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JOINT ENERGY SECURITY OF SUPPLY WORKING GROUP (JESS) THIRD REPORT

November 2003

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www.dti.gov.uk/energy/jess

Contents

The JESS group

In July 2001, DTI and Ofgem set up the Joint Energy Security of Supply working group (JESS) to assess risks to the UK's future gas and electricity supplies. This is its third report, covering the period March to October 2003.

The terms of reference of the JESS group are:

- to assess the available data relevant to security of supply, to identify the gaps in that data and develop appropriate indicators;
- to monitor at a strategic level, over a timescale of at least seven years ahead:

(a) the availability of supplies of gas;

(b) the availability of supplies of electricity and fuels used for electricity generation;

(c) the adequacy of generating capacity; and

(d) the adequacy of the UK's gas and electricity infrastructure.

- to assess whether appropriate market-based mechanisms are bringing forward timely investment to address any weaknesses in the supply chain that are anticipated;
- to identify relevant policy issues and consider implications;
- to report twice yearly to the Secretary of State and the Gas and Electricity Market Authority.

Introduction

1. The JESS group, chaired jointly by DTI and Ofgem, brings together contributions from DTI, Ofgem, National Grid Transco (NGT) and the Foreign and Commonwealth Office (FCO) on energy security. The work that JESS undertakes on security of supply is focussed on the medium- to long-term, rather than the short-term. Short-term security of supply issues are managed by NGT[1] and monitored by Ofgem and the DTI outside of JESS.

2. This report covers the work of JESS between March and October 2003 and sets out how the group has built on its initial programme since its second report (February 2003)[2].

THIRD JESS WORK PERIOD: MARCH – OCTOBER 2003

3. JESS continued to monitor the progress of infrastructure projects and develop the indicators, looking closely at electricity generating capacity, the timing of crucial gas infrastructure projects, gas availability from the UK's North Sea gas fields and market developments such as forward prices and demand response.

4. Within the bounds of commercial confidentiality, JESS aims to ensure that energy companies, investors and consumers have access to as wide a range of information as possible. In a market-based system such as the UK's, the provision of adequate energy supplies to meet demand depends on effective market responses, which in turn relies on market players having accurate information to inform their expectations about future prices. JESS has therefore been working to improve the flows of information to the market, including on the potential availability of mothballed generating plant and distillate back-up fuel at gas-fired power stations. Since the last report there have been three full JESS meetings and a number of more specialised discussions. More information on specific work areas is given in the sections below.

5. Forward prices in both the gas and electricity markets rose significantly over the third work period (see Charts 7 and 8). In particular, peak wholesale electricity prices for winter 2003/04 have risen by around 60per cent since their lowest point in August 2002.

6. Rising forward prices are likely to stimulate investment in the electricity sector, by signalling opportunities for entering the markets. They are also likely to encourage the return of mothballed plant to generation.

7. On 19 August 2003 PowerGen announced the return of one mothballed unit (650 MW at Grain) for the coming winter, raising the projected plant margin for the winter to 17.7per cent. On 15 October PowerGen announced that they were starting work for potential de-mothballing of another 650 MW unit at Grain and on 16 October International Power announced their intention to de-mothball a 250 MW unit at Deeside from 20 October. In addition, it is understood that Innogy intend to operate two of the units at AES Fifoots Point, and production at Dinorwig is expected to return.

8. Taking account of these developments, the projected plant margin, reflecting installed capacity as formally notified to NGT, is around 19per cent, compared with 16.5per cent in the July update to the Seven Year Statement. As in previous years, the figures assume that all generating capacity formally notified to NGT is in fact available to generate and that the Interconnectors would import at full capacity if required.

9. In the gas sector, the second round of LTSEC (Long-Term System Entry Capacity) auctions was held in September. Bids were received from some shippers out to 2020: these bids provide useful information about the demand for entry capacity at different entry points over this period. This is discussed further in paragraph 41 below.

1 And, in the case of electricity, by the Scottish System Operators.

2 JESS reports are available on the DTI website at www.dti.gov.uk/energy/jess, or in hard copy from:
DTI Publications Orderline, www.dti.gov.uk/publications, Phone: 0870 150 2500, Address: ADMAIL, 528, London, SW1W 0YT
Email: publications@dti.gsi.gov.uk

10. There has been a review of existing arrangements for crisis management for the upstream oil and gas industry. Some improvements were made and a revised briefing pack was relaunched in September.

11. The Government, Ofgem and industry have been working together to update the plans for handling energy emergencies. The Gas Industry Emergency Committee (GIEC) has developed an Incident Response Plan to coordinate handling major or potentially major losses of supply to consumers. Work is also at an advanced state to bring together these plans and those for electricity to ensure that in any emergency, account is taken of the impact that one has on the other. This work is being coordinated through the GIEC and the Electricity Supply Emergency Code Review Group. It should eventually see the development of a single Joint Response Team under a Gas and Electricity Industry Emergency Committee.

Reactions to the second JESS report

12. A number of firms and individuals have responded with comments and proposals following the publication of the second report. As a result JESS is considering how best to involve the gas and electricity industries – in addition to National Grid Transco – more closely in its work. We will be inviting industry representatives to discuss particular topics at JESS meetings or at meetings with a sub-group of JESS members. There is now an area for JESS on the DTI website where comments received can be posted (unless the authors request otherwise) and non-confidential background papers be made more widely available, www.dti.gov.uk/energy/jess .

13. JESS welcomes comments on any aspect of its work (see paragraph 54 for contact details).

JESS, the Energy White Paper and the Sustainable Energy Policy Network

14. The Energy White Paper was published in February 2003. JESS features prominently in the energy reliability chapter as a key means of monitoring energy security and getting information to the energy markets. The commitments in the White Paper are being delivered by the new Sustainable Energy Policy Network (SEPN) – a network of policy units from across government departments, the devolved administrations, regulators and key delivery organisations that are jointly responsible for delivering the White Paper. The Secretary of State for Trade and Industry formally launched the SEPN web site on 4 June listing the commitments and contact details for the Senior Responsible Officers responsible for delivering the commitments. Over the next few months, as the plans develop, more details of the delivery programme will be added to the SEPN web site[3] to keep stakeholders informed. Joint JESS Chairman Neil Hirst (DTI) is responsible for the SEPN's security of supply work programme.

15. To provide a clear line of accountability for SEPN, DTI has also put in place a new Ministerial group to oversee the delivery of the commitments in the White Paper.

16. The Energy White Paper placed a commitment on Ofgem to produce every six months a retrospective report on the performance of the electricity and gas industries in delivering security. The reports will detail any issues which have given rise to energy reliability concerns and saying what, if any, actions had been taken or might be needed to address those issues in the future. In part, the new Ofgem report will take over from the 'recent events' section in previous JESS reports. The first Ofgem report is expected to be published in November 2003. For future years we intend to issue future JESS reports in March/April and September/October, each followed by an Ofgem retrospective report in April/May and October/November.

3 http://www.dti.gov.uk/energy/sepn/

Understanding interactions in security of supply

17. In the first JESS work period DTI and Ofgem jointly commissioned the development of a computer model to record the collective knowledge about interactions in the gas and electricity markets. A series of workshops and discussions with gas and electricity market experts from the JESS group took place, which identified about 200 variables and (in broad terms) quantified the key linkages. Short-, medium- and long-term influence models were constructed for both gas and electricity by consultants.

18. The intention is to use the model's framework to prioritise the JESS work on different security of supply issues and to identify where indicators are or could be most effectively used. Work is ongoing to develop a software system to utilise this information. Software licence changes have required a change to the original plan and JESS is currently looking at the best way to capture the value from this work. One option is to continue with the influence model approach and another is to utilise a Monte-Carlo simulation approach.

LATEST SECURITY OF SUPPLY DEVELOPMENTS

19. A number of key events relevant to security of supply have occurred since the last JESS report. These events will be discussed in detail within the Ofgem six-monthly retrospective report on security of supply. JESS is primarily a forward-looking group with a medium-term (at least seven years ahead) focus. The summary below therefore does not attempt to give a detailed account of all recent events.

Power cuts: summary

20. On 14 August 50 million people across the north-eastern United States and southern Canada were left without electricity for approximately 25 hours. Following the power cut, a US/Canadian Task force was established to investigate the incident.

21. During the summer heatwave France and Italy experienced shortages of generating capacity, and on 28 September, Italy was hit by its most serious power cut in decades. Over 50 million consumers lost supplies. Sweden and Denmark also experienced a widespread power cut.

22. In the early evening of 28 August, a sequence of events led to the loss of electricity supply to some 410,000 customers in South London and parts of Kent. Power was restored within the hour but there was serious disruption to surface rail, underground, streetlights and traffic systems, water supply and sewerage. Early investigations by NGT suggested that the primary cause of the loss of supply was incorrectly installed protection equipment

23. On the morning of 5 September, some 200,000 consumers in both the East Midlands and West Midlands areas suffered loss of supply. Supply was again restored within the hour. Early investigations by NGT suggest that the loss of supply resulted from the incorrect operation of a protection relay.

24. Ofgem and DTI are continuing with their separate (but coordinated) investigations into the London and Birmingham incidents, both of which were caused by transmission failures rather than a lack of generation capacity. In addition, Ofgem and DTI will continue to assess the extent to which lessons might be learnt for the UK based on developments in international power markets.

25. Parallels have been drawn between the US/Canada power cut and those experienced recently in the UK, but there are major differences. In the UK, the System Operator (NGT) did not lose control of the transmission system. In contrast, the North American event involved an uncontrolled "cascading" blackout that lasted for 24 hours and affected 50 million people.

GB electricity generators

26. There have been a number of corporate transactions involving companies with significant generation capacity. Most notably, the Drax power station, the largest coal-fired power station in Europe, was the subject of a range of bids from parties seeking to take a financial stake in the company. International Power reached a preliminary agreement to take a 30per cent stake in the company in August.

27. British Energy has now formally agreed with its creditors the terms of its proposed restructuring announced on 28 November 2002. This is a significant step forward towards the implementation of British Energy's restructuring plan. The Government has confirmed its support for the plan by entering into agreements which reflect the in-principle commitments announced by the Secretary of State for Trade and Industry on 28 November 2002. A back-stop date of 31 January 2005 has been put in place for State Aids approval to be received and the restructuring to be completed. If any of the restructuring conditions are not met the Government has contingency plans ready for the administration of the company. This means that whether or not the solvent restructuring plan is implemented, the nuclear power stations will continue to be available to generate electricity.

UK gas interruption

28. The unprecedented summer supply interruptions by Transco earlier this year highlighted the importance of having robust arrangements for the provision of information about gas flows and the need for active co-operation and co-ordination between terminal operators and Transco. At the end of July, The DTI asked Transco and the upstream industry terminal operators to work together to review existing practice to ensure that a more robust system was in place, in time for winter 2003/4. The DTI also asked the upstream industry to release operational information to Transco about upstream activity to facilitate efficient system operation and therefore reduce the risk of near or actual emergencies developing. The DTI also asked Transco and the upstream industry to consider what information could be released in aggregated form to the wider market.

29. Agreement has now been reached for the terminal operators to provide Transco routinely with information on planned maintenance and unplanned outages that lead to flow reductions at the onshore terminals. This agreement also provides for discussions to start immediately on the provision of information about maximum gas deliverability at onshore terminals and for further discussions on the release of information to the wider market.

EU and international developments

30. At EU level, the legislative basis for the opening of the internal energy market – two Directives and a Regulation – were adopted by the EU on 15 July 2003 and come into force on 1 July 2004. These require the opening of national gas and electricity markets for commercial customers by 1 July 2004 and for household consumers by 1 July 2007. The Government believes that their application will provide the basis for a properly competitive, European-wide energy market.

31. The UK is taking a lead in the regulation of interconnectors and LNG import terminals in Europe. The first phase of a major study into issues relating to EU and UK gas quality has also been completed.

32. The UK and Norwegian Energy Ministers issued a joint statement on 2nd October 2003 on building co-operation in the North Sea. The main element was the announcement of the key principles to be incorporated in a future treaty between the two Governments. The agreement reached on the key principles will clear the way for the construction of a new pipeline to the UK capable of delivering 20 billion cubic metres of Norwegian gas – some 20per cent of UK annual gas demand – and clarify the regulatory regime which would apply to a range of future potential cross-border oil and gas projects.

New JESS indicators

33. The indicators from the second report have been updated where possible, with new material added. The indicators are set out in Annex 1. The main changes are:

a. Chart 2: Extended to 2009/10 and proven, probable and possible gas developments added to aline it with Chart 1

b. The re-working of Chart 3: implied import dependency, to show a range of different demand forecasts and supply sources.

c. The inclusion of relative volumes traded in Charts 7 and 8, forward gas and electricity prices.

d. The inclusion of dates of planning approval in Table 1, planned major new energy projects.

e. Chart 9, existing and potential gas import capacity, has been discontinued as other sources exist in the public domain that give a more detailed and sophisticated analysis. Details are given in the Indicators annex.

34. The section below gives updates on how the gas and electricity markets have developed since the last JESS report and how this is reflected in the new set of JESS indicators.

The gas market: update and indicator development

35. In the next twenty years, as production from the UK Continental Shelf (UKCS) declines and the UK becomes more dependent on imported gas, there will be an increasing need for new gas supply sources as well as investment in infrastructure projects to meet both annual demand and the seasonal and daily swings in demand. There are a number of potential outcomes:

- additional import connections from Norway, direct to shore or via existing UKCS infrastructure;
- liquefied natural gas (LNG) terminals to import gas from worldwide sources;
- more interconnection with Europe to import gas from the Netherlands, Norway and beyond;
- pipeline upgrades to existing interconnectors to increase import capacity;
- gas storage, both onshore and offshore, to provide additional seasonal and daily swing capacity and to replace capacity which will be lost with the decline in UKCS swing capacity.

36. The previous JESS reports have discussed a DTI forecast[4] suggesting that from about winter 2004/05 there was uncertainty about the adequacy of gas supplies to meet peak gas demand from consumers during a 1 in 20 winter day or during a period of sustained cold weather[5]. The forecasts have now been revised in accordance with Transco's 2003 supply and demand forecast and the latest developments in planned gas infrastructure projects. They are presented in Chart 1 of the indicators.

37. The chart presents a baseline supply forecast of minimum investment in infrastructure, together with three incremental forecasts based on the level of certainty of infrastructure projects being developed: proven, probable and possible, with the certainty level being highest for proven projects and lowest for possible projects (a full definition is provided with the chart).

38. These investment forecasts suggest that the market can respond to the demand for gas in the UK in the next decade and demonstrate that peak gas demand or sustained high demand could be met with maximum supplies from existing and new development projects, although this will be dependent upon implementation of some of the less certain projects. It is important for security, therefore, that a sufficient proportion of the projects currently under

4 Chart 1, Annex 1, and Annex 3 of first JESS report.

5 It is not expected that such demand will be experienced often: the gas industry works on the probability of such severely-cold winter days occurring once every 20 years. The last such day occurred in 1986/87.

consideration proceed to full-scale development in a timely fashion. Examples of new projects which show how the market is reacting include the announcements by Exxon Mobil, Petroplus and, most recently, BP to import LNG to the UK from overseas and the recent agreement of principles with Norway.

39. JESS is also currently looking at gas availability from the UKCS and at the demand side flexibility of the gas market. Demand side flexibility facilitates the balancing of the gas network. Transco has been consulting with the gas industry on the results of research undertaken by consultants NERA to assess the responsiveness of the gas market to high prices at periods of high gas demand. NERA looked particularly at the likelihood of gas-fired power station (CCGT) customers with firm gas supply contracts voluntarily reducing their gas demand at times of high gas prices, for example by switching to a substitute distillate fuel. These customers are the largest single gas users, and their behaviour in response to high gas prices is key to achieving a demand response through market mechanisms.

40. Transco's consultation on the results suggests that CCGT customers with firm contracts might respond to a differential between gas and electricity prices (the spark spread) if it was wide enough, but the response would be very dependent on market conditions and expected to be lower than the 50per cent of CCGT responding that NERA had predicted. Due to the relatively limited feedback and the ongoing developments in the electricity sector, notably the tightening of the electricity market, no allowance for this potential response is currently included in Transco's demand forecasts. Transco will continue its analysis and monitoring of CCGTs that might be willing to self-interrupt in response to high gas prices.

41. In the second LTSEC auction, held in September 2003, NTS entry capacity was offered on a quarterly basis in every quarter until Q1 2020. Bids for capacity were received in a number of these quarters, including Q1 2020 at Barrow, Easington and St Fergus. The major development of the auction was the sale of around 40mcm/d for some quarters at Easington. Bids totalling this amount were placed in the winter quarters (Q4 and Q1) in each year from 2007/08 to 2018/19. This provides useful and objective information on bidders' expected use of this terminal to deliver gas in the future.

Electricity generating availability: update and indicator development

42. Falling wholesale electricity prices during 2001 and 2002 contributed to 'mothballing' of electricity generating plant, to the postponement of construction on a number of new power stations which had received planning permission, and to reductions in projected levels of plant margin (excluding mothballed plant).

43. A new column has been added to Table 1A on whether construction has commenced on new large power stations which have received planning permission. This shows a significant amount of 'approved' plant (around 8 GW) on which construction has yet to commence, which JESS will be able to monitor in future reports. As forward electricity prices have risen in response to a tightening supply and demand position, JESS would expect a gradual increase in construction activity, including the reinstatement of postponed projects. However this would be slowed proportionately if prices had risen partly in response to increases in fuel input prices.

44. Table 1A shows a total of 7,930 MW of approved projects – 5,640 MW of CCGT, 430 MW of ICGCC, 1,207 MW of CHP, and 65 MW of renewables. Since the last JESS report work has started at two large windfarms: North Hoyle (90 MW), where we reported some onshore work in progress in the last report, and onshore at Scroby Sands (76 MW). This table does not take account of smaller renewable generating projects under 50 MW.

45. In response to uncertainties identified by JESS about mothballed plant availability and the availability/use of distillate back-up fuel in combined cycle gas turbine plant, NGT undertook an informal exercise in September to gather information from generators. Its findings were reported in its Winter Operations Report 2003/04, published on 14 October[6]. The informal exercise collected information on mothballed plant and CCGT alternative fuel capability

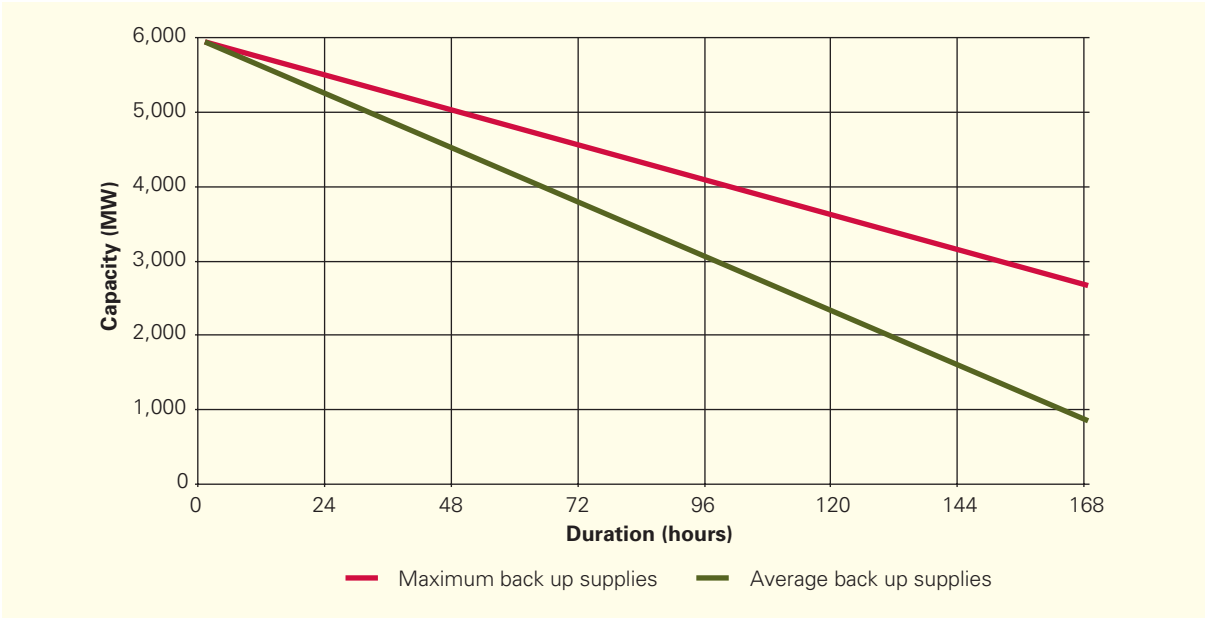
46. A total of 4.2 GW of mothballed plant was identified, of which 2.6 GW had the physical potential to be returned for winter 2003/04. Of the 4.2 GW, 0.5 GW has subsequently returned to service. The following table shows the view given by the generators and contained in the Winter Operations Report, updated in light of recent announcements and changes in contracted positions. More generation is now reported to be capable of returning within three months than generators reported in September.

Timescales for mothballed generation return

	0-3 months	3-6 months	6-12 months	12-24 months
Winter Operations Report				
Generation Capable of being returned (GW)	0.8	0.7	1.6	1.1
JESS 3rd Report				
Generation Capable of being returned (GW)	1.3	0.3	1.0	1.1

47. Of the total 21.6 GW of CCGT plant available this winter, taking into account mothballed and commissioning plant, some 8.6 GW of output is interruptible by NGT and/or gas shippers. The total CCGT distillate capacity across all firm and interruptible gas supplied power stations is 5.9 GW. To protect commercially sensitive information the following graph shows the smoothed aggregated position with regard to alternative fuel capability. It assumes that all CCGTs with this capability, if interrupted (whether by a shipper or NGT), will switch to alternative fuel and are capable of doing so. However, it does not take into account the facts that interruptions may be limited to time periods significantly less than the duration of available distillate stocks, that interrupted CCGTs may choose not to generate throughout the entire day, and that the potential for power station operators to restock between (or during) periods of running on distillate fuel.

Load-duration curve back-up fuel supplies (assuming full outout)



6 Available on the Ofgem website at http://www.ofgem.gov.uk/ofgem/whats-new/index.jsp

48. For future years NGT has proposed a modification to the Grid Code reporting obligations to collect information on mothballed plant and distillate back-up. A Grid Code Working Group has been set up to address this issue. It intends to report to the Grid Code Review Panel in late November, following which the industry will be consulted on the proposed changes prior to a report being submitted to Ofgem.

FUTURE WORKPLAN

49. Over the next six months JESS will continue to develop its work on:

- obtaining and publishing better information on the gas and electricity markets, for example on forward prices, market responsiveness and liquidity;
- refining DTI information about future supply and demand;
- investigating the scope for new indicators and identifying the purpose of any such indicators.

50. In addition, JESS will consider:

- the implications of environmental legislation;
- the outcomes of Ofgem and DTI investigations into the power cuts in London and Birmingham and the work on system resilience following investigations into the storms of October 2002;
- the implications/lessons for the UK of power cuts experienced in North America, Denmark, Sweden and Italy;
- the potential for demand reduction in both the gas and electricity sectors.

51. A more detailed workplan will be placed on the JESS website before the next JESS meeting (scheduled for 11 December 2003). Comments are welcome.

52. Possible new indicators for future reports include:

- **forward prices for gas entry capacity at different entry points and Transco's response to the price signals**, drawing on data from the new long-term gas system entry capacity auctions that started in mid-January 2003 and the second auction in September 2003. The auction of entry capacity rights will indicate the demand for onshore network capacity for up to 15 years ahead. Demand in excess of planned capacity would indicate a potential tightening of the supply-demand balance, in the absence of further network capacity extension;
- building on the NGT information-gathering exercise (see paragraph 45 above) there may over time be scope for an indicator to show **changes in the level of mothballed generation plant and the time needed to return it to service**. This would indicate the ability of the market to respond to relatively short-term changes in electricity supply or demand conditions;
- similarly there may be scope for an indicator of **trends in the availability/use of back-up distillate fuel at gas-fired generating plant**. The ability of generators to use alternative fuel sources would give an indications of the extent to which various fuel supply shocks could impact upon security of gas and electricity supplies, and the extent to which the two interact;
- measures of the availability of gas storage and other flexible sources of gas supply. This would give an indicator of the availability of gas supply sources to meet peak conditions or unexpected events.

53. The table below shows the development of the indicators since the first report:

Jess report	I Supply and demand Forecasts		II Market signals		III Market response	
	Gas	**Electricity**	**Gas**	**Electricity**	**Gas**	**Electricity**
1st report June 2002	Daily gas supply vs. peak 1 in 20 demand – UK Demand duration curves Implied import dependency Import capacity[7]	Electricity generation by fuel type – UK Generator margin – England and Wales Generation profile summer/ winter – England and Wales	Forward gas prices – GB	Forward electricity prices – GB	Gas production capital expenditure – GB Import capacity	Electricity capital expenditure – GB Planned new generation capacity
Added in 2nd report Feb 2003					Planned major new energy projects, including construction status of approved projects	
Added in 3rd report Nov 2003	Demand duration curves developed for three different winters More detailed indicators of how new gas infra-structure projects may meet future peak gas demand		Inclusion of relative volumes traded in forward price charts	Inclusion of relative volumes traded in forward price charts	Dates of planning approval included in table of major new energy projects	
Being considered for future reports			Forward prices revealed at auction for gas entry capacity Gas storage prices	Forward prices for electricity transmission capacity	Availability of demand-side contracting The response of Transco to capacity prices	Availability of demand-side contracting Changes in the level of mothballed generation plant and the time needed to return it to service Changes in the availability/ use of back-up distillate fuel at CCGT plant The response of NGT to capacity prices

7 moved from Supply and demand forecasts to Market response section for 2nd report.

54. JESS is keen to have feedback from a wider audience on its work programme and its developing conclusions and indicators. If you would like to comment, please contact the Secretary to JESS:

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Tel: 020 7215 5293
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Please make clear if you would like your views to be treated as confidential. Non-confidential responses may be summarised or placed on the DTI website.

Annex 1
Security of supply indicators

Background

1. One of the key tasks for the JESS group has been to establish a series of indicators to monitor security of supply. It should be noted that, through this work, JESS does not seek to detract from the roles of National Grid Transco in planning and operating their systems to maintain continuity of supply. Nor does it seek to replace the responsibilities of market participants in gas and electricity to comply with their licence obligations to make adequate provisions to meet their customers' requirements for gas and electricity. The group does, however, believe in presenting such non-confidential information as is available to DTI and Ofgem that may be of use to market participants and observers.

2. The indicators concentrate on issues relating only to gas and electricity. This reflects both Ofgem's areas of interest and the remit of the JESS group. However, security issues do go beyond those presented here and DTI will continue to consider issues such as oil supply as part of its ongoing work on general fuel security.

Developing the indicators

3. Any single presentation of indicators can only provide a 'point in time' analysis of the issues. Furthermore, considerable uncertainty surrounds any forecasts and the extent of the impact that other factors, such as increased energy efficiency (which could reduce energy demand) or global price rises (which may result in increased supply from increased exploration or technical progress) may have on the analysis.

4. Previous experience has shown the difficulties of predicting the future in energy markets, especially over relatively long timescales. Information is, however, now becoming available in the form of future prices (based on commercial contracts) in the electricity and gas markets.

5. The remit of JESS is to look at a timeframe at least seven years ahead. Indicators looking ahead provide an indication of possible future trends, which may inform market participants' decisions, for example about their future investments. Equally, to see market changes in their full context, the future needs to be seen against the background of historic events. Historic data are therefore presented alongside the forecasts where available.

Supply and demand forecasts

6. To meet the forward-looking requirement, JESS has used planning forecasts (primarily from National Grid Transco) and economic modelling data (primarily from the DTI's Energy Projections, EP68). However, because forecast data is subject to uncertainty, especially for long time periods ahead, forecasts should be seen as an informed view of the future rather than an absolute prediction.

Market signals

7. The market signals charts set out forward prices for gas and electricity. These are key indicators in competitive markets. Competition provides the incentive for suppliers to meet their customers' requirements for keenly-priced and secure electricity and gas supplies, or risk losing their business. Competitive markets therefore have an important and increasing role to play in addressing uncertainty through individual participants' own assessment of future customer needs. Through a forward price such uncertainty can be analysed and turned into a value for a product in the future. Thus competitive markets help to provide – mostly through price signals – information which otherwise would not be available.

8. Price signals help consumers, suppliers and producers alike to see when supplies are relatively plentiful or tight. This is particularly important in the gas and electricity industries since the two industries are becoming ever more dynamic, inter-linked and international. This in turn means that the best mix of fuels, generation plant, and indigenous versus imported sources to achieve security of supply in the future will inevitably also be constantly changing. The actions of market participants generate and reveal, through price information, their changing views of the security of supply position. The diversity of market participants and their differing viewpoints create a rich source of information that would not be available from centralised planning.

9. Forward prices for gas and electricity are now emerging several years ahead. For example, the International Petroleum Exchange (IPE) and Heren are publishing price assessments to summer 2006. The development of information on forward prices and liquidity in forward markets will be kept under review by the JESS group.

Market response

10. Market participants are expected to respond to the forward price signals, for example by building additional capacity in response to price increases that signal scarcity. In addition, market participants have been observed to enter into contracts over periods longer than the publicly reported prices. If such capacity was not being built in these circumstances, then it would be important to understand whether there were barriers to building it, or if the forward price signals were incomplete or being distorted, for example by anti-competitive behaviour or by customers being unable to signal clearly the value they place on security.

11. JESS has developed indicators showing the actual market response to forward price signals, e.g. capital expenditure and applications for consents to build new generation capacity.

12. It will be equally important to have information on likely demand-side response, for neither demand nor supply is fixed. This will be an important element of JESS's future work.

I. Supply and demand forecasts

Gas

1 Potential daily gas capacity versus peak gas demand (1 in 20 winter day) – UK

2 Demand duration curves

3 Annual UK gas supply and demand

Electricity

4 Electricity generation by fuel type – UK

5 Generator margin – England and Wales

6 Generation profile summer/winter (England and Wales)

II. Market signals

7 Forward gas prices – GB

8 Forward electricity prices – GB

III. Market response

Gas

9 Import capacity (This chart has been discontinued: see note at section [31] above)

10 Gas production capital expenditure – UK

Electricity

11 Electricity capital expenditure – GB

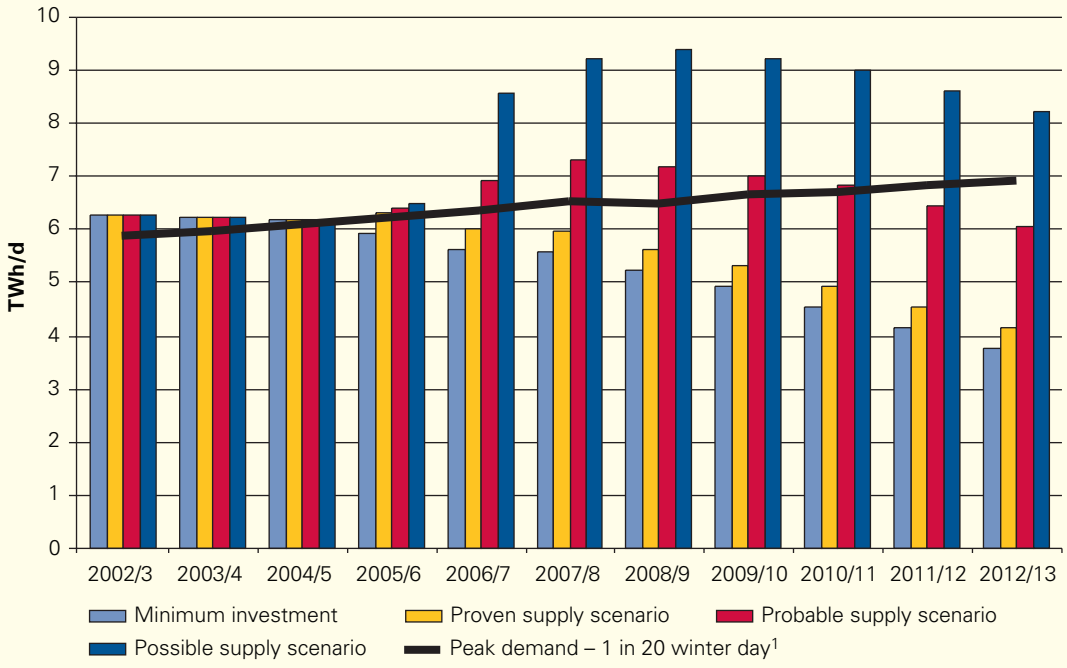
Table 1: Planned major new energy projects

1A Electricity

1B Gas

Supply and demand forecasts – gas

1 Potential daily gas capacity (various supply scenarios) versus undiversified peak gas demand (1 in 20 winter day) – UK



Context:

How the UK will cope with peak gas demand associated with a 1 in 20 winter day over the next 10 years. The potential gap between existing gas supplies (minimum investment forecast) and peak gas demand gives an indication of the opportunity/need to invest.

Key Points:

The chart shows a number of scenarios presented by DTI of how peak demand could be met over the next decade. Since the last JESS report, the overall gas demand forecast has increased due to growth in exports to Europe, plus higher exports to Ireland due to the slippage in the Corrib field development, although this is partly negated by lower forecast demand in the traditional industrial and commercial markets in the UK. However, by 2008/09 there is no difference between this demand forecast and that presented in the last JESS report. Also, a number of projects have been further developed by the market, which should increase the UK's ability to access gas to meet peak demand.

Delays to projects could mean supply shortages, leading to unplanned firm load supply interruption, in 2005/06 or beyond if the UK were to experience peak gas demand during a 1 in 20 winter day. However, in reality market dynamics are likely to result in higher prices as supplies tighten, so those consumers on contracts that are exposed to short term price changes would be incentivised to reduce consumption if technically or commercially viable. Such mechanisms could limit the risk of mandatory load shedding.

The supply data assume that all supply sources are delivering at maximum capability. Experience has shown that for operational and commercial reasons this may not always be the case. UKCS production outages could result in gas supply shortfalls to the UK and cold weather in Europe could see some gas being sold on the continent instead of being delivered to the UK.

Background:

Peak gas demand based on a 1 in 20 winter day is the level of demand that, in a long series of winters, with connected load held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters, with each winter counted only once. Peak gas demand is firm load only and excludes 'interruptible' load.

Undiversified demand assumes that the whole of Great Britain is experiencing a 1 in 20 winter day and therefore demand is at a peak in every region throughout the country. The probability that this level of demand will be experienced is therefore rather less than once in every 20 years.

Minimum investment forecast: There is no major new infrastructure investment offshore or onshore so potential supply falls off in line with the projected decline in UKCS production.

Proven investment forecast: Minimum investment forecast plus those projects which, on available evidence, are virtually certain to be technically and economically successful (ie better than a 90 per cent chance of being developed).

Probable investment forecast: Minimum investment forecast plus proven projects, plus those projects which are not yet proven but have a better than 50per cent chance of being technically and economically successful.

Possible investment forecast: Minimum investment forecast plus proven and probable projects, plus those projects which at present cannot be regarded as probable, but are estimated to have a significant but less than 50per cent chance of being technically and economically successful.

The proven investment forecast makes the following assumptions about investment in gas infrastructure projects:

- Additional compression at Zeebrugge available from 2005/06.
- Some LNG import capacity available from 2005/06.

The probable investment forecast is as above and with the following additions:

- Further LNG import capacity available from 2007/08.
- New interconnection available from 2006/07.
- Additional onshore gas storage from 2005/06.
- Additional Norwegian imports from 2006/07[2].

The possible investment forecast is as above and with the following additions:

- Further import capacity from 2006/07.
- Additional onshore storage from 2006/07, with increases from 2007/08.

Existing supplies include UKCS production, current import capacity through the European Interconnector and links to Norway (Vesterled), plus current onshore and offshore storage.

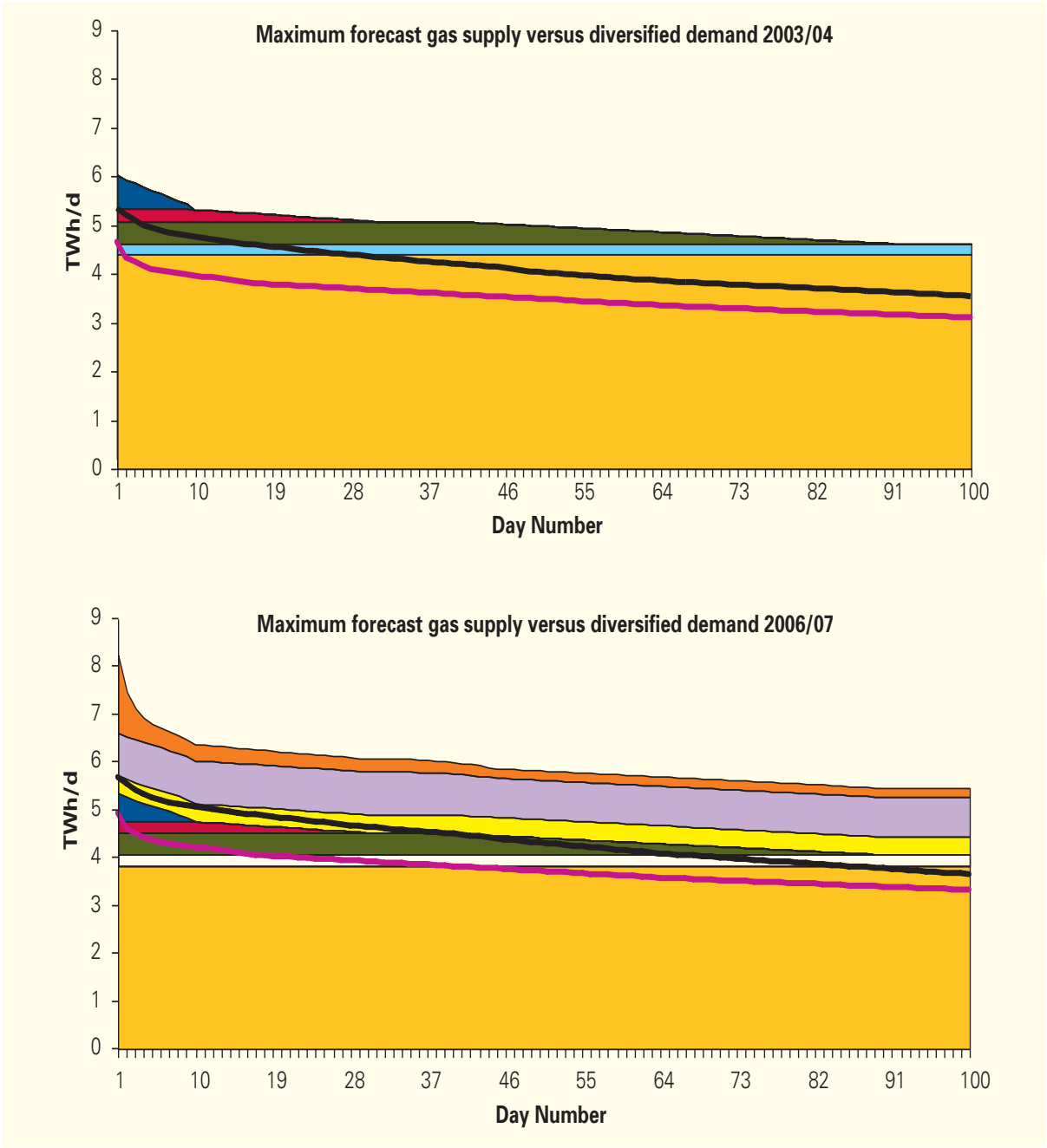
Source:

Peak gas demand and the 'minimum investment' forecast are based on National Grid Transco data. They therefore exclude gas supplied through other networks (eg direct to certain power stations). DTI has produced its three investment scenarios based on current information.

2 Latest position: Agreement of Principles for new pipeline from Sleipner to Easington signed 2 October 2003

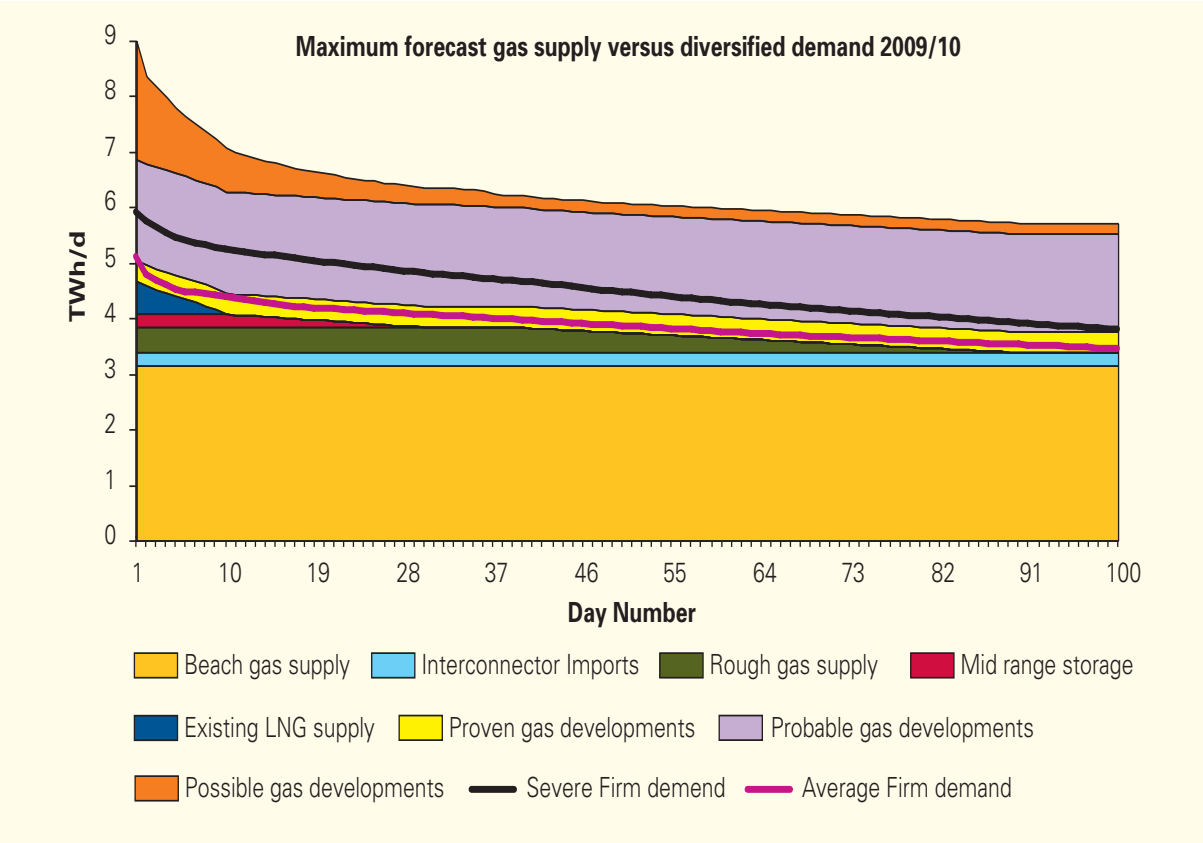
Supply and demand forecasts – gas

2 Demand duration curves



Context:

The charts show the various sources of gas that can be utilised during a winter and how storage may be depleted, leaving only continuous supply available. It includes the proven, probable and possible gas supply scenarios as forecast in Chart 1. The demand duration curves have been shown for three selected winters over the next 6 years. As with the forecasts in Chart 1, these curves also assume that all supply sources are delivering gas at maximum capability (see 'Key Points' in Chart 1).



Key Points:

The demand lines 'severe firm' and 'average firm' indicate the demand during the coldest 100 days of a 1 in 50 winter and an average winter, respectively. The graphs show this demand being met from a variety of sources including stored gas, LNG and imports.

Data for subsequent years indicate a decline in UKCS production (beach gas), a projected increase in further imports from Continental Europe and Norway, new storage facilities and LNG import facilities. The details are provided under 'Background' in Chart 1. Without these new supplies there may not be sufficient gas to meet demand; this can be seen in the charts for winters 2006/07 and 2009/10.

The extent to which market participants perceive that there will be a future scarcity of gas supply should be reflected in forward gas prices. Where prices indicate a scarcity, market participants will (subject to any barriers) invest in additional capacity when it is economic to do so. Indeed, the significant rise in gas volume likely from probable developments over the period indicates that market participants are anticipating a need to increase output and deliver new sources of gas.

Background:

'Beach' is the forecast of maximum offshore supplies from the UK continental shelf and the Norwegian continental shelf. 'Interconnector' is imports through the continental interconnector. 'Mid Range Storage' includes salt cavities and depleted onshore fields.

'Severe Firm' relates to a 1 in 50 winter period of high demand where all interruptible loads are not being supplied. Transco's Network Code contains the formal definition of a 1 in 50 winter, but in summary it is a winter such as would occur once in 50 years that will see high demand and the possibility of one or more days of peak demand within its duration. Consumers on interruptible contracts pay reduced transportation charges to compensate for the risk of losing supply.

The charts assume a gradual decline in gas deliverability from storage facilities over an estimated period of time consistent with their storage capacity.

The demand curves are based on diversified demand, which is the combined (variable) gas demand likely to be experienced throughout the country taking into account that the regional peak days are unlikely to co-incide.

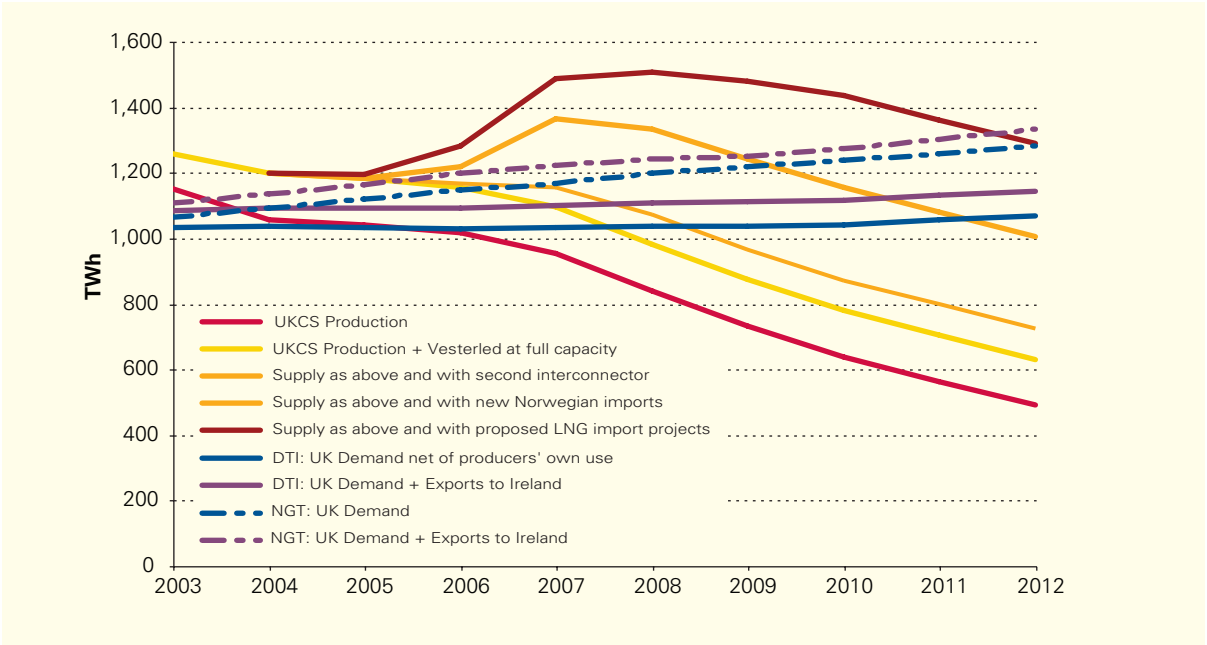
The supply data assume that all supply sources are delivering at maximum capability. Experience has shown that for operational and commercial reasons this may not always be the case. UKCS production outages could result in gas supply shortfalls to the UK and cold weather in Europe could see some gas being sold on the continent instead of being delivered to the UK.

Source:

Gas demand and the 'minimum investment' forecast are based on National Grid Transco data. They therefore exclude gas supplied through other networks (eg direct to certain power stations). DTI has produced its three investment scenarios based on current information.

Supply and demand forecasts – gas

3 Annual UK gas supply and demand



Context:

A key feature of Charts 1 and 2 is the projected progressive reduction in production of gas from the UK Continental Shelf (UKCS). Against a background of continuing rising demand, the prospective growing need for imports has implications for import infrastructure and for the underpinning commercial and intergovernmental agreements.

Key Points:

Since 1997, the UK been a net exporter of gas, mainly via the Bacton–Zeebrugge interconnector. On an annual basis, the UK is expected to become a net importer of gas by around 2006 with a large and growing import requirement by the end of this decade and beyond. Although reliance on gas imports is not a new feature of the UK energy supply mix, the extent of previous dependence - imports met as much as 25 per cent of UK demand in the 1980s - was not on the scale now anticipated (perhaps 40 per cent by 2010 and 80 per cent or more by 2020). Existing and proposed import projects could meet the annual shortfall in supplies from the UKCS until the end of this decade. Imports are likely to come from a range of sources and by a variety of routes. This will contribute to maintaining diversity of gas supply. There is also some upside potential from UKCS production and some from planned infrastructure developments.

Background:

The chart gives an indication of the possible availability of gas to meet UK (and Irish) demand over the period to 2012.

The UKCS Production line on the chart summarises data provided by operators to DTI in early 2003 on future gas production expected from all discovered fields on the UK Continental Shelf (UKCS), before any contribution from future discoveries[3].

3 UKCS production includes the UK share of production from the Markham Field and production from the Windermere Field which is exported directly to the Netherlands. The total volume is not material in the context of overall UK production so no explicit adjustment has been made to the projections shown here.

There is existing infrastructure in place permitting imports of gas from Norway, principally the Vesterled pipeline to St Fergus. This is assumed to be run at full capacity throughout the year. Imports are also currently possible from the Continent through the Bacton-Zeebrugge Interconnector. However, because the extent of its use will depend on relative prices in the UK and on the Continent, the chart assumes no contribution to annual supply (or demand) through the Interconnector, notwithstanding the progressive increase in its import capacity through the installation of additional compression at the Belgian end.

A number of additional infrastructure projects are being considered and these have been recognised in the chart as additional supplies from Norway, a second gas interconnector and a number of Liquefied Natural Gas import projects. The chart shows the progressive build up of supplies to the UK these would make if they go ahead on the schedules currently expected.

The DTI UK gas demand projection shown here is based on the estimates of energy demand in Estimates of primary energy demand and electricity generation, a paper published on the DTI website (at http://www.dti.gov.uk/energy/whitepaper/) alongside the February 2003 Energy White Paper Our energy future – creating a low carbon economy. That paper gives high and low estimates for 2020 consistent with the goals in the White Paper. The chart is based on the higher of these estimates. The demand projections shown have been adjusted to exclude producers' own use so that they are comparable with the production projections which are also net of own use. Own use of gas is currently significant but is expected to fall as UK gas production declines in the years ahead. The projections also include an estimate of non-energy demand for gas (e.g. use for petrochemicals, which is small and has been assumed to remain constant).

The extent to which Irish demand will be met by gas piped from/via the UK is uncertain, depending on both the timing of development of the Corrib Field west of Ireland and on the success of future discoveries and developments. A purely illustrative net import requirement has been added to DTI's UK demand projection for the purposes of the chart above.

The DTI demand line is the Central growth, High prices scenario (CH) from Energy Paper 68. The projections in EP68 excluded the effect of many of the measures in the Climate Change Programme and are thus higher than the estimates embodied in the February 2003 White Paper. The DTI is currently engaged in an exercise to update EP68 projections. It is expected that these will be available for publication in March 2004.

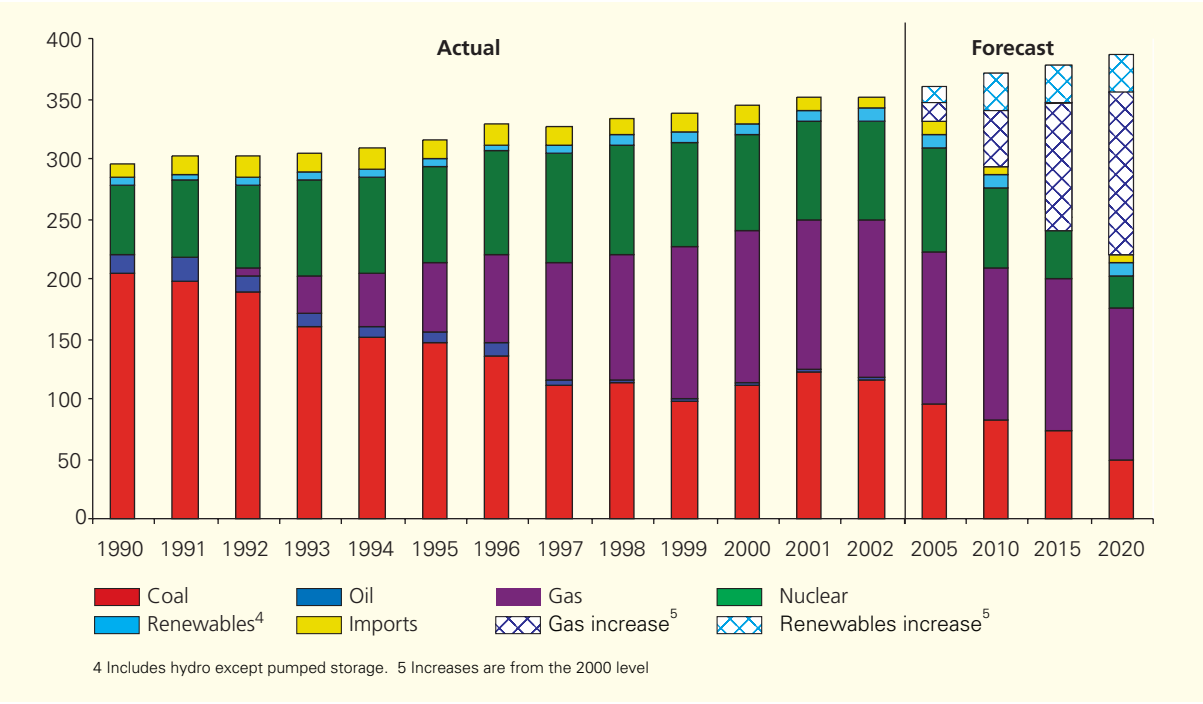
There is great uncertainty attached to these demand estimates and the DTI UK demand line shown is not a central projection. More robust estimates will be available once a full review of Energy Paper 68 (Energy Projections for the UK, "EP68", published in late 2000) has been carried out. DTI is currently engaged in an exercise to update EP68 projections. It is expected that these will be available for publication in March 2004. Full DTI estimates of UK gas demand in 2010 and 2020, as presented in EP68, are much higher than those shown here (at least partly because the projections in EP68 did not include the effect on demand of many of the measures in the Climate Change Programme). In line with those full estimates, many outside DTI are still assuming higher rates of growth in UK gas demand (partly reflecting withdrawal of nuclear generating capacity and its presumed replacement by gas-fired plant). The chart therefore also includes National Grid Transco's (NGT's) latest projections of UK demand and exports to Ireland. These indicate a significantly tighter supply position.

Source:

DTI projections and estimates as described above and National Grid Transco demand projections based on an average weather condition derived from 35 year trend data.

Supply and demand forecasts – electricity

4 Electricity generation by fuel type – UK



Context:

The chart shows how electricity demand is likely to be met by different forms of generation. It is based on modelled (Energy Paper 68) data, but illustrates the potential requirement for new investment. Data on current plant build and consents are presented at Table 1a.

Key Points:

Within the overall total, changes are likely in the generation mix and new investment will be needed to replace generation plant once closed.

By 2010 gas fired generation is modelled to be producing 46 TWh more than was produced in 2000, rising to an additional 137 TWh in 2020. A mixture of large-scale plant and CHP will meet this generation, although the exact contribution of both, and of gas itself, will be dependent on relative costs and availability of other sources.

In contrast nuclear's contribution is expected to drop from its peak of 90 TWh in 1998 to 66 TWh in 2010 and 27 TWh in 2020.

In DTI's Energy Paper 68 renewables are modelled to reach their 10 per cent target in 2010 and remain at that level in 2015 and 2020.

Background:

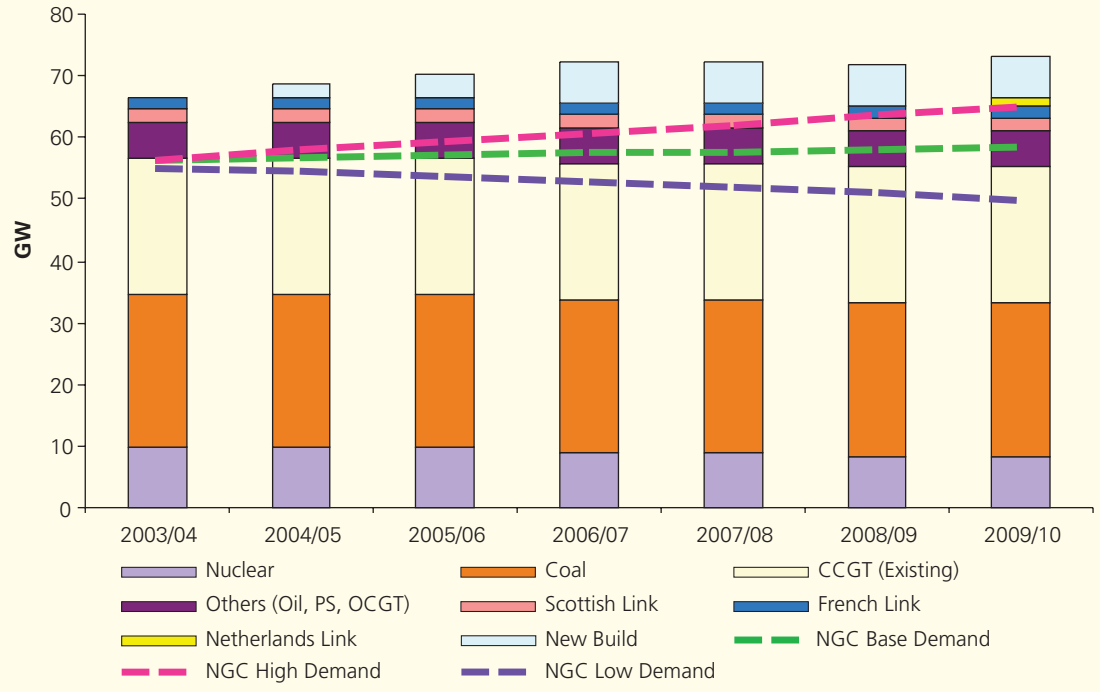
The data presented are demand and supply as measured in TWh, therefore improvement in efficiency and utilisation can increase output without the need for new build.

Sources:

Historic: DTI, Digest of UK Energy Statistics 2003 -Table 5.6 and corresponding tables in earlier editions.
Projections: DTI Energy Paper 68. (DTI currently updating EP68 – see 'Background' section under Indicator 3)

Supply and demand forecasts – electricity

5 Generator margin – England and Wales



The demand lines on this chart are average cold spell (ACS) peak demands

Context:

This chart allows us to consider the plant margin, the amount by which the installed generating capacity exceeds average cold spell (ACS) peak demand. The margin should not be viewed as surplus capacity since this margin is required to cover the risk of generating plant unavailability (e.g. breakdown) or higher than predicted peak demand (e.g. due to severe weather).

Key points:

The dotted straight lines represent NGC's three demand scenarios (low, base and high cases) as shown in the 2003 Seven Year Statement (SYS). The bars show the generation mix split into the major fuel types and consented new build.

Given the status quo (no new build beyond what is under construction and no closures) the plant margin compared with the base case demand, is around 19 per cent in 2003/04, and would rise to 21 per cent in 2004/05 before falling back to 11 per cent by 2009/10. However, if account is taken of all plant that has obtained the necessary consents and/or has signed a connection agreement with NGC, then the plant margin would rise to around 26 per cent in 2006/07 and fall back to 24 per cent in 2009/10.

The chart shows a generation scenario between these two extremes (explained further below). Here the plant margin is 19 per cent in 2003/04 rising to 23 per cent in 2006/07 before falling back to 20 per cent in 2009/10. In the High demand case the margins shown in the chart stay below 20 per cent.

In all cases, any closures or mothballing will reduce the quoted plant margin.

The chart assumes full CCGT availability at peak and so does not take into account any potential interactions with the gas networks. However, on a peak gas demand day some

CCGTs might be contractually interrupted. At present around 30 per cent of gas fired generation is on some form of interruptible contract with Transco (although not all use Transco's network as primary supply). The extent to which interruptible CCGTs can continue to generate under alternative fuels is discussed in section 47 of this report.

Background:

The chart above is based on the NGC's Consents Background, a central projection which contains all existing plant, that portion of plant under construction which has obtained the necessary S36 and S14 consent, and planned future plant that has also obtained consent. It is considered unlikely that all these projects will be built in the notified timescales. There are no assumptions on plant closures other those already notified by nuclear generators. Closure information is not normally known, as operators only have to give 6 months notice to NGC. NGC's peak demand forecast includes high and low scenarios to capture a range of possible peak outcomes.

Plant margin is defined as:

$$\frac{\text{(Installed Capacity – Peak ACS Demand)}}{\text{Peak ACS Demand}}$$ expressed as a percentage.

It differs from the Operational Planning Margin Requirement which is the very short term 'safety cushion' ie the amount of extra generation over and above the forecast demand required to meet a Loss of Load Expectation (LOLE) of one occasion per year.

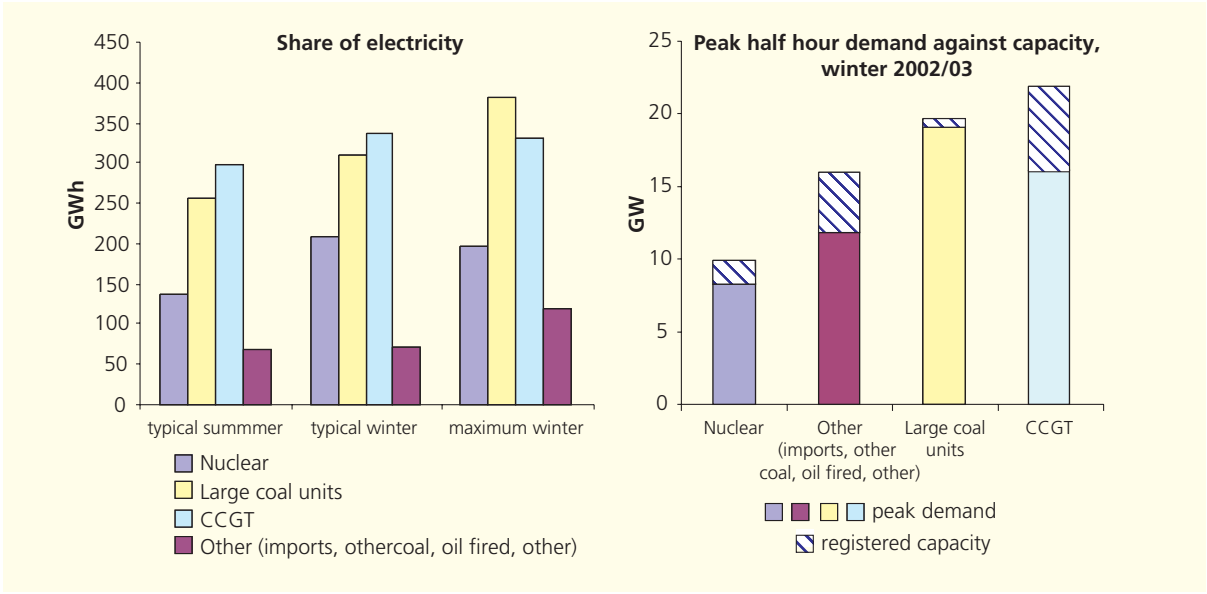
Source:

NGC – Seven Year Statement 2003 and subsequent updates

www.nationalgrid.com/uk/library/documents/sys_03/default.asp

Supply and demand forecasts – electricity

6 Generation profile summer/winter (England and Wales)



Context:

These charts show the diversity of sources of electricity generation; in particular, the use of coal-fired generation to meet peak winter demand.

Key Points:

Maximum demand for England and Wales for winter 2002/03 was 55,600 MW on 10 December 2002 at just after 17.00, of which over 21,000 MW was from coal. DTI understands that coal power stations were called as a result of their flexibility and the higher costs associated with running gas plant (due to high gas prices) and imports.

Large coal stations were running at their maximum capacity to meet peak demand, meaning that any additional requirement was met from other plant types. At the time gas prices were relatively high which made coal more economic.

Background:

The relative economics of running plant, including fuel costs and the responsiveness of different kinds of plant to short-term peaks, will be reflected in bids made to the market. This will change in accordance with global primary fuel supply and demand and local factors.

Chart a demonstrates the electricity (split by plant type) required on each of the three scenarios of a typical summer day (25 June 2002), a typical winter day (3 December 2002) and a maximum winter day (10 December 2002). Coal generated 420,000 MWh on the winter maximum day compared with 336,000 MWh for a typical winter day.

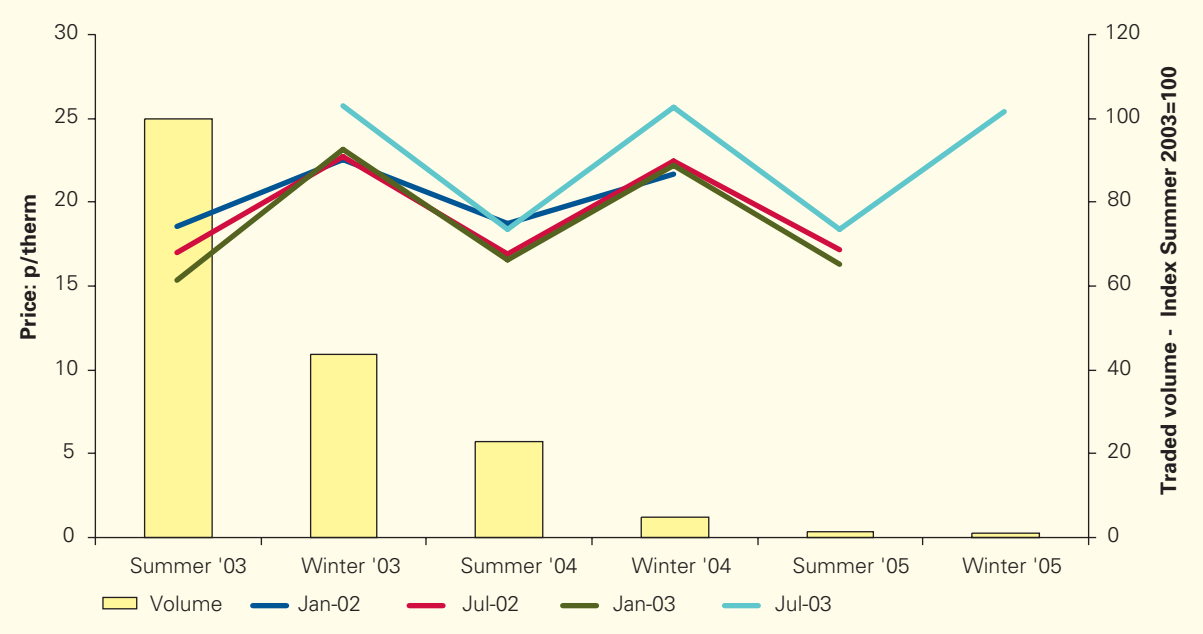
Chart b highlights the amount of capacity required, by plant, to meet peak demand and the amount of spare capacity available. It should be noted that the plant utilisation to meet peak demand will vary day to day and so although looking at the winter peak is useful, a comparison across the whole of the winter period can be more informative.

Source:

NGC – Seven Year Statement 2003.

Market signals – gas

7 Forward gas prices – GB



Context:

Forward gas prices show the price you would pay if a commitment were made today for gas to be delivered on a specified future date. Monthly prices are incorporated into the calculation of the first season's price (i.e. Winter 2003). They have equal weighting with the quarterly price for Q4 2003. The winter 2003 price is the average of this result, and the Q1 2004 price. The calculation basis for these prices has changed since the second JESS report. This reflects improved data availability and an improvement to the calculation methodology. All the figures have been re-calculated using this new methodology.

Traded volume data (for gas volumes traded in January 2003) are presented along with forward gas price data.

Key Points:

The forward prices of gas are lower in the summers and marginally higher in the winters compared to those quoted in January 2002. The exception is winter 2004, when the forward prices of gas in January 2003 are slightly lower than the prices corresponding to volumes traded in July 2002.

More notably, the July 2003 forward prices of gas are significantly higher in both summer and winter than earlier forward price curves, with the only exception being summer 2004, where July 2003 prices are slightly lower than that for volumes traded in January 2002. The higher forward price of gas from July 2003 suggests that the market expects the demand-supply balance to change, either because of an increase in demand for gas, or a decrease in the supply costs of gas.

Information on traded volumes is included in this JESS report for the first time. These data relate to gas traded in January 2003 for delivery in future winter and summer months. The data show that greater volumes of gas were traded for short-term delivery (i.e. summer 2003), with smaller volumes traded for future periods.

The proportion of total traded volume captured is variable, and thus it may not be an exact measure of liquidity. Further, it should be noted that forward curves are based on forward-

looking price assessments and traded volumes are historic; therefore the price given as the forward price is not necessarily representative of the price at which the volumes were actually traded. The reported information illustrates the relative volumes traded each period.

Background:

Gas prices are seasonal, as demand for gas is higher in the winter than in the summer. This is reflected in the forward curves with higher prices for winter. Although forward prices show seasonality, they do not show prices for a specific day.

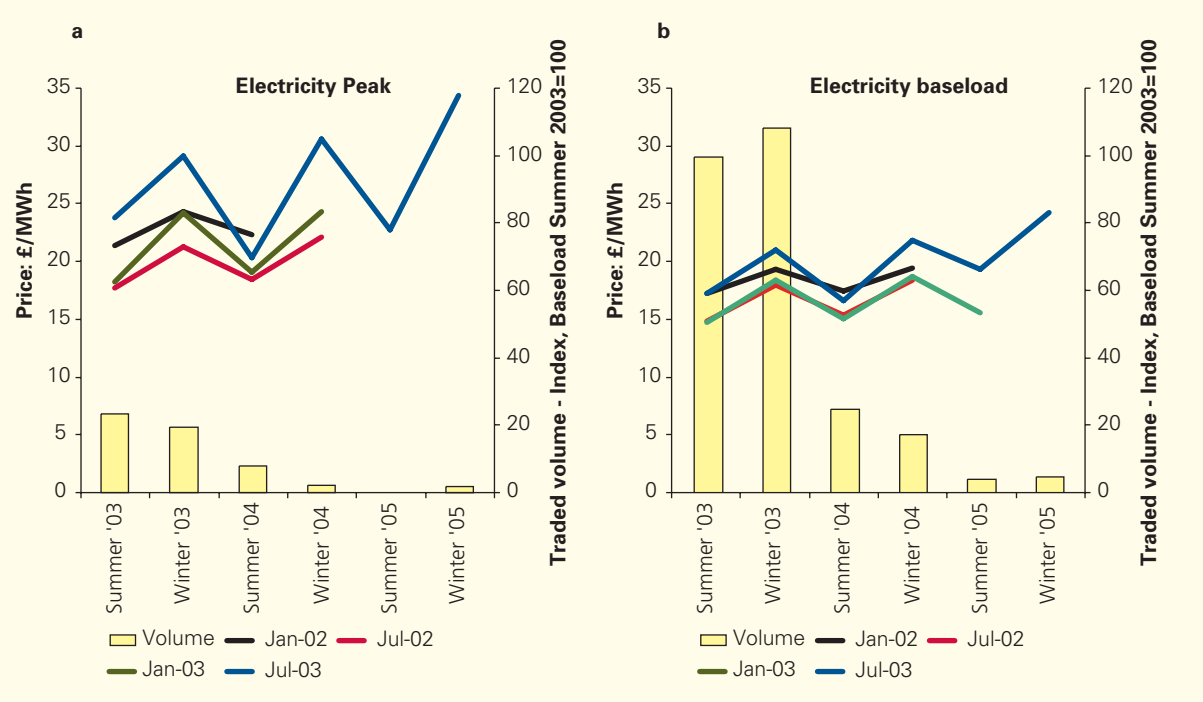
Source:

Daily 'European Spot Gas Markets' report (the Heren report). Series derived by Ofgem using an average of bid and offer for trades at National Balancing Point (NBP). A simple average of these prices quoted each day for a product in the month has been used, subject to the time-weighting of products explained below. The prices used are all in nominal terms. There is significant overlap of gas products across seasons, so it was necessary to time-weight the quoted products to get a seasonal price. Below is an illustration of how the methodology has been employed.

Product	Price	No of days covered	Time weighted average price
Quarter 2 2004	18.8	91	18.8*(91/183) = 9.35
Quarter 3 2004	23.5	92	17.8*(92/183) = 8.95
Summer 2004 price		183	(9.35 + 8.95) = 18.30

Market signals – electricity

8 Forward electricity prices – GB



Context:

Forward electricity prices show the price you would pay if a commitment were made today for electricity to be delivered on a specified future date. The prices are calculated from seasonal products. The calculation basis for these prices has changed since the second JESS report. This reflects improved data availability and an improvement to the calculation methodology. Due to improved data availability, the July 2003 prices also include quarterly prices.

Traded volume data (for electricity volumes traded in July 2003) are presented along with forward electricity price data.

Key Points:

Both peak and baseload prices fell in July 2002 and January 2003, before increasing significantly for volumes traded in July 2003. This increase is across the whole curve, but is most marked for 2005. The price increase is also far greater for peak electricity. This is likely to reflect, among other things, that the market (and wholesale prices) is responding to tightening capacity margins. This is creating signals and incentives for generators to return previously mothballed plant to service in order to meet short-term peak demand (rather than provide baseload capacity, as the incentives for providing peak demand generation are relatively stronger than those associated with baseload because prices are higher).

Carbon trading is due to be introduced in 2005 and will increase the opportunity cost of carbon-emitting generation. As such, it is possible that the increase in forward electricity prices for 2005 in part reflects expectations about this increased opportunity cost.

As with the gas figures shown in Chart 7, information on traded volumes is included in this JESS report for the first time. These data relate to electricity traded in July 2003 for delivery in future winter and summer months. The data show two key things – that greater volumes of baseload rather than peak electricity are traded (as to be expected by their nature), and greater volumes of electricity are traded for short-term delivery (i.e. 2003), with decreasing

volumes traded for periods post-2003. Note, however, that the volumes indicated in the chart are survey based and not absolute volumes. They are used to illustrate the relative volumes traded each period.

Background:

Electricity prices are seasonal, tracking seasonal levels of demand. This is reflected in the forward curves with higher prices for winter. Although forward prices show seasonality, they do not show prices for a specific day.

Source:

The forward curves for electricity were created by Ofgem using Heren's daily price assessments, as quoted in European Daily Electricity Market (EDEM) reports. A simple average of the prices quoted each day for a product in the month has been used. The prices used are all in nominal terms. The price assessments are for GTMA contracts quoted since NETA Go Live. There was an overlap between the products quoted for the seasons nearest to delivery, so it was necessary to time-weight the quoted products to get a seasonal price. A similar methodology was used to that outlined for indicator 7. There was no overlap for the remaining seasons so it was not necessary to time-weight the products.

Market response – gas

Chart 9 (Existing and potential import capacity) has been discontinued as aggregate information on pipeline ullage is not a useful overall indicator of available capacity, since the ullage is shared between multiple pipelines. Individually the available ullage may be very small and not of commercial benefit to gas importers. Other sources exist in the public domain that provide a more detailed and sophisticated analysis of gas infrastructure capacity and available ullage. These include:

1) 2002 Economic Report, United Kingdom Offshore Operators Association (UKOOA), 'Oil and Gas Markets and Security of Supply' chapter, figure 33. This chart is available free on the web at:

   www.oilandgas.org.uk/issues/economic/econ02/images/figure33-large.jpg

   and the full report is available at:

   www.oilandgas.org.uk/issues/economic/econ02/econ02_markets.htm

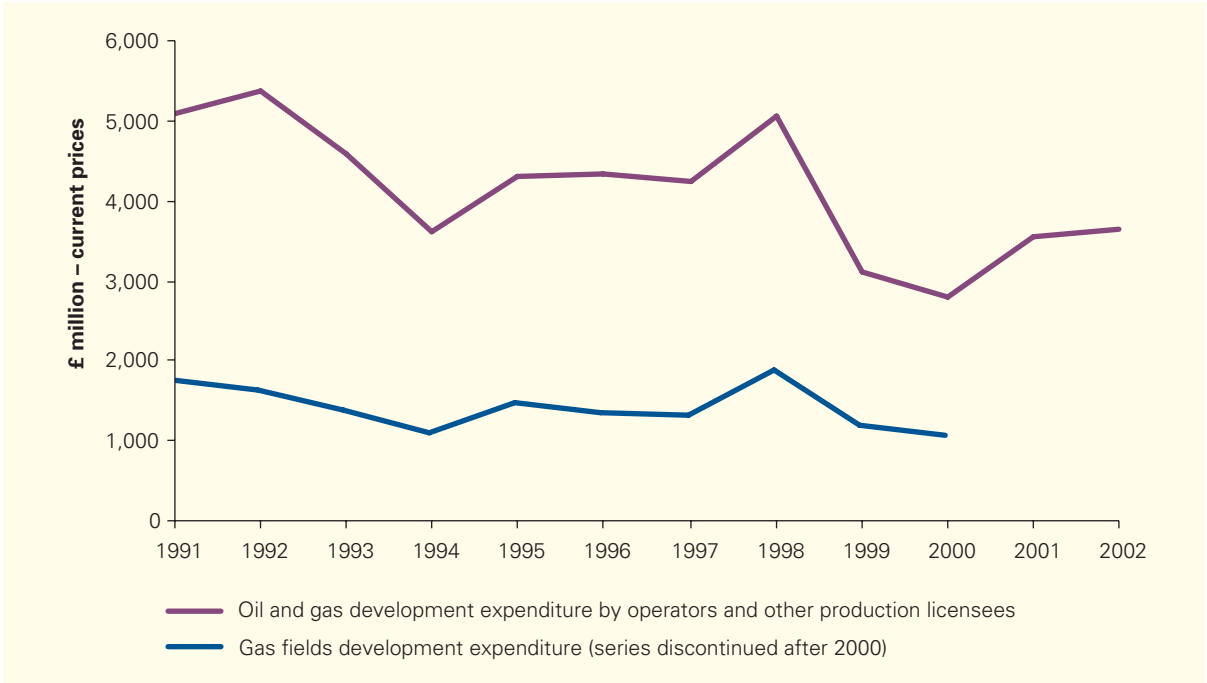
   or in hard copy by ordering online on the UKOOA website

   or by telephone 020 7802 2400, fax 020 7802 2401, email info@ukooa.co.uk.

2) North Sea Study Occasional Paper No. 90, 'UK Oil and Gas Production Prospects, the Optimal Use of UKCS Infrastructure, and the 2003 Budget Tax Changes', University of Aberdeen, Professor Alexander G. Kemp and Linda Stephen, April 2003. ISSN 0143-022X. Priced £20. Available from The Secretary (NSO Papers), Department of Economics, University of Aberdeen, Edward Wright Building, Dunbar Street, Aberdeen, A24 3QY. Telephone 01224 273427, fax 01224 272181, email a.g.kemp@aberdeen.ac.uk.

Market response – gas

10 Gas production capital expenditure – UK



Context:

Investment in gas fields is a market response to the perception of expected future profits and is a useful indicator of potential developments and therefore continuing UKCS gas supply. Because expenditure is increasingly linked to the continuing development of oil in the UKCS, expenditure for gas can no longer be reliably separated from expenditure for oil and the two expenditures are therefore given jointly for 2001 and 2002. However, in the future capital expenditure on infrastructure for importing gas will be equally as important as that on UKCS production. JESS is therefore investigating a replacement for this indicator.

Key Points:

Joint investment has fluctuated through the 1990s (linked to both demand for gas and price of gas and oil) but has remained above £2,500 million each year and rose to above £3,500 million in 2002.

Investment in the UKCS is just one element of the gas supply chain as it relates to production only.

Background:

Investment is total and includes investment in platform structures, modules and equipment, offshore loading systems, pipelines, terminals and development wells.

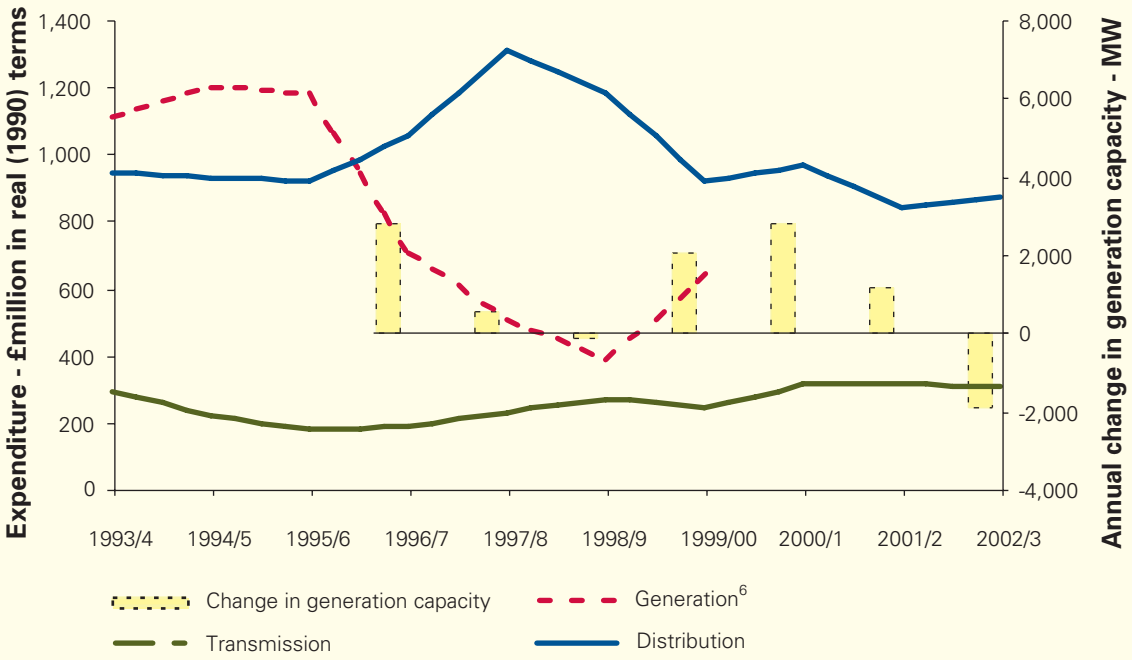
Source:

DTI, Development of the Oil and Gas Resources of the UK as updated on the DTI web site at

www.og.dti.gov.uk/information/bb_updates/appendices/Appendix7.htm .

Market response – electricity

11 Electricity capital expenditure – GB



6 Generation information discontinued by the CRI after 1999/2000.

Context:

The chart shows how much has been invested in the various components of the electricity industry. Investment, especially in generation, should follow a similar path to prices; eg a high fuel price would indicate tightening supply and an opportunity for investment in new plant.

Key Points:

Transmission and Distribution investment is lumpy and in part difficult to predict (eg it could reflect customer demands for new connections and network refurbishment). It should be noted that the key is how investment has improved performance not just the level of investment. It is very difficult to judge against a benchmark, and so investment is at best a broad indicator of security.

The Centre for Regulated Industries (CRI) discontinued the generation investment series after 1999/2000, but an approximate path can be inferred from the change in UK generating capacity.

The data used in this chart are now shown in constant price terms.

Background:

Electricity transmission and distribution are businesses regulated by Ofgem.

Sources:

Expenditure on Generation from Centre for Regulated Industries (up to 1999/2000). Expenditure on transmission and distribution Ofgem. Capacity from Digest of UK Energy Statistics.

Table 1: Planned major new energy projects

Context:

The tables overleaf provide an indication of potential major new investments in electricity generation or gas infrastructure.

Key Points:

Compared with the last JESS report, there has been an apparent drop in planned capacity of CCGT and ICGCC from 10,265 MW to 6,550 MW, and of CHP from 1,514 MW to 1,451 MW. This is because DTI have consulted the developers on their intent and all inactive applications have how been dropped from the table: Yelland (CCGT), Rhosgoch (CCGT), and some from 'Other CCGT applications' and 'Other CHP applications'. However, some of these inactive applications still remain in NGT's Seven Year Statement as their contracts to generate retain a commercial value and their consented status could be sold.

The status of Hatfield Colliery has progressed from 'being processed' to 'approved' and the planned capacity of renewables has increased from 1,313 MW to 1,701.5 MW. This is because new applications have been received for onshore windfarms at Scout Moor (65 MW) and Whinash (67.5 MW) and an offshore windfarm at Shell Flat (324 MW).

Many of the approved applications for CCGT and CHP projects are still not under construction. Having a 'bank' of approved (consented) projects does improve the ability of the market to respond to future requirements, by minimising the risk of potential planning delays. However, development must begin within five years for the permissions to remain valid. Consents can be transferred or sold on to another company.

Background:

Approvals for major energy projects are generally sought from national government. Small scale investments (eg below 50 MW generating schemes) typically receive planning approval from local councils and therefore do not feature in the tables below.

Source:

DTI.

1A Electricity (as at October 2003)

As a consequence of the Secretary of State's powers under section 36 of the Electricity Act 1989[7] and section 14 of the Energy Act 1976 the DTI gains an appreciation of the potential significant new electricity capacity planned to be built in England and Wales. In Scotland significant new electricity generating stations are authorised by Scottish Ministers and DTI are formally only involved if it is oil or gas-fired capacity where clearance is also required from the Secretary of State for Trade and Industry under section 14 of the Electricity Act 1989.

Station	Owner	Size	Type	Status	Under Construction
CCGTs:					
Partington, Greater Manchester	AES now TXU	380 MW	CCGT	Approved November 2000	No
Spalding, Lincolnshire	Intergen	800 MW	CCGT	Approved November 2000	Yes
Fleetwood, North West Lancashire	Fleetwood Power (GE)	1,000 MW	CCGT	Approved November 2000	No
Raventhorpe	ABB	450 MW	CCGT	Approved November 2000	No
Isle of Grain, Thames Estuary	Enron (in administration)	1,200 MW	CCGT	Approved November 2000	No
Langage, South Devon	Wainstones (Carlton Power)	1,010 MW	CCGT	Approved November 2000	No
Marchwood, Hampshire	Marchwood Power (Aquila)	800 MW	CCGT	Approved November 2002	No
Total – CCGTs		**5,640 MW**			**800 MW**
Integrated coal gasification combined cycles ICGCC					
Hatfield Colliery	Coalpower	430 MW	ICGCC	Approved August 2003	No
Onllwyn, Port Talbot	Progressive Energy Ltd	480 MW	ICGCC	Being processed	..
Total ICGCCs		**910 MW**			
CHPs:					
Immingham, Humberside	Conoco	760 MW	CCGT/ CHP	Approved final size March 2001	Yes
St Regis Paper, South Wales	St Regis Paper	115 MW	Gas CHP	Has energy policy clearance – application for development consent awaited	..
Other CHPs	Various	447MW	Gas CHP	Approved November 2000	Varies
Other CHP applications	Various	129 MW	Gas CHP	Being processed	..
Total CHPs		**1,451 MW**			**760+ MW**
Dual-firing:					
Indian Queens	AES		Dual oil/ gas capability	Approved September 2001	No
Littlebrook	Innogy		Dual oil/ gas capability	Approved August 2002	No

Station	Owner	Size	Type	Status	Under Construction
Renewables and energy from waste:					
Belvedere, London	Riverside Resources	70 MW	Energy from waste	Public inquiry underway	..
Cefn Croes, West Wales	RDC	60 MW	Onshore windfarm	Approved May 2002	No
Little Cheyne Court, Walland Marsh, Kent	National Wind Power	78 MW	Onshore windfarm	Being processed	..
Scout Moor, nr Rochdale, Lancashire	United Utilities and Green Energy	65 MW	Onshore windfarm	Just started in process	..
Whinash, nr Tebay, Cumbria	RDC and Falck Renewables Ltd	67.5 MW	Onshore windfarm	Just started in process	..
Scroby Sands, off East Anglia	PowerGen	76 MW	Offshore windfarm	Approved April 2002	Some onshore work started
North Hoyle, off North Wales	NWP Offshore (Innogy)	90 MW	Offshore windfarm	Approved July 2002	Yes
Rhyl Flats, off North Wales	NWP Offshore (Innogy)	100 MW	Offshore windfarm	Approved December 2002	No
Barrow, off Walney Island	DONG	108 MW	Offshore windfarm	Approved March 2003	No
Kentish Flats, off Whitstable	GREP	129 MW	Offshore windfarm	Approved July 2003	No
Burbo Bank, off Wirral	Seascape Energy	90 MW	Offshore windfarm	Approved July 2003	No
Inner Dowsing, off Skegness	OWP	120 MW	Offshore windfarm	TWA Order[8] being processed	..
Lynn, off Skegness	AMEC Offshore	108 MW	Offshore windfarm	TWA Order being processed	..
Cromer, off Cromer Wind Limited	Norfolk Offshore	108 MW	Offshore windfarm	TWA Order being processed	..
Gunfleet Sands, off Clacton	GE Wind Energy	108 MW	Offshore windfarm	TWA Order being processed	..
Shell Flat, off Cleveleys	Cirrus Energy	324 MW	Offshore windfarm	TWA Order being processed	..
Total Renewables and energy from waste		**1,701.5 MW**			**90 MW**

The table shows approvals from November 2000 (when the stricter consents policy was lifted) and state of play on applications for stations over 50 MW.

7 Section 36 consent can be transferred or sold on to another company.

8 TWA Order = Transport and Works Act Order

Key: .. indicates that the project has yet to reach the stage where construction can begin.

1B Gas (as at October 2003)

The following projects have been publicly announced or acknowledged. JESS is aware of a number of other projects that are under consideration, but for commercial reasons have yet to be announced. These projects are included in aggregated terms in the preceding indicators but cannot be separately listed because of these commercial considerations. No new projects have been added since the last JESS report (February 2003) but the status of projects has been updated. As expected, the second Irish Interconnector (the sub-sea pipeline for which was completed in November 2002) is now fully operational. The new Interconnector runs parallel to the first Interconnector, linking Beattock in Southwest Scotland and Ballough, north of Dublin in Ireland. IC2 is a high-pressure pipeline 195 km in length and 30 inches in diameter and operates at a pressure of 150 bar. The two Irish Interconnectors have a combined capacity of 344,53 MWh/day and are operated together.

Project	Owner/Proposer	Size	Date	Status	Under Construction
Ormen Lange gas field development in Norway. Southern pipeline from Sleipner to Easington.	Norsk Hydro / Shell Norge	60-80 Mcm/d capacity	2007/08 (but could be delivering other Norwegian gas in 2006/07)	Principles for pipeline agreed 2 October 2003.	..
Compressors at Zeebrugge to increase import capacity into UK	Interconnector UK	Increase from 23 Mcm/d to 45 Mcm/d	By December 2005	Planning permission awarded in Q4 2002	Yes
Interconnector from Bacton to Balgzand (Groningen)	Gasunie	23 Mcm/d	2006/07	Project under consideration	..
Aldbrough storage (North)	Statoil	170-230 Mcm storage capacity	2007/08	Planning permission awarded in February 2000	..
Aldbrough storage (South)	Scottish and Southern Hornsea Ltd Energy	170 Mcm storage capacity	2006/07	Planning permission awarded in February 2000	..
Cheshire storage – Byley	Scottish Power	170 Mcm	2008/09	Public Inquiry held; Inspector's report with Ministers for a decision	..
Isle of Grain LNG import/storage facility; redevelopment of existing site	National Grid Transco	12 Mcm/d	First gas in early 2005	Planning permission granted in April 2003, and regulatory approval given in July 2003	Yes
Milford Haven LNG import/storage facility on Gulf Oil Refinery site	Petroplus	16.5 Mcm/d	2006/07	Planning permission granted in February 2003	..
LNG import/storage facility	Qatar Petroleum Ltd/ Exxon-Mobil Corporation	First train up to 10.5 bcm/ year (1.25 bcf/day)	2007/08 consideration,	Terminal site under consideration, including own build at Milford Haven	..
Humbly Grove storage facility	Star Energy Ltd	280 Mcm	2005/06	Planning permission being sought	..
Welton storage facility	Star Energy Ltd	280 Mcm	2005/06	Pre planning	..
Lancashire storage facility	Cantaxx	Not yet determined	Pre planning	..	

Key: .. indicates that the project has yet to reach the stage where construction can begin.

Annex 2
Security of supply background

DUTIES AND ROLES

1. As regulator of the electricity industry and the onshore gas industry in Great Britain, Ofgem's principal objective, under the Gas Act 1986 (as amended) and the Electricity Act 1989 (as amended), is to protect the interests of gas and electricity consumers in Great Britain, wherever appropriate by promoting effective competition. This objective is supplemented by specific 'security of supply' duties to ensure that all reasonable demands for electricity and gas are met and to secure a diverse and viable long term energy supply. Ofgem also has other duties, including environmental and social responsibilities, although the implementation of environmental and social measures that would have significant financial implications is reserved to Government. The Secretary of State for Trade and Industry shares the duties of Ofgem explained above and is generally answerable to Parliament on energy matters for the UK.

2. National Grid Company and Transco, respectively electricity and gas system operators (SOs), play a major role in ensuring security of supply by providing residual balancing services. Both have commercial incentives, put in place by Ofgem, to ensure that they as monopoly service providers are responding efficiently and effectively to market signals and that their actions are sending appropriate signals to the market. National Grid Company and Transco are both able to utilise the option of buying and selling gas and electricity to keep their systems in balance.

3. Ofgem also has a key role in providing appropriate incentives through effective regulation of the 'natural monopoly' gas and electricity networks to ensure timely expansion of capacity and efficient system operation.

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