DTI initial contribution to the PIU Energy Policy Review

The DTI welcomes the review of energy policy and see the review as an opportunity to shape future long term energy policy on the principles of sustainability. DTI will be working closely with the PIU to help them to make the review as valuable as possible

This document represents officials preliminary analysis of some of the key issues that the PIU will need to consider during the review. It has been produced in a detailed question and answer format. The analysis presented here represents an initial view, designed to give the PIU team a broad background to current issues surrounding Energy Policy. It does not represent finished thinking by the Department nor have we attempted at this stage to draw out detailed implications of policy tensions and interactions. Its purpose is to stimulate thought around the issues of energy policy. It represents the views of DTI officials only and should not be taken to imply any change in government energy policy.

The document recognises the crucial role that demand management, including energy efficiency, will need to play in energy policy. The DTI works closely with DEFRA in developing our energy efficiency strategy. However, most of the detail of the text is focussed on energy supply issues because these are areas in which the DTI has the lead responsibility.

We hope it will provide a useful stimulus to the PIU project.

Please note the text was prepared before the conclusion of negotiations on the Kyoto Protocol in Bonn on 23 July.

DTI initial contribution to the PIU Energy Policy Review

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DTI initial contribution to the PIU Energy Policy Review - Summary

The key aims of UK energy policy are to achieve competitive energy markets and prices, combined with security of supply as well as social and environmental objectives.

Many of the policy initiatives of recent years have aimed at establishing open energy markets to deliver energy at competitive prices. That was a key element in the last energy policy White Paper, in 1998, and in the new regulatory structure that has been put in place under the Utilities Act 2000. As a result we now have one of the most competitive energy markets in the world and consumers have benefited through prices following a downward trend. We are working with the Commission and other EU Member States to complete the European single market in energy so that Europe as a whole can benefit from competitive energy markets.

Competition will remain central to energy policy, as it is to the Government's strategy for business as a whole, and Ofgem are continuing to refine the relevant regulatory framework with this in mind. As a general rule, the achievement of other energy policy objectives is most likely to be achieved through the efficient functioning of competitive markets within the right framework.

The energy policy agenda is now changing in a number of important ways. Until last year the overall picture was that energy supplies were plentiful, that there was ample capacity and infrastructure, and the tendency of prices downwards. This outlook has changed with the sharp increases in oil and gas prices, the petrol crisis, the crisis of electricity supply in California and the forecasts of a less balanced UK fuel mix. At present the UK is virtually self sufficient in energy, we have a good balance between coal, gas, and nuclear, in our electricity supply and ample overall generating capacity. But as gas becomes the key fuel and dominates our electricity generation, whilst our own North Sea production peaks, we will increasingly (from about 2005) become reliant year round on gas imports. Reliance on gas from elsewhere is not new and the UK was a net gas importer during winter of 2000/01. But we will need to pay much more attention to the security of our energy systems. Our energy strategy for the future needs to be pitched at the European, and in some cases the Global level.

At the same time the UK, along with every other country in the world faces the challenge of global warming and future UK energy policy needs to be based on the principles of

sustainability. Major programmes are in place to promote renewables and increase our energy efficiency and the UK is on-course to meet its Kyoto targets to 2008 - 12. The EU, including the UK, is committed to ratifying the Protocol with the aim of it coming into force in 2002.

But without further action UK carbon emissions will start to rise again, post 2010, as economic growth continues and our existing nuclear power stations successively come to the end of their lives. This raises acutely the related questions of the speed at which renewable energy sources can be developed and whether new nuclear build will be needed, to replace existing capacity, if we are to maintain the downward trend of carbon emissions, or equally to maintain diversity. It also means that transport policy may have to contribute more to carbon savings. In the past continuing increases in carbon savings chiefly in the energy sector have masked emissions from transport. The impact of energy production and use on the environment goes much wider than CO_2 emissions and there are a range of environmental factors to be taken into account in relation to specific energy technologies.

The Government has also been concerned to ensure that the less well off benefit from low energy prices and has developed a strategy to alleviate fuel poverty. Any policies that imply higher prices would need to take account of the social costs of such policies as well as the impact e.g. on schools, hospitals and business.

The EU Commission has issued a Green Paper on Energy Security, now being debated with the Member States, and in the US the Bush Administration has recently delivered its report on National Energy Policy.

It is clear, therefore, that energy policy has to be directed at a number of objectives – competitiveness (encompassing social objectives too), energy security and the environment. In recent years there has been a high degree of synergy between these. For example, the pursuit of competitive markets has encouraged the switch towards electricity generation from gas, has reduced electricity prices, and emissions, and been based on securing supplies from the UKCS. As we look ahead, however, we have to consider if those synergies will, or can, continue, or whether conflict between objectives will rise in profile. As output from the UKCS runs down the UK is likely to become more dependent on fuel supplies from further afield, possibly at higher prices. Environmental pressures would be greater, possibly adding to those price pressures. A variety of questions will need addressing in this context. Amongst these, and these are meant to be illustrative only, are:

- to what extent can renewables replace fossil fuels as a source of electricity generation, how quickly, at what cost, and, with what impact on security (a more diverse mix, but including some intermittent sources);

- embedded generation brings greater diversity in supply but how does this weigh against increased reliance on local balancing

- to what extent can we rely on competitive markets to deliver infrastructure requirements and supply security.

- how can higher energy prices – if necessary to meet environmental objectives, including promotion of energy efficiency – be reconciled with reduction in fuel poverty, business competitiveness and the funding requirements of, for example, schools and hospitals.

Against this background the Government has decided to ask the PIU to carry out a review of energy policy. Brian Wilson, the Minster for Energy and Industry, will chair the Advisory Group overseeing the Review.

The DTI will be working closely with the PIU to help them to make the Review as valuable as possible and see the review as an opportunity to shape future long term energy policy on the principles of sustainability. Our preliminary analysis of some of the key issues that they will be considering is given below in the detailed question and answer sections. The analysis presented here represents an initial view, designed to give the PIU team a broad background to current issues surrounding Energy Policy. It does not represent finished thinking by the Department nor have we attempted at this stage to draw out detailed implications of policy tensions and interactions. Its purpose is to stimulate thought around the issues of energy policy. The document recognises the crucial role that demand management, including energy efficiency will need to play in energy policy. The DTI works closely with DEFRA in developing our energy efficiency strategy. However, most of the detail of the text is focussed on energy supply issues because these are areas in which the DTI has the lead responsibility.

The following is a short summary of the key issues that arise.

Security of Supply

There are many aspects to security of supply. These include the effectiveness of regulation to ensure competition and access for consumers, the management of shocks and emergencies and the reliability of gas and electricity networks. We would expect the PIU to focus mainly on the more strategic and longer term aspects.

Forecasts of the leading international bodies do not suggest that the World faces a shortage of conventional fuel at least for the next 20 to 30 years. There are more alarmist forecasters, but they are very much in the minority. In any consideration of prices, it has to be remembered that the oil market is volatile and great uncertainty exists around predictions of future prices. The broad consensus on oil prices is that the high prices seen during 2000 are not sustainable in the medium to long run and a fall within the next 18 months or so towards the lower end of the OPEC price range (if not lower) is considered likely. This would suggest average oil prices (Brent crude, which trades at a premium of about $1.50/barrel compared to the OPEC basket) at around $23/barrel or lower, compared to around $26/27 per barrel so far in 2001. In the longer term, oil prices are expected to average $16–18/barrel *in real terms.* A continuing link between oil and gas prices suggests that, as oil prices fall, wholesale gas prices should fall as well from 2000/01 levels. As liberalisation continues across the EU, it will also exert downward pressure on transportation and retail margins. When gas on gas competition finally arrives it is not certain that gas prices will be any lower, relative to oil, than now. It will depend on how protracted the process is and how the supply side reacts to rising demand for gas in Europe. A large fall in gas prices (to levels seen in the late 1990’s in the UK) requires large over supply, and is not foreseen.

The UK, however, faces the prospect of moving from its current roughly equal balance between coal, nuclear and gas to being 70% dependent on gas for electricity generation by 2020. Our North Sea gas production is expected to peak in the next few years and, from 2005, we will again increasingly be reliant on imported gas, but to a greater extent than in the 1980’s. Already we were a net importer this past winter. By 2020 our gas import dependency could be as high as 90%, depending on the extent to which yet-to-be-found reserves might be developed and contribute to future indigenous production. Continental gas prices significantly influence those in the UK year round, through the interconnector.

There are ample reserves of gas in Norway, North Africa, the Caspian and Russia to meet Europe's needs for the foreseeable future. All of these sources will be important to the European market and, therefore, in all probability, to the availability and price of gas in the UK. Our interest is in access to them at competitive prices. This means both open gas markets in Europe and a dependable basis for investment in the reserves and infrastructure of the producer countries. Generally speaking the producer countries are highly motivated to supply the EU to secure revenue, although concerns remain over the reliability of an ageing and under-invested infrastructures.

Russia is, of course, a key player, with by far the largest reserves of accessible gas. But it is not the only player and we should not focus on it to the exclusion of others. Both Norway and Algeria are linked to the EU gas Network and between them hold 5% of global proven reserves. The UK favours EU dialogue with Russia and supports initiatives such as the Energy Charter and the promotion of production sharing agreements, designed to open up investment opportunities.

We are pressing hard in Europe towards the liberalisation and integration of energy markets. This is important to ensure that we have access to diverse gas supplies at competitive prices. At present very large and restrictive long term contracts dominate continental gas markets and new entrants have found in difficult to access the gas network. In gas some element of long term contracting will continue to be needed to facilitate investment, but we need to eliminate anti-competitive provisions, such as restrictions on re-sale and to ensure access to the network on equal terms. The development of longer term futures markets is also crucial for investment finance in an open market.

It is plainly important to ensure that the UK's energy infrastructure, and particularly the gas pipeline network, gives us as much flexibility as possible to draw supplies from different sources. This includes making the most of our opportunities for linking up with Norway, which will continue to be a major gas exporter for many years. It also includes diversifying our energy links to the Continent and possibly developing new LNG facilities.

Making sure that our regulation of the gas network, and other infrastructure, takes due account of the national interest in security and diversity of supply is something that requires co-operation between the Department and OFGEM. The privatisation of energy industries and the opening up of energy markets took place at a time of plentiful supply and excess capacity. We need to watch closely, particularly in the light of California, that investment continues, when required, in both regulated and non-regulated markets. In 1999 the electricity and gas industries invested £3.5billion, 15% of total UK industrial investment. We need to continue to refine the framework to enable the competitive market to send the right price signals.

Ofgem are currently reviewing the price regulation of Transco (the gas pipeline company) and published their initial proposals on 27 June.

A degree of reliance on imported gas, in common with the rest of Europe, seems inevitable and is not necessarily a matter of concern. Nevertheless it is prudent to consider policies that will enable us to maintain diversity and flexibility in our energy supply. Our success or failure in opening up European gas markets is relevant in considering whether we are content to see gas increasing its share of the UK energy market.

We need in any case to ensure that we exploit to the maximum the potential for sustaining UKCS oil and gas production and the Department is working on that through PILOT.

Coal is the most plentiful fossil fuel, widely available from geographically diverse parts of the World. Cleaner coal technologies can ensure that we keep the option of coal fired generation in the UK for the longer term in the face of challenging emissions targets. It could also provide a market for UK produced coal for as long as it remains competitive. In parallel with the PIU Review, the Department is undertaking a consultation exercise on the case for a demonstration clean coal power station in the UK. A cleaner coal plant that included the underground sequestration of carbon dioxide could demonstrate the potential for burning coal (or indeed other fossil fuels) in a largely carbon free way.

Measures introduced to address the problem of global warming, such as greater use of renewables and CHP, improved energy efficiency are discussed below. There is an important inter-action between security and environmental energy policy because, to varying degrees, these can also contribute to our security and diversity of supply by substituting for further gas-fired generation. There is thus a strategic as well as environmental case for promoting low carbon energy sources.

Energy and the Environment

In the medium term, to about 2010, the UK is more or less on course to meet its global warming targets. However greater efforts will be needed in the longer term as part of a global approach to addressing climate change. The Royal Commission on Environmental Pollution has advocated that the UK should aim to reduce its CO_2 emissions by 60% by about 2050. The Government has not adopted this target, but it has recognised that fundamental change will be needed in the years to come and will need to reply formally to the RCEP report once the PIU study has concluded.

A range of major policies is already being put in place to promote renewables, CHP, and energy savings, including the Climate Change Levy, the Renewables Obligation, and Energy Efficiency Commitments (EEC). For instance, over £260 million has already been allocated to funding renewables R&D and deployment whilst by 2010, the Renewables Obligation will benefit the renewables industry by around £800 million per year. The Climate Change Programme goes beyond the measures briefly described above. Taking this programme into account (but discounting the effects of the, largely unrepeatable, switch of electricity generation from coal to gas) the carbon intensity of the UK economy is expected to decline by 2.9% per annum from 2000 to 2010. In order to meet the RCEP's 60% target provisional work suggests that our carbon intensity would need to decline by 4.4% per annum continuously from 2010-2050. This is even more challenging when one takes account of the fact that, in the period from 2010-2025, our carbon intensity might actually increase if our nuclear capacity (currently about 25% of electricity supply) is replaced by fossil fuels as it is retired.

The potential for renewables is huge. The key questions are how much can and will be developed, how quickly and at what cost. Our present target of meeting 10% of electricity supply from renewables in 2010 (subject to cost) is challenging and the Government is introducing a range of measures to achieve the target. These include a new obligation on electricity suppliers, exemption from the Climate Change Levy and funding of more than £260m over the next 3 years. Further commitment of funds is likely to be required over the period if the target is to be met. Planning and other institutional barriers will also need to be addressed. Ofgem are reviewing the impact of NETA on small mainly renewable generators which some have argued is further barrier to development. Offshore wind alone offers vast potential, with one project already operational and a further 18 proposed in the UK. Some renewable options are now commercially viable, such as onshore wind and waste generation. Others (energy crops, photovoltaics) in the demonstration stage in the UK have great potential if barriers can be overcome and cost reductions achieved. Other technologies, including wave and tidal flow power also have potential. The contribution that wind power, which is inherently intermittent, can make to security of supply also requires further study. As do the implications of adopting our electricity network to a much higher proportion of renewables over the next 10 years or so.

Fuel cells and hydrogen as an energy vector are important new technologies with huge potential for the longer term. Nuclear fusion is also a long term prospect but with considerable uncertainties attached to its development.

Another option is the capture and storage of carbon emissions underground. As on option for the long-term, preliminary work suggests that this might be quite cost effective. The UK has ample geological storage potential although the acceptability of this route, and the integrity of the reservoirs, remains untested.

It is also important to consider the role of nuclear power – including possible new build – as a low carbon option. Government policy is that existing stations should continue to operate so long as it is economic, safe and environmentally acceptable for them to do so. For the longer term, new build could represent a carbon-free source of baseload electricity that also supports security of supply objectives. New and lower cost designs are emerging. But the issues of public acceptability and regulatory risk need to be resolved as well as the economics for new build to be a realistic option. Crucial to both is the question of long-term waste management, on which DEFRA’s forthcoming consultation paper should pave the way to defining the future policy and regulatory framework.

Large scale reductions in carbon emissions can not be addressed solely or even mainly from the supply side. Demand management, including energy efficiency as well as CHP and energy services, will have just as important role to play. More work is needed in this area, which the Analysts group is taking forward and the PIU will consider alongside supply side issues.

Transport accounts for about a quarter of the UK's CO_2 emissions and transport emissions are growing much more rapidly than those of the economy as a whole. This means that transport policy has to play a key part in our climate change strategy.

Past experience has demonstrated the huge uncertainties in attempting to draw long-term energy policy conclusions from future trends. This points towards measures that will contribute to a range of objectives, such as energy security, fuel poverty, and economic competitiveness (encompassing social objectives), as well as carbon saving, or which can provide the platform for more rapid changes later on. Examples include:

- Energy efficiency measures, including energy service marketing.
- Removing barriers to the implementation of new technologies including planning and regulatory barriers such as those being addressed by the Embedded Generation Group.
- R & D for advance energy technology.
- Market stimulation for key near market technologies, such as the Renewables Obligation
- Development and refining of carbon trading mechanisms.
- Continued refinement of market mechanisms to deliver secure energy at the minimum cost.

There are also wide issues which the PIU will need to address of how to set the right overall economic framework so that incentives are in place for the adaptation of the energy economy in accordance with principles of sustainability. We would hope that the PIU output would include an analytical framework for taking decisions about environmental commitments which impact on energy policy over the next few years.

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Energy supply, demand and prices

I What is the medium and longer term outlook for energy supply, demand, and prices at EU, Global, and UK levels? This will need to cover, as appropriate, oil, gas, coal, renewables, nuclear, electricity and motor fuel. What strategies should we be pursuing in relation to OPEC and oil and in relation to liberalising global energy markets for gas and other primary fuels? How can we best decouple gas prices from oil? Given the uncertainties, how do different outlooks for prices impact on policy choices for the environment and security?

a) What is the medium and longer term outlook for energy supply, demand, and prices at EU, Global, and UK levels?

Global Energy Trends

The World Energy Outlook (WEO) provides the IEA's latest world energy projections[1] to 2020 and that DTI are in broad agreement with. The central projections are derived from a "Reference Scenario" based on global economic growth above 3% per cent p.a., a slowdown in the rate of population growth and the continuation of known environmental policies but no new measures.

Key conclusions (more detail on findings from the WEO are given at Annex 1):

- international trade in energy will increase sharply, especially oil and gas;
- the reliance on imported oil and gas of the main consuming regions, including Europe, will increase substantially;
- Projected world primary energy demand increases by 57% between 1997 and 2020, an average annual rate of 2%, compared to an annual average rate of 2.2% from 1971 - 1997.
- World-energy intensity — primary energy demand per unit of real GDP — is expected to decline over the projection period by 1.1% a year, equal to the historical rate since 1971

[1] Forecasts and projections are used throughout the analysis and whilst they are informative, they can only be used as a guide to future events, not a guaranteed assessment.

- energy-related CO_2 emissions in 2010 will still be significantly higher than required to meet commitments under the Kyoto Protocol.

Global Resources

The majority assessment of fossil fuel reserves is that they are sufficient to meet demand over projection periods, generally to 2020 – 2030. The IEA consider that the physical world oil-resource base is adequate to meet demand to 2020, although the concentrated in a small number of producing countries. World gas reserves are also considered sufficient to meet the projected 86% increase in demand over the outlook period. The United States Geological Survey (USGS) share the view that globally these is no shortage of oil and gas resources. Shell's assessment is that oil supply matches demand for at least the next 20 – 30 years, with increased R&D in alternative fuel prolonging supply further. They estimate that by 2020, approximately 1440 billion bbl will have been produced, around half of total potential recoverable oil, a figure in line with the USGS total. The US Energy Information Administration have assessed the total "oil in ground" at around 6,000 billion bbl implying a total recoverable amount of 3,000 billion bbl with an assumed recovery factor of 50%. Recent work by BP suggests that the recovery rate could rise to 60%, given a resource of 3600 billion bbl. It should also be recognised that just as technological developments have greatly increased our access to oil and gas reserves and has confounded past projections of resource constraints; future developments should not be discounted.

However, others argue that such an assessment of oil reserves is too complacent. Recent work by Reading University argues that oil production outside the 5 largest OPEC producers[2] is about to peak and the big 5 will peak in the next 5 – 15 years. They point out that, but for events like Piper Alpha, UK production would already have peaked. Once production peaks demand will outstrip supply and oil shortages are likely unless remedial demand side action is taken. They take the view that increases in reserves will not necessarily lead to an equivalent increase in production. They also stress that all large oil finds have been made, which is generally true but for some recent large discoveries in Kazakhstan and Iran. Those with a more optimistic outlook argue that with new technology, what is defined as conventional oil will change especially as many state of art techniques are not applied world-wide, and that market signals will reduce demand if supply gets tight. However, whilst the Reading case may be in a

[2] Saudi Arabia, Iran, Iraq, UAE and Kuwait.

minority, it could be argued that their timing is simply out and that at some future point oil and gas supply will inevitably not meet demand. By comparison coal reserves are thought (IEA - WEO) capable of lasting for 200 years.

EU Energy Trends

The European Commission published its forecasts in the EU Energy Outlook to 2020. The policy background is similar to the IEA's (e.g. no new environmental policies on top of those announced by 1998). EU population is forecast to grow by less than 0.2 % per year with annual economic growth at 2.4% (2000 – 2010) and 1.8% (2010 – 2020). Specific EU policies include continuing gas and electricity liberalisation, economic convergence with low interest rates and prices and gas introduction and expansion. Overall the projections indicate a larger role for Nuclear than the IEA.

Key findings for the EU

Production of primary energy peaks in 2000. Post 2000 only renewables grow, representing 16% of primary EU production in 2020, as production of other fuel declines. Nuclear power represents one third of primary production in 2020. Primary energy demand is expected to grow by 1% (1995 to 2010) and 0.4% (2010 – 2020) p.a. an implied energy intensity reduction of 1.5% p.a. Primary demand is still dominated by fossil fuel, which accounts for 90% in 2020.

Annual final energy demand is projected to grow faster than primary demand (1.2% 1995 – 2010 and 0.5% 2010 – 2020) reflecting improved energy conversion efficiency. Electricity use grows at 1.8% p.a. and by 2020 represents 24% of final demand, a growth rate less than GDP, which may indicate a slowing of growth for future electricity demand. The projections show a growth in coal use post 2010 as a result of nuclear decommissioning and higher gas prices (the latter is discussed below). A summary energy balance is at Annex 1, Table A1. 2

Total EU import energy dependency rises from 48% in 2000 to 63% in 2020. For specific traded fuels by 2020 the EU is projected to import 68% of solid fuel and gas needs and 86% of liquid fuels. However, from analysis of UK data these estimates could be on the low side (see question 2).

UK Energy Trends

Oil production

A record 137.1 million tonnes of oil was produced in 1999 from 134 offshore fields with no field producing more than 5 per cent. On current forecasts, UKCS oil production will fall from around 129 million tonnes in 2002 to around 88 million tonnes by 2006. However, the later forecasts are subject to upward revisions if continued high oil prices mean potential developments e.g. West of Shetland become economic. A fuller description of future UKCS production is given at Annex 1.

Gas Production, supply and demand (covered in more detail in question 2)

Annual gas production on the UKCS is expected to reach a maximum of around 40,400 therms (approx. 102 Mtoe) between 2002 and 2004, falling by around 2,800 million therms (about 7%) in 2005 with a further fall of over 4,000 million therms in 2006. These estimates are subject to upside revision as potential developments become economic. UK production is projected to fall sharply post 2010. However, throughout the period demand will continue to rise, largely driven by demand for gas-fired power generation. Coal production is covered in question 5.

Future energy demand (also see question 4)

The UK's Primary energy demand is projected to grow by 0.7 – 0.8% p.a. between 2000 and 2010 which represents a fall in the energy ratio of around 1.6% p.a. By 2020 gas is the dominant fuel in the UK accounting for nearly 50% of primary energy demand, compared to about 30% in 1995 and 70% of electricity generation compared to 18% in 1995. Overall by 2020 petroleum and gas could account for over 85% of primary energy needs. For comparison final primarily inland energy consumption in 1999 was 227.8 Mtoe made up of coal 36.7 Mtoe (16%), petroleum 73.4 Mtoe (32%), gas 90.9 Mtoe (40%) and primary electricity (mainly nuclear, hydro and imports) 24.4 Mtoe (11%).

Energy prices

There is no single view of the future of energy prices. Even between the IEA and EU estimates there are significant differences (see tables A1.3 to A1.5 in Annex 1), although looking towards 2020 there are some common themes. Global oil prices will rise by 20 – 40% in real terms between 2010 and 2020. Gas prices will stay linked to oil prices and rise significantly by

30-60% from 2010 to 2020 (after 2005 in the US) with coal prices remaining flat. However, it should be remembered both the IEA and EU projections were made before the high oil prices seen in 2000 more analysis is needed on how the assumed price trends will change (long term projections of levels may still hold but percentage changes will be different) as a result and the impact of such prices on other fuel prices.

In any consideration of prices, it has to be remembered that the oil market is volatile and great uncertainty exists around predictions of future prices. Despite OPEC's current successful actions to keep its basket price in the range $25-28/bbl (that is $26.5-29.5/bbl for 2 month Brent), it is unlikely that they can sustain these high prices past the short term. This is because they only control short-term supply and not long-term oil supply or short or long-term oil demand. OPEC clearly understands this situation: their outlook for the period to 2010, talks of prices in the range of $20-23/bbl. Put simply, continuing high oil prices will have two effects that OPEC cannot control: (a) it will stimulate non-OPEC supply; and (b) it will reduce oil demand growth, especially in the important developing economies as oil becomes "unaffordable". This would suggest average oil prices (Brent crude, which trades at a premium of about $1.50/barrel compared to the OPEC basket) at around $23/barrel or lower, compared to around $26/27 per barrel so far in 2001. However, DTI and the oil industry consider that in the longer term, the OPEC price expectations are still to high and for reasons expressed above oil prices are expected to average $16–18/barrel in real terms. A continuing link between oil and gas prices suggests that, as oil prices fall, wholesale gas prices should fall as well from 2000/01 levels. As liberalisation continues across the EU, it will also exert downward pressure on transportation and retail margins. When gas on gas competition finally arrives it is not certain that gas prices will be any lower, relative to oil, than now. It will depend on how protracted the process is and how the supply side copes with the rising demand for gas in Europe. A large fall in gas prices (to levels seen in the late 1990's in the UK) requires large over supply, which is not foreseen. Producer power is another risk factor, which may drive up the price of gas in the long term.

Price changes are largely driven by the assumptions made. For example Table A1.5 shows 3 scenarios for oil prices. In the reference case the USGS estimate of recoverable resource is assumed and the real price is 16% lower in 2020 than in 1990. By comparison an assumption that only half the recoverable resource will be available see prices rise by 5%, whilst an assumption that a prolonged Asian economic crisis would lower demand sees prices fall by

20%. This example also indicates the role played by the base point in any comparison. 1990 was a price high, whilst 1997 (used for table A1.4) was an oil price low and hence it shows large % rises to 2020).

The EU study includes some analysis of future electricity prices, concluding that, despite rising fuel prices, electricity prices will fall as a result of competition, increasing generation efficiency, increasing use of co-generation and new capacity. They estimate that by 2020 average EU electricity prices will be 15% lower in real terms than in 1995, before rising by 2% to 2030. Whilst such a scenario may be reasonable for a EU average it may not hold for all countries especially the UK which has already seen large price falls as a result of competition of the supply market. UK average industrial electricity prices were 26% lower in real terms in 2000 compared to 1995. More recently average UK industrial electricity prices have fallen by 13% in real terms in the year to Q4 2000. Early indications suggest that electricity prices have continued to fall in 2001, although the Climate Change Levy, which took effect on 1 April 2001, will have reduced the size of this fall.

Forward electricity prices fell significantly in anticipation of NETA. By the time of go-live they were, in real terms, 30% below the level of pool prices when the reform programme began in October 1998. Since go-live forward prices have, in broad terms, remained at this level. This reduction reflects factors other than NETA alone – in particular, divestment of coal-fired plant. Nevertheless, NETA has significantly enhanced competition in trading building on the success of introducing competition to generation and supply.

Energy price assumptions are central to the DTI modelling work. These do not provide a single estimate of future prices, rather 2 scenarios representing a high and low price future. Prices are at least in part driven by assumptions about the price of crude oil, assumed to be $10/bbl in a low price scenario and $20/bbl in a high price for the period 2005 – 2020 in 1999 real prices. Whilst higher prices are not discounted (e.g. 200 high of $27) it is assumed that prices will not be sustained at these levels (see text above). Table A1.6 gives some illustrative price assumptions used in the modelling work.

b) What strategies should we be pursuing in relation to OPEC and oil and in relation to liberalising global energy markets for gas and other primary fuels?

Our current aims in relationship to OPEC and oil markets in general are as follows:

- engage in dialogue bilaterally with individual OPEC countries and multilaterally (through the IEA and the new secretariat proposed at Riyadh, if accepted) to seek to increase market transparency through better data, open up OPEC upstream markets; (DTI/FCO)
- encourage (through IEA and bilaterally) non-OPEC producers to operate in line with free market principles; (DTI/FCO)
- strengthen dialogue between consumer countries especially those (e.g. ASEAN) most vulnerable to instability in oil prices; (FCO lead)

c) How can we best decouple gas prices from oil?

Our analysis suggests that the primary cause of the higher gas prices witnessed in 2000 (described more fully at Annex 1) was the renewed link between gas and oil prices, with typically a 6–9 month lag. On the Continent, gas is generally supplied under long-term contracts, which index the price to the price of oil, with a time lag. The rapid increase in the world oil price from early 1999 therefore fed through directly to higher European gas prices.

The UK was affected as the volumes of gas exported through the Bacton-Zeebrugge Interconnector grew allowing producers and shippers-to arbitrage between Continental and UK gas prices. Annual export capacity is 20 per cent of GB annual gas production, with import capacity 10 per cent of GB; compared with the electricity interconnector with France, where the figure is 4–5 per cent of our electricity. Therefore, the interconnector is very large in GB terms - its swing capacity (from full export to full import) is equivalent to about 30% of our average annual gas consumption - so that our gas prices have become more aligned with continental because of trade, or the possibility of trade, across the interconnector. However, there are concerns about the operation of the interconnector - for example, the physical flows have never been more than about 75% of capacity in either direction. Following extensive discussions between DTI officials and IUK (the interconnector operator) and the interconnector capacity owners, IUK has published better information about how the interconnector works, including physical flows, and are seeking to improve arrangements for marketing spare capacity. Some of these improvements are being made now; others, which would require substantial changes to computer systems, will take longer to agree and implement.

Separately the European Commission announced an inquiry into the operation of the interconnector, on 1 February. Although the Commission has not yet given a target date for completing the inquiry, we understand that it is making good progress.

DTI and Ofgem are also considering other factors which some in the industry have alleged have contributed to the price increases.

The recent rapid increase in gas prices has reinforced efforts in pressing the Commission and other Member States to bring about full and effective liberalisation of the EU's gas market. The Lisbon summit last Spring agreed to accelerate the process of gas market liberalisation. A new draft electricity and gas Directive was presented at Stockholm, and this provides for 100% liberalisation of the gas (and electricity) market by 2005, plus the structural measures needed to ensure effective competition. The Commission and most member states recognise the need for progress but access to the market in France and Germany remains difficult.

At present the continental gas market is dominated by entrenched gas supply and transmission companies with interlocking ownership on the basis of long term gas contracts, in many cases with anti-competitive provisions. This will not change quickly. But over time the adoption of market liberalisation measures combined with an active EU competition policy can be expected to lead to a more competitive gas to gas market. Long term contracts will continue to play a legitimate role, particularly to make possible the financing of major production or infrastructure projects. But shorter term contracting should begin to play a more important role. Indexation with oil price should no longer be automatic. However, liberalisation will have an impact on UK markets and work considering this is currently underway within DTI.

d) Given the uncertainties, how do different outlooks for prices impact on policy choices for the environment and security?

The Department’s Energy Projections (EP68) provides a view of the potential impact of different energy price outlooks (Table 1 below shows how the price assumptions affect some key policy variables). Overall high fossil fuel prices (case CH) tend to encourage renewables and diversity in generation mix in general. In particular more coal is used in electricity generation at the expense of gas, as gas prices rise more than coal, although this could be limited by sulphur constraints (see question 5). The increase in coal consumption increases both CO_2 and SO_2 emissions and negates some of the environmental benefits associated with higher prices leading to lower energy consumption. The high price scenario assumes an oil price of $20/bbl post 2005 down from $27/bbl in 2000, a level believed to be a high sustainable price. Analysis with a $30 price to 2005 and a graduated fall to $20 by 2007, shows emissions reduced by 0.7MtC by 2010 and a 0.5% rise in coal use for electricity generation compared to the CH case (higher still against the CL case), indicating that reduction in energy demand outweigh the carbon increase associated with fuel switching. The impact of fuel prices on fuel poverty policy is discussed at question 12.

Table 1.1 Impact of high and low energy prices on key variables in EP68

	2000		2010		2020	
	CL	**CH**	**CL**	**CH**	**CL**	**CH**
Primary Demand (Mtoe)	229.8	227.9	247.4	242.8	258.6	251.3
o/w coal	35.1	35.0	17.4	27.8	13.8	19.1
o/w gas	96.8	94.7	115.9	102.4	129.9	119.4
o/w oil	73.6	73.8	85.9	83.8	97.1	94.3
Gas % of elec. gen.	38.8	38.4	60.5	46.6	75.2	68.2
Coal % of elec. gen.	30.4	30.3	9.7	22.4	6.4	12.7
Emissions, MtC	147.8	146.7	147.5	148.7	157.3	155.2
o/w power stations	40.5	40.0	33.5	37.6	37.1	37.8
o/w residential	22.5	22.0	23.1	22.0	24.3	23.1
o/w industrial	33.9	33.7	32.7	31.8	32.2	31.5
o/w road	32.0	32.0	37.6	36.9	42.6	41.8
SO2 emissions	1238	1238	491	577	395	425

The impact on GDP of high prices cannot be estimated in the DTI model as GDP is an input variable, but the distribution of GDP across sectors shows lower output in energy intensive sectors such as iron and steel and higher output in sectors such as food, drink and tobacco. The impact of high fuel prices on sectors though the fuel mix is discussed in question 4 below.

II When will the UK cease to be self-sufficient in gas and what is the outlook for EU dependency on imported supplies of gas? As single European energy markets take shape, do we increasingly need to look at supply and demand from an EU (or at least NW Europe) perspective rather than an UK perspective? Should we be concerned about the availability and competitiveness of imports? What is the right strategy for relations with major suppliers such as Russia, Algeria and Libya and for tackling the issue of long-term contracts? Could LNG (imported from further afield) play a more important role given our current lack of suitable infrastructure? What are the infrastructure implications for future imported energy supplies (i.e. port, pipeline and interconnectors) including the links with Norway?

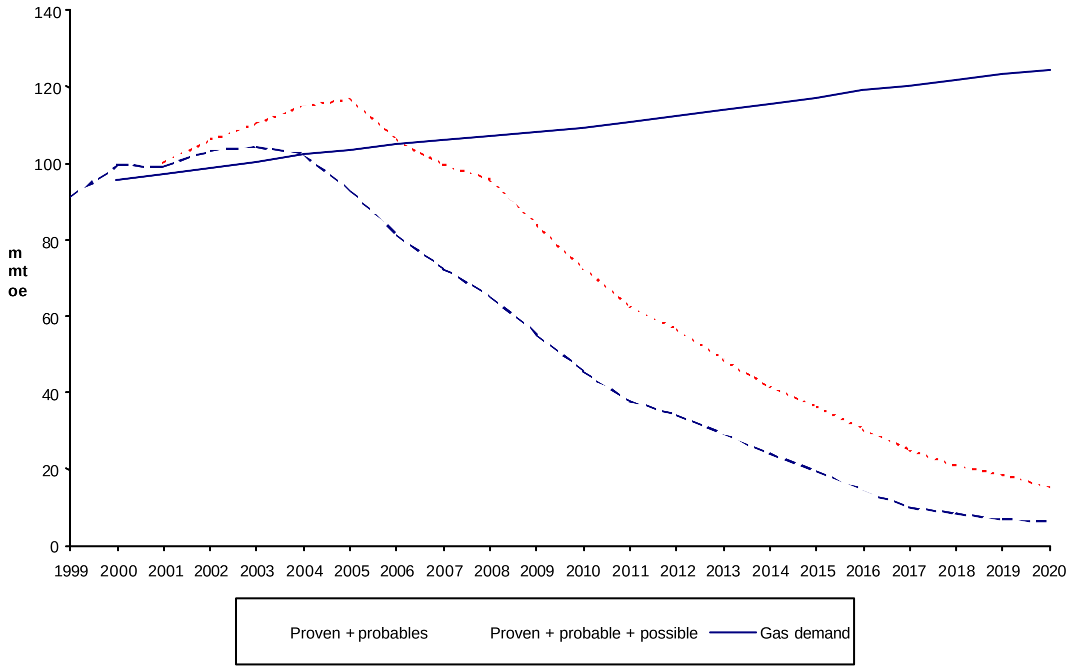
a) When will the UK cease to be self-sufficient in gas and what is the outlook for EU dependency on imported supplies of gas?

In 1999 the UK consumed around 90 Mtoe of gas. With total EU consumption around 400 Mtoe. Annual UK demand is expected to exceed UKCS production by 2005, although, seasonal shortfalls started in November 2000. On current projections the difference in 2005 between UKCS production (less direct exports) and UK demand (plus exports to the Irish Republic) is around 5 bcm (4.7 Mtoe) rising to 18 bcm (17 Mtoe) in 2006. This represents a net import requirement of 1 and 13 Mtoe respectively.

The supply shortfall is expected to be made up of imports from Norway and via the Bacton–Zeebrugge Interconnector. The Bacton-Zeebrugge gas interconnector has a full export capacity of 20 bcm/year (18.8 Mtoe), 20% of UK production, and an import capacity of 8.5 bcm/year (8 Mtoe), 10% of UK demand. Existing and possible new links to existing UK pipelines could give a potential capacity of at least 26 bcm (23.3 Mtoe) of gas per year from Norway from 2005/06. With an upgrade to the interconnector so the import volume matches exports (which is being proposed but which could take 3 – 4 years, dependent mainly on Belgian planning law), the UK could import up to 46 bcm (43.3 Mtoe) by 2006. The need for imports will be more concentrated in the winter months, as such the flow capacity of pipeline systems will need to take this into account as well as the need to supply gas to Ireland (see Annex 2) which could further increase the import requirement.

Looking further ahead the UK's import dependency is likely to increase rapidly, as chart 2.1 below illustrates. The chart shows two UK Continental Shelf production profiles. The first is a profile for production of "proven" plus "probable" discovered recoverable gas reserves. The second is a profile assuming all "possible" reserves are produced.. These profiles are shown against modelled results for primary gas demand from EP68. If proven correct this data indicates a significant need for increased import capacity over the next 10 – 15 years. By 2010 the UK needs to import 36 and 63 Mtoe of gas, (depending on what view is taken on possibles), whilst by 2020 projected demand shows the UK importing around 110 Mtoe.

Chart 2.1 UK gas supply and demand projections



Demand is average of CL and CH from EP68

As with all long term projections, there is much uncertainty over both supply and demand, especially looking nearly 20 years into the future. But, on the basis of the best information we have now, although the data are subject to revision, the future contribution to production from as-yet-undiscovered reserves is likely to be small, unless *very* significant discoveries are made West of Shetland.. Past predictions of imminent decline have proved wrong. But we are inclined to believe that these projections are better founded. First, we have better information than previously, due to both experience and technology. Second, the past successes at increasing recovery have left far less scope for further increase. While technology can certainly still be developed, it cannot yield reserves unless they are present, and much of the original resource base has already been depleted. So whilst UK production from "yet-to-be-found" reserves, may eventually exceed the "possibles" line it is unlikely to be a significant underestimate. The above analysis of future import and infrastructure requirements is consistent with analysis produce by Wood Mackenzie for the 1998 Energy White Paper. A fuller description of the assessment of reserves is given at Annex 2. Equally it is also important to recognise that there is uncertainty about UK demand (as well as supply). Increases in energy efficiency or more renewable generation above current targets are two examples of how current projected gas demand could change in the future.

The long-term data above indicates the UK will have a gas import dependency of 33 – 58% in 2010 and up to 90% by 2020. This figure is significantly higher than the European Commission's estimate of 26% by 2020. However the EU figure must be open to considerable doubt as it is based on assumed UK gas production in 2020 of 71 Mtoe (75bcm), far higher than DTI projections. As such the EU's estimate for all EU of 63% is perhaps on the low side. The IEA's World Energy Outlook includes Norway with in OECD Europe so their estimate of 62% import dependency for the region will imply a much higher figure for the EU alone. Whatever the exact figure, the EU could well be looking at having to import between 60 and 90% of its gas by 2020 and the UK may not be significantly better off than other EU countries in this respect.

Other European gas reserves - Norway

Europe has proven reserves[3] of around 7,180 bcm of which 3,800 bcm are in Norway. On current estimates Norway expects to be able to produce at least 90 bcm (85 Mtoe) of gas a year until 2050. However, in 2020 90 bcm will account for only 20% of the EU's projected gross consumption of gas, so despite large reserves, Norway cannot meet all the EU (and therefore the UK's import requirements).

The UK will not be the only potential buyer of Norwegian gas, although the infrastructure to the UK may make exports to the UK preferable than expanding networks to the rest of Europe, although Norwegians have been saying that entry auctions could make the UK less attractive. The Department is reviewing all aspects of the imports of gas from Norway to make sure that

[3] Natural Gas Information 2000 - IEA

we are as open as possible to the opportunities for diversity of supply that this represents. In particular we need to make sure that the necessary pipeline infrastructure can be made available. As described above, existing and possible new links to existing UK pipelines could give a potential capacity of around 26 bcm (23.3 Mtoe) of gas per year from Norway from 2005/06 which equates to around 25% of projected UK demand gas. It is for the gas suppliers and shippers to negotiate for Norwegian supplies and this will no doubt require long term contracts, especially where new infrastructure is required. Contracts allow risk to be shared – in general the purchaser take the volume risk, certainly in a take of pay contract, whilst the producer takes the price risk. Non-contracted sales often result in producers taking both volume and price risk and therefore new developments without contracts need established liquid markets and guaranteed demand. However, where long-term contracts are required we would support the EU Commission in opposing anti-competitive provisions in these (and other) contracts.

The Netherlands

The Netherlands also currently has significant proven gas reserves of around 1,770 bcm and expected reserves of 1,900 bcm (although a quarter of which is in the environmentally sensitive Wadden Sea). Around 60% of the reserves are in the large Groningen field, a swing field capable of producing between 0 and 0.5 bcm per day. The Netherlands both imports and exports gas, but was a net exporter of 23 Mtoe in 1998 with forecast exports of 30 Mtoe in 2005 – 10 and 24 Mtoe in 2015. However, exports could grow as the pipeline structure allows for 80 bcm per year a level which the Netherlands could sustain until 2024, the extent of current planning. But there may be artificial restrictions on production in the Netherlands affecting the Gronignen field which may restrict additional supplies DRT are to try and look into this. The UK is linked to the Dutch network solely through the Bacton-Zeebrugge interconnector but other connections could be developed from pipelines to existing fields.

b) Should we be concerned about the availability and competitiveness of imports?

Availability in a total resource sense no – the worlds proven gas reserves have been estimated by Cedigas at 158.3 trillion cubic metres (and 146 tcm by BP), whilst the USGS suggests that that undiscovered conventional reserves could add around 60% to known reserves. However, the distribution of reserves, with over two-thirds in Russia (33%) and other transition economies or the middle east (Iran 16%), potentially raises availability and competitiveness issues. The distribution of reserves could be important for the UK in a practical sense, given its geographical position of the edge of an enlarging EU market, the transportation costs involved alone could see the UK paying more than other countries for future gas supplies.

Essentially two issues interact. Firstly how far will the EU integrate its grid markets; and secondly how should relations with suppliers be organised, either by the UK or the EU.

c) What is the right strategy for relations with major suppliers such as Russia, Algeria and Libya and for tackling the issue of long-term contracts?

In the near future the UK will be, like most of the rest of Europe is already, dependent on imported gas. Hence in dealing with exporting countries notably Russia, Algeria and other Caspian Sea counties there is a risk that the desired UK approach will differ from an EU approach (or at least an approach desired by other EU countries). The Current UK (and EU) position was established at the 1998 GAC and EU/US summit which endorsed the concept of multiple pipelines and the principle that commercial considerations should determine the development of energy projects and export routes.

One means of seeking to improve the investment climate in Russia is through the Energy Charter Treaty. This Treaty sets out provision establishing stable investment conditions (Article 10) which are essential for economic reform. It also provides rules concerning energy transit across state boundaries (Article 7) and these are being elaborated in a Protocol that is currently under negotiation. The Energy Charter Treaty was signed in 1994 by 53 states including all the EU and transition states in Eastern Europe and 42 states have ratified. Russia, however, has not although it is applying the Treaty provisionally. In the context of the EU-Russia energy dialogue the Commission is putting great stress on the need for Russia to ratify the Treaty and conclude the Transit Protocol. Although the Treaty does not currently include any North African states its benefits have been promoted in the context of EU Euro-Med. discussions.

Looking ahead the EU and Member States need to promote greater flexibility in contracts whenever opportunity arises. Long-term contracts have been an essential feature of gas exploration and infrastructure development and will continue to play an important role in this respect. However as markets become more open and competitive and new market mechanisms develop, long term contracts need to become more flexible to reflect these changes. There is scope to make contracts more in line with competitive markets by addressing issues such as frequency of re-negotiation, level of “take or pay”, price indexation clauses, destination clauses or any other element that reduces opportunity for valid competition.

Outlook for gas from Russia

Russian gas production has fluctuated around 550 bcm/year (a quarter of world production) during the late 1990’s and is expected to be lower in 2000 than in 1996. The Russian domestic market is about 300 bcm, but prices there are considerable below world prices (and a lot of gas is “sold” free). Gasprom has an excellent record in delivering gas sold to the West and will be highly motivated to maintain these sales as a vital source of export earnings.

Investment

Russia has vast proven gas reserves 56,000 bcm in large fields in Siberia, although the majority of the new large fields are even less accessible (e.g. the Yamal Peninsula) than current gas fields and numerous smaller fields capable of producing 1 – 5 bcm per year. However, production is currently declining because of lack of investment and the development of Russia’s gas resources will require a huge investment of international capital.

Pipeline infrastructure and Network

A key security of supply issue for Russian gas (and also relevant to the far north reserves in Norway and he reserves in the Middles East) is that the gas fields are a very long away from markets in the West. This means large investment is needed to install within Russia and to maintain the existing network where gas is piped through other countries to reach export markets. Currently most exports pass through the Ukraine which raises a range of issues such as the integrity of network and impact on liberalisation and political and market stability.

There is a security of supply risk connected with Russian gas. But the source of the risk is more likely to be an ageing infrastructure than any real threat of restricted gas supply from Russia in the short-term.

d) Could LNG (imported from further afield) play a more important role given our current lack of suitable infrastructure?

LNG supplies

LNG is traditionally viewed as an alternative to gas where pipelines do not exists and as such is available from countries with natural gas reserves but no feasible pipeline infrastructure for export. Such countries include Australia, UAE, Qatar and potentially Venezuela as well as Algeria, Malaysia, Indonesia, Trinidad and Tobago and Egypt. At a company level there are four dominant major LNG players: BP Amoco, ExxonMobil, Shell and TotalFinaElf.

In 1999 124 bcm of LNG was traded worldwide, about 5% of the global gas market (and a similar proportion of the European market), with Japan, Korea and Taiwan the main purchasers (over 75%) and Indonesia, Algeria and Malaysia the chief suppliers. The US has recently imported little LNG but declining indigenous supplies and high gas prices especially over winter 2000/01 have revived substantial interest and investment in LNG. In Europe, the Mediterranean countries, France and Belgium have traditionally imported LNG (31 bcm purchased in 1999 chiefly from Algeria), as its price has generally compared favourably with other sources such as pipeline imports from Northern Europe, although this argument does not hold for Belgium.

Global interest in LNG tends to vary with movements in the oil price (although investment lags behind). However, over the next decade there are several factors that point to an increasing role (up to 15% of global gas demand) for LNG. These are:

- technical advances reducing the cost of ships, associated infrastructure and upstream costs
- exporting gas as LNG offers flexibility and options for supply markets, especially for Middle East producing countries with large gas reserves but are some distance from the main markets.
- willingness of some LNG players to build speculative LNG tankers
- liberalisation and deregulation in the key Far Eastern markets
- potential development of large new markets such as India and China
- LNG can offer more flexibility to meet seasonal demand; and
- the US and Europe are becoming increasingly import dependant, looking for diverse new sources of supply

LNG prices

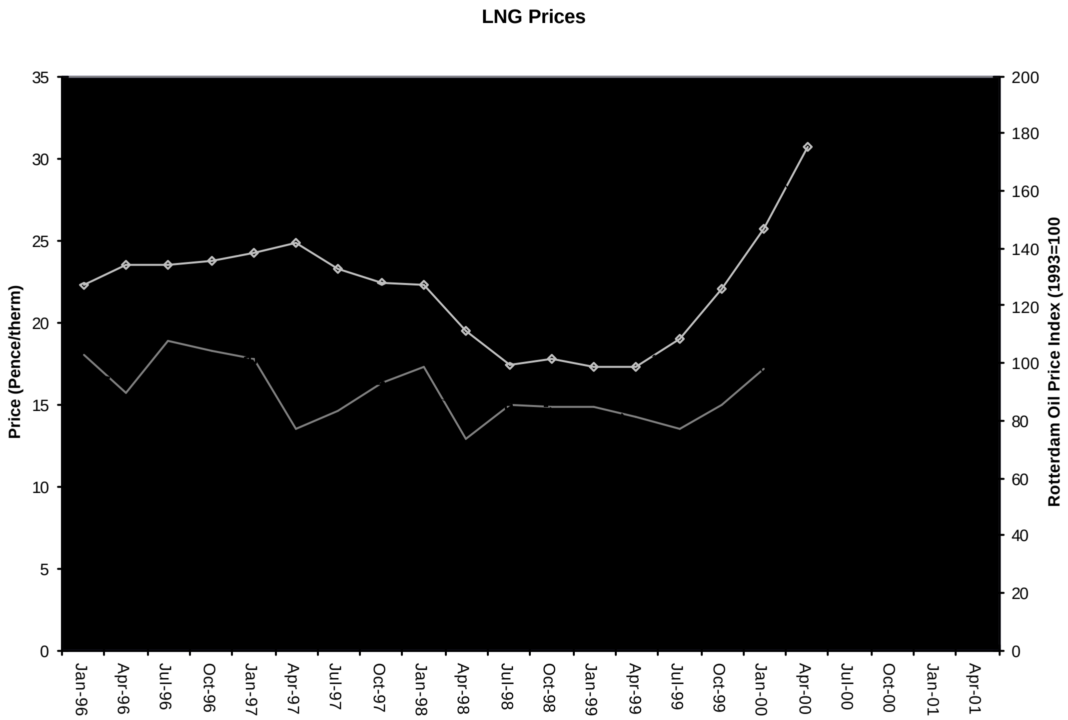
As the major player in the market, Japan has been influential in the LNG market through its long term purchasing and financing agreements. It has paid on average 40% more for its supplies than LNG delivered to the US and Europe (See chart 2.2). Some of the additional cost may reflect higher transportation charges. But there are signs that the above developments could exert some downward pressure on LNG prices. The prospect of Japan receiving some of its supplies from Sakhalin in Russia, by pipeline or LNG, may also exert some pressure on their gas prices and would also offer a direct comparison between European and Far eastern prices. To the extent that Middle East LNG can also go to both regions, the market looks set to become more global although perhaps not in the short term.

LNG is economic at the current international high gas prices and for reasons given above the long run marginal cost of LNG is likely to fall. In contrast, the underlying costs of pipeline gas supplies to Europe and the US are increasing. So LNG is likely to become more competitive at a broader range of prices than before and this should reduce the volatility and risk of this market which has resulted in some participants' bankruptcy over the past decade

LNG is currently a price taker with its price closely related to the price of oil, although a spot market in Atlantic LNG has begun to emerge. This could be an important influence on prices on either side of the Atlantic if trade reaches a critical mass. This could be achieved at quite a low level of overall consumption (possibly 20%). While European gas contracts remain linked to the oil prices, LNG is unlikely to be separately priced or have much of an impact on the overall level of gas prices. But if liberalisation really takes off , the linkage could be weakened over the next decade and LNG could become an increasing influence on price. The share of LNG is expected to grow significantly in Europe with growing imports contributions from projects in Nigeria, Egypt and the Middle East.

Chart 2.2 shows the closeness of LNG and average imports pipeline gas prices into Europe (as stated above LNG is already cheaper for South European countries) and the link between oil and LNG. LNG prices for imports by Japan (the only available forecast of future LNG prices) are expected (IEA - WEO) to remain flat until 2010 and then rise by around 38% by 2020.

<u>Chart 2.2 LNG prices</u>



LNG in the UK

In the UK, there are a limited number of sites which have been identified as suitable for receiving LNG. One is the Isle of Grain in Kent, adjacent to Transco's LNG storage capacity (though it would be open to other players than Transco to seek to develop a new import facility there).LNG supplies are most likely to come from North Africa of the Middle East, which may suggest a port facility in the South West as being preferable. The UK has a dormant (classed as closed by the IEA) LNG import capacity at Canvey Island which has a storage capacity of 0.055 bcm

LNG offers the potential for diversity of gas supplies. LNG storage is also a possible means of increasing the reliability of gas (and indirectly electricity) supplies because it can be released into the system quickly in the event of a supply disruption or shortage. The promotion of additional LNG import and storage is therefore one instrument by which the Government could seem to address some energy security concerns.

e) What are the infrastructure implications for future imported energy supplies (i.e. port, pipeline and interconnectors) including the links with Norway?

Upstream Pipeline links

The main pipeline linkages for importing upstream gas and for oil are likely to be with Norway and the Netherlands. None exist with the latter; if they were to be developed, the nature of Dutch hydrocarbon reserves is such that they would probably be for gas rather than oil.

Direct gas imports via Norwegian pipelines

The Norwegian Frigg pipeline transports gas from the Norwegian sector of transboundary Frigg field to St Fergus in Scotland. Gas from the Norwegian sector of the field is likely to have depleted completely by 2003. In order to ensure continued supplies of gas in the same potential volume to the UK, agreement has been reached between the UK and Norwegian Governments to allow for the continued use of the Norwegian Frigg pipeline from October 2001 for non-Frigg gas. This will be brought about by a new transboundary pipeline link ("Vesterled") between Norway's Heimdal field and her Frigg pipeline on the UKCS. Heimdal will then be developed as a long term gas processing hub for other Norwegian fields.

Gas imports via UK pipelines

In addition to Norway's Frigg pipeline, Norwegian gas could be imported to the UK via existing UK pipelines tied back to Norwegian infrastructure. There is already a link between Norway's sector of the transboundary Statfjord field and the UK's FLAGS[4] pipeline system. In addition, tie backs from the UK's Miller pipeline and SAGE[5] pipeline systems might also provide import capacity from 2005/06. As discussed in (a) above Vesterled, existing tie backs from FLAGS and possible new links to existing UK pipelines could give a potential capacity for at least 26 billion cubic metres of gas per year to be imported from Norway from 2005/06, about 25% of anticipated UK annual demand. However, these figures are highly speculative. Additional import capacity may become available as spare capacity in current UK infrastructure increases; any new linkages to existing UK pipelines are likely to involve considerable investment by the companies concerned; and that there is likely to be competing demand for Norwegian gas from elsewhere in Europe.

[4] Far-north Liquids and Associated Gas System

[5] Scottish Area Gas Evacuation

Implications

A "Framework Agreement" between the UK and Norway allows for new transboundary pipelines (oil and gas) to be constructed between the two countries. This Agreement would facilitate the construction of new linkages between Norwegian gas fields/pipelines and UKCS infrastructure of the type described earlier. In principle, therefore, there is nothing to hinder the development of new links with Norway in order to increase potential gas supply capacity. However, three additional factors in relation to Norwegian imports must be taken into account: (a) other export options available to Norway; (b) the implications for future UKCS development if UK infrastructure is used for Norwegian gas; (c) the impact on chemical feedstock supplies. Each of these factors is explored in a little more depth in Annex 2.

As the UK moves back to being a gas importer many questions are currently unresolved. Russia has vast gas supplies and will be a source of gas for the UK. But it will not be the only source. Supplies are likely to come from the Middle East (Iran has the second largest single country reserves), North Africa and Norway. It will be important for the UK to maintain competitive pressures on all suppliers including Norway to achieve economic gas supplies. However, at this stage much is still unknown about how any European gas supply market will develop, where key trading points will emerge and how the relative economics of supplies from different countries and the costs of long pipelines compared to shipping LNG. At this stage more work is needed on the infrastructure implications for the UK (and within Europe)

Oil

The "Framework Agreement" applies equally to the construction of new linkages with Norway for oil imports, although no projects are in prospect. Three UK/Norwegian links already exist (and are subject to their own Treaties): Norpipe, importing oil from Norway's Ekofisk field; Heimdal-Brae importing condensate via the UK's Brae and Forties infrastructure; and UK pipelines importing oil from the Norwegian sector of the transboundary Murchison field to Sullom Voe.

III Are we doing as much as we should to attract new investment and development in the North Sea?

DTI's policy in relation to the UKCS is to secure diverse and sustainable supplies at competitive prices. The UK is both producer (not a significant one in world terms, self-sufficient at present but probably not beyond this decade) and a consumer. Our objective in exploiting the UKCS is to maximise economic benefits from a national asset and not to supply at particular prices to consumers.

The DTI's Oil and Gas Directorate (OG) has reorganised so that dedicated resources are available to encourage new players to enter the UKCS and to ensuring that best practice and knowledge is disseminated as widely as possible through the industry. Attention is being focussed on oil companies who already have the skills to develop the more economically marginal discoveries and to extend the life of existing fields.

The Energy Group is aware of the need to examine the long term implications of declining oil reserves has supported a number of initiatives in collaboration with the International Energy Agency, industry and academia including coal liquefaction and underground coal gassification

The Oil and Gas Industry Task Force (OGITF) was established at the end of 1998. Its remit was to recommend ways in which the UK oil and gas industry could maintain its competitiveness in the face of increasing maturity of the UKCS and (at that time) low oil and gas prices. Besides Ministers and officials from the relevant Government Departments, the Task Force also included representatives from the operators, the supply chain and the trade unions. The Task Force's report was published in September 1999 and identified an ambitious vision for the UK Continental Shelf in 2010. Realising that vision has been remitted to a successor Government/industry group – PILOT. The vision and progress towards targets are set out in Annex 3.

Access to infrastructure is a key element in the process of extracting the UK's petroleum resources. Details of work in hand to facilitate such access, designed to encourage future UKCS development, are also set our in Annex 3.

Although not directly about attracting investment in the North Sea, an increasingly valuable spin off is that developments in the UKCS can also enhance UK business opportunities overseas. The capability of world-class exploration and production companies will be in demand and a double UK advantage can be obtained through working closely with the oil majors. The onus should be on ensuring that there are no Government policies or distortions in the tax system that might discourage private sector development of the UK's oil (and gas) reserves or of these alternative technologies. Specific areas of action are shown in Annex 3.

Security of supply

IV How will the UK's fuel mix change in the medium and longer term? What implications does the energy mix have on future economic growth and the structure of the economy? Are energy supply diversification issues different for the UK than for other developed countries? Should we be concerned about increasing reliance on gas for electricity generation? Do we fully understand the possible interactions between the electricity and gas systems? What are the trade-offs between liberalisation and security of supply? At an EU/international level, how can we encourage the construction of interconnectors to link European markets, which go against the interest of monopoly suppliers?

a) How will the UK's fuel mix change in the medium and longer term?

By 2020 gas will account for nearly half the UK's primary energy needs (based on average of CL and CH scenario in EP68[6]) compared to around 30% in 1995. Overall, over 85% of primary energy needs are forecast to be provided by gas or petroleum products A chart of the data is at Annex 4. Change in the electricity generation mix (discussed at section d below) is the main driver behind this with a decline in demand for both coal and nuclear. The forecast final fuel demand mix by sector is relatively unchanged in the period 2000 to 2020 (see Annex 4). In the domestic sector electricity's share of total fuel use grows from 21 to 24%, with gas seeing a small decline in terms of overall share. The fuel share of electricity and gas both grow by around 2- 3% for services and industry. Solid fuel declines as a proportion of total fuel use in all sectors as does oil in all but the domestic sector. In transport the biggest change is a forecast increase in aviation fuel as a percentage of the total fuel mix. Overall final energy demand is expected to increase by around 8% for the industrial sector up to around 39% for transport. No analysis has yet been carried out looking at the fuel mix beyond 2020. A crucial factor will be how fast renewables develop beyond the 10% target set for 2010, as growth in renewables is likely to be at the expense of new build gas generation.

[6] Energy Paper 68, Energy projections for the UK

In considering final demand and the future fuel mix it is important to consider the role that technology will play in increasing efficiency in the end use of energy. Such energy efficiency improvement should keep growth in energy demand well below the growth in the services that the use of energy provides. The importance of demand management was also emphasised by the EU's recent Green Paper on Security of Supply that concluded that more could be done to stimulate markets for energy efficient products within the EU. While recognising the effectiveness of appliance labelling and standards where implemented, it also identified considerable technical and economic potential for improvement that had not been achieved, partly due to market barriers.

b) What implications does the energy mix have on future economic growth and the structure of the economy?

With gas potentially accounting for 67% of the domestic sector's fuel use in 2020, over 50% for services and 40% for industry, the price rises discussed under question 1 would significantly add to costs across all sectors. However, the overall impact may be small as, currently, fuel costs account for a small proportion of expenditure in most sectors and industries. For energy intensive industries price increases are likely to be a global factor, so on a pure market driven price basis there may be no reason to assume UK industry will be affected more than other countries. Of course policy decisions taken in individual countries may aim to protect specific industries or may increase prices above "market rates" through taxation.

c) Are energy supply diversification issues different for the UK than for other developed countries?

Energy supply is determined by available supply (indigenous and imports) and in part by political and economic decisions. As such it will naturally vary across countries and regions. At an aggregate level, Table A4.2 in Annex 4 shows the projected change in fuel mix between 1997 and 2020 for the 3 key OECD regions. A common theme is the decline in coal and increase in gas (through greater in Europe than elsewhere). Oil consumption is forecast to decline as a share of overall energy use in Europe and the Pacific, but grow in North America, whilst nuclear declines in Europe and North America, but grows in the Pacific (all in Japan). Overall Europe and North America are projected to see a slight fall in diversity (here “measured” by the proportion of fuel supply provided by the two largest fuels) whilst the reverse is true for OECD Pacific.

Aggregated projected changes for a region differ from projections for individual countries (which again differ depending on who makes them!). Results from EP68 predict a sharper fall in coal and nuclear for the UK and an increase in petroleum than for Europe in the IEA data. Equivalent differences would be witnessed across the EU. Using the EU Outlook results the table below illustrates how fuel diversity varies for 3 countries, with Germany perhaps achieving a greater diversity through the continued contribution of solid fuels. Within the EU a common theme is an increase in import dependency meaning, increasingly, security has to be viewed in an international context.

Table 4.1 Primary Inland Consumption (Mtoe)

	France			Germany			UK		
	1995	**2020**	**2020 %**	**1995**	**2020**	**2020 %**	**1995**	**2020**	**2020 %**
Solids	15.3	15.7	5	92.2	77.9	22	46.6	32.3	12
Oil	86.2	104.5	36	133.6	158.3	45	82.6	100.9	38
Gas	29.7	42.9	15	66.4	74.9	21	65.0	105.1	40
Other	103.9	126.8	44	46.4	39.1	11	25.8	24.2	9
Total	**235.0**	**289.9**	**100**	**338.6**	**350.3**	**100**	**220.0**	**262.4**	**100**

Other includes nuclear, hydro, wind, imports of electricity and other
Source: EU Energy Outlook to 2020

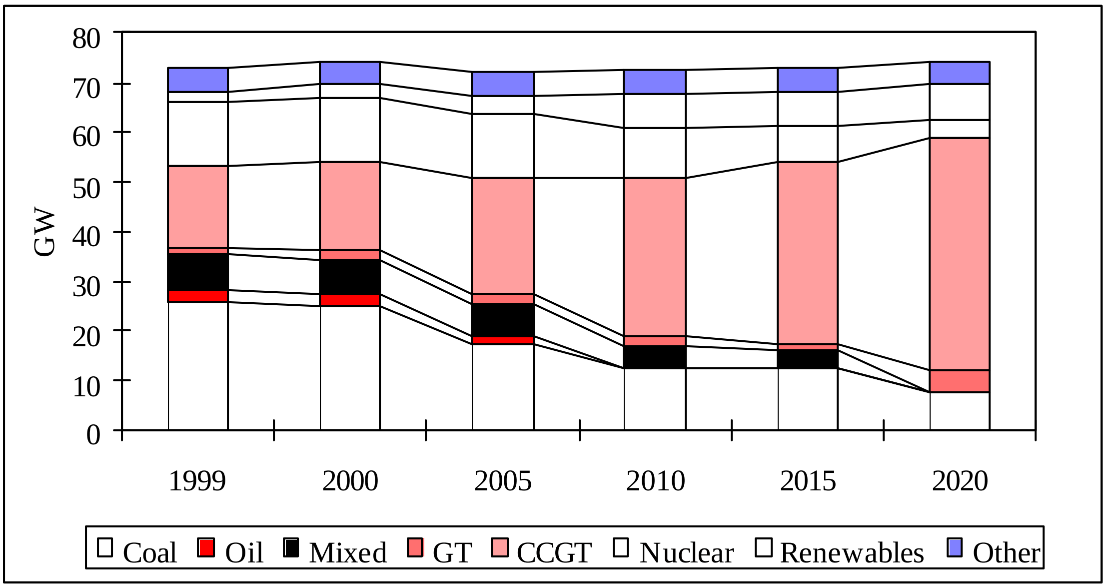
d) Should we be concerned about increasing reliance on gas for electricity generation?

Electricity demand is projected[7] to rise steadily (1 - 1¼% per annum) throughout the period 2000 - 2020 requiring substantial new generating capacity to maintain the fixed capacity margin of 17% used in EP68 calculations. Gas commands a much higher share of capacity and generation than other fuels in a low energy price case (CL), whereas coal is relatively better placed in the high price cases. Under CL assumptions, 61% of electricity generation will be gas fired in 2010, with 10% coal, 17% nuclear, and 11% renewables, whilst in CH, where the total electricity generated is lower 47 % of total electricity generated is gas fired with coal 22%,

[7] Energy Paper 68, Energy projections for the UK

nuclear 18% and renewables 11%. By 2020 gas accounts for at least 70% of electricity generated, the vast majority of gas will be imported**.**

Chart 4.1 Plant capacity by plant type in the CH case.



Whether a dependence on gas is a cause for concern about security and diversity is a central question, but (as discussed in question 2) gas exporters have an interest to sell gas and so long as adequate infrastructure exists to move gas to the UK, supplies should not be threatened. Equally it is important to realise that the projections are based on the renewables target being met in 2010 and then staying at 10% to 2020. There is good reason to expect that either through new government targets or a market led expansion , especially given the recent large funds made available from government for development, that renewables will continue to grow beyond 2010. If this occurred it would probably be at the expense of new gas build (on the assumption that it is only new gas plants that will be built and new capacity would not be able to replace existing capacity on costs grounds) and so increase diversity of supply. However, looking to 2020 and beyond the UK's nuclear generating capacity will decline, currently expected to stop completely by 2034. So whilst a significant growth in renewables is probable, whether the growth is sufficient to both replace nuclear and displace gas is at this stage uncertain.

It is not only through supply side measures that future fuel dependency can be addressed. If less electrical energy is required then less will have to be generated. Clearly measures such as increased use of CHP and improvements in energy efficiency could have a significant impact as a tool for increasing security as well as achieving environmental objectives. The Government has recognised this in setting itself a target of achieving at least 10,000 MW of CHP capacity by 2010. It is due to publish its CHP Strategy soon and this will draw together current support measures for CHP and also consult on what further measures may be necessary.

Technological advances also play a significant role, not only in generating technology but also in commercial and consumer equipment which not only use less energy to function but can also help to ease the transition to a less energy intensive lifestyle. For example, new types of electronic products are being developed, based on ubiquitous computing and intelligent automated environments, that can be "aware" of the environment and offer a range of benefits including energy efficiency. These developments also embrace metering technology and a new generation of "smart" meters could offer enhanced real-time, accurate information to both suppliers and users about energy use, showing where savings could be made. Smart meters are covered in more detail in question 16.

e) Do we fully understand the possible interactions between the electricity and gas systems?

Electricity and gas systems in the UK and elsewhere around the EU are increasingly integrated, with both physical and economic interactions between them. In the UK, the "dash for gas" in the 1990s has led to about 40 per cent of UK electricity generation being gas fired. Gas is also the main fuel of CHP plants, playing an increasingly significant environmental and embedded generation role.

The economic interaction is also important. As a significant feedstock for electricity generation, the electricity price reflects the cost of gas used in generation so if the gas price increases as predicted (from historic not necessarily current levels) then so should the electricity price. Future UK gas supply and import dependency is discussed in question 2.

From the UK's perspective, a growing dependence on imports mean gas prices will be set on a wider and perhaps less competitive market than we would want and the physical access to reliable sources will become increasingly important. That in turn will mean that we have a real interest in an open and integrated EU gas market, and in pursuing foreign policy arrangements which will provide us with access to competitively priced and reliable sources of gas from outside the EU. These are significant international energy policy challenges. They will place a premium on co-ordination with EU partners in managing the internal gas market, external sources of supply and intra EU demand management arrangements, including energy efficiency policies and programmes in both the electricity and gas sectors. It may also provide more of an incentive for the development of interconnection arrangements so that UK is more physically linked to the European gas network. That in turn will place greater emphasis on getting cross border arrangements (physical interconnection and the economic arrangements to manage cross border trade) properly settled at a European level for both electricity and for gas.

There are a wide range of interrelated issues here including management and investment in infrastructure and how they interface with North sea and international gas supplies, policy on LNG and the regulatory function. The latter is discussed in more detail in question7.

f) What are the trade-offs between liberalisation and security of supply?

Liberalisation verses security of supply is often condensed to the issue of the need for long-term contracts (discussed in question 2 in relation to securing gas supplies and question 6 in relation to new generation capacity). Some argue that long-term contracts provide stability and certainty of supply. Indeed there is nothing wrong with long-term contracts in principle provided they don't contain anti-competitive elements. However, problems arise if the whole market is tied up in long-term contracts or if continental regulators permit market dominance in order to protect the holders of long-term contracts from competition, a situation not foreseen in the UK. Long-term contracts will not necessarily provide any security against unforeseen third country political actions (e.g. trade embargoes).

Electricity generation

For generation capacity in general the key question is whether the long-term price outlook (in the absence of guaranteed contracts) encourages new capacity to be built. The time lags involved in constructing power stations are significant. So whilst prices may fluctuate in the short-term, leading to high marginal prices at times of high demand for example, it is important that longer-term signals of requirements are provided. In addition, ability to manage demand may be constrained. There are currently no short-term price incentives for domestic (or service sector) consumers to reduce demand at times of limited spare capacity. So if tight capacity were coupled with fast demand growth (as was part of the problem in California) then demand could exceed supply, and power shortages occur. To many the key question is whether competitive markets can deliver secure supplies in a sustainable manner without imposing severe price pressures.

Of course, an uncompetitive (monopoly or oligopoly) market is no guarantee of capacity. Indeed, the incentive in such markets is precisely to restrict supply and thereby reap profit from higher prices.

So the issue is to encourage competition, to encourage efficiency and lower prices, whilst ensuring that adequate incentives to new investment (by existing generating companies on new entrants) are maintained. Clearly one supply solution is to have more interconnectors and so a wider accessible supply base.

The energy crisis in California has prompted comparisons with the UK. The fundamental problem in California at present is an overall supply and demand imbalance. Californian generation is not able to cover peak demand and relies on a poor and constrained transmission system to import electricity from neighbouring states to maintain system balance. This situation has arisen because as demand rose rapidly, generation remained flat and has been exacerbated by high gas prices and weather conditions.

No significant new generation has been built in California for over 10 years. New build has been constrained by environmental regulation and high levels of local opposition (by companies and consumers) to siting of new generation. A high proportion of the current stock is now unreliable or subject to strict environment limits. A failed deregulation exercise forced the major supply companies to divest their generating assets whilst capping retail prices and denying them (and the system operator) the scope to purchase electricity in forward markets.

In summary, a number of factors and barriers combined to provoke the crisis in California. Quite apart from the current generation surplus, the UK's infrastructure and regulatory environment distinguish it from California. In particular, outside regulation of the electricity network, there are diminishing regulatory controls on generation and supply. Under current regulatory arrangements, the disconnect of wholesale and retail prices seen in California could not occur here.

The introduction of New Electricity Trading Arrangements (NETA) in England and Wales provides additional protection against the risks being realised in the US. With the growth of competitive and liquid wholesale markets within which participants can freely contract and trade and with efficient price reporting, commercial opportunities for new build should be reliably signalled to the market. NETA also anticipates and provides incentives for demand-side participation, promoting a genuinely two-sided market in which both supply and demand would be more price elastic.

Of course, it is early days for NETA. Inevitably, there are questions about how the theory will be borne out in practice – in particular, how NETA will support clear price signals to incentivise adequate and timely investment in generation. Currently the generation margin is substantial, and expected to remain so for some years ahead. In this developing market it is perhaps, therefore, not very surprising that the long-term contracting market is currently thin. But there is no obvious barrier to prevent such development (deals for up to 10 years ahead are being made), and we are seeing significant market development for periods of a year to 16 months ahead. An important issue here will be the way in which financial markets assess investment decisions in the new market and the risks they attach to, for example, the volatile (but in volume terms small) balancing market.

The ability of the demand-side to play a significant role in the new market is also not fully proven. NETA has not been long in operation. But, again, experience of the market (and in the case of domestic demand, technological innovations such as metering) will be a key factor in driving this development. It should, of course, also be recognised that political intervention in a market – if premature – runs risks of limiting the ability of markets to develop proper price signals.

It is not obvious that there are barriers which could prevent or constrain these market developments, but this would benefit from further consideration. The development of forwards markets and of the generation margin must be closely monitored.

Gas infrastructure issues are discussed in question 6 and gas supply in question 2.

g) At an EU/international level, how can we encourage the construction of interconnectors to link European markets, which go against the interest of monopoly suppliers?

This issue falls into three parts:-

(a) Combination of commercial incentives supported by the application of competition rules is likely to provide real market-based signals in many cases for the construction of new interconnection in the EU. Where possible, these processes should be allowed to bear fruit; and

(b) The European Commission's proposals for the liberalisation and integration of the electricity and gas markets will indirectly help to achieve this result in two respects. Firstly, they provide for the separate operation and management of gas and electricity transmission/distribution networks from the energy/gas transported over those networks. Separated network operators (or owners) have less incentive to maintain the market segmentation which arises from lack of physical interconnection capacity;

(c) At a physical level, the Commission is disposed to consider widening the scope to use Trans European Network funds to build physical interconnection where market operators do not find it economic to do so, but where there are clear strategic reasons for this investment taking place (generally in peripheral areas like Greece and Ireland, but Baltic interconnections may provide important interconnections for the UK). The Commission is also proposing that Member States should have a duty to review and report on the physical adequacy of generation. It may be appropriate to consider extending this requirement to look at transmission arrangements, including interconnection. The proposed regulatory committee under the draft liberalisation directive is discussed at Annex 4.

V. What is the future for the demand for coal in the UK, given economic and environmental pressures? What is the future for UK mined coal? What role has coal utilisation to play in ensuring that diversity of generation/security of supply? How can we ensure the strategic capacity to use coal, if necessary, to make us less vulnerable to rising world energy prices? What are the implications for our policy towards the coal industry? What are the implications for our policy in support of clean coal generation technologies?

a) What is the future for the demand for coal in the UK, given economic and environmental pressures?

The table below illustrates possible coal demand at low (CL) and high (CH) world energy prices (as set out in Energy Paper 68). Over a third of this demand is currently met by imports, and this proportion is likely to rise. If environmental concerns are not met, demand could be substantially lower.

	CH	CL
2000	59Mt	59Mt
2005	50Mt	33Mt
2010	43Mt	26Mt

The key determinants of the longer term demand are the price of coal relative to that of other fossil fuels, and environmental factors. These are explored in Annex 5 section A.

b) What is the future for UK mined coal?

The table below illustrates possible UK coal production at low (CL) and high (CH) world energy prices from EP68.

	CH	CL
2000	32Mt	32Mt
2005	30Mt	12Mt
2010	23Mt	6Mt

However, although the UK has huge reserves of coal from which to meet this production, relatively little of it is likely to be capable of economic extraction by conventional methods. Unless there are very significant increases in world coal prices it is very unlikely that any new UK deep mines will be commissioned. Open-cast operations are also facing increasingly tight environmental and planning controls. Increasing dependence on imported coal is therefore likely. Further details are given in Annex 5 section B.

c) What role has coal utilisation to play in ensuring that diversity of generation/security of supply?

A decline in UK coal fired generation may raise security of supply concerns. There are dangers in relying too heavily on any one fuel (e.g. gas) for electricity generation as it would leave us vulnerable to price rises and supply restrictions. A decline in UK coal production, however, is unlikely to raise serious security of supply concerns because of the geographical spread and political situation in coal exporting countries. Short term disruptions to coal supplies can also be met by stocks. Although there has been increasing consolidation in the traded coal market, it is far from clear that this gives producers the ability to raise prices above cost to any significant extent.

d) How can we ensure the strategic capacity to use coal, if necessary, to make us less vulnerable to rising world energy prices?

If it was felt that some government intervention was necessary, possible ideas that might be worth considering would include subsidies (for coal production, coal consumption or clean coal plant); supporting R&D effort on carbon sequestration technology, and working towards such carbon storage being given credit in any domestic or international emissions trading; obligations on the electricity industry to maintain a given level of coal generation or capacity; restrictions on construction of gas stations; or "mothballing" of coal-fired power stations for use if problems emerged elsewhere (mothballing of deep mines is simply not economic, and there appears to be little or no support for it in the industry). There could be very significant financial and state aid issues with such policies, and it would be important to clarify the problems that we were trying to address. Both the PIU study and Cleaner Coal Technology (CCT) review (see f below) will shed further light both on potential problems and solutions, and clearly much further work would need to be done before any specific policies could be recommended.

e) What are the implications for our policy towards the coal industry?

Both economic and environmental indicators point to a decline in coal burn and UK coal production. Government policy may be an important factor in shaping the time scale and profile of that decline and determining the long term levels of production and consumption. A clear role remains for Government intervention to promote regeneration (environmental and social) in areas where coal production ceases. If any production aid was to be paid after the current scheme (and the ECSC state aids decision on which it is based) ends in 2002, it would have to be on a different legal basis, yet to be negotiated. Environmental concerns will also need to be addressed if the future of coal production or consumption is to be secured. Security and diversity of supply arguments may be used to protect coal consumption.

f) What are the implications for our policy in support of clean coal generation technologies?

Existing and prospective environmental regulations mean that a significant share for coal in the electricity generation mix will not be maintained in the absence of effective clean coal technologies. CCT would provide considerable environmental advantages over conventional coal fired generation by substantially reducing emissions of greenhouse and other harmful gases over the next 20 years. It will be particularly important that, as well as controlling SOx and NOx emissions, it addresses CO_2 concerns. These can be reduced both by burning coal more efficiently and through sequestration. The individual technical elements needed for CCT plants have already been developed so it is more a question of bringing these together into a new plant. With ample world wide coal reserves the use of cleaner coal generation could enhance both diversity and security of supply objectives. If suitable CCT is not available, the government’s energy policy and the security of energy supply in the UK will be put at risk as emission targets could then only be met through a significant reduction in coal burn.

In parallel with the PIU’s review of energy policy, the DTI will be considering the case for supporting the construction of a cleaner coal demonstration plant. The review is expected to make a recommendation to ministers around the end of the year with its findings feeding into the PIU review. It will consider a range of technical options for a cleaner coal demonstration plant ranging from retrofitting cleaner coal components to existing power plant to the development of a new cleaner coal generating station which includes CO_2 capture and sequestration. Additionally it will consider the benefits to the UK manufacturing industry of developing such plant including the export potential to countries such as China and India which are heavily dependent on coal for power generation. The decision on whether to support a CCT demonstration plant will depend on its commercial viability and the value for money of the investment. It will also have to be judged in the context of the options and priorities arising from the PIU study.

VI Does the operation of our system of regulation (for electricity and on and offshore supplies) need to be adjusted in the light of greater concerns about security of supply and rising energy prices? Will we continue to have adequate margins of generating capacity, gas supplies and infrastructure? Need to link security of supply with questions (in XVI) on transforming supply networks to encompass "new energy" sources and energy services. How do we ensure that market mechanisms send the right signals for securing necessary investment in new electricity generation, gas supplies, and infrastructure? Is there a risk that market prices will be volatile or cyclical and are measures needed to manage the risks and protect consumers? Does the Government need to be more involved in e.g. the balance of generation? How can the UK help establish long and short–term open international product and financial markets for gas and electricity? If there is a need for market instruments or regulation in this area how will it fit in with the instruments proposed for carbon saving?

Question 7 covers the interaction between Ofgem and Government.

a) Does the operation of our system of economic regulation (for electricity and on and offshore supplies) need to be adjusted in the light of greater concerns about security of supply and rising energy prices?

Government clearly has a responsibility in relation to security of supply, reflecting both shared duties with Ofgem and real politics. The real issue is the need for greater clarity on what the market can deliver guided by the current regulatory system and what, if anything Government should do. This requires clarifying the Government's role in helping markets to work better, without undermining them, - e.g. market abuse, offshore infrastructure, the offshore code and what more the Government should do e.g. planning consents, infrastructure planning, setting standards. It is for the Government to establish the policy objectives and to introduce an appropriate framework of measures to support what the market can deliver.

b) Will we continue to have adequate margins of generating capacity, gas supplies and infrastructure? Need to link security of supply with questions (in XVI) on transforming supply networks to encompass "new energy" sources and energy services.

The debate about adequate margins relates to whether supply should be guaranteed independent from price and cost (most likely requiring Government intervention) or whether the market is allowed to assess some risks as too remote or the cost of meeting them too high. The former guarantees supply (but at a cost) the latter gives greater guarantees on cost but accepts that in extreme circumstances supply can not be guaranteed. The question of who should set the framework for acceptable risk, Government or Regulator is discussed in Question 7.

Electricity generation capacity

Total electricity generating capacity has fluctuated between 60 and 70 GW since the early 1970s before increasing in the 1990s with the growth of CCGTs, to around 75GW in 1999. Maximum demand for 1999/2000 reached a new record high of 58 GW during December 1999, equivalent to 82½% of the capacity of the major power producers (78% of total capacity) a margin which (assuming generation is made available to the system) is more than adequate for system security. By comparison the margin between peak demand and capacity in California was less than 5%. The DTI energy model calculates capacity in a fixed relationship to demand (the key driver for extra capacity). So whilst it can not provide indications of changes in future capacity margin it does provide an indication of future generation requirements if constant capacity margin is to be maintained. Current analysis shows net capacity needs to grow by 4 GW between 2000 and 2020 in a low price scenario but that no net growth is needed in a high price scenario. The implications for fuel use are discussed in question 4 above.

The Department also makes use of NGC forward projections for England and Wales plant margins. Based on plant that has *already* received the necessary consents, NGC's most recent base scenario projects a plant margin of between 32.3% and 19.8% by 2007/8, depending on assumptions about plant closures. It is important to remember that a figure of total capacity over peak demand is not a true measure of operational margin. Allowance has to be made for capacity not being available for maintenance and repair. Therefore a margin of around 20may be considered appropriate for planning margin.

Issues surrounding building new generation capacity are discussed at (c) below. Any wide ranging consideration of future generation capacity has to consider: the security and diversity implications of a largely gas fired generation capacity (question 4); the extent to which renewables could fill the capacity gap (question 10); and the implication of nuclear new build and extensions (question 13) .

<u>Gas infrastructure</u>

Offshore

A PILOT study in November 2000 into the long term potential of the offshore gas industry in the UK noted that some 45% of the field related pipelines are over 15 years old but typical design life is 25-30 years and it is anticipated that life spans could be extended by 50% or more.

The long-term need to address future import capacity is addressed in question 2.

Offshore – onshore

Auctions of entry capacity (from the offshore to onshore network) are a fundamental part of the New Gas Trading Arrangements (NGTA). Capacity is a scarce resource and auctions are considered to be an economically efficient way of distributing it. As with other parts of the NGTA, auctions are the responsibility of Ofgem. Auctions were initially designed to address the short term access but also provide price signals about where shippers want to land gas and therefore where Transco may need to invest in additional capacity.

Ofgem are proposing a new long-term investment regime as part of Transco's next price control, to commence in 2002. This is under discussion between Ofgem and Transco.

Onshore

The taskforce established to look at extending the gas network is described in question 13 and further details on Gas infrastructure are given at annex 6

<u>Gas (fuel) supplies</u>

The UK becomes a net importer of gas around 2005/6 and by 2020 could be importing up to 90% of demand. Worldwide reserves of gas are vast, but issues exist about: securing long-term supplies in liberalised markets with and without long-term contracts; the size and liquidity of any future gas market; and whether the suppliers of gas pose any security of supply issues. All covered in more detail in question 2 above, or below. Looking ahead, if the planned supported development continues, renewables will become increasingly important in the fuel mix.

Renewables increase diversity and it can be argued, by reducing the reliance on imported gas, security.

Infrastructure issues and "new" energy

Future generation and infrastructure requirements will be driven by energy demand and hence the required supply. Therefore demand side factors such as improvements in energy efficient and the growth of energy services (discussed in question 10 and 16 respectively) and generic supply issues such as embedded generation (question 16) and network connections are vital to assessing future needs and how the market will respond. This in turn will help identify the future need for electricity interconnectors, which may be seen as increasingly important as a counter to a growing reliance on gas or should renewables not grow as many hope. The question of the impact of an increase in renewables on security is less straight forward given the debate about intermittency and is an area requiring further work.

c) How do we ensure that market mechanisms send the right signals for securing necessary investment in new electricity generation, gas supplies, and infrastructure?

Electricity Generation

Electricity cannot currently be stored nor extra generation capacity quickly provided therefore when the supply/demand balance is tight prices rise. This provides two signals, one long-term for companies to invest in new generation plant and secondly a short-term signal to consumers to reduce demand. However, currently, a large proportion of demand, the domestic sector and a sizeable part of the service sector, is not short-term price responsive and it is argued by some that without a proper price signal at the domestic level fully competitive markets cannot work. Italy is currently undertaking a programme to install half-hourly meters in all domestic homes. Such a development could allow frequent price changes to be levied on domestic consumers. In the UK that would be unacceptable as it would raise the price of electricity substantially when demand was high (cold winter evenings etc) and the less well off would not be able to afford adequate heating. The solution may be to utilise usage information to reduce demand through financial incentives or more sophisticated tariffs rather than penalties. A fuller discussion of investment in generation capacity in liberalised markets is given above at 4f, with the use of price signals for the domestic market covered in Annex 6 whilst smart metering is covered in more detail in question 16.

Peak demand has to be met, so unless it can be reduced through load management, extra generation capacity is needed to meet a growing peak. Under the pool trading arrangements an entrant able to arrange back-to-back contracts through CfD together with a long-term fuel supply contract, would be in a much better position to attract debt–finance to build new capacity. Under NETA price is intended to signal the need for investment so by replacing a variable price with a known price for a given period, forward contracts give generators *some* insurance and incentive to undertake long-term investments that could avoid California type problems. However, without the development of long-term open markets it can be argued that new capacity will not be built unless long-term contracts can be achieved (although examples exist to prove otherwise such as Enron's bond financed plant construction).

In a competitive generation market the marginal plant sets the price (this will normally be the case although there is a risk that as demand begins to approach the level of available supply companies will attempt to recover returns to capital resulting in volatile pricing during the winter peak). If prices are too low or too variable there will be little incentive to construct new plant, especially plant only needed to meet peak demand (such assets risk becoming stranded or operating at below optimal price for most of the year when demand and so prices are low). So whilst the market gives clear short term signals on the supply side, a longer term signal may be required to establish the firm need and market opportunity for new plant. Ofgem's view is that the market, under NETA, will provide the necessary long term signals. If this market fails to develop the risk is of prolonged higher domestic prices, or even capacity shortfall and potential power shortages before necessary new investment is in place. Similar issues surrounding stranded assets and how price signals feed through to domestic consumers hold in consideration of gas and electricity infrastructure.

It is also worth noting that if the UK is importing electricity its cost could rise as a result of increased demand (especially at peak time) elsewhere in Europe. As a result the question of capacity needs to be consider at the EU level, although limited UK-EU interconnection restricts this effect.

The discussion above assumes that electricity cannot be stored, However, developments such as Regenysis could change that. If electricity was able to be stored easily, not only would that enhance the scope for sustainable renewable generation, but would allow more plants to run more efficiently at optimal output.

Gas supplies and infrastructure

These issues are discussed at (b) above, but again the market mechanism is price. Price rises will signal the need for both additional supplies, the cost of available gas will increase, and the need for new infrastructure, entry auction prices will rise. In a fully integrated markets gas costs could rise as a result of increased demand in the rest of the EU.

d) Is there a risk that market prices will be volatile or cyclical and are measures needed to manage the risks and protect consumers?

In theory, electricity prices tend – in the short run – to be volatile because of inelastic (indeed ultimately fixed) but shifting supply, inelastic but shifting demand coupled with a (critical) need for continuous supply and demand equilibrium, and the current uneconomic nature of storage technology. In order that companies can have sufficient certainty to invest in new assets, they will need to use or develop ways of managing the risks of short run price volatility.

Under NETA electricity is traded through a number of markets spanning from years to hours before real time. From three and a half hours before real time NGC takes actions in the Balancing Mechanism to keep the physical system in balance and the settlement arrangements then charge or credit participants taking into account the extent to which they met their contractual commitments and the costs of keeping the system in balance.

The early days of NETA saw some extreme ‘imbalance prices’ and consequently participants have sought ways of avoiding or offsetting the effects of being in imbalance. Although imbalance prices have been less volatile of late, unpredictable and inflexible generators (for example windpower and CHP) run a higher risk – individually - of facing the effect of imbalance prices.

There are a number of ways in which participants can manage risk, in particular exposure to imbalance prices. The main protection will be gained through bilaterally contracting for generation or supply, and using secondary markets and the power exchanges to fine tune positions approaching real time. Future developments in financial markets could increase the number of instruments available to participants to hedge risk.

Vertically integrated participants are able better to manage their exposure to imbalance prices by contracting internally. For unlicensed smaller generators, there are a few companies which are offering ‘consolidation’ services through which the consolidator will combine a portfolio of generators (most probably subject to different patterns of unpredictability) to smooth out the unpredictability of each component. A key area of concern is what impact NETA will have on small generators, many of which are renewables. Ofgem are undertaking a review of this issue based on evidence from the first two months of NETA. A report should be available August. A clearer picture will emerge then, but the following gives some background of how renewable generators are treated under NETA.

<u>Do all renewable generators have to secure individual supply contracts?</u>

As renewables generators are generally licence-exempt, they were never centrally dispatched under the Electricity Pool and are therefore not directly affected by its abolition. Just as under the old system, they need to secure a local outlet for their exported generation, normally via a supplier.

<u>Do embedded generators face the cost of NETA directly or indirectly?</u>

NETA is designed impose the costs of putting the system out of balance back onto those BSC parties which cause such imbalances. The vast majority of embedded generators are licence-exempt. This means that they do not have to become Parties to the Balancing and Settlement Code (BSC) and are therefore not directly exposed to imbalance prices (which are applied under the BSC). However, they are indirectly exposed through the contracts with their suppliers. If a supplier is put out of balance as result of its contract with an unlicensed generator, it is likely to pass through the cost of this imbalance to the generator by offering a lower price for its generation in future.

<u>Is there any support mechanism to counter intermittency or do they just face balancing costs?</u>

A number of CHP and renewables plant have unpredictable or inflexible output and might therefore be significantly (indirectly) exposed to imbalance prices. In view of this and HMG’s wider environmental policies, in advance of go-live, the NETA Programme developed ways in which licence-exempt generators would be able to reduce their exposure to imbalance by being able to consolidate the unpredictable part of their output with other such generators or with a supplier as negative demand. They would still be able to sell the predictable part of their output locally, thereby retaining the embedded benefits for that part.

For consolidation to work, it requires the existence of consolidators to co-ordinate the arrangements. Whilst a number of companies have announced their intention to provide such services (Enron, Concert Energy, Vattenfall, Yorkshire, Dynegy and Utility Link), it is not yet clear whether licence-exempt plant are using such services and if not, why not. This is something which Ofgem's Review of the impact of NETA on smaller generators will look into.

e) Does the Government need to be more involved in e.g. the balance of generation?

By setting a 10% renewables target and introducing the Renewables Obligation, the Government is in part determining the balance of generation. Whether it needs to be more involved depends on how it sees new market entrants (generally good for markets as they innovate) or new technologies establishing themselves in an open market. Equally any decision to support schemes has to consider who will take the risk (developers or electricity suppliers) and how capital will be raised. It may be enough, though unlikely - in the absence of financial signals, that a clear long-term signal from government of a commitment to a low carbon future is enough for the market to further develop renewable technologies and overcome structural barriers. However it may be of strategic, rather than economic importance to consider a long-term fuel mix (including he future role of both renewables, fuels other than gas, and nuclear) and import dependency. If so these are issues for the Government to tackle through appropriate incentives, not the market alone.

f) How can the UK help establish long and short–term open international product and financial markets for gas and electricity?

UK players have amassed considerable experience over the years in physical and financial trading of electricity and gas. The UK is regarded as a centre of expertise in trading and this is borne out by the fact that a number of traders now operate out of London, notably Enron and a number of US concerns but also EdF Trading. Electricity exchanges are now operating in a number of places in Europe, e.g. Frankfurt and Amsterdam as well as the long-running

Nordpool in Scandinavia. Gas trading hubs are being developed in northwest Europe, and UK traders are exerting considerable influence in the design and operation of these exchanges.

g) If there is a need for market instruments or regulation in this area how will it fit in with the instruments proposed for carbon saving?

The Renewables Obligation, and associated Renewables (Scotland) Obligation, will oblige all licensed electricity suppliers to supply a specified proportion of their supplies from renewable sourced electricity. This helps establish a market for renewables promoting their development and helps the government achieve its 2010 CO_2 emission reduction target. So government action or regulation can both stimulate investment and achieve environmental goals as such further extensions to the renewables target may be desirable. Equally it will remain desirable to keep prices for domestic consumers low to help address fuel poverty. The majority of the reduction in fuel poverty in recent years can be attributed to lower real energy prices.

VII In a regulated liberalised market what are Ofgem's and the Department's roles and responsibilities *for security of supply* in *relation to* a) *the* risk of *company failure* b) ensuring that there is sufficient capacity margins for electricity generation, gas supplies and infrastructure and c) ensuring the UK looks sufficiently far forward in time in relation to a) and b). How should we deal with the wider public policy objectives under our regulatory system?

Roles and responsibilities – the general framework

The Secretary of State for Trade and Industry is responsible for setting the overall regulatory framework for the supply of electricity and gas. A key part of this framework is set out in the Electricity Act 1989 and the Gas Act 1986. These provide that:

> In carrying out their functions the Secretary of State and Ofgem shall have regard to the need to secure that all reasonable demands in Great Britain for electricity and (so far as it is economical to do so) for gas are met.

Thus under the legislation, on a strict legal interpretation, the duties of the Secretary of State and Ofgem relating to security of supply apply only to the extent that they exercise particular functions. The main functions relate to licensing. The Secretary of State lays down Standard Licence conditions which apply to all classes of licensees. Power to modify these rests with Ofgem with reference to the Competition Commission if the company and Ofgem cannot agree. The Secretary of State has a power to veto any modifications. Enforcement of licence conditions is for Ofgem.

The two main means of influencing the activities of gas and electricity companies are by way of standards or by schemes for incentivising behaviour. Standards are often included in Standard Licence conditions. Schemes for incentivising behaviour have become increasingly important and are generally implemented by modifying licence conditions or by amending relevant industry codes, which have to be agreed with Ofgem. Ofgem therefore exercises key powers and in practice has the main expertise.

The Secretary of State has responsibility for off shore regulation of gas and for strategic international issues including European policy and hence for security of supply issues falling within these areas. There are also provisions under HSE's Gas Safety (Management) Regulations 1996 and under the Electricity Supply Regulations 1988 which provide for maintaining security of supply.

Roles and responsibilities – company failure and capacity margins

Company failure

Standard gas licence conditions enable Ofgem to nominate a supplier of last resort to supply gas to customers of an insolvent supplier. This ensures continuity of supply to the consumer and provides a legal basis for the supplier to require payment. It is intended to put in place analogous Standard licence conditions for electricity.

Capacity margins – short term

Electricity

Following the introduction of NETA there are no longer any security standards relating to generating capacity. NETA however provides incentives for short notice demand and supply flexibility including incentives for generators to maintain spare capacity and to make this capacity available if supply is tight. DTI and Ofgem developed NETA jointly but Ofgem had responsibility for the day to day management and implementation of the project**.**

Standard Licence conditions require distribution and transmission companies to plan and develop their infrastructure systems to meet certain minimum standards. There are also guaranteed standards of service for individual customers and overall standards for all customers applicable to distribution companies determined by Ofgem. Ofgem will shortly be consulting on new transmission access and pricing arrangements in order to ensure that the value of transmission access is efficiently signalled.

Gas

There are no formal security standards relating to gas supplies for shippers (i.e. wholesale supplies of gas into the National Transmission System (NTS). Shippers source their supplies mainly from UKCS production but when supplies are tight they also rely on the UK-Belgium interconnector and Norway. The Department has general responsibility for continuity of off shore supplies and specific regulatory responsibility for third party access. Stocks of processed gas have an important role to play in maintaining security of supply and these fall within Ofgem's responsibility.

The Standard Licence conditions for Public Gas Transporters require licensees to plan and develop their pipeline infrastructure systems to meet certain minimum standards. Ofgem agreed New Gas Trading Arrangements (NGTA) which were introduced in October 1999. These provide for auctioning of short term entry capacity into the NTS and seek to incentivise the best use of existing capacity.

Capacity margins - long term

Electricity

NETA was developed with the intention of providing, insofar as it is possible before transmission access arrangements are in place, short and long term signals for plant availability and investment. It is too early to say anything about the effectiveness of longer term investment signals but - as indicated above under short term capacity margins - there are currently signals which have encouraged short notice generation/demand flexibility.

Gas

As the output of the UKCS runs down the availability of gas supplies will depend critically on imports of gas. The issues surrounding this and attracting new investment to the UKCS are covered in the replies to Questions II and III.

Ofgem is currently developing proposals for long-term signals and incentives in transmission capacity on the NTS. The objective of these proposals is to ensure that Transco undertakes an efficient level of investment in the NTS over the longer term and at the same time provide shippers with access to longer term capacity rights.

How should we deal with wider public policy objectives?

The public looks to government as well as Ofgem to ensure that the national gas and electricity supply systems are very reliable and in practice the relevant functions are shared between the

Department and Ofgem. The events in California and last year's fuel crisis have underlined the importance of security of supply issues.

Innovative schemes for incentivising behaviour being developed by Ofgem are playing an increasingly important role in relation to security of supply. Their principal objectives are to increase efficiency, tackle distortions to competition and promote timely and efficient investment. In securing these objectives they should enhance security of supply. Their effectiveness – in terms of impact on investment signals – will require monitoring and consideration.

Some Member States are arguing that further liberalisation will threaten energy security. UK experience has been that competitive markets have helped the Government work towards its wider social, environmental and security of supply objectives and that instruments available to the Government such as legislation, regulation, taxation and partnerships are most effective when working with the grain of the market rather than against it. Therefore, from the UK's perspective open markets will be crucial for securing our future supplies at competitive prices as we become increasingly dependent on imports. This will be particularly important in the context of the Commission's Green Paper on Energy Security of Supply. A fuller analysis of the ways in which energy markets can be used to deliver social, environmental and security of supply objectives in the UK up to 2000 is described in "Social, Environmental and Security of Supply Policies in a Competitive Energy Market – DTI publication May 2001"

Against this background of interlinked responsibilities, reliance on innovative schemes and difficult trade-offs, close working relations will be required between the relevant authorities and companies. For this reason the Government and Ofgem have set up a joint mechanism to monitor security of supply in close association with the NGC and Transco. This will need to be tied into the Commission's recent draft proposal that Member States should designate a body to monitor security of supply.

The Environment

VIII What is the longer term need, in the UK, for green house gas savings? What targets should we be aiming for beyond 2010 and what position should we adopt on the RCEP's proposals? What are implications of such targets for various sectors of the economy? What kind of step change is needed against past trends? This will need to take account of our best view of the implications of global warming and the prospects for global agreement. The UK needs to be part of a global effort.

a) What is the longer term need, in the UK, for green house gas savings?

"Need" can be interpreted in a number of ways. There is clear evidence emerging from sources such as the IPCC of the global impact of climate change. The IPCC Working Group I concluded in January 2001, that global temperatures rose by around 0.6C over the 20th century but by 2100 they could be 1.4 – 5.8 C above 1990 levels. Over the same time scale sea levels are projected to rise by 0.09 to 0.88 meters. The impact of such changes will vary around the world, but likely changes include: increased flooding (including the loss of small island states); drinking water shortages; failing crop yields and increased disease levels. Rising temperatures could have some benefits including increased water availability in South East Asia and reduced winter mortality in mid and high latitudes, but globally these are outweighed by the adverse implications. Equally although the risk of large scale changes such as melting ice sheets are currently considered small, the likelihood of such risks is expected to increase with the rate, magnitude and duration of climate change.

Global events will affect the UK. Average temperatures have risen in the UK: 4 of the 5 warmest years in the past 340 were experienced in the 1990's. Perhaps the biggest impact of climate change on the UK will come from rising sea levels and coastal erosion (including high quality agricultural land) and increased flooding. And whilst there may be some benefits, such as increased agricultural yields in some areas and fewer winter deaths, the overall increased frequency of floods and droughts and risk of new diseases to the UK (e.g. malaria) mean the UK will not escape the impact of climate change and the need to act.

One result of the increased evidence on climate change has been the start of global action to address the issue. As a signatory to the UN Framework Convention on Climate Change, the

UK was committed to aim to reduce greenhouse gas (GHG) emissions to 1990 levels by 2000. The UK was one of a few countries to achieve this aim. Equally the UK has a target under the Kyoto Protocol to reduce GHG emissions to 12.5% below 1990 levels by 2008-20012. Again current projections show the UK is on line to achieve this reduction and is on course to meet the Government's own domestic goal of a 20% reduction in CO_2 by 2010 with the Climate Change Programme (CCP) playing a major part. Future worldwide targets are unknown, but likely, so the UK has a need to reduce emissions as part of the global effort to reduce GHG emissions. At present, there is considerable uncertainty over the international negotiations on climate change, given recent Bush Administration announcements.

In considering future CO_2 reductions it is helpful to consider current emissions by source and how these have changed over the past 10 years. These data are given in Table 8.1 below. Although, the impact of energy production and use on the environment goes much wider than CO_2 emissions and there are a range of environmental factors to be taken into account in relation to specific energy technologies.

Table 8.1: CO_2 emissions by source by IPCC definition

Million tonnes of carbon

	1990	**1995**	**1998**	**1999**	**2000 prov**
Power stations	54.1	44.1	40.6	38.5	41.9
Domestic	21.6	21.8	23.3	23.3	23.5
Commercial and Public service; land use change and forestry	14.3	13.7	13.6	13.2	13.3
Industrial combustion	37.7	38.3	38.8	38.2	37.0
Transport	31.8	32.2	33.5	33.2	33.3
Other sectors[1]	4.9	3.7	3.0	3.1	3.1
Total	164.4	153.7	152.8	149.4	152.1

(1) Includes waste, fugitive emissions from fuels.
Note total for 1990 is different from that shown in table 8.2 as a result of a revision to land use change emissions in the data provided by National Environmental Technology Centre.

b) What targets should we be aiming for beyond 2010 and what position should we adopt on the RCEP's proposals?

The Royal Commission on Environmental Pollution (RCEP) published, in June 2000, a report[8] on the long-term challenges for UK energy and environmental policy posed by climate change. One key recommendation is the following:

[8] Energy – the Changing Climate, RCEP, June 2000, Cm 4749

> *The Government should now adopt a strategy which puts the UK on a path to reducing carbon dioxide emissions by some 60% from current*[9] *levels by about 2050. This would be in line with a global agreement based on contraction and convergence which set an upper limit for the carbon dioxide concentration in the atmosphere of some 550 ppmv and a convergence date of 2050.*

The RCEP recommends that the Government should press for a future global climate agreement on a contraction and convergence approach[10], allowing also for emissions trading. It selects one path for achieving stabilisation of CO_2 concentrations in the atmosphere at 550ppm that implies a convergence date of 2050. Many other paths to stabilisation at this level could be taken.

The Government has recognised that action now will lay the foundation for the more fundamental changes that will be needed in years to come.[11] The 20% goal provides a signal of the direction in which policy is moving, but no commitment to any further figure for longer-term reduction has been made. Nor has the Government agreed the contraction and convergence approach.

The Government will need to reply formally to the RCEP report and clearly it will need to be a joint response as many of the RCEP proposals directly relate to areas of DTI policy such as renewables as well as DEFRA policy leads. On going work such as the PIU's studies on Resource Productivity and the Energy Policy Review mean that at this stage views on many of the proposals are not formed. Future targets will need to be part of a global effort to reduce GHG emissions; the UK is only responsible for around 2% of emissions. Whilst there is scope and potential benefit (as discussed in question 9 below) for the UK to take a lead in addressing global change, this has to be balanced against competitiveness issues, as well as not weakening the UK's hand in global negotiations of (probable) mandatory future targets.

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[9] For "current" the RCEP report uses 1997 levels of emissions.

[10] A contraction and convergence approach means that over the coming decades each country's emission allocation would gradually shift from its current level towards a level set on a uniform per capita basis. The allocations of developed countries would fall, year by year, while those of developing countries would rise, until all had an entitlement to emit an equal quantity of greenhouse gases per head *(convergence)*. From then on the entitlements of all countries would decline at the same rate *(contraction)*.

[11] Climate Change: the UK Programme, DETR, November 2000, Cm 4913

c) What are implications of such targets for various sectors of the economy?

In order to help inform the Government's response to the RCEP recommendations, an inter-department analysts group (IAG) has been established. A preliminary report from the group was presented to the DTI's Energy Advisory Panel in April 2001. It is important to be clear from the outset that any consideration of prospects over a 50 year timescale must be very uncertain and also that at this stage much of the group's work is incomplete. However, the preliminary findings are of some use in beginning to consider some of the environmental questions raised.

To determine the impact of any future policy on sectors it is necessary to try and establish a baseline of how the future may develop. The IAG has done this by taking DTI energy projections to 2010 or 2020 as a starting point and projecting these forward on the basis of a range of basic assumptions for continued carbon intensity[12] improvement, but also including the impact of the closure of existing nuclear generation plant, constraints to reflect limits on fuel switching potential and allowance for the impact of the CCP. Various other baselines have been developed using scenarios to represent alternative business as usual worlds. A summary of this work is given at Annex 8.

At this stage costings have not been produced on the impact on specific sectors of adapting to large-scale CO_2 reduction targets. But the IAG analysis does provide an insight to the relative size of future tasks against what has been achieved thus far. The first table below shows CO_2 emissions, whilst the second table shows the annual changes in carbon intensity achieved or required – to meet an illustrative 40% reduction, or the 60% proposed by the RCEP.

These figures illustrate the fact that a future task of achieving large (60%) reductions in greenhouse gas emissions would go beyond anything so far achieved. The position may be relatively better for industry but it is questionable how much scope remains for reductions in energy use. Further work on potential energy efficiency improvement is underway, but as the changes to 2010 reflect the CCP (and so the climate change levy) extra savings may be hard to

[12] Ratio of carbon emissions to final energy demand.

realise. It is clear that if significant carbon savings are to be realised then significant structural, behavioural and supply changes will be required.

Table 8.2 CO_2 emissions by sector (MtC)

	1990	2010 (ex CCP)	2010 (inc. CCP)	2050 to meet a 40% reduction	2050 to meet a 60% reduction
Domestic	42.6	38.8	33.6	24.8	14.0
Transport	37.3	45.4	38.5	21.7	13.9
Industry	49.8	37.8	32.7	29.0	14.9
Services	23.3	20.8	19.1	13.6	7.5
Total (Inc other and land use change)	168	153.8	136.1	100.8	62.0

Assumptions:

1) Baseline includes nuclear closures as planned
2) RCEP and 40% targets based on an "equal pain" principle of equi-proportionate reductions across the four sectors to meet the required target in 2050.
3) "Other" emissions (inc. military, exports, marine bunkers and other) constant at 7.3 MtC after 2020 for sectoral analysis
4) Land use changes assumed constant at 4.4 MtC after 2020
5) RCEP and 40% target are effective 64.5% and 41.77% cuts per sector, respectively.

Table 8.3 Carbon intensity change per annum

	Past Inc. dash for gas	Past ex DFG and fuel switching	2000 – 2010, ex CCP, ex DFG	2000 – 2010, Inc. CCP, ex DFG	Req. from 2010 to meet a 40% reduction	Req. from 2010 to meet a 60% reduction
Domestic	-4.2	-2.94	-2.96	-3.94	-3.24	-4.79
Transport	-1.23	-1.13	-1.72	-3.06	-3.23	-4.34
Industry	-3.7	-3.01	-1.58	-2.87	-1.9	-3.65
Services	-2.67	-1.83	-2.32	-2.98	-3.42	-5.06
Tot (Inc. other)	-2.98	-2.09	-1.84	-2.86	-3.04	-4.40

d) What kind of step change is needed against past trends?

The rate of carbon intensity improvement required to hit a 60% CO_2 reduction target by 2050 is 4.4% a year starting in 2010. Such a reduction is:

- Greater than the improvement expected over the period 2000-2010 (2.9% a year) which includes the impact of the CCP; and

- greater than the historic trend (3.0% a year 1970-2000).

Depending on assumption made for a “business as usual” baseline projection of CO_2, the projected gap against a 60% reduction target in 2050 ranges from 40-103 MtC. However, figures towards the lower end of this range assume that the historic trend improvement can be continued. This may be unlikely as “business as usual” since the easiest energy efficiency improvements are likely to have been made first. Additionally, the historic trend reflects switching into gas in generation, the scope for which will not be as significant in future.

IX What opportunities do other countries in the EU and elsewhere have to reduce their carbon emissions? How are we placed in relation to the EU as a whole (and other competitors)? What is expected to happen on EU ratification of the Kyoto Protocol and the EU's burden sharing arrangements? What is our share of future EU targets likely to be and what is likely to be the effect of the UK over-achieving its targets? To what extent, and at what cost, should we assume that the UK will be able to meet part of its targets from international emissions trading arrangements and the other Kyoto mechanisms?

a) What opportunities do other countries in the EU and elsewhere have to reduce their carbon emissions and how are we placed in relation to the EU as a whole (and other competitors)?

In the same way that the RCEP path to 550 ppmv implies a 60% reduction in the UK's current CO_2 emissions, it is possible to estimate[13] the implied reductions for other developed countries in 2050. These are summarised in chart 1. Key points from this are that:

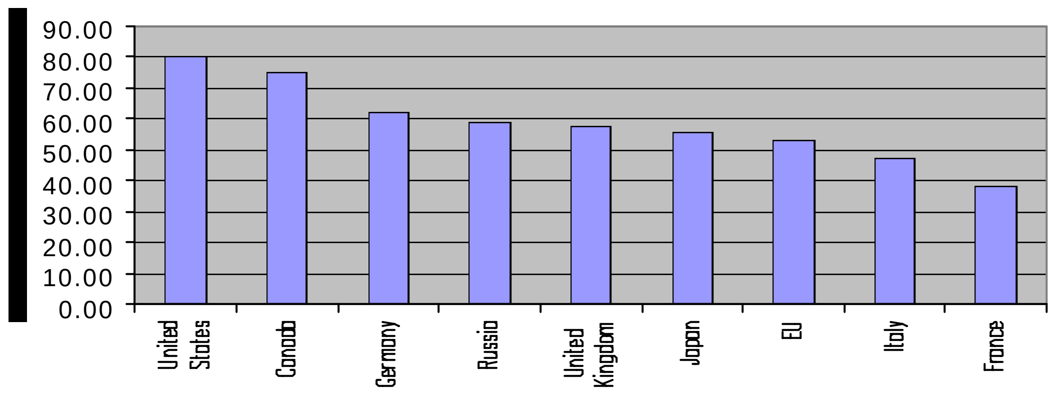
- the UK would need to reduce emissions by 57%, the US by 80%, and the EU by 53%.
- in terms of scale of reduction, in percentage terms the UK reduction is mid-table in both EU[14] and G8 rankings.
- during the period from 1990 to 1998 the UK has improved its performance relative to the EU and G8.

In comparative terms it would seem, therefore, that the UK is broadly mid-ranked in terms of scale of emission reduction that would be required. Of course, in international competitiveness terms what matters is not just the scale of reduction required but also the availability and cost of measures to achieve the target. Currently very little can be said about cost for the UK, let alone likely costs for other countries.

[13] All these estimates are from a base year of emissions in 1998.

[14] The UK (57% reduction) has more to do than Portugal (27%), Sweden (35%), France (38%), Spain (39%), Italy (47%), Austria (48%) and Greece (50%); less than Ireland (62%), Germany (62%), Denmark (63%), Netherlands (64%), Finland (66%), Belgium (67%), Luxembourg (76%).

Chart 1: Reductions Required of CO2 in 2050 Under 550ppmv Scenario (1998 base Year)



However, work within the IAG is currently attempting to produce broad-brush estimates of the supply side costs of low carbon futures as illustrated by the 4 RECP scenarios. Costs would be derived for the non-fossil fuel energy produced under the 4 scenarios by applying a range of indicative prices (in p/kWh) to the output from each technology converted from GW in the RCEP report (Table E5) to TWh. These costs might be compared to the cost of producing the same amount of output from gas fired electricity generation to produce a gross marginal annual cost to the economy of choosing the renewable package compared to a gas fired package.

Costs of system or grid changes and energy efficiency/demand side costs would be additional. Such estimates will be entirely dependent on price assumptions for developing technologies and gas. Tables showing the RCEP scenarios and price assumptions used are in Annex 9.

b) What is expected to happen on EU ratification of the Kyoto Protocol and the EU's burden sharing arrangements?

There is considerable uncertainty over the Kyoto Protocol and, in particular, the prospects for its entry into force, following announcements from the Bush Administration that it does not intend to ratify it. The US is currently undertaking a review of its energy and climate change policy and it is not currently clear whether there will be sufficient international backing for the Protocol for it to enter into force. The EU, including the UK, is committed to ratifying the Protocol with the aim of it coming into force in 2002.

c) What is our share of future EU targets likely to be and what is likely to be the effect of the UK over-achieving its targets?

At the international level, the role of the UK in the first commitment period will be determined by our performance relative to our Kyoto target. The CCP shows the UK achieving emissions reduction of 23% on 1990 levels by 2010, compared with the target of 12.5%. If this were achieved, it would leave the UK with around 22MtC per annum to sell or bank in the Kyoto commitment period. The decision on what to do with this excess would depend on the factors such as limits on sales, expected future costs of permits (likely to be higher) and wider availability of permits. But the UK could be constrained in the use of its excess, depending on the way in which the EU burden-sharing arrangements finally operate. The UK and Germany could be the only EU countries to meet their Kyoto commitments with significant surpluses, but there is likely to be political pressure for these excess achievements to be assigned across the EU to help meet the total EU target. If so what is the pay back for the UK?

The EU's and UK's targets under the Kyoto Protocol relate to the period 2008-2012. The Protocol plans for future targets to be set for further commitment periods beyond 2012. However, these discussions have not yet started. The position on future EU targets and the UK's share is therefore unclear, especially given the current uncertainties about the Kyoto Protocol and whether it will enter into force.

d) To what extent, and at what cost, should we assume that the UK will be able to meet part of its targets from international emissions trading arrangements and the other Kyoto mechanisms?

One of the key innovations of the Kyoto Protocol in 1997 is the role it gives to market mechanisms in achieving emissions reductions. These market mechanisms **(**described in full in Annex 9) are international emissions trading, the Clean Development Mechanism and Joint Implementation.

The Kyoto mechanisms do not in themselves deliver emissions reductions. Instead, they create a market in emissions reductions, which enables those reductions to be achieved at least cost, and which provides an ongoing incentive to develop new and cost-effective ways of reducing emissions. Economic models provide some analyses of how the mechanisms can reduce costs. For example the wider inclusion of the 6 greenhouse gases, rather than just CO_2 could significantly reduce costs (some models suggest by up to 50% but the exact amount depends on the target level and timing). Trading is another measure to reduce costs. Under trading scenarios, costs to Annex I countries could fall to 60–90 % of levels in a non-trading scenario (depending on the scope of trading). Overall, if rules are flexible and more options are considered to control emissions, the lower the costs.

Short-term use of mechanisms

In the initial period (up to 2012) the UK will not need to use the mechanisms to achieve its target. Rather as mentioned above, and confirmed by a Dames & Moore project carried for the DEFRA, the UK will/could be a seller of permits in the first agreement period. The UK's marginal cost of abatement being less than the average across the whole of Annex I countries. The project also considers the implications of some of the constraints on the UK's position in 2010. Relative to a base case of Annex B trading only, with no restrictions but no CDM, the report finds that:

- A "**concrete ceiling**" restricting use of the mechanisms to 50% of effort would **reduce** UK sales by **40%**;
- The existence of the **CDM** with relatively **high** transactions costs would **reduce** sales by **5%**;
- The existence of the **CDM** with relatively **low** transactions costs would **reduce** sales by **50%**;

Longer-term use of mechanisms

Looking further ahead, the UK's position is likely to switch from that of being a seller a buyer. In the majority of scenarios where the Kyoto targets are maintained indefinitely into the future, the UK starts as a moderate seller in 2010, becomes a moderate buyer in 2020 and then a significant buyer in 2030. As such the existence of a restriction such as the "concrete ceiling" adds up to 20% to the costs faced by the UK.

Further information on the potential for Kyoto type mechanisms to reduce long-term mitigation costs is given in The Energy Journal Special Edition: The Costs of the Kyoto Protocol. Most models stopped in around 2020, but 3 gave specific estimates for permit costs for the EU in

2050. These models showed the cost of permits in a global trade scenario could be between 2 and 5 times lower than with just Annex I trading and up to 10 times lower than with no trade.

The main uncertainty in assessing the future impact of the mechanisms is the question of developing country targets. Once the CDM process beds in, and transactions costs are reduced, emissions reduction projects in the developing world could be expected to provide an increasingly significant source of credits to be used in compliance with caps. For example, the Dames and Moore project for DEFRA shows CDM sales from China increasing from 190MtC in 2010 (less than half the sales from the FSU) to over 900MtC in 2030 in one fairly central scenario).

But the role of the CDM in the longer term is crucially dependent on the wider role of the developing countries in the Kyoto process. With projections showing developing country emissions over-taking those from the developed world in the next quarter of a century, there will be an increasing imperative to limit the growth in these emissions and eventually to reduce them. The impact the mechanisms could have on the permit trading price is discussed at Annex 9.

X What, realistically, is the scope and cost of low carbon and energy efficiency options, including transport options, that may exist to achieve large scale carbon savings in the UK? This will need to assess the prospective impact of renewables and energy efficiency programmes as well as other relevant emerging technologies such as carbon sequestration, low emission fuels technologies, hydrogen, and fuel cells, alongside the prospective contribution of extensions of nuclear capacity and new build. It will also need to cover transport policy.

Overall potential

Achieving large-scale carbon emission reductions requires either, or more probably a combination of, fundamental change to the current generation mix; widespread application of carbon capture and storage technology applied to existing and new fossil fuel plants; improvements in the efficiency of energy use. However, by way a quick summary, the options so far consider by the IAG could be broadly categorise as follows at the time of writing other options such as wave and tidal are still to be studied.

Proven – commercially viable now

Onshore wind

Hybrid vehicles

Waste generation

Landfill gas

Biomass

Energy efficiency measures

Existing Hydro

Potential in medium term (including demonstration projects in existence)

Off shore wind

New nuclear build

Carbon capture and storage

Energy crops for electricity generation

Fuel cells (inc. vehicles)

PV

Electricity storage

Bio-diesel

New Hydro

Of course it is not a rigid classification and specific technologies could develop more quickly especially where government funding is being directed to promote new technologies especially energy crops, offshore wind and PV. Examples of this work include for:

- Offshore wind £39 million from the Climate change Levy for capital grants and £10 million from the National Lottery New Opportunities Fund
- Solar PV £10 million for large scale demonstration projects and £4.4 million to develop domestic solar PV via two calls for proposals from industry the first to cover 166 houses was announced in May 2000, the second for an additional 300 in May 2001. These are seen as the first steps towards a major PV roofs programme in line with those of Germany and Japan.
- Energy crops £33 million from the National Lottery new Opportunities Fund (in conjunction with biomass) and £29 million over 7 years from MAFF.

In addition the Prime Minister announced £100 million of funding for renewables on 6 March. The allocation of this funding is being determined by the PIU – Resource Productivity study, but it is likely that substantial funding will go towards especially energy crops, offshore wind and PV.

As well as financial support in March it was announced that green energy projects proposed under the NFFO but have failed to obtain planning permission could be relocated without the developer losing the benefit of their NFFO contract. This support coupled with the new Renewables Obligation should advance the development of renewables by stimulating both demand and supply. Future support could see renewable technologies, especially offshore wind playing an increasingly important role in widescale electricity generation.

An outline position of the potential for groups of options is given below with more detail in Annex 10.

Renewables

The potential for renewables is huge. The key questions are how much can and will be developed, how quickly and at what cost. The Government is introducing a range of very ambitious policy instruments aimed at bringing forward renewables. These are described at Annex 15. Offshore wind alone offers vast potential, and one project has been commissioned in the UK with a further 18 proposed. Advancements in installation methods and demonstration plants could prove the technology, reduce costs and increase deployment.

Some renewable options are already commercially viable such as onshore wind, landfill gas, biomass, hydro and waste generation. Others (energy crops, PV's) are in development stages but have potential if barriers can be overcome and cost proven competitive. Other technologies such as tidal and wave have not been studied in depth as part of the IAG work, but need to included in future work as they have the potential to make an important contribution.

The development of renewable generation options rests with a clear commitment to a long-term low carbon future, institutional barriers (planning, public perception, grid, land use etc) being overcome and technology improvements reducing costs. As part of government's clear support for renewables consideration is being given to planning barriers, these are discussed in question 16e. There currently is concern at the impact of NETA on smallscale (often renewable) generators. This is discussed in question 6d above.

Estimates of costs looking towards 2050 (in practise more closely responding to a 2025-2030 cost) are almost entirely speculative, not only in terms of likely development of the option but also the future development of gas prices (probably the main competing fuel). Both are unknown, but using informed estimates the cost per tonne of carbon abated (referred to as carbon cost (£/tC) for ease) for renewable options in 2050 against a gas generation cost of 2.9[15] p/kWh could be around -£59 to £93 for onshore wind, -£57 to £58 for offshore wind and £16 to £142 for energy crops. For other options preliminary cost estimates are not yet available. However, it is important to remember that looking so far ahead such costs can only be illustrative. The range of costs considered for renewable energy sources is presented at Annex 10, they are of course subject to great uncertainty and change and markets and technologies develop.

[15] The IAG considered a range of possible gas generation costs for 2050 ranging from 2.3 to 3.6 p/kWh, results in the paper are shown against a single figure of 2.9 p/kWh for ease. Precise future gas generation costs, like renewables costs are unknown.

Capture and storage

Carbon capture and storage (CS) has potential – with intensive capital investment - to save significant amounts of carbon. All the elements of the technology are proven and commercially deployed. Capture applied to a new CCGT plant with transport over 300 km and storage in geological aquifers adds around 0.7 p/kWh to the cost of gas at a carbon cost of around £84/tonne (against a gas price of 2.9 p/kWh). Public acceptability of CS is largely untested in the UK and concerns about reservoir integrity need to be.

CS can be used on any fossil fuel generating plant, but there are significant benefits in applying the technology to new plants (spreads capital cost over longer life; less efficiency reduction). CS could be used with viable clean coal generation to further reduce emissions for coal fired generation. There is vast storage potential in the UK alone. Storage estimates for offshore UK are: Deep aquifers, 2333 MtC; Oil fields, 713 MtC; Gas fields, 1329 MtC; onshore deep aquifer capacity of 67 MtC. By comparison in 1999 UK CO2 emissions were around 150 MtC.

New nuclear build (Nuclear is addressed fully in question 13)

There are obvious public concerns relating to new nuclear build. But its potential as a low carbon energy source should not be ignored. Based on current costs new nuclear build on current technology is probably not economic, a point emphasised in part by the lack of plans for new builds. However, looking towards 2050, cost reductions with new designs are possible. Assuming a price range of 2.6 p/kWh to 4.0 p/kWh for nuclear, the implied carbon cost is -£26 to £103 compared to a gas price of 2.9p/kW.

Energy efficiency

Energy efficiency occurs because replacement capital is generally more efficient than the corresponding equipment which has been in place for a number of years. This applies whether the equipment was the “standard” model installed by the majority, or the most energy efficient, installed only by the “innovators” at the leading edge of the distribution.

The rate of energy efficiency improvement can be increased in at least three ways. First, by narrowing the distribution – which is largely what past programmes and the proposed Climate Change Programme do. Second, by reducing the length of the current capital replacement cycle – although at some stage, this could increase overall energy consumption (e.g. for the manufacture of the capital) and so would become counter productive. Third, by accelerating the rate of innovation – the leading edge is "pulled faster" by RD&D programmes, while normal market mechanisms ensure that in the medium to longer term, the rest of the population in the distribution follows at the faster rate. In the longer term, because the scope for the first type is intrinsically limited by the length of the capital replacement cycle, and the second eventually has the problems indicated above, the third may offer the most opportunity for improvement.

Resource potential

The IAG is currently undertaking a detailed look at the potential for energy efficiency to provide carbon savings and the cost involved. This work is still in progress. However, based on analysis for the PIU Resource Productivity study a top-level assessment of potential is possible. This work suggests that energy efficiency has a technical potential to save 48.9 MtC per year and an economic potential to reduce emissions by 28 MtC. Achieving such potential remains problematic. This analysis excludes the transport sector.

The work uses the following definitions:

- *Technical potential.* All commercially available energy efficiency technologies.
- *Economic potential.* A sub-set of the technical potential that passes a cost-effectiveness condition. In this paper we use a payback time of less than 5 years in the domestic sector and less than 4 years in the business sectors.
- *Economic potential to 2010.* That part of the economic potential that can be realised short-term, taking account of capacity and capital constraints.

None of these allow for opportunities to be developed from further technical progress. They only reflect opportunities attached to currently available commercial technologies. Micro-CHP, for example, is excluded. Estimates of potential are shown in Table A10.1 below.

Table 10.1: Energy efficiency savings potential MtC

	Technical	Economic
Domestic sector[16]		
Loft insulation	1.4	1.4
Cavity wall insulation	2.6	2.6
Hot water cylinder insulation	0.3	0.3
Condensing boilers	5.3	5.3
Energy efficient lighting	1.1	1.1
Energy efficient appliances	3.6	3.6
Controls	0.4	0.4
Solid wall insulation	2.8	-
Double glazing (+low emissivity)	1.7	-
Draught proofing	0.3	-
Solar water heating	1.6	-
Ground source heat pump	5.3	-
High performance glazing	1.2	-
Sub-total	*27.5*	*14.7*
Commercial and service sector[17]		
Various costed measures	6.1	3.4
Office equipment	0.2	0.1
CHP[18]	0.9	0.9
Energy management	1.0	0.8
Sub-total	*8.2*	*5.1*
Industrial sector[19]		
Metals	3.2	2.2
Minerals and ceramics	1.8	1.3
Chemicals	1.9	1.1
Food and drink	0.8	0.7
Paper and textiles	2.4	1.4
Engineering and other	3.3	1.9
Sub-total	*13.2*	*8.6*
TOTAL	**48.9**	**28.4**
Climate Change Programme already scored:		
Domestic sector[20]		- *4.5 – 6.0*
Commercial and service sector[21]		- *0.4*
Industrial sector[22]		- *4.5*

[16] Domestic sector savings based on combination of sources, including BRE, ACE, EST and ECU, with judgement applied to provide estimates shown

[17] Source: background paper prepared for the RCEP, Fisher, Blyth, Collings, Boyle, Wilder, Henderson and Grubb, Prospects for energy saving and reducing demand for energy in the UK.

[18] Moss and Shorrock, BRE, have estimated a range of CHP savings in buildings from 0.9-3.4MtC.

[19] Source: background paper prepared for the RCEP, Fisher, Blyth, Collings, Boyle, Wilder, Henderson and Grubb, Prospects for energy saving and reducing demand for energy in the UK.

[20] Estimated impact of EEC, new HEES, appliance standards and labelling, new building regulations, improvements to community heating.

[21] Estimated impact of new building regulations.

TOTAL after CCP		**17.5 – 19.0**

The broad messages from Table 10.1 can be summarised:

- in the domestic sector, currently available technology can reduce carbon emissions by at least 50%. This does not allow for any comfort effect, but over the longer-run any such effect should be fairly small. A cost-effective potential of almost 15MtC represents around 30% of total domestic emissions.

- not all the economic potential identified above could be achieved within the next decade. The EST, for example, identifies potential 5.6MtC savings by 2010, above business as usual, based on its assessment of reasonable installation rates (see box next page).

- The CCP itself has identified savings of 4.5-6.0MtC by 2010 from the domestic sector. The scope to achieve more than that by 2010 therefore looks small.

- in the commercial and services sector, a cost effective potential around 5.1MtC represents around 24% of total sector emissions.

- Not all that potential could be achieved within the next decade. The background paper from which the technical potential estimates are drawn also indicates around 2.3MtC economic potential by 2010.

- Relatively little of this potential – perhaps 0.4MtC – is directly targeted by the CCP, though the climate change levy will also have an impact at the margin.

- In the industrial sector the figures relate to the potential for 2010. The technical potential represents around 30% of total industrial emissions.

- The economic potential of 8.6MtC represents around 20% of sectoral emissions;

- But a relatively large part of this potential has been targeted by the CCP, especially by the climate change agreements. The scope to produce much greater saving by 2010, at least, looks very limited.

[22] Estimated impact of climate change agreements, energy efficiency measures under Carbon Trust and emissions trading scheme.

XI What are the lifestyle implications and key opportunities for innovation and growth? Transport is likely to be one of the key sectors here. What are the advantages/disadvantages to the UK of being in the vanguard of emission reduction in commercial and in environmental terms?

a) What are the lifestyle implications and key opportunities for innovation and growth?

Innovation is all about using new technologies and doing business in new ways to provide better more customer orientated products, services and processes. It leads to greater customer/consumer choice, it contributes to economic growth and makes it easier to protect and enhance the environment whilst accommodating such growth through significantly improved resource productivity, clean technologies and more efficient and effective services. Innovation is therefore the engine of improved standards of living and quality of life.

By its very nature innovation has unpredictable impacts and it is difficult to speculate on how innovation will specifically lead to lifestyle changes and economic growth but examples might include wider choice of energy efficient modes of transport (mobility), greater flexibilities in home design and scope for energy self-sufficiency.

b) What are the advantages/disadvantages to the UK of being in the vanguard of emission reduction in commercial and in environmental terms?

Although the UK accounts for a small proportion of global emissions, the Government has made clear in the CCP that it expects the UK to take a leading role in the fight against climate change.

Even ignoring the carbon benefits, many of the measures in the CCP are designed to deliver wider environmental, social and economic benefits. But as we move beyond Kyoto it seems likely that we will increasingly have to look to measures that impose real costs and raise competitiveness concerns. Even in those circumstances there may be arguments for moving faster than others, depending on:

- the potential of early mover advantage. Whilst there may be benefits, addressing climate change is a global problem and it will not be possible for the UK to lead on every technology; and

- the scope to which use of the Kyoto flexible mechanisms gives a value to over-achievement of targets. Alternatively any surplus might be “banked” for future periods.

When deciding on whether there is early mover advantage a number of issues need to be considered:

- will early increased investment in new technologies and ways of doing business sufficiently differentiate UK business provision to confer competitive advantage or to create entirely new market opportunities; are the scale of the market opportunities commensurate with the risks;

- if other countries do not follow suit in reducing emissions will they secure sufficient short/medium term cost advantages that nullify the potential advantages of early investment; in this respect, even the already agreed UK Climate Change Programme contains opportunity costs which could disadvantage the UK if enough other countries do not play their anticipated full part;

- what direct subsidy, fiscal or tax incentives are available to businesses in other countries; are these relevant to the UK, do they risk being a diversion from market forces.

None of these questions can be answered effectively in the abstract. It is more a question of establishing a set of principles against which specific opportunities can be judged but on the basis that an aggressive, rather than defensive, approach to new business opportunities and growth will be the more successful over the long run.

Social Issues

XII The Government published its fuel poverty[23] strategy on 23 February. This assumes that prices will stay broadly constant or fall. What action should we take if they rise significantly whether as a result of market forces or environmental energy policy? How should we reconcile the need to reflect the external costs of the environment in fuel prices with protecting the fuel poor, given our commitment in the Fuel Poverty Strategy? Should we contemplate using the powers under the Utilities Act to cross subsidise the fuel poor? Should we consider new policies, for example, re-directing revenue from oil and gas royalties as a result of higher prices (or a new carbon tax) to subsidise low-income consumers, as suggested by the RCEP. We also need to consider how to incentivise investment on new network infrastructure to allow the fuel poor to have access to gas.

a) The Government published its fuel poverty strategy on 23 February. This assumes that prices will stay broadly constant or fall. What action should we take if they rise significantly whether as a result of market forces or environmental energy policy?

The role of lower energy prices to help alleviate fuel poverty is an important element of the Government's draft UK Fuel Poverty Strategy (described at Annex 12). Between 1996 and 1999 it is estimated that lower prices have taken around 0.7 million households, from a total of $5^1/_2$ million households, out of fuel poverty. These households will have been at the margin of fuel poverty. The "hard core" cases will need energy efficiency improvements as well. These severely fuel poor households, would suffer heavily in monetary terms from an increase in prices and long term solutions will need to reduce bills through lower prices and improved housing conditions.

Whilst the competitive market has secured substantially lower prices, with consequential benefits for the poor, there are still a number of consumers who could benefit from cheaper tariffs. Work needs to continue, through Ofgem and Energywatch, to ensure the poor are aware of the most advantageous tariffs and then encouraged to take them up.

[23] Fuel poverty is defined as a household that needs to spend in excess of 10% of household income in order to maintain a satisfactory heating regime

The draft consultation document on the Government's Fuel Poverty strategy does not try to forecast future energy prices. It sets out a range of possible price movements, against which the numbers of households in fuel poverty could be estimated. For domestic gas prices these price sensitivities are plus 10% to minus 10% in real terms between 1999 and 2010. For domestic electricity prices these are - plus 5% to minus 10%. Future prices are, however, uncertain, and will be affected by a number of factors, and it is therefore possible that price movements may fall outside of these ranges: but there is a general expectation that domestic prices, in the longer term, should broadly remain unchanged from recent prices in real terms.

The Government has taken the view that increased energy taxes introduced for environmental reasons - for example, the Climate Change Levy and full rate of Value Added Tax - should not be passed through to domestic consumers because of their adverse impact on the poor. Against this background, there are two areas of domestic pricing policy to consider: first, the position of households in relation to increased taxes on energy use; and, second, the position of households if market prices increase significantly. In both cases the Government would wish to consider how to protect the poor, either fully or partially, from the impact of any such price increase.

However, we need to be clear what the impact of increased market prices might be, and what level of increase might be acceptable before it is considered that action might be desirable to mitigate those price changes. Domestic prices have gone down in real terms by 14% for electricity and 12% for gas since 1997 (8% and 6% respectively in cash terms): and, taking account of income changes as well, the Family Expenditure Survey shows that the bottom 3 income percentiles spend on average 7% of their income on energy. While accepting that the average conceals a range, this implies that energy expenditure could increase - before many of the poorest members of society become technically fuel poor (at the 10% expenditure level). Such increases would, of course, be undesirable for wider social reasons: but the question needs to be asked as to what level of increase – if any – is acceptable and when might intervention be deemed necessary.

b) How should we reconcile the need to reflect the external costs of the environment in fuel prices with protecting the fuel poor, given our commitment in the Fuel Poverty Strategy?

If it is accepted that it is necessary to shield the fuel poor from the effects of rising energy prices while not so shielding people who can afford to pay (higher prices being beneficial overall in environmental terms), then the least distortive mechanism for doing this would need to be found.

c) Should we contemplate using the powers under the Utilities Act to cross subsidise the fuel poor?

There are several policies that could be used to reduce prices for the poor. The Government has powers under the Utilities Act 2000 to cross subsidise certain types of disadvantaged consumers, if such a group is being treated less favourably than other customers. The category of consumer to benefit would be defined in secondary legislation. The clause in the Utilities Act was intended to help prepayment meter customers, who had not benefited equitably from the competitive market, if this proved necessary. But it was recognised that this was a poor proxy for the fuel poor, so the definition was left flexible. One possible way that the scheme may work would be through adjusting transmission and distribution charges but this would mean that households not in the defined group would pay more for their gas and/or electricity. This approach could be used to cross subsidise poor consumers (i.e. those on benefits) and protect them from higher prices. It is however unlikely that the Utilities Act could be used for this purpose - new legislation would probably be needed.

However, use of such a cross subsidy power needs to be approached with caution for a number of reasons. Legislation would need to be passed,. and it would be difficult to find any single indicator or combination of indicators to delineate accurately the fuel poor as opposed to the poor more generally (use of a prepayment meter or even receipt of benefit are not in themselves sufficient). For the moment, we believe that the use of the cross subsidy power is unnecessary. The Government's Fuel Poverty Strategy sets out a range of policies and programmes for alleviating fuel poverty. These measures include the provision of grants to improve the energy efficiency of the homes (e.g. HEES), measures to improve incomes (e.g. Winter Fuel Payments, Minimum Income Guarantee), energy company initiatives to offer cheaper fuel, or to improve heating systems/energy efficiency. A key issue is the delivery of these measures and a pilot scheme taking a local area approach to this has been launched, "Warm Zones". The effectiveness of this scheme will be closely monitored to ensure that the most effective ways of delivering assistance to the fuel poor are developed. We should assess progress on these measures, along with further analysis of the groups not being helped sufficiently, before consideration is given to using the power.

d) Should we consider new policies, for example, re-directing revenue from oil and gas royalties as a result of higher prices (or a new carbon tax) to subsidise low-income consumers, as suggested by the RCEP.

The approach being adopted by the US Government, to combat current high oil and gas prices, is to divert higher receipts from royalty payments (in relation to oil and gas production) to a fund that helps the poor (those on benefit) to pay higher energy bills. In the UK, petroleum royalties are payable only in respect of oil and gas fields given development consent before April 1982. Production from these fields is falling rapidly, so (notwithstanding various other objectives that could be raised to using them as a hypothecated source of funding for a fuel price subsidy), petroleum royalties would not be a secure long-term source of revenue to subsidise fuel prices for a sector of the community.

e) how can investment on new network infrastructure be incentivised to allow the fuel poor to have access to gas?

It is generally accepted that in the UK gas is the most effective and economical heating fuel. About 20% of households in Great Britain have no access to mains gas. A significant number of these households are likely to be in fuel poverty. Given that gas is widely accepted to be the most efficient and economical heating fuel, extending the gas network could make a material contribution to reducing fuel poverty. The draft Fuel Poverty Strategy therefore included a commitment to establishing a task force to ensure that, wherever possible, the gas network provides the widest viable coverage and the fullest viable capacity.

Invitations to participate in the task force were issued to a wide range of key parties in Government (DEFRA, OFGEM, SE, NAW) and beyond (Gas and Electricity Consumer Council (Energywatch), Energy Saving Trust, National Energy Action, Combined Heat and Power Association, Society of British Industries, Gas Forum, Transco and Centrica). The task force held its first meeting in May and will work towards producing an interim report in September. The task force's terms of reference are given at Annex 12.

Nuclear power

XIII What does the preceding analysis of environmental and security of supply issues tell us about the prospective benefits of extending the life of plant or new build, and (if relevant) the scale and timetable by which it might be required? What elements in the present regulatory and fiscal framework influence the prospects for new build, and are they sending the right signals? How can Government improve its understanding of public concern, and what if any leadership should it give on this?

a) What does the preceding analysis of environmental and security of supply issues tell us about the prospective benefits of extending the life of plant or new build, and (if relevant) the scale and timetable by which it might be required?

Security of supply and environmental background

Nuclear generation currently provides just under a quarter of the UK's electricity generation. EP68 projects that throughout the period 2000 to 2020 electricity demand will rise by 1 - $1^{1}/_{4}$% per annum and that, to maintain the fixed capacity margin of 17% used in EP 68 calculations, substantial new generating capacity will be required. The projections estimate that by 2010 nuclear's contribution will have declined to about 17-18% of generation (10GW providing about 66TWh) and by 2020 to about 7-8% (about 4GW providing 27TWh). Gas will account for around 70% of fuel use, the vast majority of that gas being imported. The projections assume that the renewables target of 10% will be met by 2010 and will remain at that figure until 2020.

Secure uranium supplies:

Fossil fuel generation is fuel intensive. Nuclear generation requires minimal quantities of uranium which is in abundant supply. The European Commission Security of Supply Green Paper recognises 40 years known reserves of uranium at current prices with about a further 15 years known further reserves. The NEA estimates reserves at some 250 years at current consumption rates. Only 5% or so of EU current uranium requirements are sourced locally but unlike some fossil fuels, import dependence is mitigated by large numbers of world-wide supplying countries including Australia, Canada, Russia, South Africa and the USA. And unlike fossil fuel, spent fuel can be re-cycled. The Green Paper confirms that EU nuclear operators typically have a few years of fuel stocks; uranium is easy to store and the cost is relatively low.

The Euratom Supply Agency is responsible for ensuring that there is a wide range of supply sources and for preventing excessive dependence. The Euratom Treaty envisaged a market in which demand and uranium prices would be rising and supply scarce. In reality, however, supplies have remained plentiful and prices relatively low. The Agency believes these market conditions are likely to prevail for the foreseeable future.

Environment:

Nuclear stations, currently providing output in the region of 80TWh pa, avoid around 12 million tonnes carbon (MtC) pa (depending on the generation mix displaced. EP 68 assumes an increase in carbon emissions of around 5.5 MtC resulting from the closure of nuclear capacity between 2005 and 2020.

Nuclear fission – a proven technology, generating on a large scale and with zero emissions – already provides energy diversity and security benefits as well as contributing substantially to the achievement of UK and international emissions targets. These benefits could be increased and/or continue over a longer period by:

- extending the lifetimes of existing stations;
- increasing output; or
- increasing capacity.

The main influencing factors on these options are set out below.

Nuclear station lifetimes and lifetime extensions

Current details of expected UK nuclear station lifetimes are below. In some cases these are the current licensed lifetimes of the plant and in others they are the accounting lifetimes announced by the companies and which assume an extension. It should be noted that EP68 assumes that some stations would close later than these dates – Hinkley Point B, Hunterston B and Heysham

1 all between 2016 and 2020 – and others earlier – Wylfa between 2010 and 2015. To some extent therefore EP68 already anticipates further contributions from nuclear and thus there is a limit to additional potential, but see below.

BE	**Commissioned**	**Capacity MW**	**Published lifetime**
Hinkley Point B	1976	1300	2011
Hunterston B	1976	1150	2011
Dungeness B	1985	1104	2008
Hartlepool	1983	1237	2014
Heysham I	1984	1148	2014
Heysham II	1988	1320	2023
Torness	1988	1250	2023
Sizewell B PWR	1995	1220	2035

Magnox	**Commissioned**	**Capacity MW**	**Published Lifetime**
Calder Hall	1956	192	2006-8
Chapelcross	1959	196	2008-10
Bradwell	1961	240	2002
Sizewell A	1965	430	2006
Dungeness A	1965	445	2006
Oldbury	1967	430	2013
Wylfa	1971	1050	2016-21

Prospects for extending station lifetimes

Lifetime extensions depend on a combination of related commercial, technical and safety factors. Lifetimes can be extended if the licensee can demonstrate satisfactorily to HSE(NII) the station's continuing operational safety and that they could meet the cost of any necessary safety improvements. Making such a case to Ofgem is expensive and time consuming involving hundreds of man hours of work over a number of years. This is therefore a material cost which has to be factored in. For licensees, extensions become a question of whether the commercial gain outweighs the various and inevitably large costs of meeting HSE(NII) requirements. Whether HSE(NII) accept a case to allow a station to continue to operate would depend crucially on the state of, in particular, the pressure vessel and the graphite core – neither of which can be replaced. If HSE(NII) considered that the integrity of these or any other critical components was compromised, they would not permit the station to continue to operate.

Magnox:

BNFL announced the lifetime strategy for its Magnox stations (currently about 7% of UK electricity generation) in May 2000. Under that strategy the majority of stations would close by 2010 and magnox fuel reprocessing at the Sellafield would stop once all the fuel had been dealt with, around 2012. Oldbury and Wylfa stations could be operated safely for a longer period, depending on the availability of alternative fuel options and/or fuel management facilities. BNFL concluded earlier this year that one such fuel option (magrox) was not commercially viable.

*BE AGRs and PWR***:**

These currently provide about 17% of UK electricity supplies. The technology is less likely to be susceptible to technical problems overall (despite a graphite core) and constraints over fuel treatment are not expected to arise. Extensions are already anticipated for some stations and much of this potential has already been built into EP68. The water cooled PWR is not susceptible to core problems and so from this perspective the prospects for a significant lifetime extension are more certain. American reactors are, in the main, water cooled and it is primarily this factor which has enabled operators there to seek lifetime extensions from 40 years to 60 years from NRC, the USA equivalent of HSE/NII. (It has been reported that up to 85% of US reactors could obtain such an extension.) This experience suggests that there could be a reasonable case for assuming BE's PWR station could continue to operate beyond 2035 (when it will have been operating for 40 years) and perhaps beyond 2050.

Once a station has closed, whether or not it may be reopened would depend (a) on whether critical components which cannot be replaced, e.g. the pressure vessel, were judged by HSE(NII) to be safe, or (b) on how far decommissioning had advanced. It would not be possible for any UK stations already closed to be re-opened. Theoretically, however, provided the safety and technical criteria could be met, it would be possible for stations to be mothballed – for example pending an improvement in electricity market conditions - but this is untested in the UK.

Increasing output

Nuclear stations in the main run at their designed high load capacity and there is little potential for large scale increases in output. Small scale increases in output above a business as usual case are realisable which have the effect of additional emissions avoidance. Such projects could include increases in reactor power, improving station efficiency and reductions in outage losses e.g. by extending the period between refuelling. The cost of such projects can vary from hundreds of thousands of pounds to millions – much less than for lifetime extension - and importantly, unlike an extension, offers the flexibility to be undertaken at a given point during the station's operation.

Additional capacity

All UK nuclear stations were built as part of public sector programme. The last nuclear station built in the UK was Sizewell B, commissioned in 1995 by Nuclear Electric, then in the public sector. New nuclear stations have not been regarded either by the industry or by Government as a viable option in the UK for the last decade. The conclusions of the 1995 Nuclear Review were broadly restated in the 1998 Energy Sources White Paper, that proposals for new nuclear build should be a commercial decision for the applicants and that all the present indicators pointed to nuclear being too expensive for new capacity. Both BNFL and BE have stated recently that current market conditions rule out their submitting any proposals for new stations. But both – as well as other commentators on the energy sector - are satisfied that nuclear remains a longer term option.

*R&D***:**

Forecasts of increasing global energy demand coupled with growing awareness of climate change and security of supply issues have led to international R&D effort on nuclear fission R&D becoming more prominent over recent years. The UK is involved (but without financial or energy policy commitment) in two such initiatives: the USA DoE Generation IV International Forum and the IAE Innovative Reactor Project. The objective is to identify and pursue R&D needed to develop reactors which could be commissioned from 2030 (or earlier) providing:

- competitively priced electricity: the target is construction at $1000kW equivalent to generating costs of 3c/kWh;

- proliferation resistance – plutonium inaccessible and/or irretrievable;
- exceptional safety performance through improved design to reduce engineered elements such as valves, pipes and pumps, and implementing gravity operated emergency systems rather than engineered systems;
- waste minimisation advancing on current technology.

Both initiatives are also considering the shorter term potential for new build and whether there are factors outside the control of electricity generation companies (such as different licensing approaches, fiscal incentives) that might be influential in bringing this forward. USA DoE work is expected to report this autumn.

Economics:

The prime factor for operators is the high capital cost of nuclear plant and the risks associated with tying up large amounts of capital for lengthy periods pending planning decisions and market uncertainty.

The 1995 Nuclear Review estimated the cost of new capacity at 3.7p-4.5p/kWh at today's prices. Current estimates of CCGT costs are around 2-2.5pkWh. Coal is estimated at around 2.5-3.6p/kWh. Forward wholesale electricity prices for the year ahead are currently in the region of 1.9p/kWh. Over the past 12 months British Energy and BNFL have become more confident that reactor technology developments could reduce the levelised costs of new nuclear stations to less than 2.5p/kWh – assuming series build, lower discount rates, long station lifetimes (60years) and high load factors (90%). Industry estimates have been criticised as over-optimistic. However, the recently submitted Finnish application in principle for construction of a new nuclear plant is based on estimated costs broadly in line with those figures. Nuclear stations have traditionally benefited from economies of scale and BNFL Westinghouse has developed the AP1000 from the smaller AP600 in an attempt to secure further cost advantages. BNFL also has a stake in the ESKOM PBMR, a small reactor (100MW) for which claims of generation at 1p/kWh have been made. Neither reactor has yet been built. The AP600 has been licensed by NRC. The PBMR is at the feasibility study stage and expected to report later this year.

Both BE and BNFL have argued that changes to existing mechanisms in particular the climate change levy or emissions trading could, if extended to include nuclear, materially alter the economics of new capacity, provide the necessary incentive to undertake projects to achieve genuine additional output, and justify lifetime extensions.

Public Acceptability:

Plainly the issue of public acceptability remains a key issue for any consideration of new nuclear build. One of the main arguments against new nuclear capacity is likely to be that, irrespective of technology developments, policy on the management of existing nuclear waste remains to be agreed.

b) What elements in the present regulatory and fiscal framework influence the prospects for new build, and are they sending the right signals? How can Government improve its understanding of public concern, and what if any leadership should it give on this?

Electricity Market

Historically nuclear has been a baseload generator – both Magnox and AGR stations operate as baseload. NETA, by contrast, encourages flexibility and so disadvantages much of the existing UK nuclear plant. More modern technology – PWRs and innovative reactors such as the PBMR – are more flexible and can load follow if necessary. This is the position in France, which has 80% nuclear generation. Market liberalisation should not therefore in itself deter new nuclear proposals.

Power Station Approvals

The approval of new nuclear stations requires a series of approvals. These include principally: pre-construction safety design approval by HSE(NII), planning consent, and full pre-commissioning approvals to operate, from both safety and environmental regulators.

For a new nuclear station (as with any other generating station over 50MW) development consent would need to be sought from the Secretary of State for Trade and Industry under Section 36 of the Electricity Act 1989. (In Scotland the process is administered by the Scottish

Parliament). It is a comprehensive process involving local planning authorities. Objections can trigger a public inquiry. The overall timescales have been long. The most recent UK nuclear station application, for BE's Sizewell B station, covered a period of about 15 years from the application being made to station commissioning. This compares to an average of 6 years for a CCGT station. In a competitive electricity generation market this adds significantly to both capital risk and economic cost, relative to other technologies.

Regulatory Approval

Two principle regulatory systems apply to the nuclear industry. HSE's Nuclear Installations Inspectorate (NII) licenses nuclear sites for safety purposes, while the Environment Agency (EA) (in England and Wales) and Scottish Environmental Protection Agency (SEPA) regulate aerial and liquid discharges, and the disposal of solid wastes, from nuclear sites. While statutory limits on individuals' exposures to nuclear radiation have been set out in the Ionising Radiation Regulations, the hazardous nature of nuclear operations means that - under both safety and environmental regimes - active regulator "permissioning" is required for many operational decisions. In recognition of the high intrinsic hazard of nuclear operations, and reinforced by strong public aversion to radiation risks, a strongly precautionary approach is applied under both regimes.

While the costs of safety and environmental regulatory activities are recovered by levies on operators, the main costs are those of meeting the required standards – for both plant and management – together with (sometimes lengthy) interruptions to operation while improvements are implemented and approvals secured. The criteria in HSE's "Tolerability of Risks from Nuclear Power Stations" (rev. 1992) produced in response to a recommendation of the Sizewell B Public have provided the starting point for HSE/NII in regulating the full range of nuclear operations, through some 333 "Safety Assessment Principles" (SAPs) developed successively to cover nuclear power plant and fuel cycle (fuel manufacture and reprocessing) operations. The S.A.P.s combine use of probabilistic risk assessment (where experimental evidence is available on failure rates etc.) with specific requirements to ensure the integrity of key elements of plant, supported by prudent engineering judgement.

Licensing covers all stages in the development of a site from planning, design, construction, commissioning and operation. HSE(NII) must be satisfied that an applicant has the capacity to meet all of their stringent safety requirements and observe the licence conditions attached to the site licence. An applicant must produce a comprehensive written safety case for each plant acceptable to the HSE before a licence is granted. The safety case must be continually revised and updated throughout a plant's operations to take account of any changes in its operating conditions. The applicant must also demonstrate the adequacy of the corporate structure and company management arrangements. Performance against standards and conditions is monitored and enforced to exacting standards by HSE(NII). The Inspectorate has extensive powers and can include additional licence conditions, direct the cessation of plant operation and ultimately direct that it be shut down altogether.

HSE(NII) has a well developed regime. An application for new capacity would in all probability mean the need to license a plant design new to the UK – a time consuming process. Apart from the direct costs involved, the uncertainty creates additional financing risk for the applicant. And requirements for design or engineering modifications during construction could be very costly.

Environmental and discharge implications arise from extending lifetimes or constructing new stations. The disposal of radioactive material and discharge to the environment from licensed sites is strictly controlled, the operator needing to obtain authorisations under the Radioactive Substances Act 1993 from the relevant environment agency. Whilst these are normally sought after station construction and licensing i.e. after the planning process and once the very substantial capital commitment has been made, it is possible to apply for an outline authorisation prior to this.

An additional requirement is that of Justification. An EU Directive requires that all types of practice involving radioactivity be justified prior to first adoption. Consideration of justification will be carried out by the relevant Secretary of State. Depending on the type of reactor built, operation may be considered already justified, in which case the SoS would need only to consider whether new or important information had been received since the earlier decision. If the plant was considered a new type of practice full consideration would be needed. This could take some time.

The OSPAR strategy on Radioactive Substances commits the UK to progressive and substantial reductions in discharges affecting the sea with the intention of additional concentrations being close to zero above historic levels by 2020. There is still work to be done on the definition of some of these terms but the draft strategy for meeting the requirements refers to increases in discharges only being permitted in exceptional cases for justified practices. New power station development has been accepted as an example of such a case. The strategy, however, remains to be confirmed.

Experience in the USA has been that prior to the 1980s, nuclear plant took an average of only 5 years to licence and build. More recently this has been almost 12 years – twice as long as in France, Japan and Sweden. This has been attributed to changes in regulatory requirements during the construction process and resulted in significant increases in the capital cost of plant constriction. As a result, reforms have been made to the American licensing process in an attempt to create a more stable and predictable environment for the public and the applicant. Through standardisation, plant will be almost fully designed before it is ordered (hence the BNFL Westinghouse AP 600 has been licensed for the USA even before any orders have been received) so that extensive (and expensive) design and engineering work will not be needed during construction. Information on design, siting and construction will be made available to the public early in the process. Operators will agree all relevant regulatory issues before construction begins. The USA DoE are continuing to look at regulatory and other infrastructure issues in order to identify any further scope for improvement.

Climate Change Mechanisms

The industry has argued that recognition of nuclear's zero carbon status through, for example exemption from the Climate Change Levy, or inclusion in an Emissions Trading Scheme, would influence decisions over projects to extend or increase output or capacity. The industry's arguments are broadly that:

- nuclear makes a significant contribution to the UK's emissions reduction strategy and, without it, Kyoto and national targets could not be met;
- as CO_2 is the principal gas responsible for climate change, measures should focus on reducing CO_2 rather than on energy use;

- current and future contributions from carbon-free generation from nuclear should receive the same recognition as renewables, CHP and emissions reductions in the fossil sector;
- unlike other generation options, all nuclear costs – environmental included – are internalised and paid for e.g. through provisions for decommissioning, but nuclear gets no credit for its environmental benefits. A carbon tax would internalise environmental costs associated with fossil generation and place those generators on a level playing field with nuclear.

The industry has also argued that, whilst mechanisms such as the Climate Change Levy and Emissions Trading might be time limited, any additional output would continue over the longer term providing emissions benefits after those schemes had ended but at no continuing cost.

Based on EP68, the loss of 8GW of nuclear capacity will increase emissions by 5.5 million tonnes of carbon. Using industry estimates for the cost of new build (2.6 – 4.0 p/kWh), work for the Interdepartmental Analysts group on low carbon has calculated that a typical station of 1.3GW capacity saving 0.9 million tonnes of carbon would imply a cost per tonne of carbon saved of -£26 to £103, looking towards 2050 against a gas generation cost of 2.9 p/kWh. The work recognises that this is a fairly crude calculation but it suggests that if new build costs proved accurate, and allowing a reasonable value for carbon savings, there are prospects for new build to be economic.

Radioactive Waste Management

Both public and commercial operators of nuclear sites are accountable for final decommissioning and disposal of plant: ranging from research reactors pre-dating the birth of nuclear energy, through commercial generating plant, to storage facilities and their contents (spent fuel etc.) Timescales for decommissioning and disposal typically run into decades, allowing for the benefits of radioactive decay in lessening the hazards of decommissioning.

There is currently only one fully approved and operational repository for radioactive waste - the WIPP facility for military wastes in the USA. Underground interim stores exist in Sweden and Germany, and there are development facilities for repositories e.g. Yucca Mountain, USA. Parliamentary approval was given, in May 2001, for the next stage towards development of a repository in Finland. A notable feature of the Scandinavian experience is that their process involves much public participation and in Finland is based on volunteer communities – who receive benefits in exchange for co-operation.

The large and complex mixture of wastes included in the UK waste inventory has been determined by the way in which the nuclear industry has developed in the UK with both a weapons programme and a variety of experimental facilities. In other countries e.g. Netherlands or Spain, which have just bought PWR technology from others, wastes are much simpler and very much smaller in amount. Any new nuclear capacity in the UK would be analogous to that situation. For illustrative purposes RWMAC's report "Rethinking Disposal" stated that a programme of 8 new PWRS in the UK would increase the amount of intermediate level waste by only 10%.

Questions concerning the future management, funding and regulation of publicly owned nuclear liabilities are currently being addressed in the DTI's Quinquennial Review of the UKAEA. This review is considering general questions relevant to the management of all nuclear liabilities for which HMG has a long-term responsibility and which amount to about £70 billion.

DEFRA's forthcoming consultation paper on radioactive waste management will address the issue of disposal of intermediate and high level waste issues in the UK and set a timetable for reaching agreement on policy.

Measures needed to meet environmental and other imperatives

XIV What is the right balance of measures required to achieve the necessary changes in the longer term? This will need to include regulation, planning, taxation, trading mechanisms, and other economic instruments. If environmental concerns are to be given priority, these almost certainly mean higher prices and, if so, what policies are needed to alleviate the impact on the poor and the effects on competitiveness? What further scope is there for taxation which signals the need for changes in behaviour and which can also be hypothecated to encourage business or individuals to move in the right direction e.g. through R&D or energy saving measures?

a) What is the right balance of measures (including regulation, planning, taxation, trading mechanisms, and other economic instruments) required to achieve the necessary changes in the longer term?

A given target is most likely to be met, at least cost, if carbon is given value, via emissions trading or carbon tax, and the market responds. The efficiency of such a system depends on the coverage being as wide as possible. But such decisions are subject to constraints which inevitably arise from other policy considerations. Therefore, a prime consideration must be to create the right framework, which will reward the best, most cost-effective technologies and encourage their development. The latter means addressing issues such as planning, structural barriers (e.g. grid constraints) as well as physical technological advancement and cost reduction.

This means developing policy that is not primarily about picking winners, but which allows the market to provide appropriate incentives. That could mean using the market to promote the achievement of regulated standards or targets (as with the renewables obligation or the energy efficiency commitment).

As government has wider policy objectives than simply tackling climate change, which tends to determine the feasibility of sending price signals in some areas (e.g. domestic energy bills), it is only through an evidence-based approach that Government can make the right decisions and send the right long-term price signals. Equally it has to be recognised that we are not starting from a blank sheet or optimal position and action may be limited by practical or political concerns. As such price signals alone can not achieve large reductions in emissions without causing serious conflict with other policy objectives on competitiveness and fuel poverty and others.

Like most aspects of policy there is a wider EU dimension and the development of international emissions trading may effectively impose this on us, at least with respect to the business and energy supply sectors – and conceivably to the whole economy.

b) If environmental concerns are to be given priority, these almost certainly mean higher prices and, if so, what policies are needed to alleviate the impact on the poor and the effects on competitiveness?

Fuel poor

The impact of higher prices on the fuel poor is discussed in question 12.

UK competitiveness

In consider the impact of higher prices it is not only the fuel poor or UK business, including especially energy intensive business, which will be impacted upon. But also key services such as schools and hospitals who could face higher costs. Such impact re-emphasise the need for revenues to be recycled (as discussed below) especially where they can be used to improve energy efficiency and reduce energy consumption.

Domestic policy actions can be taken to target support to specific sectors or technologies with potential to take advantage of growing “green” markets. But beyond this, 3 main principles are probably that (1) whilst the UK may want to adopt a position in the vanguard of progress on climate change it should also continue to look for targets on GHG reduction to be internationally applied. And such targets should be expected to move beyond the Annex I countries over time. (2) In terms of policies and measures we would want domestic freedom to decide on what makes most sense. Nevertheless, we would want the potential for the use of the flexible mechanisms to be wide. (3) Where the UK chooses to use economic instruments with a revenue raising component, we should like to see such receipts recycled and not primarily regarded as a source of additional revenue.

c) What further scope is there for taxation which signals the need for changes in behaviour and which can also be hypothecated to encourage business or individuals to move in the right direction e.g. through R&D or energy saving measures?

Discussion

Economic instruments (here tax and carbon permits can be thought of as broadly equivalent) work by pricing the externality to ensure that (if the correct price is set) a desired reduction in pollution is achieved in a least-cost manner. To work optimally the externality has to be clearly identified measured and targeted. However, carbon emissions can be clearly quantified and linked to the quantity of fuel consumed. So in this respect, they are a good candidate for use of economic instruments.

With imperfect information it is impossible to set the correct price level. But greenhouse gas reduction policy is more likely to be set with regard to required levels of emission reduction than precise quantification of externality costs. Emissions trading will be well suited to such quantified emission targets. Tax may be more problematic. To ensure a target is met it may be desirable to set a high rate with the hope that information revealed in running the scheme will allow the rate to be cut. But this imposes higher costs on energy consumers. Therefore, it may be more desirable to set a low rate that can be raised as necessary, in the light of experience. This runs the risk that a target many not be met, because the price incentives to act are not great enough, but that can be overcome if the long-term policy objectives are clear.

Hypothecation is often suggested as a good means of linking objective to policy instrument. The benefit of hypothecation is that it provides a clear link between aim and measure. For example if the fuel duty (or an identified element) was solely aimed to reduce carbon, then its revenue could be recycled to widen public transport and develop low-carbon engines as well as sending a price signal to encourage individuals to use fuel more efficiently.

Current price signals

The high-level price signals currently determined by Government vary across different sectors of the economy. In the domestic sector, there is no explicit price signal to reduce greenhouse gas emissions. In the transport sector, the major price signal is the fuel duty applied to the price of transport fuel (although this tax is not simply there to reflect carbon emissions). In the business sector the major price signal will be provided by the climate change levy (CCL), though this is targeted at energy use rather than at carbon directly. In general terms, – though new renewables and good quality CHP are exempt from the CCL - the energy supply sector currently faces no direct price incentive to reduce greenhouse gas emissions beyond the point where there is a “private” benefit to do so. The Renewable Obligation will begin to impact on this. Therefore in the UK, some sources of greenhouse gas emissions face no incentive to reduce emissions, while those that do face a variety of different prices, dependent on the type of source. The position is further complicated by the slightly less direct price signals, which can channel emission-reducing activities to specific areas, rather than allowing them to occur where they are cheapest (e.g. the Renewables Obligation).

Scope for further tax measures

Clearly taxation remains a matter for HMT.

The Energy Advisory Panel (and many others) has argued that economic instruments to address global warming should focus on carbon since this provides the desired incentive from an environmental point of view to use less carbon and should provide a boost for no and low carbon fuels. However, a key question is whether carbon trading would be more effective than a carbon tax. The Energy Advisory Panel considers there are strong arguments in favour of tradable carbon permits. Tradable permits control emission directly rather than via an unknown price elasticity and allow the price of carbon to be set by the market and innovation. It is argued that the UK Emissions Trading Scheme has limitations but could be regarded as a step in the right direction. If it is successful the current scheme could evolve into one of wider applicability, with wider coverage - should wider policy considerations allow. The scheme will have three strands: incentivised cap and trade - firms receiving subsidy to take on emission caps; Climate Change Levy Negotiated Agreement - firms, mostly with relative targets, who have taken emission reduction targets to receive a rebate of CCL; Projects - activities that reduce emissions will receive permits that can be traded into the wider scheme.

The RCEP shares a similar view that the CCL should be replaced by a carbon tax applied to all sectors with revenue recycled to reduce fuel poverty and increase investment in renewables and energy efficiency.

XV If we want to keep open the possibility of substantial long-term cuts in emissions, what are the priority policy measures that would make sense now (over and above those in the Climate Change Programme)? How could we prepare public opinion? Which emission saving measures would also contribute to other policy objectives?

a) **If we want to keep open the possibility of substantial long-term cuts in emissions, what are the priority policy measures that would make sense now (over and above those in the Climate Change Programme)?**

Given an unknown future, the key for action today is to make any required future action easier. Therefore the priority should be on enabling measures that remove barriers or open up potential. Examples include: network transformation, following up the Embedded Generation Working Group (described more fully in question 16); the smart metering initiative (a working group was established on 26 April – also described more fully in question 16); and; work on smart energy initiatives. Other areas for consideration could be the role energy services could play, especially for improved energy efficiency and the issues of planning and conflict of interests in the deployment of renewable technologies.

Enabling measures also include developing technologies and the DTI are expecting to create a £1 billion market for renewable energy by 2010. Key elements of the plan are to create demand via the Renewables Obligation requiring suppliers to supply a fixed proportion of electricity from renewable sources (at an estimated benefit to the renewables industry of up to £800 million by 2010) and to boost supply with £260 million of funding of research, development and deployment over the next 3 years. Some research funding is directly linked to a specific technology (e.g. DTI capital grants for offshore wind) for others the allocation is being determined on an evidence basis through the PIU Resources Productivity study and the DTI's R&D Route Mapping exercise. Further details of funding are given at Annex 15.

Looking further ahead, other enabling issues will have to be resolved possibly including energy storage, or in the longer term the production of hydrogen and the hydrogen economy. However, it may not be until preferred technologies and new deployment obstacles appear that specific work areas can be identified.

As well as measures and technologies, continued effort will be needed in enabling mechanisms that allow the UK to meet future obligations in a least cost way. This includes continuing to develop the UK trading emissions scheme (and consistency with other countries and EU schemes) and to consider how trading, quota or tax schemes could be introduced at a wider level, including how/if price signals could be given to domestic sector.

b) How could we prepare public opinion?

Energy policy has far reaching economic, social and environmental implications to many 'stakeholders' and is of profound public interest. Consultation and public debate will, therefore, be an essential part of the formulation of a new framework for decision making.

c) Which emission saving measures would also contribute to other policy objectives?

There is a high degree of synergy between objectives. Developing renewables can contribute to security and diversity. It is generally accepted that any increase in renewable generation is likely to be in place of new build gas generation (a reasonable assumption as new renewables are unlikely to replace existing generation on cost grounds before retirement). However, whilst clearly diversity will be increased, more work is needed to resolve the question of intermittency and whether security is enhanced.

Energy efficiency means using less energy to enjoy the same service or benefit. This has benefits for security (by reducing demand and peak capacity) and for fuel poverty objectives (by reducing the energy required to provides sufficient heating and appliance use and therefore reducing the required expenditure on energy). Targeted energy efficiency improvement, such as the new Home Energy Efficiency Scheme, are clear examples of this type of approach and may in future, once widely deployed, be part of a means of protecting the fuel poor from the full impact of environmentally driven price rises.

XVI What steps should we be taking now to incentivise, develop and introduce technologies that seem particularly important for the future? This should cover not only our response to global warming but also the more general development of future fuels. What do uncertainties over future technologies and costs imply for policy development now? We will need to look at measures that can link energy efficiency with the solution to fuel poverty. How do we encourage a switch towards the provision of energy services (heat, light and motive power) and away from competition focussed on selling more electricity and gas? How big a role can CHP play? We will need to look at ways of removing the barriers to change including planning and regulatory barriers and at how we should transform electricity networks to cope with increased levels of embedded generation and micro power such as domestic CHP and photovoltaics. We need to look at energy services marketing and at the development of trading mechanisms that may make large scale national and international carbon trading possible for the future.

a) What steps should we be taking now to incentivise, develop and introduce technologies that seem particularly important for the future? This should cover not only our response to global warming but also the more general development of future fuels

DTI has initiated a major technology Route Mapping exercise on low carbon technologies, including hydrogen, in collaboration with industry and industry. The exercise is identifying the key technology targets up to and beyond 2010 for a wide portfolio of low or zero emission technologies covering the supply of electricity, heat and transport fuels. We have carried out extensive consulting involving industry and academia on the draft individual route maps and the route maps are currently on the DTI website for wider consultation.

We are also working to strengthen the links across the Science Base with Government to ensure support for long term, strategic energy R&D is focused on technologies which offer both the promise of helping to meet any future greenhouse gas emission targets, and wealth creation and jobs in new industries associated with such technologies. For example there is considerable merit in establishing jointly funded collaborative programmes between the DTI renewables and sustainable energy programmes and that of programmes supported by the Research Councils. These could include joint funding of "Centres of Excellence" in key technologies such as solar energy, ocean energy, advanced biofuels, and carbon dioxide capture and storage; support for feasibility studies for investigating totally new energy technologies which may have potential beyond 2050. New science and research centres may also merit consideration for developing the hydrogen economy and ensuring the potential for Fusion can still be pursued as an option.

More generally, development of international and UK emissions trading provides a route for valuing carbon savings and thereby incentivising development of cleaner technologies. Aside from pressing ahead with such scheme development, it will be important to ensure that industry understands that the commitment to such trading and to reducing emissions is real and long-term. To help with this important exercise the Energy Group have recruited, in partnership with industry sponsors, and Trade Partners UK, an export promoter with specific responsibilities to both promote the business opportunities associated with climate change and emission trading and to ensure business is kept fully informed of developments in the UK and overseas.

b) What do uncertainties over future technologies and costs imply for policy development now? We will need to look at measures that can link energy efficiency with the solution to fuel poverty.

Policy development needs to take account of the very long lead times needed to bring low carbon technologies to commercial fruition and be prepared to support a portfolio of measures to ensure industry is able to deliver appropriate technology solutions in a timescale to match the urgency of the problem. The Government has already recognised this by the range of measures being put in place to support the substantial growth in renewables over the next decade. These include a market support mechanism in the shape of the Renewable Obligation, a Capital grants scheme to support the first few commercial scale schemes, and support for long term strategic Research, Development and Demonstration – back up by appropriate technology transfer and export promotion activities. This holistic approach should create an innovative framework to kick start low carbon technology development in the UK.

Again, these uncertainties imply a need for policy to provide a broad framework, within which the market can develop and incentivise the least cost approaches. This implies mechanisms such as emissions trading and emphasises the need for industry to recognise the long-term Government commitment to such measures.

c) How do we encourage a switch towards the provision of energy services and away from competition focused on selling more electricity and gas?

Energy services supply heat, light and motive power, in place of electricity and gas units, as a way to reduce electricity and gas consumption thereby enhancing security of supply, reducing carbon emissions and potentially reducing demands on networks. In the business sector energy services, including CHP schemes and heating/lighting control systems, have already taken an increasing share of the energy market. They have yet to develop to any significant extent in the domestic sector where utilities may see selling increasing volumes of energy units as the main driver of profitability.

Changing the domestic market towards an energy service approach requires two changes. First, motivating consumers to want to make a change that can require up front. Second, encouraging suppliers to enter into longer term relationships with their customers which are implied by the development of energy service solutions. Care will be needed that this does not run counter to competitive markets. Future energy contracts could also involve domestic CHP and PV where domestic consumers could be exporting electricity in small amounts. Metering developments are likely to be crucial to the development of energy services in the longer term to facilitate the measurement of energy services provided and their billing.

DTI have carried out work into why energy services were not being developed in the domestic energy supply market and the ways in which the Government could stimulate their development. Suggestions for ways in which the industry and Government could work together to overcome barriers included:

i. Raising awareness of both the industry and consumers of the potential environmental benefits;
ii. Providing supply side incentives for companies; and
iii. Providing demand side incentives for consumers.

d) How big a role can CHP play?

Government has a national target to achieve at least 10,000 MWe of CHP capacity by 2010 and DEFRA plan to publish for consultation a strategy for achieving that target. Current CHP capacity (around 4,300 MWe) is estimated to save around 4 MtC per year. In practice the current economic conditions for CHP are difficult: gas prices are relatively high and electricity prices relatively low and NETA is also expected to have the effect of lowering electricity prices. Small generators have also lobbied for transitional arrangements to help them adjust to trading under NETA. The take-up of CHP depends largely on gas prices and on the relativity of gas to electricity prices and whilst DTI supports a number of measures to encourage the take up of CHP, it recognises that much depends on future market conditions (i.e. the balance between electricity and gas prices). As discussed above, future gas prices are expected to continue to be related to oil prices, the current level of which ($27/barrel) is regarded as being un-sustainably high in the medium to long term. But the link between gas and oil prices may weaken over time depending on the pace of European gas market liberalisation, giving gas prices their own dynamic. In the longer term, gas prices may rise again as the growth of demand outstrips supply.

A key area for the future and one that could increase the carbon savings available through CHP, is the development and marketing of domestic CHP. Although it is not yet a commercial prospect in the UK, companies (including BG International and Powerline) are exploring the options for marketing within the next year or two. Network and metering issues, considered in (e) below will also play a part in bringing domestic CHP to market.

e) We will need to look at ways of removing the barriers to change including planning and regulatory barriers and at how we should transform electricity networks to cope with increased levels of embedded generation and micro power such as domestic CHP and photovoltaics.

In January the Embedded Generation Working Group published for consultation its initial report on addressing current barriers to the development of embedded generation. The Group published its final report in June. A co-ordinating group has been set up chaired jointly by DTI and Ofgem. The group will set itself a programme for taking forward the recommendations set out in the EGWG report. Some recommendations may be completed within months, but others will take considerably longer and it is expected that the process will extend over a number of years.

Ofgem has recently consulted on their metering strategy, following up on their review of competition in metering services and seeking to bring the benefits of technological advances and lower prices in metering to customers. Government is also considering the role that Smart Metering could play. This would offer electronic, remote, real-time monitoring and collection of usage data through the use of communications-enabled utility meters. Potential benefits from smart metering are wide and include:

- better displays of consumer usage of energy that enable them to budget better. Reductions in consumer bills (rather than prices) should be the main driver for change. The kinds of reductions in fuel usage that may be in prospect could make a significant contribution towards the reduction of fuel poverty as well as reducing in carbon emissions

- quicker development of the mass use of PV and micro-CHP generation. This would contribute to the Government's targets for renewables generation and CHP capacity;

- development of more cost reflective tariffs that enable domestic consumers to further reduce their bills and reduce peak electricity demand, for example as technology enables the "internet under the stairs" to manage individual consumers' energy demands. This would contribute towards the Government's objectives in relation to security of supply;

- the encouragement of the development of energy services, for example through measurement of the heat used or measurement of the use of different appliances;

- enable the development of other domestic services, for example it has been suggested that monitoring of metered use of energy may assist monitoring the health and welfare of elderly people; and
- provide a digital gateway in the home to enable the use of other smart technology including alerting suppliers as soon as power cuts happen.

A Smart Metering Working Group has been established to consider how metering technologies can assist in the pursuit of DTI energy and information age objectives and will be reporting to Ministers with recommendations by the end of September 2001.

Planning

The Government recognises that the planning system has an important role to play if renewable energy targets are to be met. The Government wants to promote a positive and strategic approach to planning, and to create an atmosphere conducive to open and constructive dialogue among operators, the planning authorities and local people so that suitable sites can be identified with sensitivity and care.

In order to promote this strategic approach from the regional level downwards, the Government in February 2000 initiated work to prepare regional assessments and targets for renewable energy provision based upon - and, where necessary, updating - existing resource studies.

This results of these assessments should be incorporated following through consultation with interested stakeholders into Regional Sustainable Development Frameworks, which will elaborate a regional approach to renewable energy, including regional targets which flow from the assessments of each region's capacity to generate electricity from a range of different sources.

The frameworks will work alongside Regional Planning Guidance (RPG) and Regional Development Agencies' Economic Strategies in promoting sustainable development. Thus we envisage RPG taking forward in land-use terms a region's strategy for delivering renewable energy targets by defining broad locations for renewable energy development and setting criteria to help local authorities select suitable sites in their plans. We would encourage regional planning bodies to set targets in RPG, where sensible to do so, for the structure plan and unitary development plan areas within the region consistent with the regional targets provided by the regional sustainable development frameworks.

Together with the national planning policy guidance in PPG 22: Renewable Energy, RPG - as taken forward through structure plans and Part I unitary development plans - will provide a strategic framework for policies and proposals for renewable energy development in local plans, including the identification in those plans of suitable sites. This, in turn, will feed through to decisions on individual planning applications.

More positive planning at regional and local levels will contribute to greater public familiarity with, and acceptance of, prospective renewable energy developments. It remains important, however, for operators to prepare the ground with local authorities, environmental organisations and local people before formal planning applications are submitted and to develop proposals in consultation with them

Offshore Wind

The Department recently held a consultation exercise on the consents process for offshore windfarms. It proposed that instead of the current fragmented situation the DTI would act as a “one stop shop”, receiving and co-ordinating the administration of proposals for offshore windfarms in England and Wales. It also proposed that DTI became, in effect, the planning authority for the smaller offshore windfarms i.e. those at or below 50 MW since the local planning regime generally does not extend offshore. Responses were sought by the DTI by 23 April; these have now been analysed and it is hoped that a response can soon be agreed with the other consenting authorities and made public. The details of the consenting process will be developed over the summer in a guidance note. Discussions are continuing with MOD and NAW over policy issues relating to offshore windfarms.

f) We need to look at energy services marketing and at the development of trading mechanisms that may make large scale national and international carbon trading possible for the future.

DEFRA’s Energy Efficiency Commitment will place an obligation on energy suppliers to encourage or assist consumers to take up energy saving opportunities, leaving companies the flexibility to develop innovative and cost-effective programmes. The EEC will also encourage companies to bring energy efficiency into their mainstream services to customers and into a more energy services-oriented business. Government is currently considering an industry proposal that the forthcoming EEC for 2002-2005 should make specific provision to encourage energy services experimentation, based either on ring-fencing a proportion of the obligation or giving an enhanced weighting to energy services schemes. The EEC proposals include provision for companies to trade either obligations or accredited performance with other EEC-obligated companies. A similar point to the Government's proposals for a new Carbon Trading mechanism also included the suggestion that energy supply companies should be able to trade carbon credits won through energy efficiency promotional work, additional to meeting their EEC obligation

ANNEXES

The attached annexes provide additional information to the answers above. They are numbered in line with the most relevant question and answer, rather than numerically, to aide the reader.

ANNEX 1

A. Summary findings from the IEA world Energy Outlook

Primary Energy Mix

Oil
World oil demand is projected to be 115 million barrels per day in 2020, compared to 75 Mb/d in 1997. In the OECD countries, the transport sector accounts for all oil-demand growth. The *Outlook* views the physical world oil-resource base as adequate to meet demand over the projection period although the concentration of oil resources in a small number of producing countries will also mean an increase in the oil-import dependence of the major consuming regions.

Natural Gas
Gas demand rises at 2.7% per annum over the projection period, and its share in world primary energy demand increases from 22% today to 26% in 2020. The bulk of this increase will come at the expense of nuclear and coal.

World reserves of natural gas are thought by the *Outlook* to be more than sufficient to meet the projected 86% increase in demand over the outlook period. However, gas resources are not always located conveniently near centres of demand. Pipelines will continue to provide the principal means of transport for gas from North Africa, Russia and the Caspian region to growing gas markets in Europe Liquefied natural gas transportation mainly to East Asia is nonetheless expected to account for a growing share of the increase in international trade.

Coal
Projected world coal demand advances by 1.7% a year, slower than total primary energy demand, so that its share declines slightly, from 26% in 1997 to 24% in 2020. China and India, account for more than two-thirds of the increase in world coal.

Nuclear
After peaking around 2010, production of nuclear power is projected to decline slightly by the end of the outlook period. Its share in the primary energy mix falls from 7% in 1997 to 5% in 2020. Nuclear power output increases only in a few countries, mostly in Asia.

Final Energy Demand Trends

World final energy demand increases at 2% a year over the outlook period — the same rate as for primary energy demand. Growth is significantly faster in transportation (2.4%) than in all the other end-use sectors (1.8%). Electricity demand grows more rapidly than for any other end-use fuel. Its projected share in world final energy consumption increases from 17% today to 20% by 2020.

Regional Energy Trends and International Trade

The bulk of the projected increase in world energy demand will come from developing regions. They will account for 68% of the increase between 1997 and 2020. OECD countries will contribute only 23%. Nonetheless, the uneven distribution of per capita energy use between industrialised and developing countries will not change much over the projection period.

A big increase in international trade is projected to meet the widening gap between consumption and indigenous output in many parts of the world. Regions that depend on imports to meet a major part of their oil needs (e.g. Europe) become even more dependent on imports over the projection period, both in absolute terms and as a proportion of their total oil consumption. The OPEC countries are expected to supply much of this increase in import requirements.

The share of gas in the fuel mix increases in all regions. Growth rates are highest in East Asia, China, India and Latin America. The largest increment in absolute terms comes from OECD Europe, which alone accounts for about 19% of the increase in world gas demand over the projection period. The region becomes increasingly dependent on imports of gas as demand outstrips indigenous production. The transition economies and Africa are expected to remain the main sources of gas supply to Europe.

Table A1.1 Summary energy balances for the EU from European Energy Outlook to 2020

		Annual consumption Mtoe			**% Annual growth rate**		
		1995	**2010**	**2020**	**1995-2010**	**2010-20**	**1995-2020**
Solid fuel	Gross inland consumption	237	182	218	-1.7	1.8	-0.3
	o/w Elec gen	171	137	183	-1.5	2.9	0.3
	Final demand	43	27	20	-3.1	-2.7	-3.0
Gas	Gross inland consumption	273	400	430	2.6	0.7	1.8
	o/w Elec gen	117	204	229	3.8	1.2	2.7
	Final demand	177	211	212	1.2	0.0	0.7
Liquid fuels	Gross inland consumption	576	653	660	0.8	0.1	0.5
	o/w Elec gen	75	59	49	-1.6	-1.8	-1.6
	Final demand	4.2	477	487	1.10	0.2	0.8
Renewables	Gross inland consumption	72.1	88.2	99.7	1.4	1.2	1.3
	o/w Elec gen	47.9	66.0	77.9	2.1	1.7	2.0
	Final demand	22.4	22.2	21.8	-0.1	-0.2	-0.1
Electricity	Final demand	170	227	266	1.9	1.6	1.8

B. Future UKCS production

The North Sea is more mature than its competitor provinces and is a relatively more expensive area to exploit. Development costs are the highest among competitors at $4.0/boe and operation costs are also high at $4.3/boe. As a result, current levels of exploration are low. Five significant discoveries were announced in 1999, representing a 30 per cent success rate. Overall, exploration drilling is low, only 16 exploration wells were started, compared with 47 in 1998. This was the lowest level of exploration since 1965.

Development of UKCS is dependent on world prices, and on new technology. An UKOOA's survey of industry investment plans in November 1999 suggested that investment in 2001 would be less than £3bn, whereas the same survey undertaken in September 2000 forecast investment could possibly rise to over £4bn. New technology is central to finding and extracting oil. For example, standard predictions for the Forties Field in 1975 were that it would stop production by the early 1990s; by 1990 the standard prediction was that it would close by 2000. In fact, the field continues to produce 70,000 barrels a day and on current plans is expected to continue for at least another 15 years. When production started, the estimated recovery rate was 42 per cent, but it is now 62 per cent - an extra 800m barrels - and the current target is to reach 70 per cent.

The table below shows estimates of recoverable reserves of oil and gas, in which the main point to note is the size of the ranges. For oil, for example, on the most pessimistic assessment, remaining reserves are much less than half total production to date; on the most optimistic assumption, reserves are almost twice as great as past production. Past forecasts of reserves, though, suggest that the most pessimistic scenarios are unlikely to come true. For example, remaining oil reserves (proven, probable and possible) in 1979 were forecast to be around 2,500m tonnes, but almost this amount has been extracted from the UKCS since then and reserves (forecast on the same basis) are still estimated at close to 2,000m tonnes.

Table A1.2 UKCS initially recoverable reserves of oil and gas.

	Oil (million tonnes)	Gas (billion cubic metres)
production to date	2,444	1,410
discovered	666-1,661	760-1,755
potential additional reserves	85-370	75-245
estimated undiscovered	250-2,600	355-1,465

Source: DTI's Brown Book, 2000

C. Price forecasts/assumptions

Table A1.3 IEA World Energy Outlook Prices Assumptions

Product	**1990 US$**				**%Change**	
	1997	**1999**	**2010**	**2020**	**1997-2020**	**2010-2020**
IEA crude oil import price in US$ /barrel	16.0	13.9	16.5	22.5	40.6	36.4
OECD Steam coal import price in US$/tonne	36.8	29.3	37.4	37.4	1.6	0
US natural gas wellhead price in US$/tcf	1.9	1.7	2.5	3.5	84.2	40.0
Natural gas import price into Europe in US$/toe	90.5	67.3	80.9	132.8	46.7	64.2
Japan LNG import price in US$/toe	136.2	102.2	132.0	182.3	33.9	38.1

Source: World Energy Outlook, IEA

IEA view on future primary energy prices

Although oil industries in some countries and regions are maturing, the resource base of the world as a whole is not a constraining factor. Utilising these requires large and sustained capital investment, particularly in Middle East OPEC countries, hence the assumption that the international crude oil price is flat until 2010, but then rises steadily through to 2020. The

Outlook assumes that it will be possible to supply expanding gas markets in most regions to 2010 at stable prices (2005 for North America), but only higher prices can provide the higher volumes in the second half of the projection period.

Table A1.4 EC Global energy prices

	1990 US$			**%Change**	
	1990	**2010**	**2020**	**1990/2020**	**2010/2020**
Oil ($90/bbl)					
Reference case (no resource constraints)	23.8	16.9	20.1	-15.5	18.9
Half resources available	23.8	19.3	25.0	5.0	29.5
Protracted Asian Economic crisis	23.8	15.9	19.0	-20.2	19.5
Gas import price ($90/boe)					
American market	10.8	17.8	18.3	69.4	2.8
European market	15.2	15.2	19.8	30.3	30.3
Asian market	20.6	21.9	23.3	13.1	6.4

Source: POLES model for EU Energy Outlook

Table A1.5 European Energy Outlook Price Assumptions

	1998 EUR/boe			**%Change**	
	1995	**2010**	**2020**	**1995/2020**	**2010/2020**
Oil	14.3	15.1	18.0	25.9	19.2
Gas	11.5	14.0	16.9	47.0	20.7
Hard Coal	9.1	9.0	9.2	1.1	2.2

Source: EU Energy Outlook

Table A1.6: Price assumptions used in EP68 (all real 1999 prices)

	2000		2010 – 2020	
	Low	**High**	**Low**	**High**
Crude oil $US/bbl	24.0	27.0	10.0	20.0
ARA coal $US/tonne	31.8	37.1	26.5	42.4
Delivered coal p/term				
Industry	12.5	13.8	11.1	14.9
Services	17.3	18.6	15.9	19.6
Domestic	56.1	57.4	54.7	58.4
Delivered gas p/therm				
Industry	12.3	16.6	12.3	24.3
Services	17.8	21.5	17.6	28.5
Domestic	41.0	46.7	40.4	56.6

Source: Energy Projections for the UK EP68

D. Background on Energy prices

Why did prices rise so high in 2000?

Crude prices[24] troughed at $10 in early 1999. They have risen steadily since then to peak at nearly $35 in October 2000 and have subsequently fallen back to around $27. The sharp rise was chiefly caused by stronger demand – on the back of a more rapid recovery in world output than many expected – and tighter supply, as OPEC squeezed production in 1999 which wiped out the usual annual seasonal stockbuild in the summer of 1999. OPEC eased supply constraints from March 2000 adding 3.4m barrels per day in 2000. However, net supply did not rise sufficiently to rebuild stocks to normal levels, chiefly because product stocks were very low in 2000, putting more pressure on refineries to raise output at a time when spare capacity was low (reducing scope for restocking). In particular, there was strong US gasoline demand over the summer, while refineries were having difficulty producing gasoline to new stricter environmental specifications.

With low stocks, the link between product and crude markets is more direct. Crude prices responded more directly to adverse product market news, even as crude production has been rising. Further, stockbuilding was deterred by persistent (but incorrect) expectation that future prices would fall. Imperfect information in the oil market seemed to exacerbated price movements in a tightly stretched market.

The relationship between gas and oil prices

Since Spring 2000 wholesale gas prices have risen from between 9- 11p per therm to highs of 25 – 30p per therm. Prices have now fallen back to around 16 - 18p per therm but lower prices are expected in the summer time and prices are likely to be higher than this in the Autumn and Winter. It is unlikely that we will see a return to Spring 2000 prices.

The major cause of the price rise has been arbitrage across the interconnector with high oil related gas prices in Europe. This situation has arisen because of the lack of liberalisation and competition in Europe and the consequent lack of competition between gas suppliers. Many industrial and commercial customers have contracts tied to the wholesale market and have therefore felt the effect of the rise immediately. Others have felt the effects as and when their contracts were renewed. DTI data shows that, on average, industrial retail gas prices rose by around 50% in the year to Q1 2001. We have however, anecdotal evidence that some industrial and commercial customers are facing rises of 60% or more.

Such price rises also have implications for domestic gas consumers, but less so in percentage terms for whom the cost of gas is a much smaller proportion of the supply price. In the longer term, there could also be an impact on electricity prices, as gas accounts for around 35 per cent of generation, and wholesale electricity prices account for around half of a domestic customer's final bill. However, there is no indication that higher gas prices have led to higher wholesale electricity prices to date, nor do forward prices seem to have been affected.

[24] Brent 2-month futures prices

ANNEX 2

A Background issues to UK supply and Demand

Ireland's gas import requirement

Exports to the Irish Republic will grow at least until the Corrib field enters production (now estimated for 2003), and even then Corrib is not expected to be in production for longer than 6 years. The Irish Government has commissioned a second Scotland–Ireland Interconnector, as the capacity of the existing Interconnector is not expected to be sufficient to match the demand in Ireland for UK gas.

UKCS gas reserves

Proven reserves are known reserves which, on current evidence, are almost certain to be technically and economically producible i.e. have a better than 90 per cent chance of being produced. Probable reserves are known reserves which are not yet proven but which are estimated to have a better than 50 per cent chance of being technically and economically producible. Possible reserves are those reserves which, at present, cannot be regarded as 'probable' but are estimated to have a significant but less than 50 per cent chance of being technically and economically producible.

In addition to discovered reserves shown in the chart in section 2a of the main paper, further exploration activity is likely to discover additional reserves in as-yet-undiscovered fields. The extent of production from these fields will depend on the pace and success of exploration activity. This, in turn, depends on expected levels of oil and gas prices. Oil prices are relevant because much gas is produced in association with oil. The contribution from yet-to-be-found reserves is likely to increase over time and may eventually exceed the "possible" line.

Norwegian gas reserves

The latest Norwegian (NPD) estimates suggest that Norway has around 7,000 billion cubic meters of recoverable gas (in both already discovered and potential new discoveries). Of this around half is in the North Sea with around 1,000 bcm remaining in existing, in producing North Sea fields (a figure more in line with the proven reserves quoted by BP[25]) and slightly less in other already discovered reserves in North Sea fields.

B. Infrastructure implication for imported gas, including links with Norway

Potential import capacity in pipeline systems

A combination of existing Norwegian and UK infrastructure gives a known potential import capacity of 26 bcm per year. The extent to which that potential is realised will depend on at least 3 important factors:

i) Norway's options

[25] BP Amoco statistical review of world energy 2000

Norway has five existing gas export pipelines to continental Europe: Zeepipe I to Zeebrugge; Franpipe to Dunkerque; Norpipe, Europipe I and Europipe II to Emden (see map on page). Gas from any of the Norwegian fields that might supply the UK could be diverted to Europe via any of these pipelines. Gas via Zeepipe I can, in addition, enter the UK directly via the UK/Belgian downstream Interconnector (gas from the other pipelines could enter the Interconnector indirectly via other Member States transmissions systems).

ii) Future UKCS developments

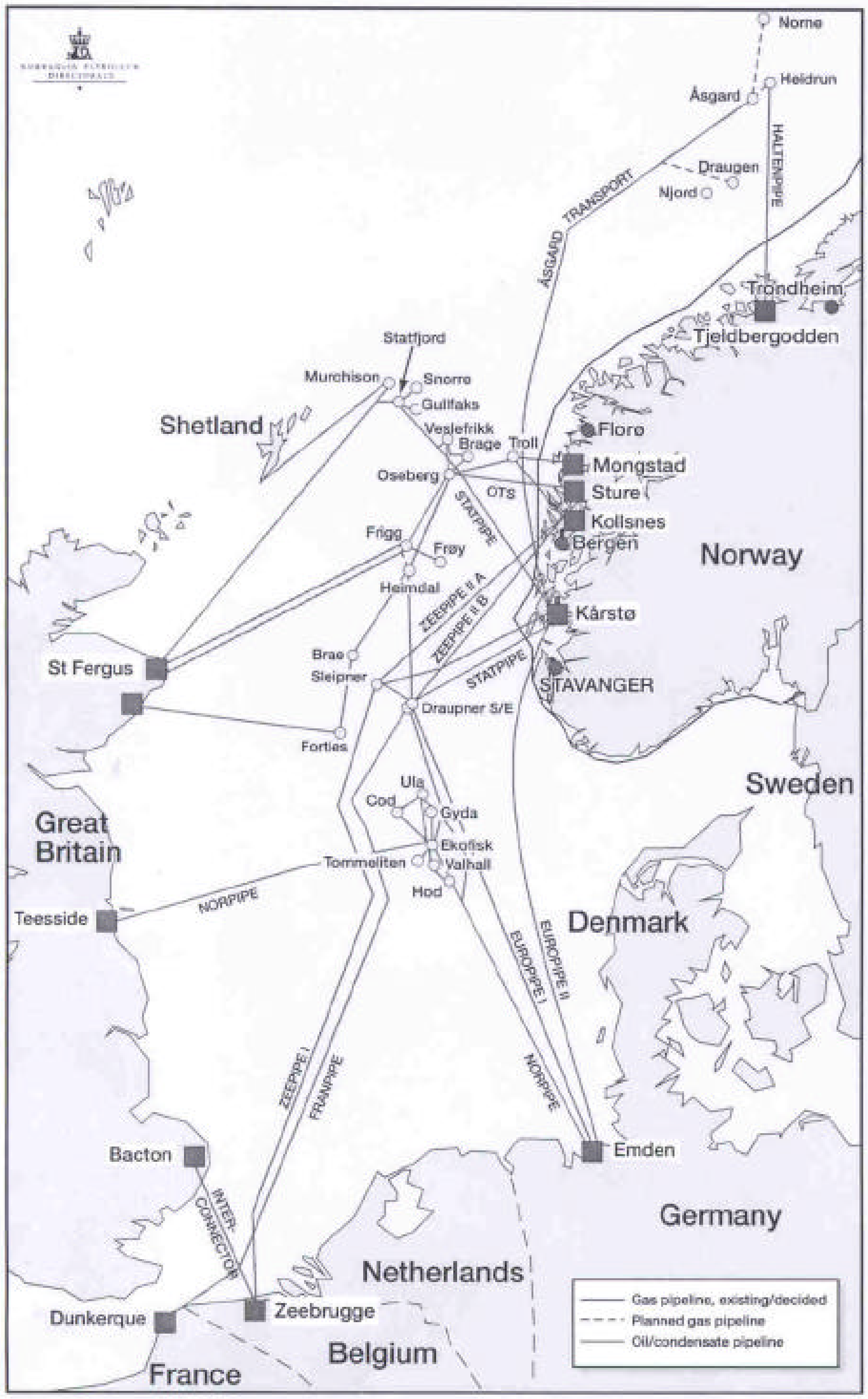
The UKCS is a mature province and UK average annual gas supply is expected to diminish from 2005/06, but production will not suddenly stop at that point. Although on a declining trend, UKCS production could be prolonged by making use of increasingly available UK pipeline capacity to transport gas from third party UKCS fields for which the construction of dedicated pipelines would not be economically viable (and which might therefore not go ahead without access to adjacent third party infrastructure). This gives rise to two main issues when considering the implications for UK infrastructure of increased imports from Norway. First, whether the volume of Norwegian gas carried in UK pipelines would effectively block out capacity for UK fields; second, whether the type of gas from Norway would make UK pipelines incompatible for UKCS product.[26]

iii) Chemical feedstock

The UK chemical industry depends in part on supplies of wet gas as a major feedstock material. This requirement needs to be considered alongside the need for additional dry gas supplies.

[26] UKCS fields close to infrastructure which might be accessible to Norway are largely “wet gas”, containing a high volume of liquid which is processed out at onshore UK terminals; relevant UK pipelines accordingly also carry mainly wet gas. Gas from Norway can be “dry” with much of the processing done offshore on the Norwegian Continental Shelf before the gas is exported. Carrying Norwegian dry gas in UK pipelines could therefore make the transport of wet gas from UKCS marginal developments uneconomic.

North Sea gas pipelines



ANNEX 3

A Attracting new investment and developments in the North Sea

Oil and Gas Industry Task Force Vision for 2010

- investment in the UKCS sustained at £3bn per annum;
- UK share of world supplies market increased by at least 50 per cent, an increase of £2bn, over the next five years;
- £1bn additional value from new businesses;
- supporting up to 100,000 jobs more than there would otherwise have been;
- production at 3m barrels of oil equivalent per day;
- prolonged self-sufficiency in oil and gas.

Turning the vision into reality

A series of individual initiatives under PILOT have been devised to improve the industry's performance. These include:

- LOGIC, a project aimed at improving supply chain management, which it is thought could generate savings on the UKCS of £1bn by 2002;
- LIFT, a project using the internet to bring together parties interested in licence trading, so that, for example, smaller specialist companies can exploit opportunities which may be too small for the majors to bother with;
- improvements to the regulation and licensing system so as to minimise regulatory burdens;
- a review of undeveloped discoveries and "fallow acreage" to see if more can be done to encourage development and further exploration;
- collaboration on decommissioning, where the OGITF concluded that industry-wide collaboration could generate savings of up to £2bn over the next ten year.

Progress to date

PILOT appears to be on target to meet its targets. In particular, the September 2000 UKOOA survey forecast:

- investment in 2002 should be around £3bn – about the same as in 1999 and 2000, but rather lower than forecast for 2001;

- production levels for oil are expected to continue to rise over the next three years and for gas for the next five years.

B Third Party Access to Upstream Pipelines

Offshore infrastructure (upstream pipelines and processing facilities) is built and owned by a variety of companies and consortia. If third party fields are too small to support their own infrastructure, their developers must negotiate with the owners of neighbouring infrastructure for access to it to transport and/or process their oil or gas. The negotiation of third party access to infrastructure is subject to both a voluntary industry Code of Practice and a legislative backstop.

DTI published a consultation document *Oil and Gas Infrastructure: Access Provisions and Voluntary Arrangements* on 15 February 2001 to see whether (inter alia) there are barriers to exploration for and development of new fields posed by high tariffs or difficulties of third party access to infrastructure. The Department's proposals, which also include minimum requirements for publication of main commercial conditions for onshore gas processing and proposals for guiding principles on the use of the Secretary of State's powers to settle disputes over access to pipelines and other infrastructure when requested by third parties, are intended to encourage a pro-competitive environment in relation to third party access to oil and gas transportation and processing infrastructure.

C Enhancing Business Opportunities Overseas

Specific actions already in hand are to:

- promote, in bilateral dialogue with individual OPEC members, the opening up of upstream activity in the oil and gas sectors to UK investment: (DTI/FCO);
- seek also a level-playing field, in terms of fiscal and environmental regimes, for UK investment in all non-OPEC producing countries; (DTI/FCO)

ANNEX 4

A UK Fuel Mix

Modelled future primary energy demand (Based in average of CH and CL from EP68)

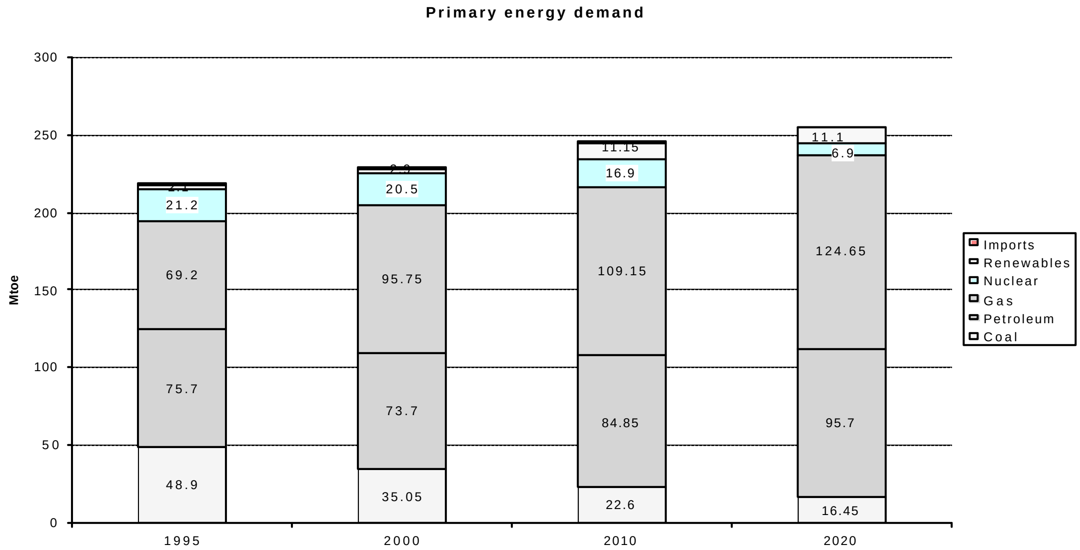


Table A4.1

Final Energy Demand from EP68, Ave of CL and CH — Fuel mix, % of total

	2000	2005	2010	2015	2020	% change 2000 - 2020	2000	2005	2010	2015	2020
Domestic											
Electricity	9.6	10.7	11.6	11.9	12.2	28.0	21.1	22.8	24.0	24.1	24.1
Gas	31.3	32.3	32.6	33.4	34.1	8.9	68.9	68.6	67.6	67.3	67.1
Oil	3.4	3.3	3.6	3.9	4.2	22.9	7.5	7.1	7.5	7.9	8.3
Solid Fuel	1.1	0.7	0.5	0.3	0.2	-78.8	2.5	1.4	1.0	0.7	0.5
Renewables	0.0	0.0	0.0	0.0	0.0	-75.0	0.1	0.1	0.0	0.0	0.0
Total	45.4	47.0	48.3	49.6	50.7	11.7	100	100	100	100	100
Transport											
Motor Spirit	23.3	23.8	25.2	27.3	29.3	25.5	42.4	39.5	38.3	38.6	38.4
DERV	18.1	21.2	23.1	24.2	25.4	39.9	33.0	35.1	35.1	34.2	33.3
Aviation	11.2	13.1	15.3	17.2	19.5	74.4	20.3	21.6	23.3	24.3	25.6
Other	2.4	2.3	2.2	2.1	2.1	-10.6	4.3	3.8	3.3	2.9	2.8
Total	55.0	60.4	65.8	70.8	76.3	38.6	100	100	100	100	100
Service											
Electricity	8.5	9.3	9.6	9.9	10.1	19.4	37.3	39.2	39.5	39.5	39.3
Gas	11.3	11.9	12.4	13.0	13.8	21.6	49.8	50.2	50.8	51.9	53.4
Oil	2.6	2.2	2.0	1.9	1.6	-38.8	11.4	9.3	8.4	7.4	6.1
Solid Fuel	0.3	0.3	0.2	0.2	0.1	-54.8	1.4	1.1	0.9	0.7	0.5
Renewables	0.0	0.1	0.1	0.1	0.2	466.7	0.1	0.3	0.4	0.6	0.7
Total	22.8	23.6	24.4	25.1	25.8	13.5	100	100	100	100	100
Industry (incl. Agric)											
Electricity	10.0	10.5	11.0	11.4	11.9	18.8	24.8	25.6	26.3	26.9	27.4
Gas	17.1	17.6	17.9	18.4	18.8	10.0	42.4	43.0	43.0	43.2	43.4
Oil	6.4	6.3	6.5	6.5	6.6	2.7	15.9	15.3	15.6	15.3	15.2
Solid Fuel	6.3	5.9	5.7	5.6	5.5	-12.4	15.5	14.4	13.6	13.1	12.6
Renewables	0.6	0.7	0.6	0.6	0.6	3.3	1.5	1.7	1.5	1.5	1.4
Total	40.4	41.0	41.7	42.5	43.4	7.5	100	100	100	100	100

B Energy diversification projections from World Energy Outlook

Table A4.2 Total Primary Energy Supply % fuel mix

	OECD North America		OECD Europe		OECD Pacific	
	1997	2020	1997	2020	1997	2020
Coal	23	22	20	14	21	18
Oil	39	41	40	38	50	44
Gas	24	26	20	30	12	15
Nuclear	8	5	14	9	13	16
Hydro	2	2	2	2	2	2
Other renewables	4	4	4	6	3	5

Source: World Energy Outlook, IEA

C European –wide market regulation

Some commentators have raised the possibility of the new EU Electricity and gas liberalisation Directive leading to a new super regulator to oversee pricing and assess to cross-border interconnectors. In turn wider integration of electricity grids could be expected which may reduce capacity constraints or lead to excess capacity. But numerous issues arise concerning how individual electricity markets are regulated in a European wide market.

The draft new liberalisation directive (as discussed at the Stockholm Council) lays down the principles underlying charges for access to national transmission networks, the management of congestion and the allocation of interconnector capacity. The directive provides provision for a regulatory committee that would act as such in approving Commission guidelines on the procedures and methodologies for access to cross-border electricity transmission capacity. But would only act as an advisory committee to the Commission on deciding amounts of compensation received by operators for transit flows through their networks. Thus the Regulatory committee falls far short of a European electricity regulator. But would provide a means of enforcing decisions on cross-border trading reached by member states and regulators.

ANNEX 5

A. Factors affecting UK coal demand

(i) Competition from other fuels

Although the UK has approximately 30 GW of power stations able to use coal, most of these stations were built in the 1960s or early 1970s and are thus already 30 or more years old. Although coal fired stations can in theory be kept going more or less indefinitely with appropriate maintenance, this becomes increasingly expensive. Furthermore the chances of significant new coal power stations being built by 2010 on commercial grounds alone is low - not least because of the considerable uncertainty surrounding future environmental regulations (more of which below). There is therefore a longer term risk that if decisions on new capacity and capacity closure are left to the market, the share of electricity generation from coal will decline to 15% or less of the total by 2010 – even assuming no further downward pressure resulting from stricter environmental limits. Even with energy prices at the top end of a sustainable range, coal's share of generation will decline to 22% or less. This compares to 33% share of electricity generation in 2000.

Coal fired generation has some advantages over other energy sources. Loads can be varied relatively easily, so coal fired generation is particularly useful in meeting peak demand or covering for supply difficulties in other fuels (indeed some sources suggest that coal plant has provided about 70% of the balancing for NETA). This may be more important as the share of renewables – whose generating capacity can be subject to fluctuations caused by external factors such as wind strength, and therefore requires alternative back-up – increases. At present coal fired stations also tend to be more resilient and easily repairable than the higher precision CCGT stations, although the latter can be expected to improve significantly in the next few years. Coal fired stations therefore make an important contribution to security of energy supply.

At current coal and gas prices, coal stations are likely to be competitive against many of the existing gas stations, although some fall in coal consumption is likely over the next decade. If international prices remain high relative to coal, then by 2005 coal's share of the electricity market could stand at about 27%. But at the gas prices of the late 1990s, coal would struggle to compete – its share of the generation market could fall to about 15% by 2005 or soon thereafter.

The table below illustrates possible coal demand at low (CL) and high (CH) world energy prices, as forecast in Energy Paper 68. These levels would be enough to absorb UK deep mined output (if this can compete on price), but if environmental concerns are not met demand could be substantially lower.

	CH	CL
2000	59Mt	59Mt
2005	50Mt	33Mt
2010	43Mt	26Mt

(ii) Environmental concerns

Future coal use in the UK is threatened by environmental concerns on 3 main fronts – sulphur, NOx and CO_2. The first two contribute to acid rain emissions and the last to greenhouse gases. Future controls on these emissions could considerably dent coal prospects, and not just in the period beyond 2010.

Sulphur

The sulphur issue is particularly significant for UK (especially English) coal since much of it has a higher sulphur content than most imported coals. Flue-gas desulphurisation (FGD) can remove approximately 90% of sulphur emissions. But generators have been reluctant to fit FGD due to its cost (c£200m to retrofit at a typical 2GWcoal power station) and the risk that future progressively tighter control on NOx and CO_2 may undermine the value of the investment needed.

Current FGD plant (6GW already in place, and another 2GW likely) could provide a market for up to 15-20Mt/year of higher sulphur UK coal. (There are also reports that a further 4-5GW of FGD is planned, but in current circumstances, with considerable uncertainty over future levels of wholesale electricity prices and emissions abatement standards, there remains doubt as to whether generators will be persuaded to commit investment to these projects.) This could potentially provide enough capacity to absorb UK deep mined production. However some deep mines depend on particular power stations, so if the latter don't fit FGD the former may be forced to close; this level of demand would not be enough to absorb open-cast output. UK FGD plant would not necessarily use UK coal – the latter would have to compete on price with imports and gas. Actual coal use is likely to be a good deal lower if coal prices are high relative to gas – the CH scenario.

Nitrogen oxides (NOx)

Limits on emissions of NOx affect UK and imported coal equally, except that Welsh anthracite (used at Aberthaw power station) is particularly vulnerable to tightening NOx controls. There is a real risk that future tightening of regulations on NOx emissions could force the premature closure of coal generation plant, including that already fitted with FGD.

Selective catalytic reduction (SCR) is proven technology for abating NOx emissions and would be regarded as “Best Available Technique” (BAT) for new coal-fired plant. However this is not economic to fit to existing plant and run at current prices of gas and coal (costing c£100m /GW to install combined with significant running costs), and requires the transportation of large quantities of highly toxic substances (typically ammonia and catalyst materials) for its operation. Nevertheless the Germans have already fitted this to all their coal-fired plant, consistent with their policy of continued subsidies to coal, and they are leading the pressure to see it installed elsewhere. There have been some developments in gas reburn technology which may provide a more economic solution, going some way towards the lower emission limit values proposed by the EP. Other abatement technologies such as coal reburn and overfire air are also less expensive than SCR.

Carbon dioxide

The UK is likely to meet its Kyoto greenhouse gas targets for 2008-12 without further policy measures. In that sense CO_2 is not an immediate problem for coal. However the UK domestic goal to reduce CO_2 by 20% on 1990 levels by 2010 is much more difficult. Whilst the Climate

Change Programme does not currently include new measures cutting coal use beyond existing projections, such measures could be returned to if that Programme were seen not to be delivering. Coal powered stations emit approximately twice the CO_2 emitted from equivalent gas powered stations, per unit of electricity generated. UK and imported coals release about the same amount of carbon dioxide upon combustion. Thus tightening of CO_2 targets, and other possible future measures such as carbon emissions trading, are likely to impact on the demand for coal generally, unless coal burn is combined with other measures such as sequestration. As policies on CO_2 become more stringent, it will become increasingly difficult to shield the coal industry unless we have an overt policy for doing so. This might be desirable both for security of supply and value for money reasons - it is not entirely clear where the balance of advantage, in terms of cost per tonne of CO_2 saved, lies between coal and other energy sources. In the short-medium term, reduced use of coal offers a relatively cheap source of CO_2 savings, albeit at an increased risk in terms of security of supply. CO_2 sequestration may become cost-effective in the longer-term (perhaps 2020 or beyond) if much tighter greenhouse gas limits are enforced.

B. Factors affecting UK production

(i) International price of coal – can UK coal compete?

There was a considerable rise in coal prices last year, combined with an increase in coal burn. Much of the increase was supplied by imported coal. If coal prices remain at current levels, most UK mines ought to be able to compete against imported coal in the short to medium term. But significant falls in the international price of coal are by no means out of the question over the next few years, and in such circumstances it is likely that much of the deep mined sector would find it hard to compete.

Even in the best case scenario (i.e. with high gas prices), UK coal mine sales would be expected to fall from their current level of 32m tonnes to 30Mt in 2005 and 23Mt in 2010. With low gas prices, UK production might fall to as little as 12Mt in 2005 and 6Mt by 2010.

Unless world coal prices reach the order of £36/tonne, it very unlikely that any new UK deep mines will be commissioned (although new reserves in existing mines may be developed at lower price levels). Opencast mines are also facing increasingly stringent planning controls. This points to considerably lower UK production beyond 2010, unless world coal prices rise above all current expectations.

(ii) Geology

The UK has huge reserves of coal. However, relatively little of it is likely to be capable of economic extraction by conventional. Estimates for UK coal reserves accessible by currently active deep mines are around 200-300 Mt, and perhaps an additional 700 Mt might be accessible through recently operating deep mines (closed since 1993). However much of this, for geological, geographical or technical reasons, is unlikely to be economically viable to mine.

Opencast sites have 20-25 Mt of reserves at operating sites and a further 230 Mt available under conditional licence. Opencast sites can be accessed much more quickly than deep mine seams and it can be argued that longer term security of supply concerns are best addressed by ensuring that a significant amount of readily accessible opencast reserves remain unexploited.

The licensing of opencast operations is constantly being tightened up (for environmental and planning reasons) which will restrict the output from that sector. There is a strong feeling within the industry that planning regulations are putting a very real constraint on the future of open-cast mining, and those involved have been keen to point out that this will mean more coal imports rather than more UK deep mined production.

(iii): Infrastructure constraints

Shortage of port facilities does not in itself appear to be a major factor inhibiting the short or longer term ability of the UK to use imported coal, although problems with rail limit the flexibility with which these port facilities can be used. In 2000, the UK imported some 15 Mt of steam coal and it is likely that it could import at least 20 Mt per year without any addition to port facilities. Plant closures in the steel sector could also free up port capacity currently used to import coking coal.

The ability of the rail network to handle larger volumes of imported coal is less clear. For example, one generator complained to us of real problems on the railways that have left their power stations very short of stock as demand has risen and prevented them from exploiting profitable weekend running opportunities. Another told us that they have come close to running out of coal at one power station due to rail transport problems.

The rail network showed signs of being close to capacity last year, but this may have been a temporary problem due to the unanticipated rise in coal imports of some 3 Mt. Indeed it is quite likely that, over a period of time, the system could accommodate 20 Mt /year of imported steam coal without significant extra cost. That would comprise almost 60% of our upper projections for coal demand in 2010, the rest of which could be supplied from UK produced coal. However the current management of the system, no doubt caused at least in part by the low level of competition in the freight market, raises real concerns for coal generators.

ANNEX 6

A Off shore capacity

Offshore gas supply infrastructure broadly falls into two categories: pipelines and associated facilities primarily designed for the delivery of largely unprocessed gas from offshore fields and purpose built interconnectors to transmit processed gas between the UK, Belgium and Ireland.

A likely scenario is that when new and existing UK gas fields are exhausted then associated small 'branch pipelines' feeding into large 'trunk pipelines' to shore could well close. Several large trunk lines are however likely to remain open and could increasingly attract Norwegian gas imports or provide opportunities for links between the Southern North Sea and Dutch pipeline systems.'

B Onshore – offshore link (capacity auctions)

Under the old regime (which was in place until October 1999) Transco allowed shippers to have as much capacity as they wanted at any terminal. However this meant that there was no guarantee that a shipper would actually be able to access the capacity they thought they had as demand often exceeded capacity supply. The events of summer 1998 at St Fergus also proved that this system was open to abuse. Auctions for entry capacity now take place on a six monthly basis for the summer period (April to September) and winter (October to March). Firm entry capacity at each terminal is auctioned off in tranches over four rounds. Any remaining capacity is sold in a fifth round and can be allocated to whichever terminal the shipper chooses.

Transco, which operates the NTS, has a target revenue to recover from the auctions and as they are price capped they are not allowed any excess. In this round Transco over recovered by £300 million. Transco consulted on proposals to redistribute the money and has decided that it will go back to shippers via a reduction in the transportation charge. Transco believe that this method will cause the least distortions, even so it is likely that the largest shippers will gain most. There is also the possibility that this may have influenced their bidding behaviour in the first place. Shippers are not obliged to return any of this money to final customers.

<u>Ofgem's long term investment regime proposals for Transco</u>

Ofgem are proposing a new long-term investment regime as part of Transco's next price control, to commence in 2002. This is under discussion between Ofgem and Transco.

C Cost-reflective pricing and the domestic sector

<u>Implications for fuel poverty</u>

Key to the development of cost-reflective pricing will be the development and installation of intelligent meters which can (a) detect and implement pricing changes and (b) communicate those changes to consumers such that they have the option to alter their behaviour so as to affect the prices they are charged.

Ofgem has recently published a consultation paper on intelligent metering[27] which exposes some of the issues around the concept. Potential benefits for customers include:

- more accurate billing;
- more effective energy management;
- development of new tariffs (which could include cost-reflective ones relating immediate price to levels of consumption or demand);
- greater demand side participation in energy trading (more for industrial users);
- cheaper prepayment meters, or meters that could easily change between types of charging mode.

Potential benefits for the supply side include better load management, lower supply peaks, reduced need for system reinforcement, and reduced need for additional capacity. For suppliers, there could be significant cost savings from remote meter reading and more regular billing.

These meters have yet to be developed, although DTI (CII) hopes to sponsor a programme later in the year to help the progress along. The primary DTI interest is in using the new metering technology as a means of ensuring internet access for those who cannot afford home computers, or do not want, or cannot get, cable TV, or do not want to buy "internet TVs" which plug into the telephone socket.

One handicap to the development of such meters is the diversity of ownership of the meters themselves and of the ownership of the benefits flowing from newer (and more expensive) equipment. For gas, the PGTs (essentially Transco) own the meters, shippers purchase metering services. For electricity, the position is more complex. For half-hourly (industrial) meters, there are a range of meter providers, including second tier RECs and independent third parties. For domestic meters, the meter owner may be the REC, or the (possibly independent) distribution business set up after the Utilities Act, or a third party. The purchaser of the meter services is the supplier. Given the diversity of interests, and absence of a direct match between those who own or operate the meters and the recipient of the benefits from the use of the meter (not just final consumers, but also, for example, the Grid and generators), there is an issue about how and indeed whether a concerted supply side push might develop for the improvement of meters.

For the purposes of consumer benefit, smart metering and cost-reflective pricing must be considered as separate issues. For the reasons given above, better metering could benefit consumers, including the fuel poor: irregular billing, or unexpected large bills because of previous estimated readings, are significant factors in the development of debt. The advantages of smart metering may or may not be combined with a move to cost-reflective pricing: and the benefits of this to consumers, and particularly the fuel poor, are much less clear.

For the various benefits of cost-reflective pricing to be captured, it would be essential not just for the meters to be developed and installed, but for the customer base to use them appropriately. For all customers, the opportunity to profit from the pricing signals from new meters would depend on their ability to shift their consumption away from expensive peak times. This in turn would depend on the timing of need (for example, people could not

[27] *Ofgem's strategy for metering – a consultation paper*: 28 March 2001.

necessarily shift cooking to mid-afternoon or late night simply because it was cheaper) and their capacity to understand and use whatever information the meter was giving out. There is an issue here of the type of information shown, and how easily it would be understood.

ANNEX 8

A. Scenarios

Rather than establishing a simple baseline projection, another approach, used to deal with the inherent uncertainties associated with the longer term, is the development of scenarios. Energy and emission scenarios are used extensively in long-term policy work to stimulate debate about the future. Notably, the emissions scenarios developed by IPCC provide 4 qualitative storylines which explore alternative directions in which social, economic and technical changes may evolve over coming decades. Closely linked to these scenarios and developed by SPRU and the DTI, are the Foresight scenarios.

The point of scenario development is to provide a range of “views of the world”. They don’t have to be considered equally likely. Indeed, some might be considered very unlikely. But they can be helpful in a planning context – for example, to consider potential policy developments which may be consistent with a range of future outcomes. Generally an emissions scenario represents a complete set of assumptions regarding the possible state of the future. These include assumptions about the socio-economic situation, future climatic effects and the impact of technological change on the environment.

The IAG needed a baseline or range of baselines, in order to explore potential policy implications, including a scenario approach and used the Foresight Environmental Futures scenarios[28]. The four scenarios are described briefly as:

> **World Markets**: - based on individual consumerist values, a high degree of globalisation and scant regard for the environment.
> **Global Sustainability**: -based on predominance of social and ecological values, strong collective environmental action and globalisation of governance systems.
> **Provincial Enterprise**: -based on individualistic consumerist values, reinforced governance systems at national and sub-national level
> **Local Stewardship**: - based on communitarian and strong conservation values, diverse political systems and economic regionalisation.

The key assumptions for each scenario were based on developmental work by SPRU. The scenarios aim to represent a range of demographic, social, economic and technological driving forces. They produce a wide a range of carbon emissions scenarios. The IAG took some of their key assumptions (including rates of growth of GDP, and population and household numbers) and projected forward from 2010 or 2020 baselines on those different assumptions. The scenario assumptions do not consider the more rapid or radical technological change that may be associated with each scenario, although these may to some extent be reflected in the assumptions on GDP, population and household growth. This gives another 4 projections of CO_2 emissions beyond 2010 based on the socio-economic conditions associated with each of the four scenarios.

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[28] The Foresight scenarios were developed in co-operation with SPRU. They are closely aligned to the IPCC emission SRES scenarios, most recently updated in 2000.

In this way, the range of CO_2 projections through to 2050 is increased. This is not the same as providing a full range of CO_2 projections based on fully different scenarios - because the fully different scenarios probably imply different rates of technology improvement, of environmental behaviour and of willingness and capacity to introduce policy measures to reduce emissions that we have not allowed for[29]. But this does provide a set of projections of CO_2 emissions which imply different scale of gap to a 60% reduction target – gaps which would have to be filled by other actions.

In all cases our scenarios only start to diverge after 2010 or 2020 depending on the base point chosen. Up to then they all reflect the average of the EP68 central scenarios. Allowing for divergence from 2010 rather increases the range of results for 2050. On some scenarios it will indicates we are further from the RCEP target.

The scale of the gap, MtC, to the 60% reduction target in 2050 is summarised in Table A9.1 below. It might be considered that an assumption of continued improvement in carbon intensity at the higher rate projected for the UK in the period 2000-2010 (reflecting the CCP) is more relevant to the global sustainability and local stewardship scenarios. Or that improvement at the same rate as observed from 1970-2000 has more in common with world markets or provincial enterprise. In the table these correspond to the highlighted figures in bold.

Table A8.1: size of gap in 2050 relative to Kyoto[30] and RCEP targets, CO_2 only, based on a 2010 forecast base

Target	**Basecase**	**World Markets**	**Provincial Enterprise**	**Global sustainability**	**Local Stewardship**
Kyoto	Goes beyond by between 9 and 55 MtC	Goes beyond by 39 MtC to **falls short** by **17** MtC	**Goes beyond** by between **37** and 71 MtC	**Goes beyond** by between 33 and **67** MtC	**Goes beyond** by between 67 and **89** MtC
RCEP	Falls short by between 30 and 76 MtC	**Falls short** by between 46 and **102** MtC	**Falls short** by between 14 and **48** MtC	**Falls short** by between **18** and 52 MtC	**Goes beyond** by **4** MtC to falls short by 18 MtC

Source: Preliminary work of Interdepartmental Analysts Group

[29] Our scenarios do include some basic assumptions which reflect a de-coupling of economic growth and transport growth, and improvements in emissions associated with the vehicle stock.

[30] A proxy. The Kyoto target is a 12.5% reduction in a basket of greenhouse gases. The benchmark against which the comparison is drawn is a 12.5% reduction in CO2.

Table A8.1 (cont.): based on a 2020 forecast base

Target	**Basecase**	**World Markets**	**Provincial Enterprise**	**Global Sustainability**	**Local Stewardship**
Kyoto	Goes beyond by between 6 and 23 MtC	**Goes beyond** by **8** MtC to falls short by 14 MtC	**Goes beyond** by between 27 and **41** MtC	**Goes beyond** by between **25** and 37 MtC	**Goes beyond** by between 52 and **61** MtC
RCEP	Falls short by between 62 and 80 MtC	**Falls short** by between **77** and 99 MtC	**Falls short** by between **44** and 58 MtC	**Falls short** by between 48 and **60** MtC	**Falls short** by between 24 and **31** MtC

Source: Preliminary work of Interdepartmental Analysts Group

Note: The figures in this table reflect the same assumption for carbon dioxide from land use change in each projection[31]

[31] New land use change (LUC) figures for past emissions and for projections have also just become available. These are not reflected here, but will be included in further work. The implications of the revisions for the above results will be small. Throughout these calculations the assumption is of constant LUC to 2050 of 4.4 MtC.

ANNEX 9

Table A9.1 : RCEP Scenarios for 2050 from RCEP report – Energy The Changing Climate

Four scenarios to illustrate the options available for balancing demand and supply for energy in the middle of the 21st century if the UK has to reduce carbon dioxide emissions from the burning of fossil fuels by 60%:

Scenario 1: no increase on 1998 demand, combination of renewables and *either* nuclear power stations *or* large fossil fuel power stations at which carbon dioxide is recovered and disposed of

Scenario 2: demand reductions, renewables

Scenario 3: demand reductions, combination of renewables and *either* nuclear power stations *or* large fossil fuel power stations at which carbon dioxide is recovered and disposed of

Scenario 4: very large demand reductions, renewables

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Percentage reduction in 1997 CO2	57	60	60	60
DEMAND (%)				
Reduction from 1998 final consumption				
Low grade heat	0	50	50	66
High grade heat	0	25	25	33
Electricity	0	25	25	33
Transport	0	25	25	33
Total	0	36	36	47
SUPPLY (GW)				
Annual average rates				
Fossil fuels	106	106	106	106
Intermittent renewables	34	26	16	16
Other renewables	19	19	9	4
Baseload stations (nuclear or fossil fuel with recovery)	52	0	19	0

Prices suggested for the renewables options have been taken largely from work by ETSU on resource cost curves, (taking 2025 as a proxy for 2050 given a lack of data looking further ahead and that the maximum potential identified by ETSU had not been breached). However, this approach is clearly not ideal and much further work is required. Where the output included in the scenario for an option exceeds the total cost effective resource identified by ETSU and shown in Table 7.1 of the RCEP report, the price used is that given in Table 7.1.[32] Where possible a range of prices was used for each option including gas. The prices are given in table below. All prices are discounted lifetime costs, with minimum prices generally using an 8% rate and maximum 15%. Max t1 prices are taken from ETSU cost resource curves where maxt2 represent an alternative "high" view[33] that the resource costs may understate true cost. Prices are essentially on a 1999 basis.

Table A9.2: Suggested electricity output prices for 2050 for use in RCEP scenario cost analysis (p/kWh)

	Min	Max t1	Max t2
On shore	2.25	3.25	3.9
Off shore	2.3	3.3	3.5
Solar PV	7	7	7
Wave	3.2	5.2	5.2
Tidal stream	6.5	6.5	6.5
Tidal barrage	10	10	10
Large hydro	2	2	2
Small hydro	7	7	7
Energy Crops	3.05	4.05	4.4
Ag and forest waste	4	5	5
MSW	2.2	4	4
Nuclear	2.6	4	4
Gas	2.31	2.88	3.6

Source: Preliminary work of Interdepartmental Analysts Group and ETSU

The Kyoto Mechanisms

The United Nations Framework Convention on Climate Change (UNFCCC) provides the framework for international negotiations on climate change. Following "COP6bis" in Bonn between 16-27 July – the follow-up to the unsuccessful talks in The Hague last year – the next major event will be COP7 in Marrakech, scheduled for 29 October - 9 November

The focus of the negotiations has been to agree the detailed rules and modalities that will underpin the Kyoto Protocol published in 1997. The Kyoto Protocol provides a framework for action to tackle greenhouse gas emissions in the period to 2012. But it is very limited on detail,

[32] This applies to Solar PV, Tidal Stream, small hydro and tidal barrage.

[33] DTI (ENP3) judgements.

and agreement on the underlying rules is needed before the Protocol can be ratified and hence come into force.

One of the key innovations of the Kyoto Protocol is the role it gives to market mechanisms in achieving emissions reductions. These market mechanisms are international emissions trading, the Clean Development Mechanism and Joint Implementation. The rules for these mechanisms are among the key sets of issues that need to be resolved before ratification of the Protocol.

International emissions trading is established under Article 17 of the Kyoto Protocol. At its simplest level, it would involve transfer of “units of Assigned Amount” (the currency of international trading) between those Parties that have taken on caps on their emissions (Annex B Parties) for the period 2008-12. But there is an expectation that units of Assigned Amount will (at least in part) be devolved to legal entities which have taken on caps within each Party. This would mean that at least some trading would occur at legal entity level, which is likely to be the most efficient solution. Article 17 requires that emissions trading should be “supplemental” to domestic action.

Article 12 of the Kyoto protocol establishes the **Clean Development Mechanism (CDM)**, which consists of individual emissions reduction projects carried out in developing countries without emissions caps. It will be for legal entities to undertake these projects, with appropriate Government approvals. These projects will generate a stream of Certified Emissions Reductions (CERs), which can then be used to help deliver Kyoto targets. In principle, CDM projects could be generating CERs now. But there are a number of stumbling blocks which are preventing this from happening.

The third of the mechanisms is **Joint Implementation (JI)**, established under Article 6 of the Kyoto Protocol. JI projects will reduce emissions in developed countries that have taken on emissions caps. Once again, these projects will be carried out by legal entities, but with appropriate Government approvals. JI projects will generate Emission Reduction Units (ERUs) that are likely to be fully fungible with the international trading scheme.

ANNEX 10

Renewable electricity Generation

For electricity generation a wide range of renewable/non-fossil options exist and their production potential, as far as it is currently understood, is summarised in table A10.1 below.

The data indicates that some options have in theory limitless potential. For example the theoretical capacity offered by offshore wind could alone meet the UK's future electricity needs – the potential output at around 4,000 TWh is 10 times the UK's electricity production in 1999. Even considering the practical resource (derived from total resource by reducing capacity to account for distance from shore, difficulties of development in high wind speed areas off the outer Hebrides etc and achievable if grid connections in place and planning issues overcome) offshore wind could provide around 100 TWh of electricity a year.

On the other extreme some options such municipal waste currently appear to have only limited resource potential, regardless of the scope for significant technical advancement. However, technology and efficiency could improve (as has been witnessed in oil and gas extraction and future potential could be revised upwards).

Another factor to consider is whether the options offer a long–term potential. It is likely that whilst landfill gas is currently broadly a cost effective measure, changes to landfill practises will reduce the resource. This probably has very little potential looking to 2050 and beyond. Similarly the potential for generation from the incineration of municipal waste could be constrained in the longer term if the absolute amount of waste produced starts to fall or recycling increases substantially. In the medium term, though, there is potential for significant growth which is also consistent with the Government's Waste Strategy. But, of course, increased recycling has potential benefits for energy efficiency.

The table shows the gap between current capacity or output and potential output. This is both an indicator of current cost-effectiveness, the need for future technology development and the requirement to overcome structural barriers such as planning, grid constraints, intermittency etc. The gap can also provide a clue to market potential. Some options such as MSW and landfill gas generation can be considered broadly cost-effective in the sense that they have achieved a sizeable production and few technological developments are required. Onshore wind similarly is deployed and whilst some cost reductions are possible, its deployment is affected by factors such as grid connections and planning. It is currently more expensive than gas, but if carbon costs are internalised cost differentials close. Similar arguments hold for off-shore wind, with the proviso that the anticipated major first round of development goes ahead and costs fall as anticipated. Of the other options featured in the table (except hydro), none can be consider as commercially viable now. Useful demonstration projects are underway with energy crops, but its chief obstacle is land use and crop yield. Hydro (large and small) is deployed, but future expansion maybe limited.

The table also includes estimates for the carbon cost in £/tC for the options studied in detail against two alternative gas prices. The ranges produced indicate that against high cost gas scenarios wind power could be considered cost effective (regardless of climate change mitigation benefit) if its costs turn out at the lower end of the potential range. All options suggest a maximum carbon cost of less than £200/tC, except for municipal waste (though the small carbon savings relative to gas offered by MSW produced a wide range of potential costs). Negative cost figures indicate reflect an economic benefit.

Table A10.1: Indicative resource potential for renewable electricity generation options – based on ETSU data

		Onshore wind	Offshore Wind	Energy crops	Mun Waste	Landfill gas	Solar PV	Large Hydro	Small Hydro	Tidal	Wave
Current (1999)[1]	Capacity (GW)	0.36	0.004	0.010	0.16 (DNC)	0.3 (DNC)	0.0012 (DNC)	1.4 (DNC)	0.06 (DNC)		
	Electricity generated (TWh)	0.9			1.4	1.7	0.001	5.1	0.2		
Theoretical max	Capacity (GW)	110	1088	3 – 4 GW per 1 mill ha. Max 74 (all UK ag land)				13 (all hydro)		Tidal stream 36 TWh Barrage 50TWh	Elec gen. Shore 2 Nearshore 100 Offshore 600
	Electricity generated (TWh)	318	approx. 4,000		13.5		266 of which BIPV 37	40			
Practical max	Capacity (GW)	19							0.3 – 0.55		Elec gen. Shore 0.4 Nearshore 2.1 Offshore 50
	Electricity generated (TWh)		100			5					
Current max	Capacity (GW)	2.75						Potential for additional 1GW, but unlikely	0.04 – 0.1		
	Electricity generated (TWh)	8				5	BIPV 0.17				
Lifetime emissions g CO2/kWh[2]		9	9	14	364	49	59 -71	32	5		
Est. Cost of carbon in 2050 vs low gas price 2.3p/kWh,[3,4] £/tC		-6 to 147	-4 to 111	70 to 196	-115 to 1720	-14 to 30					
Est. Cost of carbon in 2050 vs high gas price 2.9p/kWh[3,4], £/tC		-59 to 93	-57 to 58	16 to 142	-693 to 1142	-74 to -40					

1. Data from 2000 Digest of UK Energy Statistics table 7.4, expect for offshore wind, energy crops. DNC is declared net capacity
2. Estimates from ETSU, except PV which are from Government – Industry PV group report, gas generation taken as 400g CO2/kWh
3. Price ranges used all p/kWh: Onshore wind 2.25 – 3.9, Offshore wind 2.28 – 3.5, Energy crops 3.05 – 4.38, MSW 2.2 – 4, Landfill gas 2.18 – 2.5
4. The cost analysis represents ongoing work within the Inter departmental analysts group. At the time of writing the cost analysis of other options had not been completed.
Note: Data are a guide to potential, actual utilisation will depend on many factors discussed in section 10. Gaps indicate areas where much further work is needed.

Renewable electricity generation – detail on resource potential

On-shore wind

The UK has one of the best wind resources in Europe. Clearly not all that land can be used as it includes towns, lakes, woods and other constrained areas such as National Parks etc. Removing these areas and applying limiting assumptions[34] ETSU have calculated an accessible resource of nearly 110 GW, capable of producing 318 TWh/year. Further planning limitations, such as minimum distance apart for wind farms, and minimum and maximum farm size, reduces the usable land further. As does the speed farms can be built. ETSU calculations with these factors produce an estimate of "basecase" capacity of 19 GW. ETSU then estimate that current network limitations reduce the realistic potential to around 2,750 MW, capable of producing 8, 000 GWh/year.

Off-shore wind

The UK has enormous potential for offshore wind. At the optimal turbine height of 60m above sea level, almost all of the UK's offshore wind has speed between 7 and 9 m/s. The only real limitations are practical water depths, the use of maritime areas for other activities, environmental impact and limitations of the onshore electrical network. An 'accessible resource' estimate shows[35] the potential UK offshore capacity is estimated at 1, 088 GW (total UK capacity at end 1999 was 75 GW)

Further constraints are needed to turn the theoretical maximum estimate into an estimate of practical resource estimate.[36]These restrictions produced an estimated offshore wind resource capable of producing 100 TWh per year (approx. 30% of current UK demand) of which nearly half could be produced less than 10km from the shore. However, currently network and planning constraints (although an assessment for this is included in the derivation of the practical resource) mean that the potential can not be realised.

Energy crops

1M ha of land used for energy crops would be capable of generating between 3 – 4000 MWe. There are currently 18.5M ha used for agriculture in the UK, but not all could be used for energy crops. The maximum potential is largely dependent on agricultural policy, (specifically CAP reform), crop subsidies and competition for land from different crops.,., though improvements in crop yield would also help.

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[34] maximum turbine density of 9 MW/km^2; buffer zones ranging from 100m around roads to 6km around airports; and ignoring land with a gradient in excess of 10%.

[35] derived by limiting water to 30km from shore and 40m deep and discounting sea bed with either gradient greater than 5 degrees, shipping lanes, military zones, pipelines or other constraints such as fishing grounds or wildlife reserves etc).

[36] assumes that only 5% of potential sites will be developed (as a result of seabed composition or planning constraints – a higher figure would of course increase potential); reduces capacity by 50% for sites less than 10kn from shore, for reasons of public acceptability; further reduces capacity of sites with wind speed over 9m/s by 95% to account for development barriers presented by hostile environment; finally other sites with average wind speed 8 – 9 m/s had capacities reduced by 5%.

Hydro

The total hydro power resource for the UK is estimated at 40TWh/year or 13GW of installed capacity. This is based on mean annual rainfall figures, land area and elevation data. Allowing for geographical and environmental constraints on potential sites will indicate a much reduced accessible resource. In Scotland there may be an unexploited accessible large-scale resource of 1GW or 3TWh/year. But this would require reservoir storage and its development is likely to be limited by environmental constraints. Remaining UK small hydro resource which might be commercially attractive is small – between 40 and 110 MW (under 5p/kWh unit generation cost at 15% and 8% discount rate over 15 years respectively).

Environmental constraints prevent development of the remaining resource in the UK in sensitive areas. Since the good quality, most commercially attractive resource has been virtually completely developed the domestic market is limited. Overseas markets could be significant although manufacture may be sited in the host countries. The UK has well-established turbine & electrical plant manufacturers, civil engineering companies and hydropower consultants selling predominantly overseas.

PV

The maximum practicable resource for PV is calculated as the electricity generated by the application of PV to all available domestic and non-domestic buildings. This gives a maximum of 266 TWh/year in 2025 the calculation is based on a series of assumptions made by ETSU on solar radiation, building rate, PV and inverter efficiency, property numbers etc. A substantial proportion of this resource will be relatively high cost due to low levels of received sunlight, e.g. for north-facing surfaces. For building integrated PV an ETSU study has calculated potential in 2010 as 7.2TWh/year and market potential at 32.5GWh/year; with potential extrapolation to 37TWh/year and 170GWh/year respectively by 2025 (possibly more if environmental drivers are strong).

Carbon capture and storage

CS can be used on any fossil fuel generating plant, but there are significant benefits in applying the technology to new plants (spreads capital cost over longer life; less efficiency reduction). CS could be used with viable clean coal generation to further reduce emissions for coal fired generation. There is vast storage potential in the UK alone. Storage estimates for offshore UK are: Deep aquifers, 8563 Mt CO_2; Oil fields, 2617 Mt CO_2; Gas fields, 4878 Mt CO_2; onshore deep aquifer capacity of 245 Mt CO_2. Public acceptability of CS is largely untested in the UK and concerns about reservoir integrity would need to be addressed, particularly is onshore disposal were envisaged.

ANNEX 12

The Government's draft UK Fuel Poverty Strategy

The Government's draft UK Fuel Poverty Strategy seeks to end fuel poverty for vulnerable households by 2010. Fuel poverty in other households will also be tackled once progress is made on the priority vulnerable groups. Fuel poverty is defined as a household that needs to spend in excess of 10% of household income in order to maintain a satisfactory heating regime.

The strategy sets out a range of progammes and measures to address the main causes of fuel poverty. These are:

- Programmes to improve the energy efficiency of fuel poor households, including separate home energy efficiency schemes in each country as well as efforts through local authorities, registered social landlords and energy supply companies.

- Continuing action to tackle poverty and social exclusion, recognising that these are multi-dimensional problems.

- Continuing action to maintain the downward pressure on fuel bills, ensuring fair treatment for the less well off and supporting the development of energy industry initiatives to combat fuel poverty.

DETR, and the Devolved Administrations, have put in place programmes to improve the energy efficiency of homes through better insulation and heating. These include grants for improving the energy efficiency of poor households, work by local authorities and social landlords to improve the energy efficiency of their properties, and energy supply companies' obligations under the Energy Efficiency Commitment.

Similarly the Government, and the Devolved Administrations, have put in place strategies for tackling poverty and social exclusion. These involve ensuring people are better equipped to work (through better education and training); a more active welfare system to help people become better prepared for, and find, work (New Deal); an improved position at work (National Minimum Wage, Working Families Tax Credit, etc), and increased support for pensioners (Minimum Income Guarantee and Winter Fuel Payments).

<u>Task force on expanding the gas network terms of reference</u>

- determine the number of people in fuel poverty who would benefit from extension of the gas network
- review the current arrangements for gas suppliers and public gas transporters to provide gas supplies to new areas
- review how the arrangements have worked and consider what lessons might be learned from that experience
- in the light of the Fuel Poverty Strategy, consider options for changing those arrangements to make schemes for extending the gas network easier and more economic for the gas industry. In reviewing options, the economic costs of extending the system should be

considered in relation to the expected economic benefits, both generally and in respect of the fuel poor
- make recommendations, including on matters related to regulatory arrangements and the coherence of existing arrangements with other aspects of the fuel poverty strategy, and on other practical steps

The task force will also need to consider other relevant issues, including:

- the inter-relationship between extending the gas network and access to the electricity network (about 250,000 households - 1% - do not have access to mains electricity)
- the economic impacts of extending the gas network on suppliers of other domestic fuels, including electricity, petroleum products and coal and coal products (in 1999, household expenditure on petroleum products (excluding motor fuels) was £488m, and that on coal and coke, £474m, compared with £7,392m on electricity and £5,030m on gas)
- the ability of Gas Network Codes to encourage competition between suppliers
- any competition or state aid issues arising from proposals to extend the gas network
- approaches to properties that it is not feasible to link to the network
- the economic and environmental costs and benefits of improving access to other fuels compared with extending the gas network
- the interaction with other services, and potential economies of scale arising from it
- interaction between the fuel poor and other residents of rural areas
- the additional investment in heating equipment required to enable the fuel poor to take advantage of any extension of the gas network

ANNEX 15

Renewable energy funding

In broad terms DTI are expecting to create a £1billion market for renewable energy by 2010. The key components of this are:

- The Renewables Obligation, which will require all licensed electricity suppliers to supply a specified proportion of electricity from renewable sources. Based on the proposals in the Preliminary Consultation this will benefit the renewables industry by up to £800m per year by 2010 (the maximum cost of the RO may increase if only the biodegradable fraction of waste is included in the 10% target and/or we extend eligibility to advanced energy recovery technologies such as gasification and pyrolysis).

- The Climate Change Levy exemption which will apply to most renewable generation. This exemption is expected to be worth up to about £160m per year by 2010.

- The Non Fossil Fuel Obligation (NFFO). This is the former mechanism for supporting renewables and the Government is putting in place legislation to protect all the existing contracts that were concluded under the NFFO arrangements. We are also amending the legislation to allow flexibility on the location of NFFO projects, enabling more projects to go ahead than had previously been possible. Planning constraints has blocked many NFFO projects and it is estimated that this new flexibility will free up around 100 renewable energy projects. The cost of the NFFO to electricity consumers was some £50m last year and could rise to around £150m per year once all the contracted power stations are on line.

- The Government has also announced further funding for renewables research, development and deployment in excess of £260m over the next three years. This is a combination of funding from the Climate Change Levy Energy Efficiency Fund, National Lottery money, the Treasury's Capital Modernisation Fund, the Performance and Innovation Fund of the Cabinet Office, and funding from MAFF and DTI.

This further funding is split as follows:

- DTI capital grants for offshore wind. £39m from the Climate Change Levy Energy Efficiency fund will be made available for offshore wind over the next three years. We are in close consultation with the offshore wind industry about the detail of the scheme with a view to finalising the details over the next couple of months. Clearly the availability of this funding has been a major element in encouraging so many developers (18 consortia) to come forward and bid for leases for offshore wind sites from Crown Estates.

- £50m will be made available from Lottery money (New Opportunities Fund) over the next three years. This is to be allocated so that at least £33m goes to the development of energy crops/biomass power generation, at least £10m goes to offshore wind, and £3m goes to small scale biomass heating. These funds must all be committed by 2005 and we are currently working with the Department of Culture, Media and Sport (who administer this fund) to finalise details of the grant schemes, aiming to align them as much as possible with our own scheme for offshore wind.

- In his speech to the World Wildlife Fund on 6 March, the Prime Minister announced a further £100m of new funding for renewable energy over the next three years. The £100m comprises £60m from the Treasury's Capital Modernisation Fund. This Fund involves annual bids from Government for projects that are meant to be innovative and relate to capital expenditure. The balance of the £100 million will be made up of £20m from the Performance and Innovation Fund in the Cabinet Office and £20m from the DTI. The precise allocation of this funding to different renewable technologies will be decided in the light of recommendations of the Cabinet Office's Performance and Innovation Unit (our understanding is that a first draft will be made available to Government Departments by the PIU in June or July). In his speech to the World Wildlife Fund, the Prime Minister indicated that the new money would help to promote solar photovoltaics, give a boost to offshore wind, kick start energy crops and bring on stream other new generation technologies. He described the funding as a major down payment on our future which would help to open up huge commercial opportunities for Britain.

- £29m from MAFF for their energy crops planting scheme. This is funded by the Climate Change Levy Energy Efficiency Fund and includes £12m over the next three years, rising to £29m over seven years. The funding will support the planting of energy crops such as short rotation coppice and miscanthus grass and producer groups for energy crops.

- An initial £10m has been announced by the DTI as the first phase of an ambitious market stimulation programme for PV roofs. It is intended that this programme will rival the Japanese £70 000 roofs programme and the Germans 100,000 roofs programme.

- £55.5m over the next three years for DTI's new and renewable energy research and development programme. This programme will cover the following renewable technologies / resources:

    - PV/solar energy;
    - Wind energy (mainly offshore);
    - Biofuels (including energy crops);
    - Hydroelectric energy;
    - Wave and tidal energy;
    - Fuel cells; and
    - Embedded generation (covering cross-technology barriers to take-up of renewable energy such as planning).
    - Technology transfer and export promotion

This funding supports an existing programme and some 50% of the funding has already been committed to ongoing projects. New projects will be recruited by means of a twice yearly call for proposals. Final decisions have not yet been taken on the allocation between the various technologies and these decisions will be taken in the light of the technology route mapping exercise that DTI have been undertaking with industry and the academic world to review the future prospects of the different renewable technologies and agree realistic targets that will provide a basis for funding proposals.