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

# Technical Annex

A report for the Department of Energy and Climate Change, November 2009 – URN 09D/813

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**REDPOINT**

***Version History***

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| 1.0 | 8/11/09 | Final version | Saleem Lalani<br>Richard Faulkner<br>Harsh Pershad | Oliver Rix |

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# 1 Introduction

This document is the Technical Annex to the study 'Carbon Capture and Storage demonstration: analysis of policies on coal/CCS and financial incentive schemes' and should be read in conjunction with the main report. It provides further information about the assumptions and approach taken in the modelling and development of our analysis, and supplemental analysis of the results.

The Annex is structured as follows.

- In Section 2, we provide a more detailed description of our modelling assumptions
- In Section 3, we describe the transportation and storage cost modelling used to derive the associated inputs to the main analysis
- In Section 4, we describe our demonstration plant (Risk Assessment Model) and electricity market (Investment Decision Model) modelling approach in more detail
- In Section 5, we present supplementary analysis from the demonstration project modelling (RAM)
- In Section 6, we present supplementary analysis from the electricity market modelling (IDM)
- In Section 7, we summarise our review of the technical literature on CCS.

# 2 Assumptions

In this section, we present our assumptions in detail, broken out into the following categories:

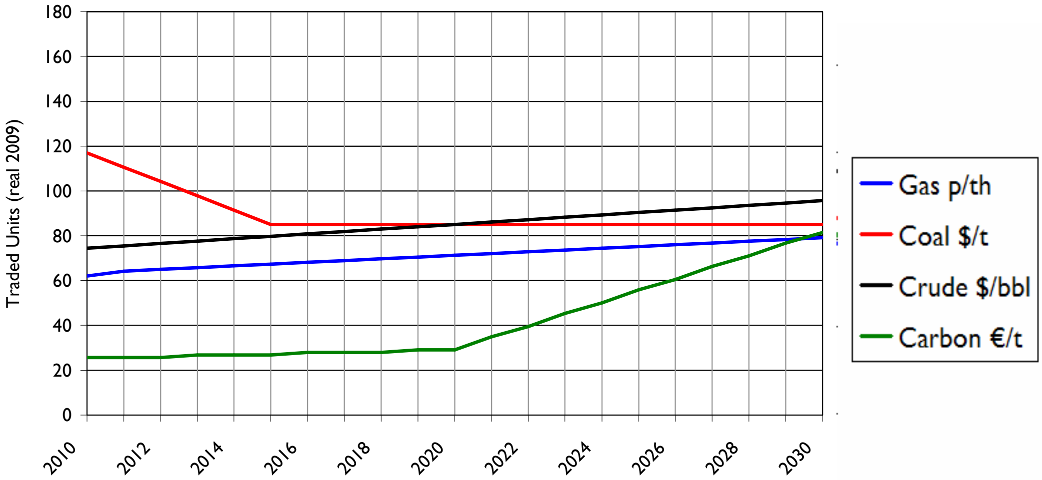
- general assumptions;
- CCS assumptions; *and*
- market assumptions.

## 2.1 General assumptions

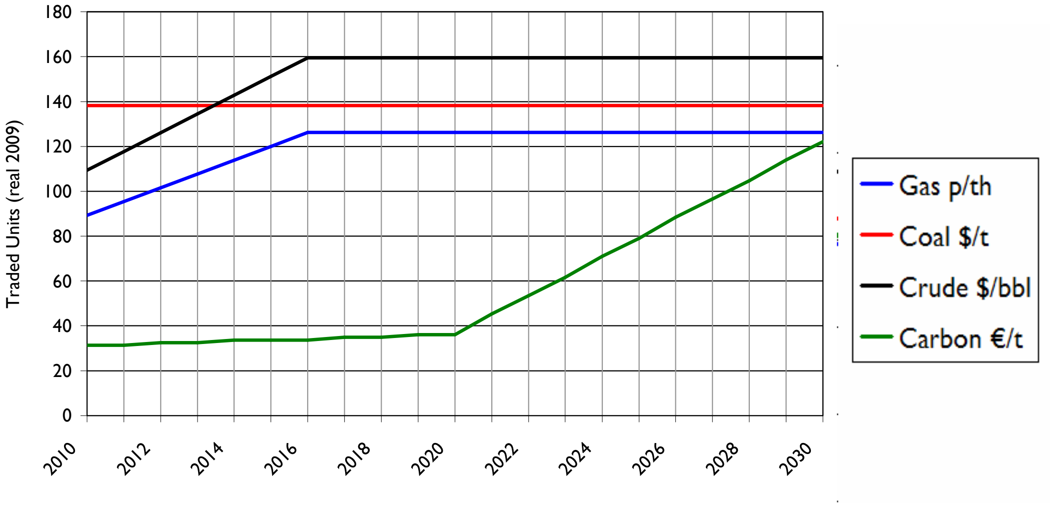
### 2.1.1 Commodity prices

Four commodity price Cases have been used through the modelling. The fuel prices in the Central, Low and High High scenarios (shown in Figure 1 to Figure 3) are based on DECC's January 2009 Updated Fossil Fuel Price Assumptions (UFFP), and the carbon prices for these were also provided by DECC for the study. The 'investor expected' case (shown in Figure 4) was developed by Redpoint and used exclusively in the Risk Assessment Model (RAM).

**Figure 1 Central commodity prices, real 2009**



### Figure 2 High High commodity prices, real 2009



### Figure 3 Low commodity prices, real 2009

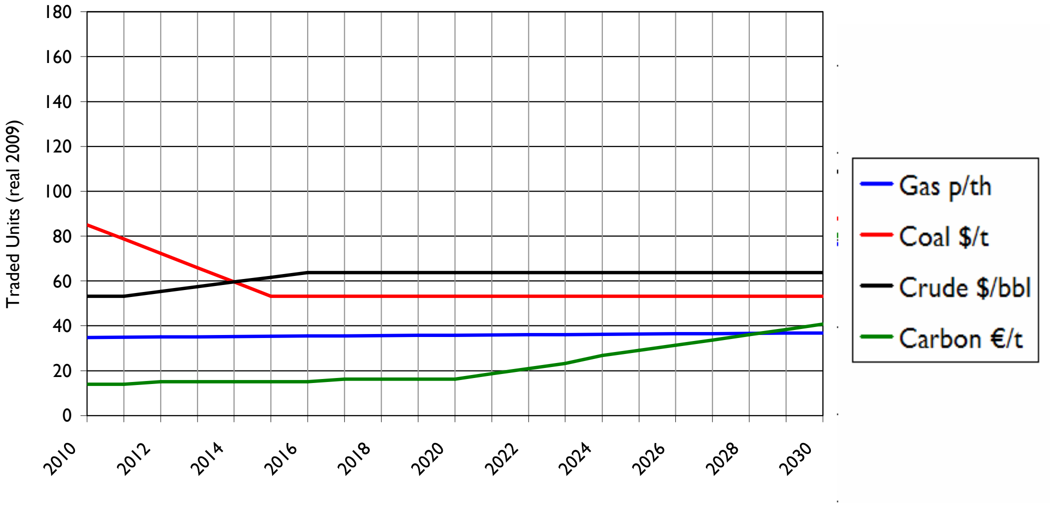
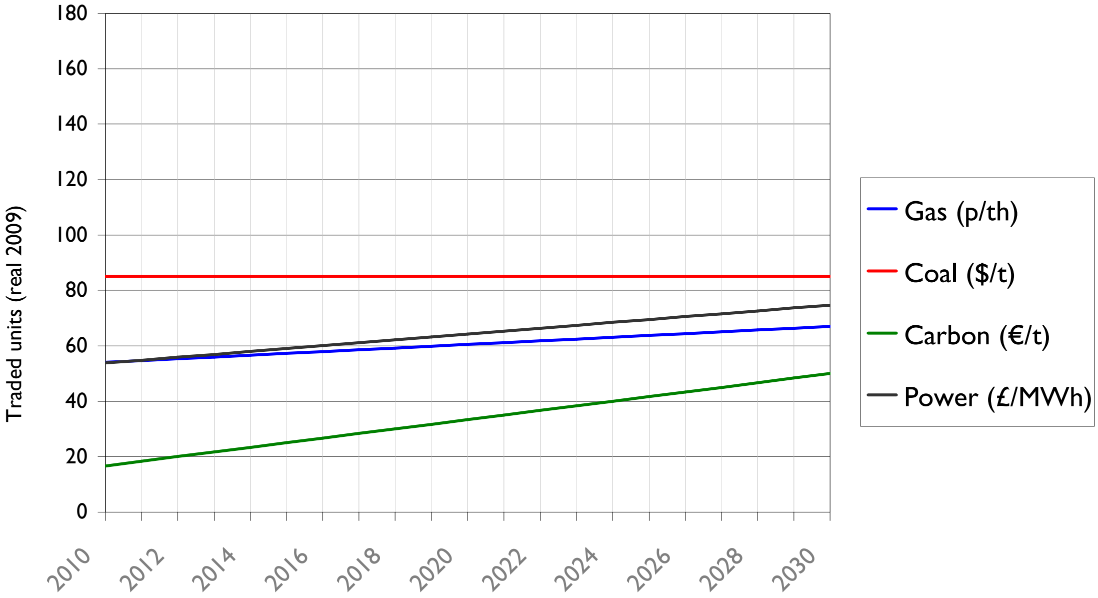


**Figure 4** **Investor-expected commodity prices, real 2009**



## 2.1.2 Financial parameters

The financial parameters used in the modelling are summarised in Table 1.

**Table 1** **Financial parameters**

| Parameter | Value | Basis |
|---|---|---|
| Inflation rate | 2.5% | Consumer Price Index |
| Depreciation rate | 40% | Reducing balance |
| Tax rate | 28% | Flat |
| Green Book rate | 3.5% | Real |
| GBP – EUR | 1.16 | -- |
| GBP – USD | 1.63 | -- |

## 2.1.3 Fuel characteristics

Fuel characteristics are summarised in Table 2.

**Table 2 Physical constants**

| Parameter | Value | Units |
|---|---|---|
| Coal - Calorific Value | 25.1 | GJ/t |
| Coal - $CO_2$ Emissions Rate | 0.34 | $tCO_2$/MWh of coal |
| Gas - Calorific Value | 9.48 | th/GJ |
| Gas – $CO_2$ Emissions Rate | 0.17 | $tCO_2$/MWh of gas |

## 2.2 CCS Assumptions

Assumptions on costs and technical parameters for the base coal generation facilities and CCS equipment were provided by DECC. The capital cost assumptions on the Advanced Super Critical (ASC) coal plant and the Integrated Gasification Combined Cycle (IGCC) plant (which are respectively the base plants for post-combustion and pre-combustion technologies) are consistent with those used in Redpoint's June 2009 report for DECC 'Implementation of the EU 2020 Renewables Target in the UK Electricity Sector: RO Reform'. Capital and operating expenses of transport and storage facilities were based on an internal model, described in Section 3.

### 2.2.1 Technical assumptions

Technical assumptions used in the Risk Assessment Model (RAM) and the Investment Decision Model (IDM) are summarised in Table 3 and the plant build profiles are presented in Table 4.

**Table 3 Technical assumptions**

| | Unit | Post-combustion | Pre-combustion (part CCS) | Pre-combustion (full CCS) | Oxyfuel |
|---|---|---|---|---|---|
| Configurations | | | | | |
| Total capacity (gross) | MW | 1600[†] | 986 | 986 | 393 |
| Capacity of CCS demonstration unit (gross) | MW | 400[‡] | 493 | 986 | 393 |
| Capital expenses | | | | | |
| Base plant – CCS ready | £/kW | 1136 | 1533 | 1533 | 1768 |
| CCS equipment | £/kW | 769 | 329 | 282 | 654 |
| Initial transport and storage costs | £/kW | 650 | 591 | 388 | 650 |
| Retrofit (incl. transport and storage resizing) | £/kW | 933 | 797 | n/a | n/a |
| Operating expenses | | | | | |
| Variable O&M Cost - base plant | £/MWh | 4.1 | 5.6 | 5.6 | 4.4 |
| Variable O&M cost (incremental) - CCS equipment | £/MWh | 2.0 | 1.0 | 1.0 | (1.5) |
| Fixed O&M cost - base plant | £/kW | 33.3 | 46.4 | 46.4 | 33.3 |
| Fixed O&M Cost (incremental) - CCS equipment | £/kW | 14.0 | 6.0 | 5.1 | 11.9 |
| Variable CO2 transport and storage costs | £/t | - | - | - | - |
| Fixed CO2 transport and storage costs | £/t | 9.6 | 10.9 | 10.9 | 9.4 |
| Operatinal parameters | | | | | |
| Forced outage rate | % | 5% | 6% | 6% | 7% |
| Planned outage rate | % | 10% | 9% | 9% | 8% |
| Efficiency - base plant | % | 45% | 43% | 43% | 44% |
| Parasitic load - base plant | % gross | 8.3% | 7.9% | 7.9% | 8.4% |
| Parasitic load - base plant + CCS equipment | % gross | 28.9% | 27.0% | 27.0% | 23.7% |
| CCS emissions capture rate | % gross | 91% | 90% | 90% | 90% |

† - Modelled station capacities varied slightly in the market modelling to fit within the granularity of the model.

**Table 4 Capex spend profiles of demonstration plants**

| Technology | Capex type | Year 1 | Year 2 | Year 3 | Year 4 |
|---|---|---|---|---|---|
| Post-combustion | Base plant | 13.8% | 23.8% | 35.0% | 27.5% |
| | CCS equipment | 6.6% | 14.0% | 35.0% | 44.4% |
| | CCS retrofit | 8.1% | 16.1% | 35.0% | 40.8% |
| Pre-combustion (part-fitted) | Base plant | 13.8% | 23.8% | 35.0% | 27.5% |
| | CCS equipment | 4.2% | 10.8% | 35.0% | 50.0% |
| | CCS retrofit | 3.0% | 9.1% | 35.0% | 52.9% |
| Pre-combustion (fully-fitted) | Base plant | 13.8% | 23.8% | 35.0% | 27.5% |
| | CCS equipment | 5.4% | 12.4% | 35.0% | 47.2% |
| Oxyfuel | Base plant | 13.8% | 23.8% | 35.0% | 27.5% |
| | CCS kit | 5.8% | 13.0% | 35.0% | 46.2% |

## 2.2.2 Build constraints

In Table 5 we present the assumed maximum build rates used in the market modelling for each CCS technology. These apply to any new build after the demonstration projects, which are treated separately. Each new unit is assumed to be 500 MW in size. New plant is only permitted in proven (retrofitted) Outcomes.

**Table 5 Build Constraints for CCS technologies**

| Year | MW/year | | |
|---|---|---|---|
| | Oxyfuel | Pre-combustion | Post-combustion |
| 2015 | 0 | 0 | 0 |
| 2016 | 0 | 500 | 500 |
| 2020 | 0 | 1000 | 1000 |
| 2025 | 500 | 1500 | 1500 |
| 2031 | 1000 | 2000 | 2000 |

## 2.2.3 Learning Curves

Capital costs for a fully fitted and operational plant are split into three sections:

- Plant capital expenditure
- CCS equipment capital expenditure
- Transport and storage capital expenditure

Dependent on the number of demonstration plant, the learning curves are different, as are the dates at which 'nth of a kind' (NOAK) is assumed to be reached. Transport and storage learning from demonstrations is assumed to lead to benefits across all CCS types, whilst plant capital expenditure benefits are only assumed to accrue for the specific plant types involved.

One post-combustion demonstration plant is built in our Counterfactuals. An additional pre-combustion plant is built in our 'two demonstration' runs. For our 'four demonstration' runs, a further post-combustion plant and an oxyfuel plant are also built.

The corresponding learning curves for the Counterfactuals, the 'two demonstration', and the 'four demonstration' cases are shown in Figure 5 to Figure 7 below for each technology. Graphs show the total capacity cost (including the base plant, the CCS equipment, and the transportation and storage infrastructure) on a net capacity basis.

**Figure 5** **Post-combustion learning curves**

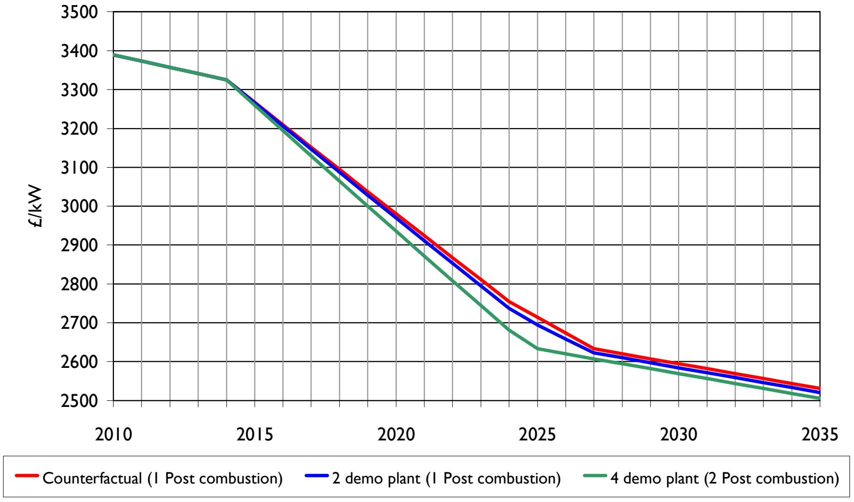


**Figure 6** **Pre-combustion learning curves**

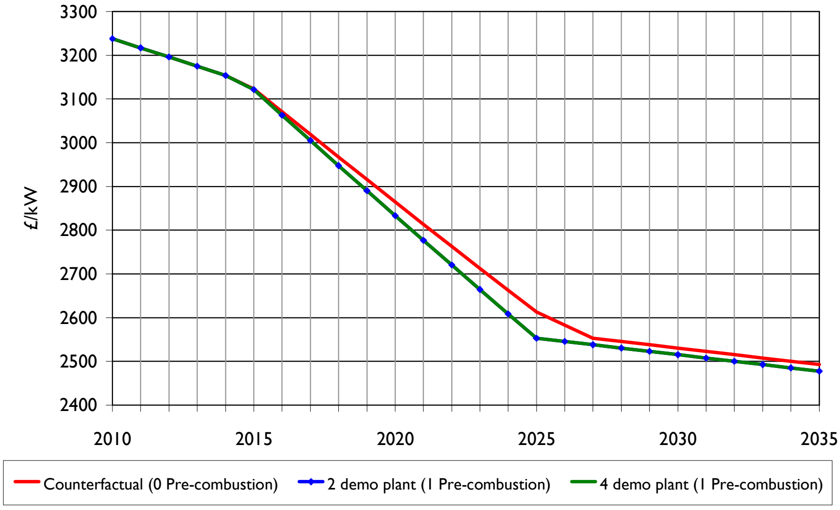
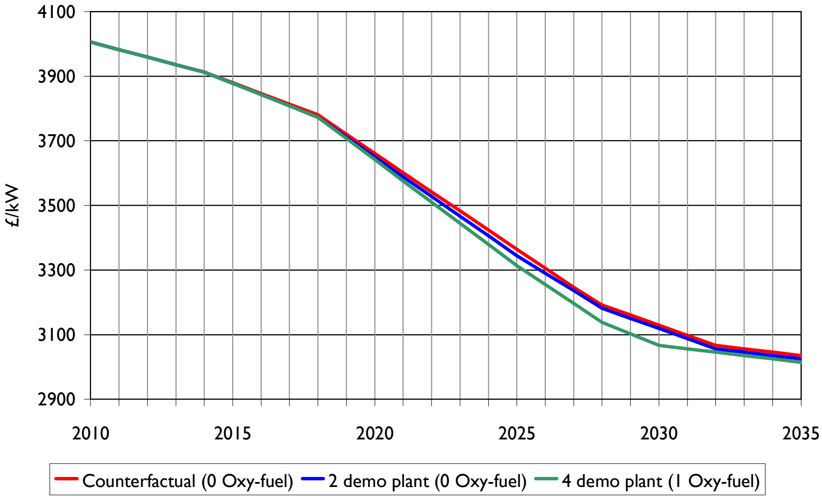


**Figure 7** **Oxyfuel learning curves**



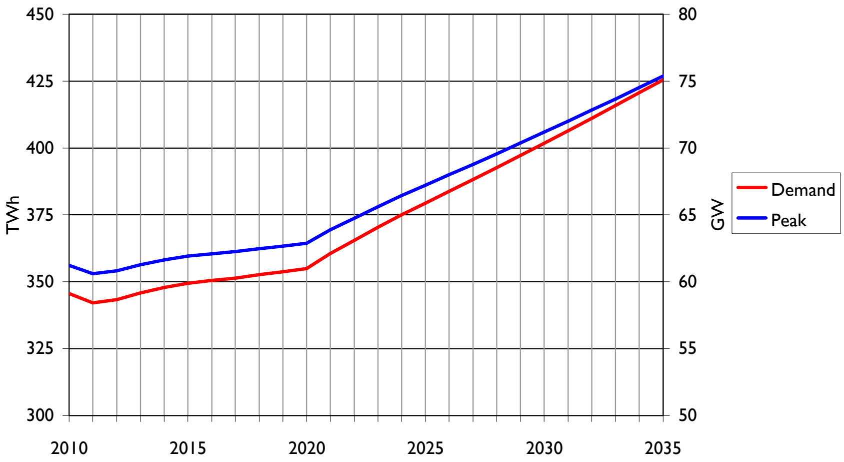
# 2.3 Market assumptions

## 2.3.1 Demand

We use a 'station-gate' definition of demand, which correspondingly is gross of transmission and distribution losses, but net of parasitic load and pumped storage load. We include demand served by distributed generation. These demand values are therefore typically higher than National Grid reported demand, which is net of distributed generation. As we model the BETTA market, our demand is for Great Britain only.

We assume that peak demand increases at the same rate (in percentage terms) to that of energy demand.

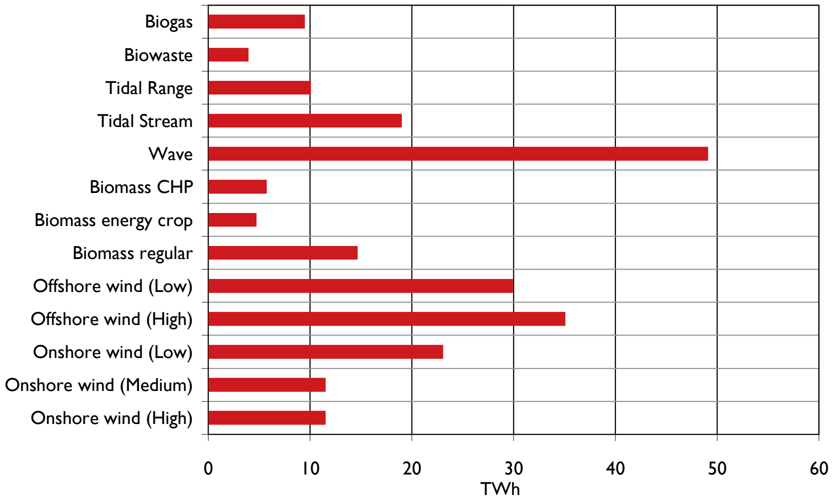
**Figure 8 Demand**



### 2.3.2 Renewables resource

Figure 9 shows the total resource potential for the major technologies in 2020 as derived by Redpoint from the European Commission's Green-X study[1]. These total potentials take no account of build rate constraints which will restrict the speed at which these resources can be exploited.

**Figure 9 Renewables resource availability in 2020**



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[1] http://www.erec.org/projects/finalised-projects/green-x.html

## 2.3.3 Maximum build rate constraints (non-CCS)

Table 6 shows the maximum build rate constraints that we apply to renewable deployment.

**Table 6 Maximum renewable build constraints**

| Max build, MW/annum | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Onshore wind | 600 | 700 | 800 | 900 | 1000 | 1100 | 1200 | 1300 | 1400 | 1500 | 1500 | 1500 |
| Offshore wind | 660 | 870 | 1090 | 1310 | 1400 | 1400 | 1600 | 1600 | 1600 | 1800 | 1800 | 1800 |
| Biomass regular | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Biomass energy crop | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| Biomass CHP | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| Wave | 0 | 25 | 35 | 45 | 55 | 65 | 75 | 85 | 95 | 100 | 110 | 150 |
| Tidal Stream | 0 | 60 | 120 | 180 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 240 |
| Tidal Range | 0 | 0 | 0 | 35 | 75 | 120 | 200 | 200 | 200 | 200 | 200 | 200 |
| Biowaste | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 |
| Biogas | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 |

We assume that a maximum of 1.6 GW of nuclear can be built every other year, with first new plant on line in 2020.

## 2.3.4 Nuclear retirements

Our nuclear retirement dates are shown in Table 7 and are in line with those determined by the Nuclear Installations Inspectorate.

**Table 7 Nuclear retirements**

| Plant | Capacity (MW) | Year |
|---|---|---|
| DUNGENESS | 1110 | 2018 |
| HARTLEPOOL | 1210 | 2019 |
| HEYSHAM 1 | 1150 | 2019 |
| HEYSHAM 2 | 1250 | 2028 |
| HINKLEY POINT | 1220 | 2016 |
| OLDBURY | 434 | 2010 |
| SIZEWELL B | 1190 | 2045 |
| WYLFA | 980 | 2012 |
| HUNTERSTON | 1190 | 2016 |
| TORNESS | 1250 | 2028 |

## 2.3.5 LCPD and IED assumptions

### *Large Combustion Plant Directive*

Coal and oil plant which have opted out of the Large Combustion Plant Directive (LCPD) must retire by 2015. Our assumptions on closure dates are shown in Table 8.

### Table 8 Large Combustion Plant Directive retirements

| Plant | Capacity (MW) | Year |
|---|---|---|
| DIDCOT A | 1960 | 2014 |
| FAWLEY | 518 | 2015 |
| GRAIN | 650 | 2015 |
| LITTLEBROOK | 1370 | 2014 |
| LITTLEBROOK GT | 105 | 2014 |
| TILBURY GT | 34 | 2013 |
| FERRYBRIDGE (2 of 4 units) | 980 | 2012 |
| IRONBRIDGE | 964 | 2012 |
| KINGSNORTH | 2000 | 2013 |
| TILBURY | 1075 | 2013 |
| COCKENZIE | 1200 | 2015 |

### *Industrial Emissions Directive*

The Industrial Emissions (Integrated Pollution Prevention and Control) Directive, known as the IED, has been drafted with the objective of consolidating a number of existing directives, including the LCPD, to cover all industrial emissions, not only gaseous emissions to the atmosphere. In its current draft form, the IED requires a further tightening in emissions standards beyond the end of the current LCPD compliance period in 2015. Tighter emissions limits under the IED will apply to gas-fired plant as well as solid and liquid fuel plant.

The proposed emission standards under the IED are defined as instantaneous limits (ELVs) but a number of derogations for existing plant have been added to the draft directive[2]:

- Transitional National Plan (TNP) – analogous to the NERP under the LCPD, with plant subject to an annual emissions ceiling[3] from January 2016 to December 2020;
- Limited Lifetime Derogation –analogous to a LCPD opt-out, with plant committing to close by the end of 2023 and subject to a limit of 20,000 running hours from 2016;
- Restricted operation – less onerous ELVs are applied to plant subject to an operating limit of 1,500 hours per year.

Table 9 shows our assumptions on how plant (capacity by type) will elect to operate under the IED.

### Table 9 Industrial Emissions Directive

| Plant type | Not affected | Fit SCR | TNP | LLO | Close |
|---|---|---|---|---|---|
| Coal capacity (MW) | 0 | 11,200 | 0 | 9,000 | 0 |
| CCGT capacity (MW) | 16,000 | 0 | 5,800 | 3,300 | 0 |

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[2] Draft IED published on 26 June 2009 reflecting the text on which the Council of EU environment ministers reached political agreement.

[3] The TNP emission ceiling will be a function of the rated thermal input of the plant and its actual operating hours and fuel usage in the decade to December 2010. The ceiling for 2016 is calculated using the ELVs from the LCPD and the ceiling for both 2019 and 2020 is calculated using the ELVs in the IED.

### 2.3.6 Renewable Obligation bands

Table 10 presents our banding assumptions for the Renewables Obligation.

**Table 10 Banding assumptions**

| | Central and High High | | | Low | | |
|---|---|---|---|---|---|---|
| | 2009 | 2013 | 2018 | 2009 | 2013 | 2018 |
| Onshore wind | 1 | 1.25 | 1.25 | 1 | 1.5 | 1.25 |
| Offshore wind[4] | 1.5 | 2 | 2 | 1.5 | 2.25 | 2.25 |
| Biomass regular | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Biomass energy crop | 2 | 2 | 2 | 2 | 2 | 2 |
| Biomass CHP | 2 | 2 | 2 | 2 | 2 | 2 |
| Wave | 2 | 3.5 | 3 | 2 | 4 | 3 |
| Tidal Stream | 2 | 3.5 | 3 | 2 | 4 | 3 |
| Tidal Range | 2 | 3 | 3 | 2 | 4 | 3 |
| Biowaste | 1 | 1 | 1 | 1 | 1 | 1 |
| Biogas | 2 | 2 | 2 | 2 | 2 | 2 |

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[4] The changes to offshore wind banding arrangements announced in the 2009 Budget (2 ROCs for projects ordering turbines in 2009/10 and 1.75 ROCs for those ordering in 2011/12) affect projects that are evaluated exogenously to the model and provided as inputs. (Due to the planning and construction times involved, the IDM does not 'build' capacity endogenously prior to 2013.)

# 3 Transportation and storage cost modelling

In-house models for pipeline transport and offshore storage costs were used to develop high, median and low scenarios for transportation and storage costs. This was used to provide the input assumptions to the Risk Assessment Model and the Investment Decision Model. These models have been reviewed by experts within the oil and gas industry.

Pipeline sizes were estimated for different $CO_2$ throughputs using the equation below:

$$D = \left( \frac{Q_m}{v \cdot \pi \cdot 0.25 \cdot \rho} \right)^{0.5}$$

In this equation, *D* is the diameter in metres, Q is the mass flow rate in kg/s, v is the velocity in m/s and $\rho$ is the density of $CO_2$ in $kg/m^3$. It is assumed the mean onshore velocity is1.5 m/s, and the mean offshore velocity is 3 m/s. The assumed $CO_2$ density is 800 $kg/m^3$. Note no full hydraulic calculation is carried out – the equation allows for high level analysis only, and is not a substitute for site-specific hydraulic modelling. The impact of static head or impurities on pressures is not considered.

Pipeline capital costs were estimated from diameter and length using a coefficient of $50,000 ± $20,000 per inch.km. Pipeline annual operating costs were estimated at 1.5% of capex for onshore pipelines and 3% for offshore pipelines.

Booster capex (for pumping and recompression) is modelled at $6,000,000 per MW.

Pipeline and boosting costs depend strongly on configuration assumed. It is assumed $CO_2$ is transported onshore at 150 bar and offshore at 250 bar, with the minimum allowable pressure estimated at 85 bar.

The energy price for boosting and pumping is modelled at $90/MWh.

This model and the storage costs presented here have been peer-reviewed by the North Sea Basin Taskforce, IEA Greenhouse Gas R&D Programme, and experts within oil and gas industry and accepted as suitable for high level cost estimation.

The costs for the median, low and high transport scenarios are shown below. Costs are expressed in £/kW gross for consistency with capture cost modelling assumptions.

**Table 11 Median case for transport and storage**

| 20 km onshore pipeline, 100 km offshore pipeline and 1mtCO2/year/well with new injection facility in 75m water depth | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| MW Gross | 2400 | 2000 | 1600 | 1400 | 1200 | 1000 | 800 | 600 | 400 | 300 |
| Assumed mtCO2 transported per year | 13 | 11 | 9 | 8 | 6 | 5 | 4 | 3 | 2 | 2 |
| Transport capex (incl. owner's cost) £/kW gross | 182 | 196 | 215 | 216 | 249 | 256 | 311 | 345 | 412 | 533 |
| Transport annual opex (incl. owner's cost) £/kW gross | 8 | 9 | 9 | 12 | 11 | 12 | 13 | 16 | 19 | 20 |
| Storage capex £/kW | 109 | 111 | 123 | 132 | 144 | 132 | 149 | 179 | 238 | 159 |
| Storage annual opex £/kW | 2 | 2 | 3 | 3 | 3 | 3 | 3 | 4 | 5 | 3 |

## Table 12 Low case for transport and storage

| 2 km onshore pipeline, 50 km offshore pipeline and 2mtCO2/year/well with new injection facility in 30m water depth | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| MW Gross | 2400 | 2000 | 1600 | 1400 | 1200 | 1000 | 800 | 600 | 400 | 300 |
| Transport capex (incl. owner's cost) £/kW gross | 97 | 103 | 112 | 112 | 127 | 130 | 156 | 171 | 202 | 260 |
| Transport annual opex (incl. owner’s cost) £/kW gross | 6 | 6 | 6 | 6 | 7 | 8 | 9 | 10 | 12 | 12 |
| Storage capex £/kW | 108 | 102 | 113 | 111 | 130 | 132 | 165 | 120 | 180 | 159 |
| Storage annual opex £/kW | 2 | 2 | 3 | 3 | 3 | 3 | 4 | 3 | 4 | 3 |

## Table 13 High case for transport and storage

| 200 km onshore pipeline, 200 km offshore pipeline and 0.25mtCO2/year/well with new injection facility in 200m water depth | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| MW Gross | 2400 | 2000 | 1600 | 1400 | 1200 | 1000 | 800 | 600 | 400 | 300 |
| Transport capex (incl. owner's cost) £/kW gross | 455 | 494 | 552 | 559 | 648 | 677 | 809 | 910 | 1114 | 1420 |
| Transport annual opex (incl. owner’s cost) £/kW gross | 15 | 15 | 17 | 22 | 29 | 23 | 25 | 31 | 39 | 41 |
| Storage capex £/kW | 799 | 849 | 804 | 850 | 890 | 970 | 819 | 890 | 988 | 1155 |
| Storage annual opex £/kW | 19 | 19 | 19 | 19 | 20 | 21 | 19 | 20 | 21 | 24 |

The inputs to the RAM and IDM modelling were based on the median case.

# 4 Modelling approach

This section provides further details to supplement the descriptions in the main report.

## 4.1 Risk Assessment Model

### 4.1.1 Model Inputs

Exogenous inputs the Risk Assessment Model (RAM) are as follows:

***Commodity Prices***

Coal, gas and carbon prices are exogenous inputs to the RAM and are discussed in Section 2.1.1 Power prices are determined endogenously at run-time in the model using the prevalent commodity prices. The power price calculation is based on the short run marginal cost of gas plant, combined with a function (calibrated to historic data) that adds an additional 'uplift' component. A simplified representation of the price duration curve is used to allow load factors to be estimated.

***Technology-specific inputs***

These include plant configuration, capital expenses and its profile of spend, operating costs and parameters as summarised in Table 3. The model operates on any one choice of technology and configuration at a time.

***Funding mechanism definition***

This includes the funding mechanism activation year, maximum number of years the mechanism can be active and caps on total funding. The mechanism was modelled to start from the first year of plant operation. A maximum policy life of 15 years or a cap of 20mT of $CO_2$ stored, whichever is encountered earlier, was applied to determine the effective expiry of the mechanism.

The Additional Payment mechanism was modelled to pay against the net CCS output (MWh) at station-gate while the CfD mechanism was modelled to pay against the net $CO_2$ in tonnes stored during the respective year. If the policy was found to expire mid-year (due to hitting the cap), pay-outs for the respective year were scaled linearly for the proportion of year for which the policy is active.

The model can be run to determine the mechanism price levels that make the project economically viable. Alternatively, mechanism price levels can be input to the model to determine the mechanism pay-outs or its effect on project NPV.

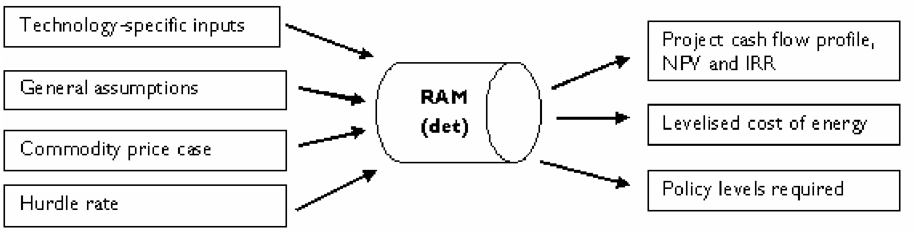
### 4.1.2 Modes of Operation and Model Outputs

The model was designed to operate in both deterministic and stochastic modes. The inputs to the model and its outputs under the two modes are discussed in this section.

### *Deterministic mode*

The Model in its deterministic mode is used to determine the project NPV and IRR, levelised energy costs and policy levels needed to make the project economically viable for the chosen technology and plant configuration and at a given hurdle rate. It should be noted that the hurdle rate is exogenous to the model in this mode. A schematic of this mode is shown in Figure 10.

**Figure 10 RAM in deterministic mode**



### *Stochastic mode*

In this mode, the model considers plant configuration, funding mechanism specification and the investor-expected commodity prices, applies uncertainties around various key inputs, executes the specified number of simulations and returns the distribution of project NPVs and the funding mechanism pay-outs (if applicable). From this it determines the risk-adjusted hurdle rate and the % risk premium. Table 14 shows a list of inputs varied stochastically. Hurdle rate and % risk premium calculations are discussed in Section 0. A schematic of the RAM in stochastic mode is shown in Figure 11.

**Table 14 Parameters varied stochastically in the RAM**

| Capital expenditure | Operating expenditure | Operational parameters | Commodity Prices[5] |
|---|---|---|---|
| Base plant | Variable O&M | Availability and load factors | Coal |
| CCS equipment | Fixed O&M | Parasitic load | Gas |
| Transport and storage infrastructure | Fixed transport and storage costs | % emissions captured | Carbon |
| Retrofit costs | | | Electricity price 'uplift' |
| Base plant - build time | | | |
| CCS equipment - build time | | | |
| Retrofit - build time | | | |

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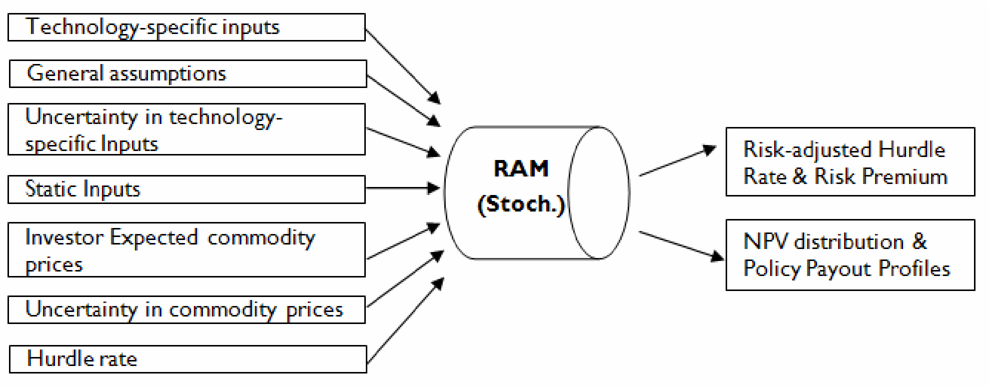
[5] As electricity prices are calculated endogenously in the RAM, these will vary with commodity prices and uplift.

**Figure 11 RAM in stochastic mode**



### 4.1.3 Calculation Methodology

***Discounted cash flows***

A Discounted Cash Flow (DCF) analysis module lies at the core of the RAM. Project NPVs are calculated in 2009 real terms. We accounted for gearing implicitly, via an assumption on the level of gearing used to calculate the developer's project hurdle rate (analogous to a WACC adjusted for the risk profile of this project). This is assumed to reflect the developer's overall capital structure. A Reducing Balance method is used for calculating depreciation. Tax benefits of depreciation, if not used in the year of their accrual, are transferred to subsequent years.

***Load factor determination***

Load factors were modelled in RAM at annual granularity and were determined endogenously as follows:

- The maximum realisable load factor (i.e. the plant's annual availability) was determined first from the forced and planned outage rates.
- The annual economically optimal load factors were derived by using a simplified price duration curve of power for the respective year compared to the plant SRMC (capped by maximum availability). The price duration curve used for this purpose was based on a model calibrated using historical power and commodity prices.
- Load factors were finally adjusted to take account of any emissions limit constraints where applicable in the respective year of operation.

***Risk premium and hurdle rate determination***

The methodology for the calculation of the risk premia using the RAM was based on Prokopczuk et. al.[6] and can be summarised as follows. The project NPV is calculated in deterministic mode at benchmark hurdle rate (assumed as 10% for thermal power projects). The model is then run in stochastic mode and results are logged for 20,000 simulations. Risk premium (£ mn) or the cost of risk capital required to support the project is calculated as:

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[6] Prokopzuk, M., Rachev, S., Truck, S. (2004), 'Quantifying Risk in the Electricity Business: A RAROC-based Approach, UniversitÄat Karlsruhe, Germany and University of California, USA

Risk premium (£ mn) = (Mean NPV – NPV at low 99th percentile) * Benchmark hurdle rate

The model is then used to goal seek for the risk adjusted hurdle rate that gives the same impact on NPV as the risk premium (£ mn). The % risk premium is then calculated as:

Risk premium (%) = Risk-adjusted hurdle rate – Benchmark hurdle rate

### *Adjusting for the certainty of funding mechanism*

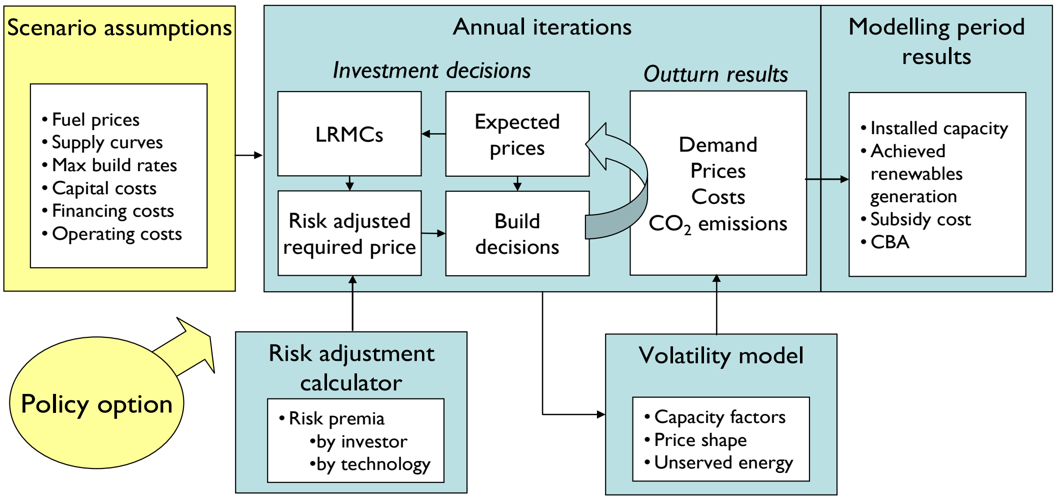
The expectation of a funding mechanism leads to reduction in the downside risk to the project. This in turn reduces the level of funding required for the projects to be economic. The effect of this is approximated in RAM, using a single step iteration as follows:

1. The risk premium is calculated without the certainty of a funding mechanism as described above.
2. The mechanism price levels (AP support level or the CfD support level) are determined.
3. The model is then run in deterministic mode and thereafter in the stochastic mode with the funding mechanism in place at the calculated levels.
4. The funding-adjusted hurdle rate and risk premium are now re-evaluated.
5. Finally, the funding mechanism price levels are recalculated using this funding-adjusted risk premium.

## 4.2 Investment Decision Model

An overview of the modelling framework used for the study is shown schematically in Figure 12.

**Figure 12 Modelling framework**



At the heart of the framework lies an ***investment decisions*** simulator. This computes the risk-adjusted long run marginal costs (LRMCs) of all generation technologies by player type. Where these are less than expected revenues (given assumed load factors and future price expectations), players move new plant first to a planning stage, and subsequently, if still economic, to a committed development phase. On an annual basis, ***outturn results*** for demand, prices, generation output and carbon emissions are computed. These in turn feed back to expected prices for the following year's iteration.

The LRMCs used in the build decision algorithm are risk-adjusted in the ***risk adjustment calculator*** by computing a distribution of gross margins for each investment under the full range of uncertainties in revenues and project costs. The ***volatility model*** analyses the market at an hourly level for each year by simulating demand, spot fuel prices, forced outages and renewables output. It produces annual price duration curves and estimates of price volatility and volumes of short term demand side response and expected energy unserved. It is used to calibrate the expected price and renewables 'capacity credit' functions within the investment decisions simulator.

The modelling approach provides a comprehensive framework for the quantitative assessment of market impacts of whether CCS is proven or not, different contingencies if CCS is not proven, and the impact of sensitivities. However, as with any modelling exercise, the limitations of the approach should be carefully considered. Key points to note include:

- We make no assumptions about revisions to policy or targets post-2020. In practice, these are likely to evolve within the context of the UK Government's legally binding commitment to an 80% reduction in $CO_2$ by 2050.
- The modelling requires multiple input assumptions including variables that are very uncertain such as commodity prices, future capital costs of plant, and maximum build rates.
- Sensitivities have been used to test these uncertainties, but it was not possible to model all the possible and relevant sensitivities. One area that we have not tested is the risk of a systematic failure of emerging renewables technologies to achieve the operational availability levels expected.
- The modelling approach is dynamic and evolves prices and investment/retirements decisions through time in each run. This results in year on year variability as would be expected in reality. However, care should be used when comparing the results in individual years.
- The model estimates different hurdle rates for different technologies by simulating gross margin risk for a set of different investor types over the project lifetime. This is a simplified way to capture the complex interaction of factors that determine the cost of capital for different players in different technologies under different support schemes.
- We do not explicitly model specific transmission upgrade projects. We implicitly capture the cost impact of necessary transmission investments within the supply curve defined for each technology.
- We model plant operation on an unconstrained basis. In reality, transmission constraints could reduce the output from renewables plant and impact on the achievement of the renewables target.
- The model captures the evolution of market prices over time, and the impact on investment and retirements, in an internally consistent manner, taking into account the capacity margin and the mix and penetration of renewables on the system. However, there is huge uncertainty surrounding the market dynamics in a world of significantly higher renewables output.
- The model captures short term demand side response in determining expected energy unserved and peak prices. However, it does not include longer term demand side elasticity or changing shape in demand in response to evolving price signals.
- The model only covers the GB electricity market, and excludes Northern Ireland.

# 5 RAM supplementary results

This section provides supplementary analysis from the RAM results in the following areas:

- a sensitivity analysis of project NPVs to key inputs;
- a more detailed analysis of the relative NPVs for the pre-combustion configurations (fully- and part-fitted at outset);
- an assessment of the relativity between funding mechanism price levels and project levelised energy costs; *and*
- a more detailed analysis of the impact of funding mechanisms on carbon price exposure for projects.

## 5.1 Sensitivity of funding gap to input assumptions

Table 15 provides a sensitivity analysis for the three considered technologies.

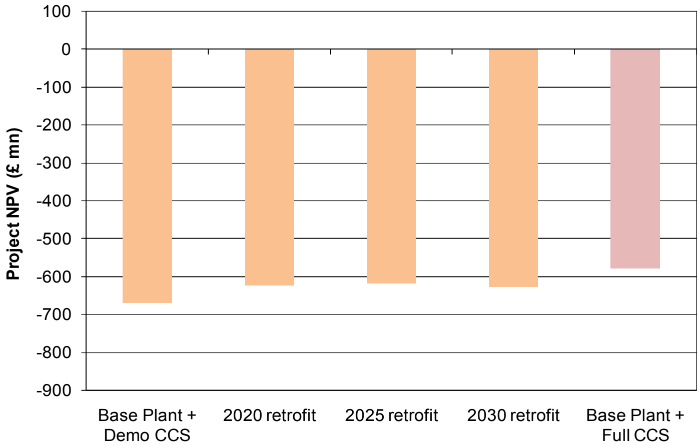
**Table 15 Sensitivity of project NPV to input assumptions**

| | | | Post-combustion | | Pre-combustion (full CCS) | | Oxyfuel | |
|---|---|---|---|---|---|---|---|---|
| | Unit | Δ Parameter | ΔNPV (£m) | ΔNPV (%) | ΔNPV (£m) | ΔNPV (%) | ΔNPV (£m) | ΔNPV (%) |
| Scenario specification | | | | | | | | |
| Year of retrofit CCS | Year | -- | 2025 | | n/a | | n/a | |
| Operational parameters | | | | | | | | |
| Parasitic load (CCS) | % | plus 1% | -24.0 | -4.8% | -30.8 | -4.4% | -12.0 | -2.8% |
| % Carbon capture | % | minus 1% | -9.5 | -1.9% | -11.1 | -1.6% | -4.0 | -0.9% |
| Plant costs | | | | | | | | |
| CCS development capex | £ / kW | plus 1% | -2.0 | -0.4% | -1.8 | -0.2% | -1.6 | -0.4% |
| T&S development capex | £ m | plus 1% | -1.7 | -0.3% | -2.4 | -0.3% | -1.6 | -0.4% |
| Retrofit capex | £ / kW | plus 1% | -2.0 | -0.4% | n/a | n/a | n/a | n/a |
| Variable O&M | £ / MWh | plus 1% | -3.2 | -0.6% | -2.6 | -0.4% | -0.5 | -0.1% |
| Fixed O&M | £ / kW | plus 1% | -3.8 | -0.8% | -3.0 | -0.4% | -1.0 | -0.2% |
| Fixed T&S costs | £ m | plus 1% | -0.6 | -0.1% | -0.7 | -0.1% | -0.5 | -0.1% |
| Project hurdle rate | | | | | | | | |
| Project hurdle rate | % | plus 0.1% | -12.7 | -2.5% | -7.4 | -1.0% | -2.9 | -0.7% |
| External parameters | | | | | | | | |
| Corporate tax rate | % | plus 1% | -5.2 | -1.0% | -2.7 | -0.4% | -1.1 | -0.3% |
| Carbon price | € / t | plus 1% | -0.7 | -0.1% | 3.3 | 0.5% | 1.3 | 0.3% |
| Coal price | $ / t | plus 1% | -11.0 | -2.2% | -7.0 | -1.0% | -2.6 | -0.6% |

## 5.2 Pre-combustion configuration comparison

When looking at configurations for pre-combustion plant, we calculated that (given our assumptions) the fully-fitted configuration had a less negative NPV than the partially-fitted configuration. The partially-fitted configuration benefits from the discounting effect of moving part of the capital expenditure until later, and additional revenue due to avoidance of higher (CCS) parasitic load on the entire station. This is (again, given our assumptions) more than offset by additional savings on carbon costs realised by fitting the entire station with CCS from outset. Figure 13 shows the NPVs calculated from these configurations and different retrofit scenarios. (The first four bars from the left represent the configuration with part CCS at onset and the fifth represent the configuration fully-fitted from onset.)

## Figure 13 Choice of configuration for pre-combustion plant



We found that, for a partially-fitted configuration, it was economically attractive to retrofit, and that 2024 was the optimal year in which to do so. A detailed comparison of the NPV differences between the fully-fitted configuration and the partially-fitted configuration with 2024 retrofit is shown in Table 16. The figures are in 2009 real terms discounted using the benchmark hurdle rate.

As can be seen, the difference is relatively small, and the result is very sensitive to our input assumptions. Other assumptions could easily reverse the relative economics of the configurations.

### Table 16 NPV analysis of the pre-combustion configurations

| NPV (£ m) | Fully-fitted | Retrofit 2024 | Difference | Explanation |
|---|---|---|---|---|
| **EBITDA** | | | | |
| Revenue | 3,293 | 3,501 | | Fully-fitted case: reduced revenue due to CCS parasitic load losses |
| Fuel Costs | (1,185) | (1,166) | | Retrofit 2024 case: lower fuel costs as non-CCS fitted unit runs at lower load factors between 2018 and 2027 (before retrofitting is complete) due to high Carbon prices |
| Carbon Costs | (166) | (522) | | Retrofit 2024 case: higher Carbon costs for the non-CCS fitted unit |
| Operating Costs | (806) | (776) | | Retrofit 2024 case: no incremental CCS costs until retrofit is complete; which is partially offset by higher incremental fixed costs for CCS equipment compared to fully-fitted case (CCS fixed incr. costs are £6/KW in case of retrofit 2024 compared to £5.1/KW in case of fully-fitted config.) |
| TOTAL | 1,136 | 1,037 | 99 | Carbon cost savings in fully-fitted configuration more than offset lost revenue due to parasitic load |
| **Capital expenditure** | | | | Economies of scale in having all the T&S installation done upfront in fully-fitted configuration are overpowered by the discounting benefits in retrofit 2024 case |
| CCS Equipment | (197) | (114) | | |
| Initial T&S | (271) | (205) | | |
| CCS Retrofit | -- | (28) | | |
| Retrofit T&S | -- | (82) | | |
| TOTAL | (468) | (430) | (38) | |
| **Tax payable** | (100) | (80) | (21) | Lower tax payable in Retrofit 2024 case mainly because of reduced earnings and partly because of utilisation of tax losses (from depreciation) for longer |
| **Net difference** | | | 40 | Benefits of complete fitting at onset outweigh benefits of moving retrofitting to later date primarily at the back of Carbon cost benefits |

## 5.3 Analysing the funding mechanism price levels

The funding mechanism price levels required to make the projects economic were found to be high compared to the projects' levelised energy costs. We compare these two results below for the Addional Payment case for a post-combustion configuration. Similar analysis would apply in case of other plant configurations and the CfD funding mechanism.

The results of RAM (without taking account of policy certainty) are as follows:

Project NPV (funding gap) = -£499 mn

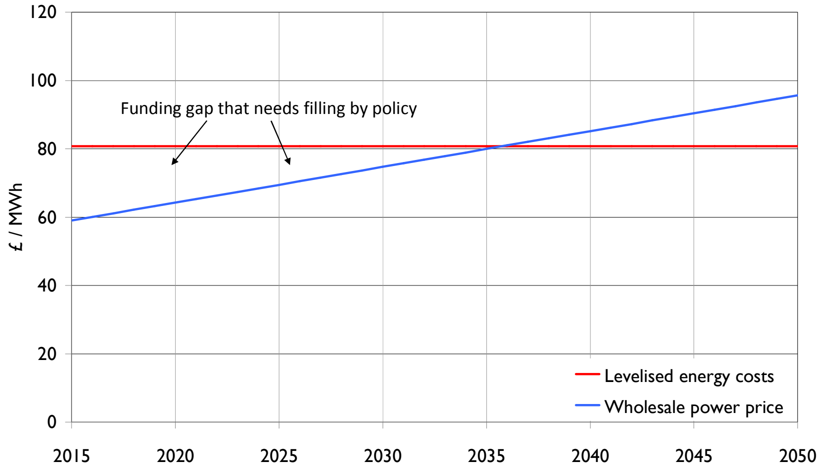
Levelised energy costs = 81 £/MWh

AP price level = 68 £/MWh

The following considerations apply to the relative levels of these results:

- The levelised cost represents the constant real cost of power throughout the project life required to make its NPV zero, for output from the full plant (abated and unabated).
- The difference between the levelised cost and the realised power prices (shown in Figure 14) is indicative of the total project funding gap on a per MWh basis and has to be filled by the policy funding to make the project breakeven.
- Since the policy is capped at 20mT/15years, the funding gap has to be filled within this period as opposed to the total life of the project, thereby increasing the absolute funding level required.
- In case of post-combustion, where only a fourth of the plant is CCS-fitted, the funding level needs need to be even higher as only about a fourth of it would be attributable per MWh of the total station output.

**Figure 14 Levelised cost and realised power prices**



The costs and prices shown in the above figure are in 2009 real terms and have been determined based on the investor-expected price case. It should also be noted that though the surplus of power prices over the levelised costs in later years appears to partially offset the funding gap, the offsetting effect is diminished due to discounting, such that the funding gap at front end dominates the overall project NPV.

## 5.4 Impact of funding mechanisms on carbon price risks

The Additional Payment pay-outs, being independent of carbon prices, are expected not to have any impact on the carbon price exposure for the projects. This was confirmed by our RAM results. On the other hand, CfD pay-outs are negatively correlated with carbon prices (and through it power prices) and could therefore act as a hedge to the carbon price risk. However, using the RAM, we found that at the levels of pay-outs calculated, the effect of the mechanism is in fact somewhat to over-hedge the carbon price risk. This effect is illustrated in Table 17 by considering the impact of a +1£/t parallel shift in $CO_2$ prices on the different components of short run margin with and without the CfD funding mechanism for the median year when the mechanism is active.

**Table 17 Effect of 1 £/t parallel shift in carbon prices on the short run margin per $\text{MWh}_e$**

| | Δ Power | - (Δ SRMC) | Δ CfD pay out | Δ Short run margin | |
|---|---|---|---|---|---|
| | | | | w/o CfD pay out<br>Δ (Power–SRMC) | w/ CfD pay out<br>Δ (Power–SRMC+CfD pay-out) |
| Post-combustion | 0.39 | -0.62 | -0.18 | -0.23 | -0.42 |
| Pre-combustion | 0.39 | -0.10 | -0.90 | 0.29 | -0.61 |
| Oxyfuel | 0.39 | -0.09 | -0.83 | 0.29 | -0.54 |

As can be seen from the table, CfD pay-outs increase the absolute sensitivity of short run margin to carbon prices in case of each technology, increasing susceptibility of cash flows to carbon price variations. It should however be noted that this effect is very sensitive to the CfD strikes and the assumption on the relationship between power and carbon prices.

## 5.5 Funding gaps and risk premia for partially fitted plant

Table 18 Table 19 present a summary of the calculations for post-combustion and pre-combustion plant where these are partially-fitted at outset, showing results both with and without funding mechanism certainty.

### Table 18 Funding gap and risk premia for post-combustion

| | Post-combustion | | | | |
|---|---|---|---|---|---|
| | Demo | 2020 retrofit | 2025 retrofit | 2030 retrofit | 2025 contingency |
| **% Risk premia** | | | | | |
| Without funding mechanism | 1.34% | 1.20% | 1.19% | 1.21% | 1.61% |
| AP mechanism | 1.07% | 1.01% | 1.00% | 1.02% | 1.34% |
| CfD mechanism | 1.12% | 1.03% | 1.02% | 1.04% | 1.39% |
| | | | | | |
| **Funding gap (£ mn)** | | | | | |
| Without funding mechanism | -499 | -581 | -502 | -478 | -623 |
| AP mechanism | -469 | -555 | -476 | -453 | -601 |
| CfD mechanism | -475 | -558 | -478 | -456 | -606 |

### Table 19 Funding gap and risk premia for pre-combustion

| | Pre-combustion (partially-fitted) | | | | |
|---|---|---|---|---|---|
| | Demo | 2020 retrofit | 2025 retrofit | 2030 retrofit | 2025 contingency |
| **% Risk premia** | | | | | |
| Without funding mechanism | 2.66% | 1.77% | 1.83% | 1.95% | 2.69% |
| AP mechanism | 1.11% | 0.96% | 1.03% | 1.15% | 1.13% |
| CfD mechanism | 1.17% | 0.99% | 1.06% | 1.18% | 1.19% |
| | | | | | |
| **Funding gap (£ mn)** | | | | | |
| Without funding mechanism | -794 | -757 | -750 | -756 | -796 |
| AP mechanism | -738 | -707 | -704 | -714 | -741 |
| CfD mechanism | -741 | -710 | -706 | -716 | -744 |

# 6 IDM supplementary results

This section provides supplementary results from the market modelling in the following areas:

- a more detailed description of the results from the Counterfactual runs;
- a comparison of the Central Counterfactual with the Renewable Energy Strategy Lead Scenario;
- an analysis of the impact of different CCS Outcomes on the system short run marginal cost;
- an analysis of the evolution of the generation supply stacks under different Cases under an outcome where CCS is proven and how this affects carbon emissions;
- annual funding mechanism payments for two and four demonstration plant; *and*
- a presentation of the results from the five sensitivity runs.

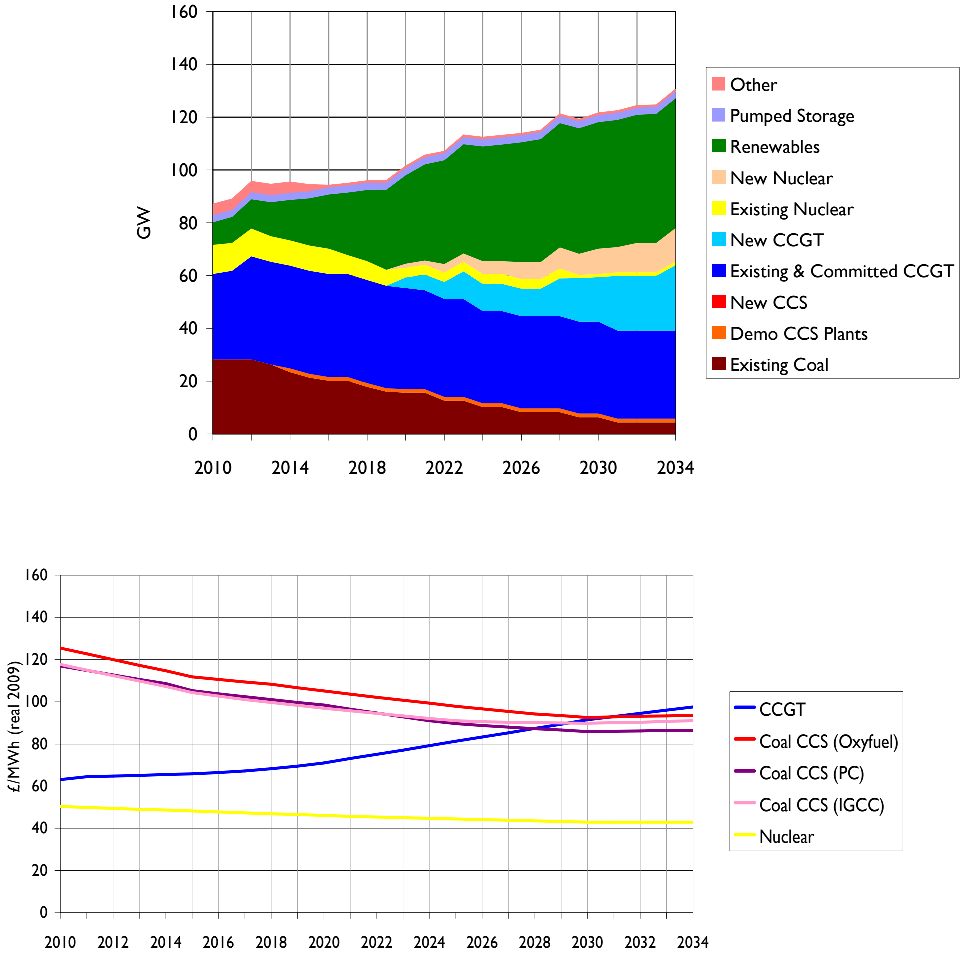
## 6.1 Counterfactuals

Here we present more detailed results for capacity mix, capacity margins, thermal plant load factors, and carbon emissions from the Low, Base, and High High Proven Counterfactuals.

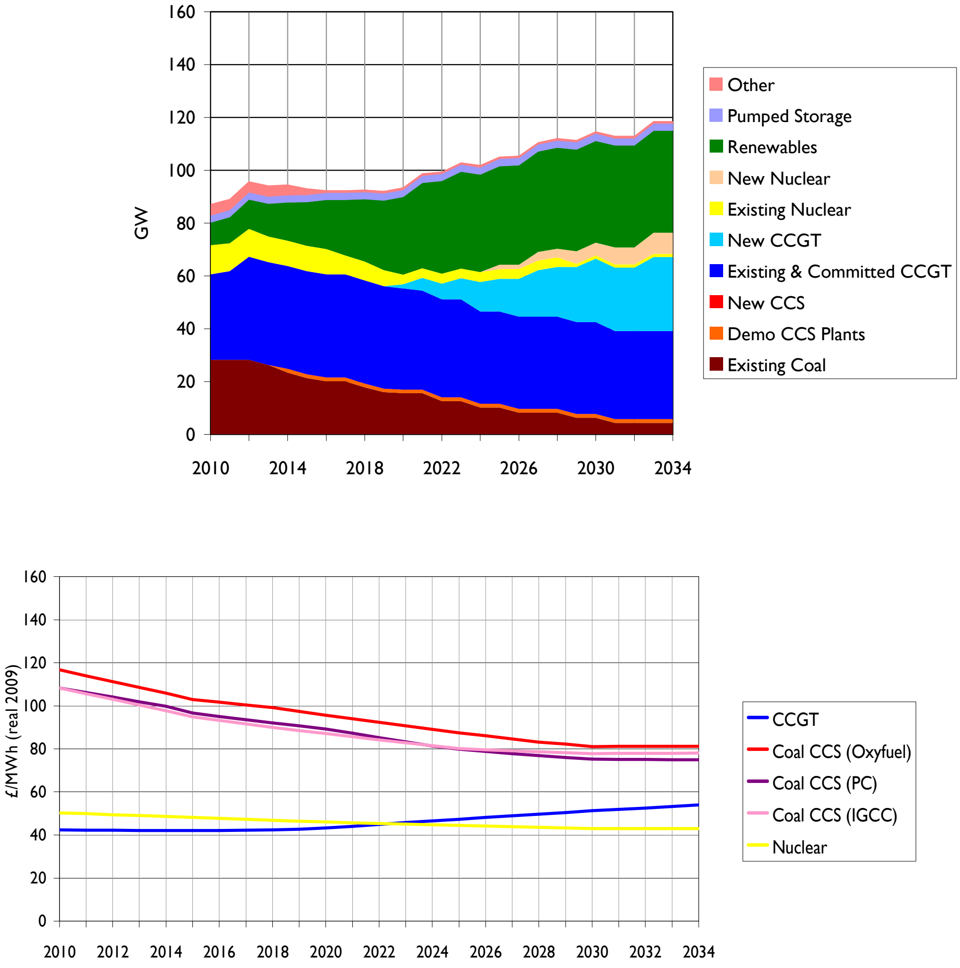
***Capacity mix***

The capacity mixes for each Counterfactual are shown in Figure 15 to Figure 17, with the long run marginal costs for each technology for reference. In the Central and High High Cases, nuclear is developed in line with our maximum deployment assumptions, with the first plant online in 2020 and 9.6 GW by 2030, but emerges later and more slowly in the Low Case. Renewables build is highest in the High High Case, especially after 2020, and is significantly depressed in the Low Case. CCGTs are the swing technology relative to the Central Case: there is more CCGT build in the Low Case to compensate for reduced nuclear and renewables, and less in the High High Case in response to greater renewable investment.

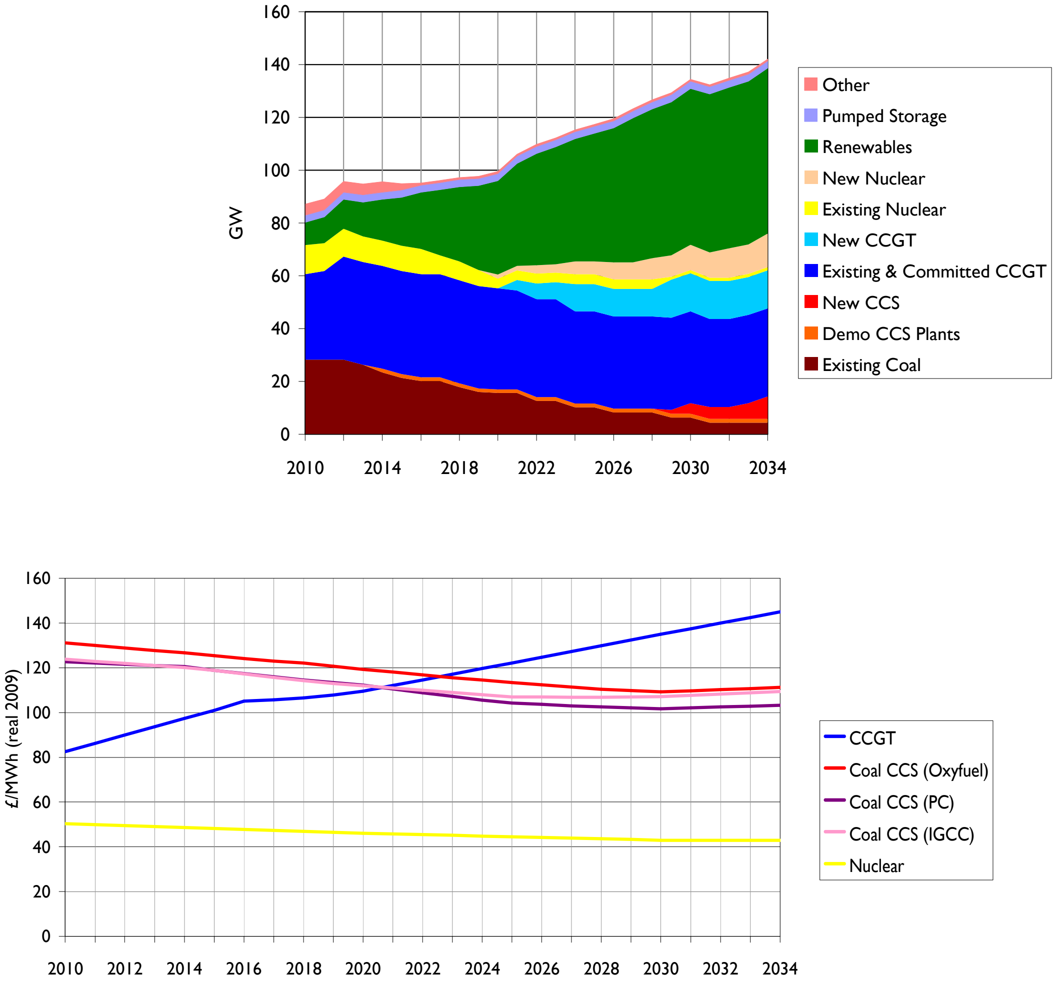
**Figure 15 Capacity mix and LRMCs, Central Case Counterfactual**



## Figure 16 Capacity mix and LRMCs, Low Case Counterfactual

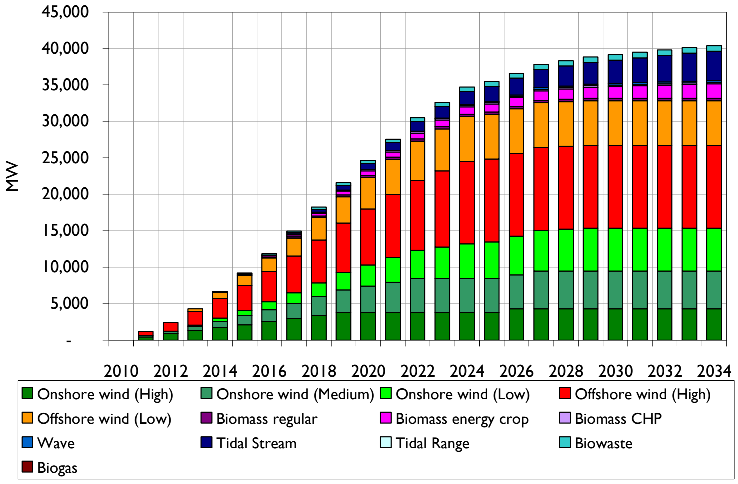


## Figure 17 Capacity mix and LRMCs, High High Case Proven Counterfactual



In Figure 18 we show the breakdown of new renewables build. The overriding feature is the dominance of wind, both on- and offshore. This mix is common throughout all of the analysis.

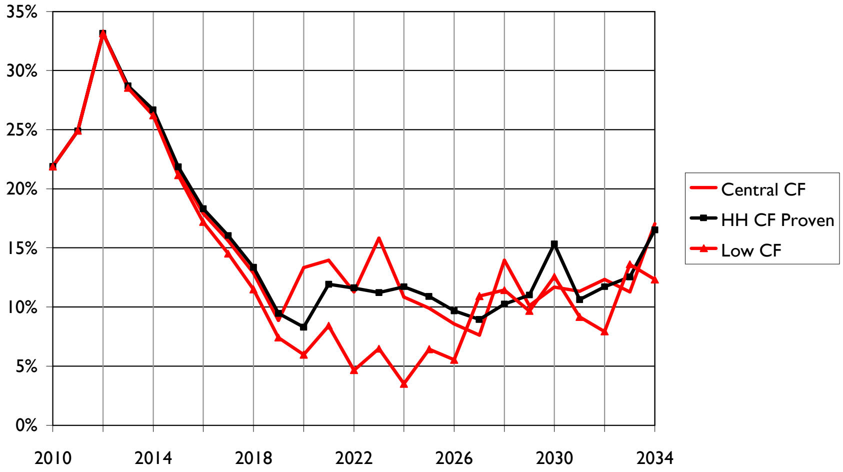
**Figure 18 New renewable build, Central Counterfactual**



### *Capacity margins*

Capacity margins in the early part of the modelling period are high due to lower demand combined with a significant amount of committed capacity coming onto the system. In the Central and High High Cases, the de-rated capacity margins are similar: the greater renewable deployment in the High High Case makes a relatively small contribution to the de-rated margin, captured through a low capacity credit. In the Low Case, slower investment contributes to lower capacity margins in the period 2020 – 2025.

**Figure 19 De-rated capacity margins, all Counterfactuals**



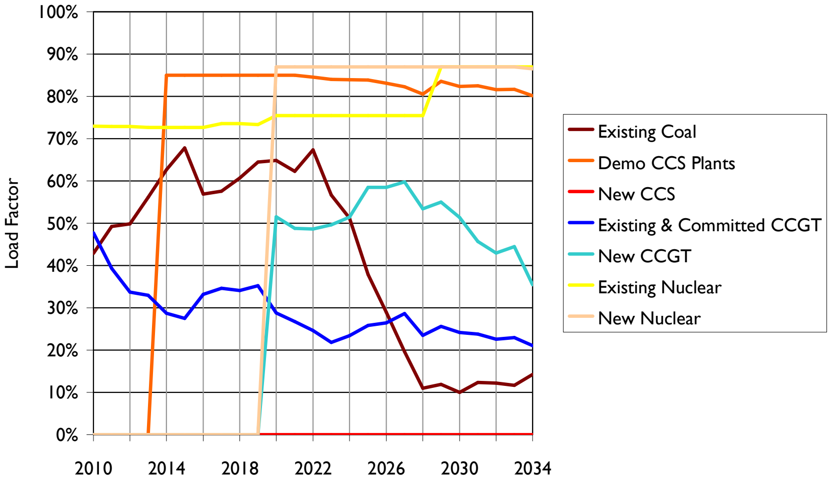
### *Load factors*

In Figure 20 to Figure 22 we present the load factors[7] of the fossil fuel technologies. Declining load factors for the CCS demonstration plant (averaged across both the abated and unabated capacity) are observed post 2025. In the High High Proven Counterfactual, new CCS which comes online in 2029 does not operate baseload. Load factors for these plant decline due to the high penetrations of nuclear and renewables.

The load factors of existing CCGTs decline over time. To 2020, these Cases are typically coal favouring on a short run basis. Beyond 2020, new entry forces existing CCGTs 'up the stack'. New CCGTs enter as mid-merit (again, due to nuclear and renewable capacity on the system). In the High High Case, this is further exacerbated when new CCS enters the market.

Other than the Low Case, existing coal plant operate at higher load factors up until 2020. When the carbon price increases, combined with new plant on the system, we see load factors reduce rapidly. By 2030, 6.3 GW of existing coal remains on the system, but they are operating only at peak times, at less than 20% load factor.

**Figure 20 Fossil and nuclear plant load factors, Central Case Counterfactual**



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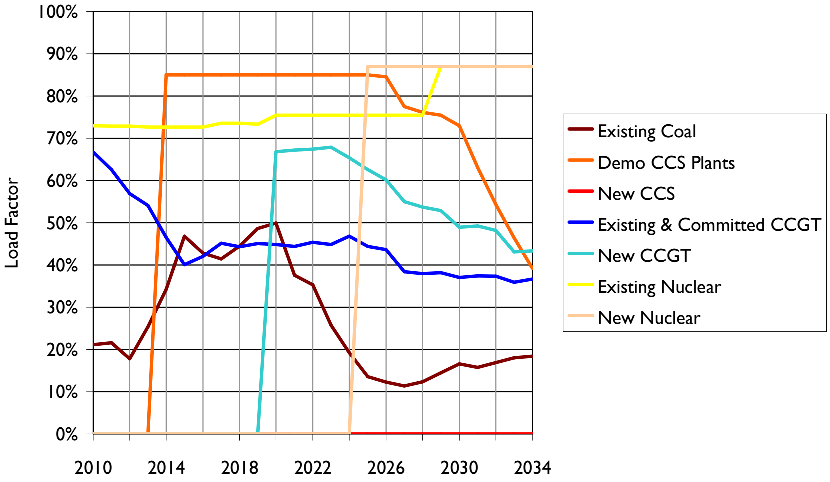
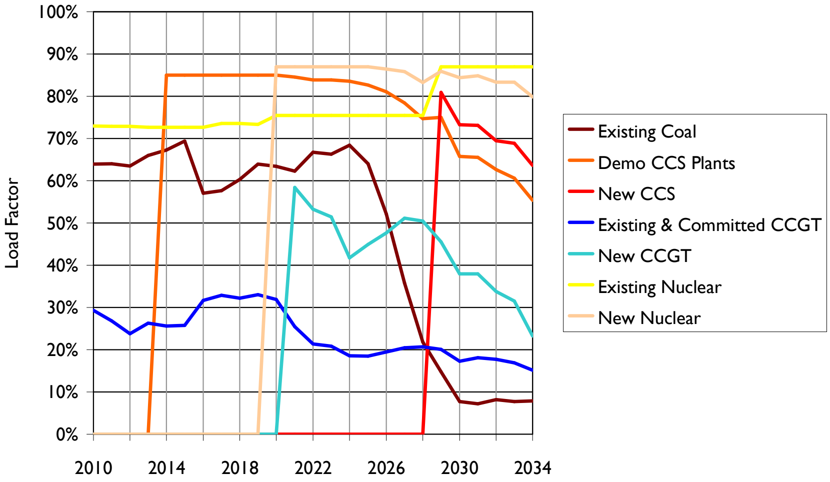
[7] Calculated based on 8760 hour availability.

## Figure 21 Fossil and nuclear plant load factor, Low Case Counterfactual



## Figure 22 Fossil and nuclear load factor, High High Proven Counterfactual



### *Carbon emissions*

Carbon emissions from the different technology types are shown in Figure 23 to Figure 25. The relativities of coal and gas prices drive the different emission levels in the first five years. Plant closures and IED restrictions reduce emissions from both existing coal and gas plant, as, beyond 2020, does the rising carbon price. By 2030, the emissions from the entire coal sector are broadly similar across Cases at around 10 $mtCO_2$. However, emissions from gas-fired generation show a large range, dependent on the investment in renewables and nuclear.

**Figure 23 Annual $CO_2$ emissions, Central Case Counterfactual**

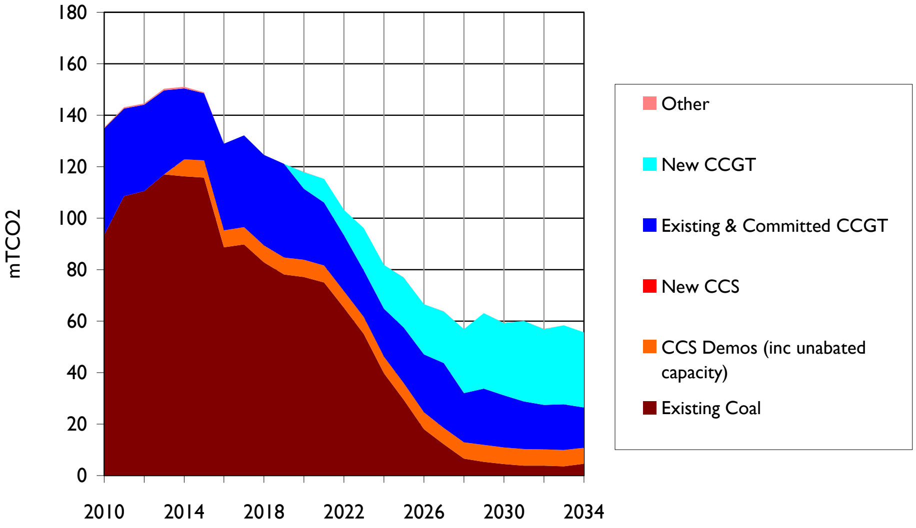
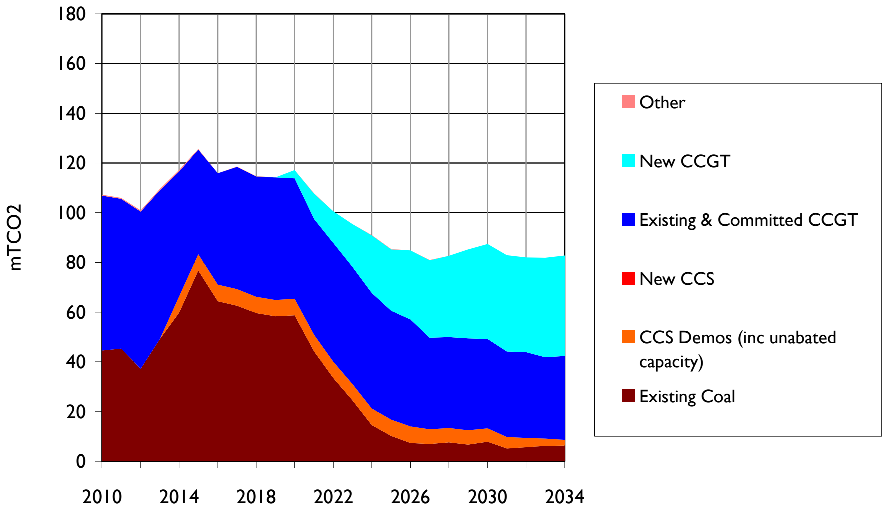
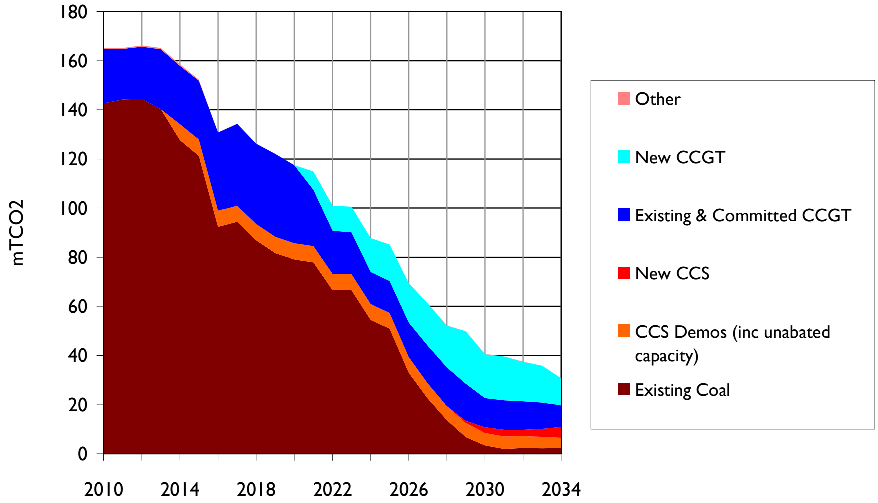


**Figure 24 Annual $CO_2$ emissions, Low Case Counterfactual**

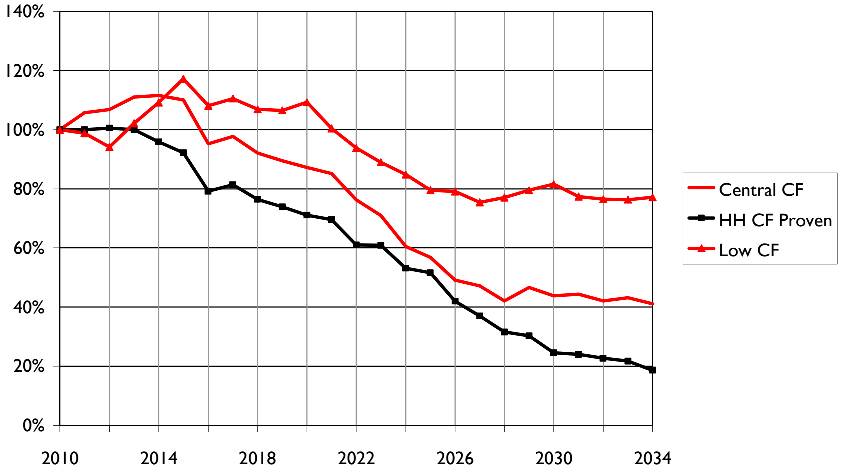


## Figure 25 Annual $CO_2$ emissions, High High Case Proven Counterfactual



Using the 2010 emission values in each Case, we can show the relative abatement path under the three Cases. Through to 2025 we see additional abatement from Low to Central to High High driven by greater nuclear and renewables investment. However, only in the High High Case do we see continued abatement after 2028 due to the new CCS plant that come online.

## Figure 26 Carbon abatement, all Counterfactuals



## 6.2 Comparison of the Central Counterfactual and the RES Lead Scenario

The Government's Renewable Energy Strategy (RES), published in July 2009, is supported by modelling of the electricity sector conducted as a part of a study by Redpoint and Trilemma, 'Implementation of the EU 2020 Renewables Target in the UK Electricity Sector: RO Reform', from June 2009. The work in this CCS study has involved updating a number of assumptions relative to the previous report. In this section, we detail these changes and summarise the difference in results between the Central Counterfactual used in this study and the RES Lead Scenario, which was designed to deliver 29% renewable generation in 2020 under 'Base' commodity prices with minimum changes to the Renewables Obligation.

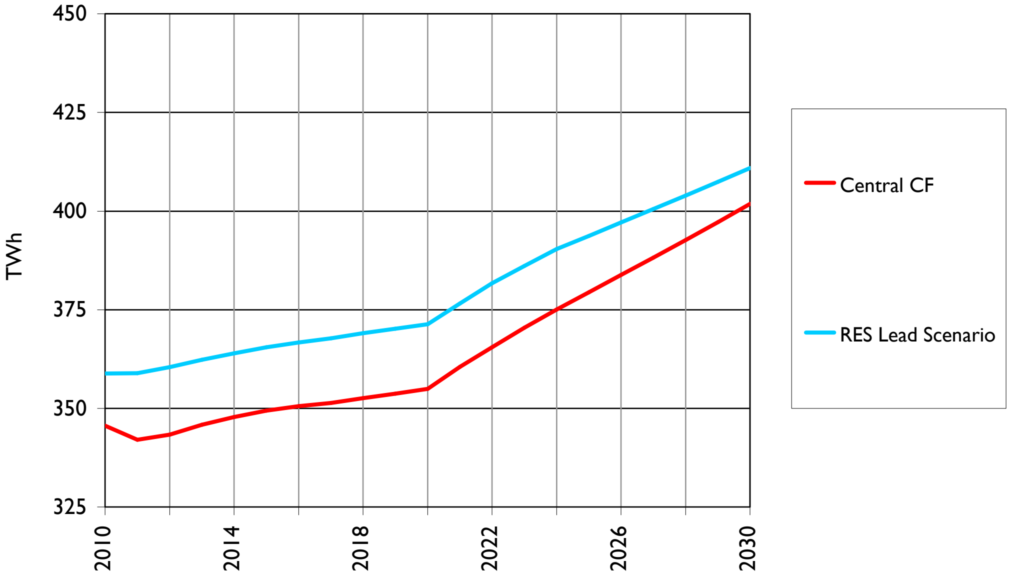
### 6.2.1 Assumptions

The two largest assumptions changes are in future demand, and in carbon prices. A range of smaller changes have been made to reflect the latest information available on the IED and UK coal policy.

***Annual demand***

Figure 27 shows the DECC annual demand assumptions[8] used in the Central Counterfactual and the RES Lead Scenario. The assumptions have changed as the result of further analysis undertaken as part of the Low Carbon Transition Plan projections.

**Figure 27 Annual demand, Central CF and RES Lead Scenario**



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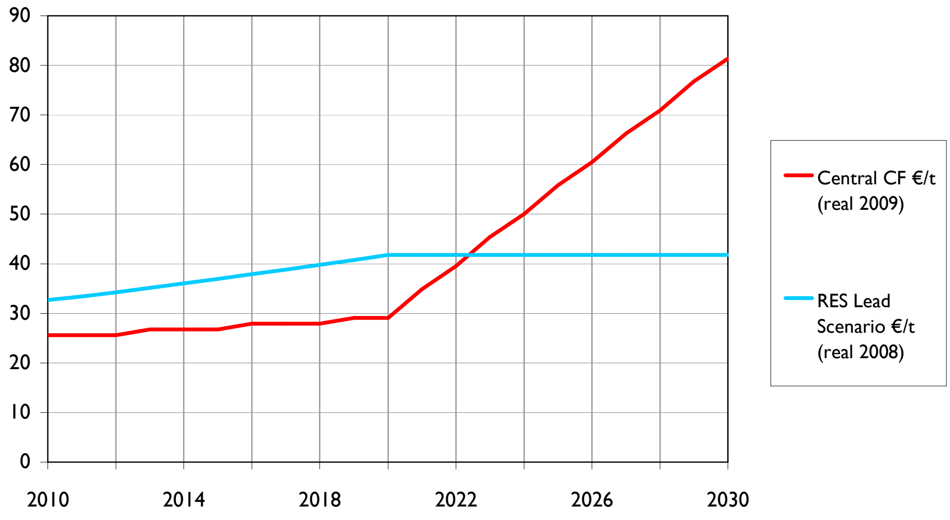
[8] The definition of the demand basis used in this study is provided in Section 2.3.1.

### *Carbon prices*

The EUA price assumptions are compared in Figure 28. The modelling for the RES Lead Scenario assumed flat carbon prices after 2020, compared to rising carbon prices in the Central Counterfactual.

**Figure 28 EUA prices, Central CF and RES Lead Scenario**



### *Other assumptions*

We incorporated the latest information on the IED proposals into our assumptions for this study, as described in Section 2.3.5[9]. Economic analysis of the decisions faced by owners of these plant led to different assumptions as to the options different tranches of capacity would make under the proposals. The differences are shown in Table 20 and Table 21.

**Table 20 IED assumptions, Central CF**

| Plant type | Not affected | Fit SCR | TNP | LLO | Close |
|---|---|---|---|---|---|
| Coal capacity (MW) | 0 | 11,200 | 0 | 9,000 | 0 |
| CCGT capacity (MW) | 16,000 | 0 | 5,800 | 3,300 | 0 |

---

[9] A description of our previous assumptions can be found in the report of our Renewables Obligation study, available on the DECC website (http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/res/res.aspx)

**Table 21 IED assumptions, RES Lead Scenario**

| Plant type | Not affected | Fit SCR | NERP | Close |
|---|---|---|---|---|
| Coal capacity (MW) | 0 | 11,200 | 9,000 | 0 |
| CCGT capacity (MW) | 16,000 | 0 | 9,100 | 0 |

The assumptions on renewables policy and the Renewables Obligation banding are identical, with the exception that in the CCS work we accounted for the 2009 announcement that banding for offshore wind would be increased in 2010 and 2011.

In the RES Lead Scenario, we assumed that one fully-fitted demonstration CCS plant was built in 2014, with a net capacity of 500MW. We updated this assumption in this work, such that our demonstration plant is a single partially fitted post-combustion demonstration plant with a configuration consistent with that described in Section 6.2 of the main report. The RES Lead Scenario assumptions were finalised before the Government's announcement of no new coal without Carbon Capture and Storage. In the results, 1.5 GW of new ASC coal is commissioned in each of 2020 and 2021. In the Central Counterfactual, it is assumed that unabated coal cannot be built as a standalone project.

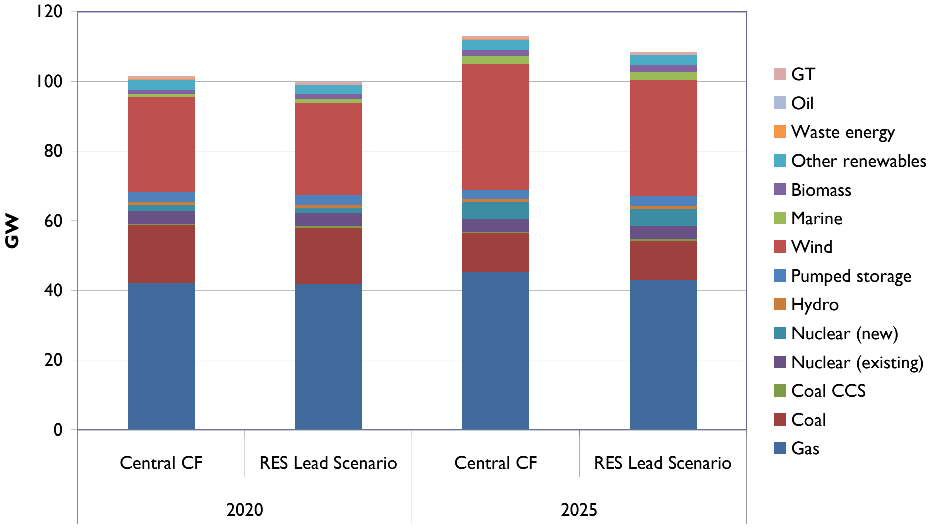
Cost and performance parameters for carbon capture equipment were updated based on new assumptions provided by DECC, and for carbon transport and storage based on the internal model described in 3.

### 6.2.2 Results

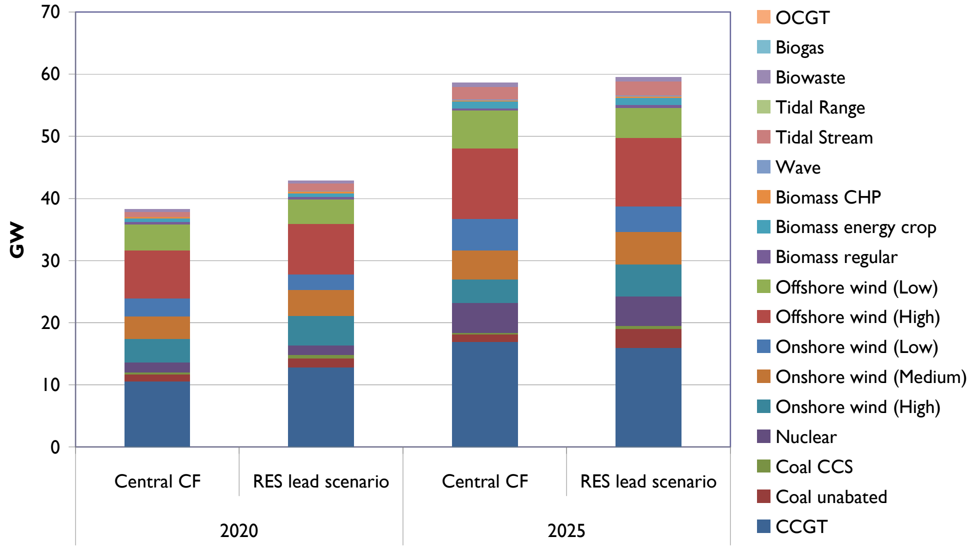
These differences in input assumptions lead to some changes in results. Whilst the overall capacity mix after 2020 is very similar, the lower demand assumption in the Central Counterfactual leads to higher capacity margins in the period upto 2020, and the higher longer term carbon prices lead to reduced carbon emissions relative to the RES Lead Scenario. Other differences are relatively minor.

The total capacity mix in 2020 and 2025 is compared in Figure 29, and the new capacity build by 2020 and 2025 respectively is shown in Figure 30. (Note that there are differences in plant retirements between the two, explaining why the Central Counterfactual has slightly less new build and slightly more total capacity in 2025.)

### Figure 29 Total capacity mix 2020 and 2025, Central CF and RES Lead Scenario

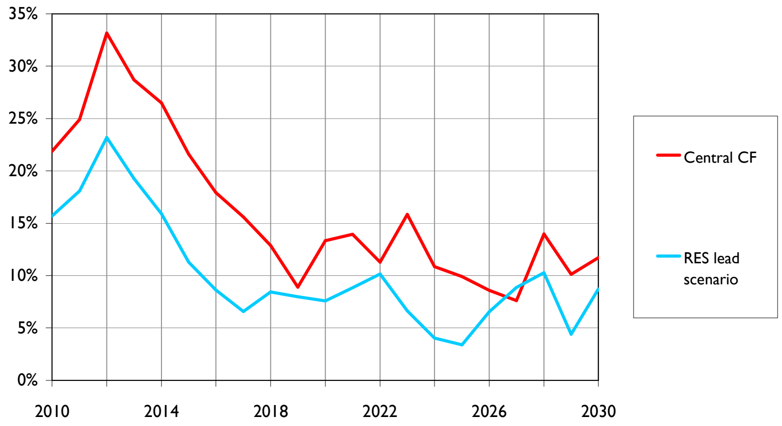


### Figure 30 New capacity build by 2020 and 2025, Central CF and RES Lead Scenario



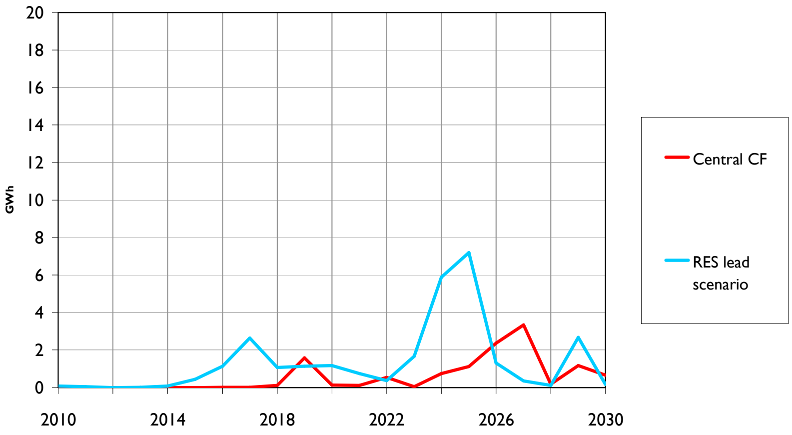
The increase in capacity margin in the period to 2020 is shown in Figure 31. Capacity margins in both cases are relatively volatile thereafter.

### Figure 31 Derated Peak Capacity Margin, Central CF and RES Lead Scenario



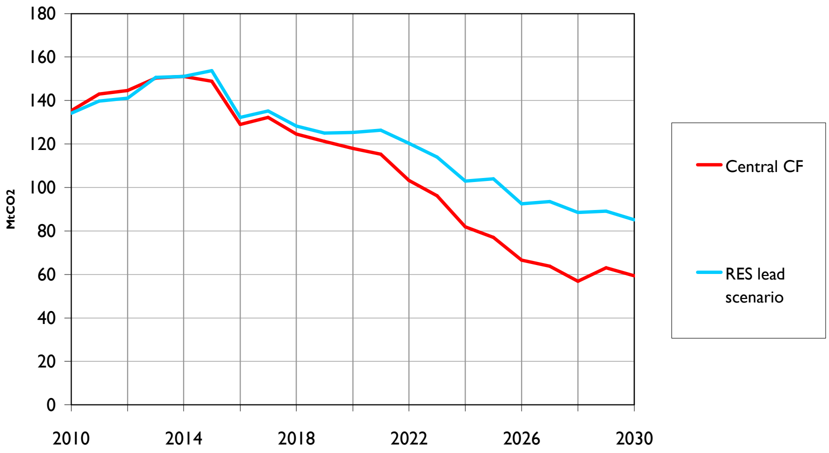
The expected energy unserved (a probabilistic estimate of the average total level of demand that cannot be met by generation on a national basis each year) is compared in Figure 32. This is at a similar low level in both cases (for comparison, it is estimated that demand not met through transmission and distribution failures is around 10 GWh/year). There are two higher years in the RES Lead Scenario corresponding to a short term drop in capacity margin that does not occur in the Central Counterfactual.

### Figure 32 Expected Energy Unserved, Central CF and RES Lead Scenario



The carbon emissions are compared in Figure 33, showing increasingly lower levels from the Central Counterfactual as EUA prices are relatively increasingly higher.

**Figure 33** **CO₂ emissions, Central CF and RES Lead Scenario**

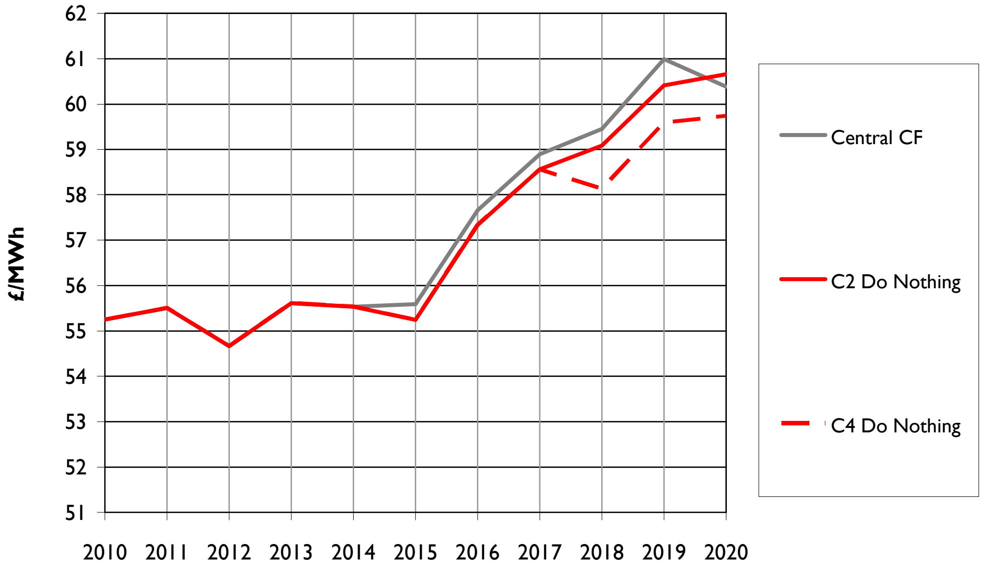


## 6.3 System short run marginal cost

Here we show how the system short run marginal cost varies between different CCS Outcomes under the Central Case.

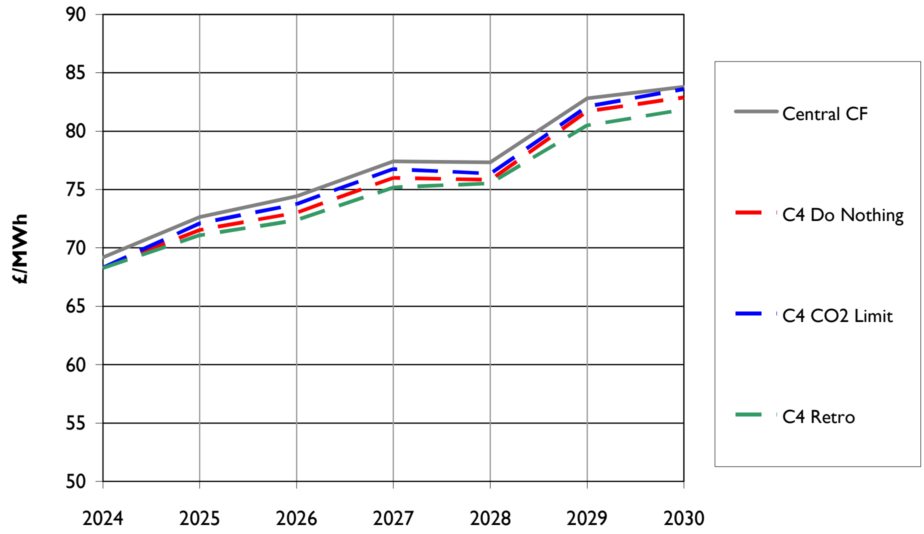
Figure 34 shows the average annual system short run marginal cost to 2020 for the Counterfactual, and the Do Nothing Outcome for two and four demonstrations. With two demonstrations, we see a reduction of 0.3 £/MWh in 2015, and with four, a reduction by over 1 £/MWh after 2017. The reduction in 2020 in the Counterfactual is due to the first new CCGT coming online changing the merit order.

**Figure 34** **System SRMC, Central, Counterfactual and Do Nothing, 2010 - 2020**



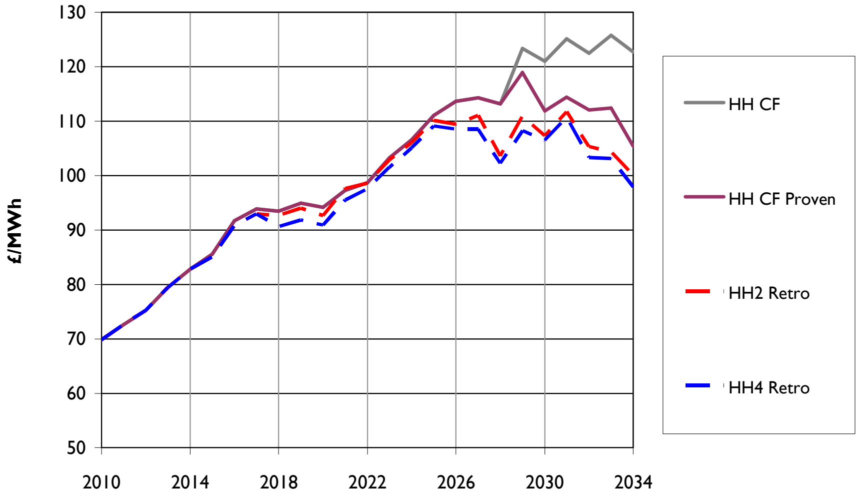
Next we consider 2025 and beyond, when any additional policy measures (retrofit or emissions limits) may be in place. Figure 35 shows the system SRMC with four demonstration plant under the Do Nothing, Limit, and Retrofit Outcomes compared to the Counterfactual. The Retrofit Outcome leads to the lowest SRMCs. If CCS is not proven, then imposing an annual emissions limit leads to a slight increase over the Do Nothing Outcome because the reduced CCS operation is replaced by more expensive plant.

**Figure 35 System SRMC, Central, Counterfactual and all 4, 2024 - 2030**



In the High High Case, the impact of new CCS build in the Proven Counterfactual reduces SRMC by around 10 £/MWh by 2030 compared to the Counterfactual in which no new CCS is built. Retrofitted demonstration plant reduces the marginal cost by a further 5 £/MWh in the same time period. It is at this point that the these relative differences in SRMC start to dominate the overall wholesale price between Outcomes, over and above the variations caused by fluctuations in capacity margin.

**Figure 36 System SRMC, High High, Counterfactual and Retrofit**



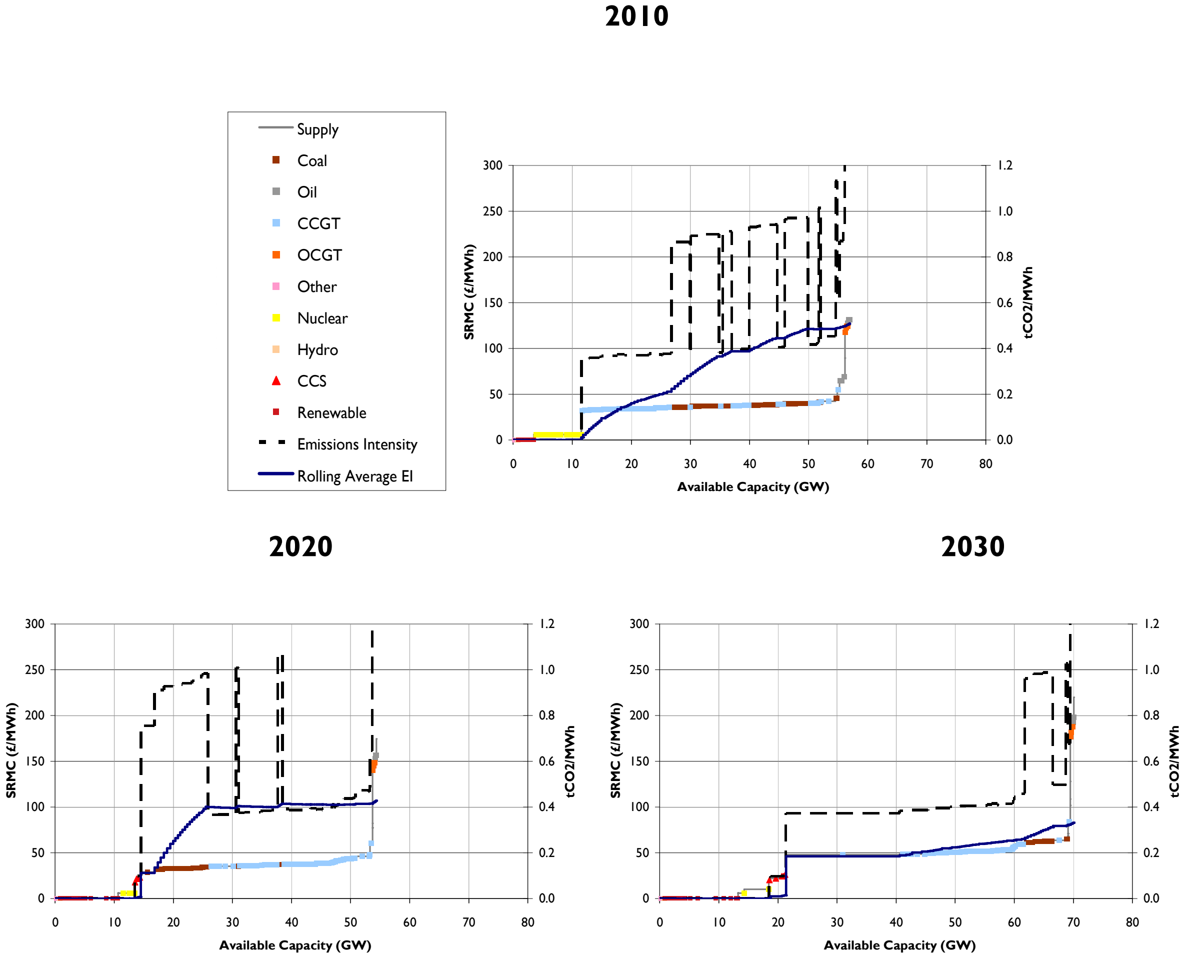
## 6.4 Supply stacks and emissions

In Figure 37 and Figure 38, we present representative supply stacks combined with an indication of the carbon emission rates of the generation. On the left axis we show the SRMC of the plant, plotted against cumulative average available capacity. On the right axis we show the marginal and average emission intensities. The marginal emission intensity is the intensity of the plant at that point on the supply curve. The average emission intensity indicates the overall system emissions at that demand level, based on average operating conditions. These plots are helpful in understanding the impact on carbon emissions in more detail. We focus on the Retrofit Outcome for four demonstrations under the Low and High High Cases, and show the stacks from 2010, 2020 and 2030.

In the Low Case in 2010, there are just over 10 GW of available wind and nuclear capacity at the bottom end of the stack, with no carbon emissions. The supply curve is then very competitive between coal and gas. With limited carbon free generation, the weighted average emission intensity rises rapidly, reaching 0.4 tCO2/MWh at around 40 GW (approximately the average demand level). By 2020, we see a reduction in nuclear capacity which is offset by renewable expansion and the four demonstration plant. Commodity prices favour coal over gas at this point. The intensity reaches 0.4 tCO2/MWh at around 25 GW, but then levels off. This increase in emission intensity combined with rising demand is the cause of increased emissions in 2020.

By 2030, the capacity mix is very different. Nuclear and renewables capacity has expanded, existing coal has retired and a large volume of new CCGTs have been built. The carbon price is such that the stack is in order of emission intensity. The average emission intensity reaches a maximum of 0.35 tCO2/MWh and is now much flatter.

**Figure 37 Supply stacks, 4 Retrofit, Low**

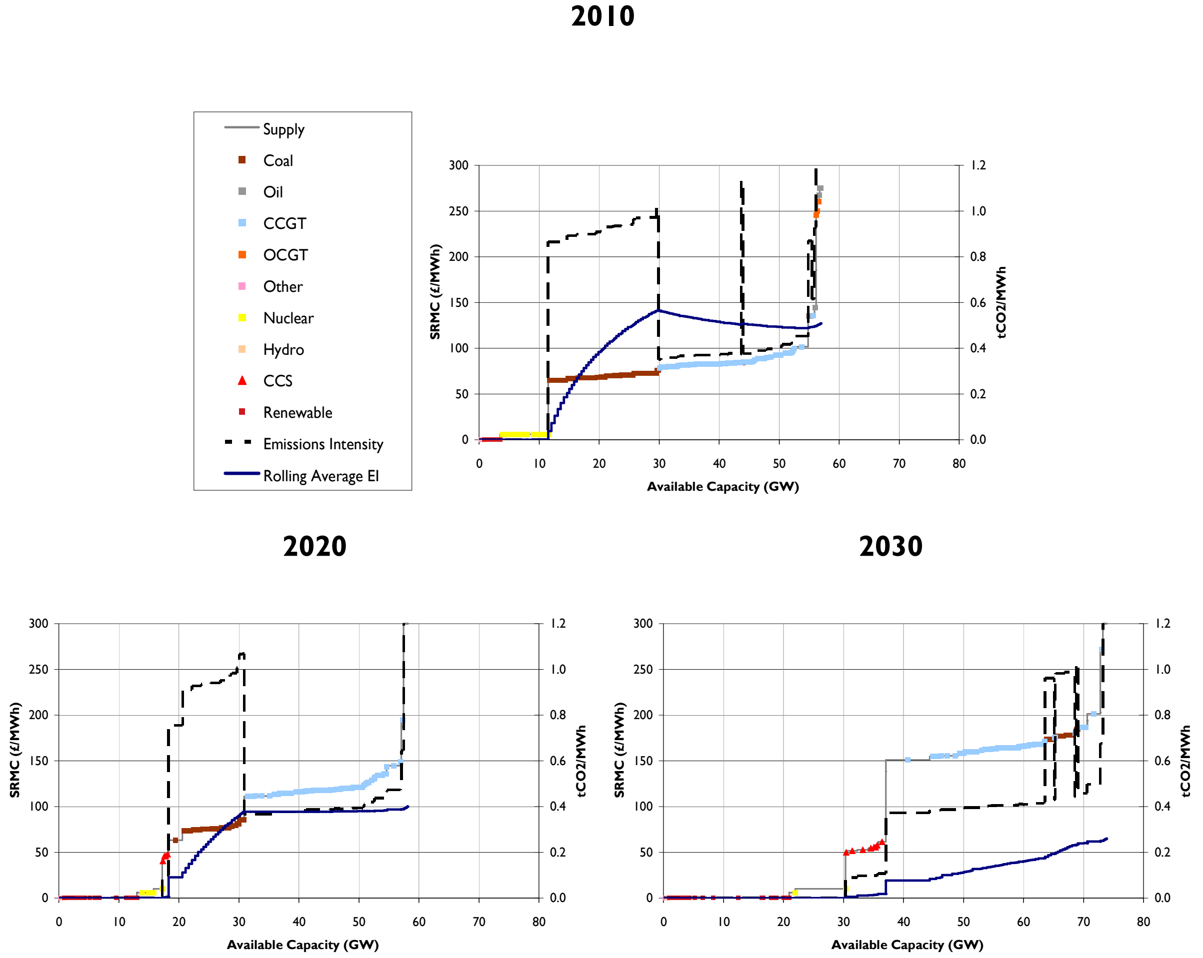

2010

2020

2030

Under the High High Case, in 2010 coal is a much cheaper than gas, and therefore the average emission intensity rises to 0.55 tCO2/MWh, before falling again as lower emitting plant are included. In 2020, the picture is very similar to that of the Low Case, with coal plant being slightly cheaper, and an average emission intensity of just under 0.4 tCO2/MWh. A large change is apparent in 2030: significant volumes of renewable capacity, nuclear and CCS mean that approximately 37 GW of available capacity has very little or no carbon exposure. CCGT plant are next up the stack, in preference to coal. Again, the stack is in order of emission intensity. The average carbon intensity only breaches 0.2 tCO2/MWh beyond 65 GW of available capacity, when coal is the marginal plant.

**Figure 38 Supply Stacks, 4 Retrofit, High High**



## 6.5 Annual funding mechanism payments

Table 22 presents the annual funding mechanism payments made to two (first row) and four (second row) demonstration plant in the IDM in real 2009 terms. In each case, the total amount (in £m) is shown, as well as the amount per unit of demand (in £/MWh) (where we have simply divided the total by the annual demand in each year). The profile of payments reflects the (exogenous) assumptions on the operational start dates of each demonstration and the end of the funding corresponding to the cap of 20 mT carbon dioxide stored.

**Table 22 Annual funding mechanism payments (real 2009)**

| CCS Subsidy | | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 Demo plant | £mn | 0 | 0 | 0 | 0 | 156 | 376 | 376 | 376 | 376 | 376 | 376 | 376 | 372 | 226 | 36 | 0 | 0 | 0 | 0 | 0 | 0 |
| | £/MWh demand | 0 | 0 | 0 | 0 | 0.5 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 0.6 | 0.1 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 Demo plant | £mn | 0 | 0 | 0 | 0 | 156 | 376 | 376 | 376 | 639 | 639 | 639 | 639 | 634 | 487 | 296 | 260 | 258 | 258 | 133 | 0 | 0 |
| | £/MWh demand | 0 | 0 | 0 | 0 | 0.5 | 1.1 | 1.1 | 1.1 | 1.9 | 1.9 | 1.9 | 1.9 | 1.8 | 1.4 | 0.8 | 0.7 | 0.7 | 0.7 | 0.4 | 0 | 0 |

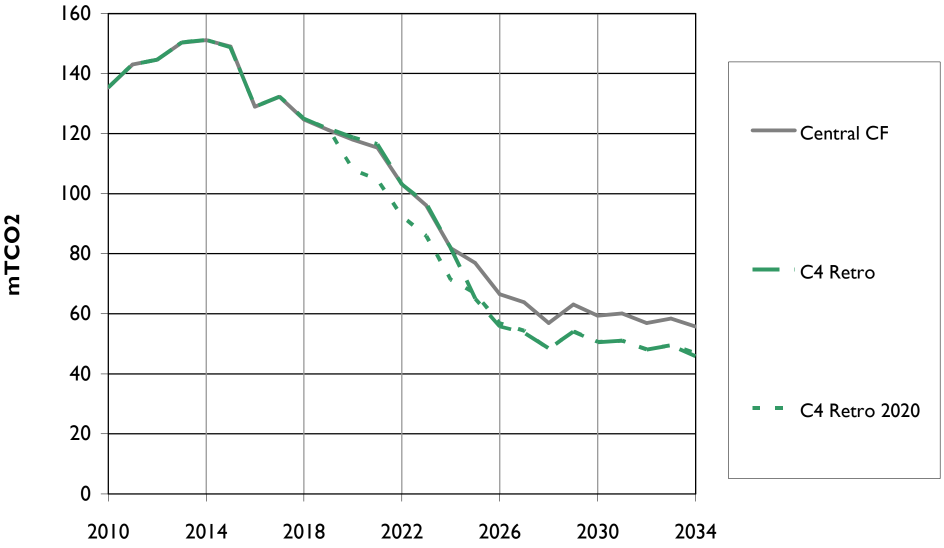
## 6.6 Sensitivities

We performed five sensitivities in addition to our main runs. These sensitivities focus on bringing forward implementation dates of retrofit or contingency, along with the option to expand the coverage of an annual emissions limit to all coal plant (new and existing).

### 6.6.1 Four plant, Central Case, Retrofit operational 2020

In this sensitivity, we assume four demonstration plant with a Retrofit Outcome. However, we bring the date of operational retrofit forward five years, to 2020. When retrofitting, there is a reduction in net capacity which reduces the total generation output (but with no impact on load factor) from demonstration plant. This reduction in generation is compensated for by CCGT predominantly. Retrofitting earlier, despite the increased CCGT output, sees a carbon emissions reduction of approximately 10 mt$CO_2$ per annum, as shown in Figure 39. Beyond 2025, the two are essentially indistinguishable.

Figure 39 Carbon emissions, Central 4, retrofit, 2020



## 6.6.2 Four plant, Central Case, Limit, tightening constraint 2020-2025

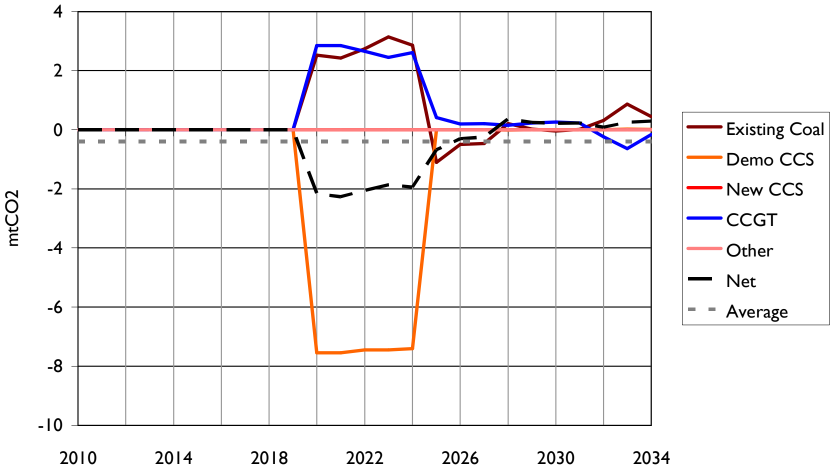
In our main runs, the annual emissions limit was applied abruptly in 2025. In this sensitivity we linearly tighten the constraint to the same final level (baseload CCGT emissions equivalent), starting in 2020.

Each year sees a tightening equivalent to approximately 2 TWh less demonstration plant output per annum compared to the standard run. This leads to increasing output from CCGT and existing coal. Overall, total emissions are reduced by 4 $mtCO_2$ in the five years.

## 6.6.3 Four plant, Central Case, Limit enforced 2020

In this sensitivity, an annual emissions limit is abruptly enforced in 2020. This sees total demonstration plant output reduced by 10 TWh per annum. This is compensated for by mainly by CCGT with some additional existing coal output. We see a small reduction in carbon emissions in the five years from 2020 to 2025. This is shown in Figure 40, which shows the emissions produced by each technology type.

**Figure 40** **Carbon emissions, Central 4, $CO_2$ Limit 2020 less Central 4 $CO_2$ Limit 2025**

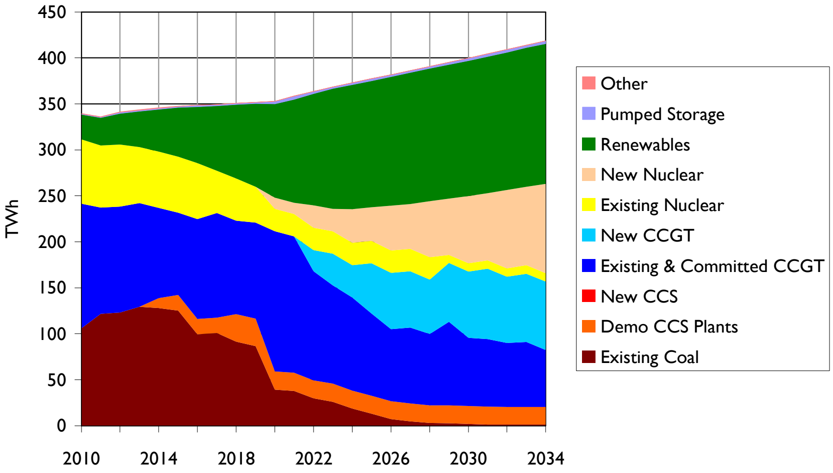


### 6.6.4 Four plant, Central Case, Limit enforced 2020 on all coal plant

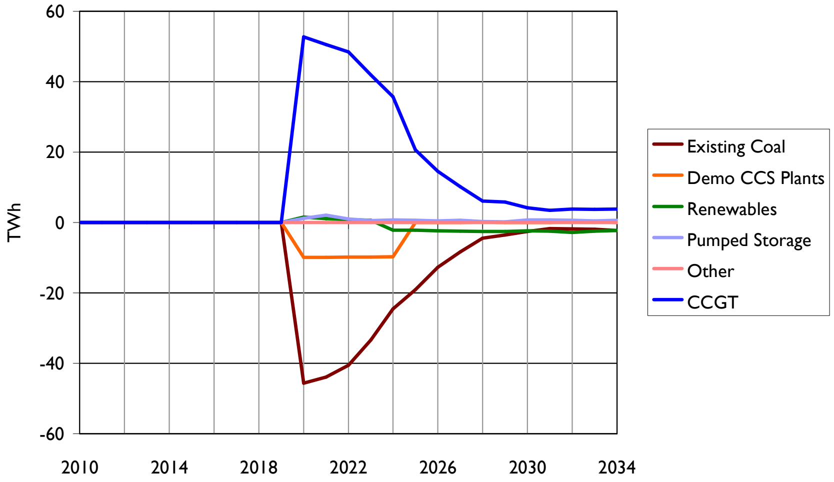
In this sensitivity, the annual emissions limit is abruptly enforced in 2020 not only on the demonstration plant but also on the existing coal fleet. (Note that we have not adjusted any of our closure date assumptions as a result.).

In Figure 41 we present the generation mix over time. It is clear in 2020 that coal output reduces significantly. In comparison to the limit applied just to demonstration plant in 2025, coal generates 40 TWh (about 50%) less under these assumptions. CCGT generation increases to over 150 TWh, 43% of total generation. The relative output changes are shown in Figure 42.

**Figure 41** **Generation mix, Central 4 Limit 2020 All**

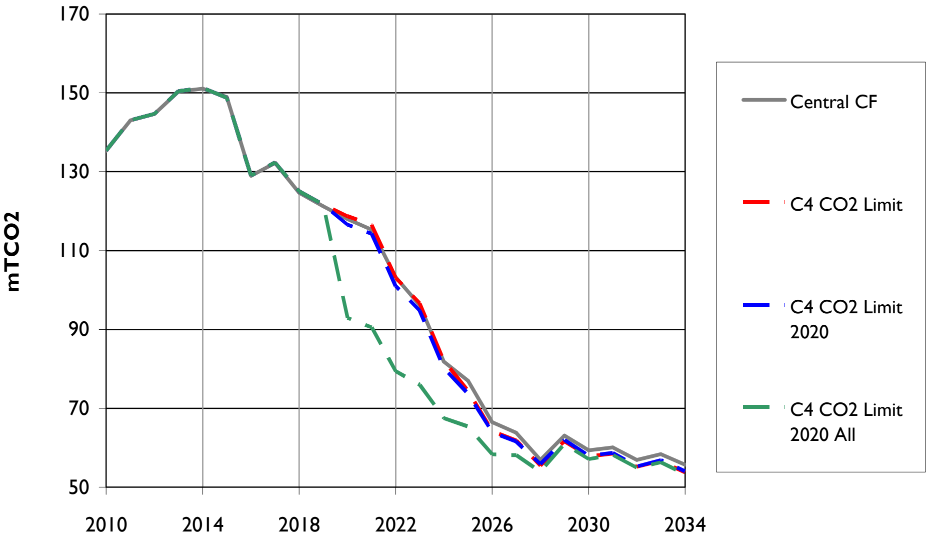


### Figure 42 Change in generation, Central 4 Limit 2020 All less Central 4 Limit



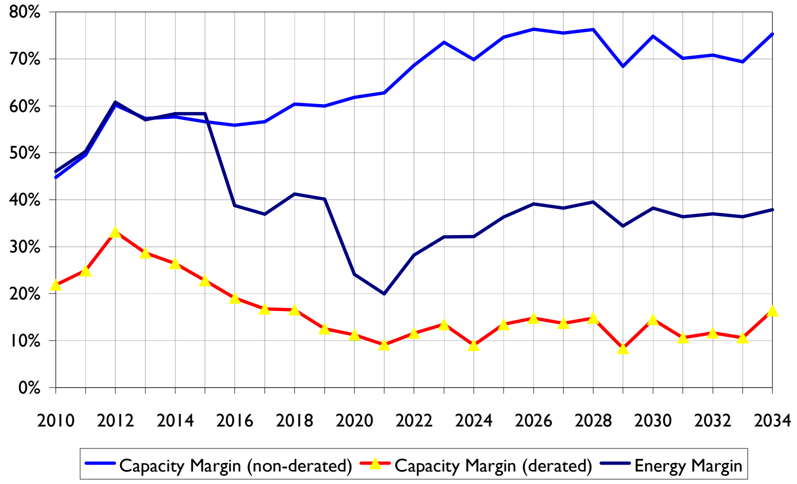
There is a corresponding significant reduction in carbon emissions during the 2020s. In total, 120 mt less $CO_2$ is emitted during the 2020s, as shown in Figure 43.

### Figure 43 Carbon emissions, Central 4, $CO_2$ Limit 2020 All



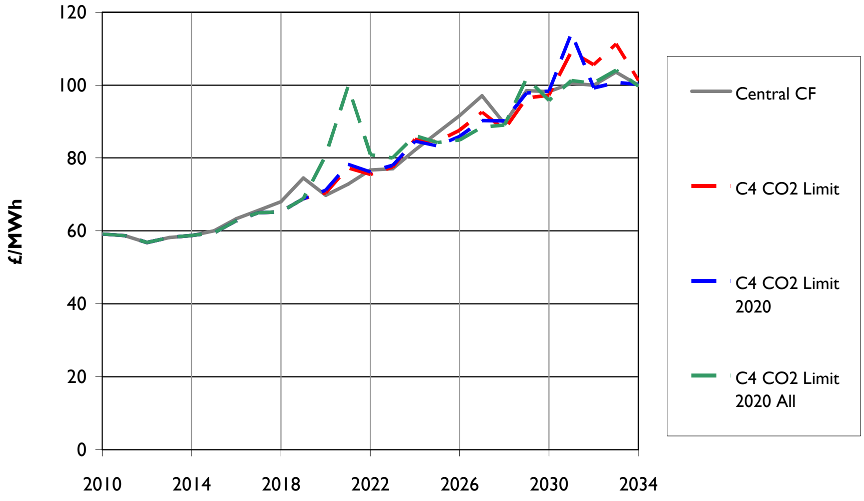
These constraints do come at a cost: a significant reduction in energy margin to historically low levels. In Figure 44 we show the de-rated capacity margin and energy margins in this sensitivity. The energy margin drops in any case in 2016 due to the combination of LCPD closures and running restrictions due to the IED, but this is now further compounded by the annual emissions limit being enforced on the entire coal fleet in 2020.

Figure 44 Capacity and energy margin, Central 4, $CO_2$ Limit 2020 All



This reduction in energy margin leads to higher prices, shown in Figure 45, for a couple of years just after 2020, until the market responds with further CCGT investment. (In practice foreknowledge of the implementation of such a policy may in reality stimulate further earlier investment earlier, lessening the impacts shown here.)

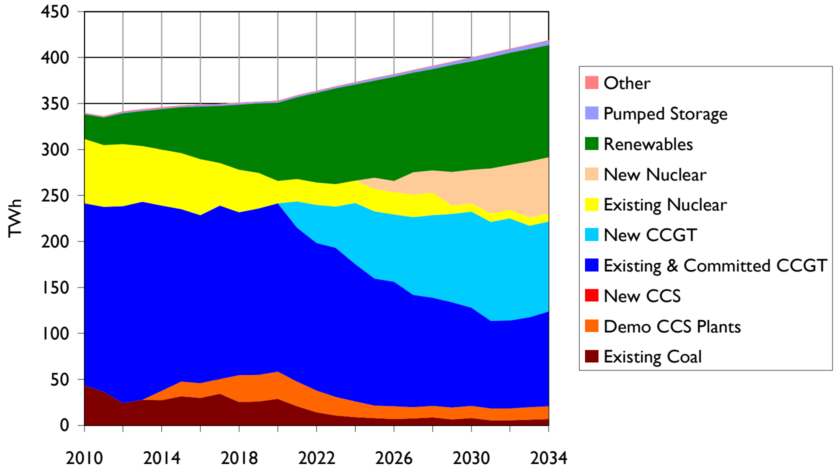
Figure 45 Wholesale price, Central 4, Limit 2020 All



## 6.6.5 Four plant, Low Case, Carbon Central Case, Do Nothing

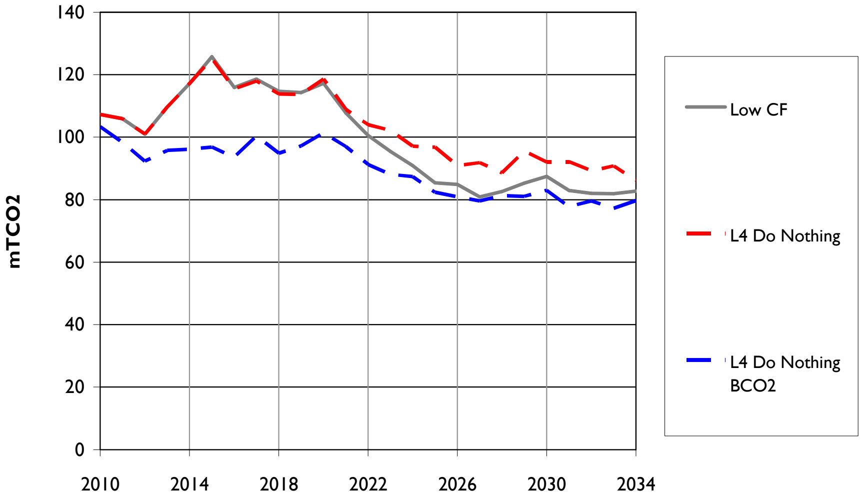
This sensitivity mixed low fuel prices from the Low Case with the carbon price from the Central Case. The Low Case is heavily gas favouring, and increasing the carbon price just increases the attractiveness of gas: throughout the modelled horizon more than 50% of generation is from CCGTs. Beyond 2020, the carbon price is sufficient to outweigh the higher efficiency of the unabated elements of CCS, and the load factors start to decline. The abated units continue to run baseload.

**Figure 46 Generation mix, Low 4 Do Nothing, Central Carbon**



The higher carbon price does not offset the low commodity prices sufficiently to stimulate further renewable investment prior to 2020. Throughout, emissions are lower than in the Low Case with low carbon (based on gas being favoured over coal), but percentage reduction is similar over time, as shown in Figure 47.

**Figure 47 Carbon emissions, Low 4 Do Nothing, Base Carbon**



# 7 Technical assumptions literature review

## 7.1 Review objectives and scope

As a part of the study, we conducted a literature review of information on the technical performance and costs of CCS. We aimed to identify technical requirements, capital and operating costs and performance metrics (i.e. efficiency, load factors /outage rates) for the three main components of the generation and capture process:

- new capture-ready coal plant;
- the retrofit installation of CCS equipment onto capture ready plants; *and*
- the cost of new coal plants which capture *ca*. 90% of $CO_2$ from outset.

This chapter summarises the results of the literature review.

***It should be noted that the results from this review were not used as a direct inputs for the study analysis and modelling, as all CCS assumptions (other than transport and storage) were independently provided directly by DECC.***

The review served to provide support for the probability distributions used in our risk analysis, and to highlight the very high level uncertainty that surrounds CCS cost and performance assumptions.

## 7.2 Methodology and assumptions

Academic papers or reviews describing aspects of CCS costs and performance, and reports in the 'grey' literature (such as industry presentations and press releases) were examined for this study. Two aspects are noteworthy. First, different authors and reports identify different values for costs and performance, and in some cases these differences are substantial. Second, no single paper we reviewed provides a single comprehensive and consistent set of information.

Data therefore had to be compiled from different sources. Whilst this reduces the bias from one particular source, there are some critical limitations. In particular, inputs, processes and outputs and study boundaries usually differ, and costs are reported in different locations, currencies and at different times.

The types of variations in inputs between studies include:

- the moisture content of the coal, which affects the energy required for drying and the energy density;
- the heavy metal or sulphur content of the coal, which influences the technology choices, extent and costs of clean-up processes;
- cooling water temperature and availability, which can limit overall plant thermodynamic efficiency;
- the type of boilers (sub-critical, super-critical, advanced or ultra-super critical);
- types of gasifiers and turbines;
- the processes used to capture CO2; *and*

- the processes for cleaning up pollutants or impurities within the CO2 (these might include SOx, NOx, and particulates).

Variations in study outputs constitute an additional source of difference between studies. Differences include net power (MWe), temperature and pressure of $CO_2$, volumes and purity of $CO_2$ stream, compositions and volumes of flue gases or other wastes.

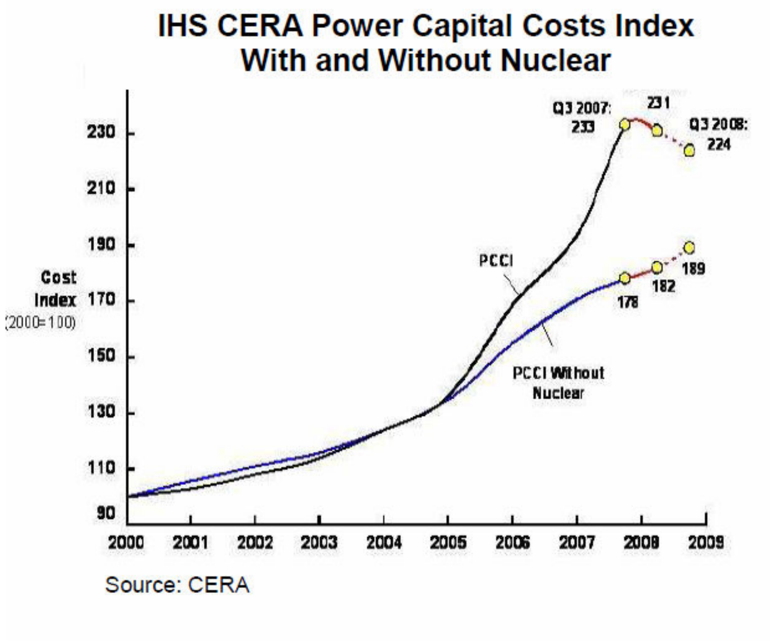
Studies of the costs of plants that are larger may show benefits that derive from economies of scale, or projects that have less onerous clean up requirements either for the $CO_2$ or for other by-products may have lower costs. Cost allocation and models for scaling are however seldom described in a manner that allows a consistent comparison between studies reported on plants at different sizes.

Further to differences in inputs, processes and outputs, there are frequently differences in economic models and in presentation that hamper technology comparison. The variations include assumptions on contingency and owner's costs, but also economic lifetime. Detailed engineering studies tend to be transparent in terms of conventions for reporting efficiencies, parasitic losses and other units. However, engineering studies tend to focus on only one technology or one aspect of technology performance at a time. Finally, whereas a number of academic papers explore the characteristics of CCS plant, only a few have quantified the requirements, performance and costs for capture ready plant and retrofit.

Assumptions on currencies and prevailing exchange rates are important. Any UK analysis needs to be mindful that the market for many of the underlying CCS technologies is global. Nearly all published cost estimates are presented in US dollars or Euros. The exchange rate has varied between $1.4/£1 and $2/£1 in recent years, so that CCS costs expressed in pound sterling would show a similar variation from exchange rate reasons alone.

Timing is a critical feature in cost estimation. There is no dedicated index of CCS cost escalation over time, but there are generic indices for engineering, power and chemical plant costs. The IHS CERA power capital costs index is frequently cited as a useful index for CCS, although it is necessarily limited by the absence of a history of large CCS plant costs. Nevertheless the index can be used to provide a starting point in providing a correction multiplication factor that allows costs in a given year to be converted to a common year. Figure 48 clearly shows how costs for power plants have risen by nearly a factor of two over the last ten years, which would imply a similar variation in capital costs for CCS hardware.

**Figure 48 IHS CERA power capital costs index**


IHS CERA Power Capital Costs Index
With and Without Nuclear

Source: CERA

Given these challenges, and the high volume but mixed quality of literature available (listed in the bibliography), the study found it necessary to filter the literature and apply corrections to convert cost data to Sterling in real 2009 terms. The papers that provided the most input to data collection were able to meet the following criteria:

- The lead authors were experienced in calculating costs and performances of power and chemical plants.
- The data had been peer reviewed.
- The cost and performance data had been calculated within the last five years, and hence took account of recent technology and market developments.
- Capture technologies or capture ready assumptions were described in some detail and compared on as close as possible on a like-for-like basis.

Examples of studies that met these criteria include:

- ‘$CO_2$ capture ready plants – Technical Study 2007/4’, published by the IEA Greenhouse Gas R&D Programme
- ‘Cost and performance baseline for fossil energy plants and Pulverized Coal Oxycombustion power plants’, both published by the US Department of Energy/NETL,
- ‘The future of coal’, an interdisciplinary Massachussets Institute of Technology study.

## 7.3 Review summary

Based on these data sources and others mentioned in the bibliography, key technology assumptions for each of the three components of the generation and capture process are presented below.

### 7.3.1 Technical assumptions for baseline coal plant

Whereas all coal plants require coal receiving and storage facilities and control facilities, supercritical pulverised fuel plant and IGCC plant differ in the main components.

The key elements for a supercritical (or advanced/ultrasupercritical) pulverised coal power plant (a baseline for post-combustion and oxyfuel plant) are the supercritical boiler island, clean up facilities (flue gas desulphurisation and $NO_x$ removal, a supercritical steam island, and balance of plant equipment.

For IGCC plants, the key elements are gasifiers, air separation units, water gas shift reaction, mercury removal, acid gas removal, sulphur recovery, F-class gas turbines, heat recovery steam generators, and steam generation and accessories.

### 7.3.2 Technical requirements for capture ready coal plant

The principle behind ‘capture ready’ is that a plant is designed to be retrofitted for carbon dioxide capture, transport and geological storage. The Consultation Document defined capture ready plant as being “designed with operational CCS in mind and that there are no known barriers to installation once the technology has been proven”. Proposals for how developers can demonstrate capture readiness are listed.

As reviewed by Bohm et al. (2007) and by IEA GHG (2007), all capture ready plants will require

- space for ducting to ease interconnections and heat exchangers, and for $CO_2$ drying and compression facilities; *and*
- design of common plant systems to allow reconfiguration with minimum downtime and at low cost.

Readiness for each capture technology implies tailoring design appropriately.

For post-combustion plant, space must be specifically set aside for amine scrubbers, steam turbine reboilers, flue gas desulphurisation, associated heat exchangers and the turbines should be designed to suit $CO_2$ capture requirements.

For pre-combustion plant, space should be set aside for a two-stage shift reactor, supplementary acid gas removal, and SCR facilities. In addition, the air separation unit, gasifiers, and gas turbines will need to be optimised for the throughput expected when operating with capture facilities. Importantly, the gas turbine will need to be compatible with combustion of hydrogen rich gas.

For oxyfuel plant, space must be specifically set aside for an air separation unit and associated heat exchangers. The steam turbines should be optimised for operation after capture, with oversized cooling towers and cooling water pumps.

### 7.3.3 Technical requirements for coal plant with CCS operational

For all coal power plants, the transition from capture ready to CCS operational will require additional piping, heat exchangers and cooling equipment, $CO_2$ drying and compression facilities, and additional balance of plant.

For post-combustion capture involving an amine scrubbing unit this would specifically comprise pumps, an absorption tower, storage tanks, a reboiler, heat exchangers, stripper, dosing equipment, filters and blowers.

For pre-combustion capture, there would be a requirement for a 2-stage separation unit (e.g. selexol based) to capture the $CO_2$.

For oxyfuel capture, there would be a specific requirement for air compressors and a purification system, an air separation unit, heat exchangers, reboilers and condensers, and an oxygen backup system.

The differences between baseline, capture ready and CCS operational plant are schematised in Figure 49 to Figure 51 below for post-combustion, pre-combustion and oxyfuel capture technologies in sequence:

**Figure 49 Baseline, capture ready and CCS: post-combustion**

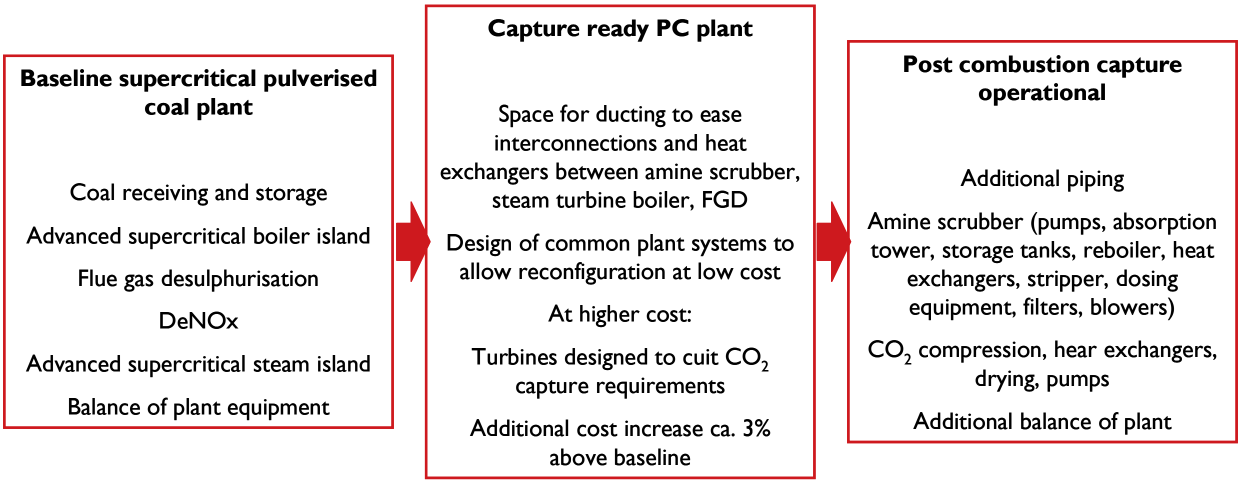
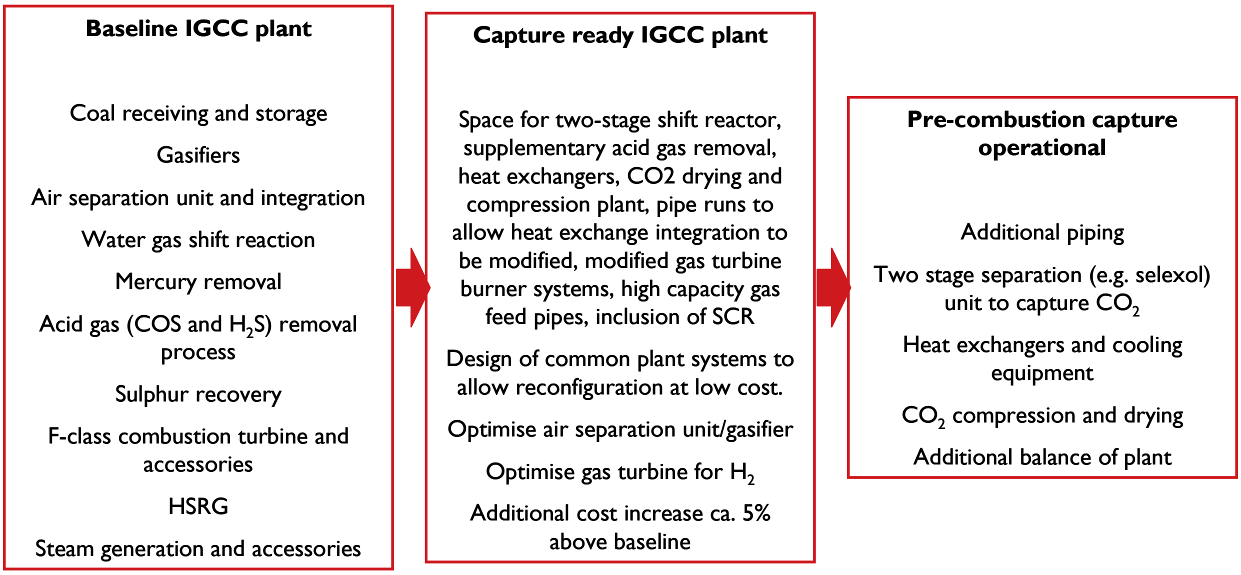


**Figure 50 Baseline, capture ready and CCS: pre-combustion**



**Baseline IGCC plant**

Coal receiving and storage

Gasifiers

Air separation unit and integration

Water gas shift reaction

Mercury removal

Acid gas (COS and $H_2S$) removal process

Sulphur recovery

F-class combustion turbine and accessories

HSRG

Steam generation and accessories

**Capture ready IGCC plant**

Space for two-stage shift reactor, supplementary acid gas removal, heat exchangers, CO2 drying and compression plant, pipe runs to allow heat exchange integration to be modified, modified gas turbine burner systems, high capacity gas feed pipes, inclusion of SCR

Design of common plant systems to allow reconfiguration at low cost.

Optimise air separation unit/gasifier

Optimise gas turbine for $H_2$

Additional cost increase ca. 5% above baseline

**Pre-combustion capture operational**

Additional piping

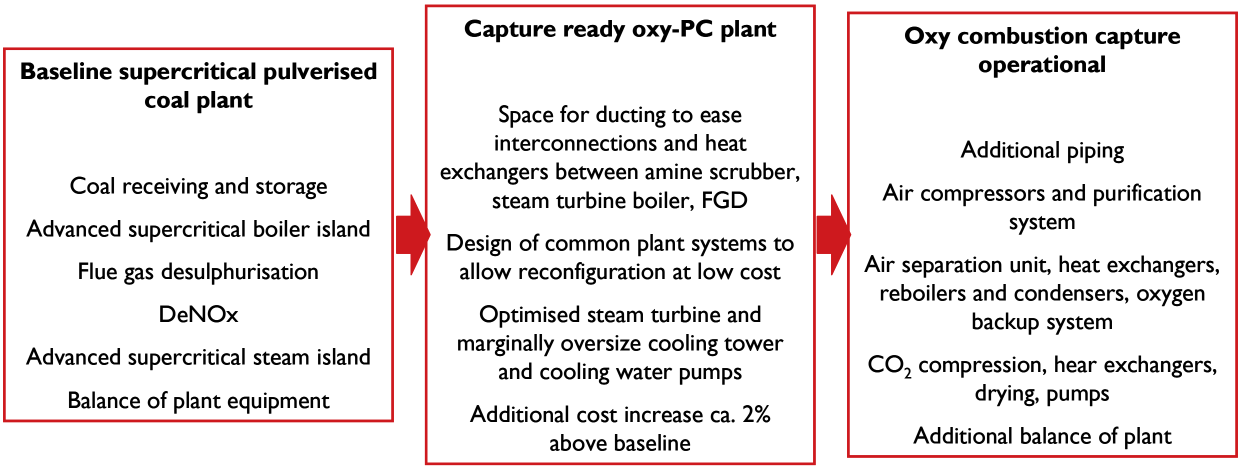
Two stage separation (e.g. selexol) unit to capture $CO_2$

Heat exchangers and cooling equipment

$CO_2$ compression and drying

Additional balance of plant

**Figure 51 Baseline, capture ready and CCS: oxyfuel**



**Baseline supercritical pulverised coal plant**

Coal receiving and storage

Advanced supercritical boiler island

Flue gas desulphurisation

DeNOx

Advanced supercritical steam island

Balance of plant equipment

**Capture ready oxy-PC plant**

Space for ducting to ease interconnections and heat exchangers between amine scrubber, steam turbine boiler, FGD

Design of common plant systems to allow reconfiguration at low cost

Optimised steam turbine and marginally oversize cooling tower and cooling water pumps

Additional cost increase ca. 2% above baseline

**Oxy combustion capture operational**

Additional piping

Air compressors and purification system

Air separation unit, heat exchangers, reboilers and condensers, oxygen backup system

$CO_2$ compression, hear exchangers, drying, pumps

Additional balance of plant

The gross output represents the total plant generation without considering internal demands. It is technically possible to construct capture facilities at any specified size. From the perspective of capture equipment availability, two limitations on plant output are important:

- For IGCC power stations, gas turbines are currently only available at discrete sizes.
- Oxyfuel equipment has largely only been tested at around the 30 MW scale, therefore in the early demonstration phase it is considered unlikely that suppliers will produce units that are individually more than 300 MW. (In the longer term, once such experience is gained, there ought to be no maximum size for oxyfuel technologies.)

The net plant power output is the total power generated from the turbines less the total auxiliary power consumption, and therefore reflects the capacity available for dispatch.

Net plant efficiency is defined as the ratio of electrical energy available to fuel supplied. The table shows efficiencies reported at higher heating value, and takes into account the latent heat of vaporisation of water as the products of combustion are returned to a low temperature.

The ambition for percentage of $CO_2$ captured is typically quoted around 90% (of the $CO_2$ produced from combustion). It is possible that the actual percentage captured in early years will be lower as systems are optimised. For oxyfuel capture specifically, some studies identify capture percentages approaching 100%.

Forced outage refers to the shutdown of a generating unit for emergency reasons or for unanticipated breakdown. In the short term, it is possible that the rates of forced outage may be higher for CCS than for conventional plant as operators gain experience with plant performance, although there is little public data on these issues.

**Table 23 Performance data ranges**

| Plant | Baseline IGCC | Capture ready IGCC | IGCC+CCS | SC baseline | SC ready for post-combustion | SC + post-combustion | SC ready for oxyfuel | SC + oxyfuel |
|---|---|---|---|---|---|---|---|---|
| Lifetime | 20-40 years | 20-40 years | 20-40 years | 20-40 years | 20-40 years | 20-40 years | 20-40 years | 20-40 years |
| Load factor | 75-90% | 75-90% | 50-86% | 75-86% | 75-86% | 50-86% | 75-86% | 50-86% |
| Gross output | 400-950 MWe | 400-950 MWe | 400-950 MWe | 400-950 MWe | 400-950 MWe | 400-950 MWe | 400-950 MWe | 400-950 MWe |
| Net output | 400-750 MWe | 400-750 MWe | 300-750 MWe | 400-750 MWe | 400-750 MWe | 300-750 MWe | 400-750 MWe | 300-750 MWe |
| Parasitic capacity loss | 17% | 17% | 25% | 5% | 5% | 19% | 5-8% | 30% |
| Efficiency (% HHV, net of auxiliaries) | 38-46% | 38-46% | 29-37% | 35-46% | 35-46% | 25-36% | 35-46% | 22-36% |
| % $CO_2$ captured | 0% | 0% | 50-90% | 0% | 0% | 50-90% | 0% | 50-99.99% |
| Forced outage | 10% | 10% | 10-40% | 10% | 10% | 10-40% | 10% | 10-40% |

From left to right the above table shows baseline, capture ready, and CCS operational performance data for pre-combustion, post-combustion and oxyfuel combustion plant. It should be noted that 'SC' refers to Supercritical and includes the Advanced and Ultra-supercritical variations.

Cost ranges were drawn from the literature and corrected as follows:

- Costs were escalated to 2009 prices using the IHS CERA cost index for power stations (excluding nuclear – see Figure 48)[10]
- Costs were converted into GBP at the rates of £0.86/€1 and £0.61/$1 as required. Recently exchange rates have been volatile, with a significant impact on costs expressed in GBP.
- Where contingency was not included, this has been assumed as 30% for first-of-a-kind capture plant.
- Where owner's costs have not been included, an estimate of 20% was applied.

The resulting analysis provides the following cost ranges. Costs are divided into fixed capital costs and operating costs. Both are assumed to scale linearly with output and are expressed in the table as £/kW. A variable opex is also provided that scales with energy output (and thus $CO_2$ throughput).

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[10] Note this may under-represent historic volatility. For example, the Duke Energy Carolina Cliffside 960 MW coal fired power plant project cost more than doubled between spring 2006 and spring 2007 from $1250/kW to $3100/kW.

Estimated build times are also shown. An important uncertainty in build time relates to the requirements to permit and construct additional transport and storage infrastructure for retrofit CCS installation.

**Table 24 Baseline, Capture Ready and CCS operating cost estimates**

| Plant | Baseline IGCC | Capture ready IGCC | IGCC+CCS | SC baseline | SC ready for post-combustion | SC + post-combustion | SC ready for oxyfuel | SC + oxyfuel |
|---|---|---|---|---|---|---|---|---|
| Capex £ per kWe net (incl. owners costs) | 803-2484 | 844-2608 | 1061-3649 | 719-1923 | 740-1981 | 1174-3101 | 734-1962 | 1126-4618 |
| Fixed opex £/kWe net year | 23.0 | 23.0 | 28.8 | 16.4 | 16.4 | 24.5 | 16.4 | 22.0 |
| Variable opex (£/MWh) | 3.9 | 3.9 | 4.9 | 3.0 | 3.0 | 5.5 | 3.0 | 6.0 |
| Build time/ months | 36-60 | 36-60 | 36-120 | 36-60 | 36-60 | 36-120 | 36-60 | 36-120 |
| Retrofit time / months |  | 5-120 |  |  | 5-120 |  | 5-120 |  |

For capex, the full range of values presented is shown. Opex data are drawn primarily from NETL/DoE.

## 7.4 Review conclusions

Although there are no large scale coal power plant constructed capture ready or CCS operational anywhere worldwide, the published literature provides indications on expected costs. However, a literature review reveals significant variations in the apparent costs and performance of baseline coal, capture ready, and CCS operational plant. Some of this variation can be attributed to differences in assumptions on currency, timing and whether contingency assumptions are for first of a kind (FOAK) or 'nth'of a kind (NOAK) plant. Other variations reflect substantial differences in plant assumptions that reflect differences in size, type of coal, pressure and purity of $CO_2$ stream, and the extent of clean up required. The study has summarised the cost and performance data available in a common format.

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