National Grid Transco

Winter Outlook Report – 2004/05

Introduction

1. This report provides a review of the 2003/04 winter and an overview of the coming winter, covering both electricity and gas transmission systems. It updates the preliminary report published in May 2004.

2. The operation of the electricity transmission network is undertaken under the National Grid Company Electricity Transmission licence and the gas transmission network under the Transco Gas Transporter licence. For the purpose of this report "NGT" is used to cover both licensed entities, whereas in practice our activities and the sharing of information are governed by the respective licences.

3. We report on a wide range of scenarios, including some low probability extreme conditions, which we are required to consider under the established standards for severe winter planning.

4. We have reflected the latest information available to NGT from the gas and electricity industries on beach gas availability, likely future demand levels, developments in the interruptible gas market and power station availability, but such information is as always subject to revision. As with all scenario modelling the results are subject to interpretation and NGT will continue to discuss its observations with Ofgem, the DTI and other industry participants.

5. The report is presented in four sections with the introduction and summary preceding the main body of the report. Section A contains a review of the winter 2003/4 outturn. Section B presents an overview of this coming winter. In Section C we consider electricity/gas interaction. Section D outlines ongoing discussions concerning the development of the commercial frameworks in both markets.

Summary

6. The Transco and National Grid networks have the physical capacity to meet the published transportation requirements of cold winters, due to:

   - High network availability.
   - Outage programme due to be completed.
   - High availability of gas compressor stations.
   - The benefit of continued high levels of investment in our networks.

7. In evaluating the gas supply/demand balance for this coming winter, we have considered the level of demand, which is highly influenced by weather, the availability of beach gas, interconnector capacity, potential market response and the potential use of storage:

   - Decline of UKCS gas supplies is occurring faster than previously forecast. A consolidation of industry data suggests a beach gas availability of 346 mcm/d for a sustained period over the coming winter. This represents a reduction of 38 mcm/d from that forecast in autumn 2003. We have discussed this assessment with the DTI and we understand that it is reasonably consistent with the DTI's view, although some offshore operators believe this to be optimistic.
   - Beach gas availability at these levels should be sufficient to meet the expected demand in average winter conditions.
   - If worse than average weather is experienced or there are significant supply difficulties, including lower than forecast beach supplies, then an effective demand-side market response will be required to maintain a supply/demand balance.
   - We are required to consider the effects of low probability extremely poor winter conditions, represented by a 1 in 50 expectation of occurrence. Based on our analysis of supply and demand, under such conditions the market will need to deliver a response of around 2.4 bcm over the winter period to maintain a balance. This would be equivalent to the cessation of gas consumption for approximately 25% of all non-domestic demand over a 40 day period. This would have to be provided though a combination of interruption contracts and other demand-side arrangements developed between suppliers and customers.
   - NGT's rights to trigger interruptible load are limited with the primary focus relating to physical network capacity management. The market would need to provide the response indicated above to secure the necessary supply/demand balance.

8. In evaluating the electricity supply/demand balance for this coming winter we have considered the level of demand which is also highly weather related, the availability of generation, European market effects on the direction of flow of the French interconnector, and levels of gas interruption and availability of alternative fuels at CCGT stations.

- The current 2004 Seven Year Statement Plant Margin (July Update) for winter 2004/05 is 20.2%, based on a transmission contracted generation capacity of 67.2 GW. In addition, a further 2.0 GW of plant has been mothballed by releasing its Transmission Entry Capacity, which could choose to return and thus increase the plant margin to 23.8%. At this stage last year, the plant margin as reported in the Seven Year Statement[1] for 2003 was 16.2%, though with generation returning during the winter the actual margin was 21.6%.
- The above level of generation availability will be sufficient to meet demands expected under average cold spell (ACS) conditions.
- In low probability severe winter conditions, demand may increase in the order of 2 GW above ACS demand. Under these circumstances, the anticipated margin would be sufficient, provided we do not experience high levels of plant breakdowns. As there would simultaneously be an increased likelihood of CCGT interruption to provide a gas supply/demand balance an increased reliance would also be placed upon those CCGTs that are able to run on distillate.
- If there were a combination of very low probability events (e.g. extensive generation failure and/or severe winter demands) a balance may be achieved by applying voltage reduction over restricted periods which should not be discernable to domestic end customers.

9. Our analysis of the gas and electricity market interaction indicates that the generation sector has the potential to contribute in part to any necessary gas demand response in a severe winter without creating electricity supply difficulties. Under these low probability scenarios the significance of the electricity generation response will be determined by the conditions prevailing at the time.
10. NGT remains committed to supporting the development of commercial arrangements that encourage timely and appropriate market response to secure energy supply/demand balances. The publication of this report is consistent with NGT's role in providing information to the market to enable participants to ensure they have appropriate commercial arrangements in place.

[1] The July 2003 Update to the 2003 Seven Year Statement (SYS) quotes 16.2%. The 2003 SYS used Registered Capacities, whilst the 2004 SYS now uses Transmission Entry Capacity (TEC), introduced under CAP43.

Section A – Experience of 2003/04 - Weather

11. The 2003/04 winter was generally mild, and comparing the actual temperatures across the whole of the winter against our 75 year historical records, outturned around '1 in 7 warm'; i.e. around 86% of previous winters have been colder. Temperatures ranged from –16.1 °C at Kinbrace in December to a record high of 17.9 °C at Gravesend in February.

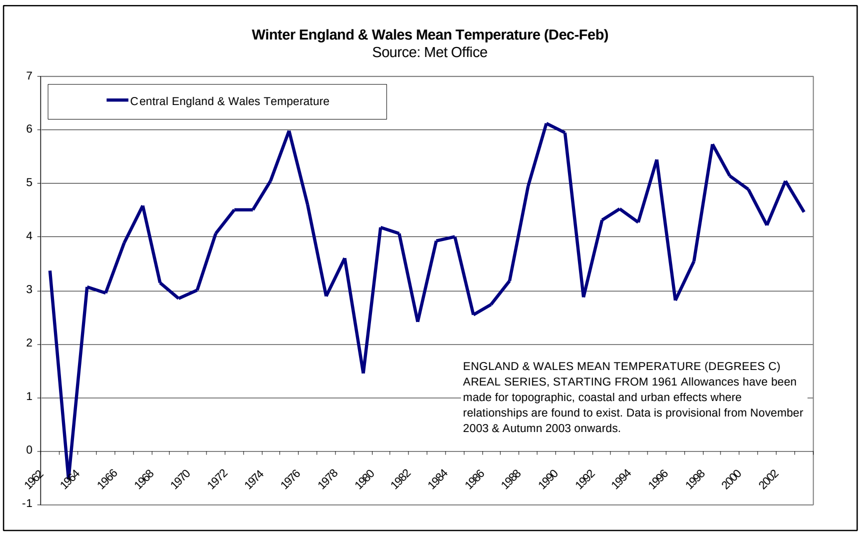
12. Table 1 shows the variances from normal for the key weather variables, excluding wind speed that drive electricity and gas demand for the period December to February. This is based on a 30-year long-term average from 180 observing sites in the UK. This shows that the averages were above normal.

Table 1 – Summary of 2003/04 Weather

Winter 2003/2004 (Dec – Feb, source Met. Office)										
Region	Max temp		Min temp		Mean temp		Sun		Rain	
	Actual	Variance	Actual	Variance	Actual	Variance	Actual	Variance	Actual	Variance
	[°C]	[°C]	[°C]	[°C]	[°C]	[°C]	[hours]	[%]	[mm]	[%]
UK	7.2	1.2	1.5	0.9	4.4	1.1	183	23	332.9	8
England	7.8	1.3	2	1.1	4.9	1.2	198.8	24	246.3	10
Wales	7.5	1.1	2	0.8	4.8	1	184.8	23	480.3	15
Scotland	6.2	1.2	0.4	0.7	3.3	1	154.9	20	449.3	8
England and Wales	7.7	1.3	2	1.1	4.9	1.2	196.9	24	278.4	11

13. The England and Wales Mean Temperature of 4.9 °C was in the upper quartile of temperatures for the last 40 years as were 5 of the last 7 years. It was sunnier than normal having 123% of the sunshine and with average rainfall compared to the 30 year long term average.

Figure 1 – Average Winter Temperatures, 1962-2003



Section A – Experience of 2003/04 - Gas

Gas Demand

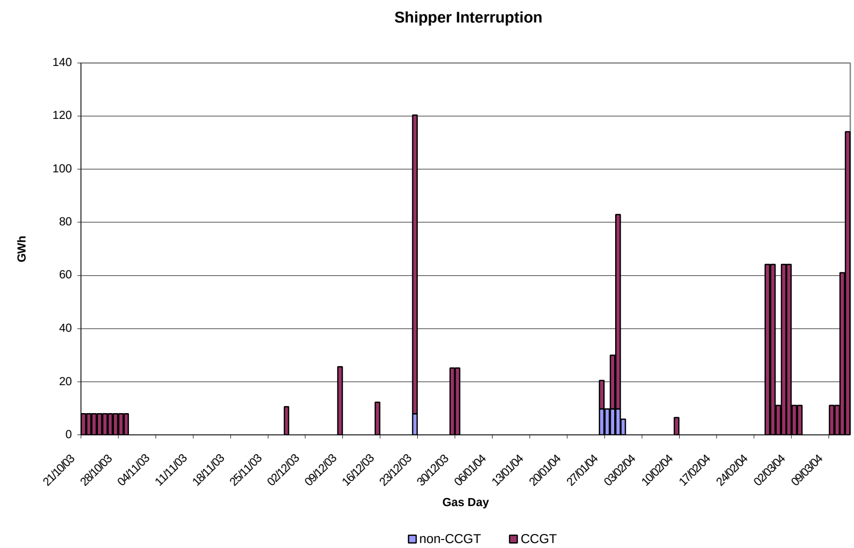
14. UK daily gas demand peaked at 4,840 GWh (444 mcm) on 28 January 2004, at a level which represents 83% of the forecast undiversified 1 in 20 peak day of 5821 GWh (535 mcm). This was 1.4% lower than the 2002/03 peak demand of 4,910 GWh (449 mcm).

15. NGT interrupted around 15 GWh LDZ demand on each of 28 and 29 January 2004 to resolve locational transportation constraints. There was no NGT interruption of NTS load or gas-fired power stations on these occasions, though it is estimated that there was around 120 GWh of additional load management of CCGTs on 29 January 2004, around 75% of which came from interruptible stations.

Shipper Interruption

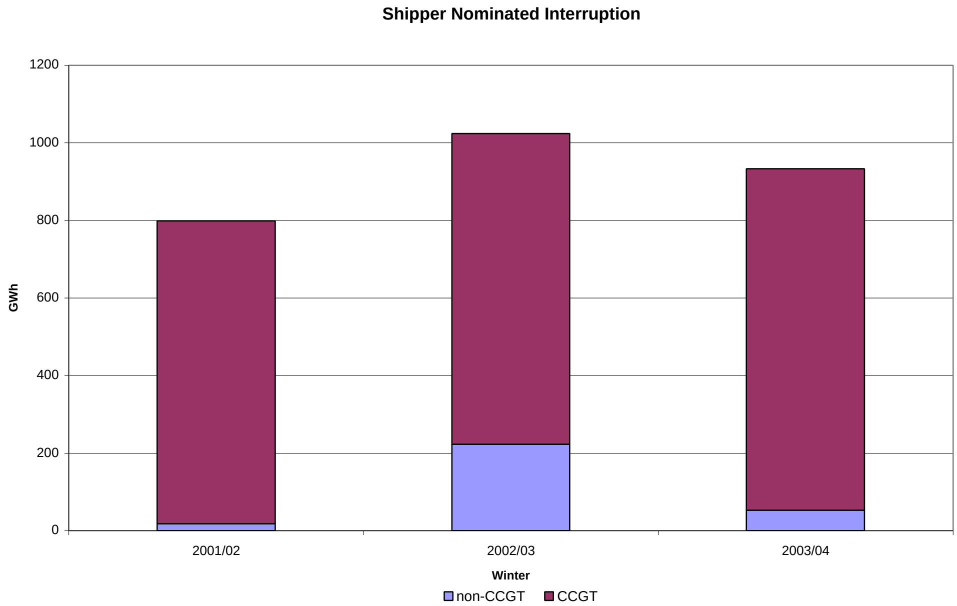
16. Under the terms of bilaterally negotiated commercial contracts, gas shippers have the right to commercially interrupt the gas supply to certain end customers. On 32 days last winter, shippers notified NGT of interruption, as detailed in Figure 2. Interruption was high during late January 2004, but peaked in the period before Christmas.

Figure 2 – Shipper Interruption, Winter 2003/04



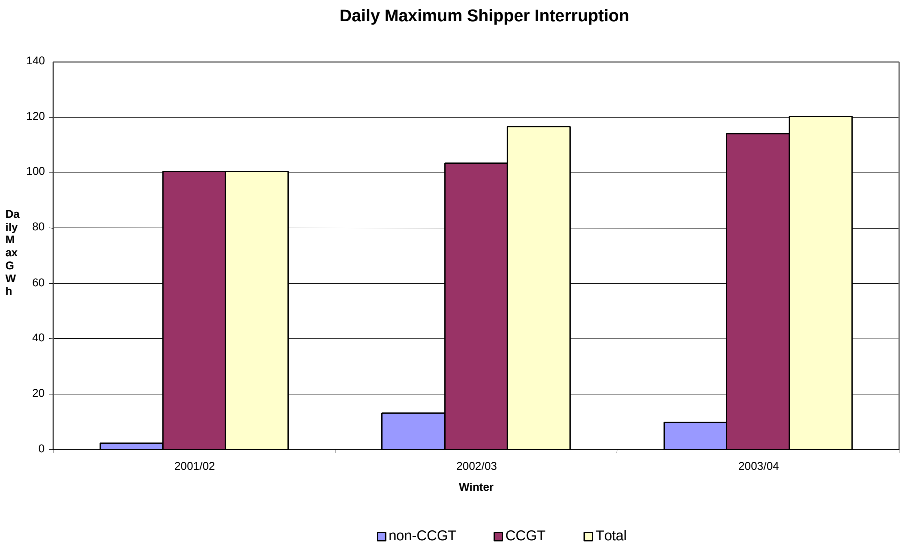
17. Overall NGT was notified of 0.9 TWh of shipper interruption over winter 2003/04, 9% less than was notified during 2002/03, as detailed in Figure 3. As detailed, the vast proportion of interruption has been to CCGTs over recent winters, with non-power station winter interruption reaching a maximum of only 0.2 TWh during 2002/03.

Figure 3 – Shipper Interruption, Winter 2001/02 – 2003/04



18. As detailed in Figure 4, the maximum daily volume of CCGT shipper interruption has been between 100 and 115 GWh over the past 3 years, whilst the maximum daily non-CCGT interruption has been 10-15 GWh (1-2 mcm) over the last 2 years. This non-CCGT interruption represents less than 0.3% of daily peak demand.

Figure 4 – Maximum Daily Shipper Interruption, Winter 2001/02 – 2003/04



Gas Supply

19. UK daily gas supply peaked at 4,824 GWh (439 mcm) on 29 January 2004. This was met by 330 mcm from beach, 82 mcm from storage and 27 mcm from the Belgium – England interconnector, I(UK).

20. Beach supplies peaked at 338 mcm on 12 March 2004, 30 mcm lower than the maximum beach supply of 368 mcm in 2002/03. As detailed in Table 2, the aggregate of the maximum flows from each terminal was 371 mcm for 2003/04.

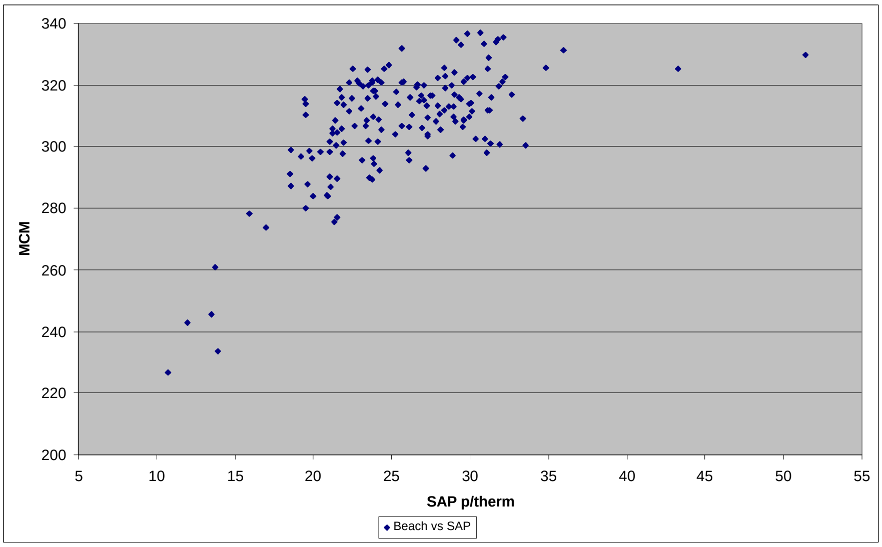
Table 2 - Maximum Gas Supplies, mcm

	12-Mar-04	Terminal Max
Bacton	82	88
Barrow	40	45
Easington	16	26
St Fergus	135	139
Teesside	33	38
Theddlethorpe	28	30
Burton Point	3	5
Total Beach	338	371

21. Prior to the winter, our forecast maximum beach delivery was 401 mcm/day. We have reassessed this in the light of the winter experience and improved upstream information arising out of the DTI's information initiative. For reasons including greater than expected UKCS decline and late commissioning of new fields, a revised maximum beach figure of 377 mcm/d now appears a more realistic reflection of the position in 2003/04. This is broadly consistent with the sum of the terminal maxima shown in the table above.

22. As Figure 5 illustrates, the winter maximum beach delivery of 338 mcm occurred when SAP was less than 30 p/therm and indeed at this price level beach deliveries flattened off. There were 25 other days when SAP exceeded 30 p/therm, but no additional beach gas was delivered on these days. There were a number of offshore problems reported on the two occasions when SAP exceeded 40 p/therm, and it is possible that material volumes of additional beach gas were not available on these days.

Figure 5 – Beach Supplies and SAP



23. As illustrated in Figure 6, beach supplies during 2003/04 tended to be significantly below 2002/03 beach levels. Figure 7 shows that this reduction in delivered beach gas was broadly matched by a significant increase in the level of imports through the continental Interconnector, which operated at or around its maximum capacity for much of the winter. In the absence of particularly high demands, it is hard to gauge the extent to which further beach gas would have been available if required.

Figure 6 – Beach Supplies and Gas Demand

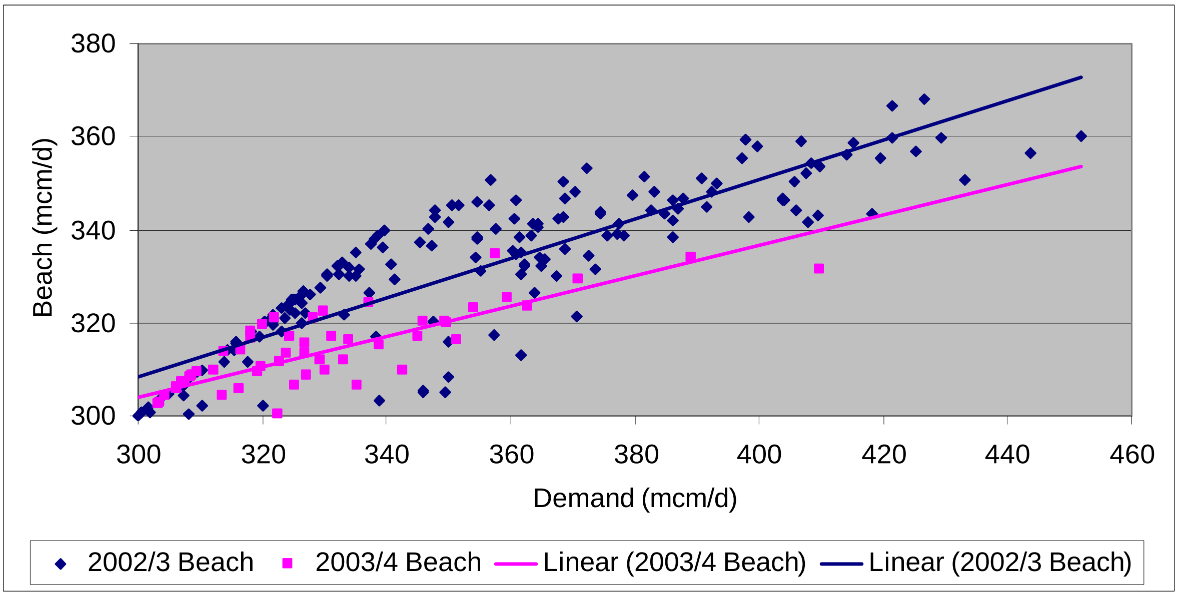
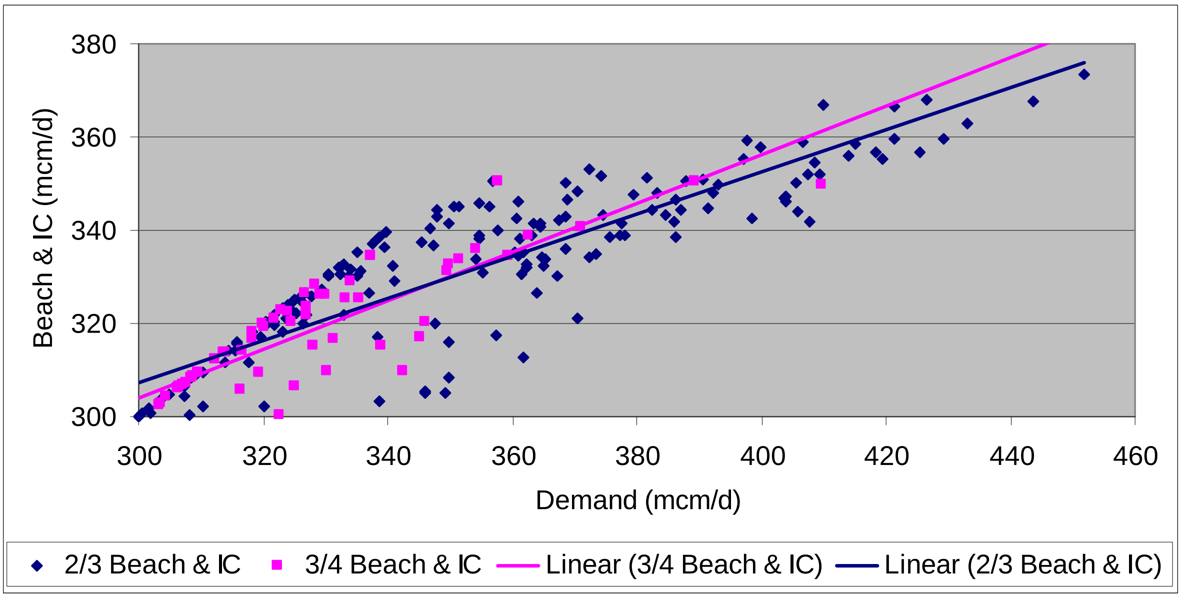


Figure 7 – Beach and Interconnector Supplies and Gas Demand



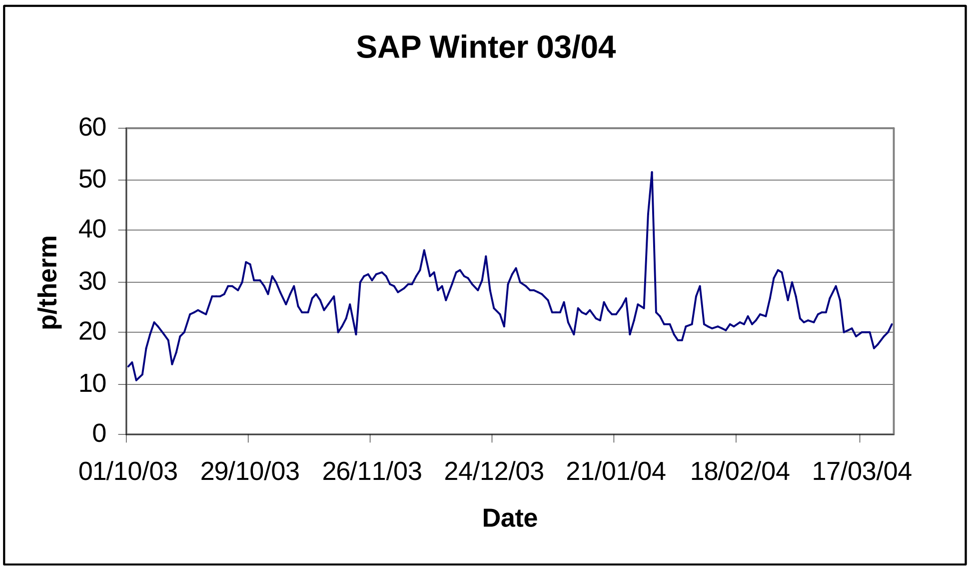
24. In the 2003/04 winter, we have continued to observe an increase in the number of reported supply reductions. On average, 50 unplanned supply reductions per month occurred last winter against 34 in the summer of 2003. A record 66 unplanned supply reductions occurred in each of December 2003 and February 2004. While many such events will not ultimately result in an end-of-day loss, with increased flows later in the day making up the shortfall, there have also been a number of material offshore outages reported. Of particular significance were the loss of withdrawal capability from Rough between 22 and 26 January 2004 and a combination of beach supply losses on 28 and 29 January.

25. The electricity market reacted to the supply problems during late January 2004, with gas-fired stations responding to high day-ahead and on-the-day gas prices by reducing gas demand. The electricity market was able to provide relief to the gas market during these two occasions as plant availability was high, electricity demand at 52.1 GW was over 3 GW lower than the ACS peak demand, electricity prices were relatively benign, and there appeared to be sufficient stocks of back-up fuels to allow gas-fired generation to continue to generate whilst not taking gas from the NTS.

Gas Prices

26. Generally the System Average Price (SAP) price was between 20 p/therm and 35 p/therm, over the period October 2003-March 2004, as illustrated in Figure 8. On 29 January 2004 SAP was 51 p/therm, when on-the-day supply losses coincided with high gas demand.

Figure 8 - Gas Prices over winter 2003/04



Conclusions

- Beach supplies were lower than forecast and lower than those in 2002/03. Higher flows through the continental Interconnector broadly matched this reduction in beach gas.
- A mild winter led to a peak demand only 83% of the peak undiversified level, a 1.4% decrease on 2002/03.
- We continued to observe an increase in the incidence of reported offshore supply reductions.
- A response of around 2.5% of national demand was observed from the power market as CCGTs reduced their gas consumption during late January 2004, at times of low electricity demand and benign electricity prices. Around 75% of this response came from interruptible power stations.

Section A – Experience of 2003/04 – Electricity

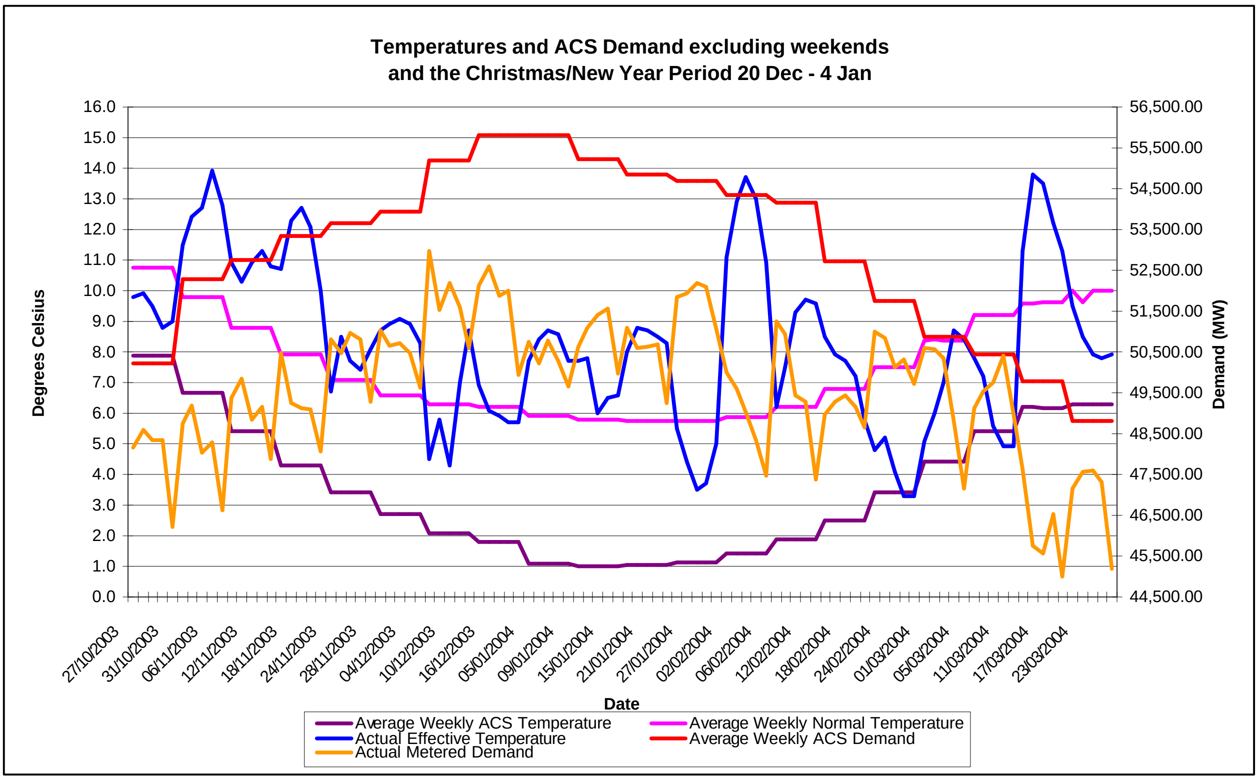
Electricity Demand

27. The highest electricity demand over the winter reached 52,965 MW for the half-hour ending 17:30hrs on Monday 8 December, after 206 MW of Notified Demand Management. This compares to the record demand of 54,430 MW, after 235 MW of Notified Demand Management, which was in the same week the previous winter.

28. The overall mildness of the winter kept demands low. Peak demands were also low due to the timing of the cold spells, which were in the twelfth-percentile i.e. there was an 88% probability of having higher peak electricity demands.

29. Figure 9 compares the effective temperature at 17:00hrs against the Average Cold Spell temperatures. The ACS Demand weekly forecast at the ACS temperatures is also shown; this assumes that the other demand drivers would also be at ACS conditions.

Figure 9 – Daily Temperature and Demand, Winter 2003/04



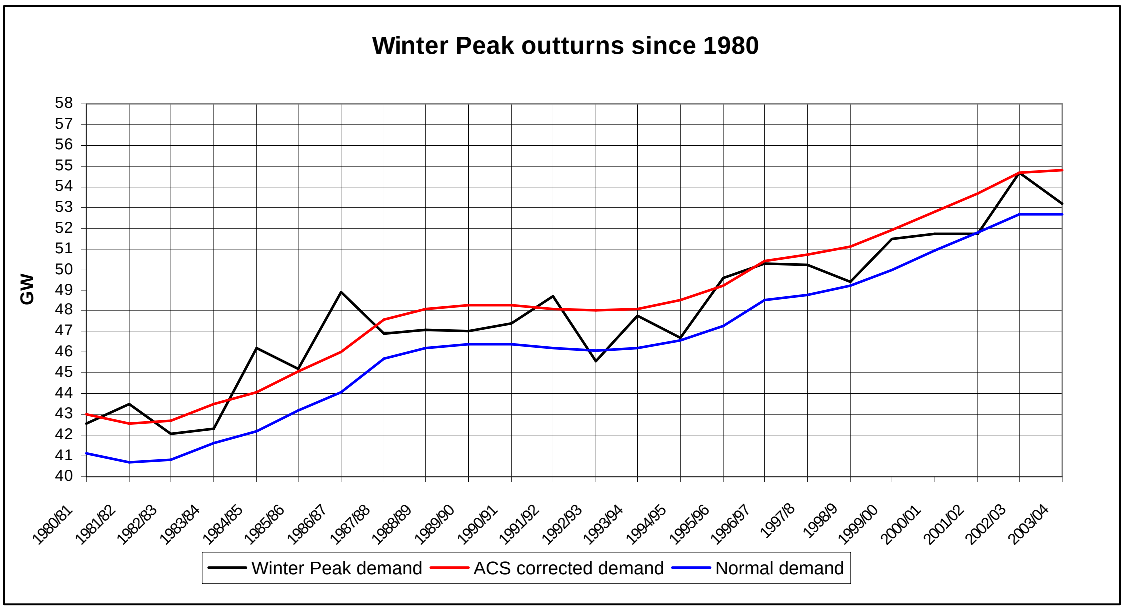
This figure excludes weekends and the holiday period 20 December to 4 January as peak demands occur typically Monday to Thursday and to a lesser extent Friday, due to the underlying demand pattern.

30. As can be seen above, the timing of the two cold spells where temperatures were close or dropped below the ACS temperature occurred when ACS demand would be around 51 GW. The actual metered peak demands in these weeks were 51.0 GW (against a weekly ACS demand of 51.8 GW) and 50.4 GW (against a weekly ACS demand of 50.4 GW). If ACS temperatures had occurred immediately before or after the holiday period then the demand could have exceeded 55 GW. The temperatures across the highest potential demand peaks were generally at or above average.

31. The year on year growth in average demand across the winter period was around 440 MW compared to the winter 2002/03, however there was little growth on the winter peak demands. The normalised demand outturn for 2003/04 is 52.8 GW, compared to a forecast of 53.5 GW in the October 2003 Winter Outlook Report and an outturn of 52.4 GW in 2002/03.

32. Figure 10 shows the Winter Peak outturn ACS, normalised demands and the metered demand. The figures for 2003/04 show the almost zero increase on the peaks between 2002/03 and 2003/04.

Figure 10 –Winter Peak Outturns since 1980



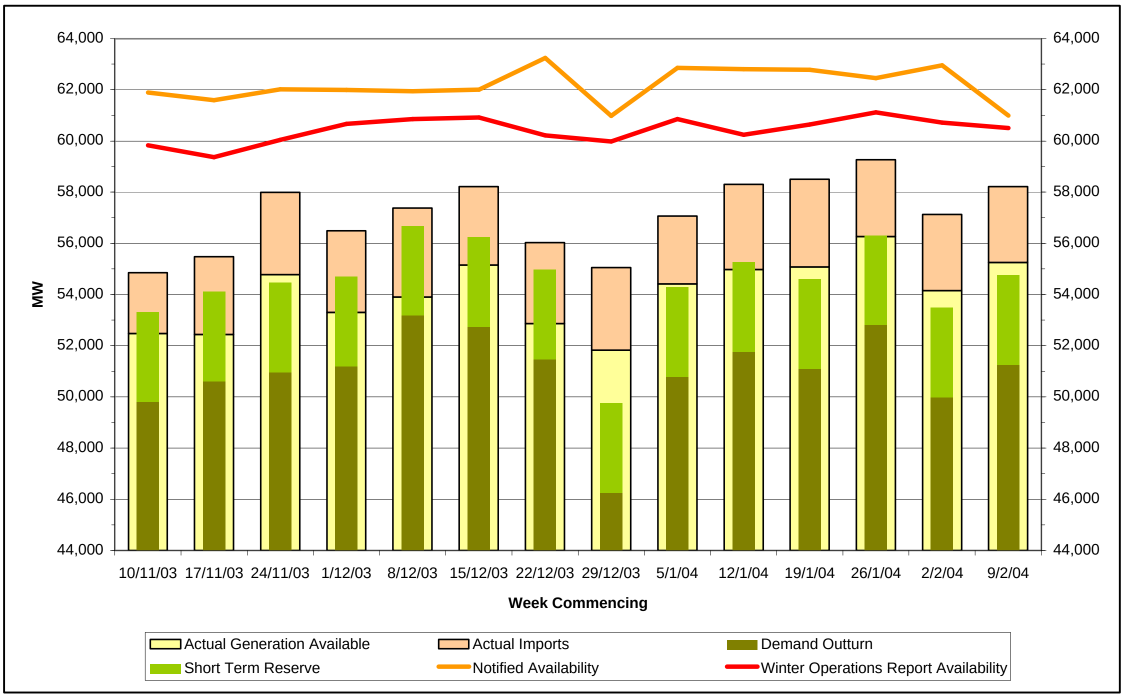
Demand Management

33. Up to 800 MW of demand management or reduction has been observed at times of peak demand in the winter of 2003/04. Around 200 MW Notified Customer Demand Management was notified to NGT under the obligations in the Grid Code. The balance of the 600 MW of demand reduction includes both customer demand management and potentially the increased running of Licence Exempt Embedded Generators during the peak demand periods. Where this behaviour is repeated year on year it is effectively taken in to account in the demand modelling and forecasts.

Electricity Generation

34. Figure 11 compares the generation availability declared to NGT in different timescales. The red line is the generation available as shown in the October 2003 Winter Outlook Report, which assumed full interconnector capacities of 4.2 GW and 0.8 GW of mothballed plant. The orange line shows the generation available as declared to NGT on a weekly basis under Grid Code OC2, also assuming full interconnector capacities of 4.2 GW. This demonstrates the impact of the additional plant that returned to service from mothballs. The bars show the total availability and the interconnector imports, and the demand and short-term reserve requirement at the time of peak demand.

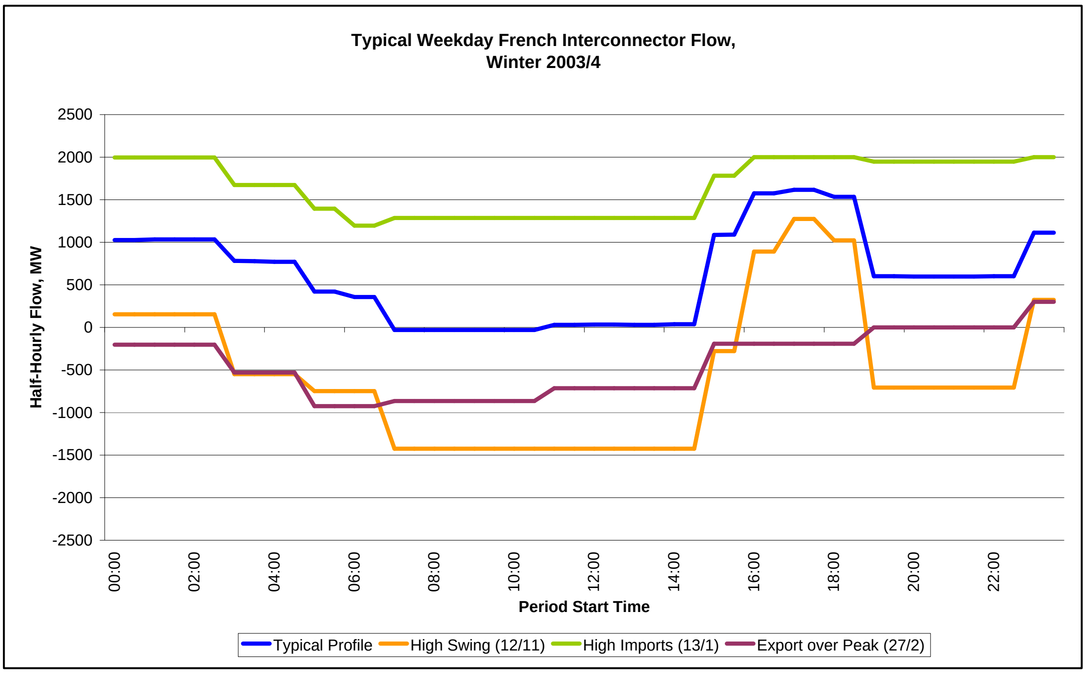
Figure 11 - Plant Availability and demand



35. Figure 11 shows that there was adequate generation plant available in real time to meet the level of peak demands and operating margin (Short Term Reserve). Generator outages, planned and unplanned, were around 5 – 6 GW. Further generation plant may have become available if demands had been higher.

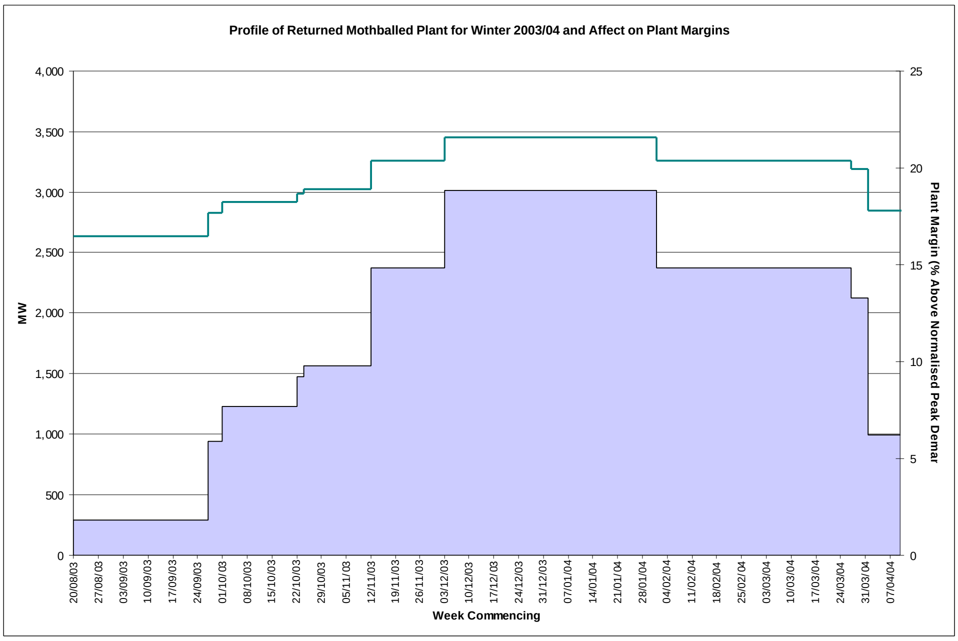
36. Across the winter the interconnectors with Scotland and France were importing to England and Wales at the time of peak demand each day. The average interconnector import at the time of peak demands was 3 GW. The France interconnector flows varied across the day, on occasions exporting to France in the morning before reversing direction to flow to England and Wales for the evening peak. A typical interconnector profile is shown below, along with examples of a high swing profile, a high import profile and a low level of export across the demand peak.

Figure 12 - French Interconnector Flows



37. The available generation for the winter increased from the time of the publication of the Winter Outlook Report, bringing the Plant Margin to 21.6% (2003 Seven Year Statement January Update). Figure 13 shows the profile of mothballed generation that returned to service for the winter and the improvement in plant margin, based upon power station availability as notified to us during the winter.

Figure 13 – Mothballed Plant and Plant Margin, SYS2003 basis

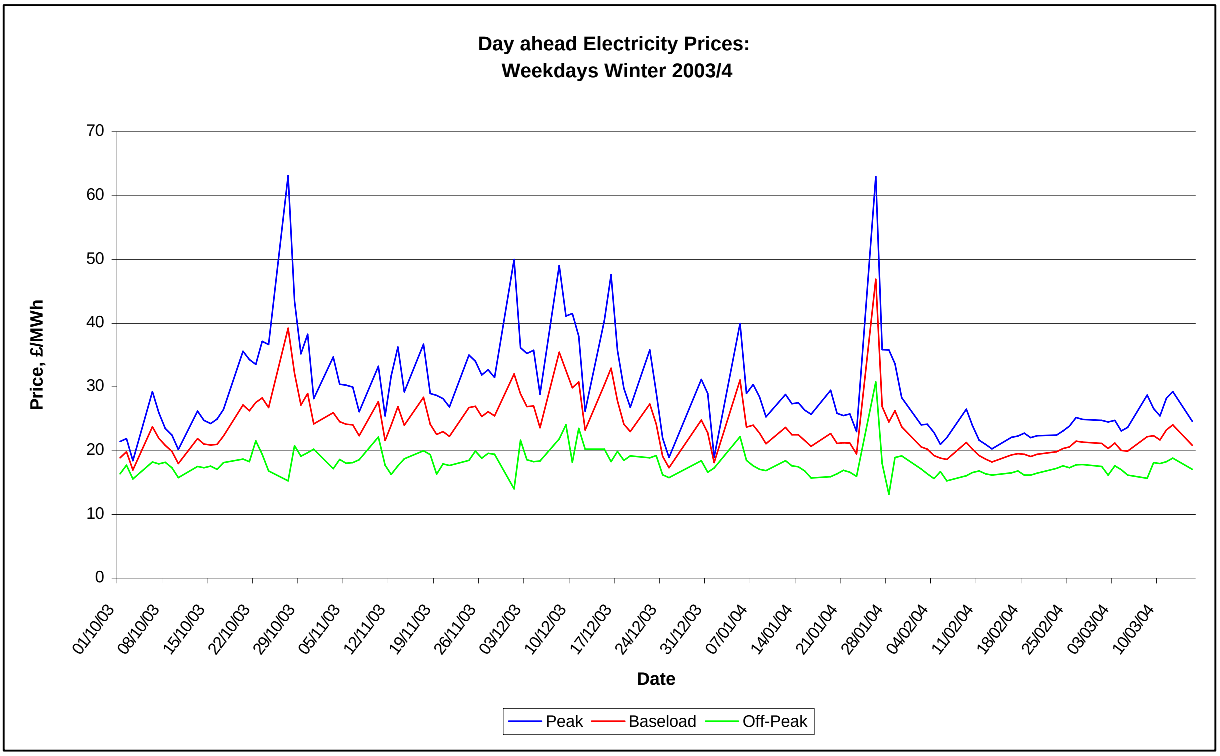


38. A total 3 GW of mothballed plant was returned to service by the generators from the 16.2% Plant Margin position reported in July 2003 (2003 Seven Year Statement Update). Of this 3 GW, 0.7 GW was contracted via the Supplementary Standing Reserve tender to provide a short- term reserve service between November 2003 to March 2004.

Prices

39. Day-ahead base load electricity prices rose from 19 £/MWh at the beginning of October 2003 to between 20 £/MWh and 35 £/MWh by mid-December, as detailed in Figure 14. Following the Christmas period, prices remained in the low twenties until the last week in January, when there was a leap in prices to over 45 £/MWh at the beginning of the week settling down to between 28 £/MWh and 35 £/MWh for the rest of the week. Following the last week in January, prices fell and remained steady at around 20 £/MWh. There was a slight increase in early March, prices rising to 23 £/MWh. Peak load prices have followed the same pattern, reaching over 60 £/MWh on 26 January 2004.

Figure 14 – Day-ahead Electricity Prices



Conclusions

- A mild winter and the timing of the cold weather led to low peak demands.
- The return of 3 GW of mothballed plant provided sufficient margin to deliver electricity security of supply over the actual winter peak demands.
- Electricity prices spiked in October due to market concerns over unplanned generator outages, and in January at a time of low gas margins.
- Demand growth over the winter was lower than forecast, due in part to greater demand side response and embedded generator output compared to previous years.
- Imports to England and Wales from France and Scotland were below the full capacity of 4.2 GW, at around 3 GW over the peak time of the day. The half-hourly profile of the interconnector varied considerably across the winter. On occasion the interconnector to France swung through 3 GW from exporting to importing to England and Wales in the hour ahead of the peak demand.

Section B – Outlook for Winter 2004/05 – Gas

40. This section examines the outlook for gas in the forthcoming winter, with a particular focus on the supply-demand position. In relation to our role of developing the transportation system to provide sufficient capacity for the 1 in 20 peak day, we can confirm that the transportation system will continue to have this capability in 2004/05.

41. Our assessment of the supply-demand outlook uses our 2004 forecasts. These take account of information provided to us in the course of the 2004 Transporting Britain's Energy (TBE) consultation process from producers, shippers, end-users, gas importers, storage operators, consultants and other interested parties. We have had an excellent response to this consultation from producers this year, as a result of which our 2004 supply forecasts reflect the collective expectations of the upstream UK gas industry more directly that at any time since liberalisation of the gas market in the mid-1990s.

42. Since the publication of our preliminary report in May, Ofgem has undertaken a review of the Top-up arrangements, which presently form part of the Network Code. In its conclusions document, Ofgem expressed the view that Top-up should be removed from the Network Code and that there are significant benefits associated with achieving this in time for the forthcoming winter. We have therefore progressed with HSE and Ofgem the necessary changes to the Transco Safety Case and the Network Code.

43. We received the acceptance of the HSE for our proposed Safety Case revision on 4 October 2004. These revised arrangements ensure that there will be no diminution in safety arising from the removal of Top-up from the Safety Case. Key to this is the introduction of a set of 'safety monitors', which, in broad terms, will define a level of stock required in each type of gas storage facility to support those customers whose gas demand could not be safely curtailed should the need arise. It is expected that these monitors will be significantly lower than the corresponding Top-up monitors.

44. While the HSE has approved the removal of Top-up from the Safety Case, its removal from the Network Code remains subject to Ofgem's approval of the associated Network Code Modification Proposal. However, given Ofgem's conclusions, for the purposes of this report we are assuming that Top-up will be removed from both the Safety Case and the Network Code in time for the forthcoming winter.

45. The following sub-sections explain the assumptions that we have used to derive a base case with which to assess the winter outlook. This outlook is presented, together with an analysis of key sensitivities to the base case assumptions.

Beach gas

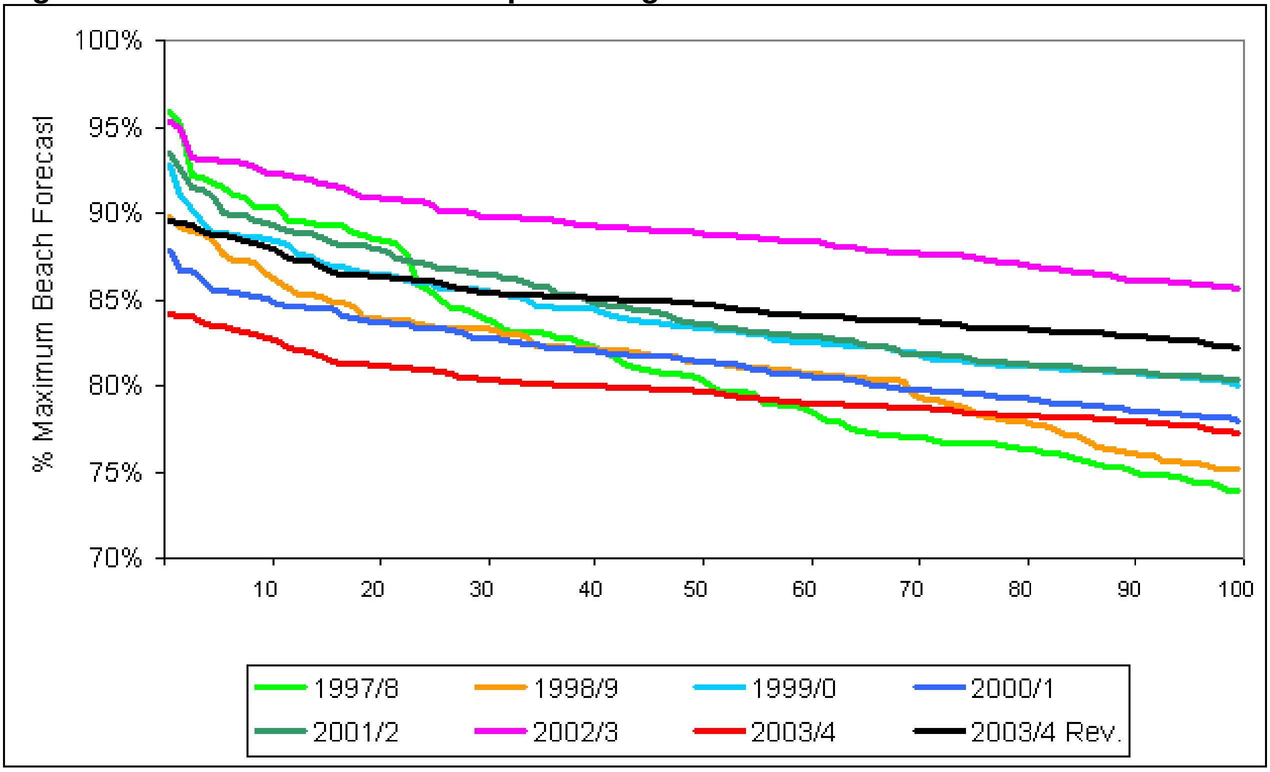
46. Our forecast of 2004/05 beach gas availability is materially lower than last year's forecast for the same period. Our 2003 maximum beach forecast for 2004/05 was 404 mcm/d[2]. This represents a forecast of the maximum level of gas that we could expect at the beach given sufficient demand and assuming no outages. On the basis of information received in our 2004 TBE consultation, our maximum beach forecast, which we have reviewed with the DTI, is now 364 mcm/d. Most of the difference between the current forecast of 364 mcm/d and our 2003 forecast of 404 mcm/d is accounted for by faster UKCS decline than had previously been assumed. Our TBE consultation discussions with market participants and other industry experts confirm a widespread view that the UKCS has begun to decline faster than previously anticipated. The remaining difference is due to assumed delays in the development of some new fields.

47. Experience has shown that it is unlikely that beach deliveries at this level would be achievable for a sustained period. Figure 15 shows the level of actual beach deliveries as a percentage of the maximum beach forecast for each of the last seven years. 2003/04 is included twice, the lower line based on our 2003 maximum beach forecast of 401 mcm/d and the higher line based on our latest, hindsight-based, estimate of 377 mcm/d.

48. As Figure 15 illustrates, beach deliveries in recent years have rarely reached 95% of our forecast maximum, albeit that we have not had a particularly cold winter over this period. For the purpose of supply / demand balance analysis and safety monitor assessments, we believe it is appropriate to assume a level of beach supply below the maximum forecast. The chosen level should reflect the level of beach gas deliverability that we might expect on average during a prolonged cold spell in a severe winter. This is untested. For 2003/04 winter analysis, we used 95% of the maximum beach forecast, reflecting the trends highlighted in Figure 15, but assuming that higher levels of beach gas would be seen if demand was sufficiently high.

[2] Excluding imports through the Belgium – England Interconnector and direct supplies to certain power stations, which do not pass through NGT's network.

Figure 15 - Beach deliveries as a percentage of forecast maximum beach



49. NGT continues to assume 95% maximum beach availability for this purpose, and we understand that it is reasonably consistent with DTI's view, although some offshore operators believe this to be optimistic. Whilst continuing to keep our beach supply assumption under review, our analysis of the 2004/05 supply-demand position assumes a beach gas level of 346 mcm/d, approximately 95% of 364 mcm/d. The implications of lower beach supplies have also been considered.

Continental Interconnector

50. Section A highlighted that the Belgium-England Interconnector was importing into the UK at levels at or above its nameplate capacity for prolonged periods during the 2003/04 winter. With the supply-demand position tightening further, it seems reasonable to assume that this trend will continue in 2004/05.

51. For 2003/04 supply / demand balance analysis purposes, we assumed that deliveries from Rough and the Interconnector would be pro-rata to their assumed delivery capacities (42 mcm/d and 22 mcm/d respectively). As a modelling assumption for the forthcoming winter, we now assume that the Interconnector will import prior to the use of Rough. Furthermore, while Interconnector deliveries above 22 mcm/d cannot be guaranteed, the 2003/04 winter experience, where import flows were often above 22 mcm/d and reached 29 mcm/d, suggests that an assumed import rate of 25 mcm/d would not be unreasonable.

Storage

52. Table 3 gives assumed storage space and levels of deliverability from LNG, Mid Range Storage (MRS) and Rough. These exclude space for operating margins gas that NGT procures to provide short-term cover against operational events such as offshore supply losses, demand forecast errors and compressor trips. The MRS figures include Hatfield Moor and Hole House Farm.

Table 3 – Assumed 2004/05 storage capacities and deliverability levels

	Space (GWh)	Deliverability (GWh/d)	Deliverability (mcm/d)	Days at full rate
Short (LNG)	1962	712	66	3
Medium (MRS)	4962	250	23	20
Long (Rough)	34126[3]	455	42	75

Gas demand

53. Our analysis is based on our 2004 demand forecasts, derived as part of the 2004 TBE process. These forecasts will be presented in more detail in the 2004 Ten Year Statement, which will be published in December 2004.

54. It should be noted that these forecasts do not make an adjustment for potential interruption by NGT for capacity management purposes, nor for potential reductions in demand that might occur in response to high prices in a severe winter. As we noted in Section A, the highest level of NGT-initiated interruption in 2003/04 was around 15 GWh/d.

Interruption

55. We noted last year that the market is moving away from traditional interruptible arrangements. Under these contracts, the customer could be interrupted by their supplier, either for the supplier’s own supply-demand balancing purposes or if called to do so by NGT, primarily for transportation capacity management purposes.

56. Whilst there has been an apparent reduction in suppliers’ rights to interrupt customers, this does not preclude suppliers securing other arrangements to deliver a necessary demand response.

Gas-fired power station demand

57. Our power generation demand forecasts are based on analysis of the historical gas demand of these customers. In general, total power generation demand has been flat across the year, with only a few occasions when there was been discernible price responsiveness. Accordingly, the severe winter load duration curve

[3] In addition to this assumed capacity, Centrica Storage Limited has recently announced that it will sell up to 20 million therms (586 GWh) of additional capacity for winter 2004/05.

incorporates a constant daily demand in relation to this sector, broadly equivalent to the average daily historical demand, adjusted for known market changes, principally new connections. For 2004/05 we have assumed 550 GWh of firm power station load and 150 GWh of interruptible power station load.

58. However, as we noted in Section A, the 2003/04 winter has provided some empirical evidence of CCGT responsiveness to gas price, with a number of stations curtailing their gas burn at relatively high gas prices in late January 2004.

59. As further discussed in Section C, analysis implies a potential for further response from CCGTs, including those on firm transportation arrangements, but the extent of this response is clearly influenced by the level of electricity demand, the availability of back-up fuels and the attractiveness to the power market of switching to non-gas fired generation, as indicated by the gas and coal spreads[4]. Whilst there may be a potential for a high degree of price-response from CCGTs, the level of price responsiveness experienced and required to date has only been a fraction of that required to ensure a supply / demand balance in a 1 in 50 winter.

Climate change

60. There is now a substantial weight of evidence to suggest that climate change has resulted in a shift in average winter temperatures. Reflecting this, for the last three years we have used a 35-year weather trend as the basis of our analysis of average weather conditions, rather than using the 75 years from 1928/29, which form the basis of our severe winter analysis. Our latest analysis indicates that use of the 17 years weather data from 1987/88 has greater statistical validity, and we intend to move to this basis next year.

61. However, there is no clear evidence that climate change has had an impact on severe conditions. Indeed, the coldest day since our records began in 1928/29 occurred as recently as the 1986/87 winter. Accordingly, our severe load duration curves are based on the 75-year weather history. We are conducting further analysis to test the validity of this approach. Our initial thoughts are that it may be appropriate to make an adjustment to the severe load curve away from the peak period, e.g. from around day 15. This would reflect the fact that, while there is no evidence to suggest peak conditions have changed as a result of global warming, average conditions are clearly warmer than would be indicated by the 75 year weather database.

62. We intend to undertake further analysis in this area over the coming months, with a view to amending the methodology, if this is found to be appropriate, in 2005.

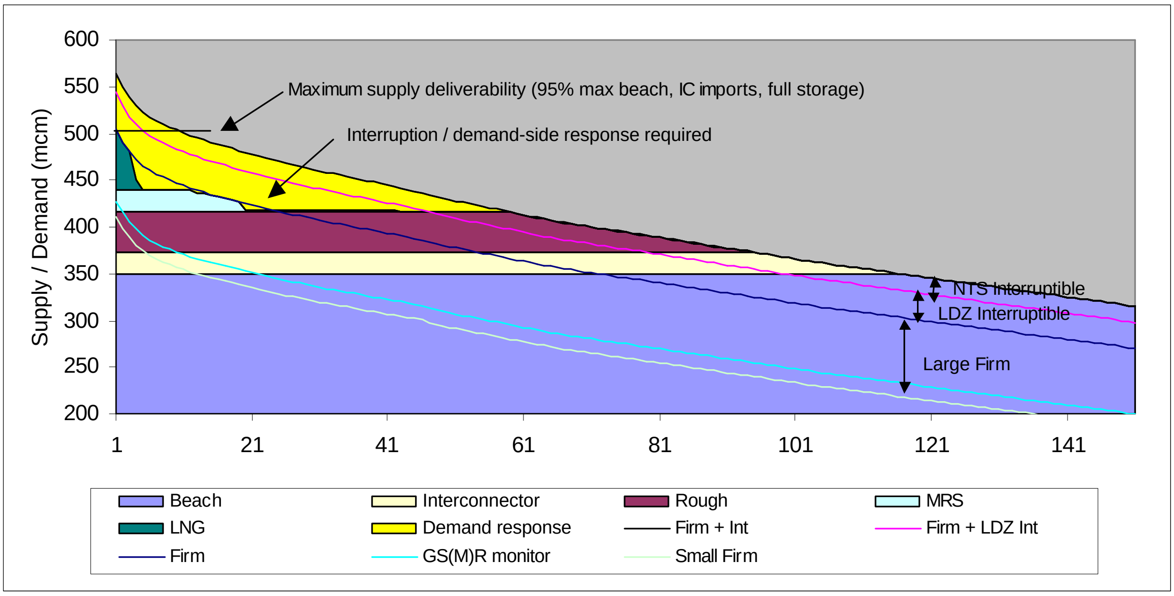
Gas supply-demand outlook, including 1 in 50 winter

63. The previous sub-sections have outlined our assumptions for gas supply and demand in 2004/05, and reflected on the potential requirement for suppliers to deliver demand turn-down. This section shows, with the use of a load duration

[4] The gas spread is the premium in £/MWh of the electricity price above the gas price, at an assumed efficiency of around 50%. The coal spread is the premium in £/MWh of the electricity price above the coal price, at an assumed efficiency of around 30%. Currently, the coal spread is close to the gas spread.

curve analysis, a view of the supply-demand outlook for the 2004/05 winter, based upon these supply assumptions and forecast demand patterns under a 1 in 50 winter. This analysis does not include an adjustment for potential demand-side responses under severe conditions. It does, however, provide an indication of the extent of the demand-side response that the market would be required to deliver under 1 in 50 winter conditions.

Figure 16 – 1 in 50 load duration curve analysis for 2004/05



64. The 1 in 50 load duration curve shown above distinguishes between firm demand, LDZ interruptible demand and NTS interruptible demand. For this purpose, firm demand is split into 'Large' and 'Small' categories, with 'Large' (equating to around 100 mcm/d of demand at the top of the curve) incorporating daily metered LDZ firm loads, other LDZ firm loads greater than 200,000 therms per annum, NTS firm loads, and firm exports to the Irish power sector. Also shown is a demand line that reflects those demands taken into account in the calculation of the GS(M)R Safety Monitor. These demands include all Non Daily Metered (NDM) customers, large priority customers and firm Irish demands. The various sources of supply are shown underneath the load duration curve – beach gas first, then Interconnector imports, and then the three types of storage.

65. Figure 16 indicates that, given the base case assumptions of supply and demand in a 1 in 50 winter, there would be sufficient deliverability to meet demand on the peak day of the 1 in 50 load duration curve. Over the duration of the winter, our analysis indicates that around 2.4 bcm of demand-side response, whether interruption or demand management would be required in total. The load duration curve in Figure 16 illustrates that this 2.4 bcm requirement is broadly equivalent to interruption from the NTS and LDZ interruptible sectors (c. 50 - 60 mcm/d) at demands above around 410 mcm. In volume terms, this would be equivalent to the cessation of gas consumption for approximately 25% of all non-domestic demand over a 40 day period.

66. This analysis shows that for the low probability extreme conditions in a 1 in 50 winter, the supply / demand balance could be maintained provided the market delivers appropriate levels of beach supplies, use of storage, and the necessary levels of demand-side response.

67. A similar analysis for average winter conditions indicates sufficient supplies would be available to meet forecast levels of demand if identical supply-side assumptions are maintained.

Implications for safety monitors

68. As we described above, we are assuming that the Top-up arrangements will be replaced by a set of safety monitors prior to the 2004/05 winter. The methodology for setting these monitor levels is presently under development. However, based on indicative analysis, initial monitor levels of 6%, 5% and 15% are envisaged for Rough, Mid-Range Storage (MRS) and Liquefied Natural Gas (LNG) respectively. Were Top-up to be retained in the Network Code, on the basis of our 2003/04 Top-Up methodology, the monitors for LNG and MRS would both start the winter at 100%. The monitor for Rough (long duration storage) would start at around 80%.

Sensitivities

69. In order to illustrate the scale of the response highlighted above, the following table quantifies the potential impacts of certain supply-side and demand-side sensitivities. For example, the first scenario, which shows a contribution of 2.26 bcm, illustrates the conclusion that interruption from the full NTS and LDZ interruptible sectors would almost be sufficient to deliver 1 in 50 security. Of course, 1 in 50 security could also be delivered with less than this amount of interruptibility if there was a corresponding reduction in firm gas demand. Another scenario indicates that if beach availability was 90%, rather than the assumed 95%, a further 1.9 bcm of demand-side response would be required.

70. The inclusion of a particular sensitivity should not be seen as an indication of its feasibility. For example, 100% response of the non-power large firm sector is clearly an extreme case, included to give a feel for the size of the market compared with the level of total response required. It should also be noted that these impacts are not fully additive, i.e. two scenarios in combination will generally have a lower impact than the sum of their individual impacts.

Table 4 – Sensitivity Analysis

Sensitivity	Modelling comments	Contribution of response in bcm
Demand-side sensitivities		
100% response of NTS and LDZ interruptibles	All interruptibles fully interrupt when required	2.26
100% response of GB non-power interruptibles	All GB non-power interruptibles fully interrupt when required	1.81
100% response of non-power large firm	All non-power 'Large' firm loads fully respond when required	1.70
Less CCGT gas demand	1 GW less baseload CCGT running for 40 days, due to either lower electricity demand or more distillate running	0.2
Response from power stations	Potential minimum CCGT demand (see Section C)	1.6
Supply-side sensitivities		
97.5% Max Beach	Higher beach assumption for all days in winter	0.52
Beach Profile	Beach deliveries based on historical profile entering the winter, and sustained beach levels (at 95%) through and after the most severe part of winter	-1.09
90% Max Beach	Lower beach assumption for all days in winter	-1.87
Continental Interconnector unavailable for 14 days	Assumed 2 week outage from days 10 to 23	-0.35
Winter MRS storage cycling	Re-injection into MRS storage based on analysis for all cold winters	0.11

Conclusions

- Decline of UKCS gas supplies is occurring faster than previously forecast. Our latest analysis, based upon a consolidation of industry data, suggests a beach gas availability of 346 mcm/d for a sustained period over the coming winter. This represents a reduction of 38 mcm/d from that forecast in autumn 2003. We have discussed this assessment with the DTI and we understand that it is reasonably consistent with their view, although some offshore operators believe this to be optimistic.
- Beach gas availability at these levels should be sufficient to meet expected demand in average winter conditions.
- If worse than average weather is experienced or there are significant supply difficulties, including lower than expected beach supplies, then an effective market response will be required to maintain a supply/demand balance.
- We are required to consider the effects of low probability extremely poor winter conditions, represented by a 1 in 50 expectation of occurrence. Our analysis indicates that a balance of supply and demand would depend upon the market delivering a demand reduction of around 2.4 bcm over the winter period. This would be equivalent to the cessation of gas consumption for approximately 25% of all non-domestic demand over a 40 day period. This would have to be provided though a combination of interruption contracts and other demand-side arrangements developed between suppliers and customers.
- NGT's rights to trigger interruptible load are limited with the primary focus relating to network capacity management. The market would be expected to provide the response indicated above to secure the necessary supply/demand balance.

Section B – Outlook for Winter 2004/05 – Electricity

Electricity Demand Levels for 2004/05

71. The NGT cold winter peak demand forecast for the coming winter is 55.4 GW and the normal demand forecast is 53.3 GW. The “1 in 20” peak demand forecast is 56.9 GW.

72. As discussed in Section A, up to 800 MW of demand management or reduction has been observed at times of peak demand in the winter of 2003/04. Where this behaviour is repeated year on year it is effectively taken in to account in the demand modelling and forecasts.

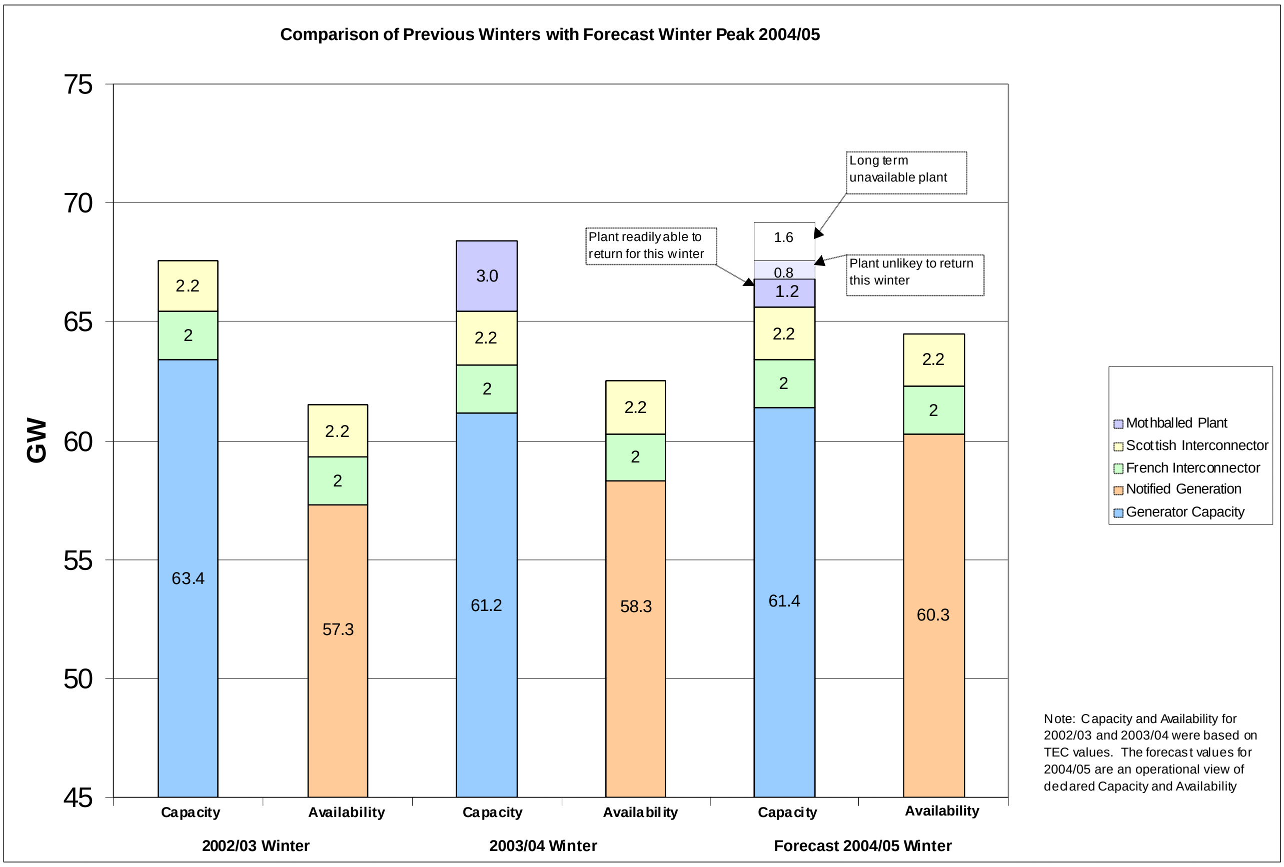
73. Given the run of mild winters since the introduction of NETA it is difficult to assess how the market will respond to very high demands / prices based on the observable behaviour to date, and no additional demand response has been assumed further to that observed to date.

Notified Generation Availability

74. The current forecast Plant Margin for winter 2004/05 is 20.2%, based on a transmission contracted generation capacity of 67.2 GW, as described in the July update to the 2004 SYS. The NGT forecast of actual generation capacity anticipated to be operationally available for winter 2004/05 is 65.6 GW. In addition, a further 2.0 GW of plant has been mothballed by releasing its Transmission Entry Capacity, which could choose to return, and thus increase the plant margin to 23.8%. Of this plant, 1.2 GW could reasonably be expected to return for this winter under appropriate market conditions.

75. Figure 17 shows that the forecast generation capacity has increased over the transmission contracted generation capacity of the last couple of years. The increase is due to the commissioning of new plant and the return from mothball of other plant.

Figure 17 – Forecast Winter Peak Availability



76. In addition to the declared generation capacity, there are a number of generating plants presently in mothballs. The generating companies provided us in June 2004 with a list of the 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. This has fed into our operational view of the return of mothballed plant:

Table 5 – Mothballed Capacity, Winter 2004/05

	Could Return This Winter	Unlikely to Return This Winter	Long Term Unavailable Plant
Generation capable of being returned within period (GW)	1.2	0.8	1.6

Contracted Reserve

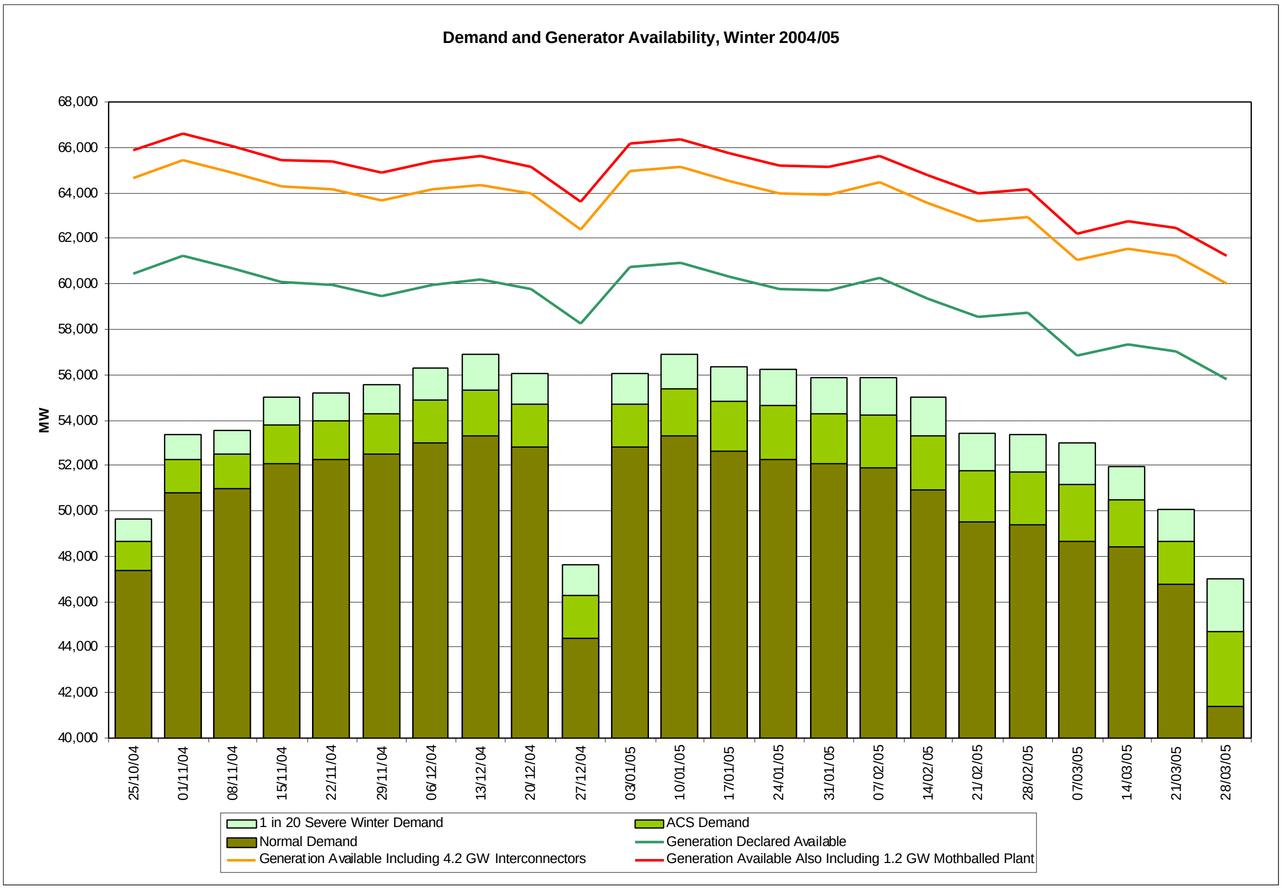
77. At certain times of the day NGT needs extra power in the form of either generation or demand reduction to be able to deal with actual demand being greater than forecast demand and plant breakdowns. This requirement is met from synchronised and non-synchronised sources. NGT procures the non-synchronised requirement by contracting for Standing Reserve, provided by a range of service providers including generating units, demand reduction and independent generating plant. For winter 2003/04, we contracted for 2.0 GW of Standing Reserve via an annual tender round and a further 0.9 GW via the Supplementary Standing Reserve (SSR) tender in November 2003. For winter 2004/05, the volume of contracted Standing Reserve is currently 2.2 GW, of which around 0.6 GW is provided outside of the Balancing Mechanism. NGT has recently invited market participants to tender for SSR for this coming winter, with a view to NGT procuring additional contracted reserve, if economic.

78. Frequency Response Services consist of automatic actions that happen within seconds in response to a large change in frequency (e.g. when a large generator trips off the system). In generators, this would normally be provided by governor action on synchronised plant. On demand side, it is initiated using low frequency relays to trip demand. In order to provide a reliable service, there has to be a reasonably steady and predictable demand so that a physical effect will occur when required. The ability to provide response is mandatory under the terms of the Grid Code for large generators, but in addition to the mandatory services, contracts continue to be struck directly with individual response service providers to ensure the firm availability of commercial response services.

Forecast Position for Winter 2004/05

79. Figure 18 reflects the forecast normal peak demand for the winter of 53.3 GW and an ACS peak demand forecast of 55.4 GW. The generation available is the forecast availability declared to NGT by the generators under the Grid Code Operating Code 2, and as such does not have a full allowance for generator breakdowns or station demand. With full exports from Scotland and France the excess generation over normal demand will be around 9 - 11 GW. This surplus will be eroded if only 3 GW of imports are sustained over the peak demands as has occurred over the preceding two years. In addition, Figure 18 does not reflect the requirement to hold Contingency or Short Term Operating Reserve, of which around 6 GW in total comes from generation shown in this figure.

Figure 18 – Demand and Notified Generator Availability, Winter 2004/05



80. From the above graph it can be seen that there is a surplus generation over ACS demand of 9 GW in mid December 2004, allowing for 4.2 GW of imports and 1.2 GW return of mothballed plant. However, this is reduced to 3 GW after taking in to account the NGT Day Ahead Operating Reserve Requirement. Whilst this margin could be reduced still further due to abnormal levels of generator breakdowns, in most scenarios there should be sufficient generation to meet ACS demands.

81. The forecast demands with day ahead operating margins are shown for both average and ACS conditions below:

Figure 19 – Forecast Demand and Notified Availability – ACS Conditions

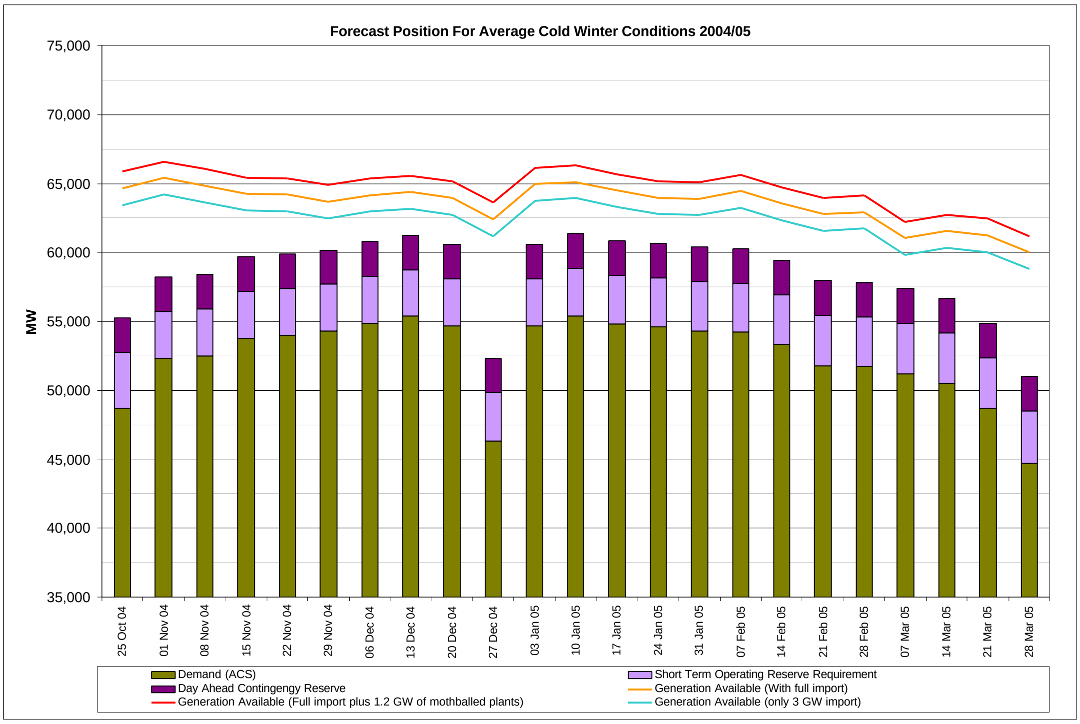
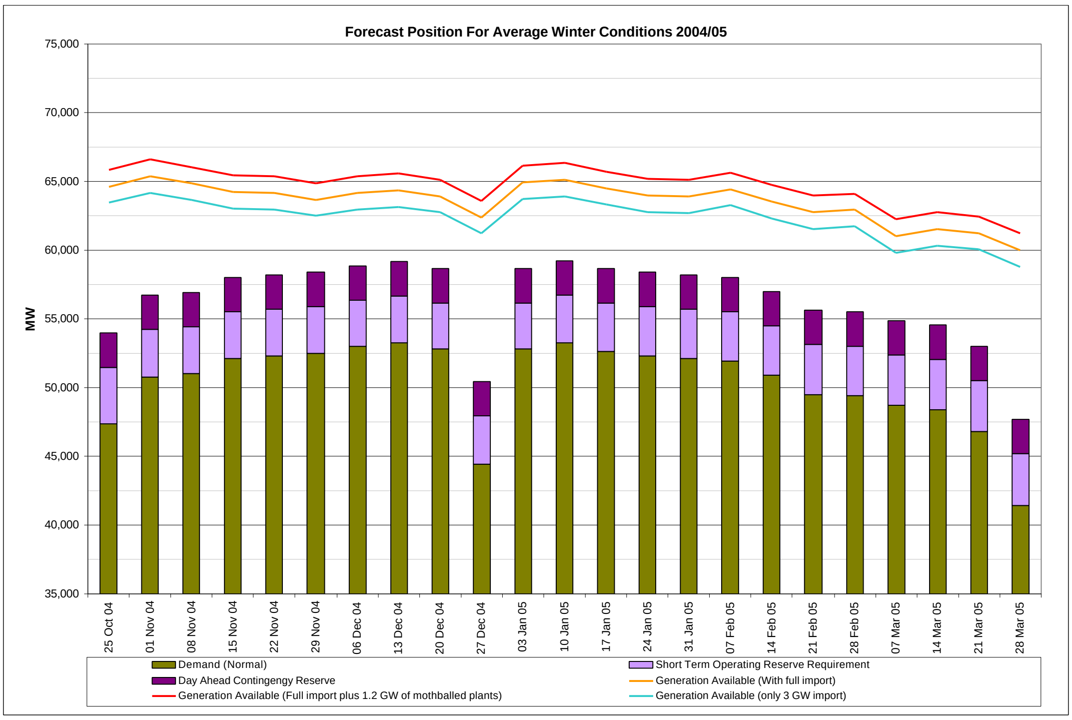


Figure 20 – Forecast Demand and Notified Availabilities – Average Winter Conditions



82. In even colder, severe winter conditions, as may be expected in a 1 in 50 winter, demand may increase in the order of 2 GW above ACS demand. Under these circumstances, the anticipated margin would be sufficient, provided we do not experience high levels of plant breakdowns. During such weather conditions, as there would be an increased likelihood of CCGT interruption to support the gas market, security of supply will be dependent upon appropriate response from both the electricity and gas markets.

83. In a severe winter, if there were very low probability generation failures, above the levels normally experienced, there may be a need to apply the existing operational arrangements whereby demand reductions can be instructed, potentially providing additional short duration margin of around 3 – 4 GW, to maintain security of supply. Demand reductions can be achieved by the Distribution Network Operators (DNOs) by voltage reductions. Such a combination of low probability circumstances is improbable, and any applied voltage reductions should not be discernible to the domestic end customer.

Conclusions

- The current 2004 Seven Year Statement Plant Margin (July Update) for winter 2004/05 is 20.2%, based on a transmission contracted generation capacity of 67.2 GW. In addition, a further 2.0 GW of plant has been mothballed by releasing its Transmission Entry Capacity, which could choose to return and thus increase the plant margin to 23.8%. At this stage last year, the plant margin as reported in the Seven Year Statement for 2003 was 16.2%, though with generation returning during the winter the actual margin was 21.6%.
- The above level of generation availability will be sufficient to meet demands expected under average cold spell (ACS) conditions.
- In low probability severe winter conditions, demand may increase in the order of 2 GW above ACS demand. Under these circumstances, the anticipated margin would be sufficient, provided we do not experience high levels of plant breakdowns. As there would simultaneously be an increased likelihood of CCGT interruption to provide a gas supply/demand balance an increased reliance would also be placed upon those CCGTs that are able to run on distillate.
- If there were a combination of very low probability events (e.g. extensive generation failure and/or severe winter demands) a balance may be achieved by applying voltage reduction over restricted periods which should not be discernable to domestic end customers.

Section C – Gas / Electricity Interaction

Power Generation Gas Demand

84. The maximum contractual power generation gas demand in England and Wales for winter 2004/05 is shown in Table 6. These figures include plant commissioning in 2004/05, but exclude power stations whose gas supply does not pass through the NTS and smaller embedded power generators, typically Combined Heat and Power stations.

Table 6 – Maximum Power Generation Demand 2004/2005 for England and Wales

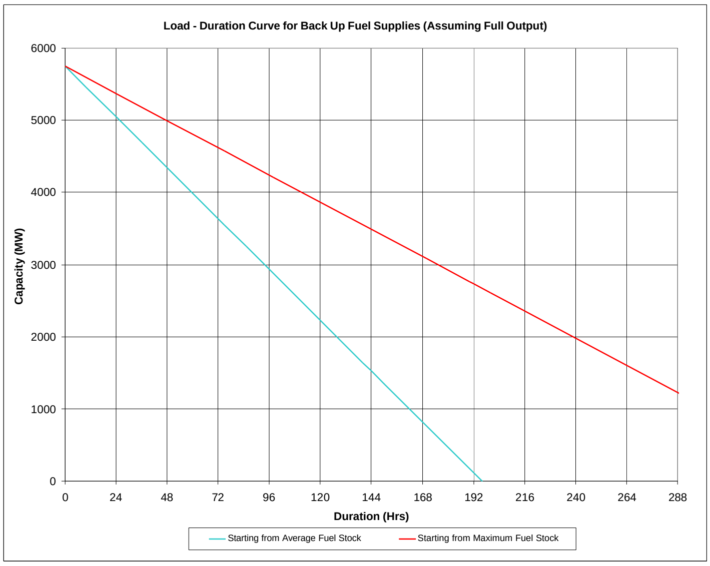
	Firm	Interruptible	Total	Number
	mcm/d	mcm/d	mcm/d	of CCGTs
NTS Connected	61	26	87	29
LDZ Connected	3	2	5	4
Total	63	29	92	33

85. Across winter 2003/04, the peak daily demand from large power generation sites, on a diversified basis, was only around 60-70 mcm. Demand from power stations with firm transportation arrangements tended to be 40-45 mcm on peak days, whilst demand from CCGTs with interruptible transportation arrangements typically was 20-25 mcm on peak days.

Power Stations with Alternative Fuels

86. Around 6 GW of gas fired plant has the capability to run on alternative, back up, fuel supplies. Based upon information submitted by generating companies, as required by the Grid Code, the load duration curves for back up fuel capacity is detailed below:

Figure 21 – Load Duration Curves for Back Up Fuel Supplies



87. Figure 21 shows the decay of capacity of generation available from back up fuels 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 normal fuel stocks and maximum fuel stocks. Note that this graph is not intended to suggest that all plant with back up fuel capability would run continuously on back up fuel supplies for several days or at full load. In reality different plants would adopt different commercial strategies. It would be reasonable to assume that most of this capacity would only run on back up fuel over the peak demand periods of the day.

Potential for Demand-Side Response from Gas Fired Generation

88. Gas-fired stations have the potential 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 power stations with NGT interruptible contracts, with some recent experience of firm CCGTs commercially self-interrupting. Of the total England and Wales CCGT capacity of 22 GW, around 4 GW of commercial interruption has been sufficient to maintain a balance in recent winters.

89. There has been evidence of the electricity market responding to high forward and on-the-day gas prices, but this response has been for relatively short periods and on days of non-peak electricity demand and benign electricity prices. The willingness of the CCGTs to commercially interrupt themselves will be determined by the spark spread, which is itself influenced by the ability of the power generation sector to switch to other fuels and the level of electricity demand. Out of a total of 22 GW of CCGTs currently declared available for winter 2004/05, 6 GW have back-up fuels, most of which have interruptible transportation arrangements, and a further 2 GW also have access to gas through non-NTS pipelines.

90. Given the within-day profile of electricity demand, there is more scope for gas-fired generators to reduce their gas demand outside the peak half-hours of the day, as well as at other times of low electricity demand, such as at weekends and during holiday periods.

91. Since we published our preliminary Winter Outlook Report, we have carried out a detailed analysis to estimate the potential extent of CCGT demand reduction that may be possible in response to high gas prices, whilst ensuring that electricity demands continue to be met. This analysis has been based on simulations of gas and electricity demand under historical weather conditions, and has required a number of assumptions over the availability of plant and the potential (both physical and contractual) for generators to switch in response to sufficiently strong price signals.

92. In relation to plant availability, we have used typical unavailability rates to derive assumed plant availability factors. These are shown in the following table.

Table 7 – Assumed plant availability factors for demand-side response analysis

Power Station Type	Factor
Coal	90% (a reduction of 10%)
Oil	90%
Nuclear	95%
OCGT	95%
CCGT	100% (no reduction)

93. A key assumption in this modeling is the order in which the various generators are assumed to be used within the simulation analysis. This assumed 'ranking order' varies according to the level of simulated gas demand. For relatively low winter gas demands, the ranking order is based on typical operational behaviour experienced in previous winters. The results, however, are relatively insensitive to this assumption. Once gas demand reaches the level of assumed maximum beach supplies plus imports, the ranking order changes to one in which CCGT power stations are moved towards the bottom of the list, but reflecting certain assumptions concerning the operation of plant. For example:

- that an element of CCGT is "must run", i.e. they have existing obligations to industrial processes;
- that CCGTs directly connected to offshore gas supplies , i.e. not necessarily supplied via the NTS, would also operate as baseload;
- that while there are no explicit constraints applied to coal generation in terms of fuel stocks, CO_2/SO_2 emission limits etc, the presence of the above baseload CCGT generation reflects the likelihood that some coal generation would not run at baseload as a result of such constraints;
- that some units have reserve and response obligations to NGT;
- that the market works efficiently and has sufficient notice to substitute coal for gas;
- that on days when gas demand is above the level at which LNG would normally be utilised, an allowance for use of distillate at gas-fired stations is incorporated;
- that imports into the England & Wales electricity market through the French and Scottish Interconnectors would be available at the full, combined rate of 4.2 GW, rather than the normal import level of 3 GW.

94. The ability of the markets to operate in a manner consistent with these assumptions is largely untested given the succession of mild winters experienced in recent years, which has necessitated only a low requirement for gas demand-side response. In particular, the ability of the electricity market to switch extensively and consistently to other fuels is untested.

95. As detailed in Figures 22 and 23, the results of these assumptions are that approximately 6.5 GW of CCGT plant, including those running on direct gas, is

modelled as running baseload on the coldest days, and another 7-10 GW is restricted to generation across the peak 15:00–21:00 period. This compares with a baseline assumption of 12 GW running baseload, and a further 8-10 GW running at the peak.

Figure 22 – Assumed plausible generation pattern on a high gas demand day

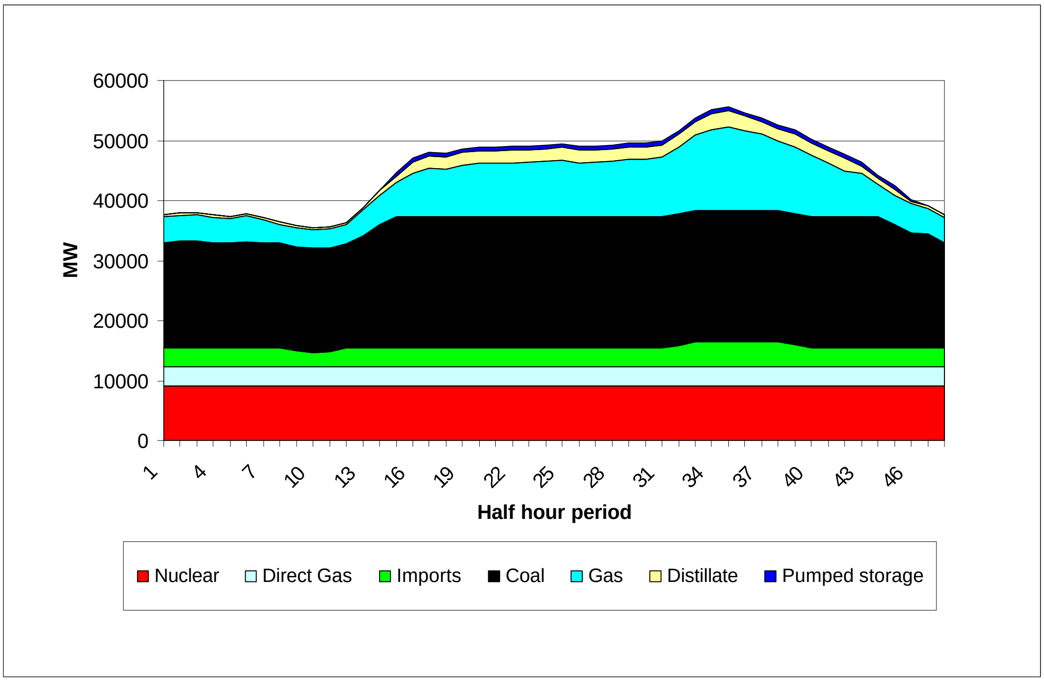
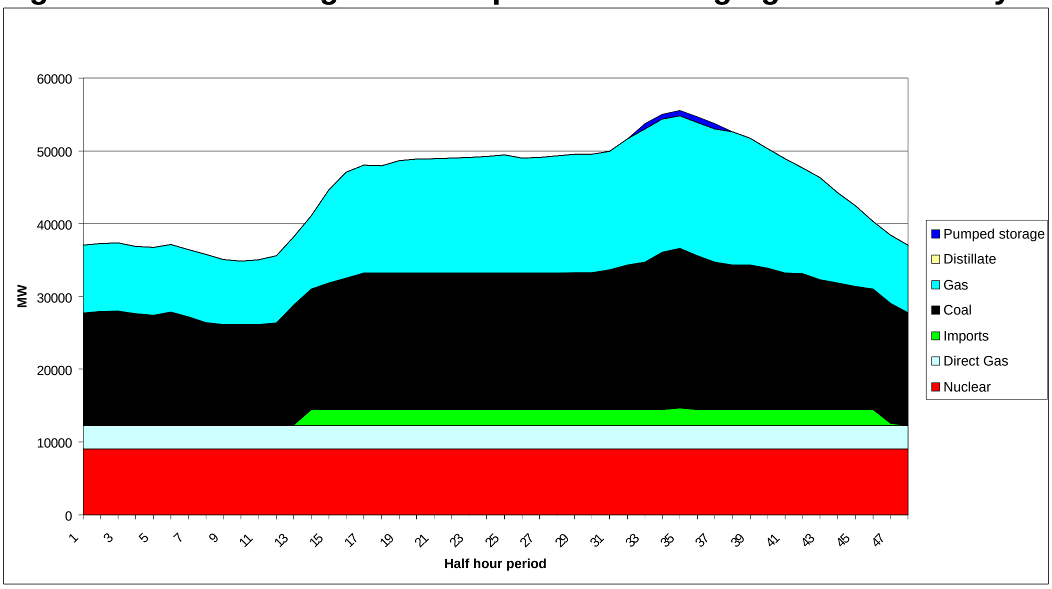


Figure 23 – Baseline generation pattern on a high gas demand day

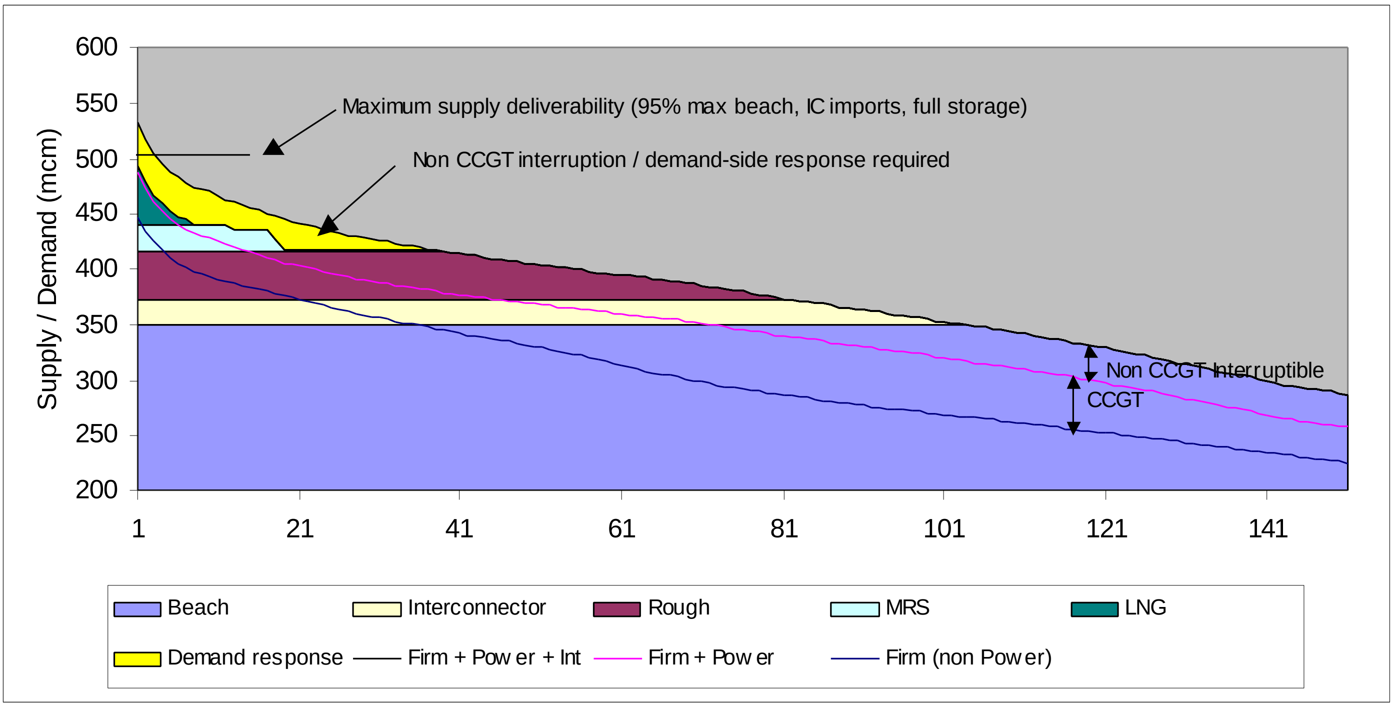


96. In Section B we explained that our analysis indicated the requirement for around 2.4 bcm of gas demand-side response in a severe winter. Given the scenario described above, our analysis suggests a potential contribution to this requirement from the CCGT sector of up to 1.6 bcm may be possible under 1 in 50 winter conditions provided the market reacted in such a way as to minimise gas demand from CCGTs. As detailed in Section B, a decline of 1 GW in baseload gas-fired

generation for 40 days reduces total gas demand by 0.2 bcm. This 1.6 bcm demand response is therefore equivalent to 8 GW less baseload CCGT running for well-over 1 month. Gas demand side response could also be achieved indirectly if the electricity demand response to high prices is greater than that observed to date and assumed in our modeling. However, the scale of total demand response assumed in our modeling is far in excess of that either required or seen to date.

97. Figure 24 illustrates this analysis by way of a 1 in 50 load duration curve. CCGT demand implied by this scenario is shown above non-CCGT firm demand. Non-CCGT interruptible demand is indicated at the top of the curve. The yellow block indicates the residual interruption and/or demand-side response that would be required from other sectors of the market for supply and demand to balance in a 1 in 50 winter. Under these circumstances, the required response is 0.8 bcm.

Figure 24 – 1 in 50 load duration curve analysis for 2004/05



Conclusions

- Our analysis suggests a potential contribution from the CCGT sector of up to 1.6 bcm may be possible under 1 in 50 winter conditions provided the market reacted in such a way as to minimise gas demand from CCGTs.
- This compares with an overall requirement of 2.4 bcm, leaving a residual requirement of 0.8 bcm to be met by the non-CCGT sector.

Section D – Ongoing Developments to Industry Codes and Arrangements

98. This section reflects ongoing industry discussions concerning the development of the commercial frameworks relating to security of supply.

99. There are a number of modification proposals in progress in both the gas and electricity market intended to enhance security of supply for winter 04/05 and beyond. However, the timescales associated with code governance processes, Safety Case submissions, and any necessary development of IT systems to implement modifications, may prohibit some of these changes taking effect before winter 2004/05.

Network Code

Top – up regime

100. We note the view set out in Ofgem’s recent document ‘The Review of Top-up Arrangements in Gas: Conclusions Document’ that Top-up arrangements should be removed from the Network Code. We also note Ofgem's concerns over the potential for the present Top-up arrangements to distort competition in the wholesale gas and gas storage markets. As a result of Ofgem’s document, and consistent with our proposed Safety Case revision to introduce a system of safety monitors, we have raised an Urgent Modification Proposal 0710 ‘Removal of Top-up Arrangements’. Implementation of this Proposal would ensure that we continue to meet our obligations under our Safety Case and GT License, particularly those relating to the safe and efficient operation of the System, whilst removing a potential source of distortion to competition in the wholesale gas and gas storage markets. This Modification Proposal is currently awaiting a decision from Ofgem.

Other Security of Supply related Modifications

101. Should Modification Proposal 0710 not be implemented prior to this coming winter, then we would see benefit in taking forward the specific issue of the current methodology for the calculation of the Top-up Market Offer Price (TMOP) as it does not consistently provide the most appropriate incentives for shippers to balance. In order to partly address this, NGT has raised Modification Proposal 0671 “Enhancements to Winter Injection Process” which addresses a consistency issue in respect of the TMOP. This Modification Proposal is currently awaiting a decision from Ofgem.

102. In our 2003/4 Winter Outlook Report we raised the issue of the potential effect that the interruption of CCGTs would have on generation margins. In response to these concerns we raised Modification Proposal 0657 – Partial ‘Volume’ Interruption Service which was designed to allow Supply Points that have Partial Interruption arrangements to offtake a restricted volume of gas, with no restriction to the hourly

'rate', other than that which normally applies at the Supply Point. This would allow customers such as CCGTs to profile their gas demand take over the day so that they could continue to receive gas at times that it is most valuable to them (e.g. during the periods of electricity peak demands). This proposal was rejected by Ofgem.

103. Given the forecasts in this report, there is an increased possibility of significant volumes of supply and demand balancing related gas interruption this winter. Therefore, we have raised Modification Proposal 0702 'Partial volume interruption'. This Proposal is designed to allow Supply Points that have Partial Interruption arrangements to offtake a restricted volume of gas, with less restriction to the hourly 'rate' when they are subject to Interruption for Supply and Demand management reasons. This proposal is awaiting a decision from Ofgem.

104. We have also proposed Modification 0705 'Changing the Basis for Triggering Supply Demand Interruption', along with an associated consultation on changes to our System Management Principles Statement. Modification Proposal 0705 seeks to better define our role as residual system balancer in relation to interruption of gas supplies due to an imbalance between gas deliveries and offtakes. The Modification Proposal changes the existing trigger for our ability to call for such interruption from one of demand level to one of only using such interruption to avoid entering a gas supply emergency. This proposal is awaiting a decision from Ofgem.

Imbalance Prices

105. NGT welcomes Ofgem's announcement of a review of the current gas cashout arrangements. We consider that the design of cashout pricing mechanisms should strive to reflect all the costs incurred in balancing the system. The market would then have a clear signal of the costs of securing the system during the balancing period and market participants would have the incentives to try to ensure balance for low probability events.

Gas Information Initiatives

106. As part of the DTI information initiative, NGT is proposing to facilitate publication of the following information over the next 12 months:

Table 8 – Information Initiatives

Information description	Timescale
Deliverability with respect to planned maintenance, aggregated to 2 national zones – North and South	Q4 2004
End of day NTS system entry flows	Q4 2004
Forecast NTS System Entry hourly flows – North and South	Q1 2005
Actual NTS System Entry hourly flows – North and South	Q3 2005

107. This information will be made available via NGT's Information Exchange website – http://info.transco.co.uk/

Other Gas Balancing Issues

108. Our balancing tools have been developed with a residual balancing objective assuming that the commercial incentives set out by the Network Code will deliver gas flows on the system so as to satisfy operational requirements. Provided this remains the case we believe that the regime can be operated in an economic, efficient and co-ordinated manner.

109. Current modelling and use of linepack suggests we will be able to continue to manage within-day flow rate variations. This depends on there being no material increases in input and offtake flow rate variations, which would further reduce the availability of linepack flexibility. We will be working with Ofgem and Shippers to ensure that we receive accurate and timely information in relation to this.

110. We remain of the view that should further increases in the within day flow variation become apparent it will be essential to consider reform of the regime, although as previously stated we would advocate incremental reform that might better enable the preservation of the daily balancing regime.

Connection and Use of System Code

Short Term Transmission Access

111. We are pleased to note that Ofgem has approved CUSC Amendment Proposal 070 Alternative Amendment Proposal. This provides for short-term firm finite access products to facilitate the within year return of plant and serves to provide an additional avenue for generation to be returned and hence improve security of supply. The associated changes to the Transmission Charging Methodology Statements have also been approved by Ofgem. The changes to the CUSC and Charging Methodology Statements will enable short term access to be offered from 1 November 2004.

Maximum Generation Service

112. We are also pleased to note that Ofgem has approved the changes to CUSC to facilitate the implementation of an enduring maximum generation service (CUSC Amendment Proposal 071). Changes to the Grid Code and statements established pursuant to Special Condition AA4 of the Transmission Licence have also been approved. All the changes become effective on 1 October 2004 and NGT is now working towards getting the bilateral contracts in place with service providers. We hope that this will provide us with access to some 800 MW of additional generation capacity thus improving security of supply.

Grid Code

Alternative Fuel Capability

113. Changes to the Grid Code have previously been approved to allow for collection of information relating to mothballed plant and the ability of generators to switch to alternative fuel sources (e.g. CCGT station switching over to distillate). This information has now been collected as part of the planning data submitted by generators and has been used during the compilation of this report.

Review of Electricity Market Information

114. We are also pleased to note that Ofgem has approved changes to the Grid Code that change the way that generators submit Output Usable information to us. This change, along with a number of other developments that NGT is implementing at the same time, 11 October 2004, is designed to provide additional transparency and consistency on the margin of generation above demand across different timescales. We will also be providing additional information on the volume of reserve we will be seeking to procure on the day, and the actions we take to do this.

Balancing and Settlement Code

Imbalance Prices

115. Energy imbalance prices are essential in providing key signals to the market and should be designed to provide incentives for participants to trade energy ahead of Gate Closure and be in a position to be able to balance their positions at Gate Closure. For some time NGT has been of the view that the current mechanism for calculating imbalance prices (as described in the BSC) is not providing strong enough signals and that a move to a marginal pricing methodology would be more effective in meeting the overall objectives of imbalance prices. We welcome Ofgem's initiative to undertake a review of the cashout arrangements and look forward to engaging with the industry in a constructive debate. We note that no changes, which may improve security of supply, will be possible ahead of winter 2004/05 and note Ofgem's comments that the cashout review will focus on changes that could be implemented ahead of winter 2006/07.

Appendix I - Glossary

"1 in 20" gas peak day

The 1 in 20 peak day gas demand is the peak day demand that, in a long series of winters, with connected load being held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters each winter being counted only once.

The 1 in 20 standard is the established security standard in the gas industry for the peak day. Under its Gas Transporter Licence, Transco is required to develop its system to have the capacity to transport 1 in 20 peak demand."

"1 in 50" gas demand

The 1 in 50 severe annual gas demand is the annual demand represented by the area (above a demand threshold of zero) under the 1 in 50 load duration curve, being the curve which, in a long series of years, with connected load held at the levels appropriate to the year in question, would be such that the volume of demand above any given demand threshold (represented by the area under the curve and above the threshold) would be exceeded in one out of 50 years.

The 1 in 50 standard is the established security standard in the gas industry for severe winter planning. The Network Code requires Transco to forecast 1 in 50 system demand and to use this forecast in its Top-up calculations.

Average Cold Spell (ACS)

Under Special Condition AA2 of the Electricity Licence, the licensee is required to plan, develop and operate the licensee's transmission system in accordance with "NGC Transmission System Security and Quality of Supply Standard", Issue 2 (dated November 2000) (known as the SQSS), among other standards.

The SQSS includes the following definitions:

ACS Peak Demand
The estimated winter peak demand (MW and Mvar) on the NGC Transmission System for the Average Cold Spell (ACS) condition. This includes both transmission and distribution losses and represents the demand to be met by Large Power Stations (directly connected or embedded), Medium and Small Power Stations which are directly connected to the NGC Transmission System and by electricity imported into the NGC Transmission System from External Systems across External Interconnections.

Average Cold Spell (ACS)
A particular combination of weather elements which give rise to a level of peak demand within a financial year (1 April to 31 March) which has a 50% chance of being exceeded as a result of weather variation alone.

The ACS Peak Demand is used in the SQSS in the derivation of the required Planned Transfer Capacity of the Transmission System.

In order to generate the forecast ACS, the weather conditions seen in each week over a historic 22-year period are analysed and a probabilistic distribution generated. The weather conditions are described using NGT derived variables for temperature, cooling power and illumination from MET Office data. The probabilistic distribution is used to generate both the mean (normal) and ACS demand forecasts.

To calculate a mean weekly demand forecast, the mean expected weather conditions from the probabilistic distribution are fed into the demand forecasting model used for operational forecasts (as published to the market on the BMRS). This is the ‘normal’ demand forecast.

The weekly ACS demand forecast is produced using the same model using the weather conditions corresponding to the 12th percentile of the weather distribution rather than the mean expected weather conditions. That is to say that there is a 12% chance that the weather conditions in the week itself will be worse than those in the weekly ACS forecast.

The methodology of using the 12th percentile was established as the maximum of the weekly ACS peaks in any winter (which are typically weeks 50/51 and weeks 2/3 depending on the position of the holiday period) also gives the Annual Peak ACS demand (i.e. a 50% chance of being exceeded in any winter).

Electricity Demand

Unless otherwise noted, the electricity demands used in this report are normalised (weather adjusted to average weather conditions for the appropriate period), unrestricted (ie exclude potential notified customer demand management) and excluding interconnector demands, pumping loads and generating station demand.

Operating Reserve

Short-Term Operating Reserve consists of Short Term Reserve (STR) and Reserve for Response. STR is the availability of generation or demand reduction maintained by NGT that can be manually instructed to allow for the effects of Electricity Demand Forecasting Errors or Generation Shortfall between the Final Planning Stage (3-4 hours ahead of Real Time) and Real Time itself. Response is necessary to manage second by second fluctuations in frequency caused by a mismatch in generation and demand. Reserve for Response is the headroom on synchronised plant necessary to deliver such Response.

Day Ahead Contingency Reserve is the additional reserve required over and above the Short Term Reserve Requirement to allow for the effects of Electricity Demand Forecasting Errors or Generation Shortfall between the day ahead stage and the Final Planning Stage.

Undiversified Demand

Diversity in the context of gas demand refers to how the demands at different points of the network are added together. To forecast undiversified demand, the peak demands are calculated for each location separately and then summed. Diversified demand is forecast by modeling the aggregated demands over all locations first, and then calculating peak day demand from the aggregate number.