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# Meeting the UK's 2020 energy challenge - Do we need new nuclear?

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## Executive Summary

The Climate Change Bill, which went before the House of Commons in November 2007, sets out a target for $CO_2$ emission reductions from the UK of 'at least' 60% by 2050. In the UK in 2006 the energy supply sector accounted for 38% of $CO_2$ emissions by source – by far the largest source sector. Radically reducing the emissions from this sector is therefore crucial to our success in reducing $CO_2$ emissions.

Further to that, between now and 2050, there will be dramatic changes in the UK's capacity to generate electricity, as an unprecedented number of existing power stations will go out of service. In order to keep the lights on then, we will need to build a considerable level of electricity generating capacity. . Nuclear might appear to be the logical solution, but we believe that the 'stark facts', when looked at in detail, suggest that it will not and cannot ride to the rescue of our 2020 energy mix in the way that we might hope.

This is for two reasons:

1. Profitability: There are no direct subsidies available for the build of *any* form of new power station. Developers of such plants need to bear the cost of the build, and factor in the profitability of whatever power is produced over the likely life of the plant. Alongside that, the current system of trading electricity is based on market principles, so that the longer the term for supply is, the lower the price per kilowatt hour. As nuclear power cannot be switched on and off, it cannot be used to produce the more lucrative short-term electricity as it gets older making it less competitive.

2. Timescale: Given current planning, European and other relevant regulations, and assuming no delays, an application for a new nuclear power station received in 2010 would not actually come on stream until 2024. In order to bring any new nuclear generation online before 2020 therefore, the government would need to introduce measures that would break all precedents in planning.

Improvements in the efficiency and safety of coal and/or gas power stations mean that they can play a part in replacing existing capacity. However, if we are to reach our $CO_2$ emissions targets and ensure UK energy security then all new plants between now and 2020 must be fitted with combined heat and power capability and developed on sites where they can be linked up to heating and cooling networks.

In addition, renewable electricity and heat generation has to expand enormously, with perhaps 50% of new capacity over the period up to 2020 being generated from renewable sources:

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|---|---|
| Wind onshore and offshore | 18GW replaces 7GW now – 2025 [BWEA, 2007] |
| European Super Grid (deep sea wind) | 10GW replaces 4GW 2015 – 2025 |
| Severn Barrage | 5GW replaces 4GW 2020 – 2025 |
| Mixed fuel/biogas/Gas CHP | 10GW (with potential for up to 21) replaces 10GW now - 2025 [CHPA, 2007] |

While carbon trading will be valuable in helping 'cost' $CO_2$ emissions and therefore enhancing the case for renewables, a carbon market driven by sufficient $CO_2$ price certainty is unlikely to emerge in time to determine many of the early decisions that will shape the energy supply picture over the next ten years or so.

The measures that are already in place to encourage investment in renewable or near renewable forms of power will, therefore, need to give greater long term certainty to the industry so as to ensure investment. Incentives must also be devised and systemic barriers removed to a range of other low-$CO_2$ technologies, in particular, the creation of a heat market.

Most importantly Government must articulate a clear vision to all, including the energy regulator, Ofgem, of the diversified energy structure that we all agree is needed if we are to develop a secure and low- $CO_2$ energy future.

## Background

### a. Our targets for greenhouse gas emission reductions.

The Climate Change Bill, which went before the House of Commons in November 2007 sets out a target for $CO_2$ emission reductions from the UK of 'at least' 60% by 2050, a figure that will almost certainly be revised upwards by the Climate Change Committee.

However, the Climate Change Bill creates more than end term targets – the Bill will create, in the very near future, three five-year 'carbon budgets' which will set out a quantum of emissions for the UK over each period, 2008-2023. Carbon budgets are important because without them it would be possible to reach a 'target' by emitting on an unrestrained basis for a period leading up to the target date, and then meeting the target by a sudden drop in emissions in the years immediately approaching the target date. The profligate emissions would however, still be in the atmosphere.

Keeping the quantum out of the atmosphere over all the intervening years leading up to the target is vital. The first fifteen years, which coincide almost with the period of most extensive replacement of UK power plants. This will be crucial both in keeping the trajectory on the right path, and in establishing and developing the structures that can meet the challenges of the next twenty years and the next budget periods. There are, of course targets now in place for that first fifteen years (or to be precise, thirteen years) agreed by the UK government at the EU Heads of State meeting in spring 2007. The four targets (on greenhouse gas emissions, renewable energy, biofuels and energy efficiency) all have a bearing on our energy supply mix. They are:

- 20% reduction in greenhouse gas emissions by 2020
- 20% overall binding target of renewable energy sources in the energy mix by 2020
- 10% minimum binding target for biofuels for each member state by 2020
- 20% energy efficiency improvement by 2020.

While it is true that the 20% target from renewable energy sources represents an EU average, and therefore will result in variable targets for each member state, it is also a renewable *energy* target, and not one for renewable electricity. This therefore includes gas for heating and road fuel, both sectors where little has been done to date to achieve high penetration of renewables or low-$CO_2$ technologies. The 'load' on renewables generating electricity, therefore, will, at least initially, be higher than the headline rate; and even if this turns out to be well below 20% for the UK, the eventual target for renewables in primary energy is likely to need to be substantially in excess of 20%. In 2006 the level of renewables in electricity generation was 4.6% *[Wicks: 2007a]*

**b. Energy supply and carbon dioxide (**$CO_2$**) emissions.**

According to 'Climate Change: The UK Programme 2006' energy supply accounted for no less than 38% of $CO_2$ emissions by source – by far the largest source sector. Radically reducing the emissions from this sector is therefore crucial to the success of any carbon budget. As matters stand, the Programme projects that greenhouse gas emissions from energy supply will fall by about 16% by 2020 – about what would be needed to be needed to fulfill likely EU targets, but implying a very high level of renewables in the electricity supply sector. The projections furthermore, mix savings from generation with energy efficiency – part of another of the EU targets *[DTI: 2006a].*

**c. The UK's energy generating requirements**

Over the same period there will be dramatic changes in the UK's capacity to generate electricity. Over a decade and a half, an unprecedented number of existing power stations will go out of service. In order to keep the lights on, there will therefore be a similar requirement for an unprecedented level of replacement electricity generating capacity, both to provide the reliable power load the system needs and to maintain a viable pool of reserve capacity (about 22% of overall installed capacity) to meet surges in demand from the network.

The '*Future of Nuclear Power*' consultative document states:

'*we could see around 30-35GW of new electricity generating capacity being built over the next two decades, with about two thirds of this by 2020*.' *[DTI: 2007a, p89]*

The causes of the huge reductions in plant capacity (current UK installed capacity is about 76GW) over the next thirteen years (to 2020) are:

- 8GW of coal fired power stations and 3gw oil fired power stations will close by 2016 under the terms of the EU large plant directive which requires the installation of flue desulpherisation equipment to all operating power stations from the end of 2015

- 7GW of nuclear power stations will go out of commission by 2020

- A further 4.5GW of coal and gas will close between 2020 and 2030, because of age, together with a further 2.5GW of nuclear power.

In addition, it is estimated that between 5-10GW of additional installed capacity will be needed to cope with anticipated increased demand for energy.

The government's model does not explicitly include the consideration of the impact on energy demand arising from meeting EU energy efficiency targets, but does include some allowance for energy efficiency measures *[ibid. p89-90].* A successful energy efficiency programme over the period could save much of the anticipated increase in demand, but would not affect the known closures or the need to maintain capacity reserve in the system.

**d. The generating options?**

We will need to replace a large part of our energy supply plant over the next fifteen years. Much of the loss will be of high $CO_2$-emitting plant. Some emission savings will result simply if these plant are replaced by more efficient plant, burning the same types of fuel. However, all but one of our current nuclear power stations will be decommissioned by 2025, which means that we will be losing most of our low $CO_2$ emitting power stations. This was, in essence, the summary delivered by Tony Blair, referring to the Energy Review last year:

'*The facts are stark…By 2025, if current policy is unchanged, there will be a dramatic gap in our targets to reduce $CO_2$ emissions: we will become heavily dependent on gas; and at the same time move from being 80/90% self-reliant in gas to 80/90% dependent on foreign imports, mostly from the middle East and Africa and Russia. These facts put the replacement of nuclear power stations, a big push on renewables and a step change on energy efficiency, engaging both businesses and consumers, back on the agenda with a vengeance'* (Blair: 2006, p6).

So it cannot be the 'business as usual' default of coal or gas, if we are not to send any targets on UK $CO_2$ emissions smartly into reverse. Substantial new conventional gas generation (Combined Cycle generation or CCGT) is also unacceptable if we want to avoid becoming dependent on gas from insecure parts of the world.

It seems a logical argument then that we must replace the lost nuclear with new nuclear if we are to have any chance of providing secure and low $CO_2$. But the 'stark facts', when looked at in detail suggest that, even if we think nuclear is a useful long-term choice, it will not and cannot ride to the rescue of our 2020 energy mix in the way that we might hope. This is because in order to bring any new nuclear generation online before 2025 the government would need to introduce measures that would break all precedents in planning and wreck the structures of energy supply in the process.

That leaves the big push on renewables and energy efficiency (including CHP), as the Energy Review and subsequent White Paper set out clearly. The government has already committed substantial effort to these in the form of investment in renewables and the development of frameworks for further investment through measures such as the Renewables Obligation. Despite its detractors there also exists already a substantial body of onshore and offshore wind and indeed the UK will shortly, with the development of the London Array windfarm, become the world leader in installed offshore wind. Almost 17gw of renewable energy of various kinds (mostly wind) is under construction, consented, or is in the planning process. This demonstrates that far from being the impractical, edge of common-sense option, renewables and energy efficiency (including CHP) are central to our supply replacement options over the next period.

So what are the 'stark facts' that lead to these conclusions and what exactly should we now be doing to close the 'energy gap' over the next fifteen years in a low $CO_2$ and sustainable way?

## Replacing lost generating capacity – the 'stark' facts about nuclear and gas

### a. Nuclear

#### i. The costs and profitability of building new power stations

There are no direct subsidies available for the build of *any* form of new power station. Developers of such plants need to bear the cost of the build, and factor in the profitability of whatever power is produced over the likely life of the plant. While there are forms of underwriting for renewable energy (such as Renewable Obligation Certificates and exemption from Climate Change Levy), these refer to the return of the energy produced and not to the cost of producing the power station in the first place. The likely profitability or otherwise of selling energy will, of course, have a bearing on investment decisions, but the original capital still needs to found. The government has re-iterated this principle in the case of possible new nuclear build – that is, any new nuclear power station will have to bear the cost of build, operation and decommissioning. It is not a renewable technology.

There *is* however, a further consideration about how the profitability of power stations over their lives can be calculated. This arises from the system of trading electricity so that the energy supplied balances the electricity produced at any time, regardless of the size of demand at that moment. In fact, the system that governs the purchase and supply of electricity is designed to encourage the replacement of ageing plants by more competitive supply, as old stock moves away from being able to compete in the supply market. The electricity supply and distribution system is governed by BETTA (the British Energy Trading Arrangement) - a byzantine, but effective system of balancing supply and demand for electricity, taking bids to supply the grid on a matrix of different supply periods, ranging from very long term (nuclear energy, for example), to three month contracts, through to very short term half hourly contracts that 'top up' the system when peak demand requires it.

The whole bidding system is based on market principles, so that the longer the term for supply is, the lower the price per kilowatt hour. This enables a range of supply to be available. Some supply forms the 'base load' and will work close to the capacity of the plant on cheap contracts over the long term. At the other end of the scale, some plants will be mothballed for most of the year, but will make their living by bidding for the peak demand 'panic' contracts which will be very highly priced. The oil fired plant at Fawley, for example is 'on line' for just a few hours a year, and has the merit of being able to switch on or off at a few hours notice. The system therefore, in theory does two things: an older and less competitive plant migrates up the system - it is not decommissioned, but instead performs more occasional but potentially profitable service when peak demand makes it temporarily competitive. The market itself then makes the commissioning and building of newer and more competitive plants a viable economic proposition, and therefore fills whatever 'gap' in supply emerges.

While this arrangement works well for non-nuclear plants, it cannot do so for nuclear. Nuclear power cannot be switched on and off; it cannot 'migrate up the system' as it gets older and less competitive. The calculations for the profitability of its output over the life of a nuclear plant must turn on its ability to supply long-term base-load at a price below that which might be achieved under more short-term contracts. There is, therefore a massive assumption at the heart of the notion that the 'go ahead' should be given for new nuclear power - that developers of new nuclear power stations will need to be encouraged to invest by their appraisal of the market conditions perhaps ten years hence.

It is also worth noting that it is already and always has been the case that a private energy company could agree to finance and build a nuclear power plant and submit its proposals successfully to the planning and permissioning process. *[Wicks: 2006]* In this respect, gaining permission for and building a nuclear power station is no different from building any other type of power station. The key point is that, no energy company has sought to do this in the UK for twenty-six years (since the completion of Sizewell B). Indeed, at the time of the construction of Sizewell B, planning was granted for a reactor of a similar design at Hinckley Point, but was never built (and nor was another planned reactor at Sizewell) because, as the 2007 White Paper states '*in the newly privatised energy market, the government ruled out providing public sector support for new nuclear power stations. In the then prevailing financial climate, it was unlikely that the private sector would fund such projects*'. *[DTI: 2007b p44.]*

So there is no requirement to '*conclude that energy companies should be allowed to invest in new nuclear power stations*' *[DTI, 2007a p29].* Decisions as to whether to invest will, in the absence of positive financial support, or guarantees concerning the purchase price of any resulting electricity generated, be taken by the energy companies, and as the Government says '*a consequence of this is that we cannot be sure of the timing and number of nuclear power stations that might be proposed*' *[Ibid. p131]*

There may be proposals for several, or perhaps for none at all, which makes planning for a nuclear contribution to the energy mix rather hazardous. What the government is proposing to do, however, is to reduce some of the perceived impediments to energy companies coming forward to invest, or as they put it, undertaking 'facilitative action'. This consists of:

- Bringing the process of obtaining planning permission into the national planning framework, anticipated to be on the Statute Books by 2009. This would, among other matters refer large programmes such as new nuclear power stations to the Independent Planning Commission

- Developing criteria for suitable sites
- Running and completing a 'justification' process according to the 2004 Ionising radiation regulations
- Seveloping 'pre-licensing' criteria for reactor designs. *[Ibid. p30]*

The purpose of all this work would be to reduce, as far as possible, the uncertainty surrounding the process of planning and constructing a nuclear power plant in future. Potential developers would not have to start from scratch on each application, substantial elements of each application would be effectively 'taken as read'. Questions about the design of the reactor would not be an issue and hopefully nor would siting issues. The process prior to building would be as compressed as possible.

While this might help in the uncertain process of bringing the nuclear horse to water, other criteria, chiefly financial, would still be the ones that would make it drink – specifically: would the investment make money? In the absence of covert or overt subsidy for nuclear, which the government has set its face against, the nuclear investor must judge this question in light of the likely energy scenario and, particularly, the price of $CO_2$ in the early 2020s. If the $CO_2$ price remains low – that is if competing high $CO_2$ emitting technologies such as gas and coal are not priced out of the market, then it is unlikely that investment decisions would be taken. But carbon trading, the government's chosen instrument to provide a price for $CO_2$, is by its nature not an instrument that can provide a guaranteed price for $CO_2$ in the way that an obligation or a feed in tariff can provide certainty of market for the forms of energy to which it is attached.

Indeed, the combination of a raised – but not certain - price for carbon, together with the continuation of the renewables obligation *does* on the other hand, provide a considerable degree of certainty for technologies that will compete with nuclear - even if the higher price of carbon begins to drive investment in new coal or gas plant away (and even if the undesirable nature of the emissions and the measures that might be necessary to mitigate them are not taken into account).

**ii. The timescale for new nuclear build.**
Private investment, without subsidy other than devices such as the Renewables Obligation, will need to commission, receive permission for, and build some 20GW of new capacity by 2020, and 10GW by 2030. Within this new build envelope, the government states that 'new nuclear power stations could make only a limited contribution to new electricity generation up to 2020' *[Ibid. p90].* This is a rather generous statement. According to the scenarios set out in the document itself (the so-called 'central case') the pre-development period for a new build would be eight years, and the construction period six years.

This timescale is unpacked further in a cost-benefit study first published for the July 2006 Energy Review but updated now to April 2007 *[DTI: 2007d]*. It suggests that the pre-development period would consist of five years to 'obtain technical and site licence' and 'three years public enquiry'. It then further suggests that the likely build period subsequent to this would be five years, whilst noting that the build of the last nuclear power station (Sizewell B) took seven years.

Further clarity on the content of the pre-development period is provided by the Health and Safety Executive *[HSE. 2007],* which is in the process of undertaking a 'generic design assessment' to evaluate the 'safety, security and environmental implications of new designs' before any application is made to build a particular power station on an agreed site. This assessment will take, the HSE estimates, some three and a half years, and some preliminary work to advertise for design submissions has already taken place. HSE also estimates that, following this, a period of about a year would be needed to deal with the permission necessary to run a reactor on a particular site. This stage would entail a developer finding and dealing with any site specific issues, before commencing the planning application process itself. This estimate itself seems extremely truncated, bearing in mind that site viability itself is the subject of considerable and separate investigation. The present assumption is that site search will be speeded up considerably by building new plant on, or close to existing sites, and it is reasonable to assume that the 'one year' additional period refers to this. All but one of the present sites are potentially at risk through flooding however, brought about by a combination of more extreme weather conditions, rises in sea level as climate change occurs and the natural sinking of the land in parts of the country. This was appraised in a report in February 2007 by the Met. Office *[Met Office: 2007])* and the conclusion was that

*'Although mean sea level increases in themselves are not thought to be a major future hazard, the increases in future surge heights of potentially more than a metre in places could, when combined with wind speed increases, threaten some sites unless the existing defences are enhanced'* (Ibid. p. 91).

In other words, concluding all the site preparations in one year if, for example, serious work needs to be done to strengthen flood defences before work can be contemplated is likely to be very optimistic: the alternative of finding completely new sites would certainly take far longer than a year to conclude.

This may be incorporated into a 'strategic site assessment' proposed as part of the 'future of nuclear power' package - but this, it is suggested would start in early 2008 '*in response to the main 'in principle' consultation…..dates…might need to change, for example as a result of this consultation*'. [*DTI: 2007c, p24].* The indicative timetable, based on, again, an optimistic timetable for a start is that a general statement on the suitability of nominated sites would be produced in about seventeen months from the start of the process.

Finally, under the terms of European regulations incorporated into UK law, a period of time would need to be spent on 'justification'. 'Justification' is a process now required under the terms of the EURATOM Treaty to demonstrate whether proposals for the disposal of new radioactive waste by one EU member have any effect on other members. This has been incorporated into UK law by 2004 regulations and is a required process for all new nuclear waste generated after 2000 (previous waste is regarded as 'already justified'). The process will apply to all new nuclear technology therefore and the likely technologies involved in the development of new power stations in general will need to have been 'justified' in advance of their application. *[Ibid. p5-12]*

All this is perhaps rather obscure, except that no 'justification' process has yet been undertaken and will need to be before any new nuclear power station can come on line. The process is 'generic' and does not reflect on any specific application, but nevertheless will take time, estimated to be one-and–a-half years from an assumed start in the spring of 2008.

Taking all this into account, we can come up with an indicative timeline that would represent the *absolute minimum* time the processes would take if there are not further changes to the rules governing the permission and planning process:

Early 2008: The government decides that nuclear generation has a role to play in the future UK generating mix

Autumn 2009: Justification and strategic siting reviews complete

Early 2010: First application for new nuclear power station received. (This assumes that energy companies are unlikely to commit to a definite process of permission and build until the justification and site review is complete)

Early 2015: Technical and site licence process completed

Early 2018: Planning permission agreed after inquiry

Early 2024: Building programme completed: first power station (1.0GW) comes on stream

This it should be noted, assumes that there are no delays, that each part of the process follows on seamlessly from the last, and that build programmes stay within the schedule of six years. It is therefore possible, but not overwhelmingly likely, that power from new nuclear will flow by a little before 2025 - certainly *not before 2020 and even on 'official' detailed estimates well after that date.*

However, the Nuclear Power White Paper, published January 2008, sets out a different time scale *[BERR, 2008, chart 3 p. 136]*. This pathway chart suggests a process to power output ending in 2018

– a date that coincides with the most optimistic pronouncements of the date b y which nuclear power plants could be ‘on stream’ made by potential nuclear power plant constructors themselves.

The chart is supported by virtually no evidence, except to put into the timescale the known and published timetables on justification, generic design assessment and strategic siting assessment. These would, the timeline suggests, enable a ‘possible operator decision to proceed in principle’ by the end of 2009, or approximately in line with the timetable set out above. But thereafter the timeline diverges wildly, and, it appears, in opposition to the published documents and studies that have already been referred to.

The timeline truncates the planning process to eighteen months - far short of the three years suggested in the 2007 Cost Benefit Analysis. Furthermore it seems to make the unlikely assumption that the planning process could be complete *before* the licencing or even the generic design assessment is finished. An inspector at an enquiry, (or the Infrastructure Planning Commission) it seems, would be required to proceed and decide on an application without necessarily knowing whether the applicant actually could technically proceed on the site specified, or that the equipment that was proposed really could operate on the site.

In short, the magic date of the end of 2018 is ‘achieved’ by placing processes in parallel when as the existing government published documents suggest, they should be undertaken in series if the decision making process itself is not to become hopelessly compromised. If the processes are placed back into sequence, and a realistic view of the planning process is restored, the timetable then looks not dissimilar to that already established from existing documents.

These dates are very important because they demonstrate that, according to the projections in the Energy White Paper, the option on what will replace up to 20GW of end-of-life power stations by 2020 will certainly not involve nuclear power. If the ‘lights are to be kept on’ the construction of other forms of power generation will have to be involved.

But they also demonstrate a further significant point. The whole case for keeping nuclear in the mix relies on the idea that a) nuclear power *will* come on stream from 2020 onwards and b) that there will a further considerable requirement for the replacement of power plant 2020-2030, much of which can be provided at that point by new nuclear power, judged to be competitive in output cost by that point.

The detail of this is also set out in the ‘Nuclear Power Generation Cost-Benefit Analysis’. The cost-benefit analysis is far more specific than the generalisations of the Energy White Paper, and concludes that, if nuclear first comes on stream (it suggests) by 2021, then it would be possible to have 6GW of nuclear power capacity installed by 2025. *[DTI: ‘2007d. p9]*

This in itself is a somewhat heroic assumption; even if one believes that new nuclear will be producing power by 2021, it assumes that four new power stations of 1.5GW will come on stream, one a year, until 2025. It also assumes, according to the outline assumptions made in the main White Paper, that the lions’ share of the 10GW capacity that will be added between 2020 and 2030 will be nuclear. If one makes the assumption as the White Paper implies, the 10GW capacity needed will be spread evenly over the period, that ALL new capacity between 2020 and 2025 will be nuclear*[Ibid. p12].* This looks very unlikely, but is possible if it is recognised that the requirement for new capacity 2020 – 2030 is NOT uniform, but is concentrated in the early years of the decade. The cost-benefit analysis puts the requirement for new capacity in a slightly different framework, suggesting that 14GW of capacity will be required between 2018 and 2025, and will include during that period the ‘retirement’ of all other nuclear capacity except Sizewell B scheduled to continue to produce power until 2035. *[DTI: 2006b. p40]*

In other words, there will be a requirement for all but about 4-5GW of new installed capacity, estimated by the White Paper as 30-35GW up to 2030, *by the early years of the decade 2020-2030.*

**If the government’s own central case assumption for the timescale is right therefore, it has to be concluded that virtually none of the new capacity required can reasonably be met from new nuclear and it will have to be installed from other sources. *[Ibid. p12]***

**b. If there is no nuclear then are we stuck with new combined cycle (CCGT) gas stations?**

This conclusion has significant consequences for other assumptions about what the future ' mix' of generation might look like. The question then has to be asked; if 26 or 27GW of capacity replaced by 2025 will not reasonably include nuclear, then what will it be? The Future of Nuclear Power document makes something of a case in pointing out just how much in the way of additional emissions of $CO_2$ would be caused if the present nuclear power 'fleet' were to be replaced by gas.

*'As an illustration'* it says, *'if our existing nuclear power stations were all to be replaced with fossil fuelled power stations, our emissions would be between eight and sixteen mtc higher as a result…..This would be equivalent to about 30-60% of the total carbon savings we project to achieve under our central scenario from all the measures we are bringing forward in the Energy White Paper.'* *[*DTI: 2007a. *p8]*

That is one reason for baulking at a CCGT-only future between now and 2025. But the comparison, although useful, is misleading. Current nuclear capacity stands at just over 10GW, and runs at a 'capacity value' of about 75%. That is, nuclear power, assuming it remains fully operational, will supply the equivalent of 7.6GW of installed capacity running 100% of the time. 'Capacity value' is important in the debate on future power needs, since it is the device by which the relationship between installed capacity and what the network can reasonably plan to receive in the form of actual electricity. This measure is crucially important as far as wind is concerned, since among other things, it clearly makes the distinction between 'intermittent' supply and 'variable ' supply. It will be discussed further in this context later. The currently operational consented or planned onshore and offshore wind capacity of the UK is some 23GW installed capacity (BWEA 2007). All or most of these will be built well before the decommissioning of the current nuclear power station fleet. The likely capacity value of this substantial wind resource is about 35%. This means that over the same period of time, even if no more wind plants than had already been built or planned emerged, it would provide electricity at the equivalent capacity of just over 8GW running 100% of the time. Even if only about 90% of the present planned wind is built by 2025 *it will more than replace the additional emissions in our energy portfolio that might otherwise arise as a result of the replacement of nuclear power stations by non-nuclear plants.*

Instead, the question we ought to ask from an emissions point of view is what will the emissions total look like when existing gas and coal-fired power stations are replaced by other forms of non-nuclear energy over the period? Clearly, if CCGT continues to replace current gas/coal, then the only gain in emissions will be marginally improved efficiency from these newer forms of gas turbine (up to 10%), and a marginal overall gain from the emergence of wind to replace deceased nuclear plants.

There are two further reasons why we should worry about gas replacing gas/coal. Firstly, reliable and cheap supplies of oil and gas will simply not be around over a thirty or forty year period to supply a mainly gas fuelled power economy *[see e.g. Energywatch Group (2007) Crude Oil: the supply outlook]* Secondly even if they were, with the depletion of North Sea gas resources they would be likely to be controlled by states and parts of the world less than conducive to our energy security [*See The Foreign Policy Centre (2005) Britain's energy future: securing the home front].*

## The third way - A Sustainable Power Station Programme up to 2025

To summarise the current problems:

- It is very unlikely that there will be any new low $CO_2$ nuclear power stations onstream before the beginning of 2025

- Gas fired power stations on present build arrangements (CCGT) will send us disastrously off-course on already agreed $CO_2$ targets and cause increasing national security problems as indigenous supplies of gas run out.

So what would a largely non-nuclear and non–CCGT alternative look like over the next fifteen years or so? Would it follow with the market, as much investment in power plant has over the last few years?

Or are there measures that would need to be put into place to shape the market to achieve the right outcome? If we know that nuclear is not going to ride to the rescue, and that CCGT could only do so at a catastrophic climate change cost, should we be putting regulatory and fiscal effort into a range of shaping mechanisms similar to, but to better and earlier effect than those contemplated for new nuclear?

To get a grip on these questions we need to return to our European Council Commitments, recently confirmed by the Prime Minister. The commitments, as the 'Future of Nuclear Power' paper points out, set the UK a very ambitious target, even if we set aside the point that 20% of energy in the context of heat, fuel and power means that either advances in renewable supply would have to be made in each sector or would have to be concentrated in those sectors where more renewable power is feasible *[*DTI 2007a*]*. Assuming that around 25% of heating could be and is provided by CHP, and the remainder by non-renewable gas, a large amount of the obligation would have to fall on to power generation – perhaps a 'target' up to 35% of electricity generated from renewables or near renewables by 2020. All of this would be during the period when nuclear could not by definition come to the rescue with low $CO_2$ generation.

Indeed, the Future of Nuclear Power paper concludes that *'after a decision has been reached on each member state's contribution to the EU agreement, it is very likely that the UK will need to take further measures, beyond those set out in the energy White Paper…to make our contribution to meeting those targets, and in particular to increase the share of renewable electricity, heat and transport, in our mix, by 2020.' [Ibid. p7]*

What does all this mean, therefore? It strongly suggests that, in order to reach or get close to the required targets, renewable electricity generation has to expand enormously – perhaps 50% of new capacity over the period up to 2020 needs to be from renewable sources. If much of the requirement for renewed capacity is inevitably allowed to be from CCGT or coal after 2020 and before any nuclear comes on stream, the gains that will have been made during the first three carbon budget period will be disastrously undone in the fourth.

It is therefore not just 'likely', but certain, that the government will need to put measures in place well beyond those of the Energy White Paper, if targets to 2020 are to be achieved. What this will mean is that the response of 'the market' to renewal of supply will have to be directed away from CCGT: but for all the reasons set out here, it cannot conversely be 'directed' towards nuclear. This will have to be done at an early stage, since the current response of the industry is to plan to renew retiring gas and coal fired power stations with CCGT plants and even coal fired units.

Indeed, as matters stand, there are currently large numbers of gas or coal fired power stations in the pipeline:

| | | |
|---|---|---|
| Under construction | two gas fired | 1.7GW |
| Consent obtained | three gas fired | 3.0GW |
| Planning app. submitted | five gas one coal | 8.1GW |
| Proposals made | three coal | 3.0GW* |

*[BERR 2007c]*
**[BBC News, 2007a,] [BBC News, 2007b]*

15.8GW, or two thirds of the total new capacity required by 2020, will, if these proposals go forward, be 'on stream' by 2013. In other words, as matters stand, the response of the energy construction market is to replace most gas or coal power stations with CCGT or coal power stations. The only gain in this programme is provided by increased efficiency of new plant, and the possibility that new coal fired power stations can burn mixed fuel as an alternative to coal.

**a. Stop wasting heat - the role of CHP**

As the White Paper notes, the above stations will be without carbon capture and storage and CHP technology, *[*DTI. 2007b*]* CCS is as yet an unproven technology and it is suggested cannot come on stream before 2020. CHP remains however a technology, which, if integrated into the power supply generally, would be able to make enormous inroads into the overall $CO_2$ emissions balance sheet of the power industry.

It would do so because the present inefficiency of the power industry is staggering. 65% of fuel going into conventional power stations is simply lost as a vehicle for energy production because it disappears up the chimney in heat loss. A further 15% of the energy produced is 'lost in transmission' one way or another, and further power is lost by inefficiencies in domestic electrical equipment. Indeed, it has been suggested that the combination of fuel conversion inefficiency, transport losses through the grid, and inefficiencies in the use of the final power load means that only 10% of the fuel that produces the electricity in a light bulb actually ends up lighting it *[DTI, 2004a].*

In more general terms, the conversion of fuel even in the most efficient CCGT power station is a maximum of 60% of fuel used with the rest simply disappearing up chimneys as heat loss during the process of making the electricity from the fuel supplied *[DEFRA, 2004].*

CHP increases the overall capture of fuel to energy (heat and power) to up to 90% - a huge leap in efficiency - but it requires some way of receiving and using the heat that has been captured effectively. Currently the main use in the UK is for industrial purposes, where there is, as it were, a single customer (e.g. Conoco Phillips CHP at Immingham).

However, larger CHP plant is used in other northern European Countries (e.g. Denmark *[DTI, 2004b]*) and can deliver to a variety of industrial and residential customers through an installed network of distribution. The effect of new gas fired power stations could, therefore, be substantially mitigated in terms of $CO_2$ emissions overall.

Historic problems with fluctuations in the wholesale price of gas and electricity (which meant that the high gas price created an uneconomic electricity cost and hence unattractive investment option) have now largely gone. However, the scarcity of viable uses for CHP's heat output remains a serious issue. The success of CHP depends on a long term demand being engineered at commercial rates for the heat output. On a more basic level, the plant needs to be sited near commercial, industrial and/or domestic properties that *are linked into* the CHP derived heat.

Therefore, while the government's policy of only providing Section 36 permissions for two new gas-fired power stations if they are CHP enabled is to be applauded *[BERR, 2007a]*, it will only lead to a meaningful improvement in the sustainability of our energy system if take-off facilities for the heat really do exist or have a real chance of existing in the future. At present, these do not exist.

Roughly speaking, taking heat derived from 50 megawatts power generation provides substitute central heating for about 4,000 homes; that is either alone or combining a smaller domestic supply with a substantial commercial supply. This is the measure of the real meaning of making a reasonably sized gas fired power station CHP enabled. It costs about £20 million to install the heat mains, the substation and the boiler replacement insulation for a 4,000 home domestic system, but this investment can be recovered through supply charges that facilitate very cheap heat (60% of previous costs of gas heating) over a 20 year period. Alternatively, incentivised investment in the replacement of boilers of existing large industrial plants that use gas as their source of fuel, by CHP plants that maintain the existing service but also produce electricity could be contemplated: estimates suggest that if this were done on a widespread basis across industry, up to 6.5Gw equivalent of installed generating capacity could be established *[DEFRA. 2007, p. 12]*

However, in order to make CHP-enabled power stations reality, it would be necessary to incentivise investment in the heat network. One method of doing this would be through some form of feed in tariff that would ensure a profitable price for CHP heat. Another method would be to develop some form of regulatory asset base, analogous to that for the electricity or gas networks. This would guarantee the rate of return (adjusted for efficiency and inflation) on the heat network and encourage investment. Although a not-for-profit community asset holder (local council or other community organisation) would act as the demand side aggregator, the network would need to be administered by an industry regulator. As suggested by several groups *[e.g. SDC Report, 2007],* the most obvious route would be to grant the energy regulator, Ofgem, a mandate to create and regulate this new 'heat' network.

It is estimated that approximately 15GW of power (and up to 21GW) could be supplied by CHP by 2020. This would ensure that up to 25% of the UK's heating and cooling requirement was also covered at no additional cost (the total heat energy need in the UK is 40.6 million tonnes of Oil Equivalent). Currently there is only just over 5.5 GW of power capacity and nearly 6GW of heat *[DTI, 2007e and Sustainable Development Commission 2007a].*

**b. A big push on renewables?**

Despite the contribution from CHP, we still need to address three further questions:

- What mix over what timescale will best both fill the remaining "gap" and *securely* usher in a low carbon economy?

- How might the investment needed to secure this mix be made?

- Will the answers to these two questions enable the supply and demand system and the balancing of both to be maintained, so that the lights stay on?

**(i) The role of wind, tide, waste and biogas**

In addressing these questions, it is tempting to take shortcuts – to do the arithmetic of likely supply and suggest to the government that it ought to "get on with it". This implies that we quickly usher in a command power economy, funded in its construction by central government, and organised in its supply to the consumer by central command – effectively, a return to the Central Electricity Generating Board, with a monopoly supplier and prices that reflected it.

It would require, therefore, the expropriation of the major energy supply companies and a regime for purchasing power from inter-connectors that relied on central pricing. This would entail, in addition to expropriation, a reversal of EU energy policy and the establishment of a far higher redundancy factor in energy provision to cope with possible demand, rather than the aggregate and probable demand, which it must be said the BETTA system undertakes at a high level of efficiency.

It will be almost unthinkable to seriously contemplate – and implement in a few years – the cost to the Exchequer of this appropriation, *plus* the cost of investments in new plant, even if the problem of EU energy policy and the extent to which the delivery grid system would remain outside such central direction could be resolved.

The question, therefore, has to be addressed in terms of what investment decisions can be ushered in and over what period, using market shaping devices: and in this context, a crucial factor is likely to be the extent to which investment decisions might founder on the rocks of "stranded assets" – that is encouragement to invest in forms of energy supply that will be abandoned very shortly and before a return on investments has been secured, because other forms of supply at that point appear to be more advantageous from a climate change point of view. Indeed, the fear of "stranded assets" does two things to energy investors: either the price of the investment inflates hugely because the return is required over a short period before the asset becomes "stranded" or the investment will simply not be made in the first place. BETTA does allow considerable protection against the stranding of assets by moving plant efficiency up the supply hierarchy provided they can profitably sit at the margins of supply in their later years of operation.

Wind is unlikely to become "stranded" and in any event, the operational life of a wind farm before it requires refurbishment and upgrading is about 20 years, at which point the refurbishment effectively represents a new investment decision.

Over the next 20 years, in addition to the development of further licences (phase three) for offshore wind, investment in larger, more ambitious offshore might be encouraged. This would be in addition to further larger, medium distance offshore farms, such as the London Array. The process of bringing such schemes to fruition should be assisted by the new structure of strategic planning now making its way into legislation and the "one licence" regime of marine spatial planning now being incorporated into the Marine Bill.

Very large offshore wind is at present best represented by the “European Super Grid ” proposal to develop grid connected super wind farms in relatively shallow, but distant waters in the North Sea and possibly in other areas of the continental shelf. Supply would be landed by grid connections in the UK, Germany and Holland, but for the purposes of capacity, most could be counted as available to the UK. The capacity of the first “super field” (others would follow linked to the grid) is estimated to be ten gigawatts, which would equate to the replacement of four gigawatts or more of existing supply, bearing in mind the scale efficiency and reduction in variability that a large development would bring *[Airtricity, 2006].*

The proposal, both in terms of turbine construction and grid connection, would be privately funded: the issue of the conditions under which the proposed grid would serve different markets is a potential problem and would require further equalisation of European energy markets *[Blair, 2007],* but the examination of the proposals by UK and German civil servants is a positive sign.

A timetable for commissioning and construction - if a reasonably early (say two to three years) in principle decision to facilitate this construction were given - would be less than ten years, placing it firmly within the window during which capacity has to be renewed.

A second major project capable of producing a very substantial input to capacity – and at “capacity value” for the grid at levels approaching that of nuclear is the proposed Severn Barrage. This scheme would place a barrage across the River Severn between Cardiff and Minehead, Somerset and would aim to use the high tidal power value of the Severn as its driving device.

Put simply, the barrage would open the upper Severn to tidal entry as the tide came in and would retain it once full tide was past. Water would then be let out through turbines over the period of tidal ebb, creating an absolutely reliable and predictable source of power each day. The barrage would also have the added advantage of protecting the Severn and the major towns and cities on its banks from flooding, in much the same way that the Thames Barrage does currently and it could be the vehicle for new rail links across its surface.

The government has now committed itself to a feasibility study for the project at public expense, but otherwise, would be privately funded and it is of course very unlikely to be become a “stranded asset” in the future. Its contribution to replaced capacity would be perhaps six gigawatts at about 70% capacity value (account would need to be taken of the fact that power would not be available during tidal ingress). On current estimates of build time, a barrage, if proceeded with reasonably promptly, could be providing power by the early 2020s.

There will, of course, be some contribution from smaller biomass power stations coming on stream and as the Energy Savings Trust has projected, some offsetting contribution from the emergence of micro-generation capacity, which in aggregate, can contribute some power to the grid *[Energy Saving Trust. 2005]*. Overall, however, these will be small contributions and it is unlikely, for example, that micro-generation will make a significant contribution to overall power demand until 2030 or after. Solar PV has similarly, a huge potential to contribute significantly to grid power over the next thirty years, but is unlikely to supply substantial amounts of transportable electricity before 2025. PV during this period will instead make a considerable contribution to the energy efficiency of homes in particular, by offsetting the need for imported electricity into the home.

So, the question then is: what additional transitional technologies or technologies that are near-renewable would be able to come on stream in the period up to 2025 in a way that would both substantially mitigate emissions of $CO_2$ and prove viable from a long term investment point of view?

One area of potential supply that has been largely neglected both by government and by those urging greater renewable power sourcing lies on our doorstep – waste. This neglect probably stems from the idea on the one hand, that incineration of waste as historically undertaken is a monumental misuse of a primary source and should be discouraged in future waste hierarchy planning, and on the other, that the electricity provided as a by-product of additional incineration is so marginal as to be insignificant.

A step change in these two perceptions is, however, achieved by examining where in the fuel cycle into power stations waste might appear. If biomass-rich fractions of residual waste (after other elements of waste have been reused or recycled) displaces conventional sources of fuel such as coal, then a dual $CO_2$ saving effect emerges – waste which otherwise might have been incinerated, but instead supplies power, and the coal that otherwise might have been burnt at a high $CO_2$ emission cost is displaced.

This is the principle behind "co-firing" of waste materials in conventional power stations – a practice already underway to a limited extent, but possible on a much more extensive basis and at commercially viable terms, since with the increasing cost of landfill, alternative options to waste disposal will have an increasing value in their own right.

Waste available for co-firing can take several forms – extracted waste such as wood from industrial and commercial waste streams; biomass residue such as husks and pips from agricultural and food processing waste; refuse derived fuel (RDF in "flock" or pellet form from domestic and general industrial waste). The latter can be produced to a consistency of about 60 - 65% biomass, which represents a substantial saving on the $CO_2$ emissions of the fuels it displaces.

The burning of waste for power is governed by a European directive, the Waste Incineration Directive (WID), which sets up standards for the transport and use of waste, even if its destination as a fuel is guaranteed. This produces difficulties with the burning of waste in co-firing procedures, since the burners in power stations themselves have to be compliant with the directive to accept waste, a process that adds cost to power stations that have, in any case, a relatively short life ahead of them, being affected by the standards required by the European Large Plant Directive due to come into force in 2015. This directive, among other considerations, lies behind the likely demise of existing coal fired power stations after that date, a contribution to the "energy gap".

However, recent clarification of the effect of the WID on power stations represents a substantial opportunity for the development of "co-firing": instead of requiring the compliance of an entire power station if co-firing is contemplated, compliance of the burner (power stations typically have perhaps five separate burners firing up in different combinations to produce required output) to receive the mixed fuel only is required, reducing substantially the investment required to introduce a relatively high level of co-firing into the process.

Even so, co-firing does not in itself introduce any new capacity into the system. It provides – short term – a potentially valuable method of reducing $CO_2$ emissions whilst providing power that is already "spoken for" and for that reason, it should be encouraged, but beyond the Large Plant Directive implementation, it appears that power stations that co-fire themselves will disappear.

However, there are two very important consequences of the use of waste as a fuel (but not via traditional incineration) that will make a contribution to low carbon power provision in the future.

The first is that the Large Plant Directive introduces requirements for fuel use and emissions standards that are very similar to the WID – that is planners of future power stations will have to introduce in effect WID compliance in all future burners in power stations after 2015. This opens the way to the development of mixed fuel power stations – either burning exclusively waste derived fuel or mixing it with a minority of coal. Mixed fuel power stations can be efficient, relatively low carbon and economically viable. This route can also take advantage of measures to remove wood from landfill. Current estimates suggest that up to 7 million tonnes of wood, mainly from construction is buried in landfill each year. Retrieval of this source and its use as a mixed fuel in biomass rich power plants would introduce a very emission-efficient new power source. A relatively simple change to landfill regulations, forbidding the burying of timber in landfill (as has occurred in Germany) would incentivise this market quickly and efficiently.

The supply of commercial, industrial and domestic waste after all other processes of recovery have been undertaken (perhaps extracting 50 – 60% of the waste stream thereby) is very considerable, even discounting the contribution that energy crops grown or harvested specifically for the purpose of providing feedstock for mixed fuel or biomass power stations, such as short rotation willow coppicing or miscanthus. Altogether, biomass and RDF could perhaps provide capacity in the way I have described of up to eight gigawatts, producing reliable “base load” and offsetting imported carbon rich fuel in the process. Such power stations also have a short build period and are comparable in construction time to the power source of last resort – the combined cycle gas turbine power station.

This brings us to the second consequence – the effect of waste processing technologies on the use of gas as a fuel in its own right.

Gas as a “bogey fuel” features highly in both the 2003 and 2007 Energy White Papers *[DTI 2007b, p. 4], [DTI, 2003. p. 9-10]*. Both papers express concern about “security of supply”, with the control of gas sources increasingly becoming concentrated in the hands of states not necessarily likely to provide favours to the UK in its supply, as North Sea gas runs out – and the prospect of an economy perhaps 70% dependent on gas for power if a business as usual scenario is played out until the middle 2020’s.

So, to what extent might the disappearing UK gas supply from the North Sea be substituted by domestically sourced gas from other processes?

At present, a small amount of biogas is produced in the UK from two sources – the collection of mine methane (gas being emitted from old coalmine workings, which if not collected, constitutes the emission into the atmosphere of a climate change gas 22 times as potent as $CO_2$) and methane also collected from landfill (the capture of emissions from spent and capped landfill sites, where the contents continue to putrefy and emit gas.) Both sources are finite and could, therefore, make only limited contribution to gas supply. *[Wicks 2007b*].

However, a third source of biogas, presently very small in extent, but with substantial potential, is represented by the application of waste processing technologies which release gas from putrefying biomass, but without burying it in landfill or, indeed, waiting for millions of years for it to emerge from coal seams. Bio-digestion of waste – the anaerobic action of microbes on domestic waste and sewage produces an inert digestate and copious quantities of biogas. By and large, bio-digestion of sewage is non-existent, as is the collection and processing of agricultural sewage or animal by-products, but could with some incentives become a substantial source of biogas.

Other technologies now exist which produce a similar outcome, but by other methods - heating a waste stream, so that by a process called pyrolysis, gas is given off and the remaining solids either emerge as an inert compost or as a mineralised product similar to hardcore clinker.

It is difficult to assess the impact of substantially greater production of biogas and the emission calculations surrounding it are complex. However, it is true that biogas is a substitute for mineral gas, even after taking into account the energy expended in producing it and already private sector enterprises such as EON are taking it seriously as demonstrated by their planned development of a biogas site near Sheffield. It also represents a very substantial (perhaps 60%) saving on the emissions of a given quantum of gas. In itself, it does not, of course, represent the introduction of new capacity to the grid, and to the extent it is currently considered, is seen as a possible solution to waste disposal that avoids landfill.

However, if we changed the terms of supply, then biogas might begin to contribute to the supply of gas as a power fuel overall – perhaps with the introduction of a renewable gas obligation, which could be couched in similar terms to those of the existing renewable transport fuel obligation and the renewables obligation itself, which could more accurately be described as a renewable electricity sourcing obligation.

A renewable gas obligation, perhaps set as a percentage of the domestic gas supply would, therefore, become part of the regime for the construction of any new gas power station in the future. Bio-gas would not (and probably could not) easily be fed into the domestic gas supply network, but gas suppliers would need to purchase obligation certificates from producers of biogas in order to supply gas in general. An obligation of perhaps 10% in the domestic gas supply sector alone looks to be feasible, in the light of possible supply of biomass through landfill gas capture, anaerobic digestion and pyrolysis. *[BERR 2007b. p. 170, chart 7.1]* and would stimulate markedly the development of biogas electricity and CHP plants. Such plants could represent in terms of likely future supply, the equivalent of three gigawatts of power supply.

**(ii) Can we solve the 'base load' problem?**

In order to have a system that works, which produces electricity when it is needed, a base load of power is important, but present assumptions seem to point to the new base load producing power stations being configured in almost the same way as those going out of commission by 2025 - and gas could be the dominant base load fuel (this point is dealt with in greater detail below).

There are champions in both corners arguing about the viability of renewables to provide that reliable supply. Some claim that renewables are the missing link and that we can replace all existing plant with renewables, thereby solving our $CO_2$ problem. Others pour cold water on the idea that this can be done – not just because of the improbability of the thousands of wind turbines supposedly required, but also because, and the White Paper again stresses this *[DTI. 2007b]*, renewables will not and objectively cannot, they claim, reliably form the element of the supply banding that makes the market work. The existence of a continuous base load of known supply which is cheaply delivered and upon which other forms of supply can be switched on or off to cope with the variable nature of the seasonal and even daily demand for energy supply is a sine qua non for everything else.

Oddly, both sides are right. Let us start though with who is wrong about what. There is one immediate and obvious point to make – renewables are not just about wind, whether offshore or onshore. Renewables come in all kinds of forms: wind, tide, wave, biomass, solar, ground source heat and solar thermal - all of which are as different from each other in potential advantages and disadvantages as say oil, coal and gas are in a high carbon power economy.

However, even if the prime mover of our replacement plant were to be wind, then it is not true that the base load capacity of the system would simply melt away. Wind power is variable, but it is inaccurate to call it intermittent. An appreciable amount of wind capacity, whether it is onshore or off, will reliably supply power in aggregate – and it is aggregate capacity that the system accounts for, even as far as gas and nuclear are concerned. The contribution that wind might make to the grid is also, contrary to myth, relatively predictable and studies have demonstrated the close correlation of predicted output of wind based on meteorological data and the actual performance of wind farms *[Sustainable Development Commission, 2005].*

The system, therefore, does not have a problem with balancing itself and matching up supply of power to its demand – even where wind makes up a far greater proportion of the available capacity to call on than is presently the case. Indeed, the National Grid itself confirms that *"if there is a limit to the amount of wind that can be accommodated, that limit is likely to be determined by economic/market considerations". [Ibid. p26]*

Although the limit is defined by economics, the economics of balancing becomes increasingly precarious above a penetration of installed wind capacity into the grid of about 20%. This is because the "capacity value" of wind – that is the proportion of the theoretically installed capacity of wind that, in aggregate, can be relied on by those calculating the balance of the grid process is about 35%. By the same token, taking into account outages for maintenance and breakdowns, the "capacity value" of gas is about 90% and for nuclear about 75%.

Balancing the system where the "capacity value" varies by this amount and where wind occupies less than 20% of the total available capacity is not difficult, but if the proportion goes above this level, then it becomes increasingly difficult and the "capacity value" of wind to the system correspondingly drops. In plain terms, the more one adds wind to the grid, the larger the amount needed as a balancing reserve.

It is of course feasible to do this, but eventually the process becomes economically very problematic and by the same reasoning that governs investment decisions on gas and nuclear, either the subsidy for adding capacity would have to become exponentially greater or investment decisions in wind would, in the end, simply not be taken.

The calculation for what capacity in the system as it stands is replaced by what capacity of renewables is, therefore, potentially difficult. For wind, certainly, 20% of "capacity" (i.e. about 16.5 gigawatts) would need to be represented by getting on for 80 gigawatts of installed wind *[House of Lords: Science and Technology Committee, 2004]* - a nigh on impossible number to contemplate. (The London Array currently in the process of construction, following the resolution of its planning difficulties, will supply roughly 1 gigawatt of installed capacity once complete).

Wind is the most economically viable developmentally advanced renewable, but its impact on the quantum of supply is necessarily limited, not for the reasons advanced by, regrettably, the Energy White Paper, but because of the “law of diminishing returns” that will set in above particular levels of capacity penetration. There is no set point, therefore, at which wind becomes “non-viable”, just a deterioration in its economic position as a contributor to grid power as its presence widens.

We are of course a very long way away from that point and if we maintain a clear concentration on the central problem of managing the emerging capacity gap up to 2025 with low carbon provision, then wind must play a strong role in the process and the penetration of under 20% the law of diminishing returns acts logically in reverse, capacity replacement by wind is far more efficient.

However, it is also true that we need to replace more than 40% of our generating capacity by 2025 and as it has been pointed out, none of this is likely to come from nuclear, leaving renewables, gas and coal as the realistic planning options. It is also true that, if investment decisions are to be made, they will be made earlier rather than later - precisely the reason why nuclear planning looks to be so uncertain currently.

The White Paper talks about the need to maintain an energy mix *[DTI. 2007b, p. 5]*, but that there is no one “magic bullet” - no particular form of energy supply which will by itself secure our power generation in future. This is right, except that, as has been documented here, the crucial trick of steering our energy economy away from its present high carbon, fuel wasteful configuration to a long term, stable, low carbon, fuel efficient arrangement lies in determining at what time what form of generation is likely to be dominant, bearing in mind that, left to its own devices, the energy market will opt to keep gas (and to a lesser extent coal) dominant until the logic of using gas coal founders on factors other than climate change, by which time it will be far too late.

## Adding the measures up - do they fill the gap?

Here is a rough stock take of what a combination of the measures described would look like:

**Assumption 1:** Energy efficiency measures keep demand by 2025 roughly as it is now and the capacity reserve needs to be of the same order as at present.

**Assumption 2:** By 2025, approximately 25 gigawatts of capacity (or the capacity value equivalent) will need to be replaced.

| | |
|---|---|
| Wind onshore and offshore | 18GW replaces 7GW now – 2025 [BWEA, 2007] |
| European Super Grid (deep sea wind) | 10GW replaces 4GW 2015 – 2025 |
| Severn Barrage | 5GW replaces 4GW 2020 – 2025 |
| Mixed fuel/biogas/Gas CHP | 10GW (with potential for up to 21) replaces 10GW now - 2025 [CHPA, 2007] |

It ought to be noted that none of these sources are likely to be stranded during the lifetime of the investment, especially if carbon capture and storage becomes a commercial practicality in the 2020’s. This would, for example, allow both mixed fuel and gas CHP power stations to continue in operation and for further gas/CCS power stations to be built in the latter half of the decade 2020 – 2030.

At this point, any privately financed new nuclear power station that had been commissioned previously might come on stream (whether they would find a commercial market for their electricity is a matter of conjecture) and would of course be substantially influenced by decisions that might be made now in the absence of government commitment to intervene in the price of electricity, subsidise their building or shoulder the costs of decommissioning and waste storage. Whether nuclear power companies would decide to commit to new nuclear in the light of a stable and capacity-rich energy market after 2025 is doubtful.

## Making it work

All of this pushes us along the road of concluding that the “measures well beyond those of the Energy White Paper” will not consist of any of the suggestions currently being championed by various corners of the debate. They will not consist of “more nuclear” for reasons already stated: nor can they consist of tougher targets unless a reliable carbon rationing system is in place and that too will probably be too far over the time horizon to ride to the rescue either, important though such rationing will turn out to be for the achievement of a workable low carbon economy in the medium term future (see more below).

### a. The role of carbon trading

New build power stations, it is assumed will have to work in a market framework. This means in reality a competitive rate for fuel supply taking account of all externals, as has recently been confirmed by the government for new nuclear build [*Adams, C. and Crooks, E. 2007]*. A reliable price for $CO_2$ can add a new dimension to the market by introducing carbon price as a known external, factored in for all forms of energy, to which the market will respond.

Somehow, therefore, industry has to be induced to invest in new supply, which produces electricity at competitive prices but with, at the very least, a radically reduced carbon ‘backpack’ accompanying it. The key to all this, therefore, is to provide a carbon pricing mechanism which skews price competitiveness away from gas and coal and towards low $CO_2$ generation (renewables or near renewables, such as CHP).

There are of course some methods of doing this in place already. The Renewables Obligation and the Climate Change Levy, provided they are applied over a confidence-building extended period of time, do make a difference in investment calculations of those bringing power to market. The emergence of a regime to award two ROCs (Renewable Obligation Certificates) per kilowatt hour of biomass produced electricity will over time cause investment decisions on power sources such as biomass fuelled and combined heat and power to change, but the ROCs have to be funded from somewhere and in effect they end up as a levy on customers. These measures have now begun to be factored into investment decisions, and the problem they face is that as yet they lack long-term guarantees that they will remain as factors.

The need to secure long-term stability in investment decision making is one reason why switching to a feed in tariff for energy supply, attractive as it otherwise might look, could be counterproductive in the medium-term future. A domestic feed-in tariff, which would reward microgeneration, would of course be a different matter.

But above all of these considerations, providing an overall price for carbon regardless of the mode of power seems a much better long term fit for the stability of investment decisions in the energy market of the future. A known carbon price would enable energy investors without special devices or short term proposals to factor it into all their investments decisions and inevitably make decisions based on low carbon technology whatever it might be.

So the holy grail of energy supply up to the year 2025 could lie in establishing a known carbon price early to stimulate investment decisions. This is an admirable goal and the UK has effectively taken a world lead in seeking to bring this about through the establishment of carbon trading. Carbon trading is superior in terms of “market fit” to obligations or other devices, in that no one has to fix a level of reward for doing particular things: the market does it for itself. It is, incidentally, a major assumption behind the ‘nuclear’ case which is appraised as being viable from an electricity price point of view in a future where gas prices remain relatively high and a carbon price of at least € per tonne of $CO_2$ is obtained through the carbon trading market *[DTI, 2007d, p.32].*

However, there are certain 'bottom lines' for effective carbon trading. A key requirement is that, in order to establish a stable and reliable forward price for carbon, the caps on total carbon use always have to run ahead of what has been achieved, because it is the excessive demand for carbon rich energy over its supply that produces the price for carbon – if you want it, you will buy it at a premium and hence keep the carbon price up.

The mechanisms for carbon trading are in this respect relatively straightforward. You introduce an overall ration card, the quantum of carbon that can be used. The ration can be applied to individuals or more efficiently and cheaply to those industries, such as energy, who are responsible for emitting carbon. In order to ensure that there is a sustained price then a "fine" can be imposed on those who have exceeded their own allocation by an amount well above the aimed for price that people will pay to buy parts of other people's "ration". It will always be cheaper, therefore, to trade than pay fines. Alternatively and perhaps preferably, a system can be devised whereby allocations are auctioned of at a market value price. In either case a sustainable market comes into place, which has the tremendous advantage of then by itself sustaining subsequent investment decisions without recourse to other measures.

In essence, the market is pressurised by demand. The greater pressure of demand, the higher the price. If, however, the pressure is always escaping from the system in other ways, then a carbon trading system will fail to maintain the pressure on price which then drives investment forward and the first iterations of carbon trading have suffered from precisely this.

The caps within Europe were effectively self-ascribed and, therefore, not pitched below likely future demand. Secondly, because allocations were given away as opposed to auctioned off, then many of the largest utilities received windfalls and large parts of industry, most notably aviation, remain outside the system altogether. Finally, companies could (and can) discharge some of their obligations by "offsetting" – investing in low carbon development projects which effectively buy them credits and hence avoid fines, but at prices obtained outside the system (especially if they were banked as insurance against future price rises), which allowed and allows potential price leakage out of the system.

The result of all this has been a trading price of virtually zero – in effect no one needs to go and buy credits if almost everyone can reach their target without purchases and can gain credits by other means at a cost lower than purchases and fines. The second and third phases of EU ETS should, it is hoped, fix this through much more stringent applications of caps, and reduced opportunities to offset through the incorporation of a far wider section of industry needing to trade to keep away from being fined. More people chasing fewer allowances essentially guarantee a high carbon price, which stimulates investment. But again dates are important. The first stage of EU ETS cannot exactly be counted as a failure, because enduring mechanisms have been put in place. What it has failed to do is lift a carbon price to any more than token levels. The second phase, from 2008-12 may well do more than that, but is still beset by some of the allocation problems that cursed the first stage. It looks in reality as though issues of comprehensive inclusion of major emitters and allocation questions will only firmly be resolved by the third stage, from 2012 -2016. Only at that point *might* carbon prices reach economically influential levels – probably too late to influence decisions on energy investment without other measures that do not depend on a traded carbon price being present.

Even so, the price level still remains outside the direct ability of the UK government to secure. If any one of the factors in future negotiations with Europe fails – caps continue to set at unrealistically high levels or compliance dodging is accepted or too few industrial sectors face obligations to work within the market, then the price will inevitably remain at a deflated level. Once again, time is not on the side of the UK government, whereas other EU countries do not face the same constraints, because of different investment profiles for their future energy supplies or because of different mechanisms adopted to guarantee the supply of energy within their markets, such as feed-in tariffs or trading constraints through strategic storage or contract arrangements for example.

It would be good to think that an early and sustained carbon price will emerge. If it does, it will certainly play a substantial role in influencing investment decisions concerning the replacement of capacity, but this is by no means certain. In any event, a carbon market driven by sufficient carbon price certainty is unlikely to emerge in time to determine many of the earlier decisions that will shape the energy supply picture over say the next ten years or so.

Carbon trading, therefore, will not in itself provide the means whereby investment decisions on energy supply will reliably turn out to be low carbon. It just might, but then again it might not and by the time we have found out which of these two it will be, the time for investment decisions will have passed and we may be stuck with an energy supply mix that reflects an assumed slow start to effective carbon trading over that period. This is clearly the view of those energy companies submitting proposals for gas and coal fired power stations currently: otherwise they will have stranded assets in a few years time.

**b. Shaping the market in advance of a secure carbon price.**

So, how might at least much of the present market mechanism which provides us with reliable supply be preserved in the face of the apparently opposing forces of the rock of $CO_2$ reductions and the hard place of the introduction of reliable new supply forms? A number of the devices that could encourage investment in renewable or near renewable forms of power are already in place. What is needed in terms of a perspective until 2025 is that they are given longevity, so that long-term investment can be secured. These might consist of:

- Guarantees of long term stability (post 2015) for the renewables obligation
- Guarantees of long term stability for the banding ROC regime (which from 2008, will provide two ROCs per kilo watt hour of biomass, CHP, etc)
- The introduction of a renewable gas obligation on all domestic gas supply for generation
- Banning of waste wood from landfill
- Amendments to the planning regime that speed offshore permissions and relate CHP capacity to the siting of new traditionally fuelled power stations.
- Commitment to proceed at an early date with the Severn Barrage
- PFI, or a regulated asset base overseen by Ofgem for district hearing network provision and a phase out by 2020 of waste heat
- Inter-governmental agreement on a purchase and access regime for an inter-connector for the super grid
- Funding to ensure completion of trial project of carbon capture and storage with subsequent commercial introduction.

None of these obligation and funding support suggestions are unfeasible in the present funding climate and a number will be needed only as a phase in the establishment of longer term stable large scale renewable technologies, underpinned by a known and relatively high carbon price. They are, in short, the kind of “further measures” the Energy White Paper hints at, but does not yet spell out, that will keep the lights on, restock our power generation and capacity up to 2025 *and* make substantial and sustainable progress to the goal of a 2050 permanently low carbon economy. Most importantly, there will not be a nuclear power station in sight.

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