nationalgrid

Winter 2007/8 Preliminary Consultation Report

Executive Summary

Introduction

1. The competitive gas and electricity markets in the UK 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. The structure of the markets and the monitoring of companies' conduct within it are the responsibility of Ofgem. 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.
2. In recent years, National Grid has provided information to the participants in the gas and electricity markets by publishing an outlook for the winter ahead. For the last 2 years, recognising that our sources of data are necessarily incomplete, we have conducted a consultation exercise designed both to help inform the industry and also to provide us with feedback to support the production of the winter Consultation Report.
3. In conjunction with Ofgem, we have decided to conduct a similar consultation process this year. This document represents the first stage of that process. We will issue another consultation paper in June, feeding back on the responses to this document, updating the analysis and seeking further views. We then plan to publish the Winter Consultation Report, reflecting the feedback received from industry participants, by the end of September.

Gas

4. Over the recent winter a number of major infrastructure projects have been commissioned, facilitating the importation of substantial quantities of gas into the UK. These projects include the Langeled pipeline from Norway connecting at Easington; enhancements to the Belgian Interconnector; and the BBL pipeline linking the UK market at Bacton with Holland. In addition, Excelerate Energy has recently commissioned its import LNG facility at Teesside, using onboard ship re-gasification technology.
5. During next winter we expect the commencement of flows from the two LNG terminals at Milford Haven and the Aldbrough storage facility. Storage space at Hole House Farm is also expected to increase.
6. Whilst developments in importation infrastructure continue, the supply-demand outlook for 2007/8 remains uncertain. The range of potential supply availability is wide, reflecting not only the normal risks associated with major infrastructure

projects, but also commercial uncertainties associated with the utilisation of the infrastructure.

Electricity

9. The outlook for the electricity market in 2007/8 appears less uncertain than that for the gas market, with the notified generation background (including the level of mothballed plant) broadly similar to that observed prior to the 2006/7 winter. Last winter the operation of the electricity market was characterised by gas-fired generation displacing coal-fired generation, and coal increasingly providing the marginal capacity. Combined Cycle Gas Turbine (CCGT) gas demand was well above the level implicit in our unrestricted demand forecasts. While the gas market remains dependent upon imported supplies, the swing in gas consumption by CCGT stations will continue to be key in achieving a balance between gas supply and demand.

Consultation Overview

10. Given National Grid's role in the market, our intelligence on the gas and electricity supply-demand outlooks is wholly reliant on the data and insights that we receive from others. We therefore look to market participants for information and views across a broad range of issues related to the 2007/8 winter. We will aggregate and summarise the information that we receive, and use this to inform the next stage of the consultation process.

11. In this Preliminary Consultation Report, analysis of the recent winter experience is summarised in Chapters 1-3.

12. A key focus of the consultation is the uncertainty surrounding the gas supply position for 2007/8. In Chapter 4, we examine the key issues associated with this background with reference to the individual supply sources and the way in which they may interact with one-another. The Initial View is not intended to represent a National Grid view. Its main purpose is to provide a reference point to facilitate discussion and comment. We hope that the Initial View will help industry participants in developing their own view of the forthcoming winter and establishing appropriate arrangements.

13. Chapter 5 sets out the latest view of the demand and generation background in the electricity market for 2007/8, and seeks respondents' input on issues surrounding mothballed plant, the operation of the French Interconnector and electricity demand growth.

14. In Chapter 6, we present our latest assumptions underpinning future analysis of the potential for CCGT demand response in 2007/8, and are looking for insights and views through this consultation on the extent to which such assumptions are valid should the need arise next winter.

15. The high level issues on which we are seeking views are as follows, with the question numbering as per the main body of the report:

UKCS Supplies

Q1. We welcome views on our assessment of UKCS supplies and in particular our view that for most of the winter most UKCS supplies were operating at maximum flow conditions with the exception of certain high swing supplies.

Q15. What assumptions should be made over the maximum UKCS supply availability for 2007/8, and specifically:

Q15a. What assumptions should be made over the maximum UKCS supply availability from existing fields?

Q15b. What assumption should be made over the commissioning of new UKCS developments?

Q16. Should we plan for a lower level of UKCS on the basis that high swing fields may not flow and consequently consider such fields on a comparable basis to storage facilities?

Gas Imports

Q2. We welcome views on our assessment that increased Norwegian supplies to the UK were a consequence of lower supplies to the Continent

Q3. We welcome views of whether Norwegian supplies to the UK and the Continent would have been higher if demand for the UK and Continent had been higher.

Q4. We welcome views on whether Norwegian supplies to the UK would have been as high if Continental demand had been higher.

Q5. We welcome views on the possible factors, other than short term market differentials, which may be driving BBL flows.

Q6. We welcome views on our suggestion that IUK operated as a marginal source of supply more akin to a storage facility.

Q17. What assumptions should be made for levels of imported gas from Norway for winter 2007/8 through Langeled and Vesterled?

Q18. Should we be making any allowance for additional Norwegian imports through the Tampen Link?

Q19. What assumptions should be made for levels of imported gas through BBL for winter 2007/8, and specifically:

Q19a. Should we assume a uniform supply profile throughout the winter period?

Q20. What assumptions should be made for levels of imported gas through IUK for winter 2007/8, and specifically:

Q20a. Should we assume that the IUK will operate as a marginal source of supply when UKCS and other imports can not meet UK demand?

Q20b. Should we assume that the availability of gas through IUK will increase as the certainty regarding the availability of Continental storage to meet the remainder of the winter improves?

LNG Imports

Q7. How sensitive to gas price are LNG deliveries?

Q8. How developed is a global gas market for LNG?

Q21. What assumptions should be made for levels of imported LNG through Grain, Teesside and Milford Haven for winter 2007/8?

Storage

Q9. With a back-drop of declining gas prices as the winter progressed, what were the key drivers for increased storage use later on in the winter?

Q10. Under conditions of increased demand, would storage cycling be so prominent?

Q22. We would welcome views on our assumed levels of storage space and deliverability.

Q23. We would welcome views on the extra storage space that could be made available through storage cycling.

Gas Supplies

Q24. We would welcome views on our 2007/8 Initial View, and specifically:

Q24a. Whether it is plausible that the supply availability could be so much higher than for last winter?

Q24b. If the supply position does improve as suggested, what will become the order of supplies at lower levels of demand?

Gas Demand

Q11. How will domestic prices change from this winter to next and what impact will prices and energy efficiency considerations have on demand?

Q12. If prices fall, will lower prices lead to the return of demand lost due to changes in customer behaviour, for example thermostat settings?

Q13. 2006/7 saw lower wholesale prices than forecast and as a result higher power generation demand i.e. some positive demand response. To what extent will prices change over winter 2007/8 compared to 2006/7?

Q14. In developing our updated view for 2007/8 which basis should we assume going forward i.e. unrestricted (traditional demand profile) or restricted (high priced profile) or should we assume some other growth profile?

Electricity Demand

Q25. We would welcome views on the reasons why the weather-corrected operationally metered generation fell during 2006/7 and whether demand might be expected to decline further, remain at current levels or resume its trend of growing at 1-1.5% pa.

Q26. We would welcome views on the extent to which electricity demand response at peak times might be expected to continue.

Electricity Supply

Q27. What assumptions should be made to the extent to which generation will continue to be available, i.e. will any plant currently available subsequently be mothballed for winter 2007/8?

Q28. To what extent is there scope for long-term mothballed plant to return to service prior to the 2007/8 winter?

Q29. What assumptions should be made over the availability of different classes of generating plant, and in particular nuclear plant?

Q30. What assumptions should be made over the level and direction of flow on the UK-France Interconnector given cold weather in both UK and Europe?

Q31. We would welcome views on the ability of the electricity market to deliver in practice the level of CCGT response that our analysis suggests might be theoretically achievable in a severe winter, and in particular on:

Q31a. Our assumptions relating to the generation running order under cold weather conditions and the associated availability factors

Q31b. The extent to which relative market prices will signal the requirement for CCGTs to continue to burn gas at peak electricity demand periods

Q31c. The ability and willingness of CCGT generators to switch to distillate

Q31d. Whether and for how long CCGTs could generate on distillate back-up and any restrictions to the replenishment of distillate stocks

Q31e. The ability and willingness of the market to replace gas-fired generation by coal and oil fired generation

Q31f. The extent to which increased levels of fossil fuel generation could be used to displace gas-fired generation throughout a cold winter, including considerations of reliability, environmental constraints, carbon emissions and fuel stocks

Q31g. How the level of CCGT response may compare with that experienced in 2006/7.

Next steps

16. We would appreciate responses to our questions as soon as possible but not later than Monday 14 May 2007. Please note that it is intended to include a summary of responses on a non-attributed basis in the subsequent consultation report.

17. Responses should be e-mailed to: andrew.ryan@uk.ngrid.com

18. 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 wholesale.markets@ofgem.gov.uk.

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

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Section A – Review of 2006/7

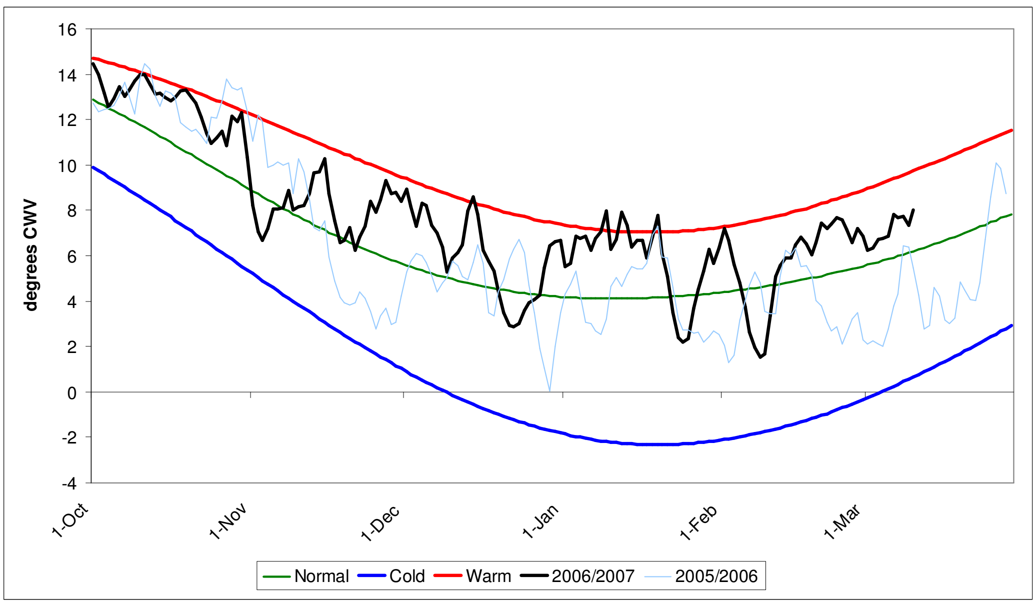
Chapter 1: Weather

19. The period December – February 2006/7 was the 2nd warmest in the UK since records began in 1914.

20. Using the Central England Temperature series (CET), the combined period for autumn (September to November) 2006 and winter 2006/7 (December to February) has been the warmest on record with a preliminary figure of nearly 10℃, beating the previous warmest in 1989/90 by nearly a degree.

21. Figure 1 illustrates the 2006/7 winter compared with the 2005/6 winter and warm, normal and cold conditions. The measure plotted in the graph is the Composite Weather Variable (CWV), which is calculated by combining temperatures and wind speeds and transforming them to produce a weather variable that is linearly related to non-daily metered gas demand.

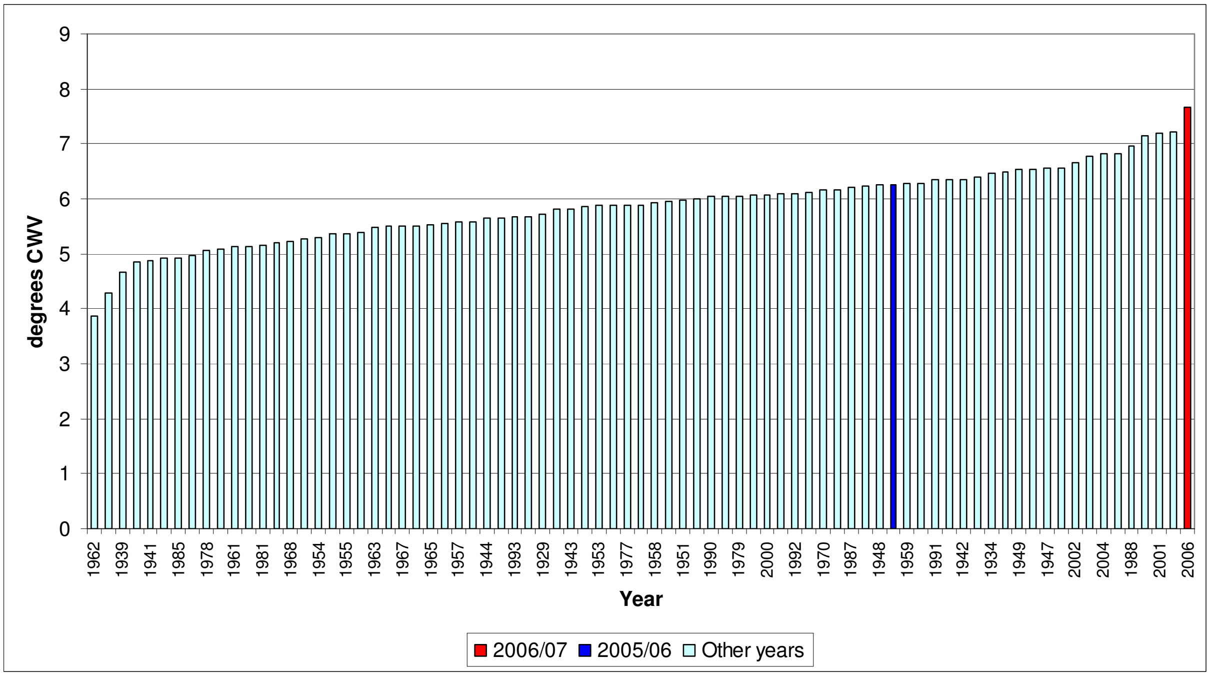
Figure 1 - 2006/7 Winter Weather (CWV) Overview[1]



22. The winter so far (1 October to 10 March) has been the warmest on record as illustrated in Figure 2 which compares the average CWV for each winter. This shows how significantly warmer 2006/7 has been, it also shows that despite being the coldest for 5 years, 2005/6 was warm when compared to previous winters.

[1] The cold and warm values are realistic daily ranges for each day of the winter. For further information please refer to http://www.nationalgrid.com/uk/Gas/OperationalInfo/operationaldocuments/Gas+Demand+and+Supply+Forecasting+Methodology/

Figure 2 - Mean National Composite Weather for 1 October to 10 March

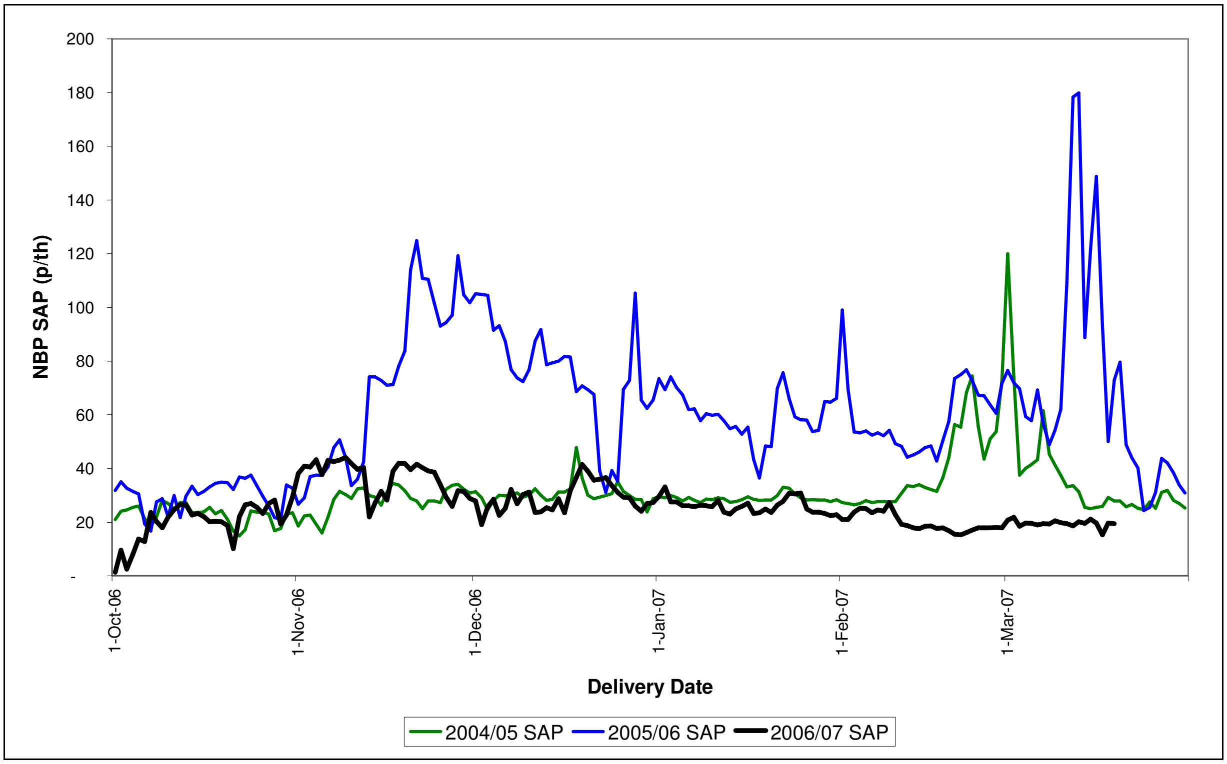


Chapter 2: Gas

Gas Prices

23. Figure 3 shows System Average Price (SAP) in pence per therm over winter 2006/7 in contrast to prices seen in the previous two winters.

Figure 3 – SAP Prices

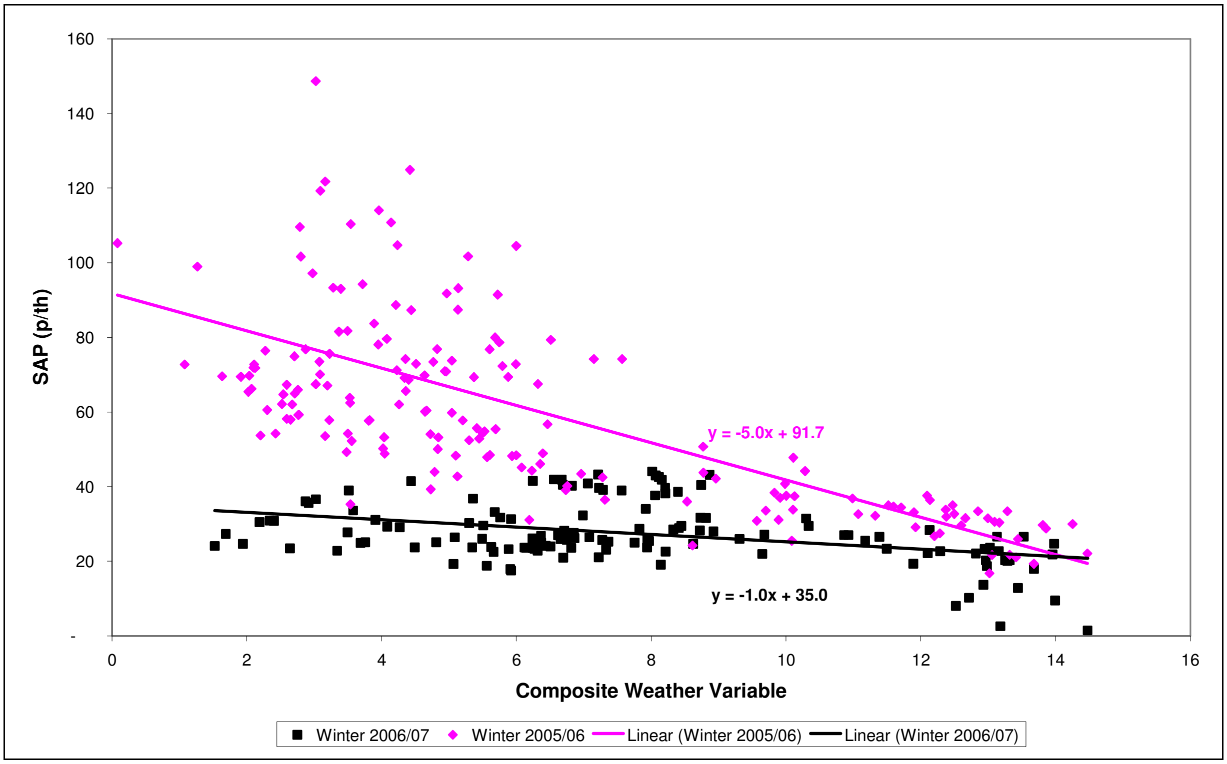


24. SAP prices in winter 2006/7 started from a very low level as unexpectedly high volumes of gas were imported during the commissioning of the new Langeled pipeline. Prices recovered over the following weeks to levels broadly similar to those seen in the previous two years. However, whilst prices rose sharply in November 2005 as the weather turned colder, prices this winter remained stable reflecting both the milder weather and improved supplies of gas.

25. From the beginning of January, SAP has trended down and become noticeably less volatile. For example, in the previous two winters there were price rises of 80 to 120 p/th in March due to cold snaps and supply losses. The highest demand of the winter on 8 February 2007 only resulted in a few pence increase in price.

26. Figure 4 shows the relationship between SAP and CWV for winters 2005/6 and 2006/7. The chart shows considerable variation in gas prices for both winters. The chart also shows the trend for SAP to increased with lower CWVs, with a much stronger relationship for winter 2005/6. The best fit lines show SAP at a CWV of 0° to be over 90 p/therm for winter 2005/6 and just 35 p/therm for winter 2006/7.

Figure 4 – SAP and CWV



27. The following table compares minimum, maximum and average SAP over the last three winters (October to March).

Table 1 – System Prices

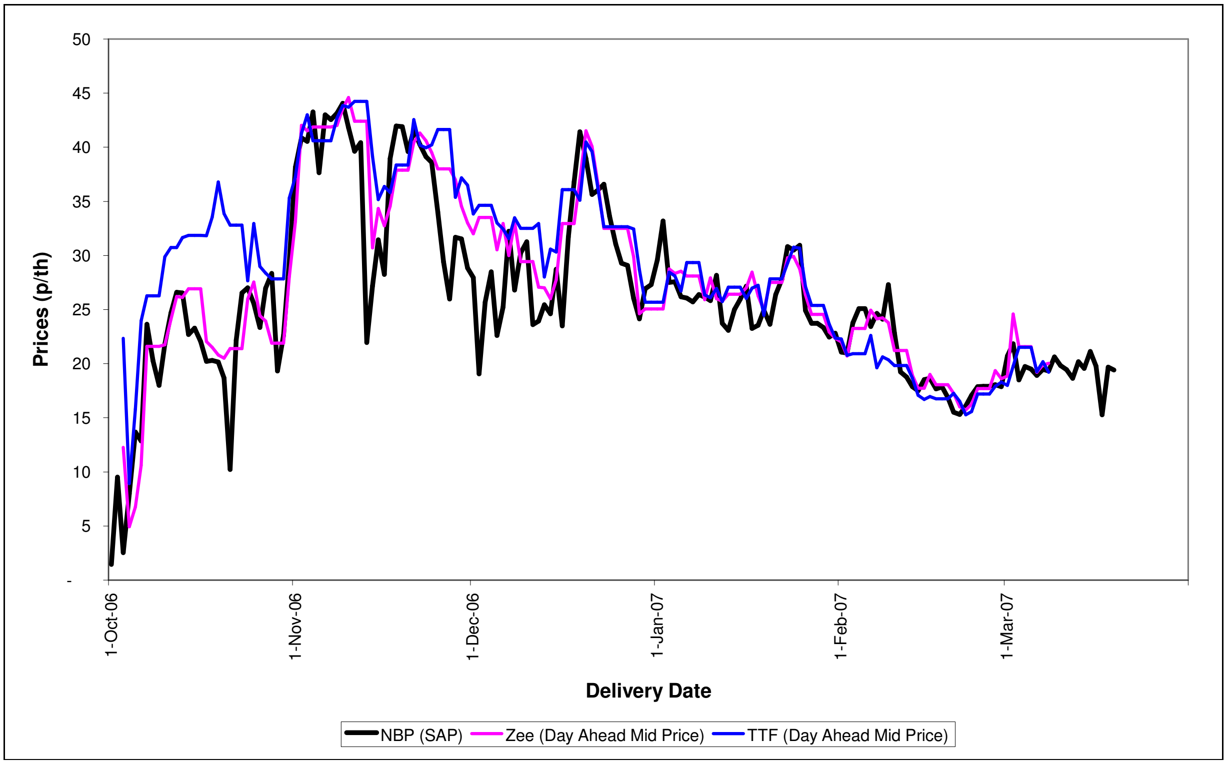
SAP p/th	Min	Ave	Max
2004/05	14.90	31.00	119.95
2005/06	16.80	60.90	179.80
2006/07[2]	1.44	25.88	44.05

International Comparisons

28. Figure 5 compares the UK SAP price to the Belgium day ahead mid price for Zeebrugge and the Dutch dayahead mid-price.

[2] 2006/07 prices are up to 14 March 2007

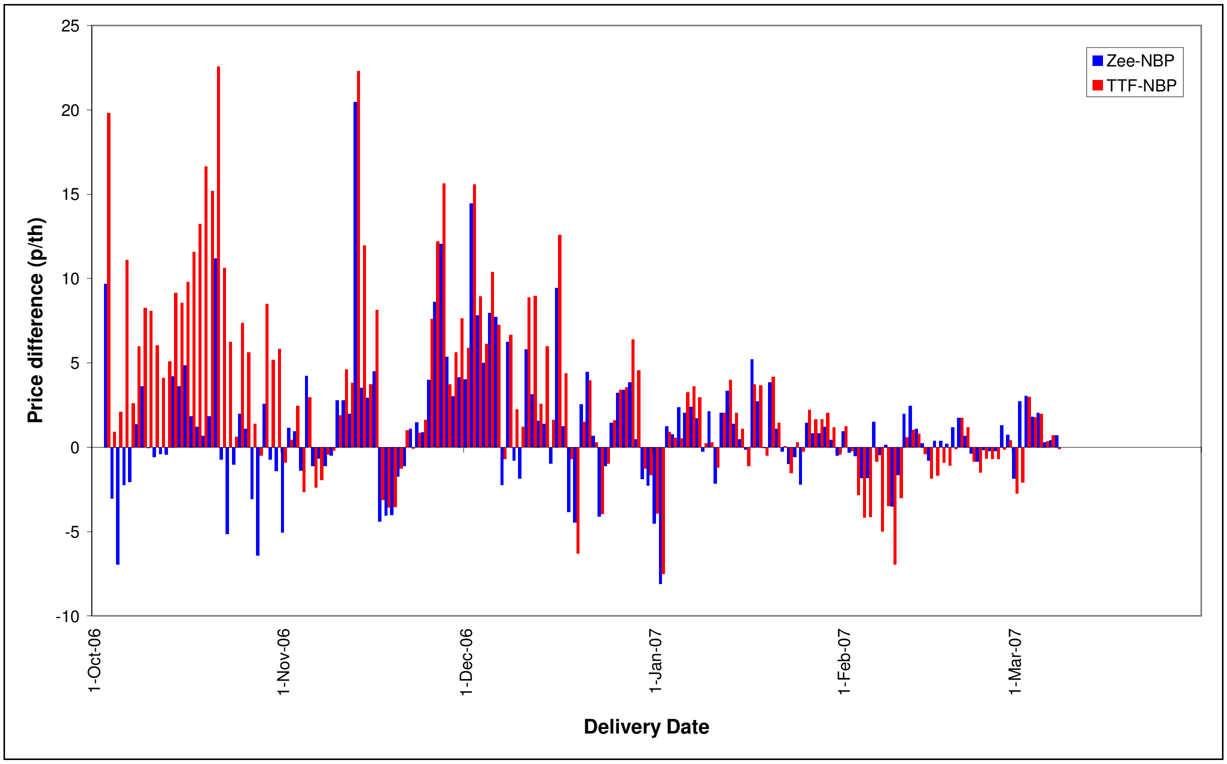
Figure 5 - UK and European Gas Prices



29. The Dutch and Belgian markets are now linked to the UK market via the BBL and IUK pipelines respectively. Consequently Zeebrugge and TTF prices have broadly tracked the UK price. All three markets generally rose between October and November and then trended downwards over the winter as fears of cold weather or storage shortages receded.

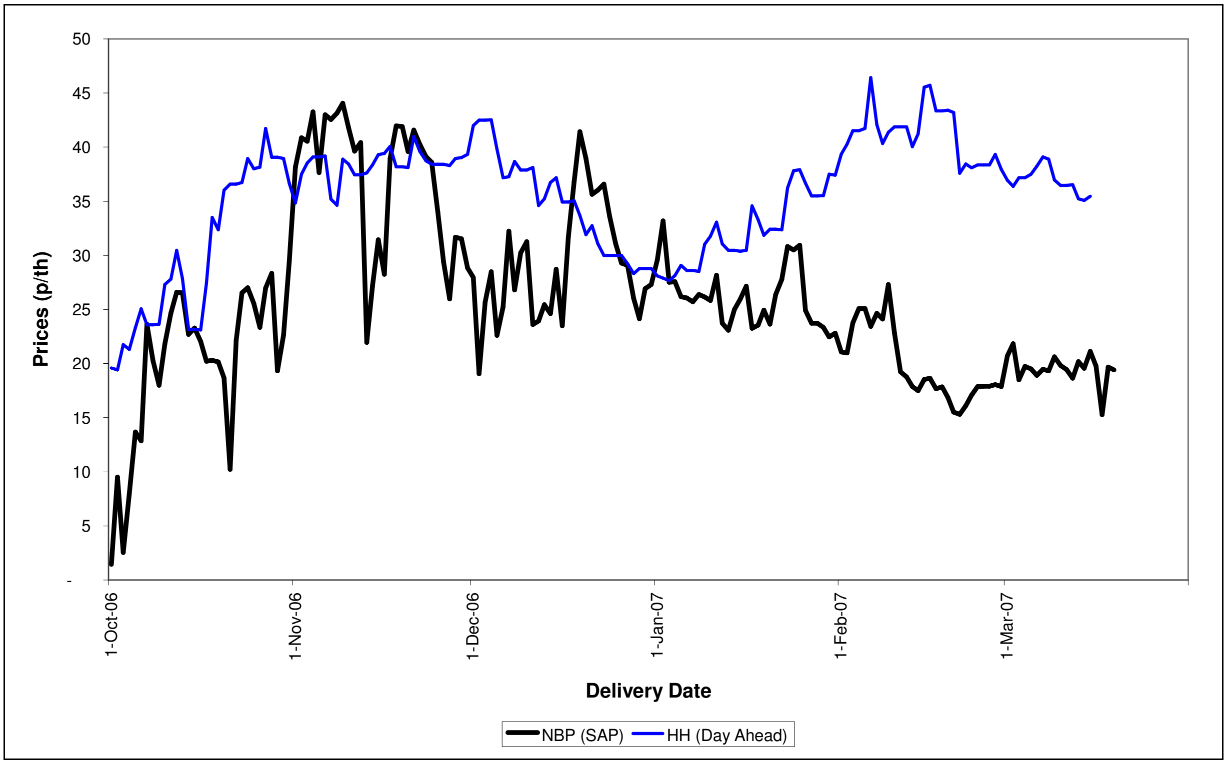
30. Figure 6 shows the price differential between the Zeebrugge and TTF markets and the NBP. The differential between the Netherlands and UK was greater in November prior to the commissioning of BBL. Since December the Netherlands and Belgian prices have been closer to each other and have trended towards the UK price. However, it is not clear if the interconnectors are the driver behind this trend because continental prices have generally been higher than the UK though the winter and yet there have been near consistent imports from BBL. Continental Imports are discussed in greater detail in Paragraphs 53-56.

Figure 6 - UK and European Gas Prices



31. Figure 7 compares the UK SAP price to the Henry Hub dayahead price. The American market rose with the European markets at the start of winter and has generally remained higher despite record storage stocks and mild weather at the start of winter. As the winter progressed the American spot and forward prices remained high due to cold weather and depletion of storage stocks.

Figure 7 - UK and Henry Hub Gas Prices

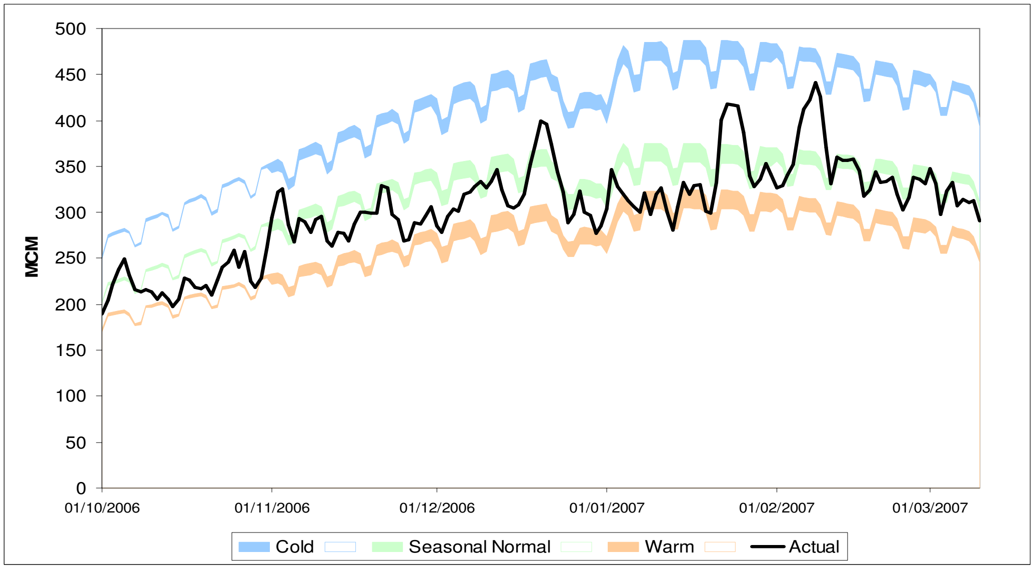


32. Elsewhere, LNG has reportedly traded around 45 p/th in India illustrating the attractiveness of Asia over Western Europe for LNG cargoes.

2006/7 Gas Demand

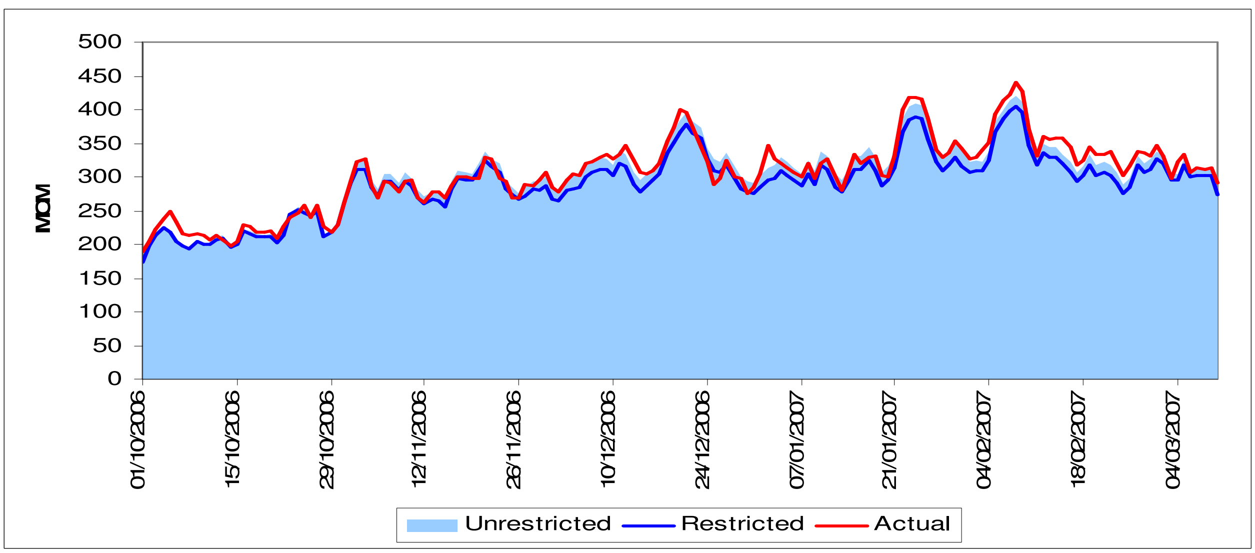
33. Figure 8 compares total demand, excluding Interconnector exports and storage injection, with seasonal normal, cold and warm demand. Reflecting the mild weather, demand was generally below normal seasonal demand.

Figure 8 – 2006/7 Seasonal and Actual Demands



34. Figure 9 compares the total actual demand with the demand modelled from actual weather and the 2006 demand forecast restricted and unrestricted models. The early part of the winter shows that the models forecast actual demand reasonably well. However, as the winter progresses, actual demand starts to exceed even the unrestricted forecast. The reason for this discrepancy can be explained by looking at the different market sectors.

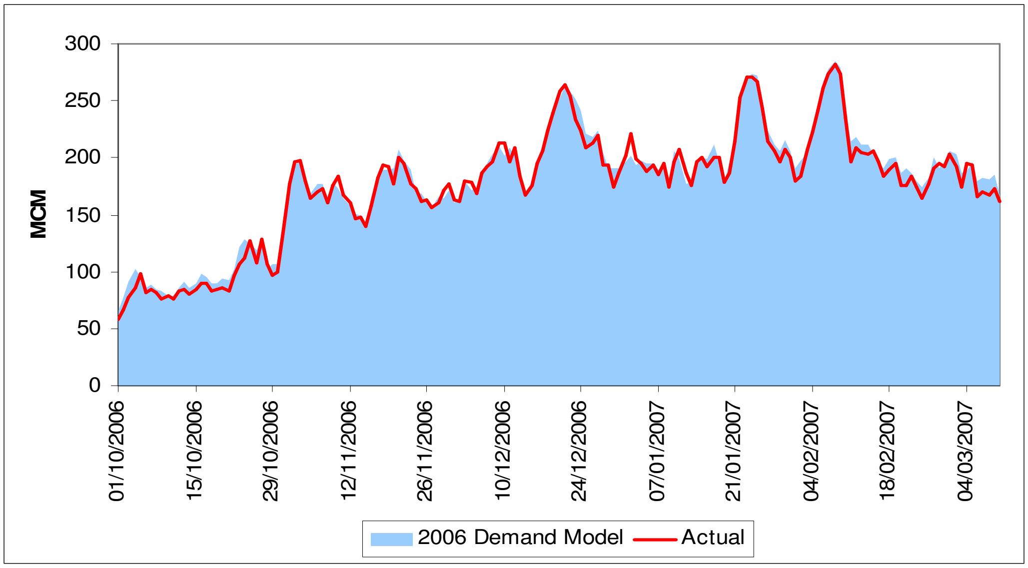
Figure 9 - 2006/7 Actual Total Demand[3]



[3] The difference between unrestricted and restricted demand forecasts is the level of demand response in the large industrial and power sectors at times of high prices

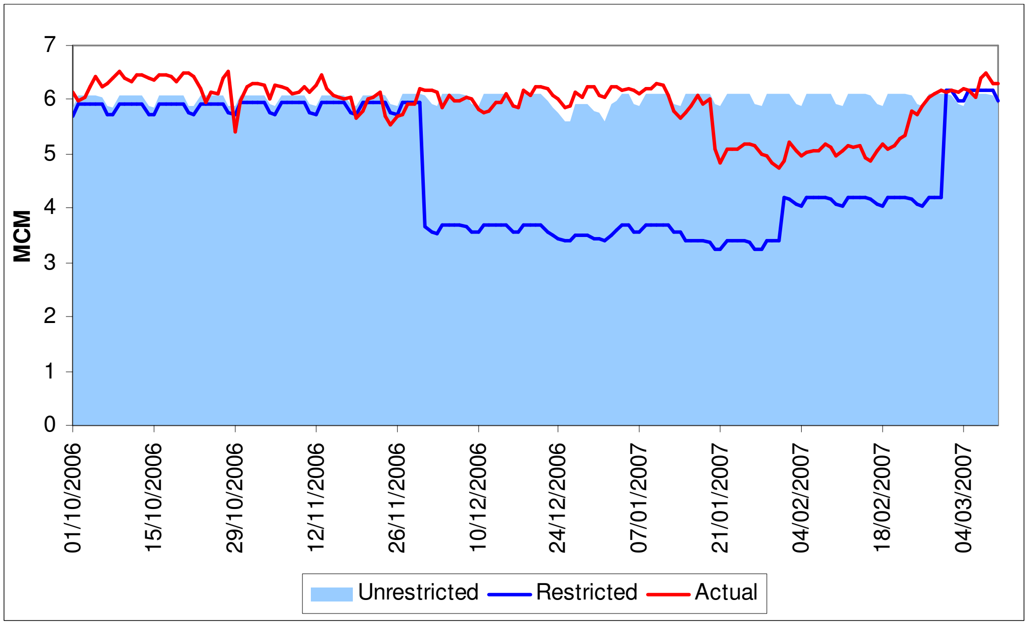
35. Figure 10 compares actual NDM demand with the demand modelled from actual weather and the 2006 demand forecast models. There is no difference between the unrestricted and restricted forecasts for NDM demand because domestic customers are not exposed to spot prices. NDM demand in 2006/7 was around 5% lower than in 2005/6 and around 2% lower than forecast. This fall was predominately due to declining domestic gas prices but also possibly changes in customer behaviour over and above those normally associated with price elasticity

Figure 10 – 2006/7 Actual NDM Demand



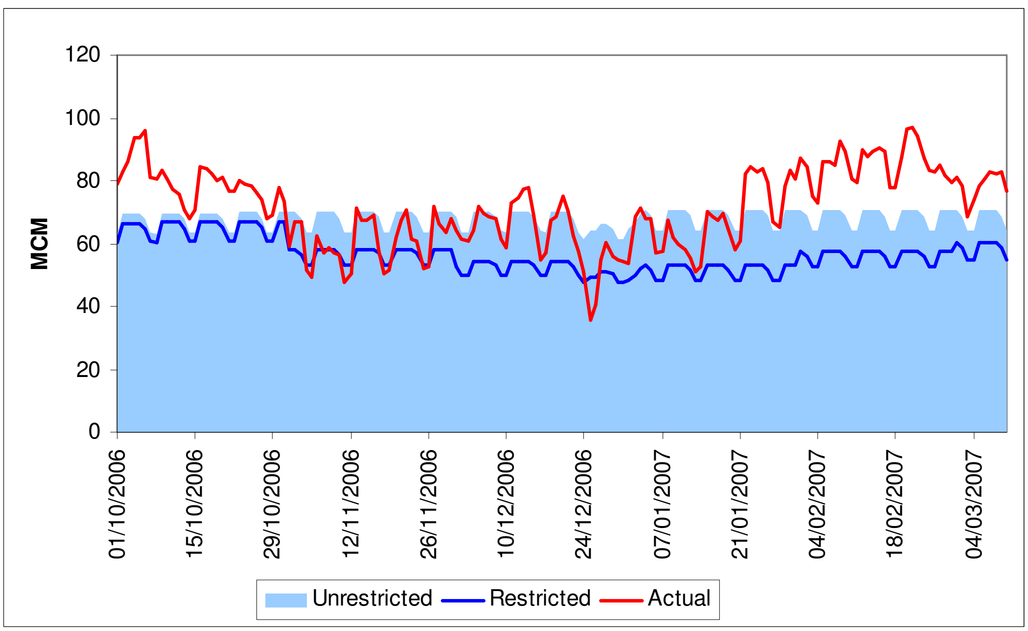
36. Figure 11 shows the same information for the large industrial loads connected to the NTS. This shows that for most of the winter actual demand has been at the unrestricted level due to the lack of demand response caused by the lower prices seen in winter 2006/7. The fall in demand seen in January and February is the result of lower consumption at one site which has subsequently returned. The reason for this is unclear; however, it is unlikely to be due to price because demand was higher when prices were higher earlier in the winter.

Figure 11– 2006/7 Actual NTS Industrial Demand



37. Figure 12 illustrates the daily power station demand for gas by comparing actual with unrestricted and restricted forecasts.

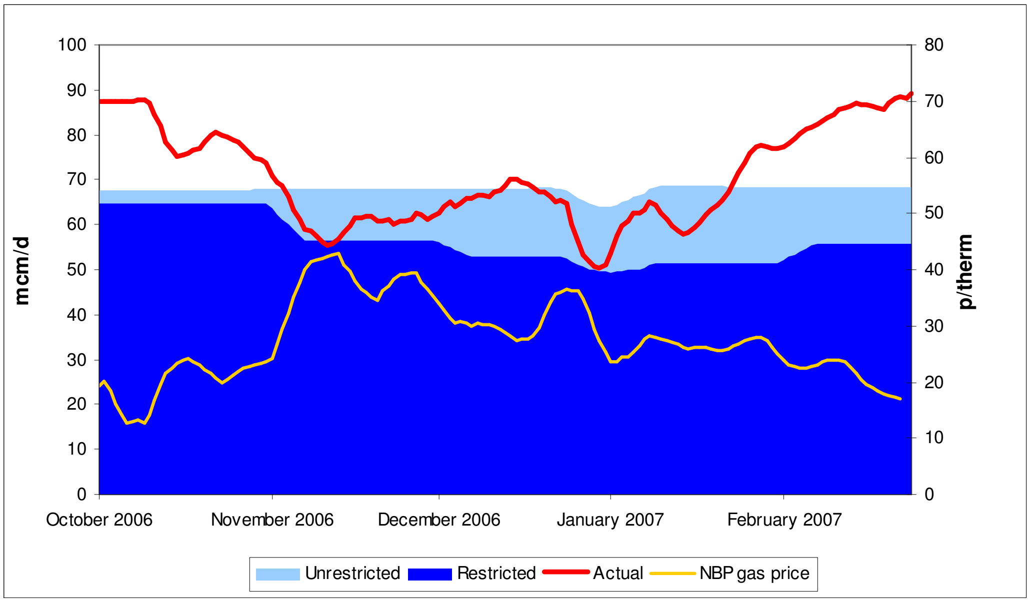
Figure 12 - 2006/7 Actual NTS Industrial Demand



38. The variation in demand becomes clearer with a 7-day moving average illustrated in Figure 13. In the warm weather in October gas prices were low and power station demand was high. The first cold snap in November sent prices over 40 p/therm resulting in power station demand dropping to the restricted forecast level. The

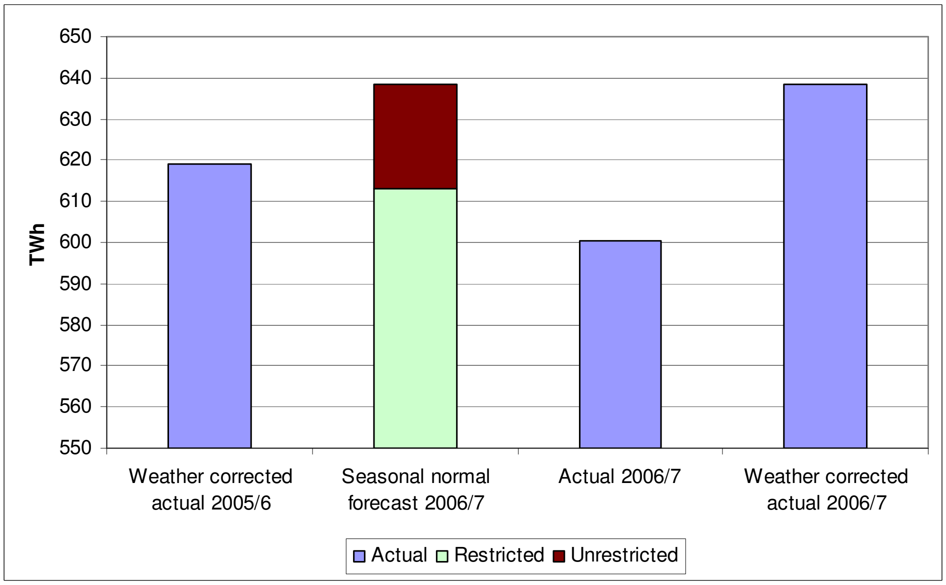
demand from November to mid-January fluctuated between restricted and unrestricted levels depending on the price, which was influenced by the weather. From mid-January it became clear that there was no shortage of gas and with the weather so mild prices started to fall. This caused gas to be preferable to coal for power generation, which when coupled with some nuclear and coal plant outages that reduced the level of non-gas fired generation, resulted in power station demand rising to pre-winter levels.

Figure 13 – 2006/7 Power Station Demand 7-day Average



39. Figure 14 compares the 2006/7 winter demand with weather corrected 2005/6 demand and forecast for 2006/7.

Figure 14 - Total Winter Demand



40. The 2006/7 restricted forecast was 1% below the 2005/6 weather corrected demand and the unrestricted forecast 3% higher. The 2006/7 weather corrected actual was very close to the 2006/7 unrestricted seasonal normal forecast with slightly lower NDM demand being compensated for by higher power generation.

2006/7 Gas Supply

41. Table 2 summarises the make-up of gas supplies for winters 2005/6 and 2006/7 by supply source. This highlights the significant increase in Norwegian imports and reduction in UKCS supplies. UKCS supplies were lower at all terminals, notably at Barrow and Bacton where high swing supplies were below our 2006/7 Base Case.

Table 2 – Gas Supply, Comparison of 2006/7 and 2005/6

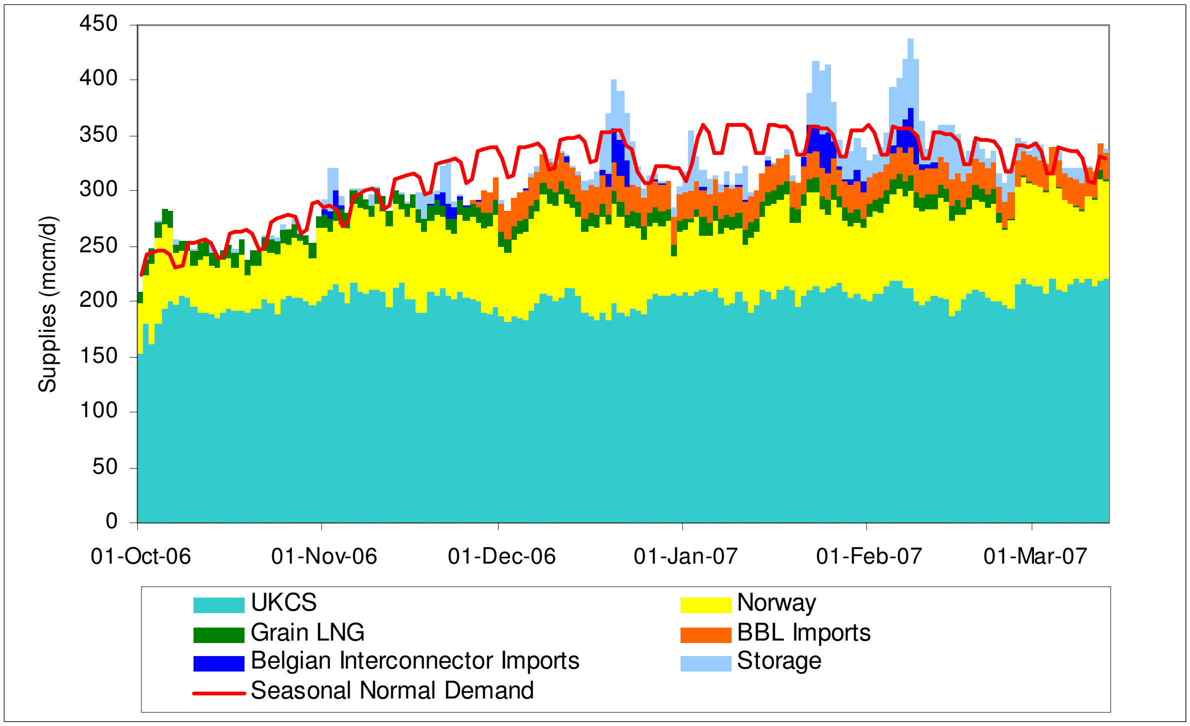
	2005/6		**2006/7**[4]	
	bcm	**%**	**bcm**	**%**
UKCS	45	76%	34	64%
Norway	5[5]	8%	12	23%
Continent	4	7%	3	6%
LNG	2	3%	2	4%
Storage	3	5%	2	4%
TOTAL	**58**		**53**	

42. Figure 15 shows how the various gas supply sources were used in winter 2006/7 against seasonal normal demand. Each of these supply sources is considered in turn in the following sub-sections.

43. From November onwards, except for three periods when the level of demand was materially higher, the level of demand was for most days in the range of 300 to 350 mcm/d.

[4] 2006/7 to 17th March 2007
[5] Estimated

Figure 15 – 2006/7 Supply Performance



UKCS Supplies

44. Figure 15 highlights that though in decline UKCS supplies continue to underpin UK demand. For the 49.6 bcm of aggregated supplies between 1 October and 17 March, UKCS supplies accounted for 34 bcm, equivalent to 64%.

45. Table 3 shows the 2006/7 Winter Consultation Base Case forecast of UKCS supplies by terminal and the actual terminal supplies for the day of highest UKCS supplies (13 March 2007) and the highest day for each terminal.

Table 3 - 2006/7 UKCS Supplies by Terminal

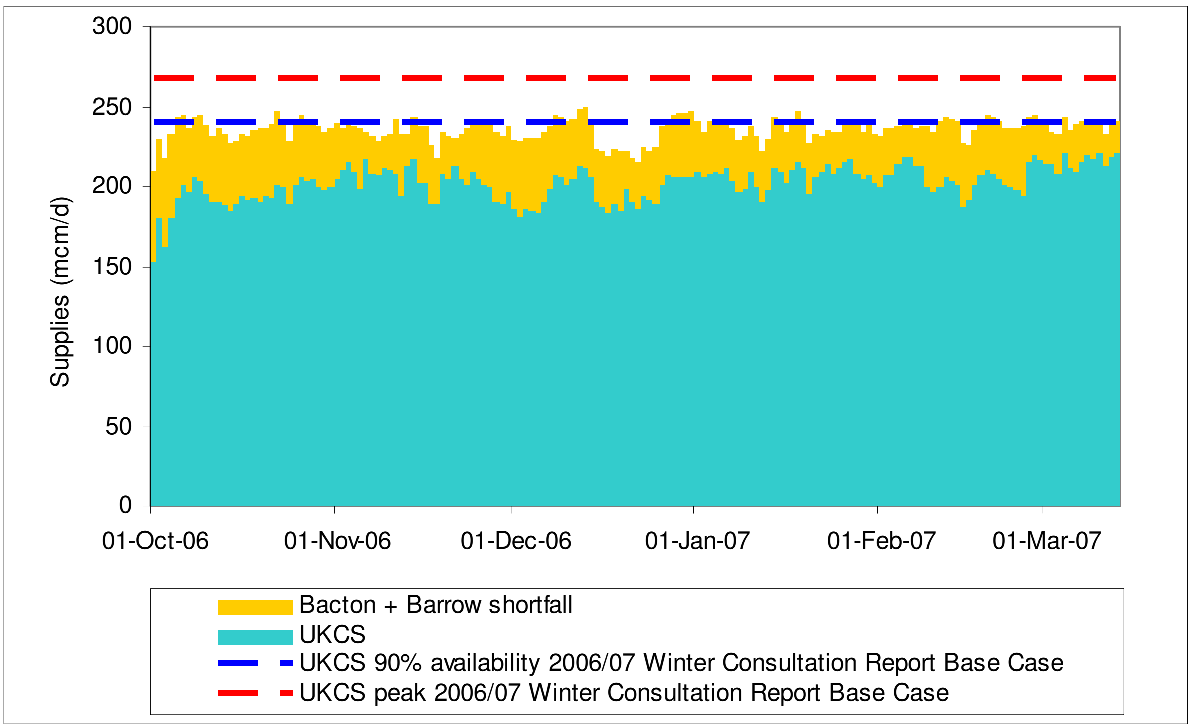
Peak (mcm/d)	Base Case	Actuals	
		Highest UKCS	Highest Terminal
Bacton	75	50	55
Barrow	24	18	25
Easington	16	13	15
Point of Ayr	2	0	4
St Fergus[6]	94	88	95
Teesside	30	29	35
Theddlethorpe	26	24	28
Total	**267 (240)**	**221**	**257**

[6] Excludes Vesterled

46. The table highlights that the day of highest UKCS supplies of 221 mcm/d was appreciably below the forecast of 267 mcm/d. However when comparing against the highest day we need to apply a factor for UKCS supply availability. For operational planning, we currently assume 90%, hence the 267 mcm/d should be assessed as 240 mcm/d. On this basis and comparing with our highest daily forecast for each terminal, our UKCS Base Case appears robust with the exception of our forecast for supplies into Bacton.

47. During the winter, as a consequence of modest demands and high supply availability we observed that for much of the winter, specific high swing supplies into Bacton and Barrow were below forecast. When this shortfall is combined to our estimate of UKCS supplies as shown in Figure 16, our Base Case of 240 mcm/d is confirmed as being appropriate for essentially all the winter. This suggests that with the exception of specific high swing supplies, most UKCS fields were producing at near maximum flow conditions for most of the winter period.

Figure 16 – 2006/7 UKCS Supplies



Question for consultation

Q1. We welcome views on our assessment of UKCS supplies and in particular our view that for most of the winter most UKCS supplies were operating at maximum flow conditions with the exception of certain high swing supplies

Norwegian Imports

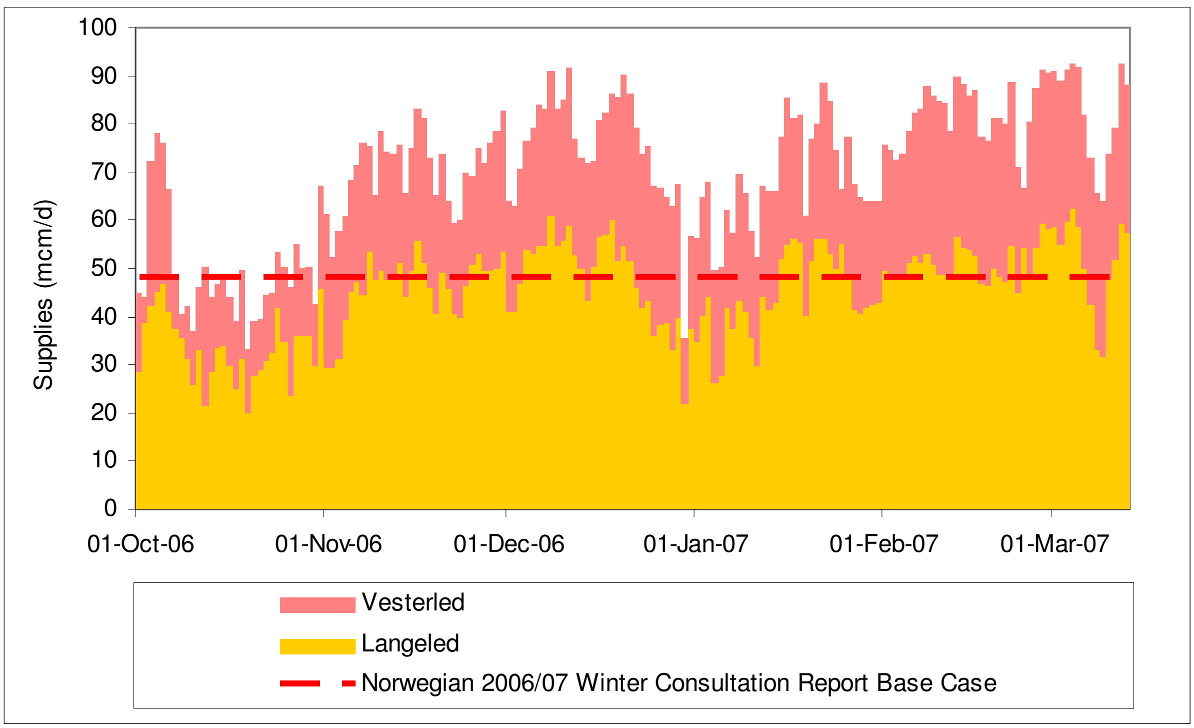
48. In late September 2006, the Langeled pipeline between the Sleipner platform in the Norwegian sector of the North Sea and Easington was commissioned. The capacity of this pipeline is reported at approximately 25 bcm/year (68.5 mcm/d). Whilst this

pipeline is integrated into the offshore Norwegian network, the pipeline has been primarily built to supply Ormen Lange gas to the UK from 2007/8.

49. For 2006/7 there was considerable uncertainty as to how much Norwegian gas would flow to the UK through Vesterled and Langeled, as whilst there was potentially some incremental Norwegian volumes available through capacity enhancements, these were considerably less than the additional capacity Langeled provided. In addition, Norwegian gas also had contractual obligations and transportation options regarding delivery to the Continent in Germany, France and Belgium. Consequently, our view for Norwegian gas flows to the UK for our Winter Consultation Base Case was 48 mcm/d. This was an increase of 15 mcm/d on the estimated flow from Norway (all through Vesterled) to the UK for the previous winter.

50. Figure 17 shows Norwegian flows through Langeled and Vesterled. The chart shows that total Norwegian flows far exceeded the 2006/7 Base Case of 48 mcm/d for most of the winter, with a peak flow of 93 mcm/d and an average flow of 70 mcm/d.

Figure 17 – 2006/7 Norwegian Imports



51. Table 4 shows Norwegian gas production as reported by the Norwegian Petroleum Directorate (NPD), and Norwegian gas received through Zeebrugge (Fluxys data), Dunkerque (GRTgaz data) and the UK[7]. Also shown on the table is implied German imports and Norwegian own use gas calculated by difference.

[7] Estimated except for Oct 06 – Jan 07

Table 4 – Norwegian Production and Exports (bcm)

	Norwegian production	Belgium Imports	French Imports	UK Imports[7]	German Imports[8]
2003/04	77.4	14.3		6.5	
2004/05	84.3	14.2		9.3	
2005/06	87.2	13.9	16.1	9.7	47.5
Oct03–Jan04	29.3	5.2		2.7	
Oct04-Jan05	30.2	5.1		3.5	
Oct05-Jan06	31.3	5.0	6.0	3.5	16.8
Oct06-Jan07	**31.7**	**4.2**	**5.2**	**8.1**	**14.2**

52. Though Table 4 is incomplete for earlier data from France, the reported data does suggest that Norwegian production this winter was not materially higher than for last winter and that the significant increase in flows to the UK is a consequence of lower exports to the Continent. This raises the questions of whether Norwegian production was constrained by the mild winter and whether flows to the UK would have been lower if Continental demand was higher.

Questions for consultation

Q2. We welcome views on our assessment that increased Norwegian supplies to the UK were a consequence of lower supplies to the Continent

Q3. We welcome views of whether Norwegian supplies to the UK and the Continent would have been higher if demand for the UK and Continent had been higher

Q4. We welcome views on whether Norwegian supplies to the UK would have been as high if Continental demand had been higher.

Continental Imports

53. For the start of winter 2006/7, the capacity of the Belgium Interconnector (IUK) for UK imports was increased through additional compression at Zeebrugge from approximately 48 mcm/d to 68 mcm/d.

54. In late November 2006 the Dutch Interconnector (BBL) was commissioned and commercial operation commenced shortly afterwards. This pipeline is currently intended for UK imports only; the initial capacity is approximately 30 mcm/d with expansion plans to increase to above 40 mcm/d following installation of further compression in spring 2007.

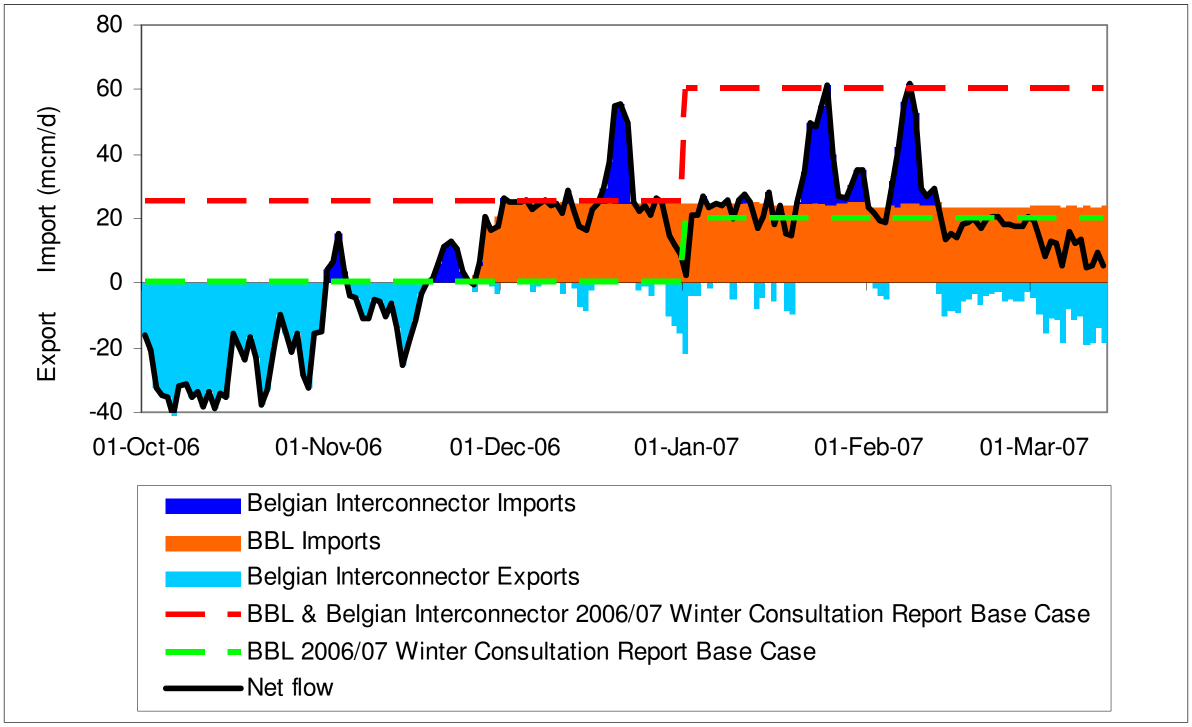
55. For 2006/7 there was considerable uncertainty regarding import flows through both of these pipelines and whether BBL would be commissioned on time. Consequently our Winter Consultation view for Continental imports to the UK for our Base Case was 25 mcm/d through to December and 60 mcm/d post December. With the 35 mcm/d increase due to a combination of BBL being fully commissioned and increased availability of Continental supplies for export through IUK.

56. Figure 18 shows Continental imports through IUK and BBL. The chart also shows IUK exports and the net flow of Continental imports. The chart shows that once

[8] Calculated by difference and includes Norwegian own use gas

commissioned, BBL from December onwards flowed at a near uniform rate of 25 mcm/d, suggesting that these flows were contracted rather than subject to market variations. IUK flows were appreciably different and as reinforced in Figure 15, these supplies behaved more akin to storage as a marginal source of supply.

Figure 18 – 2006/7 Continental Imports



Questions for consultation

Q5. We welcome views on the possible factors, other than short term market differentials, which may be driving BBL flows

Q6. We welcome views on our suggestion that IUK operated as a marginal source of supply more akin to a storage facility.

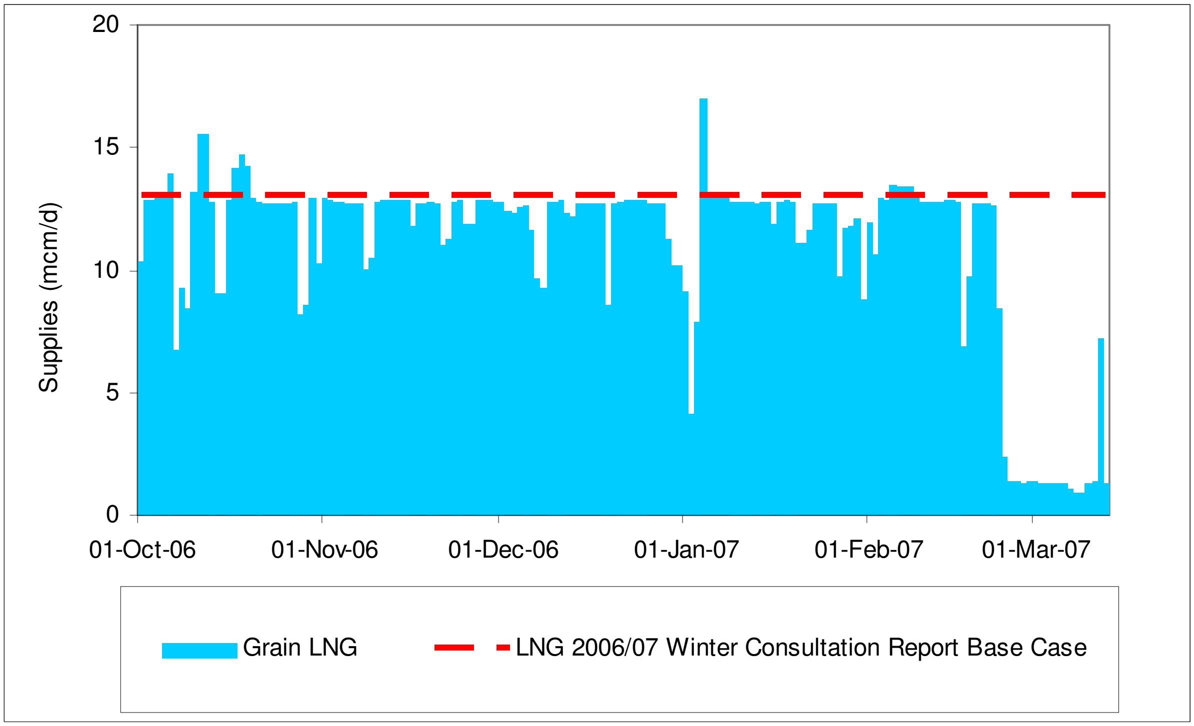
LNG Imports

57. The main uncertainties associated with LNG imports as detailed in the 2006/7 Winter Consultation were the possibility of cargoes being diverted to higher priced markets and the possible commencement of new LNG imports through Excelerate's 'Energy Bridge' concept at Teesside.

58. At the time of the reporting the final 2006/7 Winter Consultation Report, UK gas prices for the winter were much higher than those for the US and for European contracted gas. Start-up of operations at Teesside was expected to be in January 2007. On this basis we assumed LNG imports of 13 mcm/d for the winter, acknowledging both the market risk for LNG to be diverted and the upside that Grain had on occasion exceeded 13 mcm/d and that Teesside could provide additional volumes when commissioned.

59. Figure 19 shows LNG imports through Grain, the nominal commissioning volumes for Excelerate's deliveries into Teesside in late February are not shown. The chart shows that LNG flows were broadly in line with the 2006/7 Winter Consultation Base Case, though the Excelerate project was commissioned later than expected in mid February 2007.

Figure 19 – 2006/7 Grain LNG Imports



Questions for consultation:

Q7. How sensitive to gas price are LNG deliveries?

Q8. How developed is a global gas market for LNG?

Storage Performance

60. Figure 20 shows total storage stocks over the winter. Figure 21 shows storage use by type of storage facility and gas price. The charts highlights:

- Relatively limited storage use until mid December with increased use from late January
- Aggregated storage use to 7 March was just over 2 bcm, with Rough accounting for nearly 70% and essentially no use of LNG
- High levels of Mid Range Storage cycling, with withdrawals at 0.66 bcm and injection at 0.47 bcm
- Limited relationship between storage withdrawal and the gas price. As detailed previously, the overall supply position was instrumental in setting the gas price rather than the gas price dictating storage withdrawals

Figure 20 – Total Storage

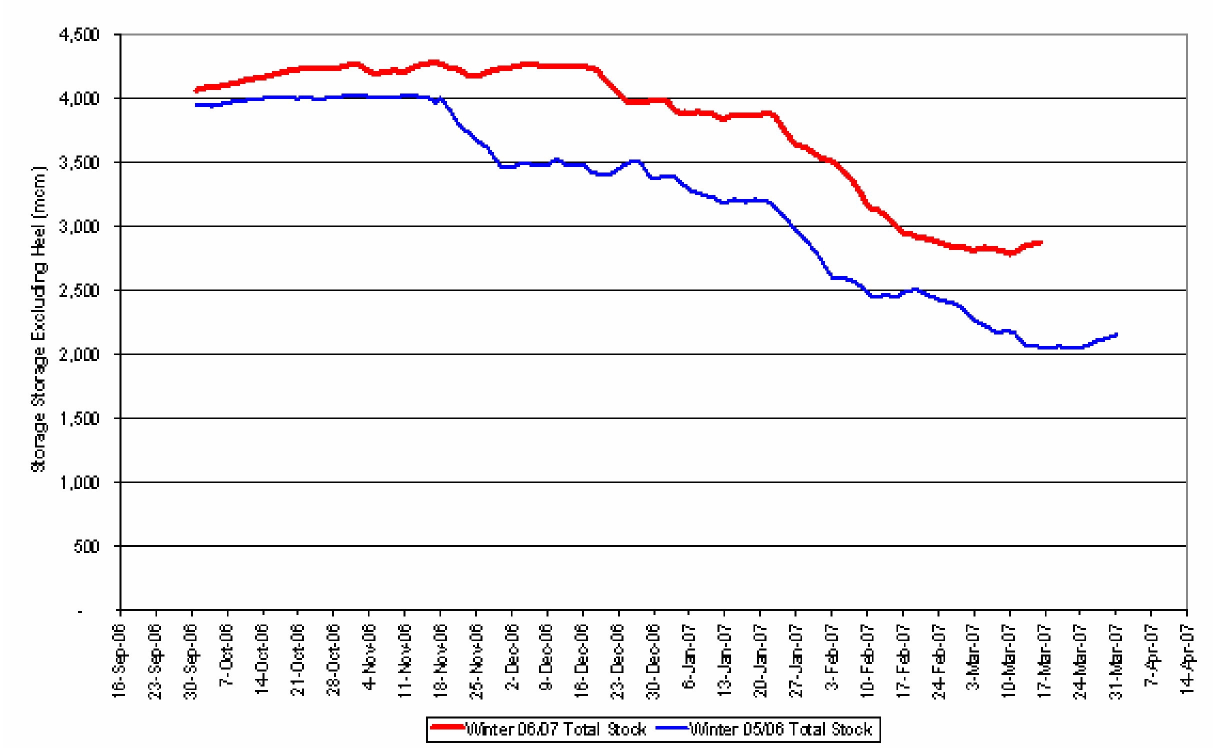
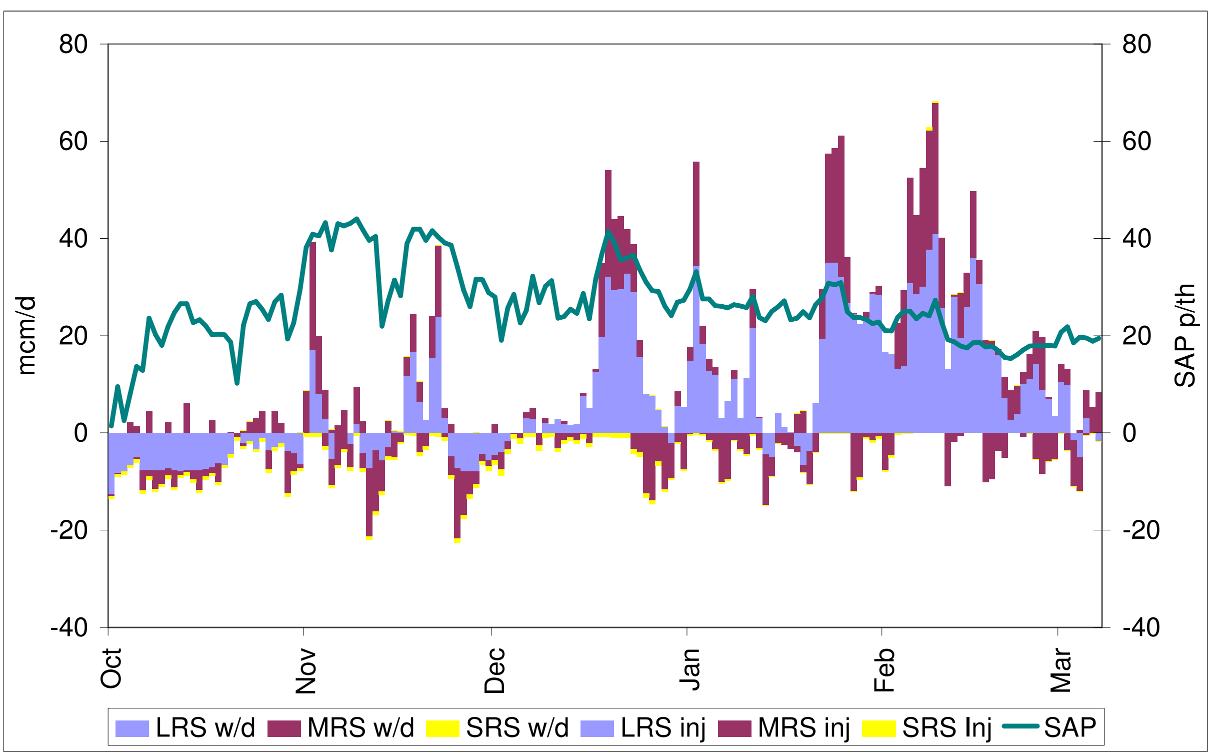


Figure 21 - Storage Injections and Withdrawals



Question for consultation

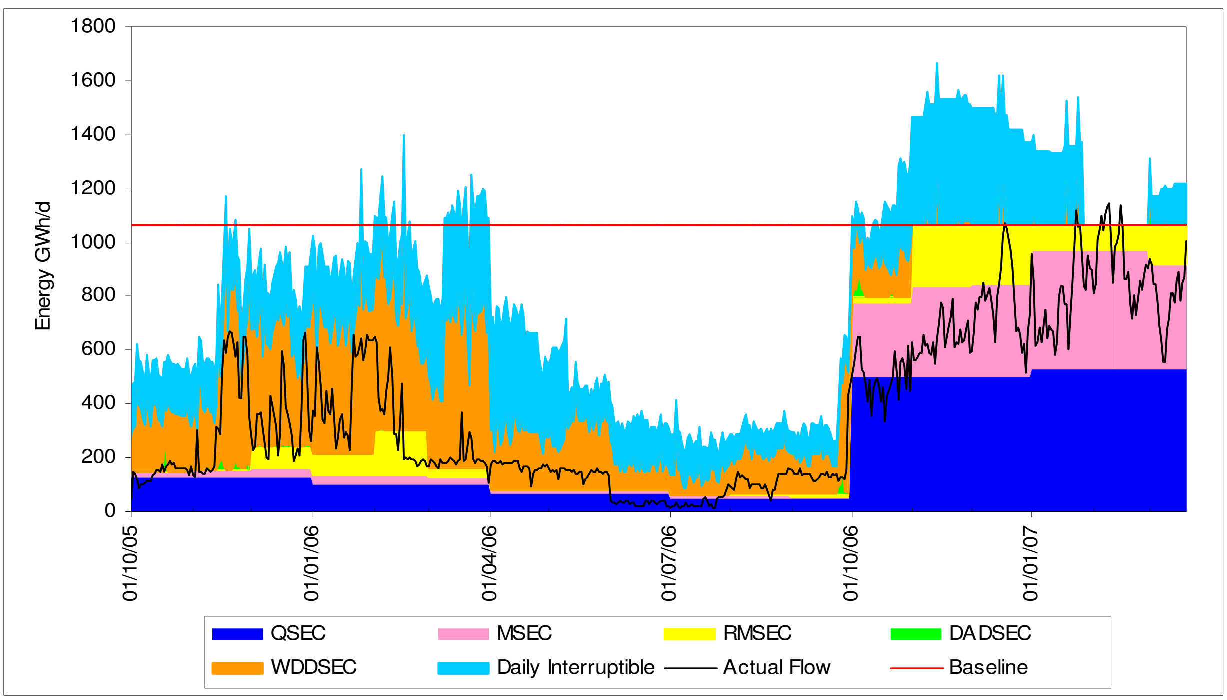
Q9. With a back-drop of declining gas prices as the winter progressed, what were the key drivers for increased storage use later on in the winter?

Q10. Under conditions of increased demand, would storage cycling be so prominent?

Network Constraints

61. Figure 22 illustrates the significant change in flows observed at the Easington Aggregate System Entry Point (ASEP) over the course of the last winter. For many years Easington flows have mainly comprised UKCS gas supplemented by Rough storage withdrawals made in response to evolving gas demands and spot prices. From the start of the winter 2006/7, Norwegian Langeled supplies have supplemented UKCS supplies, which in aggregate broadly utilise the available baseline level of firm ASEP capacity and physical capability at the terminal. Consequently National Grid has been less able to provide interruptible capacity rights than in previous years.

Figure 22 – Easington Capacity and Flows

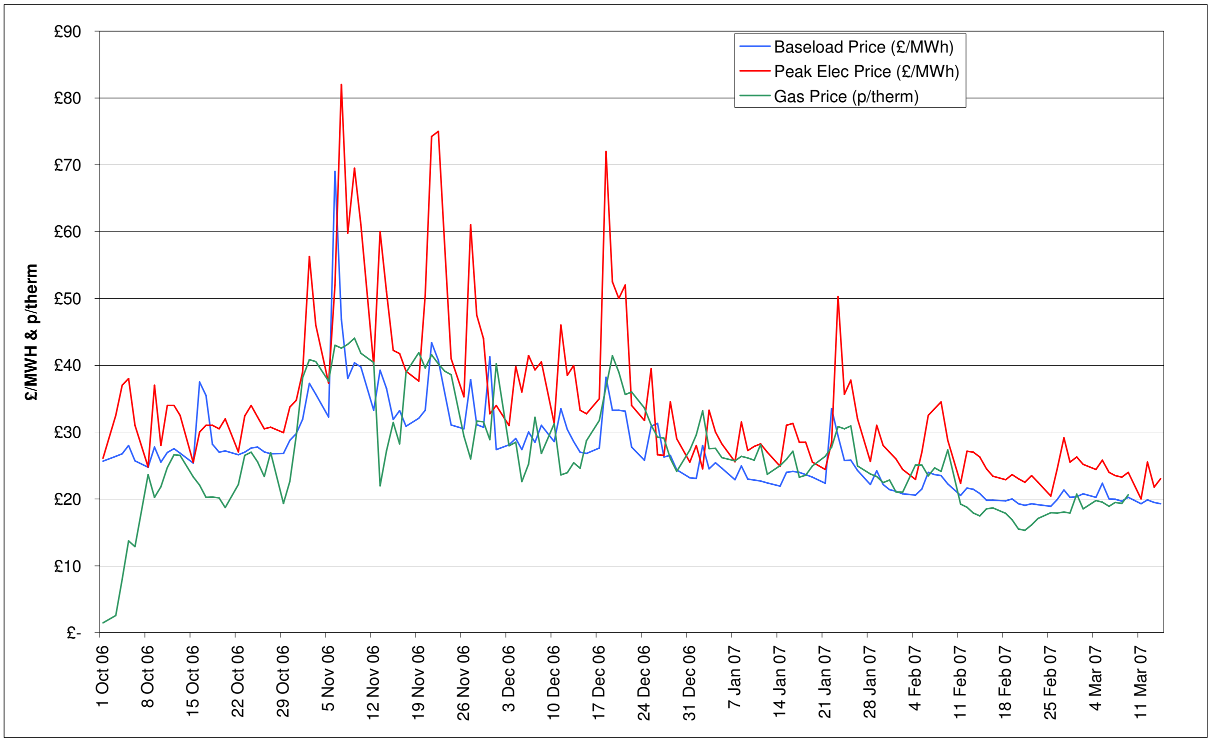


Chapter 3: Electricity

Electricity Prices

62. Figure 23 illustrates how electricity prices peaked at the start of the winter and have generally been declining since, in line with declining gas prices.

Figure 23 – Dayahead Electricity and Gas Prices



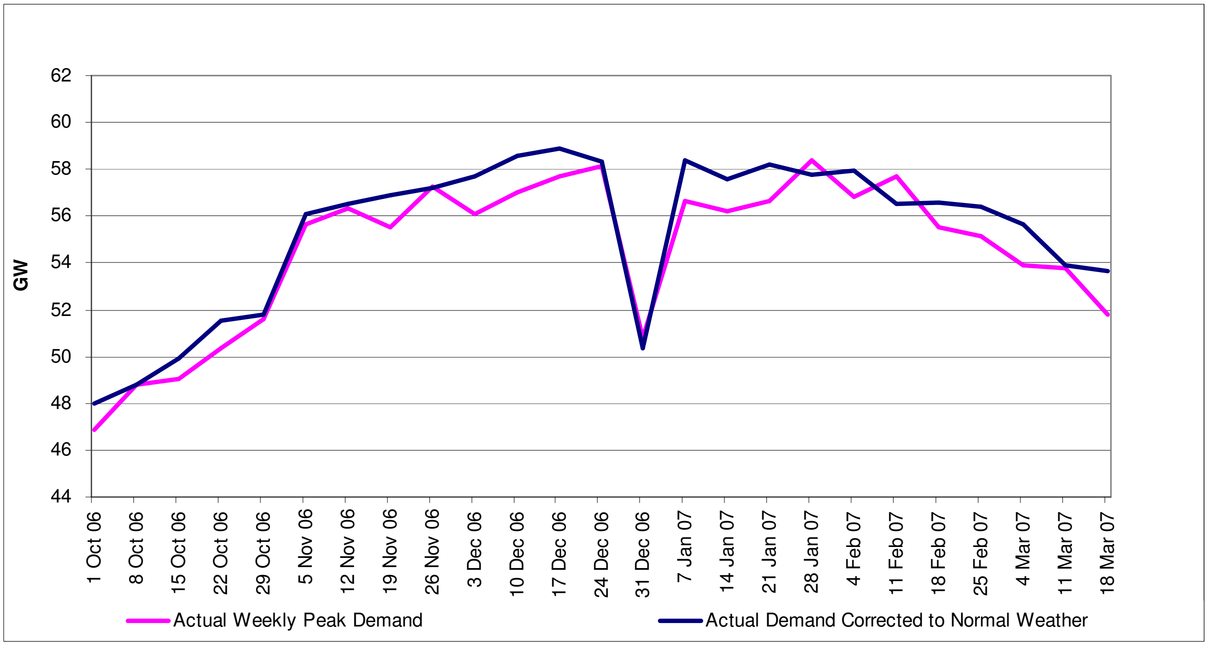
Electricity Demand

63. As detailed in Figure 24, the highest electricity demand over the winter was 58.4 GW. This peak demand occurred between 17:30 and 18:00 on Tuesday 23 January 2007. This compares to the highest demand of 60.3 GW over Winter 2005/6. These figures include power station own use and 0.3 GW export to Northern Ireland, but are net of triad avoidance Customer Demand Management.

64. National Grid has estimated that there was around 0.8 – 1.3 GW of triad avoidance demand management at the peak on potential triad days as large customers reduced demand.

65. On a weather-corrected basis, the ACS peak demand for 2006/7 was 60.8 GW. This is 0.5 GW lower than the comparable 2005/6 outturn, which itself represented no growth upon 2004/5**.** The cause of the demand reduction is currently being analysed. Likely causes include increased demand management due to high end-user electricity prices, increased embedded renewable generation, and continued energy efficiency.

Figure 24 – Weekly Peak Demand



Generation Supply Build-Up

66. The aggregate Transmission Entry Capacity (TEC) was 76.8 GW in 2006/7[9].

67. Following the September publication of the Winter Consultation Report 2006/7, 0.8 GW of short-term mothballed plant returned for the winter. There was no return of the 1 GW long-term mothballed plant. This was consistent with the modelling assumptions made in September 2006.

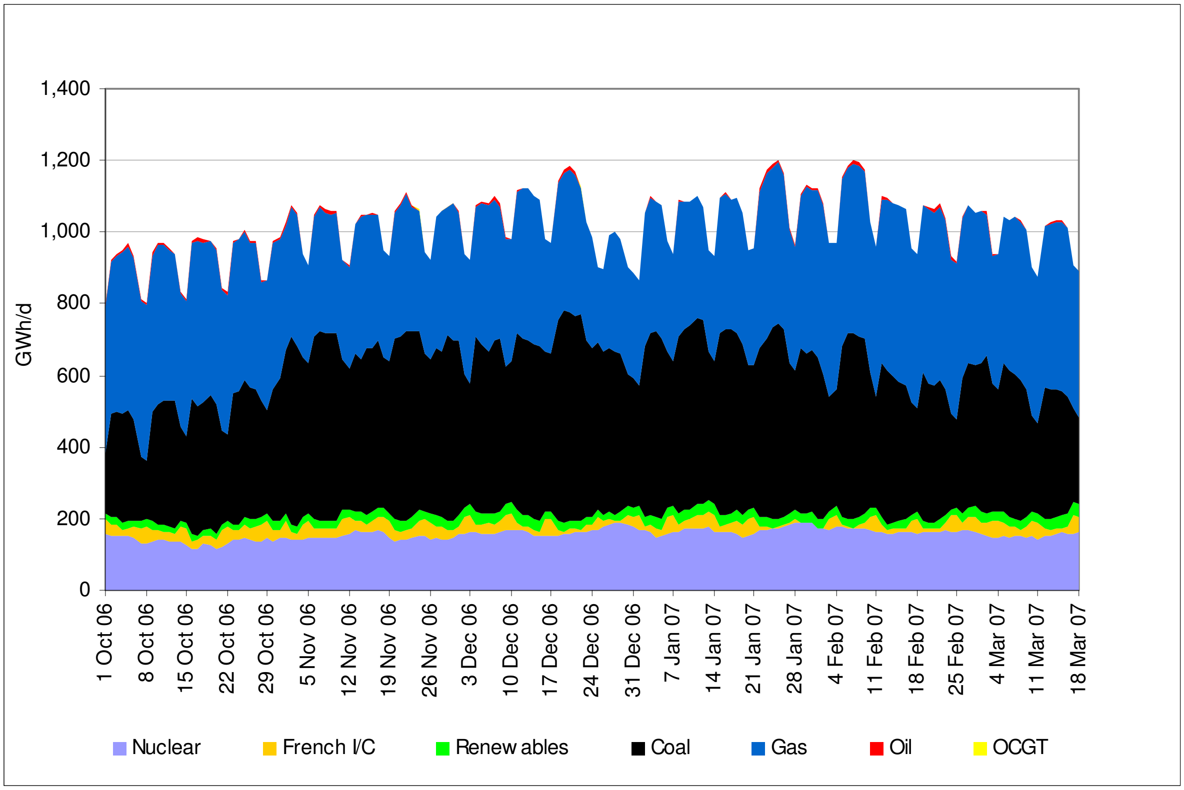
68. There was no Notice of Insufficient Margin (NISM) or High Risk of Demand Reduction (HRDR) issued over winter 2006/7.

69. Though the winter was generally very mild, on 18 January 2007 Great Britain experienced exceptionally high winds with gusts of up to 90 mph, which has been reported as the worst storm to hit the country in 17 years. The storms hit the west coast of England and moved in an easterly direction and caused wide spread damage across the country over a period of approximately 12 hours on 18 January. There were 22 faults on transmission circuits on the National Grid Electricity Transmission system over this period, but there were no losses of supply arising from these faults.

70. Figure 25 shows the build up of generation by fuel type to meet demand for winter 2006/7 and indicates that coal and gas fired generation were the dominant fuels with each tending to be between 300 and 500 GWh per day.

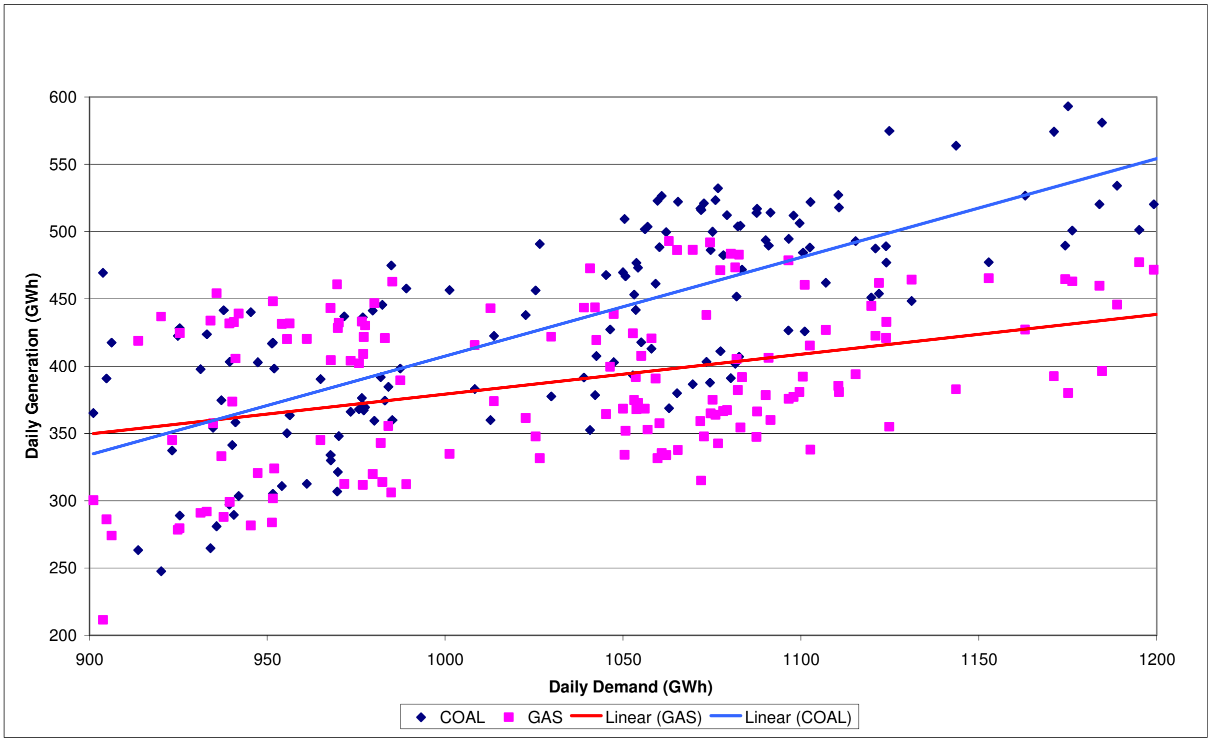
[9] Under the terms of the Connection and Use of System Code, generators are required to purchase Transmission Entry Capacity (TEC) for the generation they export on the GB transmission system.

Figure 25 - Daily Generation Supply Build-up, Winter 2006/7



71. Whilst during winter 2005/6, gas was the marginal fuel and coal was baseload, it seems that during winter 2006/7 there was more competition between coal and gas fired generation. As illustrated by Figure 26 neither coal nor gas fired generation ran as baseload generation. Overall for each 100 MW increase in demand, gas fired generation tended to increase by around 30 MW and coal-fired by around 70 MW. This behaviour was very different to the assumptions we had made in the 2006/7 Winter Consultation Report when we assumed gas fired generation would be the marginal generation, when assessing the potential level of CCGT gas demand-side response. The increased output from gas-fired generation during winter 2006/7 appears to have been driven by declining gas prices, which made gas increasingly more attractive than coal as a generation fuel. Reduced nuclear availability over winter 2005/6 was broadly offset by lower electricity demand due to the mild weather.

Figure 26 - Daily Demand and Generation Mix



72. As reported in the media by British Energy, the nuclear plants at Hinkley Point B and Hunterston B both experienced periods of unplanned unavailability during the winter. Generation at Hinkley Point B and Hunterston was halted on the 20 October 2006 due to cracking in the boiler tubes which had been identified during outage maintenance. All units at both stations are planned to return to service during spring. In outturn, this unavailability was partially offset by lower system demands that resulted from the mild weather experienced during the winter of 2006/7.

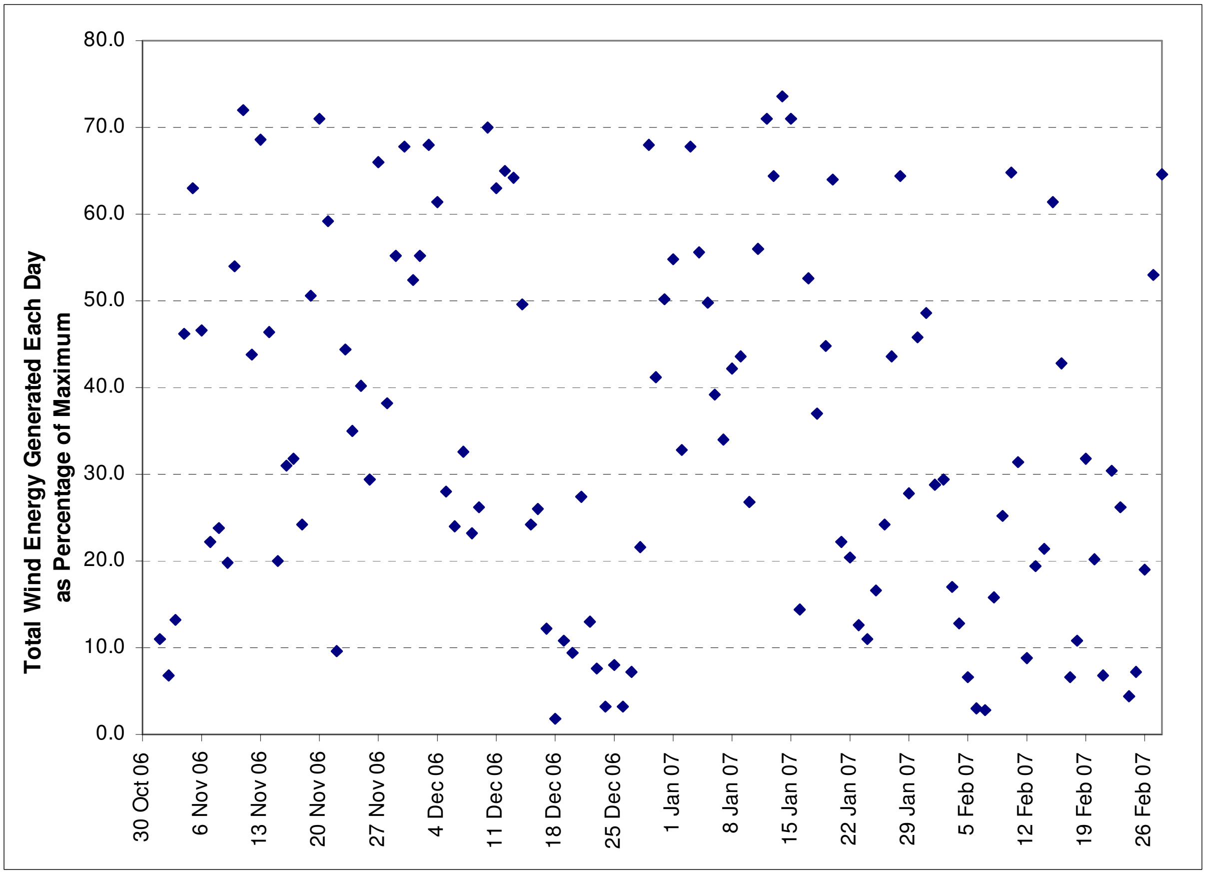
73. Longannet power station experienced a period of unplanned unavailability after a failure of the coal conveyor belt on 20 January 2007. Longannet was able to run on gas whilst the conveyor belt was repaired during February and returned to service using coal on 5 March 2007.

74. The key features of average plant availability by generation type over winter 2006/7 are:

- Nuclear availability was around 60%, due to reduced plant availability at Hinkley Point B and Hunterston from late October 2006. For the remaining stations, availability was close to 80%, close to our winter 2006/7 assumption of 85%;
- Coal availability at 87% was just above our modelling assumption of 85%;
- CCGT availability at 91% was again just above our assumption of 90%.

75. Figure 27 shows the volatility of wind generation. Though average daily loadfactor at 35% was close to our assumed factor of 36%, the actual loadfactor on any day is very uncertain.

Figure 27 – Wind Output, daily output as % of maximum



76. For illustrative purposes, Figure 28 shows the assumed generation supply build up for the peak day this winter, 23 January 2007, applying the 2006/7 Winter Consultation Report modelling assumptions. Figure 29 shows the actual generation supply build-up for the peak demand day.

77. Figure 29 also shows that behaviour on 23 January was unusual in one respect, which was that the UK-France Interconnector did not flow into the UK overnight (23:00 – 08:00 or periods 46-16). Typically on normal winter weekdays overnight there was a flow into the UK from France, as shown in Figure 30.

Figure 28 – Generation Supply Build-up Under Winter Outlook 2006/7 Assumptions, 23 January 2007

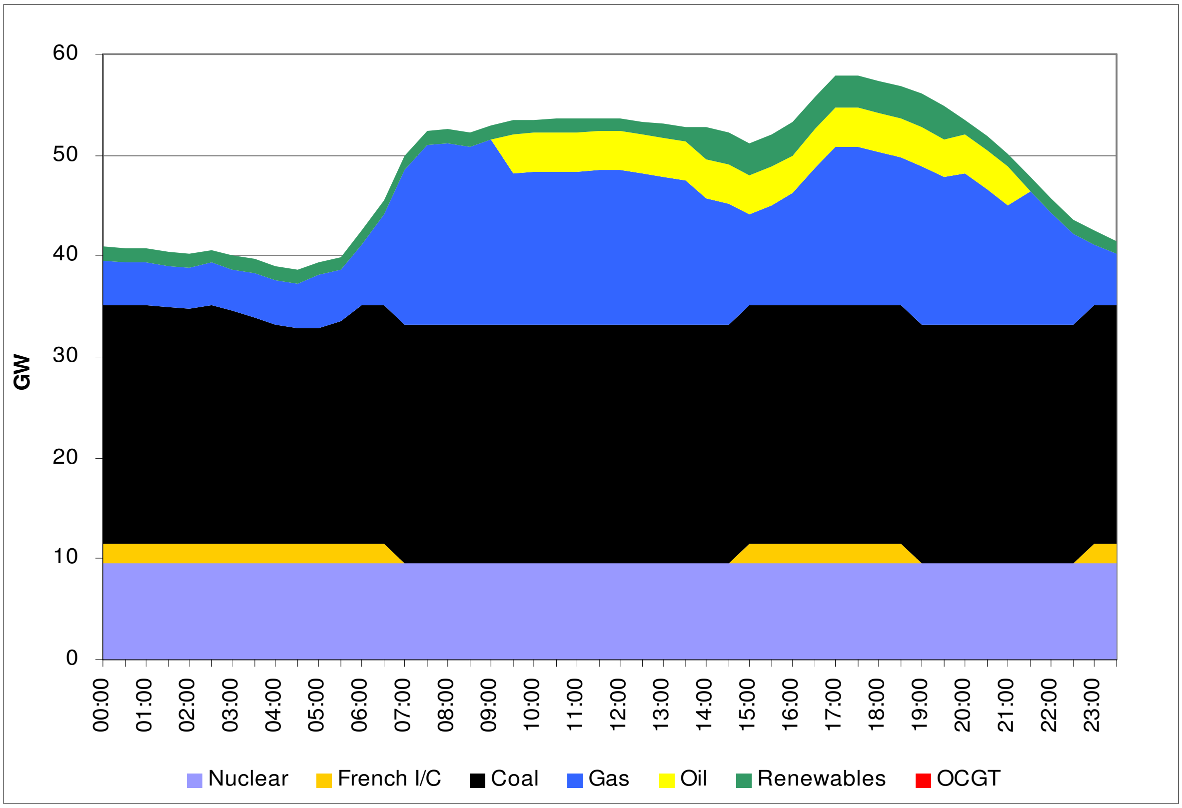
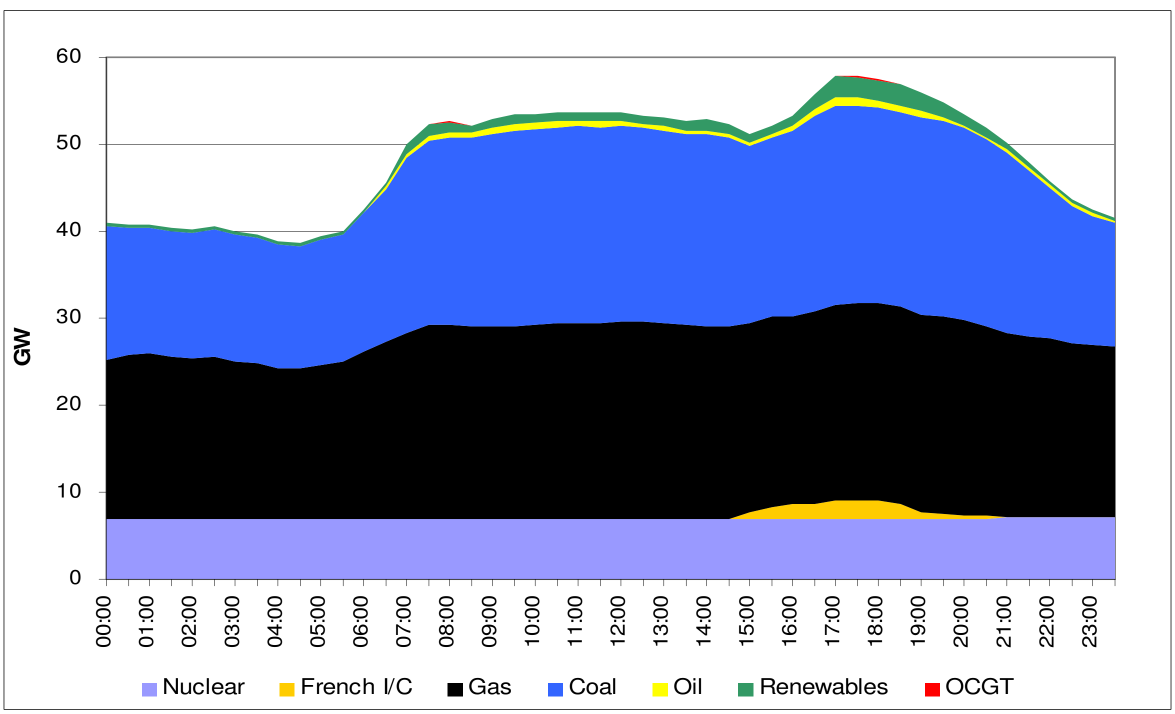


Figure 29 – Actual Generation Supply Build-up, 23 January 2007



78. As indicated by Figure 30, across the winter there was a varying profile of flows on the UK-France Interconnector. The Interconnector's flows varied across the day, on occasions exporting to France in the morning before reversing direction to flow to the UK for the evening peak. The flow had a reasonably strong relationship with price differentials, flowing to UK offpeak when UK prices were higher and reversing flow when French prices were higher.

79. Figures 30 and 31illustrate the scope for greater Interconnector imports across the day, thereby increasing the level of gas demand-side response that could be provided by the electricity market.

Figure 30 – UK France Interconnector Flow Profiles

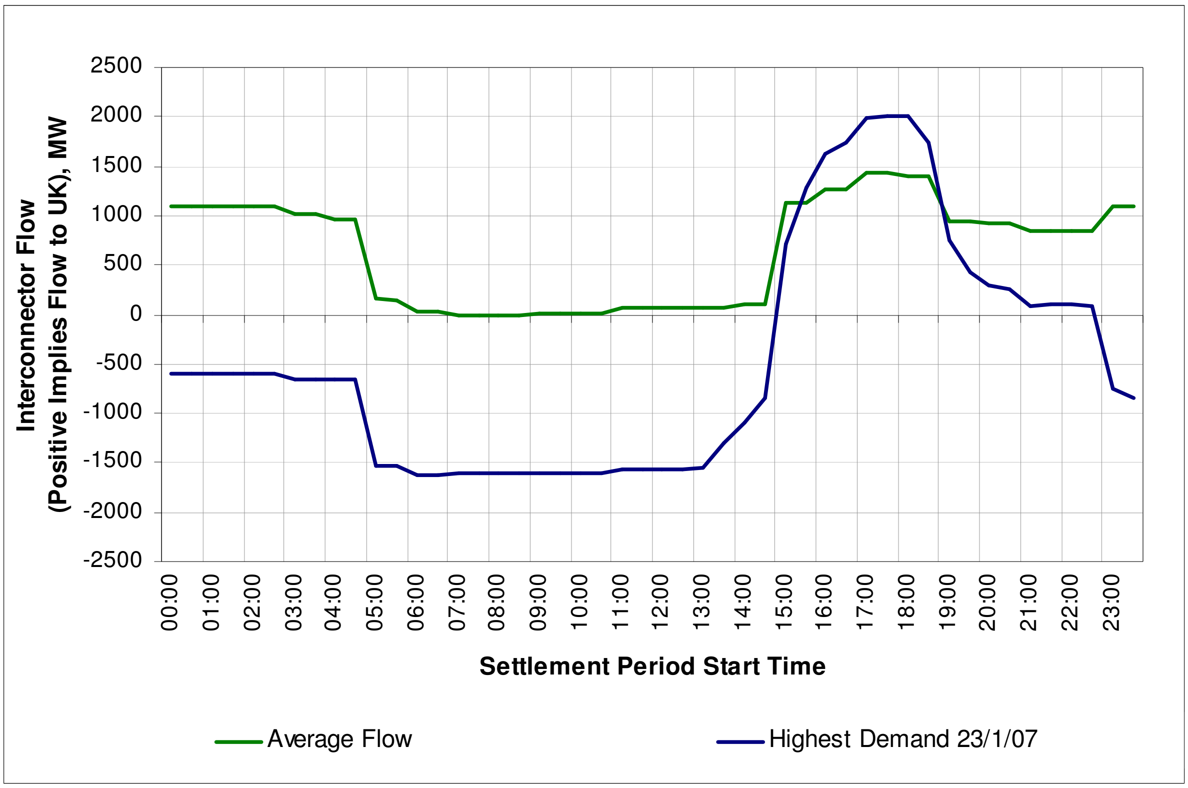
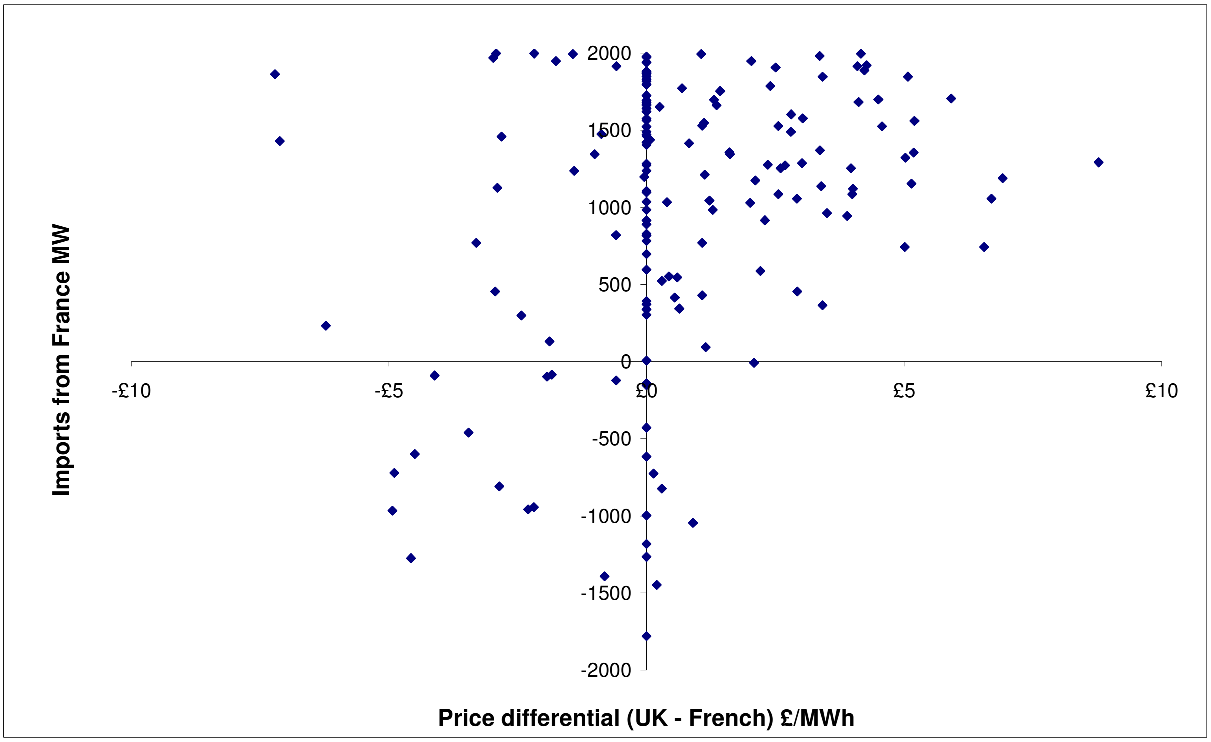


Figure 31 – UK-France Offpeak Flows and Price Differentials



Distillate Running

80. As a result of the low gas prices, we estimate there was less than 1 mcm equivalent of distillate use, compared with close to 100 mcm during 2006/7.

81. We will be writing to generators again this spring asking them to update us of their ability to run on distillate, consistent with the Grid Code obligation.

Section B – Outlook and Issues for 2007/8

Chapter 4: Gas

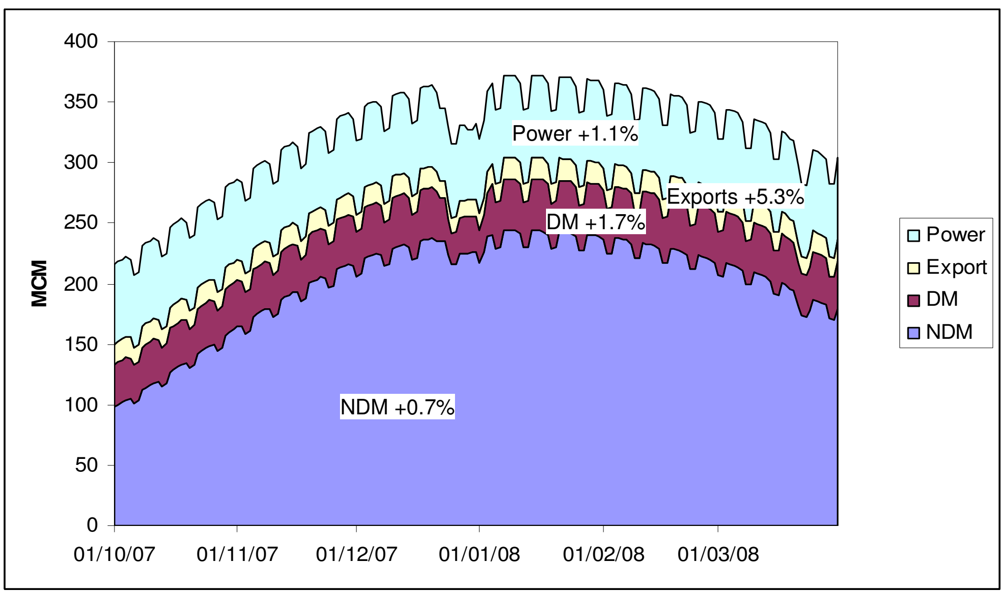
2007/8 Gas Demand

82. Figure 32 shows the underlying growth assumed in our 2006 forecast, as published in the 2006 Ten Year Statement, of around 1% between winters 2006/7 and 2007/8 split by market sector. We are presently updating our forecasts following receipt of information during the current Transporting Britain's Energy (TBE) consultation process.

83. However, if prices continue at their current levels below that assumed in our 2006 forecasts then we could expect further demand increases, notably in the power generation sector, i.e. with power demand potentially moving from the restricted to the unrestricted levels or even higher.

84. It should also be noted that the demand forecasts are not adjusted for potential interruption by National Grid or the other Distribution Network (DN) operators for capacity management purposes.

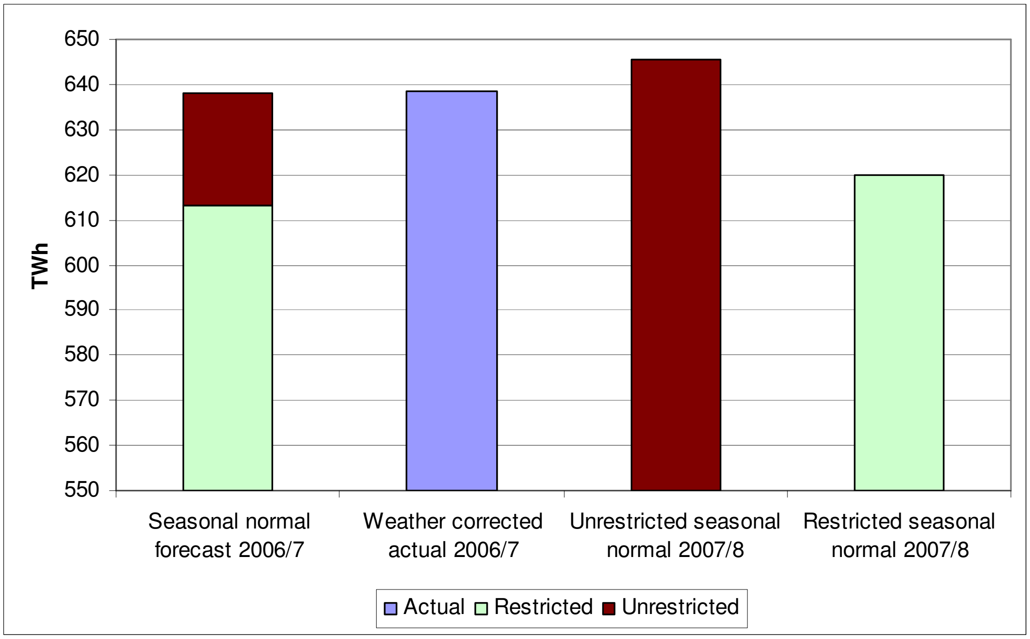
Figure 32 - 2007/8 Forecast Seasonal Demands[10]



85. Figure 33 compares the 2006 total forecast for 2006/7 and 2007/8 with the 2006/7 weather corrected actual. The 2007/8 unrestricted forecast shows 1% growth on the 2006/7 unrestricted forecast. The chart illustrates the uncertainty going forward with the restricted forecast for 2007/8 being 3% lower than the 2006/7 weather corrected actual gas demand while the unrestricted forecast is 1% higher.

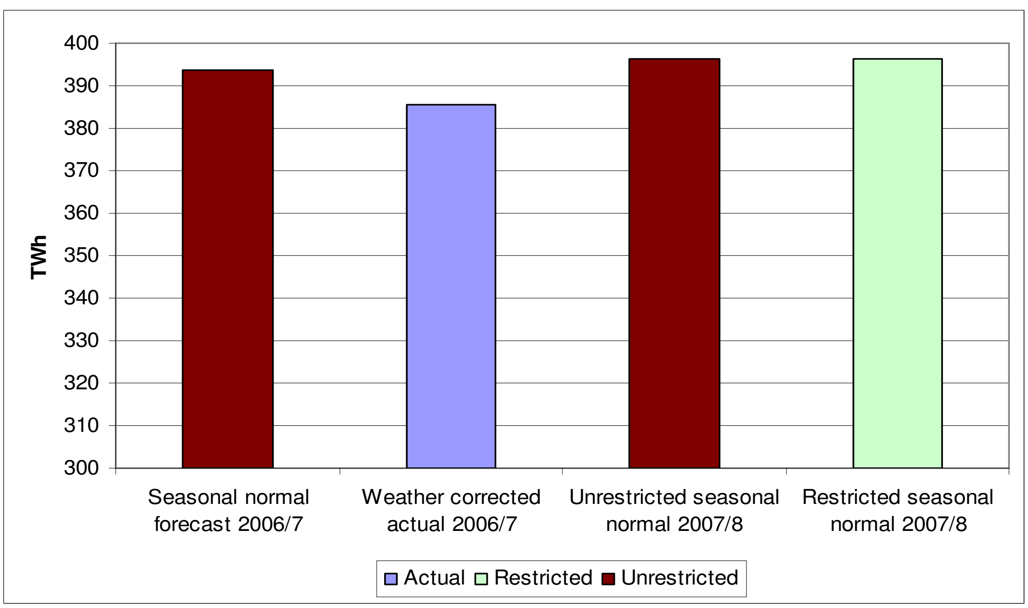
[10] Exports include flows from GB to Ireland, but not flows from GB to Belgium.

Figure 33 – Total Winter Demand



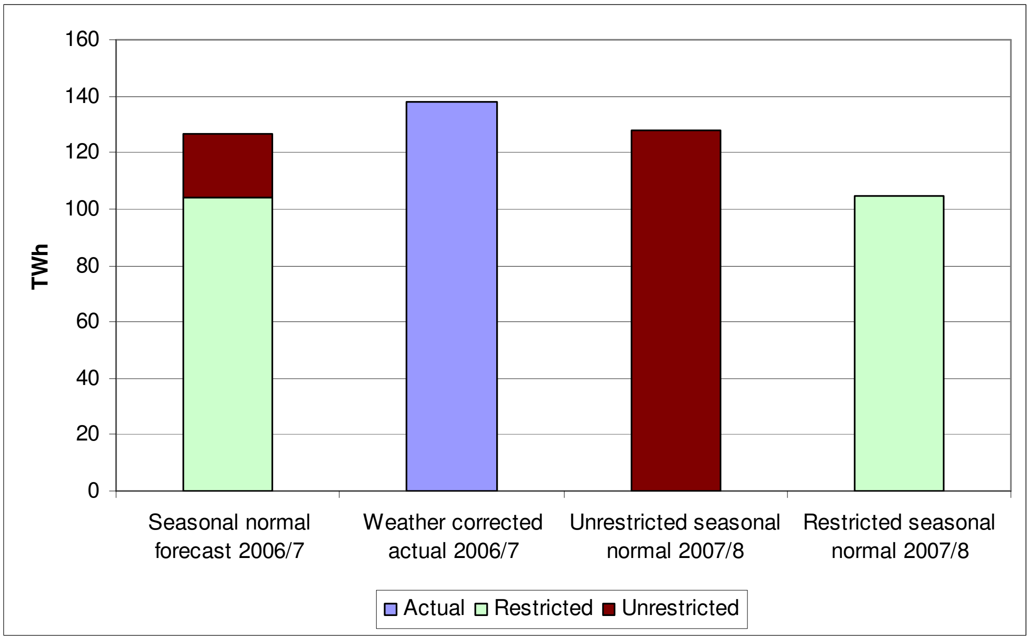
86. Figure 34 compares the 2006 NDM forecast for 2006/7 and 2007/8 with the 2006/7 weather corrected actual. There is no difference between the unrestricted and restricted forecasts for NDM demand because domestic customers are not exposed to spot prices. The 2007/8 forecast shows 0.7% growth on the 2006/7 forecast. However, the outturn for 2006/7 was 2% lower than forecast, thus questioning the growth rate of the 2007/8 forecast.

Figure 34 – NDM winter demand



87. Figure 35 compares the 2006 power generation forecast for 2006/7 and 2007/8 with the 2006/7 weather corrected actual. The 2007/8 forecast shows 1% growth on the 2006/7 forecast. However, the outturn for 2006/7 was 9% higher than the unrestricted forecast, thus highlighting the uncertainty of the 2007/8 forecast.

Figure 35 – Power Generation Winter Demand



Questions for consultation

Q11. How will domestic prices change from this winter to next and what impact will prices and energy efficiency considerations have on demand?

Q12. If prices fall, will lower prices lead to the return of demand lost due to changes in customer behaviour, for example thermostat settings?

Q13. 2006/7 saw lower wholesale prices than forecast and as a result higher power generation demand i.e. some positive demand response. To what extent will prices change over winter 2007/8 compared to 2006/7?

Q14. In developing our updated view for 2007/8 which basis should we assume going forward i.e. unrestricted (traditional demand profile) or restricted (high priced profile) or should we assume some other growth profile?

2007/8 Gas Supply

88. This section examines each of the potential (non-storage) gas supply sources in turn: UKCS and imports from Norway, the Continent and LNG. We set out the main factors associated with these supply sources and seek views on their respective prospects, in particular on how the performance of the various supply sources might vary across the winter months.

89. As there is considerable uncertainty in the level of imported supplies for next winter, our initial view is appreciably influenced by our experience last winter. This should not be seen as a best view at this stage but a means for industry engagement and consultation.

UKCS Gas Supplies

90. For the purposes of this document, our initial assessment of UKCS supplies for winter 2007/8 is based on our 2006 forecasts. These will be updated following receipt and aggregation of 2007 TBE information. Table 5 compares our forecasts of UKCS supplies for 2006/7 and our preliminary view for 2007/8.

Table 5 - Preliminary 2006/7 UKCS Maximum Forecast by Terminal

Peak (mcm/d)	2006/7		2007/8	Comments
	Base Case	Highest	Initial View	
Bacton	75	55	67	Flow from specific high swings fields not observed last winter
Barrow	24	25	23	
Easington	16	15	15	
Point of Ayr	2	4	2	Difference accounted for by local power station
St Fergus	94	95	89	
Teesside	30	35	28	Difference accounted for by local power station
Theddlethorpe	26	28	25	
Total	267	257	249	

91. Table 5 shows a preliminary UKCS maximum supply forecast of 249 mcm/d, following our TBE consultation, we will update this forecast when we publish the second consultation document.

92. The indicative 2007/8 maximum UKCS supply forecast incorporates a year-on-year decline of 28 mcm/d from existing fields. This is partially offset by our forecast of new developments of approximately 10 mcm/d. Hence our net reduction in UKCS supplies is 18 mcm/d, nearly 7% lower than for last year.

93. For the purposes of supply-demand analysis and for security planning, we assume a level of UKCS supply below the maximum forecast. For this purpose we intend to continue to use an availability of 90%, resulting in an UKCS forecast for next winter of 224 mcm/d

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

- Lower availability through poor weather conditions offshore;
- The late commissioning of new fields or delays in the resumption of production following maintenance outages, resulting in reduced supply availability early in the winter;

- Within-winter decline of existing fields resulting in reduced supply availability later in the winter;
- Limited production from high swing fields as observed this winter at Barrow and Bacton as detailed in Section A, Chapter 2.

Question for consultation:

Q15. What assumptions should be made over the maximum UKCS supply availability for 2007/8, and specifically:

Q15a What assumptions should be made over the maximum UKCS supply availability from existing fields?

Q15b. What assumption should be made over the commissioning of new UKCS developments?

Q16. Should we plan for a lower level of UKCS on the basis that high swing fields may not flow and consequently consider such fields on a comparable basis to storage facilities?

Norwegian Imports

95. Last winter we observed high Norwegian imports through Langeled and Vesterled. Next winter will see the start-up of the Ormen Lange supplies that could further increase Norwegian imports. There is also the possibility of additional Norwegian imports through the Tampen Link. This 32 inch, 23 km pipeline scheduled to be completed this summer will connect the Norwegian Statfjord field with the FLAGS pipeline to St Fergus. Initial volumes through this link are anticipated to be modest, however there is scope to deliver much higher volumes to essentially fill FLAGS at a later date.

96. Whilst the commencement of Ormen Lange should increase Norwegian imports to the UK, there are also downside risks, for example the possibility of commissioning delays to Ormen Lange or that the Continent may take higher levels of Norwegian supplies than experienced last winter.

97. In terms of NTS investment, the Pannel to Nether Kellet pipeline is planned to be operational from October 2007. This pipeline should enable the expected new gas flows at Aldbrough to be accommodated in addition to the baseline quantities at Easington and Hornsea. The transmission capability provided at Aldbrough, Easington and Hornsea are to a certain extent substitutable. On this basis it is possible that gas flow above the baseline at Easington could be accommodated when Aldbrough and Hornsea gas flows are reduced

98. To stimulate discussion and comment, our initial assumption for Norwegian imports next winter is 70 mcm/d, this is the same as the average flow experienced this winter.

Question for consultation:

Q17. What assumptions should be made for levels of imported gas from Norway for winter 2007/8 through Langeled and Vesterled?

Q18. Should we be making any allowance for additional Norwegian imports through the Tampen Link?

Continental Imports

99. Last winter, once commissioned we observed near uniform flows through BBL and flows through IUK that effectively responded to the UK's market need for gas, similar to a storage facility. For next winter there are planned capacity enhancements for both BBL and IUK. BBL's capacity is expected to increase to over 40 mcm/d and IUK to over 70 mcm/d.

100. With capacity enhancements to the Dutch network there is for next winter the possibility of higher BBL imports, however there is also the possibility that the observed near uniform flow conditions for last winter, believed to be contractual could possibly change resulting in flows that could be more sensitive to the UK's market needs. Therefore to stimulate discussion and comment, our initial assumption for BBL imports next winter is a flat 25 mcm/d, typical of the flow experienced this winter.

101. For IUK we are not aware of capacity enhancements to the Belgium and interconnecting networks. Whilst we observed IUK imports approaching 40 mcm/d these as shown in Figure 15 were never on a sustained basis and only when the UK market sought additional supplies above those supplied by UKCS, Norway, BBL and Grain LNG. Consequently, we believe that the IUK will again next winter be a marginal source of supply when UKCS and other imports can not meet UK demand. We also believe that it remains prudent to consider lower IUK supply availability up to December due to uncertainties over the release of Continental storage that may be held back for Continental markets. Therefore to stimulate discussion and comment, our initial assumption for IUK imports next winter is similar to the assumption we used last winter, with up to 30 mcm/d through to December and up to 40 mcm/d post December.

Questions for consultation:

Q19. What assumptions should be made for levels of imported gas through BBL for winter 2007/8, and specifically:

Q19a. Should we assume a uniform supply profile throughout the winter period?

Q20. What assumptions should be made for levels of imported gas through IUK for winter 2007/8, and specifically:

Q20a. Should we assume that the IUK will operate as a marginal source of supply when UKCS and other imports can not meet UK demand?

Q20b. Should we assume that the availability of gas through IUK will increase as the certainty regarding the availability of Continental storage to meet the remainder of the winter improves?

LNG Imports

102. Last winter we observed regular LNG deliveries to Grain and the unloading of part of a cargo at Teesside for commissioning purposes. For next winter we have the prospect of additional deliveries through Milford Haven through two new terminals; South Hook and Dragon.

103. South Hook is believed to be commissioning in Q1 2008, the capacity for Phase 1 is 10.5 bcm/year equivalent to a base load deliverability of 29 mcm/d.

104. Dragon is believed to be commissioning in Q4 2007, the capacity for Phase 1 is 6 bcm/year equivalent to a base load deliverability of 16 mcm/d.

105. Both facilities will be capable at times of exceeding these base load deliverabilities.

106. Through our Long Term System Entry Capacity (LTSEC) auctions we have released for Q4 2007 452 GWh/d (~41 mcm/d) capacity, this increases in Q1 2008 to 650 GWh/d (~60 mcm/d). To meet this capacity we are extending and reinforcing the NTS. The current position of our construction programme is:

    - DTI gave consent in December 2005 for the construction of a pipeline from Milford Haven to Aberdulais, this pipeline which will establish the connection between the terminals and the NTS is 90% complete and remains on track for operation from October 2007
      DTI gave consent in November 2006 for construction of a compressor at Felindre and in February 2007 for the Felindre to Tirley reinforcement pipeline
    - Work has commenced on both of these construction activities with the objective of delivering the pipeline in autumn of 2007 and the compressor in 2008.

107. Besides the uncertainty over when the Milford Haven LNG facilities will be commissioned, there is market uncertainty over whether the UK will attract LNG next winter in preference to alternative markets, notably the US where current forward gas prices are higher through to next winter and broadly similar for the key winter months.

108. To stimulate discussion and comment, our initial assumption for LNG imports next winter is 33 mcm/d through to December and 53 mcm/d post December. This assumes flows of 13 mcm/d for Grain and Teesside and 20 mcm/d for each of the Milford Haven facilities.

Questions for consultation:

Q21. What assumptions should be made for levels of imported LNG through Grain, Teesside and Milford Haven for winter 2007/8?

Storage

109. During next winter we expect the Aldbrough storage facility to become operational, though we are not expecting design flow rates until 2008/9 or 2009/10. Storage space at Hole House Farm is also expected to increase.

110. Table 6 shows our assumed levels of storage space and deliverability for next winter.

Table 6 – Assumed 2007/8 storage capacities and deliverability levels

	Space (GWh)	Deliverability (GWh/d)	Deliverability (mcm/d)	Days at full rate
Short (LNG)	1943	526	49	3.7
Medium (MRS)	9553	485	45	19.7
Long (Rough)	34126	455	42	75

Questions for consultation:

Q22.We would welcome views on our assumed levels of storage space and deliverability?

Q23. We would welcome views on the extra storage space that could be made available through storage cycling?

Preliminary 2007/8 Initial View

111. In the previous sub-sections we have outlined the basis for the assumptions incorporated into our analysis. Table 7 summarises the supply forecasts, and compares these with the 2006/7 Base Case: We should stress that these 2007/8 forecasts should not be regarded as a National Grid view. They are illustrative and for the purpose of fostering discussion and comment.

Table 7 – Non Storage Supply Forecasts for 2007/8 Initial View

(mcm/d)	2006/7 Base Case			2007/8 Initial View		
	Oct - Dec	Jan - Mar	Average	Oct - Dec	Jan - Mar	Average
UKCS	240	240	240	224	224	224
Norway	48	48	48	70	70	70
Continent	25	60	49	55	65	62
LNG Imports	13	13	13	33	53	46
Total	326	361	350	382	412	402

112. Based on the supply assumptions detailed in the previous supply sections, Table 7 suggests that the non-storage supply availability for next winter could be approximately 50 mcm/d higher than for last winter. As this level of supply will exceed the level of demand on most days within the winter, it is reasonable to expect major variations in the supply pattern, and at various levels of demand, specific supplies becoming the marginal source of supply.

Questions for consultation:

Q24. We would welcome views on our 2007/8 Initial View, and specifically:

Q24a. Whether it is plausible that the supply availability could be so much higher than for last winter?

Q24b. If the supply position does improve as suggested, what will become the order of supplies at lower levels of demand?

Chapter 5: Electricity

Electricity Demand Levels for 2007/8

113. On a weather-corrected basis, the ACS peak demand for 2006/7 was 60.8 GW. This is 0.5 GW lower than the comparable figure for 2005/06. Likely causes include increased demand management due to high end-user electricity prices, increased embedded renewable generation, and continued energy efficiency. Pending further investigation of the causes of this demand reduction, we have assumed no growth between 2006/7 and 2007/8.

114. The 2007/8 ACS forecast is therefore 60.8 GW, which includes 0.3 GW flow to Northern Ireland and is after 1.0 GW of triad avoidance demand management.

Questions for consultation:

Q25. We would welcome views on the reasons why the weather-corrected operationally metered generation fell during 2006/7 and whether demand might be expected to decline further, remain at current levels or resume its trend of growing at 1-1.5% pa?

Q26. We would welcome views on the extent to which electricity demand response at peak times might be expected to continue.

Notified Generation Availability

115. The quoted plant margin for winter 2007/8 currently reported in the January 2007 update to the 2006/7 Seven Year Statement (SYS)[11] is around 23%, based on a Transmission Entry Capacity (TEC) contracted generation capacity of 78.5 GW.

116. The SYS update figures reflect the closure of 2 Magnox stations, Dungeness A (0.4 GW) & Sizewell A (0.4 GW), at end of 2006. Though no further station closures are anticipated, British Energy has announced reduced nuclear output at Hinkley Point and Hunterston during 2007/8, which represents a loss of 0.8 GW. All other capacity available during 2006/7 is expected to be available during 2007/8.

117. However though Langage (0.85 GW) & Pembroke (0.8 GW) have contracted for TEC for 2007/8, they are not due to commission in 2007/8. 0.7 GW of renewable generation in Scotland is expected to commission prior to winter 2007/8.

118. The latest view of TEC capacity available for 2007/8 is therefore 76 GW.

119. Reflecting the low outturn demand for 2006/7 and the latest internal demand forecast of no growth, the latest internal forecast of ACS demand on a SYS unrestricted basis is 61.2 GW, excluding station load. The latest view of plant margin is therefore 24%.

120. Wind is increasing its share of the GB generation market, and there will be nearly 2 GW of installed capacity by winter 2006/7. As detailed in Section A, Chapter 3, our experience of wind generation is that over the winter it tends to generate at around

[11] 2006 Great Britain Seven Year Statement Update (Jan 2007) http://www.nationalgrid.com/uk/library/documents/sys05/mysys/updates/quarter4.pdf update

35% of its maximum output. The capacity figure assuming a wind output loadfactor of 35% is 74.8 GW, which gives a plant margin of 22%.

121. This headline plant margin as quoted in the SYS is a useful, broad indicator of the amount of generating plant on the system for the winter. 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.

122. Our current operational view of generation capacity anticipated to be available for winter 2007/8 is 75.5 GW. A broad breakdown of this capacity is shown in Figure 36.

123. The generating companies provided us in 2006 with a list of mothballed plant, together with an estimate of the time that the plant would take to return to service from a decision being made to return. Reflecting this information and the continued availability of previously short-term mothballed plant, there is no plant that could return within 3-6 months. However, as summarised in Table 8, 1 GW remains long-term mothballed, and continues not to have TEC. It is considered unlikely that this 1 GW of long-term mothballed plant would make itself available for winter 2007/8.

124. We will be writing to generators again this spring, asking them to update us of their ability to return mothballed plant to service.

Figure 36 – Generation Capacity, Winter 2007/8

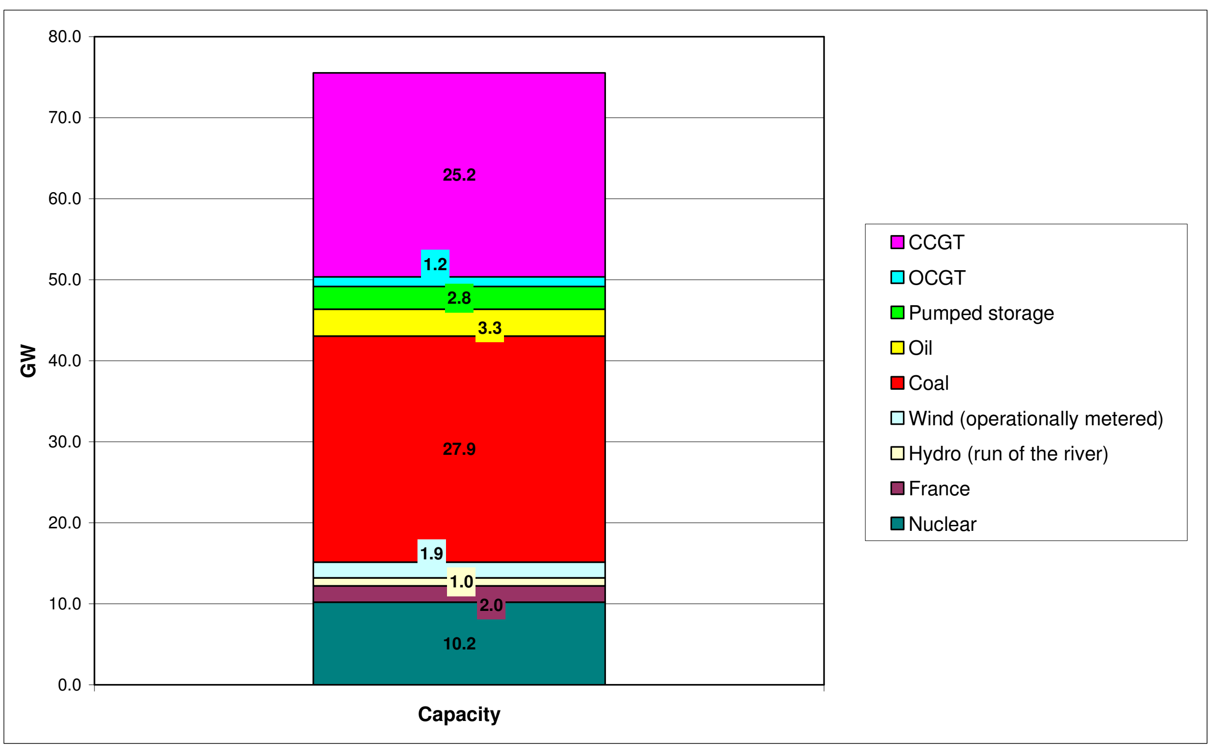


Table 8 – Mothballed Capacity, winter 2007/8

	Could Return within 3-6 months	Long Term Unavailable Plant
Generation capable of being returned within period (GW)	0	1

Questions for consultation:

Q27. What assumptions should be made to the extent to which generation will continue to available, i.e. will any plant currently available subsequently be mothballed for winter 2007/8?

Q28. To what extent is there scope for return long-term mothballed plant to service prior to the 2007/8 winter?

Contracted Reserve

125. In order to achieve a demand-supply balance, National Grid procures services from either generation or demand side providers to be able to deal with actual demand being greater than forecast demand and plant breakdowns. This requirement is met from both synchronised and non-synchronised sources. We procure the non-synchronised requirement from a range of service providers including Balancing Mechanism (BM) participants, non-BM generating plant and demand reduction.

126. Following extensive consultation with the industry, we have recently completed a review of the way in which this requirement for reserve is procured. Two key changes have resulted from this review:

- a revised BM Start-Up service to ensure that, if necessary, we are able to access all generation regardless of its fuel within the required timescale in the Balancing Mechanism
- the introduction of a revised product for Short Term Operating Reserve (STOR). STOR is procured by a tender process which is run three times per year.

127. STOR has enabled greater participation in the provision of reserve, particularly from the demand-side. Through consultation with the demand-side working group and engagement with potential providers to tailor the service to meet their specific technical requirements, STOR has facilitated market access for more participants. For winter 2007/08, we have already procured an additional 130 MW of reserve from new demand-side service providers.

128. For winter 2007/8, the current total level of contracted STOR reserve is 1.7 GW, 1.4 GW from generation in the BM and 0.4 GW from demand-side providers.

129. National Grid will implement prior to the winter two further STOR tender rounds in June and August 2007 covering services for the winter 2007/8 darkness peak.

Communications regarding this will be through electricity operational fora and on our website.

130. There is a continual requirement to provide frequency response on the system. This can either be contracted ahead of time or created on synchronised sources within the BM. There is around 1.4 GW of reserve which is typically required to create response over the winter demand peak. 0.85 GW has been contracted already, 0.3 GW within the BM and 0.55 GW with demand-side providers.

131. National Grid continues to have Maximum Generation contracts in place for winter 2007/8, which provide potential access to 1 GW of extra generation in emergency situations. However, this is a non-firm emergency service and would only be used to avoid demand control. Given that it is non-firm and that generation operating under these conditions normally has a significantly reduced reactive power capability (which in turn can have a significant impact on transmission system security), it is not included in any of our margin analysis. This service was available pre-NETA and similarly was never included in margin analysis.

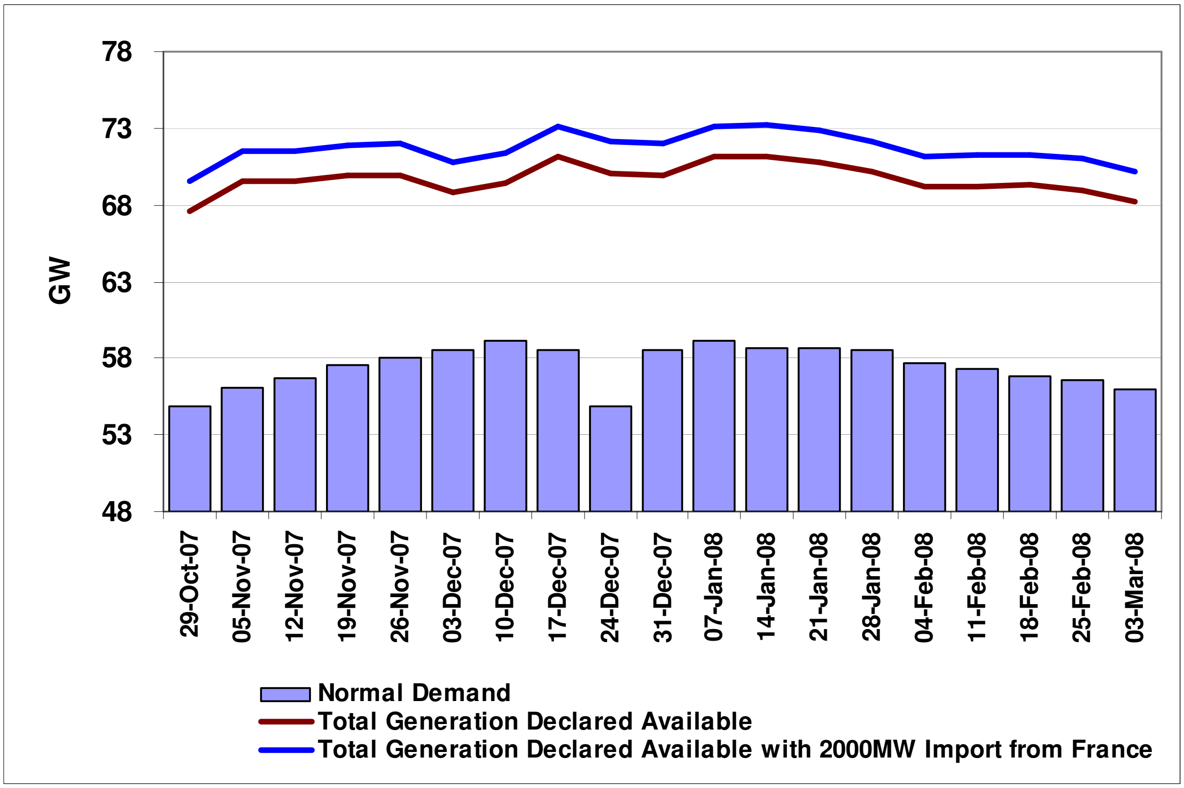
Forecast Position for Winter 2007/8

132. Figure 37 shows the normal demand forecasts, 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 UK-France Interconnector.

133. Figure 37 illustrates a winter in which average weather conditions are experienced each week, resulting in average temperatures across the winter of 7 ^{o}C. It shows weekly forecast generation availability as declared by the generators under the Grid Code. This reflects planned unavailability, but does not include an allowance for unplanned generator availability.

134. As can be seen in Figure 37, with full exports from France the excess generation over average weekly peak demand would be around 12-15 GW. However, Figure 37 does not reflect the fact that even in an average winter there will be times when demand is above normal and approaches or exceeds ACS levels.

Figure 37 – Demand and Notified Generator Availability, Winter 2007/8



135. 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 in Figure 33 above. The margin shown in Figure 37 does not reflect this requirement.

Scenario for Modelling Purposes

136. Based upon historic availability patterns, as detailed in Section A, Chapter 3, we have assumed generator availability rates as detailed in Table 9. The full 2 GW of capacity across the UK-France Interconnector at peak times has been assumed.

137. We have assumed that no plant is short-term mothballed for this forthcoming winter. This seems reasonable as the same behaviour exhibited itself in winter 2006/7. No return of long-term mothballed plant has been assumed. Overall, we assume a 86% availability rate across the winter.

138. This scenario is used to illustrate the ability of the electricity sector to meet demand under average (typical) and 1 in 50 weather conditions, and to provide gas demand side response as detailed further in Section C, Chapter 5.

Table 9 – Assumed Plant Availability

Power Station Type	Full Capacity (GW)	Assumed Availability	Assumed Availability (GW)
Nuclear	10.2	80%	8.2
French Interconnector	2.0	100%	2.0
Hydro generation	1.0	60%	0.6
Wind generation	1.9	35%	0.7
Coal	27.9	85%	23.7
Oil	3.3	95%	3.1
Pumped storage	2.8	100%	2.8
OCGT	1.2	95%	1.1
CCGT	25.2	90%	22.7
Total	75.5		64.9
Average availability		86%	

139. For the purpose of this scenario, a typical historic rate of 86% average power station availability has been assumed, and the week-by-week profile of unavailability has been smoothed across the winter as a whole.

Questions for consultation:

Q29. What assumptions should be made over the availability of different classes of generating plant, and in particular nuclear plant?

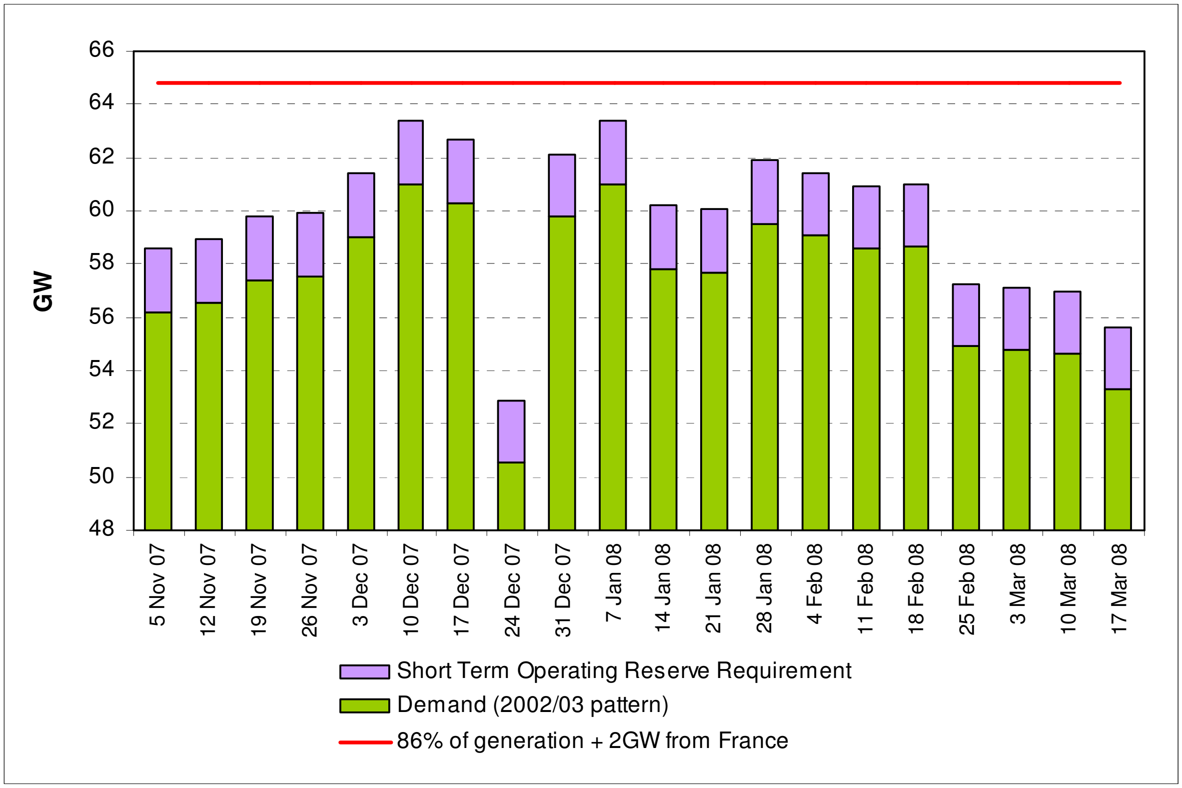
Q30. What assumptions should be made over the level and direction of flow on the UK-France Interconnector given cold weather in both UK and Europe?

Average Winter Conditions

140. To illustrate a typical winter, demand has been forecast by assuming the weather pattern of 2002/3. This is a good representation of a typical winter, with a forecast peak winter demand of around 60.8 GW and a normal pattern of high demand spells occurring in December and January.

141. As illustrated in Figure 38, under average winter conditions, there should be more than sufficient plant to meet demand. Under these average weather conditions, there would be scope for the electricity sector to reduce gas demand and provide a material level of demand-side response for the gas sector.

Figure 38 – Forecast Demand under Average Weather Conditions (2002/03 Weather Pattern) and Generator Availability, Winter 2007/8

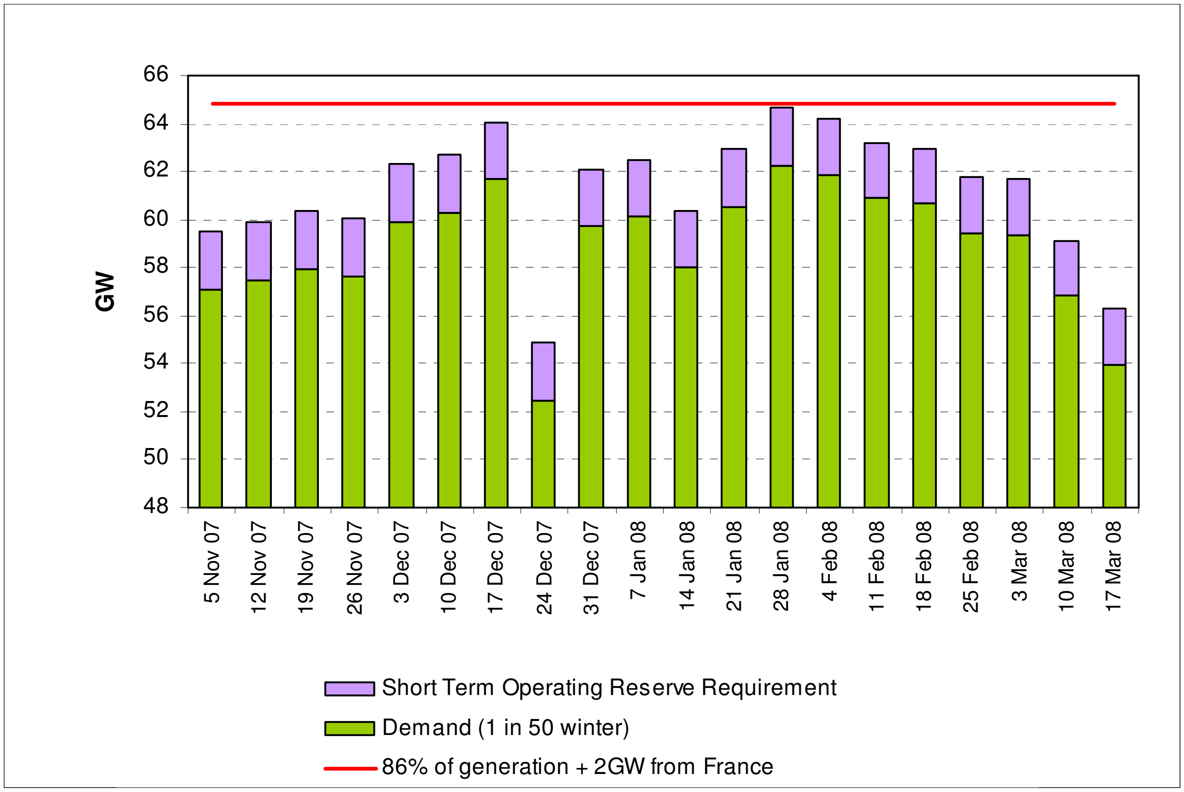


1 in 50 Cold Winter Conditions

142. In 1 in 50 cold winter conditions, where average temperatures across the country would be -2 ° C for 30 days and +2 ℃ for 60 days, peak demand may increase in the order of 2 GW above ACS demand. The weather pattern experienced in 1946/47 is representative of such a 1 in 50 winter, although we have no recent experience of how demand would respond to these extreme temperatures.

143. If these weather patterns were to occur this winter, as illustrated in Figure 39, the anticipated electricity margin would be sufficient provided we do not experience high levels of plant breakdowns or CCGT unavailability in response to high gas prices.

Figure 39 – Forecast Demand under 1 in 50 Weather Conditions (1946/47 Weather Pattern) and Generator Availability, Winter 2007/8



Chapter 6: Gas/Electricity Interactions

144. This Chapter describes our analysis of the potential gas demand response available from the power sector. Gas-fired power stations can be expected to respond to market price signals, decreasing their gas consumption when the cost of generating from other fuels is lower than the price of burning gas. This ability to arbitrage between gas and power is not restricted to those power stations that have interruptible gas transportation arrangements. For example, in the 2005/06 winter, there were occasions when firm CCGTs commercially self-interrupted whilst interruptible power stations continued to generate.

145. The willingness of the CCGTs to commercially interrupt themselves will be determined by a number of factors, including: the spark spread, which is itself influenced by the ability of the power generation sector to meet demand through switching to other fuels; the price of CO_2 emission allowances; the price of alternative fuels; and any environmental constraints (e.g. SO_2) that limit the extent of running on other fossil fuels.

Power Generation Gas Demand and Distillate Back-up

146. The maximum theoretical power generation gas demand in GB for winter 2007/8 is shown in Table 10. These figures are based on contractual limits. They include power stations that could source their gas supply from the NTS but are predominately supplied directly. The duel-fuelled Peterhead station is included within these numbers. Figures exclude smaller embedded power generators, typically Combined Heat and Power stations, which do not participate in the Balancing Mechanism.

Table 10 – Maximum 2007/8 GB Power Generation Demand

	Maximum Gas Demand (mcm/d)	CCGT Capacity (GW)
NTS-connected	117.3	24.0
LDZ-connected	5.5	1.1
Total	122.8	25.2

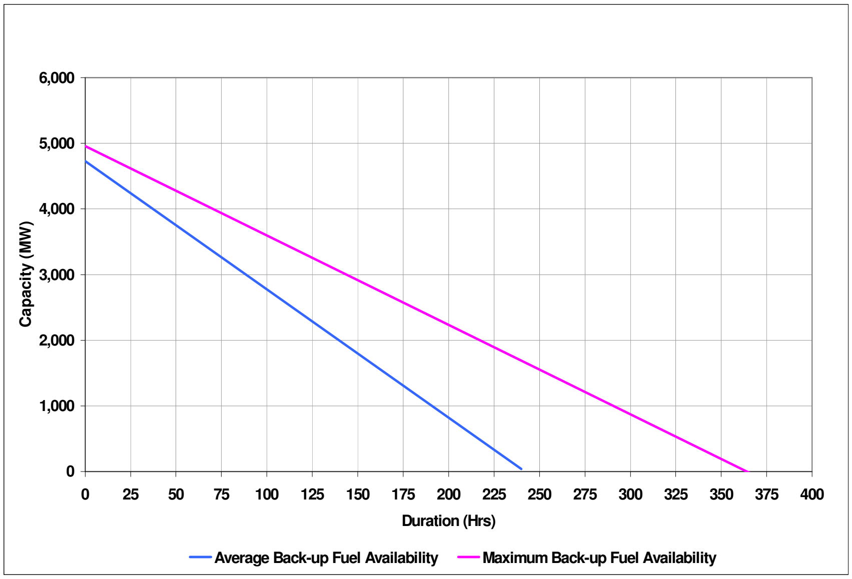
147. Daily consumption from CCGTs started the winter 2006/7 at around 90 mcm/d but by mid-November significant demand response had occurred reducing typical CCGT demand by approximately 20 mcm/d for the rest of the winter until January. From mid January as gas prices fell, the consumption from CCGTs showed an upward trend, returning to a peak of 90 mcm/d. The minimum CCGT demand on a mid-winter business day was around 45 mcm/d.

148. In electricity generation terms, CCGTs are expected to provide a maximum of 25.2 GW of generating capacity in GB for the coming winter. Of this, 3.1 GW have access to gas through non-NTS pipelines.

149. Under the terms of the Grid Code, the generating companies are required to provide us with information on their capacity to generate using back up fuel. Pending the update to this information in spring 2007, we continue to assume 4.8 GW have the capability to run on distillate

150. Figure 40 summarises our latest information in load duration curve form, showing the decay of generation capacity available from distillate with time. The data has been aggregated and smoothed to protect the commercial positions of the individual plants. The two lines show the available generation from starting points of average fuel stocks and maximum fuel stocks.

Figure 40 – Load Duration Curves for Back Up Fuel Supplies



Analysis of Potential CCGT Demand Response - Modelling Assumptions

151. A number of respondents have previously identified practical issues that could limit the extent of any CCGT response. Issues raised included:

- Technical risks associated with frequent switching to/from and prolonged use of distillate
- Potential limits on the extent to which fuel stocks can be replenished
- Limitations on the levels of switching to coal and oil as a result of environmental constraints.

152. In winter 2006/7, there was an estimated level, as reported in Chapter 3, of only 1 mcm equivalent of distillate use. Our modelling assumptions from the 2006/7 Winter Consultation Report assumed that a maximum of 200 hours of distillate use was possible; this is equivalent to around 200 mcm. Given winter 2006/7 was very mild and the gas prices were relatively low, we have not altered the assumption of 200 hours or 200 mcm at this stage. We have also maintained the assumption that distillate running would be for a maximum of 12 hours a day during weekdays.

153. Though in winter 2006/7, gas increasingly ran in merit and coal was increasingly was the marginal fuel, when assessing the potential for CCGT response under a tight gas demand-supply position, we have continued our assumption that gas operates as the marginal generation.

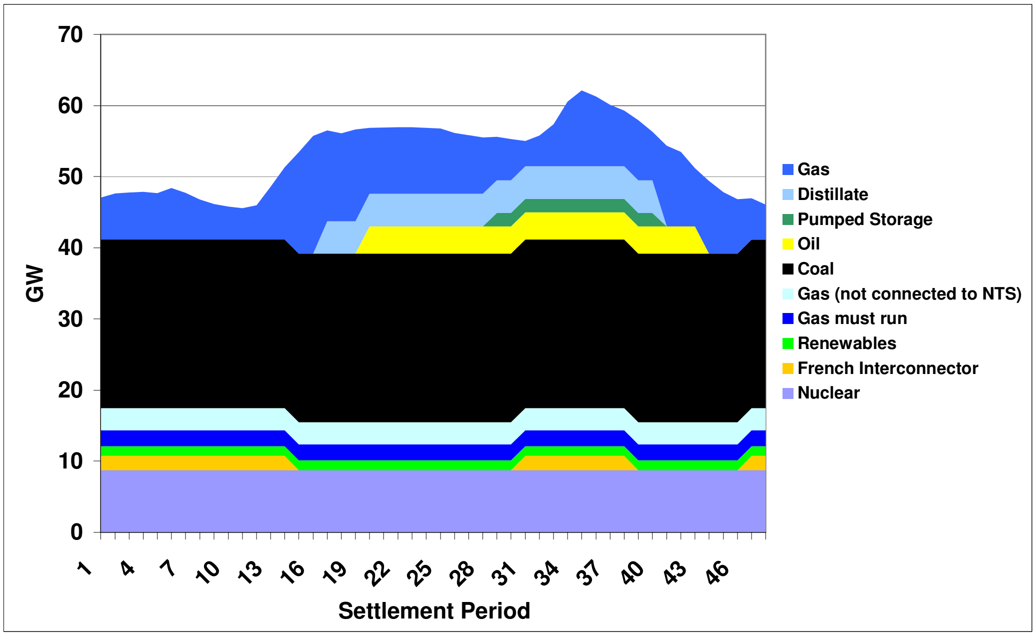
154. A full list of the most important preliminary modelling assumptions for winter 2007/8 is as follows:

- Plant capacity and availability factors are as detailed in Table 9 in Chapter 5, which gives an average availability rate of 86% across the winter
- Nuclear runs baseload – 24 hours a day, 7 days a week, at 80% availability
- Imports into GB through the French Interconnector are available continuously overnight and during the peak 4 hours at the full rate of 2 GW - at other times the link is at float
- 3.1 GW of CCGTs directly connected to offshore gas supplies (i.e. not necessarily supplied via the NTS) operate as baseload, thereby displacing other generation
- Around 1.6 GW of NTS-supplied CCGTs run as baseload, reflecting technical and contractual constraints such as the requirement to provide heat and power to industrial consumers. This has been reduced reflecting the winter 2006/7 experience
- No explicit constraints relating to fuel stocks, CO_2 or SO_2 emission limits, are applied to coal generation, but overall coal plant is assumed to operate at a maximum load-factor of only 85%
- Pumped storage stations generate only during the peak 6 hours of each day
- Oil stations generate only during the peak 12 hours of weekdays
- As several OCGT units have reserve obligations to National Grid, they are assumed to be low merit and run only very occasionally.

Analysis of Potential CCGT Demand Response

155. Figure 41 illustrates how electricity demand could be met on a typical cold day in a severe winter, consistent with the modelling assumptions described above. It shows approximately 24 GW of coal-fired generation throughout the day, gas as the marginal fuel for the bulk of the day and distillate used for 12 hours around the peak demand period. As explained above, total distillate usage across the winter has been constrained to 200 hours.

Figure 41 - Potential Generation Profile - Cold Winter Weekday



Questions for consultation:

Q31. We would welcome views on the ability of the electricity market to deliver in practice the level of CCGT response that our analysis suggests might be theoretically achievable in a severe winter, and in particular on:

Q31a. Our assumptions relating to the generation running order under cold weather conditions and the associated availability factors

Q31b. The extent to which relative market prices will signal the requirement for CCGTs to continue to burn gas at peak electricity demand periods

Q31c. The ability and willingness of CCGT generators to switch to distillate

Q31d. Whether and for how long CCGTs could generate on distillate back-up and any restrictions to the replenishment of distillate stocks

Q31e. The ability and willingness of the market to replace gas-fired generation by coal and oil fired generation

Q31f. The extent to which increased levels of fossil fuel generation could be used to displace gas-fired generation throughout a cold winter, including considerations of reliability, environmental constraints, carbon emissions and fuel stocks

Q31g. How the level of CCGT response may compare with that experienced in 2006/7?

Chapter 6: Industry Framework Developments

156. 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.

Gas Entry Capacity Transfers and Trading

157. National Grid is obliged to make available for sale entry capacity at the "baseline" quantity at each entry point in accordance with its GT licence. These baseline quantities have historically been fixed for a price control period, thereby providing certainty to Users of the available capacity amounts. However such an approach does not allow the flexibility for unsold amounts to be reallocated to where Users value it most once the baselines have been set at the start of a price control. Consistent with Ofgem's final proposals for the Transmission Price Control Review, National Grid is therefore developing arrangements by which Users may seek to transfer unsold capacity from one entry point to another. If such arrangements are implemented, then Users will need to consider bidding for unsold baseline amounts before such amounts are made available to Users at other entry points. National Grid is also developing arrangements to facilitate the transfer of sold capacity between entry points such that once a User has purchased entry capacity it may seek to move it elsewhere, consistent with any potential changes in its intended location of gas supplies.

Baseline Capacity Substitutions

158. Consistent with Ofgem's final proposals for the Transmission Price Control Review, National Grid is developing arrangements by which it may substitute unsold baseline capacity between entry points to avoid or minimise NTS investments required to meet incremental signals provided through long term entry auctions. This means that if baseline amounts are not purchased in the long term auctions, they may be used to meet requirements elsewhere and hence might not be available in subsequent annual and daily auctions. Users need to consider such changes in developing their bidding strategies for future auctions. National Grid will be consulting on such new substitution methodologies ahead of the next long term auctions scheduled for September 2007.

Gas Emergency Cashout Arrangements

159. The GB gas regime is becoming increasingly reliant upon non UKCS sources of supply. Ofgem recently chaired a series of workshops, under the heading of "Options for the design of gas emergency arrangements" which considered amongst other things how the UK's ability to draw upon or attract additional gas resources into the GB network throughout an Emergency event (Stage 2 and higher) might be enhanced.

160. Following these workshops we have further discussed and explored the issues with Ofgem, APX Ltd and Shippers and we anticipate that we shall continue to work with

these parties to develop the arrangements needed to reflect the changing gas supply patterns to the GB network.

Gas Market Information Provision

161. National Grid is continually seeking to improve the quality and reliability of its information provision. Significant improvements have been made over the past 2 years, and for winter 2006/7 we worked with Ofgem and the industry to enhance the quality of information that is available to the market to further promote industry participant response to the gas supply/demand position. Of particular note is the introduction of the quality of information incentives which have been placed on National Grid to improve the timeliness and accuracy of the information being made available to the gas market, and the introduction of longer term demand forecasts. The range of information provided, and the performance in doing so, is widely acknowledged as being class leading amongst gas transporters worldwide. Throughout 2007 we intend to work with the industry in reviewing the information that we currently publish and identifying any duplicated and/or obsolete data as well as any potential gaps in the data provision. In addition we intend to respond to user requirements by making the access to key data more intuitive, user friendly and reliable.

Electricity Cash Out Review

162. Ofgem is undertaking a review of the electricity imbalance price arrangements to assess the appropriateness and effectiveness of the current methodology. National Grid is fully committed to participating in this review and is actively engaged in supporting the review in order to achieve an outcome that best facilitates the effective and efficient operation of the electricity market If this review identifies the need to revise any of the current arrangements, then it is expected that, predominantly, this will be accomplished through proposals to change the methodology in the Balancing & Settlement Code (BSC).

Access to the Transmission System – CAP131, CAP142, CAP143 and CAP144

163. CAP131 proposes that the cost-reflective liabilities that new generators currently face prior to the completion of the transmission reinforcement works required to connect them are replaced with a generic user commitment. The generic user commitment is staged with a User Commitment Amount of £1/kW (increasing to £2/kW then £3/kW) required on connection offer acceptance and a Cancellation Charge based on a multiple of the relevant TNUoS charge required following a defined Trigger Date. CAP131 also proposes that the notice period required from an existing generator prior to a reduction in capacity is increased from 5 days to 2 years. CAP131 is currently out for industry consultation.

164. CAP142 provides the ability for two power stations to trade access rights to the Transmission System for variable periods of time between four and forty-two weeks in duration, within the same Financial Year. Such trades would be subject to an exchange rate, which would be determined by National Grid, and would describe the equivalence of network capacity in different locations. This arrangement is anticipated to provide an alternative route to market when existing short-term access

products i.e. STTEC and LDTEC are not available. CAP142 is currently out for industry consultation.

165. CAP143 proposes that a new access product, Interim TEC (ITEC), is introduced. A holder of ITEC would be able to connect to and use the transmission system in advance of the completion of the wider transmission reinforcements required. The associated impact of ITEC would be managed by limiting its availability to those that meet a set of pre-qualifiers, and including a number of hours for which the ITEC holders are required to declare down at no cost. CAP143 is currently being developed by a CUSC Working Group.

166. CAP144 proposes to extend the provisions introduced by CAP048 (Firm Access and Temporary Physical Disconnection) to include the specific circumstances when a Generator is exporting but is required to disconnect from the Transmission System in an emergency via an Emergency Instruction (EI) issued by National Grid in Balancing Mechanism timescales in accordance with the Grid Code. CAP144 is currently being developed by a Working Group.

Market Information – Demand Forecast

167. In November 2006, National Grid sponsored an industry workshop to discuss electricity demand forecasts. The aim of the workshop was to improve market understanding of National Grid's demand forecasts and to gauge industry views on the use of this information within individual organisations. The presentations by both National Grid and market participants and the subsequent discussions led by market participants provided useful insights into current demand forecast processes and how the current demand forecast information was used by the market participants. The workshop concluded that such meetings should take place on a regular basis in order to improve market understanding of the demand forecast processes and to share industry's experience of using such information.

Balancing Services

168. National Grid has introduced the BM Start-Up service (replacing Warming and Hot Standby service) which allows National Grid to access MW from BM Units that would not otherwise have run, and are unable to start-up within BM timescales on the day. This service provides greater flexibility and certainty to the market participants in that it allows the generators to submit different availability rates (depending on start-up times) and ensures that the market participants will be paid the availability fees regardless of whether the unit proceeds to synchronisation. The costs incurred in creating the additional reserve availability are allocated to the periods where the requirement exists and this ensures improved cost-reflectivity. Furthermore, the reserve creation costs feed into the imbalance prices (via the BPA - Buy Price Adjustment) which ensures improved pricing signals to the market. The market information associated with the utilisation of the BM Start-Up service (e.g. requirement periods and indicative costs) is published on National Grid's SONAR website

169. National Grid has revised the weighting factors for within day allocation of Standing Reserve and Supplemental Standing Reserve option fees. The revised weighting factors better reflect the recent historical utilisation of reserve. This change has

ensured that a more representative value of the BSAD variable BPA will feed into the cashout prices and hence will improve the pricing signals to the market.

170. National Grid has established a single service “Short Term Operating Reserve” (STOR) to replace the existing Standing Reserve and Supplemental Standing Reserve service. This change aims to improve the clarity, consistency and efficiency of the seasonal reserve procurement arrangements.

171. National Grid has proposed to update the STOR weighting factors for allocation of STOR options costs on a regular basis. The proposed change intends to incorporate an agreed calculation methodology for the weighting factors within the BSAD Methodology Statement, and to publish the STOR weighting factors on National Grid’s website. This change is awaiting Ofgem decision.