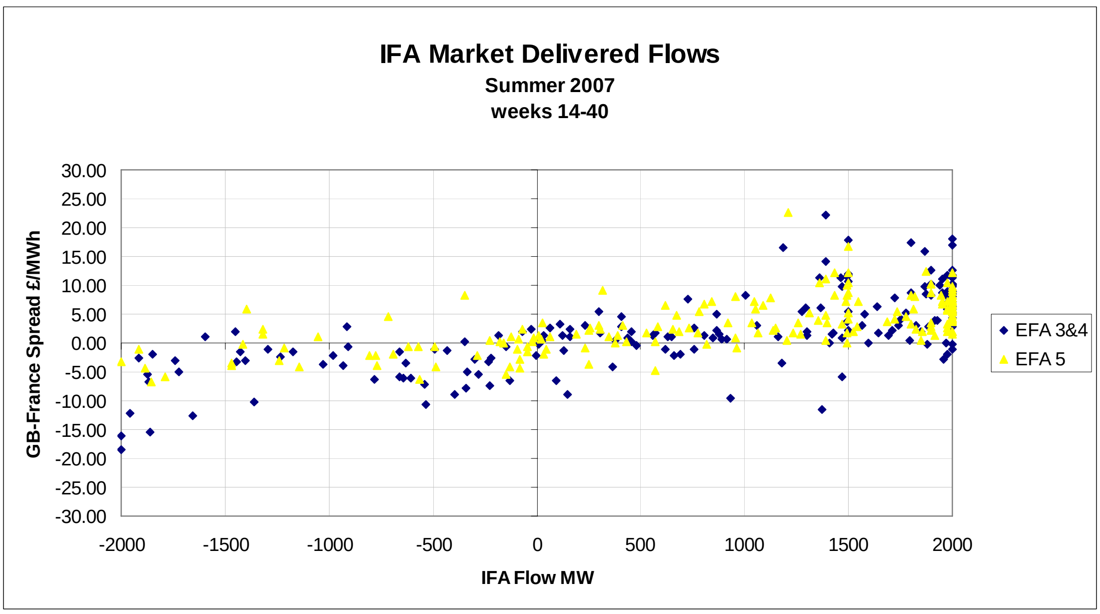


Figure 1.9 – GB-France Price differentials and flows

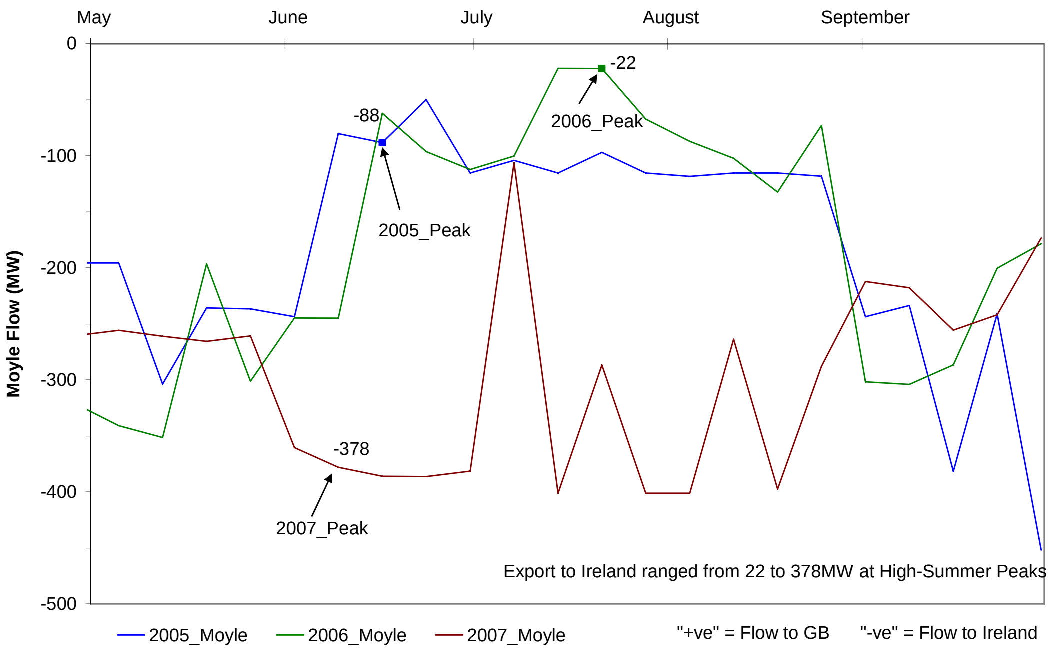


Interconnector Exports to Northern Ireland

34. There is an interconnector between GB and Northern Ireland (NI) which can physically flow 500 MW to NI and 250 MW to GB, though Transmission Entry Capacity (TEC) contractually limits the flow to GB to 80 MW.

35. Historically, across the summer there has been an export from GB to NI of around 100-400 MW, as illustrated by Figure 1.10.

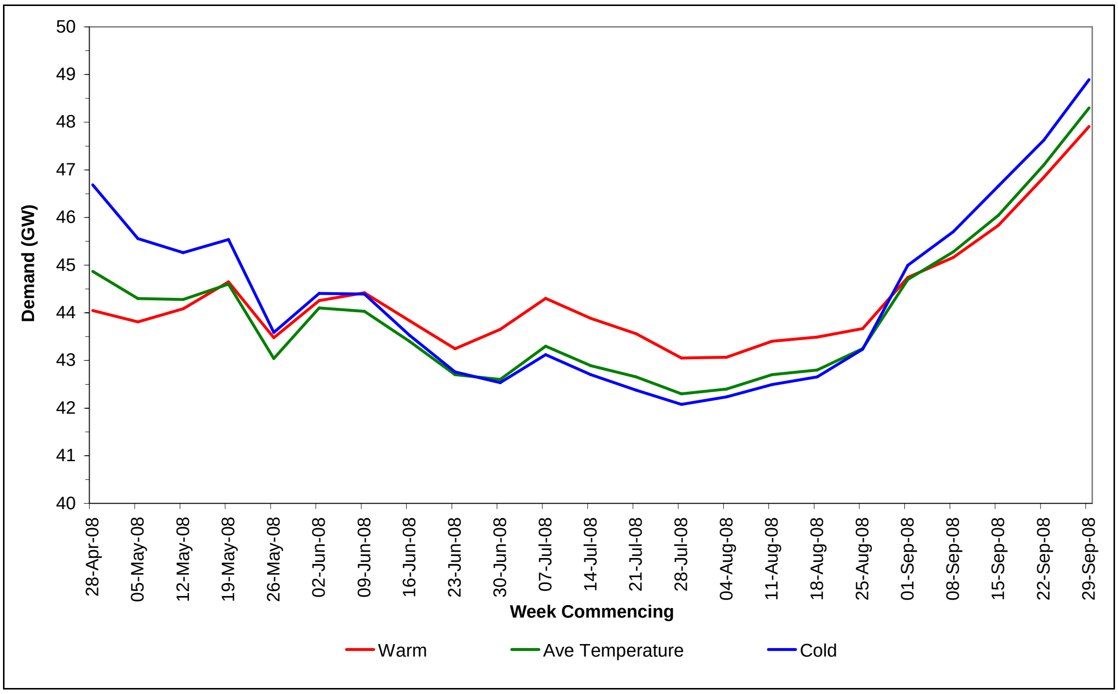
Figure 1.10 – Northern Ireland to GB



Electricity Demand Forecast

36. In addition to assuming no growth of underlying demand, we do assume 0.4 GW export to Northern Ireland. This compares with an outturn flow of 0.3 GW during summer 2007. We further assume that the GB-France interconnector is at float i.e zero power flow. This compares with an average flow of 0.7 GW from France to GB over peak periods during summer 2007 though it should be noted that at times of peak demand, the actual interconnector flow can be in either direction. Figure 1.11 shows the modelled demands on this basis.

Figure 1.11 – Modelled Demand (assuming 0.4 GW flow to NI)



Generation Capacity

37. The quoted plant margin for 2008/9 currently reported in the January 2008 update to the 2007 Seven Year Statement (SYS) is 26.5%, based on a Transmission Entry Capacity (TEC) contracted generation capacity of 79.4 GW. This includes the 2 GW GB-France Interconnector.

38. Oldbury nuclear power station, which has a capacity of 0.4GW, is due to de-commission on 31 December 2008 and is not included in the 79.4 GW capacity total. However, it is assumed to be fully available during summer 2008.

39. The reduced nuclear output at Hinkley Point and Hunterston, announced by British Energy in 2007, continues and represents a loss of 0.9 GW of capacity, not reflected in the 79.4 GW SYS figure. There are no other significant known reductions in generation capacity for this summer, though the availability of opted-out LCPD generation remains uncertain.

40. Langage (0.9 GW), Marchwood (0.9 GW) and Immingham stage 2 (0.6 GW) have contracted for TEC for 2008/9, but are not due to commission in time for summer 2008.

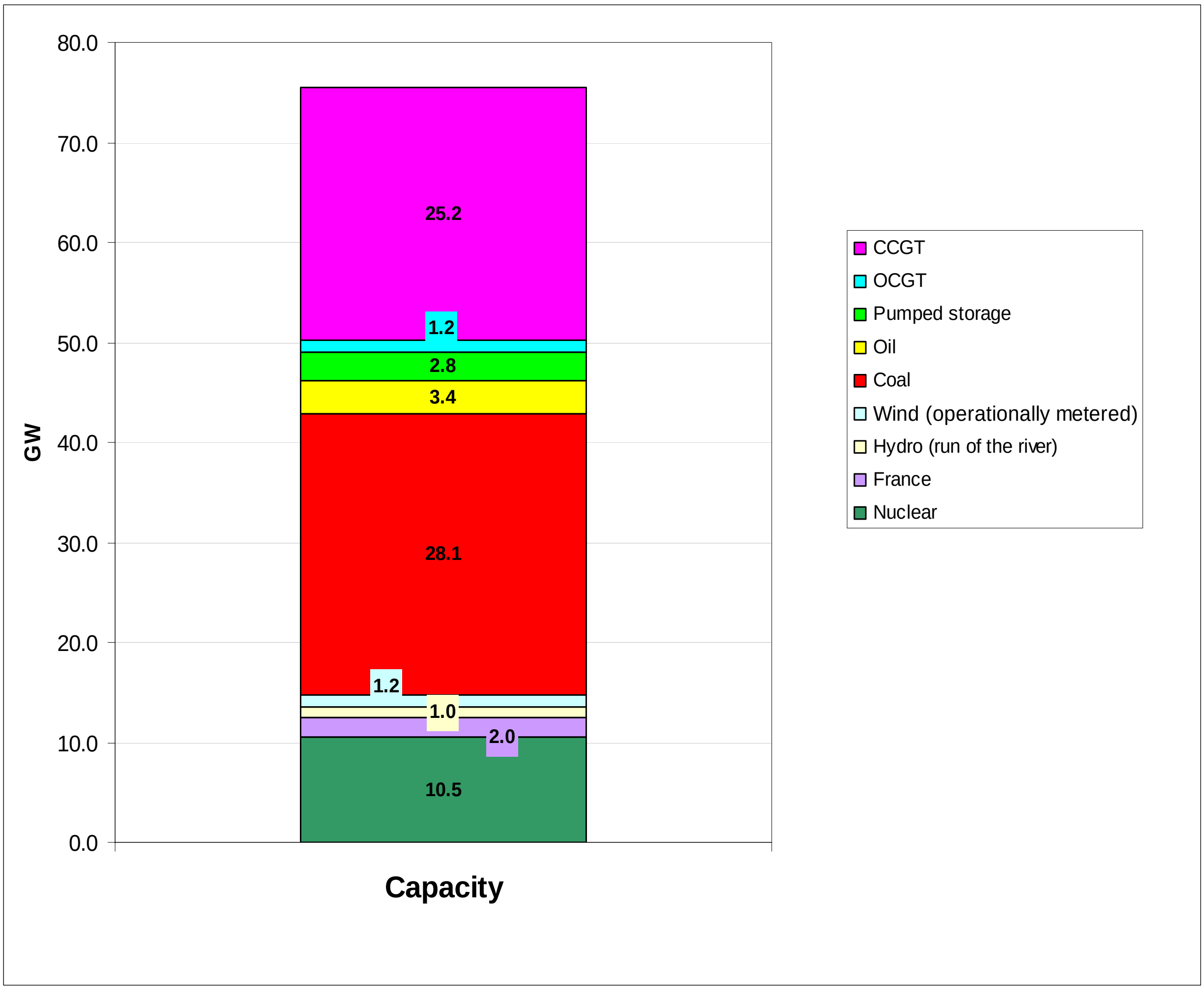
41. Wind continues to increase its share of the GB generation market, with 0.3 GW of new wind capacity being built during 2008/9. There will be about 1.5 GW of fully operational capacity visible to National Grid by the end of summer 2008. Our experience of wind generation is that over the summer it tends to generate on average around 20% of its maximum output.

42. The latest view of TEC capacity available for summer 2008 is therefore 76.5 GW, assuming Oldbury is fully available.

43. This headline plant margin as quoted in the SYS is a useful, broad indicator of the amount of generating plant on the system. At an operational level, generators provide us with more detailed information about their expected availability. We use this to derive an operational view of generation availability, which can differ from the SYS view for a variety of reasons including planned outages and operational restrictions on output.

44. Our current operational view of generation capacity anticipated to be available for the start of summer 2008 is 76 GW. A broad breakdown of this capacity is shown in Figure 1.12. In addition, we expect around 170MW of wind generation capacity to progressively become available during the course of the summer.

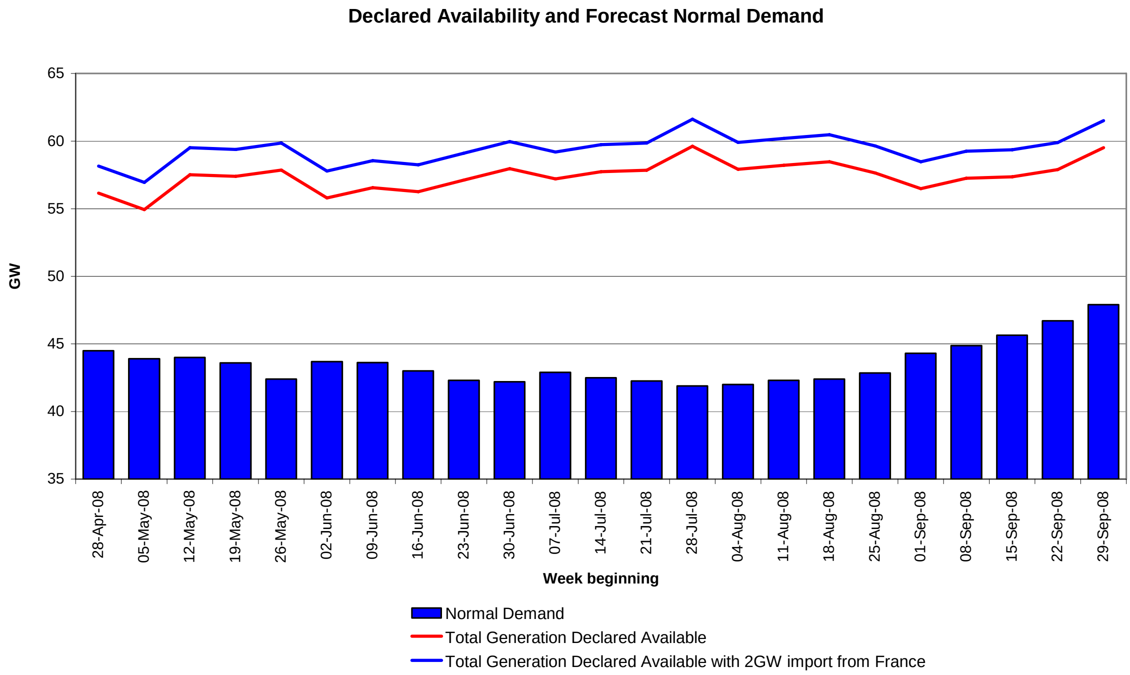
Figure 1.12 – Generation Capacity – Summer 2008



Plant Availability

45. Figure 1.13 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 delivery from the GB-France Interconnector[3]. As the interconnector between NI and GB is forecast to flow towards NI this summer, no allowance has been made for the ability to import electricity from NI. The demand forecast includes a 0.4 GW flow to NI.

Figure 1.13 – Declared Generation Availability



46. Figure 1.13 illustrates a summer in which average weather conditions are experienced each week. It shows weekly forecast generation availability as declared by generators under the Grid Code. This reflects planned unavailability as notified at this stage of generators outage plans, but does not include an allowance for unplanned generator availability.

47. It is necessary to hold varying levels of reserve services such that within-day we have adequate reserve to cover for short-term generator breakdown and demand forecast errors. On average, this amounts to a requirement of around 6 GW at the day-ahead stage from the generation shown available. The margin shown in Figure 1.13 does not reflect this requirement.

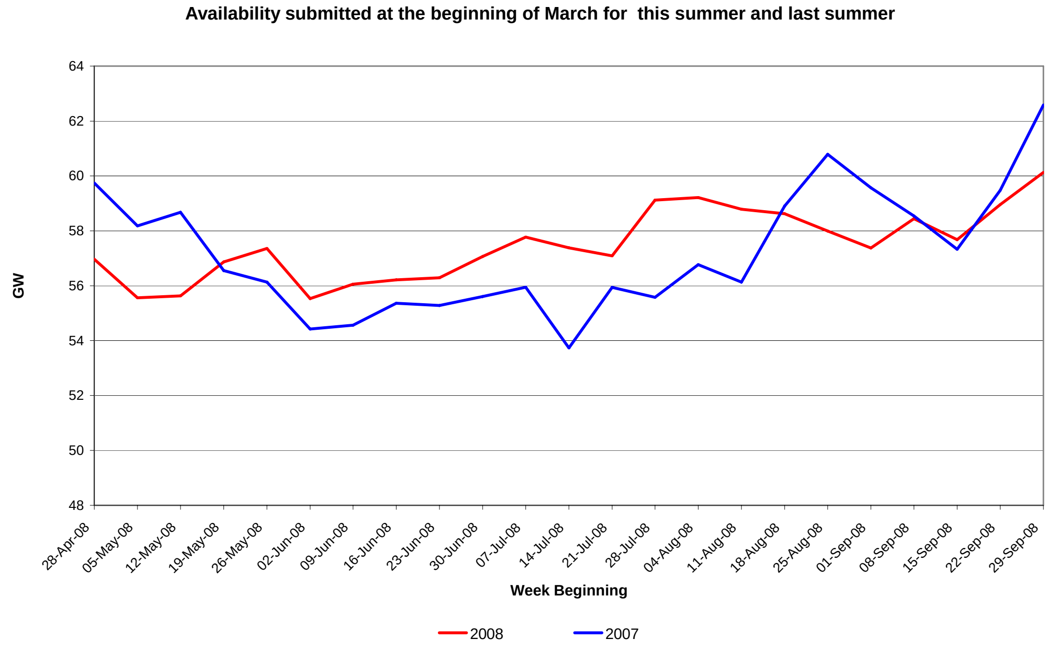
48. As can be seen in Figure 1.13, with full exports from France the excess generation over average weekly peak demand would be

[3] The French Interconnector comprises two pairs of 500MW circuits (totalling 2000MW) and has annual availability of 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.

around 12-15 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 even in an average summer there will be times when demand is 1-1.5 GW above normal.

49. Though several power stations are indicating that they will be on outage during the peak months of this summer, this is not significantly different to previous years' experience. Overall the current levels of notified unavailability are similar to historic levels, as illustrated in Figure 1.14.

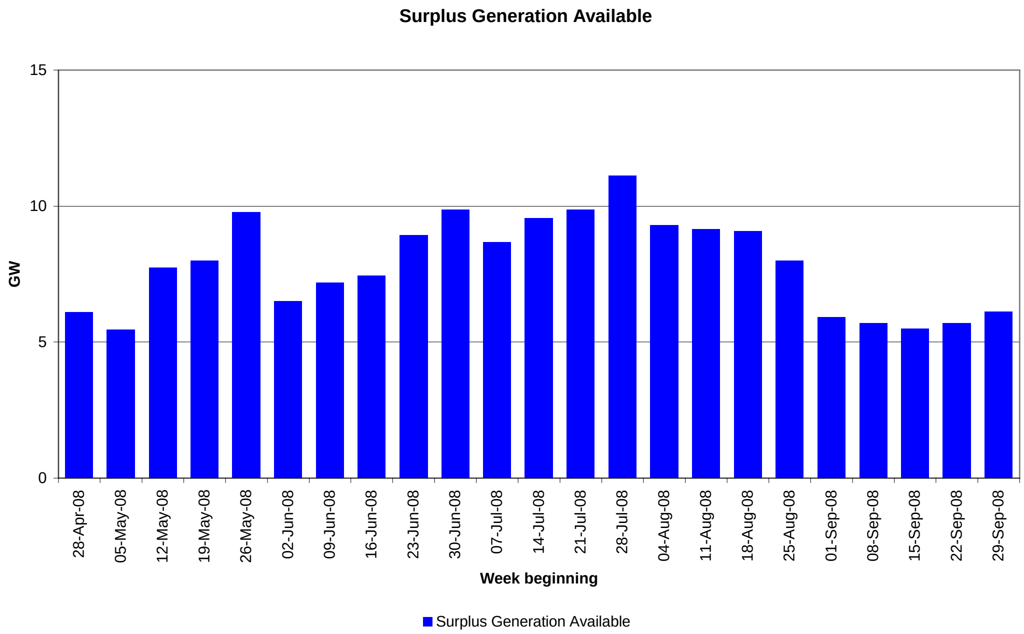
Figure 1.14 – Comparison of Declared Generation Availability 2008 v 2007



50. Our normal operational experience at this point in the year, looking forward to the summer, is that the outturn generation availability will be significantly different to that currently indicated by the information that has been provided at this point to National Grid by Generators. This is due to generation companies submitting their availability plans closer to the date of outage commencement.

51. The current surpluses, calculated as the difference between available generation and forecast demand, over the summer are shown in Figure 1.15. These surpluses will be affected by the submission timescales for generation outages, as discussed above. These surpluses are calculated using the base assumption that the interconnector between GB and France is at float i.e. zero power transfer

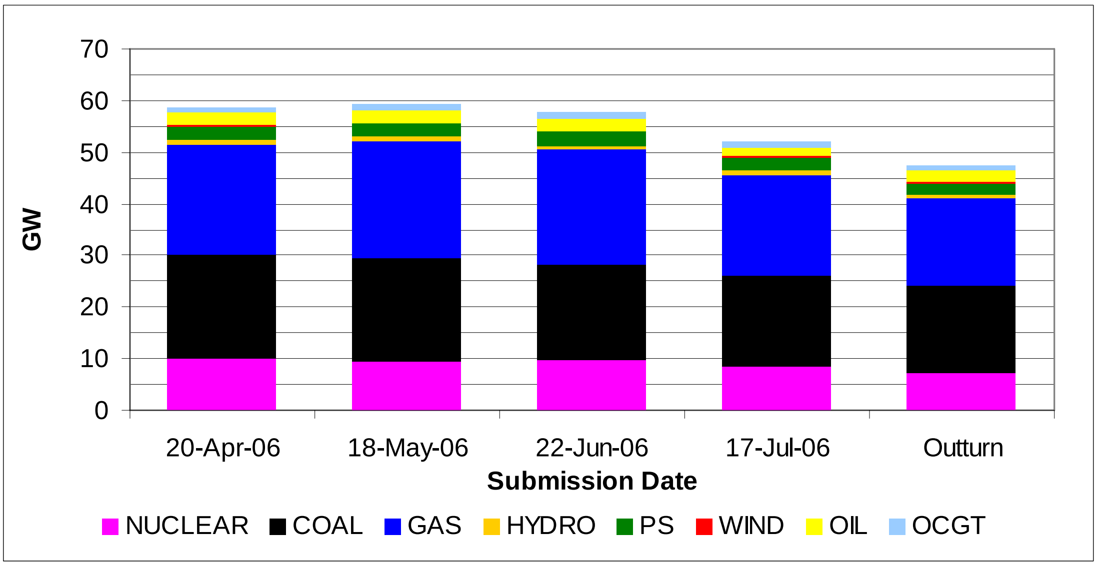
Figure 1.15 – Generation Surpluses



52. National Grid works with the changing generator availability as a matter of course. We expect that the market mechanisms will provide sufficient generation to meet demand. On occasion we look to flex our transmission system outage plans to contribute to generation availability where necessary.

53. Generally, generator availability reduces as we get closer to real time and Generators advise us of their outage programmes. However, there are occasions when we see an increase in the generation available nearer real time. For instance, if demands are higher, more generation makes itself available through the normal functioning of market mechanisms.

Figure 1.16 – Changes to Generation Availability for 19th July 2006



54. Figure 1.16 above shows the generation availability as it evolved over three months for the day of the highest summer demand experienced in 2006 on 19th July 2006. As can be seen, the snapshot shows the generation availability data evolving over the period preceding a particular day.

55. System warnings may occur at any time of the year and that recent experience shows they may be issued in high summer. System warnings concerning generation availability relative to demand were issued for the 19th July 2006, primarily due to short term breakdowns of generation plant. We presented details of how the market and National Grid reacted to generation and demand issues in July 2006 at our Operational Forum[4]. Whilst generation margins were tight by normal operational standards the situation was successfully managed.

56. In response to industry requests, National Grid and Elexon have recently 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 basis on the Elexon BM Reports website[5].

57. This information helps to facilitate efficient market operation as it informs market participants of the expected levels of demand and therefore the amount of generation they may need to contract with to meet their customer's demand. In response to industry requests, National Grid and Elexon delivered Phase 1 of improvements to

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[4] See the presentation on our website at http://www.nationalgrid.com/NR/rdonlyres/F7A90B14-15BE-4426-9D02-02713E6C268E/8122/01OpPerf2Aug06_pdf.pdf

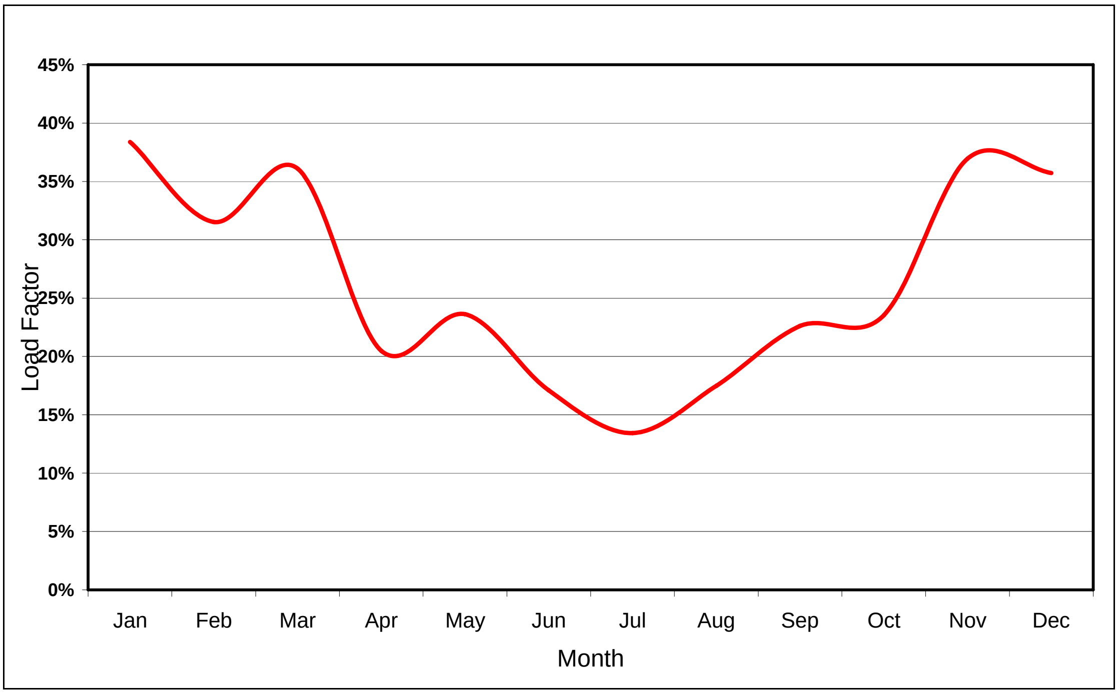
[5] See http://www.bmreports.com/bsp/bsp_home.htm for the new electricity market summary page that went live on 12th March 2008. Forecast daily surplus data for 2-14 days ahead is published towards the foot of this summary.

electricity operational information in March 2008. Other improvements sought by the industry that were identified through National Grid's consultations during late Summer 2007 are the subject of Balancing and Settlement Code (BSC) modifications P219 and P220. This second phase of improvements to information provision are planned to be delivered in November 2008 and include a number of new data items. We have provided a page on our website that focuses on developments currently taking place for electricity operational information, including providing details of the Phase 2 changes currently planned[6].

Wind

58. Wind continues to increase its share of the GB generation market, with 0.3 GW of new transmission-connected wind capacity to be built during 2008/9, of which 170MW is expected to progressively become available over the course of the summer. There will be about 1.5 GW of fully operational capacity visible to National Grid by the end of 2008/09. Our experience of wind generation is that over the summer it tends to generate on average between 15 and 25% of its maximum output, as detailed in Figure 1.17.

Figure 1.17 – Wind – Monthly Load Factor

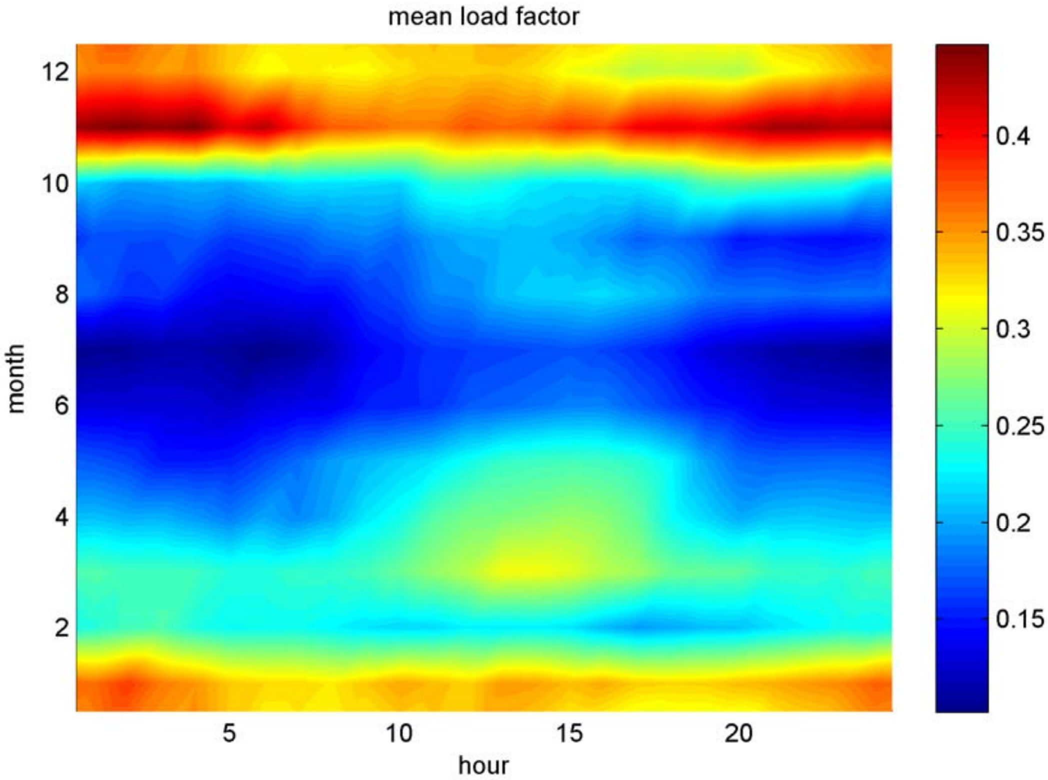


59. For the wind generation that we meter, we have undertaken further analysis of the load factors over the seasons. Figure 1.18 shows the

[6] See http://www.nationalgrid.com/uk/Electricity/Data/electricitymarketinfo/ for details of current developments.

average load factor for each hour over each month of the year. Our analysis shows that for summer months that the average (mean) load factor for wind is in the range of 15%-25% during the daytime. Furthermore, the load factor during summer overnight hours is, on average, still lower at less than 15%.

Figure 1.18 – Wind – Daily and Monthly Mean Load Factors

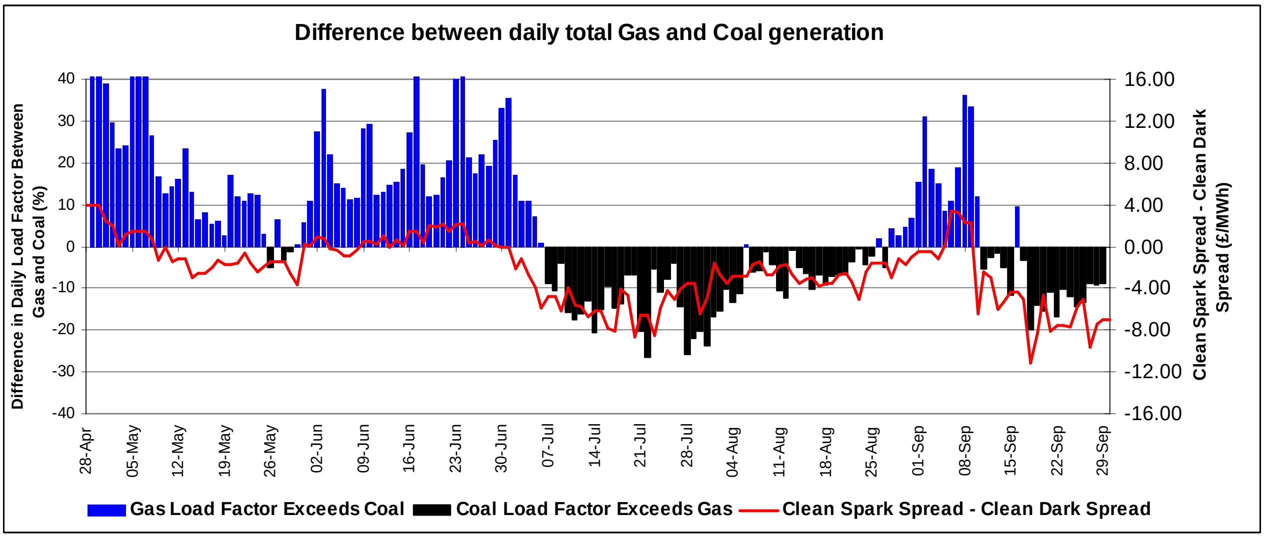


Month 1 is January. The right hand scale shows mean load factor from 0 to 0.45

Merit Order

60. Figure 1.19 shows that the relationship between spark and dark spreads was a key factor over summer 2007 in determining the load factors of coal and gas generation. When the clean dark spread is higher than the clean spark spread, particularly during July and August 2007 the load factor of coal fired generation was higher than that of gas.

Figure 1.19 – 2007 Summer Coal and Gas Load Factors and Clean Spreads.



61. At current market prices for summer 2008 a typical gas-fired generator running 24 hours a day 7 days a week (ie baseload) would earn a profit of around 7 -10 £/MWh above their gas and CO_2 costs. A typical baseload coal-fired generator could expect to earn around 12 £/MWh, implying that gas may provide the marginal generation this summer. As stated previously, fuel prices are very volatile and this may change. Additionally, gas-fired generation is very dependent upon gas spot prices. The merit order can also vary on a daily basis depending upon the gas price, and the strategies generators adopt for their 11 GW of plant which has opted out of the Large Combustion Plant Directive (LCPD).

62. Forward GB prices for the peak 12 hours of the day (EFA 3-5) are currently higher than France for Q2, but less so for Q3. However the premium is not very high and prices are volatile, and we cannot assume that there will be a flow towards GB. We expect that the flows on the French interconnector will react to relative prices between European and GB prices. We provide more detail in Appendix I on fuel prices.

63. The Large Combustion Plant Directive (LCPD) limits the running hours of 11 GW of power stations without Flue Gas Desulphurisation (FGD) to 20,000 hours from 1 January 2008 to 31 December 2015. Of the power stations that chose to retro-fit FGD plant, and hence not have their running hours limited, a number did not have their FGD equipment installed by 1 January 2008. These will effectively behave in a similar way to Opted Out plant until the FGD equipment is commissioned i.e

generating plant which has chosen not to install FGD. Over the summer, it is expected that FGD equipment will be successfully fitted to several stations.

64. Current market prices for coal, carbon and electricity imply it is more profitable for coal fired generation to run over the peak periods this summer, rather than the off-peak periods this winter, as detailed in Appendix I. At this stage we do not see any significant security of supply issues over this coming summer with the early stages of LCPD. We assume that at times of high demand or system stress during summer 2008 that coal and oil stations will continue to make themselves available, albeit at a commercially higher price.

65. The impact of LCPD opted out plant running behaviour on network constraint costs is more uncertain because of the highly localised effect each individual station’s operation may have on constraints in that area.

66. At a national-level, due to the higher volume of LCPD plant in the Southern part of the system, there will be increased pressure on all our major North–South network constraints for both the intact and outage-constrained system.

Transmission System Issues

67. Summer 2008 sees the commencement of major works to construct or rebuild major new 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 and the North of England, as part of the Transmission Investment for Renewable Generation (TIRG) works.

68. 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 first 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.

69. This scale of works, at 30 weeks in a single year, is without precedent in recent history and the resultant reduction in transmission capacity is expected to lead to a significant increase in constraint volumes, cost and risk on the Cheviot boundary for the period of the works, which started in late March 2008

70. Uncertainties remain around the outages, due to the possibility of change to the programme or acceleration or delays to works by the Transmission Owners (National Grid, SPT and SHETL). However it is expected that throughout summer 2008 there will be an unbroken programme of planned outages on one or other of the two boundary circuits themselves. An outage on one of the two double circuits reduces the boundary transmission capacity from an average of 2.2 GW to between 0.6 GW and 1.4 GW, depending on the precise nature of the outage.

71. The network outages to undertake the work will reduce the available transmission system capacity on the boundary between Scotland and England, and across several internal Scottish boundaries, and require National Grid to constrain plant output down to keep the system operating safely and securely.

72. To manage this uncertainty, 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. This year, we have also developed a new service, the constraint management service, to help ensure more competition in the provision of constraint services.

73. As a consequence of needing to manage power flows across the boundary circuits by constraining off generation, up to 1.0GW of generation within Scotland may be unavailable to National Grid this summer.

74. The reinforcement of the transmission network in Scotland and the North of England 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 in England and Wales are shown in National Grid's Seven Year Statement http://www.nationalgrid.com/uk/Electricity/SYS/

Chapter 2: Gas

Introduction

75. This Chapter focuses on the gas supply-demand outlook for the forthcoming summer. With demand levels at 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 supply infrastructure, the need to refill storage and the interaction of global and Continental markets on LNG and Interconnector (IUK) flows respectively

76. In this Chapter we examine issues associated with gas demand and gas supply. These include an assessment of the impact of the Large Combustion Plant Directive (LCPD) on gas demand and the prospects for gas imports / exports.

77. We also provide an assessment on how summer performance may be affected by; operational maintenance, new infrastructure and potential changes to the regulatory regime.

Historical Summer Gas Demand

78. 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[7] and the Continent, power station demand and storage injection.

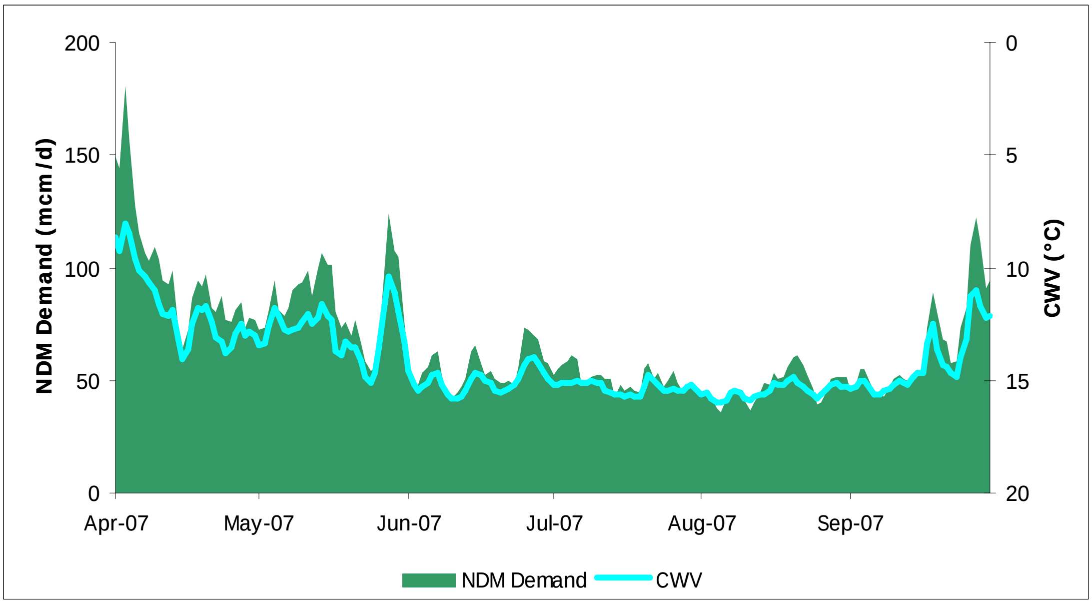
79. Due to the possibility of lower temperatures, weather has the biggest impact on summer gas demand during April, May and late September. The impact of climate change has resulted in warmer springs and earlier summers.

80. 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.

81. Figure 2.1 shows the relationship between weather expressed in terms of a Composite Weather Variable (CWV) and NDM demand for summer 2007. The CWV which is primarily a function of temperature is shown on a reverse scale to highlight the close relationship with NDM demand.

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

Figure 2.1 – NDM 2007 Summer Demand

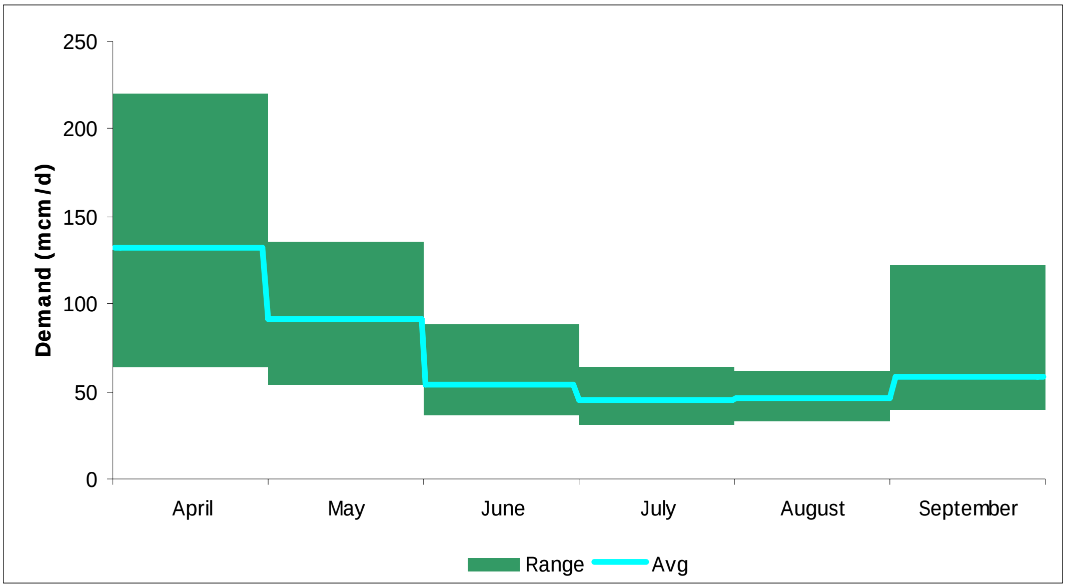


82. The NDM demand for summer 2007 is typical of most summers whereby gas demand can be considered in 3 separate periods; namely:

- i) the late spring /early summer when NDM gas demand is falling
- ii) the high summer period from June to August when NDM demand is essentially flat
- iii) the September increase in NDM gas demand as temperatures start to fall

83. Figure 2.2 shows NDM demands for the past three summers in terms of minimum, average and maximum demands for each calendar month.

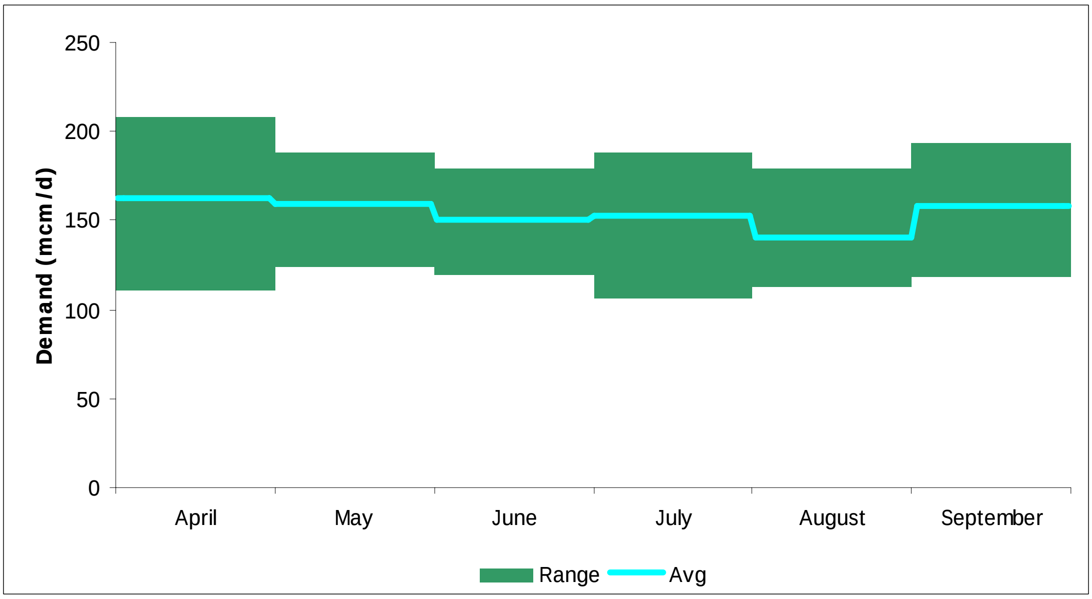
Figure 2.2 – NDM Summer Demands (2005 – 2007)



84. The figure above highlights how much NDM demand variation can occur in the shoulder months (April, May & September) compared to the high summer period. To put this into context, for the months of June, July and August the average NDM demand has been about 50 mcm/d, during this period the NDM demand has been within a +/- 15 mcm/d range for nearly 90% of all days.

85. In a similar manner, Figure 2.3 shows all other demands, namely the non weather sensitive demands of DM, exports, storage injection and power generation for the past three summers in terms of minimum, average and maximum demands for each calendar month.

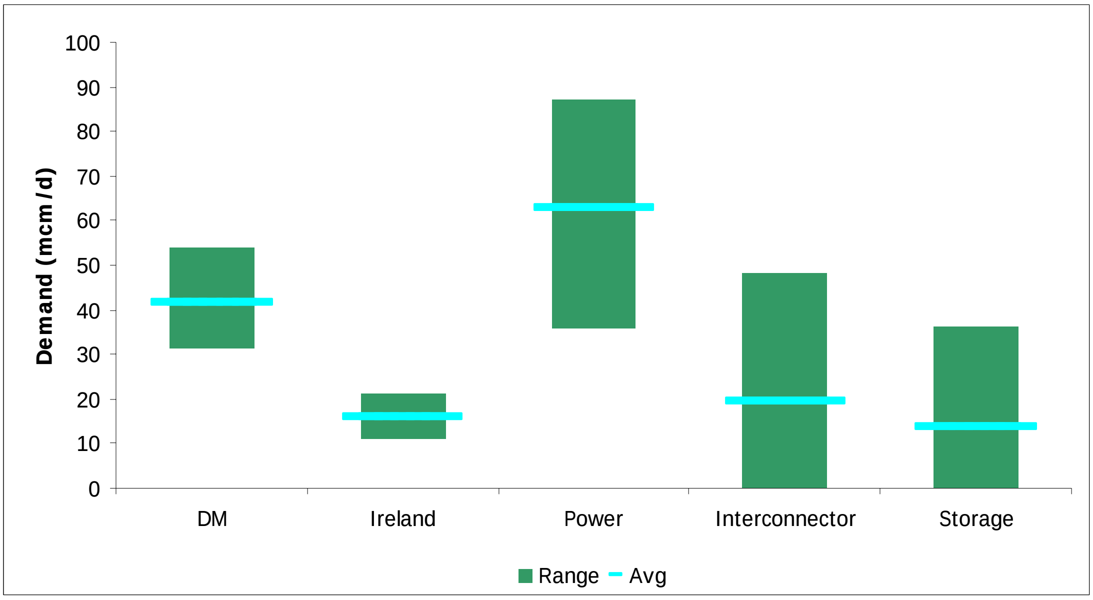
Figure 2.3 – DM, Export & Power Generation Summer Demands (2005 – 2007)



86. Whilst the figure highlights the lack of weather sensitivity in these demands, it also clearly shows the potential range of demands from about 110 to 190 mcm/d with an average of about 150 mcm/d.

87. This range of potential demands for each of these demand components is shown in Figure 2.4.

Figure 2.4 – Range of DM, Export & Power Generation Summer Demands (2005 – 2007)



88. The figure highlights relatively modest variations in DM and Irish demand of just 20 and 10 mcm/d respectively. However, the variations for power generation and IUK exports are approximately 50 mcm/d for each with storage injection up to 35 mcm/d. 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 110 to 190 mcm/d could theoretically be much greater at about 80 to 230 mcm/d.

89. Table 2.1 shows the total gas demand for April to September from 2005 to 2007 for NDM and all the demand components in Figure 2.4.

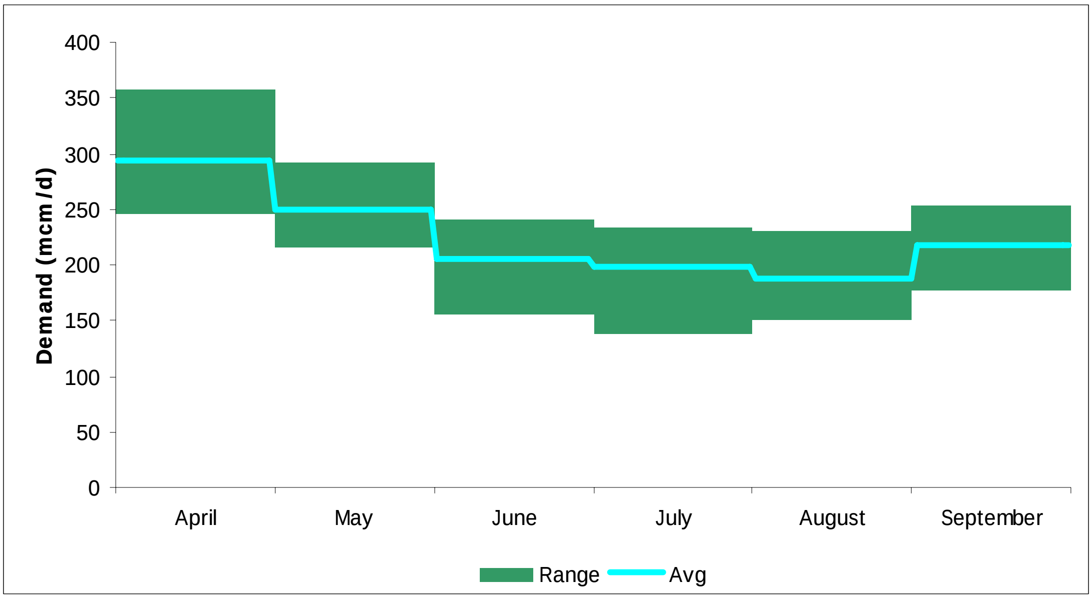
Table 2.1 – Summer Gas Demand (2005 – 2007)

(bcm)	**NDM**	**DM**	**Ireland**	**Power**	**IUK**	**Storage**	**Total**
2005	14.1	8.1	2.7	11.4	2.9	3.0	**42.2**
2006	12.7	7.5	3.0	10.4	4.5	2.3	**40.3**
2007	12.3	7.3	3.1	12.7	3.4	2.2	**41.1**
Average	13.0	7.6	3.0	11.5	3.6	2.5	**41.2**
%	32%	19%	7%	28%	9%	6%	

90. Table 2.1 shows aggregated April to September demands of about 40 bcm. The general trends suggest a decline in NDM and higher use of gas for power generation.

91. For completeness, Figure 2.5 shows 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.

Figure 2.5 – Total Summer Demands (2005 – 2007)

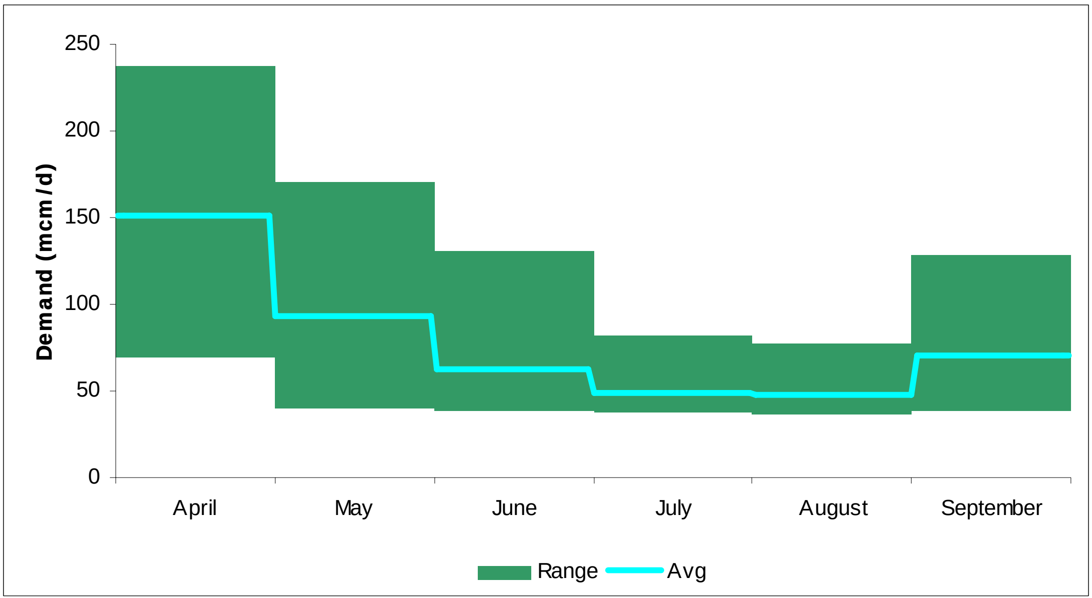


92. In terms of average demand, the figure again highlights the variation in demand for the shoulder months and the relatively stable demands for the mid summer period. However, at all times there is considerable variation in terms of the range of demand. Indeed, even during the mid summer period with average demands of typically 200 mcm/d there are days of demand as high as 250 mcm/d and as low as 150 mcm/d. As detailed previously these are primarily driven by variations in IUK exports, power generation and storage injection.

Forecast Summer 2008 Gas Demand

93. Figure 2.6 shows the monthly variation in forecast daily NDM demand based on the weather experienced in the last 20 years. If our 78 year data set were used, the upper range would be higher. Whilst the average values are broadly inline with those experienced in the last 3 summers , the maximum range is higher reflecting the potential for much higher demands if the summer were, at times, to be colder.

Figure 2.6 – NDM demand forecast for Summer 2008

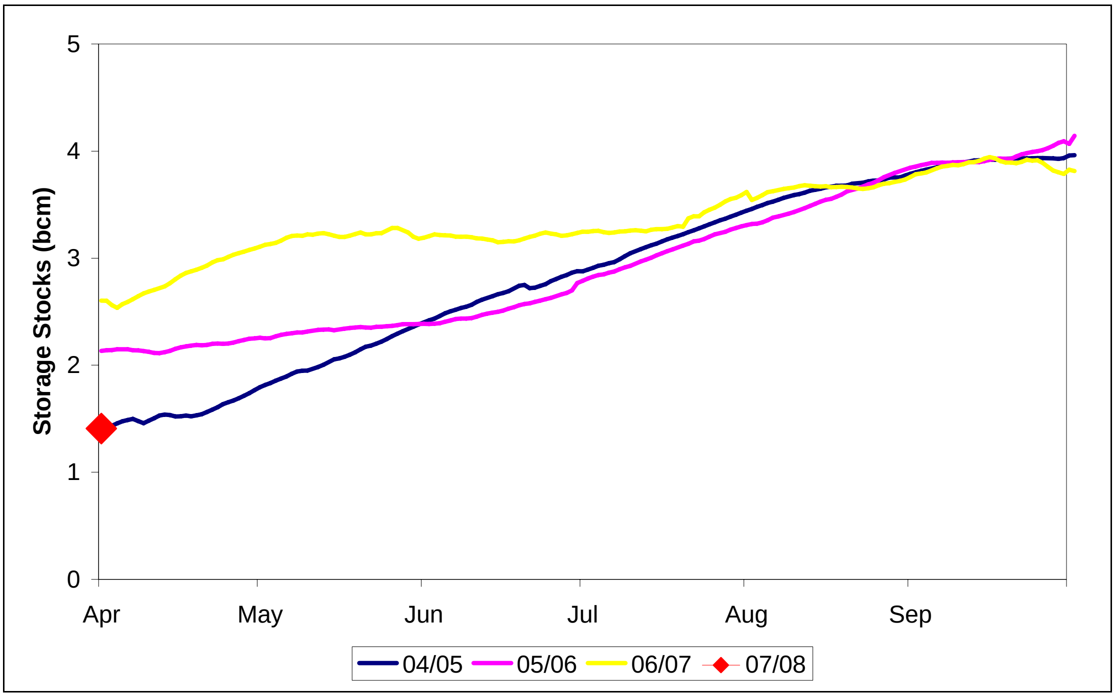


94. Forecasts demands for DM and Irish exports this summer are not expected to change much from those experienced in the last 3 years. Hence they are comparable to the range shown in Figure 2.4 and summer volumes in Table 2.1. Hence, we do not expect total gas demand for these sectors for summer 2008 to be significantly different from previous years.

95. Forecast gas demand for storage injection this summer is also expected to be within the range experienced over the last 3 years, as shown in Figure 2.4. However the duration for storage injection is expected to be longer as the aggregated demand for storage injection could be up to ~1 bcm higher than that experienced in 2006 and 2007, as storage used this winter (notably from Rough) has been higher. In general, if NDM gas demand is higher than expected due to a cold spell of weather, with a corresponding increase in spot prices, we would expect to see less storage injection.

96. Figure 2.7 shows the refilling of storage during the last three 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 2008 injection, storage stocks are comparable to the storage level in 2005. For 2008, approximately 3 bcm of storage needs to be refilled. Historically average filling rates have been 10 – 15 mcm/d and maximum storage rate have been 25 – 30 mcm/d. Hence with approximately 3 bcm to be refilled, the duration is expected to be between 120 and 200 days, well in time for next winter.

Figure 2.7 – Aggregated Storage Stocks 2005 - 2007



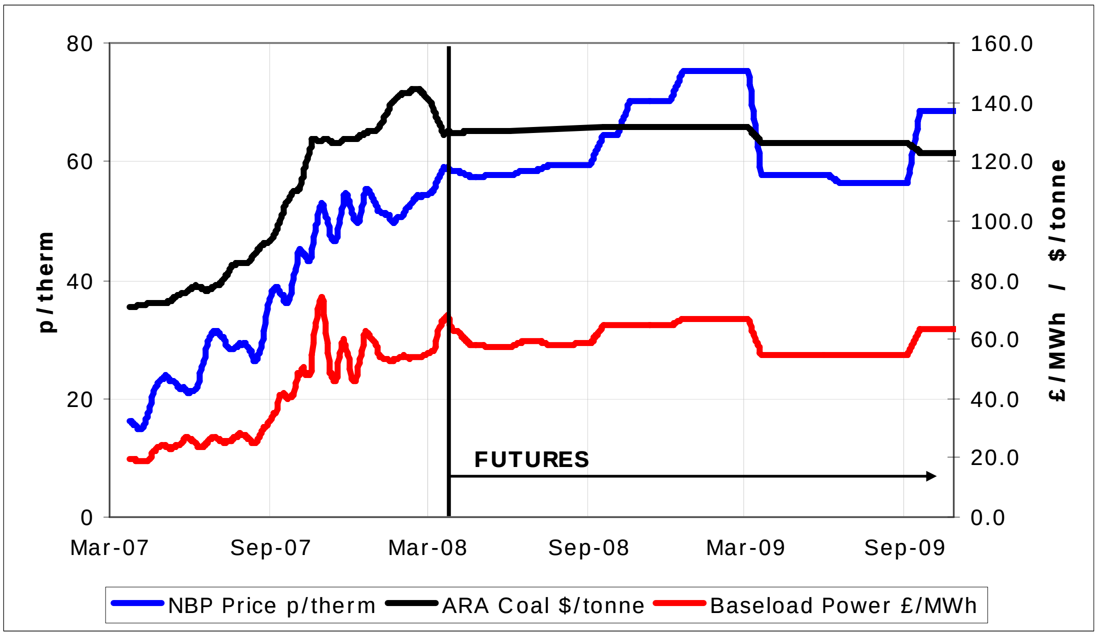
97. Forecast gas demand for IUK exports this summer are as in previous years, difficult to forecast. The price differentials between NBP and Zeebrugge (Figure 2.13) remain very small, currently favouring exports flows rather than imports. One factor that may promote higher exports this summer than in 2007 is the slightly higher use of Continental storage this winter compared to last winter.

98. Assessment of the high summer period reveal that power generation demand is the largest single demand component making up approximately one third of total gas demand.

99. Historically with a lower summer price for gas, power stations have tended to use gas for base load generation with coal used as the marginal source. This year the introduction of the LCPD and European Union Emissions Trading Scheme (EU ETS) have reduced coal's competitive advantage during the winter.

100. For this summer, the position is less clear than in previous years as the price of all three fuels have increased significantly since spring 2007. Figure 2.8 shows historic and future prices for gas, coal and base load power.

Figure 2.8 – Historic and Future Fuel Prices



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101. In determining the dark and spark spreads for summer 2008 (see Figure 1.1) we have used the fuel, carbon and power prices shown in Appendix 1.

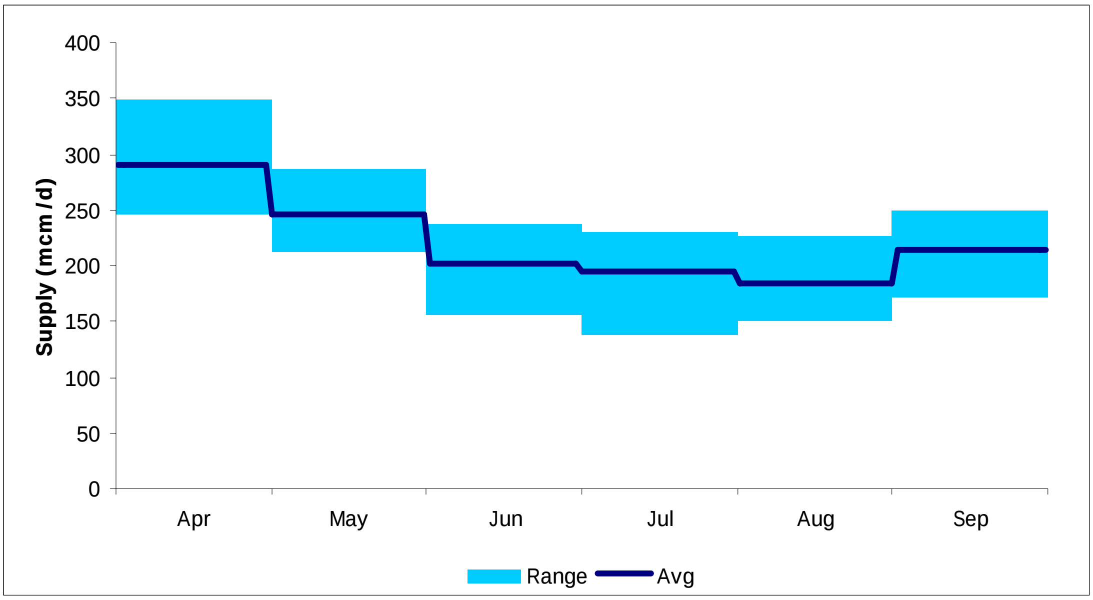
102. As discussed in Chapter 1, the current forward prices of gas, coal, power and carbon suggest that the coal-fired generation has a marginal price advantage this summer. Current fuel prices for this summer are volatile and a small change in either fuel or carbon prices will change the relative economics of gas and coal-fired generation. The use of gas for power generation is also influenced by gas prices on the spot market, where cheaper gas may lead portfolio generators to burn gas instead of coal. This highlights the need to consider a range of gas demands for power generation this summer

103. If gas were to be the lowest cost option for power generation, gas demand would be expected to be in the range 60-95 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. Hence the use of gas for power generation this summer could exceed the previous highest of 87 mcm/d in April 2007.

Historic Summer Gas Supply

104. Figure 2.9 shows aggregated gas supplies from all supply sources for the past three summers in terms of minimum, average and maximum demands for each calendar month.

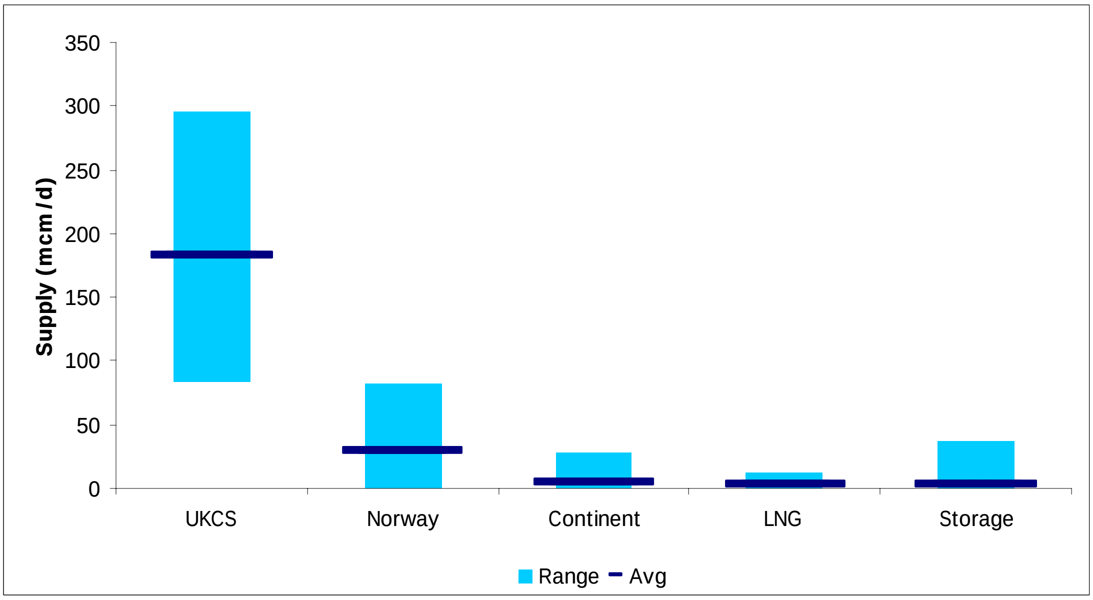
Figure 2.9 – Summer Supplies by Source (2005 – 2007)



105. As one would expect, the figure is similar but not identical to the total demand figure (Figure 2.5).

106. The range of supplies for April through to September for the past three summers for each of the supply sources is shown in Figure 2.10.

Figure 2.10 – Range of Supply Sources (2005 – 2007)



107. The figure highlights considerable variations in all of the supply sources. Minimum flows of zero have been experienced for all supply sources except UKCS. Even if the mid summer period is assessed the ranges remain considerable.

108. Table 2.2 shows the gas supply for April to September from 2005 to 2007 for each of the supply sources in Figure 2.10.

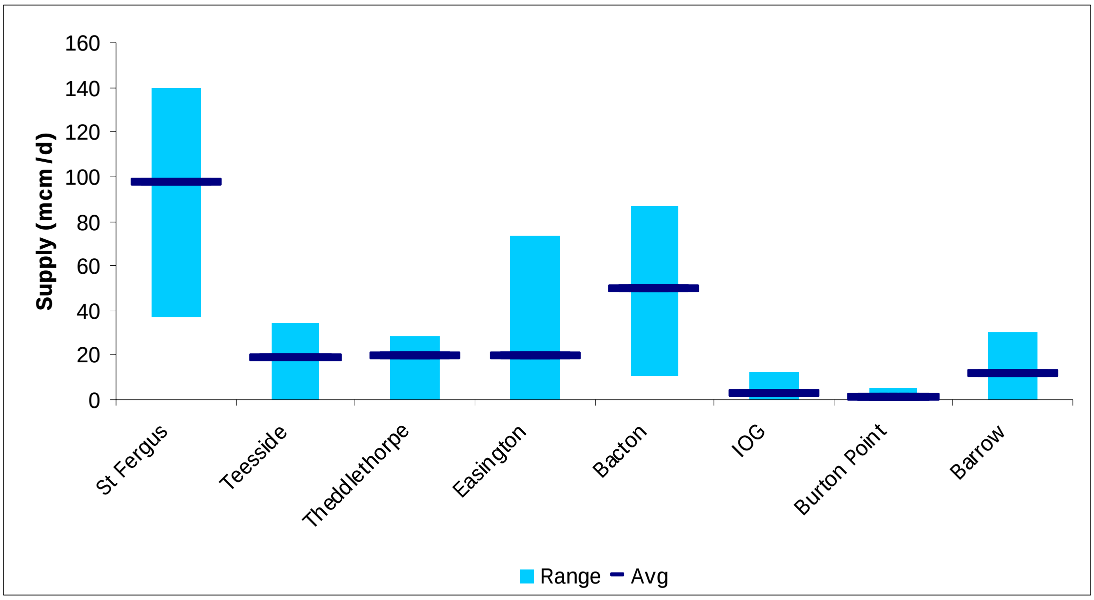
Table 2.2 – Summer Gas Supply by Source (2005 – 2007)

(bcm)	**UKCS**	**Norway**	**Continent**	**LNG**	**Storage**	**Total**
2005	37.0	4.1	0.1	0.0	0.4	**41.6**
2006	33.3	4.7	0.2	1.1	0.4	**39.6**
2007	30.0	7.1	2.4	0.1	0.9	**40.6**
Average	**33.4**	**5.3**	**0.9**	**0.4**	**0.5**	**40.6**
%	82%	13%	2%	1%	1%	

109. Table 2.2 shows aggregated April to September supplies of about 40 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 approximately 10% with increased imports from Norway and the Netherlands through BBL. If last summer's CATS outage (~1 bcm) is factored in, the decline since 2005 is approximately 8.5% per year.

110. The range of supplies for April through to September through each terminal is shown in Figure 2.11.

Figure 2.11 – Summer Supplies by Terminal (2005 – 2007)



111. The figure highlights considerable variations at all of the supply terminals. 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.

112. Table 2.3 shows the gas supply for April to September from 2005 to 2007 for each of the supply terminals in Figure 2.11.

Table 2.3 – Summer Gas Supply by Terminal (2005 – 2007)

(bcm)	St F	Tees'	Thed'	Eas'n	Bac'n	IOG	B. Pt.	Bar'w	St'ge	Total
2005	19.2	3.9	3.3	2.3	9.3	0.0	0.2	3.0	0.4	**41.6**
2006	18.5	4.1	3.8	1.8	8.4	1.1	0.4	1.0	0.4	**39.6**
2007	15.4	2.3	3.6	6.6	9.3	0.1	0.2	2.1	0.9	**40.6**
Avg	**17.7**	**3.4**	**3.6**	**3.6**	**9.0**	**0.4**	**0.2**	**2.1**	**0.5**	**40.6**
%	44%	8%	9%	9%	22%	1%	1%	5%	1%	

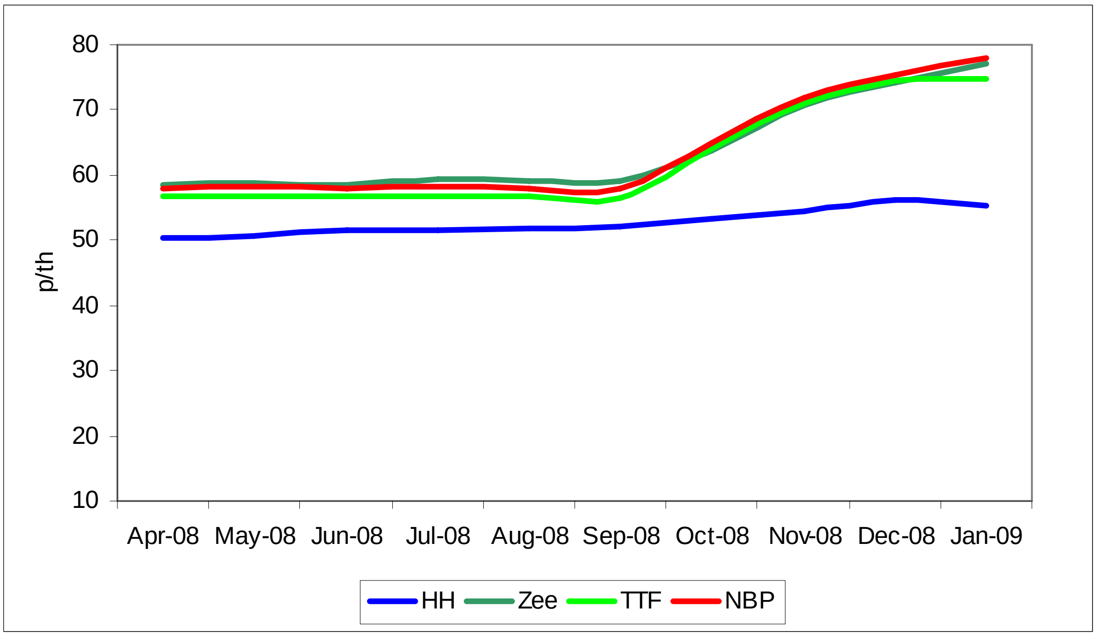
113. Table 2.3 shows that on a volumetric basis, summer supplies have been dominated by deliveries from St Fergus and to a lesser extent Bacton. However supplies from St Fergus have been in decline and Easington was higher in 2007 due to the first summer of Norwegian gas being landed through Langeled.

Forecast Summer 2008 Gas Supply

114. We expect that UKCS supplies will continue to be by far 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 10% into context, this is equivalent to about 16 mcm/d.

115. As LNG has not flowed significantly to the UK this winter and the price differential of UK vs Henry Hub is diminishing (see Figure 2.12), it is unlikely that LNG flows will be materially higher than last summer. The exception to this is the possibility of commissioning and thereafter commencement of regular cargoes at Milford Haven this summer from both South Hook and Dragon.

Figure 2.12 – Forward Gas Prices (March 2008)



116. 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. The markets also anticipate this as shown by the modest summer price advantage of Zeebrugge over NBP shown in Figure 2.12. The exception to export conditions would be if the UK experienced a supply shock resulting in an increase in the UK gas price or if UK gas demand for power generation was higher than expected due to further increases in coal or carbon.

117. Assuming LNG and IUK are discounted in meeting the need for higher imports this summer, the increase in imports is expected to be made from either Norway or BBL.

118. With an expectation of higher Norwegian production as Ormen Lange continues to be brought on stream, we assume higher Norwegian imports this summer. These are expected to be through a combination of Langeled, Vesterled and the Tampen Link.

119. 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.

120. Figure 2.13 shows our terminal forecast for next summer expressed as a range. This has been derived through a combination of our annual TBE planning process (to determine the average flows for each month) and analysis of historical data since 2005 to determine the supply range. Obviously with so many permutations to make up demand, these forecasts should be considered indicative rather than explicit. Table 2.4 shows the forecasts on a monthly basis.

Figure 2.13 – 2008 Forecast of Summer Supplies by Terminal

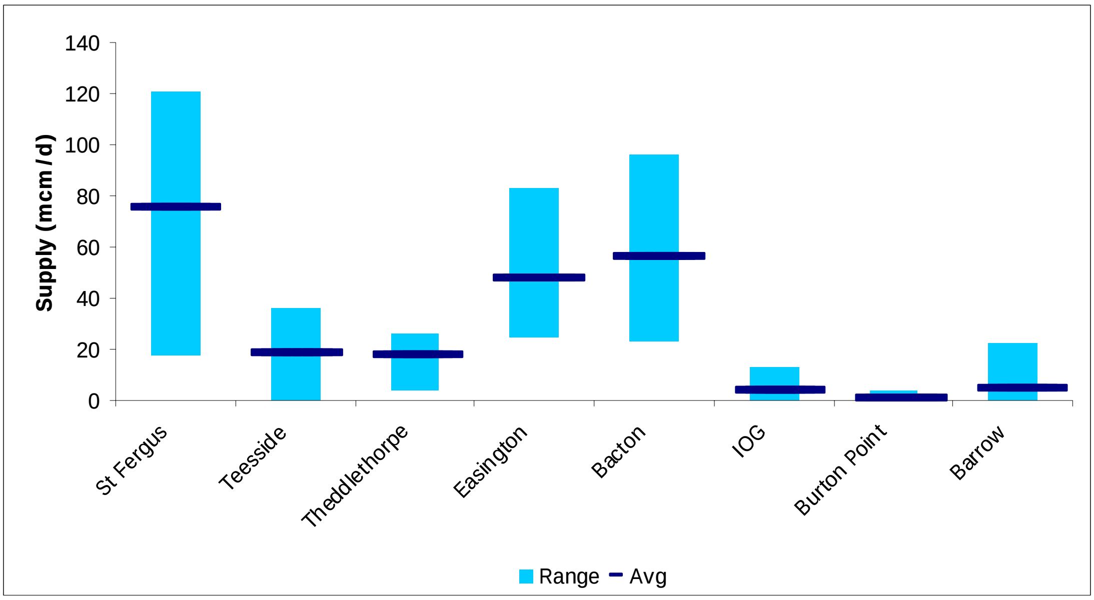


Table 2.4 – 2008 Forecast of Summer Supplies by Terminal

		St Fergus	Tees'de	Thed'pe	Eas'n	Bacton	IOG	Burton Point	Barrow
April	Min	52	7	11	47	49	0	0	0
	Avge	98	23	22	63	72	5	1	10
	Max	121	36	26	83	96	13	4	22
May	Min	38	4	8	38	39	0	0	0
	Avge	84	21	20	53	62	4	1	6
	Max	107	34	26	78	86	12	4	22
June	Min	23	1	5	28	28	0	0	0
	Avge	69	17	16	44	51	3	1	3
	Max	92	30	26	69	75	12	4	22
July	Min	20	0	4	27	26	0	0	0
	Avge	66	17	16	42	49	4	1	3
	Max	89	30	26	68	73	12	4	22
August	Min	17	0	4	24	23	0	0	0
	Avge	63	16	15	40	47	3	1	2
	Max	86	29	26	65	70	11	4	21
September	Min	27	2	5	31	31	0	0	0
	Avge	73	19	17	46	54	4	1	4
	Max	96	32	26	71	78	12	4	22

Summer 2008 NTS Maintenance Programme and Network Capacity Expansion

121. 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 risks to people and the environment caused by failure of pipelines and plant.

122. 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.

123. In addition to maintenance, National Grid is obliged to make provision of NTS entry capability to accommodate new gas flows in accordance with our Incremental Methodology Statement.

124. The NTS investments delivered last summer for capacity expansion for winter 2007/8 have provided additional capacity and network flexibility. This summer we are further investing in network capacity for further system enhancements. These investments are a direct result of the release of capacity through the Long Term System Entry Capacity (LTSEC) auction process.

125. In Kent we are making further pipeline investments to accommodate additional entry capacity at Grain. In addition to the “Trans Pennine” pipeline completed last summer we are constructing further pipelines for increased capacity for the Easington area. Similarly, in addition to the Milford Haven pipeline completed last year we are now investing for a new compressor station at Felindre in South Wales as well as new units at Wormington and Churchover.

126. Besides capacity for entry, we are also investing for new and increased demand in the South West of England. Further information on these and other expansion projects can be found at http://www.nationalgrid.co./uk/gas/pipelines

127. In aggregate, these reinforcements will increase network entry capacity at Grain, the Easington Area and Milford Haven by 50 mcm/d. This is on top of the 99 mcm/d of entry capacity delivered last summer for the same locations.

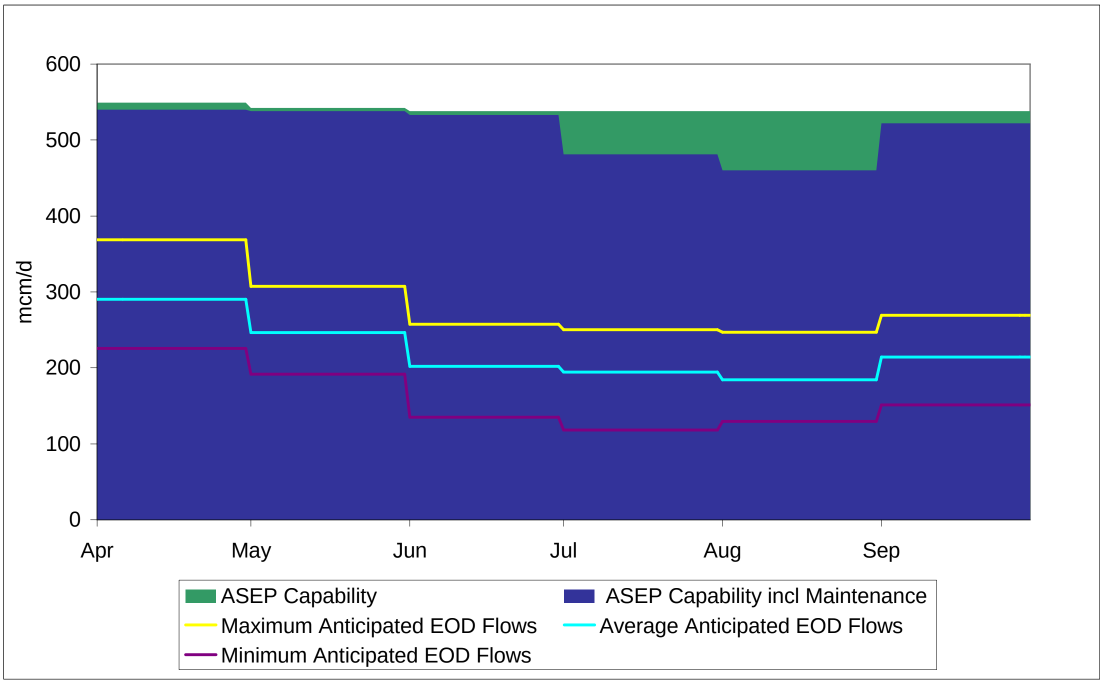
128. In terms of physical supplies, this summer we are expecting to receive notice and commissioning plans for the gassing up of the Grain Phase 2 and the South Hook and Dragon LNG facilities at Milford Haven.

129. Our maintenance plan includes the impact of network reinforcement, our annual maintenance programme and supply outages. It can be found on the National Grid website at: http://www.nationalgrid.com/uk/Gas/OperationalInfo/maintenance/

130. The above website details Aggregated System Entry Points (ASEP) deliverability with respect to offshore supply planned maintenance and capacity expansion activities, aggregated on a North / South basis.

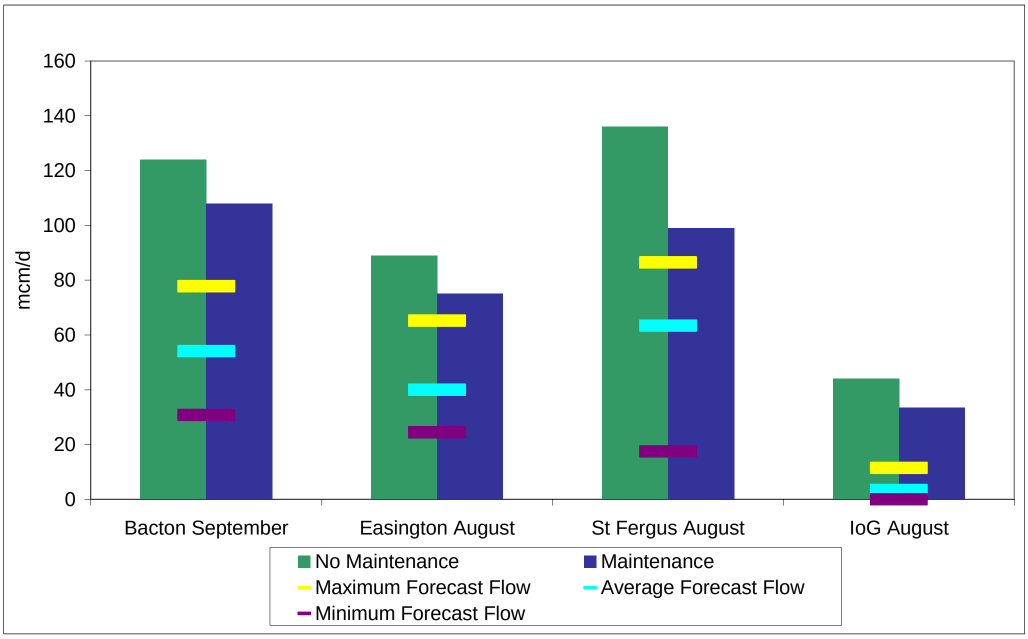
131. Figures 2.14 and 2.15 bring together our aggregated flow forecasts and the affect of this year’s summer activities on terminal entry capacity, namely physical capacity, at ASEPs.

Figure 2.14 – The Effect of the Summer maintenance and capacity expansion programme on system capability.



132. The figure shows the aggregated NTS system entry capability (aggregated ASEP Baselines) and how this is reduced due to the summer maintenance and capacity expansion programme. The data reported are based on the lowest available capability at each ASEP for that month. Also shown on a monthly basis is the aggregate average, maximum and minimum forecast supply based on historical outturn and forecasting intelligence.

Figure 2.15 – ASEPs with Reduced Capability During Summer 2008



133. The figure shows that only four NTS ASEPs are affected by this summer’s planned maintenance and capacity expansion programme. The figure also shows the month during which their capability is reduced the most. Also shown on the figure is our forecast for ASEP usage during this month expressed as an average, maximum and minimum.

134. Our flow analysis for these ASEPs based on their anticipated flows has indicated that only at maximum levels of anticipated supply is there any, albeit remote, possibility of capacity constraints during the summer 2008 period. This would indicate that the likelihood for National Grid to take commercial capacity management actions is low during this period. However, as the NTS is a highly dynamic system, very high flows at either Easington or St Fergus during August could see system capability approached and as in previous years provide us with operational challenges. It should also be noted that in order to safeguard the integrity of the system, GNCC actions due to unforeseen physical events on the NTS always remain a possibility.

Summer 2008 Commercial Regime Developments

135. Ofgem is currently considering two modifications to UNC (Modification Proposals 0187 and 0187A) which will formalise National Grid's obligations to introduce enduring Transfers and Trades arrangements within the UNC. Both Transfer and Trade Modification Proposals are based on a monthly process linked to the existing monthly (RMSEC) auctions, with the capacity obligation expected to commence on 1st July 2008. Prior to the commencement of the RMSEC process Users will be able to offer to surrender NTS Entry Capacity to National Grid NTS which will then be included within the RMSEC allocation process. The new RMSEC auction will have a two stage allocation process, the initial stage will give Users the opportunity, as now, to purchase NTS Entry Capacity at the ASEP however the second stage (Transfer and Trade) of the allocation process will facilitate the movement of NTS Entry Capacity from a point on the network where the market has signalled it is not required to a point on the network where it has indicated it is. The Transfer of NTS Entry Capacity to another ASEP will be subject to exchange rates and the Trade and Transfer Methodology Statement. Transfer and Trade gives users the opportunity to purchase additional NTS Entry Capacity (subject to the methodology statement) at ASEPs that have signalled a requirement for more capacity than is currently available at that ASEP, by trading or transferring capacity from other ASEPs for a specific month. It is, however, unlikely that this will have any significant impact ASEP capabilities during the summer months, when demand is low and few (if any) ASEPs are sold out.

136. This flow analysis utilised as part of the Transfer and Trade process assumes maximum flow rates similar to that of last summer and is based on the Draft V1.0 summer maintenance programme (February 2008). The summer maintenance programme is subject to change and

this analysis will need to be reviewed if significant changes or re-planning was required to the current summer maintenance programme. The plan is regularly reviewed, updated and published on the National Grid Website.

Industry Feedback

137. To help us improve the process for the Summer 2009 Outlook Report, we would appreciate any comments on this inaugural report, and indeed any of our analysis within this report.

138. Responses should be e-mailed to energy.operations@uk.ngrid.com Where requested, we will treat information provided to us on a confidential basis. However, respondents may send confidential information to Ofgem if they would prefer by e-mail to GB.markets@ofgem.gov.uk.

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

Appendix I – Forward Prices[8]

1) Assumed efficiencies

gas	coal	oil
49%	36%	35%

2) GB Power Prices £/MWh

	Q2 08	Q3 08	summer 08	winter 08/09
Base Load (24 hours * 7 days per week)	61.80	59.50	60.65	67.71
Peak (12 * 5)	75.36	71.60	73.48	81.46
offpeak	54.27	52.78	53.52	60.07

3) Gas Prices

	Q2 08	Q3 08	summer 08	winter 08/09
p/th	59.8	59.9	59.85	76
£/MWhe	41.6	41.7	41.68	52.9

£/MWhe is derived by the following calculation for gas-fired generation
Cost of gas-fired generation (£/MWhe)= gas price (p/therm) / *[29.3071 (kWh per therm)*efficiency] * [1000 (kWh per MWh)/100 (p per £)]*

4) Exchange Rates

€ to £	$ to £
0.801	0.5089

5) Coal Prices (ARA cif)

	Q2 08	Q3 08	summer 08	winter 08/09
$/tonne	133.35	135	134.18	135.87
£/tonne	67.9	68.7	68.3	69.1
£/MWhe	27.04	27.37	27.20	27.55

£/MWhe is derived by the following calculation for coal-fired generation
Cost of coal fired generation (£/MWhe)= [coal price (£/tonne)/25.1 (GJ per tonne)] * *[3.6 (GJ per MWh)/efficiency]*

6) Carbon Price

	€ per tonne	£ per tonne	Gas	Coal	Oil
			£/MWh	£/MWh	£/MWh
carbon intensity (tonne of CO2 per MWhe)			41%	94%	86%
Carbon 2008 (ETS II)	24.45	19.58	8.03	18.41	16.84
Carbon 2009 (ETS II)	24.87	19.9	8.17	18.73	17.13

Due to the higher carbon content of coal compared with gas, and the lower efficiency, coal-fired generation produces over twice as much CO2 per MWhe as does gas-fired generation.
Cost of carbon (£/MWhe)= carbon price (£/tonne) * carbon intensity (tonne of CO2 per MWhe)

7) Clean Spark Spread for Gas-Fired Generation £/MWh

	Q2 08	Q3 08	summer 08	winter 08/09
Base Load (24 hours * 7 days per week)	12.13	9.76	10.94	6.70
Peak (12 * 5)	25.69	21.86	23.77	20.45
offpeak	4.59	3.04	3.82	-0.94

Clean spark spread (£/MWh)= wholesale electricity price (£/MWh) – marginal fuel cost of gas-fired generation (£/MWhe) – cost of carbon (£/MWhe)

8) Clean Dark Spread £/MWh

	Q2 08	Q3 08	summer 08	winter 08/09
Base Load (24 hours * 7 days per week)	16.4	13.7	15.0	21.9
Peak (12 * 5)	29.9	25.8	27.9	35.7
offpeak	8.8	7.0	7.9	14.3

Clean dark spread (£/MWh)= wholesale electricity price (£/MWh) – marginal fuel cost of coal-fired generation (£/MWhe) – cost of carbon (£/MWhe)

Definition of terms used in the tables
Baseload denotes "flat operation" - same level 24 hours per day, 7 days per week
Peak denotes operation during the peak 12 hours of the day (07-19:00), 5 days per week
Off-Peak denotes operation during the off-peak periods (00 -07:00, 19-24:00 weekdays, and 00-24:00 weekends)

[8] Analysis based on prices on 11th April 2008.