UK MARKAL Modelling - Examining Decarbonisation Pathways in the 2020s on the Way to Meeting the 2050 Emissions Target

Final Report for the Committee on Climate Change (CCC)

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About UCL

University College London (UCL) is a research led university whose research is consistently ranked as world leading. In the 2008 Research Assessment Exercise (RAE) UCL was rated the best research university in London, and third in the UK overall. UCL has a breadth of energy research covering more than 20 departments with an income of over £20M in the area of energy. The UCL Energy Institute provides a general role in facilitating and promoting this research as well as supporting UCL with its Grand Challenges.

The UCL Energy Institute is at the forefront in modelling energy systems, so that we can fully assess the impact that changes to energy demand can have on a wide range of parameters (health, comfort, cost, energy, carbon, upstream infrastructure) at a range of different spatial and temporal scales from individual components through to an international scale. Major modelling tools at UCL include energy-economic systems models including the UK MARKAL family (including elastic demand, stochastic, macro and other variants) and the Global TIAM-UCL model.

Executive Summary

The Committee on Climate Change (CCC) was set up to provide advice to the UK Government on a range of issues, including setting legally binding carbon budgets for five year periods beginning from 2008, and a target for emissions reductions in 2050. In its first report (CCC, 2008), the Committee concluded that to respond to the threat of climate change, the UK must act now to significantly reduce greenhouse gas (GHG) emissions by 34% by 2020 and 80% by 2050. CCC's advice was based on a review of the science of climate change, the international context, the UK's existing commitments, and an assessment of the costs and abatement potential associated with different measures. Formal energy-economic modelling – including the energy systems MARKAL model – has played a key role in the evidence base for CCC and the wider UK government. Over the last 8 years, the UK MARKAL model has been extensively used for UK long-term energy pathway analysis, benefitting from iterative energy model development, and developing a strong track record of peer reviewed documentation and outputs.

CCC will provide advice on the 4th carbon budget period – covering 2023-2027 – in December 2010. As part of the underpinning evidence base for this advice, CCC commissioned this major energy modelling study, focusing on mid-term (2020-2030) uncertainties in the feasibility, costs and trade-offs of alternate pathways towards meeting the 2050 target. This latest project focused on more stringent reductions – up to a 90% or 95% reduction in carbon dioxide (CO_2) emission by 2050. This additional effort in abating UK energy CO_2 emissions recognises the uncertainties in the contribution of non-CO_2 GHGs, emissions from land-use change and emissions from international bunker fuels. Furthermore this study encompassed two areas of major energy modelling development:

Firstly, a series of model updates have been implemented. Some of these are following review of the UKERC Energy 2050 project (Anandarajah et al., 2009), and are detailed in section 3.1. Additional updates have been made via an iterative process with CCC, relating to their stakeholder engagement exercises and to encompass insights from

parallel analytical work. These updates are iteratively dealt with in two phases in the report and are discussed in detail in sections 0 and 3.3.

- A range of updates on the model's data and structure including a more detailed treatment of combined heat and power (CHP) technologies, additional detail on carbon capture and storage (CCS) resources, updated imported resource costs, updated energy service demands and a fuller depiction of conservation options in the residential and services sectors
- Imposing constraints (build rates) on the feasible rate at which major technology classes can be implemented
- Improving the representation of bio-energy chains, including the use of biomass in capture storage and sequestration (CCS) applications to generate electricity with negative emissions, and the inclusion of bio-methane in the conventional gas system
- Additional flexibility in the industrial sectors, including fuel switching and process based CCS (as in previous model runs this sector can comprise around 40% of residual emissions by 2050)
- The adoption of buildings sector technologies in terms of operation feasibility, notably heat pump technology given their unsuitability for some of the existing housing stock and in certain time periods
- Model recalibration, including alternate discounting (using social discount rates) and subsequent hurdle rate adjustment, as well as inclusion of non-energy CO_2 emissions
- Near-term policy announcements such as the Renewable Energy Strategy, DECC's policy on new coal-fired capacity and indeed the acceptance of the Committee's recommended emissions budgets to ensure the near-term aspects of this MARKAL analysis are up to date

Secondly, to systematically investigate key mid-term uncertainties in achieving long term UK decarbonisation targets requires alternate analytical approaches within an energy systems framework. To respond to this, UCL has developed a Stochastic UK MARKAL model. This retains the strengths of the technological detail, energy systems coverage and demand response of the existing model, but relaxes the assumption of forward looking model solutions. The major benefit in the new stochastic MARKAL model is a two stage stochastic decision (based on expected cost) where key parameters are made explicitly uncertain and in a first stage the model pursues *hedging strategies* based on the weighted costs of future (uncertain) outcomes. These uncertainties can include technology costs and characteristics, external drivers such as resource prices, policy drivers such as target stringency or complementary renewable polices, or consumer demand changes and prices responses. In a second stage the stochastic model then gives multiple *recourse strategies* as the model reacts to different outcomes of the uncertain variable(s). As well as generating insights into the optimal evolution of the UK energy-economic system under considerations of uncertainty (e.g., issues of path dependency), the expected value of perfect information (EVPI) can also be calculated. Thus stochastic MARKAL represents a new and insightful tool for the CCC to support long-term energy-economic systems analysis of long term decarbonisation targets.

The scenario selection process was iteratively undertaken through a ten month period, and reflected key uncertainties of interest to CCC, inclusion of findings from complementary analysis of key issues, and insights from the outputs of prior runs. Note that just one reference scenario to aid comparison between scenarios. The individual scenario changes are therefore included with the policy package for CO_2 mitigation and are included only in the relevant sensitivity scenarios.

Four core runs were developed (section 5). These encapsulated two key elements that CCC wished to explore; i) the severity of a UK CO_2 target that may be necessary and ii) the inclusion of a bundle of policy measures consistent with the ‘Extended Ambition’ target specified by the Committee.

Following the definition of the four core runs, eight Phase 1 sensitivity runs (section 6), comprising both deterministic and stochastic scenarios were run, mainly off the COR1-C90-S scenario (90% CO_2 reduction and no extended policy assumptions). These explored less severe and more severe CO_2 reduction targets, uncertainties surrounding CO_2 targets, fossil fuel prices, CCS availability, and uncertain fossil fuel prices in combination with different assumptions on biomass availability.

Iterative discussion following these Phase 1 scenarios generated feedback from the CCC leading to a revised set of assumptions for Phase 2 (see section 8). In the interim period a further eight sensitivity runs (section 7) explored uncertain fossil fuel prices, modulated electric vehicle uptake adoption of hydrogen as a transport fuel, and heat pump uptake and solid wall insulation mainly based on the (extended ambition, 90% CO_2 reduction) COR3-C90-S scenario.

A new core run for Phase 2 was developed over three runs that explored the effects of new technologies such as industrial CCS, grid injection of bio-methane as well as modified hurdle rates to represent the investment barriers seen by different actors of the energy system. From this 90% CO_2 reduction run (P2-R3-HUR-C90-5), the final nine sensitivity runs covered bio-energy, build rates, uncertain fossil fuels prices and uncertainty over biomass availability in combination with approximations of the lifecycle emissions from biomass.

In all, 32 full scenarios were delivered to the Committee on Climate Change (see Table 18). However given the multiple recourse strategies from the stochastic variant runs this amounted to 73 output runs. This give a highly detailed and rich narrative on the interactions and uncertainties of stringent UK decarbonisation pathways. Distilling such a detailed modelling outcome is challenging, however results from the 32 different scenarios included in this project give rise to a number of emergent themes. The results sections (5-8) detail for comparable runs; firstly the links, synergies and trade-offs via the interconnectedness of the energy system elements (sectors, energy chains, and supply vs. demand side measures), secondly the resilience, flexibility and uncertainty of consistent elements required to meet stringent decarbonisation pathways, and thirdly the scope of alternate supply and demand (technology and behaviour) mitigation measures.

In overall conclusion, five key findings from the broad scope of scenarios from this energy-economic modelling analysis project are:

- UK energy policy makers must be cognisant of a range of external drivers that they have only peripheral control over and which will have profound effects on the achievability and costs of stringent energy decarbonisation. These include fossil fuel prices, biomass imports, technology development and the scale of UK emissions reductions required in a global mitigation context

- There are a range of final configurations of a decarbonised energy supply with alternate elements of supply-side energy resources and secondary infrastructures (electricity, heat, hydrogen and liquid fuels), together with demand-side technology adoption and behavioural change. However, all deep decarbonisation scenarios require elements of change in supply and demand – i.e., technology and behaviour
- The stringency of deep decarbonisation targets means that there are essential (or robust) elements of decarbonisation strategies in the mid-term with either limited flexibility to exclude and/or expensive implications of not including. These elements include investment in low carbon electricity, technological change in transport, implementation of buildings conservation options, and behavioural change to moderate demand requirements
- Stringent decarbonisation targets options means that smaller emissions sources become increasingly important and need to be addressed by policy makers. Examples in the energy sector including industrial process emissions, residual emissions from CCS applications, emissions from essential consumer buildings energy service demands, and emissions from smaller transport modes (e.g., aviation).
- The aggregate welfare costs of stringent emissions reductions are substantial, amounting to a median value of £30 billion (in £2000), by the year 2050. However, the wide range of model variants indicate a very substantial variation in welfare costs – by of a factor of four or more. Disaggregated parameters – including the change in energy costs through marginal CO_2 values, and the role of sectors, resources and technologies – could see even greater variation. The continuation of iterative energy system analysis – using a range of modelling techniques – can shed further light on the response of consumers, feasibility of change in specific sectors, and impacts on the broader economy.

Contents

List of Figures

List of Tables

1 Introduction

1.1 Background and context

The Committee on Climate Change (CCC) was set up to provide advice to the Government on a range of issues, including setting legally binding carbon budgets for five year periods beginning from 2008, and a target for emissions reductions in 2050. In its first report (Committee on Climate Change, 2008), the Committee concluded that climate change poses a huge threat to human welfare, and the UK must act now to significantly reduce greenhouse gas (GHG) emissions by 34% by 2020 (or 42% by 2020 following a global deal) and 80% by 2050. CCC's advice was based on a review of the science of climate change, the international context, the UK's existing commitments, and an assessment of the costs and abatement potential associated with different measures.

CCC will provide advice on the 4th carbon budget, covering 2023-27, in December 2010. As part of that advice, the Committee is undertaking analysis on the feasibility, costs and trade-offs of alternate pathways towards meeting the 2050 target.

Committee on Climate Change (2008) recommended an 80% emissions reduction target for 2050 for all Kyoto GHGs including those from international shipping and international aviation. As noted in that report, an overall 80% target for all GHGs may mean a reduction in UK energy system CO_2 emissions of much closer to 90%, depending on what one assumes about the long-term path of emissions from aviation, shipping and non-CO_2 GHGs. That report also set out possible pathways to meeting the 2050 target, drawing on analysis undertaken using the MARKAL model of various emissions trajectories and technology sensitivities (Pye et al. 2008)

Since 2003, UK MARKAL has been used to assist policy makers (BERR, 2003; BERR, 2007; DEFRA, 2007; Department of Energy and Climate Change, 2009) through an iterative process with the model developers and academic research partners (Strachan et al. 2008c). UK MARKAL was developed primarily through funding from the UK Energy Research Centre (www.ukerc.ac.uk), with additional funding via policy related project as noted above, the UK Sustainable hydrogen energy consortia (UKSHEC) and the Japan-UK

Low Carbon Societies Project. The UK MARKAL model has been the basis for a number of peer reviewed journal publications (Anandarajah & Strachan 2010; Kannan & Strachan 2009; Strachan et al. 2008a; Strachan et al. 2008b; Strachan et al. 2009) including the development of macro and spatially enhanced model versions. Under the UKERC project, UK MARKAL was subjected to peer-review (Martinus, 2006), the model assumptions critiqued in a series of stakeholder workshops (Kannan et al. 2007). A subsequent major study – UKERC Energy 2050 – further enhanced the technological description in the model (Anandarajah et al., 2009), including the development of an elastic demand version of UK MARKAL.

Such an iterative energy model development and subsequent policy analysis (as detailed in (Strachan et al. 2008c), has provided a good analytical grounding for the CCC's examination of possible paths to meeting the 2050 target. However this project encompasses two areas of major development.

1.1.1 Model updates

Firstly, a series of model updates have been implemented. Some of these are following review of the UKERC Energy 2050 project (Anandarajah et al., 2009), and are detailed in section 3.1. Additional updates have been incorporated on request of CCC, relating to their stakeholder engagement exercises and to encompass insights from parallel analytical work. These updates are iteratively dealt with in two phases in the report and are discussed in detail in sections 0 and 3.3. These main areas of update are:

- imposing constraints (build rates) on the rate at which major technology classes are adopted
- the representation of bioenergy chains, including the use of biomass in capture storage and sequestration (CCS) applications to generate electricity with negative emissions
- Additional flexibility in the industrial sectors, including process based CCS; in previous model runs this sector can comprise around 40% of residual emissions by 2050

- the adoption of buildings sector technologies in terms of operation feasibility, notably heat pump technology given their unsuitability for some of the existing housing stock and in certain annual periods
- Model recalibration, including alternate discounting (using social discount rates) and subsequent hurdle rate adjustment, as well as inclusion of non-energy CO_2 emissions
- Near-term policy announcements such as the Renewable Energy Strategy, DECC's policy on new coal-fired capacity and indeed the acceptance of the Committee's recommended emissions budgets to ensure the near-term aspects of this MARKAL analysis are up to date

1.1.2 Investigate uncertainties

Secondly, to systematically investigate key mid-term uncertainties in achieving long term UK decarbonisation targets requires a new analytical approach within an energy systems framework. The large number of sensitivity runs carried out on long term energy scenarios for the CCC, UKERC and DECC in previous projects means there is less return in only pursuing more deterministic runs. This is particularly true in terms of undertaking conventional model runs under conditions of perfect foresight. To respond to this, UCL has developed a Stochastic UK MARKAL model. This retains the strengths of the technological detail, energy systems coverage and demand response of the existing model. The major benefit in the new stochastic MARKAL model is a two stage stochastic decision (based on expected cost or utility) where key parameters are made explicitly uncertain and the model pursues hedging strategies until such uncertainties are resolved. These uncertainties can include technology costs and characteristics, external drivers such as resource prices, policy drivers such as target stringency or complementary renewable polices, demand changes and prices responses etc. The uncertain variables can also be combined into integrated and consistency scenarios of key uncertainties. As well as generating insights into the optimal evolution of the UK energy-economic system under considerations of uncertainty, issues of path dependency, and the possibility of stranded assets, the expected value of perfect information (EVPI) can also be calculated. This represents a new and insightful tool for the CCC to support long-term energy-economic systems analysis of long term decarbonisation targets.

As a result of these two major areas of development, as well as a focus on more stringent CO_2 emissions reductions, this project (building on earlier energy systems modelling studies), is a core element of CCC's enhanced evidence base for its 4th Assessment Report.

1.2 Aims of the project

The aim of this project is to look at carbon abatement pathways through the 2020s, consistent with meeting the 2050 target, to inform Committee on Climate Change (CCC) consideration of an appropriate fourth period carbon budget of 2023-27. It also addresses perceived weaknesses or limitations of the long-term modelling performed for CCC in 2008.

The project has been divided into Phases 1 and 2, to facilitate iterative model analysis and development.

The core project aims were:

- To update the representation of a range of sectors or energy chains within the UK MARKAL model, e.g., inclusion of all relevant CCS options (electricity and process based); more detailed treatment of bio-energy chains; adoption of residential sector operational constraints
- To update the near-term constraints (i.e. out to 2020) in the model to reflect both policy developments and areas in which there is now greater understanding of deployment constraints, e.g. in the CCC's extended ambition scenario for wind and electric vehicles. These are categorised as "extended ambition" runs.
- To utilize a stochastic version of the UK MARKAL energy systems optimisation model; to relax the assumption of perfect model foresights and investigate the impact of key uncertainties in long terms UK decarbonisation pathways.
- In Phase 1 to undertake a set of four initial (deterministic) core runs for the overall path to 2050, to understand how these more stringent CO_2 emissions targets (-90%

and -95% reductions by 2050) react to the range of model changes and near-term policy ambition levels

- In Phase 1 to undertake a set of sensitivity runs (deterministic and stochastic) to investigate how key input parameter changes affect the model results and provide a assessment of key uncertainties and sensitivities.
- In Phase 2 to undertake further detailed model development work for CCC areas of key interest, to update and compare a new core C-90 scenario, and also to undertake a second set of deterministic and stochastic sensitivity analysis.

Examples of Phases 1 and 2 sensitivity runs (discussed in detail in sections 6, 7 and 8) include using different assumptions for CO_2 and other GHG emissions constraints, fossil fuel prices, availability of biomass resource, technology availability and costs in the 2020s, assumptions on the elasticities of energy service demands, sensitivities on renewable heat in different sectors, and sensitivities on transport uptake rates.

The process steps in undertaking this energy systems modelling project are:

- Explaining the UK MARKAL model updates and improvements (to version 3.24 in Phase 1 and version 3.25 in Phase 2), and the stochastic operation of the model
- Enabling the stochastic version of UK MARKAL; this builds on the fully functional model with its improvements as outlined above
- Changes to the reporting template to capture new data outputs, and stochastic information (expected costs)
- Definition of core and sensitivity run variables including detailed CCC input into defining the probabilities of key uncertainties
- Core runs, including an iterative calibration and analysis process
- Phase 1 and Phase 2 Sensitivity runs, including an iterative calibration and analysis process
- Report writing and presentation to CCC

1.3 Layout of this report

This report is laid out in 9 main sections. Section 2 details the underpinning deterministic and stochastic UK MARKAL models. Section 3 details the model updates for this latest CCC report, including updates and assumptions following the UKERC Energy 2050 report

(Anandarajah et al. 2009), and iterative updates for Phase 1 (version 3.24) and Phase 2 (version 3.25) to the UK MARKAL model. Section 4 gives a full listing of the scenarios undertaken in this project. Section 5 detail the four core model runs; C-90 and C-95 CO2 emissions with and without near term extended policy ambition. Sections 6 to 8 detail the Phase 1 and Phase 2 scenarios. Finally section 9 discusses main conclusions including drivers of model outputs and key policy insights.

2 Deterministic and Stochastic MARKAL Elastic Demand Models

The family of UK MARKAL models have a range of variants to allow alternate specifications of the UK energy system and/or alternate objective functions to be enabled. For example, (Strachan et al. 2008a) develops a MARKAL Macro variant which calculates the impacts of energy systems decarbonisation on the overall UK economy, while (Strachan et al. 2009) incorporates a geographical depiction of key energy infrastructures. In this CCC project two model versions are used: MARKAL Elastic Demand (MED) and a stochastic version of MED.

A more detailed description of MARKAL is given in the original model documentation (Loulou et al. 2004). Detailed assumptions on the UK MARKAL model are contained in Kannan et al. (2007), Anandarajah et al. (2009) and in section 3 of this report.

2.1 Deterministic MARKAL Elastic Demand

MARKAL (acronym for MARKet ALlocation) is a model generator that allow model developers to generate region-specific energy system models to analyse the tensions trade-offs between the energy-economic-environment and technology nexus. MARKAL is a widely-applied bottom-up, dynamic, linear programming (LP) optimisation model. UK MARKAL portrays the entire UK energy system, and in its elastic demand formulation maximises welfare (via the sum of producer and consumer surplus).

MARKAL portrays the entire energy system from imports and domestic production of fuel resources, through fuel processing and supply, explicit representation of infrastructures, conversion of fuels to secondary energy carriers (including electricity, heat and hydrogen (H_2)), end-use technologies and energy service demands of the entire economy. As a perfect foresight partial equilibrium optimization model, MARKAL minimizes discounted total system cost by considering the investment and operation levels of all the interconnected system elements. The inclusion of a range of policies and physical constraints, the implementation of all taxes and subsidies, and calibration of the model to base-year (2000) capital stocks and flows of energy, enables the evolution of the energy system under different scenarios to be plausibly represented.

The UK MARKAL model hence provides a systematic exploration of least-cost configurations to meet demands for energy services. These are derived from standard UK forecasts on a subsectoral level (Anandarajah et al., 2099). Generally these sources entail a projection of low energy growth, with saturation effects in key sectors. Other key input parameters are detailed in section 3 and include resource supply curves and dynamically evolving technology costs.

MARKAL optimises (minimises) the total energy system cost by choosing the investment and operation levels of all the interconnected system elements. The participants of this system are assumed to have perfect inter-temporal knowledge of future policy and economic developments. Hence, under a range of input assumptions, which are key to the model outputs, MARKAL delivers an economy-wide solution of cost-optimal energy market development. Substantial efforts have been made in respect of the transparency and completeness of the model structure and assumptions, including through a range of stakeholder events (for example Strachan et al., 2007b), expert peer review, and publication of the model documentation (Kannan et al., 2007)

A major development of the UK MARKAL model for the UKERC Energy 2050 project (Anandarajah et al., 2009) was the implementation of an elastic demand version (MED) to account for the response of energy service demands to prices. In MED, exogenously defined energy service demands are replaced with demand curves (actually implemented in a series of small steps). Following calibration to a reference case that exactly matches the standard MARKAL reference case, MED now has the option of increasing or decreasing demands as final energy costs fall and rise respectively. Thus demand responses combine with supply responses in an alternate scenario (e.g. one with a CO_2 constraint). In MED, demand functions are defined which determine how each energy service demand varies as a function of the market price of that energy service. Hence, each demand has constant own-price elasticity (E) in a given period. The demand function is assumed to have the following functional form:

$$ES/ES_0 = (p/p_0)^{E}$$

Where: ES is a demand for some energy service;

ES_0 is the demand in the reference case;

p is the marginal price of each energy service demand;

p_0 is the marginal price of each energy service demand in the reference case;

E is the (negative) own-price elasticity of the demand.

A combination of the proportional change in prices (p/p_0) and the elasticity parameter (E) determines when the energy service demand changes by the step amount. Note that changes in energy service demand also depend on the availability and costs of technological conservation, efficiency and fuel switching options. The price elasticities used in this analysis (ranging from 0.25 to 0.61) are long-run elasticities (due to the MED model's 5 year time periods and perfect foresight assumptions), and are derived from the literature of long-term energy modelling (see Anandarajah et al, 2009).

Now the MED objective function maximises both producer surplus (PS) and consumer surplus (CS). This is affected by annualized investment costs; resource import, export and domestic production costs; taxes, subsidies, emissions costs; and fuel and infrastructure costs as before in the standard model. However in addition the MED model accounts for welfare losses from reduced demands - i.e. if consumers give up some energy services that they would otherwise have used if prices were lower, there is a loss in utility to them which needs to be accounted for. Note that the MED model actually calculates the change in area under the shifted demand curve. The sum of consumer and producer surplus (economic surplus) is considered a valid metric of social welfare in microeconomic literature, giving a strong theoretical basis to the equilibrium computed by MARKAL.

Scenarios run using MARKAL Elastic Demand are deterministic. That is, only one result is obtained for any one set of inputs parameters.

2.2 Stochastic MARKAL Elastic Demand

The objective function of the stochastic MARKAL model is different to that in deterministic scenarios. It computes the expected cost of a scenario based upon a single average hedging strategy that minimises the cost of a probability weighted set of future scenarios. Thus, in addition to the solutions from MARKAL Elastic Demand, the model also computes equilibrium between 'here-and-now' decisions, that must be made before uncertainty is resolved and 'wait-and-see' decisions that can be delayed until better information is available (Hu & Hobbs 2009). Stochastic MARKAL is a 2-stage stochastic model, with the second stage specified as that in which the uncertainty is resolved. Up to this point, Stochastic MARKAL computes a hedging strategy, a social welfare maximising optimum based upon the resolution of multiple probability-weighted future scenarios. This hedging strategy is considered optimal and is solves one of the issues with deterministic models: multiple possible future strategies can be accounted for in just one model run. Analysis of hedging strategies can result in insights additional to those available through the comparison of multiple deterministic scenarios (Loulou et al., 2004).

Figure 1 shows a stochastic hedging strategy to the year 2010, with four separate recourse strategies from 2015 onwards. Note that the hedging strategy is not an average of the deterministic scenarios, but responds to the exponentially increasing costs under higher CO_2 caps. In this case, the value of a CO_2 cap is unknown until the 3rd model period. In contrast, under the assumption of perfect foresight, the dashed lines represent the optimum strategy when the emissions cap is known from 2000. The stochastic model allows a relaxation of the assumption of perfect foresight, quantification of future uncertainty through metrics such as the Expected Value of Perfect Information (EVPI) and insights into optimal near-term strategies that minimise the expected costs of future uncertainties.

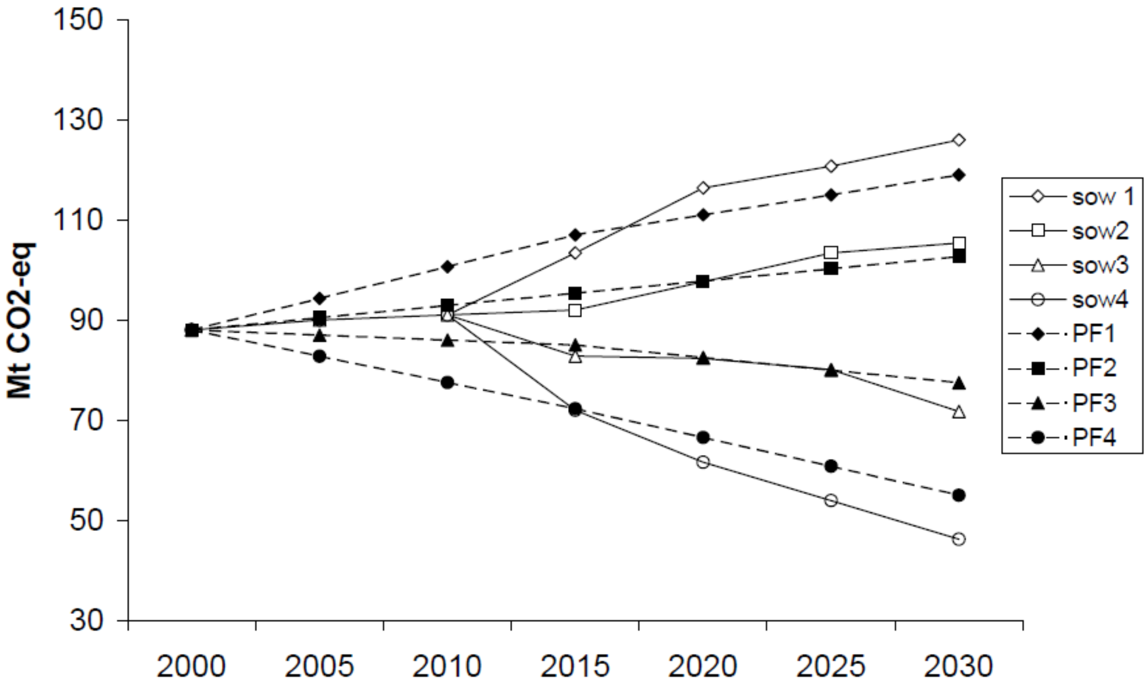


Figure 1: Stochastic and deterministic (perfect foresight) scenarios for four different values of a random variable, such as CO_2 emissions (Loulou et al. 2004)

3 Model key elements – updates and assumptions

3.1 Key Model Assumptions

This section demonstrates the range of the primary assumptions incorporated in the most recent version (v.3.24) of the UK MARKAL energy system model.

The UK MARKAL model is well recognised as a tool for the analysis of the UK energy system. As such, there is a detailed and comprehensive collection of documentation to which the reader is directed. See for example Kannan et al. (2007) for a description of the structure of the UK MARKAL model. Chapter 2 in Anandarajah et al. (2009) gives a good introduction and overview of the most recent version of the UK MARKAL model which has been recently updated with the changes listed here. Anandarajah et al. (2009) lists the updates to the UK MARKAL model and draws attention to the following list of core model drivers. These drivers are of fundamental importance to the operation and interpretation of the UK MARKAL model.

Table 1: Core conversion factors

Calorific values		**Source:**	**http://stats.berr.gov.uk/energystats/dukes07_aa.pdf**					
			Net	Gross	Conversion			
	Crude Oil	GJ/bbl.	5.8	6.1	95.0%			
	Coal	GJ/tonne	25.5	26.8	95.1%			
	Gas	GJ/cu.m.	35.8	39.8	89.9%			
GDP deflators		Source:	http://www.berr.gov.uk/files/file41491.pdf					
2000	2001	2002	2003	2004	2005	2006	2007	2008
100.00	102.20	105.30	108.60	111.40	113.90	116.90	122.30	123.90
Exchange rates		Source:	http://www.hmrc.gov.uk/exrate/usa.htm					
Unit	$/£	1.8						
Unit	€/£	1.4						
Physical conversion factors								
1 MTOE = 11.6 TWh = 48.9 PJ								

3.1.1 Resource supply curves

For this project, CCC provided four fossil fuel price scenarios, derived from Department of Energy and Climate Change (2010). As these scenarios only extend to 2030, the 2030 values were kept the same to 2050 for the purposes of this project.

Table 2: Fossil fuel price scenarios (2000£/GJ)

Scenario	Fuel	2000	2005	2010	2015	2020	2025	2030	2050
Low	Oil	4.12	9.35	4.58	5.31	5.50	5.50	5.50	5.50
	Gas	1.93	4.47	2.62	2.70	2.70	2.77	2.77	2.77
	Coal	0.91	2.97	1.62	1.01	1.01	1.01	1.01	1.01
Central	Oil	4.12	9.35	6.41	6.87	7.33	7.79	8.25	8.25
	Gas	1.93	4.47	4.47	4.85	5.16	5.47	5.70	5.70
	Coal	0.91	2.97	2.23	1.62	1.62	1.62	1.62	1.62
High	Oil	4.12	9.35	7.70	11.00	11.00	11.00	11.00	11.00
	Gas	1.93	4.47	5.39	6.40	7.47	7.47	7.47	7.47
	Coal	0.91	2.97	2.43	2.02	2.02	2.02	2.02	2.02
High High	Oil	4.12	9.35	9.44	13.01	13.74	13.74	13.74	13.74
	Gas	1.93	4.47	6.47	8.71	9.17	9.17	9.17	9.17
	Coal	0.91	2.97	2.63	2.63	2.63	2.63	2.63	2.63

Note that the availability of domestic resources is constrained from 2020 onwards, to ensure the model's resource prices are as above.

3.1.2 Biomass

Extensive updates to biomass energy chains and technologies have been implemented, taking key changes from a comprehensive review of the UK MARKAL model's biomass treatment (Jablonski et al., 2010). The main biomass chains have been broken out into wood, ligno-cellulosic crops, bio pellets (high and low quality), first and second generation bio-oils, bio-diesel, ethanol, methanol, bio-gases, bio-methane and wastes. The range of bio delivery options (oils, pellets etc.) are disaggregated to the industrial, residential and service sectors. Biomass boilers, utilising both solid and liquid fuels, are included for all buildings sectors. In terms of electricity generation, biomass-based CHP and electricity-only plants are updated, and further detail is added on enhanced co-firing to use different biomass fuels. Finally in the transport sector the extensive bio-energy chains have been added to with the option of bio-kerosene fuel chains and technologies for aviation (domestic and international).

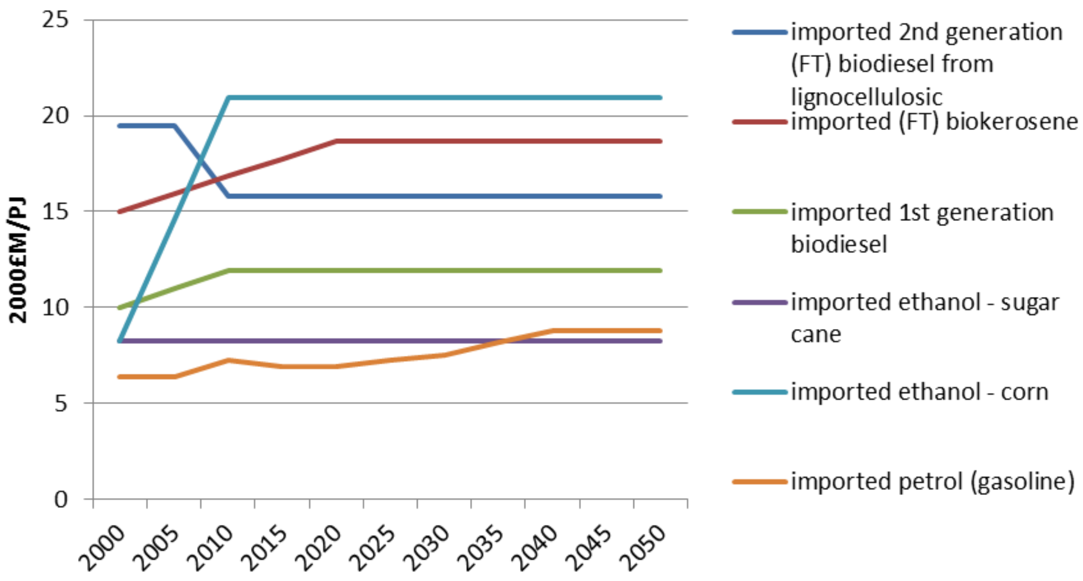


Figure 2: Resource Supply Curve for Imported Bio-alternatives to Petroleum Products (imported petrol shown for comparison)

Biomass imports compete with limited domestic resources with prices based on opportunity costs of available land, as given in Figure 2 and Figure 3 and discussed in Jablonski et al. (2010).

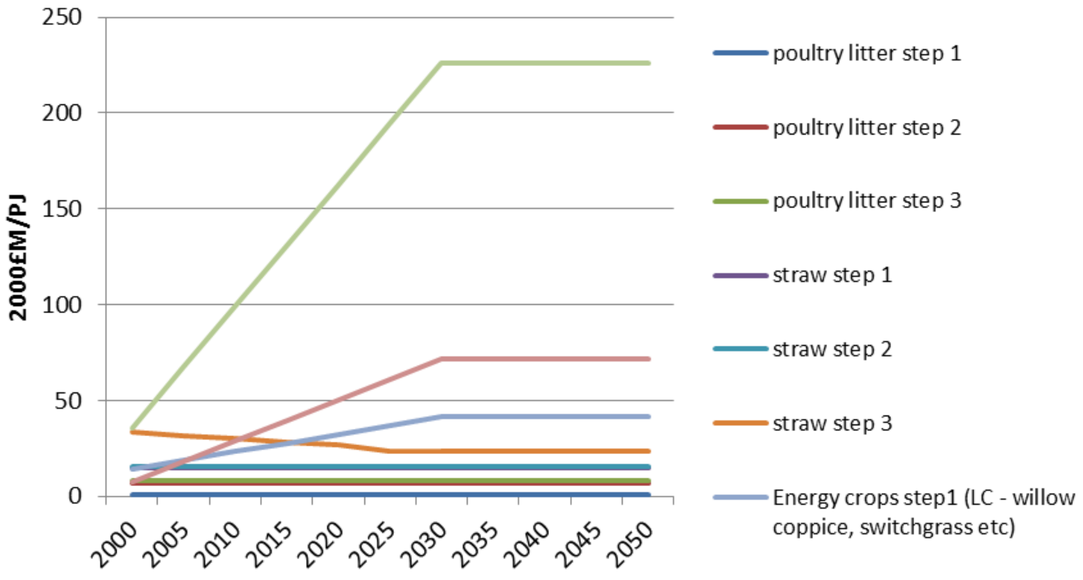


Figure 3: Domestic Resource Supply Curves for Biomass Wastes and Biomass Crops

3.1.3 Technology costs

For examples of technology cost, see Appendix 5 of the UK MARKAL documentation (Kannan et al. 2007). This table lists the primary electricity generating technologies included in the model. Recent updates have increased costs of CCS and biomass gasification plants, decreased all plant peak contribution, and reduced all plant availability factors. Future technology costs in UK MARKAL are based on expert assessment of technology vintages, or for less mature electricity and H_2 technologies via exogenous learning curves derived from an assessment of learning rates (McDonald and Schrattenholzer, 2002) combined with global forecasts of technology uptake (European Commission, 2006). Endogenous cost reductions from learning for less mature technologies are not employed as the relatively small UK market is assumed to be a price taker for globally developed technologies. The full set of upstream, power and heat, transport, industrial, commercial, agricultural, and residential technologies – together with their costs and source data – are listed in Kannan et al. (2007), with detailed assumption of updates for this report in sections 3.2 and 3.3.

For some technologies, exogenous assumptions for rates of learning are integrated into the investment cost assumptions. Table 3 shows an indexed comparison of investment costs for the technologies through time. Table 4 shows an indexed comparison of investment prices for hydrogen road transport technology vintages.

Table 3: Exogenous learning rates for renewable generation technologies

	2000	2010	2020	2030	2040	2050
Solar PV	100	66	44	36	30	24
Marine	100	91	82	75	55	41
Micro-wind	100	90	82	78	74	70
Offshore wind tranche 1	100	91	83	79	75	72
Offshore wind tranche 2	100	92	85	82	79	76
Offshore wind tranche 3	100	93	87	84	81	78
Offshore wind tranche 4	100	94	88	86	83	81
Onshore wind	100	90	82	78	74	70

Table 4: Technology vintage rates for hydrogen transport technologies

	2000	2005	2010	2015	2020	2025	2030	2040	2050
Buses	100	93	86	79	78	77	76	75	75
Cars	100	83	75	67	65	63	62	61	60
HGVs	100	80	70	59	57	54	53	50	47
LGVs	100	79	69	59	56	54	53	50	49

3.1.4 System Implementation

This refers to the characterisation of intermittency and variability of electricity generation within the model. Modelling intermittency within MARKAL is necessarily uncomplicated and is performed primarily through two parameters – contribution of the technology to peak electricity demand [PEAK(CON)] and availability or capacity factor, which can be disaggregated across the six seasonal time-frames (Winter/Summer/Intermediate & Day/Night).

For intermittent power technologies, using the example of tranches of wind resource technologies are differentiated by wind speed, with greater contribution of wind power to the electricity system providing a decreasing contribution to peak electricity demand (i.e. a declining capacity credit). A more detailed explanation can be found on page 17 of (Anandarajah et al., 2009).

3.1.5 Energy Service Demands

All energy service demand projections are the same as those reported in the relevant chapters of the UK MARKAL documentation (Kannan et al. 2007) except Domestic and International Aviation, which has been updated according to government projections (Department for Transport, 2009).

A new energy service demand for non-energy use of petroleum products has been introduced to account for the >500 PJ of energy equivalent used for chemical feedstock and other industrial and non-industrial uses such as lubrication. The energy service demand follows a similar pattern of growth to that of Other Industry, as the majority of non-energy use of petroleum products is for industrial consumption.

3.1.6 Demand elasticities

In MARKAL Elastic Demand, energy service demand elasticities define the energy service demand response to price. More detailed information can be found about this is section 2.1.2 in (Anandarajah et al., 2009).

The current elasticities are listed in Table 5 below.

Table 5 Price elasticities of energy service demands

ESD Code	Sector and Description		Price Elasticity
AGR	Agriculture	Combined agriculture	-0.32
ICH	Industry	Chemical	-0.50
IIS		Iron & Steel	-0.35
INF		Non-Ferrous metals	-0.35
IOI		Other industry demand	-0.15
IPP		Pulp-Paper	-0.15
NONNRG	Non-energy	Aggregate of non-energy demands for commodities	-0.15
RCKH	Residential	Cooking	-0.33
RCL-N		Cooling	-0.31
RETC-E		other electrical appliances for Existing house	-0.31
RETC-N		other electrical appliances for New house	-0.31
RF##		Refrigeration	-0.31
RH-#-#		Space and Water Heating	-0.34
RLIT-#		Lighting	-0.31
SCK	Service/ Commercial	Cooking	-0.23
SCL		Cooling demand	-0.32
SETC		other electrical appliances	-0.32
SH-S		Space heating	-0.26
SH-W		Hot water	-0.26
SLIT		Lighting	-0.32
SREF		Refrigeration	-0.25
TA	Transport	air (domestic)	-0.38
TB		bus	-0.38
TC		car	-0.54
TF		rail (freight)	-0.24
TH		HGV	-0.61
TI		air (international)	-0.38
TL		LGV	-0.61
TM		marine (international)	-0.18
TR		rail (passenger)	-0.24
TS		shipping (domestic)	-0.18
TW		2-wheeler	-0.41

3.1.7 Policy variables

Policies are incorporated in MARKAL modelling through the imposition of constraints on processes, technologies, resources and emissions. It is possible to restrict penetration of technologies, or place lower or upper bounds on technology activity, capacity or investment. The range of UK policies in MARKAL is primarily based of legislated measures through the 2008 Energy Bill, and are detailed in Anandarajah et al (2009). Newer policy variable implementation is discussed in section 5.

When modelling using MARKAL, there is a balance to be made between the imposition of severe constraints and allowing the model to choose an optimal solution.

3.1.7.1 *Renewable Obligation*

The Renewable Obligation has been implemented in UK MARKAL. All generation technologies covered by the RO are constrained to a minimum of 15% of total electricity generation by 2020. In 2010, 8% of electricity is derived from renewable sources, rising to 13% in 2015 and 15% in 2020. However, the weighting of technologies through banded allocation of ROCs is not modelled.

3.1.7.2 *EU ETS*

The EU ETS is not modelled explicitly to prevent double counting with imposed domestic CO_2 emissions reduction and subsequent marginal pricing, but can be included in model runs through inclusion in the marginal price of carbon emissions.

3.1.8 Taxes and subsidies

3.1.8.1 *Climate Change Levy*

Details of the Climate Change Levy incorporated into UK MARKAL are listed in section 3.3 of chapter 9 of the UK MARKAL documentation (Kannan et al., 2007).

3.1.8.2 *Fuel Duty*

Transport fuel duty is levied at the same level as that specified in section 3.8 of chapter 8 of the UK MARKAL documentation (Kannan et al., 2007).

3.1.9 System and technology-specific discount rates (market vs. social)

3.1.9.1 *Global discount rate*

The global discount rate has been changed to 3.5%, to coincide with the UK Government's guidance of policy evaluation and appraisal (HM Government 2010).

3.1.9.2 *Technology Specific Discount Rates*

Hurdle rates are implemented on conservation and transport technologies. These are scaled down to compensate for the change in discount rate from 5% to 3.5%; 12.5% to 8.75% for conservation measures in both the residential and service/commercial sectors, 10% to 7% for public transport, 7.5% to 5.25% for battery and methanol private transport, 7.5% to 5.25% for hybrid private transport modes and 10% to 7% for hydrogen private transport modes.

In this project, hurdle rates were changed in Phase II (see 8.1.3) to reflect perspectives on differentiated actor investment risk, investment barriers or cost of capital.

3.1.10 Emissions constraints

The emission trajectories for C-80, C-90 and C-95 have been updated to reflect CCC 2020 interim targets, with an exponential decline to 2050 targets. Separate targets are in place for model runs with and without international emissions. All targets are relative to 1990 UK CO_2 emission of 592.4 $MtCO_2$ (619.4$MtCO_2$ with international aviation and shipping).

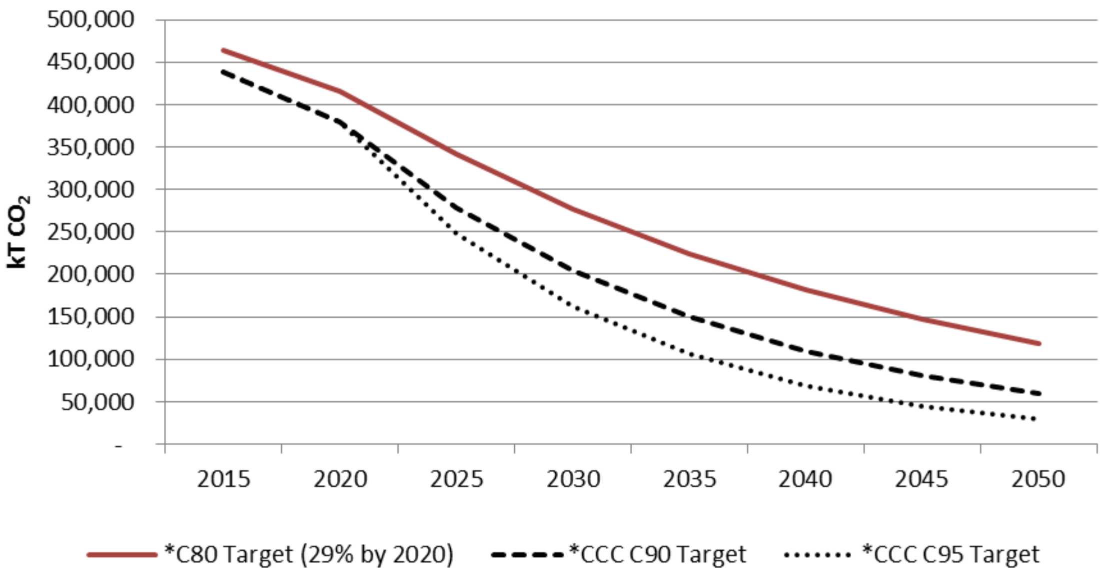


Figure 4 shows the CO_2 reduction trajectories used in this project

3.1.11 UK CCS resources

CCS resources have been updated since the previous version of the model to include the Utsira aquifer in the North Sea, available from 2030.

Table 6: CO_2 storage reservoirs available to the UK

Site of CO2 Storage	Cumulative maximum storage (ktCO2)	Annual maximum injection (ktCO2)
Aquifers (step 1)	5,043,000	
Aquifers (step 2)	5,043,000	
Aquifers (step 3)	5,043,000	
Enhanced Oil Recovery (step1)	350,000	
Enhanced Oil Recovery (step2)	350,000	
Oil / gas fields (high transport costs) (step 1)	267,000	
Oil / gas fields (high transport costs) (step 2)	267,000	
Oil / gas fields (high transport costs) (step 3)	267,000	
Oil / gas fields (low transport costs) (step 1)	1,567,000	
Oil / gas fields (low transport costs) (step 2)	1,567,000	
Oil / gas fields (low transport costs) (step 3)	1,567,000	
Utsira	15,000,000	53,700
Total	**36,331,000**	

3.1.12 Electricity T&D investment costs

The assumptions for the transmission and distribution networks are listed in section 3.3 in Chapter 5 of the UK MARKAL documentation. Losses are assumed 1.5% for the transmission network and 6% for the distribution network.

3.1.13 List of technologies that are centralised, distributed or micro-generation

MARKAL distinguishes between electricity generation technologies by exposure to transmission investment and O&M costs, transmission losses, distribution investment and O&M costs and distribution losses or neither. Remote technologies have an additional cost to connect to the TT&D network. Centralised technologies export electricity onto the transmission network. Distributed technologies are those that export electricity onto the distribution networks, therefore bypassing the losses incurred through transmission. Micro-generation occurs on, or near to, the site of consumption therefore resulting in no electricity losses from distribution.

For example, investment in micro-generation does not require the model to invest in grid reinforcement, whereas investment in transmission connected wind turbines will result in parallel investment in grid reinforcement and reoccurring O&M costs for the use of the electricity network.

The technologies listed in the updated Appendix 5, included with this document, are signified as centralised, distributed or micro-generation by the letters C, D or M.

3.1.14 List of core CHP and district heating technologies

It is possible to characterise co-generation in multiple ways in MARKAL. In the UK MARKAL model, district heating technologies are those that provide heat only to low-temperature district heating networks. CHP plants are also specified that generate both electricity and low-temperature heat for district heating. CHP plants that represent industrial auto-generation, the production of high temperature heat (steam) and electricity, are also included.

Details of the CHP and District Heating plants are included in the updated Appendix for Chapter 5 of the UK MARKAL documentation (Kannan et al. 2007).

3.1.15 H_2 distribution costs by mode (scale and distance)

Hydrogen is divided into three subsets of the hydrogen energy vector, liquid hydrogen, large gaseous hydrogen and small gaseous hydrogen. Liquid hydrogen is transported using tube trailers. Large-scale gaseous hydrogen is delivered via pipelines or in tube trailers. Small gaseous-hydrogen is produced at the site of use. It therefore incurs no transmission costs or losses. Full details of the updates made to hydrogen infrastructure and processes in the UK MARKAL model can be found in (Joffe et al., 2007).

3.1.16 EU-UK electricity imports

The Pan EU TIMES model (PET) of IER Stuttgart has contributed a projection of future electricity imports for the UK, based on anticipated power flows in the entire EU network.

Table 7: Imported UK electricity flows (PJ)

		2000	2005	2010	2015	2020	2025	2030	2040	2050
Total net Imports	TWh	14	9	6	26	32	32	32	29	26
	PJ	51	31	22	93	116	116	116	106	94

3.1.17 Conservation uptake constraint

Minimum uptakes of various conservation measures, such as tank insulation, lighting, cavity wall insulation and double-glazing are constrained into the model, with an upper cap for total uptake of energy conservation measures derived from CCC assumptions.

In MARKAL, energy conservation measures are modelled using dummy technologies. These technologies deliver an energy service demand (actually a reduction in energy to deliver the same energy service demand) but with no fuel input. More information on conservation technologies in UK MARKAL can be found in chapters 6 and 7 of the documentation (Kannan et al., 2007).

Note that in the latest version of the model, conservation potential is limited according to following constraints based upon assumptions from the Committee on Climate Change.

Table 8: Residential Conservation Measures (maximum PJ/annum)

	2005	2010	2020	2030	2040	2050
Heating controls - upgrade with boiler replacement	2	4	8	9	9	9
Heating control extra	1	2	4	6	6	6
Residential cavity insulation (Pre- 76)	22	43	78	86	86	86
Residential cavity insulation (Post- 76)	2	5	8	9	9	9
Residential Double glazing windows	17	34	62	166	166	166
Draught proofing (2010)	2	4	9	13	13	13
Residential floor insulation	2	4	10	23	23	23
Residential loft insulation measures - 250 mm	2	3	8	8	8	8
Residential loft insulation measures - 150 mm	7	14	27	27	27	27
Residential Solid wall insulation	8	16	72	239	239	239
Residential efficient lighting (CFL retail) (EEC2005-2008)	1	3	11	11	11	11
Appliances - Set top box	0	0	0	0	0	0
Residential Hot water cylinder insulation 75 mm	2	4	8	12	12	12
Residential Hot water cylinder insulation 50 mm	1	1	3	7	7	7

Table 9: Service Conservation Measures (maximum PJ/annum)

	2005	2010	2020	2030	2040	2050
IRC Tungsten-Halogen - Spots	0	0	1	3	3	3
ECG CFLs Replace Tungsten Lamps	1	1	2	10	10	10
16 mm Fluorescent Tubes Replace 26mm	0	0	1	3	3	3
Metal Halide Floodlights	0	0	0	1	1	1
HF Ballast	1	2	3	21	21	21
Basic Lighting Timer	1	2	7	24	24	24
Sunrise-Sunset Timers	0	0	1	3	3	3
Most EE Freezer	0	1	1	2	2	2
Most EE Fridge	0	1	1	1	1	1
Most EE Fridge-freezer	0	0	0	0	0	0
TRVs Fully Installed	8	16	25	33	33	33
Most EE Pitched Roof Insulation	1	2	5	26	26	26
Most EE Flat Roof Insulation	2	3	8	29	29	29
Most EE Cavity Wall Insulation	0	1	1	23	23	23
Most EE Double Glazing	0	0	0	139	139	139
Most EE External Wall Cladding/Insulation	0	0	0	40	40	40
Programmable Thermostats	4	7	23	70	70	70
Optimising Heating Start Times	1	2	8	24	24	24

Total investment in conversation measures are governed by a global constraint derived from DEFRA estimates of total conservation installation rates:

Table 10: Upper constraint to conservation measures in residential and service sectors (PJ per 5-year period)

Sector	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Residential				114.8	120.3	134.5	148.5	164.0	181.1	200.0	220.8
Service	0.0	5.0	7.1	10.2	14.65	20.9	29.9	42.9	61.4		

3.1.18 All key build rate constraints

In the power sector, these apply to generation capacities, which hold the majority of capital costs and are in the following categories - large coal (conventional and CCS), large gas, CCS (coal and gas), wind (on and off shore), nuclear, marine (tidal and wave), distributed generation (gas, H_2 and micro wind). We initially proposed that the rates be set at, until 2030, - 1GW pa per technology class and from 2030 - 2GW pa per technology class (see section 3.2.1.3 for more information).

Following consultation with the Committee on Climate Change, after examination of the first model runs, build rates were revised down to the following values in the earlier periods of the model.

Table 11: Build rate constraints for main generation technologies (e.g. nuclear, large coal)

	2000	2005	2010	2015	2020	2025	2030	2035-2050
GW per 5 year period	2.5	2.5	2.5	2.5	2.5	5.0	7.5	10

The Committee believed the near term build rates to be unrealistically high, especially for nuclear, marine and CCS as MARKAL averages 2.5 years each side of a given year rather than a 'snapshot' of a given year.

Large gas is constrained by an upper bound of 2.5GW pa, the peak building rate seen in the 'dash-to-gas' in the 1990s. An existing constraint ensures that gas generation cannot account for more than 50% of total electricity generation in any period.

Distributed generation is constrained to a rising fraction of the electricity sector, from 10% in 2000 to 20% in 2030. This constraint is intended to represent the grid management/security issues with incorporating distributed generation onto the electricity network.

3.1.19 Limits on heat pumps, night storage heaters, solar heating

Heat pumps are currently constrained to a maximum of 30% of total residential heating activity, with no new heat pump investment allowed until 2010.

Night storage heaters are constrained to a maximum of 30% of all residential electricity used for space heating.

New upper constraints were imposed in the model for the CCC scenarios:

Table 12: Upper bounds on heat pump activity

PJ/annum	2010	2015	2020	2025	2030	2035	2040	2045	2050
Upper bound on residential sector heat pump activity	1	8	39	72	131	237	431	781	1417
Upper bound on service/commercial sector heat pump activity	3	23	119	168	237	334	470	662	933

New upper bounds were also imposed for solar heating:

Table 13: Upper bounds on solar heating

PJ/annum	2010	2015	2020	2025	2030	2035	2040	2045	2050
Upper bound for service sector solar heating (hot water, district heating)	0	1	3	4	4	5	7	8	10
Upper bound for residential sector solar heating (hot water, district heating)	1	7	17	21	28	36	46	59	76

3.2 Exposition of Phase 1 Model Changes

The previous section detailed the changes undergone since the UKERC 2050 Carbon Pathways report (Anandarajah et al. 2009). For this project a further set of changes were made following supporting analysis by CCC and are incorporated for Phase 1 runs (sections 5 and 6). These changes are subdivided into three sections.

- Updates made due to new data are listed first. These include responses to criticism of previous versions of the model.
- Secondly, this document lists the updates that extend functionality of the model and what this new functionality includes.
- Listed lastly are changes to the model necessary to recalibrate to the updated DUKES energy statistics and NAEI emissions inventory.

3.2.1 Model v. 3-24 changes due to new data

3.2.1.1 *CCS costs and efficiencies and start dates*

All CCS early vintage process and electricity technology's start dates have been put back to 2015. The start dates for all CCS storage options have been pulled forward to 2015.

CCS capture efficiency has been lowered from 90% to 85% from comparison with the EU PET model. Pulverised coal capital costs have been increased also from comparison with the EU PET model.

3.2.1.2 *CCS storage extension to full North Sea resources*

The CCS characterisation in the model has been extended to include the Utsira aquifer under the North Sea with transport at €4.6/tCO_2 based on a 730km, 20Mt/year pipeline and storage at €2.8/tCO_2 based on Utsira injection level as below.

Cumulative capacity is limited to 15 GtCO_2 - 42 GTtCO_2 overall storage and 35.8% share according to UK population relative to other North Sea Countries. Annual injection is limited to 53.7 MtCO_2 - 150 MtCO_2 overall injection and 35.8% share according to UK population relative to other North Sea Countries.

Generic CCS costs have also been updated to include transportation at €3-5 /tCO_2, storage at €0-8 /tCO_2, conversion to £/PJ, electricity costs separated out and CCS O&M costs at 15% of capital costs. Finally, cumulative CCS limits for the UK have been raised to 36 GtCO_2.

3.2.1.3 *Build rates*

In the power sector, these apply to generation capacities (which hold the majority of capital costs) and are in the following categories - large coal (conventional and CCS), CCS (coal and gas), wind (on and off shore), nuclear, marine (tidal and wave), distributed generation (gas, H2 and micro wind). The rates are:

- until 2030 - 1GW pa per technology class
- from 2030 - 2GWe pa per technology class

These build rates reflect both the ability of the supply chain to raise and commit capital, find qualified personnel, pass regulatory/planning requirements on a project basis as well as the requirements to sequentially upgrade the grid to accommodate these new resources. The build rates are stepped to reflect progress in underpinning capability to deliver.

These build rates are well below those imposed by the CCC in their inaugural report (Committee on Climate Change, 2008). These were set at 3GW pa through 2030 and 5GWe pa for 2030-2050. This was despite calls for lower build rates in the report's peer review (Strachan, 2008d).

In terms of historical data, the highest capacity addition in the UK was gas CCGT in the 'dash for gas', which averaged at 2.5GW pa from 1990 to 2000 - see Fig 21 in the CCC 1st annual report (Oct 09) supporting research by Pöyry on CCS Milestones to deliver large scale deployment in the UK by 2030 (Pöyry, 2009). As noted in this report, CCGT is an ideal case for quick expansion, being a proven technology, relatively low capital cost, quick to build and flexible in operation. Newer, less flexible plant would expect to have lower build rates. Hence, modelled investment in gas generation has a fixed upper bound of 2.5 GW per annum.

Looking at the UK as a whole (BERR, 2002, p.20) gives total UK capacity expansion at 2.5GW from 1950 through 1974 (12GW to 72 GW). Looking at nuclear and assuming a 70% load factor for generation (recent years has seen an improvement in load factors) the UK built on average at 0.36GW in the 1960s, 0.16GW in the 1970s and 0.38GW in the 1980s. The final choice of build rates is somewhat arbitrary but this 1-2GW step appears reasonable.

Outside the power sector, build rates are much harder to justify. We have considered both H2 and bio infrastructures (with bio a lower priority). However, not imposing build rates of bioprocess could unfairly bias the model in terms of replacement transport fuels. However, the uncertainties on bio fuels may not transcribe well to build rates if these are liquid or solid fuel replacements and can utilise existing (adapted) supply chains. A better process would be to examine the resources limitation of biomass - which has been updated following UKERC Energy 2050 but more detailed information and scenarios, could be put in following the reviews by Jablonski et al. (2010). The exception to using bio build rates would be if the constraint were linked to large process facilities.

On hydrogen, the only good historical precedent is the UK development of town and then natural gas. For the energy sector as a whole and the residential sector in particular the respective average annual changes were:

Table 14: Historic UK growth of natural gas

Year Range	Whole Energy Sector	Residential Energy Sector
1955-65	10.7PJ	6.6PJ
1965-75	92.1PJ	38.6PJ
1975-85	71.3PJ	40.1PJ
1985-96	54.1PJ	22.7PJ
1995-2006	137.3PJ	13.3PJ

The latter numbers show the dash to gas in the power sector.

Hydrogen may well, but not necessarily, be focused on the transport sector. In PJ terms, UK transport consumption was 1855PJ in 2000 falling to 1705PJ and around 1300PJ in most scenarios in 2050 reflecting efficiency gains. In most constrained scenarios, H2 grows to around 220PJ in around 15 years - i.e. a 15PJ pa growth rate. An arbitrary suggestion would be for a hydrogen growth constraint at 25PJ pa, or 125PJ per period, which corresponds to the average residential penetration of gas. This is not expected to be triggered.

Finally, given the existing process and distribution infrastructure in a system of expected flat or falling demand, and especially falling UK fossil production, we have not and do not intend to impose build constraints on the gas or oil sectors.

3.2.1.4 *Restricted 'floors' (25% decline) for behavioural change reductions*

The variation in energy service demand (ESD) changes under MARKAL Elastic Demand - the floor and ceiling that ESDs can fall or rise to under price rises or falls - is an arbitrary assumption. Due to concerns that under high CO_2 prices ESDs in certain sectors may fall below a justifiable threshold, such as residential heating below comfort temperatures, or industrial facilities unable to operate, then the following changes are made.

- All ESDs can only fall or rise by 25% - note this is the ESD movement and not the final energy demand
- All ESDs can change in 1% increments

3.2.1.5 *Distributed generation technologies*

DG is currently constrained to 20% of total installed capacity in 2030 rising in the linear fashion from 10% in 2000. No constraint is imposed on periods after 2030 to represent improvements in integrating distributed generation - i.e. distribution network reinforcement and adoption of smart grid technology. However, some distributed technologies, such as micro CHP, infer a positive benefit upon system security while others, like wind contribute more energy than capacity value (Strbac et al., 2007).

3.2.1.6 *Further biomass chain placeholders*

As described in Anandarajah et al. (2009), biomass chains have been updated extensively through Jablonski et al. (2010).

3.2.1.7 *Biomass CCS options*

Two new technologies have been created, both a CCS option from pure biomass, required under very stringent reduction scenarios. These are built off the later vintages for biomass gasification CCGT with new multipliers for the additional costs from conventional CCGT with CCS. See line 29a in the updated Appendix 5 of the UK MARKAL documentation (Kannan et al., 2007).

3.2.1.8 *Aviation energy service demand projections*

The parameters in version 3.24 include revisions of both domestic and international aviation energy service demands. These are in agreement with the forecasts in (Department for Transport, 2009) and result in a peak in aviation CO2 emissions around 2025 of 62.1 MtCO2 in the base case. After 2025, emissions reduce to around 55 MtCO2 and stay below 58 MtCO2 to 2050. Table 3.4 of (Department for Transport, 2009) shows the efficiency assumptions included in UK MARKAL, an average of 1.1% per annum improvement on fuel efficiency from technical and operational improvements between 2005 and 2030 and 0.75% per annum improvements beyond 2030. This results in an aggregate 31% improvement in fuel efficiency between 2005 and 2030 and a further 16.1% aggregate improvement from 2030 to 2050. However, beyond 2030, the majority of efficiency improvement of the fleet occurs through replacement of earlier, less efficient technologies. In line with this, further technology efficiency improvements due to newer aviation technologies are halted after 2030 with cost improvements only included. International flights become more efficient from 2020 onwards due to the introduction of blended wing technologies, which are assumed 10% more efficient than the non-blended wing technologies. Efficiency increases to 30% in 2050 mean that carbon emissions stay relatively flat despite increases in demand for travel.

A RESID parameter was added to the 2000 international aviation technology to force out the existing fleet to 10% of 2000 Bvkm by 2020. This simulates the replacement of ageing aircraft purchased before 2000.

As an indicative sense check, we can compare the forecast increase in terminal passengers with the forecast increase in billion aircraft kilometres. We might expect operational efficiency to increase the number of passengers carried per flight (decreasing the aircraft km per person), but if overall patterns of flying stay similar and are simply scaled up, then the percentage increases of both should be comparable. This is the case, with a 224% increase in terminal passengers, and a 243% increase in aircraft kilometres for both domestic and international aviation.

In comparison to previous versions of the model, the projections to 2050 for both international and domestic aviation have changed shape and increased slightly. The previous projections of international aviation demand showed a steep increase to over 2Bvkm by 2010 and then a less rapid increase to 3.25 Bvkm by 2050. The revised forecasts show a rapid increase to 3 Bvkm by 2030 followed by a less rapid increase to 3.5 Bvkm by 2050. The slower growth after 2030 is due to the DfT assumptions of airports reaching capacity and general saturation of the market. Domestic aviation follows a similar pattern, peaking at 1.4 Bvkm by 2050 up from 1.25 Bvkm.

In comparison to a recent report on aviation (Committee on Climate Change, 2009), UK MARKAL shows a doubling of fuel use from 2000 to 2030 under a base case. Under carbon-constrained scenarios, aviation fuel demand peaks in 2030 with the adoption of alternate aviation fuels.

3.2.1.9 *Solar technologies*

We increased lifetime of solar technologies to 30 years in response to a report (Jäger-Waldau, 2009).

Solar plant for district heating systems has been added as a technology option.

3.2.1.10 *Heat pump technologies*

All residential heat pump technologies now have a lifetime of 20 years. Later residential heat pump technologies (higher efficiency options) have had their investment costs lowered to be the same as their respective earlier vintages.

3.2.1.11 *Updated mid-term CO2 constraints to match CCC targets*

The emission trajectories for C-20, C-80 and C-90 have been updated to reflect CCC 2020 interim targets, with an exponential decline to 2050 targets. Separate targets are in place for with and without international emissions.

3.2.2 Model v. 3-24 extensions in functionality

3.2.2.1 *Substitution flexibility in industrial sector*

The industrial sector has an aggregated structure with fuel share equations designed to mimic inabilities to shift part of the demand in this heterogeneous sector. However, this fuel share equation has been found to be too restrictive in terms of residual emission under severe CO_2 constraints. For all relevant industrial sectors, the natural gas minimum fuel share constraints are moderated - this increases the flexibility of this sector to an acceptable standard.

3.2.2.2 *CHP and district heating treatment greatly enhanced*

New CHP and district heating technologies have been added to the model with corresponding improvements to the results template. Users can now view penetration of CHP into the electricity system and the proportion of electricity and district heating from each group of technologies.

3.2.2.3 *International aviation and international shipping as an option*

International aviation and shipping energy service demands have been reviewed and are available to be included in model runs. As mentioned above, corresponding CO_2 emission reduction trajectories are used when operating the model with international aviation and shipping.

3.2.2.4 *Residential and service sector conservation reorganisation*

Previous versions of the model included two different options for conservation technologies within the wider UK MARKAL model. This function has now been removed with the less conservative upper bound on conservation adopted as standard.

3.2.2.5 *CCS Retrofit technologies*

Two process technologies are placed upstream of a retrofit coal or gas plant technology, one a dummy pass-through that converts EHCO to EHCOCC with no efficiency penalty or cost. The other is the retrofitted CCS capture plant with all normal parameters (e.g. INVCOST, VAROM, FIXOM etc.) also outputting EHCOCC. The model can then build the retrofit coal plant and use the pass-through technology until CCS capture is required. It will then build the CCS retrofit plant and stop using the pass-through.

Retrofit coal plants have the same parameters as standard coal plants, but with an upper bound on building in the 2015 period to 1GW (to represent demonstration plants/prototypes). There are no constraints after this time. The model is free to choose each period, from 2020 onwards, whether to use the CCS retrofit process or the pass-through process, although if there was a carbon constraint imposed it is unlikely that the model would revert to using the pass-through technology. The CCS retrofit process has both a cost and efficiency penalty for the plant to which it is fitted – the model must invest in the CCS process and use more fuel to generate the same quantity of electricity.

3.2.2.6 *Backstop technology*

A backstop technology price (set at £5000/tCO_2) enables the model to solve under extreme scenarios (e.g. no biomass imports). This was defined and placed in the

PROC18 scenario. A similar process is used for a CO_2 international permit purchase price and constraint - although this is in a separate scenario (CO2PERMIT). Both carbon prices are defined as follows:

Table 15: Details of backstop technology and CO_2 permits

	Technology	Carrier	Emission	Secondary emission(s)	Price	Constraint
Backstop	CCC-B	CO2B	CO2BCKSTP	-CO2, -CON	£5000/tCO2	none
Permit	CCC-P	CO2P	CO2PERMIT	-CO2	from CCC 2009 central case	12.5% of 1990 levels ~50MtCO2

3.2.3 Model v. 3-24 calibration

3.2.3.1 *Model horizon reduced from 2070 to 2050 (with appropriate salvage values for late investments)*

Previous versions of the model included the periods beyond 2050 due for computational reasons. The latest version of UK MARKAL has removed these later periods in order to reduce the size and increase the speed of model solution. This is especially important when running the model in stochastic mode as this can take up to 10 times longer than standard MARKAL.

3.2.3.2 *Year 2000-2005 total, sectoral and fuel matching for final energy*

Primary energy is calibrated to within 1% in 2000 and 3% in 2005. For primary energy, the main discrepancy is through excess exports of petroleum products.

Final energy is calibrated to within 0.3% of DUKES 2000 and DUKES 2005.

3.2.3.3 *Year 2000-2005 total and sectoral CO2 matching*

Carbon Dioxide emissions match to NAEI statistics (NAEI 2008) in 2000 and within 3-4% in 2005, depending on the model constraints.

3.2.3.4 *Non energy CO2 emissions added, with placeholder for future CCC mitigation*

In order to calibrate the energy balance for primary energy, it is necessary to include the 514 PJ of petroleum and gas commodities used for non-energy uses such as feedstock or that are manufactured into another product (like plastics for example). Emissions from the non-energy use of products are not reported, although a small number of emissions do arise from the oxidisation of lubricants, and through gas feedstock use in the manufacture of ammonia.

Differences between MARKAL and the NAEI methodologies include the carbon dioxide emissions from industrial processes, such as sinter or concrete production, or other processes where the primary CO_2 emissions are not derived from the combustion of fossil fuels.

To account for this, the emissions factors applied to the feedstock are adjusted to match emissions from the non-energy sector (mainly lubricants and some feedstock) while the quantities of commodity remain the same in order to match the DUKES commodity balance.

The demand growth profile for non-energy products matches that of the Other Industry sector and has similar elasticities.

3.2.3.5 *Disaggregation of fuel CO2 emissions and linking of MARKAL CO2 emissions and NAEI reporting methodologies*

Model calibration is based on both fuel consumption and primary energy. This also matches with existing UK standardised record keeping methodologies for CO_2 emissions.

3.3 Exposition of Phase 2 Model Changes

3.3.1 Implementation of industrial and process CCS options

All values for industrial CCS are taken from the Element Energy (2010) report as provided by CCC. This report breaks out the potential for CCS into key sectors and then processes (e.g. high temperature heat) within these sectors for 70 sites surveyed through the UK. Owing to the aggregation of our industry sector, we have linked these onto our industrial sector classes. This has the added advantage of making the tracking of fuels and emissions easier as it occurs still at an upstream level, and avoids the need to rejig the results template which captures final industrial energy at the process level.

As requested by CCC, we have split out CCS emissions into industry and non-energy as per Figure 9 of the Element Energy (2010) report, and the process emissions by sector statistics from NAEI (2008). It is important to note that CCS-CO_2 and other emissions on fuel applications is in industry and on processes is in non-energy (as defined in MARKAL). However all CCS related energy vectors (e.g. INGA) are allocated to the industrial sector. This is because of the limited and strict fuel use in the non-energy sector (e.g. where the majority is in misc. oils). Any change to that mix (outside the defined bands on which price changes can substitute fuels) has severe implications for overall fuel use - especially considering that MARKAL only tracks coal and gas based CCS. And additionally, fuel use in the industry vs. non-energy sectors is equivalent and is really an accounting mechanism in the model.

Minor points include that there may be a rounding error in 2025-30 in comparing CCS-P vs. overall CCS or reservoir CCS. This is due to the model investing in industrial or process CCS one period before utilizing the CCS reservoir due to the requirement for capital investment and as it is then cheaper to invest in CCS equipment rather than conventional equipment for just a single period. Another minor point is that the template CCS-P includes hydrogen based CCS and hence can be higher than the process-industry 38.3 MtCO_2 amount.

Key assumptions include:

- Installation size limit of 50 ktCO_2 pa for CHP and 200 ktCO_2 pa for other industrial sites
- Central DECC fossil prices (as we use in the rest of the model)
- 10% discount rates with capital annualised over 20 years (we have adjusted these for our values of 3.5% and 25 years respectively)
- costs in £2009 - we have deflated these to £2000 using HMT deflator of 1.239
- Majority of industrial process investigated (not aluminium)
- 90% storage potential - we utilize 85%, and have made commensurate adjustments
- Total technical limit of 43MtCO2 by 2000 falling to 38MtCO2 by 2030. Note this is dependent on fuel input - e.g. sequestering coal as part of CHP gives a higher

storage than gas, and this is accounted for with 38MtCO2 as an upper bound in UK MARKAL

- Total CCS costs ranging from £30 to £250/tCO_2 - however the final (convex) part of the industrial MACC curve is dependent on very high costs for transport and storage which we calculate separately
- Average costs are (in £/tCO_2): Refineries (62), Iron and Steel (42), CHP or steam (36), Other (26) - we actually utilise the range given by Element Energy (see below)

Implementation details into MARKAL are:

- All capture data taken from Table 3 (p22) of the Element Energy report
- Assume CCS build constraints only apply to the power sector - as this constraint is already hit, industrial CCS would not be built
- We separately calculate fuel costs via electricity requirements - this is comparable to Element Energy's figures
- We utilise a standard calculation to put £/tCO_2 metrics in terms of equivalent annualised capital, fixed O&M and variable O&M - as all our CCS chains, 31% of costs are assumed to be fuel (electricity) and of the remainder this is split 85/15 between capital and variable costs. Standard yearly deflators, discount rates and currency conversions are used.
- We separately calculate T&S costs using our more sophisticated approach based on type, distance and depth. For the first 93% of CCS T&S our costs match theirs, the final part of their costs curve spikes to £65/tCO_2 whereas we have access to the Utsira North Sea formation
- We retain the CCS capture cost floor at Element Energy's learning rate of 68% of first of a kind costs for CCS capture (and do not go to their lower level (54% by 2050))
- Note that our capture costs are incorporated in the capture nodes, not the distribution of industrial gas or coal with CCS
- We have a high and low capture cost elements (-HI and -LO tracking technologies below), with a 50/50 split between them, in order to mimic the cost range given by Element Energy

- Coal sequestration options are assumed to be the majority for Iron and steel
- Gas and bio-methane options are assumed for fuel use in refineries and other industry (note this is implemented via a separate constraint [ICCS-NGA])
- CHP sequestration is tied onto Industrial steam, with a flexible source of feedstock (coal, gas, oil, wood, blast furnace gas)
- Process emissions (accounted in the non-energy sector) are attributable to cement, ammonia, ethylene, and a minority of iron and steel
- Potentials in 2030 are (in $MtCO_2$):
    - Iron and Steel: 9.5 industry ; 2.5 process
    - Refineries: 8 industry
    - CHP (steam): 10 industry
    - Other (cement, ammonia, ethylene): 8.2 process
- SIX new distribution technologies are used to allocate possible industrial CCS - SC14 coal; SG12 gas; SG13 bio-methane; SISTM-CCS steam; SX01 - gas based process; SX02 - coal based process
- EIGHT new CCS tracking technologies are used to funnel CCS through into the CO2 capture, transport and storage costs and emissions tracking. For industrial fuel, this is (coal and gas): CCS-CIR-HI; CCS-CIR-LO; CCS-GIR-HI; CCS-GIR-LO. For processes this is (coal and gas): CCS-CNR-HI; CCS-CNR-LO; CCS-GNR-HI; CCS-GNR-LO
    - These 8 tracking technologies are used instead of the conventional CCS process tracking technologies to differentiate between COH and COI tracking. Note however that all emissions are finally counted are process CCS - i.e. CCS---P. Also note the split in COI and CON for process based accounting purposes
    - Bounds (in PJ) placed on these technologies are converted from the MtCO2 as above (using the relevant carbon content of coal or gas)
- All technologies are implemented from 2025, with a lifetime of 25 years
- An extensive checking process was undertaken that all emission match (CO2, CO2 sectoral, CCS, CCS storage, CCS process vs. electricity)

3.3.2 Modified constraints on industrial, process and electricity CCS

Three overlapping constraints were implemented for the 2nd Phase II run for the CCC project.

1. Industry CCS - no uptake by 2025 and maximum build rates in each following 5-year period of 5 $MtCO_2$, 10 $MtCO_2$and then 15 $MtCO_2$, post-2040 build rates should be adding a maximum of 20 $MtCO_2$in any 5-year period
2. On CCS as a whole - combine the build-rate constraint pre-2030 with that for power, but then not doing so post-2030, i.e. power reverts to a 2 GW per annum build constraint regardless of industry CCS deployment
3. On electrical CCS - keep in the existing build-rate constraint

These constraints were implemented under the following Rule-based User Constraints:

- Build_CCS - the original build constraint on electrical CCS
- Build_CCSI - a constraint on CCS process emissions from coal and gas (including hydrogen CCS)
- Build-ACCS - a constraint on all (electrical and process) CCS

The rule-based constraints are weighted, as there is a constant relationship between the activity of the processes and the amount of carbon sequestered, but this changes according to the fuel consumed. Thus, the different weighting to the left hand side of the constraint are derived from the ratio of the gas to coal CO2 factor.
Note that five new Named Filters have been created. These are:

- CCS-P-G - gas process CCS technologies
- CCS-P-C - coal process CCS technologies
- CCS-E-G - gas electrical CCS technologies (power stations)
- CCS-E-C - coal electrical CCS technologies (power stations)
- CCS-P - all process CCS technologies

3.3.3 Including a bio-methane to gas grid option

All costs are taken from the CCC given report - DBFZ (2009). This work covers the upgrade process for biogas to bio-methane, using PSA (pressure swing absorption). Some notes on implementing:

- No compression costs are included - these are in the gas pipeline depiction
- No production costs of biogas are included - these are in the derivation of biogas (and landfill and sewage gas options)
- A 15 year lifetime is used - reflecting the corrosive nature of biogas impurities
- A 1km pipe network is assumed to connect to the gas pipeline
- Average plant size of 500m^3/hour is used
- The efficiency loss is 2.5%
- 90% availability is assumed – i.e. 7884 hours per annum
- Energy content of biogas fuels at 38.6MJ/m3 is used
- A conversion of 1.239 from 2009£ to 2000£ is used

Data is taken on capital and O&M costs from table 4 of the DBFZ (2009) report. It has been checked (and is consistent) to the Biosys-MARKAL model of Sophie Jablonski.

Process elements SB21, SB22, and SB23 have been changed respectively. SB06 has been removed as the bio-solid to bio-methane route is available via SB23.

For consistency, the cost of bio gasification (via AD processes) has been lowered in line with the DBFZ (2009) report (i.e. SB05).

3.3.4 Revised constraints on heat pump deployment

The lower bounds on biomass boilers, heat pumps and solar thermal heating have been removed in both the residential and service sectors. Investment smoothing constraints are placed on residential and service sector heat pumps to prevent investment spikes. A 70% maximum market share is applied to service sector heat pumps (in recognition of potential building types). The table below details the residential assumptions - taken from the Central CCC set of assumptions

Table 16: Revised constraints on heat pump deployment

Residential sector	2000	2010	2015	2020	2025	2030 - 2050
SWI # of homes	0.0	0.0	1.0	2.0	2.8	3.5
SWI PJ	0.0	0.0	29.8	59.5	81.9	104.2
Total conservation PJ	0.0	0.0	144.6	179.9	216.5	252.8
Upper % heat pumps	0.0	0.0	23.7	47.4	50.0	52.6

3.3.5 Inclusion of lifecycle emissions for non-waste bioenergy chains

In UK MARKAL, biomass resources include a range of solid, liquid and gaseous forms, which are subject to conversion processes or used directly in one of the five end-use sectors. To provide an approximation of the lifecycle emissions from bio-energy resources, emission factors have been applied to the extraction and import technologies. These emission factors are based upon a fraction of the fossil equivalent. For example, in Phase 2, scenario 6, solid biomass is subject to a 0.25 x 91.68 $kTCO_2$ / PJ emission. In Phase 2, Scenario 7, gaseous forms of biomass are subject to a 0.50 x 51.66 $kTCO_2$ / PJ factor (see 8.4 for the scenario description).

Table 17: Emission factors assumed for bioenergy lifecycle emissions

Fossil equivalent commodity	UK MARKAL Fossil emission factor ($kTCO_2$/PJ)	75% saving lifecycle emission factor for bio-energy ($kTCO_2$/PJ)	50% saving lifecycle emission factor for bio-energy ($kTCO_2$/PJ)
Natural gas	51.660	12.915	25.830
Coal	91.680	22.920	45.840
Diesel/Petrol	76.260	19.065	38.130

Lifecycle emissions were tracked at resource and at sector level, and further disaggregated by biomass type (solid/liquid/gas).

Note that there is a known small discrepancy in the emissions tracking which amounts to a total of 1-2 $MtCO_2$ in the sectoral representations of emissions. The discrepancy occurs because no effort has been made to account for the complex accounting required to apply differentiated emissions factors to processes that allow for conversion between solid, liquid and gaseous forms of energy carriers from energy resources. The binding emission factors are those at the resource, so the model will be giving the 'correct' result for the given assumptions. The bio-product chains in UK are very complex and would require further structural development to allow sectoral tracking of lifecycle emissions.

3.3.6 Revised hurdle rates

Modified hurdle rates were applied for the runs P2-R3-# onwards (see 8.1.3). These include:

- Power (and electricity CCS): 10%
- Industry (and industrial CCS): 10%
- Hydrogen (and process CCS): 10%
- Service: 10%
- Residential: 3.5%
- Transport vehicle technologies:
    - Cars and 2-wheelers: 3.5%
    - Buses: 6%
    - HGV and LGVs: 8.5%
- Not specified by CCC:
    - Aviation: 3.5%
    - Navigation: 3.5%
    - Rail: 3.5%

Hurdle rates were also applied to conservation technologies in relevant sectors (so 10% in commercial sector and 3.5% in residential sector). All CCS storage technologies have a 10% power sector hurdle rate assigned. Changes to hurdle rates were consistent with the rationale of a private sector discount rate of 10% and public sector discount rate of 3.5%.

Existing hurdle rates (8.75% for conservation measures in both the residential and service/commercial sectors, 7.00% for public transport, 8.75% for battery and methanol private transport, 5.25% for hybrid private transport modes and 7.00% for hydrogen private transport modes) are overridden by the new amended hurdle rates.

4 Scenarios

The Committee on Climate Change required a new set of scenarios to inform their advice to the Government on carbon abatement pathways through the 2020s, consistent with meeting the 2050 target.

Scenarios were designed to address the following:

- Previous scenarios conducted in the UK have not explicitly represented uncertainty in a systematic manner – new scenarios should use a stochastic model to quantify uncertainty
- Policy has changed since the previous modelling projects – new scenarios should reflect an updated policy landscape
- Understanding of technology pathways is improved – new scenarios should represent the latest knowledge of energy technologies
- The particular focus is on carbon abatement pathways in the mid-term e.g. 2020-2030 – scenarios should address this

Scenario design starts with the specification of the reference, or business-as-usual scenario. The reference case is important, because it is against the reference case that the costs of constrained scenarios are measured. All welfare costs in the following scenario descriptions are a relative measurement for comparison between scenarios. By definition, the change in welfare of the reference scenario is zero. However, the magnitude of constrained case welfare costs can be increased or decreased by altering the assumptions included in the reference scenario. For example, if a 20% CO_2 reduction was included in a reference scenario, then the welfare cost of an 80% CO_2 reduction scenario would be less than if the reference scenario did not include a CO_2 reduction.

For this project, the assumptions contained in the reference scenario are listed in section 3. Note that just one reference scenario (see the description of BM-REF-S in section 5.1) was used for the entire project to aid comparison between scenarios. The changes to hurdle rates, industrial CCS and inclusion of bio-methane are therefore regarded as the results of policy that are inseparable from CO_2 mitigation and are included only in sensitivity scenarios.

After agreeing a reference scenario with CCC, four core runs were developed. These included the main assumptions that CCC wished to explore, notably i) the severity of a UK carbon dioxide target that may be necessary and ii) the inclusion of a bundle of policy measures consistent with the 'Extended Ambition' target specified by the Committee. These runs (COR1-C90-S, COR2-C95-S, COR3-C90-S and COR4-C95-S), together with an overview of the assumptions they contain are found in section 5.

Following the definition of the four core runs, eight sensitivity runs, comprising both deterministic and stochastic scenarios were run, mainly off the COR1-C90-S scenario. These explored less severe and more severe CO_2 reduction targets, uncertainties surrounding CO_2 targets, fossil fuel prices, CCS availability, and uncertain fossil fuel prices in combination with different assumptions on biomass availability.

A provisional report containing the descriptions of Phase 1 scenarios generated feedback from CCC which fed back into a revised set of assumptions for Phase 2 (see section 8.1). In the interim period a further eight sensitivity runs (see section 7) explored uncertain fossil fuel prices , modulated electric vehicle uptake adoption of hydrogen as a transport fuel, and heat pump uptake and solid wall insulation mainly based on the COR3-C90-S scenario.

A new core run for Phase 2 was developed over three runs that explored the effects of new technologies such as industrial CCS, grid injection of bio-methane as well as modified hurdle rates to represent the investment barriers seen by different actors of the energy system. From this run P2-R3-HUR-C90-5, the final nine sensitivity runs covered bio-energy; build rates, uncertain fossil fuels prices and uncertainty over biomass availability in combination with approximations of the lifecycle emissions from biomass.

In all, 32 runs were delivered to CCC, with several exploratory run undertaken internally to assist in mapping out such a complex array of findings.

Table 18: Complete set of 32 model runs included in this analysis under Phase I and Phase II

#	Scenario Code	Scenario Description	Stochastic or Deterministic	Page
	PHASE I CORE RUNS			
0	BM-REF-S	Base case, social discount rate	D	50
1	COR1-C90-S	90% reduction in CO_2 emissions, no extended ambition, social discount rate	D	52
2	COR2-C95-S	95% reduction in CO_2 emissions without extended ambition	D	53
3	COR3-C90-S	90% reduction in CO_2 emissions, with extended ambition	D	56
4	COR4-C95-S	95% reduction in CO_2 emissions, with extended ambition	D	57
	PHASE I SENSITIVITY RUNS			
5	COR0-C80-S	80% CO_2 reduction	D	59
6	COR1-HF-C90-S	90% CO_2 reduction with high-high fossil fuel prices	D	61
7	COR000-C97-S	Extreme CO_2 reduction	D	63
8	CUMCOR1/2-C90/C95-S	Uncertain CO_2 reduction (C90/C95 cumulative equivalents)	S	**Error! Bookmark not defined.**
9	COR1-STOC-FF-#	Uncertain fossil fuel prices under central biomass imports	S	69
10	COR1-STOC-HBFF-#	Uncertain fossil fuel prices under high biomass imports	S	72
11	COR1-STOC-LBFF-#	Uncertain fossil fuel prices under severe biomass import constraint	S	72
12	COR1-STOC-CCS/NOCCS-#	Uncertain availability of CCS and uncertain fossil fuel prices	S	75
	PHASE 2 PRELIMINARY RUNS			

1	COR3-LOWGAS	Extended ambition, 90% CO_2 reduction with low gas prices and central fossil fuel prices	D	80
2	COR3-STOC-FF#-S	Extended ambition, uncertain fossil fuel prices	S	82
3	COR3-CUMC90-S	Extended ambition, cumulative emissions equivalent to 90% CO_2 reduction	D	84
4	COR3-CUM2030-S	Extended ambition, cumulative emissions equivalent to 90% CO_2 reduction, with additional straight-line emission constraint through 2030	D	86
5	COR3-T1H-FF[L,C,H,HH]-S	Uncertain fossil fuel prices, extended ambition, C-90 emission reductions with restriction on electric vehicles	S	88
6	COR3-T1NH-FF[L,C,H,HH]-S	Uncertain fossil fuel prices, extended ambition, C-90 emission reductions with restriction on electric vehicles and hydrogen as a transport fuel	S	91
7	COR3-HP1-FF[L,C,H,HH]-S	C-90 extended ambition except heat sector, alternate (lower SWI) assumptions on heat pumps and solid wall insulation, uncertain fossil fuel prices	S	92
8	COR3-HP2-FF[L,C,H,HH]-S	C-90 extended ambition except heat sector, alternate (higher SWI) assumptions on heat pumps and solid wall insulation, uncertain fossil fuel prices	S	95
	PHASE 2 CORE RUNS			
1	P2-COR3-ALL-S-2	Industrial CCS, bio-methane, solid wall insulation and heat pumps	D	97
2	P2-R2-NEW-C90	Like run 1, with lower wind uptake, 30% renewable energy target, constrained mid-term CCS	D	99
3	P2-R3-HUR-C90-5	Amended hurdle rates	D	102
	PHASE 2 SENSITIVITY RUNS			
4	P2-R4-INV-C90-0	Increased electricity sector investment costs	D	105
5	P2-R5-#	Stochastic biomass availability	S	109
6	P2-R6-#	Stochastic biomass availability with crude bioenergy lifecycle emissions at 75% saving of fossil equivalents	S	113
7	P2-R7-#	Stochastic biomass availability with crude bioenergy lifecycle emissions at 50% saving of fossil equivalents	S	113
8	P2-R8-HUR-CUMC90	Cumulative CO_2 constraint (equivalent to a C90 scenario)	D	118
9	P2-R9-BUILD	Power sector build-rate sensitivity	D	121
10	P2-R10-#	Stochastic fossil fuel prices on P2-R3-HUR-C90	S	124

11	P2-R11-LOWGAS	Central fossil fuel prices for coal and oil, low fossil fuel prices for natural gas	D	128
12	P2-R12-HUR- C95	95% reduction in CO_2 emissions	D	130

5 The four core runs

The Committee on Climate Change specified four core scenarios following a simple matrix shown in Figure 5.

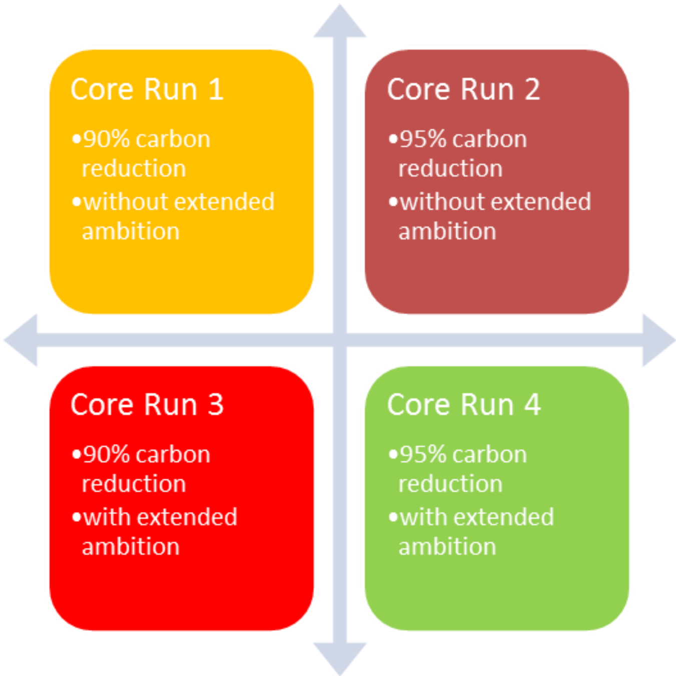


Figure 5: Phase 1 – Four core scenarios

The primary assumptions for the first two core runs are summarised in Table 19 below.

Table 19: Summary of the assumptions in the four core runs

Carbon Target	2050 target of -90% (59.3MtCO_2) and -95% (29.6MtCO_2), relative to 1990 emissions of 592.4MtCO_2 Equal annual reduction from 2020 target of 380.2MtCO_2 (35.8% reduction from 1990 levels)
Fossil Fuel Price	CCC Central scenario for oil, oil products, natural gas and coal; with no domestic fossil fuel production post 2020.
Extended Ambition	No CCC near-term (to 2020) extended ambition assumptions: (residential and service sector conservation, CCS demonstration projects, commissioned nuclear plants, commissioned wind plants plus relaxation of 2020's build rates, electricity vehicle uptake)
Biomass Imports	Central biomass import constraint (increasing to 1260PJ by 2050)
Renewable Heat Constraints	Constraints included on heat pumps and solar heating in the domestic and service sectors

The second set of core runs differ through the inclusion of the CCC extended ambition scenario. This is summarised in **Error! Reference source not found.**section 5.3.1. This revised set of CCC core runs are run with social (S) discount rates (3.5%) and corresponding hurdle rates.

The core runs have 2050 target of -90% (59.3MtCO_2) and -95% (29.6MtCO_2), relative to 1990 emissions of 592.4MtCO_2. The path consists of equal annual reduction from 2020 target of 380.2MtCO_2 (35.8% reduction from 1990 levels)

CCC Central scenarios are used for oil, oil products, natural gas and coal; with no domestic fossil fuel production post 2020 (Table 20). A central biomass import constraint is imposed (increasing to 1260PJ by 2050).

Table 20: Four fossil fuel price scenarios (2000£/GJ)

Scenario	Fuel	2000	2005	2010	2015	2020	2025	2030	2050
Low	Oil	4.12	9.35	4.58	5.31	5.50	5.50	5.50	5.50
	Gas	1.93	4.47	2.62	2.70	2.70	2.77	2.77	2.77
	Coal	0.91	2.97	1.62	1.01	1.01	1.01	1.01	1.01
Central	Oil	4.12	9.35	6.41	6.87	7.33	7.79	8.25	8.25
	Gas	1.93	4.47	4.47	4.85	5.16	5.47	5.70	5.70
	Coal	0.91	2.97	2.23	1.62	1.62	1.62	1.62	1.62
High	Oil	4.12	9.35	7.70	11.00	11.00	11.00	11.00	11.00
	Gas	1.93	4.47	5.39	6.40	7.47	7.47	7.47	7.47
	Coal	0.91	2.97	2.43	2.02	2.02	2.02	2.02	2.02
High High	Oil	4.12	9.35	9.44	13.01	13.74	13.74	13.74	13.74
	Gas	1.93	4.47	6.47	8.71	9.17	9.17	9.17	9.17
	Coal	0.91	2.97	2.63	2.63	2.63	2.63	2.63	2.63

The global discount rate has been changed to a social metric of 3.5%, to coincide with long-term UK government guidelines (HM Government, 2010). Hurdle rates are implemented on conservation and transport technologies. These are reduced in line with social discounting to 8.75% for conservation measures in both the residential and service/commercial sectors, 7% for public transport (battery buses, hydrogen buses and

HGV and LGV), 5.25% for private transport (battery, hybrid, plug-in hybrid, hydrogen, methanol).

5.1 Base Case, social discount rate (BM-REF-S)

- Primary energy decreases from the 2000 value of ~9500 PJ to ~8000 PJ in 2030, then increases to 8,100 PJ by 2050. Lower overall primary and final energy stems from more efficient transport options and higher conservation uptake as people make “more optimal” decisions under a social discount rate
- There is a transition from natural gas supplying the majority of primary energy to a coal based energy system, via low gas prices – this switch is both in terms of electricity and hydrogen production.
- Efficiency (esp. transport) improvements and adoption of conservation measures occur throughout the time horizon of the model and result in a gentle reconfiguration of final energy use, with a slightly larger amount of delivered electricity and less delivered natural gas.
- Wind, bio-wastes and other forms of renewable energy are adopted from the beginning of the model horizon, and make up roughly one third of electric capacity and 23% of energy by 2030, staying relatively constant to 2050.
- Due to oil savings in the transport sector, oil generation is retained through 2025. About 8 GW of new nuclear is constructed between 2025 and 2030, although this is less than before with reduced demand for electricity. Coal, gas, wind and bio-waste are the largest investment technologies, with an average of ~10 GW of new capacity installed in each period over the model horizon (~2 GW per year).
- CHP capacity increases 3 fold between 2010 and 2030, and supplies ~15% of electricity from 2025 onwards and 20-30% of annual residential heating requirement between 2020 and 2050.
- Transport fuel demand halves by 2030 largely driven by a significant proportion of cars moving early to petrol and diesel hybrids and then on towards electric power and LGVs towards petrol plug-in hybrid technologies. Rail is largely electrified by 2045.

- Biofuel and biomass consumption is largely driven by the RTFO policy, although 20 PJ of biomass is used in the residential or service sectors for heat. At most, biomass makes up <1% of final energy demand.
- CO_2 emissions reduce from 2000 levels to a trough of ~480 $MtCO_2$/year in 2030 before rising steeply to a peak of ~600 $MtCO_2$ in 2050. This is driven by high emissions in the electricity and hydrogen sectors

5.2 Core Runs 1 & 2: 90%/95% CO_2 reduction without extended ambition

5.2.1 Scenario Notes

To add to the assumptions included in the core runs, specific model updates were:

- Revised tracking of investment in CCS retrofit capacity. Note the general assumption that retrofitting activity is not to be included under the new CCS plant build rates.
- A second change was to disallow the take-up of hydrogen aircraft due to stratospheric warming impacts
- A third change was the inclusion of a backstop price (set at £5000/tCO_2) to enable the model to solve under extreme scenarios
- The Results template is updated, and includes calculation of CO_2 backstop and CO_2 international permit emissions

Additional model updates previously carried out for CCC are:

- Uptake of residential and service sector conservation technologies
- Uptake of heat pumps - short term restrictions on the uptake from AEA/NERA renewable heat scenarios with a geometric increase until the technical potential in 2050 (note this combines with a constant 30% upper limit for heat pumps in the residential stock)
- Retrofit options for CCS implemented via a dummy pass-through and a retrofitted CCS capture plant with all normal parameters (e.g. INVCOST, VAROM, FIXOM etc.). This is implemented for both coal and gas plants.

Costs are derived from the (Hoefnagels et al. 2010) model and (Metz et al. 2005)

- A small number of minor changes to parameters and constraint implementation in the model, as a number of minor updates to the results template.
- The RO and RTFO constraints are maintained at 15% and 5% from 2015 respectively. This represent the state of legislation under the 2008 Energy Bill, and not extended ambition under the low carbon transition plan

5.2.2 COR1-C90-S – 90% Reduction in CO2 emissions, no extended ambition, social discount rate

- By 2050, the primary energy flows are dominated by nuclear electricity (fossil fuel equivalent) and coal, with oil, biomass and wastes and renewable electricity (electrical output) providing the remaining third. Total primary energy follows a decline and then increase as the energy system follows first a transition to the optimally efficient technologies, followed by a second transition beyond 2030 as the system decarbonises.
- Conservation measures double between 2010 and 2020 then double again by 2050 to around 400PJ with a 33:67 split between service and residential sectors.
- Final energy demand declines significantly over the course of the model horizon to ~4,000 PJ in 2050.
- Electricity is a dominating decarbonisation pathway, rising from 1300PJ to 2900PJ despite a declining overall energy systems size
- Transport fuel demand is largely similar to the base case and is highly efficient (hybrid) in the mid-term moving to advanced (fuel and efficiency gains) drive-trains in the long term. Petrol and diesel vehicles are largely squeezed out in the latter periods of the model horizon.
- The later transport fuel mix is largely electricity (cars, buses), hydrogen (HGV, cars), plug-ins (LGV), traditional hydrocarbons (air, 2 wheels, some cars) and a

minor contribution from bio-diesel and ethanol/methanol (with bio resources (especially in the latter periods) being directed to the power sector.

- By 2050, CO_2 intensity of electricity is negative, with significant, co-firing CCS, nuclear and renewable resources providing energy. Biomass CCS is utilized in 2050. The capacity of the energy system is double that of the base case, largely due to the variable nature of renewable energy, while electrical energy generated is somewhat less than double the base case in 2050.
- Small amounts of coal CCS come onto the system between 2020 and 2030, largely through retrofitting 'CCS ready' plants although these are superseded by more efficient CCS (co-firing) plant. The model appears to use the retrofitted coal CCS as backup plant in the later periods, although gas plants (37GW) are a dominant back up option.
- The COR1-C90 electricity sector is larger than the base case from 2025 onwards, although greater quantities of electrical energy are generated until 2035.
- Conservation options (boosted by lowered hurdle rates) reach 400PJ by 2050
- Hydrogen production is gas SMR with CCS in the mid-term then electrolysis
- The marginal cost of CO_2 emissions reaches £100/tonne in 2025 and £300/tonne in 2050. Annual welfare costs reach £10 billion by 2030 and £30 billion by 2050

5.2.3 COR2-C95 – 95% reduction in CO_2 emissions without extended ambition

- In 2050, the primary energy sources in COR2-C95 sees a switch from CCS to nuclear compared to COR1-C90, with overall higher primary energy. The growth in nuclear, biomass and imported electricity is offset by a decline in coal and gas.
- Final energy sees a move away from petrol, coal, delivered heat (CHP/DH) and towards electricity, natural gas and hydrogen.
- Overall final energy falls further to 3970PJ, with industry accounting for the majority of the additional fall.

- The larger electricity sector (up 200PJ) send this additional electricity to the residential sector
- Electricity generation is achieved through an increased nuclear program, with an approximate 100% increase in energy generated compared to COR1-C90. Biomass CCS has a much larger role, displacing co-firing CCS. Wind, biomass, imports and marine make up the remainder of the generation in 2050, although renewable electricity is only 29% of generation. The electricity sector now contribute -46MtCO2 in 2050, compared to an economy wide target of +29MtCO2
- Gas CHP is a transitional technology – rising to 330PJ in 2030 but is largely marginalised (only 20PJ) by 2050, with residential and service sectors heat demand electrified through the use of heat pumps and storage heaters.
- Hydrogen is produced largely from electrolysis in 2050, although gas SMR technology is used in earlier periods when the problem of residual emissions is lower.
- In transport, traditional fossil fuels, bio-diesel and ethanol/methanol are marginalised towards the end of the period as hydrogen and electricity emerge as the transport fuel of choice. Compared to COR1-C90, cars see small boosts in H_2 and biodiesel vehicle, with LGVs seeing small gains in H_2 (from petrol hybrids)
- The majority of biomass is used in the transport sector, with a small amount for the provision of renewable heat in the residential sector. Biomass in the transport sectors is a transitional fuel – falling from 300PJ to only 50PJ by 2050
- Biomass is consumed between 2025 and 2035 in this scenario, slightly later than in COR1-C90 and later again than in the reference scenario. The quantity of biomass in final energy is also higher in this scenario ~1,600 PJ, compared to ~1,000 PJ in the COR1—C90 scenario and ~600 PJ in the reference case.
- Demand reductions are stretched out in 2050 in order for targets to be met, with most industrial sectors hitting the limit of a -25% change in ESDs,

together with increased reductions in residential sector ESDs and in aviation (the latter from -14.7% to -23.5%)

- In order to decarbonise in 2050 the marginal CO_2 costs are very high, rising from £230/tCO_2 in 2035 to £386/tCO_2 in 2045 and to £1415/tCO_2 in 2050
- The welfare cost implications compared to COR1 are less dramatic but still reaches £11.2 billion in 2025, £23 billion in 2035 and £43 billion in 2050.
- In terms of which build rates bite the hardest, in COR1-C90 it is CCS; in COR2-C95 it is nuclear

5.3 Core Run 3 & 4: 90%/95% CO_2 reduction with extended ambition

5.3.1 Scenario Notes

The extended ambition scenarios characterise technology-specific actions as detailed by the Committee on Climate Change. To analyse the effect of the chosen policies, the extended ambition scenarios have been compared with the first two core runs.

The assumptions are listed in the table below:

Table 21: Assumptions included in the CCC defined extended ambition scenario

Technology	Assumption	Notes
Electric Vehicles	1.7 million by 2025, 2.7 million by 2030 and held to 2050	
On-shore & offshore wind	26.6 GW by 2020 rising to 51 GW by 2030	
CCS	1.5 GW demonstration plants in an early period	Model chooses from a limited pool of early CCS technologies
Nuclear	2 GW new capacity by 2020 plus 1 GW new capacity by 2025	
Plug-in hybrid electric vehicles	4.1 million by 2030	
Biomass District Heating	3 PJ/annum by 2015 rising to 9.1 PJ/annum by 2025	Source for all renewable heat: (Radov et al. 2009) and CCC assumption
Biomass Boilers – Service & Domestic	~8 PJ/annum by 2015 rising to ~23 PJ/annum by 2025 with the majority of effort in the service sector	
Heat pumps	~41 PJ/annum in 2015 rising to ~120 PJ/annum in 2025 with a 2:1 ration between service and domestic sectors	
Energy conservation	CCC assumptions regarding mix of conservation technologies and availability	

5.3.2 COR3-C90 – 90% reduction in CO_2 emissions, with extended ambition

- This scenario sees the introduction of the CCC extended ambition scenario. The change in structure of the energy system is especially evident in the electricity sector as 26GW of wind turbines are introduced by 2020, rising to 51 GW by 2030. There is also 10 GW of extra gas capacity as backup for the 22 GW of extra wind turbines on the system.
- By 2050 the energy system looks similar to that in COR1-C90 with the exception of a switch of 270PJ from biomass to renewable electricity (with small declines in nuclear and oil)
- Comparing the electricity system size, COR1-C90 suggests that the cost optimal system is somewhat smaller than that in the COR3-C90 scenario, with approximately 25 GW less wind, and a corresponding reduction in backup plant.
- The change in the electricity system occurs in tandem with the introduction of battery electric and plug-in hybrid vehicles. These two technologies result in storage capabilities available to the electricity system. However, in comparison to COR1-C90, which sees ~200 GJ of storage from plug-in hybrid technologies, COR3-C90 sees electrical storage heaters and electric vehicles 'competing' for the provision of storage.
- The main change in final energy follows a now familiar pattern. Electricity use doubles, tradition fossil fuel sources decline. Hydrogen becomes a common energy carrier from 2030 onwards in the transport sector.
- The largest change in final energy demand occurs in the transport, residential and service sectors, with energy demand reduction accelerating from 2030.
- Transport energy demand reduction occurs through a step change in 2030 as the model adopts battery electric vehicles and hydrogen simultaneously. The extended ambition targets for electric vehicles and plug-in hybrids are dwarfed by the endogenous technology choices post-2030.

- In the mid-term additional electricity facilitate the use of petrol plug-in vehicle as a transition technology and in the long terms boosts the number of hydrogen vehicles (with H_2 from electrolysis)
- The level of CHP and district heating is less than that in COR1-C90, with greater electrification of residential heat and some uptake of residential solar water heating.
- Conservation uptake in the buildings sectors increases by another 70PJ to 470PJ
- In comparison to COR1-C90, annual welfare losses are ~£2.5 billion in 2020 and £1.3 billion in 2050 more costly – this reflects the model being made to select less optimal solutions than it otherwise would have chosen
- Marginal cost of CO_2 are generally lower (e.g. in 2020; £25/tCO_2 vs. £38/tCO_2 in COR1) as additional assumptions supplement the carbon price signal. By 2050 marginal cots are the same at £288/tCO_2.

5.3.3 COR4-C95 – 95% reduction in CO_2 emissions, with extended ambition

- Comparing extended ambition under a C95 constraint (COR4 vs. COR2) is a similar story to that of a C90 comparison (COR 3 vs. COR1). Wind is the largest change and the model overall sees a shift from nuclear and coal towards renewable electricity
- Final energy levels are similar, but with additional hydrogen from electricity (30PJ) and an additional 40PJ biomass owning to constraints in the service and residential sectors
- The marginal price of CO_2 emissions reaches £400/tonne in 2045 and more than £1,600/tonne in 2050. This is in the same range as COR2-C95 which indicates that it is the severity of the carbon constraint that causes the very high marginal price of CO_2 and not the extended ambition scenario. With additional effort being taken up by other changes in the extended ambition case it sees low marginal CO_2 prices in 2025-2045).

- Welfare losses due to the imposed extended ambition constraints are an extra £1 billion in 2020 and £3 billion in 2050, amounting to a cost of £44.8 billion in 2050
- The model chooses the optimal configuration of storage devices from plug-in hybrid vehicles (including battery electric vehicles) and storage heaters, with pumped hydro contributing a little. In COR4-C95, we see 20 PJ less storage than in COR3-C90 and more from electric and plug-in vehicles to storage heaters and heat is progressively electrified from 2030 to 2050.
- Extra conservation measures, largely in the service sector, boost overall conservation to the extended ambition limit of 470PJ by 2050.
- Unlike COR2-C95, ethanol/methanol transport fuel play a relatively minor part in the transport fuel mix, with a greater emphasis on traditional transport fuels in the middle periods of the model as the extended ambition scenario forces in plug-in hybrid vehicles – i.e., this is a different transition path.
- Negative emissions in the electricity sector play a major role in this scenario, especially as the 'non-energy use' sector (about which little is known in terms of abatement technologies) in the final period comprises the entire carbon budget.
- Hydrogen plays a major role in the transport sector in latter periods, contributing to fuel demand from cars, HGVs and LGVs.
- Energy service demand reductions are severe across all sectors (an average of -15%), and as in COR2 focused on those demands with few efficiency or fuel substitution options.
- Neither in this, nor in other core scenarios is the backstop mitigation measure required

6 Phase 1 Sensitivity Runs

6.1 80% reduction in CO_2 emissions, no extended ambition, social discount rate

6.1.1 Scenario Notes

Note that the CO_2 trajectory used in this run is slightly different in 2020 than the two core runs. This allows the model more flexibility in the earlier periods and is intended to be comparable with earlier C80 runs.

6.1.2 Results Notes

- The C-80 run is broadly similar to the C-90 runs but with far less pressure on key resources, sectors and technologies
- For example electricity remains a low carbon vector, but with much less pressure (in 2050 rising from 1705PJ in a base case to 2155PJ in C-80 and 2919 in C-90)
    - The overall electricity system is smaller, with reduced need for gas back up plant
    - The reduction in electricity is seen in less hydrogen electrolysis and less industrial sector electricity use
- Natural gas and oil are generally retained longer and overall (in 2050 natural gas rises from 500PJ in C-90 to 1150PJ in C-80). Coal remains in final energy until 2045, whereas it is squeezed out by 2025 in C-90 runs.
- Natural gas and electricity see important substitution in C-80 vs. C-90
    - An important switch is in the industrial sector, where in C-80, natural gas is retained in low and high heating instead of electricity
    - Additionally, natural gas share in residential heating is boosted
    - Hydrogen production moves from electrolysis to SMR (with CCS)
- CHP is primarily fuelled from fossil sources until 2040 when a dramatic switch to predominantly renewable sources. Heat from CHP in C-80 reaches a plateau of ~200 PJ in 2025 and falls in between the base and C-90 cases. In

the base case, high quantities of fossil fuelled CHP are used and heat production remains around 600PJ. In C-90, renewable fuels dominate CHP from 2020 onwards via a gradual increase to only ~140 PJ in 2050 is observed.

- A major finding is the retention of efficiency uptake (e.g., conservation and new transport drive-trains) - this is due to optimal decision making under a 3.5% discount rate. Hence final energy reductions in C-80 are similar to C-90.
    - Demand changes are also very similar in C-80 and C-90
- With transport remaining highly optimised, only small changes and 5-10 year lags in new fuels and technologies are seen
    - There are some small differences in minor transport transitional technologies (e.g., petrol hybrids instead of ethanol in cars)
- There is much less need for both biomass and coal. Both these resources halve from C-90 levels. This is due to the absence of biomass CSS and the demise in co-firing CCS from 1320PJ to 55PJ (with the retention of some coal CCS in C-80).
    - Without negative emission CCS, nuclear boosts its overall generation share in 2050
    - Similar level of renewable electricity are seen (22% in 2050)
- Generally all build constraints are hit less hard. Marine build constraints are not triggered in C-80, although now conventional natural gas plant build rates are hit harder
- Costs in C-80 are moderate compared to C-90
    - In 2050 marginal CO_2 costs are only £163/tCO_2 vs. £288/tCO_2, and welfare costs are £B 17.5 vs. £B 29.5
    - Through 2030, costs in C-80 are especially modest, being less than £50/tCO_2, with an overall welfare costs in 2030 of only £B 3.6

6.2 90% CO_2 reduction with high-high fossil fuel prices

6.2.1 Scenario notes

Note: When thinking about major changes (like fossil fuel prices movements), it is critical to consider the comparable base case – i.e., does this change occur in the base case or just in the CO_2 case. It is important in the comparison of demand changes and of overall costs. For the example of central vs. higher fossil fuel prices:

A: We assume this change occurs only in the CO_2 case – i.e. we still have a central base case. Now in the CO_2 case demand changes will be comparable as consumers take into account the extra costs imposed by both the CO_2 price and the higher fossil prices. However the overall cost comparison will be skewed upward as our welfare and energy systems cost change will include both the impact of the CO_2 price and the impact of higher fossil prices

B: We assume this change occurs already in the base (new higher fossil base) case. In our new base case we reconfigure the demand marginal prices to ensure that consumers still demand the same amount of energy services (even if these are delivered more efficiently or with alternate fuels and technologies). Now in the CO_2 case, demand changes will be skewed downwards as consumers are already paying higher prices to meet demands and hence the demand shift from a CO_2 price increase is less. However costs will be comparable as our energy systems and welfare cost change will only include the impact of the CO_2 price.

Generally in these CCC 2010 runs (and all stochastic runs) we assume option A (i.e. one central base case). For broader discussion this run is undertaken with an alternate base case.

6.2.2 Result notes

- This scenario is compared against a new high-fossil fuel price base case. The base case shows a move towards nuclear electricity, biomass and renewable electricity (mainly marine).
- The base case moves away from oil and gas, but not coal however, which remains at similar levels to the central fossil fuel price base case.

- Other trends include more efficient use of fossil resources e.g. through CHP.
- Base case energy system costs are £B 15.5 higher in 2050 owing to higher priced fossil fuel purchases
- When comparing COR1-HF-C90-S with COR1-C90, we see broad similarities in the overall trends governing the decarbonisation of the energy system. Namely, increasing electricity system size as a low carbon vector; a highly optimised transport sector; decrease in final energy; the predominance in electricity generation of CCS, nuclear and wind; and biomass CCS introduced towards the latter periods.
- The effect of the high fossil fuel prices mirror the differences viewed in the base case. Nuclear electricity increases in COR1-HF-C90-S, co-firing CCS decreases dramatically – to only 50% of levels in COR1-C90 from 2035 onwards. Renewable electricity rises from 23% to 27% of generation. Biomass primary energy also increases.
- The assumption of higher fossil prices in the base case leads to a reduced demand response from the CO_2 price signal. On average, demand reductions are only 10.7% (as opposed to 11.7% in COR1-C90). This leads to a larger final energy system.
- Smaller changes included
    - District heat production is boosted by 70PJ which flows through to the residential sector
    - Remaining hydrogen production from gas SMR is avoided and is replaced by hydrogen electrolysis.
- Marginal CO_2 prices remain below £100/tonne until 2035. They then increase at a higher rate than that seen in the COR1-C90 scenario reaching £350/tonne by 2050. This illustrates the reduced demand shift.
- However welfare cost changes are comparable, with the COR1-HF-C90-S strategy at almost £1B less than that of COR1-C90-S, due to the more optimised (lower carbon) energy systems due to base case higher fossil fuel prices.

6.3 Extreme CO_2 reduction - 97% reduction in CO_2 emissions, no extended ambition, social discount rate

6.3.1 Scenario notes

The purpose of this scenario is to explore the limit to which the current version of the MARKAL model can decarbonise the UK energy system through to 2050. While exogenous constraints imposed by the modeller may have an impact on the value of this limit, the structure of the model, the pool of available technologies and resources all contribute. The current version of MARKAL, version 3.24 includes a backstop technology, essentially a buy-out, which allows the model to always solve. It does this by allowing the model to select a technology that sequesters carbon dioxide at £5000/tonne. Selection of this technology is equivalent to the failure of the model to solve under the particular constrained scenario.

The model was run under increasingly stringent decarbonisation targets, until the backstop technology was chosen. This occurred at a 97% CO_2 reduction on 1990 levels by 2050. A 97% reduction is equivalent to 18 $MtCO_2$/annum by 2050, whereas a 95% reduction allows 30 $MtCO_2$/annum in 2050.

6.3.2 Results notes

- This run represents a highly extreme case, pushing the model to the limit of its solution, and owning to uncertainties in the solution obtained, likely beyond its explanatory power
- The structure of the model and the pool of modelled technologies and resources contribute to the limit of the model solution, together with the imposed exogenous constraints
- The differences between C-95 and C-97 are radical despite this entailing the 2050 emissions limit falling only from 29.6$MtCO_2$ to 18.1$MtCO_2$
- Note that UK MARKAL has limited treatment of ‘other emissions’ and residual industrial emissions (21$MtCO_2$ compared to base case of 83$MtCO_2$). Note that no industrial CCS for example is available (see Phase 2 runs for its inclusion)

- Marginal costs in C-97 hit the backstop as 4MtCO_2 are met at a backstop mitigation price of £5000/tCO_2.
    - However in 2045 the difference is still stark at £1870/tCO_2 vs. £381/tCO_2
- In 2050, welfare costs in C-97 are £B 79.9 vs. £B 42.7
- The electricity system follows a similar decarbonisation path to the COR2-C95 scenario to 2030. Beyond this period, there is a move away from co-firing CCS, and early (2035) adoption of biomass CCS and a concurrent expansion of nuclear and wind. By 2050, co-firing CCS is squeezed out of the electricity sector with nuclear, wind and biomass CCS contributing to a much larger overall system, producing a smaller quantity of electricity.
- Many bounds are hit, and hit hard
    - Biomass imports are maxed out
    - Nuclear, marine and other build rates are strongly hit
    - Final energy only reduces another 100PJ as demand changes and conservation levels are maxed out
- The model chooses very uncertain solutions as primary energy reduces by 100PJ
    - Hydrogen imports (150PJ) are required – note the costs, availability and carbon emissions from imported hydrogen are currently very uncertain
- Coal use falls dramatically, from 1370PJ to 70PJ – its embodied emissions are just too high
    - Biomass CCS is maxed out (+130PJ) but co-firing CCS falls dramatically (from 690 to only 30PJ in C-97)
- Electricity swings to additional wind and even 10PJ additional hydro
- The overall electricity sector is smaller with less CCS upstream and less hydrogen electrolysis, but the capacity of the system rises to accommodate additional wind generation
- Residential sector and service sector heat undergoes strong electrification, with district heating from CHP acting as a bridging technology, peaking in 2035, before being displaced by storage heating and heat pumps.
- Any available/possible remaining transport shifts occur – e.g. 2 wheeler hydrogen

    - Aviation cannot shift to bio kerosene due to lack of available bio resources (used for bio CCS)
- As noted earlier, demand (ESD) reductions hit the -25% limit, including non-energy use (note the ambiguous nature of this category calling into question the feasibility and accuracy of this reduction)
    - Demands that are already served with zero carbon resources do not reduce further (no CO2 reduction benefit)
    - Demands that are met via (negative emission) electricity can actually increase. This is seen in (e.g.) electricity boilers instead of heat pumps, or higher air conditioning demands. Effectively the model is increasing its electricity use (demand for electricity) in order to maximise its biomass CCS and hence negative emissions. This implication illustrates the counter-intuitive implementation of such a stringent runs.
- In terms of transitions, C-97 is generally 5 years ahead of C-95 in key technologies. For example, car H2 fuel cell vehicles in 2030 and bio CCS in 2035. This further stretches the credibility of mainstream availability and use of these technologies.

6.4 Uncertain CO_2 reduction target

6.4.1 Scenario Notes

This stochastic run on CO_2 emissions constraint levels, assumes a 75% likelihood of a 2050 target of -90% (59.3MtCO_2) relative to 1990 emissions of 592.4MtCO_2, but with a 25% likelihood of a deeper -95% (29.6MtCO_2) CO_2 reduction by 2050. In these revised stochastic emissions runs the resolution date of 2030 is now retained.

A core challenge is in having comparable deterministic runs. This is due to the annual emission bounds (2015-2050) in the C-90 and C-95, that the stochastic run must ignore in order to generate a hedging strategy pre 2030, and hence a greater degree of freedom in these stochastic runs. In order to have comparable runs the following four runs are compared:

1. CUMCOR1-C90-S – fixed CO_2 emissions (as C-90) in the near term (2000-2010), freedom to select emission levels in the mid-term (2015-2025), annual bounds (as C90) in the long term (2030-2050), and overall cumulative limits (16,652,544MtCO_2) similar to C-90
2. CUMCOR2-C95-S – fixed CO_2 emissions (as C-95) in the near term (2000-2010), freedom to select emission levels in the mid-term (2015-2025), annual bounds (as C95) in the long term (2030-2050), and overall cumulative limits (15,538,792MtCO_2) similar to C-95
3. COR1-STOC-C90-S – As run #1, 75% likelihood of C-90, resolution in 2030
4. COR2-STOC-C95-S – As run #2, 25% likelihood of C-95, resolution in 2030

Comparing emissions in the COR1 and COR2 runs to the cumulative COR1 and COR2 runs (Table 22), we see identical outputs through 2010 (as expected) and again post 2030 (again as expected). In the flexible mid-term (especially under socially optimal decision making), some inter-temporal trade-offs occur. This flexibly allows a cumulative savings of £B 1.4 and 2.9 respectively vs. the costs of C90 and C95. This represents 0.9% and 1.3% of cumulative scenarios costs.

Table 22: CO_2 emission pathways (MtCO_2)

	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
COR1-C90-S	550.2	550.0	528.3	437.9	380.2	278.9	204.6	150.1	110.2	80.8	59.3
COR2-C95-S	550.3	548.7	529.3	437.9	380.2	248.5	162.4	106.2	69.4	45.4	29.6
CUMCOR1-C90-S	550.2	550.0	528.3	441.2	350.9	304.9	204.6	150.1	110.2	80.8	59.3
CUMCOR2-C95-S	550.2	550.0	528.3	435.3	345.3	285.7	162.4	106.2	69.4	45.4	29.6
COR1-STOC-C90-S	550.2	550.0	528.3	440.3	353.2	303.4	204.6	150.1	110.2	80.8	59.3
COR2-STOC-C95-S	550.2	550.0	528.3	440.3	353.2	303.4	137.1	100.8	69.4	45.4	29.6

This adjusted cumulative run comparison is a more elegant solution that earlier stochastic runs, retaining a consistent uncertainty resolution date and recognising inter-temporal trade-offs.

6.4.2 Results Notes

6.4.2.1 ***The hedging strategy***

- Under a 75% likelihood of a C-90 scenario, the stochastic hedging strategy looks similar to CUMCOR1-C90. In 2025, emissions are 303.4 MtCO_2 (vs. 304.9 MtCO_2). Note that the cumulative C-95 runs is 285.7MtCO_2
    - This small hedge consists of additional biomass (90PJ) replacing coal and natural gas.
    - This transcribes into additional heat provision (vs. gas in the residential sector, bio and waste generation vs. coal co-firing CCS in the electric sector and an additional movement to ethanol E85 cars)
- The hedging strategy avoids CUMCOR2-C95 measures including:
    - No coal in industrial low and high temperature processes
    - Demand reductions across the board
    - Boost in coal CCS
    - Car petrol hybrids to car petrol plug ins

6.4.2.2 ***Recourse strategy***

- In 2030, if this hedge is wrong (i.e. the 25% chance of C-95 does occur) then the model has to quickly adjust.
    - Emissions falls below the annual limit in 2030 and 2035 (to 139.1 and 100.8MtCO_2 respectively. The social discount rate and stringent target ensures that any required over-compliance does not occur in 2050
- In 2030 this entails higher costs: £198.MtCO_2 and £B 18.1 in the stochastic run vs. £124/tCO_2 and £B 13.4 in the deterministic C95 run.
    - In terms of measures, (additional) demand reductions (generally 2%) occur across all sectors
    - Note that only industrial, service and residential see less final energy due to changes to low carbon but higher energy fuels/technologies in the transport sector
    - Biomass (+300PJ) is a major substitution for coal (-200PJ)

  - This is seen in -70PJ of coal CCS (conventional coal CCS falls out by 2040 in all runs to be replaced by co-firing and biomass CCS options
  - Shift to delivered heat instead of natural gas in the residential sector (note in C-95 biomass heat is a critical transition technology – before a shift to biomass CCS
  - In C-90 biomass heat is an important end of period technology leaving more room under the CO_2 cap
  - A final major transformation is in domestic aviation where dual fuel planes (which can switch fuels following maintenance and retrofit) switch to bio kerosene (and switch back to conventional kerosene by 2040)
- In terms of the pace of change, Table 23 compares the deterministic and stochastic emission change in the immediate recourse strategy

Table 23: 2030-2035 sectoral emissions change

	CUMCOR2-C95-S		COR2-C95-STOC-S	
Sectoral Emissions (MtCO2)	2025	2030	2025	2030
Upstream	14.7	6.7	15.3	6.3
Agriculture	2.0	2.2	2.0	2.1
Electricity	33.3	1.7	33.4	-0.7
Hydrogen	0.0	1.5	0.0	1.5
Industry	50.8	48.5	53.8	45.4
Residential	45.6	28.7	54.4	20.9
Services	17.1	6.2	19.3	2.6
Transport	87.3	30.7	89.9	23.3
Other Emissions	34.8	36.1	35.4	35.6
Total	285.7	162.4	303.4	137.1

- By 2050 C-90 largely converges to its deterministic solution
  - This is unsurprising given the small divergence of the hedging strategy
- By 2050 C-95 also largely converges to its deterministic solution
  - This is largely driven by the stringency of the target and the limited freedom to meet this strategy
  - Costs in 2045 and 2050 are slightly cheaper (0.3 out of cost of £B 42.8) due to the effort of 2025-30 readjustments

- Comparing the expected value of perfect information (EVPI) gives a measure of the value of knowing now (perfect foresight) what the uncertainty resolution is, rather than waiting until the recourse period.
  - EVPI = Expected cost of hedge – ($\sum$(prob$_i$ * cost of PF$_i$), where i is the stochastic scenarios (or states of the world).
    - Under a 75% chance of a C-90 and a 25% chance of C95 resolved by 2030, the EVPI =£M 1,431

6.5 Uncertain fossil fuel prices under Central Biomass Imports and 90% CO_2 reduction

6.5.1 Scenario Notes

The two-stage stochastic variant of UK MARKAL calculates a hedging strategy and recourse strategy for each pre-defined state of the world. The objective function is an *expected cost criterion* (as opposed to *expected utility*), based upon the weighted average expected cost of the each future states of the world. The defining assumptions are the predetermined weightings given to the future states of the world, the assumptions chosen to represent these future states, the period in which uncertainty is resolved, and the above assumption of risk neutral decision-making. Stochastic MARKAL is limited to defining nine future scenarios in each 2-stage stochastic run.

The C90 stochastic run with uncertain fossil fuel prices is identical in most respected to the COR1-C90 deterministic run. However, in addition to the central fossil fuel prices derived from the DECC central scenario, three other fossil fuel price scenarios are included. These include low, high and high-high scenarios. Each of the four fossil fuel price scenarios has a weighting of 0.25. Note that the model will hedge against high fossil fuels prices due to the inclusion of the two above-central fossil fuel price scenarios.

6.5.2 Results Notes

6.5.2.1 *The hedging strategy*

- There are only minor differences between the deterministic COR1-C90 scenario and the C-90 stochastic fossil fuel price hedging strategy. With a 50%

chance of higher fossil fuel prices vs. only a 25% chance of lower fossil fuel prices, the model hedges slightly and reduces some fossil fuel use.

- By the end of the hedging strategy (2025), in primary energy there are very minor movements away from oil (-28 PJ) towards natural gas (+20 PJ) and biomass and waste (+15 PJ). In final energy, there is a small move towards ethanol/methanol in the transport sector (+23 PJ). This reflects a switch from petrol to ethanol.
- The electricity generation mix in energy terms is virtually identical to the deterministic scenario, while investment in capacity is some 5 GW lower. Here, the differences are more clear, as there is less investment in coal CCS (-1.7 GW), more investment in unabated coal (+1.7 GW). The model invests in retrofit ready CCGTs (+5 GW) instead of normal CCGTs. The smaller system means that the renewable energy share increases 2 percentage points to 38% by capacity.
- There is a minor reconfiguration in end-use fuels, notably less demand reduction and an increase in natural gas (the most efficient fossil fuel)
- By 2025 this very modest hedging strategy costs an additional £B 0.17.

6.5.2.2 *Recourse strategy*

- In 2030, uncertainty is resolved and recourse strategies move to the optimal configuration for each state of the world.
    - Note that all scenarios follow the central fossil fuel price until 2030 when the low, high or high-high scenarios take over. This results in a different fossil fuel price trajectory to those seen in deterministic fossil fuel price runs, and as such, the runs are not directly comparable.
- Secondly, due to the use of the central reference price, the model is reacting to both the imposition of a CO_2 constraint and the alternate fossil fuel prices.
- In 2030, there is an instant response to the different fossil fuel price scenarios, seen most notably in the low fossil fuel price recourse strategy.

- Here, 5.3 GW of the un-retrofitted gas plant invested in at the end of the hedging strategy are converted to CCS, generating about 10% of the electricity from the sector. The gas CCS retrofit plants are not seen in any of the other strategies, and the plant stay in throughout the rest of the model horizon.
- Similarly, under the high-high case, transport bio-diesel and industrial steam and coal are seen in 2030

- As the recourse strategy works through there is a logical progression in terms of energy use and costs from low to central to high to high-high runs.
- Given that the hedging strategy was so similar to the deterministic COR1-C90 run, one would expect to see little effect on the recourse strategy of the central fossil fuel price scenario - this is the case and indeed any minor changes in 2025 have converged by 2050.
- By 2050, there is a clear difference between the fossil fuel price scenarios, with an interplay between nuclear and CCS. The high high fossil fuel price recourse strategy has approximately 50% of the capacity of co-firing CCS as the high fossil fuel price strategy (~24GW vs. ~46 GW), although a much larger nuclear power sector (~45 GW vs. 34 GW).
    - Overall electricity system size decreases with increasing fossil fuel price
    - Use of bio-waste in the electricity sector increases with fossil fuel price.
    - Wind uptake is consistent between all the scenarios, including the deterministic COR1-C90, at ~28 GW, with marine also providing a large contribution at ~13 GW.
    - All recourse strategies invest in biomass CCS in 2050 to meet the final reduction to 90% below 1990 levels.
- There is a trade-off between negative emissions in the electricity sector (from increasing co-firing CCS in the central and low fossil fuel price scenarios vs. high and high-high fossil fuel price scenarios) and decarbonisation effort in the transport sector. There is significant movement between fuel types,

primarily the displacement of diesel with bio-diesel. This is throughout the model horizon, although use spikes in the midterm.

    - Overall transport fuel demand remains relatively consistent in 2050 between the recourse strategies, a reflection of high optimisation under a social discount rate

- Over half of hydrogen production is derived from natural gas SMR with CO_2 capture in the low-gas recourse strategy, with the other scenarios using electrolysis.
- CHP increases dramatically as the fossil fuel price increases, with the resulting delivered heat displacing electric storage heaters. This efficient generation reflects the high fossil fuel prices
- Demand changes increase as fossil prices increase - in 2050 rising from an average reduction of 10.9% to 13.0% in the low to high-high cases
- In terms of costs, with fossil fuel price rises aiding the decarbonisation process, marginal CO_2 prices fall, from £304/tCO_2 in low to £263/tCO_2 in high-high fossil price cases.
- Higher fossil prices entail a greater demand reduction which offsets higher system costs until the high-high case which sees an increase in welfare costs of £2.8B

6.6 Uncertain fossil fuel prices under High Biomass Imports and Uncertain fossil fuel prices under Severe Biomass Import Constraint

6.6.1 Scenario Notes

In setting up these stochastic runs, we have followed our earlier method B - in that the (deterministic) bio imports assumptions and the (stochastic) fossil fuel prices changes are implemented together in the policy case (i.e. in meeting the C-90 CO_2 target). Of particular interest is that the demand change, welfare cost calculation and general energy systems changes will combine *three* effects (the imposition of the CO_2 constraint, the role of bio-imports, and the impact of the stochastic fossil prices). The reference case remains a central bio-imports and central fossil fuel price case.

Note that we are running and reporting on sensitivity runs with multiple things changing - in order to better understand these runs, one could examine the individual elements of the runs first (e.g. base or C-90 runs with just high or low bio imports). The interim runs would then be compared sequentially to glean the clearest insights. And note that the interim runs could be run in a different order to develop further insights into the interaction between drivers.

In running these sensitivities, if we impose no bio-imports (and no 1st generation domestic biodiesel) from 2000, we get very strange results (and indeed the model may not solve) as the model cannot meet the RTFO (renewable transport fuels obligation) in the transport sector. To alleviate this, the no-bio constraint is imposed only from 2020. For consistency the doubling of potential bio-imports in the high case is also imposed from 2020 (although this makes no practical difference). Further, we must have a very small amount of bio-diesel (around 0.1% of primary energy) through the model horizon, and so a small amount of domestic rape seed oil is allowed (and is selected in the absence of bio-imports). As requested, the option of domestic wheat is removed in the low biomass runs.

6.6.2 Result Notes

- The availability of biomass is a key constraint. In the low (no) biomass cases, the backstop technology is just triggered in 2050.
- This extreme solution holds similarities to the no CCS stochastic runs (see section 6.7, page 75), as co-firing CCS is effectively unavailable. The role of stochastic fossil fuel prices is a secondary role on the overall solution trajectory
- Compared to COR1-C90, welfare costs in the central run jump (by 2050 from £B 25.5 to £B 58.7. The fossil fuel variation are +/- £B 1.3 around this higher figure.
- The effect of the changing fossil fuel prices is much less evident in the low biomass scenario, as the lack of biomass imports makes the level of co-firing CCS seen in COR1-C90 difficult. Until 2030, co-firing CCS is very similar to the deterministic scenario, in 2035; the influence of fossil fuel price is seen, with

smaller amounts of co-firing CCS as fossil fuel prices increase. In 2040, the biomass constraint begins to limit co-firing CCS activity until it is largely unused in the system by 2050.

  - As a premium avenue to overall stringent reductions, the amount of biomass CCS in 2050 is the same as in the unconstrained deterministic case COR1-C90.

- Overall electricity generation (and hence zero or negative emissions electricity) is reduced with consequences across all other sectors, from fuel switching in the industrial sectors, maxing out demand reductions, or new transport technologies
  - In 2050, the electricity system configuration is broadly similar between the fossil fuel recourse strategies, although the low fossil fuel price scenario sees uptake of gas CCS technologies, used between 2030 and 2045. In comparison to the COR1-C90 scenario, co-firing CCS capacity is halved and nuclear and wind capacity doubles in response to the biomass constraint.
- Noticeably in C90 scenarios, primary coal demand is contingent on the availability of biomass. The only plants in which coal can be used are those that also require biomass e.g. co-firing CCS. When the biomass runs out, as it does in 2050 in this scenario, coal demand is forced to near 0 PJ.
- There are some extreme effects in the transport sector, evident even in the hedging strategy. For example, the model invests in battery buses in 2010, with all buses battery powered by 2035, although the latter is common to COR1-C90 as well. In the hedging strategy, the car fleet is primarily petrol hybrid vehicles, with bio-diesel to satisfy the renewable transport fuel obligation. Hydrogen HGVs play a role, also from 2010, with hydrogen (~200 PJ) derived from gas SMR, then liquefied for domestic delivery.
- Similarly to other scenarios in this series, hydrogen plays a large role in the transport sector from 2030. What is different in the low biomass scenario is the source of the hydrogen, 100% is imported as liquefied H_2 in 2050. Prior to the final period, hydrogen is predominantly derived from the natural gas

SMR process with carbon capture, there is a small amount of electrolysis and some liquefaction of domestic H_2.

- At the end of the hedging strategy, the model shifts away from biomass and wastes and increases renewable electricity. Natural gas demand also increases slightly.
- In the residential sector, heat pumps are adopted at the end of the hedging strategy (+24 PJ) with a corresponding decrease in the use of gas condensing boilers and storage heaters. Biomass is used for service and residential sector heating in 2025, but then is removed in all recourse strategies from 2030 onwards.
- Welfare costs at the end of the hedging strategy (2025) increase by ~£1B on the COR1-C90 run.

6.7 Uncertain availability of CCS and uncertain fossil fuel prices

This stochastic run aims to determine the implications for the near term given the uncertainty surrounding the timely availability of carbon capture and storage technology together with uncertainty in future fossil fuel prices.

6.7.1 Scenario Notes

Previous stochastic runs in this project have modulated just one variable; with one state of the world (SOW) corresponding to each view of the future. To define the stochastic model for two variables, weighting given to each outcome for each variable are multiplied together. There are four defined outcomes for fossil fuel price, each assigned a weighting of 0.25. There are two outcomes for CCS availability – available from 2030 onwards only – 0.75 – and not available at all – 0.25.

There are therefore eight possible outcomes listed in the table below:

Table 24: Weighting assigned to the eight states of the world

SOW	CCS availability	Fossil Fuel Price	Weighting
1	2030 onwards	Low	0.1825
2	2030 onwards	Central	0.1825
3	2030 onwards	High	0.1825
4	2030 onwards	High High	0.1825
5	Never	Low	0.0625
6	Never	Central	0.0625
7	Never	High	0.0625
8	Never	High High	0.0625

Note that there is no deterministic run to account for the effect of adjusting both the availability of CCS (i.e. now available from 2030 or not at all) and fossil fuel prices (from 2030). Hence the Expected value of perfect information (EVPI) cannot be calculated. This stochastic run can only then be compared with the COR1-C90 case taking into account both changes.

6.7.2 Result Notes

6.7.2.1 *The hedging strategy*

- The hedging strategy is dominated by the unavailability (at least until 2030) of CCS, combined with the small probability that it will not be available at all (with expected high prices). Laid on top of this, is the secondary influence of altered expectations of (likely higher) future fossil fuel prices.
- Compared to COR1-C90, no CCS entails the loss of 9.6GW of CCS capacity by 2025
  - This leads to -100PJ of electricity generation overall, despite a boost in bio-waste and gas fired generation
  - Nuclear, wind and marine generation cannot be increased in the mid-terms due to build constraints
  - Unabated co-firing coal plant is added as back-up capacity
  - Coal and gas retrofit-ready plants are built (7.4 GW gas and 0.1 GW coal).
- As a response, demand reduction is further increased, especially in modes that predominately use electricity (e.g. residential electric appliances, cooling refrigeration; service sector cooling, lighting, electrical appliances; transport rail)

- In terms of higher expected fossil prices, a major shift in transport from diesel to ethanol vehicles as a hedging strategy. This also aids in hitting the midterm emission target
    - A further impact is seen in increased demand reduction in domestic air
- Lastly, CHP and district heating is boosted as an efficient use of fossil fuels, displacing gas in the residential sector and electric heating in the service sector
- Overall in 2025, marginal CO_2 costs rise from £105 to £120/tCO2 and from £B 7.9 to £B 12.1 compared to COR1-C90

6.7.2.2 *Recourse strategies*

- In 2030 reacts to the resolution of uncertainty
- If CCS is available, there is a surge in investing in it - all runs invest in 7.5GW of co-firing CCS, with low and central cases adding 11.4GW and 5.6GW of gas CCS respectively, with the high price cases adding small amounts of Coal CCS
    - Between 34% and 20% in low and central cases of sequestered CO_2 is from retrofitted gas plants (~1.5% coal in high and high-high cases and ~8% in COR1-C90)
    - Investments in wind depend on the fossil fuel price (from low (0.5GW) to high-high (10GW)
    - Some of the demand reductions in the hedging strategy are given up
    - Heat and biomass both reflect the influence of rising fossil fuel prices
- If CCS is not available, wind investments are maxed out together with more electricity generation from bio wastes
    - However there is less electricity generation overall
    - Final energy overall is reduced, including the retention of demand reductions from the hedging strategy, with the impact of the fuel price overlaid on these
- By 2050 trends play out with the availability (or not) of CCS again being the dominating factor. Fossil fuel price differences are a secondary overlay on this.

  - The 3.5% social discounting sees the system already highly optimised - e.g. conservation options are always maxed out
  - Further, the model runs are all meeting a 90% CO_2 target which shapes the evolution of the energy system
- If CCS is available, the model tends to converge (in a central price case) to COR1-C90
  - There is some impact from the including less co-firing CCS (with resulting additional bio-CCS, but still less electricity overall
  - District heating increases its share by 40PJ, although transport fuel use is similar. In terms of overall cost, the hedging strategy imposes only a small penalty (£B 30.8 compared to £B 29.5)
- Looking across the fossil fuel scenarios with CCS sees a logical progression
  - Overall electricity generation sees increases in nuclear, wind, bio-wastes, and imports
  - Co-firing CCS halves in the high-high case
  - Transport sees minor shifts from petrol/diesel to bio-fuels (e.g. in LGV vehicles)
  - Hydrogen production under low fossil prices is substantially from gas SMR with CCS
  - CHP and heat production (efficient fossil fuel use) grows
  - Energy service demands reduce further (by an additional 1.5% on average)
  - With high fossil fuel prices assisting, CO_2 marginal prices fall from low through high-high from £304 to £288 to £277 to £261/tCO2
- If CCS is unavailable, the model sees a radical transformation. The loss of 260 $MtCO_2$ of CCS by 2050 sees the model struggle to adapt to meet a 90% CO_2 reduction and it is pushed into extreme territory. On top of this fossil fuel price variation makes little difference
  - With no coal (-2600PJ) and a -550PJ decrease in bio primary energy, the model maximises all mitigation options
  - Renewable electricity and nuclear hit build rates

- A further 160PJ of final energy is reduced (despite the already optimised system size)
- Demand reductions (for those demands that use fossil carriers) are maximised to 25% reductions
- A further 160PJ of oil use is reduced
- With electricity no longer a negative emissions carrier, it still falls to zero CO_2 emissions
- Industry (19), transport (14) and non-energy (18) constitute the majority of the $MtCO_2$ residual emissions
- The backstop technology is hit - with 11 $MtCO_2$ of 2050 reductions at £5000/tCO_2
- However even in 2045 very high marginal prices are required (ranging from £986 to 1085/tCO_2 depending on fuel prices)
- In 2050 welfare costs leap from £29.5 to £B 98.

7 Phase 2 Preliminary Runs

7.1 Extended ambition, 90% CO_2 reduction with low gas prices and central fossil fuel prices

This scenario is similar to the COR3-C90-S scenario; including the extended ambition scenario, a 90% CO_2 reduction target and central biomass availability. Fossil fuel prices for coal and oil are central, with the low scenario used for gas. This analysis compares COR3-LOWGAS to COR3-C90-S.

- The fossil fuel price scenarios begin to diverge from 2010 in deterministic runs and maintain this difference in gas price through the 2050 model horizon.
- Two major impacts are seen
  - Firstly in boosted natural gas use in the mid-term
  - Secondly residual differences in the long-term portfolio of fuels, technologies and measures as the decarbonisation drivers compete and then outweigh the impact of changed fossil fuel prices
- In comparison to COR3-C90-S, primary gas demand increases from 2010 (+200PJ) to peak in 2020 (+600 PJ) before reaching a plateau after 2030 (+200 PJ).
  - Primary gas demand moves around between 2020 and 2040 as the conflicting aims of decarbonisation and least-cost delivery of energy service demands results in a 'flip-flop' between the various technology options. For example, gas CCS is still more expensive than coal CCS, so in the middle periods natural gas is directed towards residential gas use for heating, with less used in district heating systems.
- In 2020, the COR3-LOWGAS scenario has an extra 4.1 GW of gas generation capacity, with a corresponding reduction in coal (-1GW), marine (-1.7 GW) and hydro (-0.8 GW).

- By 2030, the disparity between the scenarios is less noticeable, although the electricity system is 6 GW smaller, a trend which continues until 2045 when the carbon constraint essentially forces in the mixture of technologies common with the COR3-C90-S scenario.
- In 2050, natural gas use is diminished overall (due to the C-90 constraint) but retains a greater use than in the COR3-C90-S case (+270PJ)
    - The majority of hydrogen production is through gas SMR with CCS, freeing the ~200 PJ of electricity for other sectors (e.g. electrification of heat mentioned below). This is a pervasive change, with ramifications throughout the energy system.
    - The electricity system looks very similar to that in COR3-C90-S, albeit with a decline in bio-CHP
    - Additional electricity (not required for H_2) flows through to the residential sector, where it trades off against reduced heat provision.
    - A greater proportion of residential heat is derived from storage heaters (~170 PJ) and far less from district heating (-130 PJ).
    - As heat (from biomass-CHP) is reduced, the transport sector sees a larger proportion (65% vs. 35%) of 2nd Generation Fischer-Tropsch biodiesel from imported lingo-cellulosic feedstock from 2030, displacing mineral diesel.
- The marginal CO_2 price is ~10% higher in the COR3-LOWGAS scenario, finally meeting the COR3-C90 price in 2050 of ~£280/tonne.
    - This reflects the additional effort required from a carbon price as the cost gap between conventional fossil and low carbon alternatives is now higher
- Annual welfare cost is less than in COR3-C90-S, largely as a result of the lower gas prices in the CO_2 constrained case (vs. a reference base), which leads to a smaller energy system enabled through the use of gas SMR for hydrogen production, and the smaller demand reduction required. The difference in discounted welfare cost is ~£B60 over the entire model horizon.

  - The annual reduction in welfare costs start in 2010, rising from ~£ 1.0 B to £2.5B from 2010 to 2020, peaking at around £4B-5B in 2030 when lower prices gas use is at its peak, and retained at ~£2.0B through to 2050.

7.2 90% reduction and extended ambition with uncertain fossil fuel prices

Runs to compare to: COR1-STOC-FF[L,C,H,HH]-S, COR3-C90-S

7.2.1 Hedging strategy

- The period through 2025 is considerably different from COR1-STOC-FF-S due to the addition of the extended ambition scenario, as seen in the deterministic run COR3-C90-S (see page 56).
  - In comparison to the deterministic equivalent, the hedge is very similar to the central fossil fuel price trajectory, with small movements in biomass, natural gas and oil primary energy demand.
- This very minor hedging strategy costs an extra £B0.25 in 2025 over the COR3-C90-S run.
  - Although COR1-STOC-FF-S also had a modest hedging strategy, it should be noted that it is influenced both because the central deterministic path is already near-optimal when uncertainty is later considered, and because of the lack of flexibility in the model (e.g. due to the forcing in of specific technologies)

7.2.2 Recourse strategies

- Many of the insights regarding the pattern between fossil fuel price recourse strategies from COR1-STOC-FF-S run carry over to this scenario (see page 69).
- In 2050, primary energy demand changes sharply according to fossil fuel price, more dramatically than COR1-STOC-FFS.
  - Biomass increases from ~1400PJ to ~1700PJ between low and high-high fossil fuel price scenarios; natural gas ~740 to ~480PJ; coal ~2500 PJ to ~1000 PJ; while nuclear increases ~2800 PJ to ~3100 PJ.

- In final energy in 2050, a similar pattern to COR1-STOC-FF-S emerges across the fossil fuel scenarios.
    - Delivered electricity reduces from ~2500 PJ in low fossil fuel price scenario to ~2000 PJ in a high-high fossil fuel price case
    - Gas demand remains stable, as does petrol, biomass/waste and hydrogen
    - Delivered heat from CHP increases from ~50 PJ to ~430 PJ
    - Diesel is displaced by increasing bio-diesels (210/5 to 180/40 PJ)
- Electricity from co-firing reduces from ~1300 PJ to ~500 PJ across the fossil fuel price scenarios.
    - The paucity of alternatives to co-firing CCS mean that the electricity system size reduces by an almost equivalent amount (increasing biomass - non-CCS - and waste and imports are used to ease the cuts).
    - Uptake of biomass CCS does not relate directly to fossil fuel price, instead reliant on the availability of biomass, itself subject to demand from other sectors.
    - Wind produces between one sixth and one fifth of all electricity, with marine producing the next largest proportion of renewable electricity.
    - Renewable electricity totals between 28% and 39% of a larger (low FF) or smaller (high FF) energy system in 2050
    - CHP (largely bio) plays a strongly increasing role in rising fossil fuel price scenarios in 2050, with the smaller electricity system leading to a de-electrification of the heat sector and a move towards district heating (again largely bio fired)
- The move away from CCS in the electricity sector as FF price increases puts pressure on other sectors to decarbonise, with the most effort seen in transport.
    - The high-high scenario uses around double the biomass in the central scenario through the recourse strategy, with the bulk of the biomass converted to 2nd gen FT biodiesel
- Hydrogen appears in all the recourse strategies with demand increasing from ~140 PJ in 2030 to ~365 PJ in 2050 across all scenarios. An increasing proportion

of H_2 is produced through electrolysis, with the low fossil fuel price scenario retaining gas SMR w/CCS in 2050

- Demand changes respond to higher prices, with average demand reduction increasing by a further 2.5% from low to high-high cases
- Higher fossil fuel prices mitigate the required carbon price required to decarbonise the system, ranging (from low though high-high) from £304/tCO2 to £264/tCO2
    - The impact on welfare is more nuanced with lower decarbonisation costs being balanced by higher cost fuel purchases
- It appears that forcing in the mix of technologies in the extended ambition scenario is a factor both in the ability of the model to substantially hedge and to adapt to a variety of fossil fuel prices (when compared with other stochastic runs).
- The EVPI for this scenario is high at £20 billion. This indicates that the model results are sensitive to the uncertainty in fossil fuel prices under the assumptions contained within this scenario.

7.3 Extended ambition, cumulative emissions equivalent to 90% CO_2 reduction

The first run emissions path is a cumulative constraint of (16,656 $MtCO_2$), that corresponds to C-90 run with extended ambition (COR3). The model has freedom from 2015 (i.e. emissions in 2000-2010 are fixed to the COR3 path. In the second run (see page 86), two additional constraints are imposed on a COR3-C90 cumulative run:

- Straight line emissions from 2020-2030, from a 2020 target of 380.2$MtCO_2$ to a 2050 target of 59.3$MtCO_2$
- Additional constraints in 2035, and 2040 to ensure that emissions reductions are never more than 50% in any 5 year period

The figure below illustrates the emission path for the reference, COR3 (C90), and the two new runs. The impact of the social discount rate is profound, with a higher weight placed on avoiding (very expensive) later period reductions. Hence in a cumulative run (COR3-CUMC90) the model undertakes earlier action, with 2050 emissions only at 85 $MtCO_2$. When emissions are further constrained (COR3-CUM2030) the straight line trajectory through 2030 give higher emissions, and then the model decarbonises very hard to avoid later period expensive reductions. The 50% period-on-period limit is hit in both 2035 and 2040, and by 2050 this run is forced down to 35 $MtCO_2$ to reach the cumulative limit.

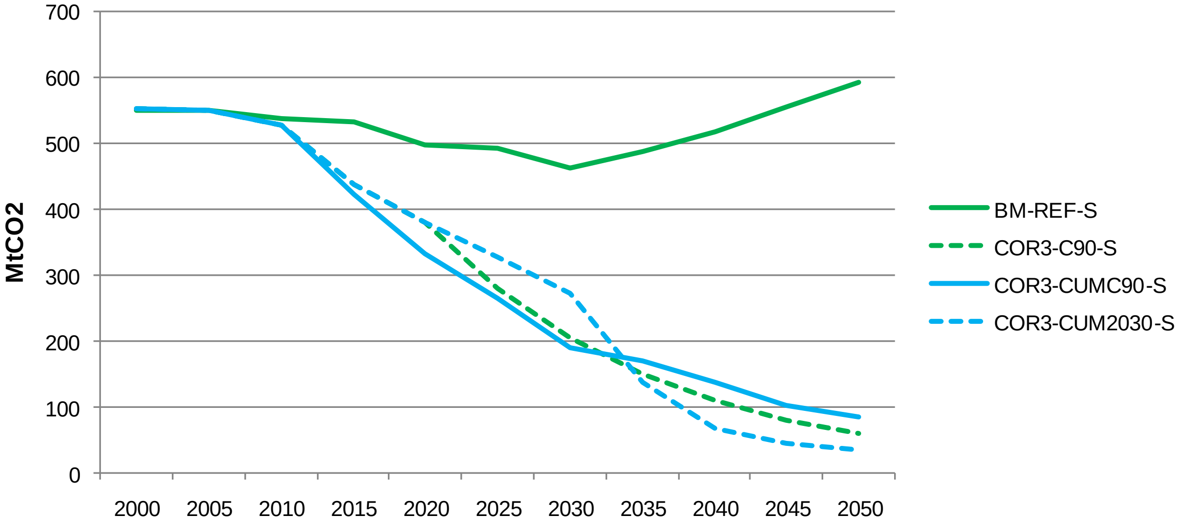


Figure 6: CO_2 emissions under cumulative CO_2 emission targets

- The additional flexibility of the cumulative constraint leads to an overall discounted welfare gain of £B 4.5
    - High costs are imposed earlier and lower costs are seen later as the socially optimal model minimises (expensive) emissions reductions in later years
- CO_2 emissions diverge in from 2015, and in 2020 are 380 $MtCO_2$ vs. 333 $MtCO_2$ in COR3-C90
- In 2020 this entails a CO_2 price of £71/tCO_2, up from £25/tCO_2, and a welfare cost of £B 6.6, up from £B 4.0
- By 2035 emission levels converge
- By 2050 the higher CO_2 emissions cap gives a CO_2 price reduction to £200/tCO_2 (from £288 in COR3-C90) and a corresponding welfare improvement of £B -24.7 (from £B -30.8)
- In 2020 (and other early periods) higher demand reductions are a major feature of this run, in 2020 rising from an average of -5% to -8%

    - Note that in this socially optimal run, some energy sector (e.g. transport is already highly efficient and conservation options are fully taken up
    - Demand reductions operate across the board but especially in residential and industry sectors
    - Demand reductions (along with fuel substitutions) enable a 280PJ reduction of coal primary energy
- In 2020 the electricity portfolio is almost the same, with only some acceleration of switching from coal to coal CCS
    - Note that 1/3 of this coal CCS is retrofit plants
- Other substitutions included LGV transport diesel hybrids to petrol plug-ins and removal of coal and coke oven gas from industry sectors
- In 2050 this run has a significantly large emission allowance – 85 vs. 59 $MtCO_2$
    - This eases pressure on zero or negative emission electricity, with 330PJ less electricity overall, no biomass CCS and a reduction in co-firing CCS
    - Hydrogen production switches from 100% electrolysis to 60/40 electrolysis vs. gas SMR with CCS
    - Expensive options in end use sectors also revert (e.g. residential heating from electricity to heat and direct biomass)
    - The accelerated demand reductions are no longer required and converge (by around 2030 or so)

7.4 Extended ambition, cumulative emissions equivalent to 90% CO_2 reduction, with additional straight-line emission constraint through 2030

- The straight-line trajectory through 2030 gives a much lower effort, with CO_2 marginal prices in 2030 only £18/tCO_2 (vs. £91/tCO_2)
    - The emission budget in 2030 is 273 $MtCO_2$ (from 205 $MtCO_2$)

  - The additional emissions budget is mostly allocated to electricity, hydrogen (for transport) and the service sector
- Average demand reductions plummet, from 7.5% to only 2.5%
  - The 500 PJ additional final energy is parcelled out to the industry, residential, services sectors (transport remains highly optimised)
  - The share of natural gas and heat in final energy is also boosted
  - With electricity generation slightly reduced, the portfolio shifts from imports, marine and nuclear to retain 100PJ of gas fired generation in 2030
  - CHP and DH (including steam production) remain fossil (as opposed to biomass)
  - In industrial sectors, coal and coke oven gas are retained
- In 2035, the model quickly reduces emissions in an attempt to minimise very expensive later reductions
  - Without lower bounds (of 50% reduction 5-year on 5-year) the model would reduce emissions by 63%
- With 50% maximum emission reduction in 2030-2035, demand reductions quickly ramp up (from 2.5% to 9.5%) and apply to all sectors
- In terms of sectors in 2035:
  - Electricity emissions contract from 39 to 5 $MtCO_2$, via growth in co-firing CCS and nuclear;
  - Hydrogen (for transport) decarbonises from 9 to only 1 $MtCO_2$ via shift to electrolysis and CCS being applied to SMR H_2 production
  - The residential sector falls from 24 to 3 $MtCO_2$ via switching from gas and heat to electricity
  - Industry falls from 58 to 39 $MtCO_2$ with the elimination of coal
  - Service sector falls from 13 to 1 $MtCO_2$ with the elimination of natural gas
- In 2035-2045 transition technologies include natural gas in industry, biofuels in transport, and gas SMR with CCS in hydrogen production
  - These eventually fall out as the emission caps tightens severely

- In 2050 the emission cap is much tighter than COR3-C90 at 34.8 $MtCO_2$ which is a 94% reduction
    - Hence the overall structure of the energy system has similarities to a C-95 run, but with important differences at the margin
    - As costs are extremely convex at this point in the abatement curve this run's marginal price is £468/tCO_2 as opposed to £1415/tCO_2 for COR2-C95
- Welfare losses (at £B 38.6) are more comparable falling between a C-90 case (£B 30.8) and a C-95 case (£B 42.7)
- Compared to the COR1-C90-S case, major changes include a larger electricity sector, with a coal to biomass (CCS) switch and more nuclear.
    - The electricity sector's emissions fall even further into negative territory (from -26$MtCO_2$ to -42$MtCO_2$)
    - The already optimised energy system sees a further 1.5% reduction in energy service demands
    - A range of additional changes include bio resources being switched from CHP to CCS (which results in residential heat being replaced by electricity), and a contribution of hydrogen cars to the LGV subsector

7.5 Uncertain fossil fuel prices, extended ambition, C-90 emission reductions with restriction on electric vehicles

In the first set of scenarios, restrictions are placed on electric vehicles (EVs). The overall limit on EV car-kms (63%) is maintained for a combination of Battery EVs and Plug-in Hybrid EVs, but BEVs uptake is zero until 2030 and are allowed to comprise no more than 20% of car-kms by 2050 (ramped up from 0% in 2030, by 5% per 5-year period). Hence the other 43% can only be done with PHEVs. Furthermore, no battery electric buses are allowed.

In the second set of scenarios, in addition to EV restrictions as above, no hydrogen is allowed for any transport mode.

The runs have 2050 targets of -90% (59.3$MtCO_2$) relative to 1990 emissions of 592.4$MtCO_2$. The path consists of equal annual reduction from 2020 target of 380.2$MtCO_2$ (35.8% reduction from 1990 levels).

Under the stochastic formulation, alternate CCC scenarios are used for oil, oil products, natural gas and coal; with no domestic fossil fuel production post 2020. Uncertainty is resolved post 2025 - i.e. 2030 is the first period of the recourse strategy. This resolution date has been retained in all the stochastic emissions runs.

Runs to compare to: COR3-STOC-FF[L,C,H,HH]-S, COR3-C90-S

Note there are no direct deterministic runs to compare to, and hence no EVPI can be calculated.

7.5.1 Hedging strategy

- Compared to earlier COR3 extended ambition runs, the model is responding both to the restricted availability of electric cars and buses, and to an upper bias in future fossil fuel price expectations
- As the previous electric bus transition cannot occur, less electricity is required
    - This means less co-firing CCS (less biomass availability, more expensive coal) and less marine (more expensive)
- With electric cars restricted, a major hedging technology is E85 ethanol cars. These are retained until a further transition to hydrogen in 2040/45.
- Overall slightly higher mid-term CO_2 marginal prices are required (£87/tCO_2 instead of £80/tCO_2

7.5.2 Recourse strategies

- In 2030, immediate changes are seen under lower/higher fossil fuel prices
    - This is seen in the marginal CO_2 signal having to be stronger/weaker respectively – with the range from £39/tCO_2 in the high high to £111/tCO_2 in the low case
    - Energy service demand reductions under higher fossil fuel prices are relaxed
    - Under higher FF prices, a further intermediate transition to E85 and bio diesel vehicles is seen

- In terms of prioritised electricity investment this varies from co-firing CCS in low FF cases, to marine in high-high. Gas back up plant investment is required on all scenarios

- In 2050, the overall impact of the C-90 emission reduction is seen across all scenarios with the impact of fossil fuel variations laid on top of this
    - Marginal CO_2 prices continue to vary from low to high-high (from £305/tCO_2 to £268/tCO_2) as the fossil fuel price rise ensures some emissions reductions
    - A range of key technologies are similar to earlier COR3 stochastic runs – e.g. hydrogen cars by 2050
    - Looking across low to high-high scenarios
        - Low favours natural gas, oil, coal and electricity (nuclear), H_2 from SMR
        - High-high favours heat, biomass, renewable & nuclear electricity, demand reductions, and H2 from electrolysis
        - The demise of coal in high-high is the most striking (from 2400 to 840PJ)
        - The role of nuclear is interesting and is boosted in the low case due to the need for a large zero carbon electricity sector to meet targets, and it is large in the high-high case due to costs of fossil CCS alternates. Nuclear's role is less in intermediate FF cases
        - Low to high-high cases sees a shift from electricity to (bio) heat, primarily in the residential sector
        - In transport there is an additional switch from diesel to biodiesel

7.6 Uncertain fossil fuel prices, extended ambition, C-90 emission reductions with restriction on electric vehicles and hydrogen as a transport fuel

Note that the restrictions on hydrogen constitute a major further change. In COR3 runs, H_2 comes in from 2030 (140 PJ, rising to 370 PJ in 2050). In the above restricted EV transport sensitivity, the long term role of H_2 is boosted to 500 PJ in 2050

7.6.1 Hedging strategy

- The hedging strategy is similar to the above run in section 7.5, but with an additional hedge due to the future costs of not being able to substitute to H_2 in the transport sector.
    - A reduction of 120PJ of coal and 20PJ of gas is partly replaced by 50PJ more of biomass
    - This is seen in a rise in biomass CHP and heat production, and a switch from diesel to bio-diesel in transport

7.6.2 Recourse strategies

- The 2030 transition is similar to the previous transport sensitivity but by 2050 very considerable difference emerge
- Not having access to H_2 for any transport model ensures a rapid increase in welfare costs, and a greater impact than restriction on EVs: from a central case of £B 30.8 in COR3, to £B 33.8 under the above transport sensitivity to £B 40.2 in this transport (no H_2) sensitivity by 2050
- Cars cannot transition to hydrogen and remain predominately ethanol E85
    - In 2050, 44% E85 in the low case to 85% ethanol in high-high
- Buses and HGV vehicles remain bio-diesel hybrid options
- Domestic air switches to bio-kerosene - 0% in low to nearly 100% in high-high FF price cases
- With 800 to over 100PJ of biomass in the transport sector, overall biomass requirements come largely from imported sources (around a 75/25 share of imports vs. domestic production).

- By 2050 import constraints on biomass are triggered
- Demand reduction requirements are up in all scenarios, and most notably in higher FF price case (ranging from an average of 12.4% to 14.6% in 2050)
- Overall electricity requirements are substantially reduced (owing to less electricity in transport (either directly or indirectly via hydrogen electrolysis)
  - In terms of the electricity portfolio, low FF price use of co-firing CCS switches to bio CCS, nuclear, hydro, marine and imports in higher price variants
  - Note wind penetration levels are maxed out at 500PJ by 2050
- Although all no H_2 variants are more expensive than earlier comparative runs, the FF price signal still impact the require CO2 marginal with falls from £511/tCO_2 to £397/tCO_2 as fossil prices rise.

7.7 C-90 extended ambition except heat sector, low assumptions on heat pumps and solid wall insulation, uncertain fossil fuel prices

CCC assumptions on extended ambition (COR3) are used (except in the heat sector as below). Lower bounds (from CCC) are removed in the residential sector on biomass boilers, heat pumps, solar thermal heat. Lower bounds (from CCC) are removed in the service sector on biomass boilers, heat pumps, solar thermal heat. A 70% maximum limit on service sector heat pumps is put in place. Investment smoothing constraints are placed on overall categories of residential and service sector heat pumps to prevent unrealistic spikes of investment. Revised CCC assumptions on solid wall installation (SWI) conservation and on heat pump potentials are included in the residential sector:

1. For the first run (below), low SWI conservation assumptions are made for 0.3 million homes in 2020 and 0.6 million in 2030 (linearly interpolated from 2010) and held at the upper level through 2050. In the model this is transcribed into a PJ/a conversation uptake. The overall limit on all conversation measures is also updated to take this SWI uptake into account. Corresponding maximum heat pump uptake in the residential sector is 41.5% in 2020 and 42.5% in 2030.

2. For the second run (see page 95), high SWI conservation assumptions are made for 2.7 million homes in 2020 and 5.7 million in 2030 (linearly interpolated from 2010) and held at the upper level through 2050. This is transcribed into a PJ/a conversation uptake. The overall limit on all conversation measures is also updated to take this SWI uptake into account. Corresponding maximum heat pump uptake in the residential sector is 49.8% in 2020 and 60.3% in 2030.

Runs to compare to: COR3-C90-S; COR3-STOC-FF[L,C,H,HH]-S

Note there are no direct deterministic runs to compare to, and hence no EVPI can be calculated.

7.7.1 Hedging strategy

- As in previous stochastic fossil fuel runs, we would expect some hedging bias against the overall higher likelihood of higher fossil prices
- This will be laid on top of the changes from Solid wall insulation (SWI) and heat pump assumption changes
- In 2025
    - The higher level of conservation forced into the residential section (15PJ) and a rise in residential heat pumps is only partly balanced out by less penetration of service sector heat pumps (no lower bound). Hence final energy is 60PJ less overall.
    - The reduction of service biomass (removed lower bound assumption) is taken up in the residential sector, partially in response to higher expected fossil prices
    - An additional small hedge is seen (also 15PJ) in a switch from natural gas and oil to renewable electricity and biomass
    - CO2 marginal prices rise from £80 to £82/tCO_2 as a result of these scenario changes plus hedging strategy

7.7.2 Recourse strategies

- In 2030 some immediate changes are seen
    - Coal quickly comes down (co-firing CCS) in the power sector in the high-high case. This ensures that electricity does not decarbonise until 2035 in the HH run.
    - In the HH run there is an additional immediate switch from diesel to biodiesel
    - The fossil fuel runs see a range in CO_2 prices as the carbon signal has to work more or less hard to meet interim targets – from low to high-high runs, CO_2 prices vary from £109 to £48/tCO_2 in 2030
    - Similar demand reductions rage from 5.4% to 8.2%
- In 2050, the core assumption changes to conservation and heat pumps play out
    - By enabling additional conservation (which is cost effective) and raising the limits on heat pumps, this run is generally cheaper than the equivalent COR3 extended ambitions runs
    - The increase in conservation and increases in residential heat pumps continue to outweigh the reduction in service sector heat pumps to give an overall -70PJ final energy decline
- By 2050 the changes from stochastic fossil fuel prices have also played out
    - In terms of final energy there is a 1000PJ range (from a central value of 8760PJ
    - Moving from low to high-high scenarios; gas, oil and coal, is replaced with biomass, nuclear, imported electricity and demand reductions
    - Coal in the high-high cases is decimated, with a major swift between co-firing CCS to a combination of biomass CHP and biomass-CCS
    - The high-high run sees an addition diesel – biodiesel switch
    - Low price runs retain more fossil fuels e.g., in SMR (with CCS) in hydrogen production
    - Renewable electricity is limited by build rates and power sector operation, and does not increase its absolute energy production

- A major resultant end-use shift is in the residential sector with (as fossil prices rise) a move from electricity to (bio) heat)
- Demand reductions vary from 10.1% to 13.1% under low to high-high cases
- CO2 marginal costs sees a 2050 variation from £305 to £261/tCO2

7.8 C-90 extended ambition except heat sector, high assumptions on heat pumps and solid wall insulation, uncertain fossil fuel prices

Note that the high heat pump and insulation assumptions constitute a major further change. The energy systems is substantially smaller (and cheaper), which alleviates pressure on other sectors and energy chain to decarbonise; although the overall pattern of technologies and measures are similar.

7.8.1 Hedging strategy

- Now in 2025, overall conservation increases from 225 to 350PJ
- A 50% increase in residential heat pumps is only partially balanced out by interim declines in service sector heat pumps
- Overall in 2025, final energy is reduced by 70PJ
- This reduced pressure on mid-term decarbonisation, for example in the decline in natural gas requirements for buildings
    - Marginal CO_2 prices ease back from £80 to £73/tCO_2
- This also means that any impacts of an additional hedging strategy is very small

7.8.2 Recourse strategies

- By 2050 the conservation and heat pump assumptions give a relative 190 PJ decline in final energy
- In particular the SWI conservation and the further rise in heat pumps give a much smaller residential sector
- Marginal CO_2 prices at the margin are the same as in the HP1 case, but overall welfare costs are down by around £B 2.3 (to an average of £B 27.7 in 2050)

- Fossil fuel difference give a similar pattern of variation but at a much reduced variation and impact, as the model has much more flexibility in its smaller energy system
  - Hence the fossil fuel scenario range in primary energy is now only 600PJ (8290 – 7700PJ
  - Demand changes now range from 9.9% to 12.7% (low to high-high)
  - The electricity to biomass-heat trade-off is much less pronounced (now only tens instead of hundreds of PJ)

8 Phase 2 Core and Sensitivity Runs

8.1 Revised Core Runs

8.1.1 P2-COR3-ALL-S-2

This run demonstrates the dramatic effect of including:

- industrial CCS (process and combustion)
- grid injection of bio-methane and
- revision of solid wall insulation and heat pumps

All comparisons are made against the COR3-C90 scenario.

The majority of changes occur in the latter half of the model horizon, noticeably in the large reduction in primary energy consumption (-500 PJ in 2035 >-1000PJ in 2050). This reduction in primary energy is largely in coal and biomass & waste and is due to a significant decrease of electricity demand in the hydrogen, industrial and residential sectors. Primary biomass and waste reaches a maximum of ~600 PJ in 2050. Primary coal demand resurges in the late 2020s after reaching a low of ~400 PJ in 2025, plateaus at ~1000 PJ in the 30-40s and peaks at ~1500 PJ in 2050 as new co-firing CCS capacity comes online. In the COR3-C90 run, decarbonisation of the electricity system was largely through co-firing CCS, and in the later periods, biomass CCS. This scenario sees 10 GW less co-firing CCS capacity in 2035 and ~30 GW less co-firing CCS capacity in 2050. 4 GW of nuclear investment is delayed by a decade to 2045-50. As a result of the reduction in electricity demand, the electricity system in 2050 is much smaller; ~185 GW instead of ~220 GW in the COR3-C90 scenario.

As mentioned above, the reduction in electricity demand comprises reductions in hydrogen, industrial and residential sectors. These are explored briefly below.

Hydrogen demand (~360 PJ in 2050) is very similar to that in the COR3-C90 scenario, and is used in the transport sector for HGVs from 2030 and cars from 2040. The reduction in emissions generated by industrial CCS allows hydrogen production to remain 50% gas SMR (with CCS), instead of fully moving to electrolysis.

There is a dramatic increase in the use of bio-products in the **industrial sector**, mainly through the adoption of bio-methane, later combined with CCS to achieve negative emissions. Total industrial bio-methane demand increases from ~70 PJ in 2025 to ~120 PJ in 2050. As the industrial gas demand decreases from ~600 PJ in 2020 to ~400 PJ in 2050, bio-methane makes up an increasing percentage.

The increase in solid wall insulation coupled with high uptake of heat pumps in the **residential sector** creates a dramatic overall reduction in residential electricity demand. Half of this is due to the higher efficiency of the heat pumps and the move from (less efficient) storage heaters. The other half is due to increase in energy conservation measures (~100 PJ in 2030 onwards). Energy demand for heat pumps increases from ~40 PJ in 2025 to ~200 PJ in 2050 while gas demand from boilers reduces from 900 PJ in 2020 to 0 PJ in 2045. Note that bio-methane is concentrated in the industrial sector and does not penetrate the residential sector; under a 90% CO_2 reduction target the residual emissions are too high, together with the opportunity cost of taking bio-methane CCS away from the industrial sector.

Compared to the COR3-C90 scenario, consumption of bio-products increases overall, although this increase is dominated by the uptake of bio-methane in the industrial sector. Wood demand between 2020 and 2035 switches from the service sector to residential sector. Bio-products in final energy peak at ~100 PJ in the 2020s, and 200 PJ in 2030-40s. This is an increase of ~100 PJ over the COR3-C90 scenario. Note that bio-fuels in the transport sector are lower and decline from a high of ~70 PJ in 2010 to ~10 PJ in 2050. This is in contrast to the COR3-C90 scenario in which biofuels increase to a peak of ~90 PJ in 2035 before declining to ~10 PJ in 2050.

Industrial CCS is adopted from 2030 onwards, with 20 $MtCO_2$ captured increasing to 45 $MtCO_2$ in 2050. Note that the extra 7 $MtCO_2$ in 2050 over the industrial CCS is from hydrogen SMR with CCS. Compared with COR3-C90, overall levels of CCS are reduced by ~10 $MtCO_2$ in 2035 and ~80 $MtCO_2$ in 2050. The reduction is entirely from lower (co-firing) CCS capacity in the electricity sector. However, this still results in ~100 $MtCO_2$ captured per year from 2030 rising to around 180 $MtCO_2$ captured per year in 2050. One third goes to enhanced oil recovery, with the remainder stored in aquifers.

Emissions move around between sectors, primarily as the reduction in industrial emissions (process and combustion emissions down 9 MtCO2 and 11 MtCO2 respectively) give more freedom to the electricity sector (up 17 MtCO2), transport sector (up 1 to 4 MtCO2), and hydrogen production (up 1 MtCO2). This is shown in Figure 7. Note that the reduction in 'Other emissions' is a result of the reduction in industrial *process* emissions. Reductions in industrial emissions through combustion CCS measures are included under the *industry* category.

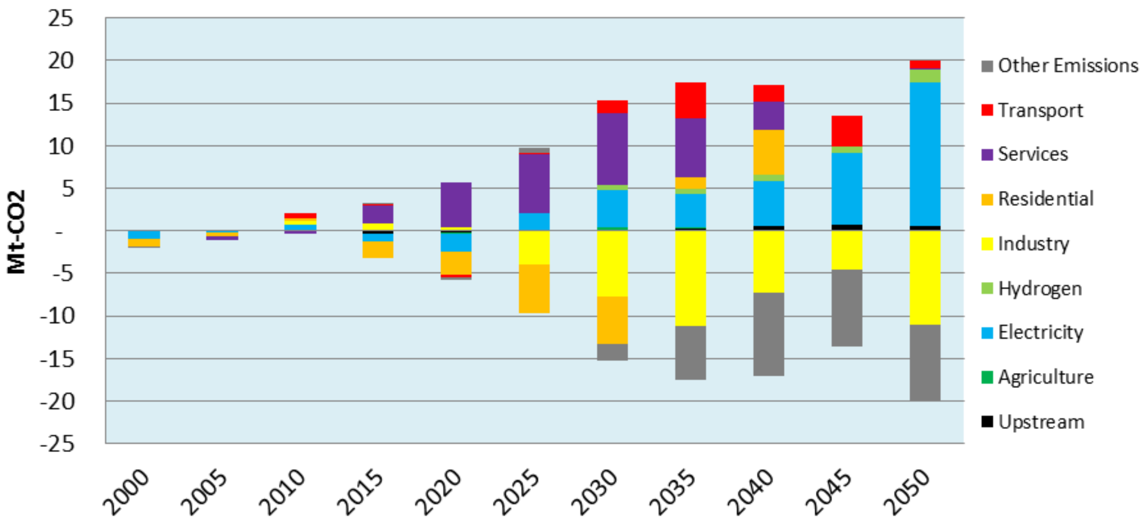


Figure 7: Change in sectoral emissions (COR3-C90 to P2-COR3-ALL-S-2)

The extra freedom given to the energy system through inclusion of industrial CCS and bio-methane is significant. Under a 90% CO_2 reduction target, the welfare benefit of industrial CCS, bio-methane, and revised solid wall insulation and heat pumps constraints rises from £1B in 2020 to £9B in 2050. Two thirds of the welfare benefit is as a result of the smaller energy system, with the remaining third from smaller energy service demand reductions – concentrated in residential and industrial sectors.

8.1.2 P2-R2-NEW-C90: Run 2, with lower wind uptake, 30% RE target, constrained mid-term CCS

8.1.2.1 *Scenario notes*

The following changes are made to the model since the previous (P2-COR3-ALL-S-2):

- Offshore wind forced in as per the previous extended ambition run to 2020, but then that 2020 minimum constraint installed capacity kept flat to 2050
- Wind build-rate constrained to the maximum seen pre-2025 e.g. ~13 GW per 5-year period
- From 2020 to 2050, a minimum of 30% renewable electricity is constrained in
- On industry CCS, no uptake by 2025, and the maximum build rates in each following 5-year period of 5 $MtCO_2$, 10 $MtCO_2$and then 15 $MtCO_2$ (i.e. if it hits the build constraint in each period the cumulative installed capacity would be 5 $MtCO_2$ in 2030, $MtCO_2$ Mt in 2035 and 30 $MtCO_2$ in 2040); post-2040 build rates added using a maximum of 20 $MtCO_2$ in any 5-year period
- On CCS as a whole (including industrial, electricity and hydrogen), combined build-rate constraint pre-2030 (0.5 GW/annum 2020; 1GW/annum 2025; 1.5 GW/annum 2030), but then not doing so post-2030, i.e. power reverts to a 2GW per annum build constraint regardless of industry CCS deployment

Table 25: CCS emissions captured in P2-R2-New-C90

Emissions (ktCO2)	2030	2035	2040	2045	2050
Industrial coal CCS (combustion)	2,991	5,678	7,883	8,973	8,973
H2 SMR with CCS			126	7,649	7,649
Industrial gas CCS (combustion)		1,474	7,798	8,002	2,804
industrial bio-methane CCS (combustion)					4,994
CHP CCS			2,478	9,444	9,444
Process CCS coal	802	5,468	8,202	8,202	8,202
Process CCS gas	787	1,574	2,361	2,361	2,361
	4,580	14,194	28,847	44,630	44,426
% hydrogen			0.4%	17.1%	17.2%

8.1.2.2 *Results*

This run builds on the first phase II run, P2-COR3-ALL-S-2. In this run we relax an aggressive constraint forcing in wind technologies in favour of a least cost renewable portfolio standard post-2030 and constrain back industrial, hydrogen and electricity sector CCS technologies. Industrial CCS is unavailable pre-2030, growth in both industrial and hydrogen CCS is limited from 2030 onwards, and hydrogen CCS is incorporated into the power sector build rate constraint before 2030. The 2030 period is important, as this is when hydrogen becomes available and electricity sector decarbonisation is well under way.

As wind is no longer forced in, installed capacity drops by ~11 GW in 2025 and ~7 GW in 2030, with a small compensatory increase in bio-wastes (~7 GW) and marine (~7 GW). Installed wind capacity from 2035 onwards, both onshore and offshore exceeds the levels seen in P2-COR3-ALL-S-2, largely to meet the 30% renewable electricity constraint in the latter periods (post-2035). Electricity generation dips by around 100 PJ during this 10 year period compared to P2-COR3-ALL-S-2. The smaller electricity system requires a corresponding reduction in energy service demands. Energy service demand *reductions* increase in response to price on average ~6% in industry, ~5% in residential and ~1% in transport and service sector in 2030. Note that wind capacity actually increases above the level seen in P2-COR3-ALL-S-2, reaching ~70 GW in 2050.

The reductions (in final electricity) are split between industry, residential and service sectors in the middle periods, and hydrogen and industry in latter periods. Residential decarbonisation occurs through a combination of supply and demand measures; there is a move from gas condensing boilers (-200 PJ in 2030) to electricity and heat pumps. District heating plays an important role in conjunction with solid and wood fuels (up 80 PJ in 2030). Final energy demand is around 90 PJ lower than the P2-COR3-ALL-S-2 scenario.

Electricity CCS hits the build rate in 2020 and 2025 as the co-firing CCS fleet reaches 17.7 GW of installed capacity in 2035, increasing to 26 GW in 2050. Growth in electricity CCS capacity in 2030 is lower than the build-rate as some CCS resource is concentrated upon industrial sector. This demonstrates the trade-off between industrial, hydrogen and electricity sector CCS investment.

The mid-term (2035-40) uptake of CCS increases marginally in this scenario, compared to P2-COR3-ALL-S-2 as the model is forced to choose the least-cost CCS option from the hydrogen, industrial and electricity sectors. Adoption of both hydrogen and industrial CCS is delayed (reduced) until 2045, with electricity CCS taking preference in the near term (2035-40) - CCS increases from ~10 $MtCO_2$ in 2015 to ~180 $MtCO_2$ in 2050. However, the preference for electricity sector CCS is reversed in the later periods, with the hydrogen and industrial sectors demanding equal share of the CCS potential. By 2045, the mid-term constraint no longer applies, and electricity, industry and hydrogen CCS processes resume the pathways seen in P2-COR3-ALL-S-2.

Note that overall CCS capacity declines in comparison to the P2-COR3-ALL-S-2 scenario. However, the electricity sector increases in capacity (as more wind than base load plant is built) but is smaller from an electrical generation perspective. The inclusion of hydrogen CCS in the industrial CCS constraint in the latter periods has a significant effect on the consumption of electricity, with ~160 PJ of electricity diverted to hydrogen electrolysis in 2035. Hydrogen production switches to electrolysis from natural gas SMR from 2030 onwards, with gas SMR with CCS increasing over the remaining periods (as the constraint on industrial & hydrogen CCS decreases in severity).

For most sectors, energy service demand reduction is marginally increased over P2-COR3-ALL-S-2 from 2025 onwards e.g. due to the increased system cost of electricity.

The welfare cost changes over time in a very similar way to the pattern seen in P2-COR3-ALL-S-2. Discounted welfare costs for the two scenarios are close enough to be within the margin for error. The marginal price of CO_2 increases smoothly from 2015 (~£40/tCO_2) to 2050 (~£230/tCO_2).

8.1.3 P2-R3-HUR-C90-5: Run 3 Amended hurdle rates

In this scenario, alternative hurdle rates (as discussed in section 3.3.6) are applied:

- Power (and electricity CCS): 10%
- Industry (and industrial CCS): 10%
- Hydrogen (and process CCS): 10%
- Service: 10%
- Residential: 3.5%
- Transport vehicle technologies:
  - Cars and 2-wheelers: 3.5%
  - Buses: 6%

    - HGV and LGVs: 8.5%
- Not specified by CCC:
    - Aviation: 3.5%
    - Navigation: 3.5%
    - Rail: 3.5%

Hurdle rates are applied to conservation technologies in equivalent sectors (so 10% in commercial sector and 3.5% in residential sector). All CCS storage technologies have 10% power sector hurdle rate assigned. The changes to hurdle rates were consistent with the rationale of a private sector discount rate of 10% and public sector discount rate of 3.5%.

Existing hurdle rates (8.75% for conservation measures in both the residential and service/commercial sectors, 7.00% for public transport, 8.75% for battery and methanol private transport, 5.25% for hybrid private transport modes and 7.00% for hydrogen private transport modes) are overridden by the new amended hurdle rates.

8.1.3.1 ***Results***

- New hurdle rates result in pervasive and system wide effects
- There is a focus on "well-to-wheel" efficiency i.e. increase in CHP, reduction in electricity conversion technologies
- Demand reductions are greater than the previous scenario (P2-R2), but not significantly so and are balanced with the reduction in supply side
- H_2 demand is slightly lower than in run 2, and bio-fuels replace a portion of H_2 in transport
- 50-150 PJ of hydrogen production moves from electrolysis to gas SMR with CCS
- The electricity system is significantly smaller than run 2 (~60 GW in 2050 – 40 GW less renewables and 16 GW less co-firing CCS) as a result of the hurdle rate increases

This scenario was run as a constrained scenario - without running a separate base case. The added (or reduced) cost of investing in technologies due to the imposition of amended hurdle rates therefore result in some relatively large changes across the energy system. This occurs because the cost of meeting almost all energy service demands increases as a result of the new hurdle rates. However, where one might expect a significant demand response, this scenario demonstrates a large reconfiguration of the entire energy system, with a much smaller electricity sector than previous scenarios, in partnership with demand side reduction in response to increases electricity prices. Electricity makes up a lower proportion of delivered (final) energy as the cost of conversion has increased relative to the use of primary fuels in final energy, or more efficient technologies such as CHP.

Primary energy demand is ~200 PJ lower from 2010 onwards and significantly lower in 2050 (by ~600 PJ). The largest reductions are in coal, nuclear electricity and renewable electricity. Biomass and natural gas increase roughly equally by ~500 PJ (over P2-R2) in 2050. The largest increase is in biomass, increasing to ~1,100 PJ (overall) in 2050, with much of the increase directed to wood-fired CHP for residential heating.

Final energy demand is on average ~125 PJ lower over the model horizon, while final demand for heat from CHP displaces gas/bio-methane and electricity. An increase in bio-diesel and petrol displaces mineral diesel and hydrogen in transport. The reduction in final energy demand occurs in different sectors in different periods. Between 2010 and 2015, final energy demand in transport is reduced by 50-100 PJ. In the mid periods, 2025 to 2035, final energy demand is reduced in the residential sector. In the later periods, reductions in final energy demand are equally distributed between transport, service, residential and industrial sectors. Final energy demand for electricity is the single largest reduction from 2040 onwards.

The reduction in final electricity demand explains only part of the ~500 PJ (and ~60 GW capacity) reduction in electricity generation. The increase in the hurdle rate of the power sector to 10% has stimulated a reorganisation of the energy system, with a much smaller electricity system, less conversion of energy commodities, an increase in efficiency and direct delivery of fuels to demand sectors (e.g. less electricity and more gas to meet final industrial demand). The biggest reduction is in large, capital intensive plant and accompanying infrastructure, such as CCS technologies, wind and marine and to a lesser extent nuclear. There is a small increase in biomass CCS (2 GW in 2050) and bio-waste technologies.

In this set of scenarios, hydrogen is a resilient fuel in the future low carbon transport sector. Hydrogen meets an increasing percentage of transport fuel demand (12% in 2030 rising to 37% in 2050) and is produced using a mixture of electrolysis (~100 PJ) and natural gas SMR with CCS (~180 PJ).

The changes in hurdle rates for hybrid transport technologies (from 5.25% to 3.5%) result in a move from standard petrol and diesel internal combustion engine vehicles to hybrid vehicles in 2010 to 2015. Conversely, buses swap from hybrid technologies to ICE technologies in the early periods of the model, and from battery technologies in the mid-periods to hybrid technologies. There are similar flips across all the transport modes. Overall, transport diesel consumption reduces significantly in the early parts of the model with petrol and biodiesel/kerosene increasing. There is a greater consumption of bio-fuels in final transport demand from 2035 (~40 PJ).

District heating from CHP and heat pumps are the largest providers of space and water heating services to both the residential and service sectors from 2035. Residential gas condensing boilers are largely phased out by 2035. CHP generates >100 PJ heat annually from 2030, delivered to residential and service sectors, also meeting ~4% of total electricity demand.

The marginal price of CO_2 reaches ~£290/tCO_2 in 2050, up ~£70/tCO_2 on P2-R2. The welfare cost also increases to ~£27B/annum (from ~£22B) in 2050, with the majority of the change the result of changes in energy service demands as opposed to system costs.

8.2 P2-R4-INV-C90-0: Run 4 Increased electricity sector investment costs

In June 2010, DECC published a report composed by Mott MacDonald on the levelised costs of electricity generation in the UK (Mott MacDonald, 2010). The appendices contain various assumptions including those for the current costs of electricity plant.

Table 26: Comparison of UK MARKAL and (Mott MacDonald, 2010) technology costs

Technology	UK MARKAL Range (2000£M)	Mott Prices (2000£M)		Ratio of Mott prices to MARKAL	
		Low	High	Low/Low	High/High
New IGCC	835-891	1,391	1,761	1.7	2.0
New IGCC with CCS	944-1,210	1,772	2,117	1.9	1.7
New PF plant	791-870	1,255	1,568	1.6	1.8
New PF plant with CCS	1107-1363	1,772	2,117	1.6	1.6
GTCC	400	505	621	1.3	1.6
Nuclear - combined E-PWR and AP1000 (URN)	1,050	1,945	2,606	1.9	2.5
Wind - Onshore /Off-shore	675-1315				
Wind: On shore	675	1,062	1,337	1.6	2.0
Wind - off shore	1196-1751	1,846	2,869	1.5	1.6

As noted in the study, the relationship between technology costs is relatively stable, such that a nuclear power plant will typically cost 30-50% more than a coal fired power station. However, many of the generation plant share component technologies, so a driver that influences a price increase in one or more components will be reflected across the generating technologies.

An important component driver of the increase in capital costs seen for all the generating plant in the above table is due to the global increase in commodity prices. The recent spike in costs of non-energy commodities such as metals, concrete has chemicals has had an impact on current costs of generation plant (as well as most other technologies built using the same commodities). However, UK MARKAL uses long-term costs for technologies – the Mott Macdonald (2010) report notes that the long term outlook for all technologies are likely to be at lower cost than currently quoted. Naturally, the future costs are subject to uncertainties as to their range of possible values. A second contributor to the high costs quoted in the report are supply chain constraints, and the long term outlook for most of the technologies lies along similar conclusions to those made above – new suppliers will enter the market in response to the price increase as a result of the supply/demand imbalance. Long term costs are likely to decrease or at least stay in the same area as those in the UK MARKAL model.

The costs in UK MARKAL were subjected to a rigorous peer review process outlined in the model documentation (Kannan et al. 2007).

8.2.1 Results

This scenario demonstrates the impact of more expensive electricity generation technologies, while the costs of other parts of the energy system are not subject to cost increases. The investment costs for all generation technologies (including CHP, wind, coal, gas, nuclear, biomass etc.) have been increased by a factor of 1.6 across the model time horizon, given the assumption that the differences seen in the Mott MacDonald (2010) report are a permanent phenomenon e.g. we have moved to a fundamentally more expensive technology landscape due to constrained supply chains, resources, commodities, greater demand from BRIC countries etc.

Main points are as follows:

- Electricity demand is lower, primarily from reduced demand for hydrogen, again used in the transport sector
- Biofuels displace some of the hydrogen in transport, with some biofuels imported
- Direct consumption of biomass increases, especially in residential and service sectors as a cheaper alternative to now expensive conversion devices such as CHP and district heating systems
- Final energy demands switch from heat (now too expensive relatively), coal (too dirty given the expense of decarbonising with electricity) and hydrogen, to petrol, biodiesel and bio-solids. Primary demand moves away from coal and biomass, to natural gas and nuclear electricity.
- Primary energy and especially final energy rise in later periods relative to energy service demand reductions - as the model switches away from the most energy efficient solution in meeting the CO_2 constraint (e.g. biomass pellets in residential and service sectors)
- There is an enhanced role for gas and gas CCS in the mid-term as these are relatively lower cost electricity technologies

- That delivered electricity is reduced most to H_2 production but also there is a reduction in all sectors (e.g. demise of LGV plug-in hybrid vehicles and assorted buildings technologies that use electricity)
- There is a reallocation of biomass from power and heat to buildings and transport

All comparisons are made to Phase II Run 3 unless stated.

As expected from a scenario in which the capital costs of power production have increased by 160%, the electricity sector is smaller and delivery of secondary fuels is reduced. In this scenario, electricity generation capacity falls by around 15 GW in 2050 to 121 GW. In order of decreasing size, the cuts are made in bio-waste & others, wind, co-firing CCS and coal CCS. There is a small increase in nuclear, gas CCS and biomass CCS. Gas investment shifts to earlier periods.

Electricity demand falls across all sectors, but especially in hydrogen. Hydrogen production from electrolysis is reduced by around 80 PJ from 2030 onwards, with around 40 PJ moving to gas SMR with CCS.

Electricity demand in the transport sector is reduced to an average of ~270 PJ from 2030, with petrol plug-in LGVs displaced by bio-diesel hybrids. There are other smaller reconfigurations – for example bio-diesel buses displace hydrogen buses in the middle periods and hydrogen buses displace battery buses in the latter periods.

The consumption of bio-products doubles to around 400 PJ by 2050, with the increase divided between transport, service and residential sectors. Biofuels make up >10% of total transport fuel demand from 2035 onwards. In contrast, hydrogen still makes up an increasing fraction of transport fuel demand; 12% in 2030 to >30% in 2050.

In the residential sector, energy service demands are reduced absolutely, heat from CHP is now displaced by gas condensing boilers in the medium term, and there is an increase in delivered solid biomass, including pellet boilers for hot water heating in 2050 (~50 PJ). The service sector suffers an absolute reduction in final energy consumption in the medium term, while in the final period, solid fuel deliveries increase even as energy service demands fall. In other words, the switch to final consumption in biomass results in less efficient delivery of energy service demands.

In the industrial sector, final demand for electricity and coal falls and there is a movement towards process use of natural gas.

Aside from the difference made to the transport sector and greater consumption of bio-fuels, the system wide changes are small – in the region of tens of PJ switching from one technology to another. Despite the electricity system shrinking a little in response to the increased technology investment costs, the overall effect is of increasing welfare costs by around 20% to around £33B in 2050. Decarbonisation of the electricity sector is still the predominant cost optimal strategy for such a deep reduction in CO_2 emissions to 2050.   The marginal cost of CO_2 reaches £100/tCO_2 in 2030 and £320/tCO_2 in 2050.

8.3 P2-R5-#: Run 5 Stochastic biomass availability

8.3.1 Changes since Run P2-R3

A stochastic bound on biomass availability (imports to the UK) is applied in accordance with the assumptions made in Phase I. Note that the SOW bounds are effective only from 2030 onwards. Before this period, central bounds are applied to all scenarios. These are summarised in the table below:

Table 27: Upper bound on biomass imports in PJ/annum

	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Central	0	210	420	630	840	1050	1260	1260	1260	1260	1260
High	0	420	840	1260	1680	2100	2520	2520	2520	2520	2520
None	0	0	0	0	0	0	0	0	0	0	0

Three future states of the world (SOW) are defined in the stochastic scenario that correspond to the *Central*, *High* and *None* biomass constraints, each weighted with an equal 1/3 probability (actually 0.34, 0.33 and 0.33 as total must sum to 1.00). The resolution of uncertainty was set to 2030 – the hedging strategy then runs until the 2025 period. Until 2030, the central biomass scenario holds for all states of the world. From 2030 to 2050, a recourse strategy is in place, in which the respective upper constraints are active.

The stochastic scenario was applied to P2-R3-HUR-C90-#, so the modified hurdle rates apply in this scenario and are compounded with uncertainty surrounding biomass resource availability.

8.3.2 Results: P2-R5-#

Key points:

- The hedging strategy is very minor – no single change amounts to more than 10 PJ of energy or 2 GW capacity.
- Neither the central nor high biomass constraints are hit in the relevant scenarios (this is also the case for the deterministic scenarios P2-R3-HUR-C90-# and P2-R4-INV-C90-#). As such, the recourse strategies for *High* and *Central* scenarios are identical.
- Domestic biomass production increases slightly in the *none* state-of-the-world recourse period to <800 PJ by 2050 over <600 PJ in *Central* and *High* SOWs.
- The EVPI of £91M shows that introducing uncertainty in biomass availability has only a small cost under the current scenario assumptions

8.3.2.1 *Hedging strategy*

The hedging strategy of the current run, in comparison to P2-R3-HUR-C90-#, has only minor differences. Evidently, either the cost of including uncertain biomass availability is minor in comparison to the 90% CO_2 reduction target imposed in both the scenarios, or the model is unable to respond given the stringency of the decarbonisation target.

To 2025, the energy system exhibits a minor, inter-temporal reordering. Final energy demand drops a few PJ, with electricity consumption decreasing 12 PJ and gas/bio-methane consumption increasing by 13 PJ in 2015. In 2025, gas/bio-methane consumption drops back by 24 PJ. The service sector reduced final energy use by 20 PJ in 2025, the end of the hedging period, while the residential sector increases biomass consumption by the same amount.

Note that bio-product imports average ~50 PJ/annum during the hedging strategy, and consist of imports of bio-diesel and ethanol to meet the RTFO. The levels of imports in the hedging strategy are the same is in the equivalent years of the P2-R3 scenario.

8.3.2.2 ***Recourse strategies***

As mentioned above, the recourse strategies for *Central* and *High* scenarios are identical. The availability of biomass in the *Central* and *High* scenarios is the same as the P2-R3-HUR-C90 scenario. The recourse strategies essentially 'correct' for the expected-cost based decisions made in the hedging strategy, while the hedging strategy is optimised to minimise the weighted welfare costs in the recourse strategies. Given the minor changes seen in the hedging strategy, the changes in the recourse strategies are equally small.

In 2050, there is 1 GW more wind in the electricity sector and slightly less electricity CCS (-1 $MtCO_2$). The transition, 2030-onwards, shows an increased for district heat (~10 PJ) consumed in the residential sector and a minor re-ordering in transport with a reduction of bio-diesel in the transport sector in 2035.

The *Low* recourse strategy displays relatively more dramatic behaviour in response to a ban of biomass imports from 2030 onwards. There is an increase in size of the electricity sector, specifically in co-firing CCS (+3 GW from 2030), gas (+2GW in 2040 to +4 GW in 2045-50). Biomass CCS is excluded in the final two periods and ~11 GW of nuclear is built between 2040 and 2050. Wind capacity also increases 13 GW over P2-R3-HUR-C90 to a total of 37 GW by 2050. Biomass consumption by co-firing CCS increases by 40 PJ/annum from 2030 onwards. The 30% renewable electricity constraint is less binding in the *Low* SOW than other scenarios, indicating that there is some tension between availability of bio-energy resources and renewable electricity.

Domestic biomass production increases in response to the constraint on imports, mainly through the exploitation of additional agricultural wastes (up ~190 PJ in 2050). Domestic biomass resources are not exploited to their physical limit under the no-import constraint.

While primary energy increases by ~180 PJ to 2050, final energy decreases overall by ~130 PJ, with a number of adjustments to the mix of delivered fuels. There is a fall in wood fired CHP from 2030 (-180 PJ), replaced through a combination of demand reduction (3-5% below P2-R3), gas condensing boilers (in the service sector) and electric heating in both sectors. However, space and water heating for both service and residential sectors continues to rely on electricity, heat pumps and district heating from wood fired CHP in 2050. Transport fuel demand decreases by ~40 PJ by 2050, with increased consumption of diesel and hydrogen displacing petrol and bio-fuels. Diesel plug-in cars replace diesel hybrids, while hydrogen cars replace petrol hybrids and plug-ins. Final use of electricity increases by ~200 PJ in 2050, 60 PJ more to produce hydrogen, 85 PJ to industry and ~70 PJ to the residential sector.

The lack of biomass generates a readjustment in CO_2 emissions between sectors. In comparison with P2-R3, residential and transport emissions increase in the mid-term (2030 to 2040). From 2045, emissions savings are found in transport and industry sectors to allow for greater emissions in the electricity sector. Hydrogen production switches from gas SMR to electrolysis (~50 PJ) in 2040.

While consumption of primary biomass is reduced by ~250-500 PJ between 2040 and 2050, the reduction in final consumption of biomass is much lower. This is due to i) most biomass is consumed by conversion processes such as co-firing CCS or wood fired CHP ii) the decrease is transport consumption of bio-products (~70 PJ in 2035) is countered by an increase in industry (~30 PJ increase in bio-methane consumption). The constraints on biomass result in a prioritisation of final biomass use in industry and service sectors; while transport and residential sectors are able to decarbonise through alternative technologies (electricity and hydrogen respectively).

The constraint on biomass availability results in a steeply rising CO_2 marginal price from £100/tCO_2 in 2030 to ~£400/tCO_2 in 2050. The extra welfare costs incurred are largely a result of demand reduction in the latter periods of the recourse strategy (~£2B in 2050).

8.4 P2-R6-# & P2-R7-#: Run 6 Stochastic biomass availability with crude bioenergy lifecycle emissions at 75% saving of fossil equivalents & Run 7 Stochastic biomass availability with crude bioenergy lifecycle emissions at 50% saving of fossil equivalents

In addition to the stochastic bound on bio-energy availability applied in the previous run, scenarios 6 and 7 include a crude approximation of the lifecycle emissions from bio-energy resources.

The bio-energy lifecycle emission factors have the effect of reducing the carbon benefits of biomass resource use. The 75% saving scenario (P2-R6) is more modest than the 50% saving scenario (P2-R7).

UK MARKAL previously assumed zero carbon emissions for biomass resources. This assumption is consistent with the fact that any carbon contained within a plant is sequestered from the atmosphere when the plant grows. However, this assumption ignores any carbon emitted from, e.g. harvesting, fertiliser or transport use during the production of the biomass. In UK MARKAL, certain bio-products are able to indirectly replace fossil equivalent technologies e.g. co-firing and co-firing CCS plants allow a mixture of up to 25% solid biomass in the input fuel stream, and so the carbon benefit depends upon the end use of the biomass. The hedging and recourse strategies for both scenarios are modest both through 2025 and in the slight amount of reshuffling in the later periods. This seems fair given the model is only reacting to a 33% chance of low bio imports (central and high cases are identical).

The largest driver is the assumed biomass lifecycle emission factor which significantly diminishes its decarbonisation attractiveness. Laid on top of this, the impact of no bio imports is a smaller effect as the demand for biomass has declined significantly anyway.

The main reasons for the minor hedging strategies are: i) the lifecycle emission factors only have a significant effect in the later periods of the model in combination with the stringent carbon constraint and critical requirement for low-carbon fuels ii) biomass use in the early periods of the model is largely constrained in by the RTFO iii) the difference between optimal biomass imports with lifecycle emissions and biomass imports constrained to zero is just 28 PJ in 2050 in P2-R7 and 41 PJ in 2050 in P2-R6.

Note that both the timing and quantity of emissions change throughout the model horizon, depending upon the assumed emissions factor.

Table 28: Annual lifecycle emissions in the two scenarios P2-R6 and P2-R7 (kilotonnes of CO_2)

	2000	2010	2020	2030	2040	2050
75% lifecycle, central avail.	545	2,864	3,242	8,094	11,294	10,475
50% lifecycle, central avail.	1,090	5,536	4,923	8,896	9,030	5,624

For each run, the “-1” suffix denotes Central biomass availability, “-2” Low biomass availability and “-3” High biomass availability.

8.4.1 Results: P2-R6-#

8.4.1.1 *Effect of including biomass emissions*

The obvious effect of including 25% emissions burden on biomass is of significantly reducing biomass consumption in comparison to runs without the emissions burden. By 2050, 500 PJ less primary biomass is consumed in 90% CO_2 reduction scenarios. There are tandem reductions in oil and gas consumption, perhaps indicative of the ‘enabling’ power of biomass resources for bio-fuel blends and bio-gas/bio-methane production. However, the reductions in primary biomass are not significant until the post-2030 period when the severe carbon target becomes the most significant constraint upon the development of the energy system. Electricity is the primary replacement for the reduction in biomass in the lifecycle emissions scenarios.

In final energy, there is a large reduction in delivered heat; largely as the wood fired CHP in the P2-R3 related scenarios is less viable from a carbon perspective if the lifecycle emissions of biomass are included. Final energy reduces by around 140 PJ by 2050 over non-lifecycle scenarios with the largest reductions in residential and service sectors, followed by industry and transport.

While biomass CCS is squeezed to just 1.2 GW in 2050, co-firing with CCS increases over the model horizon to a maximum of ~13 GW in 2050. Primary coal also increases by 50 to 100 PJ per annum from 2030 onwards. Nuclear, gas, co-firing CCS and wind make up the components of a large (170 GW) electricity system in 2050 producing almost 2,300 PJ of electricity per annum. Half of the electricity is generated by a 44 GW nuclear fleet and almost 60 GW of wind turbines produce ~500 PJ of electricity in 2050. Nuclear availability is important (i.e. the nuclear build rate constraint is very restrictive) for reducing costs of the decarbonisation in both the scenarios – as a relatively low carbon technology independent of biomass. Note that negative emissions do not occur in the electricity sector in either scenario; inclusion of the life-cycle biomass emissions cancels out the negative emissions from sequestering biomass due to the reduced efficiency of biomass combustion, when compared with coal, and the inherent inefficiencies in carbon capture and storage processes. Note that biomass and co-firing CCS processes *are* still chosen, it is just that they are less effective (more costly) at reducing the same quantities of CO_2.

As a result of the change in the structure of the energy system, through accommodating the lifecycle emissions from biomass, the electricity system sees a >10MtCO_2 increase by 2050, with large decreases in response focussed on the hydrogen, industrial and transport sectors.

Notably, the transport sector does not electrify further given the reduction in biofuels consumed, with hydrogen, diesel and demand reduction largely replacing energy requirements in the latter two model periods. The increase in electricity generation is consumed primarily by the residential, industrial and hydrogen sectors in 2035 to 2050.

Demand reduction is deeper than the non-bio-energy lifecycle emission scenarios for most energy service demands (especially residential and service sector heating and hot water) and less for others (such as residential and service cooling and the iron and steel sector). Contrary to the received wisdom that biomass was essential for transport sector decarbonisation; if hydrogen is available (and viable) then residential and service sector heating and hot water are the areas in which reductions in biomass are felt most keenly. However, there is an indirect effect on the transport sector, as the reduced 'headroom' under the carbon cap by accounting for biomass lifecycle emissions results in greater pressure for demand reduction placed on the inflexible transport options, such as domestic navigation and domestic aviation.

Residential and service sector heating and hot water, moves strongly away (~-80%) from district heating and wood CHP and is largely met from increased uptake of delivered electricity for heat. There is also a small reduction in heat pumps. There is a mid-model increase in the direct consumption of solid biomass for both residential and service sectors.

Between 2030 and 2050, biofuel imports are ~50% of those in the P2-R3 scenario. Bio-diesel is lower from 2035 onwards. Hydrogen production increases (up 3 to 50 PJ) from 2035 and production shifts to electrolysis.

8.4.1.2 *Effect of introducing uncertainty in biomass availability*

The introduction of uncertainty results in only very small change in primary energy use. A deterministic run under a low biomass constraint results in an early response to the future reduction in biomass availability. The hedging strategy is very close to the deterministic central and high availability of biomass scenarios. This is understandable given the very small recourse response in the low biomass scenario, coupled with the 33% likelihood.

8.4.2 Results: P2-R7

8.4.2.1 *Effect of including lifecycle emissions for biomass at 50%*

The core message of this run is similar to that of the previous run, except that the reductions in biomass are deeper, as are the corresponding moves to alternative sources of energy. Primary energy is reduced by ~2 PJ per year from 2025, until 2035 when primary energy then increases by around 200-300 PJ for the final two periods as a result of significant additional nuclear and renewable capacity. Primary biomass consumption decreases by a further 300 PJ on P2-R6; a total of ~950 PJ on P2-R3. Primary biomass consumption hovers at the low level of 200-250 PJ from 2010 to 2050.

Final energy is cut by 60 PJ from 2015, to ~300 PJ in 2050. The largest reductions are from district heat, gas/bio-methane and petrol. Final consumption of electricity (1,600 PJ) and hydrogen (400 PJ) increase, to equivalent levels to P2-R6. Note that overall final energy consumption is 200 PJ less that in P2-R6 in 2050, but similar in the earlier model periods. A significant proportion of bio-products are directed to the industrial sector, with 75 PJ to 170 PJ between 2030 and 2050 comprised of up to 2/3 bio-methane. This is in conjunction with significant decarbonisation of the industrial sector processes through uptake of industrial CCS that hits the build constraints.

There is a large increase in conservation uptake in the service sector of 130 PJ.

In the electricity sector, the withdrawal of biomass results in a slightly smaller (in capacity) electricity system by 2050. 4 GW of coal CCS displaces 5 GW of co-firing CCS, while 11 GW of nuclear displaces 4 GW of wind, 2 GW of bio-waste & others and 8 GW of gas. In energy terms, more electricity is produced in comparison to P2-R6 in the penultimate three model periods. In 2050, however, electricity production is constrained by the severe carbon target. As mentioned above, coal CCS displaces around 5 GW of co-firing CCS. However, the electricity output decreases over the horizon, so that the 110 PJ increase over P2-R6 in 2030 decreases to 100 PJ in 2040 and 0 PJ in 2050. Nuclear displaces both this decreasing electrical output, and that of wind.

The sectoral demand for electricity continues the patterns seen in P2-R6. Hydrogen demand increases by ~60 PJ from 2035, and comprises the majority of increase in demand. Residential demand also increases by 20 PJ from 2040, followed by industry in 2045 (up 20 PJ). All other sectoral electricity demand decreases.

There are a number of conflicts between constraints and the biomass emissions in both scenarios. For example, a constraint specifying a minimum quantity of biomass boilers in the core scenario is costly, especially in 2050.

8.4.2.2 *Effect of including uncertainty in biomass availability with lifecycle emissions for biomass at 50%*

Again, like the previous run P2-R6, exploring lifecycle emissions with uncertain biomass availability results in little extra insight besides that from the introduction of lifecycle emissions factor.

There is a minor hedge to account for the (now) small effect of constraining biomass imports to zero in the low biomass availability scenario, but this in the order of hundreds of TJ rather than PJ (i.e. an order of magnitude lower than that shown in the results sheets).

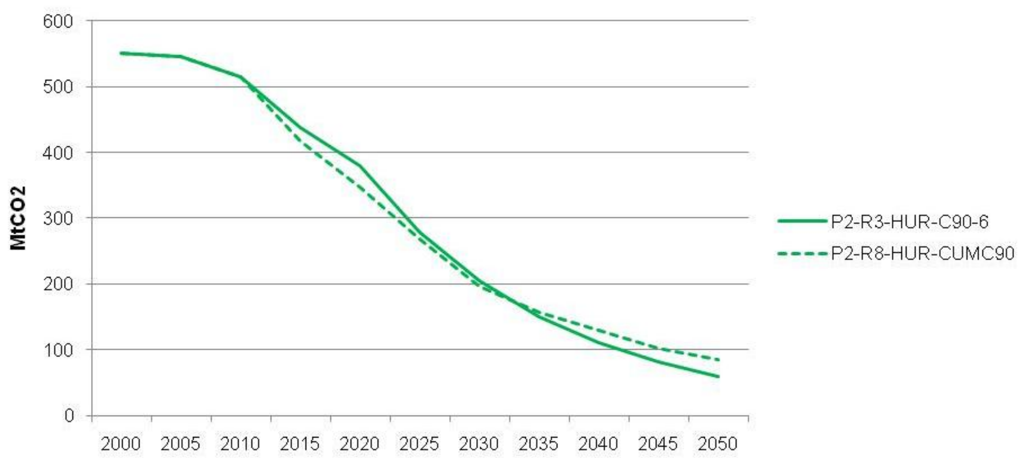
The lack of zero carbon biomass has significant cost implications, especially at the margin. CO_2 marginal prices rise from £290/tCO_2 to £520/tCO_2 (£610/tCO_2 in the low biomass recourse) in the 75% saving scenario to £1320 (£1440/tCO_2 in the low biomass recourse) in the 50% saving scenario. Welfare costs rise from £27B in P2-R5 to £33B (£33.1B in the low biomass recourse) in the 75% saving scenario and to £36.1B (£36.9 in the low biomass recourse) in the 50% saving scenario. This is due both to a more expensive, albeit smaller, overall energy system and also the cost of increased demand reductions.

8.5 P2-R8-HUR-CUMC90 – Cumulative CO_2 constraint (equivalent to a C90 scenario)

In this scenario, the model has full inter-temporal flexibility in allocating emission reduction in order to meet a cumulative CO_2 constraint (16.56 GtCO_2 over a 50 year horizon), set to be equal to the Phase 2 core C90 case (P2-R3-HUR-C90-6). Note that the cumulative constraint is additionally constrained to match this core P2-R3 case's CO_2 emission in 2000-2010. Thus the emissions inter-temporal flexibility is from 2015-2050.

This deterministic scenario is compared directly against P2-R3-HUR-C90-6.

Figure 8: CO_2 emissions in P2-R8 under a cumulative constraint



Generally speaking the temporal flexibility moves abatement action earlier (2015-2030) and reduces CO_2 abatement in later periods (2035-2050). Note the largest impacts are seen in year periods 2020 and 2050 respectively. This inter-temporal switch occurs because the model is striving to minimise the very high cost emission reductions in later periods, and replaces them with relatively cheaper near term reductions. This effect outweighs the opposing effect of discounting (which is only at 3.5%) which would be expected to shift emissions abatement later. This pattern of temporal shifting to earlier abatement is consistent for CO_2 emissions, final energy, CO_2 prices and welfare costs.

Compared to P2-R3-HUR-C90-6, the cumulative CO_2 run reduces emissions by a further 34 $MtCO_2$ in 2020 and increases emissions by 26 $MtCO_2$ in 2050. Near term emission reductions occur across all sectors but especially electricity, industry and transport. This raises the 2050 emission cap in 2050 from 59 to 86$MtCO_2$, and critically this additional emission allowance means that a range of expensive mitigation options are not required.

Additional flexibility gives clear changes in cost impacts, with 2020 CO_2 marginal prices rising £40/tCO_2 to a level of £70/tCO_2, and 2050 CO_2 marginal prices falling by £90/tCO_2 to only £200/tCO_2. Welfare costs are similarly impacted with an additional £1.9billion cost in 2020 (driven largely by loss in consumer surplus from accelerated demand reductions) but with a £5.9billion gain in 2050. Discounting (at 3.5%) across the whole model horizon, gives a saving from inter-temporal CO_2 target flexibility of £4.8billion.

Final energy is reduced by a cumulative 2EJ, with the biggest annual reduction of 280PJ in 2020, and a long term increase of 70PJ seen in 2050. Final energy near- and long-term changes are seen in all sectors. In the near term reductions are in coal, diesel, gas and manufactured industrial fuels. In the long term, more gas and diesel is allowed with reductions in (expensive) hydrogen and biodiesel use. Impacts on heat are further nuanced with reductions in the near term due to demand reduction and reductions in the long term due to the avoidance of (expensive) biomass-CHP derived heat.

Primary energy shows a similar pattern with a cumulative reduction of 4EJ. Near term reductions in coal, oil and gas, are partially balanced by near-term increases in biomass resources. 2020 sees the maximum decline in primary energy of 350PJ. In the long-term, additional fossil fuel use alleviates the use of biomass resources and some nuclear. Note that primary energy is down in 2045-2050 due to the avoidance of expensive and energy-inefficient zero carbon options. In terms of primary bio resources, cumulative reductions of 4.3EJ are seen (out of a total of around 28EJ in the core P2-R3 run).

Electricity generation sees the avoidance of a range of long-term expensive zero carbon options and an overall reduction in electricity of 70PJ in 2050. In 2050 electricity CO_2 emissions are no longer negative (1MtCO_2 vs. -12MtCO_2 in the core P2-R3 case). Specifically, no biomass CCS is required (-90PJ), and around 70PJ of co-firing CCS switches to coal CCS. Additionally 55PJ of nuclear is not required and this additional system flexibility (combined with more plug-in hybrid vehicle electricity storage) facilitates an additional 35PJ of long term wind generation. In terms of electricity capacity, early investments (in 2015) in CCS are boosted (1.5GW – up from 1.0GW), and an additional 7GW of wind is seen by 2050.

Transport sees a similar alleviation of expensive long-term mitigation options, with 2050 transport emission rising from 14 to 23 MtCO_2. An inter-temporal switch in use of petrol & diesel cars reduces the use of 40PJ of hydrogen and 25-60PJ of biodiesels. This is supported by early adoption of bus hybrid vehicles, and near term demand reductions in HGV and LGV options. Also in the near-term, higher levels of low carbon electricity facilitates LGV plug-in vehicles and an accelerated electrification of the rail network.

Near-term energy service demand reduction is particularly important with an average 2020 reduction rising from a core run level of 7% to 9%. Individual energy service demand reduction increases (>5% in addition to core P2 reductions) are even more striking in the near term, notably industrial subsectors, agriculture, residential space and water heating, service space and water heating, HGVs, shipping and non-energy demands.

In remaining impacts, there is a near term coal to gas switch in industrial sectors, cumulative CCS requirements rise by 113MtCO_2 (but only a 4.3% increase in a total of 2630MtCO_2 and hence no additional constraint on reservoir capacity), while hydrogen reductions (50PJ in 2050) are from both methane SMR (-10PJ) but mainly from electrolysis (-40PJ).

8.6 P2-R9-BUILD – Power sector build-rate sensitivity

8.6.1 Changes since Run P2-R3

In this scenario, the build rate constraints enforced in P2-R3-HUR-C90 are relaxed. These were:

Table 29: Build rates for main generation technologies in P2-R3

GW/year	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
CCS (elec)	0.5	0.5	0.5	0.5	0.5	1.0	1.5	2.0	2.0	2.0	2.0
Nuclear	0.5	0.5	0.5	0.5	0.5	1.0	1.5	2.0	2.0	2.0	2.0
Wind	n/a	n/a	n/a	n/a	2.7	2.7	2.7	2.7	2.7	2.7	2.7

The new build rates for the current scenario are:

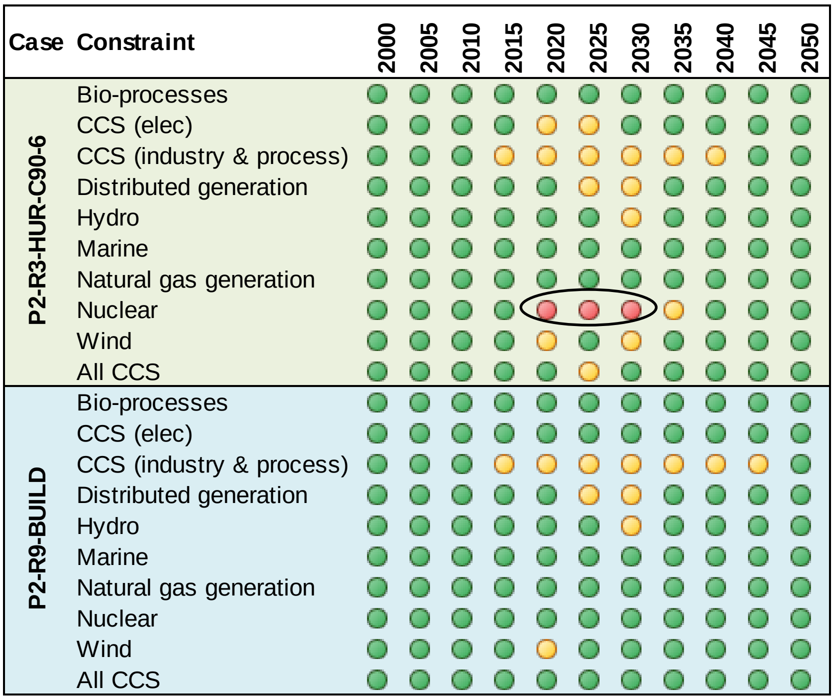
Table 30: Build rates for main generation technologies in P2-R9

GW/year	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
CCS (elec)	0.5	0.5	0.5	0.5	2.0	2.0	2.0	3.0	3.0	3.0	3.0
Nuclear	0.5	0.5	0.5	0.5	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Wind	n/a	n/a	n/a	n/a	2.7	2.7	2.7	2.7	2.7	2.7	2.7

8.6.2 Results

Figure 9 lists the build constraints in the model and shows an indication of the severity at which the build constraints bind in two scenarios. The nuclear build constraint in P2-R3-HUR-C90 has a particular effect between 2020 and 2030 inclusive. In P2-R9- BUILD, increasing the build rate constraint from 0.5-1.5 GW per year to 3 GW per year enables a lower cost decarbonisation effort. Likewise, relaxing the electricity sector CCS build constraint seems to have had a similar effect – however this is not the case as CCS is largely displaced by nuclear in this scenario.

Figure 9: Indication of level at which build-rates constraints apply in alternate scenarios



Relaxing the nuclear build constraint allows the model to build earlier than in P2-R3-HUR-C90, netting out as an additional 6-8 GW total, displacing co-firing CCS in the process, as well as later nuclear investment (note that the nuclear share is up 15GW in 2030 for one period only). Generally, nuclear capacity averages 37 GW from 2030, in an electricity system rising from around 110 GW to 130 GW between 2030 and 2050. This scenario's electricity system is around 4 GW smaller than P2-R3 in 2050.

The large increase in the severely binding nuclear build constraint results in extra investment of ~8 GW of nuclear in the 2025 and 2030 periods. This largely displaces investments in co-firing CCS, hydro, wind and gas in 2025 and wind, co-firing CCS, coal CCS and imports as well as later nuclear investment. By 2050, the electricity system has much the same structure as in other low carbon scenarios (i.e. P2-R3-HUR-C90 and P2-R11-LOWGAS), with gas, nuclear and wind holding a 25% share of generation capacity each, the remaining 35 GW made up of co-firing CCS, biomass CCS and other renewables. In energy output terms, nuclear generates 50% of the electricity - some 900 PJ per annum.

The relaxation of the nuclear build constraint allows earlier and faster decarbonisation of the electricity system, allowing other sectors to delay investments in more expensive low carbon technologies. The peak impact is in 2030 – this greater availability of nuclear electricity gives path dependent effects through 2050.

The reduction in co-firing CCS result in an annual reduction in biomass demand of ~90 PJ and ~370 PJ of coal and means that captured CO_2 drops by 30-40 $MtCO_2$ to total 85 $MtCO_2$ in 2050 including 47 $MtCO_2$ from industrial and process CCS technologies. This reduction in CCS results in a -20 PJ demand reduction in upstream electricity use.

The increase in nuclear capacity results in ~ 72 PJ of extra electricity available for consumption in 2030, and this is directed to industry, residential and service sectors. The nuclear electricity displaces some gas generation, and this natural gas is instead used as delivered fuel for generating residential, service and industrial sector heat.

The effect on the transport sector is rather modest - there is a small increase in transport electricity consumption, and the extra emission freedom allowed by a 'cleaner' electricity system accommodates a switch of bio-diesel for mineral diesel in 2035. Hydrogen production is relatively stable, although there is a small move to gas SMR with CCS from electrolysis in 2040.

Residential heating switches a proportion of demand from district heating to gas, heat pumps and solid fuel/wood in the medium term, some of which is a direct switch from the service sector. A proportion of district heating moves to the later periods from (2020-30 to 2035-40), and demand also moves to the service sector. The service sector sees increased early (2025-40) investment in heat pumps, as well as a reduction in solid wood fuel, electricity and gas.

Direct rebound effect in industry and the residential are evident in 2030, as electricity is cheaper here although this is reversed in later periods. Those energy service demands that are more completely served by electricity are most effected e.g. 'residential refrigeration' and 'electrical', rail transport (freight and passenger), service sector lighting and 'other electrical'.

The CO_2 marginal costs are down by ~£10/tCO_2 (70 vs. 80) in 2030s but up £10-20/tCO_2 in 2040s &2050 (300 vs. 290). This occurs as the model is optimizing over the full time period and discounts later periods.

Welfare gains in 2030s are maintained (but with diminished gains) through 2045 but with increased welfare loss (increase of 2.6B to 29.6B) in 2050. The change in overall discounted welfare is ~ £5B.

8.7 P2-R10-#: Run 10 Stochastic fossil fuel prices on P2-R3-HUR-C90

This run considers the effect of uncertainty in future fossil fuel prices on the UK energy system, given the amended assumptions of P2-R3-HUR-C90.

For ease of comparison, the resolution of uncertainty is the year 2030, so that a stochastic hedging strategy is revealed, demonstrating optimum near-term behaviour given the uncertainty in future fossil fuel price. As in previous stochastic fossil fuel price scenarios, the distribution of future prices is defined by four states of the world of equal weight; low, central, high and high-high scenarios. This results in a hedging strategy that responds to an, on average, high fossil fuel price future.

8.7.1 Hedging strategy:

There is one hedging strategy for the P2-R10 scenario. The hedge is minor, with primary energy increasing in the early periods in comparison to the deterministic P2-R3-HUR-C90 scenario (used as a reference throughout this analysis). Natural gas increases the most (on average 10 PJ/year), while coal and oil decrease.

Final energy demand increases, predominantly in the residential, industrial and service sectors, again mostly through increases in final consumption of natural gas.

In the electricity sector, there is some, minor restructuring, with 1 GW less wind by 2025 replaced by an extra 1 GW of gas CHP. Electricity demand also changes, with demand increasing slightly in industrial and residential sectors, and decreasing in the service sector.

In transport, there is an early adoption of small quantities of hydrogen (+2 PJ) in 2025, displacing diesel (-3 PJ).

Residential and service sector heating configurations see much change, with symmetrical swaps of wood between the two sectors in different time periods (probably because they share very similar technologies and parameter specifications). Overall, residential gas consumption increases on average by 10 PJ per year, while oil decreases by 2 PJ per year and heat increases by 1 PJ per year. The service sector increases consumption of gas and wood, but decreases consumption of diesel, electricity and heat. CHP output increases by 3 PJ (electricity) in 2025.

Industrial demand for coal falls.

8.7.2 Recourse strategies:

In 2030, there are strong responses to the change in price of fossil fuels from the central price prevalent in the hedging period. Primary natural gas demand increases/decreases the most, with the low scenario consuming ~270 PJ more in 2030 and ~40 PJ more in 2050 than P2-R3.

General trends are as follows:

In 2050, as fossil fuel prices increase across the scenarios, the level of primary fossil fuels and biomass & waste decrease, while 'low' carbon technologies (renewables and nuclear) increase. In 2050, the scenarios are relatively similar, with the low and high fossil fuel price within 2% of each other. However, trade-offs within primary resources and final energy change between the scenarios for the middle periods (2030 to 2045). Across all the scenarios, there is an overall reduction in the consumption of primary fossil fuels to 2050, thus reducing the 'exposure' of the system to the changes in fossil fuel price. CHP capacity increases as fossil fuel prices decrease.

Low fossil fuel price:

In comparison to the deterministic central fossil fuel price scenario (P2-R3-HUR-C90), natural gas displaces biomass, coal and nuclear electricity in the middle periods. Almost two thirds of the natural gas is in final energy (residential and service sectors, with a little in industry), with the remaining third used in various conversion technologies (gas CCS and hydrogen from gas SMR with CCS).

Central fossil fuel price:

Given the minor adjustments in the hedging strategy, the recourse strategy for central fossil fuel prices moves to a slightly different energy system to that if uncertainty is ignored under a purely deterministic scenario (such as P2-R3-HUR-C90). The electricity system has less wind and co-firing and more nuclear than P2-R3. There is a decrease in primary energy demand for coal and biomass in the recourse strategy, while there is an increase in demand for natural gas and nuclear.

High fossil fuel price:

Under a high fossil fuel price investments in coal CCS and nuclear increase over the central scenario. Co-firing CCS and biomass CCS investment is lower than in P2-R3-HUR-C90. Bio-fuels and hydrogen (increasing demand for electricity) make stronger inroads into the transport sector, while the emissions saved in the transport sector enable industry and the electricity sector to emit more.

High high fossil fuel price:

The use of natural gas tends to be very sensitive to assumed price, far more so than the other energy carriers in the model. In this scenario, demand for natural gas is very much reduced, and this has a large effect on decarbonisation of the electricity system in 2030, which takes up a disproportionately large share of emissions (10% instead of 5% in the other scenarios). This means that the burdens for emission reductions are placed on the following sectors: transport - through a very large (+100 PJ) increase in imported bio-diesel; residential – a reduction in gas central heating and increase in district heating and demand reduction; and upstream - through using less CCS. High fossil fuels prices seem to slow decarbonisation of the electricity system meaning more pressure is placed upon other sectors and more emphasis on demand reduction. It becomes cost effective in 2050 to invest in biomass CCS.

Electricity system:

Common features between 2030 and 2050 across the scenarios are as follows. Nuclear power increases in capacity from 16 GW to 32-37 GW. The electricity system increases in size from 107-108 GW to 131-141 GW, and electricity output from 1,386-1,432 PJ to 1,839-1,890 PJ. As the energy system decarbonises (i.e. out to 2050), the scenarios' energy systems become more alike as they move away from fossil fuels. Note that the percentage of renewables on the system stays constant across the scenarios in 2050 (at ~33% of energy), but differs in 2030 when renewable investment increases with higher fossil fuel prices.

Marginal price of CO_2

There is a relationship between the fossil fuel price and the marginal price of CO_2 to meet a 90% target by 2050, such that as the fossil fuel price increases, the marginal price of CO_2 decreases. In the low fossil fuel price scenario, the price increases to £120/tCO2 in 2030, in comparison to £40/tCO2 for the high-high scenario. However, as the system decarbonises, due to the lack of alternative technological choices and reflecting the homogeneity between the scenarios in the 2050, there is a convergence between the carbon prices, so that the range sits between £260-320/tCO2 (high-high to low).

Constraints:

Under low fossil fuel prices, access to more CCS (e.g. industrial CCS) offers a lower cost option to decarbonisation, but this benefit reduces as i) fossil fuel prices increase and ii) the energy system decarbonises and the carbon cap lowers. Conversely, under high-high fossil fuel prices, constraints on distributed generation and renewables are more costly than under low fossil fuel prices. In all scenarios, build constraints on nuclear increase the cost of decarbonising the energy system. Biofuel consumption is linked to fossil fuel demand, so that low fossil fuel prices enable a greater uptake of biofuels in the transport sector, but often high fossil fuel prices are required to make biofuels appear cost effective. Hydrogen uptake is relatively stable across all the scenarios, (138 PJ in 2030 rising to 350-369 PJ in 2050). Electric vehicle and plug-in hybrid uptake is constrained in the core scenario, and there is not much variation around this constraint because of this.

Scenario cost:

The expected value of perfect information, that is the cost of including uncertainty in this scenario is £5B, implying that improving information on future fossil fuel prices (if this were possible) would significantly reduce the cost of moving to a low carbon energy system.

8.8 P2-R11-LOWGAS – Central fossil fuel prices for coal and oil, low fossil fuel prices for natural gas

In this scenario, a low fossil fuel price is applied to natural gas, while all other commodities experience central prices. Note that the price trajectory is not the same as that in the stochastic fossil fuel price scenarios (P2-R10-#) as the central price for all commodities is held in these scenarios until the resolution of uncertainty period (2030 in most cases). The low fossil fuel price scenario, derived from UK Government figures and published by the DECC (2010), begins much earlier and shows a smooth transition to a low natural gas price.

This deterministic scenario is compared directly against P2-R3-HUR-C90-6.

Primary natural gas demand increases dramatically, peaking at a 600 PJ increase in 2030 over the P2-R3 scenario. Natural gas use does decrease over time, as in other low carbon scenarios, but remains 100 PJ above that seen in P2-R3 from 2010 onwards. The increase in primary natural gas results in decreasing consumption of other fossil fuels, particularly coal and oil. As coal consumption is largely used in co-firing CCS plants, biomass consumption also falls. Primary energy increases overall as a result of cheap natural gas and, in the latter periods of the model, sees increases in nuclear energy.

Note that there is a mid-term growth in final energy; +160PJ in 2020. This is in effect a direct rebound effect. In later periods, the declining role of natural gas and the growing proportion of CO_2 price erode final energy gains.

The majority of the increase in primary natural gas is used directly by end-use sectors. The remainder of the gas is directed towards a large increase in gas CCS, with 6 GW built in 2030 displacing 3 GW of co-firing CCS, 1 GW of coal CCS, 2 GW of unabated gas generation and 1 GW of wind. Despite these changes, the majority of electricity generation is produced by nuclear, wind and co-firing CCS. Note towards 2050, the residual emissions from gas CCS are too high, and electricity from gas CCS reduces as the carbon cap descends. Medium term electricity demand increases slightly in the residential, industrial and transport sectors. There is a large (relative) decrease in electricity consumption for hydrogen production in the 2035-40 periods, although a small increase in 2045 and 2050 as negative emissions electricity becomes available through investment in biomass CCS.

Bio-fuel in transport increases between 2030 and 2040 displacing similar quantities of diesel and petrol. In the final periods, hydrogen increases, produced from a mixture of gas SMR with CCS and electrolysis. In 2030, emissions from the transport sector are 8 $MtCO_2$ lower than P2-R3, allowing growth in residential, service and electricity sectors. This is afforded largely through a move away from petrol hybrid vehicles to diesel/biodiesel hybrids coupled with the displacement of ~100 PJ of mineral diesel with biodiesel, earlier adoption of hydrogen HGVs, two-wheelers moving to hydrogen and demand reduction.

In the residential sector, natural gas demand for heating increases in the near term, and displaces alternative fuels such as oil, solid fuel and wood fuel. In the medium to long term, district heating is mildly reduced while electric heating and heat pumps increase very slightly. There is an overall increase in energy consumption in residential heating, which addresses the large energy service demand reductions seen in the energy service demands for hot water and heating in 2015 and 2020. The model is balancing the welfare benefit of lower energy service demand reduction, with the carbon implications of consuming cheap natural gas instead of oil, solid fuel or delivered electricity.

In the mid-term, emissions move around between sectors, with CO_2 from electricity and residential sectors up and those from transport down. This is occurs due to the trade-off between much cheaper (but slightly dirtier – due to displacement of co-firing CCS with gas CCS) electricity making more expensive emissions mitigation in the transport sector cost effective at a system level. Over the longer term, this trade-off flips, so that the cheap but (relatively) dirty electricity begins to hit higher cost of further mitigation in other sectors. Ultimately, the result is that gas is pushed out of the electricity system and a now-familiar 2050 energy system instated.

The social benefits of the lower cost electricity and natural gas are evident in the change in consumer & producer surplus, with 2020 - 2030 increases over P2-R3 of £5B-£6B (-£13B in P2-R3 to -£8B in P2-R11). Welfare costs ease by £6B (2020) to £1.2B (2050) largely due to cheaper gas and hence cheaper energy system – hence overall there is only a very small net loss in welfare in 2020 but in 2050 compare welfare losses increase from £25.8B to £27.0B.

The CO_2 marginal price is up £20-40/tCO_2 – largely as there is cheaper gas, hence the need for a higher price signal to decarbonise – to £100/tCO_2 in 2025 and £310/tCO_2 in 2050.

8.9 P2-R12-HUR-C95 – 95% CO_2

This run is run under identical assumptions to P2-R3-HUR-C90-6, except with a 95% CO_2 reduction by 2050. This trajectory follows the same trajectory in 2015 and 2020 as C90, but descends to a steeper reduction to 2025 and beyond. Emissions in 2050 are constrained to 29 MtCO_2.

This run has been compared with P2-R3-HUR-C90-6 from Phase II and COR4-C95-S from Phase I.

The extra 'effort' to meet this more stringent 95% CO_2 reduction target is divided across all sectors, although a greater proportion of mid-term mitigation is made in the transport sector, while electricity system decarbonisation takes greater precedence from 2040. From 2035, net emissions from the electricity sector are negative, reaching -29 MtCO_2 in 2050, equivalent to the entire emissions constraint. In other words, negative CO_2 emissions through the use of biomass CCS in the electricity sector effectively double the allowable system wide emissions.

Primary energy is characterised by an early and large move away from natural gas and oil from 2025 with a net reduction (compared to P2-R3) in primary energy until 2040. Primary energy reaches a minimum of ~6,100 PJ in 2030. The net reduction is mitigated by 2035 with increasing consumption of biomass and waste (250 PJ in 2010 to 1,800 PJ in 2050). From 2040 onwards there is again a large increase in primary energy (a ~ 570 PJ net increase over P2-R3) due to an additional 5 GW of nuclear generation (note that primary nuclear electricity is the heat equivalent).

The mid-term net decrease in primary energy induces an equally severe decrease in mid-term final energy demand (-220 PJ in 2025) which relaxes to the end of the model horizon. Natural gas, coal, petrol and diesel in final energy all decrease and are displaced by biodiesels, bioethanol, heat, and from 2035, electricity. These reductions in final energy are focussed on residential, service and industrial sectors. Final energy demand decreases throughout the model horizon and its construction changes over time. The 'dirtier' fossil fuels are squeezed out, mostly by 2035, with electricity, natural gas, hydrogen and delivered heat making up the majority of delivered energy. Residential (~750 PJ in 2050), service (~320 PJ) and transport (~960 PJ) sector final energy demands halve from 2000 to 2050, while industry (~1200 PJ) decreases by a smaller amount.

Uptake of conservation technologies does not increase over P2-R3, with ~280 PJ of energy delivered through conservation in the residential sector in 2040 and ~100 PJ in the service sector. Between 2040 and 2050 there is then a rapid jump in conservation uptake with a total of ~240 PJ in the service sector and ~325 PJ in the residential sector.

Unabated biomass electricity generation is displaced by 5 GW biomass CCS from 2040. This rises to 11 GW in 2050. By 2050, the installed wind capacity is ~ 8 GW lower than in P2-R3, while an extra 3 GW of co-firing CCS and unabated gas (largely for backup) is installed. The result is an energy system that is the same size (in capacity) as that in P2-R3, but with a larger proportion of base-load generation resulting in an extra 300 PJ of electricity from 2040. Between 2020 and 2040, electricity output almost doubles to 2000 PJ. The change in composition of the electricity sector is different to that in P2-R3, with a focus on mid-term investment in co-firing CCS (extra 3 GW of capacity in 2030), natural gas (extra 4 GW between 2030 and 2040) and lower investment in bio-waste capacity. Between 2025 and 2035 around 8 GW of non-base load capacity is swapped for base load generation.

This increase in electricity production is largely consumed by a slightly larger (~20 PJ net increase) hydrogen sector, switching from gas SMR with CCS and industry. There are minor increases in electricity consumption from the residential, service, transport and upstream sectors.

Transport moves increasingly to biofuels from 2025 - 100 PJ switch to ethanol away from petrol; 2030 - ~200 PJ switch to biodiesel from mineral diesel plus a 100 PJ switch to ethanol from petrol and electricity; converging on a similar transport fuel mix to that seen in P2-R3 by 2050. While there is a 'base load' as such in bio-fuel demand, bio-fuels in transport are used as a transition fuel between 2025 and 2045. By 2050, transport biofuel demand returns to 2020 levels. The increase in ethanol production is consumed by a tranche of E85 cars between 2025 and 2035. Hydrogen consumption is focussed on HGVs from 2030, and encompasses a proportion of cars and LGVs from 2040.

The marginal price for CO_2 increases steeply to over £300/tCO_2 in 2050. A high midterm price is needed in order to stimulate the near term changes in the energy system (given path dependencies). With this in mind, the CO_2 price increases from ~30/tCO_2 in 2020 to >£100/tCO_2 in 2025, then rising to the 2050 value.

The change in welfare cost from the reference case is significantly greater than for other Phase II scenarios (£35B vs. £27B), but the extra flexibility introduced to the model during the Phase II additions, such as through incorporating industrial and process CCS technologies reduces the pressure on electricity system decarbonisation and thus mitigates this increase in welfare cost. The P2-R12 scenario does not move as far up the electricity generation cost curve as COR4-C95-S (£45B) due to availability of the extra mitigation options.

In comparison to COR4-C95-S from Phase I (see page 57), P2-R12 allows an extra 100 PJ for energy conservation. Extra mitigation flexibility, e.g. through the incorporation of industrial and process CCS allow a reduction of around 8 MtCO_2 from emissions categorised as 'non-energy use' (which includes all emissions in the NAEI that are not captured by the UK MARKAL model, such as industrial non-energy process emissions such as those from the chemical reactions in manufacture of concrete). Note that there is a greater average demand-side response to price in the P2-R12 scenario than in the COR4-C95-S, with less severe, but more equally spread reductions in energy service demands across the different sectors, and also within the sectors. This seems to agree with common sense reasoning, that the greater choice of mitigation options within each sector results in a more balanced low carbon energy system.

9 Conclusions and Policy Implications

9.1 Modelling overview

The Committee on Climate Change (CCC) will provide advice on the 4th carbon budget period – covering 2023-2027 – in December 2010. As part of that advice, the Committee is undertaking analysis on the feasibility, costs and trade-offs of alternate pathways towards meeting the 2050 target.

Over the last 8 years, the UK MARKAL model has been extensively used for UK long-term energy pathway analysis, benefitting from iterative energy model development, and developing a strong track record of peer reviewed documentation and outputs. For this new examination of possible paths to meeting the 2050 target, this project encompassed two areas of major development:

- Firstly, an extensive model development process to address areas of key concern, including bio energy chains and biomass CCS, industrial sector mitigation flexibility, operation aspects of buildings technologies, build rates of key technology sectors, non-energy emissions, and inclusion of recent energy policy developments

- Secondly, the development of a stochastic UK MARKAL model to systematically investigate key mid-term uncertainties in achieving long term UK decarbonisation targets. This retains the strengths of the technological detail, energy systems coverage and demand response of the existing model. The major benefit in the new stochastic MARKAL model is a two stage stochastic decision (based on expected cost) where key parameters are made explicitly uncertain and the model pursues hedging strategies until such uncertainties are resolved (with subsequent multiple resolution pathways).

As a result of these two major areas of development, as well as a focus on more stringent CO_2 emissions reductions, this project (building on earlier energy systems modelling studies), is a core element of CCC's enhanced evidence base for its 4th Assessment Report.

9.2 Scenario selection

CCC required a new set of scenarios to inform their advice to the Government on carbon abatement pathways through the 2020s, consistent with meeting the 2050 target. The scenario selection process was iteratively undertaken through a ten month period, and reflected key uncertainties of interest to CCC and inclusion of findings from complementary analysis of key issues. Subsequent model runs were undertaken to re-examine both these key issues and new trade-offs and findings from the outputs of prior runs.

Scenario design starts with the specification of the reference, or business-as-usual scenario. The reference case is important, because it is against the reference case that the costs of constrained scenarios are measured. All welfare costs in the following scenario descriptions are a relative measurement for comparison between scenarios. Note that just one reference scenario was used for the entire project to aid comparison between scenarios. The individual scenario changes are therefore included with the policy package for CO_2 mitigation and are included only in the relevant sensitivity scenarios.

After agreeing a reference scenario with the CCC, four core runs were developed (section 5). These included the main assumptions that CCC wished to explore, notably i) the severity of a UK carbon dioxide target that may be necessary and ii) the inclusion of a bundle of policy measures consistent with the 'Extended Ambition' target specified by the Committee. These runs were labelled: COR1-C90-S, COR2-C95-S, COR3-C90-S and COR4-C95-S.

Following the definition of the four core runs, eight Phase 1 sensitivity runs (section 6), comprising both deterministic and stochastic scenarios were run, mainly off the COR1-C90-S scenario. These explored less severe and more severe CO_2 reduction targets, uncertainties surrounding CO_2 targets, fossil fuel prices, CCS availability, and uncertain fossil fuel prices in combination with different assumptions on biomass availability.

Iterative discussion following these Phase 1 scenarios generated feedback from the CCC leading to a revised set of assumptions for Phase 2 (see section 8). In the interim period a further eight sensitivity runs (section 7) explored uncertain fossil fuel prices, modulated electric vehicle uptake adoption of hydrogen as a transport fuel, and heat pump uptake and solid wall insulation mainly based on the COR3-C90-S scenario.

A new core run for Phase 2 was developed over three runs that explored the effects of new technologies such as industrial CCS, grid injection of bio-methane as well as modified hurdle rates to represent the investment barriers seen by different actors of the energy system. From this run P2-R3-HUR-C90-5, the final nine sensitivity runs covered bio-energy, build rates, uncertain fossil fuels prices and uncertainty over biomass availability in combination with approximations of the lifecycle emissions from biomass.

In all, 32 full scenario runs were delivered to the Committee on Climate Change (see Table 18). The use of deterministic or stochastic UK MARKAL versions for a given scenario was based on a judgement of the most appropriate way to represent given uncertainties.

9.3 Comparing the full scenario set

It is difficult to summarize the range of insights that come from such a broad analysis. This report (sections 5-8) has 85 pages discussing the results, with the CCC reviving full data outputs in Excel form (totalling over 400,000 data points).

To take one metric – welfare costs in 2050 (in £2000) – Table 31 summarizes all 73 discrete strategies (as stochastic runs give multiple recourse strategies depending on the number of state-of-the-world defined per scenario). The table breaks out all runs by the stringency of the CO_2 emission reduction and the assumption over fossil fuel prices. The range of outputs per category is still dependent on the wide range of model variations, including assumptions over biomass imports, availability of key technologies (CCS, advanced vehicles, heat pumps etc), hurdle rates and other model variation. As the scenario set is a discrete selection of runs of interest to policy makers (defined by the CCC), it is impossible to undertake a statistical analysis on the range of outcomes. However descriptive summary statistics illustrate the extremely wide range in this aggregate parameter – by a factor of 4 or more, which outweighs even the convex cost driver of CO_2 reduction target stringency. Disaggregated outputs, such as technology selection or demand changes would likely show even more variation – as discussed in the rich narrative in sections 5-8.

Fossil Price	Low		Central			High	High-high
CO_2 reduction target	90	80	90	95	97	90	90
Count	13	1	31	4	1	11	12
Deterministic	2	1	10	3	1		1
Stochastic	11		21	1		11	11
Mean	37.7		33.3	41.2		39.5	39.8
Median	30.3	17.5	29.9	42.6	79.9	30.7	32.3
Standard Deviation	19.8		13.6	4.5		21.0	19.8
Range	72.4		76.7	10.1		71.2	72.6
Maximum	98.2		97.8	44.8		97.9	97.9
Minimum	25.8		21.1	34.7		26.7	25.3

Table 31: Welfare costs in 2050 (£2000 billion), from full set of 73 deterministic and stochastic (recourse) scenarios

Other comparative mechanisms could be to compare similar runs on a sensitivity of interest (for example on the availability of sustainable biomass imports) across either deterministic and stochastic runs, or across similar runs in different iterative project phases.

9.4 Emergent policy themes

However, results from the 32 different scenarios included in this project give rise to a number of emergent themes. One of the virtues of energy system modelling is that the interconnectedness of the energy system elements (sectors, energy chains, and supply vs. demand side measures) is able to be represented.

9.4.1 Links, synergies and trade-offs

There are multiple final configurations (and costs) for a future UK energy system that is almost decarbonised. These alternate final configurations are dependent of the costs, availability and timing of key low carbon energy vectors. Modelling studies will have alternate final configurations based on the assumptions on key drivers, the model set up (i.e., the model has to include a given mitigation option), and in the timing/consideration of uncertainty resolution (e.g., the time period and subjective probabilities in the stochastic model formulation).

Broad drivers of energy system development (and costs) under alternate scenarios include the severity of reductions in carbon dioxide, the investment costs of electricity generation technologies, underpinning model parameters including discount and hurdle rates, the availability of biomass, and the build rate constraints of key low carbon energy chains.

There are many links, synergies and trade-offs between aspects of the energy system model that give insights for the decarbonisation of the UK energy system. The strongest links between factors in the model are exhibited in the relationship between fossil fuels and bio-products. For example, in COR1-STOC-FF, HBFF and LBFF, the constraint on biomass availability affected the role of co-firing CCS, with transport relatively unaffected. In P2-R6 and P2-R7, the inclusion of lifecycle emissions for biomass had a dual effect on both oil and natural gas consumption; given biofuel blends and bio-methane mixes enable decarbonisation of conventional fossil fuel vectors. The complex interplay, exhibited in P2-R10, between fossil fuel prices and biofuels extend to bio-resources and renewable energy (see P2-R5). There is also a tension between delivered biomass, seen in varying amounts across all scenarios and use in conversion technologies. While biomass CCS is unaffected directly by fossil fuel price changes (excluding the improvements in financial attractiveness due to more expensive running costs for the counterfactual technologies), competition with transport biofuel demand (which *is* linked to fossil fuel price) has a secondary effect.

In COR4-C95-S, the forcing in of hybrid vehicles in the extended ambition scenario tended to emphasise the links with conventional fossil transport fuels where alternative low-carbon options exist.

Interactions between sectors was a common feature of every scenario, specifically the role of negative emissions in the electricity sector from biomass CCS and co-firing CCS 'enabling' less mitigation effort in demand sectors. However, introduction of improved model flexibility in Phase 2, especially through industrial CCS and bio-methane options for industrial and 'other emission' sectors had a great impact on all other sector mitigation options.

9.4.2 Resilience, flexibility and uncertainty

Under stringent CO_2 reductions there are robust elements of alternate scenarios, especially in the mid-term. Specifically, limited hedging strategies from the stochastic formulation are in part derived from the necessary interim steps the UK energy system has to make through the 2020s, to achieve 2050 final targets.

Many of the stochastic scenarios included in this project had relatively minor hedging strategies. The set of biomass availability runs with uncertain fossil prices (COR1-STOC-FF, -HBFF, -LBFF) suggested the biomass constraint exhibited a larger effect on the near-term strategy than the uncertainty. P2-R5 showed that the model seemed to have enough flexibility, even with the severe build constraints imposed, to react to the uncertainties modelled. In this scenario, the fossil fuel price uncertainties were outweighed by the severity of the CO_2 reduction target. COR1-STOC-C90S explored the effect of an uncertain CO_2 reduction – 90% or 95% on 1990 levels by 2050. Again this showed little significant near-term response to the uncertainties, with far more mid-term investment after resolution of these uncertainties.

P2-R10 showed that uncertainty in fossil fuel prices has little effect on the 2050 scenario, again suggesting that the CO_2 reduction is the driving factor.

Under COR3-STOC-FF#-S, demand for natural gas, petrol, biomass and hydrogen were not affected by changes in fossil fuel price, although the sector demand biomass was affected as described above. COR3-HP2-FF#-S showed the sensitivity of co-firing CCS to high coal prices, due to the decreasing economic competitiveness. However, carbon storage is a resilient technology across all scenarios. This scenario also showed how a smaller overall energy system reduces exposure to fossil fuel price uncertainty and that there is significant potential for energy conservation.

P2-COR3-ALL-S-2 showed the very significant effect of increasing mitigation options in one sector has on the whole energy system. Introducing CCS to industrial processes together with grid injection of bio-methane allow potential for mitigation in sectors than were previously very difficult to decarbonise. The scenario results show that there is great utility in increasing the number of mitigation options in sectors that are currently underexploited.

9.4.3 Scope of mitigation measures

There were a range of insights into the role of the different mitigation measures available in the model. These include efficiency improvements, conservation measures, demand reduction and technologies

The majority of scenarios included a 2050 90% reduction in CO_2 emissions on 1990 levels. There is a certain amount of homogeneity between the phase 2 scenarios in 2050, and between the phase 1 scenarios in 2050. However, the changes in assumptions, namely hurdle rates and industrial CCS, between phases 1 and 2 made a large impact and resulted smaller overall energy systems. However, patterns can be seen between the two phases that are resilient across all of the scenarios.

Decarbonisation of the electricity system is a persistent factor in all low-carbon scenarios, while the availability of 'negative emission' technologies, such as co-firing CCS and biomass CCS further establish electricity decarbonisation as an essential element of a low carbon system. However, phase 2 showed that increasing alternative options for mitigation reduced the role of electricity decarbonisation, especially in the latter stages of the model.

Decarbonisation of the transport system occurred in all scenarios, primarily through improvements in vehicle efficiency (seen in the base case, BM-REF-S, as an optimal decision under no low-carbon policy). However, while efficiency improvements are seen fleet wide, P2-R5 showed a mix of highly efficient hydrogen vehicles and moderately efficient conventionally fuelled vehicles. Across scenarios, biofuel use was dependent on alternative uses, with the main demand from the electricity sector for co-firing CCS and biomass CCS.

As mentioned above, efficiency improvements are a key factor in near and mid-term decarbonisation of the transport sector, particularly road transport (see BM-REF-S and COR1-C90-S). Under carbon constrained cases fossil fuels are forced out of the model in later periods. The uncertain fossil fuel price scenarios demonstrated a shift towards more efficient conversion technologies, such as CHP, increasingly important as fossil fuel prices increased (see COR3-STOC-FF#-S) and when in P2-R4 there was an increase in capital costs of electricity generation. However, P2-R4 also showed how a switch to low-carbon energy vectors like biomass results in a less efficient overall system, generally with greater demand reduction due to the increased cost of energy supply.

Energy conservation technologies have a very important role to play, as seen in COR3-HP1-FF#-S and COR3-HP2-FF#-S, as they enable a smaller, more resilient and flexible energy system, less exposed to uncertainties in fossil fuel prices.

To fully understanding the results from the 32 scenarios presented in this document, it is necessary to acknowledge the limitations of an energy systems model such as UK MARKAL. The model seeks the least cost solution to supply energy service demands and is able to invest in a large database technologies and conservation measures or demand reduction through price responses. However, as seen in COR000-C97-S, the explanatory power of the model is limited by the pool of technologies included in the database, and stretching the model to its limit can result in seemingly bizarre (but rational under the objective function of the model) behaviour. This includes increasing electricity use to ‘farm’ negative emissions from co-firing CCS and biomass CCS technologies. Increasing the mitigation options in the database, as seen in the transition to Phase 2, especially P2-COR3-ALL-S-2, greatly improves the model flexibility, reducing welfare costs. P2-R4 show the importance of recognising the difference between short and long-term cost projections, as a short-term increase in the capital cost of investments may have negligible effect in the long term. Overestimation of these impacts could lead to significantly different policy decisions, as demonstrated by P2-R4. In a system wide analysis, the relative costs of alternative mitigation options are more important than absolute values.

The effect of changing assumptions, particularly discount and hurdle rates are pervasive, significant and should be explicitly recognised when understanding these scenarios. However, the effects seen in the model are also common sense, so that increasing the investment cost of the electricity sector does result in a reduction in delivered electricity. The strengths of energy system modelling lie in the analysis of the response to these changes in assumptions.

9.5 Main Policy Insights

In overall conclusion, five key findings from the broad scope of scenarios from this energy-economic modelling analysis project are:

- UK energy policy makers must be cognisant of a range of external drivers that they have only peripheral control over and which will have profound effects on the achievability and costs of stringent energy decarbonisation. These include fossil fuel prices, biomass imports, technology development and the scale of UK emissions reductions required in a global mitigation context.
- There are a range of final configurations of a decarbonised energy supply with alternate elements of supply-side energy resources and secondary infrastructures (electricity, heat, hydrogen and liquid fuels), together with demand-side technology adoption and behavioural change. However, all deep decarbonisation scenarios require elements of change in supply and demand – i.e., technology and behaviour
- The stringency of deep decarbonisation targets means that there are essential (or robust) elements of decarbonisation strategies in the mid-term with either limited flexibility to exclude and/or expensive implications of not including. These elements include investment in low carbon electricity, technological change in transport, implementation of buildings conservation options, and behavioural change to moderate demand requirements
- Stringent decarbonisation targets options means that smaller emissions sources become increasingly important and need to be addressed by policy makers. Examples in the energy sector including industrial process emissions, residual emissions from CCS applications, emissions from essential consumer buildings energy service demands, and emissions from smaller transport modes (e.g., aviation. Although not covered here, non-CO_2 greenhouse gas emissions and land-use change emissions need to be addressed.
- The aggregate welfare costs of stringent emissions reductions are substantial, amounting to a median value of £30 billion (in £2000), by the year 2050. However, the wide range of model variants indicate a very substantial variation in welfare costs – by of a factor of four or more. Disaggregated parameters – including the

change in energy costs through marginal CO_2 values, and the role of sectors, resources and technologies – could see even greater variation. The continuation of iterative energy system analysis – using a range of modelling techniques – can shed further light on the response of consumers, feasibility of change in specific sectors, and impacts on the broader economy.

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