Power To The People

Future-proofing the security of UK power supplies

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Foreword

By Chris Lambert, Adam Smith Institute

The function of this paper is to stress the importance of security of power supplies within national energy policy. It recommends evidence-based actions to address gaps in current practice that would help to futureproof the UK against the possibility of serious power failures.

The need for a sustainable UK energy policy that guarantees a secure power supply has never been more pressing. Security of supply should be the primary policy objective, with environmental enhancement and economic value being maximised within this context. However, when the DTI set out its energy policy in February 2003 with the publication of the White Paper, ‘Creating a Low Carbon Economy’ it fell short of delivering the essential policy initiatives. Long-term security and its associated costs were issues not addressed satisfactorily in the Paper whose dominating criteria were environmental. This was an error of emphasis since security of supply must be actively determined, it cannot be assumed.

Key Findings & Recommendations

As the UK’s society and economy increasingly become dependent on technology the need for a reliable, sustainable and controllable supply of electricity assumes ever greater importance. Power blackouts can no longer be endured without serious consequences, and therefore power supply security, as well as energy supply security, must be the top priorities of future energy policy. Environmental goals can still be attained within this context, but the mix of generation plant must be urgently reconsidered.

Single fuel dependency on gas, and the associated infrastructure implications, will significantly raise the risk of supply interruption, price instability and economic damage, and by raising carbon levels will reduce environmental quality too.

An objective assessment of current and future gas security issues should be carried out in order to quantify more clearly the potential for severe power shortages that might arise from import interruption, and to identify actions that would mitigate against this.

Renewables must remain an important part of the energy mix but for the foreseeable future the intermittent nature of generation, the requirement for fossil fuel back-up and high costs suggests strongly that their role will remain limited.

An objective, independent appraisal of the current and future cost implications of deploying renewable technologies should be carried out to determine the entire economic context of delivering carbon-free electricity from renewables. Further analysis of the interaction of intermittency with supply security is necessary and, in addition, real incentives should be created for all controllable low carbon energy conversion technologies.

Nuclear energy costs are on track to achieve equivalence with gas within a decade but in the early years will require support, including long-term contracts to secure investment. While no immediate commitment to new nuclear build is essential it is important that, in order to maintain the diversity of generation needed to guarantee supply security, the issue of nuclear new build should be put firmly back on the political agenda.

A commitment to debate the nuclear new build issue is necessary in both the public and political domains. Indeed, an objective programme of public education regarding all forms of generation and their social, economic, and environmental implications would be beneficial. Furthermore, in order that the nuclear option can genuinely be kept open, pragmatic and bold steps should be taken to ensure maintenance of the nuclear skills base, to explore licensing of new technologies and begin initial modelling of business frameworks that will provide a working base for the commercialisation of any future new build programme.

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Executive Summary

Prioritising security of supply

According to the International Chamber of Commerce (ICC) security of supply will be the biggest energy challenge for EU and OECD industries during this century. Therefore, to build a strong energy policy around this premise, it must be recognised that security means both security of primary energy supplies (from oil, gas, coal, nuclear and renewable resources) as well as of power supplies to the final consumers. Indeed, *one does not guarantee the other*, a factor not appropriately recognised by existing energy policy.

Long-term security of power supplies, with electricity delivered on demand to consumers, requires primary energy sources that have three essential characteristics:

1. Reliability
2. Sustainability
3. Controllability

This paper examines these prime requirements in the context of the UK's electricity supply industry, and presents a different re-ordering of objectives and constraints compared with the Government White Paper on energy policy which puts carbon emission reduction as the main objective.

A rethink regarding investment in generating plant is also required. Britain is facing a shortage of generating capacity in the next few years as unfavorable market conditions see mothballing of much existing plant and discourage new investment. In the longer term to 2020 most of the existing coal and nuclear generation capacity currently supplying 54% of the UK's electrical energy will be retired either by scheduled plant closures due to age or as a result of EU rules governing emissions. This plant has to be replaced before a shortage of generating capacity results.

The risks of single fuel dependency on gas

The government foresees the market replacing these coal and nuclear plants, and meeting Britain's growing power demands, by increased investment in new gas-fired stations, supported possibly by 20% generation from renewable sources. Under the market conditions assumed gas requirements would grow such that by 2020 it would provide 68–75% of UK electricity generation, with perhaps 70-90% of the gas being imported. It would make Britain extremely reliant on stable gas supplies, vulnerable to market price behaviour and gas availability – in short, single-fuel dependency, especially when based on imports, may equate to *insecurity* of power supplies.

It is sobering to note, then, that the adequacy of the gas transmission network is also a concern, especially since Britain will become a net importer of gas as early as 2006. Irrespective of the severe negative impact on the balance of payments, there is real concern about such a step-change in gas import volumes. Being on the Western extremity of Europe's gas transmission networks, the UK is particularly exposed to inadequacies in the system connecting our market to the remote sources of gas supply, raising the risk of power cuts in a harsh winter.

One consequence of this could be that investors could lose confidence in short-term supply contracts, further damaging companies' ability to invest in the large gas projects needed for the future. Long-term contracts with competitive pricing are therefore essential for investment and security, and in this respect the European Commission's aims of enhancing security of supplies while introducing full competition into the market may not be compatible.

In addition, there is the question of politically motivated disruption. Russia is seen as a key supplier of gas in the future, yet according to insurance market data up to half of the potential flows of Russian gas to the UK may be interrupted by political or terrorist action. The data also indicates that LNG supplies, while less prone to political disruption, may have even higher probabilities of infrastructure or transportation risks.

This 'single-fuel dependency' on gas is an unacceptably high risk given that a guaranteed electricity supply is the economic lifeblood of the nation. In short, gas is not the completely reliable or sustainable source desired, and thus a greater diversity of primary energy sources would considerably enhance security of power supplies.

Coal – an uncertain future

The European Commission sees coal as an attractive economic energy supply resource that will continue to be used for electricity generation in the long-term to the benefit of energy diversity and security of supply. Use of carbon sequestration via Enhanced Oil Recovery (EOR) could clean up UK coal fired plants, allow another 20 years of North Sea oil and gas production and sequester 20 – 40 million t/year of CO2 for the next fifty to 100 years, but many financial, technical and legal hurdles need to be overcome first.

In the meantime the EU Emission Trading Scheme has the potential to *add* to the cost of generation from fossil fuels. This will ultimately lead to an increase in the electricity prices of fossil-fired plant, coal in particular, and thereby provide a further disincentive to keeping existing coal stations in operation.

Limitations of renewable generation

Prior to 2010 the only renewable energy sources capable of making a significant extra contribution to electricity supply are wind and waste, particularly municipal solid waste combustion. In the decade following 2020 perhaps an increasing amount of wave and tidal stream generated electricity might appear if present prototype developments are successful.

While the integration of renewable generation is to be encouraged in principle as generally satisfying the reliability and sustainability criteria for power supplies, the weakness is their *lack of controllability*. Indeed, the main drawback of renewables is that while able to supply a certain amount of energy over the course of a year, most are intermittent (some randomly so) and thus are limited in their contributions to security of power supply. The government's ambitions for 10% & 20% renewables contributions by 2010 and 2020 respectively are thus not bankable guarantees that can be translated into secure generation capacity available on demand.

Having to balance supply and demand with a large amount of intermittent capacity also requires conventional fossil fuel power stations to continually follow customer demand, possibly providing a back up of 100% equivalent capacity and producing significant emissions as a result; thus regardless of the amount of wind generation installed it cannot *replace* conventional plant capacity because of the unreliable contribution it makes to the electricity supply. The need for sufficient conventional plant capacity to meet maximum load (power) demand remains approximately unaltered, a feature rarely recognized in energy debate.

Apart from the considerable costs associated with having such apparent spare capacity attached to the supply system (witness the consumer electricity prices in Denmark and Germany) these engineering realities and the rates of build necessary for generating plant, together with the associated electrical substation and network investments, impose severe practical limits on the capacity that might be in place by 2010 or by 2020 - certainly less than the Government's targets and aspirations.

Perhaps 6-7% might be possible in total by 2010, but even this would create a situation at odds with the Government Renewable Obligation commencing October 2001 requiring all licensed suppliers to purchase 10% of electricity sales by end of March 2011 from renewable energy sources. Indeed, it appears inevitable that suppliers will be penalised without being physically able to fulfil obligations that cannot physically be supplied.

It is true that at current market prices the only new generation projects that are 'economic' are government-supported renewables. However, the real cost of electricity produced by offshore wind, at least until 2010, will be of the order of £80-85/MWh. That is a premium of 350% over the current non-renewable wholesale forward electricity price for 2004.

The case for retaining nuclear power

A unique aspect of the UK's nuclear position is that only the UK needs to start replacing its nuclear reactors in the short term just to maintain its nuclear generation capability. Other countries can afford to wait for up to a couple of decades. At the moment no new reactors are planned in the UK. If that situation persists the nuclear generation capacity in the UK will decrease to zero before the mid-century.

Loss of nuclear as a key baseload generator would further undermine security. The overall average across all EU countries is around 23% of installed generation capacity and 35% of electricity production, and low carbon nations (eg France, Finland, Sweden, Belgium) all have significant nuclear within their energy portfolios. It is the second largest source of electricity generation and, therefore, a very important contributor to EU security of electricity supply. Given the government's intention to base the vast majority of our electricity generation on a fossil fuel it is worth noting that in Canada tax concessions have been extended from renewables to nuclear power in recognition of its very low environmental effects. In view of present government environmental ambitions, it should be recognized in Britain that nuclear offers an emission free solution to power generation.

The loss of skills in the nuclear industry means that when manufacturing capability losses are also considered this energy option, based on UK resources alone as in the past, will not be available other than on a project management basis using imported technology. The level of activity being carried out elsewhere in the world, however, indicates that nuclear technology is accessible and that nuclear energy is seen in other countries as a viable solution to electrical power supply.

Public opinion is central to the nuclear issue, and it changes little over time, no matter what the 'marketing' strategy. However, recent experience elsewhere shows that once the issue becomes personal, i.e. electricity bills will rise or security of power supplies threatened, people (if openly and clearly appraised of the facts) vote against scrapping nuclear. This is an important social feature. The public do not actively want nuclear, but they understand that they need it and so are even less in favour of abandoning it. It seems entirely sensible, therefore, to embark upon a balanced and objective programme of public education about all forms of energy generation.

In this regard the examples of public opinion in Switzerland and Sweden tend to support such developments as in Finland inasmuch as nuclear power will be tolerated when there is widespread acknowledgement that the benefits of having it outweigh the problems caused by not having it. Waste disposal is not a technical problem but one of social, political and economic concern. The example of Finland shows that these concerns can be addressed and met by open debate.

Economics of the technology choices for security of power supply

Using arbitrary single discount rates for all project generating costs (as practiced by the leading agencies including the European Commission and the International Energy Agency) cost of electricity estimates show that electricity from new nuclear plant is not as competitive as that from new gas combined cycle plant if gas prices are low as in the UK to date. If the price of gas, and thus of gas-fired electricity, rises as expected, however, with the start of EU emissions trading or because of import supply constraints, then costs soon become comparable.

With these traditional investment models[1] electricity generation from new nuclear appears to be at least as competitive as that from gas in the EU and cheaper in the United States where gas prices are much higher, despite relatively high capital costs and the need to internalise all waste disposal and decommissioning costs. If the social, health and environmental costs of fossil fuels are also taken into account then nuclear is clearly a preferred option both economically and environmentally. Certainly positive contexts for new nuclear investment can be found, and other countries, like Finland, are finding ways to finance it.

The way forward – a *balanced* mixed energy policy

It is essential that Britain's energy policy is reviewed as a matter of urgency with the primary remit of ensuring security of power supplies. Against a programme of retirements of conventional plant, the escalating dependence on imported gas and with intermittent renewables having limited ability to contribute to security, significant

[1] Note, if risks are factored into the financial investment models considerably higher costs can result, e.g. fuel price volatility for CCGT plant, climatic variability in northern Europe producing variations in wind energy of up to 30% from one decade to another in the case of wind, but these financial implications are not considered in this paper

questions are raised concerning the increasing vulnerability of the UK electricity supply industry.

The benefits of a mixed energy policy that ensures security of supply and supports the aim of a low carbon economy are obvious and should be actively pursued, with further analysis of security-related issues carried out.

Security of supply would be enhanced by greater diversity of reliable and controllable plant fuelled from sustainable energy sources. If coal is not considered then rather than replacing nuclear with gas-fired plant capacity, replacing retiring nuclear plant with new nuclear capacity is the only sensible option.

Serious consideration of nuclear new build should be back on the government's agenda and, in addition, real incentives should be created for all low carbon energy producers.

1. Introduction

Long-term security of supply and its associated costs - these are two issues that are not addressed satisfactorily in the recent Government White Paper on energy policy![2] The major aim of the White Paper is to ensure that the UK reduces its CO_2 emissions by 60% by 2050, i.e. the dominating criteria is environmental. To achieve this goal the path of future energy policy is to be based on the demand side through energy efficiency gains and on the supply side through support of a growing role for renewable sources of energy. The latter is seen to supplement an anticipated market-determined background of fuel substitution with gas replacing both coal and nuclear generation in electricity supply.

Both of these strategies are examined further in this paper. According to the International Chamber of Commerce (ICC)[3], however, the biggest energy challenge for EU and OECD industries over this century will be security of supply. Furthermore, price uncertainties are an even greater risk than the price increases themselves. This raises the question of the future role of nuclear power in providing both security of power supplies and stability of electricity prices. If new build is to be a tangible possibility then much transparent debate has to occur, starting with the facts of electrical energy supply, some of which are considered here.

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[2] The Energy White Paper, *Our energy future – creating a low carbon economy* (DTI, 2003) www.dti.gov.uk/energy/whitepaper/index.shtml

[3] ICC Finland 30/6/03, www.iccwbo.org/home/news_archive/2003/stories/energy.asp

2. The UK electricity supply industry

2.1 Background

The last fifty years have seen many changes in direction in the electricity supply industry. In the 1950's the 'prevailing beliefs about the potentials' led to the nuclear build programme, in the 1960's to the large coal-fired stations then to oil-fired plant. In the 1970's OPEC induced the abandoning of oil as an option against a background of much reduced peak load demand and hence need for new generating capacity. This was followed in the 1980's by an interest in energy saving and then the privatisation of electricity industry. The 1990's featured the dash for gas and a growing interest in renewable energy leading finally to the present focus on the environmental effects of electricity generation and the Kyoto obligations. This concern is coupled with emission controls, the belief in the promise of renewables, wind in particular, and again in the potential for energy saving. There is no reason to suppose that the next fifty years will not also see further fundamental changes arising from different economic, political and technology developments.

The approximate percentage shares of UK electrical energy production by the end of 2002[4] and percentages of total generating capacity of all generating companies is shown in Table 1.

Table 1 Percentage shares of electrical energy production and percentage capacity of all generating companies in 2002

	Coal %	Gas %	Nuclear %	Hydro-electric %	Renewables other than hydro[5] %
Electrical energy supplied	32	40	22	2	2
Generating capacity	42	32	16	5.5	1.5

The differences between the percentages of energy supplied and total generating capacity reflect the different uses of the plants in meeting the daily and seasonal load –cycles.

Disregarding all considerations other than those of economic stability and ideal security of supply, then looking ahead to 2020 with scenarios based on a range of estimates for GDP growth and either low or high electricity prices, the DTI forecasts electricity generation to increase from 344 TWh in 2000 to between 371 TWh and approximately 400 TWh in 2010 with a lower rate of increase in the period 2010 to 2020. The changes are shown in Figure 1. These forecasts were produced by extrapolations of past and present energy related behaviour using an econometric forecasting model linking fuel share, stock and energy demand, and a range of results being published in the paper EPA 68[6].

[4] "Digest of United Kingdom Energy Statistics 2003", DTI, London, The Stationery Office.
[5] Mainly biomass
[6] DTI (2000). *"Energy Projections in the UK",* Energy Paper 68, The Stationary Office. http://www.dti.gov.uk/energy/ep68_final.pdf

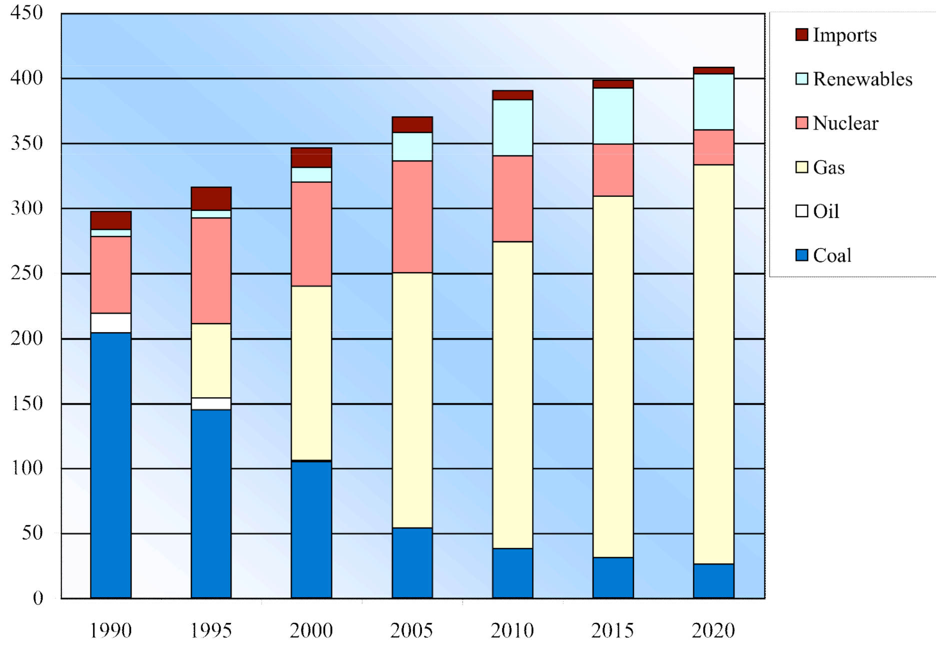

Figure 1 Forecasts of the UK electrical energy supply under the low electricity price scenario

Under the market conditions assumed the gas requirements for electricity generation grow such that by 2020 gas provides 68 – 75% of electricity supplied.

2.2 Security of power supply

2.2.1 Requirements

For the electricity supply, there are two necessary components to examine to guarantee security

- security of primary energy supplies – from oil, gas, coal, nuclear and renewable resources, and
- security of power supplies to the final consumers.

Unfortunately security of primary energy supplies does not guarantee security of power supplies. This requires observance of the stricter constraint of power being delivered instantaneously on demand, a necessity not reflected in either economic models or in the MARKAL model used in the White Paper studies. The main inadequacies of the MARKAL model as far as the electrical supply industry is concerned are discussed further in Appendix 7.3

Guaranteeing energy supplies to power stations over a period of time is one problem, but to schedule power generation to match a variable demand requires power being produced to be equal to the demand for power at all times. Electrical energy cannot be stored, as is the case with other commodities being traded, and the possibilities of using large-scale transformation into other forms such as hydrogen which can be stored only to be re-transformed back into electricity as required belong, if at all, to the very long-term future. This technical need for an instantaneous balance of power in supply and demand acts against most renewable sources. For most such sources output is intermittent and the instant availability depends, for example, on weather or sea conditions or time of day. Intermittency, especially of a random sort, is particularly difficult to accommodate in electricity supply where continuity is essential.

2.2.2 Present narrow margins

For the National Grid system of England and Wales the current (i.e. July 2003) forecasts for contracted generation in 2004/5 amount to 65,000 MW of capacity to meet a peak demand of possibly 56,000 MW. This difference implies a plant margin of 16% including the full potential capacity from imports via interconnectors. There is an interconnector linking the UK grid to France (and therefore to mainland Europe and additional interconnector links are planned from England & Wales to the Netherlands and also to Norway to be commissioned in 2006/2007. These links could in theory assist in meeting peak demand; however following the experiences in 2003 of power being exported to France to meet shortages incurred there, the practice now is not to include these link capacities in calculating the overall plant margin.

Historically, based on CEGB experience, only 85% of installed generating plant capacity will be available on any day. This implies a planning margin of about 20% is needed to ensure security of supply, i.e. sufficient plant available to meet 100% of the maximum load while allowing for loss of plant capacity through unexpected outages.

Britain is, therefore, facing a shortage of generating capacity in the next few years, i.e. a power supply security problem.[7]

[7] "Narrow Margins" and "Narrow Margins revisited", http://www.raeng.co.uk/policy/responses/

3. Security of primary energy supplies for the electricity supply industry

With North Sea oil and gas production declining in the next decade from their present levels the UK's dependence on the rest of the world will grow. The issue of where the UK energy comes from has not been a problem since the Seventies. The EU is increasingly dependent on imported energy supplies. Best available estimates show that the Community's overall import dependency based on present policies and technologies will rise from today's 50% to about 60-70 % in 2020 and rising further by 2030. Especially critical are the import shares of oil and natural gas.

3.1 Oil

Oil does not feature much in UK electricity supply, but gas prices tend to be loosely indexed to oil prices; thus oil prices are likely to remain a significant determinant of energy and electricity costs into the foreseeable future. Imported oil is likely to increase from 80% of total EU oil supply in 1997 to 87% in 2010 and to 90% by 2020. The Commission notes that international oil prices are not subject to the free market principles and that OPEC exerts a strong influence on oil trading markets, which puts the EU in a weak position. Currently Norway is the biggest exporter to the EU (17%), but unless the almost complete reliance of the growing transport sector on oil can be broken, Europe's reliance on Middle East (OPEC) oil will be virtually complete in the long-term. Transport could account for up to 65% of EU oil demand by 2020. In the transport area and elsewhere, however, it has been found that users are relatively insensitive to price increases over the short term, an observation that complicates putative energy taxation policies to reduce demand.

The IEA noted recently, as have many others including the European Commission[8], that mature oil reservoirs in OECD countries will soon peak and decline and consumers will grow increasingly dependent on a small number of oil suppliers in the Middle East.[9]

There is a body of opinion based on a study of all available data that believes the world oil production peak may occur before 2020. This does not signify a lack of exploitable reserves, far from it, merely the end of an era of cheap oil.

3.2 Gas

Gas requirements grow under the market conditions assumed such that by 2020 gas provides 68 – 75% of UK electricity generation. A viable electricity supply would then be subject to single fuel dependence, being extremely reliant on stable gas supplies, vulnerable to market price behaviour and gas availability, a situation giving rise to some concern on the grounds of security of supply.

3.2.1 Sources

EU gas imports are forecast to rise from 40% today to, 66% in 2020. To prevent this situation from developing into a crisis is seen by the Commission as "a challenge" [10, 11]. Gas is especially important in the supply security analysis because of its increasingly strategic role in electricity generation throughout Europe. It is also the key to the expansion of CHP where it

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8 "Towards a European Strategy for the Security of Supply", COM (2000) 769.

9 World Energy Outlook: 2001 Insights: Assessing Today's Supplies to Fuel Tomorrow's Growth http://www.iea.org/weo/insights.htm

10 *"European Community Gas Supply and Prospects",* COM (95) 478 of 18.10.1995.

11 *"Security of EU Gas Supply",* COM (99) 571 of 10.11.1999.

is replacing oil and coal for many types of energy services and thus to the achievement of the government's target of 10GW of CHP in the UK by 2010. To date, ample supplies of natural gas have always been available from UK offshore fields - and some in the Norwegian sector. Essentially, the British gas supply system has been a 'just-in-time' operation, with much of the gas flowing directly from offshore reservoirs, including that needed to meet peak winter requirements.

Peak levels of gas demand in winter are sensitive to temperature. Against the foreseen requirements for the statistical 1 winter in 20 standard which Transco's network must be ready to handle, supplies of peak winter gas are already tight, requiring the use of Britain's relatively limited gas storage capability and imports through the existing Interconnector to supplement supplies flowing from offshore fields. From a supply security point of view, the critical factor is the ability to meet peak winter demand, including the growing requirement of gas for electricity generation.[12]

The non-associated gas, particularly that in the southern North Sea, is now largely depleted. The previously available non-associated sources of gas were more readily suited to following the seasonal swing of the British market. Today, much of the gas being produced is associated with oil, condensate or natural gas liquids. Here there are commercial and operational drivers to maintain continuous high levels of production in order to maximise the recovery of remaining reserves before the cost of maintaining ageing offshore assets threatens economic viability, i.e. the gas has to be produced regardless of market demand and, therefore, price.

According to the latest Transco predictions, gas production from UK offshore fields peaked in 2000 and is widely expected to follow a course of steady decline. In 2002 Transco's analysis of the outlook for gas demand and supply the import requirement had been forecast to be 40% by 2010. Current 2003 expectations, however, have increased this figure such that now 50% of the UK's gas requirements will have to be imported by 2010. This trend is being reinforced and accelerated by the export of surplus summer gas to Continental Europe. This year (2003) maximum levels of export have been seen since March. At times of low demand in Britain, the export level is roughly a quarter of British gas demand. The electricity supply industry in particular, therefore, will become heavily dependent on imported European gas, without which given the present and planned investment in CCGT plant, it would not be able to function. There are no adequate alternatives either in place or intended!

Norwegian gas should be a prime source of imported gas for the British market, but there will be strong competing demands from Continental European markets and, in relation to the overall needs of the EU, Norway's reserves are limited. Like the rest of Europe, the UK has potential access to well over half the world's gas reserves from remote sources such as Russia (Siberia), North Africa, the Caspian Region, and – in the form of LNG – Russia, the Middle East and Nigeria, always provided the connecting infrastructure is adequate. A new feature that should not be overlooked is the entry of the United States as a customer with large needs into the world markets and having access to the same supplies. Plans exist for twenty-six new LNG terminals in the USA although probably only six or seven will be built; nevertheless there is the potential here for significant new demand in the future to influence prices.

3.2.2 Gas infrastructure needs

The EU perceptions of energy dependence and assumptions of security of supply are based largely on simple rules of behaviour, i.e. the inter-dependency model of co-operation will ensure stable relationships with the fuel sources, but the adequacy of the linking infrastructure is of concern. The reliability of gas supplies to consumers is crucially dependent on the capital-intensive, fixed infrastructure required for its primary transportation, whether by pipeline or as LNG. Being on the Western extremity of Europe's gas transmission networks,

[12] Joint Energy Security of Supply Working Group (JESS) First Report, June 2002. DTI and OFGEM

the UK is particularly exposed to inadequacies in the system connecting our market to the remote sources of gas supply. It is the adequacy of investment in this infrastructure that will determine security of supply in average conditions.

Continental gas networks have been designed primarily to accommodate the supply patterns of individual EU countries. In an increasingly interdependent and liberalised European gas market, networks will have to be designed and managed to accommodate mounting pan-European flows and rapidly changing supply patterns driven by both commercial factors and physical availability, especially of gas for peak requirements when UK peak demand may well coincide with peak demand elsewhere in North West Europe.

Although there has been a positive market response to Britain's foreseen supply gap with a number of substantive import projects currently being planned including pipelines and LNG facilities, given the rapidity of development of the projected supply gap, the timing of the new import schemes will be critical. Necessarily, there are timing risks associated with such major capital projects, sometimes involving sensitive local planning constraints.

In the immediate future the winter of 2005/06 is seen as the most critical. No additional sources of peak winter gas will be available to cover the requirements of the market until the winter of 2005/06 when in December 2005 the import capacity of the existing Interconnector is currently expected to begin building up to double the existing rate. All being well the first cargoes of LNG through the Isle of Grain terminal should also be supplementing supplies over the winter of 2005/06, but delays in the availability of these new sources and the construction of new onshore gas storage capacity will strain the system.

Apart from more interconnector capacity Britain needs far more strategic storage for gas; self-sufficiency to date has not encouraged such developments. With a growing proportion of imports, the flexibility and cushion against 'shocks' provided by strategic storage will become more important as will additional LNG and access to Continental gas storage via interconnectors. Compared with continental European markets where storage capacity is equivalent to approximately 25% of annual import requirements for France, Italy and Germany respectively, the UK has at present only about 8% of the projected 2010 import requirement. The continental storage facilities buy gas in the summer when demand and, hence, prices are low to provide support in the winter when the opposite conditions occur. Increasing the capacity of interconnectors will presumably also increase the export of the remaining UK gas during the summer months.

3.2.3 Gas and electricity market interactions

A potential problem concerns the timing of new import schemes. For investors in large new pipelines, for example, there is a strong commercial preference to commission the line only when there is a good probability of it being used from the outset. From a consumer point of view, there is likely to be value in having the new source of supply available earlier against the possibility of severe conditions.

As already noted peak levels of gas demand are sensitive to temperature and extreme conditions. In procuring supplies ahead of each winter, suppliers will not cover all possible demands. Commercial considerations will inevitably impose a need to make a cut-off at some point on grounds of cost and risk. Because of the long time required to reinstate safely gas supplies after a large-scale cut-off to many small users, the relatively small numbers of large users would be the first to be disconnected at times of shortage.

It is from this increased dependence on gas for electricity generation that the UK could be at risk of power cuts because the nation’s gas industry is no longer able to meet peak demand in a harsh winter. In such a case a Californian-style power shortage could emerge. Under Transco’s emergency procedures, power stations would be the first to be cut off from gas supplies with domestic users the last to be affected. About 85% of the gas-fired stations have interruptible contracts so that in the event of, say, a 1 in 20 winter peak demand for gas, several CCGT stations would be cut off from gas supply. Many of these would be in the south near to the major load centre of the southeast of the country because the most interruptible sites are those near to the edge of the Transco network. For a while these stations could keep functioning if adequate stocks of distillate oil capacity were to be kept in reserve at each site. Although the interruptibility and interruptible supply contracts of such stations is a prime source of flexibility, this may be limited by the tightening of electricity supplies and the fact that high levels of gas demand generally coincide with high levels of electricity demand.

Liberalised markets have little incentive to invest in insurance measures such as storage capacity, the only sure means of averting sudden unexpected shortages. Otherwise resort can be made to employ an advantage of gas market liberalisation through the increased scope and stimulus for market-based, demand-side flexibility. One of the benefits of the liberalised British gas market is the potential it offers for the development of a growing market for 'interruptibility' on the demand side, particularly when coupled with the scope for automated metering and intelligent energy management systems. Customer take-up, however, will be severely limited by the perceived high reliability of existing supplies.

On the other hand industry sources warn that liberalisation of the European gas market and a move to shorter supply contracts could lead to higher prices for consumers and threaten the security of supplies. In addition industry sources maintain that a move towards spot market and short term trading rather than the long term "take or pay" supply contracts used exclusively in the past could undermine investors' confidence in demand security, making it difficult to finance large projects.

The European Commission's aims of enhancing security of supplies while introducing full competition into the market may not be compatible. Tying gas prices purely to the mechanisms of short-run supply and demand means running the risks of tight reserves and under-investment such as that recently seen in the US market. Increased short-term and spot-trading of gas in the US was meant to lower prices, but led to prices quadrupling for a short period of time in 2000. Europe could have more severe problems because new gas projects, particularly those that cross national borders, take much longer to bring on-stream.

3.3 Coal

Coal’s output is considerably less than its share of the capacity. This indicates that the older coal-fired steam plants are cycling on and off with the daily load variations, i.e. are fulfilling the essential function of load-following by occupying the substantial mid-range of generation. This position in the merit order of generation is important for future generating plant mix which will also have to contain plant technically capable of load-following as well as others which operate at base-load. Naturally generators earn the best commercial return when operating on base-load, but there will never be enough base-load to satisfy all who must be connected because the load demand is not constant throughout a day.

The European Commission sees coal as an attractive economic and energy supply resource that will continue to be used for electricity generation in the long-term to the benefit of energy diversity and security of supply. It will benefit from the advent of new technologies, which reduce extraction costs, reduce emissions and significantly increase its efficiency. This does not appear to be the view of the UK government where coal’s contribution to primary energy and electricity supply is seen in Figure 1 to fade away over the next two decades under pressure of market forces and environmental concerns over carbon emissions. A move back to coal in the UK has been noticed recently, however, with increases in gas prices, so maybe market forces will not produce results as assumed.

The present world coal production could, it is estimated, be tripled by the year 2020. Only about 8% of coal is exported, most coal-producing countries being primarily concerned with satisfying their own needs. This implies a substantial increase in the production of coal for export is essential if coal is to contribute to the energy needs of all countries. There is no immediate worry about resources and reserves; the problem would be to increase the rate of coal production if needed against the high cost of new mining facilities and the time it takes to build them.

The existing large coal-fired plants in the UK will be strongly affected by the Community legislation that seeks to set emission ceilings for SO_2 and NOx related to power generation.[13] The revised Large Combustion Plants Directive states that for 'existing' plants (i.e. those in operation pre-1987), Member States can choose to meet the obligations by either:

- Complying with Emissions Limit Values (ELVs) for NOx, SO_2, and particles, or
- Operating within a 'National Plan', set on an annual national level of emissions calculated by applying the ELV approach to existing plants, on the basis of those plants' average actual operating hours, fuel used and thermal input, over the 5 years to 2000.

In the case of newer plants, the so-called directive on Integrated Pollution and Prevention Control[14] requests that generation plants above 50 MW will take all appropriate measures to reduce their emissions by introducing best technology techniques. These advances are still in the future in the form of clean-coal technologies or in the use of carbon capture and sequestration. With regard to the latter option it is claimed that if implemented, this project would clean up UK coal fired plants, allow another 20 years of North Sea oil and gas production and sequester 20 – 40 million t/year of CO2 for the next fifty to 100 years, but many financial, technical and legal hurdles need to be overcome first.

The Government's preferred approach is the use of a national plan – although it has just begun a second round of consultation on the best way forward. Note, as an alternative to meeting the ELVs or being included in a National Plan, operators of existing combustion plants can commit to close the plant within 20,000 operational hours starting from 1 January 2008. This derogation has an end date of 31 December 2015.

Whichever option the UK adopts will have a very large impact on the potential for existing fossil fuel plant on the system and also on the potential to recommission mothballed plant. Should the UK adopt an approach consistent with ELVs, then all existing or recommissioned coal and oil fired plant would have to fit abatement equipment (or to reduce operation very significantly). This would significantly change the operating economics for fossil fuel plant – both for existing plant and also importantly for decommissioned plant.

Finally all fossil-fuelled plant will be affected by the the EU Emissions Trading Scheme (ETS), the first phase to begin in 2005 for three years in duration, and a second, five-year phase to begin in 2008. The Scheme offers the potential for a lower cost method of reducing carbon emissions than a tax or regulated limits. Carbon dioxide will be addressed in the first phase and the trading of other greenhouse gases will be allowed in the second phase. The EU scheme will be mandatory for clearly identified sectors from 2005. Power generators, which are excluded from the UK ETS will, therefore, be included in the EU scheme from 2005.

The Scheme has the potential to add to the cost of generation from fossil fuels. This will ultimately lead to an increase in the electricity prices of fossil-fired plant, coal in particular, and thereby provide a further disincentive to keeping existing coal stations in operation.

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[13] Directive EEC/1984/360; Directive EEC/1988/609. Under new provisions, combustion plants commissioned before 1987 are included as well.
[14] Directive EEC/1996/61

3.4 Nuclear

3.4.1 Overall perspectives

At present nuclear plant supplies a larger proportion of energy than its proportion of capacity reflecting its use in base load operation. On current plans the nuclear capability will develop as shown in Figure 2. Over the period to 2010, some fourteen Magnox reactors[15] and one AGR station[16] are scheduled for closure totalling 3572 MW capacity, followed in the decade 2010-2020 by most of the AGR stations and many large coal-fired plants.

Since fuel costs are a much smaller proportion of the whole than for fossil fuelled plants there is less pressure to phase out the older and less efficient plant (Magnox). For Magnox stations the end of life is dictated by other factors, notably the integrity of the main containment vessel and the primary cooling circuits; for AGR stations the limiting factor is more likely to be the graphite shrinkage in the core.

A unique aspect of the UK's nuclear position is that only the UK needs to start replacing its nuclear reactors in the short term just to maintain its nuclear generation capability. Other countries can afford to wait for up to a couple of decades because:

- their reactors are mainly light water reactors (LWR's)whose lifetime can realistically be extended to 60 years
- Many countries (e.g. France, Japan) also benefit from having a very much younger population of reactors which again gives a longer timeframe

In contrast, the expected operational lifetimes for the UK's gas cooled reactors have very little leeway (a matter of no more than 2 or 3 years) rather than the decades for LWR's so the UK projected decline curve as shown in Figure 2 is real.

At the moment no new reactors are planned in the UK. If that situation persists the nuclear generation capacity in the UK will decrease to zero before the mid-century. The rate of decrease may well be moderated by extensions of reactor lifetimes, but the overall shape of the curve will not alter by much.

The advent of cheap North Sea gas together with the privatisation of the electricity supply industry spelled the end of the period of investment in nuclear power stations in the UK. Not only were CCGT stations more efficient they were cheaper to build and were into operation faster, thus producing returns to the investors in a shorter time period. Now, despite the new awareness of a period of self-sufficiency in indigenous energy supplies soon coming to an end, combined environmental lobby and political opposition to nuclear power complicate decisions regarding new nuclear capacity, although apparently in both the UK and USA polls indicate that public perceptions are somewhat equivocal.

The importance of nuclear energy to the UK and within the EU can be seen from the following Eurostat figures:[17]

- In the UK, **23%** of electrical energy came from nuclear in 2000
- The overall average across all EU countries in 2000 was **21%** of installed generation capacity and **33%** of electricity production (but Foratom say **35%)**
- Average nuclear energy in those EU countries that produce nuclear was about **41%** in 2000

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[15] Source for Magnox lifetimes and outputs: BNFL

[16] Source for British energy lifetime and capacity: Parliamentary Question response, 25 March 2002, http://www.parliament.the-stationery-office.co.uk/pa/cm200102/cmhansrd/vo020325/text/20325w41.htm#20325w41.html_sbhd9

[17] http://www.europa.eu.int/comm/energy_transport/etif/energy_electricity/generation.html
http://www.europa.eu.int/comm/energy_transport/etif/energy_electricity/production_capacity.html

- Nuclear energy electricity production grew by **6.6%** between **1995** and **2000**. However, electricity production grew by **10.7%.**

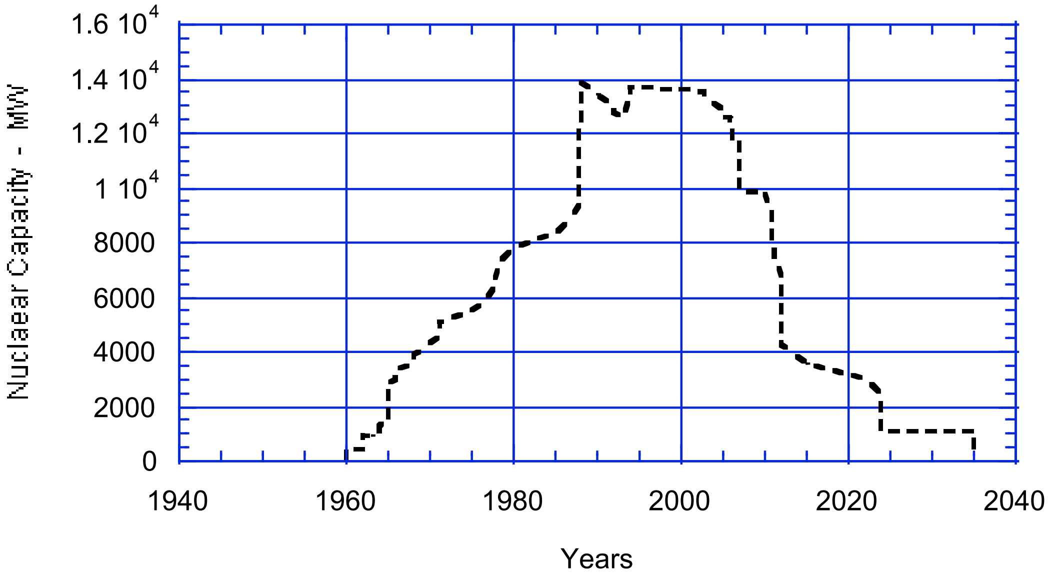

Figure 2 UK nuclear generating capacity in the absence of new build

On the worldwide scene:[18, 19]

- **439** reactors in operation in 2000 had a total installed capacity of **360,046 MW**
- electrical energy provided in 2000 was **2421 TWh**
- nuclear provides about 16% of the world's electricity demand
- **444** reactors in operation at the end of 2002 with a total installed capacity of **374,939 MW**
- electrical energy supplied in 2002 was **2574 TWh**
- **63** reactors are proposed around the world but there are some heavy caveats on these figures. For example the data also includes some Russian units but the status of these is very uncertain.
- China has ambitious plans, but these are excluded from the data as there was no information at the time on sites, capacities and dates for proposed units. (A plan being developed by the National Development and Reform Commission has now been announced that could lead to the construction of 30 new nuclear power reactors in the next 17 years, with the country's nuclear capacity expected to grow from some 3600 MWe today to at least 32 000 MWe by 2020.
- **27** reactors under construction in **9** countries.

In addition other developments include for example,

- Numerous power reactors in Belgium, Finland, Germany, Spain, Sweden, Switzerland and USA have had or are having their generating capacities increased,
- In the Netherlands a new parliamentary committee on technology issues has been created, whose mandate includes issues related to nuclear energy. 'The time is ripe' in the context of implementation of commitments under the Kyoto Protocol for a fresh look at nuclear energy, the Parliamentary Presidium noted in setting up the committee.

[18] World Nuclear Association, http://www.world-nuclear.org/info/reactors.htm
[19] 2003 World Nuclear Industry Handbook, Nuclear Engineering International,

- In India construction of a 500 MWe prototype fast breeder reactor (PFBR) is set to begin following approval by the country's Cabinet Committee on Economic Affairs.

This is hardly a picture that supports the claims of those in the anti-nuclear lobby that nuclear plant is “dangerous, dirty and too expensive”. Security of electricity supplies at stable and competitive market prices are the major attractions of nuclear energy. In addition in view of present government environmental ambitions, nuclear offers an emission free solution to power generation.

3.4.2 UK skills shortage

Despite this worldwide activity there is now a serious shortage of skills in this industry in the UK as there is in other industries. The lack of activity over the past years since the last nuclear stations were designed and built has led to a significant loss of trained manpower and, with the stock of engineering skills from Universities being inadequate, the Nuclear Inspectorate would probably have difficulties in licensing new build. For decommissioning tasks engineers have to be brought back from retirement and so on. In short, when manufacturing capability losses are also considered this energy option, based on UK resources alone as in the past, is not available other than on a project management basis using imported technology. The level of activity being carried out elsewhere in the world, however, indicates that nuclear technology is accessible and that nuclear energy is seen in other countries as a viable solution to electrical power supply.

Whatever the short to medium term future for nuclear power in the UK the observation by the EU Commission is relevant inasmuch as *“in the longer-term beyond 2010 the long lead-in time for energy technology means that it is essential to maintain long-term research, partly to find a solution to nuclear waste and partly to hand down nuclear expertise to future generations”.*

3.4.3 Public opinion - experience elsewhere

Overall the European scene is somewhat confused. The Swiss cantons have twice recently voted against scrapping nuclear power on a security of supply and consumer cost basis. This raises an interesting paradox about nuclear power – the European public in general have very fixed and largely negative opinions about nuclear power. These opinions change little over time, no matter what the ‘marketing’ strategy. However, once the issue becomes personal, i.e. electricity bills are rising or commercial security is threatened, people (if openly and clearly appraised of the facts) vote against scrapping nuclear.

This is an important social feature. The public do not actively want nuclear, but they understand that they need it and so are even less in favour of abandoning it. Even Swedish opinion reflects this where in a 1980 referendum it was voted to close their nuclear stock on environmental grounds with nuclear power to be replaced with renewable sources of energy by 2010. But the country still gets half of its power from nuclear plants as the new sources have not materialised with the rest coming from hydro-power facilities. These in turn depend on sufficient rainfall in the summer and autumn to gather water in reservoirs for use during the winter demand peak.

The 2002 dry summer and autumn, however, created low reservoir water levels and relatively harsh winter weather boosted demand for electricity, driving prices at the Nordic Power bourse Nordpool to almost five times the May 2002 price and three times the average of December 2001. Subsequently in January 2003 an independent poll revealed that as a result a majority of Swedes now favour keeping nuclear power plants going, or even building new ones.

The Finish experience is also relevant and can be summarized as follows (based on an internal report of the Adam Smith Institute of a Fact Finding visit to Finland, 23-25 June 2003). First of all the well-known facts that can be corroborated independently are:

1. Finland has committed to building an additional fifth nuclear power plant.
2. Finland's climate change policy formally acknowledges the role nuclear must play to reduce carbon emissions
3. Finland's energy policy has been independently and positively appraised.
4. Finland's energy policy deliberately avoided dependence on Russian gas imports.
5. Nuclear power is the most economic form of generation in Finland, and the least sensitive to changing economic inputs.
6. Finland has agreed a solution to its nuclear waste disposal problem.

The Report then goes on, however, to make subsequent observations concerning public opinion:

1. Finnish energy policy has pragmatically addressed the same issues of security of supply, low carbon generation and rising consumption that face the UK.
2. Key drivers which helped a decision in favour of new nuclear build will also converge in the UK in the next few years, e.g. diversity of energy supplies, long-term security of power supplies, environmental goals related to climate change.
3. The pro-nuclear lobby in Finland does not involve the nuclear generators, and as a result public debate is seen as unbiased and transparent.

These are of course subjective judgments based on personal interviews,[20] but what becomes clear from the Finnish experience is that although most people and politicians are inherently *anti-nuclear* (Finnish and UK public opinion polls are quite similar in attitudes) a sustained factual awareness / lobbying campaign has brought clarity and transparency to a debate which previously did not exist. The examples of public opinion in Switzerland and Sweden also tend to support developments in Finland inasmuch as nuclear power will be tolerated when there is widespread acknowledgement that the benefits of having it outweigh the problems caused by not having it.

3.4.4 Environmental benefits - recognition elsewhere

The formal acknowledgement in Finland's climate change policy of the role nuclear plays in reducing carbon emissions is echoed elsewhere as the following reports show.

- Recently the Massachusetts Institute of Technology (MIT) published an interdisciplinary study that examines the prospects and challenges faced by the nuclear power industry, focused on the USA. The report says that nuclear energy has an important role in meeting future global electricity needs without emitting carbon dioxide (CO2) and other air pollutants. The study states that the nuclear option must be retained 'precisely because it is an important CO2-free source of power'. [21]
- In Canada the Ontario government has extended tax concessions from renewables to nuclear power in recognition of its very low environmental effects. The concessions were brought in last year to encourage more generation from clean sources, particularly wind and hydro. They include an immediate full tax write-off of generation assets acquired before 2008, a ten-year exemption from property tax, and exemption from provincial sales tax on materials.

[20] Much of the same information can be found in a Finnish government report produced by the Ministry of Trade and Industry on why Finland is going for a new Nuclear Power Programme. It has been written for people in the nuclear industry outside Finland. This provides an independent corroboration of the visit findings. The report can be downloaded from :http://www.vtt.fi/pro/pro1/ats/nuclfinland.pdf

[21] 'The Future of Nuclear Power', <http://web.mit.edu/nuclearpower/>

- Finally the French National Academy of Medicine has thrown its weight behind nuclear energy for electricity as having the least impact on public health.[22] They said also that energy supply interruptions represented the most serious health risk. Climate change was a further problem identified, but concern about low levels of radiation exposure is "not scientifically justified". The opinion followed a seminar on Energy Options and Health, part of the national energy policy debate.

[22] www.academie-medecine.fr

4. UK Renewable Energy

4.1 Prospects 2000 to 2010

The Government has set a target of 10% of electrical energy coming from renewables by 2010 with aspirations in the White paper for 20% by 2020. The Government target of meeting 10% of electrical energy supplied in the UK by renewables by 2010 is an energy target not a power capacity target. The DTI forecasts in Figure 1 show this amount, but with no further addition beyond 2010.

The reasonableness of achieving the 2010 target is questionable because it is argued that the current base is too small to achieve this level. In 2002, approximately 3 % of the electricity generated in the United Kingdom was from renewables. Biofuels and wastes accounted for 83% of renewable energy resources, hydro 12% and windpower $3^1/_2$%.

Using the electricity growth rates forecast by the DTI [23] as a guide, the Government's 10% target for renewable generation is 39 – 41 TWh and perhaps 80TWh as an aspiration for 2020. The respective renewable resources contributions in 2003 are as shown in Table 2 which reveals the scale of such ambitions given the low base from which to start. The White Paper suggests a further 10,000 MW of capacity is required by 2010.[24]

Little growth before 2020 can be anticipated from other than wind, waste and especially municipal solid waste combustion. Other technologies are either still in the research and development stage or are resource limited.

Table 2 Annual Generation of Electrical Energy by Renewables in 2002[25].

Technology	**TWh**
Wind - onshore	1.251
Wind - offshore	0.005
Solar	0.003
Hydro - small	0.204
Hydro - large	4.548
Biofuels	
-Landfill gas	2.679
-Sewage	0.397
-MSW combustion	0.958
-Other (farm wastes, etc)	0.870
Wastes (Municipal, etc)	0.494
Other wastes	0.035
TOTAL	**11.444**

The likelihood of achieving the 10% target can be examined rationally, however, and found to be suspect. By way of an example the DTI intends that offshore wind alone will supply 1.8% of total UK electricity supply by 2010, i.e. from approximately 2300 MW of installed

[23] DTI (2000). *"Energy Projections in the UK",* Energy Paper 68, The Stationary Office. http://www.dti.gov.uk/energy/ep68_final.pdf

[24] In the White Paper, Chapter 4, para 9, the 2010 renewables capacity target makes it clear that large-scale hydro is excluded from the Government's target. The base figure - the 1.3% current output from renewables - is quoted ex large-scale hydro and also ex mixed waste incineration.

[25] "Digest of United Kingdom Energy Statistics 2003", DTI, London, The Stationery Office.

offshore capacity.[26] Achieving this target would require one thousand one hundred and fifty 2MW wind turbines. Simple arithmetic shows that the rates of build necessary for wind turbine generators allowing for consents, finance, manufacture, availability of barges and civil engineering equipment, plus the associated electrical substation and network investments, impose severe practical limits on the capacity that might be in place by 2010 and more so by 2020. Similar questions apply to small biomass fuelled plants if pursued.

This situation appears to be somewhat at odds with the Government Renewable Obligation commencing October 2001 requiring all licensed suppliers to purchase 3% of electricity sales up to 2003 from renewable energy sources to a gradually increasing amount of 10% by end of March 2011.[27] The alternative is to pay OFGEM £30 / MWh as a buy-out price. Investors in renewables then receive the prevailing market price for electricity, plus up to £30 / MWh through their contracts with suppliers, plus a share of buy-out payments from non-compliant suppliers. It appears inevitable that suppliers will be penalised without being able to fulfil their obligations, with OFGEM still collecting revenues on the energy differences, which cannot physically be supplied.

4.2 Renewables and security of supply

The energy policy review published by the PIU in February 2002 recommended an increase in renewable capacity to 20% of electricity supply. The recent White Paper echoed similar thoughts and many politicians and environmental lobbyists say the same. It is thus a serious matter. The existence of such a recommendation will presume to many if not most that it is a feasible course of action and thereby have a knock-on effect in eliminating alternative strategies. For this reason a more detailed examination of one aspect is necessary, namely that concerning the interaction of random intermittency of supply with security, bearing in mind that security of supply of electricity requires continuity of power delivery, not energy. From the consumers' point of view an electricity supply system must deliver power (MW) as needed. Herein lies a dichotomy. Policy makers and others such as energy economists, environmentalists and trade organisations are concerned primarily with energy (MWh), the commodity that is bought and sold.

The main drawback of renewables is that while able to supply with reasonable assurance a certain amount of energy over a year all are intermittent, some randomly so; thus all except biofuels are unable to supply power on demand, i.e. are limited in their contributions to security of power supply. Such variations in power output can cause problems for a power system if the resources penetrate the system on a large scale. Large weather systems, particularly high-pressure windless systems can cover most of the country, as seen during the January 2003 cold spell for several days and again during the subsequent July heat wave. At such times the contributions from any wind and wave generation are severely curtailed. This implies the need for conventional backup appropriate for the risks assumed, possibly 100% spare capacity.[28]

Much is made of the penetration of wind into the Danish electricity system. Denmark has a small electric system with an annual demand less than 10% of the UK demand, somewhat akin to Scotland. Having to balance supply and demand with input from a very substantial

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[26] Assuming an average offshore wind farm load factor to be a generous 35%, then one TWh would be produced from some 326 MW of wind turbine capacity.

[27] It will be interesting to see whether the power supplied via the UK-France interconnector will ever be classified as renewable, thereby qualifying for the support price of at least 3p/kWh above the market price for conventional generation. This would prove an expensive repetition of NFFO history and a perverse result of the Renewable Obligation.

[28] Laughton,M.A., "Renewables and the UK Electricity Grid supply infrastructure" Platts Power in Europe, Issue 383, 9 September 2002, pp 9-11.

installed wind power capacity requires conventional thermal power stations to continually follow customer demand less wind input, a task for which they were never designed. In addition interconnectors with Norway, Sweden and Germany provide the added flexibility needed in operation, allowing power importing if need be or surplus power to be exported. Britain does not have that degree of flexibility being essentially an island system and can only balance supply and demand by the use of unused thermal station standby capacity.

This situation would result in the highly efficient thermal power stations running at less than optimal, requiring a certain amount of the thermal capacity to be kept in "spinning reserve" where they consume energy, but deliver no useful power with further plant "kept hot" ready to start up on short notice, again a highly inefficient process. In total, therefore, wind power, whilst itself emission free at the point of electricity generation, does not lead to an emission-free energy supply policy.

The Government electrical energy supply targets for renewable contributions of 10% and perhaps 20% for 2010 and 2020 respectively are only ambitions. They are not bankable guarantees that can be translated into generation capacity available on demand. Intermittent renewable capacity does not replace the need for conventional plant capacity to meet varying power demand levels, therefore, and so the Government and the industry must plan for sufficient conventional capacity for security of power supply without regard for renewable plant. With renewable energy supplied generation, when available, taking market shares, however, this capacity of conventional plant will as a consequence be operating in a reduced market at higher marginal costs in order to cover its fixed costs.

5. The economics of generation

5.1 Technology choices to be made for security of power supply

The relative costs of generating electricity from coal, gas and nuclear plants vary considerably depending on location. Coal is, and will probably remain, economically attractive in countries such as China, the USA and Australia with abundant and accessible domestic coal resources.

In the UK an additional £10/MWh is expected from the impact of LCPD/EUETS on the marginal cost of coal fired generating plant. It is noted, however, that around 10 British power stations already co-burn biomass fuels, largely imported from abroad. Particularly favoured are milled palm nuts from Malaysia and Indonesia and olive pulp. The most recent stations to apply to the Environment Agency for permission to do this are Drax and Rugeley. Drax plans trials at one of its units burning a mix including up to 10 percent palm nuts. This co-firing has allowed coal plant operators to begin to sell ROC's to supply firms, often in the same vertically integrated group, and hence meet their renewables obligations without purchasing ROC's from other forms of renewable capacity. Large hydro projects have always been excluded from being ROC's eligible and the UK government is currently considering whether co-fired plant burning imported biomass should remain eligible to issue ROC's after 1 April 2006.[29]

Gas is also competitive for base-load power and has been so in the UK for several years particularly using combined-cycle plants, though rising gas prices both at present and probably in the future have removed much of the perceived advantage for future CCGT plant investments. Plant choice is likely to depend on a country's international balance of payments situation.

Nuclear power is very capital-intensive while fuel costs are relatively much more significant for systems based on fossil fuels. Therefore if a country such as Japan or France has to choose between importing large quantities of fuel or spending a lot of capital at home, simple costs may be less important than wider economic considerations. Overseas purchases over the lifetime of a new coal-fired plant in Japan, for example, may be subject to price rises which could be a more serious drain on foreign currency reserves than less costly uranium.

5.2 Nuclear

There are a number of potential technologies for the next generation of nuclear generation plant being proposed or developed.

A snapshot of opinions on generation costs is provided by the following news items.[30]

- In 1999 Siemens (now Framatome ANP) published an economic analysis comparing combined-cycle gas plants with new designs. Looking at power costs, both the 1550 MWe EPR if built as a series in France /Germany and the SWR-1000 boiling water reactor (with an 8% discount rate) are competitive with gas combined cycle, at EUR 2.6 cents/kWh. But once depreciated, their costs fall to about 1.5 cents/kWh compared with gas at 2.5 cents.

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[29] "UK offshore wind generation capacity: a return to picking winners?", John Bower, Oxford Institute for Energy Studies, July 2003

[30] NEI Nuclear Energy Overview 25/8/03.

- The current-generation Konvoi plants operating in Germany produce power at 3.0 cents/kWh including full capital costs, falling to 1.5 c/kWh after complete depreciation.

- A new French government cost study, the latest in a long series, assessed the relative costs in 2003 Euros of different means of electricity generation starting operation in 2015. In terms of overnight capital costs, the European Pressurised Water reactor (EPR) could be built for EUR 1043 /kW. But taking into account interest (8% discount rate), project management etc and also decommissioning, the cost is EUR 1663 /kW. This compares with only EUR 569 /kW for gas - CCGT, and EUR 1400 or 1276 /kW for coal. Actual power costs (8% discount rate, 8000 hrs per year) are 3.04 c/kWh for the EPR, 3.50 c/kWh for CCGT and 3.37 or 3.23 c/kWh for coal. If externalities (external costs) are included, these become 3.30 c/kWh for EPR, 4.24 c/kWh for CCGT and 4.95 or 4.81 c/kWh for coal. The study assumes that a series of ten EPRs would be built - if only four, then the unit capital cost would increase by 6%.

- A detailed study of energy economics in Finland published in mid 2000 shows that nuclear energy would be the least-cost option for new generating capacity. The study compared nuclear, coal, gas turbine combined cycle and peat. Nuclear has very much higher capital costs than the others --EUR 1749/kW including initial fuel load, which is about three times the cost of the gas plant. But its fuel costs are much lower, and so at capacity factors above 64% it is the cheapest option.

  Later April 2001 figures put nuclear costs at EUR 2.40 c/kWh, coal 3.18 c/kWh and natural gas at 3.21 c/kWh (on the basis of 91% capacity factor, 5% interest rate, 40 year plant life).

  The Finnish study in 2000 also quantified fuel price sensitivity to electricity costs:

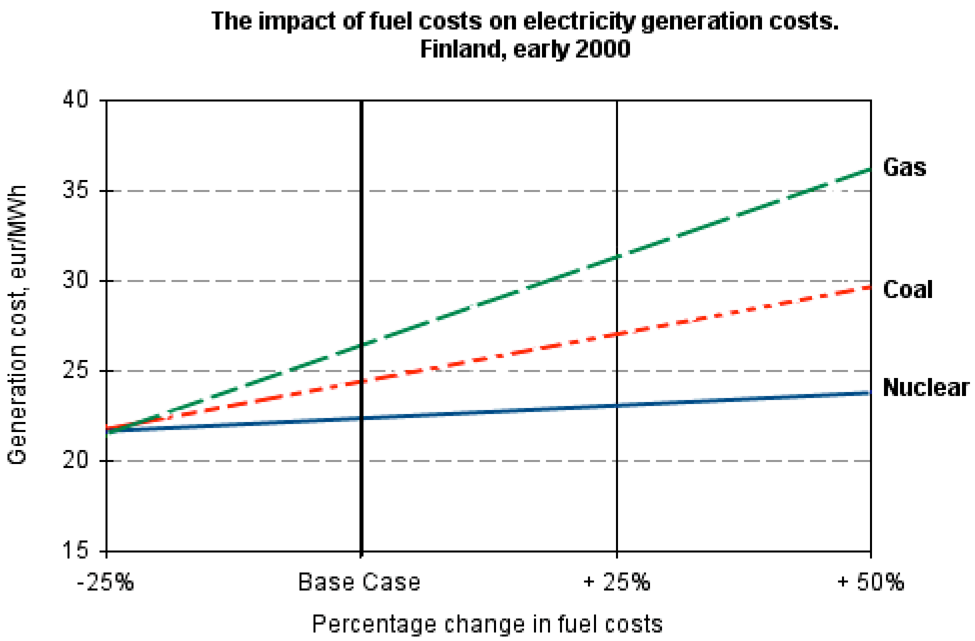

Figure 3 Finnish assessment of generation costs in 2002

- The French Energy Secretariat in 2003 published updated figures for new generating plant. The advanced European PWR (EPR) would cost EUR 1650-1700 per kilowatt to build, compared with EUR 500-550 for a gas combined cycle plant and 1200-1400 for a coal plant. The EPR would generate power at 2.74 cents/kWh, competitively with gas which would be very dependent on fuel price. Capital costs contributed 60% to nuclear's power price but only 20% to gas's. While the figures are based on 40-year plant life, the EPR is designed for 60 years.

- In the United States the 103 US reactors last year maintained their position as lowest-cost producers of electricity, at 1.71 c/kWh for fuel, operation and maintenance. This includes 0.45c fuel cost, of which about 0.1 cent would be the ex-mine uranium before manufacture into fuel. Coal came in at 1.85 c/kWh (1.36c of this for fuel), and gas was 4.06 c/kWh (3.44c of this being fuel). The implications of increased fossil fuel costs stand out. Reactor capacity factors reached an average of 91.5% - a record.[31]

Gathering these statistics into a table shows the general belief that new nuclear is at least as competitive as gas in the EU and cheaper in the United States where gas prices are much higher.

Table 3 International assessments of new plant costs

Source	New Nuclear Euro cents /kWh	New CCGT Euro cents /kWh	New Coal Euro cents /kWh
1999 Siemens	2.6	Comparable	
Germany Existing plant	3.0		
France 2002	3.20	3.05 – 4.26	3.81 – 4.57
Finland 2001	2.40	3.18	3.21
France 2003	3.04	3.50	3.23 – 3.37
USA 2002 Existing plant	1.71 US c/kWh	4.06 US c/kWh	1.85 US c/kWh

In the UK BNFL and British Energy undertook a joint feasibility study of the BNFL/Westinghouse AP1000 reactor, based on the AP600 design, for suitability as replacements for British Energy's existing fleet of reactors in the UK. Other possible technologies include the Canadian CANDU reactor, the pebble bed modular reactor (PBMR), the European passive reactor (EPR), and GE's boiling water reactor (BWR). BNFL/Westinghouse have released a document outlining the main points of the AP1000 design and associated costs (BNFL/Westinghouse)[32]. In this initial assessment, the production costs range from £30/MWh for a first-of-a-kind single unit, to £22/MWh for the fourth in the series. More recent estimates based on a series of twin-unit reactors range from £25/MWh for the first units to £20/MWh for the fifth set. Some uncertainty can be attached to decommissioning costs, but new plants are very different in design and much has been learned over the years.

The PIU also looked at the issue of new nuclear build based on a single unit assessment and, ignoring the industry estimates submitted, arrived at a cost of £30-£40/MWh[33]. These figures

[31] NEI Nuclear Energy Overview 25/8/03.
[32] BNFL/Westinghouse. “AP1000…the reactor technology ready now”. www.bnfl.com/website.nsf/images/energyreview_ap1000_summary/$file/Energy_Consultation_AP1000_summary.doc
[33] “The Energy Review”, Performance and Innovation Unit, Cabinet Office, February, 2002.

are attributed to the 1995 review[34] whereby lifetime nuclear generation costs at 1990 prices were translated to today's prices, thus disregarding the high load factors now being achieved and the very considerable reductions in costs brought about by the use of modern CAD techniques, modular plant build and site construction practices. These developments are enabling various reactor designs to deliver electricity from between three to fours years from the signing of contract in new build projects in Japan, Korea and China. For the purpose of this analysis the factual data provided by the industry both in the UK and internationally being based on much greater experience are taken as the only credible estimates.

5.3Combined-Cycle gas turbines

Here it is necessary to separate out clearly the capital and fuel costs because of the significance of variable fuel prices.

Capital cost

Installed costs for new CCGT in the UK in recent months are reflecting higher insurance and staff costs, and the need to make provision for higher commissioning costs under the New Electricity Trading Arrangements. The two most recent complete contracts come out at £450/kW (Power UK, February). An earlier analysis by Power UK (November) suggested an average installed cost of £500/kW.[35]

Gas turbine technology is still developing and the US Department of Energy anticipates a modest fall of 7% in capital cost by 2020.

Again these capital cost figures contrast with the views of the PIU report, of current capital costs of £270/kW falling to £260/kW in 2020 (PIU, 2002).

With a 10% real annual rate of return, a 20 year plant life with 5% O&M costs and 85% availability, then the capital plus O&M component of generation costs is 1.26 to 1.40 p /kWh (£12.6 to £14.0/MWh) for capital costs of £450-500/kW capacity installed. It is important to note, however, that this component of cost can increase considerably with decreasing load factor. Already the overall load factor has been reduced from 84% in 1999 to 68.4% in 2002.[36] The addition of large intermittent power supplies from wind to the supply system will further reduce the load factor thus adding extra to this fixed cost recovery component.

Fuel costs

The average price for gas paid by the electricity generators in 2001 was 22.5p/therm, which translates to a fuel cost of 0.77 p / kWh (thermal) and assuming 55% thermal conversion efficiency to 1.40p/kWh (electrical). The average thermal efficiency of all CCGT stations in 2002, however, was only 47.1% which translates to an electricity cost of 1.63 p / kWh (£16.3 / MWh).

Total costs

Adding these two cost elements together gives for a fuel cost of 22.5p/therm an electricity cost of £28.9 to £30.3/MWh based on 85% availability and existing average thermal efficiencies and £26.6 to £28.0/MWh for new plant with average thermal efficiencies of 55%.

The future price of gas is uncertain and the sensitivity of total costs to gas prices is shown in figure 4. In the longer term significant increases in the gas price are most likely to be related to parallel movements in the oil price, i.e. to the prices of fuels which compete with gas and

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[34] The prospects for nuclear power in the UK. Cm 2860. HMSO, London

[35] "A shift to wind is not unfeasible", Lewis Dale, David Milborrow, Richard Slark & Goran Strbac, Platts Power UK Issue 109, March 2003.

[36] "Digest of United Kingdom Energy Statistics 2003", DTI, London, The Stationery Office.

not to mirror the supply costs involved. Continental wholesale prices, unlike in Britain, are linked to oil prices that rose sharply in early 2003. Continental gas prices lag oil price movements by about three to six months; thus the key German wholesale gas price as a result rose in April to 25.6p a therm compared to then current British equivalent of 17p. This led to unseasonally high gas exports from the UK as traders chased higher prices in mainland Europe. Recent history suggests that higher wholesale prices on the Continent will drag up British prices in their wake.

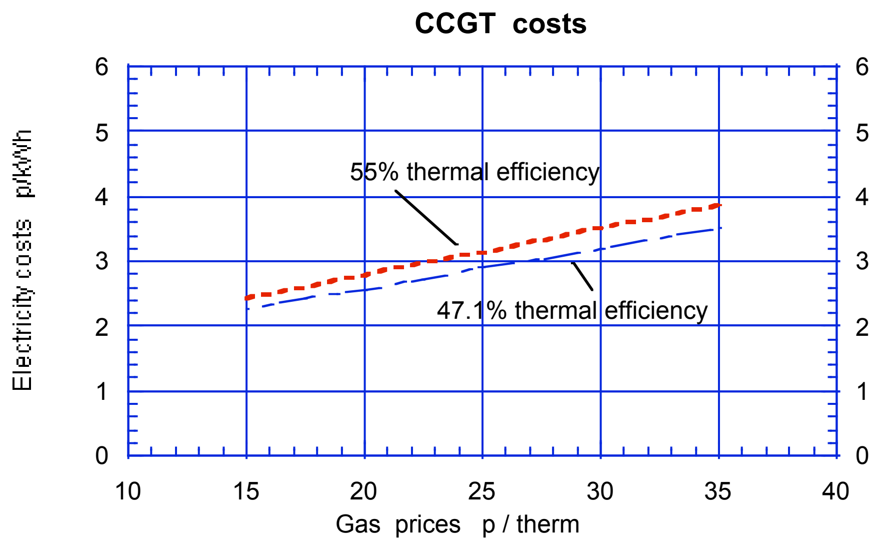

Figure 4 Electricity from CCGT plant cost sensitivity with gas price - UK capital costs of £450-£500 / kW

5.4 Wind

Although wind is not a significant contributor to power supply security at present its costs are presented here to add further perspective to the UK picture.

The present-day installed cost for onshore wind in the UK is about £650/kW, and for offshore around £1000/kW [37] For offshore wind this includes around £100/kW for the farm to shore connection and £150/kW for inter-turbine cabling. The extent of cost reductions that can be achieved in this industry is a matter of speculation and figures produced from a number of studies should not be taken as accurate, especially those based on unreal learning curve optimism. Offshore prices should show a bigger drop, partly due to maturation of the industry and partly due to the moves towards much bigger wind farms. Onshore and offshore windfarms will benefit as well from manufacturing cost savings with the advent of larger turbines, but the potential for savings from the Civil Engineering work is not so great. Some 30% of the present cost of onshore windfarms, using the French Parc Aolien de Goulien as an example, is attributed to site infrastructure.

Using the above capital costs, nevertheless, the present generation costs based on a 10% real rate of return, 20 years plant life, 3-4% annual O&M costs, 95% availability and, importantly, the published average overall load factors (not nominal load factors) gives total average generating costs for onshore windfarms of approximately £37 / MWh. This cost applies, however, only to the relatively limited areas (estimated as being only 10% of the total exploitable areas) having the best wind speeds with nominal load factors of 35%. For offshore windfarms a preliminary basic cost of £55 / MWh results although further costing needs to be

[37] DTI, 2002. Future offshore. A strategic framework for the offshore wind industry.

carried out to reflect experience gained and also anticipated cost reductions in this new industry.

A recently published detailed analysis of the Government's policy with regard to offshore wind, however, provides an expanded and more realistic view of likely costs as follows.[38]

"The price of renewable electricity underpinning the offshore wind projects currently being planned, and expected to come on stream in 2006/07, can be imputed from the sum of the current £18.00/MWh forward wholesale price for 2004, plus £44.00/MWh current ROC's premium, plus the £10/MWh expected impact of LCPD/EUETS on the marginal cost of coal fired generating plant, plus the £9.25/MWh implied ROC's equivalent value of direct capital subsidies, plus the ROC's equivalent value of socialised grid reinforcement of £2.75/MWh. In total this suggests the true cost of electricity produced by offshore wind, at least until 2010, will be of the order of £80-85/MWh. That is a premium of 350% over the current non-renewable wholesale forward electricity price for 2004."

5.5 Consumer prices

The consequences of subsidising high cost electricity generation can be seen in a comparison of EU consumer prices as illustrated in Table 4.

Table 4 EU Domestic Prices [39]
Price per KWh, including local taxes and VAT, from a representative utility, for a customer on a domestic standard tariff using 3,300 KWh per year, at January 1st 2002.

	Price Eurocents/kWh
Denmark	13.37
Germany	10.36
Belgium	10.04
Netherlands	9.97[a]
Italy	9.29
Austria	8.59[b]
Portugal	8.56
France	8.43
Luxembourg	8.38
Spain	7.58
UK	7.52
Ireland	7.43
Finland	5.36[b]
Greece	4.84

Notes a: 2001 data, b: 2000 data
All prices based on 30/12/2001 exchange rates

Denmark subsidises both wind and CHP plants in a country that in 2001 operated 17 central conventional power stations, about 600 decentralised, combined power and heating stations, and over 6,000 wind turbines. More specifically it is claimed that Danish electricity

[38] "UK offshore wind generation capacity: a return to picking winners?", John Bower, Oxford Institute for Energy Studies, July 2003
[39] Electricity Industry Review, March 2003, Electricity Association,

consumers annually pay more than DKK 10 billion (including VAT) in excess of what they would if the country only operated its central power stations, said to be amongst the most modern and least polluting in the world.[40] A third of the country's electricity demand costs 30 – 60 øre per KWh to produce when the market price is 10 – 20 øre per KWh. The effect shows through on the total price.

In Germany an Economy Ministry study shows that 40% of the electricity price charged by utilities to households is simply to cover subsidies on wind power and coal production (for business the subsidy proportion is 33%). Coal (including lignite) provides about half of the country's electricity, and nuclear 30% (without any subsidy). Disagreement in Germany's coalition government about the levels of subsidies provided for wind generation has provoked wider discussion. A bill to increase subsidies for power generation from wind to about EUR 2.5 billion per year has prompted calls from several quarters to abandon the country's nuclear phase-out plans, though it will be some years before these begin to affect supply. Significant investment in new base-load generating plant is likely to be required by the end of the decade.

5.6 Overview

Energy traders predict that the days of cheap power in Britain are coming to an end as the market is pulled into line with more expensive electricity on the Continent. On the forward market, prices for October 2003 to March 2004 have been trading at £23 per MW-hour against £18.00 a year ago The cost of wholesale electricity is expected to rise by a third this winter (2003/4), delivering a blow to industry, especially intensive users such as the chemical sector, which requires big quantities of power.

Table 5 Estimated new entry prices for generation from various fuel types.

	New entry price [a]
Nuclear	£25 - £30 / MWh [b]
Gas, combined-cycle	£20 - £25 / MWh [c] £26.6 to £28.0/MWh[d]
New coal	£25 - 36 /MWh [c]
Wind	£37 - £55 / MWh[e]
Current post-NETA Electricity price	Less than £20 / MWh

Notes:
a. New entry price is equivalent to levelised life-time cost
b. Source: British Energy, based on 11% return over 20 years.
c. Source: DTI Initial Submission to the PIU Energy Policy Review
d. Based on gas at 22.5p/therm, 10% return over 20 years
e. Without Renewable Obligation Certificate subsidy

At present at current market prices no new generation projects are economic other than government-supported renewables. Table 5 sets out the estimated new entry prices of various fuel types. Competition, low gas prices and regulatory pressure have produced low electricity prices, but it should be noted that only six years ago California had a surplus of electricity capacity similar to that currently enjoyed by England and Wales. In California a lack of investment in new generating plant for a variety of reasons including over-regulation meant that power shortages became inevitable.

[40] Krogsgaard, O.T., 2001: Politiken, 14th January. "Energipolitik som vinden blæser". ["Energy policy as the wind blows"].

The predicted cost of electricity from new nuclear plant is not as competitive as that from new gas combined cycle electricity if gas prices are low, i.e. below, say, 20p/therm, but if gas prices rise as expected, then costs are comparable. Nuclear energy is, in many countries, competitive with fossil fuel for electricity generation, despite relatively high capital costs and the need to internalise all waste disposal and decommissioning costs. If the social, health and environmental costs of fossil fuels are also taken into account then nuclear is clearly a preferred option both economically and environmentally.

From the viewpoint of generation costs is difficult to assess why nuclear power should ever be questioned on economic grounds. The industry claims its *total costs* for new build for the latest designs including decommissioning and waste will be *below the subsidy* offered to renewables in the White Paper.[41] Assuming electrical energy production of around 400TWh by 2010 of which 10% will be supplied by renewable energy sources, then subsidies to renewable energy electricity producers will reach £1.2 billion per annum by 2010. Should the target fail to be met the subsidy per unit of renewable electricity supplied would be higher as seen in the present market price of Renewable Obligation Certificates. Electricity costs will be further inflated by the extra costs of keeping most of existing conventional plant on standby in its varying degrees to cover for intermittency, although at present it is not clear that the market would ensure this provision.

5.7 An alternative investment model

Throughout this paper costs have been assumed against the cost of 100% debt. There remains, of course, the alternative method of mixed debt/equity arrangements, prevalent at present in the wind industry. Finland provides an interesting example of this approach being applied to the financing of new nuclear plant.

A group of energy intensive industries and municipalities formed a non-profit consortium, TVO, to coordinate the lobbying and project management of a new reactor. Finn5. TVO shareholders provide 20% in direct finance and 80% from borrowed funds to privately finance the new plant (although the state is a 30% shareholder by virtue of owning 70% of Fortum, a major energy company which itself has a 40% stake in TVO). In return for this investment the TVO shareholders obtain guaranteed cheap electricity at a fixed cost price for the duration of the plant's lifetime, or they can sell it in the NORDPOOL (Nordic electricity market) for profit. A key feature of NORDPOOL is the ability to sell futures, i.e. long-term electricity at a guaranteed price, and the low price of nuclear compared with other forms of generation makes it a very attractive option in this market.

[41] "Our energy future – creating a low carbon economy - A critical commentary on the 2003 DTI Energy White Paper", Malcolm C. Grimston, Prepared for Trade Unionists for Safe Nuclear Energy (TUSNE)

6. Conclusions

From the point of view of the consumer, security of power supplies depends on the diversity of sources and ability of power plants to provide a cushion against forced system outages or loss of energy supplies. Here the escalating dependence on imported gas raises serious questions concerning the increasing vulnerability of the UK electricity supply industry. Major failures of either gas or electricity supplies can never be totally discounted and, although they are very rare occurrences, the consequences do not pass unnoticed, as seen recently in the blackout in US and Canada of 14 August, the London blackout of 27 August, or the Italian blackout of 28 September 2003. Probabilistic analysis creates a sense of security but not of impact severity because results are either not measured or simply valued strictly in financial terms, i.e. cost.

Russia is seen as a key supplier of gas in the future, yet according to the insurance market data there may be a significant political risk of disruption in Russian gas supplies.[42] "Potentially significant interruptions of up to *180 days* have been identified as possible through disruption to the transportation infrastructure (notably the Yamal-Europe pipeline) caused by political or terrorist action…....data suggests that politically motivated risks of interruption, accounting for around half of the potential flows of Russian gas to the UK, could *occur once every eight years*. The data also indicates that LNG supplies, while less prone to political disruption, may have higher probabilities of infrastructure or transportation risks."

That is not good news for the forecast shown in figure 1 where gas will be supplying 70% of electricity by 2020!

With intermittent renewables having limited ability to contribute to security of power supplies, new renewable generation capacity needs an equivalent level of supporting conventional plant capacity. New renewable capacity over the next two decades, therefore, cannot replace nuclear capacity as most of the nuclear power stations are closed by 2020. All retired nuclear capacity will have to be replaced by an equal level of conventional plant capacity. Replacing nuclear with gas-fired plant would ensure security of instantaneous power supplies if gas is available, but would move the problem back to the reliability of gas supplies; thus both diversity and security of primary energy for electricity supply would be diminished, as discussed above in section 3.

Coal as well as gas might be an option in theory if carbon sequestration becomes a reality (costs unknown). Otherwise replacing zero emission nuclear base load with fossil-fired plant would have an extremely high impact on UK greenhouse gas emissions and have a dramatic bearing on the UK meeting its international and domestic commitments.

For these reasons new nuclear build appears to be the most dependable and beneficial option.

In a market for electricity where intermittent renewable generation meets an increasing share of the base load demand, investment in new plant may not be attractive from the potential investor's point of view. New plant will have to carry and cover its capital investment costs while competing with existing plant, perhaps having paid off much or all of its capital cost, and bidding for uncertain and non-continuous load. For investors in large new plant, there is a strong commercial preference to commission the plant only when there is a good probability of it being used from the outset. From a consumer point of view, there is likely to be value in having the new source of supply available earlier against the possibility of severe conditions.

[42] " The Non-market value of generation technologies", OXERA, June 2003

It is at least possible, then, that the signals for new investment will point not to the moment of the first power cut, but some time later, when power cuts will have dramatically increased the price of electricity.

If the decision were taken today to order a new nuclear power station, then, a possible timetable might involve:[43]

- 2-5 years – recruitment and training of NII and operating staff and familiarisation with the designs on offer, e.g. AP1000, ACR, PBMR;
- 3 years – planning, including Public Inquiry;
- 5 years – construction.

It would therefore be about 2013 at the earliest before a new nuclear plant could be operating in the UK, assuming that no insuperable obstacles were met. Clearly if nothing is done now, and the review of renewables in 2005/6 reveals disappointing progress and prospects, the 10-13 years would delay new nuclear deployment to at least 2015 or 2018.

If no action is taken to commence serious consideration of new nuclear build then should any circumstance arise where it was decided that nuclear electricity was needed, concerns have been expressed that pressure to cut corners might result. It would be sensible, therefore, to give early consideration to type-approval of plant so that standard designs need not be evaluated at every public hearing for site licences. This could be started now, without committing the UK to any future programme of new nuclear investment.

In large measure our energy future will be the result of the policies we pursue, and policies, in turn, are the products of the prevailing beliefs about the potentials that we foresee. Buried in such beliefs should be some appreciation of contingency analysis that is not obscured by dogmatism with which the ideas, assumptions, and attitudes behind those beliefs are held. The present population of the world is about 6 billion people, and is doubling about every 35 years. The demand for energy is rising even more rapidly, increasing by 5% per year, equivalent to doubling about every fourteen years placing increasing demands on the hydrocarbon sources that are also identified as part of the UK future supply scene. In such circumstances the development of sustainable energy resources is essential. Renewables have a significant role, but also nuclear power is inevitably an important contributor to our future energy needs.

[43] "Our energy future – creating a low carbon economy - A critical commentary on the 2003 DTI Energy White Paper", Malcolm C. Grimston, Prepared for Trade Unionists for Safe Nuclear Energy (TUSNE)

7. Appendix: Other White Paper policies

7.1 Combined Heat and Power (CHP)

A further important component in the Government's electricity supply policy is to encourage the development of combined heat and power plants (CHP) embedded in industry and the electricity distribution systems. The Government has a target of at least 10,000 MW of installed combined heat and power capacity by 2010 as part of its Climate Change Programme. At present, however, the CHP situation in the UK is dire. While the major reason behind this is the spark-spread (the fuel:electricity cost ratio), CHP is hampered by market uncertainties, constant Government Energy Policy Reviews & White papers, non-technical barriers such as high grid connection charges, and the difficulties associated with trading electricity. To sum things up simply in the words of one industrialist, "It is just too difficult for most people to do CHP in the UK !"

Government policies – both actual enactment and simple announcement of policy reviews – have caused the UK cogeneration (CHP) market to virtually disappear. At the smaller level (sub-20MW), in the UK as a whole, cogeneration plants are being decommissioned at a rate faster than new capacity is being installed. Many of these plants will not be restarted and the units sold on the second-hand market to developing nations where the economic conditions for cogeneration are more favourable.

The EU Cogeneration Directive is supposed to help promote Cogeneration. However, there are some aspects of the Directive which may actually inhibit the growth of cogeneration within Europe or actually disadvantage certain potential cogeneration applications. The Directive may actually discriminate against specific types of CHP such as those producing high-pressure steam for industry in favour of hot water district-heating schemes. This will be another disincentive to new plant build.

In a free market, cogeneration will displace the most expensive form of power generation, not the most efficient. However, current market conditions are affecting the economic viability of Cogeneration to such an extent that in several member countries the installation of new Cogeneration plant is negligible and existing schemes are being mothballed. While the slump in the CHP market has been evident across Europe, nowhere has this slump been more apparent than in the UK. This marked change in market size is due largely to changes in Government Policy. However, it must be recognised that it is not just the *enactment* of legislation that has triggered the changes, but also the uncertainty caused by announcements of Policy Reviews, publication of Consultation Documents and early announcement of proposed legislative changes.

The sudden drop in sales volume after 1998 coincides with three Government Energy Policy activities. First came the Energy Review White Paper and the introduction of the Stricter Consents Policy in October 1998. The second event was the publication of the Marshall Report in November 1998. This report, which led to the announcement of the introduction of the Climate Change Levy, started to create uncertainties in the market, as potential investors in CHP projects waited to see how Government reacted to the report's recommendations and what form the levy would take. Projects were delayed and the level of incoming enquiries started to slow down.

The third, and probably most significant event, was the release of the consultation document on the Revision of Electricity Trading Arrangements. It became clear during this consultation process, that cogeneration would be disadvantaged compared to large centrally dispatched power plant. As the consultation process continued, it became apparent that the benefits gained through Enhanced Capital Allowances and the possible gains through the Climate Change Levy (CCL) exemption on exported electricity would be more than negated by the New Electricity Trading Arrangements (NETA).

As a result of these events manufacturers experienced equipment purchases being shelved indefinitely as projects were no longer economically viable with associated tens of millions of pounds loss of revenues. A total UK market had collapsed to less than 10% of its pre-1998 levels.

In 2001 NETA went live, and the fears of the developers and operators were realised.

However, it is not just new CHP plant orders that have been affected by Government policy. Although rising gas prices have played their part, the extremely low prices cogeneration schemes receive for exported electricity, and the disproportionate risks faced by small generators under NETA, have led to the mothballing, or even removal and sale abroad, of a number of existing plants. OFGEM's own figures suggest that electricity exports from UK cogeneration schemes have fallen by 61% since the introduction of NETA.

The current state of the UK market will make it extremely difficult for the Government to meet its target by 2010, and will reduce the contribution that this part of the power generation industry will be able to make towards the reduction of Greenhouse Gas emissions.

Government policy 'to help CHP' is seen as basically just tinkering at the edges. The Government attitude is to let the markets sort things out for themselves.

Without incentives from Government similar to those enjoyed by the renewable industry the Government target of 10GWe from CHP by 2010 is seen by the industry as just a fantasy.

7.2 Energy saving

One area where the White Paper was very positive in setting targets was in setting targets for the results of improved energy efficiency. Whilst worthy of general support the Government's reliance on energy saving to *reduce* emission levels is not without controversy. The link between energy efficiency and economic activity lies at the heart of the debate as to whether improved energy efficiency reduces overall energy demand. Environmentalists promote energy efficiency as a means of reducing energy consumption – that every benefit from each individual act of energy efficiency can be identified and then aggregated to produce a macroeconomic total. Energy economists, however, are divided over the conceptual underpinnings and the empirical evidence; thus the question is impossible to resolve either way. In the recent Government White Paper the conservationist argument appears to have won and been adopted without question.

In 1989 a Select Committee recommended to the Government that
" More efficient use of electricity can reduce significantly both future investment in electrical power generation and the demand for primary energy, which would in turn have an environmental benefit[44]*"*

The response was
"We believe a more efficient use of energy can mitigate environmental effects and lead to savings (for example, in the UK between 1983 and 1987 energy intensity, or the amount of

[44] "Efficiency of Electricity Use", European Communities Committee (Sub-Committee B), Session 1988-89, 8th Report, HL Paper 37.

energy used for each £ of GDP, fell by 7%), but we do not agree that this would necessarily lead to significant reductions in both future investment in electrical power generation and the demand for primary energy. It might lead to higher comfort levels being taken in the domestic environment, or increased production in industry. In some cases, it could encourage a switch to an electrical process from another fuel. Demand for electricity is growing and likely to continue to grow in all major industrialised countries even after taking account of prospective efficiency gains, as the economy grows and as consumers install new electrical processes and equipment. This view is shared by international organisations such as the IEA and the EC.".[45]

This government reply coincides with economic theory both at that time and the present together with the historical record for most of this century. This background suggests that increased energy efficiency at the microeconomic level, while leading to a reduction of energy use at this level, leads not to a reduction, but instead to an increase in energy use, at the national, or macroeconomic level. Essentially the precise effects of energy efficiency decisions at the microeconomic level, while undoubtedly contributing to a slowing in the growth of energy demand, are impossible to quantify at the macroeconomic level and, because of the complex non-linear relationships, the effects may be counter to those expected.

The government's targets for sector emission savings between to 2020 and 2050 beyond, therefore, cannot be accepted as more than aspirations. If treated seriously then the danger is that emission reductions that are possible through alternative supply side measures will be delayed.

7.3 The MARKAL model conclusions

The White Paper was supported by a series of model-based analyses using the MARKAL model. This computer model represents a 'schematic network' of energy flows from sources through a menu of different technologies characterising the production, transmission and use of energy. It takes externally supplied energy demand figures and determines the least cost energy supply and end use that can meet the demand. Thus, unlike some "bottom-up" technical-economic models, MARKAL does not require, or permit, an *a priori* ranking of, for example, greenhouse gas abatement measures as an input to the model. The model chooses the preferred technologies and provides the ranking as a result.

The linear programming (LP) technique used allows very large problems to be represented and analysed. Its weakness lies in the simplification and scenario assumptions made in representing the national energy scene, e.g. 20-30% emission reductions by 2020, along with the estimates of data parameters, cost values, projections of energy service demands and forecasts of future economic levels of activity. In theory the model selects that combination of technologies that minimizes total energy system cost over selected snapshot periods in the future, subject to whatever constraints are imposed, such as emission levels, renewable or nuclear penetration, etc.

The model allows a grand superficial view to be obtained of the consequences of a number of 'what-if' scenarios, but the results are of unknown quality. A very large amount of detailed output is produced that is difficult to fault without industry-specific expert knowledge. To mention a few of the drawbacks, big changes in investment patterns can result from small marginal changes in technical data values, i.e. the results can be highly sensitive with respect to the estimated numbers assigned to data. Furthermore there is no feedback in the model allowing costs and prices to interact according to energy demand.

Although repeated results tend to suggest broad conclusions such as the identification of key families of technologies that are consistently important for attaining a low carbon future, e.g.

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[45] MEMORANDUM, Department of Energy, August 1989

energy efficiency, carbon sequestration, renewables, nuclear and hydrogen, the main inadequacy of the MARKAL model as far as the electrical supply industry is concerned is that it cannot capture operational constraints and requirements that guarantee security of power supply. Power supply security is based on plant combinations with probability analyses using historic forced outage rates and is not related to the question of security of energy supplies.