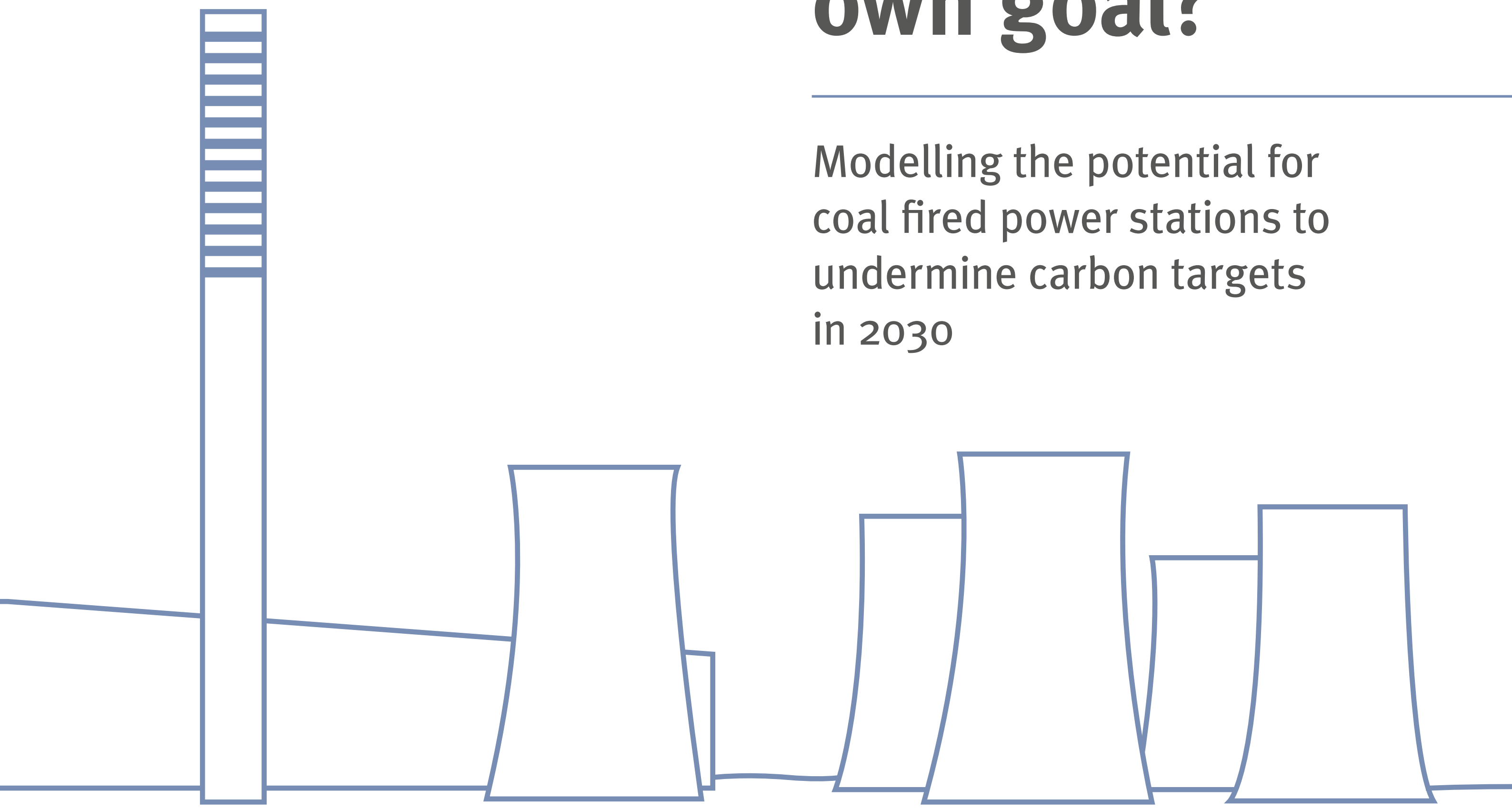
Imperial College London

# Could retaining old coal lead to a policy own goal?

## Modelling the potential for coal fired power stations to undermine carbon targets in 2030



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THIS REPORT SUPPORTS WWF'S VISION FOR AN ENVIRONMENTALLY SUSTAINABLE POWER SECTOR

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# Executive Summary

**Is there a long term role for coal?**
This report considers the long term future of coal fired power stations in the UK. It asks whether emerging market and policy conditions could encourage electricity generators to operate old coal-fired power stations until 2030 and beyond - to the detriment of the UK's legally binding target to reduce carbon dioxide emissions.

**Assuming coal away?**
Until recently the prevailing view amongst energy analysts was that existing coal fired power stations would close by the mid-2020s, with the exception of a small number converting to biomass. However it is becoming increasingly clear that neither the age of coal power stations nor the costs of complying with the EU Industrial Emissions Directive (IED) are necessarily impediments to the continued operation of coal fired power stations.

This is important because coal is carbon intensive, producing twice as much carbon dioxide as gas fired power stations (CCGTs) and orders of magnitude more than low carbon options such as wind power. Retaining old coal fired power stations threatens policy goals to decarbonise the UK electricity sector. Moreover, if market and policy conditions favour the ongoing operation of existing coal plant, this represents a risk to investment in replacement capacity such as gas, storage, demand response, interconnection and low carbon plant. Hence creating a self-fulfilling prophecy where coal has to operate to keep the system secure despite the implications for carbon dioxide emissions – an explicit and ongoing failure of policy.

**Modelling the market opportunity for coal**
This study uses a cost optimising engineering/economic model to explore how policy and market conditions might affect investment in maintaining and upgrading existing coal beyond the early 2020s in a range of different scenarios. The modelling explores the extent of any *market opportunity* for existing coal. It seeks to answer the questions:

1. **Are emerging policy and market conditions creating a greater incentive for coal plant operators to extend the lives of existing power stations through the 2020s?**
2. **How much coal might continue to operate, for how much of the time and what will the implications of this be for the UK's commitments under the Climate Change Act – in particular how would coal affect power sector emissions in 2030?**
3. **If old-coal threatens energy and climate policy goals how best can policy respond?**

The modelling incorporates a range of policy and market factors; the cost of keeping coal stations maintained and running, fuel costs, carbon prices, a range of costs for IED compliance and different levels of capacity payment through the capacity market (CM). A range of plausible scenarios is considered for each factor. The model tests sensitivity to these factors holding other key variables - such as demand growth, payments to low carbon generation through Contracts for Difference (CfDs) and technology costs – constant in a range of scenarios.

**Old coal should not be assumed away**

**In all our scenarios some old coal capacity is retained by the model and is still operational in 2030.** This suggests that coal plant operators are likely to have identified a credible market opportunity for continued operation through the 2020s.

**The amount of coal generation selected by the model to operate during the 2020s is primarily a function of the carbon price, in the absence of other policies to constrain the use of existing coal fired power stations.** This suggests that the view of plant operators on the future level of the Carbon Price Support will be a key driver of investment and operating decisions relating to coal out to 2030.

**Retaining coal spells climate policy failure**

**The continued use of unabated coal could significantly undermine the potential for Britain to meet targets for emissions from power generation in 2030 recommended by the Committee on Climate Change (CCC).**

The carbon intensities of power generation in Great Britain in our scenarios are much higher than the 2030 target of 50g$CO_2$/kWh recommended by the CCC as part of a least cost approach to cutting national emissions, and above central projections provided by DECC.

- In scenarios with a very low carbon price in 2030 up to 9 GW of unabated coal is retained by the model, generating up to 56 TWh of electricity, with power sector emissions of 240g$CO_2$/kWh.
- Even with the carbon price reaching £75/tonne in 2030 around 5 GW of old coal is retained, generating 8 TWh, in these scenarios emissions are 130g$CO_2$/kWh.

**Policy needs to give investors more clarity**

The behaviour of investors is driven by their perceptions of risk. Investments in coal and in other forms of generation are not independent of one another – a potential benefit or opportunity for coal (in particular policy weakening on the carbon price) represents an increased risk for investment in gas or low carbon plant.

Power sector investors face numerous risks post-2020. There is uncertainty about CfD payments to low carbon generators, uncertainty about the carbon price, as well as uncertain fossil fuel prices and demand projections. The modelling shows that the role of coal is highly sensitive to carbon prices. More targeted support for low carbon generation (through CfDs) could also significantly affect the role for coal. A regulation to cap carbon emissions from IED compliant coal would provide greater certainty that old coal will not run unconstrained throughout the 2020s. This would improve the prospects for investment in gas and low carbon generation in the 2020s, benefitting security of supply and helping to avoid policy failure.

The UK carbon price is vulnerable to political uncertainty given the direct impact on energy prices. Future CfD prices and availability of support for low carbon generation post 2020 are also uncertain. Greater policy clarity on the role of the CfD and on carbon prices would help secure low carbon investment and direct regulation on coal emissions would give investors more clarity.

**To ensure that coal does not threaten UK climate change goals we recommend the following:**

- **The carbon price is a key driver of investment decisions. Government should provide a clear trajectory for UK carbon prices in the 2020s and continue to support a strong carbon price through the EU Emissions Trading Scheme.**
- **Clear signals should also be provided on the availability of CfDs to drive growth in low carbon generation post 2020 and provide confidence to investors.**
- **Additional clarity for investors would also be provided if the Emissions Performance Standard is extended to existing coal that becomes IED compliant by 2023. Regulation would need to ensure that by 2030 old coal plants are strictly limited to very low operating hours, or closed.**



# Contents

# 1. Introduction

## Could there be a long term role for coal power stations in the UK and what would this mean for carbon targets?

### Overview

This report considers the long-term future of coal fired power stations in the UK[1]. It asks whether emerging market and policy conditions might encourage electricity generators to continue to operate coal power stations until 2030 and beyond, to the detriment of the UK's targets to reduce carbon dioxide emissions. The report also considers the impacts of extended operation of coal on security of supply and investment in gas and low carbon generation. It asks whether existing policy does enough to provide investors with clarity about the need to remove unabated coal from the generation mix by 2030 in order to meet carbon targets.

### Context

Until recently it was widely believed that most, if not all, of Britain's coal fired power stations would close by the mid-2020s (CCC 2010; DECC 2011). This is because GB coal fired power stations are old; most date from the 1960s and the newest (Drax) first opened in 1974[2]. Moreover, coal power stations are highly polluting and must comply with increasingly stringent air pollution regulations (the Large Combustion Plants Directive (LCPD) and Industrial Emissions Directive (IED)) (DEFRA 2012). This combination of age and the cost of compliance with the IED and LCPD – together with an expectation of rising carbon prices – led many analysts to discount the possibility of the continued operation of existing coal fired power stations beyond the mid to late 2020s. In short, many scenarios of the UK power sector to 2030 have assumed coal away.

This matters greatly in the context of the UK's legally binding commitments to reduce $CO_2$ emissions (Great Britain Climate Change Act 2008). The advice of the Committee on Climate Change (CCC), accepted by government, is that the UK should adhere to an interim carbon abatement target for 2030 and in particular should seek to substantially decarbonise the power sector by that time (CCC 2010; CCC 2013).

If decarbonisation targets are to be met, *any* role for coal needs to be carefully controlled. Coal is the most carbon intensive form of power generation, producing more than double the emissions of carbon dioxide ($CO_2$) per unit of electricity generated compared to modern gas fired plants (DECC 2014b). The potential for coal fired power stations to undermine long term carbon-abatement goals is substantial. Despite recent coal plant closures and the dash for gas of the 1990s and 2000s, Great Britain still has nine operational coal fired power stations, representing approximately 19 GW[2] or around one fifth of existing electricity generating capacity (DECC 2014b). In 2013 coal generated 131 TWh of electricity, or 36% of total UK generation.

Whilst around 8 GW of coal power stations have already closed (see Section 2.2), the future of the remaining ~19 GW is uncertain. At the time of writing it is not clear which coal plant operators will opt to fully comply with IED legislation and which will opt out to avoid the required investment and, therefore, it is unclear exactly if/when each plant is likely to close. The economics of coal plant will be affected by the UK's plans to increase the carbon price through the Carbon Price Support scheme (CPS), but also by the relative prices of coal and gas, cost of complying with the IED, by the introduction of the capacity mechanism (CM) and by the need for any other significant investments.

The long-term future of the UK carbon price is uncertain given ongoing discussions over the future of European Emission Trading Scheme (ETS) and the recent decision by the UK Government to freeze the level of the UK Carbon Floor Price until 2019 (HM Revenue & Customs 2014). Importantly, existing coal plants are not subject to any specific regulations related to $CO_2$. The ($CO_2$) Emissions Performance Standard (EPS) introduced as part of Electricity Market Reform (EMR) will only apply to new plants and there are no $CO_2$ related regulations requiring existing coal stations to close during the 2020s (DECC 2014d).

**In short any assumption that coal stations will inevitably close during the 2020s is highly questionable. It is important to assess how policy and markets might affect investment in and operation of coal plant until 2030.**

### Objectives for this report

This report sets out to explore the plethora of issues affecting the future operating decisions of UK coal plant operators and addresses these questions:

1. **Are emerging policy and market conditions creating a greater incentive for coal plant operators to extend the lives of existing power stations through the 2020s?**
2. **How much coal might continue to operate, for how much of the time and what will the implications of this be for the UK's commitments under the Climate Change Act – in particular how would coal affect power sector emissions in 2030?**
3. **If old-coal threatens energy and climate policy goals how best can policy respond?**

### Report structure

The remainder of the report is structured as follows:

- Chapter 2 discusses the range of factors influencing Britain's coal plant operators. It reviews the existing policy environment, including the form of the Industrial Emissions Directive (IED) (EC 2010), and various aspects Electricity Market Reform (EMR) (DECC 2014d). It examines the capital and operating costs associated with extending the life of the coal fleet, and the specific capital and operating costs associated with compliance with the tightening emissions legislation under the IED. The chapter reviews projections of future economic conditions that will influence the market opportunity for coal plant: the price of coal, carbon price, the price of competing gas, and the wholesale price of electricity.
- Chapter 3 tests the implications of factors exposed in the previous chapter by modelling a range of assumptions for each. It is based on analysis using the GB Power model of the UK TIMES modelling framework to investigate the impact of policies and other economic factors on the potential future operation of the existing coal fleet (Hawkes 2014). This includes examining the implications of CPS, fuel prices, the costs of life extension and IED compliance, and the influence of capacity payments.
- Chapter 4 reviews the implications of our modelling for carbon emissions and discusses the implications for electricity markets and investment, discussing both the future operation of existing coal fired power stations in the UK and the potential for impacts on investment in other forms of generation. It considers the importance of policy certainty for investment and derives policy implications.
- Chapter 5 provides a review of the main findings of the report and presents our conclusions and recommendations for policymakers.

[1] This report focuses on and discusses UK policies however we restrict our modelling and analysis to England, Scotland and Wales because power stations in Northern Ireland operate in the slightly different context of the All-Ireland electricity Market. Additional to the coal fired power stations discussed herein is the 520 MW coal fired power station at Kilroot in Northern Ireland. When referring to policy we discuss 'the UK' and when discussing power system operation we refer to GB or Britain.

[2] See Annex 1 for details of the existing coal fired power station fleet

# 2. Lifting the veil

## What key factors influence future coal plant operation?

### 2.1. Introduction

In order to investigate the likely decisions of coal plant operators in the future it is important to fully understand the range of factors influencing those decisions. UK coal plant is operated by commercial companies and the decisions they make are therefore commercial in nature, focusing of the costs of operation, and the revenues available on the electricity market. However, a number of policies affect the costs of operation significantly, and the conditions within which coal plant must operate.

In this chapter we first focus on the policies impacting on the decision making of UK coal plant operators. This includes legislation to control the emissions of gases and particulates from industrial plant, and the policy measures recently designed to reform the UK electricity market (EC 2010; DECC 2014d). The chapter then examines the costs of operating coal plant, the costs of extending its operational lifetime and the costs of compliance with industrial emissions legislation. Finally the chapter examines a range of economic conditions likely to affect the decision-making of coal power plant operators in the future, including the price of coal, the price of gas and the wholesale electricity price.

### 2.2. The policy framework

Two types of policy intervention have a significant impact on existing UK coal power stations: policies designed to regulate industrial emission of atmospheric pollutants and policies designed to regulate the electricity market. In the UK the Industrial Emissions Directive (IED) (EC 2010) regulates the emission of atmospheric pollutants, while Electricity Market Reform (EMR) is having profound impacts on the operation of the UK electricity market (DECC 2014d). Below we describe these policy regimes in more detail, focusing on their impact on the operation of the existing UK coal power station fleet.

#### Legislation to control industrial emissions

In October 2001 the EU Large Combustion Plant Directive (LCPD) was published, requiring member states to begin a process of emission reduction for industrial plant with a thermal rating of 50MW or greater, including existing coal power stations (EC 2001). The directive was designed to limit the emissions of sulphur dioxide ($SO_2$), nitrogen oxides ($NO_X$) and particulate emissions. Plant built before 1987, which includes all the UK's coal power stations, were required to commit to one of three options by the 1st of January 2008. These options were:

- Comply, plant by plant, with the emissions limit values specified in the directive;
- Enter a National Emissions Reduction Plan (NERP), whereby participating plant meets collective emissions reduction targets, and can trade their emissions allowances; or
- 'Opt-out' of the LCPD and agree to operate no more than 20,000 hours between 1st of January 2008 and the 31st of December 2015 (EC 2001) and close.

Of the sixteen coal power stations operating in the UK in 2008, six chose to opt-out of the LCPD, and have subsequently closed (Figure 1). These six plants contributed 8GW of the 28GW of coal fired electricity generating capacity in 2008. A seventh plant, Uskmouth B, opted into the LCPD but subsequently closed in 2014 after operator SSE failed to find a suitable purchaser. ~19GW of coal fired electricity generating capacity are therefore LCPD compliant and remain in operation.

In January 2011 the EU Industrial Emissions Directive (IED) came into force, rationalising several separate directives, including the LCPD, into one. The IED requires industrial plant, including the UK's existing coal power stations, to reduce $SO_2$, $NO_X$ and particulate emissions in order to meet more stringent emissions limit values (ELVs) than previously required under the LCPD (Table 1).

Under the IED coal power station operators wishing to continue operating after 31st December 2015 have three options. Plant can:

- be entered into the Limited Life Derogation (LLD) and be exempt from the ELVs, provided the plant is closed after 17,500 hours of operation from the 1st January 2016 or closed by 31st December 2023, whichever is first;
- enter a Transitional National Plan (TNP), which defines a maximum combined emissions ceiling for all participating plant for each of the three pollutants covered in the IED, declining over time and permitting decision making over full IED compliance to be delayed until 2020; or
- become fully compliant on a plant by plant basis with the ELVs mandated in the IED.

ELVs are set based on the total rated thermal output of plant, and type of fuel. The ELVs applying to coal power stations in the UK are set out in Table 1. However, these limits are subject to amendment if Best Available Technology (BAT) improves, facilitating more stringent ELVs. The consultation draft of the Large Combustion Sector BAT reference guide (JRC 2013) proposes the $NO_X$ ELV for plant larger than 300MW tightens from the 200mg/Nm$^3$ quoted in Table 1 to 65-180mg/Nm$^3$.

**Table 1: the emissions limit values for coal fired power stations as set out in annex v of the industrial emissions directive**

| | Emissions in mg/Nm$^3$ | | |
|---|---|---|---|
| Total rated thermal output (MW) | $SO_2$ | $NO_X$ | Dust |
| 50-100 | 400 | 300 | 30 |
| 100-300 | 250 | 200 | 25 |
| >300 | 200 | 200 | 20 |

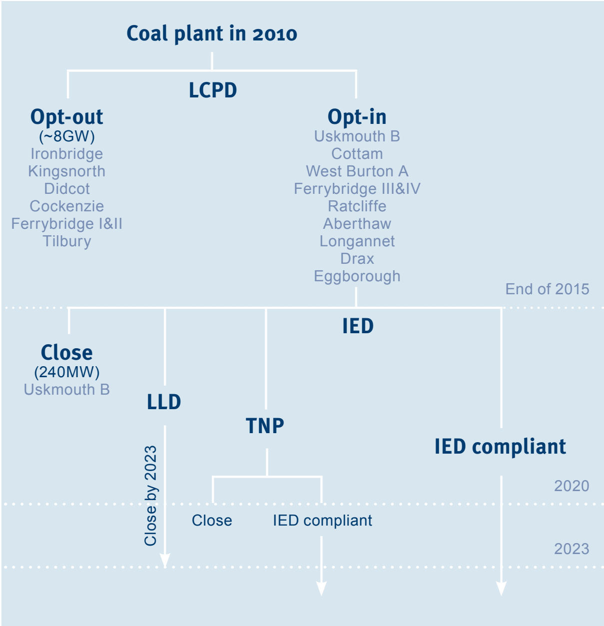
Source: (EC 2010)

The TNP creates an emissions ceiling for participating plant that is set to descend linearly, beginning in 2016 with a ceiling equivalent to emissions limits "at least as stringent" as those in existing permits applicable on 31st December 2015 (EC 2010; DEFRA 2011). This then descends to a ceiling in 2019 equivalent to the ELVs set out in Table 1. During the period from 2016 to 2020 a plant's proportion of the emissions ceiling may be partially transferred to any other plant, mirroring the existing arrangements under the LCPDs NERP, and therefore allowing for trade of emissions limits between operators.

Reduction of $SO_2$, $NO_X$ and particulate emissions in existing power stations is achieved by retrofitting some form of abatement technology. Doing so entails capital and operating costs, and may also reduce plant efficiency. This additional cost is a significant factor affecting the decision of coal power station operators when deciding on the options presented by the IED. The costs associated with IED compliance are discussed in more detail in the 'The Costs of Coal' section below.

At time of writing there is uncertainty about the intentions of coal plant operators regarding the IED. All plant has a free choice between LLD, TNP and full IED compliance until January 1st 2016. In some cases plant that had previously announced IED plans have subsequently recanted, making it difficult to predict the final picture for coal fired power stations by the Jan 2016 deadline. For example RWE announced in January 2014 that it was opting Aberthaw out of complying with the IED and would consider the LLD (Utility Week 2014). In July 2014 RWE announced that it was investing £12 million installing 'low $NO_X$ boiler technology in one generating unit as part of a wider aspiration to be IED compliant by January 2016 (RWE 2014). However, in August 2014 it was revealed that the UK is lobbying the European Commission for derogation allowing Aberthaw power station to operate above the $NO_X$ emissions limits set out in the IED (Mathiesen 2014)[3].

**Figure 1:**
**LCPD and ied decision tree for existing coal fired power stations**[4]




## Electricity market reform

Electricity Market Reform (EMR) is a suite of electricity market policies aimed at delivering a decarbonised electricity system while maintaining sufficient generating capacity and minimising consumer costs (DECC 2014d). EMR was introduced because of concerns that existing policies would either not deliver policy goals or would do so at higher costs than necessary. In particular, EMR was intended to reduce investment risks, both in low carbon plant and in flexible capacity/demand response. EMR has several parts including:

- Contracts for Difference (CfD), which provides a subsidy for low carbon electricity generation;
- Emissions performance standards (EPS), which sets limits on carbon emissions of new electricity generating plant;
- Capacity Mechanism, which pays generators (and demand side response, storage and interconnectors) to guarantee levels of capacity four years in the future; and
- Carbon Price Support (CPS) which forces UK electricity generators to pay the difference between the EU ETS price of carbon and an administratively set Carbon Price Floor (CPF)

CfDs are the main mechanism through which low-carbon generation will be subsidised. Coal fired electricity generation is not eligible for these contracts given its carbon emissions. The EPS sets a statutory limit on the amount of annual $CO_2$ emissions from new fossil fuel power stations, to 450g$CO_2$/kWh operating at baseload (DECC 2013b). The policy only applies to new power stations and therefore existing coal power stations are not subject to the EPS. The remaining elements of EMR are the capacity mechanism and CPS. Both of these apply to existing coal fired power stations and are worth further discussion.

## Capacity Market

The objective of the capacity market is to encourage investment in and retention of capacity, which can include new and existing power stations, electricity storage and demand side management (DSM) and in the future interconnected capacity, such that there is an adequate level of electricity capacity to meet future needs, thereby ensuring the security of future electricity supply (DECC 2014c). In particular, the capacity mechanism is intended to ensure that there is enough capacity to reliably meet peak demand, which in Britain occurs on cold winter's evenings. The UK faces three important pressures on future capacity:

1. A significant proportion of existing electricity generating plant is expected to close due to age and non-compliance with emissions legislation
2. A proportion of the electricity generating capacity expected to come online in the future will be intermittent renewables, which will reduce emissions and reduce overall dependence on fossil fuels. However it is also essential that peak demand can be met reliably – through investment in demand response, interconnection, storage and flexible plant.
3. Overall demand for electricity is uncertain but is expected to increase during the 2020s as a result of the electrification of our transport and heating systems (DECC 2014c; DECC 2014d)

Britain does not currently have a capacity mechanism (although it did in the 1990s), because it was believed that markets would deliver capacity without the need for explicit payments to do so. In liberalised energy markets investors may be expected to build generating capacity in anticipation of the high returns they could earn at times of 'system stress' where



electricity prices are likely to be high (DECC 2014d). It is important to note that there is contestation around the need or otherwise for a capacity market and indeed how best to design such a market. Internationally and historically a range of approaches have been taken – some markets have/had such mechanisms others not. However, UK policymakers have become concerned that imperfections in the market could mean that the market fails to bring forward sufficient capacity (DECC 2014d). The principal concerns are referred to as 'missing money', which arises for three reasons (DECC 2014d):

1. Current wholesale energy prices do not rise high enough to reflect the value of additional capacity at time of scarcity. This is due to the charges to generators who are out of balance in the Balancing Mechanism ("cash-out") not reflecting the full costs of balancing actions taken by the System Operator (such as use of reserve capacity or customer disconnections)[5].
2. Stress events are unlikely to occur frequently. With an increasingly decarbonised power sector, investors face uncertainty about operating hours and so will be increasingly reliant on recovering fixed costs through infrequent and uncertain periods of high prices. This may make it more difficult for plant owners to obtain low cost finance.
3. At times when the wholesale energy market prices peak to high levels, investors are concerned that the Government/regulator will act on a perceived abuse of market power, for example through the introduction of a price cap (DECC 2014d; DECC 2014c).

The capacity market is designed to address this market failure by providing financial incentive for future capacity investment, thus replacing the 'missing money'. The structure of the UK capacity market is set out in the EMR implementing document (DECC 2014d) and summarised in Box 1 overleaf.

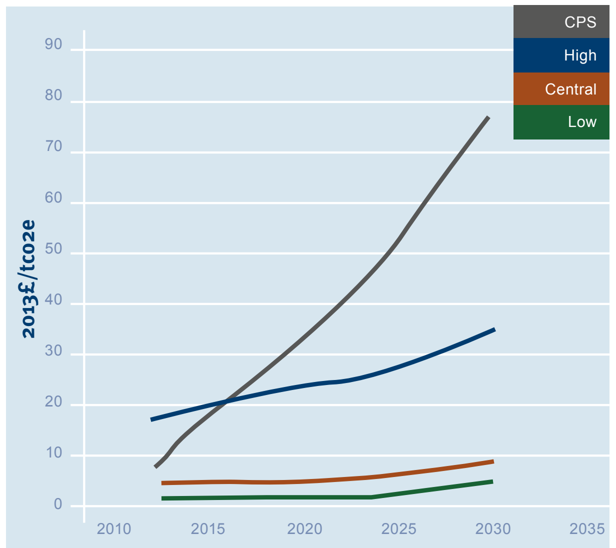
## Carbon Price Support (CPS)

The EU Emissions Trading Scheme (EU ETS) was established to create a price on carbon emissions for Europe's larger emitters of $CO_2$. However, a number of factors, including over allocation of permits, the success of other decarbonisation policies and the economic recession have contributed to a very low carbon price (Ares 2014). To remedy this the UK government introduced Carbon Price Support (CPS) in 2013, which requires power stations burning fossil fuels to pay any deficit between the EU ETS carbon price and a pre-determined Carbon Price Floor (CPF) (Ares 2014).

The intention of the policy was to have a rising CPF between 2013 and 2030, with DECC forecasting the CPF reaching approximately £75/t$CO_2$ in 2030 (Figure 2). DECC present four scenarios of the future carbon price (Figure 2). Three of those forecast a low, central and high EU ETS carbon price without the additional cost of CPS while the fourth presents an EU ETS plus CPS scenario.

In 2014 the UK Government announced reform of the CPS, freezing it at £18/t$CO_2$ from 2016 to 2019 (HM Revenue & Customs 2014). Because the EU ETS price is lower than was expected when the CPF was introduced, the purpose of this reform is to protect UK firms from the increasing gap between the EU ETS carbon price paid by European firms and the CPF, paid by UK firms. This reform dramatically alters the level of the CPS in the short term, but at the time of writing there has been no revision to the longer term scenarios. DECC has not signalled any intent to reduce long term ambition, but it is not clear what form the trajectory might take beyond 2019. Given uncertainty over further changes to the CPS, and uncertainty over ETS prices, it appears that the potential carbon price faced by electricity generators during the 2020s lies in a range. We return to this in Part 3.

**Figure2:**
**DECC forecast of future EU ETS carbon price and the impact of carbon price support**




Source: (DECC 2013c)

**Box 1 – the Capacity market**

**How does it work?**

The capacity market will pay capacity payments to generators to guarantee a certain level of capacity four years in the future. Capacity providers will bid in competitive auctions for these capacity payments, with the goal of clearing a fixed level of desired capacity. This capacity level is determined by an annual security of supply assessment conducted by National Grid (the delivery body), and a capacity demand curve, established by government, allowing for the trade-off between security and cost to be automatically established at auction.

**Who can bid?**

Electricity generation, demand side response and electricity generation, demand side response and electricity storage are all eligible in the capacity market. Government has committed to allow interconnected capacity to bid from 2015 onwards. Any new or existing electricity generating capacity can bid in the auctions provided it does not:

- Receive any other type of support, such as the Renewables Obligation (RO) or Contracts for Difference (CfD);
- Hold a long-term contract to provide Short-Term Operating Reserve (STOR); or
- Provide capacity from outside the UK delivering to the UK market through interconnection.

Existing coal fired power stations can therefore bid in the capacity auctions and are eligible to receive payments.

**Contract length**

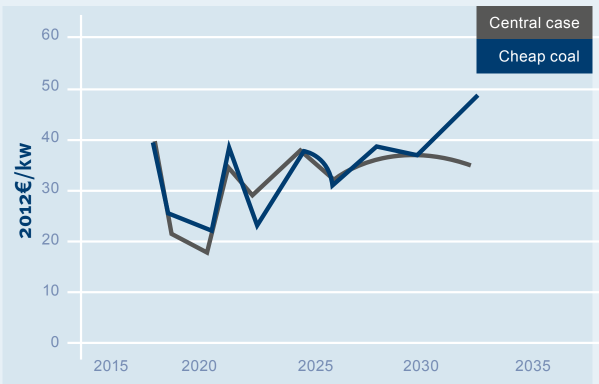
The first capacity payments will be paid for capacity in 2019, auctioned at the end of 2014 and the capacity contract will last for one year. However, for plants undergoing retrofit in order to deliver future capacity, and spending over £125/kW, 3 year capacity contracts will be available, providing the necessary certainty to encourage these types of retrofit investment. This would mean that retrofit plant bidding successfully would not need to re-enter the capacity auction for a further three years, and would get the same capacity payment over the three years in which the capacity is delivered. Existing coal plants are eligible for these contracts. For new capacity spending over a £250/kW threshold, 15 year contracts will be available, increasing the certainty to investors in these projects. DECC have undergone consultation on the rules governing these 15 year contracts and the rules are likely to be amended to ensure that only new or substantially new build electricity capacity will be able to access these contract lengths (DECC 2014a). Existing coal will therefore not be eligible for these 15 year contracts.

**What can be expected in terms of payments?**

The value of capacity payments is determined through auctions and constrained within certain limits defined in the implementing document (DECC 2014d). A payment cap is set at £75/kW. DECC present two forecasts of capacity payments from 2019 (the first year capacity payments will be available from) to 2030 (Figure 3). The first forecast assumes DECCs central estimates for fossil fuel prices while the second forecast assumes DECCs low coal price forecast (See 'The economic conditions' below). This is to test the impact of an increasing differential between coal and gas prices on the resulting capacity auction price. DECC conclude that a "change in relative price between gas and coal has had little impact on the energy market rents of the marginal plant in the Capacity Market".

DECC 2014d

**Figure 3:**
**DECC forecast for future capacity payments under central and low coal prices**




Source: (DECC 2014c)

## 2.3. The costs of coal

There are a number of costs associated with the operation of existing coal plant. These include fixed and variable operating costs, the costs of extending the life of ageing coal plant, and the costs of complying with emissions legislation. Other factors affecting the economics of coal plant operation including the cost of carbon and capacity payments are discussed separately above.

One of the factors that affect overall costs is ongoing operation and maintenance (O&M). Recent data from UK government sources suggests that the O&M costs for coal plant tend to be high relative to gas, even for more modern plant (see Table 2).

**Table 2: fixed O&M costs of fossil fuelled electricity generation (£2010)**

| | |
|---|---|
| Coal | £56/kW |
| Gas CCGT | £26/kW |
| Gas OCGT | £21/kW |

Source: Mott Mott Macdonald (2010)

The additional costs of extending the lives of old coal plant are not all captured by this high operating cost. In analysis for the UK government, engineering consultants Parsons Brinkerhoff (PB) contend that many coal plants will need to replace main steam pipework to maintain operation into the future. This replacement costs £16/kW, and is estimated to provide a further 10 years of operation (PB 2014).

The final cost associated with coal plant is compliance with IED regulations. In order to meet the ELVs set out in the directive coal plant will have to retrofit emissions abatement technology, with an associated cost.

To meet the IED $NO_x$ emissions limits there are a number of different combinations of technologies that might be employed. These include combustion and post combustion techniques. Of these techniques only selective catalytic reduction (SCR) and a hybridisation of this with selective non-catalytic reduction (Hybrid SCR/SNCR) are capable of reducing $NO_x$ emissions sufficiently to meet the ELVs set out in the IED. SCR and Hybrid SCR/SNCR have both capital and operating costs. The capital costs of retrofit of these technology options vary widely, reflecting the plant specific issues and the range of different SCR options. Parson Brinkerhoff estimate a low, medium and high capital cost for SCR retrofit, and a low and medium cost for the Hybrid SCR/SNCR option (PB 2014) (Table 3).

**Table 3: estimated capital costs of $NO_x$ abatement options**

| | |
|---|---|
| Low SCR | £100/kW |
| Med SCR | £130/kW |
| High SCR | £200/kW |
| Low Hybrid | £86.7/kW |
| Med Hybrid | £97.5/kW |

Source: PB (2014)

These $NO_x$ abatement options also have an operating and maintenance cost. This includes the cost of reductant (ammonia or urea), replacement of catalyst, cost of auxiliary power use, and losses in power station efficiency. Parsons Brinkerhoff estimate low medium and high fixed and variable operating costs for SCR operation, and low and medium variable operating costs for Hybrid SCR/SNCR[6] (Table 4).

**Table 4: estimated operating costs of $NO_x$ abatement options**

| | |
|---|---|
| Low SCR | £1,345/MW/yr and £0.2/MWh |
| Med SCR | £1,345/MW/yr and £0.35/MWh |
| High SCR | £1,345/MW/yr and £0.5/MWh |
| Low Hybrid | £8,517/MW/yr |
| Med Hybrid | £8,517/MW/yr |

Source: PB (2014)

Drax have stated that they can meet IED compliance for $NO_x$ more cheaply than estimated by PB (Drax 2014). Application of abatement measures to all six generating units is estimated to cost between £75 and £100 million, or ~£25/kW. The applicability of this approach for other power stations is not known.

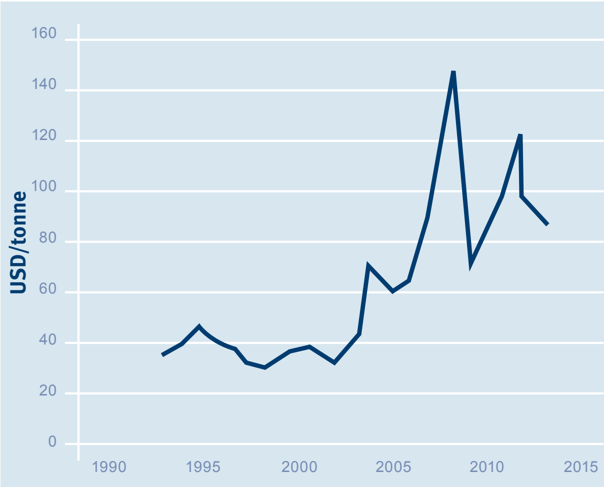
## 2.4. The economic conditions

The economics of coal plant operation are dependent on a number other economic factors which are incurred as costs or impacts on competitiveness. These include the coal price, the gas price, and the wholesale electricity price.

**Coal price**

The coal price is a cost to coal power stations and with all other costs fixed a rising coal price decreases the competitiveness of coal fired power stations. The coal price has steadily risen since the 1990s. However, in recent years the European coal price has decreased, driven by the displacement of coal by shale gas in the US, leading to price reductions in other markets (Figure 4).

**Figure 4:**
**Coal price in northwest Europe from 1993 to 2013**

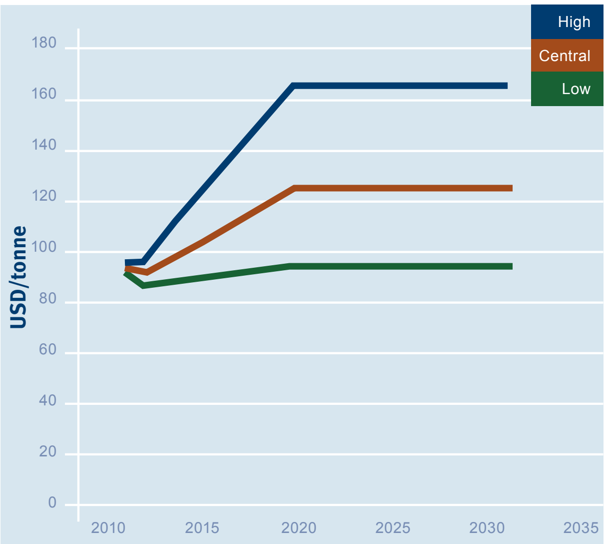



Source: BP (2014)

Future coal prices are therefore a fundamental input to the modelling undertaken in this study. We use UK government projections. DECC presents three scenarios of the future coal price: High; Central; and Low (Figure 5). The central forecast to 2015 is based on forward prices, then interpolated to 2020 (DECC 2013a). From 2020 to 2030 the central estimate is based on the relationship between coal and gas prices (DECC 2013a).

The high forecast is based on forward prices to 2015, inflated by 5% in 2013-2014 and by 10% in 2014-2015. Interpolation is then used out to 2024, and from 2025 to 2030 based on long term cost estimates (DECC 2013a). The low forecast is based on forward prices to 2014 and interpolation to 2020.

**Figure 5:**
**DECC coal wholesale price forecasts**



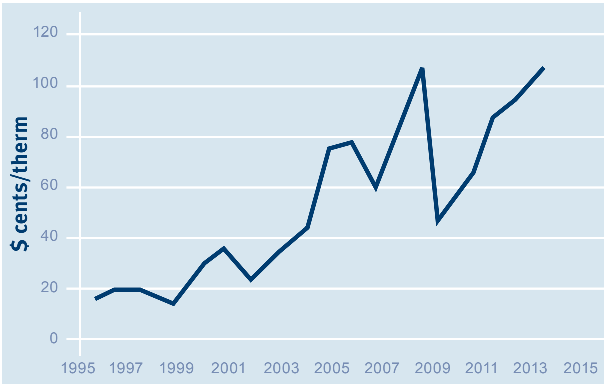

Source: (DECC 2013a)

### Gas price

The gas price can influence the operation of coal power stations by changing relative competitiveness of coal and gas fired power stations. If other variables are constant a reduction in the price of gas reduces the competitiveness of coal fired power stations. As noted above, the marginal cost of coal and gas has a direct impact on which power station is higher in the 'merit order', plants with highest 'merit' (lowest marginal cost) run first (Stoft 2002). In recent years, changes in the relative price of gas and coal have led to marked shifts in the operating hours of coal and gas plants (DECC 2014b).

Figure 6 shows historical developments in UK gas prices. Even allowing for a sharp downturn with the onset of the global financial crisis in 2008 the gas price in the UK has maintained an upward trajectory since 2003, despite the developments in US shale gas and the descending US gas price.

**Figure 6:**
**UK national balancing point (NBP) gas price**



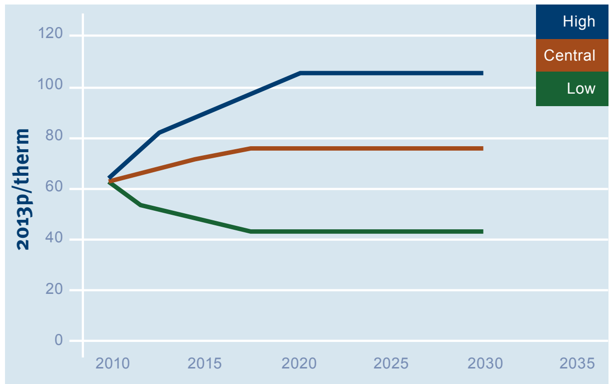

Source: BP (2014)

For the purposes of this study it is important to consider gas price movements over the period to 2030, so that gas as well as coal prices can be factored into our modelling. The UK government presents Central, High and Low gas price forecasts (Figure 7). In the Central forecast DECC assumes the UK gas price is linked to oil prices with an 11% discount until 2017-2018. This link is applied to DECCs Central oil price forecast. From 2018 to 2030 this link is assumed to break, and the gas price is assumed to be 74p/therm, based on estimates of long scenario marginal cost (DECC 2013a).

The High forecast assumes a linking of the gas and oil price to 2020, based on DECCs High oil price forecast. From 2020 to 2030 the oil and gas prices are assumed to delink, and fixed at 105p/therm. The Low forecast assumes that the gas price falls from current levels to a long scenario price of 42p/therm.



**Figure 7:**
**DECC gas price forecasts**

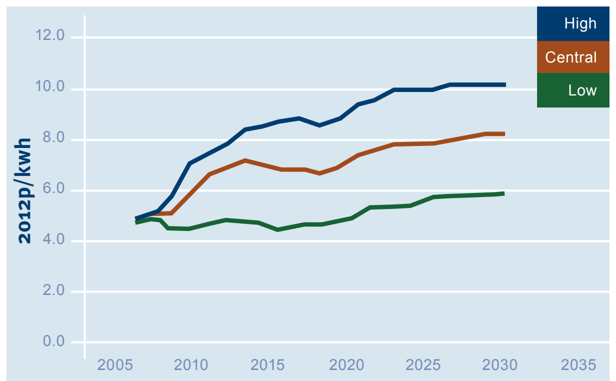



Source: (DECC 2013a)

### Electricity price

The wholesale electricity price influences the operating decisions of and revenues recoverable by power stations. However, wholesale prices are not independent of fuel prices and other costs associated with power generation, rather they emerge from a complex interaction between plant mix (for example the shares of low carbon plant, gas, coal, and degree of interconnection), policy (for example carbon prices) and the price of fossil fuels (Gross *et al.* 2007). Therefore, unlike fuel prices, electricity price is not an input to the modelling undertaken for this study, rather the model optimises to minimise overall system costs. Nevertheless it is important to note that UK wholesale power prices, like coal and gas prices, are subject to considerable uncertainty. DECC present several future wholesale electricity price forecasts (DECC 2012). We present their Central, High Price and Low Price forecasts in Figure 8. DECC base their forecasts on the short run marginal cost of generation including carbon price impacts and a mark-up based on historical data.

**Figure 8:**
**DECC wholesale electricity price forecasts**




Source: (DECC 2012)

### CfD prices in the 2020s

Contracts for difference (CfDs) will only be available for new coal with CCS and so cannot provide a direct incentive for investment in existing coal capacity. However, the role of CfDs in driving investment in low carbon plant will have a profound impact on the overall mix of power stations generating in the 2020s, hence on electricity price formation and on the market opportunity for coal. At the time of writing CfD strike prices have been set by technology type for renewable energy until 2019 (with auctions for mature technologies) and the Government has agreed a strike price through the commercial agreement with EDF for the first new nuclear power projects at Hinckley Point C and Sizewell C[7]. However, the strike prices, level of ambition and degree of technology differentiation in the CfD scheme beyond 2020 have not been announced by the Government. The Government has expressed an intent to move to technology neutral auctions in the 2020s and ultimately for an outcome where 'technologies are mature enough and the carbon price is high and sustainable enough to allow all generators to compete without intervention'[8]. In the modelling described in Part 3 below we provide a simplified representation of the CfD that aligns with these aspirations.

## 2.5 Chapter summary and conclusions

### Air pollution legislation

Coal power stations are significantly affected by legislation to control air pollution emissions from industrial plant. Around 8 GW of coal plant recently closed due to the LCPD and around 19 GW of coal plant is currently operational. The remaining plant can choose whether to comply fully with the IED, enter into a transitional national plan (TNP) or operate for a limited amount of time and then close (LLD).

- At time of writing there is uncertainty about the intentions of coal plant operators regarding the IED. All plant have a free choice between LLD, TNP and full IED compliance until January 1st 2016. In some cases plant that had previously announced IED plans have subsequently recanted, making it difficult to know the final picture for coal fired power stations by the Jan 2016 deadline.

**Electricity market reform**
The revenues available to and costs faced by coal plants will also be affected by the provisions of Electricity Market Reform (EMR), a suite of electricity market policies aimed at delivering a decarbonised electricity system while maintaining sufficient generating capacity and minimising consumer costs (DECC 2014d). Since existing coal is not subject to the emissions performance standard and cannot secure a contract for difference, the two provisions of most relevance to coal life-extension are:

- Capacity Mechanism, which pays generators (and demand side response, storage and interconnectors) to guarantee levels of capacity four years in the future; and
- Carbon Price Support (CPS) which forces UK electricity generators to pay the difference between the EU ETS price of carbon and an administratively set Carbon Price Floor (CPF)

Coal plant will be eligible for capacity payments, available to investors retrofitting older plants, set for 1 to 3 years, determined by auction under a price cap of £75/kW. Coal-plants will be subject to a carbon price of up to £75/tonne $CO_2$ in 2030. There is currently uncertainty over the future trajectory that the carbon price will take.

[3] Aberthaw has operated historically on an exemption from emissions legislation on the basis that it burns local coal and therefore protects local industry (Mathiesen 2014).

[4] Derogation is available for plant to leave the TNP if operating less than 1,500 hours annually averaged over 5 years. This derogation relaxes the $NO_x$ and $SO_2$ emissions limit values and must be taken by 1st July 2020.

[5] Ofgem are currently reforming the Balancing and Settlement Code (BSC) which includes cash-out arrangements in order to try to make the arrangements more cost reflective. These reforms may affect the differential between charges to out-of –balance operators and the costs of balancing actions taken by the system operator (Ofgem 2014). Nevertheless, concerns remain as it is technically challenging to be fully cost-reflective within the UK cash out/balancing mechanism system.

[6] Parsons Brinkerhoff note that "Hybrid cost would in reality consist of a fixed and variable amount, but this is estimated as fixed only".

[7] Contract for difference prices described at *https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/360269/Updated_Final AF.pdf* and press release on Hinkley.

[8] *https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324176/Implementing_Electricity_Market_Reform.pdf*



# 3. Running the numbers

## Modelling future coal generating scenarios

This chapter introduces a number of scenarios, modelled in the TIMES environment and used to explore the factors influencing the future operation of coal fired power stations. The model identifies a least cost way to meet demand, subject to various assumptions (for example about costs) and constraints (for example about build rates or availability to meet peak demand). If coal plant is scheduled to run in such an optimisation model this suggests there may be an opportunity for coal to operate profitably in a competitive market (we discuss real world investment choices in Part 4). The modelling environment is briefly introduced before discussing the assumptions informing the scenarios run, and the results of these scenarios in terms of future coal capacity, energy generation, and $CO_2$ emissions.

### 3.1. The Modelling

This report asks whether there are possible future conditions that might encourage the operators of existing coal plant to make the investments that will allow continued operation after the early 2020s. In short – will there be a market opportunity for coal power? The British electricity market is liberalised and privately owned. Investment and operating decisions will be the outcome of choices by diverse and independent market participants. However it is possible to analyse the fundamental economic drivers at play by using a model of the electricity system, under various assumptions about prices, costs and policies.

The various economic and policy conditions that will inform the future decision making of coal plant operators are discussed in Part 2. In order to test the impact of these conditions, examine the range of possible structural changes in the electricity system and their impacts on the prospective economic choices of coal plant operators we employed the TIMES modelling framework (see Annex 2) to investigate six different scenarios, representing a range of different future conditions that operators may anticipate. By examining the modelled outcomes to a range of scenarios we can explore the future market for existing coal plant under different conditions.

The model used here (the "GBPower" TIMES model) has been adapted for this project, was developed at Imperial College London and has been published in Hawkes (2014). It represents a partial equilibrium model of the British power sector, characterising fuel prices, electricity demand and power sector investment and dispatch for each class of technology present in the system from 2010 to 2050 and beyond. The basic structure and sources of input data for the model are summarised in Annex 2.

GBPower was adapted to investigate the possibility of life extension of the existing coal fleet. This was achieved via creation of three options for existing coal plant in 2016:

1. **Closure;**
2. **IED opt out and entry into LLD, with plant choosing this option forced to close in 2023; and**
3. **IED opt-in at a cost equivalent to IED compliance cost, with plant choosing this option not forced to close until 2030[9].**

### 3.2. The scenario assumptions

In this report we examine six separate scenarios. In these scenarios we vary six different assumptions: the coal price; the gas price; the carbon price; the cost of IED compliance; the value of capacity payment and build rates for gas and low carbon plants[10]. These assumptions are important as they represent the most significant aspects of future policy and economic conditions likely to affect the future operation of existing coal fired power stations.

The scenarios chosen seek to be exploratory rather than exhaustive. They explore a variety of plausible future conditions and in particular to assess what happens to coal under plausible conditions when any *assumption* of coal closure is removed. The modelling does not indicate that coal is retained in each and every imaginable scenario, or *each and every* possible out-turn in terms of plant mix and emissions, since this exercise does not consider every possible future state. However we have chosen six reasonably plausible combinations of existing data on key factors. The scenarios are as follows:

The *high CPS scenario* represents the best central estimates found in the literature including DECC's central forecast for coal price and gas price. In this scenario the carbon price rises to £75/tonne in line with the current published trajectory (including carbon price support[11]) (DECC 2012; DECC 2013c; DECC 2013a). The cost of IED compliance is taken as the cost of selective catalytic reduction in the central case in Section 2.3 (PB 2014) with the exception of Drax, for which we use Drax stated IED compliance costs presented in Section 2.3. The value of capacity payments is taken as the average of the DECC central case, presented in Section 2.2.

The *Low CPS* scenario tests the impact of carbon price support on the model outcomes by removing CPS from the carbon price assumptions. As we discuss in Section 2.2, the trajectory for carbon prices during the 2020s is uncertain at the time of writing. Given the decision to reduce the CPS until 2019 it is not yet clear whether and by what trajectory CPS will return to the level originally planned. However, the Government has not signalled any intent to reduce the aspiration for carbon price in 2030. Therefore the modelling tests a plausible upper and lower range of carbon price outcomes. The upper limit is £75/tonne as set out in current projections for the CPS and we take as a lower bound DECC's central projection for the ETS price in 2030. Whilst it is possible to envisage any number of intermediate levels of carbon price the objective of this analysis is to test the response of the model to a plausible range.

The *High IED and Low IED* scenarios test the impact of IED costs on operation of coal plant by varying the assumed cost of IED compliance from the low Drax IED compliance cost in the Low IED scenario, to the highest estimate for IED compliance from recent official cost estimates (PB 2014).

The *High CM* scenario tests the impact of capacity payment on the operation of coal plant by assuming that all capacity payments are received at the cap level, £75/kW[12].

We have also created a 'credible upside for coal' in the *Pro-coal* scenario for coal plant in which key assumptions are set to favour coal fired power station operation. The low coal price and high gas price forecasts presented in Section 2.4 are assumed, and the low carbon price forecast with no CPS is assumed as the carbon price. The cost of IED compliance is assumed to be the Drax IED compliance cost for all plants, being the cheapest costs found in the literature. The capacity payment price is assumed unchanged from the central case. The scenarios are detailed in Table 5.



**Table 5:**
**the differing assumptions used in the six scenarios**

| Scenario | Coal price | Gas price | Carbon price | IED compliance cost | Capacity payment | Build rates |
|---|---|---|---|---|---|---|
| High CPS | DECC central forecast | DECC central forecast | DECC forecast inc £75/tonne CPS | £130/kW Drax £25/kW | Average of DECC central case (£32.5/kW) | As National Grid Ten Year Statement* |
| No CPS central | DECC central forecast | DECC central forecast | DECC central forecast without CPS | £130/kW Drax £25/kW | £32.5/kW | As National Grid Ten Year Statement* |
| High IED | DECC central forecast | DECC central forecast | DECC forecast inc £75/tonne CPS | £200/kW for all plant | £32.5/kW | As National Grid Ten Year Statement* |
| Low IED | DECC central forecast | DECC central forecast | DECC forecast inc £75/tonne CPS | £25/kW for all plant | £32.5/kW | As National Grid Ten Year Statement* |
| High CM | DECC central forecast | DECC central forecast | DECC forecast inc £75/tonne CPS | £130/kW Drax £25/kW | £75/kW | As National Grid Ten Year Statement* |
| Pro-coal | DECC Low forecast | DECC high forecast | DECC central forecast without CPS | £25/kW for all plant | £32.5/kW scenario | Delayed nuclear build and low gas build |

Source: DECC (2013c) PB (2014) DECC (2014c) DECC (2013a)

**As per NG Ten Year Statement including all under construction, consented, awaiting consents, and plant under scoping*

**Key background assumptions**

Other parameters and assumptions are held constant in all scenarios and described in detail in Annex 2. Annual demand level is the same in each and is drawn from the DECC Updated Energy Projections (UEP) for electricity demand to 2030 (DECC 2012), with linear projection to 2050, constant thereafter. Demand allocation into time slices is based on observed GB power system load duration curve, by time slice season and for the peak day, from Elexon (2014). Demand is assumed to be inelastic (demand does not respond to price). The Emissions Performance Standard (EPS) applies to any new coal or gas fired stations.

One of the most significant factors affecting power sector carbon emissions in 2030 will be the role of CfDs in driving investment in low carbon plant. As noted in Part 2, at the time of writing there is considerable uncertainty surrounding the evolution of the CfD during the 2020s, with no clarity about CfD prices or indeed the overall ambition of the scheme. In order to simplify this complex picture and test sensitivity to the key factors that affect coal described above, the model was adapted to represent a situation where current CfD bands run until 2025 and are then replaced by a technology neutral system which closes in 2040. This represents a long term transition to a situation where a carbon price provides the core incentive for low carbon generation. The base level of low carbon capacity associated with this CfD level in each year was then held constant in all scenarios. More detail on how the CfD was represented in the model is provided in Annex 2.

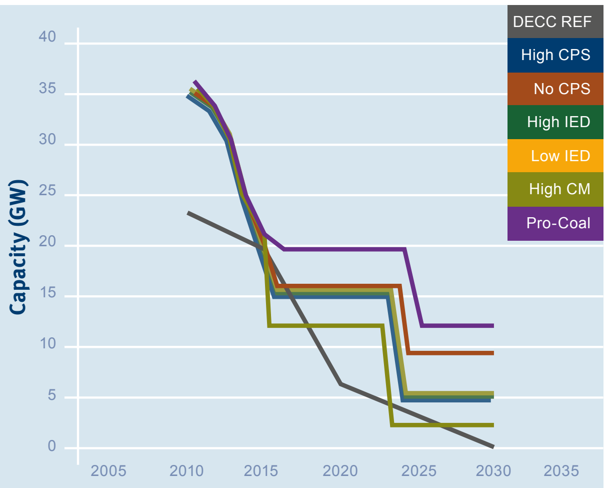
Specific attention is also paid to time slicing and peak demand periods to ensure adequate representation of the power sector and security of supply. Intermittent renewable resources are assumed to be unavailable in peak periods (a capacity credit of zero), thereby forcing the model to adopt more technologies with firm output to ensure system resilience. This is a conservative assumption, designed to provide a high level of system security (for a discussion of renewable energy capacity credits see Gross *et al*. (2006)).

### 3.3. The results

The following figures present the results of the six scenarios described above. The first three figures present the resulting coal capacity, coal electricity generation and the $CO_2$ intensity of electricity (Figure 9, Figure 10 and Figure 11). Each of these figures also presents DECCs central view ('DECC REF') from their "pathways to 2050" report (DECC 2011).

The scenarios show how prices and policies interact at important decision points for coal operators. In our scenarios the model has different coal capacities enter into LLD or opt for IED compliance, depending on the impact of the CPS and other factors, as we discuss in more detail below. This differs substantially from the DECC central scenario, which simply sees a progressive closure of coal and DECC project no unabated coal generation capacity in 2030. By contrast, in all our scenarios at least some coal is retained in 2030. The High CPS scenarios (both high and low IED costs) projects ~5GW of remaining unabated coal capacity, with as much as 11 GW of unabated coal retained in the Pro-coal case (Figure 9). An increase in the capacity mechanism clearing price (High CM) results in a modest amount of investment shifting from coal to gas - as we explain below. Our No CPS scenario retains 9GW of old coal.

**Figure 9:**
**Unabated coal power station capacity**

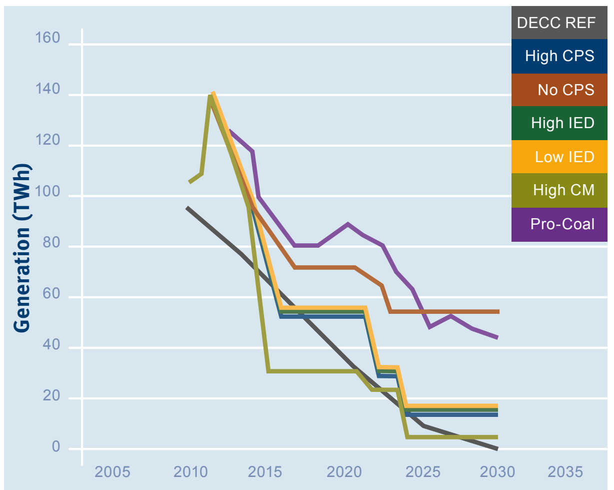



Source: DECC REF scenario from DECC (2011)

Much of the remaining coal capacity in the High CPS scenario operates at a low load factor (averaging less than 20%) and produces ~8TWh of electricity in 2030 (Figure 10). This capacity is maintained in the early 2020s in order to meet the capacity margin necessary to deliver security of electricity supply in a period where supply is increasingly tight due to plant closure and the time taken to replace it. In the model, in the absence of policies that explicitly oblige coal to close, the choice of whether or not to run coal plant and indeed how much coal to retain then becomes a question of relative economics taking into account the full range of costs, including the cost of carbon.

This is why the model retains a higher capacity of coal, and uses it more, in the scenarios where carbon prices are low. This represents something of a simplification, in that the full range of alternative options to provide capacity margin cannot be explored in depth. In particular, the modelling is not able to assess in full the potential of new means to incentivise active demand side response (for example through 'smart appliances'), the fine details of operation of storage technologies, or comprehensive representation of the incentives presented by the capacity market. If demand response can be secured at low cost then the need for both coal and other forms of conventional generation would reduce. In some respects our modelling represents a 'worse case', where the principal choices for ensuring peak demand turn upon the relative economics of different forms of conventional generation (coal and gas fired CCGT/OCGT), with a limited role for demand, interconnection or storage.

**Figure 10:**
**Energy generated in unabated coal power stations**




Source: DECC REF scenario from DECC (2011)

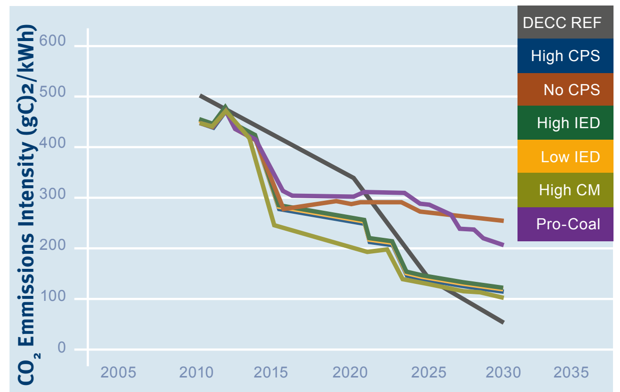


The impact on $CO_2$ emissions intensity of electricity varies through the 2020s. The High CPS scenario projects a lower $CO_2$ intensity than the DECC REF scenario for the majority of the time horizon modelled (Figure 11). However, this relationship shifts in 2025 and by 2030 the High CPS scenario projects a $CO_2$ intensity of 128g$CO_2$/kWh, more than double the 50g$CO_2$/kWh target suggested by the Committee on Climate Change (CCC 2010).

The modelling also shows that the role of gas-fired generation is also sensitive to the level of the CPS. Coal fired generation is impacted most substantially by the presence or absence of a strong carbon price – coal fired generation is over 6 times higher in the No CPS case than in the scenarios that incorporate the CPS. However, the use of gas also increases by around 20% in the No CPS scenario, with coal and gas displacing low carbon plant. In the model a small amount of new coal with CCS is built in preference to gas and other low carbon plant in the late 2020s in the Pro-coal scenario, reflecting the high price of gas, low coal price and presence of the EPS for new build plant in this scenario. Figure 10 shows only the output from *unabated* coal, which is why coal output (and emissions, see Figure 11) declines slightly at the end of the time period in the Pro-coal scenario.

Overall, the modelling suggests that the carbon price plays a key role in determining the overall mix of gas, coal and low carbon plant. In all scenarios at least some coal is retained, in contrast to the DECC reference case, which assumed coal closure. The detailed interplay of the various factors considered in the modelling are described below.

**Figure 11:**
**$CO_2$ emissions intentisty of grid electricity**




Source: DECC REF scenario from DECC (2011)

### Carbon price support

The impact of CPS on the scenarios can be seen by comparing the High CPS and No CPS scenarios in Figure 9, Figure 10 and Figure 11. By 2030 there are 9 GW of unabated coal in the absence of CPS (no CPS scenario) and 11 GW in the Pro-coal scenario. This is compared to the 5GW remaining unabated coal capacity in the High CPS scenario, which assumes the CPF forecast by DECC and presented in Figure 3.

The remaining unabated coal capacity in the No CPS scenario also operates at a high load factor (averaging approximately 67%). This results in ~53TWh of unabated coal fired generation in the No CPS scenario in 2030, significantly greater than the ~8TWh in the High CPS scenario (Figure 10). This translates to a significantly higher emissions intensity of electricity in 2030. The High CPS scenario has an emissions intensity of 128g$CO_2$/kWh, while the No CPS scenario is over 100g higher, at 238g$CO_2$/kWh.

As noted above, in our modelling the absence of a strong carbon price also encourages the model to increase the role of gas relative to low carbon plant. Yet as we discuss in part 4, the level of the CPS in the 2020s is subject to considerable uncertainty, which adds further to the case for investing in retaining old coal, favours investment in gas over low carbon plant, and increases the risk that carbon emissions are considerably above policy targets.

### IED compliance

The impact of IED compliance costs can be examined by comparing The High CPS, High IED and Low IED scenarios in Figure 9, Figure 10 and Figure 11. Based upon the range of costs from the literature reviewed in part 2, these scenarios vary the cost of IED compliance from £25/kW to £200/kW. However, in each case the resulting trajectory for capacity, energy generated, and $CO_2$ intensity of electricity is the same. This suggests that economics of coal power station operation are not particularly sensitive to the costs of IED compliance. They are far more sensitive to marginal fuel and carbon prices. This can be explained in part by examining the difference between the costs of maintaining existing coal plant and the costs of commissioning new OCGT or CCGT (noting that this is a partial comparison, see footnote 10). Table 6 presents the costs of IED compliance, and life extension against the next cheapest new generating capacity option[13]. Given this differential it is clear that the costs of IED compliance would need to be significantly greater to make these alternative options more attractive – at least in terms of *capital* costs.

**Table 6:**
**comparison of capital costs of maintaining coal capacity and building new gas capacity**

| Capacity choice | Capital cost |
|---|---|
| Extending existing coal capacity (IED compliance plus life extension) | £216/kW |
| OCGT new capacity capital cost | £440/kW (2011 onwards) |
| CCGT new capacity capital cost | £675/kW (2020 onwards) |

**Capacity mechanism**
The impact of a capacity price can be seen by comparing the High CPS scenario with the High CM scenario. The High CPS scenario assumes a capacity payment of £32.5/kW (the average of DECCs capacity mechanism forecast), while the High CM scenario assumes the cap set in the implementing document of £75/kW. These payments are received by all eligible operating plant and received from 2019 (the first capacity market year) to the end of the model timeframe[14].

The impact of capacity payments appears to be modest in terms of unabated coal capacity, electricity generation from the capacity and emissions intensity of grid electricity. Where the increase in capacity payment does create a divergence between the High CPS and High CM scenarios it appears that unabated coal is displaced by CCGT when the capacity payment increases. This is due to the fact that this high capacity payment also benefits gas fired electricity generation. The relative benefit is actually greater for gas generators, and these power stations can therefore displace older coal fired plant. It is important to note that the modelling cannot fully represent the complexities of the capacity mechanism which has been designed to deliver different levels of support through longer contracts for new plant. However a high and certain price (and a longer time horizon) is likely to do more to favour new capacity over life extension. The modelling bears out this insight.

**Modelling limitations**
The purpose of the analysis is to explore the role of coal under a range of scenario assumptions that are broadly plausible in terms of market and policy developments and allow us to consider what happens to coal when closure due to life extension is not assumed. However, a number of important limitations need to be borne in mind when interpreting the results:

- A full-blown representation of demand response (where demand side actors bid into the capacity mechanism) has not been undertaken, and it is possible that greater progress with demand side actions will reduce the need for thermal capacity of all kinds, coal or gas.
- In addition, we have not explored the possibility of innovations in storage and we constrained the availability of interconnection at peak to 50% of interconnector capacity. Relaxing these assumptions could provide lower cost alternatives to fossil plant and enhance the potential to develop low carbon options.
- Assuming zero capacity availability at peak for wind plant in the UK is also a conservative assumption and may overstate the overall need for firm (mainly fossil fired) power generation.
- It is also important to note that it was necessary to simplify the representation of the capacity market, notably in differentiating between 1, 3 and 15 year payments for different forms of capacity
- The modelling required important judgements about how best to respond to the current uncertainty surrounding the ambition and nature of support for low carbon generation through the contracts for difference. In exploring how best to represent the CfD, and what level of low carbon plant CfDs might deliver, a range of potential CfD payment levels/periods were explored. The approach chosen seeks to represent as accurately as possible a transition to technology neutral CfDs and ultimately to mature low carbon technologies supported through a carbon price. Greater ambition and longevity for the CfD could create a larger role for the low carbon sector, and reduce the market opportunity for coal.

**3.4. Modelling summary and conclusions**
The modelling provides a number of important insights, with considerable importance for carbon abatement aspirations and wider policy goals for the period to 2030.

First it is notable that without new policy interventions, in all scenarios modelled for this study at least some coal capacity will be retained and will continue to operate throughout the 2020s. Coal plant is selected by the model to meet overall capacity requirements and, once available, is able to generate when short run marginal costs are competitive.

The modelling also demonstrates that coal (combined with the wider plant mix and in particular the share of gas and low carbon plants) has the potential to undermine carbon abatement goals. The carbon intensities of power generation in Great Britain suggested by our model lie in a range from 130 to 240g$CO_2$/kWh. The Energy Act does not contain an explicit target for $CO_2$ emissions from the power sector but enables the Secretary of State to set a target in 2016 following the publication of the Committee on Climate Change's advice on the 5th carbon budget. The recommended target suggested by the Committee on Climate Change is 50g$CO_2$/kWh. This target is based on modelling by the Committee to determine the most cost effective pathway to meeting the UK's targets legislated under the Climate Change Act. Our model suggests that in the absence of additional policy to remove or constrain coal and encourage an appropriate mix of gas and low carbon plant, there is a significant risk that emissions will be above this range and above central projections provided by DECC.

The modelling also demonstrates that the amount of coal operating during the 2020s is primarily a function of the CPS, in the absence of other policies to constrain the use of existing coal fired power stations. IED compliance and ongoing maintenance/operating costs do not deter the model from choosing continued operation of at least some coal through the 2020s. This is because the capital costs of retaining this capacity are low compared with alternatives available to the model. A substantial volume of coal capacity does close by 2023 in several of our scenarios. However, the evidence suggests that power plant operators considering investing in life-extension will be more concerned about marginal fuel/carbon costs than whether IED compliance costs are high or low (within the range we model). Similarly, the range of payments we model through the capacity mechanism does not have an overwhelming impact on investment in coal fired power. The modelling does suggest that a high and certain capacity price provides a greater incentive to invest in new CCGTs, displacing some coal. However coal investment in itself is relatively insensitive to the levels of the capacity price modelled above.

Any system optimisation model like the one used in this report, will produce different outcomes from 'real world' market conditions, where investors weigh a balance of risks – market risks, policy risks and technological risks. Instead of using the model as a predictive tool, we have used it to highlight the boundaries of plausible electricity system developments, and use these to inform our analysis. In Part 4 we discuss what the modelling is able to tell us about potential market opportunities and discuss the interaction of policy choice and market risks.

[9] In the central case, IED compliance costs are split, with 5.5GW of capacity available at a lower price as indicated by Drax and Aberthaw stations (Drax 2014; RWE 2014), and the remainder of capacity available for retro fit at the central estimate of compliance cost set out in Section 2.3. Sensitivity analysis with respect to IED compliance costs are included in the scenarios, as described below.

[10] All other assumptions are set at central views of the future (see Annex 2)

[11] At the time of writing DECC's forecast for 2030 has not been adjusted following the recent decision to freeze the CPS until 2019 (see Section 2.2).

[12] In the model we represent capacity payments as a fixed and constant payment available to all qualifying capacity (see Annex 2 and discussion of limitations at the end of the section).

[13] We do not discuss here the costs of demand response or interconnection, both of which could be cheaper, or the additional possibility of renovating older CGGT plant that might otherwise close. Doing so may represent an alternative, potentially low cost option to investment in coal. We return to this in discussing future work.

[14] Since all plant gets payment in all years we do not model the difference between the standard one year capacity payment and the additional two years payments to retrofit plant.

# 4. Modelling, real world investment decisions and the importance of policy clarity

**4.1. Coal should not be assumed away**
The modelling described in Part 3 shows how a theoretically optimised power system would make use of coal under different scenarios to 2030. The model does not assume coal will close or any additional policies to constrain its use. Under these conditions, the implications for policy goals, in particular to reduce $CO_2$ emissions, are not encouraging. Until recently one relative 'certainty' in many policy scenarios was that Britain's coal fired power stations would close by the mid-2020s. In effect the closure of old coal power stations was – in many earlier analyses – assumed to be inevitable. However, the analysis undertaken for this report indicates that without further policy interventions, there is a significant market opportunity for coal plant owners to retain capacity and operate it throughout the 2020s.

Moreover, the modelling suggests that although a high carbon price reduces the use of coal, in the absence of further policies to constrain its use, coal generation could help undermine the decarbonisation goals for 2030 set out by the Committee on Climate Change and in the Government's own scenarios. Our modelling indicates that power sector emissions in 2030 could lie in a range from approximately 130 (with a strong carbon price) to around 240g$CO_2$/kWh with a weak carbon price. Where carbon prices are weak the amount of coal retained by the model contributes significantly to carbon emissions. The range is significantly affected by the amount of coal burnt and even the lower bound is above the CCC aspiration of 50g$CO_2$/kWh and above DECC's central projection of around 100g$CO_2$/kWh (CCC 2010; DECC 2011).

The precise power mix the model chooses is complex and the carbon price affects the share of coal, gas and low carbon plants. In addition, the scale of ambition for CfD payments to low carbon generation will have a substantial impact on overall plant mix, emissions and the role for coal. Nevertheless, a key reason our modelling has higher carbon emissions than broadly similar analysis carried out previously is that earlier studies assumed coal closure. When coal is not assumed to close its presence has the potential to contribute significantly to undermining power sector decarbonisation. This is particularly true in the scenarios we modelled where carbon prices are low.

**4.2. Investment decisions and policy clarity**
The modelling undertaken for this report resembles a centrally planned outcome - or one where a highly competitive market operates in a fully 'rational' manner in order to deliver the most efficient use of resources. In the real world, the situation is more complicated and the possible implications for carbon emissions, security of supply and electricity prices are uncertain. Both electricity generators and policy makers need to make decisions in the face of considerable uncertainties – uncertainties about fossil fuel prices, demand and economic growth, and of course about one another's behaviour and choices.

In what follows we discuss these interactions in the light of the modelling undertaken for this report. The discussion is necessarily speculative in nature, since the complex judgements market investors make under uncertainty cannot be predicted through modelling. It is important to be clear – *the model indicates that a market opportunity exists for coal, but how market participants will respond is complex and impossible to model via the sort of system models employed here.* Nevertheless important principles for decision making can be identified. All point to the need for greater policy clarity about the role of coal with regard to carbon targets in 2030.

Investors' decisions are driven by the risks they perceive over future earnings. Coal plant operators will need to decide how likely it is that the value of increased generation during the 2020s outweighs the costs of investing to achieve IED compliance. The decisions coal operators make (which may at least have been partially revealed through the capacity market pre-qualification process) will have knock-on impacts on the risks that prospective investors in other forms of generation face, particularly those considering investment in unabated gas fired generation. Moreover, potential investors in low or zero carbon plant will also need to take a view on the wider market, the balance of unabated plant in operation. Many generators will own both fossil fuel and low carbon plants and will be seeking to balance investment risks across their portfolio. In what follows we discuss the implications of our modelling for investment decisions in coal and gas plant. The discussion focuses on the risks created by a lack of policy clarity about the role of coal in the 2020s.

Under the assumptions set out in our central scenario, the opportunity to increase generation in the early years (out to ~ 2023) suggest that it may be attractive for a number of coal plants to opt-in to the TNP, particularly if retrofit costs are low. They may even be able to secure a significant economic return on investment without undertaking IED retrofit, although that would mean they would have to close in 2020 and would lose the option of generating beyond this point.

However, with the high CPS trajectory, the modelling indicates that it would not be economically rational to operate coal above fairly low load factors. It is possible that in practice, alternative technologies will be more cost-effective in providing low utilisation, peaking capacity (OCGT, older CCGT, potentially demand response). Whilst a modest amount of coal capacity is retained in the model, in a market environment the value of coal-fired generation to operators would decrease significantly. Therefore where the market has confidence in a rising CPS even the IED compliant coal plant could close by the mid-2020s. In the scenarios where the CPS is not increased and/or other factors favour the economics of coal, the modelling suggests that it would be attractive to retain and operate and larger capacity of coal at much higher load factors (as high as 68% in our high CPS scenario).

In considering this from an investor perspective it is important to take stock of the balance of upside and downside risks – that is, whether investment would be profitable or unprofitable under various possible future outcomes. Investors tend to be cautious about possible upsides compared to possible downsides. A potential upside for coal plant is a downside risk for gas, low carbon plant and demand side measures and, given uncertainty over carbon prices and no other constraint on coal use, the more coal plant that is compliant with the IED the greater the risks for investors in alternatives to coal.

This asymmetry of the impact of risk on investment is very important for policy makers – in the face of uncertainty policymakers may desire to maintain options (for example, the option that coal plant might be needed beyond 2023). However this could prove counter-productive by increasing investment costs or, possibly, deterring investment in alternative capacity.

The CPS is clearly an extremely important policy lever in this regard. If it is frozen again, reduced or removed by the next government this will significantly improve the relative economics of coal versus gas and this is likely to make it much more attractive for coal plant to comply with the IED (noting that investors will know the policy agenda of the newly elected government before needing to take the decision) – even if the level of coal-fired generation in the late 2020s is uncertain. European level decisions will also be important since significant steps taken to strengthen the ETS would reduce the risk associated with UK policies and/or make a strong UK carbon price easier to achieve. However considerable uncertainty surrounds the future of the ETS as well.

Similarly, the funding available for CfD payments, overall ambition for low carbon capacity supported through the CfD, and extent to which CfDs are differentiated by technology, all affect the role for fossil plant. If more low carbon plant is supported through CfDs the energy required from coal and gas plant will reduce, electricity market price formation will change and incentives for coal operation could reduce. Our modelling held CfDs constant in all scenarios in order to test the impact of carbon prices, capacity prices and the other factors described above. However the ambition for the CfD is also a key driver of decarbonisation and significantly affects the market opportunity for coal. However at the time of writing, the level and nature of CfD payments during the 2020s has not been decided. Again, this is a source of considerable uncertainty for investors.

A large fleet of IED compliant coal and no certainty that the CfD payments will be high and/or carbon prices will be significant during the 2020s has the potential to deter investment in other forms of capacity – this risks creating a self-fulfilling prophesy that coal will have to be available to maintain security of supply, leading directly to policy failure in delivery of decarbonisation objectives. Our analysis suggests that the incoming government is likely to be faced with the prospect that a number of coal plant invest to become IED compliant – how much will depend in part on the view investors take of likely carbon prices in the 2020s. It is important that policies are introduced to provide confidence that these plants will not generate significantly throughout the 2020s and hence avoid deterring or increasing the risks (hence costs) of investment in gas, demand side and low carbon capacity.

**4.3. Regulation would give investors more clarity**

Commitment to continue with the CPS on the trajectory originally proposed by DECC for the 2020s is sufficient to ensure that coal operates at low load factors in our model and may be sufficient to ensure it closes in the real world. Similarly, clear signalling that CfD levels will be high enough, and overall support through the scheme substantive enough, to drive a significant expansion of low carbon generation would decrease the attractiveness of investment to retain old coal, and reduce the market opportunity to run coal plant.

However, in the face of uncertainty about the CPS and CfD it would be valuable to reinforce confidence for future investors in gas and low carbon technologies that unabated coal will not be able to continue to run unrestrained throughout the 2020s. This is because even if a commitment to increasing the CPS is made, the market will still fear that the Government may change its mind and it is certainly necessary to introduce other policies to constraint coal use if the decision is taken to remove or reduce the CPS.

Perhaps the simplest means to reinforce policy clarity would be by applying Emissions Performance Standard regulations to existing coal plant, which could be linked to the 2023 IED deadline. Once such a standard is in place, coal operators considering IED compliance would do so on the basis that after 2023 such plans would be subject to the overall cap of the EPS. It may also be possible to introduce new regulations that specifically target existing coal fired power stations, perhaps capping total annual operating hours at a low level for IED compliant plant after a fixed date in the 2020s.

Two other considerations also point to the importance of a regulated approach to the role of coal in the 2020s; *price* and *security of supply*.

On *prices* the model provides an indication of the direction of power prices in the form of marginal generation costs. Our scenarios all indicate that the CPS is a significant driver of such costs and of course, the more carbon intensive the energy mix the higher the overall burden the CPS places on electricity prices. In the absence of a regulated cap on coal it becomes essential that the level of the CPS rises substantially if emissions targets are to be met. This of course risks another potential self-fulfilling prophesy – that meeting carbon targets drives up prices. As rising prices are politically challenging, it is again likely that investors will be wary of the willingness of future governments to hold a firm course on the CPS, creating further downside risk for investment in low carbon and gas plant, and again conditions where coal has to be utilised to ensure security of supply.

In terms of *security of supply* in the worst case, investment uncertainty could lead to a lack of investment in *all forms of capacity* – since investment in anything becomes more risky. The model optimises on the assumption that capacity margin must be maintained. In the real world capacity margin is not guaranteed and again, if gas, low carbon investment and demand side capacity is not forthcoming because of a climate of general policy uncertainty, security of supply could be compromised. Again, a clear policy commitment that IED compliant coal would be subject to the EPS (or similar measure) would create greater certainty and improve the prospects for gas and low carbon investment, hence security of supply.

**4.4. Policy Conclusions**

Overall, our modelling reveals some very important policy issues. It suggests that without new policy intervention there are likely to be market opportunities for coal during the 2020s, and the central policy currently affecting the commercial viability or otherwise of coal is the carbon price. Moreover, if coal continues to operate at anything above low load factors it has the potential to undermine 2030 carbon abatement targets. Indeed, even in our scenarios with a high carbon price some coal power stations are still operational in 2030, which helps undermine decarbonisation goals. A larger fleet of IED compliant coal stations could also make gas and low carbon investment more risky.

Government therefore faces an important choice about whether to rely upon carbon pricing – and in the absence of EU-wide action this means increasing the level of the CPS – to ensure that the continued operation of coal does not contribute to policy failure in 2030. Alternatively, the government could take more direct, regulatory, steps to limit emissions from coal in the 2020s which would ensure that investors have greater clarity about the future role of coal. As we note above, it could for example, extend the EPS to IED compliant coal.

A full exploration of all the prospective regulatory levers is beyond the scope of this study. However, we recommend that the government review all policy options to ensure that the ongoing operation of coal is not allowed to undermine power sector carbon targets. In so doing, government needs to provide investors with maximum clarity about its intentions. Because the CPS is vulnerable to continued political uncertainty (given the direct impact on short term energy costs) and with long term ETS prices uncertain, carbon pricing alone is unlikely to provide this clarity. Similar concerns apply to the level of support for low carbon generation coming through the CfDs, as the scale and ambition of the scheme have yet to be decided after 2020.

Given this context, a clear, regulated approach to restrict carbon emissions from IED compliant coal offers the potential to encourage investment in alternative capacity and help to avoid policy failure both in terms of carbon emissions and security of supply.

# 5. Conclusions

This study reviews the range of factors that will affect the decisions coal-fired power station operators make regarding compliance with the IED and models scenarios of coal-fired power station operation in the 2020s. It uses a cost optimising engineering/economic approach to model scenarios of a key set of relevant considerations; the cost of keeping coal stations maintained and operational, fuel costs, carbon prices; range of costs for IED compliance and different levels of capacity payment. The modelling informs a discussion of real world investment choices and implications thereof for policy. The study provides us with the following conclusions:

**In all our scenarios some coal capacity is retained by the model and continues to operate until 2030.** Once available, coal capacity would be able to operate when marginal costs are competitive with alternatives.

**The continued use of unabated coal could significantly undermine the potential for Britain to meet targets for emissions from power generation in 2030.** The carbon intensities of power generation in Great Britain suggested by our model are in all cases higher than the target of 50g$CO_2$/kWh suggested by the Committee on Climate Change and above central projections of around 100g$CO_2$/kWh provided by DECC.

**In our modelling, the amount of coal that becomes IED compliant and continues to operate in the 2020s is a function primarily of the carbon price,** in the absence of other policies to constrain the use of existing coal fired power stations.

**IED compliance and ongoing maintenance/operating costs do not appear to be a barrier to continued operation of at least some coal**. Whilst a substantial volume of coal capacity does close by 2023 in several of our scenarios, the evidence suggests that the costs of compliance are low relative to the cost of building new gas or other plants. Hence the model shows coal investment is more sensitive to marginal fuel/carbon costs than it is to the range of IED compliance costs.

**Payments through the capacity mechanism do not have a substantial impact on investment in coal fired power** - the modelling does suggest that a high and certain capacity price will provide more incentive to invest in CCGT, which slightly displaces coal. However investment to life-extend coal in itself appears to be relatively insensitive to the range of capacity market prices investigated.

**In short: Coal should not be assumed away:**

**In scenarios with a very low carbon price up to 9 GW of coal is retained by the model, generating up to 56 TWh of electricity, with power sector emissions of around 240g$CO_2$/kWh.**

**Even with the carbon price reaching £75/tonne around 5 GW of coal is retained, generating 8 TWh of electricity, with power sector emissions of around 130g$CO_2$/kWh.**

The report goes on to discuss the implications of our modelling for investment decisions by market operators in the 'real world', noting that the TIMES model is able to 'centrally plan' investment and operation and that real world investors will have somewhat different priorities, risks and decision metrics. We note that investments in coal and in other forms of generation are not independent of one another – a potential upside for coal (in particular policy weakening on the CPS) represents a potential downside risk for investment in gas or low carbon plant.

Power sector investors face numerous risks post-2020. There is uncertainty about CfD payments to low carbon generators, uncertainty about the carbon price, as well as uncertain fossil fuel prices and demand projections. The modelling shows that the role of coal is highly sensitive to carbon prices. More targeted support for low carbon generation (through CfDs) could also significantly affect the role for coal. A regulation to cap carbon emissions from IED compliant coal would provide greater certainty that old coal will not run unconstrained throughout the 2020s. This would improve the prospects for investment in gas and low carbon generation in the 2020s, benefitting security of supply and helping to avoid policy failure.

The UK carbon price is vulnerable to political uncertainty given the direct impact on energy prices. Future CfD prices and availability of support for low carbon generation post 2020 are also uncertain. Greater policy clarity on the role of the CfD and on carbon prices would help secure low carbon investment and direct regulation on coal emissions would give investors more clarity.

**To ensure that coal does not threaten UK climate change goals we recommend the following:**

- **The carbon price is a key driver of investment decisions. Government should provide a clear trajectory for UK carbon prices in the 2020s and continue to support a strong carbon price through the EU Emissions Trading Scheme.**
- **Clear signals should also be provided on the availability of CfDs to drive growth in low carbon generation post 2020 and provide confidence to investors.**
- **Additional clarity for investors would also be provided if the Emissions Performance Standard is extended to existing coal that becomes IED compliant by 2023. Regulation would need to ensure that by 2030 old coal plants are strictly limited to very low operating hours, or closed.**

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# Annex 1

## Plant closed by 2015 (LCPD opt-out)

| Plant | Owner | Capacity[15] (MW) | Commissioned | Status |
|---|---|---|---|---|
| Ironbridge B | E.ON | 1,000 | 1970 | Close by Dec 2015 |
| Kingsnorth | E.ON | 1940 | 1975 | Closed Dec 2012 |
| Didcot A | RWE | 2,000 | 1970 | Closed Mar 2013 |
| Tilbury | RWE | 1,131 | 1967 | Closed Oct 2013 |
| Cockenzie | Scottish Power | 1,200 | 1968 | Closed Mar 2013 |
| Ferrybridge I&II | SSE | 1000 | 1966 | Closed Mar 2014 |

**Plant entered LLD**

| Plant | Owner | Capacity (MW) | Commissioned | Status |
|---|---|---|---|---|
| Uskmouth B | SSE | 360 | 1959 | Closed May 2014 |
| Cottam | EDF | 2,000 | 1969 | Plans for TNP |
| West Burton A | EDF | 2,000 | 1968 | Plans for TNP |
| Ferrybridge III&IV | SSE | 980 | 1966 | In TNP |
| Ratcliffe | E.ON | 2000 | 1968 | ??? |
| Aberthaw | RWE | 1,555 | 1971 | LLD |
| Longannet | Scottish Power | 2,400 | 1973 | ??? |
| Fiddlers Ferry | SSE | 2,000 | 1971 | LLD, upgrading |
| Drax | Drax Power | 3,960 | 1974 | ??? |
| Eggborough | Eggborough | 2,000 | 1967 | ??? |

[15] Plant capacity is split into Balancing Mechanism Units (BMUs) and individual BMUs can make different decisions under the IED

# Annex 2

## ETSAP TIMES modelling environment

The TIMES modelling environment is an internationally recognised and widely applied approach to energy systems modelling. It allows the modeller to create scenarios of optimal energy system transitions, based on bottom-up engineering and economic detail of the technologies available. The standard version of the model chooses the technologies for investment, and details of their operation after investment (e.g. dispatch in the power sector), in order to minimise discounted total energy system cost over the modelled time horizon. A common approach in TIMES modelling is to investigate optimal energy system transitions to achieve a long term greenhouse gas emissions target, or to examine the optimal response of the energy system to an emissions tax, which is achieved by imposing constraints and/or financial instruments on emissions. Models are calibrated to a base year, usually the most recent year available in national statistics, to ensure adequate representation of the starting point for an energy system transition.

TIMES creates a partial equilibrium on the energy system modelled such that supply equals demand in each time period. In the power sector, the fundamental principle of merit order is adhered to, with low marginal cost generators dispatched in baseload and higher marginal cost plant dispatched to balance the electricity system. Intermittency and inflexiblity of some classes of power generation are captured via constraints on operation; for example, nuclear plant is constrained to constant output across sets of time slices to reflect observed market behaviour. Key power system design parameters such as an overall capacity margin are incorporated into the model alongside constraints on peak demand periods to ensure investment choices made result in an adequately resilient power system.

Please see basic structure and data sources for electricity system times model GBpower (Hawkes 2014) overleaf.

| | Description |
|---|---|
| Basic model parameters | **Scope:** Electricity system of Great Britain. Single region model.<br>**Time horizon:** 2010 – 2100, 1-year time-steps from 2010 to 2030, 5-year time steps thereafter. The model is intended to investigate energy system change to 2050. The extension of time horizon to 2100 is to ensure the solution in 2050 is sustainable (i.e. all model input parameters are constant 2050 – 2100).<br>**Time-slicing:** 15 time slices in each year, designed to represent 3 periods (winter, summer, peak) with 5 slices within each period. Peak period represented by 5-day cold spell with no wind (an important design scenario in future electricity systems).<br>**Global discount rate:** 3.5%. Social discount rate used in UK government analysis (HM Treasury 2011).<br>**Currency:** GB pounds (2010 basis). |
| Demand | **Annual demand level:** DECC Updated Energy Projections (UEP) for electricity demand to 2030 (DECC 2012), linear projection to 2050, constant thereafter.<br>**Demand allocation into time slices:** Based on observed GB power system load duration curve, by time slice season and for the peak day, from Elexon (2014).<br>**Demand elasticity:** None. |
| Fuel prices and emissions | **Fuel price:** Drawn from a June 2013 update to the UK MARKAL model. Documentation available [27].<br>**Emissions per unit fuel consumption:** As per DUKES 2012 [28]. |
| Existing stock of technology 2010-2012 | **2010 capacity and retirement profile:** Existing capacity from 2013 edition of the Digest of UK Energy Statistics (DUKES)(DECC 2014b), retirement profile from National Grid 10-year Statement (National Grid 2012) supporting data via use of commissioning dates and assumed lifetime of existing plant.<br>**2010 capacity and retirement profile:** Existing capacity from 2013 edition of the Digest of UK Energy Statistics (DUKES)(DECC 2014b), retirement profile from National Grid 10-year Statement (National Grid 2012) supporting data via use of commissioning dates and assumed lifetime of existing plant.<br>**2010 activity:** DUKES 2012 [28] for aggregate data, and further calculations based on final physical notification dispatch data from Elexon (2014).<br>**Energy system developments 2010 – 2013:** Known capacity additions constrained to be adopted in scenarios.<br>**Electricity system capacity reserve margin:** 27% (calibrated to result in correct base year capacity)<br>**T&D efficiency:** 93% |

| | Description |
|---|---|
| New technology | **Technology characteristics:** Technical performance and cost data drawn from UK MARKAL model, adjusted to 2010 currency basis.<br>**Additional technology:** Fuel cells and fuel cells with CCS added based on IEA-ETSAP E-Tech-DS Brief 13.<br>**T&D efficiency:** 95% for new investment, constrained to 6GW peak capacity addition per 5-year period (i.e. slow progression to a more efficient grid). |
| Financial incentives | **Feed-in tariffs:** Given uncertainty about CfD support after 2020 the model was used to explore different assumptions about CfD prices, duration, and technological differentiation. Based on this analysis the level of low carbon generation in all scenarios modelled was constrained to approximate to a situation where existing CfD bands are replaced by a technology neutral payment of £95/MWh from 2025 until 2040.<br>**Carbon Price Floor (CPF) and IAG appraisal value:** Central estimate CPF as published to 2030. Post 2030 assumed government implements programmes that are a proxy for the published IAG appraisal value (traded sector, central scenario) (DECC 2013c). |
| Market constraints | **Fuel-type shares:** No fuel type (e.g. gas, coal, nuclear) can achieve greater than 70% of all generation.<br>**Growth rates:** All classes of technology constrained to an annual growth rates of 10%.<br>**Capacity:** Capacity limits for technology classes as follows – Nuclear (65GW), CCS-enabled generation (65GW), Bioenergy (12GW), from UK MARKAL. Documentation available(UCL 2013).<br>**Investment limits:** Per 5-year period limits applied for marine, CCS, nuclear, and gas generation as per UK MARKAL(UCL 2013). Unabated new coal-fired generation constrained to zero to reflect effect of the EPS. |
| Resource constraints | All wind and solar output constrained to zero in peak demand period.<br>Fossil fuel availability and supply curve as per UK MARKAL. Documentation available (UCL 2013). |

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