JESS - Long-Term Security of Energy Supply

December 2006 Report

December 2006  www.dti.gov.uk/energy/energy-reliability/index.html
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INTRODUCTION

1. The Government published the conclusions to its Energy Review on 11 July in its report ‘The Energy Challenge’\(^1\). The Review identified the need for new arrangements for the provision of forward-looking energy market information and analysis relating to security of supply. These will enable Government, suppliers, investors and consumers to base decisions on credible transparent information, particularly in the light of the scale of the change we will see in energy markets over the next few decades. The Review recommended that these arrangements be led by the DTI working with energy market players. The objective is to collect in one place relevant data and analysis on the medium- and long-term adequacy of future energy supplies to help early identification of areas where policy may need to be reviewed and assist energy market participants with their investment and purchasing decisions.

2. These arrangements will build on the work of the Joint Energy Security of Supply Working Group (JESS) that published its sixth report in April 2006. This report is the first stage in this process and is very similar in structure to the last JESS report. The first part of the report is a narrative giving the Government’s view on a range of issues relevant to the security of energy supply, whilst the second part consists of updated versions of the indicators published previously by JESS. We will be updating the indicators on a more regular basis (the indicators can now be accessed separately on the DTI’s website).

3. The report includes contributions from DTI, Ofgem, National Grid and the Foreign and Commonwealth Office (FCO). It draws on information published elsewhere, for example National Grid’s Seven Year Statement on electricity and Ten Year Statement on gas as well as reports commissioned by DTI or published by other experts in the sector. It is intended to have links to many of these reports on the DTI security of energy supply website to provide a comprehensive source of existing information on the security of energy supply.

SECURITY OF ENERGY SUPPLY DEVELOPMENTS SINCE THE SIXTH JESS REPORT

Energy Review Report

4. Several important developments have taken place since the publication of the sixth JESS report in April 2006. Clearly the most important publication from the Government was the Energy Review Report. This set out progress against the four goals that provided the basis of the 2003 Energy White Paper, including that concerned with maintaining security of energy supplies. The Review reinforced the Government’s commitment to a market-based approach to deliver security of supply. However, it also identified two key security of supply challenges for the UK: managing increased dependence on oil and gas imports, and ensuring that the market delivers timely investment. A number of areas of work where further work is needed were also identified. These are subject to a series of consultations in the run up to the publication of an Energy White Paper in 2007.

5. A consultation on the Effectiveness of Current Gas Security of Supply Arrangements was published on 16 October\(^2\). This follows up on the commitment in the Energy Arrangements to consult both industry and consumers on:
   - the effectiveness of current gas security of supply arrangements
   - their robustness as we move to higher dependence on gas imports over the next 10-15 years
   - whether new measures are needed to strengthen them.

\(^1\) The Energy Review website is: [http://www.dti.gov.uk/energy/review](http://www.dti.gov.uk/energy/review)

\(^2\) [http://www.dti.gov.uk/consultations/page34643.html](http://www.dti.gov.uk/consultations/page34643.html)
The consultation considers in greater depth what we actually mean by security of gas supply and examines the extent to which the current policy framework is likely to deliver security of supply. It also assesses the new challenge faced as the flexible sources of near-to-market gas in the UKCS decline and seeks views on the costs, benefits and risks of some possible adjustments to the current commercial and regulatory framework to strengthen our ability to rise to that challenge.

6. A consultation on the policy framework for nuclear new build was launched on the same day that the Energy Review was published. This consultation closed on 31 October. It is the Government’s intention that the outcome of this consultation and the nuclear policy framework will form a key part of an Energy White Paper in 2007.

7. The other consultations launched as a result of the Energy Review Report are:
   - Proposals on banding and amending the Renewables Obligation (launched on 9 October)
   - The Energy Efficiency Commitment April 2008 to March 2011 (launched on 31 July)
   - Electricity Act inquiry rules (launched 9 November)
   - Measures to reduce carbon emissions in large non-energy intensive business and public sector organisations (launched 8 November)
   - Energy Billing and Metering (launched 14 November)

Other Reports

8. At the same time as the Energy Review, the Secretary of State published the second Annual Report to Parliament on the Security of Energy Supply. This report is a requirement under section 172 of the Energy Act 2004.

9. National Grid published its latest Seven Year Statement (SYS) looking at the electricity sector in May 2006. On the gas side, National Grid held its annual ‘Transporting Britain's Energy’ seminar in July 2006 as part of the consultation process that will culminate in the publication of the 2006 Ten Year Statement in December.

Feedback on JESS 6 Report

10. Three companies wrote to DTI with comments on the content of the sixth JESS report. The letters from Scottish and Southern Energy, Centrica and EDF Energy will be published on the DTI website along with a summary of the comments received and a response from DTI to them.

JESS 6 Report Commitments

11. Whilst a number of commitments were made for future reports in the sixth JESS report, these have to an extent been overtaken by the recommendations on improved security of supply reporting in the Energy Review. However, it is the intention that this and future reports will go further than the commitments made in the sixth JESS report. For example, there will be rolling updates of the indicators published with this report. There is also updated information in this report on both the effect of EU liberalisation and the operation of international markets. More detailed work on the impact of energy efficiency on security of supply will follow in future reports.

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What's new in this report

12. This report includes a number of new sections as the first stage in the process of implementing the recommendations in the Energy Review. The indicators from the sixth JESS report have been updated, as have the sections on the gas and electricity markets. There are also new sections on coal, oil and nuclear/uranium issues that will be built on in future reports as well as a new section in the report on network reliability.

13. This report also gives a general outlook for the future work programme to meet the recommendations on security of supply reporting. We are seeking feedback from stakeholders on the direction planned for future reports, events and indicators. We would also welcome feedback on the effectiveness of current indicators, both in terms of their content and the presentation of that content.

European Union and International Work

European Union

14. The development of liberalised EU energy markets is important for the UK’s security of supply. This is particularly so in the case of gas as we become increasingly dependent on imported supplies with the decline of our indigenous reserves. Properly functioning and liquid EU gas markets will provide non-discriminatory and fair access to supplies of gas at market-based prices and to the pipelines transporting the gas. They will also provide the economic signals necessary for efficient investment choices to be made, for example in new infrastructure to meet the increased demand for gas.

15. We welcome the action the Commission is taking to ensure the development of a competitive energy market. At the Energy Council on 1 December 2005 they presented two reports, one an issues paper outlining the initial findings from the sectoral enquiry into EU electricity and gas markets and the other a report on the functioning of the internal energy market.

16. The Commission’s reports highlighted serious malfunctions in EU energy markets. This was particularly true of EU gas markets where implementation of the existing legislation was either not completed or deficient, and where there was considerable exercise of market power.

17. These December reports have been followed by further announcements.

18. In February the Commission published a preliminary report in its sectoral inquiry of energy. This identified a number of areas of key concern, including concentration, insufficient unbundling and a lack of cross-border competition. Commissioner Kroes said she would act decisively to remedy the serious malfunctions identified in the energy market and announced that “in the coming weeks and months the Commission will launch individual anti-trust investigations” into specific cases of closing off gas and electricity markets by means of long-term downstream contracts and of restricting access to gas and electricity transport infrastructure and storage capacity.

19. On 4 April the Commission announced that it would be taking action against Member States that had not opened their energy markets in line with EU legislation.

20. In addition, and in response to a call from Heads of State at the last European Council at Hampton Court during the UK Presidency, the Commission published a Green Paper on a European Strategy for Sustainable, Competitive and Secure Energy on 8 March. This was discussed at the Energy Council on 14 March. It prioritised the completion of the internal market in gas and electricity and stressed that “sustainable, competitive and secure energy will not be achieved without open and competitive energy markets.” The Commission invited comments by 24 September and are now considering the responses received.
21. The Commission is to announce the conclusions from responses to its Green Paper and the results of its sectoral inquiry in January, in the form of a strategic energy review. This is expected both to propose further legislation and to set out other steps the Commission will take to deal with anti-competitive practices.

International

22. The aim of the Government’s international energy strategy is to secure a reliable supply of energy into the UK, while reducing the damaging emissions that lead to climate change. This was set out originally in the White Paper “UK International Priorities – a strategy for the FCO” (2 December 2003).

23. Clearly, coal, oil and gas will play a significant part in the UK and World energy mix for the foreseeable future. As domestic production declines, we will become progressively more dependent on imported supplies of energy. At the same time, global demand and international competition for energy will increase.

24. Reserves of oil and gas are geographically concentrated, and gas markets heavily constrained by access to pipelines. While coal is more freely available, its high emissions relative to other sources present challenges to the aim of moving towards a low-carbon economy. To negotiate these constraints, the UK must aim to import fossil fuels from a variety of sources. Clean energy technologies will increase the options available.

25. The Government believes that the private sector is best placed to channel investment in the most effective way. Government does however have a role to play in creating the right incentives and frameworks.

26. The UK’s exposure to international risks will increase with rising imports and global demand - these will generally be market-related, security or accident risks. Managing these risks requires a sustained international effort in building open markets, fostering international collaboration to deploy clean energy technologies, supporting social and political stability in the major energy producing regions, taking preventative action and establishing contingency arrangements including the resilience of infrastructure to terrorism and accident. Most Governments and international energy organisations share our view that the immediate challenge is not the availability of natural resources, but accessibility – the ability to bring energy products to the market place and transport them to customers.

27. We need to deepen our engagement with major potential producers to encourage continued investment in exploration, production and throughout the supply chains, both in gas and oil. An important part of our approach is to give strategic direction to multilateral discussions between energy-consuming and producing states, working closely with world organisations. In particular we will:

- Continue to take an active role on the board of the International Energy Agency (IEA), building its capacity both to analyse the gas market and the potential of energy-efficient technologies and to use this evidence to facilitate policy-making.
- Promote the joint oil data initiative (JODI) as a credible mechanism for the exchange of oil information by 2008; and establish international support for the publication of objective data which would similarly improve the gas market.
- Use the UK’s election to the Board of the International Energy Forum Secretariat in 2006 to draw together the work of the IEA, EU and OPEC; promote a better understanding about the direction and impact of energy and climate policies; and ensure that business makes a string contribution to the political agenda for the meeting of world energy ministers in 2008, where China, India and Russia are fully involved.
- Sustain pressure on other states to deliver the collective agreements made in UN negotiations, the G8 and other summits; to account publicly for their actions; and to demonstrate their practical impact in saving emissions and managing demand for energy.
- Promote the need for market-based energy prices in emerging market economies, thereby shaping incentives to invest in domestic energy infrastructure and to improve energy efficiency.
28. The sixth JESS report looked for the first time at the position regarding Northern Ireland. Some historical background is included along with recent developments in the following paragraphs.

29. The Northern Ireland Authority for Energy Regulation (NIAER) is the independent energy regulator for Northern Ireland.

30. Natural gas was first made available to Northern Ireland in 1996 via the undersea Scotland to Northern Ireland pipeline (SNIP). In September 1996 a licence was granted to Phoenix Natural Gas Ltd for the staged development of the industrial, commercial and domestic gas markets in the Greater Belfast and Larne areas. Connections in the Phoenix licence area will reach 100,000 by end of December 2006. This will coincide with “unbundling” of Phoenix to comply with the Gas Directive 2003/55/EC, which has been transposed in Northern Ireland, and came into effect on 1 October 2006. A derogation had been obtained from the EC due to the emergent gas industry in Northern Ireland.

31. An announcement on market opening in the Phoenix licence area was made in January 2006, with remaining non-domestic consumers open to competition from 1 July 2006, and full market opening by 1 January 2007.

32. In March 2005 licences were granted to Bord Gáis Éireann (BGE) to take gas to ten towns along the routes of two newly constructed pipelines. The North West pipeline runs from near Carrickfergus to the gas-fired Coolkeeragh power station near Londonderry and was completed in October 2004. The South North pipeline was completed at the end of October 2006 from near Dublin and will link with the North West pipeline. The support for this project is in the form of a Northern Ireland Executive grant package up to £38m, and an Irish Government contribution of €12.7m.

33. The North-South pipeline will allow gas to flow to Northern Ireland from the Republic of Ireland, increasing the capacity available by 6 mcm/day. The maximum contracted capacity of the SNIP is approximately 8.8 mcm/day while booked capacity is 7.5 mcm/day.

34. The new North-South pipeline will pave the way for an all-island gas market with increased security of supply. To this end, Governments North and South are investigating the long-term possibility of natural gas and liquefied natural gas storage on the island.

35. Northern Ireland has a total installed electricity generation capacity of some 2700MW. This includes three power stations Kilroot (coal/oil firing), Ballylumford (gas firing) and Coolkeeragh (gas firing) together with an increasing portfolio of renewable generation.

36. The electricity network is connected to the neighbouring Great Britain and Republic of Ireland networks via the Moyle Interconnector and a North-South interconnector, respectively. Planning is underway to construct a second North-South interconnector by 2012 to increase transmission capacity and system stability, which will improve trading opportunities and security of supply. Work is also being undertaken to explore future all-island grid requirements to ensure that the expected growth in the long-term contribution of renewable electricity can be accommodated.

37. The electricity market is already opened to competition to non-domestic consumers and will be opened to all consumers in 2007. Four suppliers, together with Northern Ireland Electricity plc, the public electricity supplier, are currently operating in the market.

38. The Governments and Regulators North and South are working together to put in place a single wholesale electricity market (SEM) on the island of Ireland set in the context of the liberalised EU Internal Electricity Market, by November 2007. The SEM will enhance security and diversity of electricity supply as well as bring about efficiencies and economies of scale in both the generation and supply of electricity from a larger marketplace.
THE GAS MARKET

Outlook

39. National Grid’s 2006 Ten Year Statement, setting out its assessment of the future demand and supply position for natural gas in Great Britain and the consequences for investment in the gas transmission network will be published in mid-December 2006\(^5\). Over the forecast period, annual demand is forecast to grow at around 2% per annum, with peak demand forecast to grow at the same rate. Import dependency is forecast to be 53% in 2010-11 and 77% in 2015-16.

40. There will therefore 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. As shown in Chart 1 of Annex 1, new infrastructure projects currently regarded as “proven” and “probable” are projected to be necessary to meet average and severe winter demand in the next decade.

41. Although there are inevitably uncertainties with demand/supply projections and different market perceptions of these scenarios, this chart shows that market participants are identifying and responding to the need to invest in new gas infrastructure. For the longer term, there are a number of potential market options:

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

42. This changing supply pattern has implications for investment in reinforcement and expansion of the National Transmission System (NTS) as well. National Grid assesses where to target investment by means of an auction system whereby gas shippers bid for entry capacity to the NTS; this ensures that National Grid only invests in capacity which is required, and also provides an indication of where increased volumes of imports are expected in future years. The auction held in September 2006 saw signals for incremental entry capacity at some existing entry points, namely Easington, Cheshire and Hornsea. In addition, a signal was received for the release of capacity at a new entry point at Fleetwood.

Market prices

43. Over the last gas year (October 2005 – September 2006) both spot and forward prices have been volatile. The annual average wholesale gas spot price (day-ahead) over the last gas year was 51p per therm, a 63% year-on-year increase. Prices reached a monthly average peak of 83p/therm in December 2005: by September 2006 prices were on average 27p per therm, similar to September 2005. More recently, the month of October 2006 averaged 21p per therm, a year-on-year fall of 36%. New sources of supply are one of a number of factors behind this decrease.

44. Over the course of the gas year, October 2005 – September 2006, the forward price of gas for delivery in Quarter 1 2007 increased by 51% (to 82p per therm) compared to the same period 2004-05. Forward price of gas for delivery in Quarter 1 2007 reached a monthly average peak of 90p per therm in January 2006 and has been declining month-on-month since April 2006. The monthly average for September 2006 was 74p per therm, falling to 65p per therm in October 2006 (5% lower than October 2005).

\(^5\) http://www.nationalgrid.com/uk/Gas/TYS/
Gas demand-side response

45. National Grid has developed an integrated model for the simulation of gas and electricity demand under a variety of historical weather patterns. Using assumptions of generation availability through the winter, the model calculates the minimum CCGT gas demand that would be required to meet electricity demand. This analysis suggests that if the market acted in such a way as to minimise CCGT gas consumption, this sector could make a significant contribution to the total level of demand-side response that would be required under severe conditions, while maintaining electricity security of supply. The analysis and its results are summarised in National Grid’s Winter 2006-07 Report.

46. The extent to which such a response would be seen in practice is likely to depend on the relationship between the market prices for gas and electricity (the “spark spread”) and alternative fuels, such as distillate. A significant response from the electricity generating industry was observed over winter 2005-06 and the implications of the evidence for the model were carefully considered and taken on board. Analysis suggests that the level of response observed from CCGTs in 2005-06 was broadly consistent with the potential for such response identified by National Grid’s modelling.

Gas quality

47. Earlier this year the Government consulted on Great Britain’s future gas quality specification, as set out in the 1996 Gas Safety (Management) Regulations, against the background that certain future imports may not comply with those specifications. That elicited a substantial number of high quality responses, which the Government is considering carefully. To minimise regulatory risk, the Government had earlier confirmed that it would not propose changes to the regulated specification to take effect before around 2020.

48. Meanwhile Ofgem is leading an exercise to assess the potential impact of gas quality constraints on the supply of gas to the GB market in the short-to-medium term, in order to inform market participants' investment decisions on options to mitigate the impact.

49. This work will ensure that the UK remains in the best position to influence developing proposals at the EU level. Partly in response to UK concerns, since the last JESS report the European Commission has tasked consultants to carry out a cost-benefit analysis of harmonised gas quality specifications.

THE ELECTRICITY MARKET

Electricity supply and demand

50. In the liberalised UK market, generation availability is driven by commercial decisions by market participants. Electricity produced by generators is sold on the wholesale electricity market, where electricity suppliers and traders can buy power either through bilateral contracts with generators or by trading on power exchanges. National Grid however, is responsible for holding short-term reserve to deal with events, such as higher than expected levels of demand or plant loss, and also to correct any potential short-term imbalances that the market does not fully resolve. National Grid procures the majority of its contracted reserve under annual contracts via the Standing Reserve tender process.

51. For 2005-06, National Grid contracted 2.255 GW via the annual Standing Reserve tender round. In addition, National Grid contracted a further 236MW via tender for Supplemental Standing reserve (SSR) covering the period 3 October 2005 to 25 March 2006. For 2006-07, National Grid has contracted 2.5GW via the annual Standing Reserve tender, and a further 742MW via tender for Supplemental Standing Reserve.
The balance between supply and demand is usually quantified in terms of the plant margin - the proportion by which installed capacity exceeds expected peak winter demand in each year. Historically this has been around or (mostly) above 20%, but this is not to say that this is the “right” level to ensure absolute security of supply – no amount of capacity can ever provide a 100% guarantee that there will be enough supply to meet any level of demand under every conceivable circumstance - or that a higher level would necessarily be better. While a plant margin may be sub-optimally low, implying an unacceptably high risk of supply interruption due to shortage of generating capacity, it may also be sub-optimally high, implying that consumers are unnecessarily carrying the cost of providing and maintaining capacity that will almost never be used. In the latter case it might be less costly overall to accept some low level of risk of supply interruption.

In addition, the absolute level of the plant margin on its own does not provide a complete measure of electricity security of supply. By analogy to security of gas supply, factors affecting security of supply in electricity include the reliability of the plant which generates and the network which transmits and distributes it, the flexibility of the market in response to price signals reflecting the supply-demand balance, and the diversity of the generating fleet as well as total capacity. We hope to take forward work on a more comprehensive indicator in the context of work on improved market information further to the commitment in the Energy Review.

Generating Plant: Closures and their likely impact

Decisions as to the timing of future plant closures and provision of new capacity, its nature and geographical location are for market participants, based on their own assessment of likely future supply and demand and commercial and regulatory signals in place. Among the most important factors likely to be influencing those decisions are the expected reductions in the present levels of nuclear and coal-fired generating capacity.

The decision to apply for an extension of the lifetime of nuclear plants is a decision for the operators. In the case of British Energy, the company recently announced a 10-year lifetime extension for Dungeness B power station. It will be for British Energy to consider the options for lifetime extensions for its other plants. There are no proposals on the table to extend the lives of any of the BNFL managed stations. The Nuclear Development Agency set out its proposals for the lifecycle of the Magnox fleet of power stations (operated on its behalf by BNFL) in its first strategy paper. The UK’s fleet of nuclear power stations at present is scheduled to close according to the timetable at table 3 of the annex.

Decisions about the timing of closure of coal plant will be influenced by the provisions of the Large Combustion Plants Directive (LCPD), which imposes restrictions on the emission of substances such as sulphur dioxide (SO$_2$) and nitrogen oxide (NOX). Plants which are unable to meet the requirements of the Directive have the option to opt out, in which case they are required to close altogether after 20,000 hours of operation or by the end of 2015, whichever is the earlier. Table 4 in the annex sets out the opt-in status of the UK’s coal-fired operating fleet, which was finalised on 3 February 2006.

The exact timing of the closure of opted-out plants is a matter for their owners, as is the use they choose to make of their 20,000 hour allowance, taking into account factors such as other environmental restrictions and the state of repair of the plants (for example, if a plant suffers technical difficulties it may not be worth investing in repair and maintenance to restore it). At one extreme, a plant’s owners might choose to use the allowance over the full eight-year period, implying a considerably lower level of use (less than 30% load factor) than has historically been typical of such plant; at the other extreme, they might run the plant continuously, in which probably unfeasible case (given environmental and technical limitations) it could exhaust 20,000 hours in just over two years.
Generating Plant: New plant

58. Construction work has begun on two new gas-fired plants, at Langage in Devon and at Marchwood in Hampshire. Centrica intend Langage to be commercially operational by winter 2008-09 and Marchwood Power is aiming to be operational by May 2009. There have also been a number of announcements on both new CCGT and high-efficiency coal fired generation projects which is Carbon Capture and Storage (CCS) ready.

59. The owners of three of the six coal-fired plants scheduled for closure under the LCPD have announced plans suggesting that they are looking seriously at replacing this capacity with new coal-fired capacity, using supercritical technology and with the option to add carbon capture capability later. E.ON announced in October 2006 proposals to build two new 800MW supercritical units at its coal-fired Kingsnorth power station in Kent replacing four 485MW coal-fired units on the same site which are scheduled to close. Scottish-Southern Energy announced in April that they were forming a partnership with Mitsui-Babcock, Siemens and UK Coal with a view to installing cleaner coal technology at Ferrybridge, comprising a 500MW Supercritical Boiler and the subsequent deployment of CCS. RWE npower have also announced a feasibility study into the potential for replacing their Tilbury coal-fired plant with a new 1,000MW clean-coal plant with CCS which would be completed by 2016. More recently, Centrica announced that it had acquired an option to participate in what would be the UK's first complete clean coal power generation project in Teeside for a total of £715 million.

60. These are the first examples of a number of potential CCS projects. As stated in the Energy Review, the Government believes that the next stage would be a commercial demonstration of CCS, if it proved to be cost effective. More work on the costs of such a demonstration project will be undertaken, and a further statement will be made at the Pre-Budget Report.

61. Table 2 also shows that there continues to be a large number of consents for wind farms across the UK. Whilst the majority of these remain options only, construction has started on the 322MW wind farm at Whitelee in Scotland.

62. It is therefore already possible to discern in general terms that new capacity to replace that being lost by 2015 is likely to be comprised mainly of new gas, coal and some renewable generating capacity. Beyond 2015, further closures are to be expected as tightening environmental standards and potentially the carbon price, force further coal closures and more plant of all types reaches the end of it operating life.

63. In the 2006 Energy Review the Government concluded that:

“Nuclear power is a source of low carbon generation which contributes to the diversity of our energy supplies. Under likely scenarios for gas and carbon prices, new nuclear power stations would yield economic benefits in terms of carbon reduction and security of supply. The Government believes that nuclear has a role to play in the future UK generating mix alongside other low carbon generating options. Evidence gathered during the Energy Review consultation supports this view.”

64. The Energy Review concluded that it would be for the private sector to take decisions on proposing new power stations, based on commercial considerations. However it did recognise that the Government needed to create a policy framework under which developers would be able to make proposals for nuclear new build. This resulted in the publication of the Consultation on the Policy Framework for New Nuclear Build7.

Wholesale prices

65. The average wholesale electricity spot price8 during Q3 2006 was £36.3/MWh, around 11% higher than the Q3 2005 average. Over 2006 to date, monthly average spot prices increased appreciably in March and July due to a significant tightening of the short-run supply-demand balance.

7 http://www.dti.gov.uk/consultations/page32340.html
8 APX Power UK market data
66. The year-ahead (i.e. April Annual) baseload price of electricity has fallen over recent months in response to declining energy commodity prices. The price currently stands at around £40/MWh, around 20% lower than its level in July 2006.

67. Forward prices in both the gas and electricity markets can be seen in Charts 8 and 9 in the annex. Data on forward spark spread is included at Chart 10.

OIL

UK crude oil production and trade

68. Oil production from the UK Continental Shelf (UKCS) peaked in 1999 but has been in general decline since. Crude oil exports have fallen in line with the decline in production whilst imports have risen steadily. This resulted in the UK being a net importer of primary oils (crude oil and natural gas liquids - NGLs) and feedstock in 2005 for the first time since 1992. Exports in 2005 were 8% lower than imports, down from previous years where exports were 3% higher than imports in 2004 and 28% higher in 2003. For the first half of 2006 exports were 7% lower than imports compared to 1% higher for the equivalent period in 2005.

69. In 2005 about two-thirds of the UK's primary oil production was exported with imported crude oil accounting for about two-thirds of domestic refinery intake. The UK both imports and exports oil for various commercial reasons. Primarily, refineries consider the type of crude oil rather than its source origin. Most UK refineries use North Sea 'type' crude and do not differentiate between the UK and Norwegian sectors of the North Sea. Indeed, some UK refiners have production interests in both UK and Norwegian waters so the company may own the imported crude at the point of production. The close proximity of UK and Norwegian oil fields mean that they may use the same pipeline infrastructure. However, some crude oils are specifically imported for the heavier hydrocarbons they contain, which are needed for the manufacture of various petroleum products such as bitumen and lubricating oils. This is in contrast to most North Sea type crude which contains a higher proportion of the lighter hydrocarbon fuels resulting in higher yields of products such as petrol and other transport fuels. In 2005, 75% of the crude oil imported by the UK came from Norway, with 13% from Russia and just 4% from the Middle East. Of the crude oil exported by the UK, 68% went to the EU and 26% to the United States.

70. We expect, partly as a consequence of the new Buzzard field coming fully on-stream, that UK oil production will rise from current levels in 2007 and 2008, returning the UK to net-exporter status. However, production is then expected to fall, with the UK becoming a net importer of oil on a sustained annual basis by around 2010. A growing net import requirement is expected thereafter. UK oil supplies will continue to be sourced, on a commercial basis, through the international market, making it difficult to forecast where future imports will come from. However, for the commercial reasons outlined above, the majority of the oil imported is likely to continue to come from Norway, although the volumes coming from other significant global producers such as Russia, and the countries of the Caspian region, West Africa, North Africa, and the Middle East will increase.

UK supply of refined petroleum products

71. Total petroleum products output from UK refineries in 2005 was 86 million tonnes, which was 4% lower than in 2004 but 2% higher than in 2003. During the first half of 2006 output was 4% lower than the same period in 2005. In contrast to crude oil, the UK is still a net exporter of refined petroleum products and the significant refinery infrastructure suggests that it will continue to be so for some time. In 2005, UK exports of petroleum products were 32% higher than imports. The main countries receiving UK exports were the EU and the United States. The main sources of the UK's imports of petroleum products in 2005 were Norway, the Netherlands, Saudi Arabia, France, Kuwait, Estonia and Latvia.
However, UK domestic production of individual petroleum products is increasingly no longer aligned with the domestic market demand. While the UK has surplus production of petrol and fuel oil, it produces insufficient aviation turbine fuel. Production of aviation turbine fuel has fallen in recent years, primarily due to increased demand for diesel, which is extracted from the same fraction of the crude oil barrel (middle distillates). In 2005, net imports of aviation turbine fuel accounted for 62% of UK consumption. Over the first 6 months of 2006 this has fallen slightly to 60%. Looking forward to potential rising demand and changes in demand pattern (e.g. diesel versus petrol), the UK Government has initiated a review of refining capacity. This will be by product type as well as net capacity, and also include primary infrastructure (distribution to main distribution terminals). Lessons learned from the Buncefield oil storage depot explosion have resulted in there being a similar but more focused review of aviation fuel demand and supply.

**Crude oil and wholesale petroleum product prices**

The prices paid by UK refineries for crude oil are largely determined by developments in the global oil market. As a result of robust growth in global oil demand over the last few years, the levels of global spare oil production and refining capacity have fallen well below historic levels. Combined with rising concerns about geopolitical supply risks and increasing costs of production, this has pushed crude oil prices steadily upwards. In nominal terms, the average cost of crude oil acquired by UK refineries increased by 8% in 2003, 16% in 2004 and 44% in 2005. In the first nine months of 2006 the cost had risen by a further 23%, although (Brent) crude oil prices have subsequently fallen from their peak of over US$78 per barrel in early August to around US$60 per barrel for most of October and November.

Petroleum products are also traded on global markets, with wholesale product prices in the UK primarily being determined by the costs of crude oil and conditions in the North-West European product markets. Wholesale product prices have generally moved similarly to crude oil prices, although seasonal variations in demand have meant that in the winter diesel prices have typically risen more quickly or fallen more slowly than petrol prices and in the summer vice versa.

Prospects for global oil prices remain uncertain. However, market fundamentals point to a gradual easing of prices as new production and refining capacity comes on stream and demand growth tempers. In its 2006 World Energy Outlook the IEA assumes that the price of Brent crude will fall to around US$51 per barrel (in year-2005 prices) by 2012. Thereafter it is expected to rise slowly, reflecting an expected increase in the market share of a relatively small number of producers, together with a rise in marginal production costs outside OPEC.

**UK stocks of crude oil and oil products**

In order for the UK to be prepared for any oil emergency, companies supplying oil products into final consumption in the UK are required by the UK Government to maintain a certain level of stocks of oil. In order to meet EU legislation, the UK is required to hold stocks of oil equivalent to 67½ days of demand for use in the event of a disruption of global supply. The UK's obligation will increase as our domestic production of oil declines. The UK's current EU derogation of 25 per cent is expected to begin to decline around 2010. At the end of September 2006 the UK held stocks equivalent to 79 days of demand. The Government is working with the oil industry to establish a system to ensure that the UK can continue to meet its oil stocking obligations in the long term, as we import more oil from overseas.

The UK is also a member of the IEA whose members also have an obligation to hold stocks of oil. The UK currently has no obligation to hold stocks through its membership of the IEA, but it does have an obligation to take part in any collective response by IEA member countries to any major international supply disruption.
78. The Energy Review highlighted the need for effective international contingency arrangements to guard against physical supply shocks in world oil markets. Existing IEA response mechanisms proved to be effective in response to the disruptions caused by Hurricanes Katrina and Rita in the US Gulf of Mexico last year. However, with the proportion of oil consumed by non-IEA countries rising, the Government will continue to support the work of the IEA in encouraging member and non-member countries to maintain and develop oil security arrangements for use in the event of oil supply disruptions.

**COAL**

79. The Energy Review report made clear that coal-fired generation would have an important and continued presence in the UK energy mix – and that “clean coal” was the way forward. It also discussed the respective roles of UK-mined and imported coal. British coal production has fallen significantly in the last decade. In 1995-96 over 50Mt was produced from 83 deep and 122 surface mines. By 2005-06 production had fallen to around 20Mt from 13 deep and 31 surface mines. Two of the remaining deep mines (at Rossington and Harworth) have since been ‘mothballed’ by their operator.

80. As with oil and gas production, current and forward prices and geology, which can be very challenging in the UK’s mature coalfields, are key drivers of investment for UK coal production. There has been recent investment in new deep mine production, such as the re-opening of abandoned developments at Aberpergwm colliery and current work to revive Hatfield colliery. Overall the environment remains challenging.

81. For the last twelve month period for which data has been published, coal-fired generation represented around a third of UK electricity supply; during the winter of 2005-06 coal contributed 42% of electricity supply, reflecting its continued importance in the UK’s energy system. To have a long-term future, however, coal needs to tackle its heavy carbon emissions. Coal-fired generation technology is becoming cleaner and carbon capture and storage (CCS) offers the promise of genuinely low carbon electricity generation from fossil fuels. Chart 13 in the annex shows forecasts of the future UK demand and supply for coal.

82. The Government believes that it is right to make the best use of UK energy resources, including coal reserves, where it is economically viable and environmentally acceptable to do so. The Energy Review announced the creation of the Coal Forum. Comprising key figures from the coal, electricity generation and transport sectors and from the trades unions, the Forum held its inaugural meeting in November 2006 under the Chairmanship of Sir John Collins, President of the Energy Institute. The Forum’s aim is to facilitate dialogue to help ensure that we have the right framework, consistent with our energy policy goals, to secure the long-term contribution of coal-fired power generation and optimise the use of economical coal reserves in the UK.
URANIUM

83. Realising the potential of any nuclear new build would naturally be dependent on the availability of nuclear fuel. There is a range of assessments of the future prospects for uranium supplies which reflect the difficulty in making exact predictions of uranium reserves. However, every two years the International Atomic Energy Authority (IAEA) and OECD (NEA) undertakes a comprehensive assessment of the availability of uranium taking into account expected production and demand levels. Their most recent report\(^9\) estimates the identified amount of conventional uranium resources that can be mined for less than US$ 130/kg to be about 4.7 million tonnes. Based on the 2004 nuclear electricity generation rate this amount is sufficient for approximately 85 years, using currently employed fuel cycles. It is however important to bear in mind that many countries are also planning for new nuclear capacity which will of course impact on the longer-term availability of uranium.

84. There are 442 reactors operating around the world today with another 28 under construction. As at November 2006 there were 62 reactors planned (approvals and funding in place, or construction well advanced but suspended indefinitely) and 161 reactors proposed (clear intention but still without funding and/or approvals).\(^{10}\)

85. It is difficult to make exact predictions on how long uranium deposits will last in any given country because it is dependent on a number of variables:

- new mines coming on stream and possible expansion of current mining operations;
- price of uranium ore – the price effects the mining market and may make mining of certain deposits more viable;
- new nuclear reactor technology may use less uranium thereby extending the lifetime of available uranium deposits;
- more nuclear reactors may be built thereby increasing the demand on available uranium deposits;
- the rate at which current operational reactors will decommission;
- increased use of reprocessing to recycle used fuel and create MOX (Mixed Oxide) fuel (a mix of uranium and plutonium).

86. Whilst the demand for uranium has increased in recent years, resulting in higher prices for uranium ore, future increases, even with further increasing global demand, are expected by the IAEA/OECD to be modest. Prices are expected to remain substantially below the historically high levels of the 1970s, but the increases we have seen are expected to encourage further exploration of uranium resources, with new mines expected to open across the world and increasing expenditure on exploration.

87. In addition, the UK has a substantial supply of recycled uranium and enrichment tails, which could be used to supplement the supply of uranium ore from overseas. Recycled uranium would need to be treated; currently only France and Russia have the capability. With changing market conditions, it may be attractive to build such facilities in the UK. Alternative fuels such as MOX could further supplement uranium supplies.

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\(^{10}\) World Nuclear Association [http://www.world-nuclear.org/info/reactors.htm](http://www.world-nuclear.org/info/reactors.htm)
IMPACT OF ENVIRONMENTAL REGULATIONS

EU Emissions Trading Scheme

88. The first year of Phase I (2005-07) of the EU Emissions Trading Scheme (EU ETS) enabled some very preliminary conclusions to be drawn. Actual emissions from EU ETS participating sectors turned out to have been lower than had been allowed for in the allocation of emissions allowances, leaving a number of participants holding surplus allowances and leading to a fall in the price of allowances. One of the main exceptions to this was the British electricity-generating sector, which appears to be a major buyer of allowances. Economic analysis suggests that the cost of allowances is feeding through to electricity prices in the UK and elsewhere in Europe, as would be expected given that electricity generation now involves the loss of opportunity to sell allowances as well as the use of fuel.

89. EU Member States made varying degrees of progress during 2006 towards determining the allocation of carbon allowances during Phase II (2008-12) of the EU ETS. As for Phase I, the UK adopted a stringent approach and continues to support the European Commission in its assessment of Member State allocations, with a view to creating a genuine shortage of allowances across the EU. This would deliver a robust carbon price [no shortage=no price] and stronger incentives for EU ETS participants to invest in carbon emissions reduction.

90. The Government, the Commission and other EU Member States have also begun to think about the shape and form of the EU ETS beyond 2012, including such issues as the overall level of allowances, allocation methodology and the fit with other, broader international arrangements. The Commission published on 13 November a communication setting out its plans for a review of the scheme.

The security impact of environmental regulation

91. The desired outcome of environmental regulation is to shift the overall generation mix towards cleaner technologies. The EU Emissions Trading Scheme and the Large Combustion Plants Directive (as already described), the Integrated Pollution Prevention and Control Directive (taking effect for the electricity generating industry in 2006) and the National Emissions Ceiling Directive (from 2010) will all operate in the same direction, providing incentives, and limits on emissions, to encourage a move towards cleaner forms of generation. They will have the effect of incentivising certain forms of generation, including coal and gas, to reduce emissions, for example by investing in cleaner technologies, rendering such generation less economic than it would otherwise have been and tending to disadvantage coal-fired generation compared to less carbon-intensive generation and, hence, reduce coal-fired output. The extent of this reduction is, however, highly uncertain, not least because the future level of coal generation in the absence of these measures is also uncertain.

92. The measures will also add to the complexity of issues faced by power generators and the constraints on operation that they face. In principle, energy markets are capable of managing the risks that the extra complexity and constraints impose - albeit perhaps with some increase in costs. However, it is important to give the market as much advance notice and clarity as possible on the way the new measures will be implemented. This is intended to inform decision-making and therefore maximise the scope for efficient market response, including new build.

93. Broadly, where environmental regulation adds to the cost of generation this is not necessarily a threat to the economic viability of generation, as some of those costs can be passed on to consumers (competitive pressures ensuring that every effort is made to meet the costs as efficiently as possible); in turn encouraging greater efforts to ensure energy efficiency on the part of consumers. As previously noted, for example, evidence suggests that the cost of EU ETS carbon emissions allowances is being passed through to electricity prices. Such regulation is therefore neutral to positive in terms of its impact on security of supply, although it does of course carry implications for the Government’s fuel poverty and industrial competitiveness objectives.

94. Where a regulation places an absolute restriction on a generation related activity, however, this may be more problematic for security of supply, depending on the extent to which flexibility in response to external circumstances is allowed for.
ENERGY RESILIENCE

95. The Downstream Gas & Electricity National Emergency Plan (Incident Response Plan), that describes how the DTI and industry will manage a major gas and/or electricity supply emergency, has been updated and reissued\(^\text{11}\). The enhanced procedure was tested as part of Exercise Neptune held in September 2006.

96. DTI has undertaken a consultation on the gas priority user arrangements. The consultation closed on 20\(^\text{th}\) October 2006 and the many responses are currently being considered\(^\text{12}\). In conjunction with the consultation, industry with support from the Department has reviewed the existing gas and electricity priority user lists to ensure they are robust.

NETWORK RELIABILITY

97. Ofgem in its role as regulator for the energy networks continues to monitor the reliability of networks and to ensure that companies have the right incentives to ensure that investment occurs when and where it is needed, and that network development, maintenance and operation occurs in an efficient manner that provide the maximum benefit to consumers.

98. The legal and regulatory framework is geared towards ensuring that transmission and distribution systems provide efficient and timely investment to ensure sufficient network capacity and reliability so that available supplies of gas and electricity can be transported to energy consumers. With the price control allowances, licence obligations and incentives, overall decisions on investment into their networks are determined by the transmission and distribution companies themselves.

99. Following the 2003 blackouts experienced in London and the West Midlands, Ofgem introduced a new electricity transmission network reliability incentive scheme for National Grid, reinforcing the existing obligations regarding network security. The incentive scheme came into effect in January 2005. These incentive arrangements utilise an annual baseline for the amount of energy, measured in megawatt hours (MWh), unsupplied by the transmission network each year. If National Grid is unable to supply available energy due to infrastructure failure and level of energy exceeds the baseline, it can be penalised by up to 1.5 percent of its revenue. Where the level of energy unsupplied falls below the baseline, National Grid will be rewarded by up to 1.0 percent of its revenue.

Electricity: transmission

100. Ofgem monitors closely the performance of electricity and gas networks. For electricity, National Grid’s figures in relation to the electricity national grid show that it is around 99.9997-99.9999 per cent reliable and that distribution networks have seen improvements in service with power cuts down by 11 per cent since privatisation.

101. On the England and Wales electricity transmission system there were 28 loss of supply events in 2005/6. This resulted in 417MWh being lost from the transmission system – equivalent to around 0.00015% of all electricity transmitted during the period. Of this 417MWh lost, 306MWh was the result of interruptions to 4 or more customers.

102. During 2005/6 there were a combined total of 15 losses of supply events on the Scottish Transmission system, summing to around 1521MWh. This represents around 0.0036% of all electricity transmitted across the Scottish transmission systems. Of these 15 events, 6 affected four or more customers.

\(^\text{12}\) [http://www.dti.gov.uk/consultations/page32587.html](http://www.dti.gov.uk/consultations/page32587.html)
Electricity: Distribution

103. Electricity distributors face certain quality of service standards aimed at guaranteed standards of performance. These standards set service levels that must be met in specific individual cases and incidents. If the electricity distributor fails to provide the level of service required, it must make a payment to the customer affected, subject to certain exemptions and, in certain cases, taking account of weather conditions prevailing at that time. This includes amongst others, measuring response times to certain network failures; restoration of supplies; and the number of interruptions experienced by a particular customer each year.

104. Over the year April 2005 to March 2006, the total number of customer interruptions was around 21 million. The total number of customer minutes lost was 1,966 million. To put this into perspective, the previous year (April 2004 to March 2005) there were around 22 million customer interruptions and the total number of customer minutes lost was 2,268. It should be noted that the total number of customer interruptions has been falling steadily. The number of interruptions in 2005-06 was around 4.5% lower than 2004-05.

Gas

105. Over the year April 2005 to March 2006, the total number of customer interruptions was 344,000, with the total number of customer minutes lost 174 million. In the previous year (April 2004- March 2005) the total number of customer interruptions was 273,000 with the total number of minutes lost at 246 million. This data includes both the DN networks sold by National Grid and those retained by National Grid. This is the first year after DN network sales and therefore a year on year comparison is not available.

106. Customer interruption data is split between planned and unplanned interruptions. Year on year unplanned interruption has declined from 54,000 to 51,000 however planned interruptions has increased from 219,000 to 292,000, with the increase attributed to additional mains replacement work.

Winter Outlook

107. Distribution companies are incentivised to develop, maintain and operate their networks in an efficient manner and combined with incentives, to respond to and resolve network outages for example those related to storm damage to local networks.

108. Over a longer-term time frame, planning statements from National Grid and others provide associated outlook for network investment needs. Market participants are able to participate in these processes and also more directly can provide signals, for example via the long-term entry auctions in gas. Therefore, both the national grid and local distribution networks face incentives to ensure that available electricity and gas supplies can be delivered in an efficient manner.

DIRECTION FOR 2007

109. Following publication of this report the focus of the work on forward-looking market information will be on taking forward recommendations in the Energy Review over the course of 2007. There will be an update on progress in the proposed Energy White Paper in March 2007.

110. At this stage however it is worth identifying some of the key themes of this early thinking. We would welcome feedback on the approach we intend to take.
111. As suggested above, we anticipate that the information will become much more web-based and the focus moved away from the traditional set-piece report. While we expect to continue to produce an annual report (and we will also need to continue to produce the Secretary of State’s report to Parliament to meet statutory obligations), the security of supply indicators could be updated as appropriate on a continuous basis. For example, we could update the tables of new and planned infrastructure projects in real-time as we get information.

112. The website would also be able to act as a repository of the wide range of published security of supply information. As well as National Grid’s seven and ten year statements, this could include one-off reports that we have commissioned on particular security of supply subjects, possibly including a more explicit look at international issues.

113. As well as seeking feedback on this report, we will develop a stakeholder engagement plan. Informal contacts with industry so far suggest that the work JESS has been doing is of value to them, but we could do more and better. The responses to the Energy Review consultation indicated the need for more information and most stakeholders reacted positively to the announcement of new arrangements for better information in the Review itself. They did however want more clarification about what this implied.

REQUEST FOR FEEDBACK

114. DTI 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:

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Please make clear if you would like your views to be treated as confidential. Non-confidential responses will be placed on the DTI website. It would be helpful to have your comments by the end of January 2007.
Background

1. One of the key tasks for JESS has been to establish a series of indicators to monitor security of supply. This report updates these indicators. It is important to bear in mind that these updates take no account of the estimated impact of the measures proposed in the Energy Review Report. As before, this work does not seek to detract from the roles of National Grid and the other network owners/operators 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 intention has been to present such non-confidential information as is available to DTI and Ofgem that may be of use to market participants and observers.

2. Previously, the indicators have concentrated on issues relating only to gas and electricity. However, security of supply issues do go beyond those presented in previous JESS reports. This report therefore includes some initial indicators on issues such as coal, oil and uranium supply which will be developed further for subsequent reports.

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 of other factors, such as increased energy efficiency (which could reduce energy demand) or global energy price rises (which may also reduce demand or result in increased supply from increased exploration or technical progress) is unknown.

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

5. The current remit of JESS is to look at a timeframe at least seven years ahead, but for future reports DTI is looking to extend that timeframe. 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, the report draws on planning forecasts (primarily from National Grid) and economic modelling data (primarily from the DTI’s Updated Energy Projections). However, because forecast data are 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, prices on the over-the-counter gas market are reported out to Quarter 4 2008. The development of information on forward prices and liquidity in forward markets will be kept under review.

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 making investment decisions, generators also look at forward fossil fuel prices (and the relativity between prices) and expectations with regard to carbon prices. 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. Actual market response to forward price signals can be through applications for consents to build new generating capacity, public announcements of intent to undertake a project, and applications for planning permission. JESS found that the most succinct way to show this response is through tables and maps setting out the projects.
Supply and demand forecasts - gas

1 Potential daily gas delivery capability (various supply scenarios) versus peak diversified gas demand during a 1 in 50 winter in the UK

Context:

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

Key Points:

The chart shows a number of scenarios presented by DTI of how gas demand could be met over the next decade. It is based on National Grid’s forecast for UKCS production and gas demand (as published in its TBE\textsuperscript{20} 2006: Energising Global Markets) combined with DTI’s view of the most recent developments in planned gas infrastructure projects. A summary of the planned gas infrastructure projects is provided in Table 1. The main differences between the current and previous chart (JESS publication April 2006) are given below. The same forecasting assumptions are used in Charts 2 and 3.

Chart Presentation:

1. Gas supplied through Norwegian import infrastructure is now classified as either “proven” or “probable”. In this chart, only “proven” supplies are included in the base case scenario with UKCS supply at 95% of its maximum volume. “Probable” gas supplies are

\textsuperscript{20} TBE – Transporting Britain’s Energy
grouped in with the new infrastructure projects classified as “probable”. (Note: new infrastructure projects are classified both on their likelihood of being developed and on their probability of being developed in line with their proposed schedules. Thus, a project could be probable in the first year and proven in the next if there is a high risk of first gas not being met by the specified time).

2. Other import supplies are no longer shown at 100% delivery capability. These supply volumes are apportioned according to delivery expectation and this may be dependent upon many factors, such as forecast world-wide LNG demand.

**Forecasting trends:**

1. The base case supply position shows a marked improvement due to the commissioning of the Norwegian Langeled pipeline and capacity increases on the existing European Interconnector. Supply capability is set to increase further still this winter with the planned commissioning of the new Dutch interconnector pipeline, potentially balancing average winter demand to 2012. However, the provision of such infrastructure does not guarantee the supply of gas. It would be expected that, in a cold winter, the gas price would be high enough to attract sufficient gas supplies, although this would depend upon both gas availability and demand in Europe at the time. Cold weather in Europe could see some gas being sold on the continent rather than in the UK.

2. High gas prices have tempered the forecast rise in demand, which is 10% lower this winter than was forecast by National Grid last year.

3. Comparing UKCS production (at 100% capability) with last year’s forecast shows a 6% reduction in supplies for winter 2006/07. The new forecasts take account of information provided to National Grid as part of the 2006 TBE process.

Comparing the current forecast with the first JESS publication in June 2002:

4. Beach gas supplies for this winter are 80% of that forecast in 2002.

5. There is little change in gas storage: the only new development is Humbly Grove plus some upgrading at Hole House Farm, although another 7 storage projects are now under consideration and at various stages of development.

6. The new LNG import facility at the Isle of Grain has been developed and another 5 LNG import facilities are planned.

7. The new Langeled pipeline is now in operation and, combined with upgrades to the existing European Interconnector, import capability is now over 150 Mcm/d versus 48 Mcm/d in 2002.

8. In 2002, import capability from proven infrastructure projects was forecast at 60 Mcm/d for winter 2011/12. The current forecast is 120 Mcm/d plus additional supplies from planned storage facilities.

9. Gas demand for this winter is forecast to be 20% lower than was forecast in 2002.

No allowance is made in the charts for major UKCS production outages. These have a low probability of occurrence but could result in significant gas supply shortfalls to the UK.
Background:

‘Severe Firm’ relates to a 1 in 50 winter period of high demand where all interruptible loads are not being supplied. Consumers on interruptible contracts pay reduced transportation charges to compensate for the risk of losing supply. The Uniform 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 over a prolonged period.

The supply forecast is based on the following scenarios:

- **Base case scenario**: This represents current levels of gas supply and assumes 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 incremental supply capability**: Those projects that, on available evidence, are virtually certain to be technically and economically successful (i.e., better than a 90% chance of being developed).
- **Probable incremental supply capability**: Those projects which are not yet “Proven” but have a better than 50% chance of being technically and economically successful.
- **Possible incremental supply capability**: Those projects which cannot be regarded as “Probable” at present, but are estimated to have a significant, but less than 50% chance, of technical and economic success.

“Pipeline imports” are gas supplies from Norway and Europe through pipeline interconnectors. “LNG import” is liquefied natural gas such as that supplied through the new Isle of Grain LNG importation facility. “Storage/LNG” includes both the Rough field and onshore storage in depleted fields and salt cavities; and gas supply from existing onshore liquefied natural gas plant operated by National Grid.

The “Proven” investment forecast makes the assumptions listed below about investment in gas infrastructure projects. Some of these projects are considered “Probable” in their early years due to the risk that they do not meet their proposed schedules and are therefore also listed in the “Probable” category.

- Additional pipeline importation capacity from Europe from Q4 2006.
- Additional LNG importation capacity from 2008/09.
- New onshore gas storage facilities from 2007/08.

The “Probable” investment forecast includes the projects listed below. Those projects considered “Possible” in their early years, due to the risks of not meeting their proposed schedules, are also listed in the “Possible” category.

- Additional pipeline importation capacity from Europe from 2007/08.
- Further LNG import capacity available from 2007/08, with additions in subsequent years.
- Additional onshore gas storage from 2008/09, with additions from 2010/11.

The “Possible” investment forecast includes the following projects:

- Additional pipeline importation capacity from 2007/08.
- Further LNG import capacity from 2006/07, with additions in subsequent years.
- Further onshore storage from 2008/09, with additions in subsequent years.

The base case scenario, shown by the blue line in the main chart, includes all existing supply sources: UKCS production (based on 90% supply availability, although the chart also shows supply based on 95% availability); current import capacity through the European Interconnector;
Norwegian imports from Statfjord via the FLAGS, Vesterled and Langeled pipelines; current onshore and offshore storage; and LNG importation at the Isle of Grain.

Average gas demand is based on the 17 year seasonal normal average.

Source:

Gas demand and the base case supply scenario are based on National Grid data and exclude gas supplied through other networks (eg direct to certain power stations). DTI has produced its three investment scenarios based on the latest information. All data correct as of October 2006.
Supply and demand forecasts - gas

2 Demand duration curves

Forecast "expected" gas supply versus firm demand 2006/07

Forecast "expected" gas supply versus firm demand 2007/08
Context:

The charts show the various sources of gas that can be utilised during the 100 coldest days in a winter and how storage may be depleted, leaving only continuous supply available. It includes the “Proven”, “Probable” and “Possible” supply and investment scenarios included in Chart 1. The demand duration curves have been shown for three selected winters over the next 10 years on the assumption of a 1 in 50 winter and an average UKCS production availability of 90%.

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, and imports.

UKCS production is shown as 90% of maximum delivery capability representing average plant availability.

The “Chart presentation”, “Forecasting trends” and “Background” information listed in relation to Chart 1 also apply and should be read in conjunction with this chart.

Forecasting trends:

1. The first chart shows that stored gas will be required to meet average firm demand on the coldest 50 days of a severe winter in 2006/07. This would reduce if UKCS production were greater than 90% availability or Norwegian gas imports were at 100% delivery capability. Commissioning the Dutch Interconnector pipeline this winter season and some onshore storage facilities in 2007 will also improve this position, as shown in the second chart.
2. The third chart shows that by 2015/16 both “Probable” and “Possible” gas supplies will be required to meet average and severe winter demand respectively. This position has improved since the last JESS publication largely due to the commissioning of the Norwegian Langeled pipeline and the lower demand forecast.

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.

**Background:**

“Existing imports” are gas supplies from the Norwegian continental shelf and from Europe through pipeline interconnectors plus LNG imports at the Isle of Grain LNG terminal. “Mid-range Storage” includes salt cavities and depleted onshore fields.

During a severe winter it is unlikely that storage facilities, once their gas had been exhausted, could be recharged to full capacity due to the relatively slow injection rates of most facilities and the infrequency of low demand days. Whilst storage cycling is common during an average winter, the amount would be minimal during a severe winter and has not therefore been incorporated into the charts.

It is also recognised that during milder winter weather, gas demand may be met from a variety of sources and not solely UKCS production. This will be due to commercial drivers and is consistent with experiences in recent winters.

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 coincide.

**Source:**

Gas demand and the base case supply scenario are based on National Grid data and exclude gas supplied through other networks (eg direct to certain power stations). DTI has produced its three investment scenarios based on the latest information. All data correct as of October 2006.
Supply and demand forecasts - gas

3 Daily gas deliverability

Context:

The chart shows how the various supply sources might be expected to contribute to meeting gas demand in the next twenty years, based on the “Possible” gas supply scenario as described for Indicator 1 on page 23. Note that data beyond 2015/16 are extrapolated based on trends from the previous 5 years.

Key Points:

Given that lead times for new import or storage infrastructure (from the identification of a project to its physical operation) could be as short as 5-7 years, a gap between longer-term demand expectations and present plans for supply projects should not be alarming. Therefore the market is unlikely to have well developed plans now for new projects for delivery beyond 2015. Notwithstanding this, the chart suggests a good supply-demand match continuing through until about 2020, assuming all “Possible” projects are developed and all “probable” gas supplies from Norway are delivered, at which point the supply and demand gap opens up revealing the opportunity for further investment in new infrastructure. (Note: the chart no longer shows European and LNG supply sources at 100% of delivery capability, therefore gas deliveries could actually be higher than shown).

The chart also includes projected demand for an average winter and suggests that until 2014/15, supplies without storage would in theory be sufficient to provide for demand throughout an average winter; although in practice demand is more likely to continue to be met from a combination of indigenous production, imported and stored gas. From 2015 onwards there would be an increased requirement for stored gas to meet average demand throughout a winter period. Assessing the ability of such supplies to meet demand over winter durations is not straightforward as it depends on the characteristics of the storage projects. Of the new storage projects being planned, most are short-term supply projects. The limited inventory of these facilities limits their capability to supply continuously over a sustained period; although the speed with which such facilities can be re-stocked can help such short-range storage to contribute for longer durations throughout a winter. To assess
the supply-demand balance for a particular winter, a more detailed analysis is required (for example, Charts for Indicator 2 on pages 27 and 28, which show 100 day load duration curves for severe and average firm demand for 2006/07, 2007/08 and 2015/16).

Nevertheless, it is reasonable to suggest from this forecast that there will be a need for new projects to be commissioned (such as storage, interconnection or LNG) in the next decade.

The main change between the current chart and the previous chart in the sixth JESS publication, April 2006, is that UKCS production is now shown at the lower end range of 90%.

**Background:**

The “Chart presentation”, “Forecasting trends” and “Background” information listed in relation to Chart 1 also apply and should be read in conjunction with this chart.

**Source:**

Gas demand and the base case supply scenario are based on National Grid data and exclude gas supplied through other networks (eg direct to certain power stations). DTI has produced its possible investment scenario based on the latest information. All data correct as of October 2006.
Supply and demand forecasts - gas

4 Annual UK gas demand and potential supply

Context:
Gas production from the UK Continental Shelf (UKCS) peaked in 2000 and has since been declining; that decline is expected to continue. Until the end of this decade, UK demand for gas is expected to be broadly flat and then rise slowly. The implied growing need for imports has implications for import infrastructure and for the underpinning commercial and intergovernmental agreements.

Key Points:
UK gas demand is expected to be broadly flat until the end of this decade and then rise slowly over the next decade or so; the pace of change in demand will depend on a number of factors including absolute and relative energy prices. Between 1997 and 2003, the UK was a net exporter of gas on an annual basis, mainly via the Bacton–Zeebrugge interconnector. As a result of declining UKCS production, in 2004 the UK was again a net importer of gas and a large and growing import requirement is expected 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 a quarter of annual UK gas demand in the 1980s - was not on the scale now anticipated (with net imports meeting around 30% of UK annual gas demand in 2010, 60% in 2015 and 80% in 2020). Were they all to go ahead, the capacity of existing import projects and those currently being considered could meet the annual shortfall in supplies from the UKCS well into the next decade. Imports are likely to come from a range of sources and by a variety of routes, thus contributing to gas supply diversity. There is also some upside potential from UKCS production which, like UK demand, may respond to price signals.
Background:

The chart gives an indication of the possible availability of gas to meet annual UK demand over the period to 2015.

The forecast element of the ‘Actual/projected net UKCS gas production’ line on the chart is based on data provided by operators to DTI in mid 2006. A small volume of this UK gas production is exported directly to The Netherlands and is thus not available to meet UK gas demand.

Imports are currently possible from Continental Europe through the Bacton–Zeebrugge Interconnector. However, because seasonal exports are expected to continue at times of low UK demand (ie in the summer months), the chart assumes no net contribution from the Interconnector to annual UK supply (or demand), notwithstanding the expected progressive increase in its import capacity through the installation of additional compression at the Belgian end.

There is existing infrastructure in place permitting imports of gas from Norway, principally the Vesterled pipeline to St Fergus and the Langeled pipeline to Easington. The Norwegian entry on the chart also includes the import capacity of projects to bring additional Norwegian gas to the UK.

The chart also shows the capacity of the Balgzand-Bacton Line (BBL, the second gas interconnector) and of the various liquefied natural gas (LNG) import projects being planned. In both cases the chart shows the progressive build up of supplies to the UK these projects would make if they were to go ahead to the fullest extent currently expected. In practice the build up of import capacity and, particularly, of actual gas imports would be more closely matched to the growth of demand.

The (DTI) gas demand projection shown here excludes producers’ own use. It is therefore comparable with the production projection, since that is net of producers’ own use. The demand projection also includes an estimate of non-energy demand for gas (eg use for petrochemicals). Demand from Northern Ireland is included but demand from the Irish Republic - around 4 bcm of which is currently met by imports from the UK - is not. As with the production projection, there is great uncertainty attached to the gas demand projection (with industry estimates ranging up to 125 bcm or more by 2015); both should be treated as only indicative.

Source:

DTI data for actuals (through to 2005); DTI projections and estimates as described above.
Supply and demand forecasts - electricity

5 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 current DTI’s projections (published in July 2006) and illustrates the potential requirement for new investment. Two scenarios are presented: a central fossil fuel price scenario where assumed prices somewhat favour coal fired generation, and a central fossil fuel price scenario where assumed prices somewhat favour gas fired generation. Data on current plant build and consents are presented at Table 2.

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 2015 gas fired generation is modelled to be producing between 30 and 49 TWh more than was produced in 2005, rising to an additional 85 to 100 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 34 TWh in 2015 and 26 TWh in 2020. The projection for nuclear supply embodies life extension at Dungeness B but at no other station.

It is assumed that eligible renewables reach a market penetration of around 9% in 2010, though there is a great deal of uncertainty about the likely outcome. Penetration in 2015 is consistent with meeting the Government’s 15% target. When these projections were published, in summer 2006, while the 20% goal for renewables in 2020 was clear, it was judged that further measures would be required in order to achieve it so renewables were projected to remain at the same absolute level of supply between 2015 and 2020.
Background:

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

Sources:

Historic: DTI, Digest of UK Energy Statistics 2006 - Table 5.6 and corresponding tables in earlier editions.

Projections: The projections are the two central cases examined in the DTI’s latest energy and emissions projections report published in July 2006.
Supply and demand forecasts - electricity

6 Generator margin – Great Britain

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 capacity 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 National Grid’s three demand scenarios (low, base, and high cases) as shown in the 2006 Seven Year Statement (SYS), minus station demand. The bars show the generation mix split into the major fuel types and consenting new build (first and last years only).

Given the status quo (no new build beyond what is under construction and no closures) the plant margin under the base demand scenario is 23.5% in 2006/07 and falls to 20.0% by 2012/13. Any closures will reduce this and provide further opportunities for new generation.

For the data given in the figure (the "Consents" background, explained below), the plant margin under the base demand scenario is also 23.5% in 2006/07 but only falls to 22.8% by 2012/13. In the High demand case the margins fall below 20% after the first year.

However, the basic margins displayed take no account of new connection agreements for generators being signed, nor the possibility of future closures or temporary mothballing.

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 National Grid (although not all use National Grid’s gas
network as primary supply). The extent to which interruptible CCGTs can continue to generate under alternative fuels is discussed under Chart 8 of this Annex.

Background:

The chart above is based on National Grid’s Consents Background, a central projection which contains all existing plant, that portion of plant under construction which has obtained the necessary consents and planned future plant that has also obtained consents. The Consents Background includes all contracted generation with S36 (and S14) consents. It is highly unlikely that all these projects will be built. There are no assumptions on plant closures other those already notified by nuclear magnox generators because operators only have to give 6 months notice of closure to National Grid. National Grid’s peak demand forecast includes high and low scenarios to capture a range of possible peak outcomes.

It should be noted that the Seven Year Statement publishes plant margins using both customer-based demands and National Grid Base Case demand, whereas this document is based solely on National Grid demands. The Seven Year Statement publishes plant margins for the ‘SYS Background’ which consists of all transmission contracted generation, as well as the ‘Consents’ and ‘Under Construction’ backgrounds, whereas this document concentrates on the ‘Consents’ background, and to a lesser extent the ‘Existing and Under Construction’ background.

Plant margin is defined as:

\[
\frac{\text{Installed Capacity} - \text{Peak ACS Demand}}{\text{Peak ACS Demand}} \quad \text{expressed as a percentage.}
\]

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. Installed capacity is now based on TEC values (Transmission Entry Capacity), and the demand excludes station demand.

Source:

National Grid – GB Seven Year Statement October 2006 updates.
Supply and demand forecasts - electricity

7 Generation profile summer/winter (Great Britain)

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:

The maximum demand (averaged over half an hour) for Great Britain for winter 2005/06 occurred on 29 November 2005 and was 59.4 GW (excluding station demand and exports to Northern Ireland), of which over 26 GW was provided from coal-fired power stations.

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 to global primary fuel supply and demand and local factors.

Chart 7a demonstrates the electricity (split by plant) required on three different days: typical summer (15 June 2005), typical winter (15 December 2005) and winter maximum (29 November 2005). Coal generated 559 GWh on the typical winter day compared with 275 GWh for the typical summer day.

Chart 7b 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 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. In addition, changes to relative fuel costs will have a large impact on these profiles through time and should therefore not be considered in isolation.

Source:
National Grid – GB Seven Year Statement 2006.
Supply and demand forecasts – electricity

8 Load duration of back-up fuel supplies assuming full output (Great Britain)

Context:

The chart shows in simplified form the number of hours that CCGT generation output could be maintained using alternative fuels, mainly stored on-site. Data collected for the 2006/07 Winter Consultation Report shows that there is around 24.9 GW of CCGT capacity in Great Britain, of which 3.3 GW have access to alternative gas sources via direct pipeline connections to offshore fields.

Of the 24.9 GW of total CCGT capacity, 7.0 GW has transportation interruptible contracts. Some 2.9 GW (41%) of this has access to distillate as a back-up fuel. As a result, around 4.1 GW of CCGT capacity that is supplied on a transportation interruptible basis has no back-up fuel capability and would not be able to generate following the interruption of supplies from their connection to the NTS.

Of the 2.9 GW of transportation interruptible capacity that is covered by distillate back-up, the potential duration of supplies from the generators will depend on their ability to restock their stocks of distillate fuel, which can take between two and twenty-one days.

It is also worth noting that some CCGTs with firm transportation arrangements choose to install back-up fuel capability in order to facilitate a response to relative gas, distillate and electricity prices.
Key points:

Around half of the generation capacity using distillate fuel as back-up would be lost after a continuous period of 168 hours even if initially stocks were at their maximum level (assuming no refilling). If stocks were initially at an average level, less than one quarter of this capacity would remain after the same continuous period.

These results are dependent upon the daily CCGT generation profiles. For example, concentration of CCGT power generation in peak periods would extend the availability of back-up fuel stocks, as would profiling of gas supply interruptions.

Background:

Approximately 17% of all CCGT capacity has some form of back-up facility, via either a stock of distillate or a direct non-NTS gas supply. A developer’s decision to install alternative fuel availability will generally be driven by the benefit of having the option to generate even when the gas supply is interrupted and the value that can be realised from the flexibility to arbitrage between the prices of electricity, gas and distillate fuel. This economic decision will be influenced by the chosen transportation contract (firm or interruptible) for the generator and by the physical characteristics of the CCGT design.

Sources:

The back-up fuel data for this chart were submitted to National Grid under obligations placed upon generators under the Grid Code and from responses to the Winter Consultation process.
Market signals – gas

9 Forward gas prices – GB

Context:

Forward gas prices show the price you would pay if you committed today to buy gas to be delivered on a specified future date. For example, the red line shows the average price you would have paid to buy gas for delivery in Winter ’04, Summer ’05, Winter ’05, Summer ’06 and Winter ’06 in July 2004. The blue line shows the prices for many of the same packages that were obtainable 6 months later – in January 2005.

The forward prices for each package are calculated as the average of all forward trades (for each package) during each month. Monthly prices are incorporated into the calculation of the first season’s price (ie summer 2006). The six monthly and two quarterly packages that comprise summer 2006 are weighted (using the numbers of days in each package) to determine the summer 2006 forward price.

Key Points:

The forward prices of gas in July 2006 are slightly lower than quoted 6 months earlier for both Winter 06 and Winter 07 but slightly higher for Summer 07 and Summer 08, but they remain considerably higher than those quoted a year earlier in July 2005, and around double those quoted in July 2004 and January 2005. There are a number of key drivers of forward gas prices, including oil prices, which influence UK gas prices via their impact on European gas prices. Since the majority of European gas prices are still linked to the oil price, the previous increase in the forward price of oil has increased European gas prices, which impact UK gas prices via flows across the interconnector. Additional factors contributing to the increase are a decline in UKCS gas production, uncertainty over the rate of this decline and uncertainty concerning the ability to secure surplus gas in Europe. However, beyond 2006/07, as expected, gas prices show a fall as construction work on additional sources of gas supply, such as new LNG terminals, is completed.
Background:

Gas prices are seasonal, as demand for gas is higher in winter than in summer. This is reflected in the forward prices with higher prices observable for winter.

Source:

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

<table>
<thead>
<tr>
<th>Packages</th>
<th>Price</th>
<th>No of days covered</th>
<th>Time weighted average price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quarter 2 2005</td>
<td>25.69</td>
<td>91</td>
<td>25.69*(91/183) = 12.77</td>
</tr>
<tr>
<td>Summer 2005 price</td>
<td></td>
<td>183</td>
<td>12.77 + 11.99 = 24.77</td>
</tr>
</tbody>
</table>
Market signals – electricity

10 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.

Traded volume data (for electricity volumes traded in January 2006) are presented along with forward electricity price data.

Key Points:

Both peak and baseload forward prices from July 2005 are significantly higher than the prices quoted in July 2004 and January 2004. This increase is evident across all periods, but is most notable for winter 2006/07 and summer 2007 where effectively there has been a doubling of prices. Peak electricity forward prices from July 2006 are slightly lower than those recorded in January 2006 for Winter 2006 and Winter 2007, but slightly higher for Summer 2007 and Summer 2008.

The most significant driver of forward power prices is higher fuel input prices used for power generation. As described in indicator 9, forward gas prices have risen substantially over the past 18 months, increasing the cost of generation. In addition, higher coal prices have added to the cost of coal fired generation. Finally, although oil-fired generation makes up a small proportion of annual output, higher oil prices have also contributed to the rise in power prices, particularly when oil-fired power stations are likely to be the marginal generator during winter.

The recent volatility in prompt gas and power prices may have increased uncertainty over forward outturn prices, thereby increasing the risk premium for contracting power forward.
Baseload power is more actively traded than peak power and that greater volumes of electricity are traded for short-term delivery (ie winter 2006/07 and summer 2007), than for longer term periods. Additionally greater volumes are traded for winter than summer months, which is unsurprising given that demand is higher in winter than summer.

Background:

Electricity prices are seasonal, tracking seasonal levels of demand. This is reflected in the forward curves with higher prices for winter. Although the above 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. As 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 9. There was no overlap for the remaining seasons so it was not necessary to time-weight the packages.
Market signals – electricity

11 Spark spread

Context:

The forward spark spread is important for market participants with gas-fired generation in determining whether it is profitable to generate. It is also an important indicator for potential new entrants, since it indicates whether gas-fired new entry may be viable. Where the spark spread widens, we would expect companies to respond by de-mothballing existing gas fired capacity in the first instance, and then building new gas-fired plant.

Key Points:

The above graph shows forward spark spreads based on forward prices taken on 18 October 2006 and forward prices 6 months earlier on 18 April 2006. The graph shows that the most recent spark spread is broadly similar across all periods when compared with the spark spread 6 months ago. The spread has increased in winter 2006/07 where the increase is around £5.00/MWh, but has fallen for the remainder of the period shown up to September 2008 by around £4.00/MWh.

Background:

A ‘spark spread’ is a spread between the price of electricity and the price of the gas required to generate that electricity. The spark spread represents the revenue available to the gas-fired generator to finance annual fixed costs, capital costs, investment and profits.

Methodology:

The spark spread was calculated using daily, weekly, quarterly and seasonal products. For power the baseload power package was used, whilst for gas National Balancing Point (NBP) gas prices were used.

To calculate the spark spread, the estimated gas forward prices from the model were converted to a £/MWh of electricity equivalent, using an efficiency factor of 52 per cent. This was then...
subtracted from the estimated power forward prices to give the spark spread. The spark spread curve is rectangular rather than a smooth line due to the fact that monthly average data are being used. A separate quoted price for each individual day along the curve would be needed to generate a smooth line.

Sources:

Heren’s daily price assessments as quoted in the European Daily Electricity Market (EDEM) and European Spot Gas Markets (ESGM) reports. The data for this graph are taken from the 18 April 2006 and 18 October 2006 reports.
Market response – gas

Table 1: Planned major new gas projects (as at November 2006)

Context:

The following table provides an indication of potential major new investments in gas infrastructure.

All the projects included have been publicly announced or acknowledged. DTI 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.

Key Points:

- Phase 2 of Interconnector upgrade completed 1 October 2006.
- Excelerate project scheduled for commissioning in Q1 2007.
- The Langeled pipeline began flowing gas to the UK on schedule in September 2006.
- BBL pipeline due for commissioning in December 2006.

Background:

Approvals for major energy projects are generally sought from national government, whereas local government deals with smaller projects.

Source:

DTI.
<table>
<thead>
<tr>
<th>Project</th>
<th>Owner/Proposer</th>
<th>Size</th>
<th>Date</th>
<th>Status</th>
<th>Under Construction</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>GAS IMPORT INFRASTRUCTURE</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interconnector from Balgzand to Bacton (the ‘BBL’ pipeline)</td>
<td>BBL</td>
<td>Potential capacity up to 44 Mcm/day</td>
<td>First gas planned December 2006</td>
<td>Under construction – on track for commissioning 1 December 2006</td>
<td>Yes</td>
</tr>
<tr>
<td>Dragon LNG terminal at Milford Haven</td>
<td>Petroplus/BG/ Petronas</td>
<td>First train up to 16.5 Mcm/day, up to a maximum of 27 Mcm/day during peak periods</td>
<td>First gas Q4 2007</td>
<td>Under construction. Planning permission for pipeline and above ground installations ongoing</td>
<td>Yes</td>
</tr>
<tr>
<td>South Hook LNG terminal at Milford Haven Phase 1</td>
<td>Qatar Petroleum / Exxon-Mobil</td>
<td>30 Mcm/day</td>
<td>Winter 2007/2008</td>
<td>Under construction.</td>
<td>Yes</td>
</tr>
<tr>
<td>South Hook LNG terminal at Milford Haven Phase 2</td>
<td>Qatar Petroleum / Exxon-Mobil</td>
<td>30 Mcm/day</td>
<td>2009</td>
<td>Under construction.</td>
<td>Yes</td>
</tr>
<tr>
<td>Gasport LNG terminal at Teesside</td>
<td>Excelerate Energy</td>
<td>11.3 Mcm/day</td>
<td>First gas planned Q1 2007</td>
<td>Under construction</td>
<td>Yes</td>
</tr>
<tr>
<td>Statford Late Life project; delivery via FLAGS pipeline</td>
<td>Statoil</td>
<td>17 Mcm/day at plateau</td>
<td>First gas planned 2007/08</td>
<td>Project approved by both UK and Norwegian Governments</td>
<td>..</td>
</tr>
<tr>
<td>Isle of Grain LNG import and storage facility; expansion of existing site</td>
<td>National Grid</td>
<td>Phase 2 expansion for an additional 24 Mcm/day</td>
<td>Phase 2 due for completion in Q4 2008</td>
<td>Engineering, Procurement and Construction Contracts have been awarded for Phase 2</td>
<td>Yes</td>
</tr>
<tr>
<td>LNG terminal at Norsea Oil Terminal, Teesside</td>
<td>Conoco Philips</td>
<td>To be confirmed</td>
<td>First gas planned 2012/2013</td>
<td>Pre-planning</td>
<td>..</td>
</tr>
<tr>
<td>Canvey Island LNG</td>
<td>Calor</td>
<td>5.4 Bcm</td>
<td>To be confirmed</td>
<td>Planning permission refused</td>
<td>..</td>
</tr>
<tr>
<td><strong>GAS STORAGE INFRASTRUCTURE</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aldborough storage</td>
<td>Joint development between Statoil and Scottish and Southern Energy</td>
<td>420 Mcm storage capacity</td>
<td>Commissioning Q3 2007</td>
<td>Approved</td>
<td>Yes</td>
</tr>
<tr>
<td>Holford storage, Cheshire</td>
<td>Scottish Power</td>
<td>170 Mcm storage capacity</td>
<td>Proposed commissioning 2008</td>
<td>Approved</td>
<td>Yes</td>
</tr>
<tr>
<td>Caythorpe Gas Storage</td>
<td>Warwick Energy</td>
<td>210 Mcm, storage capacity</td>
<td>Q3 2008</td>
<td>Planning application refused – appeal lodged</td>
<td>..</td>
</tr>
<tr>
<td>Saltfleetby Gas Storage</td>
<td>Wingas</td>
<td>715 Mcm storage capacity</td>
<td>Proposed commissioning Q4 2008</td>
<td>Planning application submitted January 2006 – awaiting outcome</td>
<td>..</td>
</tr>
<tr>
<td>Stublach Gas storage facility</td>
<td>INEOS Enterprises</td>
<td>540 Mcm storage capacity</td>
<td>Proposed commissioning 2009</td>
<td>Under construction</td>
<td>Yes</td>
</tr>
</tbody>
</table>
**GAS STORAGE INFRASTRUCTURE (continued)**

<table>
<thead>
<tr>
<th>Project</th>
<th>Owner/Proposer</th>
<th>Size</th>
<th>Date</th>
<th>Status</th>
<th>Under Construction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albury Phase 1</td>
<td>Star Energy Ltd</td>
<td>160 Mcm storage capacity</td>
<td>Proposed commissioning 2009</td>
<td>Pre-planning</td>
<td>..</td>
</tr>
<tr>
<td>Albury Phase 2</td>
<td>Star Energy Ltd</td>
<td>Up to 715 Mcm storage capacity</td>
<td>Proposed commissioning 2010</td>
<td>Pre-planning; Drilling required</td>
<td>..</td>
</tr>
<tr>
<td>Bletchingley storage facility</td>
<td>Star Energy Ltd</td>
<td>900 Mcm storage capacity</td>
<td>Proposed commissioning 2010</td>
<td>Pre-planning; Drilling required</td>
<td>..</td>
</tr>
<tr>
<td>Gainsborough</td>
<td>Star Energy Ltd</td>
<td>220 Mcm storage capacity</td>
<td>Proposed commissioning 2010</td>
<td>Pre planning</td>
<td>..</td>
</tr>
<tr>
<td>Welton storage facility</td>
<td>Star Energy Ltd</td>
<td>435 Mcm storage capacity</td>
<td>2010</td>
<td>Local planning has refused permission. 1965 Gas Act application to be submitted</td>
<td>..</td>
</tr>
<tr>
<td>Preesall storage facility</td>
<td>Cantaxx</td>
<td>Total capacity 1.7 bcm</td>
<td>Proposed operational 2010</td>
<td>Public Inquiry held: awaiting decision</td>
<td>..</td>
</tr>
<tr>
<td>Portland Gas storage</td>
<td>Portland Gas Ltd</td>
<td>1,000 Mcm dependent on test results</td>
<td>Proposed commissioning from 2010 to 2013</td>
<td>Planning submission Q4 2006</td>
<td>..</td>
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<tr>
<td>Whitehill</td>
<td>E.On</td>
<td>To be confirmed</td>
<td>Proposed commissioning 2010-2012</td>
<td>Pre-planning</td>
<td>..</td>
</tr>
<tr>
<td>Amlwch</td>
<td>Cantaxx</td>
<td>To be confirmed</td>
<td>To be confirmed</td>
<td>Pre-planning</td>
<td>..</td>
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</tbody>
</table>

**NEWLY COMPLETED AND COMMISSIONED PROJECTS (AS OF JANUARY 2006)**

<table>
<thead>
<tr>
<th>Project</th>
<th>Owner/Proposer</th>
<th>Size</th>
<th>Date</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Langedal South pipeline supplying gas from the Ormen Lange gas field development and other Norwegian fields</td>
<td>Norsk Hydro / Shell Norge</td>
<td>Pipeline capacity about 70 Mcm/day</td>
<td>Formal opening 16 October 2006</td>
<td></td>
</tr>
<tr>
<td>Compressors at Zeebrugge to increase import capacity into UK</td>
<td>Interconnector UK</td>
<td>Second stage to increase capacity from 44 Mcm/day to 66 Mcm/day</td>
<td>Completed on 1 October 2006</td>
<td></td>
</tr>
<tr>
<td>Isle of Grain LNG import and storage facility; redevelopment of existing site</td>
<td>National Grid</td>
<td>Phase 1, 13 Mcm/day; Phase 2 expansion additional 25 Mcm/day</td>
<td>Phase 1 construction complete and has received numerous cargoes</td>
<td></td>
</tr>
</tbody>
</table>

Key: .. indicates that the project has yet to reach the stage where construction can begin.
Table 2: Planned major new electricity projects (as at November 2006)

Context:
The following table provides an indication of potential major new investments in electricity generation.

Key Points:
Compared with the figures in the Secretary of State’s Second Report to Parliament on the Security of Gas and Electricity Supply in Great Britain (July 2006), there has been an increase in planned CCGT capacity from 11,570 MW to 12,840 MW. The 941 MW of CHP capacity is unchanged from July 2006.

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.

The planned capacity of renewables has increased from 10,679 MW in July 2006 to 12,426 MW.

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

Source:
DTI.
As a consequence of the Secretary of State’s powers under section 36 of the Electricity Act 1989 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.

<table>
<thead>
<tr>
<th>Station</th>
<th>Owner</th>
<th>Size (MW)</th>
<th>Type</th>
<th>Distillate backup</th>
<th>Status</th>
<th>Under Construction</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CCGTs</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Staythorpe</td>
<td>RWE npower</td>
<td>1,630</td>
<td>CCGT</td>
<td>Yes(^{15})</td>
<td>Approved November 2000</td>
<td>Preliminary ground work begun</td>
</tr>
<tr>
<td>Langage, South Devon</td>
<td>Wainstones (Carlton Power)</td>
<td>1,010</td>
<td>CCGT</td>
<td>Black start and back up fuel issues are still under discussion</td>
<td>Approved November 2000; Preliminary work begun</td>
<td></td>
</tr>
<tr>
<td>Marchwood, Hampshire</td>
<td>ESBI (Republic of Ireland Electricity Board)</td>
<td>800</td>
<td>CCGT</td>
<td>No</td>
<td>Approved November 2002</td>
<td>No Expected to start in 2006</td>
</tr>
<tr>
<td>New Pembroke Power Station</td>
<td>RWE npower</td>
<td>2,000</td>
<td>CCGT</td>
<td></td>
<td>Being processed</td>
<td>..</td>
</tr>
<tr>
<td>Milford Haven</td>
<td>Milford Power Ltd (Petroplus)</td>
<td>1,600</td>
<td>CCGT</td>
<td></td>
<td>Application was withdrawn but revised application expected</td>
<td>..</td>
</tr>
<tr>
<td>New Drakelow Power Station</td>
<td>E.On</td>
<td>1,220</td>
<td>CCGT</td>
<td></td>
<td>Being processed</td>
<td>..</td>
</tr>
<tr>
<td>New Isle of Grain Power Station</td>
<td>E.On</td>
<td>1,200</td>
<td>CCGT</td>
<td></td>
<td>Approved 31 October 2006</td>
<td>No Expected to start in 2007</td>
</tr>
<tr>
<td>West Burton</td>
<td>EDF Energy</td>
<td>1,270</td>
<td>CCGT</td>
<td></td>
<td>Being processed</td>
<td>..</td>
</tr>
<tr>
<td>Sutton Bridge B</td>
<td>EDF Energy</td>
<td>1,260</td>
<td>CCGT</td>
<td></td>
<td>Being processed</td>
<td>..</td>
</tr>
<tr>
<td>Partington</td>
<td>Bridestones Developments Ltd</td>
<td>380</td>
<td>CCGT</td>
<td></td>
<td>Being processed</td>
<td>..</td>
</tr>
<tr>
<td>Uskmouth</td>
<td>Severn Power Ltd</td>
<td>800</td>
<td>CCGT</td>
<td></td>
<td>Being processed</td>
<td>..</td>
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<tr>
<td>Barking</td>
<td>Barking Power Ltd</td>
<td>Increase of 470</td>
<td>CCGT</td>
<td></td>
<td>Being processed</td>
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<tr>
<td><strong>Total CCGTs</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>12,840 MW</td>
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</tbody>
</table>

The table shows CCGT approvals from November 2000 (when the stricter consents policy was lifted) and state of play on applications for stations over 50 MW.
<table>
<thead>
<tr>
<th>Station</th>
<th>Owner</th>
<th>Size (MW)</th>
<th>Type</th>
<th>Distillate back-up</th>
<th>Status</th>
<th>Under Construction</th>
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</thead>
<tbody>
<tr>
<td>CHPs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Corus, Port Talbot, South Wales</td>
<td>Sun Coke Company</td>
<td>130</td>
<td>Coke fired CHP</td>
<td>Application withdrawn</td>
<td></td>
<td></td>
</tr>
<tr>
<td>West Thamesmead</td>
<td>CDCE Ltd</td>
<td>140</td>
<td>Gas CHP</td>
<td>Application withdrawn</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Immingham</td>
<td>Immingham CHP</td>
<td>Extension from 700 to 1,230</td>
<td>Gas CHP</td>
<td>Approved August 2006</td>
<td>No</td>
<td>Expected to start in 2007</td>
</tr>
<tr>
<td>Other CHPs</td>
<td>Various</td>
<td>411</td>
<td>Gas CHP</td>
<td>Approved since November 2000</td>
<td>Varies</td>
<td></td>
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<tr>
<td><strong>Total CHPs</strong></td>
<td></td>
<td><strong>941 MW</strong></td>
<td></td>
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<td></td>
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<tr>
<td>Integrated coal gasification combined cycles ICGCC</td>
<td></td>
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<tr>
<td>Hatfield Colliery</td>
<td>Coalpower</td>
<td>430</td>
<td>ICGCC</td>
<td>Approved August 2003</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Onllwyn, Port Talbot</td>
<td>Progressive Energy Ltd</td>
<td>480</td>
<td>ICGCC</td>
<td>Application withdrawn</td>
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<tr>
<td><strong>Total ICGCCs</strong></td>
<td></td>
<td><strong>430 MW</strong></td>
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<tr>
<td>Dual-firing</td>
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<td></td>
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<tr>
<td>Indian Queens</td>
<td>AES</td>
<td>Dual oil/gas capability</td>
<td>Approved September 2001</td>
<td>No</td>
<td></td>
<td></td>
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<tr>
<td>Littlebrook</td>
<td>RWE npower</td>
<td>Dual oil/gas capability</td>
<td>Approved August 2002</td>
<td>No</td>
<td></td>
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<tr>
<td><strong>Renewables and energy from waste</strong></td>
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<tr>
<td>Paul’s Hill, Moray</td>
<td>Natural Power Consultants Ltd</td>
<td>56</td>
<td>Onshore windfarm</td>
<td>Approved March 2003</td>
<td>Yes</td>
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<td></td>
<td></td>
<td>9</td>
<td></td>
<td>Extension approved December 2005</td>
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<tr>
<td>Hadyard Hill, South Ayrshire</td>
<td>SSE Generation Ltd</td>
<td>130</td>
<td>Onshore windfarm</td>
<td>Approved December 2003</td>
<td>Yes</td>
<td></td>
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<tr>
<td>Whitelee, East Renfrewshire</td>
<td>Scottish Power</td>
<td>322</td>
<td>Onshore windfarm</td>
<td>Approved April 2006</td>
<td>Yes</td>
<td></td>
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<tr>
<td>Crystal Rig windfarm extension, Scottish Borders</td>
<td>Natural Power Consultants Ltd</td>
<td>62.5</td>
<td>Onshore windfarm</td>
<td>Approved May 2004</td>
<td>No</td>
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<tr>
<td>Farr, Invernessshire, Highland</td>
<td>Npower Renewables</td>
<td>112.5</td>
<td>Onshore windfarm</td>
<td>Approved October 2004</td>
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<tr>
<td>Station</td>
<td>Owner</td>
<td>Size (MW)</td>
<td>Type</td>
<td>Status</td>
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<tr>
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<td>-------------------------------</td>
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<tr>
<td>Black Law – North Lanark</td>
<td>Scottish Power</td>
<td>142.6</td>
<td>Onshore</td>
<td>Approved February 2004</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Rothes – Moray (formerly known as Cairn Uish)</td>
<td>Natural Power Consultants</td>
<td>90</td>
<td>Onshore</td>
<td>Approved April 2004</td>
<td>Completed</td>
<td></td>
</tr>
<tr>
<td>Braes of Doune, Stirling</td>
<td>Airtricity</td>
<td>100</td>
<td>Onshore</td>
<td>Approved October 2004</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Scout Moor, nr Rochdale, Lancashire</td>
<td>United Utilities &amp; Peel Holdings</td>
<td>65</td>
<td>Onshore</td>
<td>Approved May 2005</td>
<td>No</td>
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<tr>
<td>Crystal Rig 2, Scottish Borders</td>
<td>Natural Power Consultants Ltd</td>
<td>90</td>
<td>Onshore</td>
<td>Approved July 2005</td>
<td>No</td>
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<tr>
<td>Little Cheyne Court, Walland Marsh, Kent</td>
<td>National Wind Power</td>
<td>78</td>
<td>Onshore</td>
<td>Approved October 2005</td>
<td>No, Currently subject to possible legal challenge</td>
<td></td>
</tr>
<tr>
<td>Causeymire</td>
<td>National Wind Power</td>
<td>55.2</td>
<td>Onshore</td>
<td>Approved November 2005</td>
<td>Yes</td>
<td></td>
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<tr>
<td>Whinash, Tebay, Cumbria</td>
<td>West Coast Energy</td>
<td>67</td>
<td>Onshore</td>
<td>Refused 2 March 2006</td>
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<tr>
<td>Keadby, North Lincolnshire</td>
<td>RES Ltd</td>
<td>78</td>
<td>Onshore</td>
<td>Public inquiry starts 9 windfarm January 2007</td>
<td>..</td>
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</tr>
<tr>
<td>Tween Bridge, Thorne, Lincolnshire</td>
<td>United Utilities &amp; Peel Holdings</td>
<td>84</td>
<td>Onshore</td>
<td>Public inquiry starts 9 windfarm January 2007</td>
<td>..</td>
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<tr>
<td>Fullabrook Down, North Devon</td>
<td>Devon Wind Ltd</td>
<td>66</td>
<td>Onshore</td>
<td>Public inquiry starts 28 windfarm November 2006</td>
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</tr>
<tr>
<td>Orby Marsh, Skegness</td>
<td>M Cauldwell</td>
<td>54</td>
<td>Onshore</td>
<td>To go to public inquiry</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>Ray, Northumberland</td>
<td>AMEC</td>
<td>60</td>
<td>Onshore</td>
<td>Being Processed</td>
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<tr>
<td>Middlemoor, Northumberland</td>
<td>Npower Renewables</td>
<td>75</td>
<td>Onshore</td>
<td>Being Processed</td>
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<tr>
<td>Windy Standard extension</td>
<td>Natural Power Consultants Ltd</td>
<td>90</td>
<td>Onshore</td>
<td>Application submitted windfarm December 2001</td>
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<tr>
<td>Greenock, Inverclyde</td>
<td>Airtricity</td>
<td>59</td>
<td>Onshore</td>
<td>PLI17 case being processed</td>
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<tr>
<td>Gordonbush, Highland</td>
<td>SSE Generation Ltd</td>
<td>87.5</td>
<td>Onshore</td>
<td>Being processed</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>Clashindarroch, Aberdeenshire</td>
<td>AMEC wind</td>
<td>129</td>
<td>Onshore</td>
<td>PLI case being processed</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>Station</td>
<td>Owner</td>
<td>Size (MW)</td>
<td>Type</td>
<td>Status</td>
<td>Under Construction</td>
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</tr>
<tr>
<td>-------------------------</td>
<td>--------------------------------------------</td>
<td>-----------</td>
<td>-----------------------</td>
<td>--------------------------------------------------</td>
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<td></td>
</tr>
<tr>
<td>Aultmore, Moray</td>
<td>AMEC wind</td>
<td>62</td>
<td>Onshore windfarm</td>
<td>Application submitted October 2003 – likely to be withdrawn</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kilpatrick Hills, West Dunbartonshire</td>
<td>Airtricity</td>
<td>60</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
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<td></td>
</tr>
<tr>
<td>Calliacher, Pert and Kinross</td>
<td>I &amp; H Brown Ltd</td>
<td>62.1</td>
<td>Onshore windfarm</td>
<td>At PLI</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Harittestanes, Dumfies and Galloway</td>
<td>CRE Energy Ltd</td>
<td>213</td>
<td>Onshore windfarm</td>
<td>At PLI</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ewehill, Dumfies and Galloway</td>
<td>Scottish Power</td>
<td>92</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
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<tr>
<td>Griffin, Perth and Kinross</td>
<td>Greenpower (Griffin) Limited</td>
<td>216</td>
<td>Onshore windfarm</td>
<td>At PLI</td>
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</tr>
<tr>
<td>Dersalloch, South Ayrshire</td>
<td>CRE Energy Ltd</td>
<td>78</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
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<td></td>
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<tr>
<td>Baillie, Highland</td>
<td>Dudley Developments</td>
<td>75</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
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<tr>
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<td>Force 9 Energy</td>
<td>78.3</td>
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<tr>
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<td>300</td>
<td>Onshore windfarm</td>
<td>Referred to PLI</td>
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<td>Afton, East Ayrshire</td>
<td>E.On</td>
<td>74.25</td>
<td>Onshore windfarm</td>
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<td></td>
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<tr>
<td>Clyde, South Lanarkshire</td>
<td>Airtricity</td>
<td>622.8</td>
<td>Onshore windfarm</td>
<td>At PLI</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lewis, Eilean Siar</td>
<td>Lewis Windpower</td>
<td>702</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carraig Gheal, Argyll and Bute</td>
<td>Greenpower (Carraig Gheal) Limited</td>
<td>75</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
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<td></td>
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<tr>
<td>Waterhead Moor, Largs, Ayrshire</td>
<td>SSE Ltd</td>
<td>132</td>
<td>Onshore windfarm</td>
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<td></td>
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<tr>
<td>Muaitheabhal, Eilean Siar</td>
<td>Beinn Mhor Power</td>
<td>159</td>
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<td>Being processed</td>
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<td>Dunmaglass, Highland</td>
<td>RES Group</td>
<td>100</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Station</td>
<td>Owner</td>
<td>Size (MW)</td>
<td>Type</td>
<td>Status</td>
<td>Under Construction</td>
<td></td>
</tr>
<tr>
<td>------------------------------</td>
<td>-----------------------------------------</td>
<td>-----------</td>
<td>-----------------------</td>
<td>-----------------------------</td>
<td>--------------------</td>
<td></td>
</tr>
<tr>
<td>Spireslack, East Ayrshire</td>
<td>The Scottish Coal Company</td>
<td>59.6</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fallago Ridge, Scottish Borders</td>
<td>North British Wind Energy</td>
<td>114</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Harrows Law, West Lothian</td>
<td>SSE Ltd</td>
<td>111</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mark Hill, South Ayrshire</td>
<td>Catamount Energy</td>
<td>84</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Limmer Hill, South Lanarkshire</td>
<td>West Coast Energy Ltd</td>
<td>99</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dunbeath, Highland</td>
<td>West Coast Energy Ltd</td>
<td>69</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Blackcraig Hill, Dumfries and Galloway</td>
<td>SSE Generation Ltd</td>
<td>69</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Glenkirk, Highland</td>
<td>Eurus Energy UK Ltd</td>
<td>102</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lochluichart</td>
<td>LZN Ltd</td>
<td>129</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Steadings, Northumberland</td>
<td>Steadings Windfarm Ltd</td>
<td>66</td>
<td>Onshore windfarm</td>
<td>Being Processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Arecleoch – Dumfries and Galloway</td>
<td>Scottish Power</td>
<td>180</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shira – Argyll and Bute</td>
<td>Natural Power Consultants</td>
<td>79</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid Hill upgrade</td>
<td>Natural Power Consultants</td>
<td>From 49.9 to 75</td>
<td>Onshore windfarm</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rhyl Flats, off Rhyl, North Wales</td>
<td>Npower Renewables</td>
<td>150</td>
<td>Offshore windfarm</td>
<td>Approved December 2002</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Barrow, off Walney Island, Cumbria</td>
<td>DONG</td>
<td>90</td>
<td>Offshore windfarm</td>
<td>Approved March 2003</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Burbo Bank, off Wirral/Crosby</td>
<td>Seascape Energy</td>
<td>90</td>
<td>Offshore windfarm</td>
<td>Approved July 2003</td>
<td>Yes Due for completion 2007</td>
<td></td>
</tr>
<tr>
<td>Robin Rigg, Solway Firth</td>
<td>Powergen</td>
<td>216</td>
<td>Offshore windfarm</td>
<td>Approved March 2003 by windfarm the Scottish Executive</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Inner Dowsing, off Skegness, Lincolnshire</td>
<td>OWP</td>
<td>120</td>
<td>Offshore windfarm</td>
<td>TWA Order 11th approved 21/10/03</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>Station</td>
<td>Owner</td>
<td>Size (MW)</td>
<td>Type</td>
<td>Status</td>
<td>Under Construction</td>
<td></td>
</tr>
<tr>
<td>---------------------------------------</td>
<td>--------------------------------------------</td>
<td>-----------</td>
<td>--------------</td>
<td>------------------------------------------------------------------------</td>
<td>--------------------</td>
<td></td>
</tr>
<tr>
<td>Lynn, off Skegness, Lincolnshire</td>
<td>AMEC Offshore</td>
<td>108</td>
<td>Offshore</td>
<td>TWA Order approved windfarm 21/10/03</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>Cromer, off Cromer, Norfolk</td>
<td>Norfolk Offshore Wind Limited</td>
<td>108</td>
<td>Offshore</td>
<td>TWA Order approved windfarm 21/10/03</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>Gunfleet Sands, off Clacton, Essex</td>
<td>GE Wind Energy</td>
<td>108</td>
<td>Offshore</td>
<td>TWA Order approved, windfarm 21/10/03</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>Shell Flat, off Cleveleys, Blackpool,</td>
<td>Cirrus Energy</td>
<td>324</td>
<td>Offshore</td>
<td>Application for TWA Order windfarm being considered</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>Lancashire</td>
<td>EDF (Northern Offshore) Ltd</td>
<td>90</td>
<td>Offshore</td>
<td>Being processed windfarm</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>Teesside, off Redcar Margate, Kent</td>
<td>LAL</td>
<td>1,000</td>
<td>Offshore</td>
<td>Being processed windfarm</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>Greater Gabbard, off Suffolk Coast</td>
<td>Greater Gabbard Offshore Ltd</td>
<td>500</td>
<td>Offshore</td>
<td>Being processed windfarm</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>Thanet, off Foreness Point, Kent</td>
<td>Thanet Offshore Wind Ltd</td>
<td>300</td>
<td>Offshore</td>
<td>Being processed windfarm</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>Gwynt y Mor, off Llandudno</td>
<td>Npower renewables</td>
<td>750</td>
<td>Offshore</td>
<td>Being processed windfarm</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>West of Duddon Sands off Cumbrian</td>
<td>Morecambe Offshore Wind</td>
<td>500</td>
<td>Offshore</td>
<td>Being processed windfarm</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>coast</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Walney, off Cumbrian</td>
<td>DONG Wind</td>
<td>450</td>
<td>Offshore</td>
<td>Being processed windfarm</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>coast</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sheringham Shoal, off SCIRA</td>
<td></td>
<td>315</td>
<td>Offshore</td>
<td>Being processed windfarm</td>
<td>..</td>
<td></td>
</tr>
<tr>
<td>Norfolk coast</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Braevallich, Argyll and Innogy hydro</td>
<td></td>
<td>2.5</td>
<td>Hydro</td>
<td>Approved March 2003</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Bute</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kingairloch, Highland</td>
<td>SSE Generation Ltd</td>
<td>3.5</td>
<td>Hydro</td>
<td>Approved March 2003</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Garrogie, Highland</td>
<td>Innogy hydro</td>
<td>2</td>
<td>Hydro</td>
<td>Approved June 2003</td>
<td>Completed</td>
<td></td>
</tr>
<tr>
<td>Douglas Water, Argyll</td>
<td>Innogy hydro</td>
<td>3</td>
<td>Hydro</td>
<td>Approved November 2005</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Station</td>
<td>Owner</td>
<td>Size (MW)</td>
<td>Type</td>
<td>Status</td>
<td>Under Construction</td>
<td></td>
</tr>
<tr>
<td>--------------------------</td>
<td>-------------------------</td>
<td>-----------</td>
<td>--------------------</td>
<td>------------------------------------</td>
<td>--------------------</td>
<td></td>
</tr>
<tr>
<td><strong>Renewables and energy from waste (continued)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stronelairg, Highland</td>
<td>Innogy hydro</td>
<td>10.3</td>
<td>Hydro</td>
<td>Application withdrawn 2006</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Allt Hallater, Argyll and Bute</td>
<td>Npower renewables</td>
<td>1.9</td>
<td>Hydro</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Keltneyburn, Perth and Kinross</td>
<td>Keltneyburn Hydro Ltd</td>
<td>2.2</td>
<td>Hydro</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Inverlael, Highland</td>
<td>Npower Renewables</td>
<td>3</td>
<td>Hydro</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>River Braan, Perth and Kinross</td>
<td>Npower Renewables</td>
<td>2.9</td>
<td>Hydro</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carnoch, Highland</td>
<td>Npower Renewables</td>
<td>1.5</td>
<td>Hydro</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Innerhadden, Perth and Kinross</td>
<td>Innerhadden Hydro Ltd</td>
<td>1.4</td>
<td>Hydro</td>
<td>Being processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belvedere, London</td>
<td>Riverside Resources</td>
<td>70</td>
<td>Energy from waste</td>
<td>Approved 15 June 2006</td>
<td>Currently subject to possible legal challenge</td>
<td></td>
</tr>
<tr>
<td>Peterborough</td>
<td>Peterborough Renewable</td>
<td>174</td>
<td>Energy from waste</td>
<td>To go to public enquiry</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ince, Cheshire</td>
<td>Peel Environmental</td>
<td>95</td>
<td>Energy from waste</td>
<td>Being Processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Port Talbot, Wales</td>
<td>Preenergy Power Ltd</td>
<td>350</td>
<td>Biomass</td>
<td>Being Processed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Renewables and energy from waste</td>
<td></td>
<td>12,426 MW</td>
<td></td>
<td>Excluding refused and withdrawn</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

15 Section 36 consent can be transferred or sold on to another company.
16 However, there is some uncertainty about whether this will be built.
17 PLI = Public Local Inquiry.
18 TWA Order = Transport and Works Act Order.
Key: .. indicates that the project has yet to reach the stage where construction can begin.
Table 3: Planned Nuclear Power Plant Closure Dates

<table>
<thead>
<tr>
<th>Nuclear Power Plant</th>
<th>Estimated Closure Date</th>
<th>Type of Reactor</th>
<th>Installed Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dungeness A</td>
<td>2006</td>
<td>Magnox</td>
<td>450</td>
</tr>
<tr>
<td>Sizewell A</td>
<td>2006</td>
<td>Magnox</td>
<td>420</td>
</tr>
<tr>
<td>Oldbury</td>
<td>2008</td>
<td>Magnox</td>
<td>434</td>
</tr>
<tr>
<td>Wylfa</td>
<td>2010</td>
<td>Magnox</td>
<td>980</td>
</tr>
<tr>
<td>Hinkley Point B</td>
<td>2011</td>
<td>AGR</td>
<td>1,220</td>
</tr>
<tr>
<td>Hunterston B</td>
<td>2011</td>
<td>AGR</td>
<td>1,190</td>
</tr>
<tr>
<td>Hartlepool</td>
<td>2014</td>
<td>AGR</td>
<td>1,210</td>
</tr>
<tr>
<td>Heysham 1</td>
<td>2014</td>
<td>AGR</td>
<td>1,150</td>
</tr>
<tr>
<td>Dungeness B</td>
<td>2018</td>
<td>AGR</td>
<td>1,110</td>
</tr>
<tr>
<td>Heysham 2</td>
<td>2023</td>
<td>AGR</td>
<td>1,250</td>
</tr>
<tr>
<td>Torness</td>
<td>2023</td>
<td>AGR</td>
<td>1,250</td>
</tr>
<tr>
<td>Sizewell B</td>
<td>2035</td>
<td>PWR</td>
<td>1,188</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>11,852</strong></td>
</tr>
</tbody>
</table>

Table 4: Coal-Fired Power Plant Status under the Large Combustion Plant Directive (LCPD)

<table>
<thead>
<tr>
<th>Station</th>
<th>Operator</th>
<th>Capacity (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>In</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aberthaw</td>
<td>RWE npower</td>
<td>1.5</td>
</tr>
<tr>
<td>Cottam</td>
<td>EDF</td>
<td>2.0</td>
</tr>
<tr>
<td>Drax</td>
<td>Drax Power</td>
<td>3.9</td>
</tr>
<tr>
<td>Eggborough</td>
<td>British Energy</td>
<td>2.0</td>
</tr>
<tr>
<td>Ferrybridge (stack 1)</td>
<td>SSE</td>
<td>1.0</td>
</tr>
<tr>
<td>Fiddlers Ferry</td>
<td>SSE</td>
<td>2.0</td>
</tr>
<tr>
<td>Kilroot</td>
<td>AES Kilroot</td>
<td>0.5</td>
</tr>
<tr>
<td>Longannet</td>
<td>ScottishPower</td>
<td>2.3</td>
</tr>
<tr>
<td>Ratcliffe</td>
<td>E.On-UK</td>
<td>2.0</td>
</tr>
<tr>
<td>Rugeley</td>
<td>International Power</td>
<td>1.0</td>
</tr>
<tr>
<td>Uskmouth</td>
<td>Uskmouth Energy</td>
<td>0.4</td>
</tr>
<tr>
<td>West Burton</td>
<td>EDF</td>
<td>2.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>20.6</strong></td>
</tr>
<tr>
<td><strong>Out</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kingsnorth</td>
<td>E.On-UK</td>
<td>2.0</td>
</tr>
<tr>
<td>Tilbury</td>
<td>RWE npower</td>
<td>1.0</td>
</tr>
<tr>
<td>Cockenzie</td>
<td>ScottishPower</td>
<td>1.2</td>
</tr>
<tr>
<td>Didcot</td>
<td>RWE npower</td>
<td>2.0</td>
</tr>
<tr>
<td>Ferrybridge (stack 2)</td>
<td>SSE</td>
<td>1.0</td>
</tr>
<tr>
<td>Ironbridge</td>
<td>E.On-UK</td>
<td>1.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>8.2</strong></td>
</tr>
</tbody>
</table>
Annex 2

Map of current and planned gas import and storage infrastructure projects
Annex 3

Examples of future indicators

As this report contains new sections on oil and coal that will be built on in future reports, the opportunity has been taken to present new indicators on oil and coal supply and demand. These will be developed further for future reports and the proposed web-based system, as set out in Annex 2.

12. Annual UK Oil demand and potential supply
13. Annual coal supply and demand projections
Supply and demand forecasts - oil

12 Annual UK demand for oil and oil products and UKCS oil production

Context:
Production of oil from the UK Continental Shelf (UKCS) peaked in 1999 and has since been declining; following a blip in 2007–2008, that decline is expected to continue. Until the end of this decade, UK demand for oil is expected to be broadly flat. The UK is expected become a net importer of oil on a sustained annual basis by around 2010; a large and growing net import requirement is expected thereafter.

Key Points:
UK oil demand is expected to be broadly flat until 2015; the actual level of demand will depend on a number of factors including absolute and relative energy prices. Following a further significant decline in UK oil production expected between 2005 and 2006 (albeit smaller than the trend of recent years), oil production is expected to rise very significantly in 2007 before decline sets in again after 2008. There is also some upside potential from UKCS production which, like UK demand, may respond to price signals.

The chart compares actual and projected UK oil production and UK oil demand over the period to 2015. Although the UK has been a net exporter of oil for many years it has also imported significant volumes of oil and oil products. The UK is expected to be a net importer of oil (crude, NGLs and refined products) in 2006 but, with the very large Buzzard Field coming fully on-stream and several other large fields starting production in 2007, the UK should briefly return to being a net exporter of oil before becoming a net importer on a sustained annual basis by around 2010. As we move to a position of net import dependence, imports are likely to continue to come from a range of sources and by a variety of routes, thus contributing to oil supply diversity.
Background:

UKCS oil production as shown here includes both crude oil and natural gas liquids. The forecast element of the ‘Actual/projected UKCS oil production’ line on the chart is based on data provided by operators to DTI in mid 2006.

The (DTI) projection of primary UK oil demand shown here includes an estimate for bunkers. As with the oil production projection, there is much uncertainty attached to the oil demand projection; both should be treated as only indicative.

Source:

DTI data for actuals; DTI projections and estimates as described above.
Context:

Production of coal in the UK continues to decline and to meet UK demand for coal imports have risen steeply in the years since 2002. Coal imports met over 70 per cent of UK coal demand in 2005 and are expected to match that proportion in 2006.

Key Points:

UK coal demand is expected to fall back from its 2006 level as power station demand declines, mainly through tighter emissions controls. Other transformation uses (i.e., the iron and steel industry use for coke making and in blast furnaces) show slightly increased demand levels.

Coal production levels continue on their downward path, and are only around two-thirds of their 2005 level by 2020.

In the forecast period, coal imports make up the difference between indigenous production and demand and in 2020 the proportion of demand met by imports is similar to that in 2005.

The chart compares actual and projected UK coal production and UK coal imports with UK coal demand over the period to 2020. Coal imports first exceeded UK coal production in 2001 and are expected to reach a record level of over 47 million tonnes in 2006 but then follow a falling trend.

Background:

The projections of UK coal production are based on “UK Coal Production Outlook: 2004-2016”, Final Report prepared for DTI by Mott MacDonald in March 2004 (low scenarios for both deep mined and opencast) with DTI estimates for 2020 (www.dti.gov.uk/files/file14151.pdf). The low scenarios have been chosen because the high scenarios seem no longer tenable given the reduced size of the coal industry since 2004.
The DTI projection of UK coal demand shown here is the average of the “favours coal” and “favours gas” central scenarios from the Updated Energy Projections which informed the Energy Review and were published in July 2006 (www.dti.gov.uk/energy/environment/projections/recent/page26391.html). There is much uncertainty attached to the coal demand projection; they should be treated as only indicative.

Source:

Digest of UK Energy Statistics data for actuals; DTI estimates for 2006; DTI projections as described above.