



The UK energy system in 2050: Comparing Low-Carbon, Resilient Scenarios

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Executive summary

This report was produced during a particularly fast-changing period in the field of energy policy. Readers should be aware that the cut-off date for information included was December 2012 and the report may not, therefore, reflect the situation at the time of reading

Phase 1 of the UK Energy Research Centre (UKERC) facilitated the development of a state-of-the-art MARKAL model of the UK energy system. MARKAL is a well established linear optimisation, energy system model, developed by the Energy Technology Systems Analysis Programme (ETSAP) of the International Energy Agency (IEA) in the 1970s, and was until very recently used by it for its annual Energy Technology Perspectives (ETP) reports. It is also used by many other research teams round the world, and has been regularly updated and improved over the years through the ETSAP Implementing Agreement.

Towards the end of UKERC's Phase 1, in 2007-8, UK MARKAL was used for a major modelling exercise of different projections of the UK energy system to 2050, the results of which were published in Skea et al 2011. In the ensuing years, UK MARKAL was again used for major 2050-focused modelling projects: for the Committee on Climate Change (CCC) in 2010 (CCC 2010), for the Department of Energy and Climate Change (DECC) in 2011 (HMG 2011), and again for UKERC to update the Energy 2050 scenarios in 2012. This UKERC Research Report presents the main results of each of these modelling exercises, with a view to drawing out any key messages from the set as a whole.

Comparisons between such model runs, even of the same model, need to be drawn with care. Various assumptions, including cost and other data inputs to the model, were changed between the model runs, to reflect policy and other developments, and to incorporate new information. Some of the technology representations in the model were also improved. These changes have two implications for comparisons between such model runs. The first is that detailed conclusions about the cost-preferability of particular technologies, unless they emerge as clear favourites across the whole set of runs, are unlikely to be robust. This is because the cost uncertainties of possible developments in these technologies and their competitors over four decades are very great. Where, as will be seen in these cases, the costs between the major low-carbon technologies are, or may be, of the same order

of magnitude, then there are no strong grounds on the basis of these runs of preferring one over the others on cost grounds.

The second conclusion is more positive. Where consistent patterns of development of the energy system emerge across the different runs, despite the different inputs and the fact that the runs were carried out by different modellers and modelling teams, then more confidence may be placed in these patterns as likely features of the future UK energy system under the constraints applied, the principal constraint being reductions in greenhouse gas (GHG) emissions, or carbon dioxide (CO₂) emissions in the case of the UK energy system, according to the provisions of the UK Climate Change Act of 2008. It is these consistent patterns that inform the main conclusions of this report, which are summarised here under a number of headings. The numbers on which these broad conclusions are based appear in the main report.

The need for greatly increased energy efficiency and conservation in all sectors

Producing low-carbon energy is a costly and politically controversial endeavour, whatever technologies are deployed. The more efficiently it can be used, and the less that is required to satisfy the desired level of energy services, the easier it will be to deliver the necessary low-carbon supply. All the model runs show that it is cheaper to achieve large reductions in energy demand through efficiency and conservation technologies than to provide an equivalent level of supply. However, just because it is cheaper to reduce demand does not mean that it is politically easy to achieve. Making UK buildings more efficient, especially, remains a major policy challenge.

Producing low-carbon energy is a costly and politically controversial endeavour, whatever technologies are deployed

¹ The TIMES model, the IEA's successor to MARKAL, is now used for this.



On-shore wind is currently the cheapest non-biomass low-carbon option, but experiences political opposition to its large-scale deployment

Decarbonisation of the UK electricity system

An absolutely consistent result to emerge from all the model runs is that, if the UK is to meet its GHG emission reduction target for 2050 cost effectively, the UK electricity system needs to be decarbonised by 2030 by at least 80% (a CO₂ intensity of less than 100 gCO₂/kWh compared to 500 gCO₂/kWh in the year 2000). In the context of the opposing views as to whether a decarbonisation target should be included in the 2012 Energy Bill, the draft of which was published in November 2012 without such a target, there would seem little reason not to include one, unless the intention is to repudiate the provisions of the Climate Change Act at some future date. Indeed, by giving investors in low-carbon generation assurance of the UK energy system's direction of travel, and the policy commitment necessary to achieve it, including the target in the Bill makes it more likely that the government will find the policy commitment, and adopt the measures, necessary to achieve it, while leaving it out makes this less likely. This target may therefore be seen as a litmus test of the government's determination to meet the reductions in carbon emissions to which the UK is currently statutorily committed.

Continuing uncertainty about the optimal low-carbon electricity supply

There are four main options for low-carbon electricity supply: nuclear power, large-scale renewables, and fossil fuel power stations with carbon capture and storage (CCS) technologies, all of which use the high-voltage transmission system; and small-scale renewables, more decentralised, mainly using the lower-voltage distribution system. There is a very great deal of uncertainty which of these technologies, if any, will become dominant because it is the cheapest. On-shore wind is currently the cheapest non-biomass low-carbon option, but experiences political opposition to its large-scale deployment; new-generation nuclear is still uncertain in cost and in the ability of the UK to deploy it at scale, and is also not politically popular; the commercial and technical viability of CCS at scale, and the scale of subsidy required for its deployment, are not yet proven; large-scale offshore wind, while it can be built to time and on budget, is still expensive; and the UK

is not best placed for the most decentralised renewable technology with the most potential, solar photovoltaics (PV), which is also still expensive.

How the costs and various other problems associated with these technologies will evolve and be resolved is still very uncertain. In the model runs different combinations of these technologies are chosen depending on the (especially cost) assumptions made. Quite small changes in assumptions can produce quite large changes in outcomes. It therefore seems wise to continue to develop and seek to deploy all of them until these issues are clarified and either a clear best choice among them, or something resembling an optimal mix between them, becomes apparent.

Electrification of heat, power and transport

All the model runs show some electrification of heat and/or transport, using the largely decarbonised electricity discussed above, but the degree of electrification differs markedly across the runs, as do the technologies which are deployed. It is clear that heat will no longer be provided on a large scale by individual gas boilers, or transport by vehicles using internal combustion engines and conventional petrol and diesel, and it is clear that there are low-carbon substitutes for these technologies. By 2050 electricity (directly or through heat pumps) makes a major contribution to heating in all scenarios, supplemented by biomass and solar thermal, but battery electric vehicles and plug-in hybrids do not make a similar contribution to transport in all scenarios, being replaced by biofuels and hydrogen fuel cell vehicles in the later UKERC model runs.

The future of the UK gas grid

The predominant current use of the gas grid is to transport and distribute natural gas to buildings for heating (and, to a much lower extent, cooking) purposes. As noted above, heating buildings in this way on a large scale will not be consistent with reaching the carbon emission reduction targets. So does this mean that the UK gas grid will gradually become redundant? Not necessarily. There are two main low-carbon options for the

gas grid: use it to transport bio-gas (methane derived from biomass, which is assumed to be zero or near-zero carbon because it takes from the air while growing the carbon that it emits to the air when burned); or use it to transport hydrogen produced in low-carbon ways (from biomass gasification, renewable electricity or nuclear power). All these options are currently expensive, and none of them emerge at scale in the low-carbon model runs reported below. This is an indication of the challenges that need to be addressed if the gas grid is to have a purpose in a low-carbon UK, and if it is not to become a 'stranded asset'.

The likely demise of the mass use of vehicles with internal combustion engines (ICEs)

The ICE was one of the iconic inventions of the 20th century. The 21st, if it is to be low carbon, will very likely see its demise as the major vehicle technology. In the years to 2050, first they will become more efficient; then they will be hybridised with electric motors, driven by batteries, which in due course will be able to be plugged in to the power grid for a re-charge; then they will be replaced by all-electric battery vehicles, or fuel cell vehicles, probably fuelled by hydrogen, or some combination of the two. The mix of these technologies, and the timescale over which they will be deployed, is very uncertain. Because they require very different re-charging infrastructure, the choices between them cannot be put off indefinitely. ICEs survive in large number, largely driven by biofuels, only in the later UKERC scenarios.

Bioenergy has many different possible uses, but its sustainable availability is not clear

Bioenergy may be used to produce electricity (through dedicated power stations or co-firing with coal), heat (for example, through biomass boilers linked to district heating) and transport (through biofuels). Using biomass for power generation with CCS offers the attractive prospect of 'negative' emissions. All the sets of model runs use some bioenergy, but in very different amounts and for different purposes. This not only reflects uncertainties about the costs of these different uses, but also the amount of bioenergy that is likely to be available to the UK: its own land for growing it is limited, and this and land elsewhere has many other demands on it, including food production, the maintenance of biodiversity, and recreational activities. There are also questions about the extent to which bioenergy really is a 'low-carbon' energy source. It is clearly not zero-carbon, as it is currently accounted, and it is clear that under some modes of production it can be as high-carbon as some fossil fuels. But the analytical and governance systems are not yet in place systematically to distinguish between low and high-carbon bioenergy, and only produce and use the former.

Meeting the carbon emission reduction target therefore requires a wholesale transformation of the energy system

The above conclusions emerge as robust across all the sets of model runs that are described below. Together they add up to wholesale transformation of the UK energy system, which is required if the UK's statutory carbon targets are to be met. The conclusions hold individually as well as collectively. Energy demand will need to be reduced through increased efficiency; electricity will need to be decarbonised, and will substitute for at least some, and probably most, gas use in heating and petrol and diesel in cars; all low-carbon electricity supply technologies are likely to be needed to some extent; the more use that can be made of sustainably produced, low-carbon bioenergy, the easier and less expensive it will be to meet the carbon targets.

Together these conclusions add up to a formidable policy challenge. Even so, the sets of model runs are unanimous that the technologies to meet the challenge exist, and deploying them is a much lower cost option than the damages from climate change, estimated elsewhere, that will ensue if the UK and other countries fail to rise to it.

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Introduction

Modern energy systems are complex. The only way to derive robust insights into how they might develop is through the use of energy system models. MARKAL is the model widely used by analysts round the world to study the long-term implications of different energy policies



Since the publication of its Energy White Paper in 2003 (DTI 2003) the UK has had three fundamental energy policy objectives: to reduce emissions of carbon dioxide (CO₂), that contribute to anthropogenic climate change; to maintain and increase energy security; to keep the price of energy competitive for business and affordable for households.

Since then a very large number of scenarios have been run using different models or projection methods in order to gain insights into how the UK energy system might evolve in line with these objectives, and to see what it might look like in 2050, the year by which, according to the UK's Climate Change Act of 2008, emissions of greenhouse gases (GHGs) will need to have fallen by 80% from 1990's level.

MARKAL models characterise all the significant technologies, processes and interactions in an energy system

This paper compares and contrasts four such scenario exercises: the 'Pathways to a Low Carbon Economy' runs produced by the UK Energy Research Centre (UKERC) in its Energy 2050 programme of work (Anandarajah et al. 2009, 2011); those produced most recently by UKERC, with updated policies and some different input assumptions (here called UKERC2), which are here being reported for the first time (in Section 5); the scenarios produced by the Committee on Climate Change (CCC) in its Fourth Carbon Budget Report (CCC 2010, CCC 4CB); and the scenarios produced by the consultancy AEA (2011a,b²) for the Department of Energy and Climate Change (DECC) to support the UK Government in coming to a position on the Fourth Carbon Budget. Outputs from the AEA runs were subsequently used in the Carbon Plan (HMG 2011), so that these runs are here collectively called the AEA CP runs.

All these scenarios were produced by the UK MARKAL model developed predominantly with funding from the UK Research Councils through UKERC. Between the different scenario runs the model was updated and some of the assumptions modified, to generate new insights and take account of new developments. For example, the CCC work, discussed in Section 3, used a version of the MARKAL model that sought to take account of key uncertainties, supplemented by detailed bottom-up and sectoral analysis. This means that, although the scenario sets are only comparable in broad terms, any over-arching conclusions that emerge from all of them are likely to be quite robust, although it would of course be possible to produce MARKAL or other scenarios in which such conclusions did not hold.

The main Carbon Plan report gave the broad results of a Core scenario produced by MARKAL, and then a number of other scenarios produced by the 2050 Pathways Calculator³ of the Department of Energy and Climate Change (DECC). However, as noted above, the Carbon Plan was also informed by other MARKAL modelling, which involved a large number of other scenarios, with assumptions that varied from the Core scenario, the results of which were reported in AEA 2011a,b, and which are discussed in Section 4. The DECC Calculator is not a cost-minimising model, so the scenarios chosen to compare with the Core scenario, produced by MARKAL, are simply different technology mixes chosen to comply with the 2050 UK carbon reduction target. For reasons of space, and because of their lesser comparability with MARKAL runs, these are not further discussed here.

Introducing MARKAL

MARKAL is a well established energy system model, originally developed as noted above by the Energy Technology Systems Analysis Programme (ETSAP) of the IEA in the 1970s, but much refined and developed since, and is now used by many energy modelling teams around the world. The structure and key aspects of UK MARKAL are described in Strachan et al. 2007, and its use in modelling low-carbon scenarios described further in Anandarajah et al. 2009, so that only key points necessary to the understanding of its results will be set out here. In brief, therefore, MARKAL models characterise all the significant technologies, processes and interactions in an energy system, from resources, through conversion and distribution, to end use vehicles and appliances, by their important economic and technical parameters (for example, costs, efficiencies and emission factors). In this way, the model will show how a given level of energy service demands (ESDs, for example, for heat, power or mobility) can be met, and by which energy sources.

MARKAL is a model that either minimises the energy system cost (Standard version) or maximises the sum of producer and consumer surplus (Elastic Demand version, used in these model runs) to meet exogenously specified energy service demands (e.g. in transport the number of passenger kilometres). All the MARKAL scenarios discussed below therefore describe an energy system that is in these senses cost or welfare optimal, based on the assumptions and data that have been fed into the model, and the policy or other constraints that have been applied to it. The assumptions are numerous and can be complex; only those that are relevant to the scenario comparison being carried out here are described in this report, with most detail being given for the new model runs described in Section 5 of this report. Further details of the assumptions of the other runs can be found in the more detailed references to the scenarios that are given.

² The authors of these reports were Adam Hawkes, Rasa Narkeviciute, Simon Morris and Baltazar Solano-Rodriguez

³ <http://www.decc.gov.uk/en/content/cms/tackling/2050/2050.aspx>



One of the ways in which the Elastic Demand version of MARKAL can meet policy constraints (e.g. carbon reduction targets) is to reduce energy service demands through price elasticities of demand

Given that it is a cost-minimising model, the major inputs into MARKAL that characterise different technologies are costs of various kinds, e.g. capital costs, operational and maintenance costs, etc. Assumptions are made about how these costs will develop over time, and MARKAL then chooses a cost-minimising pathway, depending on the policy or other constraints that have also been incorporated. Taking these constraints into account, it exercises perfect foresight over the entire projection period and assumes that markets will adopt the technologies as they become available in order to minimise the costs overall.

This is clearly a very strong assumption, and it can be relaxed in a number of ways. One of the most important is through the specification of 'hurdle rates' for different technologies, which are intended to take account of market barriers to the adoption of some technologies (e.g. energy conservation technologies) by increasing their capital cost as perceived by the model.

The reason that conservation technologies are often singled out for this special treatment is that there is substantial evidence (e.g. Sorrell et al. 2004) that such technologies (e.g. loft or cavity wall insulation in buildings) are not taken up to anything like the extent that seems to be economically optimal. Conservation measures are also slightly special because they save but do not themselves use energy. Technically they are modelled almost like any other technology, i.e. they have costs as an input and produce an output, which is an energy demand of some kind. For example, the conservation measure 'floor insulation' produces the demand 'residential heating', just like a heat pump or a boiler, thereby reducing the heat demand that needs to be met by other technologies. The difference from other technologies is that there is no energy input to the conservation technology. Assumptions concerning energy saving potentials dictate how widely a given energy conservation measure can be implemented.

One of the ways in which the Elastic Demand version of MARKAL can meet policy constraints (e.g. carbon reduction targets) is to reduce energy service demands through price elasticities of demand.

This is modelled in a very similar manner to technologies. For example, if it is economic to do so (from the global optimization perspective), the model 'produces' residential heating with the steps of the discretised price-demand curve (i.e. the demand curve can be seen as a set of technologies, each of which can provide demand at a certain price and for a certain volume), leaving a lower demand for the rest of the system to cover. This lower demand is again met with an optimal mix of conservation measures and heat production technologies. The demand reduction gives rise to the loss of welfare, which is computed in the model as a reduction in the sum of consumer and producer surplus arising from the scenario.

A final set of explanations is perhaps desirable concerning the economic metrics produced by MARKAL.

First there is the marginal price of CO₂, indicating, as its name suggests, the cost of the final ton of carbon reduction in any particular period in any particular CO₂ reduction scenario. In general, the marginal cost of CO₂ will increase with the emissions abatement required, but it is also affected by both the emissions trajectory and what is assumed about other policies. In respect of the former, for the same cumulative emissions, a scenario with early abatement requires lower CO₂ prices in the later periods than scenarios with little abatement early on which may then require very high CO₂ prices to induce fast abatement in the later periods. In respect of the latter, if the model is constrained to meet certain policy requirements (for example, the 2020 renewables target), this will reduce CO₂ emissions to some extent, and a lower CO₂ price will then be necessary to achieve a given emissions reduction target.

In the different model runs that are described below, very different assumptions about policies are made (in general, the later model runs incorporate more, and more recent, policies, but do not necessarily assume that they are 100% effective). This needs to be borne in mind when comparing estimates of CO₂ prices from different runs.



The total discounted energy system cost is the metric that is minimised by the Standard version of MARKAL

Second, there is the energy system cost, which is the flow of money through the energy system required to deliver the energy and satisfy the energy service demands, for the year or period under consideration, including capital investments and variable (fuel, operational and maintenance) costs. It may be reported (undiscounted) for the period in question, or the total for all periods discounted back to a base year. This metric is obviously affected by the level of energy demand – other things being equal, the higher the demand, the larger the required energy system and the higher its cost. The total discounted energy system cost is the metric that is minimised by the Standard version of MARKAL.

Third, in the Elastic Demand version of MARKAL, there is the value of the reductions in energy demand induced by the increased cost of meeting energy service demands under the carbon constraint. This value is the area under the demand curve (the price of the reduced energy multiplied by its quantity) relevant to the reduced demand. This is therefore a measure of the cost reduction to consumers associated with the reduced inputs to the energy system.

However, this cost reduction is associated with a reduction in social welfare, which is the most important of the measures discussed here, and which is captured by the fourth MARKAL economic metric – the change in the sum of producer and consumer surplus. This metric too may be reported (undiscounted) for any particular period, or the total change in the sum of producer and consumer surplus may be discounted back to the base year. The discounted sum is the metric that is minimised by the Elastic Demand version of MARKAL.

In runs with significant reductions in energy demand, and assuming that lower energy service demands imply lower welfare, welfare cost is a marked improvement on energy system cost as an economic impact measure as it captures the lost utility from the forgone consumption of energy. However, welfare costs cannot meaningfully be compared across scenarios with different welfare functions, or where major changes have been made to model input assumptions such as discount rates. The split of the welfare loss components between producers and consumers depends on the shape of the supply and demand curves, and crucially on the ability of producers to pass through costs onto consumers. This split is not reported in the results which are reported in this paper.

None of these metrics correspond to changes in GDP as a result of energy system changes, as wider investment, trade and government spending impacts are not accounted for. However, an annual change in the sum of producer and consumer surplus may be compared with the GDP figure in that year to get a ballpark impression of its significance compared to the scale of the economy overall.

The UKERC Energy 2050 Scenarios

These scenarios explored the implications for the UK energy system of a range of carbon emission trajectories, with emission reductions by 2050 ranging from 40-90%



The full modelling and other analysis related to UKERC's Energy 2050 project was reported in Skea, Ekins et al. 2011. The modelling of low-carbon pathways and of energy system resilience, which is most relevant to this report in its comparison of different scenario sets, was set out in Chapter 5 (Anandarajah et al. 2011) and Chapter 6 (Skea, Chaudry et al. 2011) of the Energy 2050 book (Skea, Ekins et al. 2011). The low-carbon pathways modelling was reported in more detail in Anandarajah et al. 2009, and it is from this source that the details in the rest of this section are taken. The description that follows is largely textual – many graphs and diagrams are included in the original report. For space reasons these are being saved mainly for the comparative analysis between all the scenarios in section 6.

The UKERC Energy 2050 low-carbon modelling produced two sets of model runs. A first set of scenarios (CFH, CLC, CAM, CSAM), focused on carbon ambition levels of CO₂ reductions (in 2050) ranging from 40% to 90% reductions. These runs also have intermediate (2020) targets of 15% to 32% reductions by 2020 (from the 1990 base year). These scenarios investigate increasingly stringent targets and the ordering of technologies, price-induced behavioural

change and policy measures to meet these targets. A second set of scenarios (CEA, CCP, CCSP) undertake sensitivity analyses around 80% CO₂ reductions with the same cumulative CO₂ emission target, notably focusing on early action (CEA) and different discount rates (CCSP). These scenarios investigate dynamic tradeoffs and path dependency in decarbonisation pathways. Together with a base reference (REF) case, all seven decarbonisation scenarios are detailed in Table 2.1.

In the base reference Case (REF), assuming that new policies/measures are not taken, CO₂ emissions in 2050 would be 583 MtCO₂, only 1% lower than 1990 levels. Then-existing (as of 2007) policies and technologies would bring down emissions in 2020 to about 500 MtCO₂ - a 15% reduction. However carbon emissions would then be considerably higher than the government target of at least 26% reduction by 2020. In the absence of a strong carbon price signal, the electricity sector, with a substantial number of conventional coal-fired power plants, is the largest contributor to CO₂ emissions, with further considerable contributions from the transport and residential sectors.

Table 2.1: Carbon pathways scenario

Scenario	Scenario name	Annual targets % reduction from 1990 level	Cumulative targets	Cumulative emissions GtCO ₂ (2000 – 2050)	2050 emissions mtCO ₂
REF	Base reference	–	–	30.03	583
CFH	Faint-heart	15% by 2020 40% by 2050	–	25.67	355
CLC	Low carbon	26% by 2020 80% by 2050	–	22.46	237
CAM	Ambition (called 'low-carbon core')	26% by 2020 80% by 2050	–	20.39	118
CSAM	Super ambition	32% by 2020 90% by 2050	–	17.98	59
CEA	Early action	32% by 2020 80% by 2050	–	19.24	118
CCP	Least cost path	Cumulative by 2050	Budget (2010 -2050) similar to CEA	19.24	67
CCSP	Socially optimal least cost path	Cumulative by 2050	Budget (2010 -2050) similar to CEA	19.24	179

For reference: UK CO₂ emissions in 1990 were 590 mtC O₂ (DECC 2012, Table 2)

⁴ For example, none of the other scenario sets examined the implications of behaviour change, as was done in Chapter 9 of Skea, Ekins et al. 2011

⁵ The -80% case (CAM is the low carbon core run. It is noted that if international bunker fuels and non-CO₂ GHGs were to be included in the UK's budget the overall 2050 target may need to be closer to CSAM i.e., a -90% case (CCC, 2008)

The electricity sector, with a substantial number of conventional coal-fired power plants, is the largest contributor to CO₂ emissions, with further considerable contributions from the transport and residential sectors

Figures 2.1 and 2.2 show that the carbon emissions reductions in the scenarios are accompanied by significant reductions in final energy demand, with the main reductions in the residential and transport sectors (Figure 2.1), and large reductions in the use of natural gas, petrol and diesel (Figure 2.2; coal is already very largely used in power generation, so that its final use is now very small).

Under all the decarbonisation pathways, the power sector is a key sector, where decarbonisation from 2020 begins with the deployment of carbon capture and storage (CCS) for coal plants in 2020-2025 in all mitigation scenarios. By 2035, as shown in Figure 2.3, CCS is a significant part of the generation mix in nearly all the scenarios. However in these model simulations there is considerable uncertainty over the dominant player in any optimal technology portfolio of CCS vs. nuclear vs. wind, due to the close marginal costs and future uncertainties in these technology classes. Specifically, when examining the investment marginal costs when CCS technologies are the optimal choice, across the scenarios from 2030-2050 further tranches of offshore wind would be competitive with a cost improvement of between £56 - £260/kWe installed – this represents only 5-25% of capital costs. Nuclear’s marginal investment costs are even closer to CCS, with a difference of between £2 and £218/kWe

Figure 2.1: Final energy demand by sector in 2035 and 2050 in the Energy 2050 scenarios

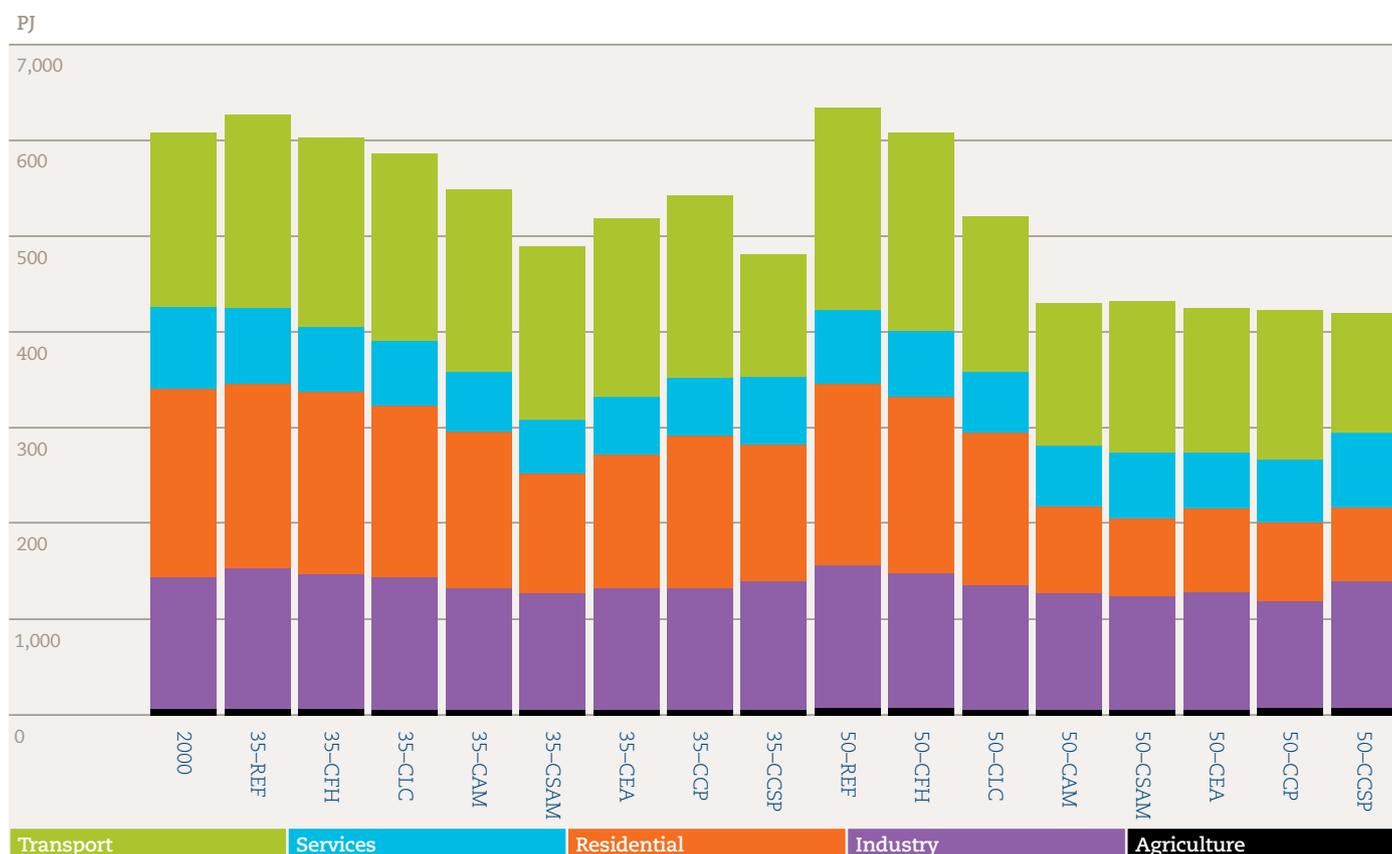


Figure 2.2: Final energy demand by fuel in 2035 and 2050 in the Energy 2050 scenarios

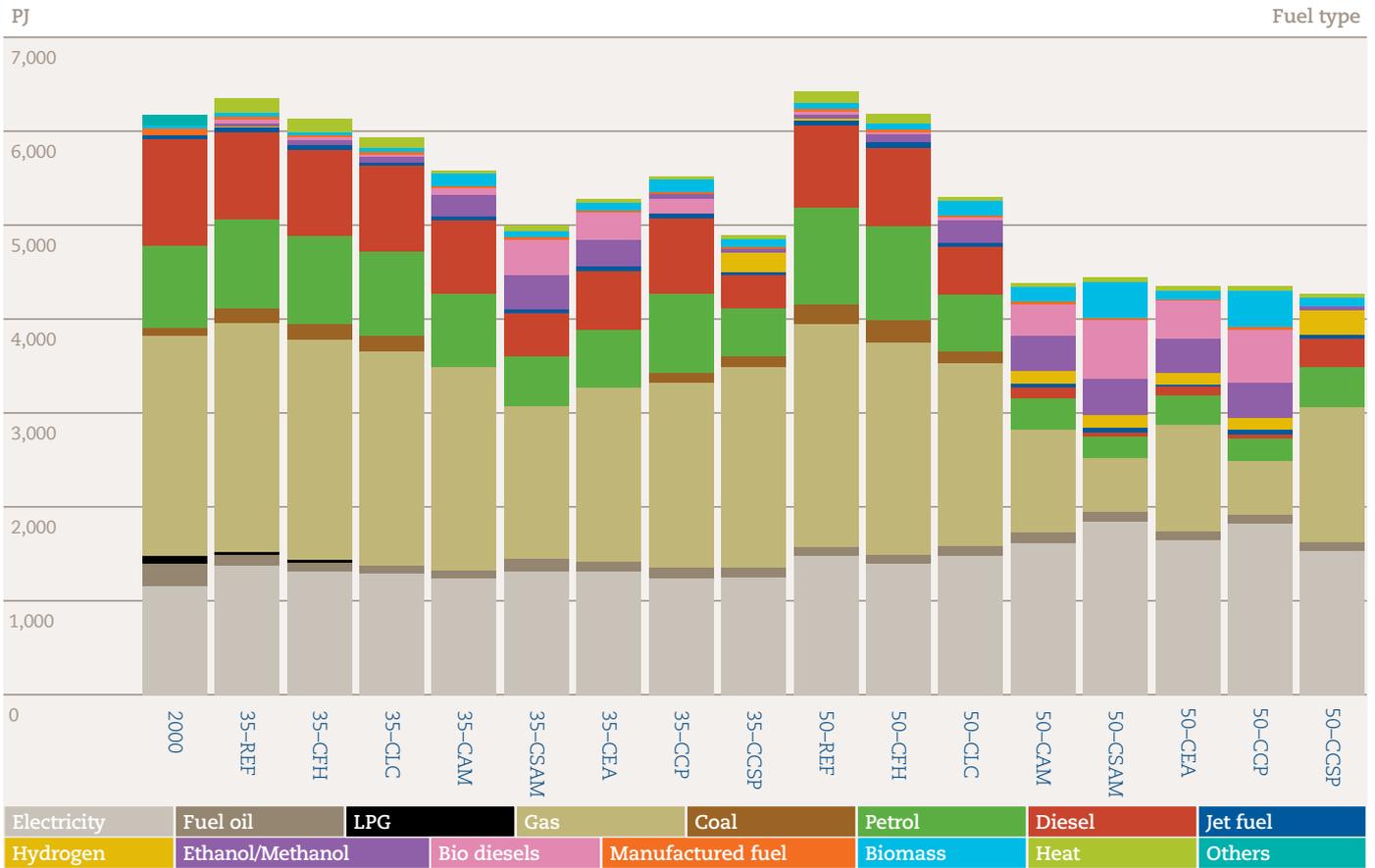
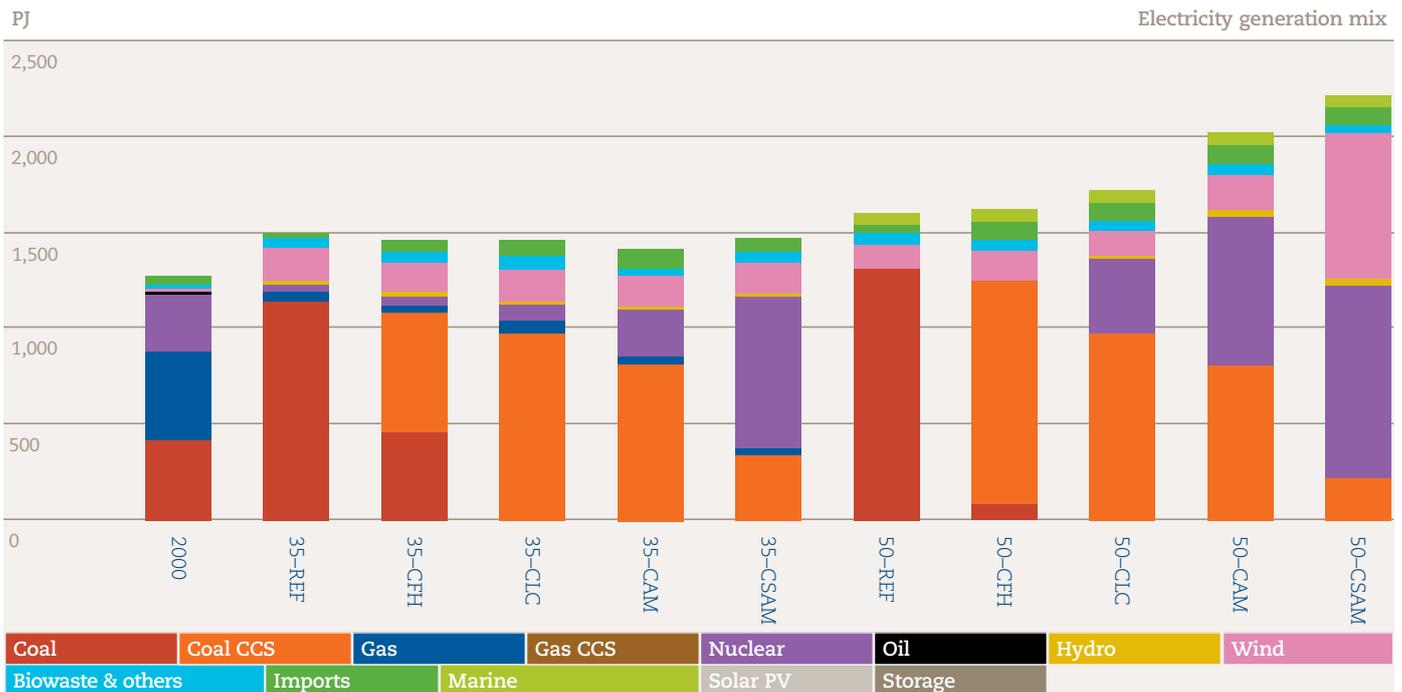


Figure 2.3: Electricity generation and generation mix in 2035 and 2050 in the Energy 2050 scenarios





Electricity decarbonisation via CCS can provide the bulk of a 40% reduction in CO₂ by 2050

When the target is increased, nuclear plus wind is selected alongside CCS. Note that in the most ambitious scenarios (especially CSAM with a 90% reduction by 2050), nuclear, in one sense a “zero-carbon” source, gains at the expense of CCS (a “low-carbon” source). Since the contribution of increasing levels of (off-shore) wind to peak load is limited, the balanced low-carbon portfolio of plants requires large amounts (20GW) of gas plants (CCGT) as reserve capacity. Under stringent CO₂ reduction scenarios, zero-carbon electricity is rounded out by imported electricity, waste-to-energy generation (landfill and sewage gas plants), and marine sources.

Electricity decarbonisation via CCS can provide the bulk of a 40% reduction in CO₂ by 2050 (CFH). To get deeper cuts in emissions requires three things: a) deeper decarbonisation of the electricity sector with progressively larger deployments of low-carbon sources; b) increased energy efficiency and demand reductions particularly in the industrial and residential sectors; c) changing transport technologies to zero-carbon fuel and more efficient vintages. For example, by 2050, to meet the 80% target in CAM, the power sector emissions are reduced by 93% compared to the REF. The reduction figures for the residential, transport, services and industrial sectors are 92%, 78%, 47% and 26% respectively. Hence remaining CO₂ emissions are concentrated in selected industrial and service sectors, and in transport modes (especially aviation).

Figure 2.3 also shows that, by 2050, electricity generation increases in line with the successively tougher targets. This is because the electricity sector has highly important interactions with transport (plug-in vehicles) and buildings (boilers and heat pumps), as these end-use sectors contribute significantly to later period decarbonisation. As a result, electricity demand rises in all scenarios, and in 2050 is over 50% higher than the level in 2000, and is at least 25% higher than REF in 2050 in all of the 80% reduction scenarios. It will be seen that this is a major difference from the most recent UKERC MARKAL scenarios discussed in Section 5.

The shift to electricity use in the residential sector (from gas) combines with technology switching from boilers to heat pumps for space heating and hot water heating to an extent that would be difficult to achieve. The service sector is similarly decarbonised by shifting to electricity (along with penetration of biomass for heating in the most stringent scenarios). Natural gas, although increasing in efficiency, is still used residually in the residential and service sectors for space heating and is a contributor to remaining emissions.

The transport sector is decarbonised via a range of technology options by mode, but principally first by electricity (hybrid plug-in), and later by bio-fuel vehicles in more stringent scenarios (CAM, CSAM). Emissions reduction in transport comes about through some combination of reduced energy service demands, increased efficiency, which reduces the final energy required to satisfy the energy service demands, and the use of zero-carbon transport fuels. For example, electric vehicles have the emissions associated with power generation, but reduce the energy required to meet transport energy service demands, because they are more efficient than internal combustion engines; while bio-fuels in stringent reduction scenarios reduce emissions through the assumption that they are zero-carbon across their life-cycle, but they do not reduce energy demand as their efficiency is similar to petrol and diesel vehicles. Different modes adopt different technology solutions depending on the characteristics of the model. Cars (the dominant mode - consuming two thirds of the transport energy) utilize plug-in vehicles and then ethanol (E85). Buses switch to battery options. Goods vehicles (HGV and LGV) switch to bio-diesel then hydrogen (only for HGV).

These least-cost optimal model scenarios do not produce decarbonisation scenarios that are compatible with the UK targets under the European Union (EU)’s renewables directive of at least 15% of UK final energy from renewables by 2020. Major contributions by bio-fuels in transport and offshore wind in electricity production only occur in later periods following tightening CO₂ targets and advanced technology learning.

Figure 2.4: CO₂ emissions and marginal cost of CO₂ in 2035 and 2050 in the Energy 2050 scenarios

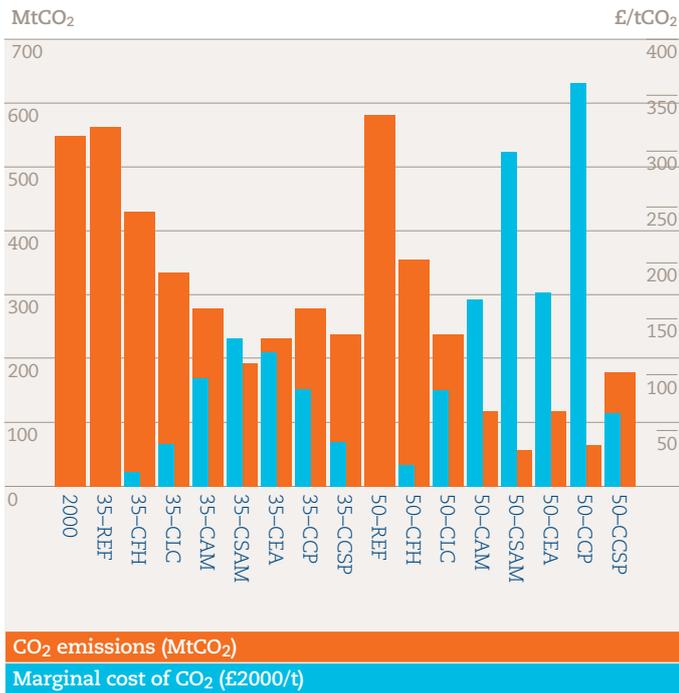
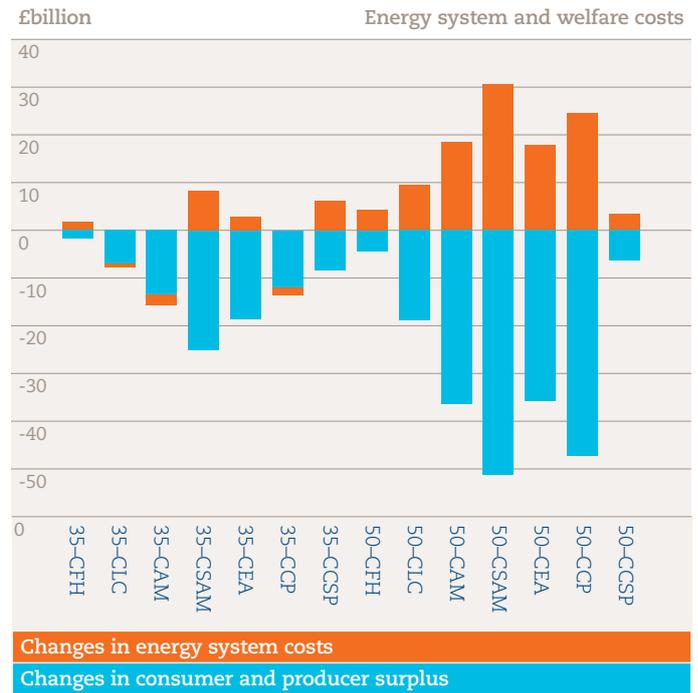


Figure 2.5: Changes in energy system and welfare costs in 2035 and 2050 in the Energy 2050 scenarios



Besides efficiency and fuel switching (and technology shifting), the demand reduction (because of the increasing implicit price of carbon emissions) also plays a major role in reducing CO₂ emissions by reducing energy service demands (ESDs) (5% - 25% by scenario and by ESD). Agriculture, industry, residential and international shipping have higher demand reductions than aviation, cars and HGV (heavy goods vehicles) in transport sectors. Lower ESD reductions are driven both by the lower price elasticities in these sectors, but crucially also by the existence of alternative (lower-cost) technological substitution options. Significant energy service demand reductions (up to 25%) in key industrial and buildings sectors could have negative employment and social policy consequences (which are outside the scope of this modelling) that would need to be addressed by further policy.

Major contributions by bio-fuels in transport and offshore wind in electricity production only occur in later periods following tightening CO₂ targets and advanced technology learning

Higher target levels (CFH to CLC to CAM to CSAM) produce a deeper array of mitigation options (probably with more uncertainty). Hence, as shown in **Figure 2.4**, these runs produce a very wide range of economic impacts, with CO₂ marginal costs in 2035 ranging from £13 - £133/tCO₂ and in 2050 from £20 - £300/tCO₂. This convexity in costs as targets tighten illustrates the difficulty in meeting more stringent carbon reduction targets.

Welfare costs (reduction in the sum of producer and consumer surplus) in 2050 range from £5 - £52 billion, as shown in **Figure 2.5**. In particular moving from a 60% to an 80% reduction scenario almost doubles welfare costs in 2050 (from £20 - £38 billion, 50-CLC to 50-CAM in **Figure 2.5**). **Figure 2.5** also shows the changes in energy system and welfare costs in the different runs: by 2050 energy system costs are increased by the necessity for carbon emissions reduction, despite the energy demands in the carbon reduction scenarios being substantially lower than in the REF case.

Overall, the runs with increasingly stringent carbon reduction targets follow similar emission reduction pathways, with additional technologies and measures being required as targets become more stringent, and costs rapidly increase. Possible differences in decarbonisation pathways are illustrated by the set of runs with the same cumulative CO₂ emissions (CEA, CCP, CCSP), but with different timings of emission reduction.



Giving the model freedom to choose timing of reductions under a cumulative constraint illustrates inter-temporal trade-offs in decarbonisation pathways.

Under a simple cumulative constraint (CCP) the model chooses to delay mitigation options, with this later action resulting in CO₂ reductions of 32% in 2020 and up to 89% in 2050. This results in very high marginal CO₂ costs in 2050, at £360/tCO₂ higher even than the constrained 90% reduction case (50-CCP against 50-CSAM in [Figure 2.4](#)).

Conversely, a cumulative constraint with a lowered (social) discount rate of 3.5% (CCSP) gives more weight to later costs and hence decarbonises earlier - with CO₂ reductions of 39% in 2020 and only 70% in 2050. Similar to the early action case (CEA), this CCSP focus on early action gives radically different technology and behavioural solutions. In particular, effort is placed on different sectors (transport instead of power, [see Figure 2.2](#)), different resources (wind, as early nuclear technologies are less cost competitive, [see Figure 2.3](#)), and increased near-term demand reductions.

Within the CCSP transport sector the broadest changes are seen with bio-fuel options not being commercialized in mid-periods. Instead the model relies on much increased diffusion of electric hybrid plug-in and hydrogen vehicles (with hydrogen generated from electrolysis). As hydrogen and electric vehicles dominate the transport mix by 2050, this has resultant impacts on the power sector with vehicles being recharged during time of low demand (night time). Note that the selection of these highly efficient but high capital cost vehicles is strongly dependent on the assumptions in this scenario of lowered discount and technology specific hurdle rates.

The inter-temporal trade-off extends to demand reductions where the CCP scenario, with an emphasis on later action, sees its greatest demand reductions in later periods. In the CCSP case demand reductions in 2050 are much lower as the model places more weight on late-period demand welfare losses. Earlier in the projection period, however, residential electricity and gas energy service demands in CCSP are sharply reduced in preference to (relatively expensive) power sector decarbonisation.

In terms of welfare costs, the flexibility in the CCP case gives lower cumulative costs than the equivalent GEA scenario with similar cumulative CO₂ reductions; the low welfare losses in the CCSP scenario are not really comparable to those in the other scenarios, because they reflect the changed assumptions about the discount and hurdle rates in this scenario. The interpretation of these changes is that they come about because consumer preferences change and/or government works to remove uncertainty, information gaps and other non-price barriers.

Hydrogen and electric vehicles dominate the transport mix by 2050, this has resultant impacts on the power sector with vehicles being recharged during time of low demand



Rising carbon reduction targets (from 40-90% in CFH through to CSAM) give a corresponding rising price of carbon and, as shown in [Figure 2.4](#), the model CO₂ price ranges in 2050 from £20-300/tCO₂. In the runs with the same cumulative emissions and discount rates (CEA, CCP) the carbon prices in 2050 are £173 and £360/tCO₂ respectively, with the latter illustrating the extra price incurred by delaying decarbonisation (though [Figure 2.4](#) shows CEA having a higher carbon price than CCP earlier in the period). For comparison, the Climate Change Levy at its rate in 2008 amounted to an implicit carbon tax of £8.6/tCO₂ for electricity and gas, and £37.6/tCO₂ for coal. Similarly, if duty on road fuels at 50p/litre is all considered as an implicit carbon tax (i.e. ignoring any other externality of road travel), this amounts to about £208/tCO₂. This means that in the perfect market of the MARKAL model under the runs considered here, for the targets to be met an economy-wide carbon price would need to be gradually imposed, on top of all existing carbon/energy taxes, reaching about the current rate of fuel duty by 2050. While these tax increases seem large, they are actually a fairly modest annual tax increase if they were imposed as an annual escalator over forty years.

For the targets to be met an economy-wide carbon price would need to be gradually imposed, on top of all existing carbon/energy taxes, reaching about the current rate of fuel duty by 2050

Further policy discussion of these runs is reserved for their comparison with the other runs to be discussed in this report in section 6. However, it should always be remembered in such discussion that these pathways and energy-economic implications come from a model with rational behaviour, competitive markets and perfect foresight on future policy and technological developments. Even so the policy challenges in achieving 80% CO₂ reductions in the UK are very considerable. Furthermore, there is a broad range of inherent uncertainties in long-term energy scenarios, as becomes apparent in the other runs to be explored here.

The CCC'S Fourth Carbon Budget Report

The Committee on Climate Change (CCC) has run a number of scenarios to support its recommendations for the Fourth Carbon Budget period of 2023-2027



The Committee on Climate Change (CCC) was set up under the UK's Climate Change Act of 2008, the year in which it published its inaugural report, CCC 2008. One of its tasks is to recommend to the UK Government five-yearly totals of greenhouse gas (GHG) emissions (called 'carbon budgets') that will reduce over the period to 2050 such that the overall 2050 emissions reduction target of an 80% reduction in GHGs from 1990's level will be met.

To support its recommendations the CCC carries out extensive analysis of the various emissions reduction options in the UK, and modelling to identify which of these options are most cost effective. This section reports on this analysis carried out in respect of the fourth carbon budget period, from 2023-2027, as set out in CCC 2010 and, for further detail on the modelling, Usher and Strachan, 2010. The model runs in this section are collectively called the CCC 4CB runs.

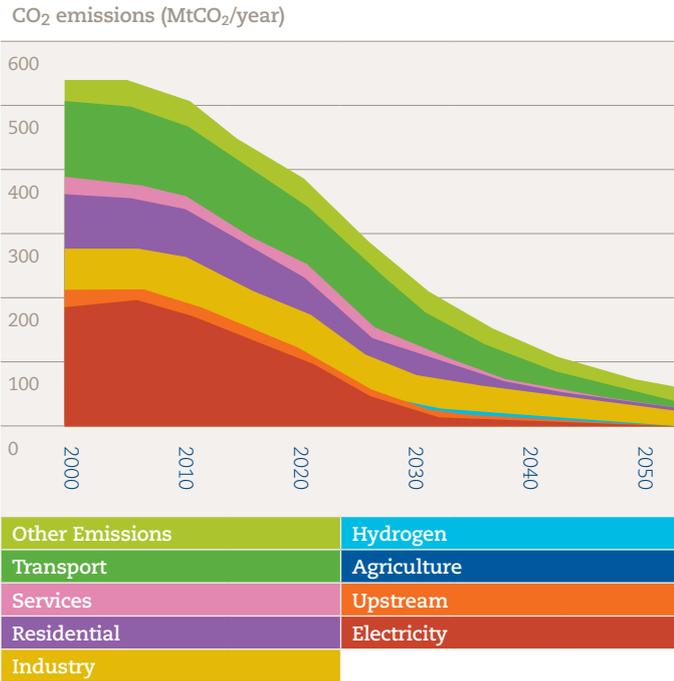
Investments made between 2010 and 2020, and through the 2020s, will therefore fundamentally affect the emissions profile to 2050, and determine whether the 2050 emissions target will be met cost effectively

As was apparent in the previous section in respect of the scenarios with the same cumulative emissions, but different timescales for reduction, it is not possible to make recommendations for, say, the 2020s without having some idea as to the overall decarbonisation trajectory that is to be followed. It is clearly not a feasible emissions reduction option to delay all reductions until the last few years, and then make swingeing cuts to meet the target. Nor would it be a cost-effective option. Much of the energy system consists of long-lasting assets, which fit together in intricate ways that cannot be changed overnight. Investments made between 2010 and 2020, and through the 2020s, will therefore fundamentally affect the emissions profile to 2050, and determine whether the 2050 emissions target will be met cost effectively, or at all. It is for this reason that in their consideration of the carbon budget for 2023-2027, the CCC gave detailed consideration to the possible characteristics of a low-carbon UK energy system of 2050, as well as giving great emphasis and doing more detailed modelling of the period through to 2030 in order to inform its recommendations for the 2023-2027 carbon budget.

However, in considering near-term emission reductions before projecting through to 2050, the CCC noted two factors that suggested that the 2020 targets should be further reduced. First, logic suggested that an 80% cut in all greenhouse gas (GHG) emissions, as mandated in the Climate Change Act, would require an 85% cut in carbon emissions (given that residual non-carbon GHGs would be more expensive or infeasible to reduce at that date), and this cut would need to be 90% in carbon emissions if emissions from international aviation and shipping (which are likely to be difficult and expensive to reduce significantly) were to be included in the overall total, as the CCC recommended. Second, emissions fell in 2009 following the recession, rather than through policy, and it seemed likely that they would remain below the trend calculated before the recession. The higher 2050 target and a lower post-recession trend, combined with detailed bottom-up calculations that showed the feasibility of short-term, cost-effective emissions reductions, caused the CCC to recommend that the 2020 target should be tightened to achieve a 37% (rather than 32%) reduction in carbon emissions from 1990's level. It may therefore be noted that the CCC projected a carbon emissions reduction pathway towards the CSAM 2050 target in [Table 2.1](#), but with greater near-term reductions (37% rather than 32% by 2020) to reduce the required rate of carbon reduction later on (CCC 2010, pp.103, 113, 118).

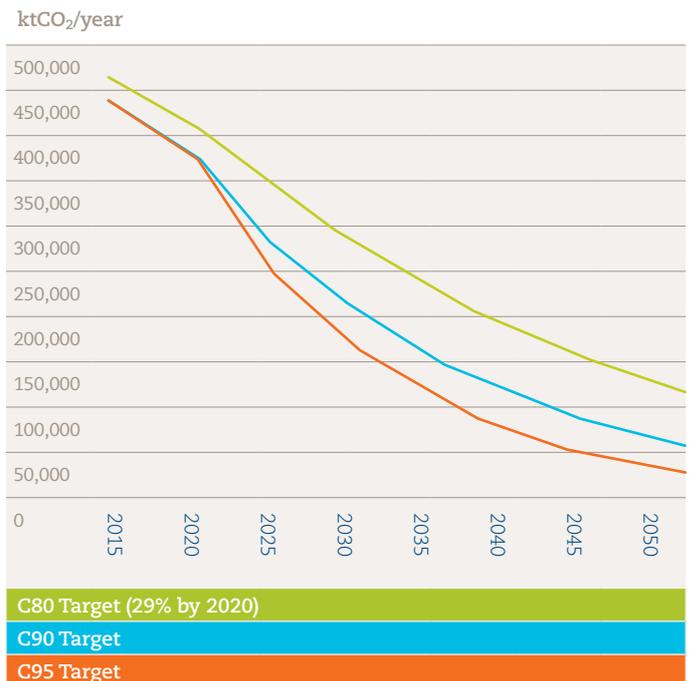
For the shape of the pathway, the CCC made the initial assumption that emissions to 2050 would be cut by an equal annual percentage (6% p.a.) from 2020, which its analysis had indicated was feasible. This resulted in an emissions trajectory as shown in [Figure 3.1](#). This is very similar to the CSAM and CCP trajectories of [Table 2.1](#) (both of which achieved a 90% or close-to-90% cut in CO₂ emissions by 2050), but involves a somewhat larger CO₂ emission cut in 2020 (as noted above). A further MARKAL run ([Figure 3.8](#) in CCC 2010, p.124, not shown here) indicated that such front-loading of emissions reduction in absolute terms was likely to be preferred on cost grounds to having larger cuts later.

Figure 3.1: Possible UK carbon emissions trajectory for a 90% cut by 2050 relative to 1990



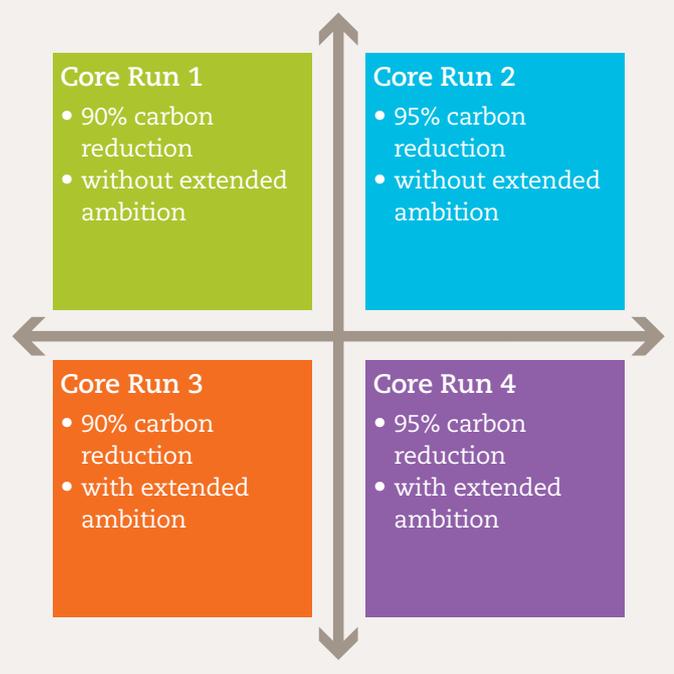
Source: CCC 2010, Figure 3.6, p. 123

Figure 3.2: Three CO₂ reduction trajectories used in the CCC modelling



Source: Usher and Strachan, 2010, Figure 4, p.21

Figure 3.3: Four core scenarios



The detailed MARKAL modelling work for CCC 2010 was published in the report of the UCL modelling team to the CCC, Usher and Strachan, 2010. In all, 32 different scenarios were constructed, which cannot be reviewed in detail here. This report focuses on just three of the CCC 4CB scenarios, with 2050 carbon reduction targets of 80, 90 and 95% (C80, C90, C95). The emissions trajectories from these targets are shown in Figure 3.2.

The Committee on Climate Change specified four core scenarios following a simple matrix shown in Figure 3.3, from which it will be seen that the 90% and 95% targets have been supplemented with assumptions about levels of policy ambition, giving four Core Runs.

The Core Runs have 2050 targets of -90% (59.3MtCO₂) and -95% (29.6MtCO₂), relative to 1990 emissions of 592.4MtCO₂. The path consists of equal annual percentage reductions from the 2020 emissions level of 380.2MtCO₂ (35.8% reduction from 1990 levels). In this report only the Core Runs 1 and 3 (here called C90 and C90+) are compared (together with C80) with a Base Case.

The Core Runs 3 and 4 differ only from 1 and 2 through the inclusion of assumptions of ‘extended ambition’ in respect of policies, as defined below. All the Core Runs, and the C80 scenario, have a social discount rate (S) of 3.5%, in line with UK government guidelines (HM Government, 2010). (In the Energy 2050 runs only the CCSP had a social discount rate; the other runs had a closer-to-market discount rate of 10%, which had the effect of reducing the present value cost of later investments, therefore encouraging the model to delay emissions reduction).



Table 3.1: Price assumptions used in the Core Runs (2000€/GJ)

Fuel	2000	2005	2010	2015	2020	2025	2030	2050
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

'Hurdle rates' are implemented on conservation and transport technologies, to simulate social and other barriers to uptake of these technologies. These are reduced from the levels in the Energy 2050 runs, in line with the 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).

The Renewables Obligation (RO) and Renewable Transport Fuel Obligation (RTFO) constraints are maintained at 15% and 5% from 2015 respectively

The scenarios used the central price assumptions of the Department of Energy and Climate Change (DECC), though the CCC work also modelled sensitivity runs with higher and lower prices (these are not reported here but are described in full in Usher and Strachan 2010). The price assumptions used are as set out in Table 3.1. A further assumption was that there was no domestic fossil fuel production post 2020.

There were further constraints on biomass imports (increasing to 1260PJ by 2050), and build rates for heat pumps and solar heating in the household and service sectors (this was combined with a constant 30% upper limit for heat pumps in the residential stock).

The Renewables Obligation (RO) and Renewable Transport Fuel Obligation (RTFO) constraints are maintained at 15% and 5% from 2015 respectively. This represented the state of legislation under the 2008 Energy Bill, and not the 'extended ambition' under the Government's Low Carbon Transition Plan (HMG 2009).



In the Base Case there is a transition from natural gas supplying the majority of primary energy to a coal-based energy system

The MARKAL model used in the CCC runs had undergone a number of significant updates since the version in the Energy 2050 runs. The most significant of these changes were:

- Higher constraints on build rates for the major generation technologies
- Maximum reductions in energy service demands due to higher carbon prices
- The introduction of CCS with biomass (either by itself or co-fired with coal). This gave the option of effectively negative emissions (the emissions from biomass, assumed to be carbon neutral in the runs reported here, being captured and stored)
- Constraints to 2030 on the introduction of Distributed Generation technologies
- The introduction of new CHP and district heating technologies

The changes make a significant difference to the model choices in the different scenarios, as will be seen.

There now follow summary comparative descriptions of the key results from the Base Case, Core Runs 1 and 3 (C90 and C90+), and the C80 scenario.

Base Case (no carbon constraint, social discount rate)

Primary energy decreases from the 2000 value of ~9500 PJ to ~8000 PJ in 2030, then increases slightly to 8100 PJ by 2050. Final energy demand falls from ~6700 PJ to ~5800 PJ. Lower overall primary and final energy stems from more efficient transport options and uptake of energy conservation options.

There is a transition from natural gas supplying the majority of primary energy to a coal-based energy system, due to the low cost of coal-fired relative to gas-fired generation – this switch occurs for the production of both electricity and hydrogen.

Efficiency improvements (especially in transport) and adoption of conservation measures (in buildings) 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 electricity by 2030, rising to 25% 2050.

About 9 GW of new nuclear is constructed between 2020 and 2030, taking nuclear generation back to 235 PJ⁶, about 83% of the level in 2000, but this is only 15% of 2030 generation. Coal, gas, wind and bio-waste are the largest power generation 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 reduces by 35% by 2030, largely driven by a significant proportion of cars moving early to petrol and diesel hybrids and then on towards electric power, while LGVs shift towards petrol plug-in hybrid technologies; from 2030 to 2050 it is largely unchanged. Rail is largely electrified by 2045.

Biofuel and biomass consumption is largely driven by the RTFO, 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.

CO₂ emissions reduce from 2000 levels to a trough of ~480 MtCO₂/year in 2030 before rising steeply to a peak of ~600 MtCO₂ in 2050. This is driven by high emissions in the electricity and hydrogen sectors as a result of the shift to coal.

⁶ Electrical energy is normally measured in terawatt (or kilowatt) hours (TWh or kWh), where 1 TWh = 3.6 PJ

C90 (Core Run 1: 90% CO₂ reduction, without extended ambition, social discount rate)

By 2050, the primary energy flows are dominated by nuclear electricity⁷ and co-firing (coal and biomass) with CCS, with oil, biomass and wastes and renewable electricity providing the remaining third. Total primary energy follows a decline to ~6900 PJ in 2025-30, followed by an increase to ~8800 PJ, as the energy system follows first a transition to the more efficient technologies, followed by a second transition beyond 2030 as the system decarbonises through greatly increased co-firing with CCS and nuclear generation.

Final energy demand declines significantly over the course of the model horizon to ~4,200 PJ in 2050, by which time electricity is 54% of final energy, compared to 27% in the Base Case. Electricity is therefore the dominating de-carbonisation pathway, with generation rising from 1300PJ to 2900PJ despite a declining overall energy system size.

Conservation measures (boosted by lowered hurdle rates) double between 2010 and 2020 then double again by 2050 to around 400PJ with a 33:67 split between the service and residential sectors.

The pattern of transport fuel demand reduction is largely similar to the Base Case and is highly efficient (hybrid) in the mid-term moving to more efficient drive-trains and advanced fuels in the long term. Petrol and diesel vehicles are largely squeezed out in the latter periods of the model horizon, in favour of hydrogen fuel cell vehicles.

The later transport fuel mix is largely electricity (cars, buses), hydrogen (HGV, cars), plug-ins (LGV), traditional hydrocarbons (aviation, 2 wheelers, some cars) and only 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, the CO₂ intensity of electricity is negative, with significant co-firing CCS, nuclear and renewable resources providing energy. Biomass CCS (with negative net emissions) is utilized in 2050. The capacity and generation of the electricity system in 2050 are both around 70% larger than in the Base Case, as electricity delivers an increasing proportion of energy service demands (ESDs) in heat and transport. The C90 electricity capacity is larger than the Base Case from 2025 onwards, although greater quantities of electrical energy are not generated until 2035.

Hydrogen production is from gas steam methane reforming (SMR) with CCS in the mid-term then electrolysis, reaching 320 PJ by 2050, compared to 244 PJ in the Base Case, when it is nearly 70% derived from coal gasification, with gas SMR and electrolysis providing 20% and 12% respectively.

The marginal cost of CO₂ emissions reaches £100/tonne in 2025 and £300/tonne in 2050. Annual welfare costs reach £10 billion by 2030 and £30 billion by 2050.

The 'extended ambition' scenarios

The extended ambition scenarios characterise technology-specific development as specified by the Committee on Climate Change (CCC). To analyse the effect of the chosen policies, the extended ambition scenarios were compared with the first two core runs. Here the results of Core Run 3 (C90+) are compared with those of Core Run 1 (C90).

The extended ambition assumptions concerned residential and service sector conservation options, CCS demonstration projects, commissioned nuclear plants, commissioned wind plants plus a relaxation of the constraints on build rates during the 2020s, and electric vehicle uptake. The assumptions are listed in [Table 3.2](#).

Table 3.2: Assumptions included in the CCC defined extended ambition scenario

Technology	Assumption
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
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	Minimum heat output 3 PJ/annum by 2015 rising to 9.1 PJ/annum by 2025
Biomass Boilers – Service & Domestic	Minimum heat output ~8 PJ/annum by 2015 rising to ~23 PJ/annum by 2025 with the majority of effort in the service sector
Heat pumps	Minimum heat output ~41 PJ/annum in 2015 rising to ~120 PJ/annum in 2025 with a 2:1 ratio between service and domestic sectors
Energy conservation	CCC assumptions from internal modelling regarding mix of conservation technologies and availability

Source: CCC 2010, Figure 3.6, p. 123

⁷Accounted as the fossil fuel equivalent

C90+ (Core Run 3: 90% reduction in CO₂ emissions, with extended ambition, social discount rate)

In this scenario the change in structure of the energy system is especially evident in the electricity sector as 27GW of wind turbines are introduced by 2020 (see Table 3.2), 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 C90 with the exception of a switch of 270PJ from biowaste and biomass to wind electricity, with also a small decline in nuclear generation. Comparing the electricity system size, C90 suggests that the cost optimal system is somewhat smaller than that in the C90+ scenario, with approximately 25 GW less wind, and a corresponding reduction in gas backup plant.

The change in the electricity system occurs in tandem with the introduction of battery electric and plug-in hybrid vehicles, as specified in the 'extended ambition' assumptions. These two technologies result in storage capabilities available to the electricity system. However, in comparison to C90, which sees almost all the storage (~170 PJ) coming from plug-in hybrid technologies, C90+, while seeing the same amount of storage overall, sees it shared between electrical storage heaters (~50 PJ) and battery electric vehicles (~120 PJ).

In the C90 scenario, petrol and diesel vehicles are largely squeezed out in the latter periods of the model horizon, in favour of hydrogen fuel cell vehicles

The main change in final energy demand follows a now familiar pattern. In 2050 electricity generation, at ~3100 PJ, is even higher than in C90 (~2900) and is nearly twice that in the Base Case (~1700 PJ), with over 40% coming from co-firing with CCS, 28% from nuclear and the rest from renewables. Final energy demand in 2050 reduces substantially from the level in 2010 in the residential sector (by 42% to ~1100 PJ), and in the service sector (by 66% to around 360 PJ). In the transport sector, hydrogen from electrolysis becomes a common energy carrier from 2030 onwards, in 2050 comprising 37% of transport final energy of ~980 PJ, with electricity providing 36% and the rest coming from fossil fuels. The efficiency increase in transport is shown by the fact that by 2050 in C90+ transport final energy is only just over half that in 2010, even while transport ESDs have increased by 55% to ~840 billion vehicle kms.

Transport energy demand reduction occurs through a step change in 2030 as the model adopts battery electric vehicles and hydrogen simultaneously, the former initially driven by the extended ambition assumptions, the latter by the model optimisation. However, the extended ambition targets for electric vehicles and plug-in hybrids are dwarfed by the endogenous technology choices post-2030, with hybrids (plug-in and normal) giving way to battery electric vehicles, except for LGVs.

By 2050 in C90+ CHP is delivering ~50 PJ of electricity and ~140 PJ of heat through district heating (in both cases double the level of 2020, but a slight decline from 2040). However, compared with C90 in 2050, this is around 40% less electricity and heat from CHP, the level of which in C90 continues growing through the 2040s. This is because in C90+ there is greater electrification of residential heat (through more electric heaters, not heat pumps, which are the same as in C90). In both C90 and C90+ gas use in homes has fallen to zero by 2045, from around 1300 PJ in 2000. With 95% of residential heat in 2050 in C90+ coming directly or indirectly from zero-carbon electricity generation (heaters, heat pumps or CHP district heating), 2050 carbon emissions from homes in both C90 and C90+ are effectively zero (and slightly negative if microgeneration is taken into account).

Conservation uptake in the buildings sectors increases by another 70PJ over C90 to ~470PJ, with all the increase coming in the service sector, which has 40% more energy saved through conservation than in C90.

Compared to C90, annual welfare losses in C90+ increase from ~£9 to ~10.5 billion in 2030, and from ~£29.5 to ~£31 billion in 2050, reflecting the fact that the extended ambition assumptions force the model to select more costly technologies than it would otherwise have chosen. This issue is returned to at the end of this report.

However, the marginal costs of CO₂ are generally lower in C90+ than in C90 (e.g. in 2020, £25/tCO₂ vs. £38/tCO₂) as the extended ambition assumptions allow less costly technologies to be chosen at the margin, effectively supplementing the carbon price signal. By 2050, however, marginal carbon costs in C90 and C90+ are the same at £288/tCO₂.

C80 (80% reduction in CO₂ emissions, no extended ambition, social discount rate)

As shown in **Figure 3.2**, the CO₂ trajectory used in this run is slightly different than in the four core runs, starting slightly higher in 2020 (30% rather than 36% reduction from the 1990 level). This allows the model more flexibility in the earlier periods. With respect to the Energy 2050 runs, this is most comparable with the CAM scenario.

The C80 run is broadly similar to the C90 run but the lower emissions reduction target exerts less pressure on key resources, sectors and technologies. For example, the transition to low-carbon electricity still takes place, but more slowly – electricity in C90 is more or less completely decarbonised in 2030, but in C80 still emits around 45MtCO₂. Similarly with the quantity of generation – electricity in 2050 in C80 increases to ~2200 PJ from the ~1700 PJ in the Base Case, but this is substantially lower than the ~2900 PJ in C90 – as the need reduces to decarbonise heat and transport with zero-carbon power. The result is that the overall electricity system is smaller (146GW in C80 in 2050, compared with 192GW in C90, with ~30GW less co-firing CCS, around 9GW less wind, and 9GW less gas back-up plant). Industrial sector electricity use in C80 is more than 50% below that in C90. Although hydrogen production in C80 only falls by about 7% from the 320 PJ level in C90, the proportion produced by electrolysis falls from 96% in C90 to 40% in C80, with the rest in C80 coming from steam methane reforming (SMR) with CCS.

Compared to C90, the extra permitted emissions in C80 bring about a switch from electricity to natural gas. In residential heating, 76 PJ of gas heating remains in 2050 in C80, whereas it was completely phased out by 2045 in C90 and C90+ in favour of electricity and district heating. In C80 industry uses more natural gas for both high- and low-temperature heating, rather than electricity. It also continues to use more than 120 PJ of coal as final energy up to the 2040s, whereas in C90 it had fallen below this level after 2020 and was practically zero after 2035. Natural gas in final energy demand is ~900 PJ in 2050 in C80, compared to ~500 PJ in C90. Petrol and diesel in final energy in 2050 add up to ~360 PJ in C80, as opposed to ~310 PJ in C90.

In C80 CHP is primarily fuelled from fossil sources until 2040, when a dramatic switch to predominantly renewable sources takes place. Heat from CHP in C80 reaches a plateau of ~200 PJ in 2020 and falls in between the Base and C90 cases. In the Base Case, high quantities of fossil-fuelled CHP are used and heat production reaches a maximum of ~590 PJ in 2035. In C90, renewable fuels dominate CHP from 2020 onwards via a gradual increase to only ~140 PJ in 2050.

High levels of uptake of energy efficiency and conservation technologies in buildings and transport (e.g. new drive-trains in vehicles) remain in C80, due to optimal decision making under a 3.5% discount rate, so that final energy demands in C80 (~4200 PJ in 2050, down from ~6700 PJ in 2000) are similar to C90.

The transport sector sees only relatively small changes, with petrol and diesel remaining a greater part of the fuel mix, and technologies like petrol hybrids a greater part of the vehicle mix, for longer, and new low-carbon fuels and technologies exhibiting 5-10 year lags compared to C90.

Conventional natural gas plant build rates increase sooner, as 12GW of CCGTs are added between 2015 and 2020 before the installed capacity of 40GW starts declining from 2025

There is much less need in C80 for primary energy in the form of both biomass and coal (with CCS). Both these resources halve from C90 levels (from ~1700 PJ and ~2600 PJ respectively). This is because biomass CCS never appears in C80 (in C90 it reaches ~130 PJ by 2050), while the co-firing with CCS of biomass and coal in 2050 falls from ~1300 PJ to 550 PJ (with the retention in 2050 of ~60 PJ coal CCS in C80, compared to none in C90).

Nuclear generation, on the other hand, in 2050 reaches ~980 PJ in C80 (compared to 900 PJ in C90), but this is 45% of C80 generation, compared to only a 31% 2050 nuclear share in C90. Renewables, however, have a comparable share (22-23%) in 2050 in the two scenarios.

Generally all constraints on the low-carbon build rates are less binding in C80, and those on marine build are not triggered at all. However, conventional natural gas plant build rates increase sooner, as 12GW of CCGTs are added between 2015 and 2020 (only 6GW in C90), before the installed capacity of 40GW (32GW in C90) starts declining from 2025, to reach 29GW in 2050 (37GW in C90, which needs more back-up capacity for wind).

As would be expected costs in C80 are lower than in C90: in 2050 marginal CO₂ costs are only £163/tCO₂ compared to £288/tCO₂, and welfare costs are £17.5 billion compared to £29.5 billion. Through 2030, costs in C80 are especially modest, being less than £50/tCO₂ (in C90 £103/tCO₂), with overall welfare costs in 2030 of only £3.6 billion (in C90 £8.9 billion).

Brief preliminary comparison between CCC and Energy 2050 runs

A number of other features of the CCC runs compare closely with the UKERC 2050 MARKAL CCP and CSAM runs, but there are also some significant differences, perhaps reflecting the fact that the model was significantly modified between the runs. The following paragraphs highlight some of the key similarities and differences (for electricity, where the more usual energy unit is TWh, it may be noted that 1TWh=3.6PJ).

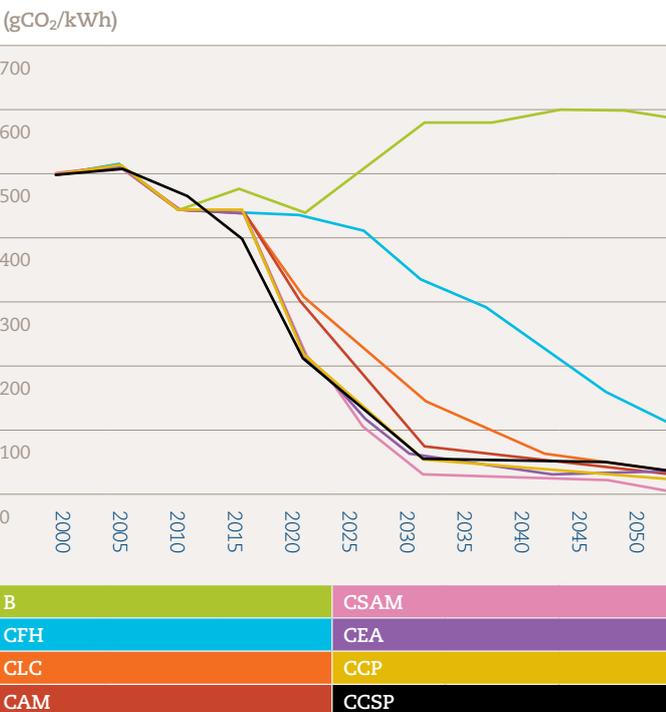
Electrification of heat and transport: all the runs project substantial future take up of heat pumps for space and water heating, and electric vehicles of some kind in transport. This results in around a doubling in the size of the power sector by 2050 over its current size. In C90 capacity and generation go from 84GW and 1300 PJ in 2000 to 192GW and 2919 PJ in 2050. In CCP the comparable 2050 numbers are 131GW and 2047 PJ, and in CSAM 177GW

and 2211 PJ, with almost all the extra capacity in CSAM compared to CCP being in wind turbines (65GW compared to 19GW) and associated gas back-up plant. In C90 wind only reaches 28GW because of the availability of co-firing CCS. This is in the context of an overall decline in final energy demand (including electricity) between 2000 and 2050 in both CCP and CSAM of 28-30% (38% in C90), emphasising the extent to which electricity has taken over from oil in transport and gas in heating.

Decarbonisation of electricity: the large increase in power generation comes about because in the model the fast decarbonisation of electricity is the most cost-effective way to achieve the large required emission reductions from the energy system as a whole. In CCC 2010 this proceeds rapidly to 2030, from around 500gCO₂/kWh in 2000 to around 50gCO₂/kWh (CCC). **Figure 3.4** shows the trajectory of the decarbonisation of power generation in the Energy 2050 scenarios, from which it can be seen that all the scenarios with CO₂ reductions of more than 60% by 2050 (CAM, CSAM, CEA, CCP, CCSP) have CO₂ intensities below 100gCO₂/kWh by 2030. By 2050 the range of CO₂ intensities across these scenarios range from 8 to 40gCO₂/kWh, and is only 43gCO₂/kWh for CLC with its 60% reduction target. Clearly there are strong cost drivers in the model to reduce oil and gas demand by switching to electricity on a large scale.

Carbon capture and storage (CCS) plays an important role in most of the high CO₂ reduction scenarios: In the Energy 2050 runs, 12-43GW of coal CCS is installed by 2050. All the scenarios except CSAM have over 25GW. In CSAM the 90% carbon reduction requirement means that the residual emissions from coal CCS (up to 10% of emissions) are too great for the target to be met, so that wind takes over from coal CCS, with an additional requirement for extra gas back-up capacity. There is effectively no gas CCS (1GW in CCP only). One of the major areas of model development for the CCC was a richer characterisation of CCS options in the model, including CCS for both biomass and co-firing of coal with biomass, and for industrial processes. In C90 this results in a take up of 50GW of co-firing CCS by 2050, which sequester 265mtCO₂.

Figure 3.4: CO₂ intensities across the carbon reduction scenarios in Energy 2050 runs



Source: Energy 2050 results database, UCL Energy Institute

One of the major areas of model development for the CCC was a richer characterisation of CCS options in the model, including CCS for both biomass and co-firing of coal with biomass, and for industrial processes

Bioenergy is used in different ways: There is a comparable quantity of bioenergy as primary energy in the CCC and Energy 2050 (except CCSP) runs. The CCSP exception is due to the fact that the social discount rate makes later abatement options relatively more expensive, so that emissions abatement takes place earlier, allowing relatively high emissions in 2050 (see Table 2.1). This allows CCSP to use more petrol and diesel in 2050 (425 PJ and 274 PJ respectively) than in the other Energy 2050 runs (for example, 243 PJ and 24 PJ respectively in CCP, which has the same cumulative emissions over 2010-2050). In the other Energy 2050 runs the great majority of bioenergy is used as biofuels.

In the CCC runs (C80, C90, C90+), significant new technologies for bioenergy have been added compared to the Energy 2050 runs: co-firing with CCS, which gives the model the opportunity for effectively 'negative' emissions, and CHP with biomass, which allows for very efficient use of the resource in both power generation and heat for buildings, via district heating. The model adopts both technologies at scale as shown in Table 3.3. In C90, for example, co-firing CCS burns 650 PJ of biomass (sequestering around 265mtCO₂). Towards 2050 some bioenergy in the CCC runs is used to provide high-temperature heat in energy-intensive industries (not shown in Table 3.3). Very little bioenergy in the CCC runs is used for biofuels in transport, which, because of the 'negative' emissions provided by co-firing CCS, is more aggressively electrified (C90 uses ~390 PJ electricity for transport, compared to only ~190 in CSAM, which has the same 2050 90% emission reduction target). These shifts in fuels and technologies illustrate the importance to the whole structure of the energy system of new fuels and technologies becoming available and affordable.

Table 3.3: Bioenergy use in the CCC and Energy 2050 runs

PJ in 2050	Total primary energy ¹	Power generation ²	CHP (power generated)	District heating (from CHP)	Service sector	Residential heat (not CHP)	Biodiesel	Bioethanol
C90	1660	650	80	255 (241)	0	32	9	4
C90+	1436	658	51	155 (142)	32	2	4	3
CCP	1648	38	na	na	375	0	582	359
CSAM	1724	38	na	na	373	0	646	359
C80	883	271	69	217 (204)	0	47	5	5
CAM	1142	38	na	na	146	0	338	393
CCSP	279	39	na	na	56	0	12	29

Source: ¹ Biomass and waste ² Biomass used in co-firing CCS (C90, C90+, C80); Power generation from biowaste (CCP, CSAM, CAM, CCSP)

The UK Government's Carbon Plan

Many MARKAL model runs fed into the preparation of the UK Government's 2011 Carbon Plan



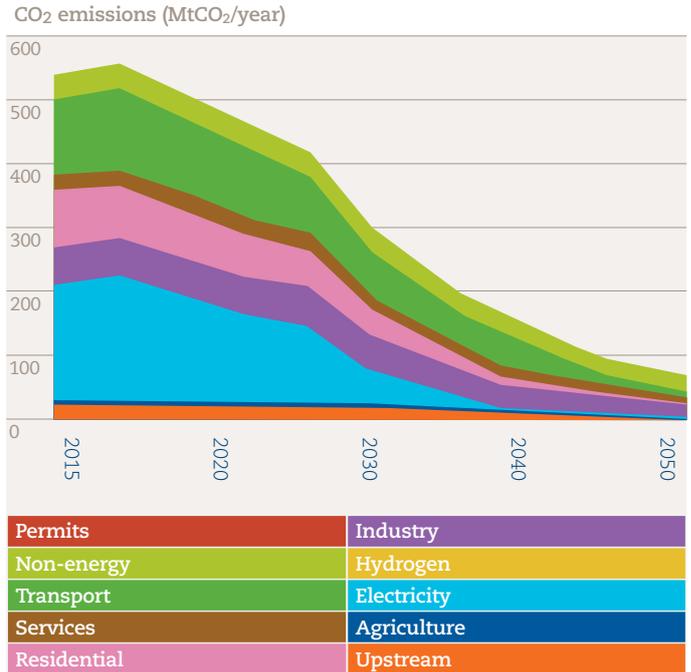
The Carbon Plan (HMG 2011) replaced the previous Government's Low Carbon Transition Plan (HMG 2009) and was published in December 2011, some months after the Government had accepted, and legislated for, the Committee on Climate Change (CCC)'s recommendations for the fourth carbon budget set out in CCC (2010).

The Carbon Plan included a 'Core MARKAL run', which was then compared with a number of other scenarios created using the DECC 2050 Calculator⁸. However, the DECC 2050 Calculator has no optimisation routine, so that the choice of technology in each of these scenarios is made by the user of the Calculator for illustrative purposes only. More interesting from the point of view of this paper were the many MARKAL runs around the 'Core MARKAL run' which were carried out and reported in AEA 2011,a,b. In this report these runs are collectively called the AEA CP runs.

The MARKAL model underpinning this work was a further development and updating of the MARKAL model used for the CCC work discussed in section 3. The updating included "revised electricity generation sector costs and constraints, including addition and removal of some technologies from the model" and generally increased energy service demands to reflect current government views (AEA 2011a, p.ii). AEA considered that the effect of these changes would be likely to increase the cost of meeting CO₂ reduction targets.

The main target for emissions reduction adopted in the model runs was 90% from 1990's level, for the same reason as in the CCC work discussed above. This makes the runs comparable on that dimension with the CCC runs. However, a major difference in these runs (apart from the changes to the model already mentioned) is that they assumed that the various policy and emission reductions in The Carbon Plan through to 2020, such as the UK's renewable energy targets, were actually achieved. This is a strong assumption, as will become clear. It means that the actual MARKAL modelling (and the associated cost and other projections) only began from 2020, and this should be borne in mind in the description and comparison with other model runs that follow.

Figure 4.1: Sectoral CO₂ emissions 90% reduction target



Source: AEA 2011a, Figure 3, p.16

The AEA modelling work consisted of 36 runs divided into 14 separate studies, which are reported in detail in AEA 2011b. The different studies varied model assumptions across demand levels, fossil fuel prices, emissions reduction targets and trajectories, the availability of international tradable permits, the extent of the ability of consumers to respond to price changes, the timing of abatement action, the availability of a variety of technologies and resources, and the rate at which these technologies and resources can be adopted. For reasons of space these runs cannot be discussed here in detail, and the description that follows largely derives from the Key Results paper of AEA 2011a, which reports ranges across the studies for the major outcomes from the modelling.

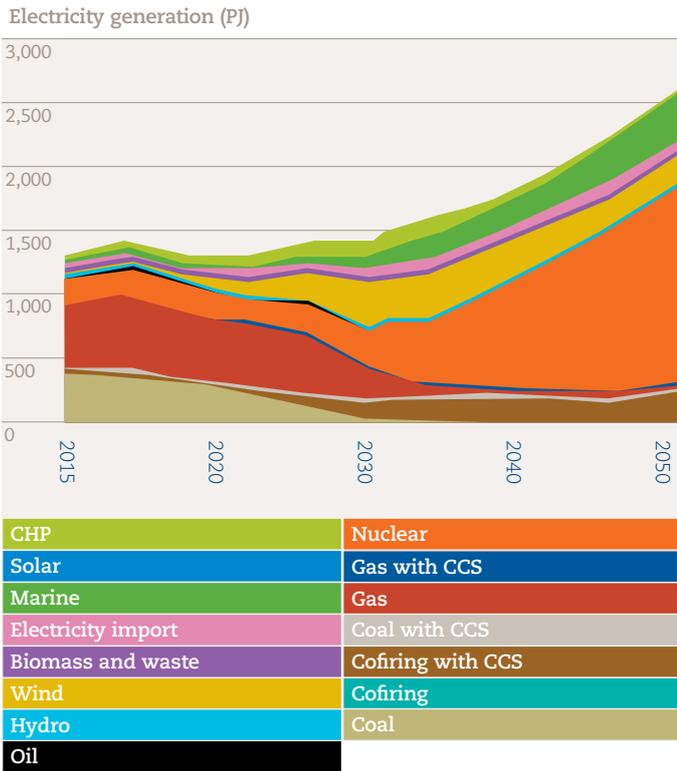
The two 'Core Runs' were:

- DECC-1A: 90% CO₂ reduction from 1990's level by 2050, equal annual percentage reduction from 2020
- DECC-1A-IAB-2A: 90% CO₂ reduction from 1990's level by 2050, equal annual percentage reduction from 2020 (i.e. as DECC-1A) plus a social discount rate (3.5% - the discount rate in DECC-1A differed across sectors) plus various 'constraints and frictions' "to better emulate the dynamics of uptake of technologies" (AEA 2011a, p.7).

Figure 4.1 shows the sectoral emissions from the Core Run in Phase 2 (DECC-1A-IAB-2A) of the AEA project, with a CO₂ reduction target of 90% (constraining 2050 CO₂ emissions to 59MtCO₂), with equal percentage annual reductions from 2020. It clearly exhibits some by now familiar features of such runs.

⁸ See <http://www.decc.gov.uk/en/content/cms/tackling/2050.aspx>

Figure 4.2: Electricity generation, 90% reduction target



Source: AEA 2011a, Figure 4, p.17

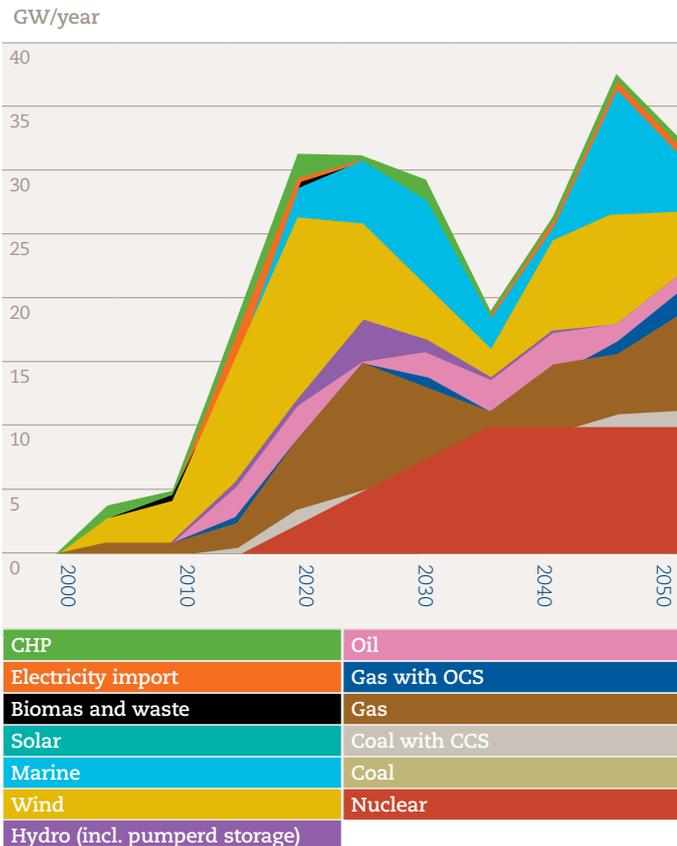
Electricity is the first sector to decarbonise. It is largely decarbonised by 2030 (CO₂ intensity around 50gCO₂/kWh, a 90% reduction on the level in 2010. The intensity falls to essentially 0 (i.e. there is complete decarbonisation) by 2035, and becomes slightly negative (through the operation of co-firing biomass with CCS) by 2050.

The decarbonisation is largely the result of huge deployment of nuclear energy post-2025, as shown in Figure 4.2. This reduces the generation from wind, which is overtaken by that from marine towards the end of the period.

Figure 4.3 shows the extent of the fall off in wind investment, and the growth in that from nuclear, after 2020. Pre-2020 the very large investment in wind is driven by the assumption that the UK meets its 2020 renewables targets. It can also be seen that marine investment comes on strongly after 2020, but that this too is affected until 2035 by the growth in new nuclear capacity. The growth of nuclear also squeezes out coal CCS, although a tiny amount, together with gas CCS, comes back in the final period of the projection timeframe. The gas without CCS is back-up plant that produces very little generation (see Figure 4.2), as with the other runs with large-scale carbon emissions reductions discussed here.

There is also relatively modest generation from co-firing with CCS (around 200 PJ), compared with the ~650 PJ in the C90 and C90+ CCC runs discussed above, and also very little CHP.

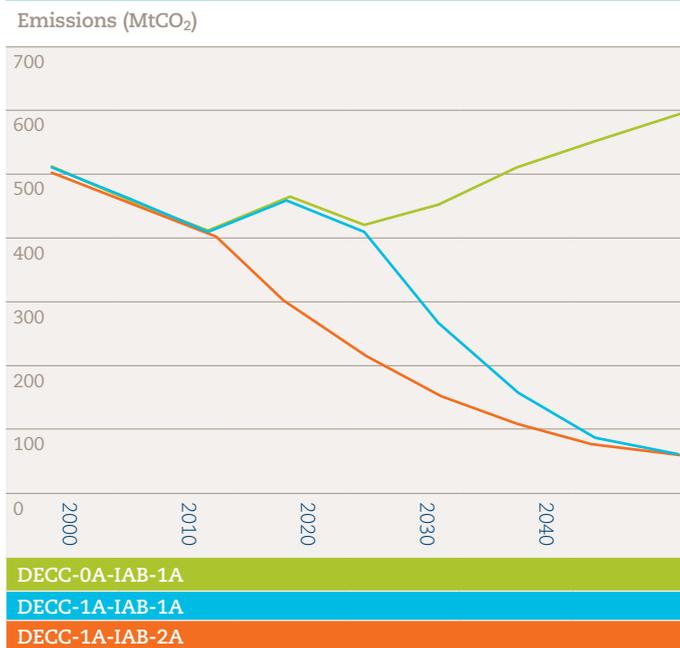
Figure 4.3: Power capacity installed in each 5-year period, 90% reduction target



Source: AEA 2011a, Figure 4, p.17

The final use of bioenergy (i.e. that not used in electricity generation) explodes later in the projection period. Up to 2030 it rises relatively gently to around 200 PJ (compared to ~140 PJ in C90), but then rises to over 800 PJ by 2045, before falling back to ~750 PJ in 2050. This is in addition to the 200 PJ electricity generated by co-firing CCS shown in Figure 4.2. However, it can be seen from Table 3.3 that this is not out of line with (in fact, is still rather less than) the final use of bioenergy in CAM, CCP and CSAM. The great majority of the use of this bioenergy is as biodiesel (rather than the biodiesel/bioethanol split shown in the Energy 2050 scenarios in Table 3.3.)

Figure 4.4: Three Emissions Pathways for the UK



Source: AEA 2011a, Figure 7, p.19

With electricity largely decarbonised by 2030, its use for lighting and appliances emits very little CO₂

Some interesting light is shed in these studies on the relative advantages and disadvantages of early and late abatement. **Figure 4.4** shows three emissions pathways to 2050. DECC-0A-IAB-1A is the Business as Usual Baseline, DECC-1A-IAB-1A follows that Baseline to 2030 and only starts to abate thereafter, and DECC-1A-IAB-2A, the Core Run that provides the results in **Figures 4.1, 4.2** and **4.3** implements equal annual percentage abatement from 2020 onwards.

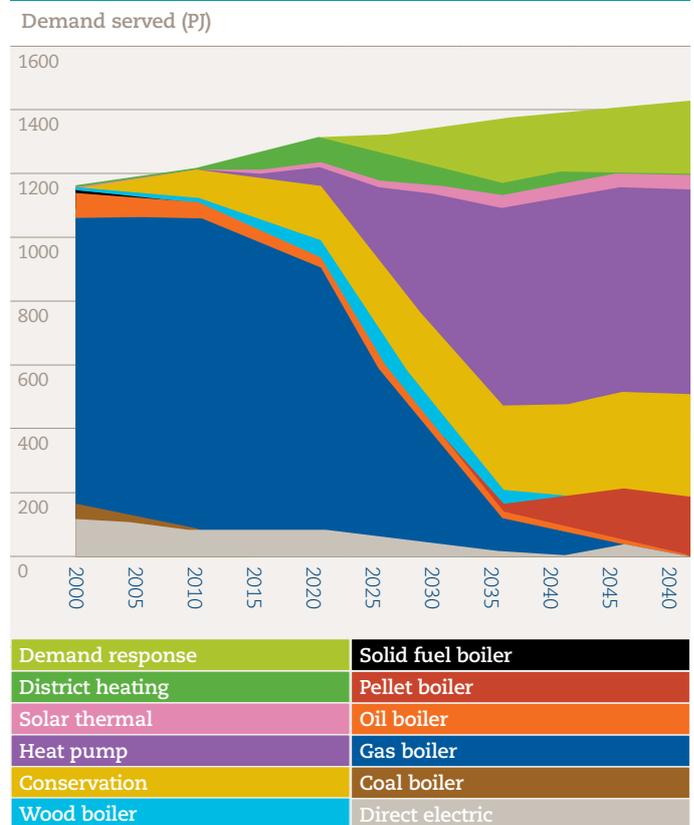
The DECC-1A-IAB-1A run turns out to cost less than DECC-1A-IAB-2A, because, although they reach the same target, DECC-1A-IAB-1A uses cheaper generation technologies in the period to 2030, and this offsets the more expensive technologies (with their future cost discounted) that are required for the fast emission reduction thereafter. The DECC-1A-IAB-1A run also emits 2500 MtCO₂ more over the projection period than DECC-1A-IAB-2A. However, if a constraint is applied such that the later abatement run can emit no more CO₂ over the projection period than DECC-1A-IAB-2A, then the model cannot solve: there are no technologies available that enable it to meet the 90% reduction target. The conclusion is stark. If the mandatory 2050 CO₂ reduction target is to be met, then emissions must fall steadily to 2020 as

shown and even faster abatement must begin (shown by the increased slope of the DECC-1A-IAB-2A line before and after 2020) and continue at that rate until 2050. There is simply no scope for abatement slippage if the target is not to be missed. This point is picked up again further in the conclusions section.

Sectoral outcomes

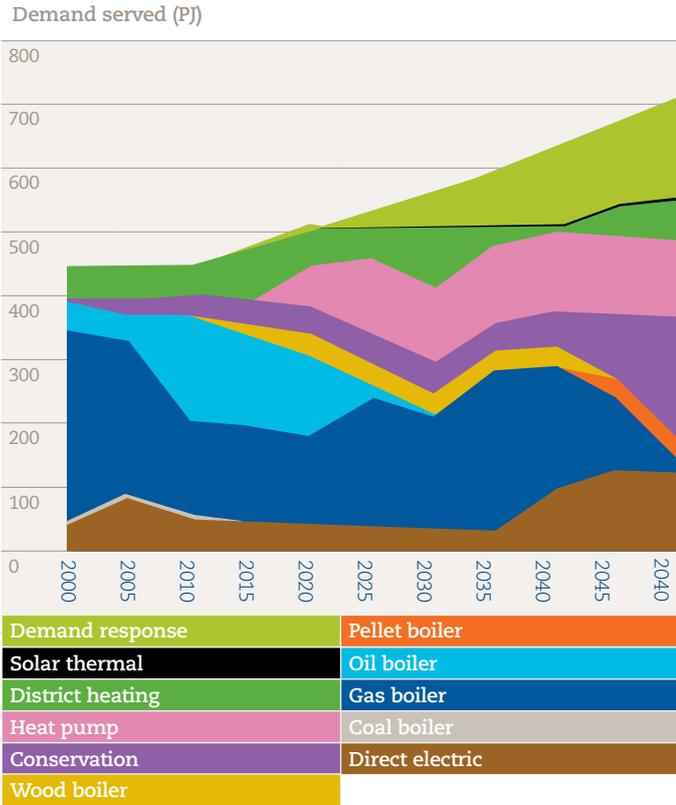
The main energy service demands in the residential and service sectors are for lighting and appliances, which can only be met by electricity, and for space and water heating, which can be met in a variety of ways. With electricity largely decarbonised by 2030, its use for lighting and appliances emits very little CO₂. The key question is: how is low-grade heat for space and water heating to be provided? There are six possible low-carbon types of answers in the MARKAL model: demand reduction (e.g. people turn down thermostats or heat fewer rooms); conservation (e.g. insulation) and efficiency improvements, which reduce energy demand but allow the same energy service demands to be met or outcomes (e.g. warm rooms) to be achieved; heat pumps, which use electricity to pump ambient heat from outside into the buildings; direct electric heating; district heating, fuelled by bioenergy, with or without CHP; and individual biomass boilers, also fuelled by bioenergy.

Figure 4.5: Demand Served by Residential Heating End-Use Technologies



Source: AEA 2011a, Figure 8, p.20 (model run DECC-1A-IAB-2A)

Figure 4.6 Demand Served by Services Heating End-Use Technologies



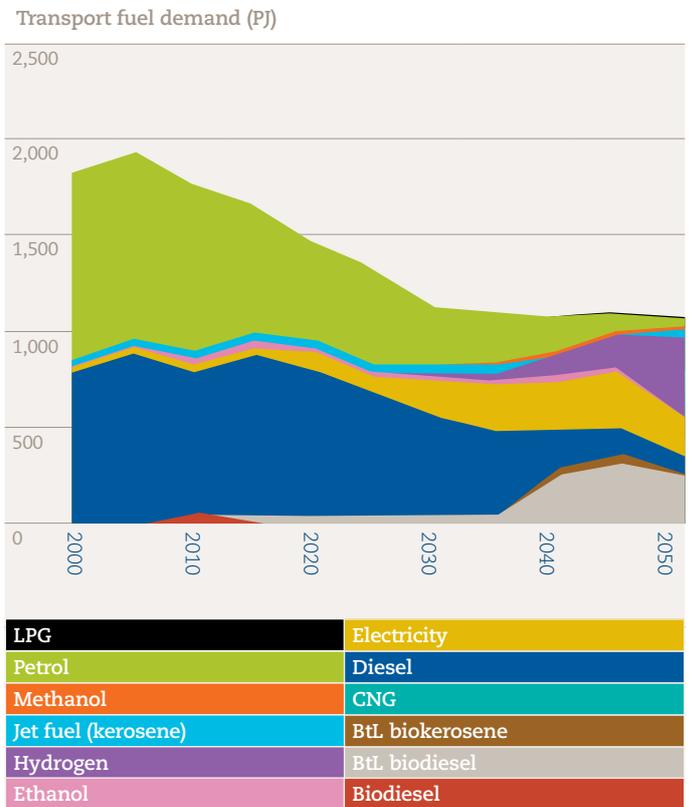
Source: AEA 2011a, Figure 9, p.20 (model run DECC-1A-IAB-2A)

In the Core Run (DECC-1A-IAB-2A) being considered here, the residential sector is mainly decarbonised in 2050 by heat pumps (~700 PJ, or 50% of residential heat demand), with about 300 PJ coming from conservation, and ~150 PJ each from individual pellet boilers and demand response. This mix is shown in Figure 4.5, which makes clear the dramatic reduction in the use of gas for residential heating, especially from 2020. The difference between this outcome and the C90 CCC runs is that by 2050 the residential sector in C90 is only demanding ~1200 PJ of heat (~1400 PJ in DECC-1A-IAB-2A), with electric heating providing 325 PJ, district heating 255 PJ (~240 PJ through CHP), demand reduction 265 PJ, conservation 220 PJ, heat pumps around ~110 PJ and individual biomass boilers ~30 PJ.

In the service sector as well, gas demand for heating collapses over 2000-2050, as shown in Figure 4.6. But a wider range of technologies than in the residential sector is used instead: service sector heat of ~700 PJ by 2050 (projected to increase dramatically over the level in 2010) is provided mainly by demand response (~200 PJ), conservation (~150 PJ), heat pumps (~125 PJ), and direct electric heating (~125 PJ), with district heating and pellet boilers providing the remainder. Again by comparison, the service sector in C90 in 2050 demands only ~320 PJ of heat (less than a half of that in DECC-1A-IAB-2A), all of which is supplied through conservation (~170 PJ), heat pumps (~100 PJ) and demand reduction (~50 PJ).

The transport sector also shows a large diversification of fuels and vehicle technologies over 2010 to 2050 as carbon emissions are reduced. Despite the fact that car energy service demands increase from 400 to over 600 billion vehicle km (bvkm), energy demand in the sector falls by over a third between 2010 and 2030, as vehicle fuel efficiency is dramatically improved, mainly through the mass introduction of hybrid petrol cars. From 2025 these hybrid petrol vehicles start declining in numbers, to be increasingly replaced by battery electric vehicles (BEVs) and, from 2035, hydrogen fuel cell vehicles (HFCVs) and biodiesel for freight vehicles. By 2050, BEVs and HFCVs are providing more than 90% of the car bvkm travelled.

Figure 4.7: Energy Consumption in the Transport Sector in DECC-1A-IAB-2A



BtL is a technology that turns biomass to liquid fuel

Source: AEA 2011a, Figure 11, p.22

The transport sector also shows a large diversification of fuels and vehicle technologies over 2010 to 2050

With regard to the industrial sector, **Figure 4.1** shows that the energy and non-energy CO₂ emissions from industry are responsible for well over 50% of the permitted emissions in 2050. The two main industrial energy sources by 2050 in DECC-1A-IAB-2A are electricity and gas (with final energy demand over 2000 to 2050 increasing from ~1500 PJ to ~1750 PJ), with the former contributing ~700 PJ, and the latter around ~500 PJ, and a range of fuels (coal, heavy and light fuel oil, wood, steam and solid wastes) providing the rest in comparable quantities. The emissions impacts of the fossil fuels used are moderated by process CCS preventing about 40MtCO₂ in 2050 from getting into the atmosphere. This process CCS is an important technology in terms of limiting the cost of emissions reduction from industry (which otherwise would need to come from zero-carbon electricity for both high- and low-grade heating).

Cost outcomes

As noted in Section 1, MARKAL generates a number of different cost metrics. All the model runs considered here used the Elastic Demand version of MARKAL, for which the two most usually reported cost metrics are the marginal CO₂ price and the welfare cost (reduction in the sum of producer and consumer surplus). **Table 4.1** reports these metrics for some of the different but most comparable runs from the Energy 2050, CCC and Carbon Plan (CP) modelling exercises discussed above.

The first point to note is that there is broad agreement between the runs on the order of magnitude of the required level of 2030 carbon prices: £24-54/tCO₂ for the 80% reductions by 2050 (CAM, CCP, C80) and £91-115/tCO₂ for the 90% reductions by 2050 (CSAM, C90, C90+ and both AEA CP runs). The UK Government's current floor price target of £70/tCO₂ in 2030 seems to be at more or less the required level to deliver the 2030 reductions that are compatible with the ultimate 2050 target. By 2050 there is more divergence in the carbon prices between the runs, with the AEA CP runs being significantly higher, as a result of the changes in the model assumptions, such as the increased energy service demands, described above.

In all the model runs the energy system cost in 2050 is higher than it would have been without the carbon reduction efforts, meaning that the cost increases driven by the low-carbon energy requirements more than offset the reduced final energy that the system is required to deliver (because of the price-driven reductions in energy service demands). The increased energy system costs for the 90% carbon reductions by 2050 are comparable in the CCC 4BP and AEA CP runs, but are lower than the increased costs in the Energy 2050 runs, because of revised technology cost assumptions in the later runs. With regard to welfare costs, the main driver of the differences between the runs, which also reduces their comparability, is the different discount rates used, with the lowest cost runs (C80 for 80% 2050 CO₂ reduction, and C90, C90+ and DECC-1A-IAB-2A for 90% 2050 CO₂ reduction) having the lowest discount rates (3.5%).

Table 4.1: Cost metrics for various MARKAL runs discussed earlier

Model run ¹	CO ₂ price, 2030, £/tCO ₂	CO ₂ price, 2050, £/tCO ₂	Undiscounted difference in 2050 energy, system cost ² £bn	Welfare cost, undiscounted at 2050, £bn ³
Energy 2050				
CAM	24	169	17	37.6
CCP	54	360	22	48.2
CSAM	115	299	29	52.3
Energy 2050				
C80	46	163	5	17.5
C90	103	288	14	29.5
C90+	91	288	15	30.8
AEA CP				
DECC-1A	113	629	11	50.6
DECC-1A-1AB-2A	~	417	15	~36

Sources: AEA 2011a, Figure 11, p.22, and the detailed spreadsheets underlying the Energy 2050 and CCC model runs

¹ All the cost metrics are given in £2000/tCO₂, except for the AEA CP runs, which are given in £2010/tCO₂

² This is the difference in energy system cost between the scenario and the appropriate baseline

³ In each case, the welfare cost is the difference (reduction) in welfare from the appropriate baseline

The UKERC Phase 2 (UKERC2) scenarios

New UKERC scenarios incorporate the most recent policies and investigate the possible impacts of lower gas prices and measures to increase energy system resilience



The UKERC Energy 2050 scenarios discussed in section 2 were generated in 2008, since when numerous policy and model developments have taken place, some of the latter of which have been described in relation to the CCC 4CB and AEA CP runs discussed in sections 3 and 4.

In light of this, a new set of UKERC scenarios was developed, using the latest version of the UK MARKAL model (incorporating some but not all of the changes that had been introduced in CCC 4CB and AEA CP) and updating a range of other policy and technology assumptions to match recent developments. The approach to modelling the investment behaviour of participants in the energy market was modified. Additional scenario variants were also constructed to test the impacts of alternative gas price trends and explicit resilience measures.

General model update

As all scenarios included the same base data and currently implemented policies, the changes described here apply to all scenario variants. In the light of all the changes to the model since the Energy 2050 and subsequent scenario sets, the scenario results are not comparable in detail with these other scenarios, but nevertheless comparisons between the overall macro-system changes across the scenarios may be instructive.

These scenarios used the most recent version of the model (that used in AEA CP), which, as noted above, included a range of data updates on the previous version of the model (CCC 4CB). The major changes with these model runs were that, first, modellable, already implemented, policies were included in the Reference case (REF). While most of these were already included in the latest version of the model, some updates and additions were also necessary, as detailed in Table 5.1, to match the UK energy policy framework as it has evolved. Second, this version of the model used sector specific hurdle rates (as in Phase 1, but not Phase 2, of the AEA CP work), the exact level of which was reassessed and updated, as discussed below. Finally, the real discount rate used in the model was changed to the standard social discount rate of 3.5% instead of the 10%, more representative of investor behaviour, that was in place for the original UKERC Energy 2050 runs (except CCSP).

Policies

The most important information for the policy changes in the scenarios is given in Table 5.1. Four policy scenarios were defined as shown in Table 5.1: Reference (REF); Additional measures (ADD), which assumes the implementation of additional measures, announced but not yet implemented, on top of those in REF; Low carbon policy gap (GAP), which implements further carbon reduction, but insufficient to reach the full 80% carbon reduction by 2050; and Low carbon (LC) which implements

enough measures to meet the 80% carbon reduction target for 2050⁹. Table 5.1 shows what policies are included under these variants, as well as saying how the given policy was implemented for UK MARKAL¹⁰. Generally speaking, the REF and ADD scenarios are unconstrained in terms of carbon and rely on individual implementation instruments, whereas the low-carbon scenarios (GAP and LC) assume binding carbon constraints and other system-wide framework policies, such as renewables targets. It should be noted that many policies are modelled in a simplified manner, compared to their more complex real life implementation. Carbon reduction commitment modelling, for example, covers a static share of the sectoral emissions, instead of targeting individual sub-sectors or facilities. Similarly, feed in tariffs use predefined degeneration rates, without feedbacks from aggregate capacity installation numbers from previous periods, and use the same time dependent tariff for all vintages (which is likely to lead to lower investments).

In the LC scenario (and its variants further discussed below) CO₂ emissions (excluding aviation and shipping) are reduced by 80% by 2050 (compared to 1990) and from 2025 to 2050 emissions follow a trajectory based on an equal annual percentage emission reduction. For the GAP scenario (and variants) it is assumed that until 2015 emission targets are reached as in the LC scenarios. After this, however, the GAP scenarios are assumed to follow an emission trajectory that corresponds to 70% of the reductions achieved in the LC scenario (calculated from the point of divergence, 2015). The gap therefore applies to the final target in 2050, as well as to the 3rd and 4th carbon budgets. The GAP scenario entails a degree of policy “failure”. However, it still involves achieving weakened carbon targets in a cost-optimal manner. It is unlikely that real-world policy failure would follow a cost-optimal path. The reduced costs associated with meeting the carbon targets set in GAP compared with the LC scenario are therefore likely to be an under-estimate.

As a number of policies are already included in REF, a set of sensitivity scenarios were run in which some of the policies were removed. This was done in order to determine what the impact of some of the individual policies might be. The sensitivity scenarios were:

1. REF-P1: The Renewables Obligation (RO) is removed, other policies implemented as before
2. REF-P2: The Carbon Price Floor (CPF) is removed, other policies implemented as before
3. REF-P3: Both the RO and the CPF are removed
4. REF-P4: The RO and the CPF as well as the Carbon Reduction Commitment (CRC) are removed.

⁹ Note, therefore, that this is less stringent than the CCC 90 and 90+ scenarios discussed above, which require a 90% carbon reduction from the energy system to accommodate other greenhouse gases (GHGs) and emissions from international aviation and shipping, which are harder to reduce, in the overall 80% target. The CCC believes a 90% reduction of carbon emissions from the energy system will be required to meet the overall 80% GHG 2050 emission reduction target in the Climate Change Act, given these other emission sources.

¹⁰ Two elements of Electricity Market Reform – the contracts for difference and capacity payments – were not modelled, because their payment rates had not been announced at the time the modelling was carried out.

Table 5.1 Policy and other assumptions for the four policy variants of the UKERC2 scenarios

	Reference (firm and funded) (REF)	Additional measures (beyond reference) (ADD)	Policy Gap (GAP)	Low Carbon (L.C)
Carbon Targets	None	None	First two carbon budgets met. For 3rd and 4th budgets and 2050 target 70% of target reductions starting from 2015 baseline are achieved.	First four carbon budgets met; 2050 reduction target of 80% (compared to 1990); equal annual percentage trajectory 2025-2050.
Renewable energy directive (RED) targets	<ul style="list-style-type: none"> Renewable obligation (15 % of electricity renewable by 2015 and until 2050), with a buy out price of 28 £(2000)/MWh included. Max. 12.5 % of the renewable production can be from co-firing. 	As reference	<ul style="list-style-type: none"> 70% achievement of RED (matches current RO achievement). 21% by 2020 and 28% by 2030. Min. targets for 2020 for onshore wind (20 % of renewables), offshore wind (30 %) and biomass (30 %) The limit on co firing is removed. 	<ul style="list-style-type: none"> 100% achievement of RED. Target for renewable electricity is 30 % for 2020, 40% by 2030 (and after that) and the buy out option is removed. Min. targets for 2020 for onshore wind (20 % of renewables), offshore wind (30 %) and biomass (30 %).
Electricity market reform	<ul style="list-style-type: none"> Carbon price floor for electricity emission. Trajectory (in £ 2009) £15.70/tCO₂ (in 2013), £30/tCO₂ (in 2020) and £70/tCO₂ (2030-2050). Interpolated linearly between the years. 	<ul style="list-style-type: none"> Emissions Performance Standard – Building of unabated coal power plants prohibited (in addition to the carbon price floor) 	<ul style="list-style-type: none"> As additional measures 	<ul style="list-style-type: none"> As additional measures
CCS demonstration plants	<ul style="list-style-type: none"> 1st demonstration plant (425 MW) forced in 	<ul style="list-style-type: none"> Three additional CCS demos (total 1.275 GW), at least one of which will be a gas fired CCS plant 	<ul style="list-style-type: none"> As additional measures 	<ul style="list-style-type: none"> As additional measures
Renewable Heat Incentive	<ul style="list-style-type: none"> No policies included 	<ul style="list-style-type: none"> Some renewable heat generation is forced in. 	<ul style="list-style-type: none"> 70 % achievement of RED leading to a target of 8 % renewable heat by 2020 	<ul style="list-style-type: none"> RED target for renewable heat is set at 12 % by 2020
Small scale Feed in Tariffs	<ul style="list-style-type: none"> Feed in tariffs (in £2009) for micro CHP (10 p/kWh), solar PV (res. and comm. sectors (36.1 p/kWh)), micro wind (34.5 p/kWh) and micro hydro power (11 p/kWh). Starts in 2010, linearly reduced to zero by 2030. 	<ul style="list-style-type: none"> As reference 	<ul style="list-style-type: none"> As reference 	<ul style="list-style-type: none"> As reference
Household energy efficiency	<ul style="list-style-type: none"> CERT/CESP are assumed to be reflected in the reference case hurdle rates 	<ul style="list-style-type: none"> Green Deal, hurdle rates in the residential sector reduced from 15 to 5 % and annual deployment constraints relaxed by 20%. 	<ul style="list-style-type: none"> As additional measures 	<ul style="list-style-type: none"> As additional measures
Industry	<ul style="list-style-type: none"> Climate Change Levy included 	<ul style="list-style-type: none"> As reference 	<ul style="list-style-type: none"> As reference 	<ul style="list-style-type: none"> As reference
Services	<ul style="list-style-type: none"> Carbon Reduction Commitment at £12/tCO₂ (in £ 2011), for 60 % of the emissions from the service and for 18 % of the emissions of the industry sector. 	<ul style="list-style-type: none"> As reference 	<ul style="list-style-type: none"> As additional measures 	<ul style="list-style-type: none"> As additional measures
Transport	<ul style="list-style-type: none"> Renewable transport fuel obligation, 5% renewables in road transport Fuel duties are kept constant 	<ul style="list-style-type: none"> As reference 	<ul style="list-style-type: none"> The target for renewable transport is increased to 10% in 2020 	<ul style="list-style-type: none"> The target for renewable transport is increased to 10% in 2020

Source: ¹ Biomass and waste ² Biomass used in co-firing CCS (C90, C90+, C80); Power generation from biowaste (CCP, CSAM, CAM, CCSP)

The CPF is a particularly important driver in the REF scenario. However, although the intention of raising the CPF to £70/tonne by 2030 has been announced, the uncertainty surrounding any fiscal instrument is considerable and investors would factor in a substantial degree of policy risk. The CPF involves “topping up” the carbon price in the EU ETS. The “top-up” has to be set in advance anticipating what the EU ETS price will be. ETS prices have fallen below those originally anticipated and the CPF therefore lies below the trajectory originally announced. This explains why the sensitivities described above are so important.

Hurdle rates

The fact that many existing policies (e.g. subsidies, taxes) are included in the model suggests that the modelling approach is not only that of an optimising ‘social planner’, and the goal is to represent also the incentives that may encourage agents to make decisions that would be deemed economically inefficient on the system level. In other words, the existing modelling approach mixes the prescriptive, optimising approach with a descriptive policy approach, in which policies in the latter are used to ‘override’ the optimal decisions of the former. Such policies and modelling approaches reflect a situation in which optimal decision making may not be politically feasible, so that other policies which are politically feasible are introduced (at extra cost) so that the policy targets are met.

The hurdle rates used in the model before these model runs were 5% for the residential and private transport sectors, 7% for public and commercial transport and 10% for the power sector, industry and service sectors. The lower numbers reflect a logic that perceives the hurdle rates to be based on a social cost-benefit approach (as opposed to trying to emulate behaviour of agents).

The approach taken in this set of scenarios was different. It is assumed that there is a central authority who takes decisions aimed at maximising social welfare. This authority applies an inter-temporal social discount rate of 3.5%. However, the authority has to take account of both the inherited policy mix (which may not be optimal), and the behaviour patterns of energy sector actors. Their behaviour patterns are represented by the implicit hurdle rates used by the agents in their investment and other energy-related behaviours. This indicates that higher rates should be implemented for the residential and transport sectors, as a number of hidden costs and uncertainties would almost certainly lead the agents to implement higher rates than those currently in the model. On the basis of this reasoning, hurdle rates were increased to 12.5% for the private transport sector and to 15% for the residential sector. This philosophy could be described as a ‘principal-agent’ approach in which the representation of social planning takes account of more realistic patterns of market behaviour.

With the new discoveries and technologies relating to unconventional gas resources, it is possible that in the future the price linkage between crude oil and natural gas may be broken, at least in some parts of the world

Table 5.2: Gas and oil price assumptions in different scenarios

Reference GAS	Natural gas import price assumptions £(2000)/GJ					
	2010	2015	2020	2025	2030	2035
	4.5	4.9	5.2	5.5	5.7	5.7
4.5	4.6	4.6	4.7	4.8	4.8	
All scenarios	Oil import price assumptions £(2000)/bbl					
	2010	2015	2020	2025	2030	2035
	39.1	41.9	44.7	47.5	50.3	50.3

Scenario variants, decoupled gas prices (GAS) and resilience targets (R)

Two further scenario variants were modelled, relating to gas prices and energy system resilience.

With the new discoveries and technologies relating to unconventional gas resources, it is possible that in the future the price linkage between crude oil and natural gas may be broken, at least in some parts of the world. To explore the implications of this, a variant set of GAS scenarios was constructed, in which the gas price was decoupled from the oil price and a significantly lower trajectory was assumed for the former as compared to REF, broadly following the trends assumed in similar work by the International Energy Agency (IEA). Oil and coal prices were unchanged from REF. The qualitative logic and price trends were adapted from IEA 2011, but were implemented in line with the model's baseline assumptions. More specifically, in the GAS scenarios the time period specific, annual growth in gas prices is reduced by 75% from that in REF, effectively stabilising gas prices (the price in 2030 is now only 6% above the price in 2010, whereas in REF the difference is close to 30%). Oil prices are assumed to keep increasing steadily also in the GAS scenario, reaching a little over 100 \$US(2005)/bbl by 2030. Trajectories for the prices are shown in Table 5.2 (price level after 2030 remains constant).

For the Resilient (R) variant scenarios explicit constraints were implemented (as in the Energy 2050 Resilient scenarios, described in Skea, Chaudry et al. 2011) targeting the diversity of the energy portfolio. These constraints set a maximum share of 40% for both any fuel at the primary energy level and any technology class in power generation. In addition to this, the final energy intensity of GDP needs to be reduced by 3.2% per year from 2010 onwards, in order to reduce the vulnerability of the economic system to energy shocks. In the latter part

of the projection period, beyond 2030, the reduction in energy intensity drives energy demand to extremely low levels, so that the Resilient scenarios cease to be useful beyond about 2025-30.

Full scenario set

All these different scenario variants may be summarized as follows. There are two resilience levels (reference (REF), resilient (R)), four climate variants (low carbon (LC), policy gap (GAP), additional policies (ADD), reference (REF)) and two gas price variants (reference (REF), decoupling of gas prices (GAS)), thus totalling sixteen scenarios in all, as shown in Table 5.3 below.

Emissions

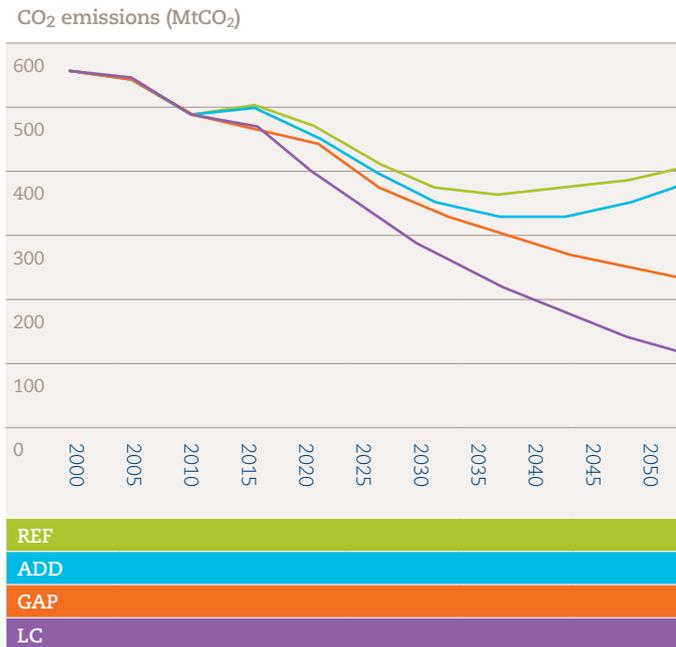
Figure 5.1 presents the emission trajectories of the alternative policy cases, with reference gas prices and no additional resilience measures in place.

In the reference case (REF) emissions decrease from 2015 until 2035 after which a slow increase in emissions starts again. The decrease is mainly driven by the effect of the carbon price floor on the power sector; the carbon intensity of power generation drops from about 440 gCO₂/kWh in 2010 to around 32 gCO₂/kWh in 2035 and emissions from the power sector are reduced by more than 90% despite a slight increase in the total demand for electricity. This effect of the carbon price floor causes CO₂ emissions to fall faster in the REF and ADD scenarios than in previous scenario exercises, reaching a 40-45% reduction (over 1990) by 2035. The Renewables Obligation (RO) increases the share of renewables until 2020, after which the target becomes redundant as the carbon price already induces enough investments into renewable generation.

Table 5.3: The full set of UKERC2 scenarios

Debarbonisation >	Conventional gas assumption Resilience >		Gas price decoupled Resilience >	
	REF	REF-R	REF-GAS	REF-R-GAS
ADD	ADD-R	ADD-GAS	ADD-R-GAS	
GAP	GAP-R	GAP-GAS	GAP-R-GAS	
LC	LC-R	LC-GAS	LC-R-GAS	

Figure 5.1 Emission paths of the alternative policy cases



The low-carbon scenario (LC) introduces a range of additional policies, ranging from more stringent renewable portfolio requirements for the power, transport and heat sectors to a framework policy covering all CO₂ emissions across the sectors. The latter ensures a steep reduction in the emissions

The strong impact of the carbon price floor in the reference case is also verified by the sensitivity runs REF-P1 – REF-P4; if the RO is removed (REF-P1) the emission path differs little from the original REF. If, however, the carbon price floor is removed (REF-P2), emissions increase strongly, ending up in 2050 about 37% above the emissions in 2010 (as opposed to 18% below in REF). Any additional changes to the policies (REF-P3, REF-P4) have little impact on the emissions trajectory. Any significant relaxation of the carbon price floor policy could be expected to increase the emissions in REF substantially, and therefore make it harder to reach the carbon targets in the GAP and LC scenarios.

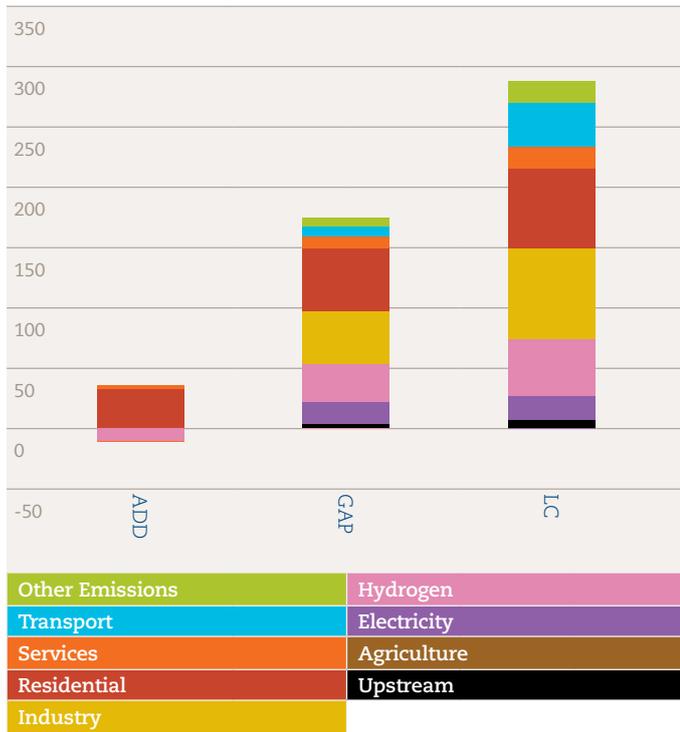
For the other sectors, different trends are observed in REF. For example, by 2050 emissions in the transport sector are reduced significantly, despite a nearly 80% increase in vehicle kilometres driven, because of the increased efficiency of hybrid engines, both petrol and diesel, and hydrogen fuel cell vehicles, which by then are cost-effective. The industry sector, without these efficiency and substitution possibilities, shows a different trend, one in which emissions in 2050 are over 85% above the emission levels of 2010. Similarly, while the residential sector slightly reduces its emissions from heating, due to the uptake of more efficient gas boilers, heat pumps and district heating, the service sector, with similar use of conservation, makes fewer such efficiency savings and increases its energy use, resulting in slightly higher emissions.

In the scenario with additional measures some further reductions beyond REF can be achieved. As power generation is nearly decarbonized already in REF and most of the additional, non-power sector policies focus on the residential sector, it doesn't come as a surprise that most of the additional reductions achieved by 2050 come from this sector. All in all, reductions don't go much beyond REF and emission levels are nowhere near what could be considered consistent with a 2°C global climate target.

The low-carbon scenario (LC) introduces a range of additional policies, ranging from more stringent renewable portfolio requirements for the power, transport and heat sectors to a framework policy covering all CO₂ emissions across the sectors. The latter ensures a steep reduction in the emissions, as shown in [Figure 5.1](#). The emission price remains relatively low until 2030, about £13/tCO₂, as the carbon reductions are also driven by the ambitious renewable requirements. From 2035 on, however, the sectoral renewables targets and other instruments are no longer nearly adequate and the emission price increases to about £60/tCO₂ in 2035 and £213/tCO₂ by 2050. Reductions take place across the sectors, with the residential sector improving most when

Figure 5.2: Mitigation (carbon reduction) per sector in 2050 (compared to REF).

(MtCO₂)



The policy gap scenario (GAP) shows qualitatively very similar trends to LC, although the renewable targets play an even bigger role in this scenario ... **Figure 5.2** summarizes the mitigation per sector for a 2050 snapshot

compared to REF (emissions in 2050 are reduced to 6% of those in REF). In addition to the residential sector, industry also plays an important role, contributing, in absolute terms, the biggest reduction when compared to REF and reducing its emissions by some 37% compared to 2010.

The policy gap scenario (GAP) shows qualitatively very similar trends to LC, although the renewable targets play an even bigger role in this scenario; there is an additional price for CO₂ emissions only in 2015 and again from 2040 onwards. For the decades in between the sectoral measures ensure the reduction of emissions below the level required by the framework policy. **Figure 5.2** summarizes the mitigation per sector for a 2050 snapshot.

Gas prices and resilience constraints have clear effects on the results and these effects are the stronger the less other policies are in place. **Figure 5.3** shows for 2020, 2030 and 2050 how emissions change across the full scenario ensemble.

A first obvious observation is that the resilience targets lead to significant emissions reductions, even if no additional policies beyond REF are introduced, as was the case in the original Energy 2050 scenarios. In 2020 and 2030 emissions are reduced more by introducing a resilience constraint than by climate policies, with lower emissions in both 2020 and 2030, the ambitious Low carbon (LC) case being an exception from this. The impact of the resilience targets, in turn, is a result of the final energy reduction requirement of about 33% less final energy used in 2050 compared to 2010. Without this target, the final energy use remains about level in REF. The portfolio requirements in the resilience targets do have a small impact, mainly reducing gas-based power production in 2015 (and to a lesser extent in 2020 and 2025), but the main impact is caused by the reduction in total use of energy. This remains the case for all the results discussed later.

In low gas price scenarios (GAS), unconstrained emissions are similar to the higher gas price scenarios to 2025 but start to rise from 2030 onwards. In principle, low gas prices could lead to either an increase or decrease in emissions, depending on the fuel they substitute for. Results in **Figure 5.3** suggest that unless policies are in place to limit all CO₂ emissions, lower gas prices lead to slightly increased emissions, especially towards 2050. This is because low gas prices by themselves increase emissions in the UK by lowering efficiency incentives and substituting for the lower carbon nuclear/renewables.

Figure 5.3: Reduction of emissions compared to 1990

2020		Reference gas price scenarios		Low gas price scenarios	
		No resilience targets	Resilience targets	No resilience targets	Resilience targets
Climate policy	Reference	-20%	-29%	-21%	-29%
	Additional policies	-23%	-29%	-23%	-29%
	Policy gap	-24%	-30%	-25%	-30%
	Low carbon	-33%	-33%	-32%	-34%
2030		Reference gas price scenarios		Low gas price scenarios	
		No resilience targets	Resilience targets	No resilience targets	Resilience targets
Climate policy	Reference	-36%	-50%	-34%	-50%
	Additional policies	-41%	-50%	-38%	-50%
	Policy gap	-43%	-50%	-44%	-50%
	Low carbon	-54%	-56%	-54%	-56%
2050		Reference gas price scenarios		Low gas price scenarios	
		No resilience targets	Resilience targets	No resilience targets	Resilience targets
Climate policy	Reference	-31%	-57%	-24%	-60%
	Additional policies	-36%	-59%	-32%	-59%
	Policy gap	-60%	-60%	-60%	-60%
	Low carbon	-80%	-80%	-80%	-80%

Primary energy, power sector de-carbonisation and generation mix

A first point to note about the energy implications of the alternative scenarios is that in REF, primary energy falls to 2025, as relatively inefficient coal is squeezed out of the generation mix by the carbon price floor (CPF), then rises again to meet the growing energy service demands. Nuclear and coal displace gas in the 2020s but gas recovers from 2035. ADD shows a similar picture but the overall level of demand is lower. In LC, in which the 2050 carbon targets are met, primary energy demand falls to 2025 and then levels off. By 2025 coal without co-firing has been squeezed out of power generation, and the same is true for gas by 2030. Oil has largely disappeared from primary energy by 2050. Nuclear is smaller than in REF, while both wind and biomass, co-fired with coal, increase their share of power generation.

The results for GAP are similar to LC, with the main difference being that GAP has the highest nuclear contribution by 2050 with biomass much less than in LC. Figure 5.4 collects the primary energy results for the policy scenarios for 2050, assuming reference gas prices and no resilience policies.

In principle, low gas prices could lead to either an increase or decrease in emissions, depending on the fuel they substitute for

Figure 5.4 shows how total primary energy consumption decreases as a function of increasing climate ambition. At least three forces can move the result in this direction:

- use of more efficient conversion and end use technologies, incentivised by the increased value of the commodities
- a reduction in the end use demand as a consequence of the increased price¹¹ and
- a move towards carbon-free resources, renewables and nuclear, both of which are accounted using the direct equivalent method (thus implying a conversion rate of 100% from primary energy to electricity). An additional driver for lower energy consumption exists between REF and the other scenarios: the hurdle rates for the residential sector are higher in REF compared to the other scenarios, therefore making, for example, investments into improving energy efficiency more expensive in REF than in the other scenarios.

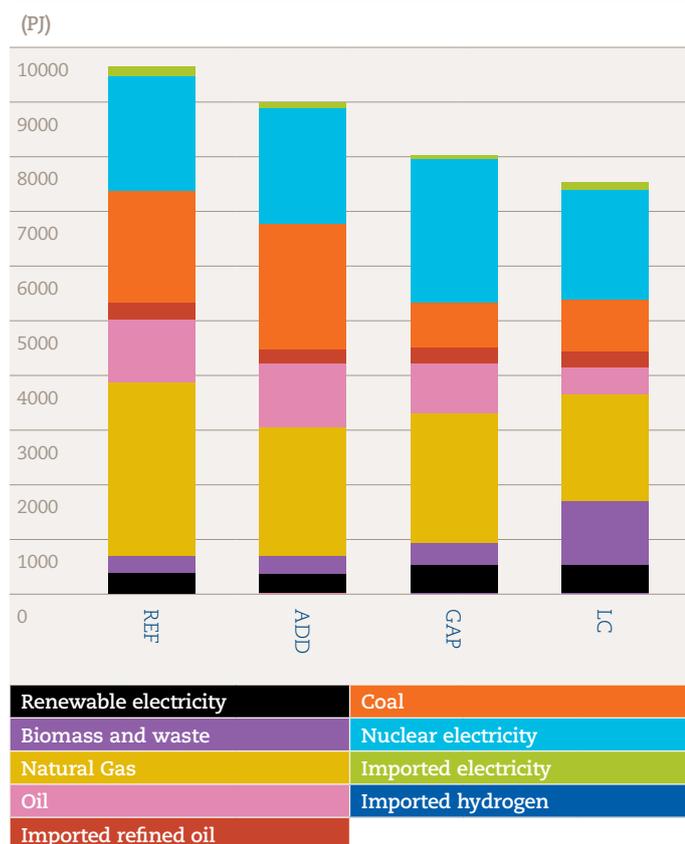
In terms of fuels used, few surprises emerge: coal use especially is reduced as a consequence of stronger climate policies, but gas and oil use also go down. Nuclear shows an increased contribution in GAP, but is again scaled down to the level of REF in LC. This is, in all likelihood, related to the increased use of bioenergy for co-firing, together with CCS, in LC.

This production option contributes more than nuclear for both the renewable and emission targets (due to the ‘negative’ emissions resulting from bioenergy use with CCS). It is worth noting that the model currently assumes that bioenergy has zero greenhouse gas emissions associated with it (i.e. the emissions from burning it match those absorbed from the atmosphere in growing it, and emissions from growing it are ignored)¹², following its current treatment in UK policy. One result of this is that the LC model run uses more bioenergy in 2050 than suggested in the CCC Bioenergy Review (CCC 2011) which factored in realistic lifecycle emissions.

The detailed results for the power sector show that all four scenarios are similar up to about 2025 as the main drivers are sector specific policies (especially the carbon price floor (CPF) and the Renewable Energy Directive). Coal declines, renewables increase. In REF and ADD (with higher gas prices), gas is squeezed after 2025, its place being taken by nuclear and, to a lesser extent, by coal and co-firing CCS, with marine renewables also expanding after 2035 and partly replacing wind. In GAP, nuclear takes the highest market share and wind expands more rapidly than under the unconstrained scenarios (REF and ADD), displacing gas. In LC, nuclear is displaced by CCS co-firing which has negative emissions and which contributes to the more ambitious renewable objectives.

In REF and ADD under high gas prices, the carbon intensity of generation falls to 80-90 g/kWh by 2030 driven by the CPF and fall further to about 30 g/kWh by 2050. However, if gas prices are low, these offset the CPF, and by 2030 the carbon intensity of generation only falls to 100-110 g/kWh and stays at that level until 2050. In LC, the carbon emissions intensity becomes zero or slightly negative due to co-firing CCS by 2030, with the GAP scenario reaching the same level by 2035.

Figure 5.4: Primary energy in 2050 across the policy cases



¹¹ Other possible behaviour changes, which could also have this effect, are not included in these scenarios, but were modelled in Eyre et al. 2011

¹² Bioenergy with CCS therefore results in negative emissions, as the carbon from the atmosphere is not released with combustion, but stored underground.

Figure 5.5a: Power production in REF, ADD, GAP and LC, in different years

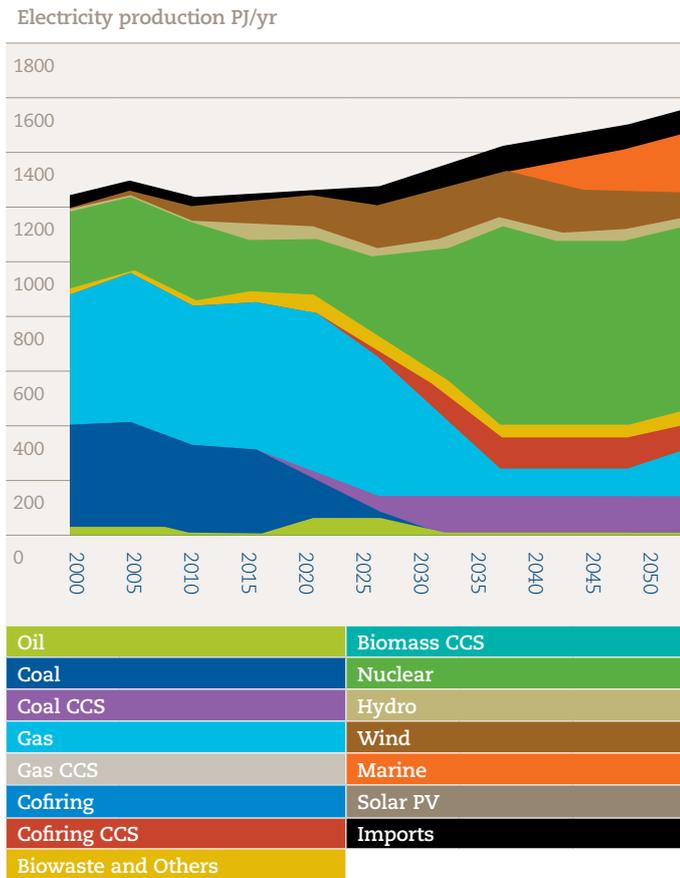
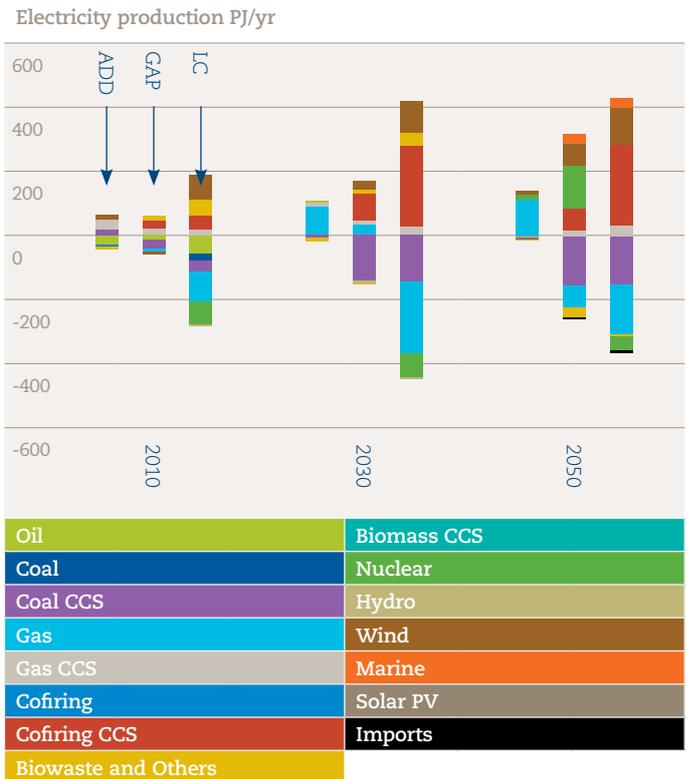


Figure 5.5b: Changes induced by altered policy environment, ADD, GAP and LC, in different years



Overall, the patterns for power production across the policy scenarios (REF, ADD, GAP, LC) are summarised in Figure 5.5. Figure 5.5a shows clearly that the CPF gives a strong incentive to reduce coal use in the power sector already in REF, leading to an increase in the use of carbon-free sources (renewables and especially nuclear). The largest renewable contribution comes from wind, although towards the end of the century also marine energy diffuses strongly, as noted above. It is worth noting if the CPF is removed (as is done in most of the sensitivity runs for REF), no new nuclear is built.

As shown in Figure 5.5b, if the policy assumptions are changed and a system-wide climate policy is introduced, the contribution from renewables, especially wind, increases. Smaller adjustments implemented in the ADD scenario lead to an increase in gas-fired power production as well as to an increase in total electricity generation (the latter is true also for the two other policy cases by 2050). Finally, the tight renewable constraint forces a reduction in the use of nuclear in the LC scenario.

The low gas price and resilience scenarios

With lower gas prices both REF and ADD show clearly increased gas use – and for both the increase is mitigated, even reversed, if resilience targets are also in place. A qualitatively similar pattern can be seen also for all the other fuels. For example, for REF, with low gas price assumptions (REF-GAS) the amount of gas in primary energy increases by 2050 by 37%.

Final energy demand by 2050 is also slightly increased, but primary energy demand falls as gas replaces less efficient coal (CCS) in power generation, in which it also displaces nuclear.

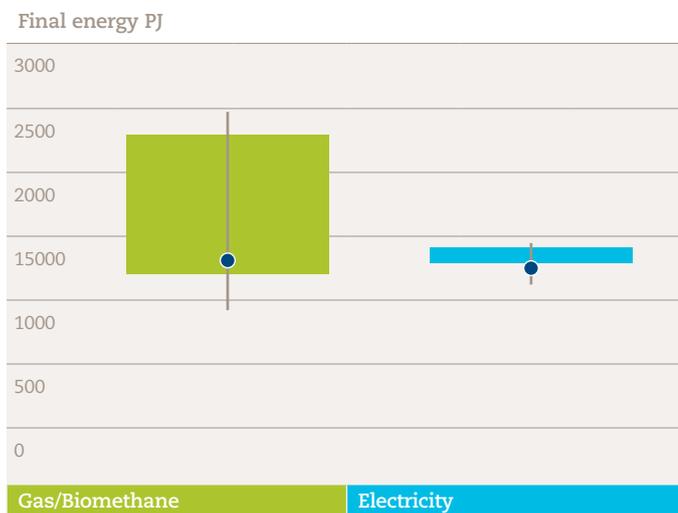
In contrast, the system wide emission targets of GAP and LC lead to rather different patterns and the scenarios are similar regardless of gas prices. Furthermore, differences are clear also between the two scenario families, GAP and LC. For example, under the LC policy environment, gas prices have little impact on the results and resilience targets lead to relatively similar reductions across the primary energy sources (with the exception of biomass, the use of which is greatly reduced).

Under the GAP regime, the impact of resilience targets is greater for most energy carriers and also gas price changes lead to an altered primary energy portfolio (with gas replacing coal). These differences are caused by:

- the much lower emission budget of LC – the emission consequences of increased gas use weigh more heavily than the benefits that would be gained from lower energy prices and
- the fact that in LC final energy use is clearly lowered, even without explicit final energy reduction resilience targets, therefore leading to a smaller “final energy reduction gap” than exists for GAP.

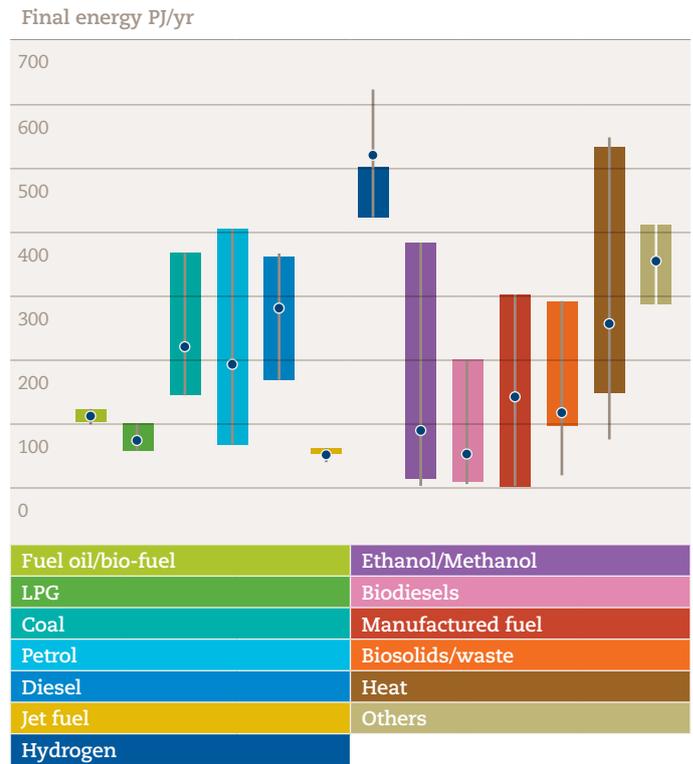
In addition, the low gas price scenarios (GAS) generally increase gas-based power production, except in the low-carbon scenario (LC-GAS) in which the system is driven by the ambitious climate and renewable targets. It is also noteworthy that the carbon price floor alone does not appear to be enough to incentivise use of CCS for gas power plants; the increase in gas-based power production comes with CCS only in the policy gap (GAP-GAS) scenario.

Figure 5.6a: Final energy in 2050 across the scenarios



The low gas price scenarios (GAS) generally increase gas-based power production, except in the low-carbon scenario (LC-GAS) in which the system is driven by the ambitious climate and renewable targets

Figure 5.6b : Final energy in 2050 across the scenarios



Resilience targets, on the other hand, tend to reduce the use of nuclear, as was already seen with primary energy, and increase the use of CCS, with either coal or co-firing, depending on the policy scenario. Again, the low-carbon scenario (LC-R) reacts less, as it is closer to the final energy target already without being explicitly constrained. Combining both dimensions, low gas prices and resilience targets, combines the individual results or the scenario families: gas use is increased (unabated, except in the GAP-R-GAS scenario), nuclear use is reduced and CCS with co-firing is increased in the REF-R-GAS and ADD-R-GAS scenarios.

Final energy across the scenarios

Figure 5.6a,b summarises the final energy related results of the scenario ensemble. (Note: Lines show the range over all scenario variants, whereas bars represent the scenarios assuming reference assumptions for gas prices and resilience. The blue dots represent the average across the scenarios)

Figure 5.6a shows the use of the two most widely spread end use energy carriers, gas and electricity. The use of electricity remains fairly steady across the scenarios, whereas the end use of gas is greatly affected by the assumptions, especially by climate policies, but also by alternative gas price developments and the absolute level of final energy use. As for the other fuels, especially hydrogen, biosolids and heat are sensitive to the gas and resilience assumptions.

The climate policies, however, cause a much wider spread across the scenarios. For example, ethanol/methanol use has a range of 13 to 384 PJ/yr and additional variations for gas prices or resilience targets do little to alter this range.

Welfare costs

Welfare costs describe changes in the sum of the consumer and producer surplus. By definition, this requires a reference level, against which these changes are shown. In these runs this scenario is REF, which is also used to determine the prices that correspond to the exogenously given reference energy service demands. Introducing additional constraints or costs, as is done with the other policy scenarios, will increase the costs, as long as everything else remains as before.

However, in this case there are two major differences to the above condition:

- 1 gas prices are lowered in the GAS scenarios
- 2 hurdle rates are lowered as a representation of the Green Deal in all non-REF scenarios.

Especially the latter is problematic in terms of comparing costs across the scenarios; hurdle rates don't necessarily represent "real" costs, but also non-economic investment barriers, in which case lowering them is assumed to be a "free lunch" (i.e. the costs of making this happen are not included) and the model deals with the costs resulting from hurdle rates as if they were any other costs. In other words, the main reason for including hurdle rates is to represent the behaviour of agents in the model better, not to claim that the hurdle rates represent actual costs and that their impact should be fully included as any other costs (as the model does at the moment). This further implies that cost differences caused by the changed hurdle rates should not be considered as "real" cost differences. In light of this, costs are shown separately for:

- 1 the REF scenarios and
- 2 for the rest of the scenarios.

For the latter we show differences in welfare change compared to the ADD scenario (the scenario closest to REF in terms of policies, but using the lowered hurdle rates).

Figure 5.7a includes both the main REF variants as well as the sensitivity runs. As the figure shows, achieving the resilience target results in a considerable welfare cost. This is, as with all the other resilience-related results, due to the limit on final energy use, which the model expresses as if it were implemented through price increases, as explained further below; the cost of the portfolio restrictions is minimal in comparison. Reductions in the gas price have a small positive effect on welfare, but if a resilience target is introduced simultaneously, this benefit is reduced and practically lost for the last decade of the modelled time frame.

The REF sensitivity runs, in turn, show how strong an effect the carbon price floor has on the system. If only the renewable constraint is removed (REF-P1), the costs change very little. When the carbon price floor is abolished (REF-P2), however, we see a clear increase in welfare.

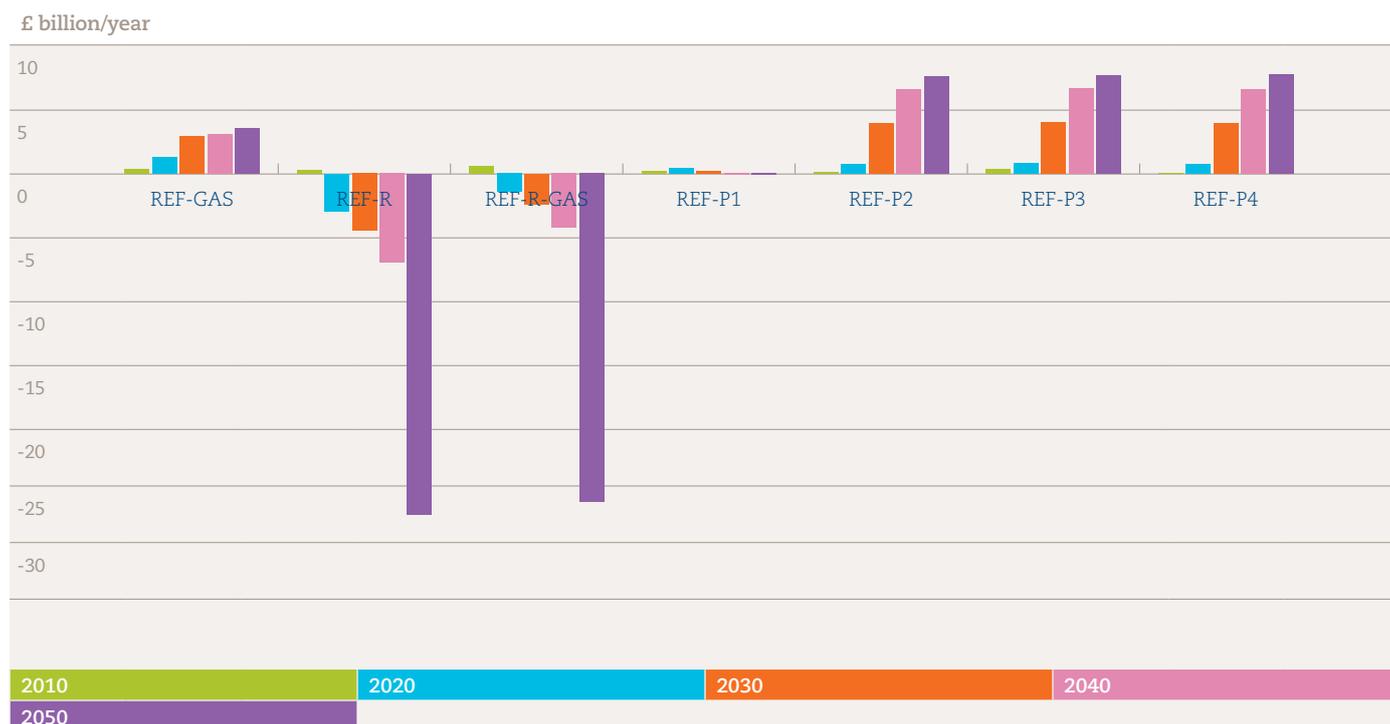
Whether additional policies are also removed together with the carbon price floor (REF-P3, REF-P4) makes little additional contribution to the welfare gain achieved by removing the price floor.

Figure 5.7b shows the cumulative, undiscounted welfare change of the rest of the scenarios, all costs in comparison to the scenario ADD (which in turn has a cumulative difference of £197 billion compared to the REF scenario). Again the impact of the resilience target in terms of welfare cost can be clearly seen; adding a resilience target to ADD, for example, induces welfare losses that are clearly above those caused by adding the targets used in the GAP scenario and are some 70% of the additional welfare costs of the LC scenario. We can also see how adding the resilience target increases the welfare costs much more, if no proper climate target is included – the cost difference between ADD and ADD-R is about £220 billion, in GAP and GAP-R it is £170 billion, while in LC and LC-R it is only £90 billion.

The demand reduction costs are very high in the resilience scenarios as a result of the final energy target, as already noted. This is understandable, because of the implementation of the demand reduction through energy price increases. The target generates a "bottleneck" on the final energy level, thus creating a clear price difference between the supply and end use sides. As the prices of the end use energy carriers increase, price-induced demand reductions, and their implied costs, also rise. One can clearly see how the system is being driven by the resilience target: the value of the lost demand across the policy cases is similar, because of the assumption that prices at the end use level are the drivers of demand reductions, and are themselves largely driven by the resilience constraint. The model runs therefore suggest that using price-based approaches to reducing energy demand might only be suitable for a more modest energy savings target, unless a very high value is placed on reducing energy use.

The demand reduction costs are very high in the resilience scenarios as a result of the final energy target

Figure 5.7a: Annual welfare changes for the different REF scenarios, compared to REF



The (green square and dots) in the right panel of Figure 5.7 show the contribution to the cumulative costs from two different main components of the system – the supply and the demand side. As the figure shows, the energy system costs (compared to ADD) actually decrease in most of the scenarios – a result caused by the reduction in demand, especially in the resilience scenarios, leading to a smaller energy system. Only in the LC and LC-GAS scenarios does the system cost slightly increase beyond the ADD scenario¹³, a result comparable to the C80 outcome in Table 4.1 (where C80 has an 80% 2050 reduction target and a 3.5% discount rate as in the LC and LC-GAS scenarios).

Sectoral implications

Electrification of the energy system

Under higher gas prices, electricity demand is around a third higher than in 2000 under all the policy scenarios except REF where it is 26% higher. In ADD, GAP and LC gas prices do not affect the level of electricity demand but electricity demand is slightly lower under low gas prices under REF due to a lower level of switching from gas to electrically-vectored heating.

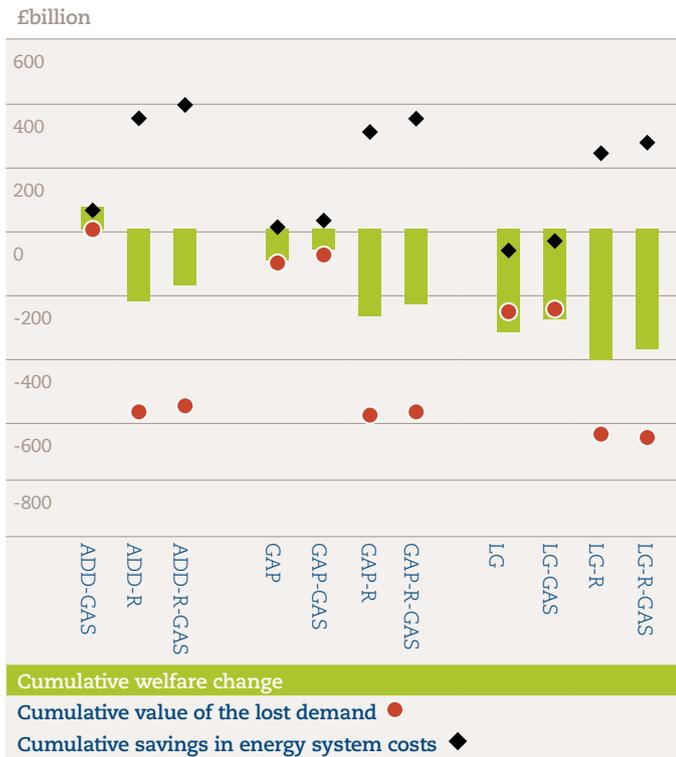
The principal reason for the increasing electrification of the energy system is the introduction of heat pumps, which play a role in all of the scenarios except REF-GAS (low gas prices). They start to be introduced in 2015-2020 in all other scenarios except REF (where they appear from 2035 and never achieve significant take up), and in LC and GAP become the most important source of home heating by 2050 (supplemented by solar and district heating or wood), and are deployed at a similar level in ADD (though in this scenario there is more district heating)¹⁴. This pattern of adoption is explained by the combination of two assumptions: the forcing in of renewable heat in all but REF and REF-GAS; and the assumption that the Green Deal has the effect of reducing hurdle rates in the residential sector. Gas is retained as a source of heating only in the REF and, at an even higher level because of the lower gas prices, in REF-GAS. In other scenarios (including ADD and ADD-GAS because of forcing in renewable heat) gas is forced out.

Irrespective of the gas price, district heating plays a substantial role in all scenarios except REF and REF-GAS. However, its role in the LC scenarios is replaced by solid/wood fuel by 2050. Solar heating becomes significant in the LC and GAP scenarios between 2030 (LC) and 2040 (GAP-GAS).

¹³ The size of the system decreases also in these scenarios, but not enough to cover the increase in the combined supply cost curve implied by the scenario.

¹⁴ Heat pumps in the residential sector are assumed to have a Coefficient of Performance (COP) of 2.6 in 2000, 3 in 2015, 3.5 in 2020 and 3.7 in 2025 (and slightly lower COP values in the service sector)

Figure 5.7b: Welfare changes in the scenarios, compared to ADD



Role of efficiency and demand reduction

The patterns of take-up of efficiency measures (conservation in the model) and demand reduction are different. Almost all the efficiency measures endogenously available in the model are progressively taken up. The only exception is in the REF scenarios, where only about 50% of the potential in the residential sector is taken up regardless of the level of gas prices. This indicates that the likely reason for the increased take up in the other scenarios is that, as noted above, the hurdle rates of efficiency measures are assumed to fall in the other scenarios making more measures cost-effective.

Inevitably, price-induced service demand reduction is less in the low gas price scenarios than in the high gas price scenarios. However, the difference in gas prices affects demand less than the level of carbon ambition. For example, in the services sector, demand for heating and hot water is reduced by 7% and 14% respectively in the GAP scenario, compared to REF, and in GAP-GAS these reductions are only reduced to 6% and 12%. Focusing on the residential sector, energy service demand in ADD actually increases in comparison with REF, because the

reduced hurdle rates reduce the effective cost of the energy service (i.e. adequate lighting or comfortable room temperature) and related conservation technologies, and in REF-GAS and ADD-GAS, due to the lower gas price. Price-induced demand reduction for residential heating reaches a maximum of 9% in 2050 in the LC scenario, with gas prices making little difference as gas plays little role. Gas prices in the residential sector make most difference in the GAP scenario where demand for residential heating is 4% down on REF and in GAP-GAS, with low gas prices, the reduction is only 1%.

Vehicle technologies and fuels, and bioenergy

Not surprisingly, gas prices make no material difference to choice of vehicle technologies, or on biomass use. Perhaps more surprisingly, battery electric vehicles play no part in any of the scenarios, due to their relatively high up-front capital costs (about a third above the investment costs assumed for a fuel cell powered hydrogen car) and the availability of biofuels. In REF and ADD there is a switch from conventional (internal combustion) engines in cars to hybrids (not plug-in) over the period 2020-30. Hydrogen fuel cell vehicles take about 30% of the market by 2050 but are only introduced from 2045 onwards.

In the LC and GAP scenarios E85 biofuel hybrid vehicles start to displace petrol hybrids from 2035 and 2040 onwards, meeting about 60% of the demand for road transport fuel before 2050 in the LC case. This is up from about 20% in GAP, indicating that biofuels are a relatively expensive decarbonisation option, and are only taken up under more stringent abatement demands. The great majority of the biofuels used are imported. Of course, the take up of biofuels depends on the availability of bioenergy for this use, whether it comes from the UK or from abroad.

In respect of the use of bioenergy more generally, in the service, residential and power sectors, where gas and bioenergy compete directly, lower gas prices push bioenergy use down. However in transport, under the constrained scenarios (LC and GAP), lower gas prices place more of the abatement burden on the transport sector, increasing bioenergy demand slightly. However, the effects are small. In all the scenarios, bioenergy plays a big role in the service sector from 2010 onwards in the form of wood products (up to 20% of demand), although this declines to about 10% by 2050. In the LC (but not the other) scenarios the use of wood products is largely transferred to the residential sector.

In the LC, and less so the GAP, scenarios, there is an acceleration of demand for biomass from 2020, due first to co-firing with CCS and then to transport biofuels. By 2050, the biomass and waste category in LC constitutes 16% of primary energy demand compared to 6% in GAP. This compares with the CCC's Bioenergy Review which concluded that 10% bioenergy would be needed to reach the UK's 80% target (CCC 2011).

Hydrogen

Hydrogen plays a number of roles in the scenarios, meeting various transport service needs. Its use is spread across the scenarios and across different transport modes. Its competitive position compared to alternative options also varies across scenarios. It may be produced in a number of different ways, including steam methane reforming (SMR) and electrolysis.

There is at least one general reason why hydrogen competes rather well. Its emissions are not controlled in ADD and REF as these focus on the sectoral policy instruments, and emissions from the production of hydrogen are not affected by these. In GAP and LC there is an emission price, but this price remains low for rather a long time, as the sector specific measures depress it for a number of decades (for example, even in LC the price goes above £15/tCO₂ no earlier than 2035). In the GAP scenario, both coal and SMR are used (first coal then gas). When in LC the price does eventually rise, then hydrogen is produced mostly by SMR with CCS.

In terms of specific uses, hydrogen already appears in REF (rail, buses and HGVs in 2030, cars and LGVs in 2050). In respect of buses, the diesel/biodiesel bus, the technology used before hydrogen is introduced, has by 2030 higher annualized costs (investment + O&M¹⁵ + fuel use) than hydrogen. As a fuel, hydrogen is more expensive than diesel, but as the efficiency of the bus is some 80% better with hydrogen fuel cells, the fixed O&M costs are lower and the investment only some 12 % higher than with a diesel bus, the model decides to go for hydrogen. The outcomes for other transport service needs are similar in character.

The resilience scenarios in more detail

As noted above in the description of the scenarios, the resilience scenarios demand both a certain diversity in primary energy and power generation, and impose an annual reduction in final energy demand. It is this latter constraint that is the most important in driving the results. Because of uncertainty as to how such a continuing demand reduction might come about, and the way they are implemented in the model through increased prices, with consequently high welfare losses, the long-term results from these scenarios are not amenable to clear interpretation, and the discussion here is limited to the 2025 timescale. A general point to be made in advance is that one way of hitting the final energy demand constraint might be to electrify, because electricity permits more efficient end use of energy.

In respect of CO₂ and primary energy, under the REF scenarios, emissions are lower in the resilience cases: 345 mtCO₂ in REF-R in 2025 as opposed to 420 in REF. This is a result of the lower final energy demand (5400 PJ in REF-R, compared to 6,400 PJ in REF), rather than more use of low-carbon electric vectors. Primary energy demand is also lower in the resilience scenarios. Under the REF scenarios, gas bumps against the 40% market share constraint on primary energy, allowing a little more coal to be used in 2025. However, gas does not bump against the fuel mix constraint in the LC scenarios and all forms of supply are down due to the demand restrictions.

One way of hitting the final energy demand constraint might be to electrify, because electricity permits more efficient end use of energy

With regard to the generation mix, resilience only makes a small difference to either the REF or LC scenarios. In each case, the electricity system is around 2% smaller in 2025. The only technology to gain significantly in REF-R is biomass co-firing, while this is the technology in LC-R that bears the brunt of the demand reduction. Gas prices make little difference to the generation mix.

¹⁵ O&M are non-fuel use related operation and maintenance costs



The resilience constraints significantly affect residential heating in the REF scenarios, with heat pumps displacing mostly gas, in order to comply with the 40% share limit in primary energy, but also some resistance electric heating. Again, gas prices make little difference to the outcome. Under the LC scenarios, the resilience constraints accelerate slightly the move to heat pumps but the impact is less dramatic than in the reference scenarios.

The resilience constraints bring about significant reductions in residential final energy demand, from 1720 PJ in REF in 2050 to 730 PJ in REF-R, a 58% reduction. This is partly due to the increased use of heat pumps, because the heat drawn from the environment is not accounted for in final energy demand. However, the resilience constraints also lead to significant price-induced demand reductions, with substantial associated welfare costs, as explained above. Once again, the level of gas prices does not have a significant influence.

In respect to cars, the resilience constraints have no material impacts on vehicle technologies up to 2025. However, extrapolating out to 2050, these constraints lead to a significant switch from petrol hybrids to hydrogen fuel cells in the REF scenarios, and a switch to plug-in hybrids and some battery electric vehicles at the expense of biofuels in the LC scenarios. The price of gas is again of little consequence.

Gas prices make little difference to the generation mix

Comparative results and key messages

A comparison of the results of the main low-carbon scenarios produces a number of robust key messages about the future development of the UK energy system if the 2050 carbon targets are to be cost-effectively achieved



This report has described and conducted a limited comparison between a number of different modelling exercises. The underlying model – UK MARKAL – in all the exercises is the same. However, as described, for each set of exercises it was subject to review and modification, to change assumptions, and update policies and data, as was appropriate at the time. These changes mean that the results of the scenarios are not generally comparable in detail. However, they also mean that any over-arching trends or messages that emerge from all the scenario sets are likely to be robust, at least within the terms of the general modelling framework adopted. This final section reviews these over-arching trends and messages, as revealed in the main 80% and 90% 2050 carbon reduction scenarios reviewed above, and draws out their implications for energy policy, primarily in the UK but probably also with relevance for other, similarly-situated, countries.

There is no clearly preferred low-carbon technology

There are three main classes of large-scale low-carbon technologies on the supply side: nuclear, renewables (the most important of which in these model runs are wind and bioenergy, with marine being added towards 2050), and carbon capture and storage (CCS). Nuclear, wind and CCS are wholly or mainly electricity-related technologies, which is therefore the focus in this section.

On the demand side there are energy efficiency and conservation, which reduce the quantity of energy required to meet a given level of energy service demand, and a range of other end-user technologies (e.g. heat pumps, biomass boilers, solar thermal and PV) which supply energy. The most significant of these in the scenarios are discussed further below.

The use of conservation in the model runs depended very much on its specification, which differed widely in different runs, so that it is not really comparable across them. However, in the CCC, AEA and UKERC2 runs conservation saved around 400-570PJ of energy, which was 9-12% of final energy demand. The energy system size, and associated costs, would have been that much larger had the conservation technologies been either not available or not been implemented.

Table 6.1 shows both the capacity (GW) and generation (PJ) in the main low-carbon (80% or 90% emission reduction by 2050) runs for the principal low-carbon electricity supply technologies.

The picture that emerges is pretty clear. First, in all the low-carbon runs, all the main low-carbon technologies (nuclear, renewables, CCS) make a significant contribution to generation, although changing the assumptions in different runs changes the mix between them. Second, nuclear consistently makes the largest low-carbon contribution, and co-firing CCS (when available) the second largest (except in the CCC C90 and C90+ runs when co-firing CCS makes the largest contribution). In a number of runs, marine makes a larger contribution by 2050 than wind. However, it should be noted that wind makes a significant contribution from 2015, whereas marine does not tend to do so until the 2030s and 2040s. In each run, the generation from these sources accounts for around or more than 90% of total generation, with the balance being provided by large hydro, imports, storage (UKERC2 runs) and CHP (AEA runs).

The policy conclusions from these runs are equally clear:

- Policy should seek to demonstrate the feasibility and viability of CCS at scale as soon as possible. There are particular reasons for proving the viability of co-firing CCS because of its contribution of ‘negative’ emissions by taking carbon from the atmosphere (through growing the biomass) and then storing this underground when the biomass is burnt
- Nuclear appears to be the most economically attractive low-carbon option. Despite using the most recent published engineering estimates (Mott McDonald 2010), even the current costs of nuclear in the model are uncertain, because the new designs of nuclear likely to be built in the UK have not yet been demonstrated anywhere in Europe. It is likely to be 7-10 years before these costs in the UK become clear, assuming a new nuclear power station can be delivered in that time. Doing so is a clear priority for generating clarification about the cost-effective low-carbon electricity pathway in the 2020s and beyond
- Wind has the present advantage over CCS and nuclear that it can be delivered at scale now, at a known cost, and with known power outputs and carbon emission reductions. Moreover, onshore wind in the best sites is already competitive, or close to competitive, with power generation from fossil fuels. This is currently the lowest cost large-scale low-carbon source of electricity. The costs of offshore wind are currently much higher, and their future development is of course uncertain. Faster cost reduction of offshore wind than currently assumed in the model could greatly increase its contribution to the 2050 electricity mix, because the available resource is very large.

Table 6.1: Power capacity and generation in 2050 in the main low-carbon model runs

Model run	CO ₂ reduction in 2050	Low-carbon Electricity Supply Technology								
		Nuclear		CCS: coal; gas (co-firing; biomass)		Renewables: wind (marine)		Renewables: biowaste		Percent of generation (%)
		GW	PJ	GW	PJ	GW	PJ	GW	PJ	%
Energy 2050: CAM	80%	29	764	31; 0 (na; na)	816; 2 (na; na)	18 (5)	189 (64)	4	38	93
CCG: C80	80%	37	979	8; 0 (21; 0)	59; 2 (550; 0)	19 (13)	195 (122)	12	125	94
UKERC2: LC	80%	23	650	0; 1 (13; 0)	0; 30 (353; 0)	23 (21)	204 (243)	6	44	89
UKERC2: LC-GAS	80%	23	662	0; 1 (12; 0)	0; 30 (349; 0)	23 (21)	204 (243)	6	44	89
Energy 2050: CSAM	90%	38	1004	12; 0 (na; na)	222; 0 (na; na)	65 (5)	748 (64)	3	38	94
CCG: C90	90%	34	898	2.1; 0 (50; 5)	0; 0 (1318; 129)	28 (13)	240 (122)	14	136	98
CCG: C90+	90%	35	883	0.5; 0 (51; 4)	0; 0 (1335; 112)	51 (13)	504 (122)	6	76	98
AEA: DECC-1A	90%	33	949	0.5; 0.5 (28; na)	0; 0 (793; na)	18 (22)	149 (255)	0	0	92
AEA: DECC-1A-IAB-2A	90%	55	1573	1.1; 2.3 (9; na)	23; 12 (238; na)	26 (33)	227 (381)	0	0	94

• Overall, it can be seen that some of the low-carbon technologies are consistently more highly ranked than others. Nuclear has the highest 2050 contribution in six of the nine scenarios, being the second highest in the remaining three (against renewables, CCS, both aggregated across the individual technologies). CCS is on top in three scenarios, second in two scenarios and third in four scenarios. Renewables are ranked 2/3 for four scenarios and 3/3 for five. The average ranks of the three options are: 1.33 for nuclear; 2.11 for CCS; 2.55 for renewables. Nuclear is therefore quite important in all scenarios; CCS is important in some scenarios, but much less so in others; and renewables contribute significantly to all the scenarios, but in none are they the main source of electricity, suggesting that it might be difficult to decarbonize the power sector if neither CCS nor nuclear is available.

The very high proportion of low-carbon electricity in the 2050 electricity mix leads on to consideration of the whole issue of the carbon intensity of power generation, and the role of gas without CCS, in the electricity mix in 2030 and 2050, if the carbon targets are to be met.

The CO₂ intensity of power generation in 2030 must be less than 100 gCO₂/kWh if carbon targets are to be met cost-effectively

Table 6.2 shows very clearly the picture in relation to gas-fired generation in the main scenarios in which the 80% carbon emissions reduction target in 2050 is met.

Moreover, it should be remembered that, as per the CCC analysis reported above, meeting the overall target is likely to need a 90% emissions reduction from the energy sector, and therefore the only runs that are really compatible with the 2050 target are those in Table 6.2 with a 90% emission reduction. From the table it can be seen that all the 90% emission reduction runs have a CO₂ intensity

of less than 100 gCO₂/kWh by 2030, i.e. a greater than 80% reduction from the level in 2000. By 2050 the CO₂ intensity is negative, because of the extensive use of co-firing CCS, which gives negative net emissions.

There is little gas-fired generation after 2030 in low-carbon scenarios, but substantial gas capacity used as back-up to renewables generation

The low CO₂ intensity means that there is little room in the electricity mix for gas-fired generation without CCS even in 2030. Of the 90% reduction runs, there is less than 70 PJ of power generation from gas in all but one of the runs (which has 128 PJ), compared to 460 PJ in 2000. It is especially interesting to see that this conclusion is very

Table 6.2: CO₂ intensity and gas capacity and generation in 2030 and 2050 in the main low-carbon model runs

Model run	CO ₂ reduction in 2050	CO ₂ intensity (gCO ₂ /kWh) ¹		Gas without CCS ²			
				Capacity (GW)		Generation (PJ)	
		2030	2050	2030	2050	2030	2050
Energy 2050: CAM	80%	75	31	13	26	61	0 ³
CCC: C80	80%	109	-7	41	29	178	0
UKERC2: LC	80%	-3	-16	33	29	84	0
UKERC2: LC-GAS	80%	-3	-16	34	30	92	0.5
Energy 2050: CSAM	90%	33	8	13	39	61	0
CCC: C90	90%	5	-32	24	37	41	0
CCC: C90+	90%	-1	-29	29	47	31	0
AEA: DECC-1A	90%	91	-19	24	33	128	8
AEA: DECC-1A-IAB-2A	90%	62	-2	26	37	67	0

¹ The CO₂ intensity of UK electricity in 2000 was around 500 gCO₂/kWh

² In 2000 the capacity and generation of gas-fired electricity were 22GW and 460 PJ respectively

³ 0 in this column means less than 0.5 PJ

little changed by a lower gas price: LC-GAS has a little more gas generation in 2030 than LC, but not much. The carbon constraint allows little response to cheaper gas, if the carbon target is to be met.

However, this does not mean that there is no gas capacity (without CCS) in 2030 and 2050. On the contrary, all the 90% emission reduction runs have more gas capacity in 2050 than they do in 2030, but the generation column shows that this capacity is very little used. It is there to act as peaking and balancing capacity for the increasing quantity of variable renewables (wind and marine) in the electricity system. What is happening is that the model is building new and replacing old gas-fired capacity throughout the period. Initially, this new capacity is being used intensively, largely as base load. This role is then largely taken over by nuclear, and the gas capacity then increasingly acts as back-up plant to the renewables¹⁶. This points to the importance of having adequate incentives in place for this back up capacity to be built, when it will be little used.

It is worth clarifying the economics of this transition. Most of the gas plant will initially be built and run at a high load factor. It will stay on the system at no extra capital cost when it becomes back up plant, when it will need to recover its operation and maintenance costs from the wholesale power market, or whatever other institutional arrangements may then apply, during the short periods when it will be operating, implying a high marginal price of power in those periods. Gas capacity that is built purely as back-up plant adds to the cost of the renewables that it is backing up – the model takes this into account in its optimisation routine, and is one of the reasons the model generally prefers nuclear to renewables. If it were possible to replace the gas back-plant with cheaper electricity storage capacity, interconnection or demand side response, then more zero-cost renewables could be captured when it was available at times of low demand, and used at times of high demand, reducing the overall cost of renewable generation. The UKERC2 runs start to pick up this possibility, generating over 50 PJ of electricity from storage by 2050. A technological breakthrough in this area in the coming years would mean that less back-up gas capacity would need to be built.

After 2030 there is no coal-fired generation (without CCS) in low-carbon scenarios and no scope therefore for a new ‘dash for gas’ either to substitute for coal or generate without CCS after that date

Finally, it is sometimes said that new gas-fired generation can help reduce carbon emissions by substituting for coal. These scenarios show that this is not true for the UK post-2030, because none of the low-carbon scenarios in **Table 6.2** have any non-CCS coal-fired generation by 2030, and the emission performance standards in the Energy Bill 2012 will ensure that no new coal-fired power stations will be built before then. Whether gas-fired generation substitutes for coal in existing power stations before 2030 depends on the difference between gas and coal prices and the level of the carbon price (currently very low).

There are a number clear policy messages coming out of this analysis

- First, the electricity market reform (**EMR**) in the Energy Bill 2012 must provide an economically viable transition for gas generators to move from base load to largely back-up generators by 2030. Whether EMR does this will not become clear until the levels of the capacity payments and their relationship to the wholesale electricity market are clarified.
- Second, the forthcoming gas strategy must make clear the difference between gas capacity and the extent to which it can be used and ensure that the capacity payments provide adequate incentives for back-up capacity when it is required, although new back-up capacity is unlikely to be required before 2030.
- Third, there should be substantial efforts to develop electricity storage technologies, in order to reduce the level of back-up gas capacity required.
- Fourth, there is absolutely no scope for a new ‘dash for gas’, if by that is meant the construction of new gas-fired stations that will generate significant levels of electricity without CCS beyond 2030. New gas-fired stations will be required before 2030 to replace closing coal and nuclear stations, but they will be operated increasingly as back-up capacity beyond 2025 and arrangements to remunerate gas generators for their construction should make this clear.

¹⁶ It is perhaps unlikely that the gas capacity would be as little used as shown in the model runs, although any greater use that entailed carbon emissions would require emissions reductions to be found elsewhere if the carbon targets were to be met.



The contribution of bioenergy to carbon reduction is still very uncertain

Table 6.3 shows the contribution of biomass as bioenergy to the different low-carbon scenarios.

Table 6.3 shows, first, that if biomass co-firing with CCS is available in the model, it tends to get used, though to differing extents, because of its contribution of negative net emissions. Second, with the exception of CSAM, liquid biofuels make only a limited contribution to transport up to 2030, but the model runs then diverge considerably over their role: ranging from almost none in 2050 in the CCC runs to a very great amount in the Energy 2050 runs, and the others in between. With regard to the use of biomass (wood or pellets) for heating (in boilers) in the residential and services sectors, only the CCC runs show little such use by 2050, although the split between them differs considerably in the other runs, and, as notes 2, 4 and 5 to **Table 6.3** make clear, the amount and the split between them varies over the projection period, so that only looking at the 2050 figure can be misleading as to the use of the resource earlier on.

The AEA runs uniquely show considerable biomass use in 2050 in industry. Overall, even in the 90% carbon reduction runs, the use of biomass varies by almost a factor of 2. Clearly there is a lot of sensitivity in the model to assumptions about the availability of biomass, and its costs for its different uses, with the CCC runs being the least optimistic on these counts.

A point that should be taken into account in the interpretation of the use of bioenergy in these scenarios is that the modelling assumes that bioenergy is a zero-carbon fuel, in other words it ignores the greenhouse gas (GHG) emissions from growing, processing and transporting the fuel, and from any land use change that might result from growing biomass. It is known that this is scientifically incorrect, but there is still considerable uncertainty as to the level of GHG emissions from producing biomass. The assumption in the modelling has therefore been retained, but the results will therefore overstate, perhaps substantially, the GHG emission reduction benefits from using biomass instead of fossil fuels.

Table 6.3: The use of bioenergy in 2030 and 2050 in the main low-carbon model runs

Model run	CO ₂ reduction in 2050	Biomass in co-firing CCS (PJ)		Liquid transport fuels		Sectoral bioenergy us (PJ)				Total (PJ)
				Bioethanol	Biodiesel	Transport ¹ (bioethanol; biodiesel)	Residential	Services	Industry	
		2030	2050	2030	2030	2050	2050	2050	2050	2050
Energy 2050: CAM	80%	na	na	56	40	731 (338;393)	0 ²	146	na	876
CCG: C80	80%	36	271	24	12	10 (5; 5)	47	0	na	328
UKERC2: LC	80%	209	206	43	34	584 (384; 155)	158	60	8	1015
UKERC2: LC-GAS	80%	207	204	43	34	585 (384; 155)	159	55	8	1011
Energy 2050: CSAM	90%	na	na	226	115	1039 (393; 612)	0	373	na	1412
CCG: C90	90%	195	650	72	23	13 (4; 9)	32	0	na	695
CCG: C90+	90%	195	658	27	22	8 (3; 4)	2	32	na	700
AEA: DECG-1A	90%	130	464	21	16	246 (77; 149)	181	312	190 ³	1393
AEA: DECG-1A-IAB-2A	90%	98	139	21	28	250 ⁴ (3; 247 ⁵)	203	101	196 ³	890

¹ The difference between the transport total and the sum of biodiesel and bioethanol is comprised of biokerosene for aviation

² In 2040 there was 88 PJ of biomass use in the residential sector in this run

³ Includes 2 PJ for agriculture

⁴ While this model run shows no biokerosene for 2050, in 2045 there was 50 PJ and 35 PJ in 2040, which has clearly become uneconomic in 2050 compared to the available alternatives for carbon reduction

⁵ Falling from 307 PJ in 2045

Residential heating by 2050 uses almost no natural gas

Table 6.4 shows the dramatic changes in residential heating implied by the carbon targets. First, residential energy use in 2050 falls to less than half, and in some of the runs (**UKERC2, AEA**) to only a third, of its level in 2000¹⁷. This could only come about while keeping buildings at current levels of warmth with a fundamental transformation of the building stock in terms of its energy efficiency. There is currently no sign that such a transformation (as opposed to a reduction in building energy demand due to price increases), at the required rate, is underway.

Second, gas use in residential heating falls dramatically by 2050, especially in the 90% emission reduction scenarios, and has largely disappeared by 2050¹⁸. Given that the use of natural gas and oil dominate residential heating at present, this implies a wholesale change in heating technology over the next four decades. Again, there is no sign that such a change has begun.

Third, while there is a range of possible substitutes for gas- and oil-fired heating, it is not clear which of the five alternatives shown in **Table 6.4** is likely to predominate. All of them, apart from electric heating, are still marginal in the UK, and unfamiliar to UK householders (though some, like district heating and heat pumps, have achieved widespread penetration in some countries on the European mainland).

Table 6.4: Residential CO₂ emissions and fuel use for heating in 2030 (natural gas only) and 2050 in the main low-carbon model runs

Model run	Residential CO ₂ emissions ¹ (mtCO ₂)		Natural Gas (PJ) ²		Electricity	Heat pumps ³	Solid/wood fuel	DH ⁴	Solar	Total ⁵ (PJ)
	2030	2050	2030	2050	2050	2050	2050	2050	2050	2050
Energy 2050: CAM	68	5	1217	36	5	345	0	14	0	399
CCC: C80	52	6	876	76	292	113	47	217	0	746
UKERC2: LC	42	4	517	0	20	185	157	3	143	509
UKERC2: LC-GAS	45	4	544	0	20	185	159	3	143	511
Energy 2050: CSAM	49	3	874	0	0	348	0	0	0	348
CCC: C90	49	2	817	0	325	112	32	254	0	724
CCC: C90+	46	2	785	0	458	112	2	155	9	737
AEA: DECC-1A	20	2	292	0	22	172	181	3	151	530
AEA: DECC-1A-IAB-2A	23	2	355	0	22	171	203	3	111	511

¹ Residential CO₂ emissions in 2000 were around 151mtCO₂. They come from cooking as well as heating. Emissions from cooking are an important component of the residual emissions from the residential sector in 2050.

² The use of natural gas in 2000 for heating in the residential sector was around 1300 PJ

³ Heat pumps deliver more heat than these numbers indicate because the figures in the table reflect the inputs to such end-use devices, and the co-efficient of performance (COP) of heat pumps is well above three, i.e. they supply at least three times as much heat energy as their electrical energy input.

⁴ DH stands for district heating, which may be with or without CHP (combined heat and power)

⁵ The total use of energy in 2000 for heating in the residential sector was around 1660 PJ (gas [1300], plus electricity [135], oil [115], coal [60], wood [30] and DH [5])

¹⁷ The numbers in the table show the combined effect of 1) energy saving measures, 2) price-induced demand reductions and 3) increases in the conversion efficiency of the end-use devices (the last being amplified by the large share of heat pumps, for which 'efficiency' is a slightly different concept than for most technologies). The extra energy delivered by heat pumps is not therefore included in these figures.

¹⁸ This also applies to oil-fired heating, though this is not shown in Table 6.4.



The mass entry of different low-carbon vehicle technologies of high efficiency permit transport distances to increase while fuel use and carbon emissions decline

Moreover, some involve large-scale changes to delivery infrastructures both outside (for example, the pipework required for district heating, or the reinforced electricity distribution networks that the large-scale deployment of heat pumps would require) and inside the home (for example, heat pumps work best with under-floor heating, rather than radiators). The challenges involved in deploying these technologies at scale, even over four decades, should not be underestimated.

Alternatively, there are replacements for natural gas, such as biomethane or hydrogen for domestic combined heat and power (CHP), which would not require such large infrastructure changes (at least for a limited proportion of hydrogen), but with these the challenge is to generate the new fuels (for example, through anaerobic digestion or electrolysis) in sufficient quantities. These options are not taken up in the model for reasons of cost.

The technologies for providing low-carbon heat for the services sector (mainly offices and other commercial buildings) are similar, but their implementation at scale is no less challenging. For the 90% reduction scenarios, C90 envisages the very large-scale deployment of heat pumps), while CSAM chooses very large quantities of bioenergy. C90+ mixes heat pumps with wood pellets. In DECC-1A pellets provide over half the heating, but significant contributions are also made by district heating, electricity and heat pumps (in that order), while in DECC-1A-1AB-2A over a third of the heating is provided by electricity, with only a slightly smaller contribution from pellets and the balance split between district heating and heat pumps (in that order). As with the residential sector, all these technologies exist and have been deployed in the UK at a small scale in the services sector, but their rapid and large-scale deployment implies an enormous change in the mindsets and cultures around heating practices in commercial buildings, as well as in building supply chains and supporting infrastructures. Even the beginning of such a change is at present hardly apparent.

Table 6.5a shows the distance travelled by different in different scenarios, together with the associated fuel demand (some of the 80% emission reduction scenarios shown in previous tables have been omitted because they convey very similar messages to those shown). The first thing to notice is that these low-carbon scenarios do not depict worlds in which everyone stays at home. The distance travelled in all the scenarios increases considerably between 2000 and 2050, by a minimum of 60% in the scenarios shown¹⁹.

Moreover, these distances travelled are reduced less than in other sectors by the increase in the carbon price that is associated with the emission reductions. Typically car travel falls by 1-5% in the scenarios shown, indicating the high value placed on car travel. However, transport fuel demand falls dramatically over 2000-2050, by 14-47% in the different scenarios. This indicates an enormous improvement in vehicle efficiency over 2000-2050. For example, in scenario C90 the average fuel efficiency over the vehicle types considered increases from 0.29 vkm/MJ to 0.86 vkm/MJ, an increase of over 200%.

¹⁹ It may be noted that while these assumptions are consistent with the long-term trend (over the 30 years from 1975-2005 distance travelled per person per year increased by 52%), from 2005-2011 the same metric fell by 5%. The scenario projections may therefore be considered to be at the top end of estimates of probable increases in travel distances.

Table 6.5a: Road travel by different vehicles in 2030 and 2050 in the 90% and one 80% emission reduction scenarios

Model run	Road travel (billion vehicle kilometers – bvkm) Year 2000: 626								
	Car Year 2000: 390		Bus 2000: 5		HGV 2000: 29		LGV 2000: 54		Total
	2030	2050	2030	2050	2030	2050	2030	2050	2050
UKERC2: LC	530	649	5	5	32	32	119	178	912
Energy 2050: CSAM	521	607	8	9	44	49	103	143	839
CCC: C90	536	637	4	4	36	40	83	115	841
CCC: C90+	535	637	4	4	37	40	83	115	842
AEA: DECC-1A	520	636	5	5	32	32	118	177	850
AEA: DECC-1A-IAB- 2A	522	642	5	5	31	32	117	178	857

Table 6.5b: Road travel by and fuel efficiency of different car types in 2030 and 2050 in the 90% and one 80% emission reduction scenarios

Model run	Petrol cars Year 2000 (all conventional): 291 bvkm; 945 PJ Fuel efficiency: 0.31 vkm/MJ					
	Conventional		Hybrid/E85 ¹		Plug-in hybrid	
	2030	2050	2030	2050	2030	2050
UKERC2: LC (bvkm)	0	0	451/0	0/338	0	0
UKERC2: LC (PJ)	0	0	661/0	0/451	0	0
Fuel efficiency vkm/MJ ²			0.68	0.76 (4)/0.75	0.76 (3)	0.97 (1)
	bvkm	bvkm	bvkm	bvkm	bvkm	bvkm
Energy 2050: CSAM (1)	208	0	0	0	0/198	220/205
CCC: C90 (2)	0	0	178	0	0	0
CCC: C90+ (3)	0	0	198	0	61	3
AEA: DECC-1A	0	0	210	28	0/0	0/66
AEA: DECC-1A-IAB-2A	0	0	214	13	0	0

* Includes bio-diesel

¹ E85 is an internal combustion engine vehicle which uses a fuel mix of 85% bioethanol

	Model run	Road energy demand (PJ) Year 2000: 1846								
		Car 2000: 1260		Bus 2000: 70		HGV 2000: 394		LGV 2000: 186		Total
		2030	2050	2030	2050	2030	2050	2030	2050	2050
	UKERC2: LC	767	698	31	18	168	123	182	224	1268
	Energy 2050: CSAM	1209	1029	29	25	334	235	181	207	1589
	CCG: C90	635	477	16	13	218	179	77	137	974
	CCG: C90+	656	481	17	13	221	179	115	136	980
	AEA: DECG-1A	577	536	25	18	166	123	180	221	1042
	AEA: DECG-1A-IAB- 2A	578	491	34	16	198	158	180	225	1051

	Diesel cars Year 2000 (all conventional): 67 bvkm; 210 PJ Fuel efficiency: 0.32 vkm/MJ						BEVs Year 2000: 0		HFCVs Year 2000: 0	
	Conventional		Hybrid		Plug-in hybrid		2030	2050	2030	2050
	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
	0	0	80	65	0	0	0	0	0	246
	0	0	106	77	0	0	0	0	0	176
			0.76	0.84		0.83 (3)	1.51 (5)	1.52 (5)		1.4
	bvkm	bvkm	bvkm	bvkm	bvkm	bvkm	bvkm	bvkm	bvkm	bvkm
	116*	183*	0	0	0	0	0	0	0	0
	0	0	80	64	0	0	238	401	0	172
	0	0	80	6	0	58	196	340	0	230
	0	0	78	64	0	0	232	193	0	286
	0	0	78	39	0	26	230	244	0	321

² This is calculated from the UKERC2: LC scenario where available, or from one of the other scenarios (with the scenario number in brackets) where it is not; the efficiencies of the same vehicles in the same year do not vary much over the different scenarios



These fuel efficiency increases derive from a complete change in vehicle technology over 2000-2050, as shown for cars in [Table 6.5b](#). In 2000 effectively all vehicles were either conventional petrol or diesel cars, with efficiencies of 0.31 and 0.32 vkm/MJ respectively. These vehicles had disappeared in all the low-carbon scenarios shown in [Table 6.4b](#) by 2030. In 2030 they were largely replaced by hybrid petrol and diesel vehicles (with efficiencies of 0.68 and 0.76 vkm/MJ respectively), though battery electric vehicles (BEVs), with a 2030 efficiency of 1.5 vkm/MJ, also make a strong entry in many of the 90% emission reduction scenarios. By 2050 there is another technology shift. The number of hybrids declines, a few plug-in hybrids appear (with an efficiency of 0.80-0.95 vkm/MJ) but the real change is the large-scale deployment of hydrogen fuel cell vehicles (HFCVs), with a comparable efficiency to BEVs. It is the three- to four-fold increase in vehicle efficiency that permits the distance travelled by cars to increase from 390 bvkm in 2000 to over 600 bvkm in all the scenarios shown in [Table 6.5a](#), while the car energy demand falls from 1260 PJ in 2000 to as low as 477 PJ in 2050 in scenario C90. Carbon emissions from the transport sector fall by an even greater proportion, of course, for example by 85% in scenario C90, because the energy for BEVs and HFCVs is almost zero-carbon electricity and hydrogen, and that for the remaining internal combustion engines is biofuels (see [Table 6.3](#)), which is accounted as zero carbon.

A similar shift in technology is shown for the other vehicle types shown in [Table 6.5a](#). Hydrogen becomes significant by 2050 for all of buses, heavy goods vehicles (HGVs) and light goods vehicles (LGVs), while hybrid diesel also features strongly in 2030 and 2050 LGVs. This is true for some scenarios for HGVs too, though in others it tends to fall away towards 2050, to be replaced by HFCVs.

In terms of the technology differences between the scenarios, [Table 6.3](#) showed that there was a significant difference in the use of biofuels, with the Energy 2050 scenarios using the most by 2050, then the UKERC2 scenarios, then the AEA scenarios, while the CCC scenarios use practically none. The other major difference, revealed by [Table 6.5b](#), is the absence of BEVs in the UKERC2 scenarios, when all the other scenarios show a massive deployment of this vehicle type. This is because the UKERC2 scenarios use far more biofuel (see [Table 6.3](#)), especially bioethanol, deployed in E85 vehicles.

Conclusions

A number of strong conclusions emerge from the individual scenarios but even more perhaps from their comparison



The main conclusion is that, as might have been expected, the large-scale decarbonisation of the UK's energy system (and it is worth remembering at this stage that the CCC estimates that there will need to be 90% decarbonisation of the energy sector if the overall 80% target from greenhouse gas emissions reduction by 2050 is to be met), will require fundamental changes in every part of the energy system

All buildings, new and existing, will have to be much more energy efficient; much less energy will be needed to heat them, and by 2050 it will not be natural gas, but electricity, perhaps driving heat pumps, and bioenergy, perhaps with district heating, with or without CHP, and solar thermal panels. This brings into question the need for the kind of natural gas grid that exists today, and the extent to which it should be maintained or readied to accept different fuels, such as biomethane, which can be fairly readily injected into it, or hydrogen, which, at high proportions,

All buildings, new and existing, will have to be much more energy efficient

would require significant changes to the grid. Road transport will continue to be the major transport mode, but the vehicles using the road will be profoundly different. Those with internal combustion engines will run on biofuels. Otherwise there will be a mixture by 2050 of battery electric and hydrogen fuel cell electric vehicles. Only biofuels can be easily distributed through current re-fuelling infrastructure (filling stations), though their availability also depends on other factors (e.g. feedstock or imports).

Both BEVs and HFCVs will require large investment in new charging, filling, or battery exchange, infrastructure (some examples of which are now starting to appear in some cities), and HFCVs will need in addition investment in a large-scale distribution network, if the hydrogen is to be produced centrally, or local production facilities will need to be sited with the filling stations.

The widespread diffusion of electric heating technologies in buildings and/or BEVs will require active management of the electricity grid both to prevent the exacerbation of peak demands (if everyone were to try to heat their buildings or re-charge their vehicles at the same time), and to take advantage of the possibilities to store electricity at times when variable renewables (such as wind) were available at times of low electricity demand.

There are a number of possibilities for more active management of the electricity grid to better match supply to demand, reduce the peakiness of demand, and store surplus power for when it is needed, but all need some combination of the development and deployment of new technologies, institutional planning and management, and changes in consumer behaviours.

The behaviour of consumers will be critical also for the take-up of low-carbon technologies in both buildings and vehicles. Currently, consumer behaviour does not readily lead to the adoption of efficiency technologies in buildings or low-carbon vehicles, like BEVs. Yet if low-carbon heating technologies are to be able to keep buildings warm cost-effectively, it is essential that they are deployed in energy-efficient homes, with around 50% lower energy demand for the same internal temperatures than at present. And it may be that with respect to vehicles, BEVs and FCEVs will need to be strongly promoted through subsidies, and taxes on high-carbon alternatives, if the gap between the low-carbon aspirations shown in the scenarios and current practice are to be bridged.

With regard to energy supply, a very strong conclusion is that the carbon intensity of electricity will need to fall by at least 80% by 2030 from the level in 2000 of 500 gCO₂/kWh. There is therefore a very strong case for including a maximum carbon intensity target of 100 gCO₂/kWh for 2030 in the 2012 Energy Bill, in order to increase the prospects of the necessary policies for decarbonisation actually being implemented.

There is still considerable uncertainty about the technologies which will supply low-carbon electricity in 2050, and the pathway of deployment of these technologies to get there. There are only three large-scale alternatives: renewables (the largest potential for which lies in wind and marine energy, and bioenergy); nuclear, and carbon capture and storage (CCS). All the low-carbon scenarios deploy some of each of these technologies, suggesting that the projected costs of the technologies are similar, and none is clearly lower than the others, though nuclear power emerges as the front-runner in most scenarios. The costs are also still very uncertain. In terms of cost-effective carbon abatement, this argues for a policy that supports the deployment of all these technologies at scale to 2020 and beyond 2020 if necessary, so that their costs in large-scale deployment, and any associated learning effects, become clear.

There is also uncertainty about the extent to which electricity will take over from fossil fuels in the residential and transport sectors, with some scenarios showing more, and others less, deployment of heat pumps in buildings and BEVs in transport. However, concerns about reducing import dependence reinforce the case for electrification and lead to greater use of electrically-vectorised technologies that reduce final energy demand and permit use of indigenous energy sources to meet demand.

The availability and accounting of bioenergy is crucial for the achievement of carbon targets. It is currently accounted as being zero carbon, when this is known not to be the case. More realistic carbon accounting for bioenergy is essential if the extent of decarbonisation of the energy system is to be accurately represented, but there are still considerable knowledge gaps about the carbon implications of the production of different kinds of biomass, and, their import would need to be accompanied by substantially more information than at present on the conditions of production and the implications for land use change.

In terms of availability, there are clear actual and potential conflicts between the use of land for fuel or food, which will be heightened by population increase and climate change, and are likely to be further exacerbated by global dietary shifts towards meat-eating. If bioenergy is generously available, and can be imported in large quantities into the UK, it will be easier to reach the carbon targets. But it is a big if, and this availability should not be unthinkingly assumed.

It has already been noted that the availability of CCS technology is a large, but uncertain, opportunity for decarbonisation. Used with low-carbon bioenergy, it can produce effectively negative emissions. It could provide a way for industry to decarbonise its large-scale energy-intensive processes. Used with natural gas, it could allow the UK to take large-scale advantage of shale and other natural gas for power generation after 2025, should gas prices fall as a result of the widespread exploitation of unconventional gas sources. Without gas CCS, the widespread use of gas in power generation after 2030 will not be compatible with the UK's carbon targets, as the earlier discussion about the maximum possible CO₂ intensity of electricity in 2030 makes clear.

Given the UK's carbon targets, and in the absence of gas CCS, the level of gas prices after about 2025 makes little difference to technology deployment. The carbon constraint effectively prevents gas being used at any price. The same of course is true for coal. With CCS, the absolute and relative price of gas and coal will determine which is used, though towards 2050 the residual emissions from both technologies even with CCS reduces their possible deployment, and in the very low-carbon scenarios prevents it altogether. The policy implications of the common messages of these scenarios are dramatic.

The Electricity Market Reform (EMR) to be implemented through the Energy Bill 2012 will need to incentivise either the large-scale deployment of new nuclear power, or an intensification of the rate of deployment of new renewables, or both. Investors in low-carbon power generation technologies will need to be assured of government commitment to long-term decarbonisation by the inclusion in the Energy Bill of a maximum average electricity carbon intensity for 2030 of 100 gCO₂/kWh, and the capacity payment component of the 2012 Energy Bill will need to re-assure prospective investors in new gas-fired generation that they will continue to receive reasonable returns even as gas changes through the 2020s from providing base load to acting more as backup to the increased renewables capacity on the grid. Finally, the new initiatives to promote the commercial demonstration of CCS will need to proceed far more effectively than their predecessors, and this demonstration will need to be successful for the envisaged level of decarbonisation to be feasible in the absence of new nuclear power.

The Green Deal and the Energy Company Obligation (ECO) will need greatly to increase the rate of uptake not just of relatively simple energy efficiency measures, like loft and cavity wall insulation, but of more difficult and expensive measures such as solid wall insulation, as well, while ensuring that associated ventilation provisions keep buildings healthy. Consumers will need to be made much more aware and accepting of new vehicle technologies, with increased subsidies to quicken their take-up, perhaps financed through higher taxes on conventional vehicles and fuels, and a faster roll-out of associated infrastructure to make their re-fuelling more convenient.

These three sectors – electricity, residential and transport – are currently the largest carbon emitters and are the key to meeting the UK's carbon targets. Industry may reduce its emissions through greater efficiency, CCS and the use of bioenergy, but unless electricity is effectively decarbonised soon after 2030, and buildings and transport are in a similar condition by 2040, the carbon target for 2050 will not be met.

Given the length of time it will take to transform these sectors to enable this decarbonisation to be achieved, policies now and through to 2020 are of critical importance

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