

Carbon Capture and Storage demonstration: analysis of policies on coal/CCS and financial incentive schemes

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Version History

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I Executive Summary

Context

In April 2009, the Government announced its proposals for the development of future coal-fired generating capacity in the UK, and in June it launched a consultation providing further details of a framework for the development of clean coal. All new power plant above 300 MW, including gas and biomass as well as coal, are required to be carbon capture ready (CCR). In addition, new coal plant (above this threshold) would need to demonstrate carbon capture and storage (CCS) equipment on at least one unit, and retrofit the entire plant within five years of CCS being technically and economically proven. The Consultation Document also proposes financial support for up to four demonstration CCS projects in addition to funding that might be available from the EU.

Scope

The scope of this study for the Department of Energy and Climate Change (DECC) was to assess options identified in the Consultation Document for funding mechanisms and policy measures covering retrofit requirements (when CCS is proven) and contingency measures (in the event that it is not proven). The work consisted of a qualitative assessment, followed by modelling to provide quantitative results with regard to the cost to consumers and the impact on the wider electricity market. We considered potential demonstrations of post-combustion, pre-combustion and oxyfuel technologies. We undertook research on CCS costs based on published literature, but the assumptions used in our modelling were largely provided by DECC and are based only generic CCS information. No information from the current DECC CCS Demonstration project has been used and the analysis is not intended to reflect any of the solutions proposed.

Policy objectives

There are a wide range of policy objectives which a CCS policy and regulatory framework may be called on to deliver. These could stretch from contributing the UK's share of support for global deployment efforts, through increasing diversity in generation capacity, to economic regeneration around CCS developments. Potential measures will be more or less effective against different objectives, and hence must be considered with a clear view of overall goals.

Consumer costs

As CCS for power generation has not yet been deployed at a commercial scale, there is a high degree of uncertainty with regard to the costs. It is also likely that potential participants in a tender process will have a strategic interest in CCS that will have a bearing on what they are prepared to bid. As a result it is difficult to estimate the potential costs to the consumer of CCS demonstration projects, but equally clear that designing the tender process to be as competitive as possible given a limited number of potential bidders is essential.

Our assessment of costs is derived by assuming that investors will seek sufficient funding to provide the required expected rate of return on the overall project given the risks involved. This may be more or less than the incremental CCS costs, for example where the base plant itself requires support, or where benefits accrue from abatement later in the project life when carbon prices are higher. We believe that most investors will factor in a substantial level of policy risk with regard to future carbon prices, and base project evaluations on a lower carbon price than the DECC Central case, with the implication that the funding requirement is in part required to offset this carbon price uncertainty.

We estimated funding requirements under this approach using a discounted cashflow model, which we used to derive project NPVs, and (through stochastic simulations to ascertain the level of uncertainty) hurdle rates under different policy options.

Based on our assumptions, and where no contingency measures are imposed, our analysis indicates potential costs to consumers of supporting four demonstrations of around £3.2-4.5 bn (at the Green Book discount rate), when all three types of technologies are supported. With only two demonstration plant, the potential costs to consumers could be around £1.8-2.4bn.

Funding mechanism

The Government has indicated that the funding for demonstration projects would be provided through a levy on consumers, and could be delivered either as a fixed Additional Payment for CCS generation, or through a Contract for Difference (CfD) struck against the carbon (EUA) price.

A carbon CfD has the benefit that it protects consumers from subsidising excessive rents for generators should carbon prices rise, as the corresponding pay-outs would fall: the liability to consumers drops by nearly £500mn between our Central and High High cases for four demonstrations. As it would also benefit developers when carbon prices are low (and vice versa), it could be seen as a hedge from the project perspective. In practice, however, it is not obvious that it will act to reduce risk for investors. Under our assumptions, there is in fact a small increase in risk compared to an Additional Payment as the CfD over-hedges the carbon exposure for the plant – but this result is very sensitive to assumptions on the correlation between power and carbon prices.

An Additional Payment mechanism, on the other hand, has the attraction of simplicity – which may be beneficial for projects seeking outside investment – as well as more certainty with regard to future consumer costs in absolute terms.

Retrofit requirement

Our analysis suggested that a retrofit obligation may not add substantially to consumer liability if investors assume a rising carbon price, particularly if that obligation would not be imposed prior to 2025. This is in part due to the discounting of the associated retrofit capital expenditure, and in part because there is a good prospect of the retrofit becoming commercially viable in any case. Including a retrofit requirement in policy would importantly send a strong message with regard in particular to the development of the overall CCS supply chain, but on the other hand may be perceived by investors as a substantial regulatory risk.

Contingency

A tight contingency (such as an Emissions Performance Standard) that significantly limits plant operation where CCS is not proven imposes an additional risk that is difficult to quantify, and will depend on an investor's judgement as to the chance of a 'not proven' outcome. However, indicatively, if an investor assumed that a contingency would be introduced limiting emissions to a level equivalent to a new CCGT, it could add £300mn to the cost for consumers (and double that for four plant). If carbon prices rise in line with the DECC Central case, unabated coal load factors will in any case decline, and where the contingency did bind, no net emissions reduction would result assuming the EU ETS caps remain binding (as the available allowances would be used elsewhere).

Future CCS build

We used an electricity market model to simulate capacity build and retirements, plant operation, and wholesale prices through to 2034 under different DECC commodity price scenarios. Only in the highest commodity and carbon price case does any further new build CCS without subsidy feature before 2035. This may indicate a future need either for additional measures to strengthen carbon signals or further

direct subsidy at a later point if CCS is to play a key role in the long term. Where new build CCS does occur, alongside high levels of renewables and nuclear, by late 2020s we begin to see a decoupling of the power price from carbon as low carbon technologies increasingly become price-setters. This may pose a challenge as the investment signal for CCS and other low carbon technologies will be dampened if the carbon price is not fully reflected in the electricity price.

Market impact

We used the same model to understand what the impact on the overall electricity market may be if two or four demonstration plant were built. We compared a range of different policy cases to counterfactuals (in which a 'status quo' policy was assumed to continue, with just the existing competition plant being developed).

Even with four demonstration plant, the impact on the electricity market as a whole is relatively limited. The additional capacity introduced tends to displace CCGT build, capacity margins are not significantly affected, wholesale price changes are small, and diversity in the technology mix is improved. Nuclear and renewable investment is not affected in the Central and High High Cases. In the Low Case, where investment is significantly lower in any case in the counterfactual, with four demonstration plant, nuclear is delayed by a year and some 4GW of renewables is displaced after 2020, which has the effect of increasing emissions compared to the two demonstration plant case. Assuming EU ETS allocations remain binding, there would of course be no overall impact on total emissions at a European level. In the Central and High High cases, there is a significant reduction in emissions within the UK in 'proven' outcomes after retrofit, with additional abatement of around 9mt/year in the Central Case.

Net welfare

The model also allows us to calculate overall societal net welfare for a given scenario, relative to the counterfactual (status quo). This includes in particular the impact on resource costs (such as capital investment costs and fuel usage) and carbon emissions, calculated based on EU ETS prices. It does not, however, directly value the RD&D gains, incremental impact on global deployment, or regeneration benefits within the UK that may be important policy objectives.

Under our central price scenario and where CCS is ultimately proven, the carbon benefits almost exactly offset the additional resource costs, with the result that there is almost no difference in net welfare relative to the counterfactual (on an NPV basis to 2040 at the Green Book discount rate of 3.5% real). 'Not proven' outcomes have a net disbenefit of around £0.5-1.0 bn. Under our low price scenario, the plant are not economic, which results in a disbenefit of up to £3.5 bn. Our third scenario had very high carbon prices and gas was expensive compared to coal: under these favourable conditions the net welfare when CCS is 'proven' rose to around £2-4bn.

2 Introduction

2.1 Background

In April 2009, the Government announced its proposals for the development of future coal-fired generating capacity in the UK, and on the 17th June 2009 launched a consultation providing further details of a framework for the development of clean coal. All new power plant above 300 MW, including gas and biomass as well as coal, are required to be carbon capture ready (CCR). In addition, new coal plant (above this threshold) would need to demonstrate carbon capture and storage (CCS) equipment on at least one unit, and retrofit the entire plant within five years of CCS being technically and economically proven. The Consultation Document¹ also proposes financial support for up to four demonstration CCS projects (of at least 300 MW and able to store at least 20 million tonnes of carbon dioxide for 10-15 years) in addition to funding that might be available from the EU.

The Department of Energy and Climate Change (DECC) engaged Redpoint Energy and its consortium partners to perform a study to run in parallel with this consultation with the objective of undertaking detailed analysis of the different policy and regulatory choices to drive future investment in CCS.

2.2 Terms of reference

The study was to consider:

- the form of financial incentives combined with the requirement to demonstrate CCS;
- ensuring CCS deployment through necessary regulations; *and*
- contingency arrangements should CCS not become economically and technically proven.

Specifically, the objective was to analyse the policy and regulatory framework options laid out in the consultation document. These included:

- funding mechanisms based on an Additional Payment (AP) for CCS electricity and a Contract for Difference (CfD) on the cost of carbon abated;
- the requirement for plant to retrofit CCS once 'proven'; *and*
- a 'do nothing' option and an emissions limit contingency measure if CCS was not 'proven'.

The study called for a qualitative assessment and quantitative analysis, based on modelling, to evaluate the impact of these options on demonstration plant investors, potential cost to consumers, and the wider implications for the electricity market as a whole, including generation and capacity mix, capacity margins, emissions, and the level and volatility of electricity prices.

2.3 Contributing organisations

The study has been led by Redpoint Energy, working with Trilemma UK, the Energy Policy Research Group at Cambridge University, and Element Energy.

¹ http://www.decc.gov.uk/en/content/cms/consultations/clean_coal/clean_coal.aspx

Redpoint Energy (www.redpointenergy.com) is a specialist energy consultancy, advising clients on investments, risk, strategy, policy and regulation across Europe's liberalised power, gas and carbon markets.

Trilemma UK (www.trilemma-uk.co.uk) provides clients with advice on regulatory, policy and strategic issues affecting UK and European energy markets.

The Electricity Policy Research Group (www.electricitypolicy.org.uk) is based at the Faculty of Economics and at the Judge Business School, University of Cambridge. The group offers rigorous independent research output that informs public and private sector decision making in the electricity and energy industry.

Element Energy (www.element-energy.co.uk) is a strategic energy consultancy practice taking an integrated approach to the growth areas of hydrogen, fuel cells, renewables and carbon capture and storage (CCS) technologies.

2.4 Report structure

The report is structured as follows:

- Section 3 summarises the overall approach to the study;
- Section 4 provides introductory CCS technical and policy background;
- Section 5 describes the policy mechanisms we considered and our qualitative assessment;
- Section 6 covers our economic modelling of the demonstration projects;
- Section 7 presents our modelling of the impact of CCS policies on the overall electricity market;
- Section 8 covers implementation issues around the 'proven' assessment for CCS; *and*
- Section 9 summarises our conclusions from the study.

2.5 Report conventions

Table I presents the conventions used throughout the report (unless otherwise stated in the accompanying text).

Table I Report conventions

Physical	Measurement Basis	Notes
Capacity	Station Gate (net of CCS)	Capacities may also be quoted gross (turbine point), net (of parasitic load)
Demand	Station Gate - same point as capacity	Lower than gross defined in DECC's Digest of UK Energy Statistics (DUKES), but higher than National Grid as we incorporate distributed generation
Load Factors	Reference point is 100%, not percentage of availability	
Financial		
Prices & Cashflows	Real 2009	
Discount Rates	Nominal	
Tax point	Post tax	
Gas price	Presented in higher heating value (HHV) terms	

3 Approach

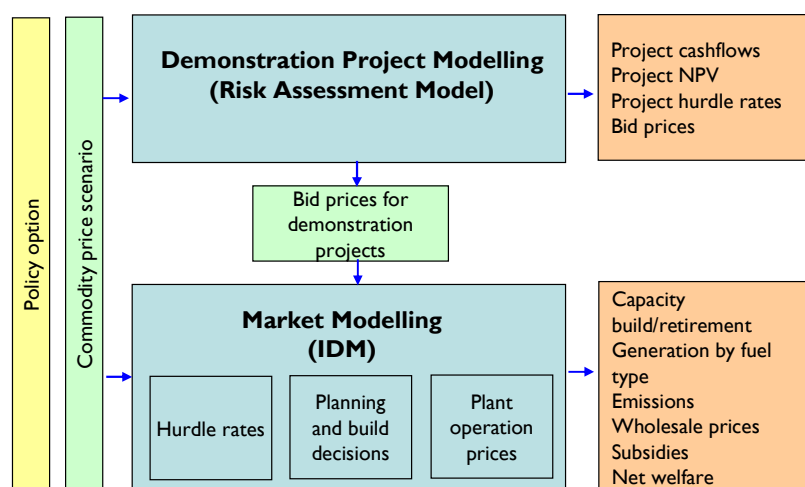
3.1 Qualitative assessment

We first developed the design of the potential regulatory and policy options laid out in the Consultation Document to a sufficient degree of detail for subsequent analysis. We explored the different variations, and their associated pros and cons. Given that the options are part of an overall framework, we did not attempt in our qualitative assessment to 'score' each element individually, but rather considered how different regimes could be constructed and how these might differ depending on the policy objectives they are designed to deliver against. We used this to draw conclusions with regard to the role each option might play.

3.2 Quantitative assessment

The greater part of the study focussed on the modelling to support the quantitative analysis. We conducted this in two parts, first modelling the economics of individual demonstration projects, and then modelling the impact of the demonstration projects on the wider electricity market. For the first, we developed a Risk Assessment Model (RAM) to analyse the value and risk of CCS demonstration projects, and the levels of subsidy required to make demonstration plant viable. For the second, we used our Investment Decision Model (IDM) to assess the impact on the rest of the market if demonstration plant are developed. The number and type of demonstration plant form exogenous inputs into the IDM to reflect different scenarios under which the Government has chosen to provide sufficient funding (through a successful tender process) to support different numbers of demonstration plant. The two models are shown schematically in Figure 1.

Figure 1 Quantitative assessment modelling framework



The assumptions used in our modelling were largely provided by DECC and are based only on generic CCS information. No information from the current DECC CCS Demonstration project has been used and the analysis is not intended to reflect any of the solutions proposed.

3.2.1 Demonstration project modelling

We used the Risk Assessment Model (RAM) to assess project economics for different demonstration plant configurations and technologies under different policy options. The modelling was based on a discounted cash flow evaluation of projects. We derived the NPV to ascertain the funding gaps and required funding levels. We used stochastic functionality to determine the uncertainty in project return, and hence estimate the risk of the projects to developers. We used this in turn to estimate the hurdle rate that may be used by investors for different capture technologies. Finally we estimated the liability to the consumer based on the cashflow associated with the funding mechanisms.

In our determination of funding requirements, we considered the economics of each project as a whole, rather than evaluating just the incremental costs of the CCS infrastructure. In our view, outside of any strategic considerations, investors will simply need to be satisfied that the overall project is commercially viable and provides the required expected rate of return, which may require more (or less) funding than that associated with extra costs of the CCS equipment in isolation. Where the base coal plant itself was uneconomic, for example, an investor would require sufficient funding to bridge this gap as well as the additional CCS costs. (This is likely to be the case for pre-combustion fitted to an IGCC plant, and depending on expectations of dark spreads, could also be true for post-combustion on supercritical coal.)

In evaluating the project economics, we consider the full project lifetime, and not just the period over which funding is paid (which would be limited to the first 15 years, or less, of plant operation). Where there is an expectation of rising carbon prices over time, substantial benefit may accrue to the project associated with the carbon abatement after the funding period. We assume that this would be taken into account in developers' bids (assuming a competitive tender process) – and could have the impact of reducing the funding that might have been calculated based only on the first 15 years.

The approach is not intended to provide a means of predicting what investors would in fact bid in any tender process. This is likely to be influenced by other strategic considerations, such as the opportunity to gain a position in a potentially huge global market, or to add diversity to an existing generation portfolio. Rather, the objective is to provide a means to compare the relative costs of potential policy options through their impact on demonstration project economics.

3.2.2 Electricity market modelling

We conducted the electricity market modelling using our Investment Decision Model (IDM). The IDM simulates capacity build and retirement, generation operation, and wholesale price over time. Different investor types and technologies are represented, and for each a hurdle rate is calculated in an analogous manner to that used in the RAM for the demonstration plant. Investment decisions are then modelled based on long run marginal costs compared to expected revenues, with projects moving through planning and commitment and then to operation. Each year market operation is simulated to determine plant load factors, fuel usage, carbon emissions and wholesale prices.

In each IDM run, we make exogenous assumptions about the number and timing of demonstration plant, since we assume that sufficient funding will be provided for the required plant to be developed. Different runs are conducted to assess the market impact under outcomes where CCS is proven, and alternatively where CCS is not proven and contingency measures come into effect.

We used the outputs from the IDM to assess the impact of demonstration plant on the capacity mix, capacity margins, wholesale prices, emissions, and overall net welfare.

4 Background

4.1 CCS technologies

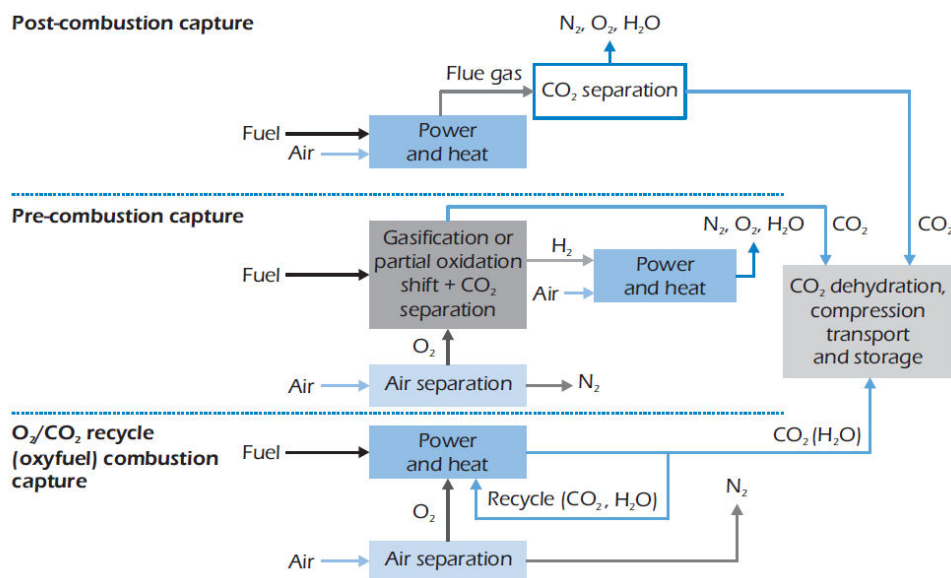
The components of CCS - carbon dioxide capture, transport, and geological storage - are individually relatively mature technologies that are currently used in diverse industries. However, the lack of experience in deployment of fully integrated CCS systems at the large scales proposed for the demonstration plant means that there is limited historic evidence to underpin cost and performance estimation.

The three key cost dimensions for fully integrated CCS projects from power stations comprise:

- **Capture processes**, whereby the CO₂ from the power station is separated from other gases, and compressed for pipeline transport. As well as a substantial outlay for capture hardware, there is a significant ongoing cost commitment within capture, to account for operating and maintenance costs and the increased energy demand for capture and compression. This power is supplied by the power plant itself, resulting in a reduction in net output from the plant, and an efficiency penalty. As a fraction of lifetime cost of carbon captured, the capture stage represents typically 80% of total CCS costs, although there is a wide range in costs reported in the literature.
- **Transport** of purified CO₂ by pipeline between the source and chosen storage sites. The CO₂ in the pipeline must be kept in an appropriate state, potentially requiring regular pressure boosting, and significant boosting to achieve required injection rates. Ship transport of CO₂ is also possible, and under certain conditions (such as very long distances or short timescales) could be viable, although this was not modelled for this study.
- **Injection and storage** of CO₂ into an appropriate site, e.g. a depleted hydrocarbon field or saline aquifer. For this stage, the principal costs would relate to the requirements for new injection facilities and to drill new wells. Additional costs for some projects would include initial site appraisal, remediation of existing infrastructure, monitoring and compliance protocols, and infrastructure for enhanced oil recovery, although these would be highly project dependent.

The three leading technologies for capture are post-combustion, pre-combustion, and oxyfuel combustion. These are depicted in Figure 2, which shows the sequence in which fossil fuels are ultimately converted to CO₂ and water. The diagram also shows that after separation from other gases, the CO₂ is compressed for transport to a suitable site for long term geological storage. The requirements and flexibility around capture readiness and retrofit differ substantially between the three approaches. The three technologies are described in more detail below.

Figure 2 The three dominant capture processes – post-combustion, pre-combustion and oxyfuel combustion²



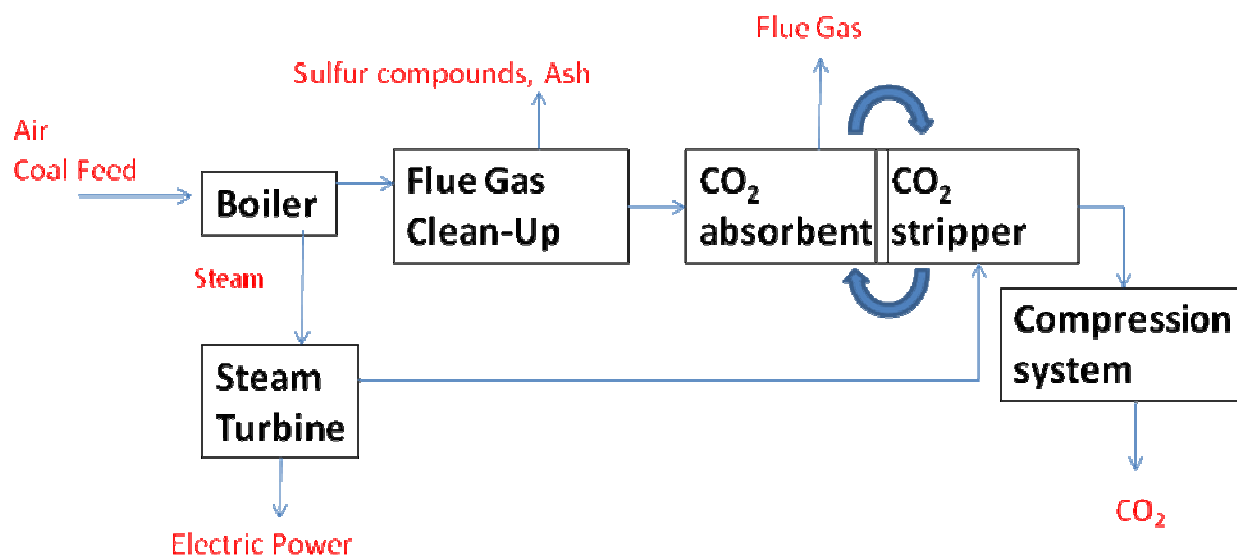
Some combinations of power plant design and capture technology are not possible. Post-combustion and oxyfuel capture processes are compatible with supercritical, advanced supercritical or subcritical pulverised coal plant, whereas pre-combustion is only compatible with the integrated gasification combined cycle (IGCC) design. The implication of this is that not all technologies can be retrofitted to existing ‘capture ready’ coal plant.

4.1.1 Post-combustion

For post-combustion, combustion of coal in air takes place in a ‘conventional’ supercritical, or advanced supercritical, power station, and the CO₂ is separated from other gases in the exhaust stream. The image in Figure 3 shows the key features of a post-combustion capture unit, namely the absorption unit, stripping unit and compressor.

² Source: IPCC Special Report on Carbon dioxide Capture and Storage, 2005.

Figure 3 Schematic of post-combustion capture



In principle, retrofit of post-combustion capture technologies can be applied to a wide range of new and existing plants, although the impacts from redirecting heat towards the CO₂ stripper may be substantial in terms of overall plant output. Depending on the precise piping and heat exchanger configurations for capture, it may be technically feasible to switch off capture equipment and maintain power generation although performance may then not be optimised.

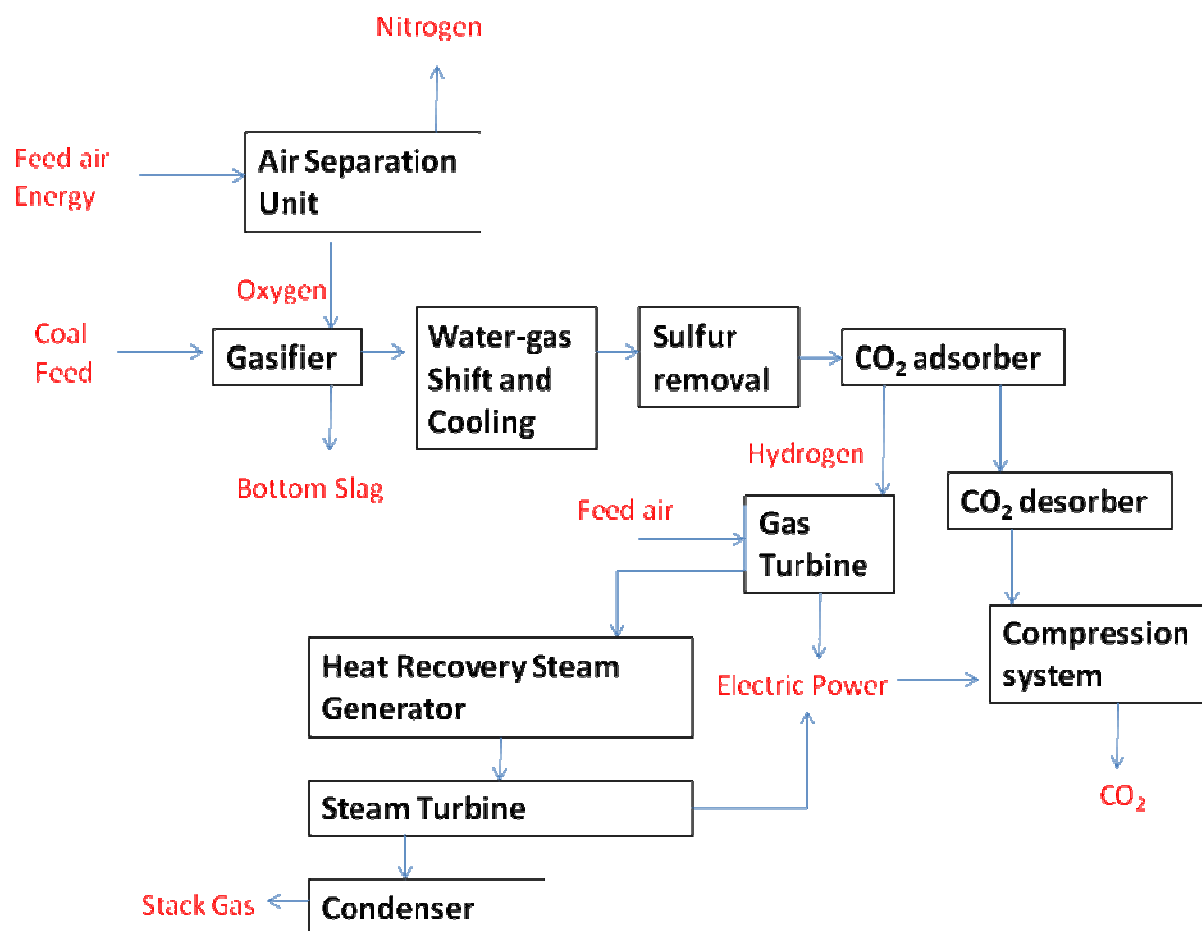
4.1.2 Pre-combustion

With pre-combustion, coal is first gasified to generate a mixture of CO and hydrogen. This is then converted to a mixture of hydrogen and CO₂ using a shift reaction as shown in Figure 4. CO₂ can be separated at this stage and purified if required before compression. Whereas the turbine in a conventional IGCC power station is optimised to burn syngas (a mixture of hydrogen and CO) in air, the pre-combustion capture plant turbine will burn hydrogen in air.

Turbines constitute a major cost item and tend to have strict specifications around fuel supply for optimum performance, making it difficult to switch between two very different gas compositions, throughputs and energy contents³. It is considered unlikely that existing specifications for gas turbines will allow for maintained efficiency or permit safe handling with hydrogen rich gas. Therefore pre-combustion capture is most relevant when designed for new build plant that is designed capture-ready or with full CCS from the start. Once pre-combustion capture equipment is operating, it may then become difficult to switch the CO₂ separation unit off and revert to standard IGCC operation.

³ Unless the gasifier in a capture ready plant is oversized, the hydrogen gas will have a lower calorific value than the original syngas.

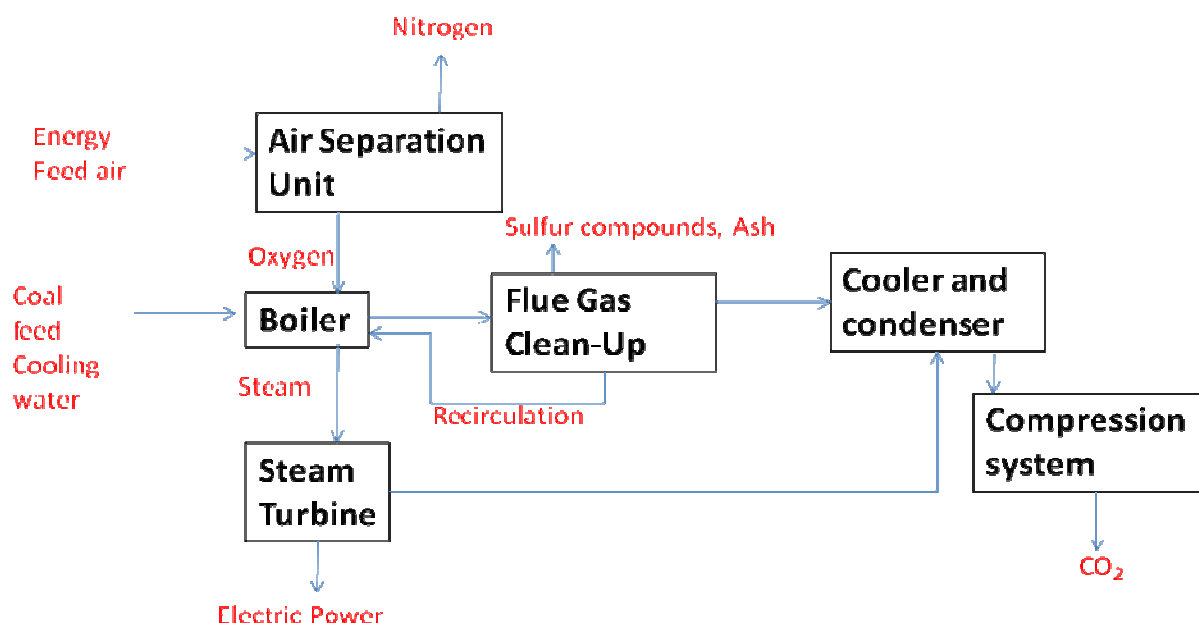
Figure 4 Schematic of pre-combustion capture



4.1.3 Oxyfuel

For oxyfuel, the combustion of the hydrocarbon takes place in pure oxygen, to give primarily CO₂ and steam from which water can be condensed and therefore CO₂ can be readily separated. The pure oxygen must be supplied, for example from an upstream air separation unit, and this requires energy. As illustrated in Figure 5, most designs feature recirculation of approximately two thirds of the oxyfuel flue gas stream – either as the transport medium for the pulverised fuel or gas recycle for the burners and furnace. Oxyfuel combustion is compatible with supercritical and advanced supercritical pulverised coal power stations, and can be retrofitted onto plant that has been designed capture ready for oxyfuel. Once Oxyfuel capture is operational, plant flexibility will likely be linked to the flexibility of the air separation unit. Where gas, heat flows and material are carefully designed it might be possible to revert to conventional supercritical plant operation without capture, i.e. air-firing.

Figure 5 Schematic of oxyfuel combustion capture



4.1.4 Transport and storage

Pipeline transport of CO₂ is considerably more mature than either capture or storage, although a wide permutation of designs and costs are available. There will also be route or location specific cost drivers (e.g. potential to reuse existing infrastructure).

Cost models and scenarios for pipeline transport and offshore storage are described in the Technical Annex, which presents high, medium and low case values for capex and opex for transport and storage configurations. Increasing throughput increases the pipeline diameter and thus costs, however there are substantial economies of scale so that costs per unit transported decrease for the larger volumes.

Pipeline costs scale more linearly with length, and are higher offshore than onshore (although permitting timescales are often shorter offshore). For this reason, offshore pipelines are modelled at higher pressure and velocity as this reduces the diameters required.

4.2 CCS Policy

4.2.1 UK

The Government initially flagged its commitment to drive forward the deployment of CCS technology in the 2006 Budget, which launched a consultation on the barriers to wide-scale commercial deployment of CCS in the UK and the potential role of economic incentives in addressing those barriers. This initiative followed the conclusions of the Stern Review⁴ which highlighted that CCS technology could contribute up to 28% of global carbon dioxide mitigation by 2050.

⁴ The Stern Review – The Economics of Climate Change. Nicholas Stern, 2006

Subsequent to this consultation, the Government launched a twin-track approach to CCS deployment:

- clarifying and developing the necessary national and international regulatory frameworks⁵; *and*
- practical demonstration of CCS technology through large scale pilot projects.

A competition to develop the first UK commercial-scale demonstration CCS project was announced in the 2007 Budget. The intention of this competition is to demonstrate post-combustion CCS on a coal-fired power station with CO₂ stored offshore, capturing CO₂ from 300 MW net (around 400 MW gross) of the power station's capacity and with the plant being operational in 2014.

In April 2009, the Government announced proposals for a new regime for the construction and operation of new coal-fired power plant, and an expansion of the CCS demonstration programme. In particular, it was confirmed that any new combustion power station at or over 300 MW would have to be built Carbon Capture Ready (CCR), which means it should be designed so there are no foreseeable barriers to retrofitting CCS technology once it is proven. The proposals were set out in more detail in "A Framework for the development of clean coal: consultation document" which was published on June 2009⁶. The proposals under consultation included:

- providing financial support for up to four commercial-scale CCS demonstrations in Britain, including the CCS demonstration competition that was launched in 2007, covering a range of CCS technologies;
- requiring any new coal power station in England and Wales to demonstrate CCS on a defined part of its capacity;
- requiring new coal power stations to retrofit CCS to their full capacity within five years of CCS being independently judged technically and economically proven; *and*
- preparing for the possibility that CCS will not become proven as early as the expected date of 2020.

The specific size of each demonstration is likely to vary depending on the particular technology selected. However, it is expected that a commercial-scale demonstration should:

- capture and transport the carbon dioxide emissions from the generation of at least 300 MW net; *and*
- store at least 20 million tonnes of carbon dioxide over a period of 10 to 15 years.

The draft legislative programme for the 2009-10 parliamentary session includes a proposed Energy Bill that would introduce a financial incentive, funded by electricity suppliers, to support the proposed CCS demonstration projects.

4.2.2 EU

In 2005, The European Commission established the Zero Emissions Platform (ZEP) to identify and remove barriers to the wide-scale deployment of CCS in Europe, and in 2006 ZEP recommended that the EU should ensure that between ten and twelve demonstration projects are established across Europe by 2015.

⁵ See, for example, 'Towards carbon capture and storage', a consultation by BERR launched in June 2008

⁶ http://www.decc.gov.uk/en/content/cms/consultations/clean_coal/clean_coal.aspx

The Communication on Sustainable Power Generation from Fossil Fuels was adopted by the European Council in January 2007 as part of the Climate and Energy Package and set out a general strategy for the EU in taking forward CCS technology. As in the UK, this has involved two key elements:

- developing an enabling legal framework and economic incentives for CCS within the EU; *and*
- encouraging a network of demonstration plants across Europe and in key third countries.

In order to address the economic issues necessary to drive forward CCS demonstration and subsequent deployment, the EU has addressed the role of CCS under the EU ETS as part of the review of the EU ETS post-2012 to ensure that it is treated equitably with other low carbon generation sources.

In addition, a number of funding streams have been identified to support the programme of demonstration plant. This includes the receipts from 300 million New Entrant Reserve ETS allowances along with direct funds from the Structural and Cohesion Funds and the European Energy Programme for Recovery (EEPR).

The EU Commission is currently engaged in a discussion process with Member States to agree how the demonstration projects are selected and the European funds allocated. It is extremely unlikely that the EU will agree to support more than two projects in the UK- probably the winner of the ongoing competition plus one other – and this support will need to be at least matched by that from the UK Government. The benefits of a UK demonstration programme can therefore be largely assessed in terms of UK costs and benefits with the impact of the EU funding being that the costs of two of the projects will be somewhat reduced.

4.2.3 Other low carbon policies

In June 2009, the Government published a Low Carbon Transition Plan⁷ which sets out a road map for how the UK will meet its first three carbon budgets out to 2022 along with the longer term target to reduce emissions by 80% by 2050. In particular, policies were outlined which are expected to reduce emissions by 18% by 2020 over 2008 levels. The policy initiatives related to CCS and clean coal are part of a number of policies aimed at ensuring 40% of generation is from low carbon sources by 2020. Others include promoting new build of nuclear power stations and delivering 30% of electricity from renewables sources. Other key elements of the transition plan include major initiatives to improve energy efficiency and to increase the proportion of electric vehicles.

⁷ http://www.decc.gov.uk/en/content/cms/publications/lc_trans_plan/lc_trans_plan.aspx

5 Qualitative policy assessment

In this section, we first outline the different CCS policy measures, and the options associated with each. Then, in order to provide a framework within which to consider the potential effect of the different options, we identify a range of hypothetical specific objectives for the overall policy and regulatory regime. This provides a more concrete means to evaluate alternative policy permutations, and assess how the different options best fit together. For each hypothetical objective, we construct and discuss a 'strawman' set of policy options.

5.1 Policy measures

In this study, we undertook both qualitative and quantitative analysis of specific policy and regulatory options outlined in the Consultation Document:

- the AP and CfD funding mechanisms; *and*
- the retrofit requirement where 'proven', and the contingency measures where not 'proven'.

In addition, in our qualitative assessment, we considered a broader range of aspects of the policy and regulatory framework, including:

- the tender process for selecting up to three additional demonstration projects beyond the existing competition;
- the 'proven' definition for determining if and when retrofit of demonstration plant will be required;
- knowledge sharing requirements for the demonstration plant developers; *and*
- the possibility of an 'ongoing subsidy' to support retrofit at a later point.

We describe these, and their associated options, in more detail below.

5.1.1 Funding mechanisms

The Government has indicated that it is appropriate to fund the demonstration projects through a levy on electricity suppliers. There are various ways in which subsidies to the demonstration projects can be set. In this analysis we have considered the two alternatives proposed in the Consultation Document, namely Additional Payments and Contracts for Difference.

Additional Payment for CCS Electricity

Under this mechanism CCS demonstration projects will be paid a fixed amount, per unit of CCS electricity supplied, in addition to the revenue gained from selling their electricity in the wholesale market. This Additional Payment (AP), to be set through the competitive tender, is intended to cover the cost of building and operating the carbon dioxide capture, transport and storage facilities.

Under this approach the fluctuations in the margin for the demonstration project would be driven (as for an unfunded plant) by changes in commodity prices including carbon price, and the associated impact on

electricity wholesale price, and these risks would need to be managed by the operator as for unabated fossil plant.

Under an AP, once successful bids have been accepted, the absolute level of subsidy paid is relatively certain (depending only on the technical performance of the project). Accordingly, this means that the maximum future cost to consumers is known. As a fixed amount of money paid on the basis of output, it also has the attraction of simplicity, which may be beneficial where financing is being sought from banks or other institutions.

Contract for Difference with the ETS carbon price

With a Contract for Difference (CfD) with the EU Emissions Trading Scheme (ETS) carbon price, CCS demonstration projects would have a fixed 'strike' price, set through the competitive tender, for the carbon they abate. Payments would then be made based on the difference between the strike price and the outturn carbon price. Under a '1-way' CfD, payments would be made (to the project) only when the outturn carbon price was below the strike price, whereas under a '2-way' CfD, when carbon prices exceeded the strike price the project would make payments (back to the administering body). Abatement would be measured relative to an agreed reference based on the emissions from an unabated fossil generation plant (e.g. the emission from the same plant without CCS or a new gas fired plant).

The potential attraction of a CfD is that it would remove some of the uncertainty surrounding the future carbon price for the CCS generator, since the level of support it would receive would increase where carbon prices (and its pass-through into electricity prices) are low, and vice versa. The CfD would leave the generator to sell its output as for any other power station, and require it to manage the remaining fossil fuel and electricity price risk.

The '1-way' CfD would leave upside associated with high outturn carbon prices with the generator. This additional 'option value' should theoretically be priced into bids in a competitive tender process, but in practice this is difficult to quantify and may not be taken into consideration. The '2-way' CfD, on the other hand, could limit rents in a high carbon price world (and correspondingly reduce costs for consumers).

5.1.2 Retrofit and contingency measures

The Consultation Document proposes that coal stations would be required to retrofit CCS to their full capacity within a defined period following CCS having been independently judged economically and technically proven. The Government is planning on the basis that CCS will be judged proven by 2020 and has proposed that there should be an independent review to assess the status of CCS technologies that would report in 2020. It is envisaged that further new coal stations would then be required to install CCS technology on the full generating capacity from the outset.

The Government has recognised that there remains the possibility that CCS technology will take significantly longer to prove than it expects, or that it will not be proven at all. It is therefore contemplating signalling a clear expectation that, with or without CCS, there will need to be substantial reductions in emissions from coal stations in the future. A number of possible measures have been flagged to achieve this objective:

- a cap on carbon dioxide emissions from individual coal stations which would allow power stations to emit up to a specified amount of carbon dioxide each year, or over a number of years;
- a limit the amount of CO₂ which could be emitted per unit of electricity generated; or

- a running hour's limit which would allow coal power stations a maximum number of running hours, either as a yearly limit or over a longer period.

Under each of these possible approaches, it would be necessary to determine the level at which any limit on operation should be set. The first two of these are possible implementations of an Emissions Performance Standard (EPS), and benchmarks that could inform the EPS level include the emissions from a new CCGT power station or projections of the necessary emissions pathway towards 2050. The third example could be considered as a simpler alternative (analogous with the mechanism for 'opted out' plant under the Large Combustion Plant Directive).

In principle, contingency measures could also be applied to existing coal plant as well as the demonstration projects and other new build.

An alternative to the retrofit/contingency structure would be to use an EPS approach under all circumstances (even where CCS technology was quickly proven), but leave the decision to retrofit as a purely commercial one on the part of the developers. If the EPS tightened over time, emissions would be controlled in cases where retrofitting was not commercially viable, and would simply become academic in cases where it was. This would have the benefit of removing the need for (and uncertainty around) an independent 'proven' decision. This option could be easily extended to cover all coal plant.

5.1.3 Tender process

A competition process for one demonstration project is already underway and it is envisaged that this will carry on as planned. Therefore, it is necessary to consider the appropriate arrangements to select up to an additional three projects. As there has thus far been no commercial scale deployment of CCS technologies for power generation anywhere in the world, there is a high degree of uncertainty with regard to costs and technical performance. The main objective of the tender process should therefore be to stimulate competition between potential developers and hence drive down the level of support required to deliver the demonstrations.

In designing the tender process, it is necessary to consider a range of other objectives for the demonstrations which have been set out by Government, namely to:

- gain experience of a range of CCS technologies;
- develop a broad and sustained UK capability in the design, construction and operation of alternative CCS technologies that will be capable of capturing a significant share of the expected global market;
- maintain momentum in the UK development of CCS that will be sustained until the technology is expected to become commercially viable;
- establish CCS as "best available techniques" (BAT) for the deployment of clean coal power generation in the UK, which will require the establishment of a strong knowledge base on the cost and performance of CCS technologies;
- help establish competitive supply chains for CCS design, equipment and operation;
- accelerate diffusion of knowledge on CCS both within the UK and globally; *and*
- deliver affordable projects that represent value for money.

The tender process will therefore be seeking to identify projects which fulfil a range of criteria and to ensure that these are delivered at the lowest possible cost to consumers. There are a range of options with regard to how the tender process could be designed. The number of projects being sought might be

fixed (i.e. 1, 2 or 3) or might be specified as 'up to' a certain number depending on, for example, the costs involved. The process could be broken into sequential 'rounds', with one or more projects selected at each point. The tender might be technology neutral (i.e. the cheapest three bids) or the Government might be seeking technology diversity and looking for specific technological solutions – perhaps to fit in with the EU process.

5.1.4 Proven definition

The Government has indicated that an independent body (most likely the Environment Agency) would be responsible for assessing when CCS technology is both technically and economically proven such that retrofit regulations might be triggered.

Technical 'proving' can be defined at various levels from 'a demonstration project has worked' to 'a number of projects have worked for a significant period of time' and the independent assessor will need to identify where on this spectrum proving occurs. Also, there are significant differences with CCS technologies and it is unlikely that they will be proven at the same time. This will need to be taken into account in light of the technical options available to operators (for example, it will not be possible to enforce retrofit on existing plant if only pre-combustion technology has been proven).

Economic 'proving' could be defined in a number of ways. In particular, the future value of abated CO₂ is critical and the independent assessor will need to decide whether future economic viability is based entirely on market expectations of EU ETS carbon prices, or whether an alternative measure, such as the Government's social cost of carbon figure, would be used even if the EUA price were below that. In the latter case, some form of ongoing subsidy may need to be included as part of the assessment.

This area is discussed in more detail in Section 8, which discusses the role of the Environment Agency in this context. The most relevant aspect for our qualitative analysis, however, is the extent to which the definition of 'economically proven' could range from 'commercially viable' (meaning that the generator would be expected to retrofit of its own accord) to a societal definition that could (for example) be based on a higher cost of carbon where the ETS price was not seen as capturing the full costs.

5.1.5 Knowledge sharing

One of the key objectives of CCS demonstration programmes is to ensure that the technology involved becomes widely available from a variety of manufacturers each using their individual design. It is, therefore, inappropriate that public money should be spent on one project such that the learning involved is restricted to a single manufacturer since this would provide the manufacturer with a strong competitive advantage and restrict ongoing competition in the market for provision of CCS equipment.

Requirements to share knowledge have therefore been key components of both the EU demonstration programme and the first UK competition and it is possible to continue this requirement into subsequent demonstrations. However, in the circumstances that other policy objectives, such as promoting diversity of supply, are deemed more important for these later demonstrations, it may be argued that knowledge sharing provisions are less relevant and could be relaxed or dropped altogether.

5.1.6 Ongoing subsidy

Beliefs about the nature of the ongoing market framework amongst investors will have a major impact on the costs and risks of investments in coal plant under the new regime. In particular, the way that a retrofit requirement is perceived will be very different where additional future (direct or indirect) financial support was expected. A number of possibilities exist:

1. Market rules continue as now with no additional mechanisms introduced. In these circumstances, the costs of CCS and coal investments will need to be recouped primarily through energy price earnings and the avoided cost of carbon emissions.
2. New broad ranging economic instruments might be introduced which improve the viability of low carbon investments by, for example, reinforcing the carbon price from the EU ETS or by providing an additional revenue stream that rewards low carbon capacity over and above the wholesale energy market.
3. It is possible that a more targeted scheme is introduced to promote directly CCS investments, whether in the form of specific support for retrofits, a more general CCS 'obligation', or even tendering for individual projects through direct contracts with some central purchasing authority.

It is impossible for any Government to give absolute certainty over the nature of the future market arrangements and, given this inherent uncertainty, it is difficult for the Government to ensure that investors include the benefits of an ongoing subsidy as part of the business case for an investment.

5.2 Policy objectives

There are clearly a wide range of potential high level policy objectives for a CCS demonstration programme which can be fulfilled to varying degrees by different combinations of detailed policy mechanisms. For the purpose of our qualitative assessment, we identified the following list of hypothetical policy objectives:

- **Quick UK deployment:** ensure a rapid roll-out of technologies to maximise technology learning within the UK.
- **Support 2050 pathway:** increase the number of low carbon investment options available to investors, helping to minimise the cost of long term decarbonisation.
- **Fair share of EU/global burden:** Play a proportionate role in the European and global efforts to roll out CCS internationally, but without incurring undue costs for UK consumers.
- **Generation diversity:** Introduce new coal into the UK generation mix in an environmentally acceptable manner to increase diversity of supply and reduce gas dependency.
- **Regeneration:** stimulate economic development and job creation through CCS.
- **Unabated coal phase-out:** limit new unabated coal as far as possible, and rapidly reduce unabated generation from existing capacity.

Whilst of course in practice the Government will be aiming to meet many objectives simultaneously, this exercise helps identify how the different policy measures can be formulated in different ways to meet different objectives. These choices are examined below.

5.2.1 Quick UK deployment

The objective here is to ensure significant CCS roll-out specifically in the UK in a relatively short timeframe.

Given the uncertainty around technologies, a quick deployment strategy is likely to need technology diversity and hence the tender process is likely to target a set of demonstration projects involving three different technologies.

Knowledge sharing is likely to be very important with this objective since, in a scenario where one technology was the clear lead, then without knowledge sharing at the demonstration stage there may be a lack of competition during the subsequent roll-out. However, such knowledge sharing would not necessarily require intervention through specific obligations tied to the funding.

Delivering a quick roll-out suggests that there needs to be an attractive ongoing business case for investors and this in turn suggests the need for a credible future subsidy to support retrofit if CCS was 'proven' but not commercially viable. Likewise there would be a danger in too strong a contingency in deterring investors through introducing risks that are difficult to manage.

It is likely that a quick deployment would lead to a 'broad' definition of proven and that this would drive the retrofit timeline. It could be appropriate in this context to compare the cost of CCS to other low carbon technologies.

5.2.2 Support 2050 pathway

Under this policy objective, the aim is to encourage CCS as one of a range of technologies likely to be needed in the 2050 timeframe to achieve near complete decarbonisation of the electricity sector. The focus is therefore on supporting the scaling up of technologies (and tackling potential market failures in the pre-commercial phase) but allowing the market to determine subsequent deployment.

The three different technologies are likely to be supported at the demonstration phase, but knowledge sharing would be less relevant. There would be no retrofit requirement, with this decision left as a commercial decision, and a 'proven' definition would focus mainly on ensuring market awareness of the technology status. It is possible that an ongoing subsidy might be considered to equalise investment incentives with other technologies which are subsidised (notably renewables). However, given that the objective here is not on CCS deployment per se, it is unlikely that strong CCS-specific contingency measures would be employed, but rather that more broad ranging measures to drive decarbonisation (in addition to the EU ETS and other incentive mechanisms) would be introduced.

5.2.3 Fair share of EU/global burden

In this case, the policy objective would be for the UK to contribute its 'fair share' to supporting CCS on a European or global basis. In this context, it could be argued that two funded demonstrations in total would be sufficient to meet this objective if wider European deployment moves ahead as planned, and hence the policy could commit to a single plant (in addition to the competition plant) through the tender, with the option of further plant depending on EU/global developments. The technology type would be that which best suited the overall EU/global strategy. There would also be an objective of maximising knowledge sharing.

In order to limit risk to investors at the demonstration stage, the definition of ‘proven’ would be more tightly defined as ‘commercially viable’, with retrofit required 5 years thereafter. For similar reasons a relatively ‘loose’ contingency would be defined. This could be in the form of an annual plant-level carbon limit in the latter part of the plant’s economic life (for example, starting in 2030).

5.2.4 Generation diversity

Under this objective, the main goal is to enable new coal capacity to be built in order to provide a greater level of fuel diversity, but in an environmentally sound manner. This would call for three funded demos as well as the competition plant, with a focus on the lowest cost rather than on technology diversity. In fact the tenders may be designed to favour (or target explicitly) post-combustion as this is likely to lead to larger scale plant, could in principle be fitted to existing plant, and does not provide an option to switch to gas at a later point. There would be no specific consideration of knowledge sharing.

The definition of economically proven would be tightly defined as ‘commercially viable’ to avoid imposing additional risk on investors, and, similarly, a ‘loose’ contingency would be put in place.

5.2.5 Regeneration

This aim here is to stimulate economic development and job creation, both through the direct impacts arising from the construction of the CCS projects and the development of the associated supply chains, and through the longer term indirect impacts associated with the potential to attract carbon intensive industry to a region with developed carbon abatement infrastructure. Whilst the objective here is focused on more general economic development rather than technology deployment in itself, the resulting policy choices are likely to be very similar to the ‘*Quick UK deployment*’ objective since in both cases the onus is on stimulating a rapid growth in CCS on a UK-centric basis. In this context, however, there could be more specific locational considerations in the tender process – either to target specific areas for regeneration, or to encourage clustering to provide more momentum behind the development of CCS industry and supply chain growth and to attract other carbon intensive industries.

5.2.6 Unabated coal phase-out

The main objective here is not to introduce CCS per se, but to eliminate unabated coal generation. There could be just one funded demonstration in addition to the competition plant (and this could allow, or indeed require, retrofit rather than new build). Knowledge sharing would not be a consideration. The retrofit requirements and contingency measures would be combined into a single strict measure, such as the introduction of an EPS or tight plant bubble limit with an explicit date. The measure would apply to both existing and new coal.

5.3 Summary

The analysis described above is summarised in Table 2 below.

Table 2 Policy summary

Policy objective	Tender design	Knowledge sharing	Application of contingency	Strength of contingency	Proven definition	Future subsidy	If proven
Quick UK deployment	+3, different technologies	Substantial	New coal only	Strongest sufficient with incentive to invest	Comparable cost to other low carbon technologies	Sufficient to make commercial	Retrofit required
Support 2050 pathway	+3, different technologies	Less relevant	n/a	Market-wide broad ranging CO2 regulation	Market awareness	If required to 'level playing field' versus other low carbon options	n/a
Fair share of EU/global burden	+1 committed with option for more	Maximise	New only	Strongest sufficient with incentive to invest	Commercially viable	No	Retrofit required
Generation diversity	+3 At lowest cost	Not relevant	New only	Strongest sufficient with incentive to invest	Commercially viable	No	Retrofit required
Regeneration	+3 (possible clustering)	Desirable	New coal only	Strongest sufficient with incentive to invest	Comparable cost to other low carbon technologies	Sufficient to make commercial	Retrofit required
Unabated coal phase-out	+1 demo (possibly requiring retrofit)	Not relevant	Existing and new coal	Strong	n/a	No commitment	n/a

This assessment demonstrates that it is important to have clear high level objectives in order to develop a consistent and effective set of policy measures. We draw out the following high level summary on the basis of our qualitative assessment:

- We saw the form of the funding mechanism (AP or CfD) as one option that can be considered relatively independently of the other aspects of the regulatory and policy framework. The CfD has the attraction that it may provide a 'hedge' against the carbon price exposure for projects, and protect consumers from the possibility of higher rents to generators. On the other hand, the AP provides a more certain absolute level of funding, and hence a known future liability, and offers a simplicity which may be beneficial where external financing is sought.
- A requirement for three additional demonstration plant, and the additional costs involved, could be based on one, or a combination of, the following benefits:
 - ensuring fast UK deployment independent of EU and global developments;
 - developing options for a 2050 low carbon pathway for the UK;
 - improving security of supply since the additional coal fired generation would replace an equivalent quantity of gas fired generation;
 - economic regeneration associated with developing the supply chain infrastructure associated with CCS deployment; *and*
 - playing a leadership role (rather than a 'fair share') in driving forward the international deployment of CCS.
- Requirements for knowledge sharing varied, but were particularly important where the UK demonstrations were an integrated part of an overall EU strategy.

- A strong contingency was seen as a potential deterrent to demonstration project investors in most cases, without providing significant benefit. However, where the objective was phasing out unabated coal, a strict EPS (or equivalent) covering both new and existing coal was seen as an effective mechanism.
- For objectives intended to accelerate UK deployment, a retrofit requirement ahead of commercial viability was seen as useful, but supported by an additional subsidy if required.
- None of our objectives related to reducing UK emissions, given that the power sector is within the EU ETS. Interventions could however play a role in reducing emissions more broadly by introducing new and cost effective abatement technologies that accelerate deployment on a global basis.

6 Demonstration project modelling

6.1 Analysis objective

The objective of the demonstration project modelling was to evaluate the relative economics and risk of CCS demonstration projects under different policy options from a developer's perspective. In order to undertake the analysis we developed a comprehensive discounted cash flow model, the Risk Assessment Model (RAM). The RAM calculates the expected demonstration project funding policy gap measured as a Net Present Value (NPV). The RAM was also used to estimate project risk premia by simulating multiple scenarios to capture the uncertainty around key input variables (e.g. commodity prices, capital costs and plant technical parameters).

Installing CCS facilities to a base coal plant involves increased capital expenditure on the CCS equipment and the CO₂ transport and storage infrastructure. There is also an increase in plant parasitic load (to run the capture processes) which reduces the net output at station gate. These factors lead to a reduction in the project NPV, which is offset (to a greater or lesser extent) by carbon cost benefits due to abatement through CCS. In addition, the lack of maturity of the technology causes greater uncertainty around capital costs, operational parameters and timings of expenditure on the CCS equipment, which leads to an increase in the project risk.

We used the RAM to help address a set of questions aimed at understanding the economics of CCS demonstration projects in the context of different policy options:

- What is the 'funding gap' for CCS projects?
- What is the impact of introducing an AP or CfD-based funding mechanism?
- What is the impact of imposing a retrofit requirement?
- What is the impact of imposing an annual carbon emissions limit as a contingency?
- What is the incremental impact on developers' bids of uncertainty around whether and when CCS is proven?
- What is the cost to the consumer of meeting the funding gap?

The approach we adopted is set out in more detail in Section 6.2, modelling results addressing the questions above are presented in Section 6.3, and key messages from the analysis in Section 6.4. Further details on assumptions, modelling methodology and illustration of key results are included in the separate Technical Annex.

6.2 Approach

6.2.1 CCS demonstration plant configurations and costs

Four specific 'first of a kind' demonstration project configurations were analysed: one post-combustion, two pre-combustion and one oxyfuel. The technical configurations of these projects were based on DECC assumptions.

For post-combustion, we modelled a 1600 MW capacity station, with 400 MW (gross) fitted with CCS from the outset.

In the case of pre-combustion, we modelled two configurations. An IGCC station of 986 MW comprising two units of 493 MW capacity was modelled in one case with a single unit fitted with CCS at the outset and the other as CCS ready; and in the second case as fully fitted with CCS from the outset⁸.

For oxyfuel, we modelled a single 393 MW unit station fully fitted with CCS. Due to the nature of the technology, the option of partial CCS fitting and retrofit was not applicable.

For partially-fitted configurations, the carbon transport and storage facilities were assumed to be sized to cater only for the CCS fitted unit at outset with need for further capital expenditure at the point of retrofit.

The configurations are summarised in Table 3.

Table 3 Modelled demonstration plant configurations

Technology	Station capacity (MW gross)	Demo unit capacity (MW gross)	Realised station capacity (MW net)	CCS component of the realised station capacity (MW net)
Post-combustion	1600	400	1385	284
Pre-combustion (partially-fitted)	986	493	814	360
Pre-combustion (fully-fitted)	986	986	720	720
Oxyfuel	393	393	300	300

To ensure comparability across technologies and plant configurations, all projects were modelled to start operation in 2014. (In our market modelling, the start dates of the projects are staggered based on assumptions about tender timings and development times). Key costs and plant technical parameters are summarised in Table 4 (with other assumptions presented in the Technical Annex)⁹. These are based on DECC assumptions, with the exception of costs for transport and storage, which we derived from based on internal models (described in the Technical Annex). The initial CCS expenditures are ‘first of a kind’, whilst retrofit costs have an assumed learning benefit.

⁸ It is also possible that developers might build a single unit IGCC, fully fitted from the outset. Whilst we have not modelled this configuration, the proportional cost of transport and storage capex would be higher for such a configuration compared to a fully fitted 2 unit configuration due to the lower economies of scale.

⁹ The analysis did not include an assessment of (or correction for) optimism bias.

Table 4 Key demonstration plant technical assumptions

	Unit	Post-combustion	Pre-combustion (part-fitted)	Pre-combustion (fully-fitted)	Oxyfuel
Capex - base plant (CCS ready)	£ / kW gross	1,136	1,533	1,533	1,768
Capex - CCS equipment	£ / kW gross	769	329	282	654
Capex - initial transport and storage costs	£ / kW gross	650	591	388 ¹⁰	650
Capex - retrofit (incl. transport and storage resizing)	£ / kW gross	933	797	n/a	n/a
Parasitic load - base plant	% of kW gross	8.3%	7.9%	7.9%	8.4%
Parasitic load - base plant + CCS equipment	% of kW gross	28.9%	27.0%	27.0%	23.7%
Efficiency - base plant (net of 'Parasitic load – base plant')	%	45.0%	43.0%	43.0%	44.0%
Efficiency - CCS unit (net of 'Parasitic load – base plant + CCS equipment')	%	34.9%	34.1%	34.1%	36.7%
CCS emissions capture rate	%	91%	90%	90%	90%

Certain technical features were not modelled within the scope of the project. In particular, the option of by-passing the CCS equipment (for post-combustion) to maximise output at times of high electricity prices, and the capability for IGCC plant to switch to running on gas from coal (as applicable in case of the pre-combustion design) were not taken into account.

6.2.2 Retrofit and contingency

For cases where CCS was deemed to be proven, and retrofit therefore required, we assumed that the works would be completed over a four year period. For example, a requirement for retrofit to be operational in 2030 would imply that capital expenditure for CCS equipment (and transport and storage resizing) would begin in 2026 and be completed by the end of 2029. The requirement and the timing of retrofit were modelled as exogenous inputs. In the following sections, when we refer to a retrofit year (e.g. '2025 retrofit'), unless stated otherwise, we mean the year the retrofit installation commences, with retrofit operation following four years later.

If CCS was deemed not to be proven, we assumed a contingency would be imposed in the form of an annual limit on carbon emissions for each plant, which would take immediate effect. This is one of the three types of contingency discussed in Section 5.1.2. We have modelled an annual limit such that carbon emissions are approximately equivalent to those produced by a CCGT gas plant of the same gross capacity operating at a load factor of 80%. In the case of a coal plant of 1,600 MW gross capacity with a 400 MW unit fitted with CCS, this translates to an emissions limit of 3.8 mT/year (equivalent to an annual load factor cap of around 49%). A variant was considered as a sensitivity, which assumes annual emissions are initially capped at the level of an advanced supercritical coal plant running at 60% load factor and then linearly tightened to those of a CCGT at 80% load factor over the course of five years.

¹⁰ The 'per kW' transport and storage capex for fully-fitted pre-combustion is lower than that for the other configurations due to economies of scale. Details are included in the Technical Annex.

6.2.3 Commodity price assumptions

In order to assess demonstration project economics, we developed an expected commodity price case designed to represent current 'investor expectations'. This case differs from the DECC price assumptions used in the market modelling, as it is intended to represent a view taken for the purposes of an investment decision, which we believe is likely to differ. Most significantly, we expect that investors will have a lower expectation of future carbon prices, taking account of the significant uncertainty with regard to future carbon policy. While carbon prices still rise in our 'investor-expected' case, they do so more gradually than the DECC price sets. This of course increases the 'funding gap' from an investor's perspective and diminishes the carbon costs benefits of fitting CCS.

The 'investor-expected' case is based on the following assumptions:

- near term prices are broadly in line with forward curves as of August 2009;
- carbon (EUA) prices are projected to increase linearly from levels as of August 2009 to €50/t in 2030; and
- coal prices are projected to remain relatively flat at \$85/t¹¹, while a linear increasing trend in gas prices was assumed such that CCGTs are broadly competitive with coal plant on a Short Run Marginal Cost (SRMC) basis.

Electricity prices are calculated within the model based on the commodity prices and capacity margins¹².

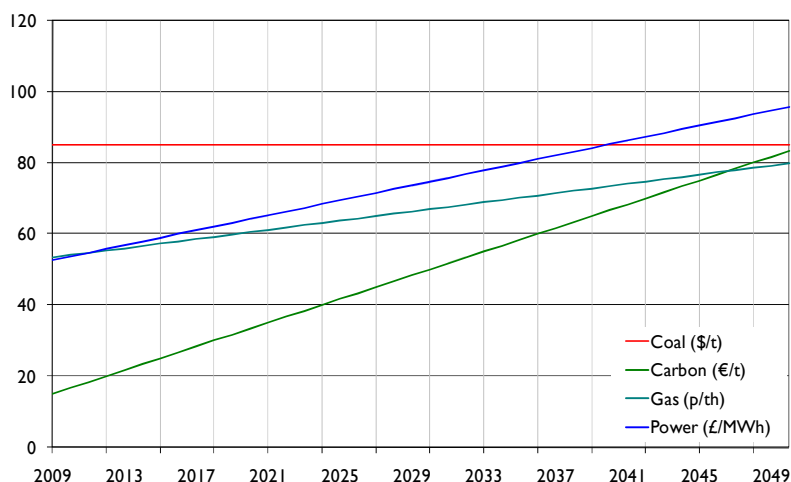
The above price case was designed in part such that a conventional supercritical coal plant just breaks even on an NPV basis. This is consistent with observations of developers recently looking to invest in unabated conventional coal capacity, and has the advantage that the base coal plant (for post-combustion) does not in itself contribute to the 'funding gap' when we analyse the project economics, making analysis of the results more straightforward¹³. A plot of commodity prices in the investor-expected case is shown in Figure 6. All prices are shown in 2009 real terms.

¹¹ Note the coal price projection is quite stable given a relative abundance of supply (in comparison to declining oil reserves).

¹² Electricity prices in the RAM are calculated based on the SRMC of a marginal gas plant, with an 'uplift' applied to reflect a premium above SRMC levels (and calibrated against historic data). A simplified price duration curve is used such that load factors can be determined endogenously.

¹³ Recent price movements have shifted the economics away from coal towards gas, and views on future carbon prices span a broad range. Were investors not to view ASC as economic in its own right, this could increase the funding gap for any demonstration project.

Figure 6 Investor-expected commodity price case



6.2.4 Model operation modes

The RAM has two modes of operation: stochastic and deterministic. In deterministic mode, the key model inputs are plant capital expenditure, operating costs, the project hurdle rate, commodity price projections and chosen policy measures. The model uses these to calculate post tax cash flows, project NPV for the duration of the project at the relevant hurdle rate, internal rate of return, the implied levelised energy cost and an estimate of the developers’ tender bids as outputs. In deterministic mode, a single set of input assumptions is used to generate a single set of outputs.

In stochastic mode, the model uses all of the above inputs along with definitions of uncertainty around the key variables (such as prices, costs and operational parameters). It executes a user specified number of simulations and returns an NPV distribution from which the risk-adjusted hurdle rate and the risk premium are backed out. Figure 7 and Figure 8 show diagrams of the two modes.

Figure 7 RAM in deterministic mode

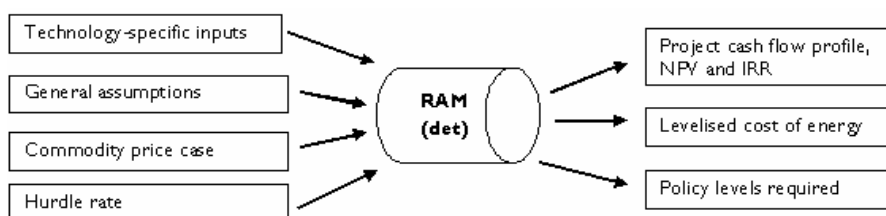
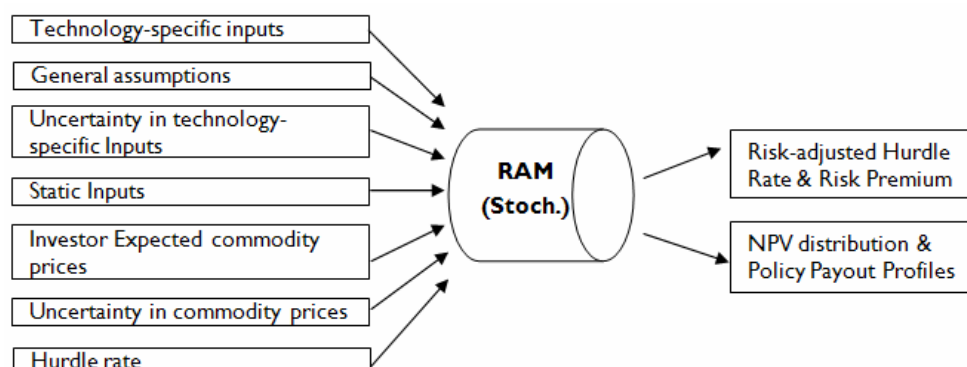


Figure 8 RAM in stochastic mode



The architecture of the RAM, the calculation methodology and the procedure for the risk premium calculation are described in more detail in the Technical Annex.

6.2.5 Project hurdle rates

The hurdle rates used in the model are key determinants of project NPV and the associated funding gap. The model calculates these by estimating a risk premium associated with each demonstration project for the considered policy scenario and adding this to a base hurdle rate of 10%¹⁴, which we use as a benchmark for conventional thermal capacity (such as a CCGT).

The key determinants of the project risk premium are the uncertainties around costs, revenues (particularly power prices) and timings. We used the NPV distributions calculated by the RAM to risk adjust a benchmark hurdle rate, which provides a consistent methodology for comparing the cost impact of the risks inherent in different policy options. (In practice, the choice of hurdle rate applied by a specific developer to a demonstration project is likely to be subjective and will be strongly influenced by factors such as the strategic benefit of winning a demonstration project bid and the perceived risk/reward trade off for that project relative to other projects undertaken.)

In order to adopt a consistent approach to the calculation of hurdle rates, we assumed a benchmark hurdle rate of 10% for a conventional thermal power plant project. It should be noted that this is a weighted average project return across debt and equity, not an equity return. We captured the impact of debt financing for the project via an assumption on the level of gearing used to calculate the developer's project hurdle rate. The project gearing is assumed to reflect an average utility developer's overall capital structure. This approach is consistent with any debt raised through the demonstration project having recourse to the developer. We considered it unlikely that non-recourse debt would be raised against CCS demonstration projects given the level of risk involved.

For each case analysed, we then adjusted the benchmark hurdle rate based on an estimation of project risk via calculation of a risk premium. This was calculated by generating 20,000 simulations of input variables to derive a distribution of demonstration project NPV. The project risk premium (in £mn) was calculated by taking the difference between the 99th percentile and the mean and multiplying it by the investor's WACC. Finally, the incremental increase in hurdle rate equivalent to the (£mn) risk premium (the project's '% risk premium') was determined by goal-seeking the rate required to increase the NPV by this amount. This

¹⁴ The 10% benchmark rate is in post tax nominal terms (assuming long run inflation of 2%).

incremental increase in hurdle rate was added to the benchmark 10% rate to yield a risk-adjusted hurdle rate that was used to discount project cash flows and generate the project NPV.

6.3 Results

In this section we use results from the Risk Assessment Model to address each of the questions introduced in Section 6.1. At the end of the section we draw high level conclusions.

It is important to note that the absolute levels of funding gap and developers' tender bids calculated in the RAM are very sensitive to these input assumptions, particularly commodity prices, capital costs and hurdle rates. An indication of sensitivities of NPV to different input assumptions is provided in the Technical Annex. Despite this, useful conclusions can be drawn in on the relative impact of different policy options on the funding gap across the three technologies.

6.3.1 What is the 'funding gap' for CCS projects?

The project economics for all three technologies are currently unattractive, with substantial negative NPVs. This 'funding gap' would need to be addressed through financial incentives to make projects commercially viable.

The calculated funding gaps are shown for each of the plant configurations in Table 5. Results are shown for projects assuming no funding, retrofit or contingency policy measures.

As the different technologies have different configurations, we also show the levelised cost of energy for each, which represents the power price (in real 2009 terms) that would be needed to support the project in the absence of any funding mechanism. This provides a more direct way to compare the relative costs of the different technologies. Levelised costs range from 81 £/MWh for post-combustion to 108 £/MWh for oxyfuel.

The absolute level of the funding gap was very sensitive to assumptions on plant configuration, capital costs, expected commodity prices and project hurdle rates. A table of sensitivities is included in the Technical Annex. The results in Table 5 assume an investment hurdle rate in the absence of any additional financial support for the CCS demonstration plant. (As we discuss in later sections, the introduction of funding support in itself reduces the risk premium and hence the funding gap.)

Table 5 Indication of funding gap across technologies

	Post-combustion	Pre-combustion (part-fitted)	Pre-combustion (fully fitted)	Oxyfuel
Configurations				
Total capacity (MW gross)	1600	986	986	393
Capacity of CCS demo unit (MW gross)	400	493	986	393
CCS net capacity (MW net)	284	360	720	300
Funding gap indication				
NPV (£ mn)	-499	-794	-709	-429
Levelised cost of energy (£/MWh) (for project as a whole)	81	100	95	108

The NPV results for the projects are a function of the overall plant capacities, and the proportion that is fitted with CCS. The levelised cost of energy figures are for the project as a whole and thus provide a means to compare relative costs across projects.

Using the investor-expected commodity price case, an unabated advanced supercritical coal plant just breaks even at the benchmark hurdle rate (as explained in Section 6.2.3). As a result the additional funding required in the case of post-combustion applies broadly to compensating the developer for the additional costs of installing and operating the CCS equipment. In the case of pre-combustion, the core IGCC plant is not economic at the investor expected prices, so funding support is required for both the core plant and the incremental costs of the CCS equipment. However, it is important to note that the incremental costs of fitting CCS are relatively low for pre-combustion (approximately 18% of the base plant capital expenditure, excluding transport and storage costs, compared to 68% in case of post-combustion). In the case of oxyfuel, the CCS capability is inherent to the development of the core plant (i.e. the option of partial fitting is not applicable).

In case of pre-combustion, under our assumptions, the benefits of savings on carbon costs associated with fully fitting immediately were found to outweigh the benefits of delaying the capital expenditure to later years, meaning that a complete fit of CCS at project from onset was found to be economically preferable in comparison with fitting CCS to only part of the plant capacity. However, this result is very sensitive to carbon price (and indeed other assumptions such as capital costs).

The funding gap faced by the developer can be considered as two components, shown in Table 6 for the different configurations:

- the negative NPV impact from undertaking the project at the benchmark hurdle rate, due to CCS equipment costs (capital and operating) and reduction in operating performance, partially offset by the savings in carbon costs (shown in the first row of the table); *and*
- the incremental negative NPV impact (shown in the second row of the table) associated with increasing the project hurdle rate to account for the project risk premium (%) that is added to the benchmark hurdle rate (shown in the bottom row of the table).

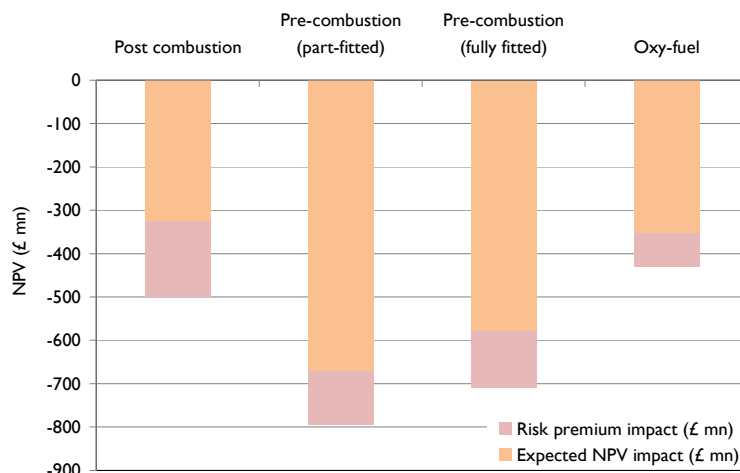
Both of these are calculated for the project as a whole (including abated and unabated capacity).

The % risk premium in the case of the pre-combustion (part-fitted) configuration was found to be high in comparison with those for other technologies. This is due to a combination of higher capital expenditure (relative to post-combustion) together with the risk of reduced load factor and margin caused by the carbon exposure from the unabated part of the plant, which leads to a higher % hurdle rate change for a given £mn risk premium.

Table 6 Funding gap analysis

	Post-Combustion	Pre-Combustion (part-fitted)	Pre-Combustion (fully fitted)	Oxyfuel
Expected NPV impact (£ mn)	-326	-670	-579	-351
Risk premium impact (£ mn)	-173	-124	-130	-78
Toil impact [=NPV+Risk Premium] (£ mn)	-499	-794	-709	-429
Risk premium (%)	1.34%	2.66%	1.35%	1.84%

Figure 9 Funding gap components



6.3.2 What is the impact of introducing an AP or CfD-based funding mechanism?

In this section we analyse the potential impact of introducing a funding mechanism, and the level which would be needed to make projects economic. We first discuss the impact on the risk premium, and then show how the calculated funding gap would translate into developers' bids.

The different types of funding mechanism affect project risk in different ways. The level of the AP pay-outs is independent of commodity prices, and will only vary where the CCS load factor changes, for example due to technical performance problems. On the other hand, CfD pay-outs will vary significantly with different levels of carbon price. As such, they may be expected to have different impacts on the distribution of overall project gross margin, our metric for project risk.

As there is reasonable flexibility within the 15 year cap on funding to cover technical performance risks, the introduction of AP funding could be expected to have a relatively small impact on the overall spread of gross margin distribution. The change in the measured risk premium in £mn should therefore be small. On the other hand, for the CfD, as pay-outs are inversely correlated with carbon price, this might be expected to act as hedge to the inherent project carbon price exposure, and hence have the effect of reducing the gross margin spread and lowering the associated £mn risk premium.

The results of our analysis on the impact of the funding mechanisms on risk premia are summarised in Table 7. While our modelling confirms our expectation with respect to an AP funding mechanism (with only small differences in £m risk premia), CfD pay-outs were in fact found in some cases to somewhat over-hedge the underlying carbon price exposure with our assumptions (resulting in small increases in £m risk premia in some cases). In other words, the reduction in revenue from the funding mechanism when carbon prices are high outweighs the benefit to the project economics elsewhere. It should however be noted that this effect is very sensitive to the CfD strikes and our modelling of the relationship between power and carbon prices. An analysis of this is presented in the Technical Annex.

Table 7 Impact of funding mechanisms on project risk premia

	Post-combustion	Pre-combustion (part-fitted)	Pre-combustion (fully fitted)	Oxyfuel
Risk premia (%)				
Without funding mechanism	1.34%	2.66%	1.35%	1.84%
AP mechanism	1.07%	1.11%	0.93%	0.95%
CfD mechanism	1.12%	1.17%	0.95%	0.98%
Risk Premium (£ mn)				
Without funding mechanism	173	124	130	78
AP mechanism	171	121	127	73
CfD mechanism	177	126	128	74

Whilst the introduction of funding mechanisms does not significantly reduce £mn risk premia, there is a significant impact on hurdle rates. This is because the sensitivity of the project NPVs to hurdle rate changes varies depending on the shape of the project cashflows: to recover the same level of NPV risk premium requires a different change in hurdle rate depending on the shape of the cashflow profile. When the funding mechanism is introduced, this contributes relatively large positive cash flows at the front end of the projects, reducing the incremental hurdle rate required to adjust for the corresponding £ mn risk premium. This explains why the impact on risk premia in NPV terms is small but the impact on risk premia as % hurdle rate changes is material. The impact of this varies between the technology configurations based on the overall project size compared to the funding, and the underlying shape of the cashflow profile.

We estimated developers' tender bids by finding the level of funding that would be required for the project just to breakeven using the hurdle rates shown above (and, again, without any additional policy measures around retrofit or contingency). For the AP, we calculated the additional £/MWh payment for all abated generation, whilst for the CfD we calculated the amount required in £/t for each tonne of CO₂ abated. The calculations assume that payments are limited to the first 20 mtCO₂ (or equivalent output). Results are summarised in Table 8.

Table 8 Bid prices calculated using the RAM

	Post-combustion	Pre-combustion (part-fitted)	Pre-combustion (fully fitted)	Oxyfuel
AP (£/MWh)	62	88	66	48
CfD Strike (£/t of CO ₂)	99	125	97	85

It can be seen from Table 8 that the tender bids calculated for the AP are high in comparison with the project levelised energy costs (shown in Table 5). This is due to the fact the financial support is limited to the lesser of a 15 year horizon or 20mT of carbon stored. In contrast to this, the levelised project costs are calculated over the life of the demonstration project (40 years). Hence payments to fill the funding policy gap (the excess of levelised cost over the investor expected power price) which exists over the life of the asset must be made within the first few years of plants' operations. In the case of the partially-fitted configurations, this effect is exacerbated by the fact that the levelised cost is measured across all MWh of station output, whereas the tender bids represent financial support on only the CCS fitted portion of the plant. A similar argument applies to the CfD strike prices, which are well above the breakeven market

carbon price that the project would require. A more detailed breakdown of this comparison is included in the Technical Annex.

There are two types of CfDs under consideration as possible funding policy instruments: a 1-way CfD and a 2-way CfD. We considered both of these in the risk assessment modelling, but the required payouts were found to be identical and hence they are presented together in a single row in Table 8. The reason there is no difference in our analysis between tender bids with a 1-way and 2-way CfD is that the required strike price on the CfDs, more than 85 €/t, is higher than any of the simulated investor-expected carbon price paths, and hence the option is sufficiently far ‘in-the-money’ under our assumptions that the theoretical value associated with the additional upside of a 1-way CfD is not material in the modelling.

6.3.3 What is the impact of imposing a retrofit requirement?

One of the possible policy measures that is under consideration in addition to the funding mechanism is a requirement that developers retrofit the unabated part of the plant once CCS has been found to be technically and economically proven. Depending on how such a policy is framed, there may be significant uncertainty in assessing the impact on project economics, as the date and outcome of a ‘proven’ assessment will not be known. We discuss this overall uncertainty below, but first we show the results of modelling the inclusion of a retrofit requirement at fixed future dates as if the outcome was already determined. This is helpful in isolating the cost impact of the retrofit irrespective of the surrounding uncertainty. The NPV results presented in this section show the funding gap calculated without a funding mechanism in place, and compared to the case of the demonstration project alone, and the bid prices are calculated based on investors assuming the respective specific retrofit scenario materialises.

As the assumed date of the retrofit is changed, the NPV impact is affected in particular both by the level of discounting of the capital expenditure (which increases as the date gets later), and by the level of carbon price (which rises over time in our investor-expected scenario) after the retrofit is operational.

In the case of post-combustion, imposing a retrofit requirement in 2020 was found to widen the funding gap by £82m. A 2025 retrofit has very little impact on NPV with these assumptions, and a retrofit in 2030 has a positive benefit. The impact of retrofit imposition on post-combustion project NPVs and the funding bid levels required to bridge the funding gap are summarised in Table 9 and Figure 10.

Table 9 Impact of retrofit imposition on the post-combustion project

	Demo only	2020 retrofit	2025 retrofit	2030 retrofit
NPV (£ mn)	-499	-581	-502	-478
AP (£/MWh)	62	70	62	60
CfD Strike (£/t of CO₂)	99	106	98	95

Figure 10 Impact of retrofit imposition on the post-combustion project

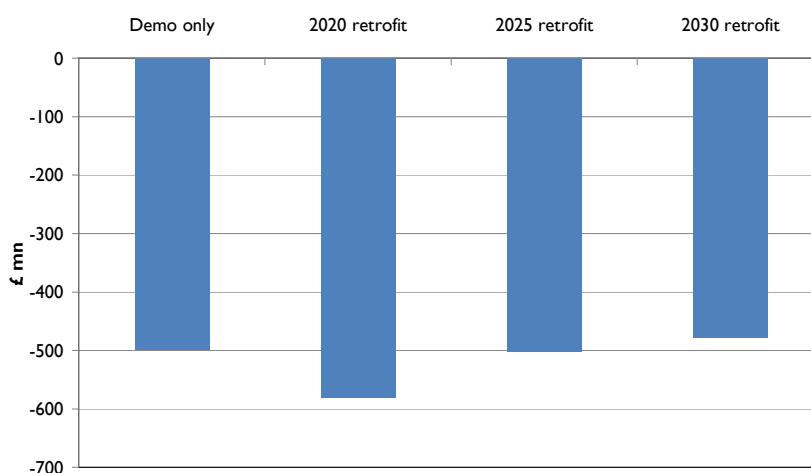


Table 10 and Figure 11 show the equivalent results for the pre-combustion technology (with the configuration of fully-fitting from the outset shown for comparison). Retrofitting the plant leads to a smaller funding gap than not retrofitting at all due to carbon cost savings. The optimal year to retrofit is given by the trade-off between the discounting benefit of delaying the associated capital expenditure¹⁵ and the carbon cost savings foregone during the period with unabated capacity. In our analysis this was found to be year 2024, a result consistent with the trend presented in the table below.

Fully-fitting a pre-combustion plant at the outset is a lower capital expenditure option than staging the fitting (excluding discounting effects), and taking into account the earlier carbon abatement benefit, we calculate a smaller funding gap than part-fitting by about £85 mn. It must however be noted that this result is very sensitive to our input assumptions, particularly the carbon prices and the structure of the capital and operating expenses on the CCS equipment. A detailed analysis with respect to this is included in the Technical Annex.

Table 10 Impact of retrofit imposition on pre-combustion project

	Demo only	2020 retrofit	2025 retrofit	2030 retrofit	Fully fitted
NPV (£ mn)	-794	-757	-750	-756	-709
AP (£/MWh)	88	82	83	85	66
CfD Strike (£/t of CO₂)	125	118	119	122	97

¹⁵ Capital expenditure is assumed to rise in accordance with the consumer price inflation, which is much lower a figure in comparison to the project hurdle (discount) rate.

Figure 11 Impact of retrofit imposition on pre-combustion project



In the case of oxyfuel, technical considerations require fitting of CCS to the entire plant from the outset, so the concept of retrofit was not applicable.

6.3.4 What is the impact of imposing an annual carbon emissions limit as a contingency?

As discussed in Section 6.2.2, we modelled contingency as an annual limit set equal to the emissions of a typical CCGT plant of the same gross capacity running at a load factor of 80%. Imposition of the bubble limit constrains the annual output a plant produces, reducing the positive cash flows from the date at which the contingency is introduced. Imposing the limit also increases the project risk premium as the project is now more susceptible to downside risks at the front end, which are not as well mitigated by the positive later cash flows from plant operation as would have been the case without the constraint.

We found that imposition of the bubble limit increased the funding gaps as well as the risk premia substantially. The impact of contingency on risk premia project NPVs and the required tender bids to fill the funding gap are summarised in Table 11 for post-combustion and Table 12 for pre-combustion.

Table 11 Impact of contingency imposition on post-combustion plant

	Demo only	2020 contingency	2025 contingency	2030 contingency
NPV (£ mn)	-499	-696	-623	-579
Risk premia (%)	1.34%	1.68%	1.61%	1.54%
AP (£/MWh)	68	98	88	81
CfD Strike (£/t of CO ₂)	104	137	126	118

Table 12 Impact of contingency imposition on pre-combustion plant

	Demo only	2020 contingency	2025 contingency	2030 contingency
NPV (£ mn)	-794	-801	-796	-794
Risk premia (%)	2.66%	2.72%	2.69%	2.66%
AP (£/MWh)	109	111	110	109
CfD Strike (£/t of CO₂)	147	149	148	147

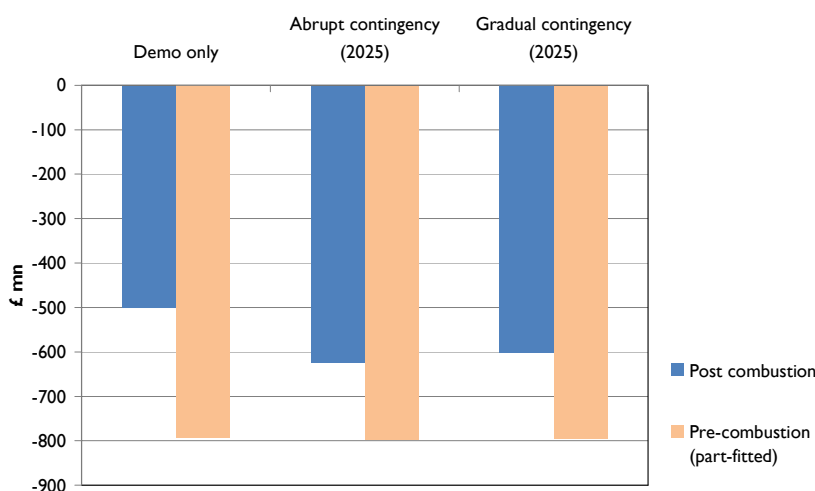
In the case of post-combustion demonstration plant with contingency imposed in 2025, the funding gap was found to increase by £124m and the risk premium from 1.3% to 1.6%. If the contingency is imposed at an earlier date, the impact (increase in funding gap and risk premium) is greater and vice-versa. Similar trends were observed in the case of pre-combustion (part-fitted), though the effect of contingency was found to be quite marginal as the unabated unit (with a lower net efficiency than the post-combustion) would tend to reduce its load factor for economic reasons even without contingency, which if imposed will have only a small incremental effect.

We also considered a gradually decreasing annual constraint. This was modelled to cap emissions initially at the level of a coal plant running at 60% load factor and tightening linearly to those of a CCGT operating at 80% load factor over the course of 5 years. We found that the gradual contingency leads to a similar but marginally lower impact when in comparison with the abrupt contingency as shown in Table 13 and Figure 12.

Table 13 Impact of abrupt v/s gradual contingency imposition on project NPVs

	Demo only	Abrupt contingency (2025)	Gradual contingency (2025)
Post-combustion	-499.4	-623.3	-602.0
Pre-combustion (part-fitted)	-793.5	-796.0	-794.0

Figure 12 Impact of abrupt v/s gradual contingency imposition on project NPVs



In cases of oxyfuel and pre-combustion (fully fitted), the entire station capacity being CCS fitted from outset, there is no concept of a contingency arrangement.

6.3.5 What is the incremental impact on developers' bids of uncertainty around whether and when CCS is proven?

The quantitative results we have presented to this point have been derived for specific policy options assuming that the outcome and timing of a 'proven' assessment for CCS is known in advance. This is helpful in understanding the different components of risk involved, and the associated impact on project economics and funding requirements. In practice, however, demonstration developers are likely to face additional uncertainty around whether and when CCS technology will be proven.

A developer may account for the impact of this uncertainty, as for others, by adding a premium to the hurdle rate used to assess project economics. However, given the much more subjective nature of the assessment of relative probabilities of outcome and timing, this is less amenable to quantification in the same way. In practice, any increase in the hurdle rate that the developer applies is likely to be based more on a qualitative assessment relative to other risks in its portfolio, rather than a complex analysis of the range of potential outcomes.

We can look at the range of expected NPVs from our specific modelled cases to determine the type of spread in outcomes associated with the uncertainty on timing and outcome of the 'proven' assessment. For post-combustion, calculated NPVs (without funding support) spanned from -£623m for a 2025 contingency to -£478m for a 2030 retrofit – a range of £145m. This could clearly be larger if stricter or earlier contingencies remained open as possibilities.

It is worth noting that this range is still relatively small in comparison to the spread associated with commodity price risks inherent within the NPV distributions we have used to calculate risk premia for specific cases. However, it is likely that many developers will be comfortable accepting commodity price exposure as a core risk that they manage within their portfolio, but much less comfortable accepting a significant regulatory exposure. A prudent strategy for a cautious developer might therefore be to seek to make the project robust against a reasonable 'worst case' outcome to the proven decision and timing. This

would suggest that where potential outcomes are not explicitly ruled out, the highest bid estimates calculated from the set of specific cases should be used where overall uncertainty is being considered.

6.3.6 What is the cost to the consumer of meeting the funding gap?

Consumers will bear the cost of funding mechanisms designed to make the demonstration projects economic through a levy on bills. The total cost will be a function of the winning bids emerging from the tender (or tenders) held for the plant, the technical performance of the plant, and (in the case of CfDs) the outturn carbon price.

The bid prices we have presented thus far have all been based on our investor-expected price case, and are summarised in Table 14. Where investors' actual expectations of commodity prices differ from those we have assumed here, particularly the carbon prices, the basis for the bids may diverge significantly. This is because, although the costs of installing the CCS equipment are not changing, the overall project economics (across the project lifetime, not just the funding period) look very different – and we assume that investors will factor this into their bidding.

To explore this sensitivity, we compared the results using the investor-expected case with the DECC commodity price cases used in the market modelling. The 2030 carbon prices across these cases are 35 £/t Low Case, 70 £/t in the Central Case, and 105 £/t in the High High Case, compared to 43 £/t in the investor-expected case. The resulting estimates of developer tender bids are also shown in Table 14. The tender bid estimates are highest if the developer anticipates the Low Case, whilst, at the other end of the spectrum, expectations of the High High Case leads to a positive NPV (as indicated by '---' entries in the Table). This indicates that the need for funding is, at least in part, driven by a lack of confidence in future carbon policy and pricing. Where other more general policy measures could provide investors with sufficient certainty that carbon prices would be at or above the level associated with DECC's Central Case, it may be that less financial support would be required to make the projects economic. There may still be a need for an incentive to drive early deployment, however, as developers may see improved economics with a later start date.

Table 14 Tender bid levels under different investor price expectations

	Post-combustion	Pre-combustion (part-fitted)	Pre-combustion (fully fitted)	Oxyfuel
AP bid (£/MWh)				
Low	160	142	117	74
Central	24	55	22	25
High High	---	---	---	---
Investor-expected	62	88	66	48
CfD (£/t)				
Low	196	173	144	105
Central	25	88	49	59
High High	---	---	---	---
Investor-expected	99	125	97	85

Bid prices are also affected by the whether or not retrofit and contingency imposition is expected by investors, as summarised in Table 15. As can be observed, expectation of retrofit (technology being proven) in most price cases reduces funding gap and also the corresponding bids, while expectation of contingency imposition (technology not being proven) has the opposite effect.

Table 15 Effect of retrofit and contingency on bid levels under different investor price expectations

	Post-combustion			Pre-combustion (part fitted)		
	Demo	2025 retrofit	2025 contingency	Demo	2025 retrofit	2025 contingency
AP bid (£/MWh)						
Low	160	155	164	142	137	142
Central	24	---	37	55	31	56
High High	---	---	---	---	---	---
Investor-expected	62	62	83	88	83	89
CfD (£/t)						
Low	196	191	201	173	168	174
Central	25	---	71	88	61	89
High High	---	---	---	---	---	---
Investor-expected	99	98	121	125	119	126

To evaluate the cost to consumers of meeting the funding gap, we have taken the bid prices calculated using the investor-expected prices, fixed these, and then calculated payments under the funding mechanisms for different outturn price cases. This includes the case where outturn prices match those we have used to calculate the bids, as well as cases where outturn prices are different from those used at the investment stage. In particular, for the latter case, we have again used the DECC price cases used in the market modelling. The funding gap was calculated as the present value of the funding mechanism pay-outs discounted at the UK Government Green Book rate (3.5% real)¹⁶. The results under the different cases are summarised for the different commodity price cases in Table 16¹⁷. Whilst the AP cost does not vary with commodity prices, the cost of a CfD based funding mechanism depends on the outturn price of carbon: the higher the carbon price, the lower is the cost to the consumer. (Of course, higher carbon prices are likely to lead to higher overall consumer bills through the impact on power prices.)

¹⁶ The value presented for costs to consumers for the investor-expected case is higher than the funding gap presented earlier because of the difference in discount rate applied.

¹⁷ The cost to the consumer is calculated taking account of the risk premium associated with undertaking the demonstration project, as well as the risk reduction benefit to the developer from receiving funding mechanism support with certainty.

Table 16 Liability to consumers from financial support mechanisms

	Post-combustion	Pre-combustion (part-fitted)	Pre-combustion (fully fitted)	Oxyfuel
Additional Payment (£ mn)				
All price cases	958	1,394	1,112	783
CfD payouts (£ mn)				
Low	1,125	1,568	1,268	938
Central	943	1,401	1,112	755
High High	820	1,301	1,025	632
Investor-expected	963	1,399	1,113	777

The liability to the consumers where investors expect imposition of contingency or retrofit are summarised in Table 17. (As for the bid levels above, these are calculated assuming that the investor expects the specific outcome.) As can be observed from this table, investor expectation that the technology will be proven (i.e. retrofitting occurs or is imposed) reduces the liability and vice-versa.

Table 17 Effect of retrofit and contingency imposition on liability to consumers

	Post-combustion			Pre-combustion (part fitted)		
	Demo	2025 retrofit	2025 contingency	Demo	2025 retrofit	2025 contingency
Additional Payment (£ mn)						
All price cases	958	952	1,268	1,394	1,305	1,403
CfD payouts (£ mn)						
Low	1,125	1,109	1,433	1,568	1,473	1,577
Central	943	927	1,251	1,401	1,307	1,411
High High	820	804	1,128	1,301	1,207	1,310
Investor Expected	963	948	1,271	1,399	1,305	1,408

Pay-outs under the 1-way and 2-way policy regimes were found to be identical for reasons discussed in Section 6.3.2. The costs to consumers associated with CCS funding mechanisms fall within a tight range under an AP mechanism but may vary significantly depending on outturn carbon price under a CfD mechanism. If the outturn carbon price is higher than that factored into developers' bids, then the CCS demonstration plant owner may earn significant rents under the AP, whereas under the CfD the funding will reduce accordingly, along with the liability on consumers. Likewise, if the outturn carbon price is lower than that expected by the developer then the cost to the consumer is capped under the AP but could substantially increase under the CfD. However, this consideration should be set against the fact that consumers' overall bills will be lower with low carbon prices (and vice versa).

6.4 Key messages

Our analysis indicates that there is likely to be a substantial funding gap that will need to be filled by financial support in order to deliver CCS demonstration projects. This varied between £429m (for a 300MW net oxyfuel plant) and £794m (for a pre-combustion plant partially fitted with 360MW net abated capacity) across the demonstration project configurations modelled, when calculated across the project lifetimes using risk-adjusted hurdle rates. It is important to note however that the funding gap and relative costs of the demonstration projects are sensitive to input assumptions, particularly around capital costs, loss of operational performance associated with fitting CCS¹⁸ and investors' expectations of commodity prices.

Modelling across the full project lifetime at risk-adjusted hurdle rates, our analysis indicated a less negative NPV for a fully-fitted pre-combustion (IGCC) demonstration plant with CCS capability, compared to a partially-fitted plant. This was driven by the incremental benefit of reduced carbon cost outweighing the incremental cost of fitting the CCS capability early. However, this result is very sensitive to the carbon price used and dependent on the benefits later in the project life. Whilst this was not the case for post-combustion, we did find that retrofit of CCS equipment to the remainder of the post-combustion project did not impose a substantial additional burden on the developer (£2m higher cost if the requirement to retrofit years comes in 2025). However, we found that imposing a contingency on the post-combustion project (in the case of CCS not being proven) substantially increased the cost of the project, by £124m for an abrupt annual emissions limit contingency imposed in 2025.

The analysis showed that the strike prices for the tender bids of the two different funding mechanisms are likely to be high relative to prevailing electricity prices (in the case of AP) and carbon prices (in the case of CfD). This is because payments under the funding mechanisms must be compressed into the specified window of the lesser of 15 years of operation or 20 mT of carbon stored. In the case of the post-combustion demonstration plant this effect is exacerbated by the fact that financial support only covers the CCS portion of the plant, whereas levelised cost is measured across the total plant output (more than four times greater than that of the CCS portion alone).

Because the required strike prices on the CfDs are high relative to expected carbon prices, we found there was likely to be little difference between a developer's tender bids under a 1-way or a 2-way CfD. It is worth noting however that we assumed all projects were operational in 2014. For projects starting later, this finding could change as (in a world of rising carbon prices) the required strike could fall and the range of carbon prices reasonably expected within the funding period could rise.

Our analysis showed that a funding mechanism (whether AP or CfD) reduces risk for the investor and should lead to lower risk premia, through the injection of a stream of front loaded and relatively stable positive cash flows into the project.

AP pay-outs are uncorrelated with carbon prices and hence do not affect the carbon price risk. CfD pay-outs, however, rise as carbon prices fall, offsetting the negative impact of low carbon prices on the project economics, and vice versa. However, with our modelling assumptions, we found that the effect is to somewhat over-hedge the carbon price risk. Hence the CfD funding mechanism appears marginally riskier than the AP for developer. It should however be noted that this observation was very sensitive to the modelled relationship between the carbon and power prices and the CfD strikes.

We estimated a range of tender bids and costs to the consumer associated with the CCS demonstration projects under different commodity price cases. The costs to consumers associated with CCS funding mechanisms fall within a tight range under an AP mechanism but may vary significantly depending on

¹⁸ Note that all analysis was based on DECC assumptions on CCS cost and operational parameters (with the exception of transport and storage).

outturn carbon price under a CfD mechanism. If the outturn carbon price is higher than that factored into developers' bids, then the CCS demonstration plant owner may earn significant rents under the AP, whereas under the CfD the funding will reduce accordingly, reducing the liability on consumers, and vice versa. This reduction in levy in a high carbon price world, however, would be small in comparison to consumers' overall higher bills.

There is an overall uncertainty for investors inherent in the fact that the outcome of a 'proven' assessment is unknown. Whilst our framework did not account for this quantitatively, the range of different cases we explored indicated that, whilst very material, the range of the expected NPV across different outcomes was significantly smaller than (say) the overall NPV distribution associated with commodity price risk. However, as a regulatory risk, this is likely to be relatively of greater concern to investors, who may then seek to cover a 'worst case' outcome in determining bids. Where limits can be placed ex-ante around the measures that could result from a 'proven' decision, this will be beneficial in allowing investors to rule out certain cases from their evaluations.

7 Electricity market modelling

7.1 Analysis objective

Following on from the demonstration project modelling, the next phase was to analyse the impacts of demonstration CCS plant on the electricity market as a whole. We explored this under a number of different outcomes with regard to the following factors:

- the number of demonstration plant developed:
 - two demonstration plant (the competition plant and one additional);
 - four demonstration plant (the competition plant and three additional);
- the outcome of a CCS ‘proven assessment’ and the associated policy measure:
 - CCS is proven and plant are retrofitted;
 - CCS is not proven, but an annual emissions limit is enforced;
 - CCS is not proven and no further action is taken; *and*
- three different sets of commodity prices.

The aim of the modelling was to address the following questions:

- What is the impact on generation investment across the rest of the market?
- How is the operation and dispatch of plant affected?
- What effect is there on wholesale prices and total subsidy levied on consumers?
- What is the impact on carbon emissions?
- What is the impact on net welfare?

In Section 7.2 we outline our modelling approach, along with key assumptions. We then address the questions in Section 7.3, drawing out the main results from the modelling. Finally, we distil these results into key messages in Section 7.4.

7.2 Approach

We performed the electricity market modelling using our Investment Decision Model (IDM). Unlike the RAM, the IDM is not designed to explore in detail the economics of specific projects, but rather to model future investments across the market as whole, and the generation sector operation and wholesale price formation based on the resulting capacity build profiles. The number and type of demonstration plant are treated as exogenous inputs in the IDM as we assume that they are funded to a sufficient level to make them economic. For more details on the modelling approach please refer to the Technical Annex.

We constructed **Counterfactuals** (reference cases) against which we measured changes in the market associated with specific policy options. The Counterfactuals assume no new CCS policy is implemented, with just a single demonstration plant being built based on the existing competition (and hence can be considered as ‘status quo’ cases). A Counterfactual run is performed for each of the different commodity

price sets, which we refer to as price **Cases**. Separate Counterfactuals are also in principle needed to reflect the ‘proven’ outcome (and hence whether further CCS build is ‘allowed’ after the demonstration plant). In practice, in the Low and Central Cases, further CCS build does not occur and hence a second Counterfactual is not required. Two Counterfactuals are required for the High High Case, where further CCS is built if ‘allowed’ within the model.

7.2.1 Assumptions

Plant Configurations

In order to measure the impact on the market, the demonstration plant configurations and timings are directly input into the IDM as shown in Table 18. The demonstration project characteristics are configured in line with Section 6.2.1¹⁹. For the pre-combustion plant, we assume that it initially only fits CCS on half of the plant²⁰.

Table 18 CCS configurations and timing

	CCS Technology	Demonstration Operational Date	Retrofit Operational date
Competition Plant	Post-combustion	2014	2025
1st Additional Demonstration	Pre-combustion	2015	2025
2nd Additional Demonstration	Post-combustion	2018	2025
3rd Additional Demonstration	Oxyfuel	2018	N/A

The dates of retrofit, or the contingency if CCS is not proven, are exogenous assumptions, as are the associated costs, which feed through into the net welfare calculation.

Funding Mechanism

Whist the type of funding mechanism will affect the costs to consumers, it has no direct impact on the rest of the generation sector. For simplicity we assume an Additional Payment (AP) mechanism is implemented, with levels (taken from the RAM results²¹) as shown in Table 19. With the abated capacity on all demonstrations being at least 300 MW, then at (or close to) baseload operation they will store 20 mT of carbon dioxide in approximately 12 years, well within the 15 year subsidy limit. We simplify the

¹⁹ Exact capacity levels are slightly different from the RAM assumptions to fit within the granularity of the IDM.

²⁰ A fully-fitted Pre-Combustion configuration was also assessed using the RAM analysis. Although the NPV was estimated to be slightly less negative for the fully-fitted configuration, we used the technically more conservative partially-fitted case for the market modelling.

²¹ We used the results from the case where a retrofit, operational in 2025, is imposed.

operational behaviour of demonstration plant as we do not model the option for plant to bypass CCS operation at times of high electricity prices, should this be allowed within the regulatory framework.

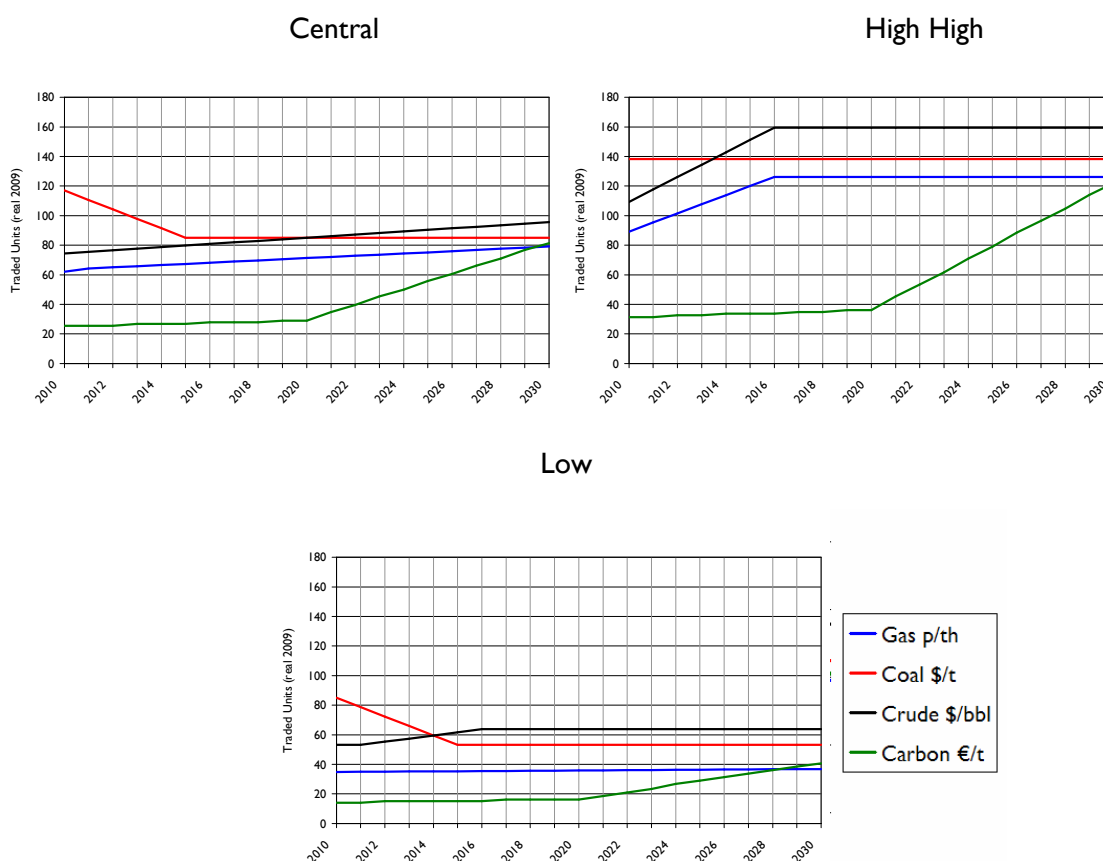
Table 19 Additional Payment levels

Plant Type	AP Level (£/MWh)
Post-combustion	69.8
Pre-combustion	82.1
Oxyfuel	48.0

Commodity price Cases

We used three price Cases, based on DECC’s ‘Central’, ‘High High’, and ‘Low’ scenarios. A key feature in each is the strongly rising carbon price post 2020. (These Cases are different to the ‘investor-expected’ prices used in the RAM, where we consider that investors take a more conservative view of future carbon price when evaluating projects.)

Figure 13 Commodity prices, all Cases (real 2009)

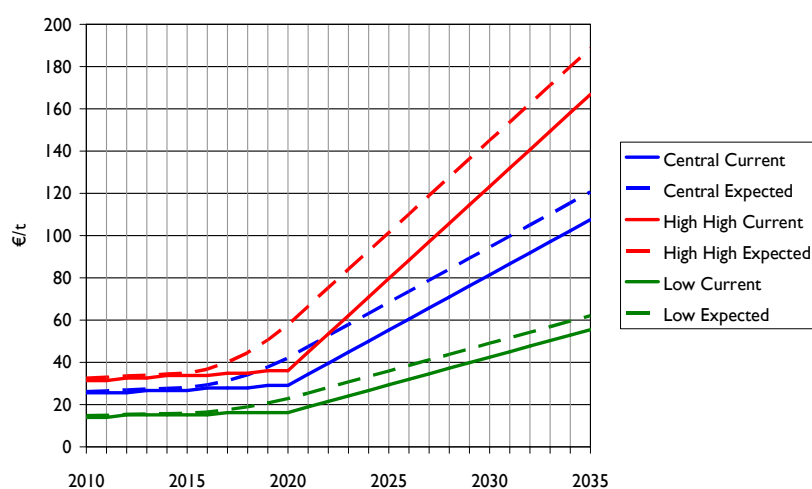


The IDM simulates decisions investors make through time in new generation capacity. The decisions are based on a risk-adjusted comparison of technology long run marginal costs with expected revenues. The expected revenues are in turn based on expected electricity prices, which are calculated based on expected commodity and carbon prices. For coal and gas, we assume no bias in price expectation, and in the model the ‘current’ price (at that point in the modelling horizon) is used as a proxy for the expected price. However, we treat the carbon price differently. We make an assumption that there is on average an

expectation that prices in the future will be higher than current prices, and we represent this in the model by calculating the expected price as the average of the following five years from that point in the modelling horizon. From 2020 onwards, this means that investments are evaluated using an expected carbon price 13 €/t higher than the 'current' price in the Central Case. In the High High Case the difference is 22 €/t, and 6.5 €/t in the Low Case.

Note that as carbon prices continue rising, this is still lower than the average outturn price over the economic life of any resulting investment. For example, an investment decision made in 2020 in the Central Case would be based on an expected carbon price of 42.4 €/t, compared to an average outturn carbon price of 68.6 €/t over the following 15 years.

Figure 14 Expected carbon prices, all cases



Policy options and 'proven assessment' outcomes

We modelled situations where CCS was proven and where it was not, combined with different resulting policy measures:

- **Retrofit:** CCS is proven and therefore retrofits are applied to the demonstration plant. Further CCS build is possible in the market. Retrofits become operational in 2025.
- **CO₂ Limit:** CCS is not proven, and an annual emissions limit is applied to demonstration plant from 2025. This constrains the plant to run such that, over the course of a year, they emit no more carbon dioxide than a CCGT (of the same capacity) operating at 80% load factor. The plant have flexibility as to when they operate during the course of the year. There is no further CCS (or unabated coal) build in the market.
- **Do Nothing:** CCS is not proven, but once not proven there are no further policy or technical restrictions on operation. There is no further CCS (or unabated coal) build in the market.

We refer to each of these permutations of policy options and 'proven'/'not proven' results as **Outcomes**. In the Outcomes where CCS is not proven, whilst there is no further CCS build in the model, we assume that the existing CCS demonstration units are able to continue operating when economic to do so.

Number of demonstration plant

We modelled each Outcome under two combinations of demonstration plant:

- **Two** demonstration projects, including a post-combustion competition plant operating in 2014 (also present in the Counterfactuals) and a pre-combustion plant, beginning operation in 2015.
- **Four** demonstration projects, which in addition includes a further post-combustion plant in 2018 and a first oxyfuel plant in 2018.

The Counterfactuals assume that only the post-combustion competition plant is developed, operational in 2014.

Learning Curve

The demonstration plant technology is 'first-of-a-kind', so costs are high. In the IDM, costs are assumed to reduce over time to 'nth of a kind'²² as the technology matures. (Retrofit costs for the demonstration projects are assumed to have benefited from learning, but due to the specific requirements are not equivalent to nth of a kind.) Nth of kind costs are based on Redpoint and DECC assumptions. Whilst the learning curve will in large part be driven by global developments, we assume that there is an incremental benefit associated with building four demonstration plant rather than two. Specifically, with four demonstration plant, we assume that nth of a kind is at date of operational retrofit (2025 for post- and pre-combustion, and 2028 for Oxyfuel). For two demonstration plant we assume the Oxyfuel and post-combustion nth of a kind dates are delayed two years.

Runs performed

We performed Counterfactual runs for each of the price Cases (with two for the High High Case, representing 'proven' and 'not proven' outcomes for CCS). These form reference results against which the results from runs including further demonstration plant are compared.

We then performed runs for each permutation of three Outcomes, across two or four demonstration plant, each across three price Cases.

This led to 22 runs in total, which are summarised in Table 20. The short codes indicated are used in graph legends through the report.

We also ran five sensitivities, in which we varied the dates of retrofit and contingency, and the application of the emissions limit constraint. These are presented in the Technical Annex.

²² Shorthand for plant built after the point at which a sufficient number of installations have been developed and operated for a long enough time that the technology is considered commercially mature.

Table 20 IDM runs performed

Policy Option/ Outcome	Date of implementation	Number of demos	Commodity Price Scenario	Short Code			
Counterfactual		1	Low	Low CF	CCS is not proven		
			Central	Central CF			
			High High	HH CF			
			High High	CF HH Proven	CCS is proven		
Proven Retrofit	2025	2	Low	L2 Retrofit			
			Central	C2 Retrofit			
			High High	HH2 Retrofit			
			Low	L4 Retrofit			
		4	Central	C4 Retrofit			
			High High	HH4 Retrofit			
			Low	L2 Do Nothing			
			Central	C2 Do Nothing			
Not proven Do Nothing (no further restriction)		2	High High	HH2 Do Nothing			
			4	Low	L4 Do Nothing		
				Central	C4 Do Nothing		
		High High		HH4 Do Nothing			
		Not proven Annual carbon emissions limit	2025	2	Low	L2 CO2 Limit	Limit equates to a CCGT operating at 80%
					Central	C2 CO2 Limit	
High High	HH2 CO2 Limit						
4	Low			L4 CO2 Limit			
	Central			C4 CO2 Limit			
	High High			HH4 CO2 Limit			

Other assumptions

- Renewable banding is set to deliver at least 29% renewables generation in Central and High High cases, but the actual level fluctuates with different Cases and Outcomes. We assume renewables are further banded up in 2018 in the Low Case, although this still only delivers approximately 25% of renewables generation.
- Demand²³ is based on DECC assumptions and reaches 345 TWh (at station gate²⁴) in 2010, 354 TWh 2020, rising to 402 TWh in 2030.
- Capital costs of nuclear and CCGT (Redpoint assumptions) fall gradually in real terms. CCGT costs in 2020 reach 90% of 2010 levels, and nuclear costs reach 85% of 2010 levels by 2030.

²³ The 2010 figure is higher than in previous studies, while the 2020 level is lower – this is due to further analysis undertaken as part of the Low Carbon Transition Plan projections.

²⁴ A full definition of our demand basis is provided in the Technical Annex.

7.3 Results

In this section, we use the modelling results to address the questions listed in Section 7.1. For each commodity price Case, conclusions are drawn for two and four demonstration plant, and across different Outcomes.

7.3.1 What is the impact on investment across the rest of the market?

The key driver of differences in market investment associated with CCS policies is the number of additional demonstration plant (themselves exogenous inputs to the model on the assumption that tenders are successfully completed for the required number). The CCS 'proven' outcome and associated contingency measures have very little impact on other generation investment decisions.

Central Case

In the Central Case, the impact of additional demonstration plant is to displace and delay CCGT investment. There is no impact on renewable and nuclear investment.

In the Central Case Counterfactual, the first new thermal investment in the model (after the new plant already committed and operational in the next three years) is in 2020²⁵, when new CCGT and the first new nuclear plant come online. This is due to high capacity margins driven by low demand, committed new build, and rapid deployment of renewables²⁶. Increasing the number of demonstration plant only affects CCGT investment relative to the Counterfactual: nuclear and renewables are unaffected. With two demonstration plant, the first CCGT is delayed a year to 2021; with four demonstration plant it is delayed to 2022. This is shown in Figure 15, which shows total new build under the Counterfactual (including committed projects), and Figure 16, which compares non-renewable new build (excluding committed projects) under different Outcomes. Not only are new CCGTs delayed, but there is less CCGT investment overall. With an additional 2.5 GW of demonstration plant compared to the Counterfactual, there is 2.4 GW less CCGT investment, indicating that the demonstration plant directly displace CCGT capacity.

²⁵ In the period 2010-2012, it is assumed that Grain, Staythorpe, Pembroke, Langage, Severn, West Burton and Marchwood CCGTs become operational. See the Technical Annex for further information.

²⁶ The assumptions and results for the Central Case Counterfactual are compared to the Renewable Energy Strategy Lead Scenario in Section 6.2 of the Technical Annex.

Figure 15 Counterfactual Central Case, new build

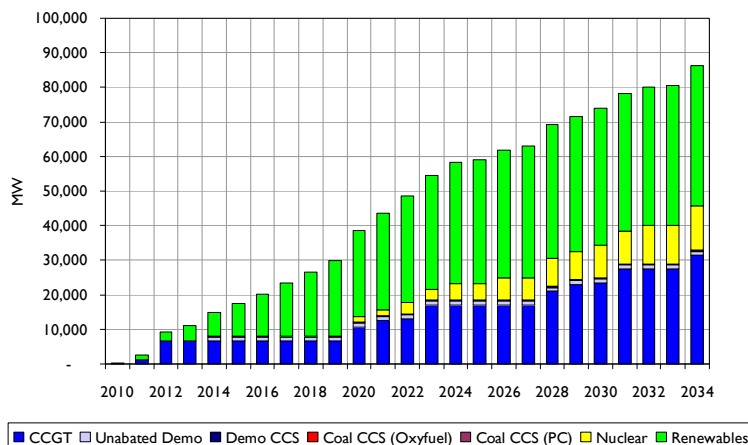
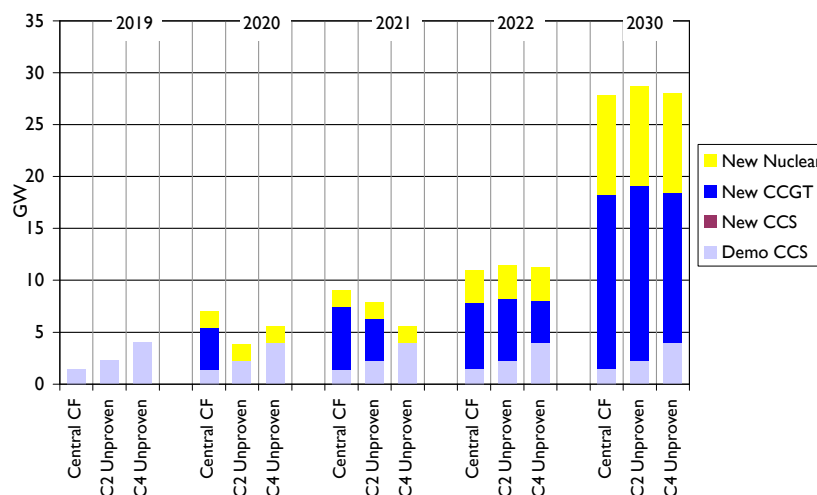


Figure 16 New build comparison (excluding committed projects), Central Case



With nuclear unaffected, the first plant is on line in 2020, and in 2030, there is a total of 9.6 GW of new nuclear operational. Renewables investment is also unaffected: in 2020 there is 31% renewable generation.

Low Case

The number of demonstration plant has little impact on investment prior to 2020. With four demonstration plant, however, renewables investment is suppressed between 2020 and 2030, and nuclear investment is delayed.

In the Low Case Counterfactual, nuclear first comes online in 2025 (later than the Central Case due to low commodity prices initially). There is no change to this with two CCS plant, but with four, nuclear investment is delayed one year to 2026.

There is very similar investment in renewables to 2020, when approximately 26.5% of electricity is provided by renewable sources. However, with additional demonstration plant, investment post 2020 is suppressed. In 2030, with four demonstration plant, there is a total of almost 35 GW of renewable capacity, compared to almost 39 GW in the Counterfactual and two demonstration plant runs.

In the case of CCGT, investment is delayed by one year relative to the Counterfactual (to 2021). By 2030, there is no significant difference in CCGT capacity. This indicates that under Low commodity prices, it is renewable and nuclear which are marginal and are displaced by additional demonstration plant. This will have an effect on emissions, which is explored in Section 7.3.4.

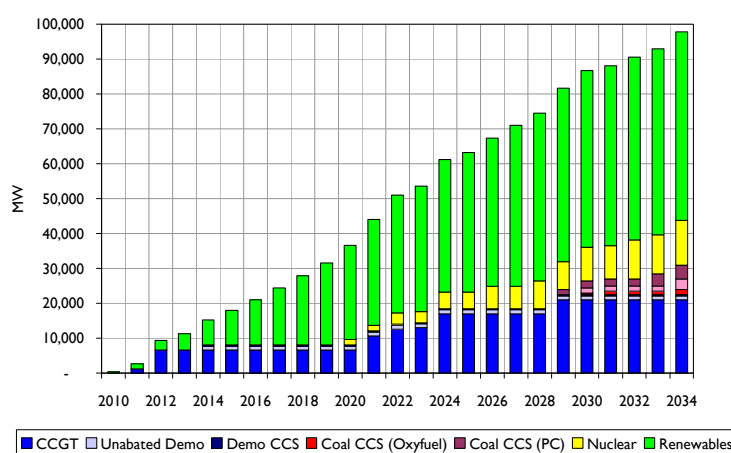
High High Case

The High High Case is the only case where CCS is built without subsidy in the modelling horizon. With more CCS demonstration plant, we see a delay and displacement of CCGT investment.

The High High commodity prices are favourable towards renewables. In 2020, 32.4% of electricity is supplied from renewable sources. The difference between the High High Case and the Central and Low Cases is that renewables continue to be strongly attractive investments in the 2020s (see Figure 17). In 2030, there is a total of 50 GW of renewables capacity on the system, of which nearly 40 GW is wind. This, combined with CCS being economic beyond the demonstration plant, sees a suppression of CCGT investment relative to the Central and Low Cases. Although higher prices make nuclear more attractive, there is no additional investment relative to the Central Case (with the first unit online in 2020 and 9.6 GW by 2030) because the rate of deployment is assumed to be a limiting factor.

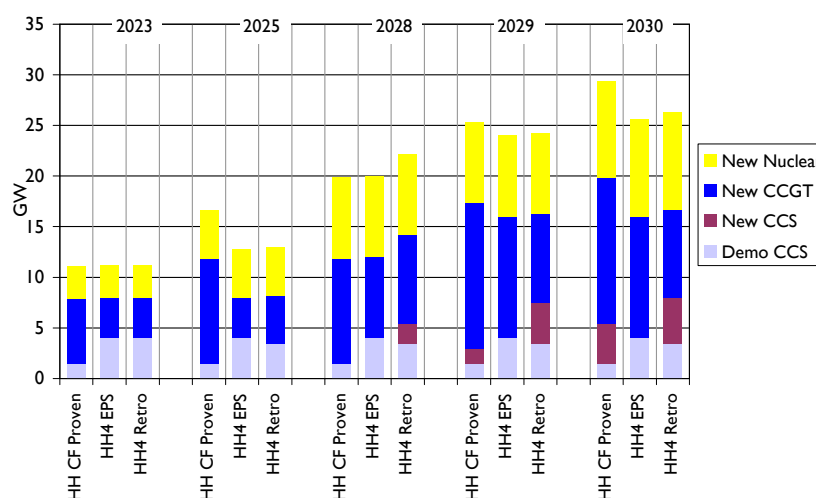
The increase in renewables causes a delay in the first CCGT investment relative to the other Cases by a year (to 2021) in the Counterfactual. With two demonstration plant it is pushed back to 2022 and with four demonstration plant it is 2023. When CCS is a proven technology, we see new build CCS without subsidy from 2029 in the Counterfactual²⁷, and from 2028 with four demonstration plant, due to our assumption on an accelerated learning curve. We show in Figure 18 that when CCS is not a proven technology additional CCGTs are developed in the late 2020s to replace the capacity. Again, increasing the number of demonstration plant reduces the CCGT investment in the long run on a MW for MW basis.

Figure 17 Counterfactual High High (CCS proven), new build



²⁷ In the graph new CCS build is split into oxyfuel and post-combustion. No new pre-combustion is built in the run.

Figure 18 New build comparison (excluding committed projects), High High Case



Summary

Broadly, increasing the number of demonstration plant displaces CCGT plant in the long term, almost on a MW for MW basis. It is only under High High commodity prices that CCS is developed without subsidy. Nuclear and renewables are broadly unaffected, except in the Low Case when both are more expensive than CCGTs. Whether or not CCS is proven, and what contingency is applied, has no significant impact on investment in the rest of the market.

7.3.2 How is the operation and dispatch of plant affected?

There are two aspects to this question. First, what effect do different policy measures have on the operation of the demonstration plant, and second what is the impact on the capacity mix of generation?

Renewables and nuclear plant run at full availability in all situations, with interconnectors and pumped storage output depending on price levels. The remainder of demand is met by the thermal plant, consisting of the demonstration plant, existing coal, CCGTs and any new CCS plant. The competitiveness of thermal plant is broadly a function of the relativities of coal, gas and carbon prices. Throughout all runs, where there are more demonstration plant, they generate more on a TWh basis for a given contingency. The question is what interaction occurs in the rest of the thermal mix. This is complicated by the changing merit order and different capacity build profiles.

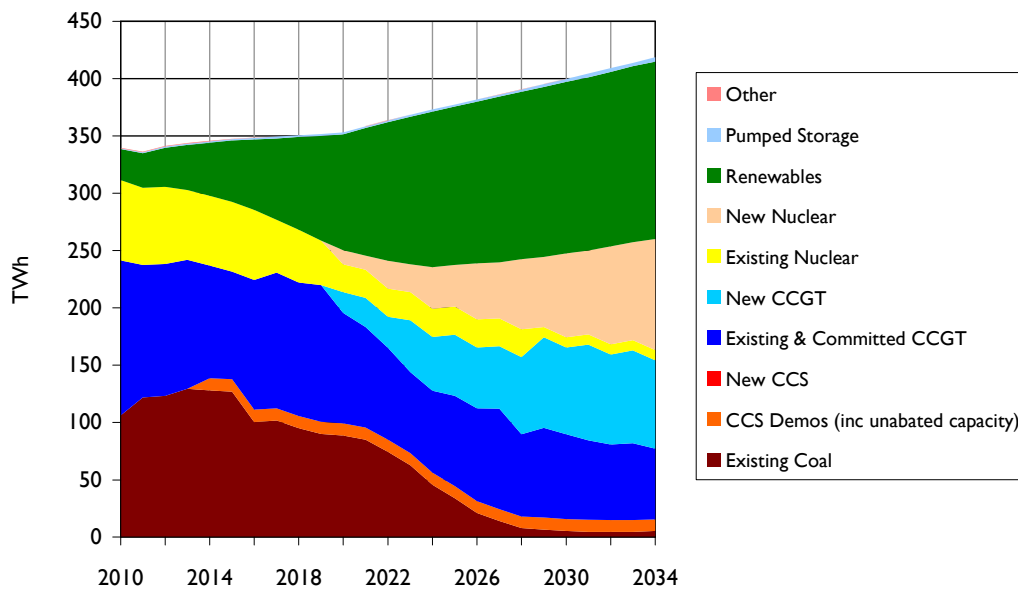
Central Case

In the Central Case, retrofitting leads to the highest CCS generation over the modelled period relative to the Do Nothing or CO₂ Limit Outcomes. The high carbon price post 2025 results in existing unabated coal running at lower load factors. CCGT is the swing generator that is most affected by different levels of output from CCS.

In Figure 19 we show the generation mix evolving over time in the Counterfactual. The key feature is the rapid expansion of renewables through to 2020. Total nuclear generation declines over the same time period as enforced closures take effect. Existing coal increases market share until 2015 when the closures under the Large Combustion Plant Directive (LCPD) occur and load factor restrictions due to Industrial

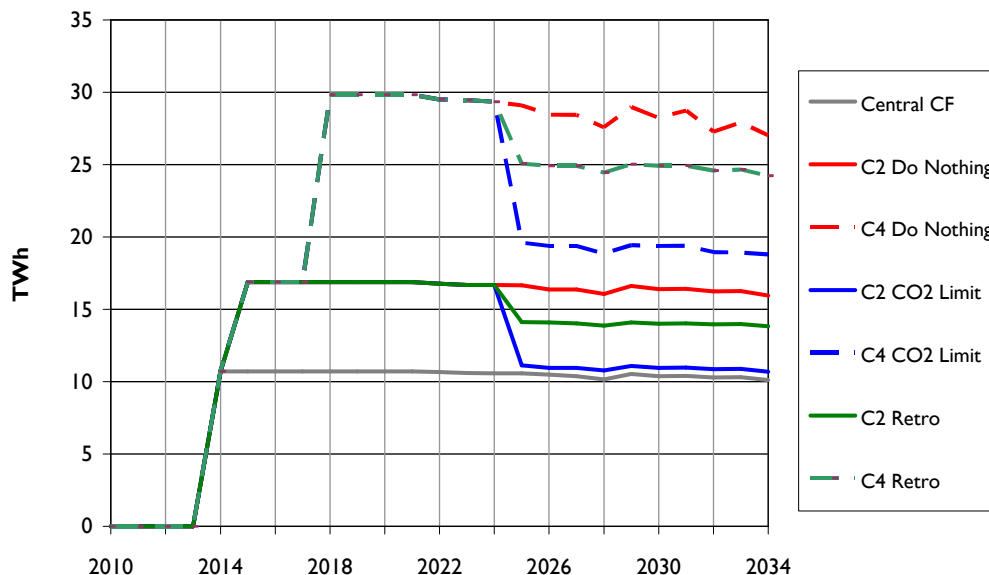
Emissions Directive (IED) come into place. Beyond 2020, we see a reduction in coal generation due to the combination of further plant closures and increasing carbon price reducing load factors.

Figure 19 Generation mix, Central Case Counterfactual



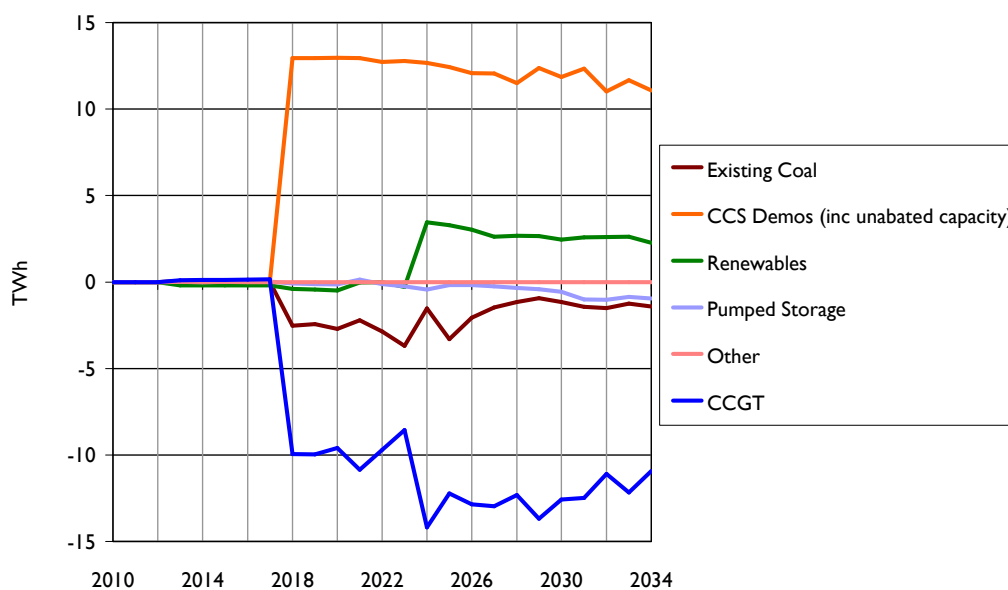
The relatively low coal price combined with the minimal exposure to the carbon price ensures CCS operates as a baseload generator. The unabated elements operate baseload until the rise in carbon price rise 2020, and even then at near baseload levels (unless limited by contingency measures). This is in contrast to the lower efficiency existing coal plant, with declining load factors. Plant that retrofit retain the insulation from carbon price movements and as such always operate baseload under these assumptions. This is shown in Figure 20. (The downwards step change observed in 2025 when retrofitting is due to the energy required to operate the new CCS equipment.)

Figure 20 Output from Demonstration plant, Central Case



With four demonstration plant, the increased output primarily displaces CCGT generation, in part because investment in new CCGTs is delayed, as described in Section 7.3.1, and in part due to a reduction in output from existing plant. Generation from the existing coal fleet also falls slightly. This is illustrated in Figure 21, which shows the difference in generation by type between the runs with two and four demonstration plant in the Do Nothing Outcome.

Figure 21 Generation change, Central 4 Do Nothing less Central 2 Do Nothing

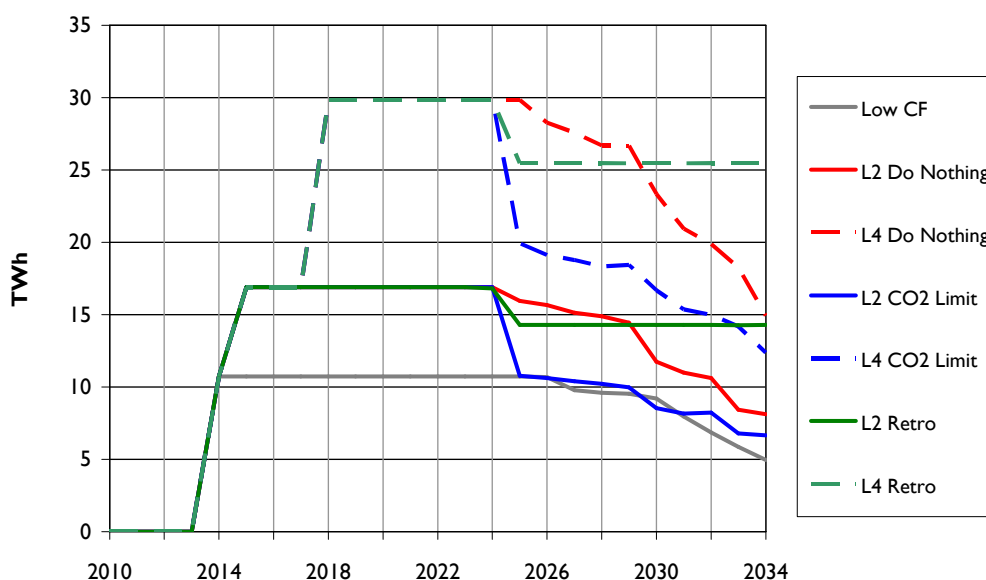


Low Case

As in the Central Case, retrofitting CCS leads to higher generation levels from demonstration plant. The reduced levels of investment in nuclear and renewables with four demonstration plant increase gas-fired output.

With coal and gas being cheaper, the carbon price is a larger component of the operating cost. Therefore, when the carbon price starts to rise after 2020, we begin to see a reduction in load factor of unabated elements of the demonstration plant. When CCS is proven, retrofitted plant operate baseload. With the Low Case favouring CCGT on an SRMC basis, CCGT covers the reduction in nuclear and renewable build, as well as displacing expensive coal units.

Figure 22 Demonstration CCS Output, Low Case

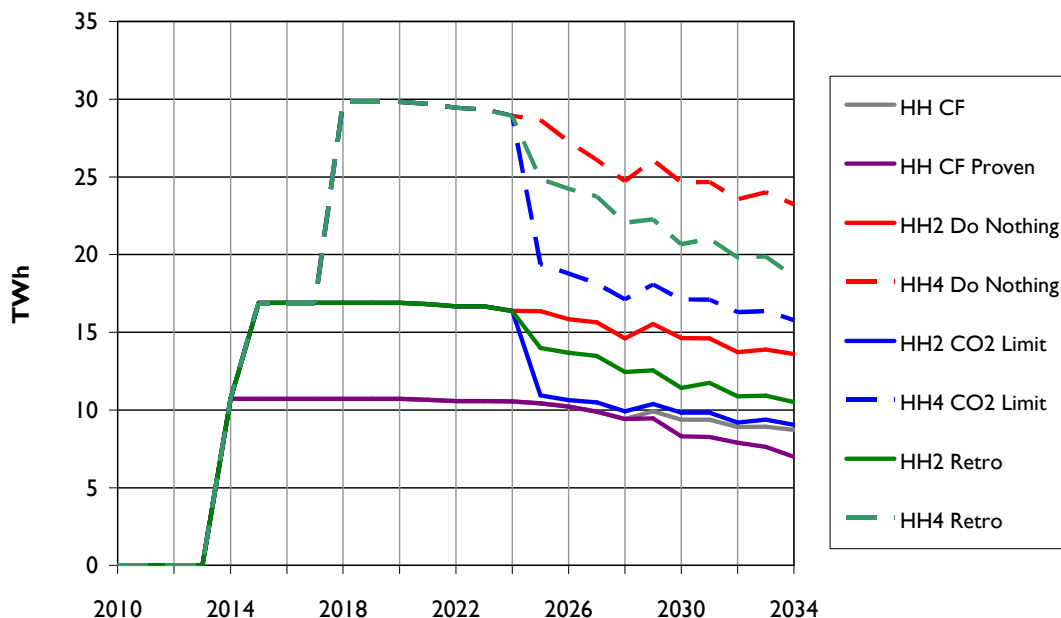


High High Case

When CCS is proven, the levels of CCS generation increase significantly, displacing gas-fired generation. When CCS is not proven, then the operation of the unabated parts of the plant in a Do Nothing Outcome is dependent on the relativities of gas and coal generation costs. In the Low and Central Cases, the unabated load factors tend to drop, but this is less true under the High High Case, due to the increased competitiveness of coal, and hence the emissions limit contingency has more of an effect compared to Do Nothing. Nevertheless, after 2025, as the carbon price rises, load factors start to reduce for the unabated elements of the demonstration plant.

When CCS is proven, the retrofitted elements operate at a high load factor. However, relative to the Central and Low cases, higher renewables penetration and more CCS build mean that this declines over time. This effect is explored further in section 7.3.3.

Figure 23 Demonstration CCS output, all Outcomes, High High Case

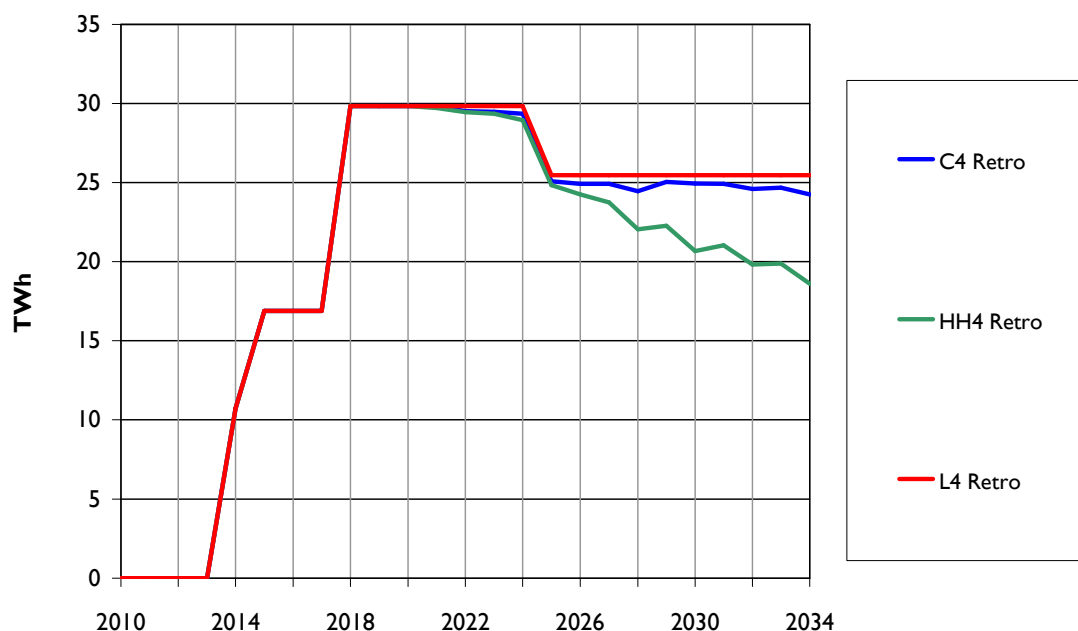


When CCS is not proven, then in a Do Nothing Outcome the carbon price post 2025 reduces the load factor of the unabated elements of the CCS plant. However, this effect is insufficient to make the emissions limit contingency completely redundant, with the unabated elements of the plant further restricted when this is in place. In this case, the reduction in unabated coal generation is primarily compensated for by gas-fired generation.

Summary

The abated parts of the demonstration plant, whether two or four in number, run baseload in the Low and Central cases. When CCS is proven and in the High High Case, we see new build CCS in 2028. This, together with higher renewables penetration, has the effect of suppressing load factors of CCS capacity. The comparison across Cases for the Retrofit Outcome is shown in Figure 24.

Figure 24 CCS generation, all Cases, 4 Retrofit



Existing coal plant operation is driven down by the high carbon price, which reaches sufficiently high levels beyond 2025 that it begins to reduce the load factor of unabated parts of the new plant – but not to the same extent as an emissions limit contingency. CCGT functions as the ‘balancing’ generation type responding to each of these changes.

7.3.3 What effect is there on wholesale prices?

Wholesale prices are driven by three major factors: underlying commodity prices, capacity mix and capacity margins. The short run marginal cost (SRMC) of the price setting plant will be driven by the marginal generation type, which is a function of the competitiveness of coal and gas plant. As capacity margins reduce, prices tend to increase above SRMC levels.

Central Case

There are small variations in wholesale price in some years, driven by a small changes in capacity margin, but overall very little impact.

Wholesale prices under different Outcomes are shown in Figure 25. With demonstration plant being brought on line before any new CCGTs, we see small reductions in prices prior to 2020, driven by the increase in capacity margin (shown in Figure 26). This is however much smaller than the underlying rising trend in prices driven by commodity prices. There is minimal impact on price of whether or not CCS is proven or what contingency is implemented. This is as expected from the minimal change in plant build discussed in Section 7.3.1. After 2030, there is a lag in CCGT investment where four demonstration plant are on the system, resulting in lower capacity margins and higher prices in those years. However it would be difficult to draw conclusions from an effect this far out in the modelling horizon.

Figure 25 Wholesale price (real 2009), Central Case

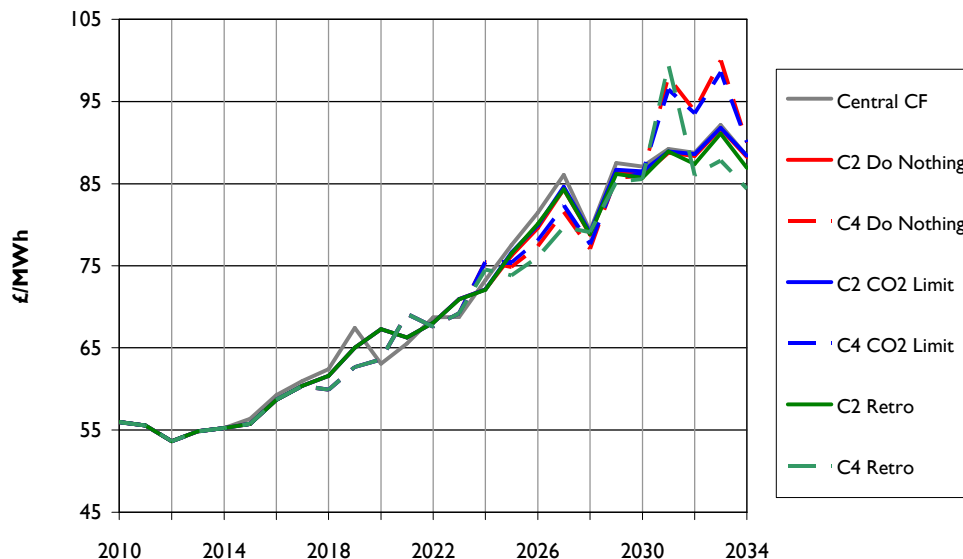
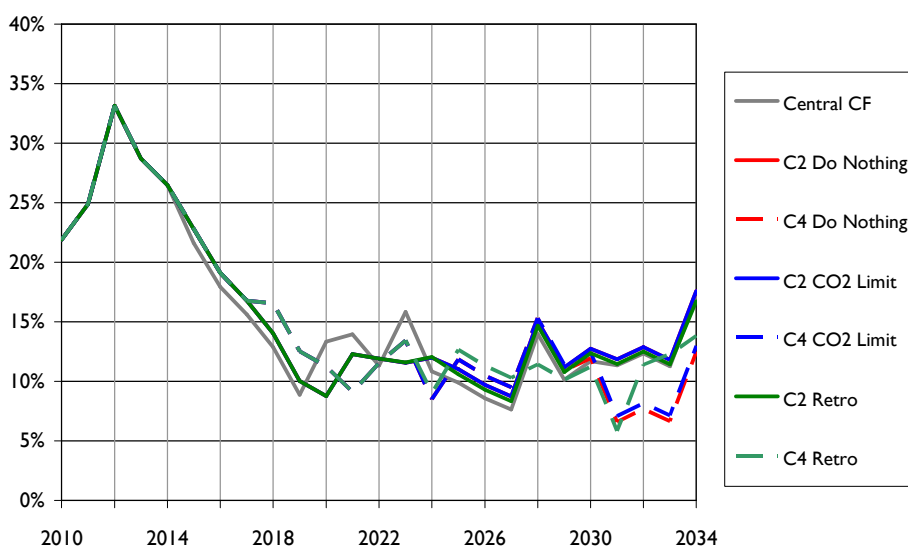


Figure 26 De-rated capacity margin²⁸, Base Case



Low Case

As for the Central Case, there is little impact on wholesale price under the Low Case. Again, changes are driven by capacity margin effects. With lower investment in renewables, the extra demonstration plant have a somewhat larger relative impact on reducing wholesale price up to 2020. Beyond that, there is no significant impact. The lower overall capacity margins also tend to increase price volatility year-to-year.

²⁸ De-rated capacity margin is a probabilistic assessment of excess available plant on the system at the time of peak demand. Each type of plant is attributed a 'capacity credit' to describe this probability measure.

Figure 27 Wholesale price (real 2009), Low Case

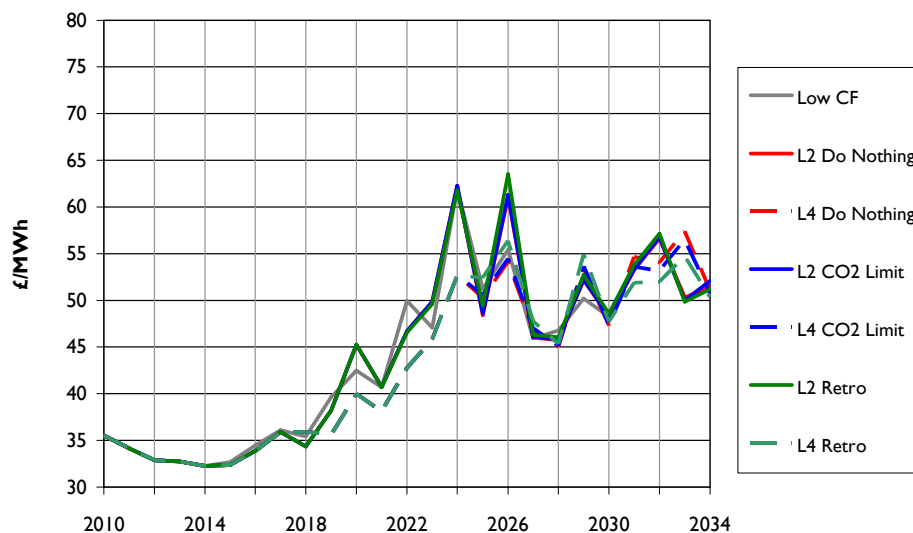
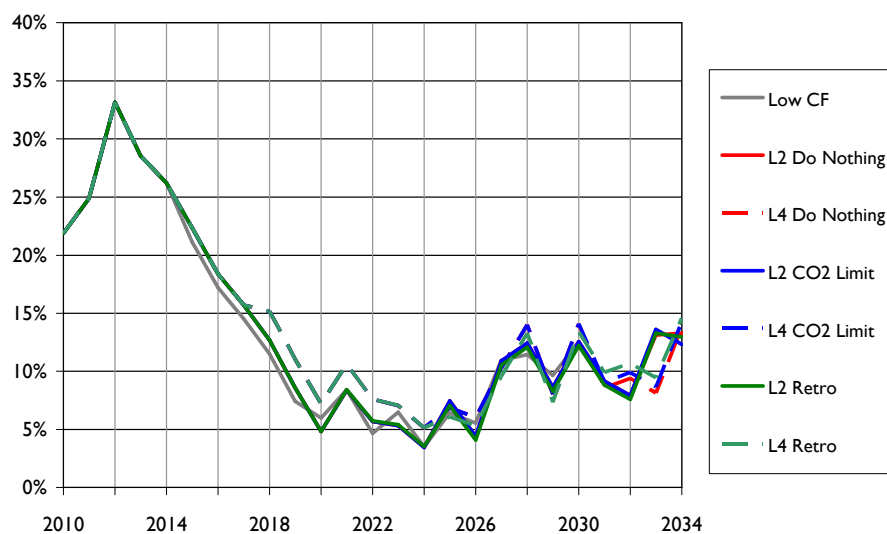


Figure 28 De-rated capacity margin, Low Case



High High Case

The main impacts under the High High commodity Case are similar to that already described in the Low and Central Cases: four demonstration plant provide increased capacity margin earlier, reducing wholesale prices. In the longer term, when CCS is proven, there is the beginning of a decoupling of wholesale electricity prices from the carbon price. Results are shown in Figure 29 and Figure 30.

From 2026, in the Retrofit Outcome, we see wholesale price suppression relative to the Do Nothing and CO₂ Limit Outcomes. This is because the tranche of capacity which has no (or little) exposure to carbon

price in its cost base is beginning to set prices a significant proportion of the time. In 2030, with four retrofitted demonstration plant, there is 59 GW of renewables, 11 GW of nuclear and 8 GW of CCS (including the retrofitted demonstration plant) on the system. This plant delivers 76% of total demand, leaving carbon emitting plant setting the price for fewer periods each year. With the wholesale price de-linked from the carbon price for many periods, the annual average time-weighted wholesale price is less correlated with the carbon price, responding less to the ongoing carbon price increase. This outcome is more a function of the commodity price Case in which CCS is economic as opposed to the policy measures – we see the same effect in the proven Counterfactual. Whilst our modelling horizon is too short to demonstrate it, there will be implications for ongoing investment in low carbon technologies if this effect becomes material, as the carbon price signal will be dampened.

Figure 29 Wholesale price (real 2009), High High Case

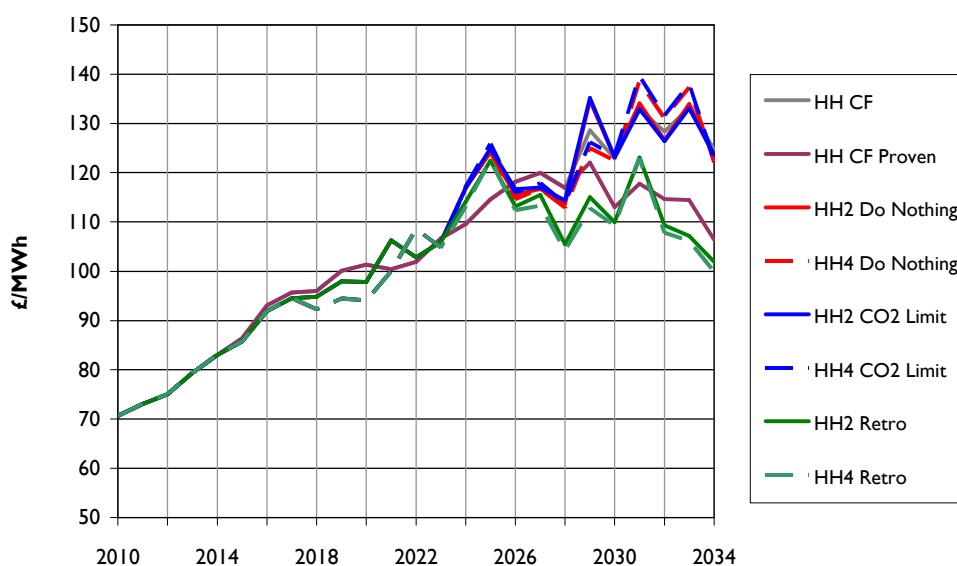
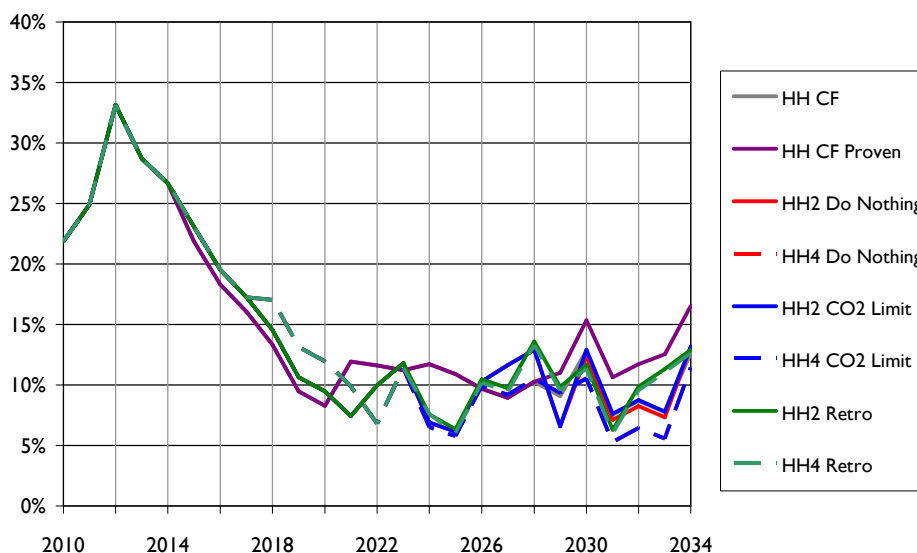


Figure 30 De-rated capacity margin, High High Case



Summary

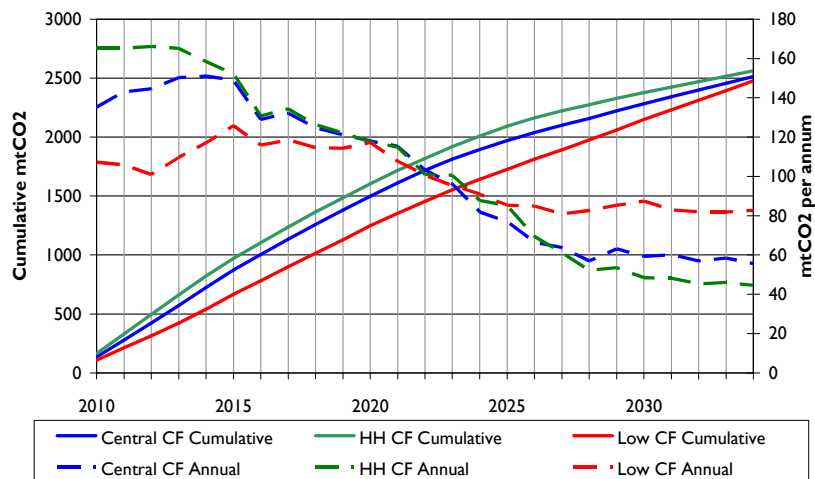
There is a small impact on wholesale prices up to 2020, as the demonstration plant tend to increase capacity margins somewhat. Beyond 2020 there is virtually no impact. In the High High commodity price Case where CCS is proven, we see some decoupling of wholesale price from the carbon price in the later part of the modelling horizon, driven by further CCS investment, and hence weakening of future price signals for low carbon investment. Overall, commodity price movements have far more of an impact on outturn price than the number of demonstration plant built and the associated policy measures.

7.3.4 What is the change in carbon emissions?

As the electricity generation sector falls within the EU ETS, any change in carbon emissions associated with CCS policy will lead to offsetting changes elsewhere in Europe, assuming that the overall ETS constraints are binding. In theory, therefore, there should be no overall impact on total carbon emissions at a European level. (In practice, it may be argued that the availability of additional low carbon options will make it politically easier to tighten targets in the long run.) Nevertheless, we can still consider the impact on domestic emissions from the GB power sector. We do not, of course, capture in the model the impact of UK developments on the global learning curve, and hence the potential wider emissions benefits that could result.

In Figure 31 we present annual and cumulative emissions over the modelled period for Counterfactuals in each Case. In the period to 2015, the emissions are driven by the relativities of coal and gas more than changes in capacity mix, with a wide variation across the Cases. During the period 2020 – 2025 the emissions are comparable in all Counterfactuals, with different levels of coal-gas competition and nuclear and renewable investment offsetting each other. Additional nuclear and renewables in the Central and High High Cases reduce emissions further. In the High High Proven Counterfactual this abatement continues with development of further fully abated CCS plant. Despite these very different paths, the total cumulative emissions over the modelled horizon are very similar across the Counterfactuals.

Figure 31 Counterfactual carbon emissions, all Cases

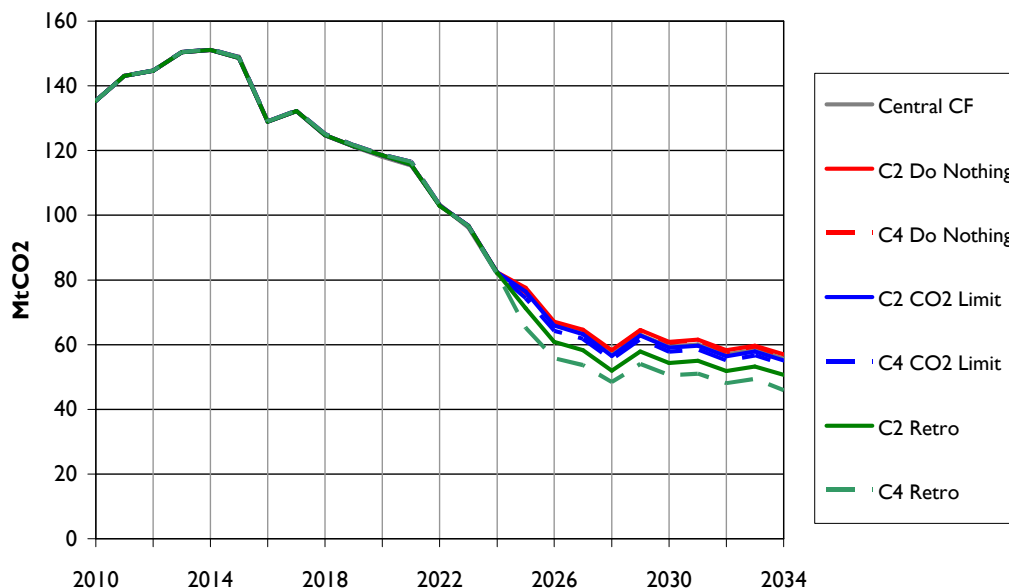


Central Case

In the Central Case, Retrofit is the most effective Outcome in terms of emission reduction, followed by CO₂ Limit. Do Nothing leads to a small increase in emissions relative to the Counterfactual. Four demonstration plant improve the emissions benefits for Retrofit and CO₂ Limit compared to two.

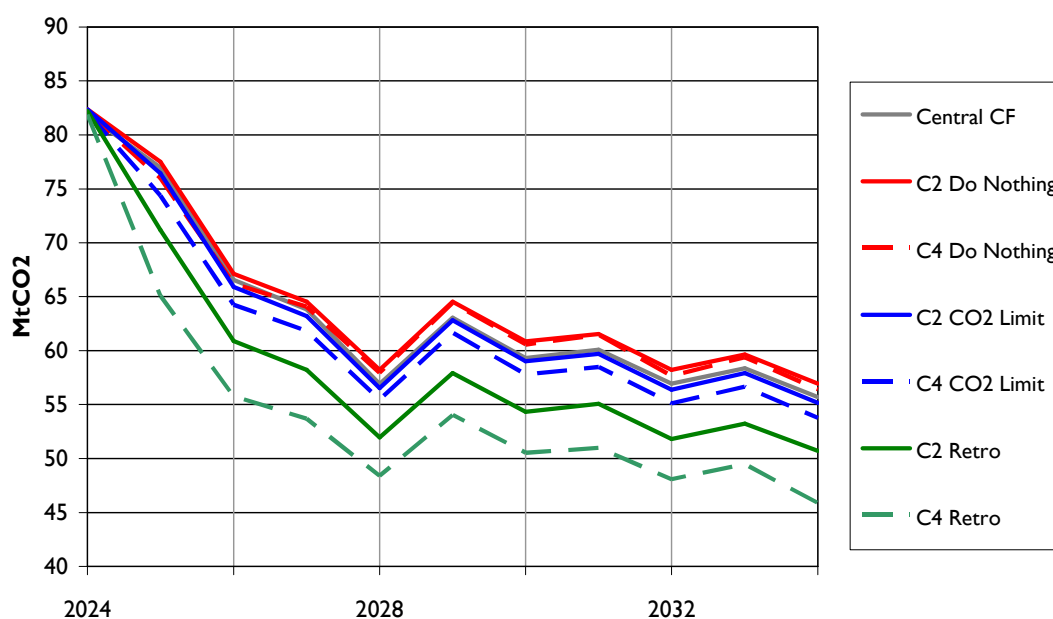
Prior to the retrofit or contingency policy measures taking operational effect in 2025, the number of demonstration plant does not have a significant impact on carbon emissions, as shown Figure 32. This is because the average carbon intensity of the CCS and unabated coal generation from the demonstration plant is very similar to the average intensity of the generation displaced, resulting in very little net change in emissions.

Figure 32 Annual CO₂ emissions, Central Case, 2010 - 2034



In Figure 33, we ‘zoom in’ on the effect of policy options and outcomes post 2025. Clearly, retrofitting provides the greatest reduction in emissions, the more so with more demonstration plant. Do Nothing, with both two and four demonstration plant, results in a small increase in emissions. This is because of the displaced investment in CCGT, which has a slightly lower emission intensity overall. (Compared to the period prior to 2025, this displaced generation has a lower average emissions level due to new plant on the system.) However, the introduction of an emissions limit contingency results in emissions returning to the level of the Counterfactual. Although there are no differences in investment, reducing the load factor of unabated coal slightly reduces the emission levels overall as the loss in output is picked up by CCGTs. If the contingency imposed was tighter, the emissions would be reduced further.

Figure 33 Annual CO₂ emissions, Central Case, 2024 - 2034



In Figure 34 we show the source of emissions over time in the Central Case Counterfactual. The overall fall is primarily driven by the reduction in emissions from the existing coal fleet, itself the result of a combination of closures and plant operating at a lower load factor. CCGT emissions start and end the modelled period at around 40 mtCO₂. IED restrictions start to reduce gas-fired emissions from existing plant from 2016, but emissions from new CCGTs, which we assume are not constrained by emissions legislation, grows and offsets this.

Figure 34 CO₂ emissions source, Central Case, 2010 - 2034

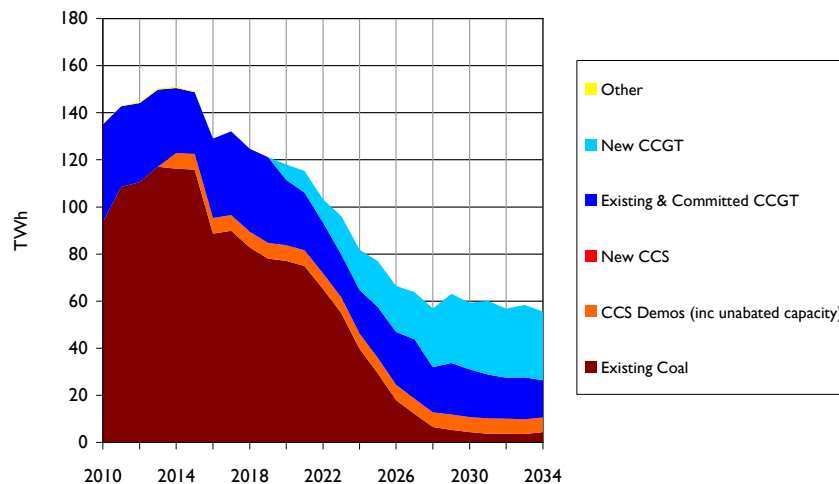
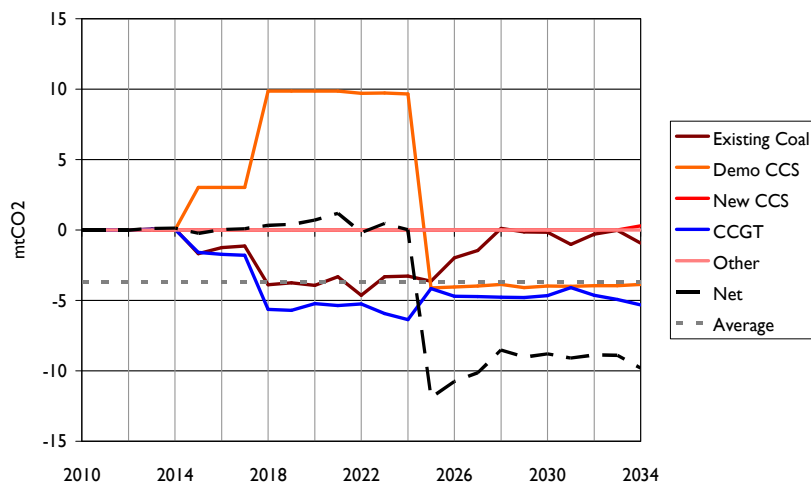


Figure 35 shows the impact of four demonstration plant, with retrofits operational in 2025, relative to the Counterfactual. Through to 2024, the increase in carbon dioxide emissions due to more demonstration plant is offset by a reduction in emissions from existing coal and the combined CCGT fleet²⁹, with a net fall in emissions from 2025 once retrofits are operational.

Figure 35 CO₂ emission change, 4 Retrofit Central less Central Counterfactual



Low Case

In the Low Case, carbon abatement is much more of a challenge as there is less renewables and nuclear on the system. Again, retrofitting leads to the most effective carbon reduction outcome, with Do Nothing the least effective. (In our modelling the retrofit date remains the same across commodity price Cases, but in practice the retrofit year may be more likely to be later with low carbon prices as the economics will be less favourable.)

²⁹ We present the combined CCGT emissions as the variation between existing and new build is quite varied, but approximately offsetting, such that the total change is relatively stable.

Under Low Case commodity assumptions, the scenario is gas favouring and as such coal generation is initially lower relative to the Central Case, leading to a lower starting point for emissions. However, with the lower deployment of nuclear and renewables it is much more of a challenge to abate carbon in the longer run. By 2030, the range is approximately 80 - 90 mtCO₂, compared to 50 - 60 mtCO₂ in the Central Case. The lower renewables and nuclear output in this Case is compensated for by an increase in CCGT generation.

The impact of additional demonstration plant becomes clearer as the carbon price rises post 2020. Relative to the Counterfactual, four demonstration plant increase total carbon emissions. Only if CCS is proven and retrofitted do we observe a reduction in carbon emissions compared to the Counterfactual. This is shown more clearly in Figure 37.

Figure 36 Annual CO₂ emissions, Low Case

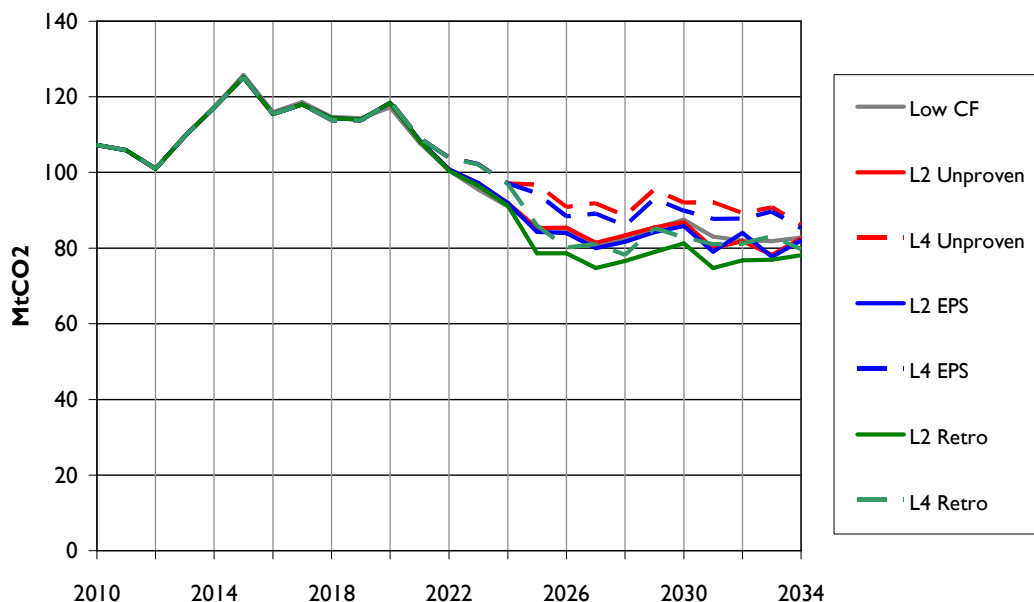
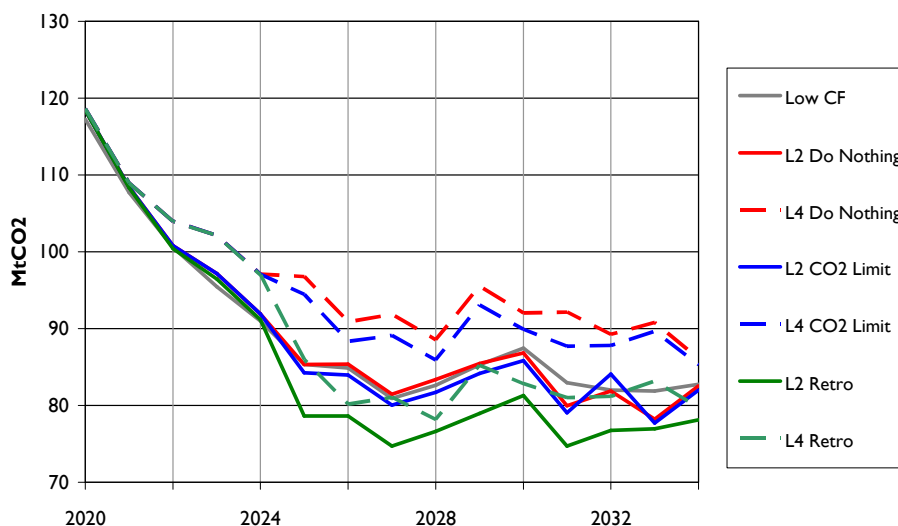


Figure 37 Annual CO₂ emissions, Low Case, 2020 - 2034

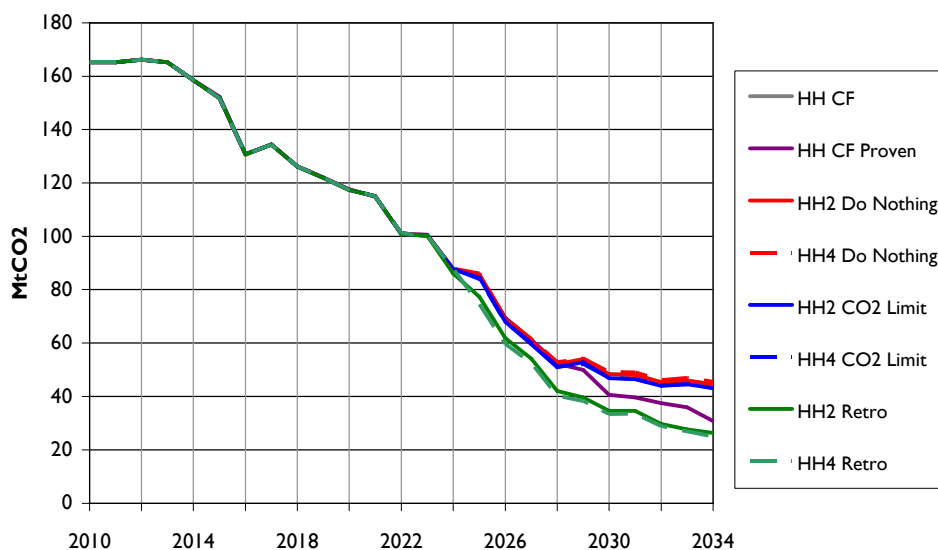


High High Case

In the High High Case we see the largest emissions benefit when CCS is proven and retrofitted. This is because new CCS is developed as well, displacing carbon-emitting generation. The differences between two and four demonstration plant and contingencies if CCS is not proven are small.

Figure 38 shows emissions under the different Outcomes in the High High Case. In the early years the scenario is heavily coal favouring, leading to emissions being over 160 mtCO₂ per annum. However, with the high renewable penetration we see that decrease rapidly through to 2030, such that the range in 2030 is 33 - 50 mtCO₂, lower than either the Central or Low Cases. The spread of outcomes in 2030 is broadest for the High High case, despite emissions being the lowest of the three commodity price Cases. This is because CCS is economically viable without subsidy under these assumptions. Therefore, with four demonstration plant and CCS being proven the electricity sector could reduce its emissions by approximately 80% by 2030, compared to 75% in the Proven Counterfactual. The additional five percentage point reduction is due to increased CCS build driven by accelerated learning. Under the Retrofit Outcome with four demonstrations, with the lowest carbon emissions in 2030 (33 mtCO₂), 77% of the emissions are from CCGTs.

Figure 38 CO₂ emissions, High High Case



Summary

Each commodity price Case has very different levels of competitiveness between coal and gas, which leads to very different emissions in the early years. However, from 2015 to 2025, the levels are broadly comparable both between commodity Cases, number of demonstration plant and CCS Outcomes. Beyond 2025, the differences are more marked. High penetrations of nuclear and renewables, combined with more stringent policy options, lead to lower emissions. Over the modelled period the total cumulative emissions between Cases are comparable, but if the post-2030 trends were to continue, there would be a long term carbon emission reduction in the High High case relative to the others.

7.3.5 What is the impact on net welfare?

We performed a cost-benefit analysis (CBA) to determine net welfare changes for society as a whole. The CBA is a relative measure, showing the change in net welfare between a given run (with two or four demonstration plant, and a given Outcome) and the relevant Counterfactual. It should be noted that the partially-fitted post-combustion competition plant is assumed in the Counterfactuals, and hence the runs show the result of one and three additional projects respectively, with along with the retrofit of the competition plant in Retrofit Outcomes.

In the tables in this section, we present net welfare changes as a net present value (NPV) between 2010 and 2040 discounted to 2010 at the Green Book rate (3.5% real). A positive value represents a positive change in net welfare in the Case relative to the Counterfactual.

There are two main drivers of the net welfare changes. The first is the cost of carbon, which is evaluated at the EU ETS price. By reducing emissions, the total cost of carbon of the system is reduced. The second major driver of welfare change is change in resource cost. This is made up of three main components: capital costs, variable operating costs and fuel costs (excluding carbon costs).

Central Case

The changes to net welfare under the three Outcomes compared to the Counterfactual are presented in Table 21. Where CCS is proven and retrofitting is implemented, the carbon benefit almost exactly offsets the additional resource costs, leading to very little change in overall net welfare. This suggests that the result of the subsidy in this situation is to bring on plant that ultimately just prove to be economic with retrofits based on outturn carbon prices – arguably correcting for the low future value investors may place on carbon given the future market uncertainty. There is a net disbenefit in the Do Nothing and CO₂ Limit Outcomes where CCS is not proven, since the unabated units under a high carbon price or running restriction turn out not to be economic.

Table 21 Net welfare change, Central Case

£bn	Two demonstrations	Four demonstrations
Retrofit	-0.04	0.02
CO ₂ Limit	-0.98	-1.24
Do Nothing	-0.70	-0.55

Low Case

In the Low Case, the plant do not become economic under any Outcome, and hence there is a negative net welfare impact associated with the demonstrations themselves. There is an offsetting effect, however, with four demonstration plant – which shows a positive NPV in the CBA. This is a consequence of the displacement of renewable investment. In 2030, with four demonstration plant, there is 5 GW less renewables on the system compared to the Counterfactual. As the displaced renewables (which will be the marginal, highest cost capacity) would have been more expensive than the demonstration CCS plant, we see a reduction in resource costs, only slightly offset by increased carbon emissions. It must be noted that there is no penalty in the CBA for missing the renewables target, and hence there is no account taken in the net welfare calculation of the lower renewable build – and consequently this does not imply a ‘good’ result when the UK’s renewables target is taken into account.

Table 22 Net welfare change, Low Case

£bn	Two demonstrations	Four demonstrations
Retrofit	-3.75	1.03
CO ₂ Limit	-1.65	2.80
Do Nothing	-1.80	3.06

High High Case

Under the High High Case, the plant are economic against outturn prices when CCS is proven and retrofitting is implemented, and there is a net welfare benefit as a result³⁰. Unlike the Central Case, there is a net welfare gain for four demonstrations when CCS is not proven, driven by more coal-favouring commodity prices such the previously uneconomic units become economic.

Table 23 Net welfare change, High High Case

£bn	Two demonstrations	Four demonstrations
Retrofit	2.15	4.20
CO ₂ Limit	-0.28	1.33
Do Nothing	0.27	2.3

Summary

In the Central Case, the carbon benefits of ‘proven’ outcomes with retrofitting just offset the additional resource costs. Under the High High Case, the positive economics of the projects given the outturn commodity prices give a positive net welfare benefit. (The impact of the date of retrofit is explored in a sensitivity in the Technical Annex.)

When CCS is not proven and an annual emissions limit is enforced, there is a net welfare decrease relative to the Do Nothing alternative in the majority of Cases. This contingency leads to higher resource costs through the need to burn more expensive fuels that is not offset by the benefit of lower emissions.

In the Low Case, although the demonstration plant are not economic, increasing the number to four brings a net welfare benefit. This is driven by the reduced investment in renewables post 2020 rather than the potential carbon benefits, but it must be remembered that there is no penalty in the CBA for missing the renewables target.

7.4 Key messages

Overall, the impact of the CCS demonstration plant on the rest of the electricity market is small.

³⁰ Note that for the High High case, the CBA comparison is to different counterfactuals for the ‘proven’ and ‘not proven’ outcomes.

By developing more demonstration plant, there is not necessarily an overall gain in capacity on the system, as investment in other plant is displaced. With more demonstration plant, we see a greater delay in investment in new CCGT build leading to some fluctuations in capacity margin. There is no significant impact on nuclear and renewable deployment, except under the Low Case. Therefore, in the long term, the capacity margin impacts are minimal. However, in the late 2010s, the demonstration plant come online before CCGT in the Counterfactual, leading to higher capacity margins over this period.

Although capacity margins are not affected in the long term, there are potentially benefits in diversity of generation and fuel mix. In 2030, total coal capacity (existing coal, demonstration plant and new build CCS) ranges from 7.7 GW in Counterfactuals (6% of capacity) to 14.2 GW (11% of capacity) in High High 4 Retrofit.

Wholesale prices are not significantly affected either by the number of demonstration plant, or the CCS Outcomes. This is because the marginal price setting plant does not change significantly. The only material impact observed is when CCS is proven and economic in its own right. When this occurs, CCS operates mid-merit in the later part of the modelling horizon and starts setting prices for material periods of the year. At this point, we see the wholesale price starting to decouple from the carbon price.

The impact on emissions is subtle, and should be considered in the context of the EU ETS, under which any GB power sector changes would be offset in other sectors or countries. The variation in cumulative emissions to 2034 is small across Cases and CCS Outcomes, although the pathway varies significantly with different levels of coal-gas competition and renewable and nuclear investment. However, although our modelling does not extend that far, there are signs of clear benefits when extrapolating to 2050 of CCS as a technically and commercially viable low carbon option. This is most apparent in the High High Case, with annual emissions being 33 mtCO₂ in 2030, compared to over 90 mtCO₂ in the Low Case. Only in this case, where new CCS is coming into the market, do emissions continue on a downward trajectory after 2028.

8 Implementation issues

8.1 Introduction

A requirement to fit or retrofit carbon capture facilities is unlikely to be implemented unless the technology meets minimum standards regarding technical maturity and acceptable economics. This section explores the term “technically and economically proven” as it would apply to CCS, the implications of applying such a requirement to plant, and the potential role of the Environment Agency (EA) in determining the status of CCS.

8.2 Technically and economically proven

The EA has been suggested for the role of assessing whether CCS is technically and economically proven. The EA is an independent, non departmental public body, with responsibility “to protect or enhance the environment, taken as a whole so as to promote the objective of achieving sustainable development”. Its existing remit covers pollutant emissions from large industrial sources, including the power sector.

The EA’s role in monitoring and controlling “local” pollutants (such as particulates, NO_x and SO_x) has required it to develop metrics for assessing the technical and economic viability of technologies for the control of these emissions. The EA’s approach to controlling local pollutants provides a useful proxy for how it might respond to a global pollutant such as CO₂.

8.2.1 Emissions Performance Standard

The EA’s approach to controlling and reducing emissions to date is via an emissions performance standard (EPS)³¹. This sets the maximum allowable concentration of pollutant in the flue gas stream. This fixed standard is applied across the fleet of power plants. When setting such a standard, there are two basic considerations:

- Is it a reasonable expectation that an emission reduction can be achieved at all?
- What level should the emission level be set?

The limit itself is set by what can be achieved by one particular technology (the Best Available Technology, BAT) but any may be used to achieve the limit.

8.2.2 Best Available Techniques/Technology

Put simply, a technology may be considered BAT if it is “out there (i.e. in use), affordable, and can achieve the required emission level”³². “Available” is defined formally in the environmental protection act 1990:

³¹ As discussed in Section 5.1.2, an EPS is one of the options available as a contingency in the event that CCS was ‘not proven’. Here we discuss it as the measure of performance to be achieved when CCS is ‘proven’.

³² Quote from an EA representative.

- “‘**available**’ should be taken to mean procurable by the operator of the process in question. It does not imply that the technique is in general use, but it does require general accessibility. It includes a technique which has been developed (or proven) at a scale which allows its implementation in the relevant industrial context with the necessary business confidence. It does not imply that sources outside the UK are ‘unavailable’. Nor does it imply a requirement for a competitive supply market. If there is a monopoly supplier the technique counts as being available provided that the operator can procure it.”

and

- “‘**available**’ techniques shall mean those developed on a scale which allows implementation in the relevant industrial sector, under economically and technically viable conditions, taking into consideration the costs and advantages, whether or not the techniques are used or produced inside the Member State in question, as long as they are reasonably accessible to the operator”.

8.2.3 Implications of BAT for CCS

For the definition of BAT to be applied to CCS, the capture technique(s) to be used would have to have been demonstrated successfully at a scale appropriate to the facility. The demonstrations are not required to be situated in the UK; rather the demonstrations would need to take place under conditions which sufficiently reflect the UK market and/or allow reasonable extrapolation to UK market conditions. For NO_x emissions, for example, the use of scrubbing technology elsewhere in Europe was sufficient for it to be defined as “available” in the UK.

Given the significant variation in capture technology (and implications for plant) between post-combustion, pre-combustion, and oxyfuel, at least one of each of these capture facilities would need to be demonstrated successfully to demonstrate availability. European wide coordination on demonstrations would facilitate the ability to assess the technologies at least cost.

A large number of demonstrations, or widespread use of the capture technique, is not required. Neither does there need to be a competitive supply chain for the technology.

8.2.4 BATNEEC

The cost of achieving a reduction in emissions levels (relative to a baseline) increases as the emission requirements become stricter. Given the different objectives of the EA (to reduce emissions) and to industry (to operate profitably) the EA must define a reasonable level at which to set the EPS. With regards to NO_x emissions, the EA defines volume emission limits (e.g. 450mg NO_x/m³ of flue gas) but does not prescribe a particular scrubbing technology to achieve this.

The EA uses “Best Available Technology Not Entailing Excessive Cost” to help define reasonable cost, and hence a reasonable emission limit. The presumption is that best available techniques will be used but, “in the Secretary of State’s view, that presumption can properly be modified by economic considerations where the costs of applying best available techniques would be excessive in relation to the nature of the industry and the environmental protection to be achieved”. For the EA, the principal consideration in determining whether an option represents BAT is that the costs of its implementation should not be disproportionate to the environmental benefit it realises.

To define the cost of a measure, the EA develops marginal abatement curves to define a reasonable level of abatement that does not “Entail Excessive Cost”. The EA also develops discounted cashflow models of the

operators' businesses. It also takes into account the value of avoided pollution. Operator and site specific economic models are used as generic models have insufficient resolution.

8.2.5 Implications of BATNEEC for CCS

For this process to apply to CCS, the EA would have to be in a position to develop the economics of the BAT for each potential CCS site. It would be possible to do this provided there was at least one example of the relevant capture technology in successful operation at an appropriate scale.

If the market price of carbon is taken as a measure of the true cost of CO₂ related "pollution", and if the fitting of capture facilities resulted in an abatement cost which exceeded that of the market price of carbon, it could be argued that costs are disproportionate. In such circumstances, financial incentives would be required, such as the CfD or AP funding mechanisms, to make the cost of the technique (to the plant owner) "proportionate" to the benefits achieved.

Alternatively the EA could take the view that the market price of carbon underestimated the true environmental cost, and attempt to enforce the use of capture techniques. Under these circumstances, the EA would be required to develop and demonstrate a robust methodology supporting its decision, which would be open to challenge by plant operators. Also, if the price was so high that it would materially affect the plant owners' business model, then the true cost of carbon would be too high and be unaffordable to implement.

8.2.6 Limits to EA: transport and storage

The discussion above applies to BAT and BATNEEC for capture, but not for transport and storage.

Transport of CO₂ is a mature technology, with extensive CO₂ pipeline networks in the United States, for example. However, transporting potentially large volumes of CO₂ in dense phase and close to heavily populated areas has not been fully explored. While developing a suitable transport solution does not require new technology (and so, transport can be taken as BAT) it is likely to result in a protracted planning process and the potential for delays and cost escalation. There is scope for an operator to deem the transport element of the chain to be of excessive risk, unless a feasibility study has been undertaken to identify a suitable pipeline route.

CO₂ storage is not a mature technology. From the plant operator's perspective it may not be reasonable or (excepting where a CCS project is vertically integrated) feasible to require that there be a BAT for storage.

With regards to conventional pollutants from power sources, the EA treats plant as geographically well defined and distinct entities of which it has oversight. For CCS, carbon can only truly be *abated* when it is captured, transported and stored successfully. Currently the EA does not deal with emissions from "beyond the fence" of a facility and this may limit its role when examining the full CCS chain. Ultimately this may be acceptable as in any case the "liability" for injected CO₂, including monitoring and unplanned emissions, would need to revert to the State given the level of technical immaturity and commensurate risk associated with CO₂ injection³³.

³³ 2009/31/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 23 April 2009

8.2.7 Time required to implement capture facilities

The time required to retrofit and implement capture facilities needs to be clearly defined during preparation work undertaken to prove that a plant is capture ready. The Consultation Document specifies an upper limit of 5 years for retrofit, following achievement of commercially and economically proven status.

The speed at which the market can respond to a legal requirement to retrofit is strongly related to the confidence that the market has beforehand that such a requirement will be adopted. For example, before the introduction of SO₂ limits in the US (clean air act in 1970), the number of patents filed which related to SO₂ control technologies began to rise in 1960³⁴, from a relatively low level. In other words, it was becoming clear to the market a decade before that such emission control technologies were worth development (or at least patenting). A strong signal of intent is itself of primary importance in ensuring that compliance can occur quickly, once it is legislated. Therefore, it should be the case that a generator building new plant must anticipate and expect that capture facilities will be fitted at some time in the future.

³⁴ In the US, emissions legislation began long before 1970, though this bill was particularly stringent on SO₂ limits.

9 Conclusions

Policy objectives

We identified six potential policy objectives associated with CCS funding in our qualitative assessment. Of these, four appeared consistent with support for four demonstration projects (including the existing competition plant):

- Quick UK deployment
- Support a 2050 pathway
- Generation diversity
- Regeneration

Two of the policy objectives could potentially be met with a smaller number of demonstration plant:

- Playing a fair part in EU and global CCS development
- Phasing out unabated coal

The longer term decarbonisation objective in ‘Support a 2050 pathway’ focused on initial demonstration of the technology but envisaged allowing developers to determine further decisions on an economic basis. The others called for mandatory retrofits, but only when commercially viable (or with additional subsidy to cover any funding gap), removing the economic risk for investors. For ‘Phased out unabated coal’, a strict contingency (applied equally to existing plant) was central, but in other cases there was a concern that the threat of a contingency might prove a deterrent to investors.

Consumer costs

It is clear that there remains a high degree of uncertainty associated with CCS costs. It is also likely that potential participants in a tender process will have a strategic interest in CCS that will have a bearing on what they are prepared to bid. As a result it is difficult to estimate the potential costs to the consumer of the CCS demonstrations, but equally clear that designing the tender process to be as competitive as possible given a limited number of potential bidders is essential. That said, based on the assumptions described here, and where no contingency measures are imposed, our analysis indicates potential costs to consumers of supporting four demonstrations of around £3.2-4.5 bn (the NPV of annual funding mechanism payments at the Green Book discount rate), when all three types of technologies are supported. With only two demonstration plant, the potential costs to consumers could fall to £1.8-2.4bn.

Retrofit requirement

Although none of our policy objectives explicitly called for forced retrofits where these were not commercially viable (or supported by additional funding), our analysis suggested that such an obligation, even without clarity on the definition of economically proven, may not add substantially to consumer liability if investors assume a rising carbon price, particularly if that obligation would not be imposed prior to 2025. This is in part due to the discounting of the associated retrofit capital expenditure, and in part because there is a good prospect of the retrofit becoming commercially viable in any case. Including a retrofit requirement in policy would importantly send a strong message with regard in particular to the development of the overall CCS supply chain.

Contingency

A tight contingency that significantly limits plant operation where CCS is not proven imposes an additional risk that is difficult to quantify, and will depend on an investor's judgement as to the chance of a 'not proven' outcome. However, indicatively, if an investor assumed that a contingency would be introduced, it could add £300mn NPV (at the Green Book rate) to the cost for consumers in this case (and double that for four plant).

Funding mechanism

A carbon CfD for a funding mechanism has an intuitive appeal in that it benefits developers when carbon prices are low, and vice versa, and hence could be seen as a hedge. In practice, however, it is not obvious that it will act to reduce risk for investors. Under our assumptions, there is in fact a small increase in risk compared to an Additional Payment as the CfD over-hedges the carbon exposure for the plant – but this result is very sensitive to assumptions on the correlation between power and carbon prices. The CfD does however reduce rents to generators under high carbon price outcomes – the liability to consumers falls by nearly £500mn NPV (at the Green Book rate) between our Central and High High cases for four demonstrations. An Additional Payment mechanism, on the other hand, has the attraction of simplicity – which may be beneficial for projects seeking outside investment.

Future CCS build

Only in the High High Case does any further new build CCS without subsidy feature before 2035 (given our assumptions on learning curves). This may indicate a future need either for additional measures to strengthen carbon signals or further direct subsidy at a later point if CCS is to play a key role in the long term. Where new build CCS does occur, alongside high levels of renewables and nuclear, by late 2020s we begin to see a decoupling of the power price from carbon as low carbon technologies increasingly become price-setters. This may pose a challenge as the investment signal for CCS and other low carbon technologies is dampened when the carbon price is not fully reflected in the electricity price.

A view on the acceleration of learning and cost reduction from the UK demonstration projects themselves needs to be taken in the context of activity at the European and global level. Under our assumptions on the impact of four UK demonstrations on the learning curve for CCS, the first unsubsidised new CCS build is accelerated by a year compared to the Counterfactual with only a single demonstration.

Market impact

Even with four demonstration plant, the impact on the market as a whole is relatively limited. The additional capacity introduced tends to displace CCGT build, capacity margins are not significantly affected, wholesale price changes are small, and diversity in the technology mix is improved. Nuclear and renewable investment is not affected in the Central and High High Cases. In the Low Case, where investment is significantly lower in any case in the Counterfactual, with four demonstration plant, nuclear is delayed by a year and some 4GW of renewables is displaced after 2020, which has the effect of increasing emissions compared to the two demonstration plant case. Assuming EU ETS allocations remain binding, there would of course be no overall impact on total emissions at a European level. In the Central and High cases, there is a significant reduction in emissions within the UK in 'proven' outcomes after retrofit, with additional abatement of around 9mt/year in the Central Case.

Net welfare

Under our central price case in the outcome where CCS is ultimately proven, the carbon benefits almost exactly offset the additional resource costs, with the result that there is almost no difference in net welfare relative to the counterfactual (on an NPV basis to 2040 at the Green Book discount rate of 3.5% real). 'Not proven' outcomes have a net disbenefit of around £0.5-1.0 bn. Under our low price Case, the plant

are not economic, which results in a disbenefit of up to £3.5 bn. Our third price Case had very high carbon prices and gas was expensive compared to coal: under these favourable conditions the net welfare when CCS is 'proven' rose to around £2-4bn.