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Renewable Energy Foundation

ELECTRICITY PRICES IN THE UNITED KINGDOM

Fundamental Drivers and Probable Trends 2008 to 2020

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2008

SCOPE AND DISCLAIMER

This overview and analysis has been prepared by Hugh Sharman, of the consultancy Incoteco (Denmark) ApS, in collaboration with the Renewable Energy Foundation. We would like to thank Professor Michael Laughton (Emeritus Professor of Electrical Engineering, University of London) for reviewing the paper and offering further comments. A draft version of this paper was also circulated to various other colleagues, and this revised version responds to their criticisms, from which we continue to benefit.

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John Constable,
Director of Policy and Research,
Renewable Energy Foundation.

May 2008

PREFACE

The present expressions of surprise and pain at sharp increases in energy costs in the UK seem designed to show that these rises and their causes and effects were unforeseen and unforeseeable. Nothing could be less true. The conditions which have created the present position and an inevitable future of price shocks and scarce supply have been apparent for some years, and have been fostered and magnified by dilatory and ill-informed policy decisions.

REF's work over several years has concentrated on the real capabilities of renewables within the workings of the energy market. A near fatal preoccupation with politically attractive but marginal forms of renewables seems to have caused a blindness towards the weakening of the UK's generating fleet and a dangerous and helpless vulnerability to one main imported fossil fuel, namely natural gas.

We have therefore prepared this straightforward analysis of the fundamentals which underpin the UK's energy position and the inescapable conclusions for both price and security of supply. The work undertaken stops at the point of the energy supplier, but it is perhaps worthwhile to offer a comment regarding the ongoing impact upon the energy consumer.

Prices, particularly electricity prices, will continue to rise, probably sharply. The price to the consumer will also have to bear the additional costs created by the political fixation with volatile forms of generation. The Energy Minister has stated in the Commons in January 2008 that the additional cost of system refurbishment and connection to accommodate these marginal generators will be just over £10 billion up to 2012, to which he adds the subsidy cost of another £23.7 billion (by Ofgem's estimate this could even be higher). All of this will go on to electricity bills, but this huge sum will add only trivial quantities of firm generating capacity. However, such firm capacity must be built, and appropriate supplies of fuel secured in competition with other, larger economies at a time when we will have turned ourselves into the world's largest importer of gas.

The consequences, military, social, and economic, of this astonishingly negligent handling of the UK's energy system will be with us for many years, creating opportunities for private enterprises willing to step up to the plate and remedy the defects of policy. This paper is a contribution to understanding that opportunity, and also a plea to government to get out of the way and allow market action to respond as effectively as may be to the onset of crisis.

Campbell Dunford,
Chief Executive Officer,
The Renewable Energy Foundation.

May 2008

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1. SUMMARY

1.1 Introduction

This paper presents a view of the likely cost of electricity to *suppliers* in the United Kingdom in the next decade, but it does not attempt to make any estimate of increases in overall system cost, for example of grid expansion or balancing costs, and thus in the price charged to *consumers*. Furthermore, we are concerned only with the macro trend in prices, which we judge to be sharply upwards. In this regard the study is intended to go beyond intuitive pessimism and provide a reasoned account of our assessment. While the Renewable Energy Foundation has been developing elements of this analysis for some years, and we refer to our *Future Proofing UK Energy* (REF, 2006) as background, it is not possible for us, or perhaps for anyone, to do more at present than indicate the probable direction and an abstract order of magnitude (trivial, significant) of price movements. However the general outlines of the matter may be derived very simply by reviewing the state of affairs in and around the United Kingdom's electricity supply industry, and then reasoning from the presumption that **the future determinants of prices to suppliers, aside from capital and operating costs, are 1. fuel costs, and 2. the opportunity for profit arising from the value of lost load**. Our view, which is given in detail in the following chapters, may be summarised thus:

1.2 Overview

- **The UK government has underestimated the rate at which electricity capacity will be retired in the next decade**.
- While EdF and E.ON UK both see a large proportion of UK generating capacity as disappearing by 2015 (32 GW and 26 GW respectively), the Department of Business, Enterprise and Regulatory Reform (BERR) maintains the view that only 20 GW will retire by 2020.
- Specifically, it seems that the UK government underestimates the impact of the Large Combustion Plant Directive (LCPD) on the UK's large, inefficient, and technically obsolete coal fleet, particularly in regard to NO_X emissions, and that much less of this plant will be available after 2016 than is currently believed.
- While the government of that day (ca. 2015) might declare that in the public interest regulations must be breached and illegal plant permitted to run, this would not only be humiliating but would also create trading distortions for LCPD compliant generators. On the other hand there may also be significant commercial opportunities for LCPD compliant generators burning coal.
- **The UK government is irrationally optimistic with regard to the likely energy (MWhs) contribution from renewable generators.** For example, the Secretary of State for Business, Enterprise and Regulatory Reform, the Rt Hon John Hutton, MP, has projected up to 33 GW of offshore wind by 2020, an incredible vision lacking realism with regard to the practicalities (two to three 3 MW turbines per

day from January 2008 through December 31, 2020), or system balancing costs and feasibilities with the new clean base load capacity also projected.

- **The UK government, and to some degree National Grid, is unduly optimistic in regard to the degree to which the currently principal renewable, windpower, can contribute firm capacity (reliable MWs) to the grid.** National Grid believes that this contribution is roughly the square root of the proposed installed capacity (eg. 25 GW yielding 5 GW firm) while REF judges, based on European experience, and its own Met Office based power flow model, that the contribution at this level will be in the region of 5%, or less, which from the strategic perspective is negligible.
- **In view of these points the Capacity Margin will be more rapidly eroded than is currently expected.**
- In addition, **as wind power grows the specific cost of retaining underused but indispensable conventional shadow capacity will result in significant electricity price increases to suppliers and consumers**.
- While the impact of the nuclear rebuild passively tolerated by government has yet to be determined it is unlikely that any of these plants will be available before 2015–2020, and in fact the trading framework that will make their financing feasible has yet to be put in place.
- It is conceivable and perhaps probable that **the necessary presence of nuclear generation and clean coal to guarantee emissions free security of supply will require a floor price for electricity**.
- The lack of a clear trading framework that rewards capacity and the threat of heavy penalties under the emissions trading scheme, or a future carbon taxation system, with no firm price for emitted carbon, makes it unlikely that new coal generation will be widely attractive to investors unless it involves carbon capture and sequestration.
- In view of these points, and because of a more favourable emissions profile compared with coal, and especially because of its low capital cost, **it is evident that only gas generation is likely to be brought forward in quantity in the next five years**. (There is some 20 GW currently in various stages of planning.)
- However, international demand for gas appears to be rising faster than global export production, so competition for gas will be significant, with a consequent effect on prices to generators.
- **There is a significant risk that gas may become physically unavailable and in any case very expensive as its price continues to converge with that of crude oil**.
- All **renewable generators will benefit from this situation, either because of low or no fuel cost (wind, tidal, solar), or, invulnerability to any penalty imposed on carbon emissions**. Furthermore, owners of renewable generation equipment may continue to enjoy some sort of subsidy that guarantees a minimum rate of return. But system costs may be visited on non-dispatchable generators, as may grid

expansion costs necessitated both by balancing needs and the fact that renewable energy flows are often located far away from demand. The price paid to renewable generators may also suffer if they are unable to deliver reliably according to demand. The value of firm and predictable generation will give a premium to certain renewables in spite of fuel input costs (biomass, waste).

1.3 Conclusion

- Examination of current system data indicates that from 2010, possibly earlier, right through to 2020, there is likely to be extended tightness of supply either caused by lack of generating capacity and/or tightness in the supply of gas. The period ca. 2015 will be especially critical. **Due to fragile capacity margins and high gas prices *any* firm or predictable non-gas generator is likely to enjoy high prices.** *Generation or electricity storage capacity able to enter the peaking market may be extremely well rewarded even by the standards of that sector.*
- While many of the risks outlined above are now unavoidable, their severity can be mitigated in the medium term if prompt and determined action is taken by government to rectify the faults of the energy policy during the previous fifteen years. **The principal of these faults is the disingenuous manner in which government has consistently claimed to favour the free market in energy, while in fact distorting the market with clumsy and covert intervention**, for example on behalf of coal from 1997–2000, against nuclear in the 2003 White Paper, and throughout, counterproductively, on behalf of renewables. This has combined with complacency towards the obviously flawed electricity market system (BETTA) and resulted in a decade during which many billions of pounds of assets have been written down, the nuclear industry almost bankrupted, and an imprudent over-commitment to gas generation compounded.
- In our view the only way of ensuring rapid remedial action is for government to actually rather than apparently withdraw from the system, thus liberating energy market participants to respond commercially to the situation as it now stands.
- In recommending this course of action we note that our view is informed by no doctrinal affection for the free market, but rather a practical recognition that no government or any single market participant can gather and assimilate sufficient information to design and realise a satisfactory outcome. We judge that only the intellectual action of the market in aggregate, and through competition, has a reasonable chance of producing an optimal result for the United Kingdom.
- Nevertheless it should be recognised that the difficulties ahead are considerable, and even assuming perfect information and flawless market reasoning, the United Kingdom and its people are now inevitably vulnerable to price shocks and perhaps to disruptions of supply. Bearing this in mind we suggest that government should prepare itself to intervene with social policy to prevent hardship and to maintain order.

2. FUTURE TRENDS IN ELECTRICITY GENERATION CAPACITY

2.1 Summary

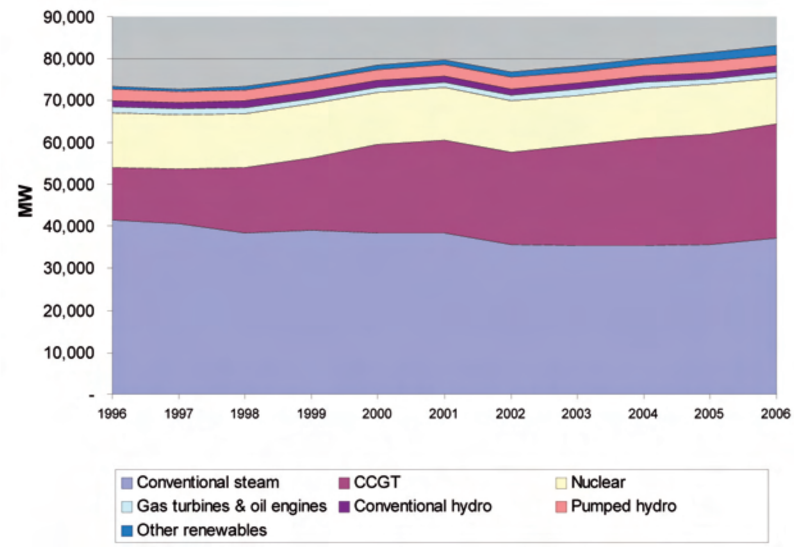
Notwithstanding governmental expectations, between now and 2015 the UK is likely to see the retirement of up to 30 GW of nuclear and coal generating capacity, some 37% of the country's total capacity, in order to meet international obligations with regard to 1. acid gas emissions and 2. Kyoto Treaty targets. To avoid protracted electricity rationing and/or rolling blackouts from 2010 onwards compensating infrastructure must be built in short order, and if this is to be diverse in fuels the cost will be in the range £50–60 billion. Given the lack of financial incentives for capacity that are offered by the electricity trading arrangements and the lack of any firm carbon price signals, and the lengthy planning horizon for nuclear and clean coal plants, the default near term solution is a dramatic increase in combined cycle gas turbine (CCGT) plant, for which there is approximately 20 GW currently in various stages of planning.[1]

Thus, the UK looks set to become even more dependent on gas. With the North Sea in decline, the UK will become the World's largest sovereign gas importer, competing with the rest of Europe for gas exports, particularly from Russia. We are aware that the Department for Business Enterprise and Regulatory Reform believes that the UK's connections with Norway, and growing LNG import capacity, insulate it to a significant degree against this international turmoil. However, we are less confident that this is the case, and we consider there to be a significant risk that new gas-fired electricity generation capacity will at best face high and volatile prices, and may even be unable to operate due to physical shortages of fuel.

2.2 Electricity Generation Capacity: The Current situation

At present the UK is securely supplied with electricity from a portfolio of ageing conventional generation equipment consisting of nuclear power plants, CCGT, coal- and oil-fired condensing steam power stations, hydro-power, pumped storage, a growing portfolio of wind energy, and other, mostly intermittent, renewable energy projects:

1 "UK faces stark choice between gas and coal', *Power UK*, 163 (Sep. 2007), 3. See also BERR, *Table of Potential New Conventional Electricity Generating Plants in Great Britain* (Nov. 2007), URN: 07/P27b, which lists 18 GW of generation for which permission has either been applied or granted. Of this all but the Kingsnorth coal station, of 1.6 GW, is gas-fired.



1. UK Power Generation by type 1996–2006.[2]

Importantly, there is a 2,000 MW inter-connector with France, and a further 1,000 MW inter-connection, with the Netherlands, is planned to enter service in 2010. During the last 20 years there has been a decline in the number of condensing steam units fired by oil and coal, and a build-up of gas-fired CCGT plants.

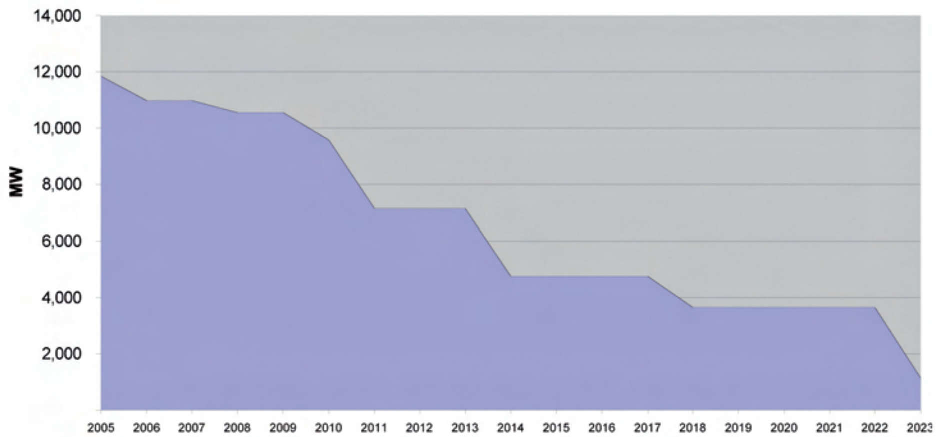
The driving force behind this evolution has been fuel price. Unlike Norway and the Netherlands, the UK has emptied its modest gas reserve very rapidly. Indeed the high rate of depletion during the late 1990s caused a temporary surplus of gas in northwest Europe that drove the market price of gas below $2/GJ. In this context there were compelling arguments in favour of constructing low cost, high efficiency CCGTs that could displace coal, especially UK-mined coal, and nuclear power. Indeed, the low price of electricity made it very hard for Britain's coal or nuclear energy to compete sucessfully. British Energy came close to bankruptcy in 2002 and several independent power producers also fell on hard times. Britain's largest, newest and most efficient coal-fired plant, Drax, came near to closure in 2003; only the intervention of its farsighted bankers saved the plant from bankruptcy (Drax is now richly profitable).

By 2003 the dash for gas had caused the UK to become the third largest sovereign consumer in the world, after the USA and Russia, and today, despite the decline in North Sea gas, it is still the fifth largest, behind Iran and Canada. During the last thirty years large parts of the UK's domestic, commercial and industrial energy infrastructure, for electricity and heat, have become dependent on gas. Rectifying this imbalance will require large investments that are not, in our view, adequately recognised or facilitated by UK energy policy.

2 Source: BERR, *Digest of United Kingdom Energy Statistics* (2007), Table 5.7.

2.3 Decline of Nuclear Generation Capacity

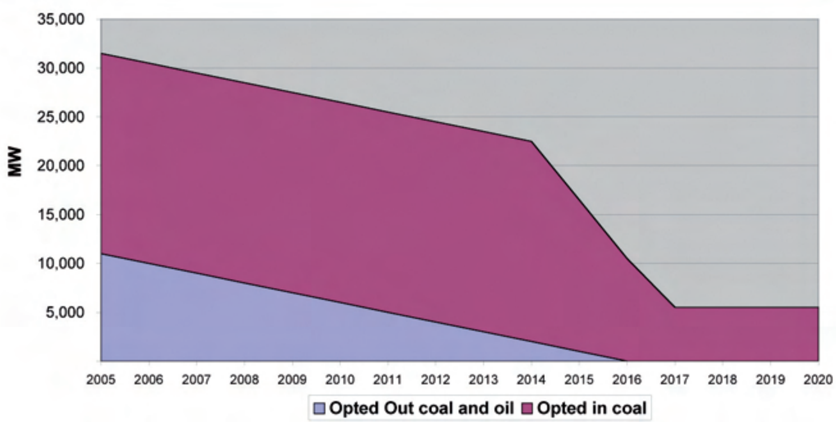
Nuclear power supplied 20% of the UK's electricity during 2006, a contribution which will be slightly reduced in 2007 because of the extended outages at Advanced Gas Reactors due to poor initial design, and to age. There is some talk of extending the life of this portfolio, but in reality there is little reason for optimism, and the run-down of existing nuclear capacity is imminent and inevitable. The UK's then Department of Trade and Industry (now BERR) forecast this in *The Energy Challenge* published in 2006:



2. Decline of UK Nuclear Capacity, MW. Re-drawn from *The Energy Challenge* (DTI: 2006).

2.4 Decline of Coal-fired Generation Capacity

More serious and less widely understood is the almost certain retirement of between 15 and 25 GW of firm coal capacity during the period 2008 to 2016:



3. Reductions in Coal- and Oil-fired Condensing Steam Generating Capacity.

Much of this retirement is being forced by the Large Combustion Plant Directive (LCPD), the EU's 1988 Directive, modified in 2001, that mandates the reduction of acid gas emissions, primarily SO_2 and NO_X, from large combustion units. SO_2 emissions are reduced through a Flue Gas Desulphurisation (FGD) plant that scrubs all the gases just ahead of their discharge into the environment. The only effective method for rendering coal plants

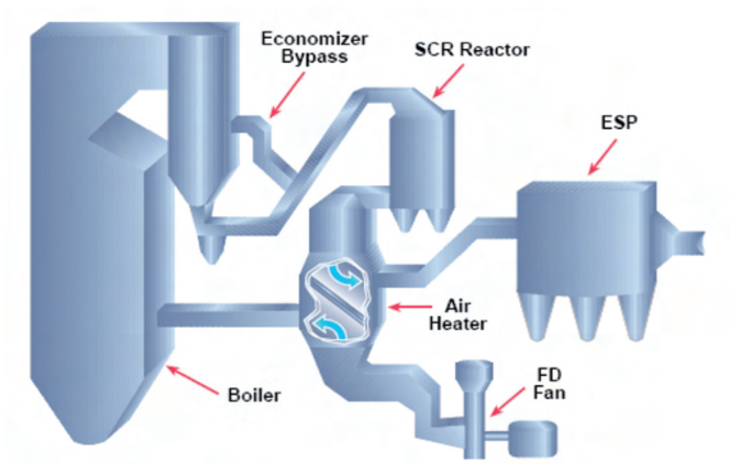
NO_X compliant requires the addition of a Selective Catalytic Reduction (SCR) reactor. This large reactor processes the hot and dusty flue gas at 300–400°C, after the economizer and ahead of the air-preheater.

The implementation of the LCPD in the UK, which commenced on the 1st of January 2008, has been slow compared to much of the rest of Europe. In Germany and Denmark legislation was written shortly after 1988 to clean up coal-fired power plants beyond the requirements of the LCPD. As a result, all large combustion plants in these countries complied fully with the LCPD by the middle of the 1990s.

By contrast, the electricity trading rules devised by UK governments since the LCPD was published have never rewarded generators for being good citizens. The two FGD plants that were built during the 1990s were part of the licensing requirement for Powergen and National Power. The lack of financial reward for the construction and operation of FGD was compounded by the fact that the system reduces overall efficiency, causing an increase in coal consumption per MWh, and also, of course, an increase in the emission of CO_2/MWh.

Each of the individual plants that comprise the 12 GW of existing coal capacity that opted out of constructing FGD plants, are now limited to 20,000 hours of operation during the period 2008–2016, an average of 2,500 hours per year. They will be decommissioned permanently upon using up their allocation. The loss of these units will seriously impact the ability of the electricity system to meet peak load and will have an effect on electricity pricing as their owners balance the need for short-term income with their obligation to close down. Each such power station, designed for base-load, must maintain a full quota of staff, between 100 and 200, including contractors, per 500 MW generating unit to stay viable.

But, and this is critical, by the 1st of January 2016, those plants which have opted into building FGD plants are *also* required to be NO_X compliant, and so must fit SCR equipment such as that represented diagrammatically below:



4. US Dept of Energy: Control of Nitrogen Oxide Emissions: Selective Catalytic Reduction, 1997.[3]

3 SCR: Selective Catalytic Reduction; ESP: Electro Static Precipitator; FD Fan: Forced Draft Fan.

The CEGB's power stations were never envisaged to be NO_X compliant, and the costs and difficulties of retrofitting SCR reactors into the flue gas system will be as much or more than the cost of installing FGD. It is hard to make a realistic estimate of the required expenditure, but the ductwork of these old stations was very tightly packed, and placing a large SCR between the economizer and air pre-heater will be an expensive, time consuming and testing undertaking, possibly requiring that both the ESP and air preheater be moved or even replaced. In any case, the concerned power station will have to be closed down for a protracted period during installation.

BERR refers to the possibility of expense and/or closure of more coal plants in its *Energy Market Outlook, October 2007* as follows:

> *These scenarios do not assume any additional plant closures after 2015. It is possible, however, that some coal fired power station owners will choose not to invest in the installation of equipment such as selective catalytic reduction that would be necessary to meet the further tightening of emissions standards which will be introduced under the Large Combustion Plant Directive from 2016 onwards. These stations would also have to close or reduce their level of operation, opening up a requirement for additional new capacity over and above that which will be needed to fill the gap left by the expected first-stage LCPD and nuclear closures. Looking still further ahead, the first generation of gas-fired power stations in Britain will start to reach the end of their normal operating lives (in the absence of refurbishment) during the 2020s.*[4]

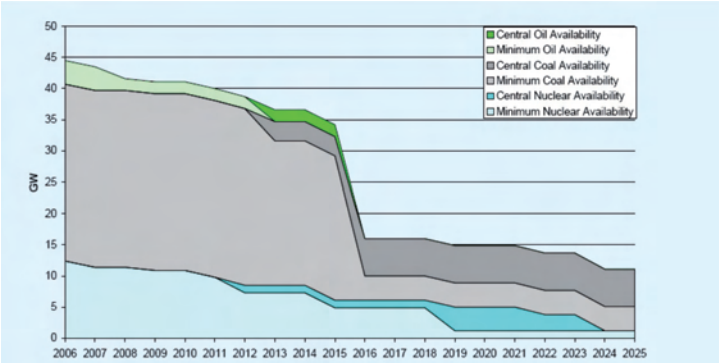
By 2016 Drax units 4, 5 and 6 will be the newest coal plants in the whole of the UK, CEGB-era fleet, and unit 6 will be thirty years old. In 2016, the average age of all the 25 GW of plants that opted-in for FGD will be over forty years old. With FGD, the whole coal fleet has a reduced average efficiency of 35–36%, an efficiency which would be further reduced by the installation of SCR. In contrast, nearly all new coal plants that are being built and delivered elsewhere in the world are well over 44% efficient, and so use 20–30% less fuel and emit 20–30% less CO_2/MWh.

Apart from the very high cost of retrofitting SCR, the desire to reduce greenhouse gas emissions will require the retirement and replacement of all but a very few of the existing plants by 2016.[5] Nevertheless, faced with the imperative need to maintain electricity supplies it is likely that the extreme situation created by the closure of so much firm capacity will require some sort of compromise between the UK and its EU partners over a derogation of the need to comply with the NO_X requirements of the LCPD. It will be shameful but may be necessary. **Mitigating the degree of this embarrassment and delivering environmentally compliant power presents considerable market opportunities to the generation industry.**

4 http://www.berr.gov.uk/files/file41999.pdf. See Para 4.10.6.

5 It is hard to see how the UK can reduce CO_2 emissions while depending on Europe's largest, oldest and most polluting coal fleet for a significant fraction of electricity generated. Doubtless, recognition of this fact, and concerns about security of supply, underly the recent support for Nuclear generation (BERR, *A White Paper on Nuclear Power*, 2008).

Confirmation of the general accuracy of this view can be found in the observations of both EdF and E.ON UK. The former, for example, has observed that some 32 GW of new plant may be needed by 2015.



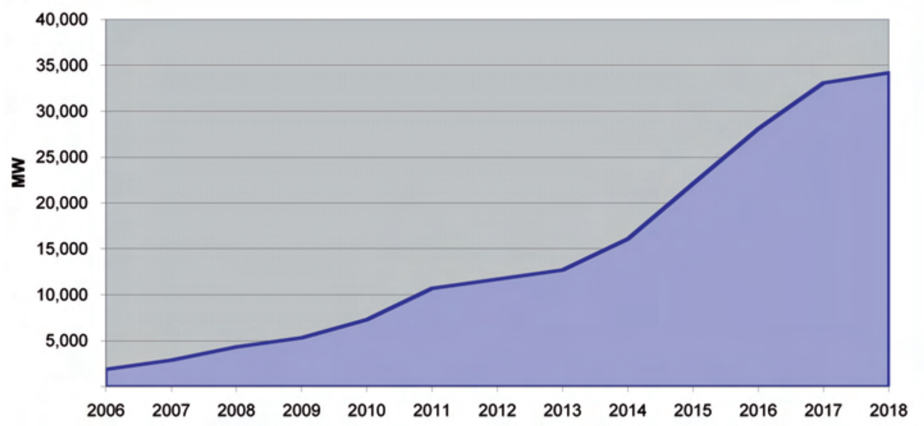
5. Profile of Generation Plant Closures 2006–2025 (GW). Source: EdF Energy Analysis.

The analysis of this scenario by EDF bears close scrutiny:

> *The UK is facing an electricity generation capacity shortage during the next decade as coal and oil-fired power stations close, largely in response to new environmental controls imposed by the Large Combustion Plants Directive (LCPD), and as gas cooled nuclear power stations reach the end of their useful lives.*
>
> *Between now and 2016, 13GW of coal and oil plant that have 'opted out' of the LCPD will close. 'Opted in' coal plant may also be closed by 2016 depending on the economics of fitting further equipment to reduce emissions of nitrogen oxides – for which new limits are to be introduced after 2015. 7.5GW of nuclear closures are scheduled by 2015. […]*
>
> *The UK will have a generation gap of 32 GW in 2016, assuming moderate demand growth and expected growth in renewables in line with the Renewables Obligation (RO). Even under very optimistic scenarios regarding grid electricity demand reduction the generation gap will still be 25 GW in 2016.*[6]

E.ON UK estimate that some 26 GW will retired by 2015, and 36 GW by 2020, while, the UK government anticipates that only 20 GW will retired by 2020. Our analysis suggests that EdF and E.ON are closer to the mark, and that to avoid the risk of energy rationing or rolling blackouts, new plant must be commissioned at the same rate as plant is being taken offline, as is shown in the following chart:

6 EDF, *Energy Review Submission 2006*, p. 12. Available online from: http://www.edfenergy.com/core/ energyreview/edfenergy-energy_review_response_main_document_v4-3.pdf #search=%22edf%20energy%20review%20response%22



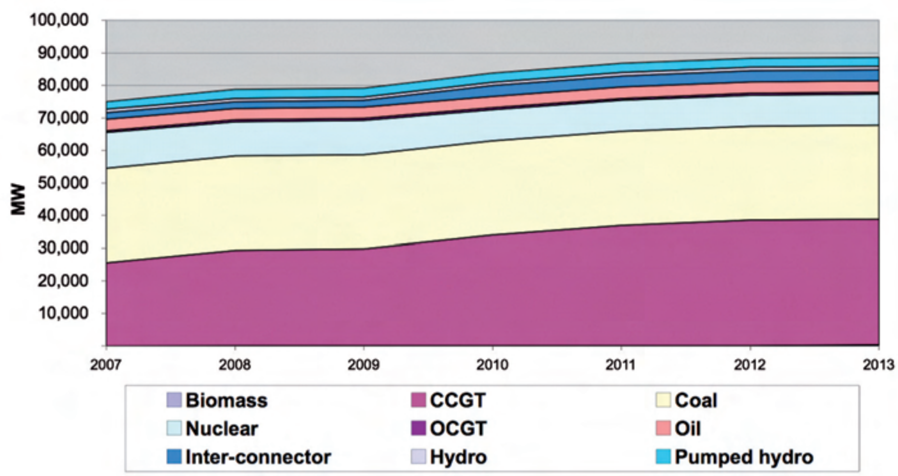
6. Cumulative Capacity Commissioning in each year to 2018 required to maintain a 25% margin (MW).

Prior to commissioning, of course, each new power plant must be planned, financed, engineered, licensed, procured and built. The only large, fossil-fuelled, fully despatchable power plants that have been commissioned in the UK during the last twenty years are CCGTs, and the experience has been largely benign. UK-based power generators, mostly non-British, are knowledgeable and solvent. Typically, it has taken roughly four years between the inception of a new project to its commissioning. Hitherto, there have been few fuel supply problems, although gas supplies were tight and pricing very spiky during the winter 2005–2006. However, the current worldwide boom for power generating equipment is stretching the capacity of the global manufacturing industry, and five years seems more realistic for plants that have not yet actually been ordered.

So even if gas-fired plant is to supply a significant fraction of the pending short-fall, it must be ordered at least four years ahead of the time when it will be participating actively in the market. Of course, major investment decisions are not snap decisions, and a long gestation is to be expected, ranging from a year to three years.

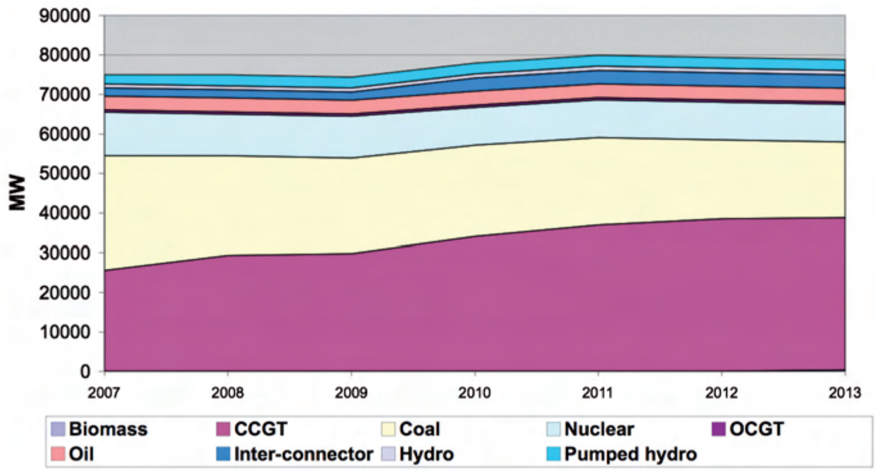
The following charts have been drawn from National Grid's 2007 *Seven Year Statement*, Table 3.5,[7] which appear to show that capacity is being built at a rate sufficient to replace nuclear closures:

7 http://www.nationalgrid.com/uk/sys_07/dddownloaddisplay.asp?sp=sys_Table3_5



7. UK Capacity, 2007–2013, if no opted-out plants close (MW). Source: National Grid, *Seven Year Statement*.

However, curiously, the table shows all the FGD opted out coal plant as being available throughout the period. If we make allowance for the possibility that 10 GW of the 12 GW of opted out coal plant will close by 2013/14 the projection changes considerably:[8]



8. UK Capacity: 10 GW of Opted-out Plants Close by 2013 (MW).

Indeed, if this scenario materialises then generation capacity will be tight throughout the period until 2014 despite the growth in CCGTs.

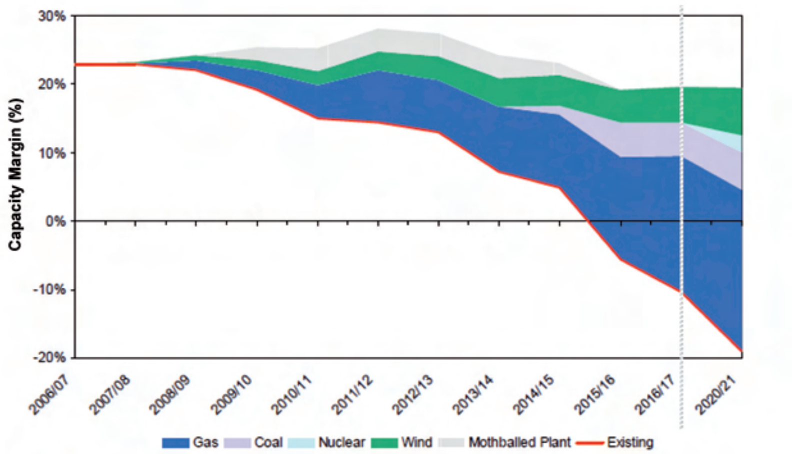
By 2010–2011 the gap caused by decommissioning some nuclear and some coal plant will amount to between 5 and 10 GW.[9] If the plant needed to fill this gap has not already been ordered, we can expect to see a tight market, if not loss of the spare capacity to meet peak power. However, even if the necessary gas plant is ordered and built, it is conceivable that physical constraint of global gas supplies may make their operation impossible. For

8 This is the view of BERR in their October *Energy Markets Outlook*.

9 British Energy announced on 11 December 2007 that it intends to carry out an extension to the lives of AGR stations.

coal and nuclear new build there is a longer planning horizon, and in any case it is a much more complex and expensive business to build new, clean, coal and nuclear power plants in the absence of any clear trading framework to underpin their financing and procurement. This makes it highly unlikely that any clean (Carbon Capture and Storage (CCS)) plant can be commissioned before 2015. Nuclear plant, even with special government support, is almost certainly still further off.

Government's apparently relaxed attitude to this decline is in part grounded in National Grid's view, which can be seen in the following chart which represents the level and composition of the margin of available generation capacity over peak load (60 GW), and shows clearly that if no new plant is built then capacity will fall below demand in 2015.



9. National Grid's projection of Capacity Margin Composition 2007–2021.[10]

The margin of ca. 24% represents some 14 GW of generation, and the extremely heavy dependence on gas generation to maintain an adequate surplus is obvious. We question whether this is wise. The chart indicates an early re-entry of nuclear generation, and the mysterious return of mothballed plant, all points which are puzzling and worth noting, but perhaps still more striking is the assumption that wind will provide a substantial degree of firm capacity, a view also present in National Grid's *Seven Year Statement*, which suggests that the square root of installed capacity may be delivered as firm:

> *[...] for 8,000 MW of wind (e.g. in line with Government's 2010 target of 10% renewables), around 3,000 MW of conventional capacity (equivalent to some 37% of the wind capacity) can be retired without any increased probability that load reductions would be required due to generation shortages on cold days. However, as the amount of wind increases, the proportion of conventional capacity that can be displaced without eroding the level of security reduces. For example, for 25,000 MW of wind only 5,000 MW (i.e. 20% of the wind capacity) of conventional capacity can be retired.*[11]

10 Source National Grid, Simon Cocks, "The Connection Challenge". Presentation to the Institute of Economic Affairs conference, October 2007.

11 National Grid, *Seven Year Statement 2007*, Chapter 4, p. 11.

However, Danish and German experience and more recent Met Office data-based modelling, *25 GW of Distributed Wind on the UK Network*, conducted by Oswald Consultancy Ltd for the Renewable Energy Foundation suggests that the square root rule of thumb attributes too high a degree of capacity credit to wind.[12] The Oswald Consultancy model demonstrates very large power swings dropping down to a minimum average output of 3.7% of installed capacity, with minimum wind output tending to occur on colder days, exactly as reported empirically by the major German grid operator E.ON Netz, and by Eirgrid in Ireland. While there is continuing debate about the precise quantification of wind capacity credit it is now not controversial to suggest that this can be extremely low (even the square root approximation produces such results at very high levels of installed capacity).

In view of this over-estimation of firm capacity from wind power we conclude that the capacity margin will erode more rapidly than is currently envisaged. When combined with the other concerns discussed above we believe that the UK electricity system will be exposed to significant and debilitating risk, resulting in high prices and even interruption of supply. The impact of large quantities of wind generation on overall system costs and thus prices to the consumer should also be considered. Adding wind generation to the electricity supply adds a more expensive source that in itself will raise electricity costs. If 20% of electrical energy (MWh) is supplied by wind then 20% has to be taken from other sources, but the wind capacity (MW) connected does not lead to an equivalent amount of conventional capacity (MW) being retired from the system. An equivalent amount of conventional capacity, or slightly less,[13] has to be retained and operated at lower load factors, and sub-optimally from an energy efficiency standpoint, producing electricity at higher unit costs and hence, also with higher emissions per unit of energy generated. Thus, **the costs of ensuring the continued presence of the proportionally growing large amounts of underused but indispensable conventional plant capacity in the shadowing role will be a source of electricity price increases**.

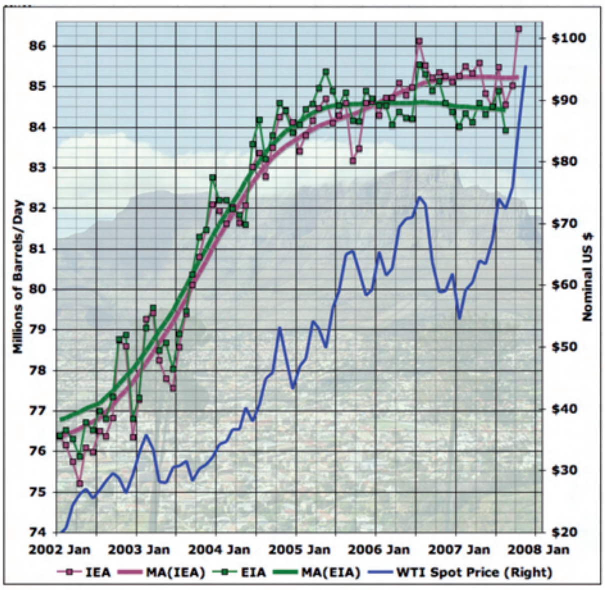
12 Renewable Energy Foundation, *25GW of distributed wind on the UK electricity system* (7 Dec. 2007). Study conducted by Oswald Consultancy Ltd. Available online: http://www.ref.org.uk/images/pdfs/ref.wind.smoothing.08.12.06.pdf. A full length version of this work is forthcoming in *Energy Policy*.

13 Probability analyses show that wind can have a capacity credit that allows a small proportion of conventional plant to be retired without lowering security of power supply; however for large penetrations of, say, 20% of electrical energy from wind additional investment is required in the form of gas turbine or diesel plant to ensure energy supply against the *loss of high load factor conventional plant capacity*, which wind cannot support. Because such additional costs are relatively small most decision makers and many analysts have been misled into thinking that the overall system costs of wind management are small, but this is incorrect.

3. FUEL AND PLANT COSTS

3.1 Energy Prices: Gas and Coal Converge on Oil

Historically, electricity prices have been determined by the price of fuel, the efficiency of the plant burning the fuel, and the capital and operating cost of the plants that employ this fuel. In recent years natural gas has been cheap and especially attractive if one discounts the fact that it is a finite resource. Consequently, since the early 1990s there has been a rapid growth of low-capital-cost, high efficiency, gas-fired combined cycle gas turbines (CCGT) in all OECD countries. With the notable exception of Sizewell B, all new, central, thermal generating plant built in the UK since the commissioning of Drax 6 in 1982 has been CCGT. Enthusiasts for gas sincerely believed that its price, based on regional markets, could be de-linked from other hydrocarbons such as oil and coal and that as depletion took place, new sources would be found. However, it is increasingly clear that this is not the case, a fact that is particularly troubling given current oil price trajectories. The following chart shows the monthly rates for oil production during the past five years as recorded by the International Energy Agency (IEA) and the Energy Information Administration (EIA) of the US Department of Energy (DoE), together with the spot price:



10. Monthly rates of oil production for the past five years, data from the IEA, the EIA, the US DoE, and the WTI Spot Price.[14]

It is clear that the rate of growth in global oil production has been decreasing since about 2004, and appears to be flattening out, despite steadily rising demand driven by China and India.

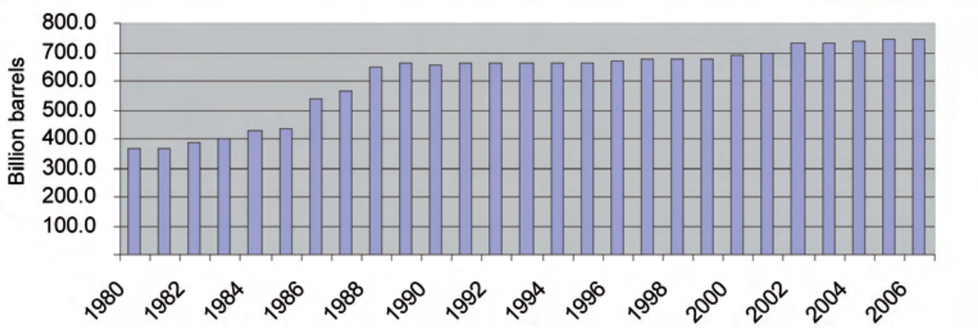
It is, of course, possible that the somewhat irregular plateau of production shown in this chart is temporary and that production rates will resume their ascent in response to what appears to be relatively price-inflexible demand growth for transport fuel. Certainly, the

14 Source. The Oil Drum: http://www.theoildrum.com/files/plateau_price_end_nov.png.

rational business response to increasing demand at ever higher prices is to seek, develop and pump oil with all feasible rapidity.

It is, however, unsettling that even at over $90/bbl (or approximately $16/GJ), most of the oil majors are choosing to return profits to their shareholders rather than devoting cash-flows to expand their non-OPEC reserves, which are currently declining. Their presumably expert judgement is that exploration prospects outside OPEC and Russia are, with some notable exceptions such as Africa and Canadian oil sands, poor. New oil, we are learning, can be difficult to find and expensive to bring to market.

No international agency has any reliable evidence of the spare capacity about which OPEC boasts. Nor is there any reliable evidence that the reserves claimed by OPEC have much credibility. The following chart, based on published data, is suspiciously stable since 1989:



11. Proven Middle East Oil Reserves 1980–2006 (billion barrels).

In BP's *Statistical Review of World Energy 2007* we note that recoverable Saudi reserves since 1999 (for example) are reported as follows:

Table 1. Saudia Arabia Recoverable Reserves, 1999–2006. Source: *BP Statistical Review of World Energy 2007*.

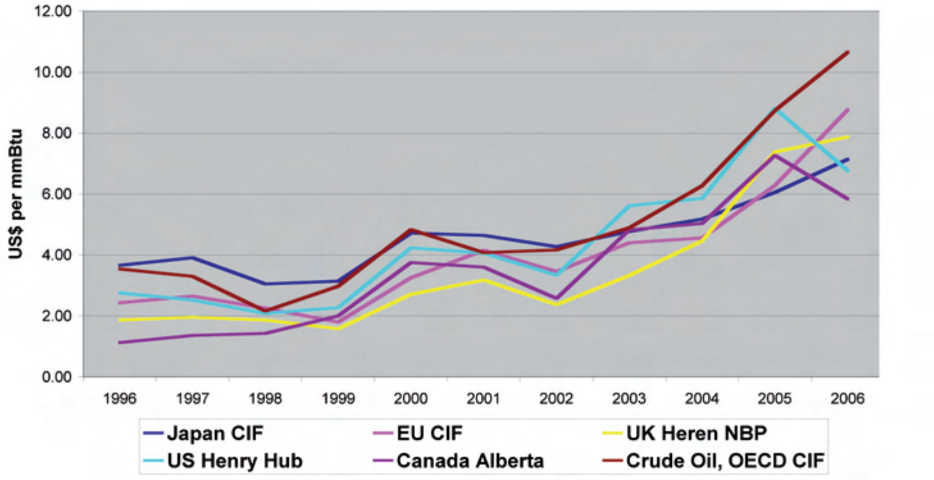
Year	1999	2000	2001	2002	2003	2004	2005	2006
Recoverable reserves: billion barrels	262.8	262.8	262.7	262.8	262.7	264.3	264.2	264.3

Bearing in mind the fact that the annual draw-down from reserves amounts to 3.3 billion barrels per annum it is remarkable that the year to year variation in reserves is reported to an accuracy of 0.1%. It is impossible to place any firm reliance on such estimates.

If, as appears possible, the global oil industry is unable to increase flows of oil to balance demand, oil will be rationed by price. The consequence of this, other things being equal, will be that the price of oil will increase further, until it reaches a point where demand will flatten or decline. Such a price rationing period will have a major effect on the other fossil sources of energy, coal and gas, and is, perhaps, already doing so. We note that the current coal price is more or less double what it was just two years ago and now stands at $80–142 per ton, or roughly $3–4/GJ. But coal, even at this higher price, enjoys a pricing advantage over crude oil of $15–16/GJ.[15] Significantly, coal can be used as a source of liquid transport fuels through the Fischer-Tropsch process, as can gas. Indeed, as longer pipelines and the

15 $90/b is equivalent to $15.5/GJ.

growth in the use of Liquefied Natural Gas (LNG) have rendered gas a global commodity, it has become quite clear that in spite of fluctuations the price is linked to oil:



12. Gas and Oil Price 1996–2006. Source: *BP Statistical Review 2007*

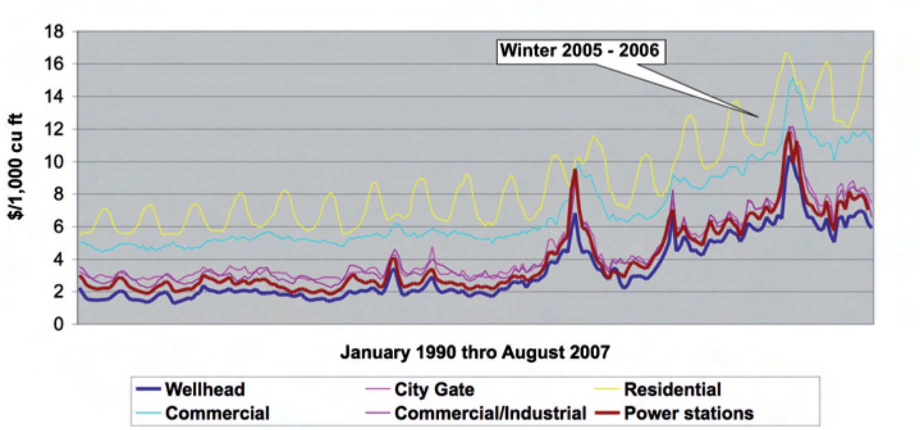
We suspect that gas prices are following the oil price on calorific equivalence, which is a matter for concern since crude oil prices have increased by a further 50% since 2006 and now stand at over $100 a barrel (roughly $16/GJ), an upward trend that has been relentless since 1999.[16] There are already signs that this is having an impact on LNG trading, as can be inferred from a recent report in the journal *World Gas Intelligence* (12 December 2007):

> *Japanese buyers have consistently outbid their neighbors for available new term supply and are reportedly paying $13/MMBtu or more to snap up Atlantic Basin spot cargoes. So it might seem that they have decided gas is worth a hefty price in the age of $80-$100 per barrel crude oil. Jumping to that conclusion might be a mistake, however, judging by pointed remarks on the state of LNG markets by officials from Japan's top two gas utilities at the CWC-sponsored World LNG Summit in Rome last week.*

However, and far from being a mistake, it is perfectly rational to assume that the right energy price is what the market is prepared to pay. In fact the US also saw such dramatic peaks during the winter of 2005–2006, when gas prices exceeded those of oil.[17] The following chart describes monthly gas prices:

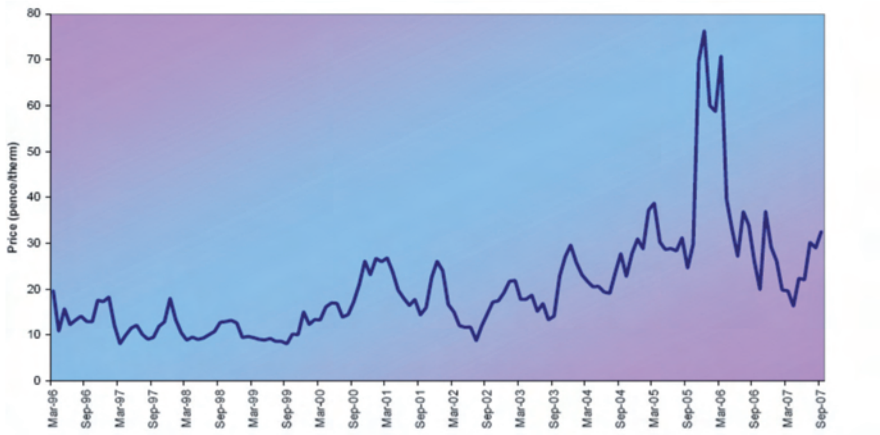
16 One million Btu (British Thermal Units). Is 1.05 GJ (Gigajoule).

17 Energy prices are reported in many confusing variations. These prices are roughly the same as $/GJ.



13. US Monthly Gas Prices, $/1,000 cu ft.[18]

Notoriously, the UK also experienced a similar spike:

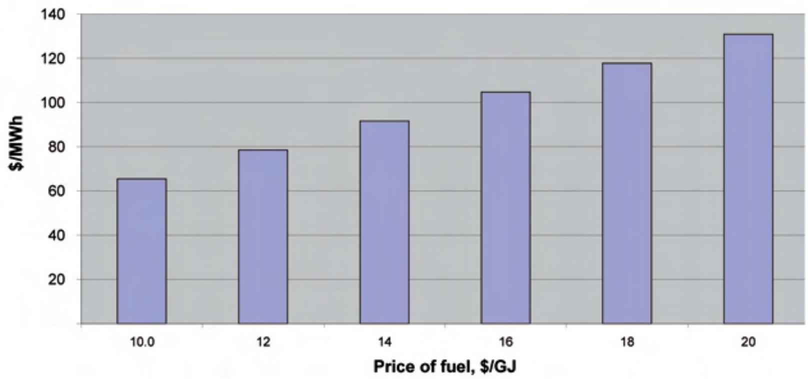


14. Monthly average GB System Average Price of Wholesale Gas.[19]

So as the market for gas continues to globalize and gas and coal are increasingly used to produce transport fuel and petrochemicals, it is reasonable to expect global gas prices to converge with oil prices. The resulting impact on the electricity generation sector will be considerable, since generation costs are extremely sensitive to fuel price, as can be readily appreciated from the following charts, the first of which shows the price of power at varying fuel prices for a modern Combined Cycle Gas Turbine:

18 Source: EIA, November 2007.

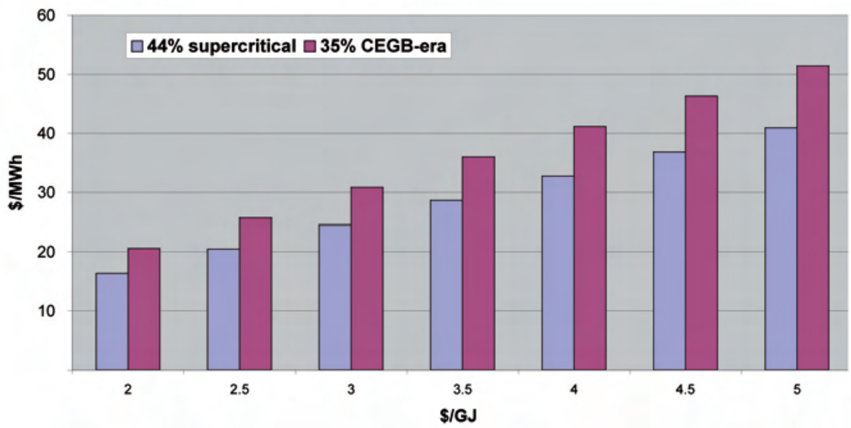
19 Source: National Grid.



15. Price of Electricity ($/MWh) at varying fuel prices ($/GJ) for a modern CCGT.[20]

It should be noted that European prices are currently, in the winter of 2007–2008, in the region of $12/GJ.

The following chart shows the generation costs for two varieties of coal plant, a modern supercritical system with a relatively high thermal efficiency, and a CEGB era system.



16. Coal-fired Unit Fuel Cost.

It should be noted here in passing that several Integrated Gasification Combined Cycle plants (IGCCs) are under consideration in the UK at this moment, largely because the process lends itself particularly well to Carbon Capture and Storage (CCS). An IGCC can be modified to produce two relatively pure streams, one of hydrogen, the fuel, and the other of carbon dioxide. In carbon capture mode, the overall efficiency of the process, fuel to electricity, is of the same order as a CEGB-era subcritical coal-fired plant, while a super-critical unit in capture mode would also be reduced from 44–46% to 35–37% overall efficiency.[21] Improved scrubbing processes may reduce the energy losses, but these are still at an early design and demonstration phase. In spite of these losses IGCC will probably be more attractive than CCGT for combination with CCS since the CO_2 concentration from CCGT is low at 3–4% by volume. By contrast, Pulverised Fuel-firing, with

20 Assuming 55% annual average thermal efficiency (with CO_2 emissions at 382 kg/MWh).

21 Studies performed by ELSAM, Denmark, during 2001–2002.

flue gas at 8–12% CO_2 concentration (depending on excess oxygen control), means that the capture reactor must be three to four times larger, rendering the process extremely costly and inefficient.

3.2 Capital Costs of Generation

There are only three serious fossil-fired options, one with a variant, for large-scale generation:

Table 2. Capital Cost of Various Generation Technologies ($/kW)[22]

Generation Technology	Cost per kW of capacity
Combined Cycle Gas Turbine	$1,200
Super-critical Pulverised Fuel coal, without CCS	$2,200
Super-critical Pulverised Fuel coal, with CCS[23]	$2,600
IGCC with CCS	$2,700

A substantial power equipment construction boom is taking place in world-wide emerging markets and as a consequence global manufacturing capacity is more or less fully occupied and will remain so for some years, entailing extended delivery delays and higher costs.[24] As a result, there is a troubling degree of uncertainty about both cost and delivery of conventional plant.

Under the British Electricity Trading and Transmission Arrangements (BETTA) electricity generating plant must pay for itself by selling electricity and related services, there being no mechanism by which the value of firm capacity provision is distinguished and recognised. Therefore, investment in expensive plant requires a very high market share. The sensitivity of capex recovery to Load Factor can be seen in the following table. Note that it has been assumed that both capital investments enjoy an IRR of 15% and that this takes place over a total 25 year period. Five years has been allowed for building the CCGT and seven years for the coal plant. Therefore the coal plant has two fewer years of operation in which to achieve its payment obligations.

Table 3. Required Capex Recovery ($/MWh) at Various Load Factors (LF)

Hours operation per year (Load Factor)	5,000 (LF 57%)	6,000 (LF 68%)	7,000 (LF 80%)
CCGT	$40.64	$33.87	$29.03
PF-fired coal	$98.40	$82.00	$70.29

The differential in price for the fuel must be consistently around $50–$60 per MWh for coal to compete successfully against gas, though the latter will be more expensive to

22 We are indebted to a power developer in the UK for these rough estimates, valid during the winter 2007–2008.

23 A variant of the super-critical power plant is under development by RWE and Vattenfall where the coal is burned in pure oxygen. After removal of SO_2 and NO_X, this will emit pure CO_2 which can be captured without any reactors, saving tail-end costs. However, its realisation at full scale is some years away, at the very earliest some time between 2015 and 2020.

24 China is building at the rate of between 70 and 90 GW per year. The UK's total generating capacity in 2007 was ca. 77 GW (BERR, Digest of United Kingdom Energy Statistics (2007), 120.

operate in most scenarios provided that gas prices do not collapse to historical levels. The following table models this probable future:

Table 4. Possible price scenarios: Gas and Coal, $/MWh

Hours of operation per year (LF)	**5,000 (LF 57%)**	**6,000 (LF 68%)**	**7,000 (LF 80%)**
CCGT Capex recovery ($/MWh)	41	34	29
Gas fuel at $16/GJ ($/MWh generated)	105	105	105
Non-fuel OPEX ($/MWh)	20	20	20
Selling Price ($/MWh)	165	159	154
PF-fired coal Capex recovery ($/MWh)	98	82	70
Coal at $3/GJ ($/MWh generated)	31	31	31
Non-fuel OPEX ($/MWh)	30	30	30
Selling Price ($/MWh)	159	143	131

However, gas could benefit from a CO_2 penalty. For example at $20/t CO_2 the overhead imposed on gas would amount to just $7.7/MWh, whereas coal would be confronted with $14/MWh, and at $40/t for CO_2 the spread between gas and coal would be $14/MWh. Bearing this in mind, and give or take probable fluctuations in the cost of fuel, if the price of gas remains low *and* a CO_2 penalty is enforced an investment in coal is exposed to considerable risk. The capital cost of nuclear is high, in comparison to gas, at ca. £1,270/MW, and might perhaps be higher.[25] Although modern nuclear plant will be able to enter the market as a flexible generator able to follow load, a valuable service and rewarded accordingly, it is conceivable that nuclear investments may be regarded by investors as risk prone if market access, practically a floor price, is not guaranteed. Since government will increasingly view nuclear generation as indispensable to its climate change and security of supply objectives the creation of such a sheltered situation may well be inevitable, but providing security in combination with a free market will require comprehensive and ingenious revision of the British Electricity Trading and Transmission Arrangements. A reliable and even-handed attitude to carbon pricing might perform a similar function.

25 Some sources estimate $4,500/MW

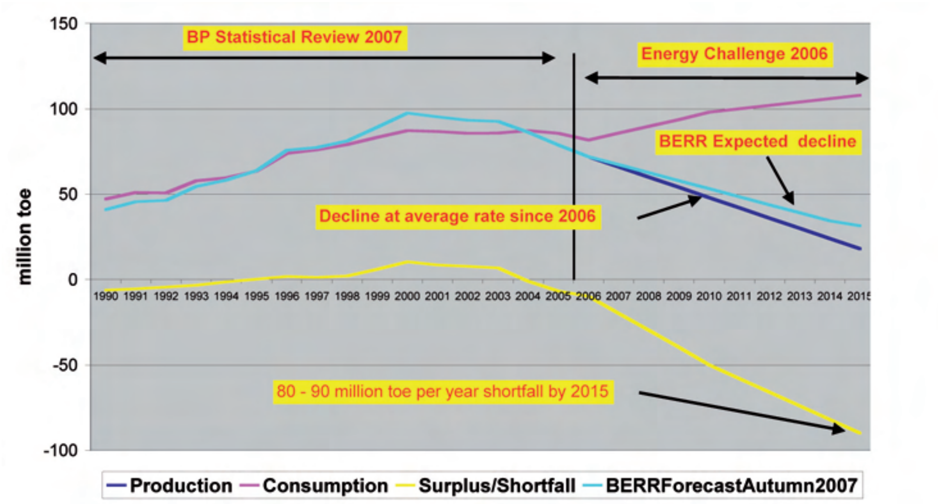
4. OVERSEAS GAS AND SECURITY OF SUPPLY

We have argued that by 2015 around 30 GW of new, firm despatchable generating capacity must be delivered to replace nuclear and coal plant. By default most of this will be gas-fired CCGT. Fuelling this fleet at reasonable cost is a cause for considerable concern.

4.1 The UK as a Natural Gas Importer

By 2015 the UK will need to import, according to conservative estimates, between 80 and 100 million tonnes of oil equivalent (Mtoe) of gas both to keep homes warm, factories and commercial premises operational and new and existing electricity plant in operation.

If, as seems likely, the 20 GW of opted in coal plant must be closed due to NO_X-compliance issues, there will be a further significant increase in requirement for gas after 2016, amounting to roughly 15.5 Mtoe per year. So by the most optimistic forecasts, the UK in just eight years time will be looking to obtain between 90 and 100 Mtoe, with that figure rising rapidly as UK gas continues to decline:



17. UK Natural Gas Production & Consumption to 2015. Sources: BP, *Statistical Review of World Energy*, DTI, *The Energy Challenge*, 2006.

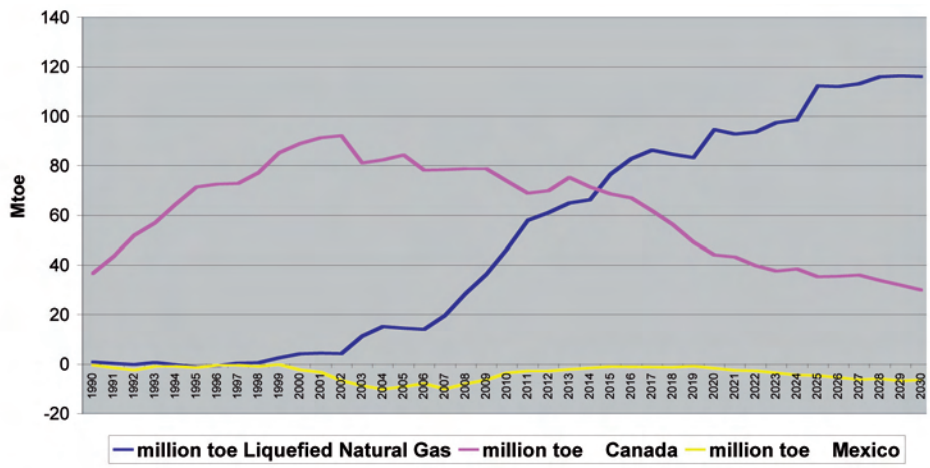
Thus the UK looks set to be the greatest sovereign importer of natural gas in the world by 2015, exceeding even much larger economies, such as the USA (a small scale importer in 2007 but set to increase to 77 Mtoe by 2015), and Japan (already the world's largest importer of LNG at 77 Mtoe in 2007, but increasing to 100 Mtoe in 2015).

4.2 US Gas Demand and Qatari Supply

By 2015, China, South Korea and other South East Asia countries will be consuming gas at roughly 589 Mtoe per year, a growing fraction of this, and all of Japan's and Korea's, being LNG.

Most nations that possess natural gas prioritize the resource for their own energy and economic developments. Iran produced and used over 90 Mtoe in 2006 and imported 2 Mtoe from its neighbours, and there is strong political resistance in Iran to plans for exporting gas, difficulties exacerbated by problematic trading conditions resulting from US trade sanctions. Saudi Arabia uses everything it produces and has no plans to export any of its large reserve, and Indonesia, until last year the second largest net gas exporter after Russia, is currently defaulting on export contracts with Japan and Korea so that it can satisfy an internal demand that is growing at the rate of 4–5% per year.[26] Demand is growing strongly in Malaysia and Australia, while Mexico and the UAE have become a significant gas importers.

The USA has until recently maintained output from tight gas[27] but now faces a sharp, imminent reduction in such sources and will soon become a major importer of LNG, not least because imports from Canada, its largest outside supplier, have been declining since 2001, and will continue to do so.[28] The US consumes 22 trillion cubic feet (tcf) of gas per year, and produces 18tcf. As Michael Morris, CEO of American Electric Power (AEP), put it recently, 'Without Canada we would be entirely upside down on gas'.[29] By 2015, the USA's LNG imports are likely to be 77 Mtoe:



18. US Natural Gas Imports, Mtoe. Source: *EIA*.

When the last LNG train is commissioned in 2012 Qatar's total LNG exports will plateau at 83 Mtoe per year from 36 Mtoe in 2006. This will find a ready market anywhere on the globe, since LNG import capacity far exceeds that for production. This gas is mainly contracted to markets in the Far East, but the US, according to the Department of Energy, also expects a large fraction of its future LNG from Qatar. However, the increase in demand for US LNG is nearly double the 47 million tonnes per year increase in LNG exports anticipated from Qatar up to 2015. Morris of AEP remarks, 'I don't see us winning the battle with China and Japan on LNG'. The UK is not better placed.

26 Indonesia fulfils its contracts with Japan and Korea by buying gas from Qatar.

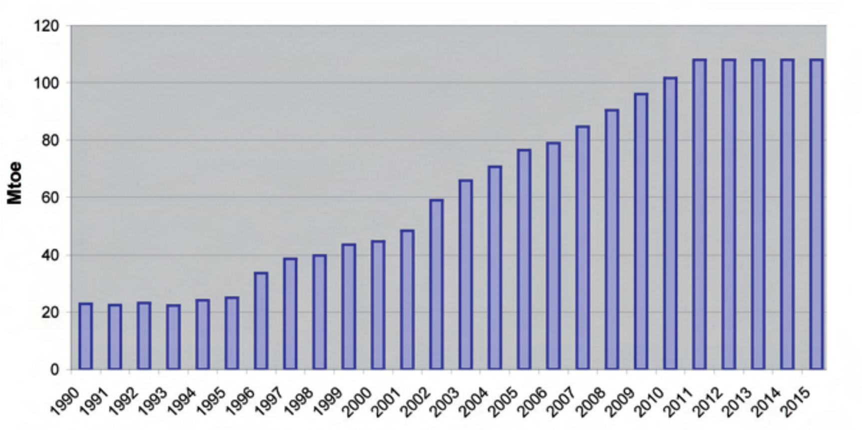
27 I.e. gas that is stuck in a very tight formation underground, for example trapped in unusually impermeable, hard rock, or in a sandstone or limestone formation that is unusually impermeable and non-porous (tight sand). Further details are well explained at http://www.naturalgas.org/overview/unconvent_ng_resource.asp.

28 *Oil & Gas Journal* (3 September 2007).

29 'AEP's Morris Warns of Possible Power Shortages', *Power Engineering International* (1 May 2008).

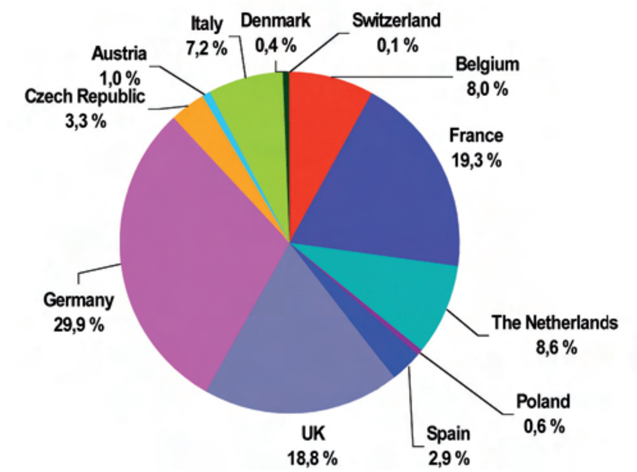
4.3 Norwegian Gas

Norway's gas production will plateau at about 108 Mtoe in 2011, up from 79 Mtoe in 2006, and has a highly diversified and diligently maintained export portfolio. It seems unlikely that expanded Norwegian production will be sufficient to fulfill contracts to EU customers and simultaneously meet the huge additional and apparently unforeseen requirements of the UK electricity generation sector:



19. Norwegian Gas Production, Mtoe. Sources: *BP Statistical Review* (2007), and Norwegian Petroleum Directive, *Fakta 2007*.

In fact, as can be seen, the whole of Norway's 2015 production is not enough to meet the UK's 2015 requirement.



20. Norwegian Natural Gas Exports, 2005, totalling 82.5 billion standard cubic metres (bscm). Exports to the UK: 15 bscm. [30]

In any case it appears unlikely that Norway will wish to allow its exports to be concentrated in one market. As this text was in the final stages of preparation the *Observer* reported Thor Otto Lohne of Norway's Gassco remarking to a BERR/Ofgem seminar that

30 Source Norwegian Petroleum Directorate.

the UK could not rely on being able to obtain Norwegian gas simply by willingness to pay extreme prices: 'The UK is a secondary priority. Like it or not, that is a fact.'[31] When prices on Continental Europe are higher than offered prices in the UK, gas can and will flow to the highest bidder, over an increasingly complex and dynamic gas network, as shown in the following map:

21. The North Sea Gas Grid.[32]

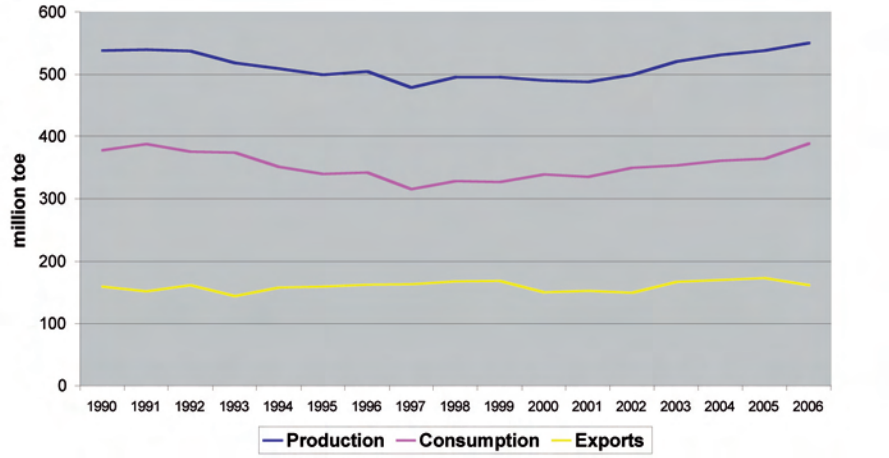
It appears, then, that the UK must, in common with the rest of Europe, also rely for a significant fraction of its future gas supplies on Russia. The events of the last few years are not encouraging in this regard.

4.4 Russian Gas

Although Russian production has risen from 479 Mtoe in 1997 to 551 Mtoe in 2006, Russia's own demand rose even faster, at 6.7% during 2006, driving exports down, as is shown in the following chart:

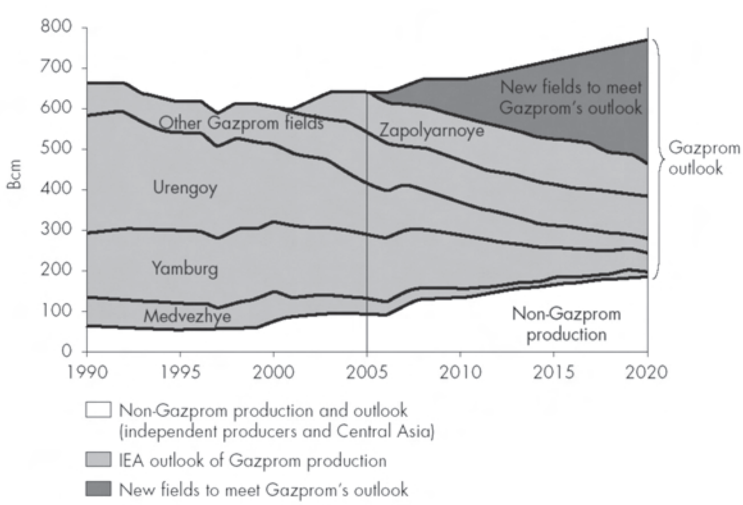
31 Tim Webb, 'Energy firms to raise bills again', *Observer* (20 Apr. 2008).

32 Source: Norwegian Petroleum Directorate.



22. Russian Natural Gas: Production and Consumption, 1990–2006.

In 2006, International Energy Agency (IEA) research revealed the bleak prospects for expanded Russian gas exports, and these have since become bleaker as Gazprom continues to focus on downstream investments, and delays the very large investments needed to produce gas from the Yamal Peninsula and offshore giants such as the Schtokman field. The IEA's expectations are for a decline in production of 18 Mtoe per year for the foreseeable future:



23. Russian Gas Supply Outlook. Source: IEA Estimates. © OECD/IEA.[33]

Ominously, Russian gas production declined during the first nine months of 2007.[34] In fact, Gazprom must secure supplies of gas from Kazakhstan and Turkmenistan to meet its contractual obligations in Asia and Western Europe. In this light it is no wonder that it is reducing exports to the Former Soviet Union (FSU) countries by raising prices, though

33 IEA, Optimising Russian Natural Gas: Reform and Climate Policy (July 2006). Available for purchase from http://www.iea.org/Textbase/press/pressdetail.asp?PRESS_REL_ID=184.

34 http://en.rian.ru/business/20070921/80330632.html.

it should be remembered that these prices are still at levels below those paid in the EU. Russia's effective nationalisation of all major upstream hydrocarbon activities in Russia is now complete, but the investments needed to offset the declines from its giant gas fields are late and the export capacity on which Gazprom and Europe have been depending is consequently years behind schedule.

In addition, imports of gas from North Africa are close to stagnant, though Nigeria's 2006 production was 25 Mtoe, up from 20 Mtoe in 2005. As can be expected from such a populous and poor country, much future gas production will be used within Nigeria itself, so the prospects for much more than the 20 Mtoe LNG produced during 2006 are poor. Indeed, during late November 2007 the Nigerian Government gave notice of its intention to use gas preferentially for domestic development, and this was widely reported. Besides, the oil and gas producing parts of Nigeria remain in a state of civil war.

We conclude from this chain of reasoning that even if gas generating capacity is built ahead of UK plant closures there is a quantifiable risk that these installations will be commissioned just as a world gas-supply crunch results in high and volatile prices and may even leave large parts of the market physically unsupplied.

From an investor's point of view the silver lining in this dark cloud is that as early as 2010 the value of any reserve capacity, especially peak reserve, and as long as it is not gas-fired, may increase dramatically.

5. CONCLUSION

While many of the outcomes outlined above are now unavoidable their severity can be mitigated in the medium term if prompt and determined action is taken by government to rectify the faults of current energy policy. The principal of these faults is the disingenuous manner in which Government has consistently claimed to favour the free market in energy, while in fact distorting the system with clumsy and covert intervention, for example on behalf of coal from 1997–2000, against nuclear in the 2003 *White Paper,* and throughout, counterproductively, on behalf of renewables. This has combined with complacency towards the obviously flawed electricity market system (BETTA) and resulted in a decade during which billions of pounds of assets have been written down. BETTA has encouraged the power industry to continue its construction of low-cost CCGTs at a time when it should have been perfectly obvious that North Sea gas was depleting and that these generators would have to be energized by imported gas, mostly from distant countries which will not necessarily comply with the UK Government's demand for open and transparent trade. Maximized oil and gas extraction rates were encouraged, even during the period of dangerously low global prices. Peak UK oil and gas extraction rates occurred respectively in 1999 and 2000, and the sector is now in permanent decline. Government elected to spend the high tax revenues, and, unlike many other major oil producing countries, no sovereign wealth fund has been created, leaving the next generation with the unremunerative task of using current tax revenues to decommission this enormous legacy. In terms of serious, non-gas developments, the electricity sector has either been stagnant or occupied with futile action intended to meet mistaken targets and engross subsidy.

In our view the only way of ensuring rapid remedial action is for government to actually rather than apparently withdraw from the system and so to permit energy market participants to respond commercially to the situation as it now stands.

In recommending this course of action we observe that our view is not informed by doctrinal affection for the free market, but rather a practical recognition that no government or any single market participant can gather and assimilate sufficient information to design and realise a satisfactory outcome. We judge that only the intellectual activity of the market in aggregate, and through competition, has a reasonable chance of producing an optimal result for the United Kingdom.

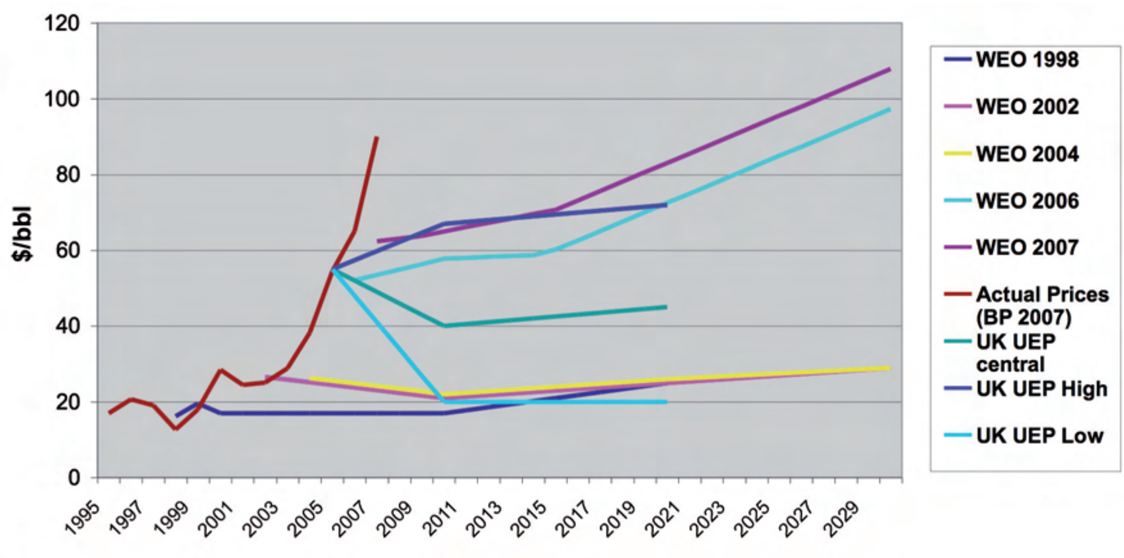
Nevertheless it should be recognised that the difficulties ahead are considerable, and even assuming perfect information and flawless market reasoning, the United Kingdom and its people are now, inevitably, vulnerable to price shocks and perhaps to disruptions of supply. Bearing this in mind we suggest that government should prepare itself to intervene with social policy to prevent hardship and to maintain order.

Although we recommend a hands off approach it is rational to anticipate some of the energy deployment outcomes that we believe might be beneficial for the United Kingdom, and thus which might be supported by facilitating and anticipatory government policy action, including generous tax breaks to private industry that engage in serious research and development, and the removal of needless regulatory barriers. In the following five points, which we do not regard as complete, we outline several areas in which positive action could and perhaps should be encouraged:

5.1. The UK needs a Realistic Oil and Gas Depletion and Pricing Strategy

The present Government has been consistently and exceptionally bullish over the forward availability and price of hydrocarbons throughout most of its term. That is to say it has believed, until very recently, that the UK is an attractive destination for international hydrocarbon exporters and that fossil energy is abundant and will remain cheap.

By and large it has been more optimistic than the IEA, whose *World Energy Outlook* for 1998 (dark blue), 2002 (pink), 2004 (yellow), 2006 (turquoise) and 2007 (dark purple) are plotted in the following chart and compared with international price developments of oil since 1995 as charted by BP (dark red). It is painfully obvious that the IEA has, no doubt unintentionally, misled OECD energy planners, though its 2007 projections show a significant change of heart. Note also the United Kingdom's *Updated Energy Projections* in the low (light blue), central (green) and high (medium blue) scenarios:



24. International Energy Agency Price Assumptions, and UK *Upated Energy Projections 2007*.[35]

Actual prices, at over $90 a barrel in the charted data, and in excess of $100 at the time of writing, are now higher than that predicted by the UK UEP high scenario for 2020, and even match the IEA's downbeat WEO 2007's prediction for the late 2020s. The UK's energy price assumptions to 2020, updated during the winter of 2007–2008, are extraordinary. The central and low scenarios show that the Government believed and perhaps still believes that the oil price might fall from 2008 through 2015. Even the high scenario is more optimistic than WEO 2007.

We have already seen that the annual growth of oil extraction has been slowing since about 2005 with little or no real growth during 2007 and 2008. Yet there seems to be undiminished, robust, demand growth in Russia, China, India and the other fast growing East Asian economies, not to mention the OPEC countries themselves. There is a high probability that energy demand reductions in the OECD will not be enough to offset demand growth in the developing world and that the remaining reserves will be developed with a

35 http://www.berr.gov.uk/energy/environment/projections/recent/page26391.html

sharp eye on depletion. Given these realities, the continued optimism of the UK Government is alarmingly unrealistic.

In view of the depletion of North Sea oil and gas reserves it is imperative that the UK government institutes a wide-ranging depletion strategy to reduce dependency, particularly on gas, and exposure to international markets. Such a policy might include measures to facilitate market action in the following areas:

- Conversion of CCGTs to operation on gasified coal, perhaps with carbon sequestration.[36]
- The requirement that CCGTs store distillate on site to enable operation at times of high prices or physical interruption.
- The gasification of coal to replace imported natural gas, perhaps with carbon sequestration.
- The use of CO_2 for Enhanced Oil Recovery (EOR) and Enhanced Gas Recovery (EGR).
- Urgent development of sea bed methods of CO_2 injection, and floating methods of oil production and wellhead treatment such as are being widely deployed in the Gulf of Mexico, off West Africa and increasingly for small fields in the Norwegian Continental Shelf.
- Revival of UK coal mining, where feasible, including underground gasification (UCG) in very deep coal structures, especially deep mines under the North Sea.
- Development of robot mining.
- Use of compressed gas and synthetic fuels as transport fuels while moving towards hybrids and plug-in transport systems.
- Maximized use of empty gas fields as inter-seasonal gas storage.
- Encouragement of non gas domestic and commercial heating, particularly biomass.
- Encouragement of flue-gas heat-recovery systems to improve the real-world efficiency of domestic condensing boilers.
- Encouragement of District Heating.
- Encouragement of industrial Combined Heat and Power.

5.2 Offshore wind turbines

Wind power probably has much to offer the UK, but getting the best from this technology will require judicious commitment to offshore deployment. However, we do not believe that the Secretary of State's December 2007 announcement of 33 GW of offshore wind by 2020 is technically credible. Supply chain and construction timescale limitations are in themselves sufficient to raise doubts, but even if built this large capacity cannot easily co-exist with the nuclear and clean coal announced in January 2008, and excess wind power capacity would probably have to be curtailed on a regular basis. Left to itself it seems to us unlikely that the market would construct so much offshore wind as to be vulnerable

36 http://www.alliedresourcecorp.com/pages/news/South%20Heart%20Industry.doc.

to such economic harm. Nevertheless, the case for prudent quantites of offshore wind may well be compelling (Shell's decision to withdraw from the London Array notwithstanding). Marine locations would allow us to obtain as many MWhs as possible from that which can be built in this time, while at the same time distributing the plant to gain some degree of geographical output smoothing, and bringing the plant into reasonable proximity to centres of load. Even so, this plant would place balancing demands on the rest of the system, and therefore we recommend:

- Development of high voltage inter-connections with Norway, Germany, Netherlands, France, to permit trading of windpower surpluses and deficits, and to add power capacity.
- Deployment of widely distributed onshore electricity storage of all types.

The latter point is an interesting example of a case where regulatory requirements inhibit market uptake. National Grid and the Distribution Network Operators are the logical owners of commercial storage, but at present they are legally prevented from possessing generation plant, and storage appears to come under this restriction. Removing such a legal block would permit the market to function more rationally.

5.3 Nuclear

It now seems inevitable that nuclear generation must form an element in the UK's future portfolio, particularly if, as we believe, the use of electricity in road and increased rail transport is a likely trend as fossil fuel prices rise. The government is apparently now considering a long-term strategy to work with France to revive and rejuvenate UK loss of nuclear know-how. In our view this is prudent, and long overdue. We note that:

- Research and development should integrate the fission and fusion strategies in a 50-100 year scenario.
- The UK should consider using current waste holdings as fuel (rather than long term burial).

5.4 Tidal Generation and other Renewables

Rising fossil fuel prices will motivate the spontaneous uptake of renewable energy sources. The provision of income support subsidy is counterproductive, since it requires civil servants and politicians to pick winners, either openly or implicitly, with the inevitable truncation of much needed technological innovation. We therefore recommend that:

- The Renewables Obligation is cancelled with immediate effect.
- The UK government repudiates the EU renewable energy targets, which are infeasible and contrary to national and European interest.
- UK government should incentivize the commercial development of novel technologies through strictly time-limited fiscal incentives for research and development, and guaranteed feed-in prices for early start power stations.

5.5 Energy Trading Arrangements

We are convinced that the current electricity trading arrangements must be revised in order to allow market participants to act optimally. Government should consider the abolition of BETTA and the creation of an energy trading strategy that fully recognises the rapidly rising cost of fossil fuel and the urgent need to provide non-gas generating capacity.

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