The Investment Case for Coal-Fired Power Generation in the UK

Final Report to the Institute for Public Policy Research

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CONTENTS

1 Introduction

A number of new investments in coal-fired power plant have been proposed by power generators in the UK, and there is concern amongst some environmental groups that such investments run counter to the need for a transformation of the energy system towards low-carbon emissions. This report provides background research on the investment case for new coal build in the UK. The report feeds into a broader IPPR study[1] which is looking at policy options available to the government with respect to the environmental consequences of building new coal plant.

An important feature of electricity systems in many countries including the UK is the expected need for a significant level of new investment in electricity generation capacity over the period to 2020. One important driver of this new investment phase is that several ageing coal plant will need to retire as a result of the introduction of the EU's Large Combustion Plant Directive (LCPD). This requires emissions of sulphur to be reduced using abatement techniques that are not cost-effective on older plant.

In an electricity market, electricity companies will be responsible for choosing the type of technology and fuel they want to use for generating electricity. This choice will be made taking into account commercial signals from the market (e.g. regarding technology costs, fuel costs etc.), as well as policy signals relating to carbon prices and financial support of specific technologies.

Although the decisions are made by private companies, the choice of technology and fuel has implications for a number of public policy goals, including energy security, fuel poverty and emissions of greenhouse gases. On the latter point, the UK government is in the process of adopting a climate change bill that will introduce a legally-binding target of 26-32% reductions in CO_2 emissions by 2020 relative to 1990. This domestic target sits within a developing international policy, which importantly includes the EU emissions trading scheme, which places mandatory caps on greenhouse gas emissions from large sources including power generation.

The aim of this report is to provide an overview of the economic, commercial and policy factors surrounding companies' decisions of whether or not to build new coal plant in the UK. The report includes an overview of the following aspects:

- Scenarios of capacity of different types of generation plant up to 2020, and the impact of potential coal build on emissions in the UK
- The economic case for building new coal plant in the context of the UK electricity market

[1] Lockwood, M (2008) 'After the Coal Rush: Assessing policy options for coal-fired electricity generation' , ippr http://www.ippr.org/publicationsandreports/publication.asp?id=617

- The role and economics of carbon capture and storage
- Impact of investment risk and uncertainty
- Policy implications, including the role of the EU emissions trading scheme and options for further support of CCS.

2 Scenarios of Coal Build in the UK

Figure 2.1 presents different scenarios of technology and fuel choice for new power generation plant up to 2020. The capacity additions depend on the expected level of demand in 2020. Included in the figure are several different scenarios:

- The Energy White Paper (EWP) scenarios are broken down by both fuel price (central, low, and high prices), and also the effectiveness of climate change policy in reducing demand (central, low and high policy)[2].
- Redpoint carried out separate modelling as background for the EWP. Out of the many different scenarios, the figure shows the baseline (i.e. business as usual projections) for two different states of the market, 'Well Functioning Market' (WFM) and 'Imperfect Markets' (IM). These scenarios are described in detail in a report available on the BERR website[3].
- Plant that are currently in the application process for Section 36 planning[4].
- Plans for new coal build, based on announcements by the main UK companies themselves[5].

On the left-hand side of Figure 2.1 is the amount of power plant that is retired between 2005 and 2020 under the central price scenario of the 2007 Energy White Paper (EWP). Retirements under this price scenario include 14GW of coal plant. This level of retirement in coal is independent of the policy scenario (i.e. the low, central and high policy impact scenarios all show the same level of coal plant retirement over this period).

The first point to note from Figure 2.1 is that nearly all the scenarios show some new coal build. The exception is the EWP low fuel price scenario, where cheap gas implies a much

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2 'Updated Energy and Carbon Emissions Projections' BERR URN 07/947
http://www.berr.gov.uk/files/file39580.pdf

3 'Dynamics of GB Electricity Generation Investment' Redpoint, 2007
http://www.berr.gov.uk/files/file38972.pdf

4 http://www.dti.gov.uk/energy/markets/consents/applications/page23224.html

5 ENDS Report 396, January 2008

greater level of CCGT is built, and no coal is built at all. In the other EWP scenarios, 3.9GW of new coal is built with a further 0.5, 1.0 and 1.9 GW of coal with carbon capture and storage under the low, central and high policy cases respectively. The modelling assumption is that under a central fuel price scenario, the companies would choose to build some new coal in order to maintain some diversity in their generation portfolios. The Redpoint baseline scenarios show 7.5GW of new coal in the well functioning market scenario, and 11.5GW in the imperfect markets scenario. The increase in the IM scenario is largely due to the lack of new nuclear build, the difference being made up with new coal. The total level of build is higher in these scenarios because they do not include the assumptions about reductions in demand built into the EWP policy scenarios.

The plant currently awaiting S36 planning consent includes some coal (1600MW at Kingsnorth planned by E.ON). This does not comprise the full range of plant that could be built before 2020, as there is time for new plans to come through. However, neither does S36 planning consent guarantee that the plant will be built; it simply gives the company the option to do so, but there is no obligation to build as a result of a successful application.

The plans announced by power companies to build 11.5GW probably represent an upper limit to the amount of coal likely to be built before 2020. Although an announcement by a company signals that they may be seriously considering an investment (including working up the financial case, applying for S36 consent etc.), it does not necessarily mean they will be built. To some extent, going through the necessary planning and analysis stages is carried out in order to build up the option to invest. Whilst these steps might cost the company several million pounds, they are nevertheless relatively cheap compared to the final investment of over a billion pounds. Once the planning phase is completed, companies will look again at the expected future economic and policy conditions regarding the investment, before deciding whether or not to go ahead.

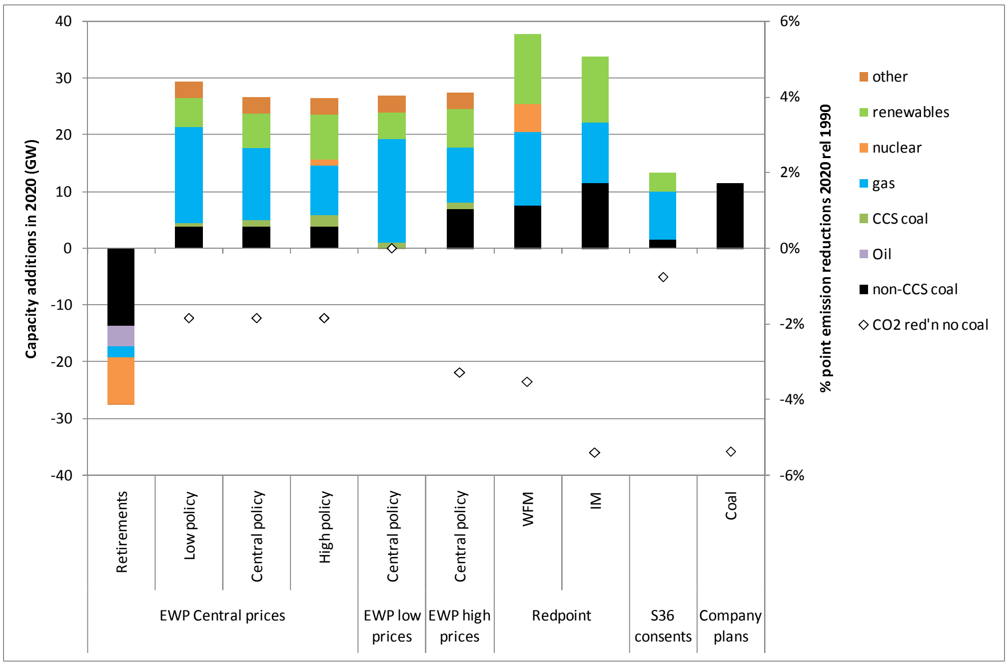

Figure 2.1 Scenarios of new generation capacity build in the UK up to 2020

There is also some element of gaming involved in these announcements, since the decision of one company will be affected by the decision of others. Collectively the market will try to capitalise on situations where there is a shortfall in capacity (leading to higher prices), whilst avoiding excess capacity (leading to low prices). The decision of one company to build is therefore contingent on their expectations about what will be built by their competitors, as everyone want to avoid a situation in which the price collapses due to overcapacity in the market.

The fuel mix for the power sector has a considerable influence on the emissions profile for the UK. The emissions for the EWP scenarios are shown in Figure 2.2.

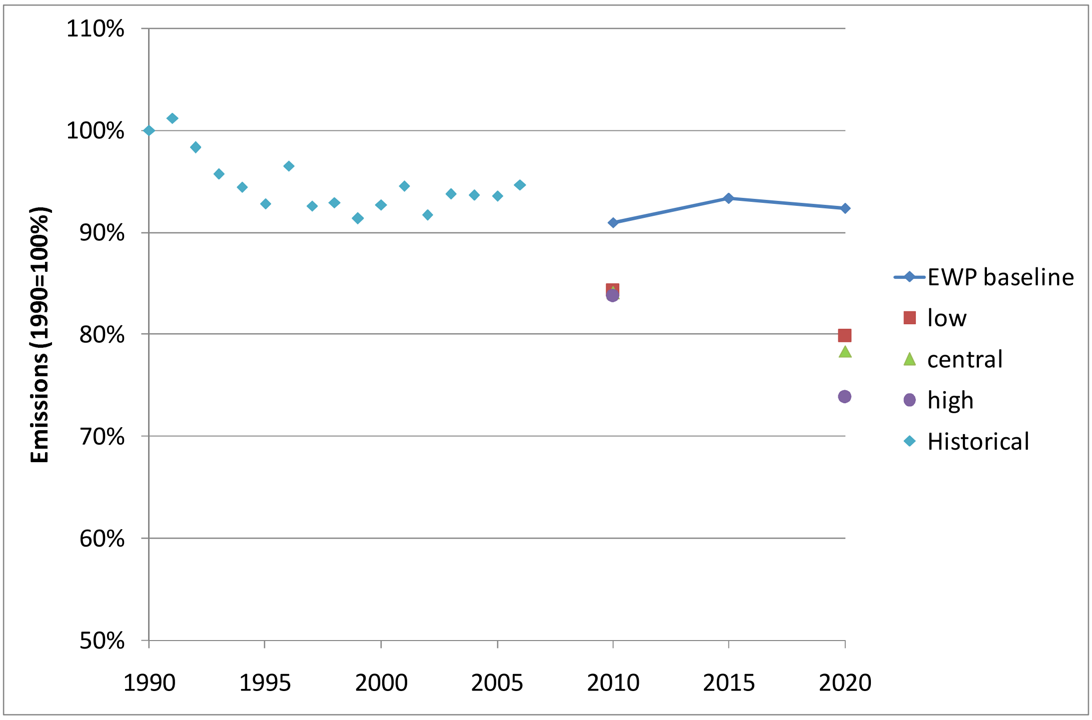

Figure 2.2 Emissions reductions relative to 1990 for the EWP scenarios

The high (i.e. optimistic) policy scenario reaches close to 26% emissions reductions in 2020 relative to 1990, a figure that is at the bottom end of the range (26-32%) suggested in the climate change bill as appropriate for the carbon budget for the UK. This emissions scenario includes the 3.9GW new coal build indicated in Figure 2.1.

The results from Figure 2.1 can be combined with Figure 2.2. to see how the fuel mix might affect these emissions trends. In the lower part of Figure 2.1 are a set of diamonds which correspond to the emission reductions that would be achieved if the coal plant were replaced with CCGT (both assumed to run at 86% capacity). These emission reductions are presented in terms of percentage point reductions relative to 1990 (read from the vertical axis on the right-hand-side of the chart). For example, if the 3.9GW of new coal under the EWP central price scenario were replaced with CCGT, this would lead to 1.8% reduction in 2020 (e.g. extending the high policy scenario from 26.2% reduction to 28% reduction). A correspondingly greater emission reduction would come from replacing the larger amount of new build indicated in the Redpoint IM scenario and companies' own stated plans –

replacing 11.5GW of coal capacity with CCGT would reduce 2020 emissions by 5.4 percentage points.

Demand reductions are obviously an important factor in reducing emissions. This can be seen indirectly in the EWP scenarios in Figure 2.1, where the total amount of new build in the high policy scenario is 2.9GW less than in the low policy scenario. The role of demand restraint can be seen more directly in Figure 2.3 looking at these same scenarios in terms of total demand (rather than capacity).

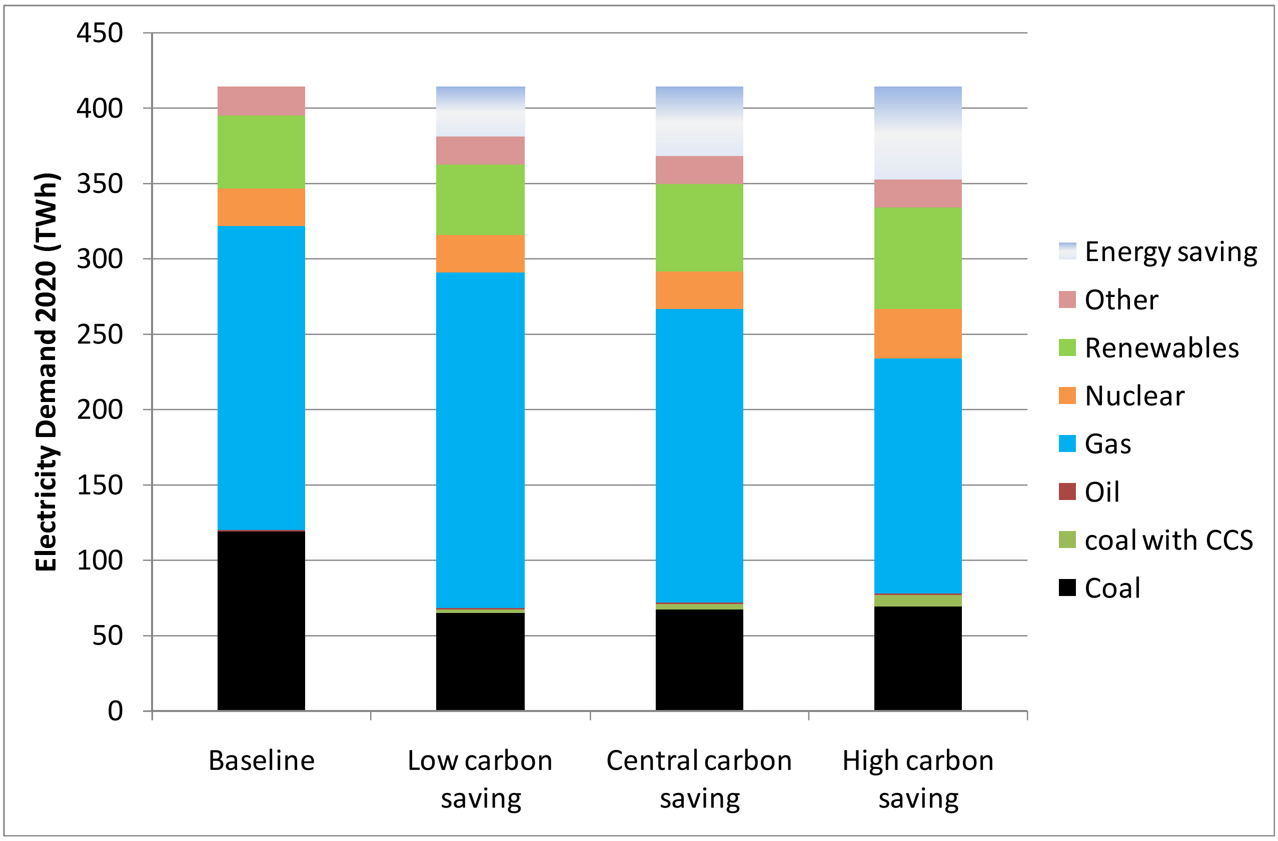

Figure 2.3 Electricity demand for 2020 under central prices, for the low, central and high policy scenarios in the Energy White Paper. Also shown is the baseline demand in 2020, which excludes the effects of the EU-ETS and other EWP policy proposals.

The high carbon saving scenario represents a saving of 61 TWh (15%) relative to the baseline scenario, and a saving of 28TWh (7%) relative to the low carbon saving policy scenario. This compares with a supply of electricity from unabated coal plant in the central price scenario of around 67TWh. The contribution of energy efficiency assumed in the EWP high policy scenario relative to the baseline would therefore need to be approximately doubled if this scenario's contribution from coal were to be replaced by demand reductions.

3 Relative Economics of Different Technologies

Different types of power generation technology have different cost structures, and therefore respond differently to changes in market prices. Clearly, the cost of generating electricity from gas, coal and nuclear will depend on the respective fuel costs for example. Coal is more carbon intensive than the other forms of generation, so will be become increasingly expensive under high carbon price scenarios. Nuclear is more capital intensive than gas, and so is more sensitive to the cost of capital.

A convenient way of comparing different technologies is to use 'levelised' costs, which calculate the full cost (including capital costs) for producing a unit of electricity. Levelised costs have their limitations, as they do not represent risk very well, and therefore do not necessarily provide a good guide to what companies will actually invest in (see Section 5 for further discussion). Nevertheless, they provide a starting point for analysis.

Figures 3.1-3.3 show 'phase diagrams' of what technology would provide the lowest cost of electricity, depending on the price of fuel and the price of emitting CO_2 within the EU emissions trading scheme. The three shaded areas divided by solid black lines show regions in which gas (blue), coal (grey) and coal + carbon capture and storage (beige) would be the most cost effective choice of technology in terms of levelised cost of electricity. We can develop the intuition of this phase diagram by looking along the horizontal axis. At low gas prices below about 30p/therm, the cheapest way of producing electricity is with gas. As gas gets more expensive than this, coal would provide a lower cost method of production. However, higher carbon prices favour gas-fired generation because it is more efficient and is a less carbon intensive fuel. This is why the solid line representing the breakeven between gas and coal slopes diagonally to the right as carbon prices increase. If carbon prices become high enough (above about €50/tCO_2 according to these figures), it becomes cheaper to generate electricity using coal + carbon capture and storage than with unabated coal. Above €50/tCO_2, the cheapest method of generation would be either gas or coal + CCS depending on the fuel price of gas.

The technology assumptions used to calculate the levelised costs used in Figures 3.1-3.3 come from the Redpoint study[6] in 2007 that fed into the EWP. These technology assumptions were then fed into a standard levelised cost spreadsheet model, assuming an 8% real discount rate for all technologies.

In Figure 3.1, a single set of coal prices is used, taken from the central EWP scenario. This results in a single set of breakeven lines between the various technologies (i.e. lines along which the levelised costs of two technologies is equal). As well as gas, coal, and coal + CCS, the figure shows the breakeven lines for wind and nuclear power. These breakeven lines are calculated comparing their costs with either gas or coal, whichever is the cheaper depending on the region of the graph. For example, in the gas (blue) region, nuclear and

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[6] 'Dynamics of GB Electricity Generation Investment' Redpoint, 2007 (ibid)

wind generation costs are compared with gas generation. The lines slope upwards to the left in this region because the lower the price of gas, the higher the carbon price needs to be in order for the alternative (i.e. nuclear or wind) to breakeven.

In the coal region on the other hand, the gas price no longer matters, since we are comparing the alternative (nuclear or wind) with the cost of coal-fired generation. We then get a single price of carbon (shown as a horizontal line) at which nuclear or wind would breakeven with coal.

Clearly, these breakeven points depend on the technology assumptions. For example, the breakeven point for CCS shown in Figure 3.1 is substantially higher (at around €50/tCO_2) than the figure of $38/t$CO_2$ derived in a similar type of analysis carried out by the IEA[7]. This is because the Redpoint assumptions are more favourable towards new coal plant (lower capital and operating costs and higher plant efficiency) and less favourable towards CCS plant (higher operating costs and lower efficiency). The technology assumptions in Figure 3.1 correspond to the costs for the 2007 vintage technology. Account is taken of technology learning in Figure 3.3 below.

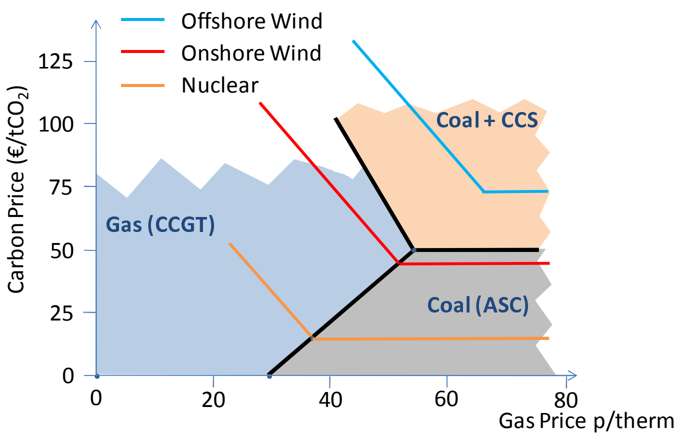

Figure 3.1 Phase diagram showing regions where different technologies would have the lowest levelised cost of electricity generation. Technology cost assumptions from Redpoint, 2007 vintage technology, central EWP coal prices.

Figure 3.2 extends the analysis in Figure 3.1, showing additional breakeven lines to show the sensitivity to coal price assumptions. The solid lines and shaded regions still represent the EWP central coal price scenario (identical to Fig 3.1). The effect of high and low coal prices are represented by dotted lines. A low coal price scenario has the effect of extending the coal region to the left, whereas a high coal price scenario extends the gas region to the

[7] Blyth, W. Yang, M. (2007) "Climate Policy Uncertainty and Investment Risk" *Book pub. International Energy Agency, Paris ISBN 978-92-64-03014-5*

right. The breakeven carbon price for CCS is relatively insensitive to these coal price scenarios, ranging from €47.4/tCO_2 under the low price scenario to €52.4/tCO_2 under the high price scenario. This is because the breakeven price is only affected by the difference in efficiency between the two types of plant.

In regions of the phase diagram where nuclear and wind are being compared against coal, a higher coal price leads to a lower CO_2 breakeven price and *vice versa*. The high and low coal price scenarios lead to a range in the breakeven price relative to coal of €8-20/tCO_2 for nuclear, €38-50/tCO_2 for onshore wind and €67-79/tCO_2 for offshore wind.

The breakeven point for nuclear and wind relative to CCGT is unaffected by the coal price, so there is still only a single upward sloping line for each of these technologies in the region where the comparison is with gas, identical to the lines in Figure 3.1.

Also shown in Figure 3.2 is the range of gas prices under the EWP low, central and high price scenarios (shown here as the averages for those scenarios over the period 2010 to 2020). It can be seen that the scenarios almost exactly span the region of the phase diagram where gas is competing with coal as the lowest cost technology, making estimates of the carbon price critical to the choice of technology. This highlights the important role of uncertainty and risk regarding estimates of the future price of both gas and carbon when it comes to choosing the right technology for new power generation investment. The role of uncertainty is discussed more fully in Section 5.

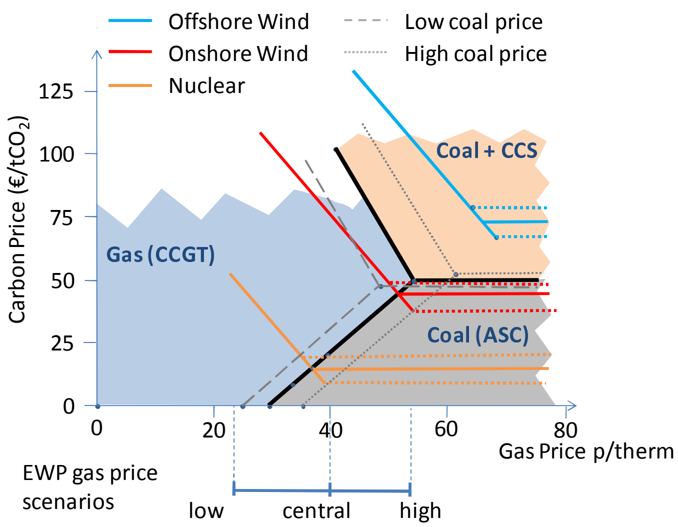

Figure 3.2 Phase diagram, again with 2007 technology costs, but showing sensitivity to coal prices. Dotted lines indicate breakeven points for EWP high and low coal price scenarios.

Figure 3.3 shows how technology learning by 2031 is expected to alter these breakeven points (according to Redpoint assumptions). The breakeven carbon price for CCS relative to coal drops to €40/tCO_2. Two effects are included in this. CCS is assumed to become more favourable due to improved efficiency, and reduced capital costs. However, the effect of these improvements in terms of the reduction in required CO_2 price is dampened by the fact that the investment case for unabated coal is also assumed to improve due to improved efficiency and reduced capital costs. This improvement in unabated coal also reduces the extent to which nuclear and wind technologies benefit from their own learning. In fact, the breakeven CO_2 price for on-shore wind relative to coal *increases* from €44.6/tCO_2 under 2007 technology costs to €51.4/tCO_2 under 2031 technology costs. This is due to a relatively small degree of cost reduction associated with on-shore wind during this period in the Redpoint assumptions, consistent with an assumption of constrained on-shore wind resource combined with the fact that the technology is already quite mature.

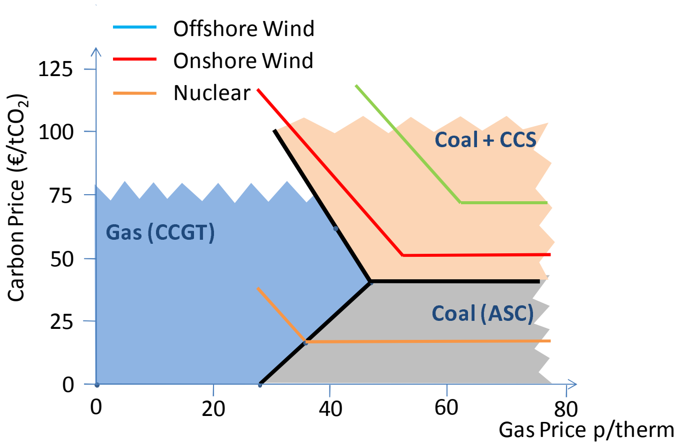

Figure 3.3 Phase diagram using 2031 vintage technology assumptions, central coal price scenario (based on average of 2010-2020 coal prices)

4 Detailed Cost Breakdown for Coal and CCS

Emissions from coal-fired power generation can in principle be reduced by up to 90 per cent through technology that captures carbon dioxide emissions from power plants, and then storing the carbon dioxide in depleted oil and gas fields, or aquifers.

There are two key routes to applying carbon capture and storage (CCS) to coal plant. The first uses an advanced version of the standard fuel cycle (advanced super-critical, ASC), in which pulverised coal is combusted in a boiler to produce steam and electricity is generated from a steam turbine. In this case, carbon dioxide is relatively dilute in the flue gas stream, and so the separation of CO_2 from the other flue gases is relatively costly.

The alternative route is to use a completely different combustion technology (integrated gasification and combined cycle, IGCC) in which the coal is converted into a combustible gaseous form so that it can be used in a gas turbine. Gas turbines generate electricity at higher efficiency, and the concentrations of CO_2 in the flue gas can be much higher, making removal of CO_2 more efficient and less costly. However, the gasification stage is more expensive, and there is less experience of using the technology at the scales required for centralised power generation.

Figure 4.1 shows the breakdown of levelised costs (in p/kWh) for different technology cost assumptions for these two different technologies. These costs are evaluated for the central EWP coal price scenario and with a carbon price of €50/tCO_2

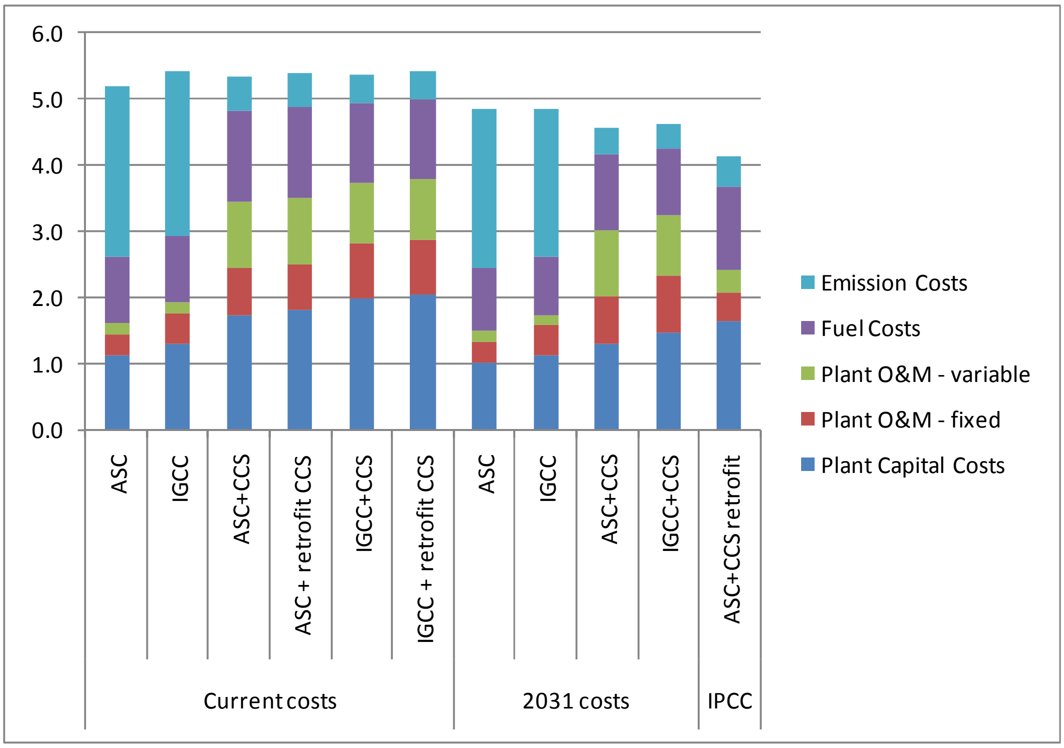

Figure 4.1 Cost breakdown for Advanced Super Critical and coal gasification (IGCC) coal plant with and without carbon capture and storate (CCS)

These costs are all based on Redpoint data except for the IPCC cost breakdown which is shown for comparison.

Under the 2007 technology vintage assumptions, IGCC is currently more expensive, with a levelised cost of 2.9p/kWh compared to 2.6p/kWh for ASC excluding the costs for emissions. The difference reduces slightly from 0.3p/kWh to 0.2p/kWh when the emissions costs are included because of the additional efficiency of IGCC (46.4%) compared to ASC (44.9%).

When the costs of CCS are added in, emission costs drop significantly because 90% of the emissions are removed. Capital and operating costs increase accordingly. Under the Redpoint assumptions, the levelised costs including CCS are very similar for the two technologies, at just over 5.3p/kWh.

Taking account of learning, the 2031 technology vintage assumptions from Redpoint show reductions in generation costs for both ASC and IGCC. Again, in the stand-alone case, ASC is cheaper than IGCC, although when CCS is fitted the costs are very similar.

Included in Figure 4.1 for comparison are the cost breakdowns taken from the IPCC report on CCS. These show much lower costs than the Redpoint assumption, largely as a result of lower capital and operating cost assumptions. It should be noted that capital costs for all types of plant have increased dramatically in recent years since the IPCC study was carried out.

Another important point arising from these figures is that under these assumptions, retrofitting CCS at a later date is hardly any more costly than fitting at the time of the new build, and that this is the case for both ASC and IGCC technologies. This means that there is no penalty for companies building unabated coal generation plant now (whilst carbon prices are below the breakeven price for CCS), with a view to retrofitting the capture and storage plant should carbon prices rise sufficiently in the future. This flexibility provides companies with a valuable option for the future. CCS technology provides an important hedge against the risk of high future carbon prices, essentially reducing the risk of building coal plant. Results from the IEA[8] show this intuitive result quantitatively, indicating that new build decisions for unabated coal could be accelerated as a result of the option to retrofit CCS at a later date.

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[8] Blyth, W. Yang, M. (2007) “Climate Policy Uncertainty and Investment Risk” *Book pub. International Energy Agency, Paris ISBN 978-92-64-03014-5*

5 Implications of Risk and Uncertainty

Whilst an analysis of levelised costs gives some idea of the comparative advantage of different technologies under different price scenarios, it is not well suited to understanding how risky different investment are likely to be, and risk is an important factor in investment decision-making. Figure 5.1 shows two sets of economic comparisons for coal and gas. This is a representation of the costs of different technologies, updating similar figures shown in a recent UKERC report[9] to include Redpoint technology assumptions and EWP fuel price scenarios.

Figure 5.1a shows the range of levelised costs for each technology under the different EWP energy price scenarios (low, central and high), and for carbon price scenarios of €0/tCO_2, €15/tCO_2, and €25/tCO_2. The range of levelised costs is greatest for CCGT (£25-53/MWh) because the gas price spread between the scenarios is higher for gas than it is for coal, and in addition the costs of generating electricity from gas are more sensitive to fuel price changes since fuel price is a higher proportion of overall costs. The range of levelised costs for ASC coal is £29-51/MWh, and for IGCC coal £33-54/MWh. The average levelised cost across these price scenarios for CCGT is very close to that for ASC coal (at around £40/MWh), with the average for IGCC coal coming out slightly more expensive at £44/MWh.

However, if we look at the revenues that would be generated from these plant, we get a different story, as shown in Figure 5.1b. This shows the range in the net present value (NPV) of the investments taking into account the effect on the electricity price of the different fuel and carbon price scenarios. These NPVs are calculated by assuming that the price of electricity follows the short-run marginal cost of the marginal plant (i.e. the most expensive) on the system required to meet demand.

Because of the large amount of gas in the supply system in the UK, it is likely that gas plant will continue to be used under all scenarios. If the price of gas is high, gas-fired generation would become the marginal plant in the system, driving up the price of electricity. Therefore, even though the cost of generation with gas increases at high gas prices, gas-fired plant would still be able to recover their costs because variations in cost and revenue can be quite closely correlated, reducing overall investment risk. We can see this effect in Figure 5.1b, where the range of NPVs for gas is significantly lower than for coal, even though the range of costs in Figure 5.1a is greater.

[9] Gross, R. Heptonstall, P. Blyth, W. (2007) “Investment in electricity generation: the role of costs, incentives and risks” *UKERC Technology and Policy Assessment report*

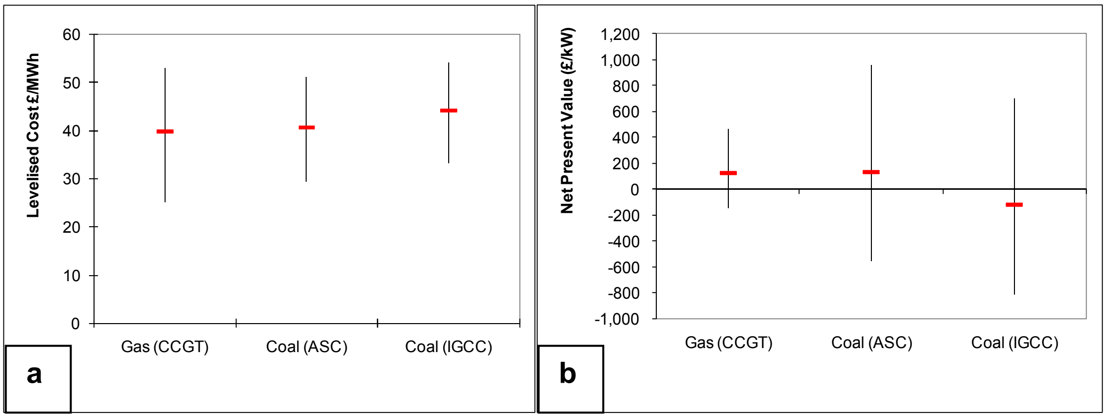

Figure 5.1 Cost comparisons for gas and coal a) levelised cost, b) NPV

The range of possible returns in Figure 5.1b provides a relatively simple indicator of risk. In this example, coal appears to be a significantly more risky investment prospect, because there is the possibility of significant losses (which would occur under a low gas price, high carbon price scenario). Even though these potential losses are balanced by the possibility of very high returns (which would be the case in a high gas price, low carbon price world) giving the same average returns as for gas, companies may be more concerned about the possibility of large losses than about the possibility of large gains.

In practice, analysis of risk is more complex than this simple comparison suggests. In particular, companies may take into account the value of diversity in the generation portfolios, favouring a spread of technologies that help to balance out their exposure to different sources of risk. This is likely to be an important factor behind companies' considerations of the value of building new coal plant given the extent to which existing coal plant is expected to retire, and given concerns over risks associated with supplies and prices for gas.

Many other factors will also enter the decision. Companies will also take into account the expected build decisions of their competitors, the overall policy framework to judge whether either excessive losses or excessive profits might be capped as a result of policy decisions, as well as other strategic factors. Practical issues such as the amount of time taken to get planning permission and to build new plant may also an important factor. Generally build times and planning processes are significantly quicker for CCGT than for coal.

6 Conclusions and Policy Implications

According to the Energy White Paper projections, approximately 14GW of coal plant will retire between 2005 and 2020, driven largely by the fact that compliance with the Large Combustion Plant Directive which requires reductions in sulphur emissions is not cost-effective for older less efficient plant. The amount of new coal plant expected to be built ranges from a minimum of zero (under the EWP low price scenario) up to what is probably a upper limit of 11.5GW of new capacity taking account of announced plans from the major power companies. The total contribution of this new coal build to total UK emissions would be in the range 0% to 11% of 1990 emissions assuming they would run unabated and at baseload capacity. If this level of coal plant could be replaced with emission-free generation, or met through additional demand restraint, then this full level of emissions could be avoided. On the other hand, the easiest substitute is probably gas plant, in which case the avoided emissions resulting from replacing new coal build with new gas would be halved to approximately 0% - 5.5% of 1990 emissions.

The most likely amount of new coal build lies somewhere in this range. Whilst some coal plant seems likely to be built, decisions will be sensitive to the outcome of decisions regarding new nuclear plant, and the large amounts of renewable capacity that would need to be built in order to meet the UK's contribution to the EU's target of 20% renewable energy (some estimates suggest that renewable energy would have to provide up to 35-40% of the UK's electricity demand in order to meet the overall primary energy target for renewables).

Given the challenge of meeting the UK's targets for CO_2 emissions by 2020, the contribution of emissions from coal could be significant. The question then arises whether policy-makers should be concerned about this source of emissions. This hinges on two key factors:

1. The role of carbon capture and storage (CCS)
2. The role of the EU emissions trading scheme (EU-ETS)

As described in Section 4, the cost of retrofitting CCS at a later date is not significantly higher than the cost of fitting the technology at the time the coal plant is built. Given that the price of carbon does not currently cover the additional costs of CCS, building coal plant with CCS is not economically viable unless separate support mechanisms are put in place. The government is committed to supporting one full-scale (300-400MW) demonstration plant in the UK based on post-combustion capture, and is currently carrying out a competition to identify a suitable site for this demonstration. The mechanism for financial support is not yet clear, but could include a guaranteed carbon price, a capital grant, or a combination of the two. In the absence of further CCS support mechanisms, any further coal plant built in the UK before 2020 will run unabated until the economic conditions justify retrofitting CCS. This may well not occur until after 2020 when experience of the technology from various demonstration projects around the world will be available, and the carbon price will presumably be getting higher in line with more stringent climate targets.

Allowing new coal plant in the UK to run unabated prior to 2020 would lead to higher cumulative emissions from within the UK national boundary than if new coal were not allowed to run unabated. However, in order to understand the implications for global emissions, we need to consider the role of the EU-ETS.

Figure 6.1 shows a schematic of the impact of increasing emissions in the UK by 30MtCO_2 as a result of building new unabated coal plant in the UK. This amount is purely illustrative, and does not constitute a projection. To put the figure in context, it is consistent with the amount of additional emissions that would result from replacing about 10GW capacity of new gas plant with new coal plant, or from replacing about 5GW of emission-free generation with new coal plant.

Case A shows the operation of the EU-ETS for Phase III (2012-2020) as set out in the Commission's latest proposals published in January 2008. In these proposals, the number of external credits from outside the EU-ETS (e.g. from the clean development mechanism CDM, or other sources) would be subject to the same quantitative limits as applied under Phase II of the scheme, i.e. 280 MtCO_2 per year. The total emissions arising from within the EU for all 27 Member States are therefore capped at a level of 2000 MtCO_2 per year (made up of the 1720 MtCO_2 EU-ETS cap plus the additional emissions that could be covered by CDM credits).

In Case A, if emissions from within the UK national boundary increase as a result of new coal build, the total emissions in the EU as a whole are unchanged – they will still be capped at 2000 MtCO_2. This works because UK companies would have to purchase emissions allowances to cover the additional emissions, thereby preventing other EU companies from using those allowances. The same would be true in reverse. Any emission reduction measures taken in the UK (such as a moratorium on new coal build) would simply free up additional allowances that would be used by other companies in the EU, leaving total emission unchanged. In both cases, the price of allowances would adjust accordingly (rising marginally in the case of additional coal build and falling marginally in the case of additional emission reduction measures).

Case B illustrates a situation in which the use of CDM credits is not limited. In this case, additional emissions within the UK national boundary could contribute to an overall increase in emissions from the EU region. However, the 'cap' of 1720 MtCO_2 in the EU-ETS would still stand, so additional credits would need to be purchased to cover these additional emissions. As long as emission reductions associated with CDM credits have real environmental benefits, then total equivalent emissions from the EU-ETS will remain at 1720 MtCO_2. This scenario of increasing dependence on CDM credits is only a second-best environmental outcome if the environmental integrity of CDM credits themselves is questionable.

We can also envisage a situation in which the maximum number of CDM credits allowed in Phase III is fixed (as per the Commission's proposal), but where the actual number being used falls short of this maximum limit. In this case, a rise in emissions within the UK could lead to an increase in the number of CDM credits being used. Again, this would only be of concern if the environmental integrity of CDM credits is questionable.

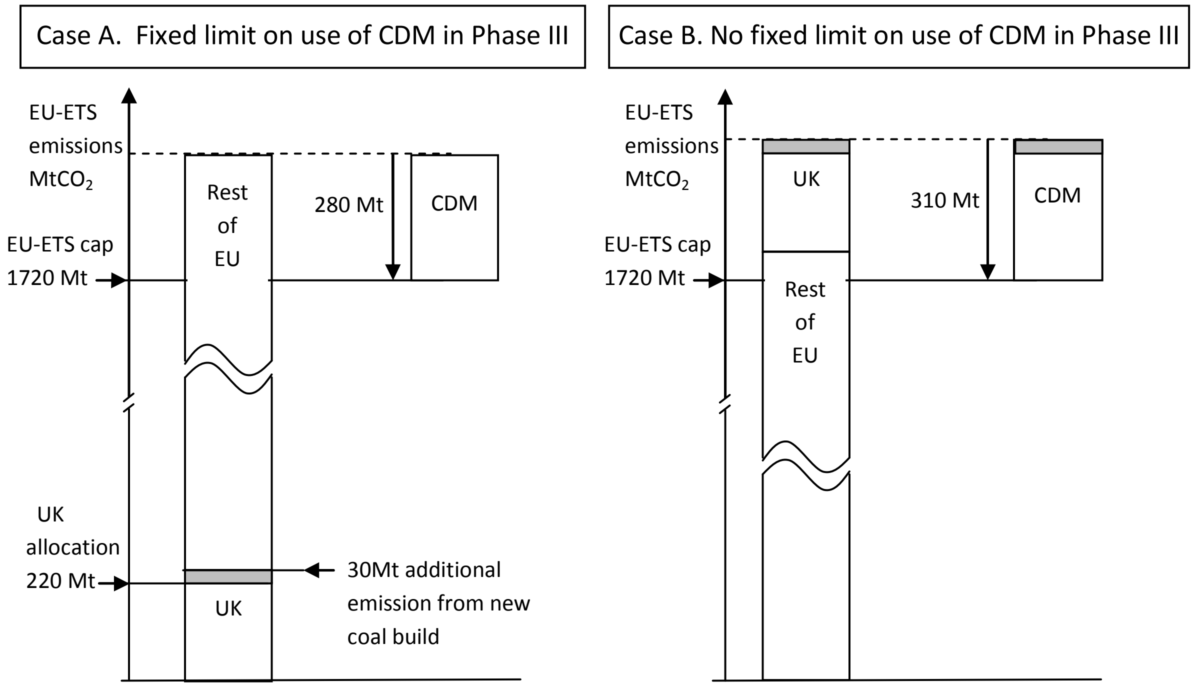

Figure 6.1 Impact of an additional increment of UK emissions in 2020 in the context of the EU emissions trading scheme

In conclusion, it seems quite likely that new coal plant will be build in the UK, and that apart from the UK CCS demonstration plant, these would run unabated up to 2020. Companies building coal plant will be taking commercial risks with respect to the possibility of a rapid increase in the price of carbon. However, this risk is partly mitigated by the possibility of retrofitting CCS at a later date, and by the portfolio benefits of maintaining a diverse range of generation plant. In the context of a fixed EU-ETS cap, relative increases or decreases of emissions within the UK national boundary have no net environmental impact as long as the EU-ETS itself remains a secure environmental instrument.