The implications of recent UK energy policy for the consumer: A report for the Consumers' Association

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Executive Summary

The Electricity Market Reform (EMR) - led by the Department of Energy and Climate Change (DECC) – is the most major reform of the power market since the restructuring and privatisation of the industry in the early 1990s. Particular concerns lie around the EMR's cost-effectiveness and impact on UK energy market structure.

The UK has signed up to the EU Renewable Energy Directive, which sets a target of 15% of final energy consumption from renewables by 2020. Electricity will play a significant role in meeting this target, and 30-40% of the UK's electricity will need to be produced from renewables by 2020. Currently renewable energy supplies only 3% of the UK's total energy needs and the share of renewables in electricity was 7.3% in 2010. Following the 2008 Climate Change Act, the UK has a very challenging target for decarbonisation of its economy: by 2050 UK emissions of greenhouse gases should be 80% lower than in 1990. It is estimated that to meet its indicative 2030 carbon reduction target and put the UK on the path to 2050, electricity generation would need to be substantially decarbonised during the 2020s – reaching 100gCO_2/kWh in 2030 from 500gCO_2/kWh today. The EMR proposes the following package of policies to meet the targets for electricity in the UK: Contracts for Differences (CFD), Carbon Price Support at £30 in 2020 (CPS30), Emissions Performance Standards (EPS) and Targeted Capacity measures (TCM).

The baseline scenario used for comparison purposes by DECC (in analysis undertaken by Redpoint) does not represent "business as usual". The baseline scenario assumes meeting the UK's renewable energy targets using current policies, through adjusting Renewable Obligation Certificates (ROC) bands. In all scenarios modelled, the renewable electricity share is fixed at 29% in 2020. There is no analysis of a more realistic scenario projecting the current rate of progress with renewable electricity deployment. Current policy - under the Renewable Obligation (RO) - envisages a maximum of 15.4% of electricity from renewables in 2015-2016.

The DECC EMR Impact Assessment estimates the effect of various policy scenarios on consumer bills. While the aggregate electricity consumption is assumed to be mostly flat till 2030, household level consumption is assumed to decrease as a result of current government policies. The consumption in the average domestic bill is assumed to decrease by 10% from 2010 to 2030, equivalent to a 0.5% reduction p.a., but the demand is held constant across the scenarios modelled. The second-round effect of reduced electricity consumption from higher electricity prices is not taken into account. Without the assumption of reduced consumption due to efficiency measures, the increase in electricity bills would be even higher than modelled.

The EMR envisages household bills rising by 32% by 2030 and by 47% per unit of electricity on average. If richer consumers subsidize the poorest consumers, they will pay significantly more than this amount. The preferred package transfers significant amounts of money to the private sector and the government from consumers. However, residential consumers will be getting very little for the extra money they are paying out, but will be committed to a higher proportion of nuclear and renewable generation.

One of the key objectives of the EMR is the reduction of the cost of capital. This is achieved through the reduction in uncertainty for investors in low carbon generation. This leads to a lower cost of capital through lower hurdle rates for generation projects. The de-risking of nuclear investments represents a big part of the source of EMR savings from CFDs. The hurdle rates for nuclear investment decrease by 2% under the CFD option. By 2030, the estimated new build for the CFD package is 9.6 GW, compared to 6.4 GW in the baseline. These savings are worth around £1.5bn on 9.6GW of nuclear investment.

Even if the costs of risk are reduced for investors, they do not disappear but are simply shifted to the government – and by extension to consumers. EMR commits consumers to a certain amount of nuclear and renewables regardless of world energy prices. Through a higher share of renewables, consumers may gain insurance against high gas prices, but they do not benefit as much if gas prices are low. Redpoint analysis for ENA (2010) suggests that there are credible scenarios where gas plays a more significant role in energy in the UK. In addition, EMR introduces new sources of risk arising from government failure. These risks arise from unclear governance of the EMR and the potential failure to set appropriate levels for CFD contracts and the amount of capacity tendered. These risks are ultimately borne by consumers.

The short term impact of the EMR on European carbon emissions is zero, given the existence of the EU Emissions Trading System. The long term impact depends on the extent to which the EMR bolsters or undermines EU emissions targets. From a game theoretic perspective, the EMR would seem to tie the UK's hands in future climate negotiations. This might well remove the UK as a credible player in determining the future of the EU ETS and European carbon policy more generally.

Two of the four elements of the EMR are redundant. The EPS performs no role in hitting any of the environmental targets and is costly. The premature introduction of a targeted capacity mechanism is also costly and at variance with best practice learning from the US. Both of these elements have negative net present value according to the government's own impact assessment of EMR policies.

An increase in electricity prices can have a disproportional impact on low-income households (DECC, 2010), as electricity constitutes a higher share of household monthly expenditure. The households in the lower expenditure decile are affected the most. In terms of increased share of overall expenditure, the hardest hit social group is that of single pensioners.

Ultimately, the costs imposed on consumers will be key in determining political support for the government's energy policy. Strong grass-roots political opposition can lead to policy U-turns. It is possible that policy developments in the heat market (e.g. the Renewable Heat Incentive) and in demand reduction (e.g. the Green Deal) may mitigate some of the aggregate household energy cost impact of EMR. However, good policies elsewhere should not be used to obscure the potentially serious impacts of the EMR on unit electricity costs.

1 Introduction

Following Ofgem's Project Discovery, the Committee on Climate Change's (CCC) Fourth Carbon Budget and the DECC/HM Treasury's Energy Market Assessment (EMA), the Coalition Government has now launched a major re-design of the electricity market, the Electricity Market Reform (EMR), led by the Department of Energy and Climate Change (DECC). This reform, which has been referred to by the media as the biggest reform since the 1990's privatisation[2] is being widely debated. Particular concerns lie around its cost-effectiveness and impact on UK energy market structure. The UK energy market has delivered substantial improvements since the early 1990s (Newbery, 1999), which has led many countries to copy the UK's model of competitive markets.[3] The origin of the EMR lies in a number of key recent publications - reviewed in this report. These argue that under the current energy policy framework, the UK electricity market will not be able to respond to the current and future challenges it is now facing. The argument that "the current market will not deliver" on the government's energy objectives forms a key premise of the EMR (DECC, 2010a, p.36).

Those challenges are indeed substantial. UK electricity policy, like policy in many other countries, is simultaneously seeking to maintain security of supply, keep bills down and meet tough environmental targets. The aging state of the electricity network, combined with a number of planned generation plant closures in the coming years, means that the UK will need to replace around a quarter of its capacity, from today's total capacity of 85,337MW (DECC, 2010). It is estimated that this will require an investment of about £110bn in new generation, transmission and distribution assets by 2020 (DECC, 2010a, p.17). Also, the government aims to do that in a way that puts the least pressure on consumer bills. These challenges to the security of supply and affordability might be exacerbated by a potential significant increase in electricity demand (both in terms of total energy and the size of peak demand requirements), due to the electrification of heat and transport at some point in the 2020s. The exact magnitude of the increases is as yet unknown, but might have a significant impact on the investment requirements for the sector. All this occurs in a context of concerns about gas supply security; and substantial challenges due to climate change concerns.

The latter has led to UK government, in its Climate Change Act (2008), to set a binding target for the UK to cut greenhouse gas emissions (GHGs) by 80% by 2050 (on 1990 levels). This target has been confirmed by the latest scientific evidence reviewed by the Committee on Climate Change in their latest carbon report (CCC, 2010). The Committee on Climate Change is charged with setting a pathway to achieve the 2050 target via a series of five year carbon budgets, published three periods in advance.[4] This gives rise to a series of interim targets. The target for 2020 is a 34% reduction on 1990. Such targets have significant impacts on the power sector, which is seen as the key source of early emissions reductions (in the period to 2030), due to the low-carbon technological opportunities it offers (a small number of stationary emissions sources which can be replaced by known low-carbon technologies) and their relative cost-effectiveness. Indeed, compared to other sectors (such as international aviation and agriculture), the power sector has significantly more scope for rapid decarbonisation (CCC, 2010). No binding target has been set specifically for the

[2] THE FINANCIAL TIMES (2010), Huhne heralds green energy upheaval. *Financial Times, 15 December 2010.*

[3] UK energy policy has been known for its market-led approach since the 1990s, with a focus on economic efficiency and the setting up of an independent regulator (first Offer and Ofgas, and now Ofgem) in charge of protecting the interests of energy consumers, 'wherever appropriate by promoting effective competition'.

[4] The first budget period is 2008-2012; the second 2013-2017, the third 2018-2022 and the fourth 2023-2027.

power sector, however it is estimated that to meet the indicative 2030 target and put the UK on the path to 2050, electricity generation would need to be substantially decarbonised during the 2020s – reaching $50gCO_2$/kWh in 2030 from $500gCO_2$/kWh today (CCC, 2010, p.33). This justifies major attention to the power sector in light of climate change, and the examination of the suitability of current electricity framework.

The UK has also signed up to the EU Renewable Energy Directive, which sets a target of 15% of final energy consumption from renewables by 2020 for the UK (see Pollitt, 2010). This is a target for the whole of the economy and once again electricity is expected to play a significant role in meeting this target. Heat from renewable sources and biofuel blended with gasoline will make modest contributions to the overall target, leaving electricity from renewables to do most of the work. 30-40% of electricity will need to be produced from renewables by 2020 for the UK to meet this target. In 2010 renewable energy only supplies 3% of the UK's total energy needs[5] and the share in electricity was 7.3%[6]. Current policy, in the form of the, Renewable Obligation (RO), only envisages a maximum of 15.4% of electricity from renewables in 2015-2016. This means that new policies are required if there is to be anything other than modest progress towards the 2020 renewable energy target.

The government's three key objectives as stated in the EMR are (1) to decarbonise the energy sector, (2) to ensure security of supply, and (3) to do so in a cost-effective way, so that energy remains affordable (DECC, 2010a, p.12). The two former objectives are naturally in tension with the latter, as they put upwards pressure on price. This focus on decarbonisation has led to an extension of Ofgem's statutory duties in the 2008 Energy Act to put more emphasis on the achievement of sustainable development and to consider the interests of future as well as current customers. The Act also refocused Ofgem's duties on prices towards keeping prices affordable for poorer (rather than all) customers, i.e. those defined to be in 'fuel poverty'.[7] Fuel poverty is an important issue within the UK. The number of fuel poor and vulnerable households has been raising at a rapid pace over the last years – from 2 million of households in 2002 to 4.5 million in 2008, and is expected to rise further given current economic conditions (DECC and National Statistics, 2010).

Hence, a number of policy options and packages have been put forward in the EMR. The impact assessment (EMR-IA) seeks to assess those options against the stated objectives (DECC, 2010a, p.14-17). The detailed design of the proposed policy packages is currently (May, 2011) under development; however, a number of scenarios are investigated, all with different impacts on consumers' bills. What is clear is that future energy system will require significant investment, estimated at £200bn by Ofgem (2009b).

This report has two objectives. First, we examine the impact of the EMR on residential consumer bills looking at the government's own analysis. The aim is to understand what impact might be expected on household electricity bills on the basis of the government's own analysis. Second, we aim to critically assess what the possible outcomes of the reform could be for residential consumers

[5] This is the 2009 figure (DECC, 2010, p.188)

[6] This is a weather normalised figure, the actual share was 6.6%. See (DECC, 2011a).

[7] Households in fuel poverty are those who spend 10% or more of their household income on home energy at normal levels of comfort.

in the light of theory and evidence. Radical reform is inherently risky and there is plenty of evidence from elsewhere that may be relevant.

Our report proceeds as follows. In section 2, we assess the internal consistency of some key documents and assumptions on which the analysis of the EMR is based. Different assumptions would lead to different outcomes and impacts on residential consumers' bills. We examine the possible impact on residential consumers' bills across the different scenarios (section 3) and discuss what, in the EMR, consumers will be getting for the prices they will be paying (section 4). Next, we contrast UK residential energy prices with those in other countries (section 5). In section 6, we discuss the likely reaction of UK's consumers to higher prices in the light of the literature and various demand response trials. We go on to broaden the perspective in section 7, where we look at the risks inherent in such radical policy changes given international experience. This leads us into a discussion in section 8 on which policies might be cheaper and/or more effective. Overall, we contribute to a growing literature examining the impacts, for households, of different types of decarbonisation policies.

2 Review of key recent energy policy documents

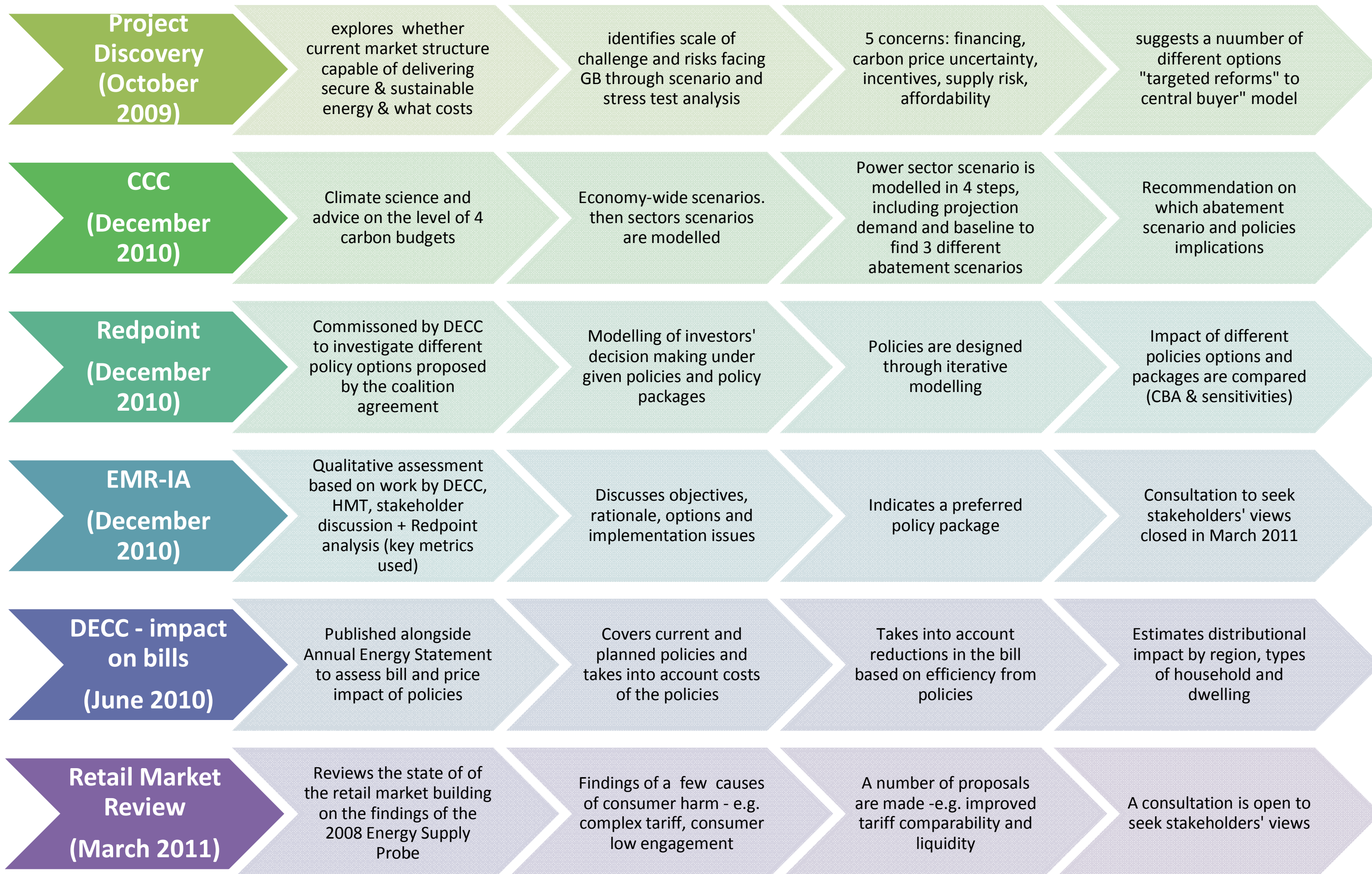
In this section, we provide short summaries of each of the key documents feeding in to the EMR and discuss the consistency of assumptions on which they are based. When comparing these documents, an important thing to note is the fact that each document has a different approach and objective.

Figure 2.1 gives an overview of the main objectives and methodologies of the following key documents: Project Discovery (Ofgem, 2009b); The Fourth Carbon Budget Report (CCC, 2010); Redpoint modelling for the EMR (Redpoint, 2010); the EMR Impact Assessment (EMR-IA) (DECC, 2010a); DECC's report on the estimated impacts of energy and climate change policies on energy prices and bills (DECC, 2010b); and Ofgem's Retail Market Review (Ofgem, 2011).

A few points on the links between the key documents are worth mentioning here. The first document in chronological order, Project Discovery, produced by Ofgem (Ofgem, 2009b) looks at both power and gas supply. It does not have a direct link with the EMR, and the scenarios and assumptions used by Ofgem were not used in the DECC, Redpoint and the CCC documents reviewed here. However, it can be seen as a first recent attempt to investigate whether the current energy framework arrangements are still suitable in the light of the challenges facing UK electricity market.

By contrast, there is a stronger link between the CCC (2010), EMR-IA and Redpoint modelling. The CCC (2010), its Chapter 6 in particular - which is the most relevant for the present research - looks into the power sector. The same holds true for Redpoint and EMR. The CCC (2010) work gives the broader picture of the power sector within the UK economy in general, and is a key guide for the targets that the government intends to reach. However, the (non-binding) targets set in the EMR for the power sector are based on the third carbon report (100gCO2/kWh), not the most recent recommendation of the CCC of 50gCO2/KWh by 2030 (CCC, 2010, p.7; DECC 2010a, p.39). The Redpoint modelling forms the basis of the qualitative assessment and bill calculations provided in the EMR-IA. In other words, the EMR-IA can be regarded as a qualitative assessment and discussion of the Redpoint modelling results. The EMR-IA does not contain any modelling as such, but derives some consumers' bills impact from the wholesale energy prices resulting from Redpoint modelling.

Figure 2.1 Approaches of the documents reviewed



Source: Ofgem, 2009b, Redpoint, 2010, CCC, 2010, DECC, 2010a, DECC, 2010d, Ofgem, 2011.

2.1 The Fourth Carbon Report: Reducing emissions through the 2020s

The aim of this report is to investigate different emissions scenarios and recommend an emission reduction path over the period up to 2050 to the UK government. It sets an appropriate and feasible target to 2030. Based on the latest climate change science, the report makes recommendations for the fourth carbon budget (2023-2027) that correspond to the UK's contribution to lowering of the risks of having more than 2° temperature increase.

The indicative 2030 target recommended seeks to reduce emissions by 60% relative to 1990 levels (46% relative to 2009 levels), based on the need for the UK to be on the path to meet the 80% cuts in greenhouse gases (GHG) by 2050 (below 1990 levels) (CCC, 2010, p.11). The CCC recommends the UK to argue for a reduction of the EU Emissions Trading Scheme (ETS) cap. If successful, the UK should adjust the traded sector to the intended path. The Domestic Action Budget (for 2023-2027) of 1950 $MtCO_2e$ is to be legislated in the first instance and achieved without credit purchase. The Global Offer budget of 1800 $MtCO_2e$ indicates a minimum UK contribution in a future global deal. In terms of costs, the CCC estimates that meeting the Domestic Action Budget would require less than 1% GDP in 2025, including £10 billion for power sector decarbonisation annually.

The report then develops economy-wide scenarios that would meet those budgets. It recommends a specific preferred economy-wide scenario. A bottom-up analysis of abatement opportunities is set. The model runs Poyry's wholesale electricity model – Zephy - which captures the interaction between variable supply and variable demand. The power sector is a key sector, given the scope of decarbonisation that it enables at a relatively cost-effective rate compared to other sectors (international aviation emissions and agriculture in particular). Decarbonisation of the power sector through the 2020s would require the addition of 30-40GW of low-carbon plants, in order to reach a grid carbon intensity of 50gCO_2/kWh (from current 500gCO_2/kWh).

The report then delves into the specific implications for each sector, including the power sector. Here, 3 different abatement scenarios are investigated: low, medium and high investment, and compared to a reference emission case. The medium scenario is the preferred scenario, given the preferred economy-wide scenario.

The approach to modelling is composed of the 4 following steps: (1) the projection of future demand from existing sectors, (2) projections demand from new sectors (electric vehicles (EV) and heat (from electric heat pumps), (3) projections of reference emissions scenarios – used as benchmark, 4) 3 abatement scenarios are envisaged, with 3 different levels of investment.

A number of policy implications (and different options) are deduced from the outcomes of those scenarios. As regards the power sector in particular, the report gives a number of reasons that drive the need for a power market reform, and argues for long-term contracts for low-carbon capacity through competitive tendering.

2.2 Electricity Market Reform: Analysis of policy options: A report by Redpoint Energy in association with Trilemma UK

Redpoint and Trilemma UK have been commissioned by DECC to undertake a quantitative assessment of proposed packages of reform, using scenario modelling of investors' decision making under different policies options. The model is an agent simulation engine which intends to mimic investors' decision making in response to expectations of future revenues versus costs. It computes the risk-adjusted long-run marginal costs of all generation technologies by player type (Redpoint, 2010, p.132). Investors' future expectation of electricity prices is based on fuel prices, carbon prices, forward looking views of demand, forward looking views of capacity, no perfect foresight, but internally consistent. It captures forward expectations of revenues under the Renewable Obligation (RO) and new low carbon support such as different types of feed in tariffs (see definition in the next section 2.3).

The modelling exercise focuses on the power sector only and investor behaviour out to 2030, in other words on financial incentives under each of the options. The policy options were given by DECC, but their specific design is found by Redpoint through iteration so that they achieve the given carbon intensity (e.g. that the level of carbon support should rise to £50/tCO_2 in 2020 and £70/tCO_2 in 2030 to achieve carbon intensity of 100g/kWh). The figure of a carbon price rising to £70/tCO2 in 2030 and £135/tCO2 in 2040 follows DECC assumptions, which are stated in their latest Updated Energy Projections (UEP) of June 2010 (DECC, 2010d).

A baseline scenario is modelled under a set of assumptions summarized in the table below. The modelling does not take into account of other factors: resource potential, planning, connections and supply chain constraints. It is assumed that these issues will be addressed; however this can have a major impact on the realisation of policy objectives. Most of the baseline assumptions are used identically for the other scenarios. Specific additional assumptions or adjustments relating to each policy option are explicitly mentioned in the table below. In total, 5 different policy options to promote decarbonisation; 2 different options to enhance security of supply and 4 different policy packages are modelled.

The impact of decarbonisation policies on various aspects (pace & extent of decarbonisation, future generation mix, electricity prices, low carbon support payment, wholesale energy costs, plant profitability, resource costs, levels of security of supply, overall resource costs, costs benefit analysis) are explicitly discussed and supplemented by a qualitative assessment. Hence, a cost-benefit analysis (CBA) is conducted for each policy and policy package against the baseline. Note that the NPV analysis does not capture the costs and benefits of the options after 2030. Also, the Redpoint report stresses the fact that low-carbon investment is generally more expensive than conventional thermal plant under the baseline. This implies that options that meet decarbonisation target will typically have lower NPV, since there is no explicit penalty for missing targets (Redpoint, 2010, p.136). A sensitivity analysis is undertaken.

The impact of security of supply options on price volatility, security of supply, retirements, new build, wholesale energy costs and decarbonisation are discussed at the end of each policy/package option, and a CBA is conducted.

Figure 2.2 Redpoint key inputs and outputs

inputs (p.21 and 134)	outputs (p.134-5)
•fuel prices •supply curves •demand •max build rates •capital costs •financing costs •operating costs •--POLICY OPTION--	•CO2 intensity •generation mix •security of supply •resource costs (carbon costs, generation costs, capital costs) •costs to consumers •economic rent

2.3 EMR Consultation document

The consultation document introduces the 4 reform proposals: (1) Carbon Price Support, (2) Feed in Tariff, (3) Capacity Payments, and (4) Emission Performance standards, and poses a number of questions as regards each of the policies. The four main policies proposed are the following (see section 7 for a more detailed description of each of the policy options) (DECC, 2010b, p.5-6):

(1) *The carbon price support*: aims to create greater long-term certainty around the economics of plants from different technologies. The intention is to encourage investment in low-carbon technologies, as this would increase the cost of carbon-intensive generation relative to low-carbon generation, and hence make the latter more attractive.

(2) *Feed-in tariffs:* are long-term contracts that also seek to offer more certainty to low-carbon generators, in particular as regards the revenue. The government suggests implementing this through a contract for difference model, on the justification that this would provide more certainty to investors.

(3) *Capacity payments:* are targeted payments that reward generation capacity or demand reduction measures (“negawatts”), to ensure security of supply, including back-up generation as intermittent generation capacity expands.

(4) *Emissions Performance Standards:* will provide a back-stop to limit the carbon intensity of new power stations, to avoid the construction and operation of new highly polluting fossil fuel power stations.

Then, it reviews the objectives of government energy policy, including the latest legislation and important work on policy, including the latest Pathways analysis, which formulates a set of transition pathways to meet the 2050 targets. Three key objectives are stated: (1) to guarantee the security of supply, (2) decarbonisation, and (3) ensure affordability. The effectiveness of the market design reform policies proposals are judged against 4 principles: cost-effectiveness, durability & flexibility, practicality and coherence.

The report turns to current market arrangements in chapter 2. The liberalisation in the 1990s delivered the required levels of investment, but new challenges are coming up. As climate change has become a priority for government, a number of policies (incentives and regulations) have been added to the policy framework: the EU Emission Trading Scheme (EU ETS), the RO, the climate change Levy (CCL), public sector investment in Carbon Capture and Storage (CCS), feed-in tariffs (FIT), the Carbon Reduction Commitment (CRC) and the Green Deal (expected to enter into force in 2012). What the market has achieved and why reform is needed is discussed, and key determinants for achieving this are mentioned: (1) the economics of low-carbon generation, (2) the investment signals and (3) the financial requirements. The characteristics of low-carbon technologies and investment signals to ensure security of supply are reviewed – in particular the reasons for insufficient investment signals. This highlights the price uncertainties faced by investors.

The conclusion of this review is that the current market arrangements will not deliver. Hence, different options for decarbonisation are proposed and assessed in terms of NPV and a set of criteria.[8] DECC 2050 analysis shows that the power sector will need to be decarbonised. The Coalition Agreement set out 3 reforms: (1) carbon price support; (2) revenue support for low-carbon (ex. FIT) and (3) an EPS. The assessment provided in the consultation is hence based on DECC internal analysis, in conjunction with the HM Treasury work on the carbon support mechanism, based on Redpoint results, and seeks stakeholders' point of views on this.

2.4 DECC, estimated impacts of energy and climate change policies on energy prices and bills

The Estimated Impact of Energy and Climate Change Policies on Energy Price and Bills was published alongside the Annual Energy Statement produced by the Government in June 2010. This document presents DECC's latest assessment of impact of energy and climate change policies. The report updates the analysis that was previously published in July 2009, and covers those policies that are already in place or those that have been planned to a sufficient degree of detail (i.e. with quantified estimates of costs and benefits). The policies that were included in the analysis are the following: CESP, CERT, CERT Extension, Future SO, Better Billing, Smart Metering, Product Policy, RHI, Security Measures, EU ETS, RO, Extended RO, CCS, FIT, CCL, CRC, CCA. See box 3.1 for more detail.

The document uses Central price assumption from UAP ($80/bbl), but also presents impacts for $60/bbl and $150/bbl. Base retail prices (excluding policies) were projected to increase by 2020, based on wholesale price increases, as well as assumptions on transmission, distribution and metering costs, extrapolated from historical trends. Energy price increases in 2020 compared to prices in the same year without policies was the following: for the domestic sector, gas 18% higher, electricity 33% higher, while for the non-domestic (medium size) sector, gas was 24% higher and electricity 43% higher. The impact of policies on bills was less than on prices, because a range of policies were estimated to improve energy efficiency. Energy bills in 2020 compared to bills without policies were the following: domestic sector 1% higher, non-domestic (Medium Size) sector 26% higher. Besides the efficiency increase as a direct result of policies modelled, demand side response to higher bills was not taken into account.

In addition to presenting the impact on average bill, the document presented the results of a distributional analysis. Savings on bills will vary depending on which renewable or efficiency measures are taken and the physical characteristics of households. The analysis uses the DIMPSA model and datasets from Living Costs and Food (LCF) survey and English House Condition Survey to identify households that can take up renewable measures based on household and dwelling characteristics. The report estimates that households will see a 25% decrease in bills in 2020 if they take up both insulation and renewable measures (compared to bills with only supply side policies), and a 7% decrease in bills if they take only insulation measures. These take into account reduced

[8] The document argues that negative NPV are due to modelling limitations – which do not include benefits after 2030. The benefits/cost ratio improves significantly towards the end of this period.

energy consumption, but not the upfront financial costs or benefits from additional payments from the feed in tariffs (FITs) and the renewable heat incentive (RHI).

DECC EMR Impact Assessment uses the same models and the same methodology to assess the bill impact of the EMR policies. The final bill including existing policies in the July 2010 paper represents the baseline for EMR (see section 3 for more detail).

2.5 Ofgem Project Discovery

Ofgem Project Discovery starts by laying out a set of five concerns about the current state of energy markets. Then, it suggests a number of different options for reforming current arrangements. Among the concerns, Ofgem mentions (1) the need to finance large amounts of investments, in a difficult economic context; (2) the issues linked to carbon price uncertainty; (3) the lack of incentives for peak capacity investments; (4) the political risks in relation to international gas supply; and (5) concerns around fuel poverty and the adverse impact of higher prices on businesses. The report examines a number of scenarios for the future out to 2025, summarised in Table 2.1.

The report then proposes five different options for reform. They range from Option A - "Targeted Reforms" - which proposes to adjust the current market through the establishment of a minimum carbon price, incentives for demand-side response and improved short-term price signals, to Option E which proposes the establishment of a Central Energy Buyer, where a single entity would buy all energy and capacity required. Option B - "Enhanced Obligations" - adds requirements on suppliers and the system operator as regards security of supply and a centralised renewable market to Option A. Option C "Enhanced Obligations and Renewable Tenders" is an extension of Option B, where tenders for renewables replace the RO. Option D "Capacity Tenders" extends Option C to include tender auctions for all new capacity. Ofgem conclude that doing nothing is not an option and that some change to the current arrangements is necessary, however it does not specify exactly what combination of the suggested reform options it prefers.[9]

Table 2.1 Ofgem Project Discovery scenarios

		Economic Recovery	
Environmental Action		Rapid	Slow
	Rapid	Green Transition	Green Stimulus
	Slow	Dash for Energy	Slow Growth

Source: Ofgem (2009)

2.6 Ofgem Energy Supply Probe (2008) and Retail Market Review (2011)

Consumer activity is considered as a key driver of competition for the retail market. This motivated Ofgem to launch, in November 2010, a review into the state of GB energy retail market. This review builds on the findings of the 2008 Energy Supply Probe (Ofgem, 2008). This 2008 review was conducted in the context of escalating global fuel prices that led to substantial increases in wholesale and retail energy prices. By then, households' energy bills had doubled since the beginning of the 2000s, with very strong adverse consequences on vulnerable households, and a significant increase in the number of households in energy debt, and a growing number of

[9] This section draws on Pollitt (2010a).

disconnections. The Supply Probe proposed a number of measures: (1) promotion of more active consumer engagement; (2) helping consumers to make well-informed choices; (3) reduction of barriers to entry and expansion; (4) help for small business consumers; and (5) reduction of unfair price differentials.

The recently published Retail Market Review (Ofgem, 2011) provides the findings and initial proposals aimed at ensuring consumers' engagement and restricting the ability for suppliers to make higher margins from some customer groups. Among the main findings, Ofgem lists a number of aspects (Ofgem, 2011, p.5) which act to weaken competition in the retail market and hence, lead to potential consumer harm: (1) high concentration in regional markets, where incumbents – the so-called Big 6 – are predominant; (2) market segmentation and stickiness that might provide unfair advantage to incumbents and lower new entry; (3) lack of transparency; and (4) evidence of convergence in pricing strategies. This led Ofgem to make a set of proposals. As regards the residential market, Ofgem will seek to enhance tariff comparability and restrict the number of the so-called "standard evergreen products" (i.e. products that do not tie consumers into a fixed-term). This would make it easier to compare the suppliers' "per unit" price.[10] Perhaps the most striking proposal seeks to enhance market liquidity. A change to their licence condition would oblige the Big 6 to make available between 10% and 20% of their own generation through a regular mandatory auction. This Mandatory Market Making (MMM) would guarantee market access for non-integrated suppliers. The review also shed light on the patchy performance against its 2008 Energy Market Supply Probe recommendations.

2.7 Commentary on modelling and consistency of assumptions

Each document has different objectives and methodologies. Redpoint models investors' decision making under different policy frameworks. Demand is given as an input in the model. There is no modelling of consumer behaviour, and the demand-side is fixed by assumption. By contrast, the CCC's Fourth Carbon Budget Report has a much wider perspective and models the whole economy. CCC's modelling looks at interactions between variable supply and variable demand, defines different abatement scenarios, and advises on preferred routes.

The assumptions used in each of the documents have been examined for internal consistency. It appears that except for Ofgem's Project Discovery (which uses Ofgem's owns assumptions), most of the assumptions used come from the (DECC, 2010d) which includes the central case assumptions for fossils fuel prices, and Mott MacDonald's analysis of technology costs. Also, there seems to have been a certain level of coordination between the CCC, DECC and Redpoint, as at least some of the assumptions (if not all) used in the sensitivity analysis are based on CCC advice (for example the higher demand levels). Hence, the assumptions used reveal an internal consistency.

Across all the documents there is an underlying assumption of accelerated progress towards meeting the UK's renewable energy targets. All the Redpoint scenarios fix renewable electricity share at 29% in 2020 (and assume 35% by 2030). There is little, if any, analysis of a more realistic scenario which would project the current rate of progress with renewable electricity deployment.

[10] This is expected to have a major impact, as 75% of customers are currently on such tariffs (Ofgem, 20011, p.7). To ensure innovation, Ofgem still wants to leave suppliers free to offer fixed-term products.

3 Projections of household bills under different policy scenarios

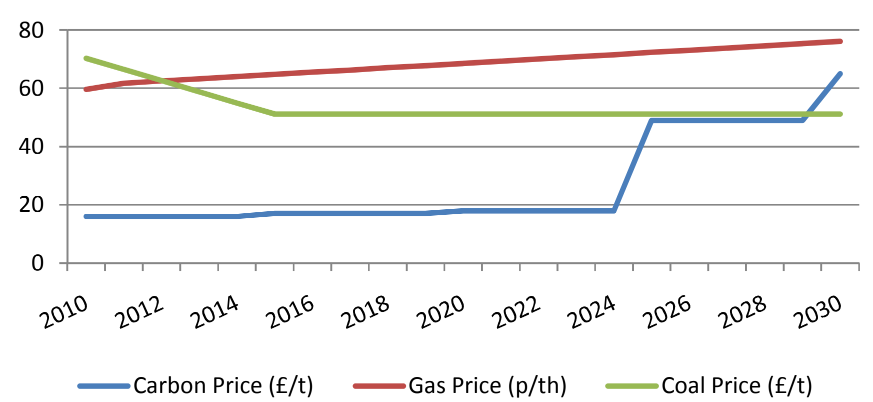
This section looks into the details of calculating the consumer bill impact of various policies proposed by the EMR. In particular, it will explore the inputs and assumptions used in the Redpoint model to produce the estimates of the electricity wholesale electricity prices for the years 2010-2030. Next, it will look at how the DECC (2010) EMR-Impact Assessment (EMR-IA) modelling uses Redpoint wholesale electricity price projections to estimate consumer bills under various scenarios. In doing so, the section will explore additional assumptions that the DECC EMR-IA makes to do the consumer bill impact projections, and how these assumptions relate to the projected electricity bill from the DECC July 2010 report (2010d).

3.1 Fossil Fuel and Carbon Prices

The Redpoint energy model takes as inputs DECC Central Assumptions for Fossil Fuel Prices and Carbon Prices (EU Allowances) 2010-2030. The fossil fuel price assumptions are derived by DECC based on global market considerations and comparison with projections from other organisations such as International Energy Agency (DECC, 2010d). These fossil fuel price assumptions were last updated in May 2009. Fossil fuel projections were reviewed in January 2010 but not changed, while carbon price assumptions were updated in June 2010. The fossil fuel and carbon price assumptions attempt to capture different demand and supply patterns through four scenarios: Low (low global energy demand), Central (timely investment and moderate demand), High (high demand and producer's market power) and High-High (High demand, significant supply constraints).

These assumptions are not forecasts or predictions, and DECC recommends that policymakers use all four scenarios for sensitivity analysis (DECC, 2010d). While all policy proposals were modelled using central gas assumptions, in addition, stress tests for some policy scenarios were conducted under high gas and low gas price scenarios, and low carbon price scenarios. However, it is worth stressing that sensitivity analysis for low/high gas price scenarios or a low carbon price scenario was not conducted for the DECC preferred EMR policy option: the combination package consisting of four components: Contracts for Differences (CFD), Carbon Price Support (CPS30), Targeted Emissions Performance Standards (EPS), and Targeted Capacity Tender (TCT). Figure 3.1 displays fossil fuel and carbon price central assumptions.

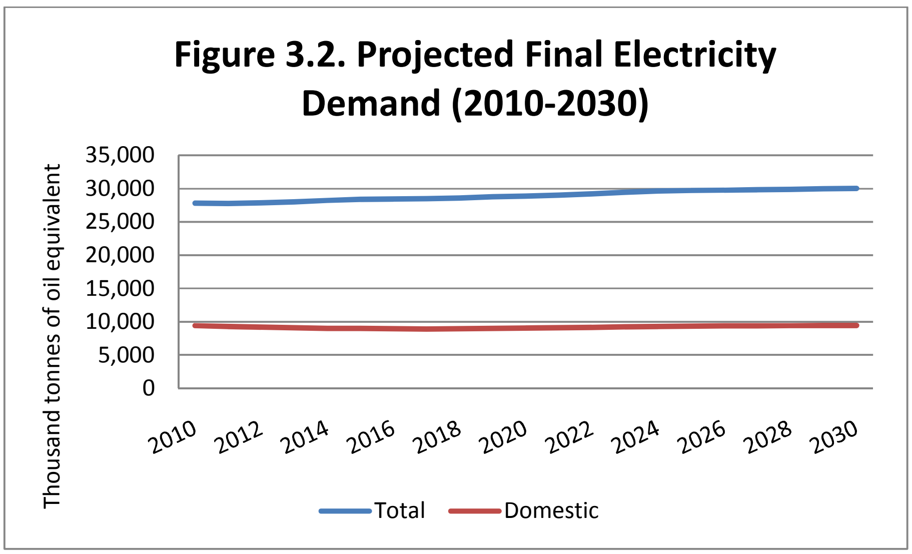
Figure 3.1. Central Fuel and Carbon Price Assumptions



Source: DECC (2010 UEP, Annex F)

3.2 Final Aggregate Electricity Demand

Besides fossil fuel and carbon prices, Redpoint wholesale electricity modelling also takes as an input DECC's central final electricity demand projections. Demand projections are published in DECC's Updated Energy and Emissions Projections (DECC, 2010d), and are based on the fossil fuel assumptions and include the effect of policies that are part of the Low Carbon Transition Plan (LCTP) (DECC, 2009). Central Demand is projected to be fairly flat in years 2010-2030. The aggregate demand used in Redpoint model is held constant across policy scenarios modelled, but slightly varies by year (Figure 3.2). Therefore the long-term assumed price elasticity of the demand is zero. Demand for any particular year does not change in the sensitivity analysis for low and high gas prices, or the low carbon price scenario – even as the prices change. There was sensitivity analysis done for two lead EMR policy packages (CFD+CPS30+EPS+TCT) and (PP+CPS30+EPS+TCT) for the high demand scenario. However there was no sensitivity analysis for the low demand scenario, and there was no demand sensitivity analysis performed for the rest of policy options.



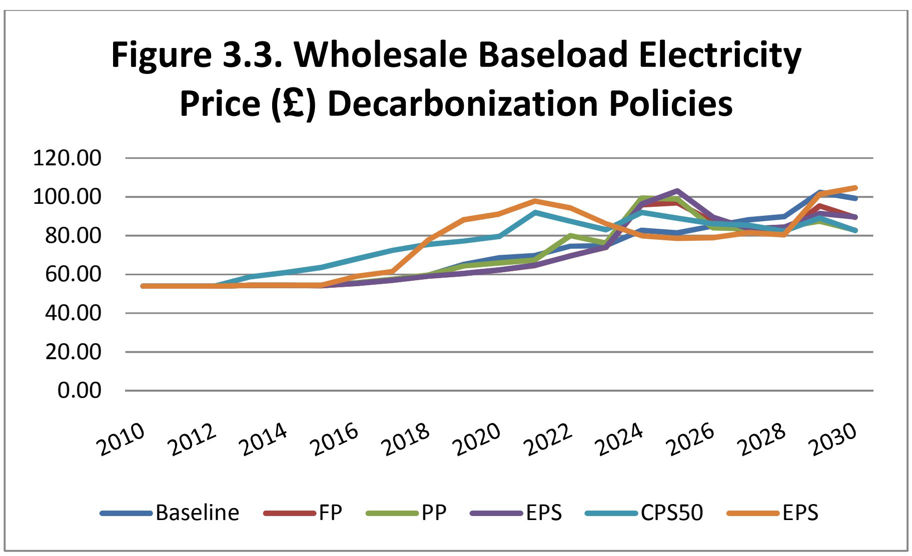
Source: DECC (2010 UEP, Annex C)

3.3 Final wholesale electricity prices and costs

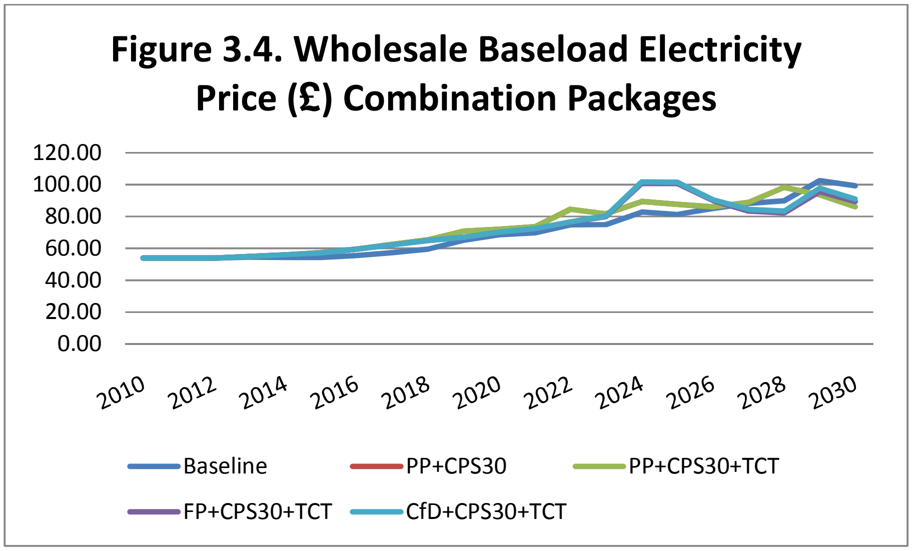
Wholesale electricity prices are endogenous to the Redpoint model. Wholesale electricity prices and net support costs result from modelling investment decisions. Electricity prices together with net support costs (costs of the policies modelled) comprise wholesale costs. Both wholesale electricity prices and net support costs are different across the scenarios, and depend on the policies that are included in the particular scenario.

When Redpoint models the baseline wholesale electricity price scenario, net support costs of some existing government policies are included. The costs included are for Renewable Obligations (RO), the Large Combustion Plant Directive (LCPD) and the cost of four carbon capture and storage (CCS) demonstration plants. The bulk of net support costs in the baseline scenario is for the cost of the RO to reach 29% renewable electricity by 2020 and 35% by 2030. Most of these policies are also included in net support costs when modelling the impact of new policies. As such, new policies modelled are in addition to the current policies, rather than replacing them, with the exception of the RO. In the packages where specific support for low carbon generation is introduced, the RO is closed to new entrants from 2014 in the Redpoint model and the support for existing generation under the RO is grandfathered. All new renewables are subject to the new support mechanism after 2014. The 2020 and 2030 renewable electricity (RES-E) targets are the same under all packages to make their costs comparable. It is also worth noting that Renewable Obligation Certificate bands are adjusted upwards to meet renewable energy targets (Box 3.1) in the baseline scenario. Therefore the baseline scenario is not a Business-as-Usual scenario, but rather a "beefing" up the existing policies to meet a target for renewable electricity. While the baseline achieves targets for renewable electricity, it does not meet decarbonisation objectives (carbon intensity of 100gCO2/kWh by 2030).

The costs and effects of other existing policies are not explicitly taken into account. However, as the effect of the current Low Carbon Transition Plan (LCTP) policies (i.e. CERT, CESP, etc) is included in the demand projections, their demand effect is implicitly included. Figures 3.3 and 3.4 present the modelled wholesale baseload electricity prices under different policies. Prices are comparable across the policies, with the exception of CPS50 and EPS, because renewables are the same across scenarios, as all scenarios reach the same renewable electricity targets. CPS50 and EPS are more expensive than the rest of the policies untill early 2020s, because fossil fuel generation puts upward pressure on prices in the case of CPS50, and a strong EPS requires generation from more expensive fuel sources instead of coal. As the carbon intensity of the system diminishes, the price under these policies also goes down. Overall, as the system decarbonizes in the 2020s, the price under the policies falls below the price under the baseline scenario.



Source: Redpoint (2010, p. 59)



Source: Redpoint (2010, p. 112)

3.4 Household electricity bills

DECC EMR-IA analysis takes the resulting Redpoint wholesale prices in order to calculate the bill impact of EMR. The baseline household bill in the EMR-IA is similar to the final electricity bill with policies in the DECC July 2010 report. Exact bills between the two documents may differ because underlying wholesale prices are projected by different models. DECC July 2010 report uses the DECC Energy Model for projecting wholesale electricity prices, while EMR-IA uses the Redpoint model. Retail prices paid by consumers are the combination of wholesale electricity prices, transmission and distribution charges, supplier margins and VAT.

3.4.1 Transmission and Distribution, Metering, VAT, Supplier Margins

The transmission and Distribution (T&D) costs used by DECC EMR-IA are from Ofgem historical data for T&D costs over the last 10 years. They are projected forwarded using the same time-trend, consistent with Ofgem advice given to DECC. As a result, T&D costs rise over time. Metering costs are unchanged over time and consistent with data provided by Ofgem. These costs are unchanged across all EMR scenarios. Overall, T&D costs are rising by about 2% p.a. Supplier costs and margins, as well as VAT (5%) are kept the same across EMR policies and over time. These costs are the same in all the Redpoint scenarios, because they are driven by the share of renewables in electricity. Even though the exact timeline of renewable generation deployment may vary between policies, trajectories of renewable output are similar across all policies. All policies reach the same renewable targets, with the same share of renewables in 2020 (29%) and 2030 (35%). A lower share of renewable electricity, by reducing the need for transmission and distribution investment would result in lower than projected bills.

In Project Discovery, Ofgem (2009b) gives higher annual increase rates for T&D. In that analysis, Ofgem looked at prospects for secure and sustainable energy supplies over next 10-15 year and drew four scenarios for possible outcomes during the next decade and beyond. Consumer bills were estimated under these four projections, and included estimation of T&D. T&D charges increased by approximately 5% p.a. for these four scenarios. If T&D charges in the EMR-IA analysis grew at the rates consistent with the Project Discovery assumptions, final bill would have been £27 higher in 2020, and £85 (17% of the 2010 bill) higher in 2030 than in the EMR-IA.

3.4.2 Average Household Electricity Demand

While aggregate electricity demand is mostly flat 2010-2030 (Figure 3.1), electricity demand at the individual household level is going down. Aggregate demand does not fall because of an increase in the number of the households, and because consumption rises in the industrial and commercial sectors (I&C). I&C consumption is subject to fewer energy efficiency policies and would be rising because of economic growth.

Household level demand decreases over time, as a result of the policies that are included both in the baseline and EMR policy scenarios. In particular, demand is assumed to decrease as a direct result of the following policies (See Box 3.1 for more detail):

- Community Energy Saving Programme (CESP)
- Carbon Emission Reduction Target (CERT)
- CERT Extension
- Supplier Obligation consistent with the Household Energy Management Strategy (SO)
- Better Billing
- Smart Metering
- Products policy

Box 3.1: Major Policies Included in Low Carbon Transition Plan

Community Energy Saving Programme (CESP)

CESP is an obligation on energy suppliers and some power generators to deliver lifetime savings of 3.9MtCO2 through the introduction of carbon-abatement measures in low income households. These measures include insulation and replacement of inefficient heat-sources.

Carbon Emission Reduction Target (CERT)

This was administered by Ofgem E-serve 2009 - 2011. It is an obligation on domestic energy suppliers to deliver reductions in carbon emissions. Suppliers can deliver this through energy-saving measures, such as insulation, low energy lighting, advice and visual display units. The scheme levies a charge on suppliers on a per-consumer basis. Savings from CERT measures are estimated to accrue in the following years.

CERT Extension

CERT extension replaces CERT, and runs 2011-2012.

Supplier Obligation consistent with the Household Energy Management Strategy

Future likely continuation of the CERT extension beyond 2012.

Better Billing

Since 2009, suppliers are required to include on bills comparisons of energy used during the previous year. This increased information feedback is estimated to reduce energy consumption.

Smart Metering

Government has committed to the roll-out of smart meters to all households by 2020. Smart meters are expected to provide savings on electricity consumption through improved information feedback.

Products Policy

Product Policy is EU policy enforced by Defra. It ensures minimum standards and labelling in order to improve energy efficiency and uptake of energy efficient products.

Renewable Obligations (RO)

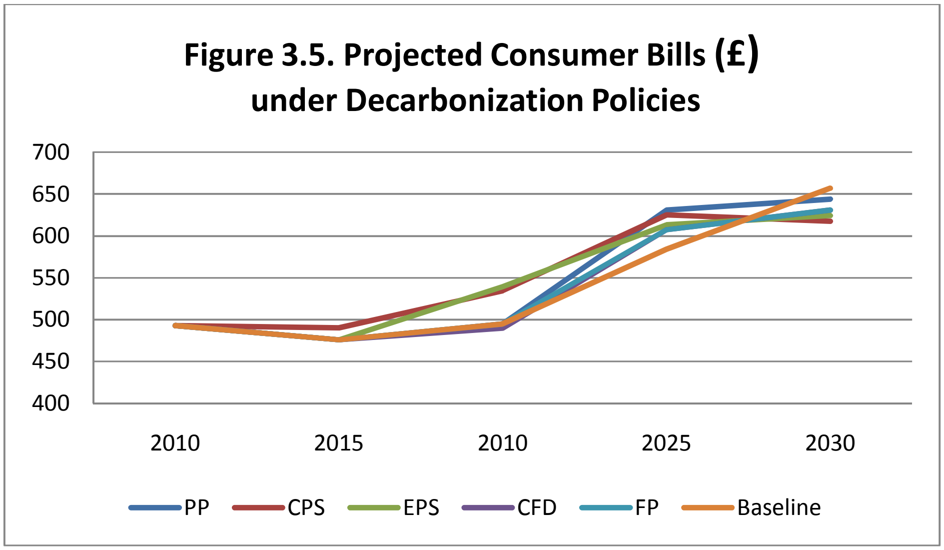
This is the specific requirement for suppliers to source a certain proportion of electricity from renewable generation, or pay a buyout fee. The buyout fee revenue is recycled to suppliers in proportion to the renewable electricity they supplied. Renewable generators are issued Renewable Obligation Certificates (ROC), which they can sell to supplier. Suppliers present these certificates to Ofgem to prove compliance with the obligation. Through ROCs, renewable generators in essence get paid premium on top of the wholesale price of electricity that they sell. In 2009 the government introduced a banding of certificates, through which generators get different numbers of ROCs per MWh of electricity generated, depending on the type of technology used.

Source: Ofgem (2010, p.91), DECC (2010d, p.17)

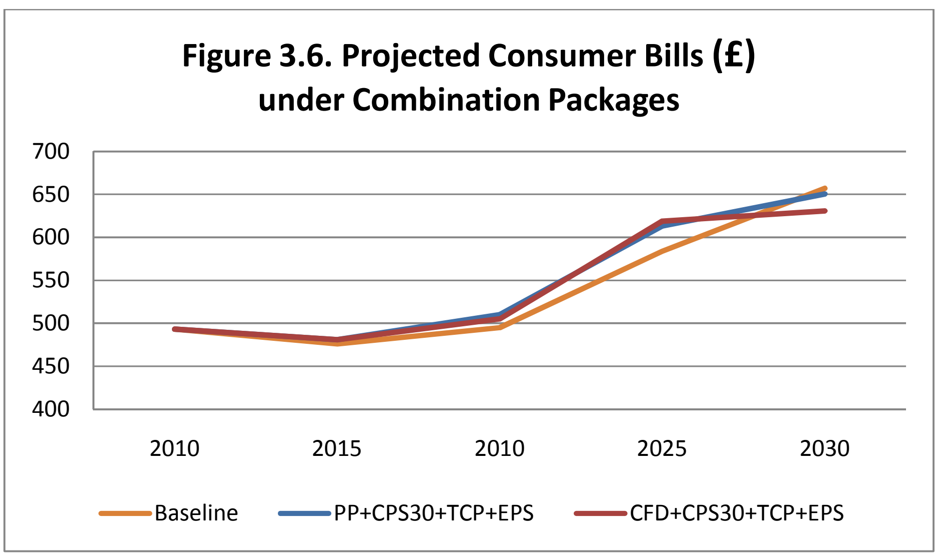
These measures result in a 10% decrease in household electricity demand from 2010 to 2030, equivalent to a 0.5% reduction p.a. Therefore, when looking at the impact of the scenarios on the projected bill, it is important to keep in mind that the baseline consumption (MWh per household) decreases over time, but that demand assumptions are held constant across scenarios modelled.

The decrease in demand varies over time. The ambition for CERT, CERT Extension and Product Policy in particular falls from the early 2020s (Box 3.1). This is because measures delivered as a result of CERT and CERT Extension are assumed to reach the end of their life-cycle and are not replaced (through the EMR policies). The Supplier Obligation delivers measures after these policies end, but these deliver slightly lower savings in electricity than the policies mentioned above. For Products Policy, the uncertainty surrounding savings post 2020 means that the estimates of savings from this policy become more conservative post 2020. As a result, although it is expected that current policies will deliver savings over the period 2020-2030, these savings are assumed to be less than the savings delivered over 2010-2020. This means that final household consumption falls to the early 2020s and starts to rise slightly again towards 2030. There is no assumption of domestic demand side response (DSR) to higher prices, and essentially the long run price elasticity of average domestic consumer is zero (beyond demand reduction specifically stemming from the existing policies modelled).

The EMR estimates that the domestic consumer bills are projected to rise 33 per cent by 2030 (even after they take costly demand reduction measures), while business bills are predicted to rise by 62 per cent by 2030. Figures 3.5 and 3.6 present projections of electricity bills under decarbonisation and combination packages. The final electricity bill in 2010 is £493. Note that these are real 2009 prices. According to EMR-IA, the bill in 2020 is 2% higher than it would have been under the baseline, but 4% lower in 2030 than it would have been in the baseline.



Source: DECC (2010 EMR-IA, p. 81)



Source: DECC (2010 EMR-IA, p. 92)

4 What consumers will be getting in the EMR

Here, we discuss what consumers will be getting according to the EMR-IA in the government's preferred package, in terms of the three main objectives of UK energy policy: sustainability, security and affordability. All policy options considered in the EMR area able to meet the government's own renewable electricity (RES) targets. These targets are 29% of electricity generated by renewables by 2020 and 35% by 2030, as per the UK Renewable Energy Strategy (HM Government, 2009) and the carbon intensity of 100gCO2/kWh by 2030, as suggested by Committee of Climate Change (2010).

Government believes that the lead package is the combination package of Carbon Price Support (CPS30), Contracts for Differences (CFD), Emissions Performance Standards (EPS) and Targeted Capacity Tender (DECC, 2010a). Here, we discuss what the consumers will be getting through this package.

4.1 Welfare Impact

Table 4.1 presents the welfare change[11] as a result of the government's preferred option relative to the baseline, both under central and high demand scenarios. The table shows the net welfare loss for the all consumers under the central case, as having a net present value (NPV) of £9,728 million in real 2009 prices. The share of domestic consumer welfare loss under the central case is £3,092 million. This is based on 32% of the final aggregate electricity demand for domestic consumers in the Central and High projections. Domestic consumer's welfare loss under the high demand scenario has an NPV of £10,264 Million. The welfare loss per household is roughly equal to NPV of £122 or annuity of £9 for 20 years (number of households in 2009 was estimated as 25.2 million by the UK Office for National Statistics). The welfare loss is due to the higher wholesale prices in the policy modelled, compared to the baseline. As was noted in the section 3.3, the baseline scenario in the Redpoint Model differs from Business-as-Usual in that Renewable Obligation bands are adjusted upwards, making sure that renewable targets are met, increasing net support cost in the baseline. Therefore, a cost-benefit analysis of the policies compared to the Business-as-Usual scenario would result in even higher reduction of welfare. The impact of policies beyond 2030 is not accounted for. In as much as the larger share of renewables beyond 2030 results in lower consumer prices, some of the welfare losses would be recouped.

Unfortunately the Redpoint report does not include a cost-benefit analysis of the preferred policy package for the low demand scenario, or for high or low fossil fuel and carbon prices. For instance, we would expect that in the low gas price scenario, EMR policies, including the preferred option, would have higher welfare losses compared to business as usual, as the larger share of renewable and nuclear would prevent the economy from taking more advantage of cheaper gas. That a future outcome in which gas prices are low is a real possibility is suggested by Redpoint Analysis for the Energy Networks Association (Redpoint, 2010a). This analysis considers four hypothetical possibilities based on the main drivers that determine future gas utilization. For each of these scenarios, Redpoint considers baseline commodity price trajectories. Two out of these trajectories assume that gas prices increase from 2010 to 2030, reaching 55p/therm in 2030. The third scenario assumes prices will be flat (40p/therm) from 2010 to 2030. Only under the scenario called "Electrical Revolution" do the gas prices reach 80p/therm in 2030, only to decrease again to 50p/therm in 2050. Redpoint (2010a, p.6) finds that "there are credible and robust scenarios in which gas could play a major role in the GB energy mix". By comparison, under the DECC Central assumption, gas prices reach 76p/therm in 2030.

[11] Note that the term 'welfare' refers to social or societal welfare.

Table 4.1 Welfare Change of the Government's Preferred Scenario Compared to the Corresponding Baseline

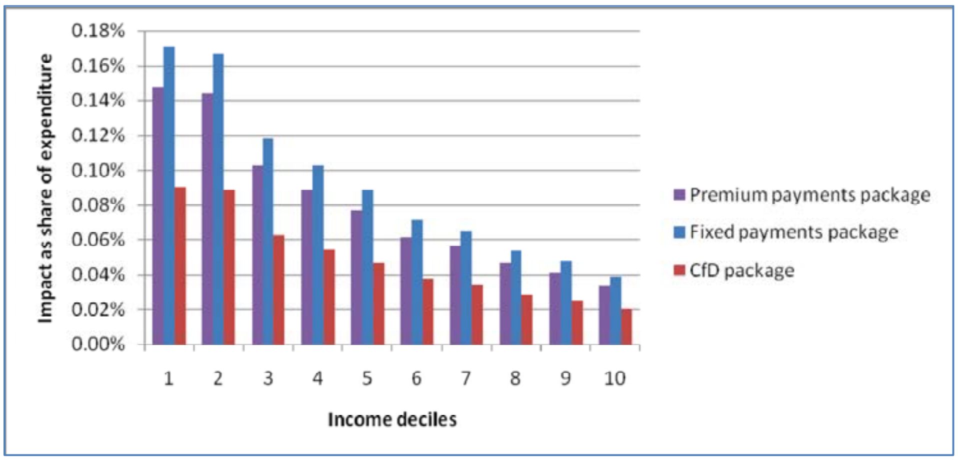
Change in welfare NPV 2010-2030, (£m 2009 real)		Central Demand £m	High Demand £m
Net Welfare	Carbon costs	11,516	12,879
	Generation costs	7,655	8,135
	Capital costs	-23,973	-14,476
	Unserved energy	198	121
	Demand side response	-18	-45
	Change in Net Welfare	**-4,622**	**6,615**
Domestic Consumer Surplus	Wholesale price	-5,169	-9,969
	Low carbon payments	2,372	178
	Capacity payments	-374	-497
	Change in Domestic Consumer Surplus	**-3,113**	**-10,264**
Industrial Consumer Surplus	Wholesale price	-11,077	-21,208
	Low carbon payments	5,084	379
	Capacity payments	-802	-1,058
	Unserved energy	198	*121*
	Demand side response	-18	*-45*
	Change in Industrial Consumer Surplus	**-6,615**	**-21,810**
	Change in Total Consumer Surplus	**-9,728**	**-32,074**
Producer Surplus	Wholesale price	16,152	31,154
	Low carbon support	-7,374	-580
	Capacity payments	1,169	1,554
	Producer costs	-14,737	-4,010
	Change in Electricity Producer Surplus	**-4,790**	**28,118**
Government Surplus	**Change in Government Surplus**	**9,896**	**10,571**

Source: Redpoint (2010, p. 123)

4.2 Distributional Analysis

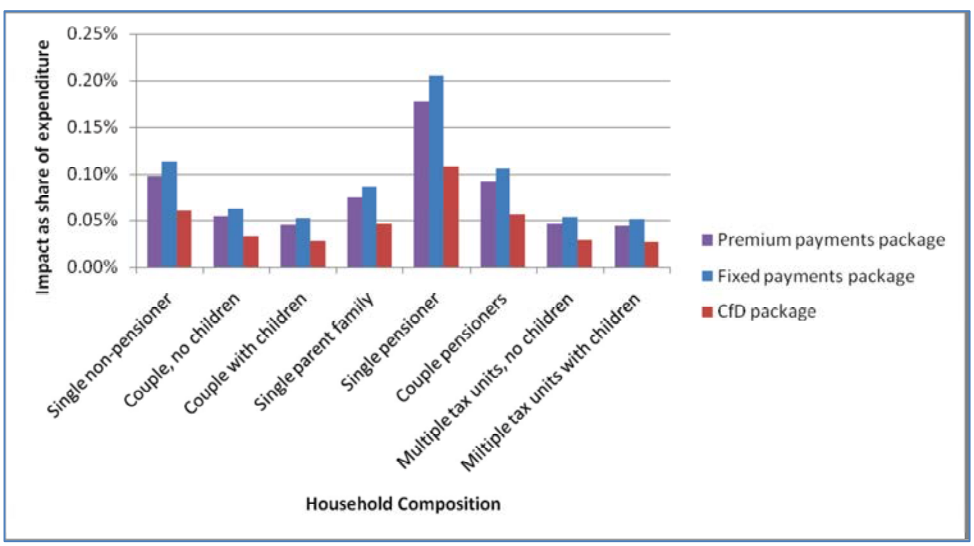
An increase in electricity prices can have disproportional impact on low-income households (DECC, 2010). Even if an increase in the domestic bill may be lower in terms of absolute size for a poorer household, this increase may constitute a higher share of household monthly expenditure. In addition, some vulnerable households maybe affected worst (see section 8.6). The results of the distributional analysis of EMR-IA are presented in figures 4.1 and 4.2. “CFD package” in the figures refers to the government’s preferred package (CFD+CPS30+EPS+TCM). Figure 4.1 indicates that the households in the lowest expenditure decile are affected the most, in terms of share of overall expenditure, including the under the preferred option (“CfD package” on the graph). Figure 4.2 indicates that in terms of increased share of overall expenditure, the hardest hit are single pensioners. These effects are calculated under central assumptions and relative to the baseline (not business as usual).

Figure 4.1 Impact of Policy Packages on Expenditure across Income Deciles in 2020



Source: Electricity Market Reform Impact Assessment, DECC, 2010, p.93.

Figure 4.2 Impact of Policy Packages on Bills in 2020 across Households



Source*:* DECC (2010, p.93).

4.3 Indirect Impact of Policies

The overall impact on the economic welfare of domestic consumers will be a combination of the spent income effect and the factor income effect. The spent income effect results from changes in the prices for the goods and services consumed (electricity and goods that require electricity), while the factor income effect results from incomes of consumers being affected as a result of changes in all prices throughout the economy (Metcalf, 2011; Metcalf 2009). Analysis of the economy-wide direct and indirect effects is normally done in General Equilibrium framework, or using input-output tables and social accounting matrix. Neither Redpoint, nor DECC EMR-IA take indirect impact into account.

4.4 Renewables

Even though under Redpoint modelling the baseline policies are able to meet the renewable targets, this is achieved in the model through ramping up the renewable obligation bands. In reality, the renewable obligations are unlikely to be met through a mere beefing up of current policies alone, or that EMR will indeed deliver more renewables.

National Grid projects the renewables in their 7 year plan (National Grid, 2009). In addition, National Grid estimates the range of offshore wind scenarios for the period 2010 – 2025. These estimates were made under three scenarios: Slow Progression, Gone Green and Strategic Environment Assessment Extended (SEA+). Off-shore wind generation is 35GW under the most optimistic scenario, but only 10GW under the Slow Progression Scenario. This indicates that there is a significant doubt about whether enough renewables can actually be delivered to meet the baseline renewables target.

4.5 Decarbonisation

While EMR will deliver more renewables, whether it will decrease global emissions reductions is debatable. In particular, under the EU ETS, if emissions in the UK power sector decrease, this will leave more permits to be used by other EU countries. Therefore, decreased emissions in the UK will lead to higher emissions in the rest of the EU. Since the aim of decarbonisation is to deal with the Climate Change, it is the reduced global carbon emissions that ultimately makes a difference.

Completely undermining EU-ETS is another potential problem of EMR. If the EU ETS carbon price drops, this seems likely to undermine the credibility of carbon pricing across Europe and make future coordinated action against climate change less likely. This possibility is not discussed in the EMR documents.

Inconsistency in carbon pricing across the EU also endangers decarbonisation prospects. If the carbon price is considerably higher in the UK compared to the EU ETS, expanding interconnections to the continental Europe may become commercially viable (HM Treasury, 2011). The EMR may then lead to increased imports from the rest of EU simply on the basis of carbon price distortions, increasing the carbon content of total UK imports and undermining the EMR as a policy for reducing the UK’s contribution to climate change.

4.6 Energy Security

The proposed EMR package delivers energy security via a targeted capacity tender. Energy security is not currently an issue in the UK, but could become more of an issue once renewables comprise a higher share of electricity generation. However, even so, the net welfare of the preferred package is negative compared to the same package without the capacity tender under the central scenario (Table 4.2).

Table 4.2. Welfare Change of the Government's Preferred Scenario Compared the Policy without Targeted Capacity Tender

Change in welfare NPV 2010-2030, (£m 2009 real)		Central Demand
Net Welfare	Carbon costs	1,879
	Generation costs	-3,135
	Capital costs	132
	Unserved energy	463
	Demand side response	5
	Change in Net Welfare	**-657**
Domestic Consumer Surplus	Wholesale price	-5,364
	Low carbon payments	2,232
	Capacity payments	-374
	Change in Domestic Consumer Surplus	**-3,356**
Industrial Consumer Surplus	Wholesale price	-11,503
	Low carbon payments	4,714
	Capacity payments	-810
	Unserved energy	463
	Demand side response	5
	Change in Industrial Consumer Surplus	**-7,131**
Total Consumer Surplus	**Change in Total Consumer Surplus**	**-10,488**
Producer Surplus	Wholesale price	16,763
	Low carbon support	-6,940
	Capacity payments	1,169
	Producer costs	-11,026
	Change in Producer Surplus	**-68**
Government Surplus	***Change in Government Surplus***	***9,899***

Source: Redpoint (2010, p. 113)

4.7 Cost of Capital and Risk

One of the key objectives of the EMR is the reduction of the cost of capital through the reduction of uncertainty for investors in low carbon generation. One benefit of giving generators higher certainty over revenues is through reduced hurdle rates for generation projects. Hurdle rates are the minimum rates of return that the project needs in order to cover all financing costs (DECC 2010, p. 69). The Redpoint analysis does not give details of how the government's preferred combination package affects various sources of risk. However, the Redpoint analysis does mention how each of the policies within the package affects the various sources of risk on its own. Under the assumption that these effects will be cumulative in the combination package, table 4.3 presents how the government's preferred package affects investor's risk. As indicated in the table EMR reduces risk for nuclear projects.

Indeed, de-risking of nuclear investment represents a big part of the source of EMR savings from CFDs. Redpoint analysis does not present how the combination package will affect the hurdle rate of various types of generation investments. However changes for hurdle rates are presented for the CFD and CPS50 policies. These estimates are presented in table 4.4, and can be seen as indication as to how the combination package will affect the hurdle rates. The highest reduction in the hurdle rates under the CFD option is for the nuclear (decrease by 2%). Table 4.5 presents information on new builds of CCS and nuclear projects under the preferred package, compared to the baseline. The first new nuclear build is estimated to appear in 2019 under the CFD package, versus 2027 in the baseline. By 2030, estimated nuclear new build under the CFD package is 9.6 GW, compared to 6.4 GW in the baseline. The 2% saving in the private cost of capital reduces the social cost of nuclear plant by 5%, under a social discount factor of 3.5% used by DECC IA (2010). These savings are worth around £1.5bn on 9.6GW of nuclear investment.

It is important to note that even if the costs of risk are reduced for investors, they do not disappear, they are simply shifted to the government – and by extension to consumers. Therefore, ultimately, it is consumers who will bear the cost of risk. Essentially EMR shifts cost risk to consumers and commits them to a certain amount of nuclear and renewables. Through a higher share of renewable and nuclear generation consumers may gain insurance against high gas prices, but they do not benefit if gas prices are low.

In addition, EMR introduces new sources of risk arising from government failure. These risks arise from unclear governance of the EMR and the potential failure to set appropriate levels for CFD contracts and the amount of capacity tendered. These risks are ultimately borne by consumers. Specific policy-related risks are discussed in detail in section 7.

Table 4.3.Impact of the Government's Preferred Package on Investment Risk

Source of Risk	**CCGT**	**Nuclear**	**CCS**	**Wind**	**Biomass**
Fuel Cost	Risk Unchanged	Risk Unchanged	**Risk Reduced**	Risk Unchanged	**Risk Reduced**
Carbon Cost	Risk Unchanged	Risk Unchanged	Risk Unchanged	Risk Unchanged	Risk Unchanged
Electricity Revenues	**Risk Reduced**	**Risk Reduced**	**Risk Reduced**	**Risk Reduced**	**Risk Reduced**
Support Level	Risk Unchanged	**New Support**	**New Support**	**Risk Removed**	**Risk Removed**
Load Factor Risk	**Risk Reduced**	**Risk Reduced**	**Risk Reduced**	Risk Unchanged	**Risk Reduced**

Source: Redpoint (2010, p. 33, 45, 87)

Table 4.4.Impact of the CFD and CPS50 on Investment Hurdle Rates

		Hurdle Rate			Change in Hurdle Rate	
		Baseline	CFD	CPS50	CFD	CPS50
Typical Utility	CCGT+CCS	12.1%	11.7%	11.6%	-0.40%	-0.50%
	Coal+CCS	12.10%	11.70%	11.60%	-0.40%	-0.50%
	Onshore wind	8.10%	7.80%	8.10%	-0.30%	0.00%
	Offshore wind (R1/R2)	10.10%	9.60%	10.10%	-0.50%	0.00%
	Offshore (R3)	12.10%	11.50%	12.10%	-0.60%	0.00%
	Biomass	12.10%	11.40%	12.10%	-0.70%	0.00%
Independent Developer	CCGT+CCS	13.30%	12.50%	12.50%	-0.80%	-0.80%
	Coal+CCS	13.30%	12.50%	12.50%	-0.80%	-0.80%
	Onshore wind	9.10%	8.10%	9.10%	-1.00%	0.00%
	Offshore wind (R1/R2)	11.20%	10.00%	11.20%	-1.20%	0.00%
	Offshore (R3)	13.30%	12.50%	13.30%	-0.80%	0.00%
	Biomass	13.30%	12.50%	13.30%	-0.80%	0.00%
Nuclear Developer	Nuclear	13.20%	11.20%	12.70%	-2.00%	-0.50%

Source: Redpoint (2010, p. 50)

Table 4.5. Indicative New Build Profile under Government's Preferred Option, Compared to the Baseline

	Baseline	CFD+CPS30+EPS+TCM
Year of First Nuclear	2027	2019
New Nuclear capacity (GW by 2030)	6.4	9.6
New CCS capacity (GW by 2030)	0	7
Retrofit of CCS Demos (GW by 2030)	0	2.2

Source: DECC (2010, IA p.89)

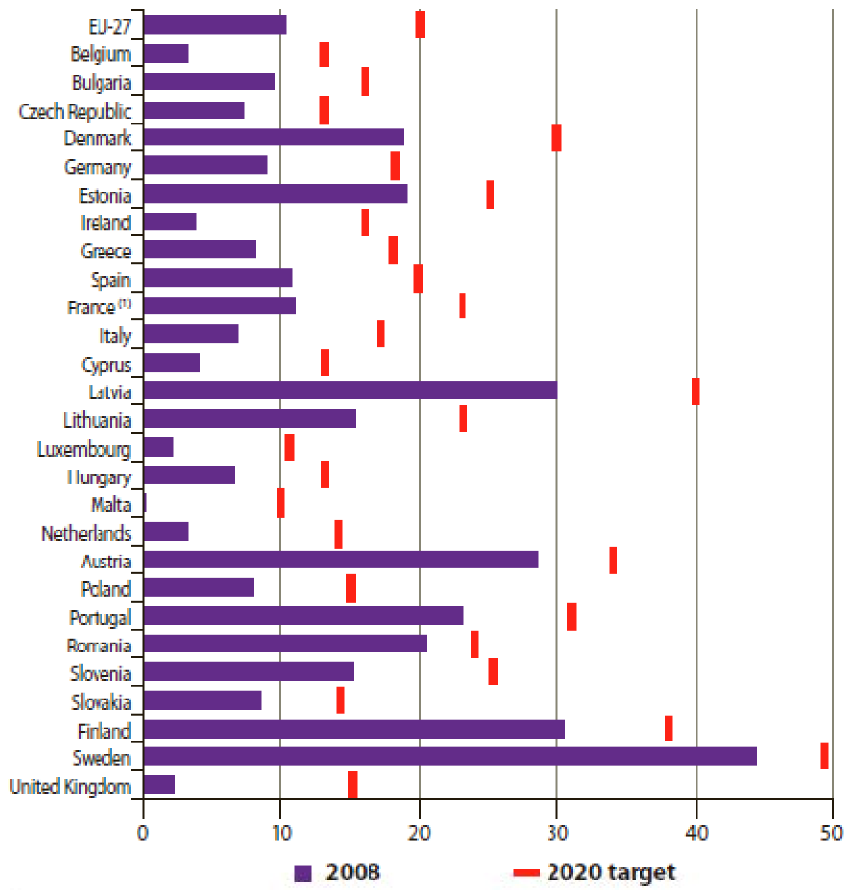
5 UK vs. International energy bills

This section demonstrates how UK domestic electricity and gas bills compare to the bills in other countries, as well as how the UK compares to other EU members in terms of meeting renewable energy targets.

Directive 2009/28/EC on the promotion of the use of energy from renewable sources sets individual targets for all Member States with a view to reaching an overall EU target of a 20 % share of total energy consumption from renewables by 2020 (see Figure 5.1). The targets vary, taking into account the different starting points of the Member States, the renewable energy potential and economic performance (Eurostat, 2010). The share of energy from renewable sources in the UK was one of the lowest in EU in 2008. The lowest shares were in Malta (0.2%), Luxembourg (2.1%) and the United

Kingdom (2.2%). Overall, renewable sources contributed 10.3% of EU-27 gross final energy consumption. The highest shares of consumption from renewable sources in EU were in Sweden (44.4%), Finland (30.5%), and Latvia (29.9%).

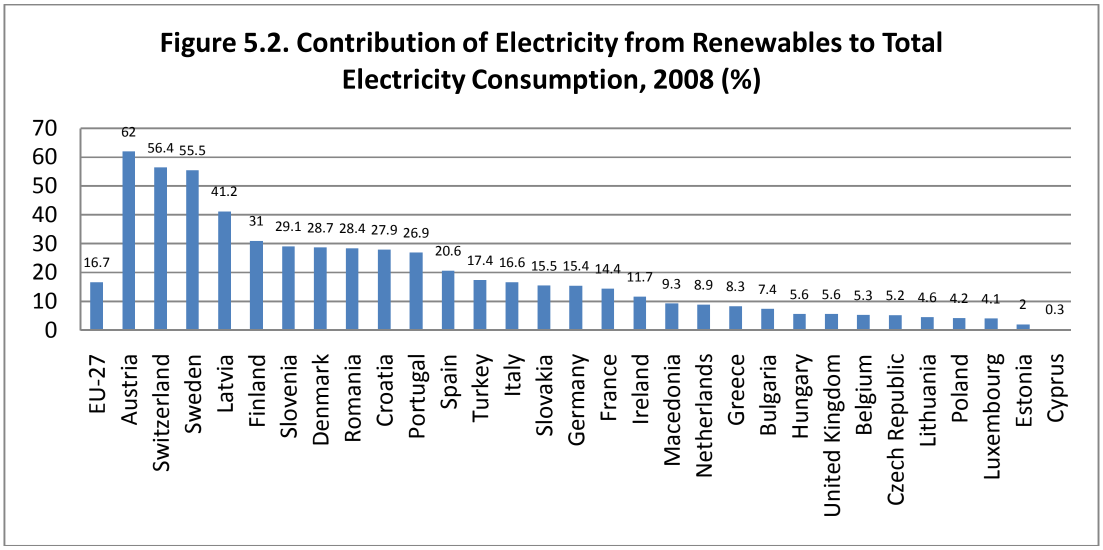
Figure 5.1 Share of Renewable energy in gross final energy consumption



[1] "France métropolitaine", excluding the four overseas departments (French Guyana, Guadeloupe, Martinique and Réunion).

Source: Eurostat (Europe 2020 indicators — online data code t2020_31)

The highest shares of renewables in total electricity consumption among the member states were in Austria (62%) followed by Switzerland (56.4) and Sweden (55.5%). In absolute terms, Sweden also had the second highest contribution of electricity from renewables (82TWh), with the highest amount being in Germany (95TWh) (Figure 5.2).

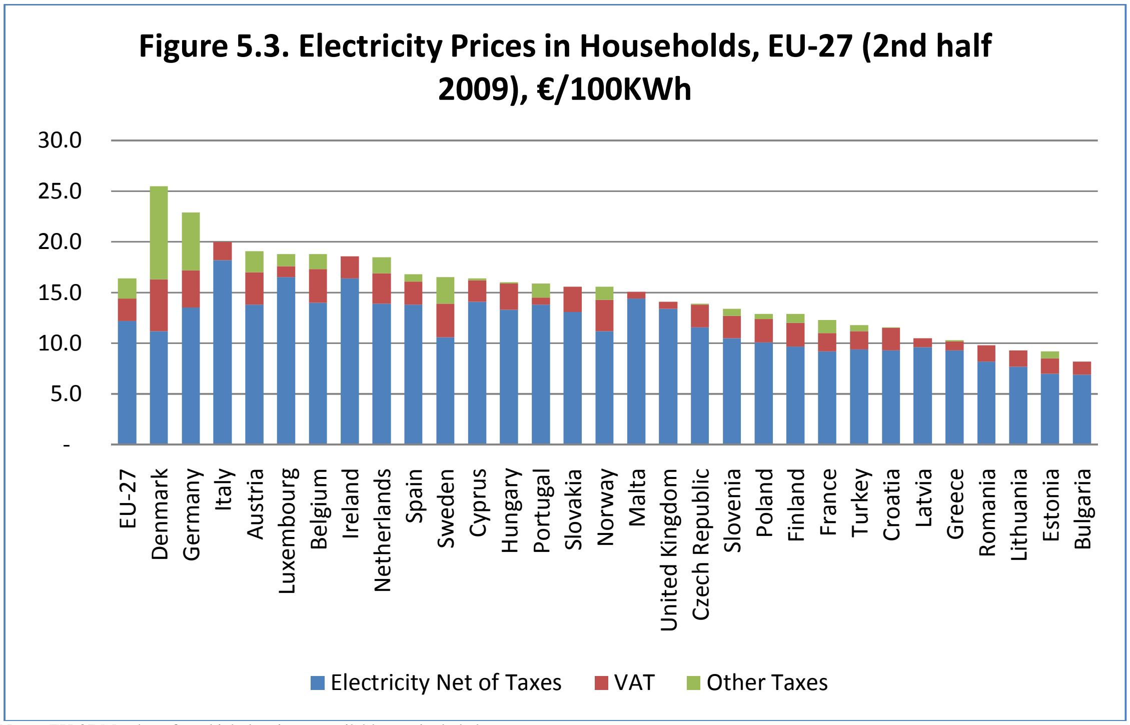


Source: Eurostat (online data codes: nrg_105a, nrg_1071a and nrg_1072a)

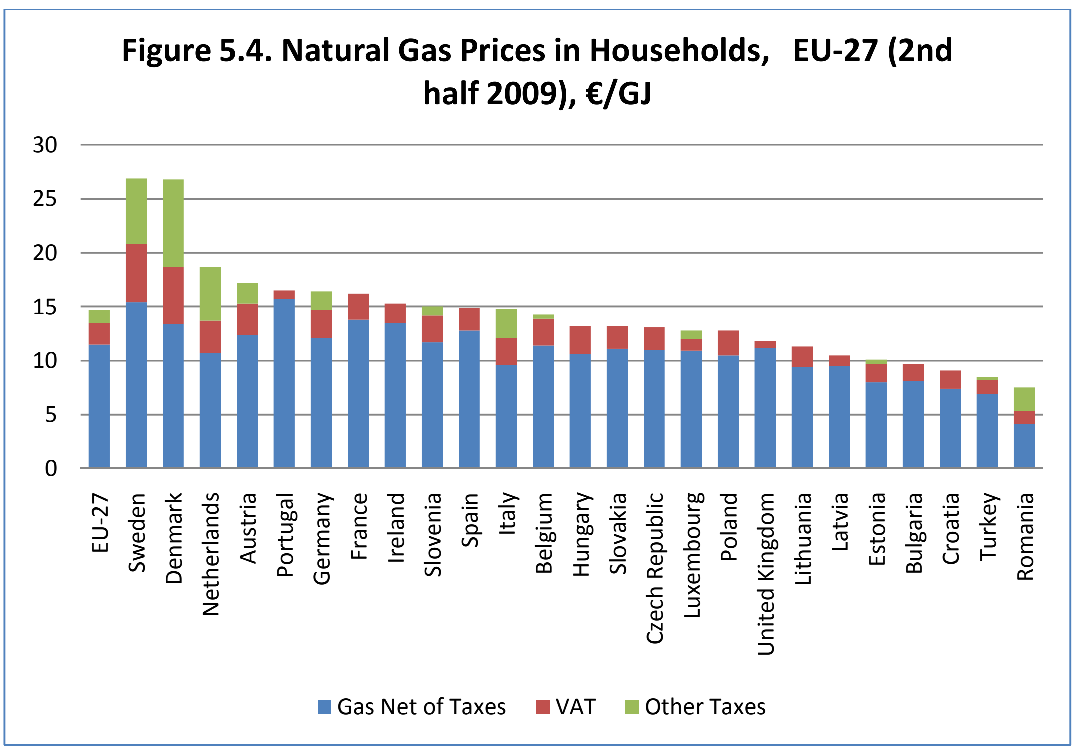
Figure 5.3 demonstrates how the UK electricity prices differ from electricity prices elsewhere in the EU. UK domestic electricity prices are currently lower than in most of the other EU members, and electricity taxes represent the lowest share of the of the final electricity price. Most EU countries, - unlike the UK - currently have taxes on electricity in addition to VAT. The highest rates of taxation are found in Denmark and Germany.

Figure 5.4 compares natural gas prices in the UK to those in other EU countries. As with electricity prices, gas prices in the UK are less than prices in most other EU members. Unlike the UK, about half of EU members for which the data is available have taxes on natural gas in addition to VAT. Overall, Sweden and Denmark have the highest gas prices, and also the highest share of taxes out of the total gas price. Taxes represent 43% of the final gas price in Sweden, and 50% in Denmark.

Overall, the price tables show that UK electricity and gas are rather lightly taxed but the pre-tax prices are currently around the average. A 47% increase in electricity unit costs, envisaged under EMR, would send UK electricity prices towards being the highest in the European Union (post-, but especially pre-tax).



Notes: EU-27 Members for which data is not available, not included
Source: Eurostat (online data codes: nrg_pc_204 and nrg_pc_205)



Notes: EU-27 Members for which data is not available, not included
Source: Eurostat (online data codes: nrg_pc_202 and nrg_pc_203)

6 Possible consumer reaction

As we have seen, the policies and packages proposed in the EMR could impose substantial increases on electricity bills by 2030, ranging from 25% to 36% (compared to 2010 bills). The impact will both vary over time and across the population, impacting in different ways households with different characteristics. It is hence crucial to examine possible consumers' reaction.

The academic literature is increasingly recognising the importance of consumer engagement with energy policy (Akcura et al., 2011) and the government is also interested in how to better engage consumers as regards the environmental agenda. It is argued that the EMR has missed opportunities to incentivise demand response such as load shifting (UKERC, 2011a). In general, demand-side management (DSM) is not reflected in the EMR, which focuses on supply.

There is much uncertainty about the level and shape of future residential electricity demand, especially given the likely uptake of electric vehicles (EV) and electric heating. For instance, in its medium scenario, CCC (2010) estimates that electrics cars will become competitive with conventional alternative - for a (private) discount rate of 7.5% and forecast fuel costs - during the 2020s. EVs might represent around 60% of new vehicles by 2030 (31% of the fleet) of which 30% are battery electric (BEV) and remaining 70% plug-in hybrid (PHEV) cars (CCC, 2010, p.161, 165).[12] Also, aggregate[13] annual electricity demand from the BEV[14], PHEV[15] and hydrogen fuel cell PHEV cars and vans could be rising from 4.4 TWh in 2020 rising to 30.6 TWh in 2030 in the medium scenario, representing a need of around 12 GW generation capacity in 2030 (CCC, 2010, p. 168). Also, the Government has announced its intention to support this market, with £400 million funding to promote the take up of ultra-low carbon vehicle technologies over the Spending Review period (CCC, 2010, p.27). Electric heat pumps (and heat from bioenergy) might also become more popular through the 2020s.[16] These technologies are already available, but not yet cost effective at the household level, hence financial support would be needed (CCC, 2010, p.28).

This section provides an overview of the range of possible consumers' reactions to the projected changes in energy bills. There are broadly two different sets of measures that the consumers could undertake to mitigate the impacts of higher electricity bills: (1) direct energy abatement, hence reducing comfort levels – i.e. cutting down or shifting energy use to times when electricity prices are cheaper; or (2) through an investment decision – either undertaking energy efficiency measures or micro-generation technologies. These measures are commonly referred to as demand-side management (DSM). In addition to modifying their electricity demand, consumers are also increasingly incentivised to invest in micro-generation technologies, allowing them to be partly (or wholly) electricity self-supplied while exporting over-supply to the grid. While focusing on electricity

[12] The CCC assumes that battery electric cars replace conventional vehicles typically used for short trips, i.e. 85% of cars do not drive more than 100 miles within the average week and 73% undertake a long-distance trip less than once a month. Also, those cars replace conventional cars in multi-car households (30% of households). Similar projections are given for electric vans.

[13] This comprises all sectors of the economy.

[14] Battery electric vehicles (BEV) are vehicles that receive all their motive power from battery (CCC, 2010, p.354)

[15] Plug-in hybrid electric vehicle (PHEV) receives their motive power both from battery and a secondary source (CCC, 2010, p.364).

[16] Today, 80% of domestic heating is provided by 18-20 million gas boilers, which are replaced at a rate of about 1.2 million per year. The remaining (5 million) homes are off the gas grid and largely rely on heating oil, liquefied gas or electric heaters. Around 1% of heat in homes currently comes from renewable sources (DECC, 2011, p.10-11).

in this report, we nevertheless recognize the importance of heating and transport, as those are an important part of households' energy spending expenditures today and are likely to be increasingly "electrified" as time goes on.

There is a substantial literature on the barriers to energy efficiency and DSM more general, and the importance and type of policy responses to overcoming these (for a review, see Brophy Haney et al., 2011). Several authors have emphasised the distinction between market failures - stemming from a flaw in the operation of the market - and market barriers due to non-market obstacles (Brown, 2001). Intervening to correct market failures improves both energy efficiency and economic efficiency, whereas overcoming a market barrier improves energy efficiency but at a cost to consumers (Jaffe et al., 1999, Brown, 2001). More recently, authors have emphasized the importance of transaction costs, organisational aspects and behavioural economics, by trying to adopt a more realistic view of the consumer decision-making process. Those authors suggest that the importance of overcoming these additional barriers is often underestimated (Sorrell, 2004). Those barriers are complex and interrelated. Market barriers, in particular access to capital due to high up-fronts, are among the most important barriers to energy efficiency in the residential sector. By contrast, behavioural barriers are perhaps amongst the most difficult to address as changing behaviour and lifestyle is very difficult. Also, the two main barriers to a more responsive demand side are closely linked to imperfect information and inelasticity of demand, mainly due to a lack of cost-reflective pricing of electricity.[17]

In the UK, a range of policies and programme have already been implemented with some success, however, considerable potential remains for both energy efficiency and demand response. Table 6.1 presents an overview of the possible actions currently available and planned at the domestic level to mitigate an increase in electricity bills. The measures involve both government agencies and/or suppliers.

Table 6.1: Possible consumer mitigation strategies

Category	Measures	Description	Support measures	Comment
Energy consumption	Absolute reduction (energy abatement)	Cutting down energy (e.g. thermostat reduction, switching off appliances)	Smart meter roll-out	To be completed by 2020
	Load shifting (differing energy use)	Shifting energy consumption to different times, taking advantage of cheaper electricity prices	Time varying tariffs (e.g. TOU, CPP)	This option would be incentivized through time-varying tariffs. Today, time-varying including Economy 7, 10 and dynamic teleswitching. They are not common in the UK, but the impact of smart-meter rollout might drive their uptake.

[17] As electricity is difficult to store, supply and demand must be matched instantaneously, and different generators are working at different times with different costs. Hence, the real time retail prices of electricity do not reflect the real time cost of producing electricity in the wholesale market.

Capital investment	Energy efficiency	Investing in buildings refurbishment[18]; more energy efficient appliances, lighting and heating	CERT, Green Deal	The Green Deal is expected to be effective in 2012.
	Micro-generation technologies	Investing in different type of microgeneration (wind, solar, micro-CHP, etc.)	FIT and RHI	FIT is in place since April 2009, while RHI will be implemented gradually for the domestic sector from 2011 until 2012.
Supplier contract	Supplier switching	Switch suppliers	Proposals for better comparability in the Retail Market Review (March 2011)	Limited potential due to tariffs complexity and diversity, however, some remedies have been advocated by Ofgem.
Support measures	Grants, subsidies, etc.	Apply to different programmes set up to address fuel poverty	Winter Fuel Payments, Cold Weather Payments, Warm front grants, Health through warmth	It is unclear whether all of those programmes will continue given the current budgets cuts.

Consumers might choose to reduce their energy consumption in absolute terms. The academic literature and several Ofgem reports have stressed the general poor quality of information on energy consumption. In its latest Energy Retail Market Review, Ofgem proposed measures to further improve billing through standardization (Ofgem, 2011). Another key policy measure is the smart meter roll-out first announced in October 2008 and which is to be completed by 2020. Studies from pilots typically observe a range of savings from direct feedback (smart meter or display monitor) of 5-15%, and there is also some indication that high energy users are more responsive than lower energy users (for a major review, see Darby, 2006). Different policies and measures have been implemented by the government to help improve consumers' consumption feedback. In trials and pilots, savings from indirect feedback (e.g. billing or statements) have typically ranged from 0-10%, varying according to context. However, given the specific context of trials, there is little evidence to suggest that improved consumption feedback will automatically lead to important and sustainable savings. To bring about sustainable levels of reduction, there is a need for a strong focus on overall demand reduction – not only on peak reduction, which requires appropriately designed energy display and other information (Darby, 2010). Indeed, it has been shown that prices interact with psychological factors such as awareness, moral obligation to reduce consumption, perceived impact of reduction consumer and trust (Stern, 2000).

Behavioural economics points to a number of phenomena that may be increasingly important as regards the future of energy demand. These include liquidity constraints, expectations, loss aversion, commitment devices and perceptions (Platchkov and Pollitt, 2011). Brutscher (2010) looks at the credit top-up behaviour of prepayment electricity consumers in Northern Ireland. Interestingly, people seem to top-up significantly more often than rationality would suggest (Baumol-Tobin model), given interest rates and the opportunity costs of topping up. According to

[18] Cavity wall insulation, drought proofing, double glazing, loft insulation, etc.

the model, individuals should top up by £230, 2.3 times a year. Instead, people are found to top-up by £13, 50 times a year. Various reasons might explain this suboptimal behaviour: liquidity constraints, expectations about future prices, loss aversion (people value a loss more than a gain of similar amount) or commitment device theory – where people by lowering their top-up seek to commit themselves to more parsimonious consumption. Finally, perceptions seem to matter, and people tend to prefer spending multiple small amounts rather than a single large amount, even if the lump-sum contract is in fact cheaper (Finkelstein, 2009). Such phenomena need to be accounted for in policy design. Smart meters for instance, if they give people more control over their energy consumption and expenditure, may reduce sensitivity to long-run rises in prices, at the same time as reducing incentives to save energy.

Energy consumption patterns are characterized by large heterogeneity driven by diversity in appliance ownership. In terms of sensitivity to prices, most studies find that electricity price elasticities are typically low. Estimates vary, but as seen in Table 6.2, in the literature covered, they typically range from -0.09 to -0.13 in the long-run; and slightly higher in the short-run, from -0.15 to -0.39.[19] In other words, a 10% increase in price might result in a change in demand of 1.5-3.9%, which reveals how weakly consumers react, and the fact that electricity is an essential good. However, price effects do vary substantially across appliances, and depending on the "shock" of the change (Reiss and White, 2005, Reiss and White, 2008). Households apparently substitute toward more price-inelastic electricity uses as income rises (Reiss and White, 2005). Finally, income effects can be significant, but the effect is more correlated to the purchases of household appliances rather than direct energy consumption behaviour (Reiss and White, 2005, Dubin and McFadden, 1984). Hence, income effects operate through capital expenditure rather than utilization of existing devices.

Table 6.2: Price and income elasticities of main domestic good/services consumed

Good/ service	Price Elasticity	Notes	Study
Electricity	-0.09 to -0.13 (LR)		Boonekamp (2007)
	-0.24 (SR)		Brännlund et al. (in press)
	-0.16/-0.39 (SR)		Filippini and Pachuari (2002)
	-0.16 (LR) & -0.15 (SR)		Holtedahl and Loutz (2004)
	-0.05/ -0.0675 (peak)	TOU pricing	Boisvert et al. (2004)
	-0.054 to -0.158 (peak) / -0.013 to -0.049 (off-peak)	TOU pricing	Aigner et al. (1994)
Public transport	-0.75 (SR) & -0.91(LR) (income: -0.62 (SR & LR))	Europe (meta-analysis) Price of petrol 0.4 (SR) & 0.73 (LR)	Holmgren (2007)
	-0.59 (SR) & -0.75 (LR) (income: -0.62 (SR & LR))	US/Australia (meta-analysis)	Holmgren (2007)
Railway	-0.22		
Gasoline	-0.34 (mean SR)/ -0.84 (mean LR)		Brons , Nijkamp, Pels and Rietveld (2008)

[19] Short-run elasticity refers to immediate changes – e.g. switching off appliances – with a given stock of appliances, whereas long-run elasticity might represent longer-term changes in consumption behaviour and/or adjustment in the stock of appliances owned. A distinction should therefore be made between direct consumption behavioural changes and changes induced by capital investments (Reiss and White, 2005).

	-0.034 to -0.077 (2001 to 2006) vs -0.21 to -0.34 (1975-1980) (SR)	US	Hughes, Knittel, & Sperling (2007)
	-0.6 to -0.8 (LR) & -0.2 to - 0.3 (SR)		Graham & Glaister (2002)

This is not to say that consumers cannot react strongly and rapidly to change in prices. Reiss and White (2008) look at the high increases in prices in California in 2000 on residential consumption. They find that the average consumption decreased by 13% in about 60 days. However, as soon as the public authorities capped the prices, consumption went back to former levels (Reiss and White, 2008). The authors infer that capping retail electricity prices precludes quick adjustment to changes in wholesale electricity prices.

The smart meter roll-out might also open the way to more sophisticated tariff structures, such as time of use (TOU) or critical peak pricing (CPP). TOU tariffs are fixed tariffs that change depending on the time of day. In the UK, Economy 7 or Economy 10 are examples of such tariffs (Ofgem, 2010a). CPP tariffs can also offer highly differentiated prices depending on time of use, but with peaking prices at peak times. Smart meters will also facilitate automated load controls. One type of tariff with automated features existing already is Dynamic Teleswitching, where heating appliances are automatically switched at certain times. The opportunities offered by smart meters are many, and provide further opportunities for households to take advantage of lower prices at specific times. Today, time-varying tariffs are not very common in the UK. It is estimated that around 20% of domestic consumers are on Economy 7 (Ofgem, 2010a). What is also interesting in the context of the smart meter rollout is the magnitude of price elasticity of substitution – i.e. the extent to which price increases at any point in time result in significant increases in demand at another time. Parks and Weitzel (1984) found this magnitude to be high.

Higher electricity prices should spur the adoption of micro-generation subsidies and the participation in demand reduction initiatives. Since April 2010, most renewable electricity generation (micro-CHP, photovoltaic, wind, hydro, anaerobic digestion) up to 5MW are eligible for a technology banded Feed-in Tariff (FIT).[20] Under this scheme, administered by Ofgem, suppliers register eligible installations, process generation data and make payments (Ofgem, 2010b).

Better insulation and energy efficiency improvements are the most cost-effective way to reduce emissions arising from heating (after demand abatement measures). This is the target of a new programme, the Green Deal, to be introduced in autumn 2012. The DECC estimates that in the case of the most energy inefficient homes, savings of around £550 per year could be achieved by installing insulation measures under the Green Deal.[21] The innovative feature in the design of the Green Deal is the idea to tie the upfront finance to the dwelling's energy meter, with the consumer paying back through its energy bills over a period. The core principle – the so-called Golden Rule- states that a "Green Deal" will not be agreed if the instalment payments for the measures (which includes the capital costs, labour, and equipment) exceeds the projected cost savings on an average bill for the duration of the arrangement – which could be up to 25 years (Smith, 2011). DECC projects

[20] The range of recently adjusted tariffs (adjusted on the 25th of February 2011) applicable from 1st of April 2011 is available at:http://www.ofgem.gov.uk/Sustainability/Environment/fits/Documents1/Feed-in%20Tariff%20Year%202%20tariff%20table%20adjusted%20for%20Retail%20Price%20Index.pdf.

[21] The impact of the Green Deal is not included in the EMR calculations.

resulting private sector investment of £7 billion per year, and that the programme could support a rise in jobs from 27,000 to 250,000 over the next 20 years (DECC, 2010c). However, there are a number of significant issues that would need to be addressed, not least what happens if the property becomes vacant and it is not at all clear how and if the intended objectives will be achieved. It is interesting however to note that the Green Deal is significantly about reducing heating demand, not about demand for power and light.

A similar financial incentive to FITs for micro-generation is the Renewable Heat Incentive (RHI). This targets renewable heat– e.g. solar thermal (below 200kWth) and heat pumps (including air source heat pumps) – and will run from 2011. Its implementation will be in several phases. In the first phase, the Government will introduce "Renewable Heat Premium Payments" for the domestic sector, a form of direct subsidy to the installation costs. Those are planned to start in July 2011 (for renewable heat technologies installed since 15th July 2009) and £15 million has been ring-fenced for the programme (DECC, 2011). In the beginning, the focus is likely to be on primary heating systems, such as heat pumps and biomass boilers and households off the gas grid, where fossil fuel heating would be both more expensive and more carbon intensive. In the second phase (starting in 2012), the range of technologies covered will be expanded and long-term support for the domestic sector will be introduced[22].

Another way consumers might benefit from energy efficiency measures is through the Carbon Emissions Reduction Target (CERT). This is an obligation on all suppliers with a customer base in excess of 50,000 customers to make savings in the amount of CO2 emitted by households (293 MtCO2 by December 2012). The third CERT period started in 2008, and will run until December 2012, with a higher target, and larger focus on supporting insulation measures.[23] The intention is for the CERT to pave the way for the Green Deal. There is substantial flexibility for suppliers as to how to meet this target, but a few specific requirements: 68% need to be delivered through installed insulation, 40% of the measures should be delivered to a 'Priority Group' (vulnerable, low-income households, those in receipt of eligible benefits and pensioners over the age of 70), and 15% of the savings need to be achieved in a subset of low income households (a Super Priority Group) considered to be at high risk of fuel poverty (DECC website)[24].

Certain categories of consumers might have opportunities to seek a direct discount on their energy bill. Indeed, under the new proposed Warm Home Discount, confirmed as part of the Spending Review, energy suppliers will required suppliers to offer discounts to the most vulnerable customers (up to £130 off for older, poorer pensioners).

Energy price increases might lead consumers to more actively investigate switching opportunities. This might help mitigate energy increases through tariffs that better suit one's consumption patterns, and it is estimated that there are today significant potential gains from switching (Waddams, 2010). This mitigation nevertheless might have limited potential as all suppliers will be impacted by higher wholesale electricity prices and support costs and will transfer those costs to

[22] Individuals in receipt of first-phase premiums will receive the long-term tariffs.
[23] The total estimated costs to suppliers of achieving the CERT (from April 2008 to December 2012) is £5.5 billion. CERT Net Present Value to society is estimated to approximately £17 billion (DECC website).
[24] http://www.decc.gov.uk/en/content/cms/what_we_do/consumers/saving_energy/cert/cert.aspx.

consumers. However, different suppliers might adjust their prices differently. The extent to which consumers might challenge market power needs to be investigated. Ultimately, in the current UK retail market structure, it is consumers that confer power to suppliers by their switching behaviour, through their tolerance of higher prices (Waddams Price, 2005). Looking at gas markets, Giulietti et al. (2006) conducted a survey asking consumers what saving would make them switch supplier. Although the survey was undertaken just after the market was opened to competition (1998), the responses suggested that it was still profitable for the incumbent to keep prices around 30% above its competitors, even if it would lose around 45% of the market (Giulietti et al., 2005)

The UK electricity market has now been open for competition for more than 10 years. Empirical evidence (see Waddams, 2010) does show that energy consumers' switching rates in the UK are higher than in other service sectors and other countries. However some customers cannot switch due to specific circumstances or are discouraged by high tariff complexity. Ofgem, in its recently published Retail Market Review estimates that around 40-60% of energy customers are sticky – even if they might have switched in the past – and that vulnerable customers are likely to be disproportionately represented in this group (Ofgem, 2011). There is still structural problem with this – firms charge around 10% more in the area where they are the former incumbent (Waddams, 2010). Ofgem also identified different groups across the population. 'Confident deal seekers' who seek the best deals and typically make good switching decisions, are found to represent a minority of customers. Others groups consist of confused, anxious or not interested in switching, or disengaged customers. Again, vulnerable consumers are disproportionately represented in these groups, and so might be even more adversely impacted, given that energy already represents a higher proportion of their total spending (Ofgem, 2010c). In a survey, (Waddams, 2010) found that 46-60% of those more vulnerable customers (those over 65 years old, the disabled, those with low income and low education) remain with the incumbent, compared to 42% for the average consumer.

7 Risks and unintended consequences of the EMR

This section discusses some of the potential risks associated with the four proposals of the EMR in the light of the literature on UK and international experience. We examine each of the policies discussed in the preferred package: (1) carbon price support; (2) feed-in tariffs; (3) capacity payments; and (4) emissions performance standard. We pay attention to the extent to which those policies risk failing to deliver the three key objectives of UK energy policy of affordability, sustainability and energy security. We also discuss, where relevant, the four broad principles advocated in the EMR consultation document: (1) cost-effectiveness; (2) durability and flexibility; (3) practicality; and (4) coherence (DECC, 2010a, p.17).

7.1 Carbon price support (CPS)

The EMR seeks to implement a CPS through a change of the climate change levy (CCL) and where oil is used, fuel duty. This would support and give certainty to the price of carbon in the electricity sector and thus encourage investment in low-carbon technologies (HM Treasury, 2010). Hence, UK electricity companies would face two different charges proportional to their emissions: the UK CPS and the cost of EU allowances. The rates would be set by the Treasury/HMRC, having a view on EU allowances price; so that government's intended carbon price trajectory is met. In the consultation, three different trajectories are proposed to reach a carbon price of £70/tCO2 by 2030. Exchequer revenues will hence depend on EU ETS trading prices relative to target price, the former being highly uncertain.

The idea of a carbon price support (CPS) is strongly supported by economic theory. The need to internalise a negative environmental externality so that polluters face the full social cost due to their environmental damage is a basic environmental economics principle (Baumol and Oates, 1988, Stern, 2007).

The literature widely agrees on the fact that low and volatile carbon prices are two of the factors affecting investment in low-carbon generation, and therefore, that high and stable carbon prices are the starting point for an economically sensible decarbonisation policy framework (Helm, 2002). In the context of the EMR, the CPS is the subject of a separate HM Treasury/HMRC consultation. A minimum carbon price can indeed provide some certainty over the return on investment in abatement technologies and reduces the risk faced by innovating firms (Fankhauser and Hepburn, 2010). However, there are a number of issues associated with implementing a CPS: the level of the CPS, its distributional impacts on investors and consumers, and its interaction with the wider EU ETS.

Obviously, the level of the CPS needs to be to be high enough in order to allow low-carbon generators to recover their risk adjusted capital costs. Indeed, in contrast to gas and coal generators, nuclear power and renewables are price takers. The latter have very high fixed costs (capital expenditures), and very low operational costs. Hence, they have a limited hedge against changes in prices (whereas fossil fuel generators can stop generating and save costs and their costs are positively correlated with electricity prices). Over forty years the day-day volatility of electricity and carbon prices may not be a big risk issue, especially compared with the other construction and operational risks associated with low carbon generation.

The literature and empirical evidence shows that there might be a credibility problem for the CPS. An inherent political risk with taxes such as the CPS is that they could be changed or removed by subsequent governments. Investors know that and therefore it can be argued that long-term contract and guaranteed prices might have more impact (UKERC, 2011b). Hence, the CPS needs to be credible and guaranteed over the long-term in order to have the intended consequence – incentivising low-carbon generation. However if the government wants investment it needs to instil credibility into the stated future path of the CPS by not changing policy, in the same way that Central Banks can establish credibility for monetary discipline. The fragility of confidence in the CPS mechanism is precisely what could incentivise the government to commit to it. However it is the case that politically it is easier to break a commitment to a path of increasing taxes than it is to renege on a financial contract such as a CFD.

Finally, in the EU, an important unintended consequence of any national CPS is via interaction with the EU ETS. One of the important lessons from the literature is that in the presence of an emissions cap – as under the EU ETS - any national additional policies aimed at increasing the level of low carbon generation in one country will not affect the absolute level of emissions in the EU, but simply shift emissions around (Fisher and Preonas, 2010). Thus lower UK emissions due to EMR will reduce EU allowance prices, given the EU-wide cap. A lower EU allowance price will alter the intended price signal and disincentivise abatement measures outside the UK (or encourage increased emissions elsewhere), as other countries will still be able to emit up to the emissions cap (Fankhauser et al., 2011). Unless the EUETS cap tightens in line with emissions reduction via the EMR, then the EMR will have no direct impact on European or global carbon emissions.

7.2 Feed-in-tariffs

FITs are long term contracts between the government (or an entity acting on behalf of the government) and a low-carbon generator. They provide a guaranteed tariff or price for a period of 15-20 years (DECC, 2010a). Three different forms of FITs have been assessed: premium FIT, fixed FIT and a FIT with CFD model.[25] The latter –part of the preferred EMR package- involves an agreed strike price and a two-way mechanism where either variable additional ("top-up") payments are made to the generator to complement its revenues from selling their electricity in the market, or the generator returns money if electricity prices are higher than the agreed tariff (DECC, 2010a, p.48). The intention is to provide more revenue certainty to low-carbon investors, in order to reduce the risk and hence the capital costs of low-carbon generation investments through lower hurdle rates. The literature suggests increased revenue certainty reduces capital costs. There has been much debate in the literature around the relative superiority of price-based (such as FIT) measures versus quantity-based measures (such as tradable green certificates – TGCs - such as the RO) (Menanteau et al., 2003, Butler and Neuhoff, 2008, Finon and Perez, 2007).[26]

The impact of FITs on consumer bills will depend both on the decarbonisation target and the choice of FIT design.[27] The EMR estimates that a key factor explaining the differences in costs is the transfer of risk from generator to the Government (DECC, 2010a, p.54).[28] However, there are significant inherent difficulties as regards design and implementation. One difficulty is finding the optimal level of support which would be set by the government given issues of information asymmetry (between the government and generation companies) with respect to renewable support costs. It hence might be difficult to set the right levels of FITs adjust them in time. With a dynamic FIT (such as fixed FIT or FIT with CFD), the support level is time varying, but there is still a need to decide on a target price.

The core effect of a FIT – a guaranteed fixed price – does not follow traditional market principles (Meyer, 2003). Generators are no longer subject to market based price signals as to the choice of generation technology or to the best way to manage price risk. FITs transfer risks to public authorities and pose important challenges as regards to the levels to be set. If FITs level are too low, they risk undersupply, hence jeopardizing the environmental agenda. If they are set too high, they risk inducing windfall profits for generators and unnecessarily high consumer prices. The danger of this happening might be lower with more mature technologies such as onshore wind, but is more acute with less mature technologies (Newbery, 2010) where learning rates and hence costs curves are subject to large uncertainties. Empirical evidence shows that FITs have typically not been

[25] There is scope for confusion in the terms. In what follows we refer to FIT with CFD as *dynamic* FIT, as support costs will vary depending on electricity prices. By contrast, premium and fixed FIT are *static* and do not vary ex post. In the case of premium FIT, the top-up payment (in addition to the revenue from wholesale market) is fixed ex-ante, regardless of the electricity market price. In the case of the fixed FIT, the payment is made to generators who receive no other revenue from the market.

[26] Finon and Perez, (2007) for instance, compare both instruments and come to the conclusion that in terms of costs for consumers, guaranteed investment, adaptability and stability, market incentive and conformity, neither offer an optimal solution, and hence, it is up to the government to select the most appropriate instrument in light of the relative importance of its objectives.

[27] The government estimated that all three designs would lead to an average increase compared to the baseline of less that 3%, and that the FIT with CfD would have the least impact (DECC, 2010a, p.53-4).

[28] The rationale put forward in the EMR consultation document is the more risk transferred, the lower the costs of capital, and hence the lower the public support needed.

adjusted in time to account for technological developments (Meyer, 2003). It is also difficult to set relative FITs for different technologies as the current banded ROC scheme illustrates.

Theoretically, FITs and TGCs could be equivalent.[29] In terms of costs, in theory, a quantity-based system such a TGC should offer more chance of controlling costs. However, in practice, TGCs are not necessarily cheaper than FITs (Butler and Neuhoff, 2008). A way to control costs is to implement an auction. In theory, the competitive bidding process should incentivise cost reductions; however it still leaves a problem in choosing the relative quantities of each technology to support in separate auctions. However, UK's experience with both TGCs and auctions for renewables is poor for reasons related to planning – it is not clear that a new financing mechanism addresses this. Box 7.1 explains with further details UK's experience with RES support.

Box 7.1: UK's experience with RES support– the NFFO and ROC schemes

Recent UK experience with renewable energy support mechanisms can be divided in three distinct phases. A first one, with the non-fossil fuel obligation (NFFO) which ran from 1990 to 2002; a second one, with the renewable obligation (RO) was set up in 2002 and is still running; and a third phase with the new FIT scheme set up in April 2010 and the RHI expected to come live in 2011, and the likely changes in light of the EMR.

Under the NFFO, competitive tenders were set up. The winners got a fixed price per kWh – a similar feature to a FIT. Five distinct competitions occurred in England and Wales, which resulted in reducing prices – probably due to the best locations being involved. However, the overall results of the NFFO are weak, with less than one third of the winning bids being realized, and an installed capacity that did not go beyond 0.4 GW by 2000. The main reasons for this failure were local opposition and planning procedures. However, recent policy reforms – via the Comprehensive Spending review of last October- have been launched, with the intention to empower local authorities in this respect. It is not clear that this will improve the likelihood of onshore renewable (or other low carbon) projects being approved.

The RO which replaced the NFFO in 2002 is essentially a form of tradable green certificates (TGC). Under the scheme, the government set minimum share of renewable electricity that suppliers must acquire. Those shares are increasing over time and rise to 15.4% in 2015. There are three ways suppliers can meet those targets: (1) buying renewable energy certificates (ROCS); (2) earning ROCS themselves; or (3) paying a penalty – the buyout price, whose revenue is recycled and allocated back to those that issue ROCs. However, the scheme is very generous to the renewable industry. Indeed, the 2007-8 buyout price was £34.30/MWh, and only 64% of the required ROCs were issued, so that the buyout price actually bound in the market. Also, this meant that 36% of total ROC payment was recycled and reallocated to generators that issued ROC. Hence, for 1 MWh of electricity, renewable generators received £34.30 plus £18.65, and this on top of the revenue earned in power markets. Also, the total cost to suppliers of the RO scheme was £876m. At the individual level, this implied an unnecessary "top-up" by consumers to pay for the buyout revenue of £316 million (which amount to 1% of total electricity expenditure in 2008) (Pollitt, 2010). Since April 2009, and on the recommendation of the Carbon Trust, the government established banding to account for different levels of technology maturity, which make the system more sophisticated.

Sources: Meyer, 2003, Finon and Perez, 2007, Pollitt, 2010, Mitchell and Connor, 2004, Wood and Dow, 2011.

[29] See Weitzman (1974) for a discussion of the fundamentals principles.

FITs in particular are very common and have been implemented in a number of European countries, Canada and a few US states (Fisher and Preonas, 2010). The experience of some countries leading in terms of levels of RES generation – Germany and Spain in particular - has often been cited as demonstrating the success of FITs. In Germany and Spain targets for renewable deployment have actually been exceeded much faster than planned. However, criticisms have been made about the cost of the schemes and the windfall profits they have created. The pressure on public finances due to the economic downturn has led to a series of abrupt cuts in the level of support, in particular for solar PV – in Spain, Germany, France and New Jersey. In addition, hopes for collateral benefits in terms of "green jobs" have failed to be fully realised, as shortages in domestic supply chains has led to increasing imports from emerging economies such as China.

In Spain for instance, which ran different models of FIT, including a premium FIT, funds allocated to FITs have been exhausted prematurely leading to significant public finance deficits (see below). This led the government to enforce radical cuts in the level of FITs that resulted in a significant shakeout in the renewables industry and damage to investor confidence.[30] In the case of Germany there is a fixed FIT, whereas in the Netherlands and Denmark operate FITs which have similar design to a FIT with CFD.[31] Box 7.2 provides further details on the international experience with FIT.

Box 7.2: International experience with feed-in tariffs

Perhaps one of the most striking examples is the Spanish experience, until recently depicted as a success story in terms of renewables uptake (Del Rio Gonzalez, 2008, Mulder, 2008). The Spanish FIT was set up in 1994. The indicative target was to reach 12% of RES in total energy consumption by 2010. In 1998, 2 options were introduced - fixed tariff schemes or a premium tariff (paid on top of electricity market price). At the end of 2004, the overall remuneration increased much more than expected due to rising electricity market prices.

The generous subsidies led to take off of onshore wind and solar PV: reaching 16% generation in 2010 (of which onshore wind was 80%). However, this led to a huge FIT deficit of €15 billion. To reduce the deficit, drastic cuts have been introduced that aim to reduce this deficit by €4.6 billion over the next 3 years., Solar PV has been at the core of the cuts, with a Royal Decree of November 2009 that reduces the tariff rate by 45% for ground mounted projects (5% for domestic rooftop projects) (Ernst and Young, 2011). At the end of January 2011, a new Decree was passed, that will cap the number of hours where generators receive the premium FIT[32] to reduce generators' revenues by 30% until 2013. These successive policy changes have had adverse consequences on renewable industry and investors' confidence, leading the PV trade associations to take legal action to the Supreme Court against the two last decrees. Onshore wind also suffered major cuts of 35% until 2013 and limitation on the hours receiving premium FIT.

In France, unforeseen reductions in the level of support have also been implemented, to control its budget deficit. In December 2010, the government introduced a moratorium on non-residential solar PV projects. Again, this led to legal action by producers seeking to abolish the decree. A consultation has now been launched to amend the FIT system and promote the development of renewables. Some of the amendments might appear paradoxical – e.g. the limitation of solar PV

[30] A report by Ernst and Young has hence dropped Spain's rank form the fifth most attractive country for investment in renewable generation to 8th due to these changes.
[31] In the Netherlands, the « sliding premium » runs since 2008. The tariffs are decided by the government and contracts signed for 15 years. In Denmark, a FIT with a tender procedure has been implemented (DECC, 2010a).
[32] The rest of the hours, generators will receive the standard rate. Also, the FIT has been extended from 25 to 28 years.

development.

In Germany, the solar PV FIT is now also subject to successive cuts: reduced by up to 15% since the beginning of this year, with a further cuts planned in 2012. Negotiations between the government and the solar industry recently led to a new flexible tariff design intended to slow down the construction of new installations. 40% of the costs of the Renewable Energy Act (EEG) arise from solar power, which generates only 9% of the electricity covered by the EEG. European countries are not the only ones to have experience such disarrays. The history of PV support in New Jersey (Hart, 2010), where rebates of up to 70% for PV installations were funded by a Societal Benefits Charge, also gives further illustration of the difficulty of managing costs of such schemes.

Sources: Hart, 2010, Haas et al., 2011, Pollitt, 2010, Laing and Grubb, 2010, Ernst and Young, 2011.

7.3 Targeted Capacity Mechanism

Fears of reduced capacity margins due to the planned closure of up to one third of total generation capacity by 2020 have led the government to propose the introduction of a targeted capacity mechanism. This would reward the provision of capacity, in addition to the provision of electricity. A central body would assess the level of spare capacity and will run tenders. The various possible designs for a capacity mechanism are discussed in Helm (2010).

A balance must be found between the level of security of the electricity system and the cost associated with providing the capacity required for that level. This is done by setting the value to society of electricity security equal to the costs of providing that security. Estimates of optimal level of security are very uncertain and depend on the value of lost load (VOLL), which is society's measure of electricity security (DECC, 2010a).

The VOLL used in the context of the EMR is £30,000/MWh. This is very high as compared to recent estimates. A study for Ireland finds an average VOLL in Northern Ireland in 2007 (and in the Republic of Ireland (ROI) in 2008) of €4000/MWh for the industrial sector (same for ROI), €13,000/MWh for the commercial sector (€14,000/MWh for ROI) and €18,000/MWh for the residential sector.[33] However, in consultation responses, the idea has been advanced that current levels of peak capacity margin do not support the introduction of capacity payments. Another measure of security of supply is the expected energy unserved (EEU).[34] Current levels are around 12 GWh per year compared to a total supply of almost 400,000 GWh in 2009 (DECC, 2010a, p.29). Hence, the proposed capacity mechanism seems to address a problem which does not yet exist, and indeed the EMR Impact Assessment (DECC, 2010, p.9) shows that a targeted capacity mechanism has a negative NPV. Also, it is not clear why the issue could not be left to the system operator (UKERC, 2011a).

There are various potential sources for risk. The assignment of a too high VOLL leads to "accepting" a similarly high level of costs. Increased costs also arise by acting too early. Implementing a capacity mechanism through a change in supplier obligations or a low carbon obligation are likely to be more costly, due to the lack of completion and potential for capture by vested interests (Helm, 2010). Auctions, by contrast, would have the advantage of maximising information revelation and competition, minimising scope for capture by vested interests, and enabling the development of secondary markets. Allowing a diverse set of technologies to bid might make explicit the political

[33] The residential value is an average which is brought down by the very low night time VOLL. The authors found that it can reach up to €60/kWh (e.g. weekends). Notably, the authors find that the peak VOLL does not occur at same time as peak electricity demand, opening some opportunities for peak shifting to minimise the damage of brown-outs.
[34] EEU is a probabilistic assessment of the likelihood of involuntarily interruption and likely size (DECC, 2010a, p.5).

preferences for certain technologies (Helm, 2010). Finally, an important aspect to ensure security of supply is the reduction of entry barriers for independent generators.

There is no evidence in favour of a targeted capacity mechanism rather than a capacity market which includes all firm capacity or interruptible demand. The US experience is that targeted mechanisms cause perverse outcomes. This occurs when capacity that is excluded from the auction becomes unavailable or cheap demand-side response is excluded from the market. US capacity markets, where they exist, are not targeted. However it is also the case that incentivising lost load directly would seem to be more sensible than having an expensive capacity market. In any case the US experience raises issues of governance of capacity markets, suggesting that capacity markets can be left to emerge within systems characterised by independent system operators, when market participants think that such a market is necessary to maintain supply security (see Pollitt, 2011).

7.4 Emissions Performance Standards

The EPS would act as a regulatory limit on the total annual amount of CO_2 to be emitted per unit of installed capacity.[35] The intention is, by providing a clear signal, to complement other market reforms and impede the construction and operation of new unabated coal-fired power stations. Different levels of EPS have been examined.[36] The government has stated its preference for a targeted EPS to prevent the building of unabated coal-fired power stations.

Theoretically, an EPS could have an adverse effect on capacity margins and security of supply. With higher levels of intermittent and inflexible generation, carbon intensive peaking plants – whose construction and operation is targeted by the EPS - would offer back up generation. However, such fears might be exaggerated, given the levels proposed in the reform and the exceptions proposed in the case of short-term or longer-term emergencies, where peaking plants would be allowed to operate unconstrained when required (DECC, 2010, p.75).

In general, there seems to be limited support among the consultation responses for an EPS (e.g. UKERC, 2011a). Gas generation is already preferred by investors for a number of reasons, and there is currently no plan to construct unabated coal power plants in the UK (UKERC, 2011b). Also, given the implementation of a CPS on 1 April 2013[37] in the chosen package, there would be little incentive for investors to invest in carbon-intensive technologies anyway. Hence, the EPS merely adds unnecessary complexity to the government's preferred package.

7.5 Other specific risks associated with the EMR

7.5.1 Complexity, redundancy and uncertainty/credibility

A number of issues could emerge as a result of the nature of the package. The exact final package and design of the specific policies remain to be determined, however, the preferred package indicates some potential for redundancy between the intended effects of FIT and CPS. In the case of a strong enough CPS, one potential adverse effect of a premium FIT would be to provide additional

[35] The government is proposing not to apply the EPS retrospectively, as it could have adverse impacts on security of supply (DECC, 2010a, p.71)

[36] 600gCO_2/kWh or 450gCO_2/kWh at baseload (DECC, 2010a, p.71).

[37] The government intends to introduce the CPS proposals in the Finance Bill 2011 (HM Treasury 2010) and did so in the 2011 budget.

windfall gains to low carbon generators. As mentioned above, with a high CPS and generous FITs a targeted EPS would end up being an unnecessarily costly layer of policy.

The general level of complexity and associated regulatory risk of the EMR proposals has been pointed in some responses to the EMR consultation (e.g. Energy Institute, 2011). The EMR might end up being "more complex than it needs to be" for achieving the intended objectives (UKERC, 2011a). In particular, a report from the Deutsche Bank suggests that "investors want TLC – transparency, longevity, and certainty - in policies regimes to mobilize capital.(…) (they) believe that investors will become increasingly concerned about regulatory risk and thus countries that deploy a transparent, long-lived, comprehensive and consistent set of policies will attract global capital" (Deutsche Bank, 2009, p.3).[38] This report makes the case for a coherent and integrated government plan supported by strong incentives, mentioning Australia, Brazil, China, France, Germany and Japan as examples (Deutsche Bank, 2009). The risks associated with policy changes and regulatory uncertainty, have been highlighted in numerous reports and studies.[39] Hence, the very complex nature of the policy package could act as a barrier for new entrants in the sector and impede its success (UKERC, 2011a).

In the case of multiple externalities and market failures (e.g. asymmetric information, principal-agent problems in energy efficiency, knowledge spillovers and the public good nature of innovation), the combination of policy instruments required should be grounded on economic principles (Goulder, 2008, cited in (Fankhauser et al., 2011)). Indeed, it has been shown that price signals alone might fail to fully incentivise investment in low-carbon technologies (Rosendahl, 2004; Jaffe et al, 2005; Hepburn, 2006, Fischer, 2008). However, there is a need for a careful design if any policy package is to be superior to pricing alone (Grimaud and Lafforgue, 2008; Schmidt and Marschinski, 2009; Acemoglu et al., 2010). Fankhauser et al. (2011) warn against the risk of implementing multiple instruments to address the same market failure, which might result in "perverse" effects and unintended consequences.

"Stacking on multiple instruments" can have a number of unintended effects. It might trigger additional tangible and less tangible costs, such as: (1) resource costs due to unintended market distortions; (2) wasted "political capital" while producing little or no environmental gain; (3) undesirable changes in distributional equity; and (4) an erosion of the credibility of regulators, due to policy fiddling (Fankhauser et al., 2011).

7.5.2 Non-economic barriers

The importance of non-cost barriers to the uptake of renewable technologies – i.e. planning issues, consumer acceptance, grid access and charging, capacity & supply chain constraints or construction risks - has been highlighted in a number of studies (ECORYS, 2008, IEA, 2008, Pollitt, 2010). Relaxing such barriers should be encouraged to reduce transaction costs and facilitate the uptake of low-carbon technologies.

[38] The report conducted a thorough review of countries' mandates and policy frameworks to rate investment risk in those countries.

[39] The UK National Audit Office has shown that there were 20 government policies, strategies and reviews on energy between 1997 and 2009, with 16 from 2003 onwards (NAO, 2008).

One of the risks associated with the EMR is the lack of attention to local planning problems. UK renewables support experience is a good illustration of this In 2008 there were around 13.2GW (195 projects) in the "GB queue", i.e. projects which wish to connect but for whom no right had been granted (Pollitt, 2010). Denmark and German experience shows that local ownership matters, and might overcome local planning barriers (Pollitt, 2010).

The international experience also shows that supply chain issues might also lead to unintended consequences. Lack of PV modules in France and Germany for instance, led to an increase imports from emerging economies, undermining the claim of green jobs creation. In Germany, land constraints have led to an increase in offshore wind projects. However, developments slowed down due to delays in the delivery of sea cables (Ernst and Young, 2011).

The German experience has shown that there have been significant transmission and distribution costs due to the uptake of wind power plants (Klessmann et al., 2008). The German Energy Agency recently published a report where it estimates a need for €9.7billion investment in the grid by 2020 to integrate the planned 39% level of generation capacity (Ernst and Young, 2011). The uptake of EV in the UK would translate into significant distribution network upgrades. It has been estimated that distribution networks will be strained even at a low levels of EV penetration of 10% (Sustainable Energy Futures, 2010).

Also, given the intended renewables levels, there might be some need for rapid response generation capacity (currently, oil and coal), due to wind lulls (prolonged periods during which significant amounts of renewable capacity are not generating). This may not be properly incentivised in a market characterised by capacity contracted under low carbon CFDs and subject to an EPS.

7.5.3 Risk transfer from market players to government (and consumers?)

Also, there are a number of risk transfer issues associated with an increased intervention from the government in the market. Given information asymmetry between the market players and public sector, the question is whether the government would be well equipped to direct the generation mix as envisaged under EMR (Less, 2010). Related to this is the extent to which investors might strategically wait until policy is finalised, leading to an investment hiatus. There is indeed evidence showing that energy policies lead to strategic reactions of utilities towards subsidies (Stenzel and Frenzel, 2008).

One of the implications of removing the long term electricity price risk from generators under a contract for difference model is that when prices would otherwise have fallen, consumer prices might be higher than necessary (UKERC, 2011, p.10).

Finally, concerns about optimal timing need to be considered. One of the justifications for early action by the government is that acting today will ensure that technologies are available when we need them. This is premised on the idea of there being an advantage to moving first. The history of UK industrial policy (and indeed from policy globally) is that there is no real advantage to moving first. It is often better to wait and see how things turn out and act then. Premature action is costly. One could well argue that waiting until market mechanisms show which technologies work or even until a global agreement on carbon emissions reductions is reached, is better than the UK's current policies as reflected in EMR. Also, abatement measures are generally cheaper if they follow the renewal cycle of the capital stock, rather than through retrofitting or premature replacement of equipment (Fankhauser and Hepburn, 2010). Strategic game theory (see for instance, Kreps, 2004) teaches us that cooperation can only be induced if there is a credible threat of punishment if other parties do not co-operate. If the UK ties its hands in global (and indeed EU) carbon negotiations by having a domestic policy to reduce GHGs no matter what happens elsewhere then this is unlikely to promote cooperation. It is more likely to illicit freeriding as other countries do less in terms of renewable investment or carbon reduction.

7.5.4 Specific technology risks

There is much uncertainty about the economics of the technologies that could form future generation capacity. For instance, some authors argue that there are no credible basis for any serious economic assessment for technologies at the research and development stage (Diesendorf, 2010). A good example of this is nuclear power, where estimated costs are less than actual outturn costs (Schneider et al., 2009). Nuclear power plants bear huge specific risks compared to other technologies, and there is much controversy about their economics. There is danger of using follow on cost (NOAK) measures based on the assumption that learning will reduce costs of first of kind builds (FOAK). A decreasing electricity demand growth and an increase in financing costs adversely effects the economics of power plants. By contrast, a CPS or ETS tend to improve the economics of it.

EMR forsees significant new build of nuclear power plants. However the costs of new nuclear plant (even ahead of the power plant emergency at Fukushima Daiichi) are somewhat uncertain. Recent nuclear power plant construction experience demonstrates escalating costs. Box 7.3 gives further details on the drivers of the costs, and the two third generation nuclear power plants currently being built in EU countries – at Flamanville in France and at Olkiluoto in Finland. In the latter case, it was a joint project by Areva and Siemens which benefited from various forms of governmental support (lower interest rates of 2.6%, etc.), so that, in fact, the terms of the deal actually avoid exposure to the competitive market (Schneider et al., 2009). Despite this, the construction is running behind schedule, by more than 3 years, and over budget by at least 55%. A consumer interest group has hence estimated that this has as driven power market prices by up to 6%, and costing the Nordic countries over 1.3 billion euros per year.[40]

Box 7.3: Escalating nuclear costs and delays

Different reasons can lead to higher costs of nuclear: 1) cost of purchased equipment and commodity prices – Du and Pearsons (2009) show that the price of fabricated structural metal increased by more than 36% 2002-2007, steel by more than 46% and cement by 37%; 2) higher on site costs; and 3) longer construction periods (leading to increased interest charges during the course of construction). The cost-effectiveness of nuclear energy also depends on the operation – which in turns depends on who bears the risk. It is difficult to compare nuclear costs across projects due to currency movement and inflation, however, the CCC estimates construction cost of about $4,140 / KW, in its Fourth carbon budget report, versus current estimates of £4,200/ kW for the Finnish plant under construction. Compared to other technologies that see costs declining, nuclear

[40] See Wikipedia entry 'The economics of new nuclear plants', accessed 10th May, 2011. Source available at: http://www.elfi.fi/fi/lehdistotiedotteet/olkiluoto-3-n-myohastyminen-tulee-kalliiksi-pohjoismaisille-sahkonkaytta-2.html, Accessed 10th May, 2011.

projects demonstrate increasing costs. The MIT 2009 study on nuclear costs (updating an earlier 2003 study) doubled its estimates from $2,000 to $4,000/KW overnight costs.[41] Fears of escalating costs have stopped the growth of nuclear energy most of countries, except Finland and France. In those countries, projects for the third generation nuclear plants have been launched in Olkilouto (Finland) and Flamanville (France) – which should be finished by 2013.

In Finland, the project, whose vendor was AREVA, is considered a "financial fiasco" (Schneider et al., 2009): the construction is more than three years behind schedule and at least 55% over budget, reaching a total cost estimate of €5 billion or close to €3,100/kW. The project, which started in 2003, was a flagship project because it seemed to show that liberalization and nuclear power were compatible. However, the deal was considered as not representative of the otherwise very competitive market conditions of Finland. The reported contract price for Olikluoto-3, was subject to a successive increases: €3bn for a 1600 MW plant in 2004, then €3.2 bn, and then €3.3 bn. By March 2009, it was acknowledge that the project was €1.7bn over budget – and some argue that it is unlikely that the increases will not stop there, as many of the problems are still unsolved. The contract is now subject of a dispute between AREVA and the customers. As the customers, Fortum and PVO, are part owned by the Finnish state it seems likely that Finnish citizens will pick up some of the cost overruns.

At Flamanville, the project is led by EDF and construction started in 2007. In May 2006, EDF estimated the cost at €3.3bn. However, these costs excluded the first fuel and finance costs. In 2008, EDF re-estimated the costs to €4bn. Also, Schneider et al. (2009) mention an AREVA official suggesting that the costs will now be at least €4.5bn – and it is not clear whether this is an overnight cost. Two specific sources of potential biases and underestimates might be mentioned: EDF's aspiration to become an international market leader; and the fact that in large organizations, costs that should be attributed to specific projects are sometimes attributed to more general headings.

Source: CCC, 2010, MacDonald, 2010, Du and Pearsons, 2009, Schneider et al., 2009.

8 Alternatives policies

Here, we discuss some possible alternative policies for decarbonisation and security of supply. Looking at alternative policies, attention should be paid to the specific context of the UK energy. The UK has been at the forefront of the energy liberalisation; hence energy policies should be consistent with liberalised energy markets. On the environmental agenda, the UK has also been a front-runner, pursuing policies to reduce emissions relatively early compared to other countries. It now has a comprehensive (though not necessarily coherent) set of measures and clear targets that are consistent with international targets. On the international stage, the UK has also advocated a global deal to reduce emissions.

[41] Overnight costs exclude financing costs. A series of studies from the beginning of the 2000s generally gave estimates of below US$2000/kW and sometimes even below US$1000/kW (Schneider et al. 2009).

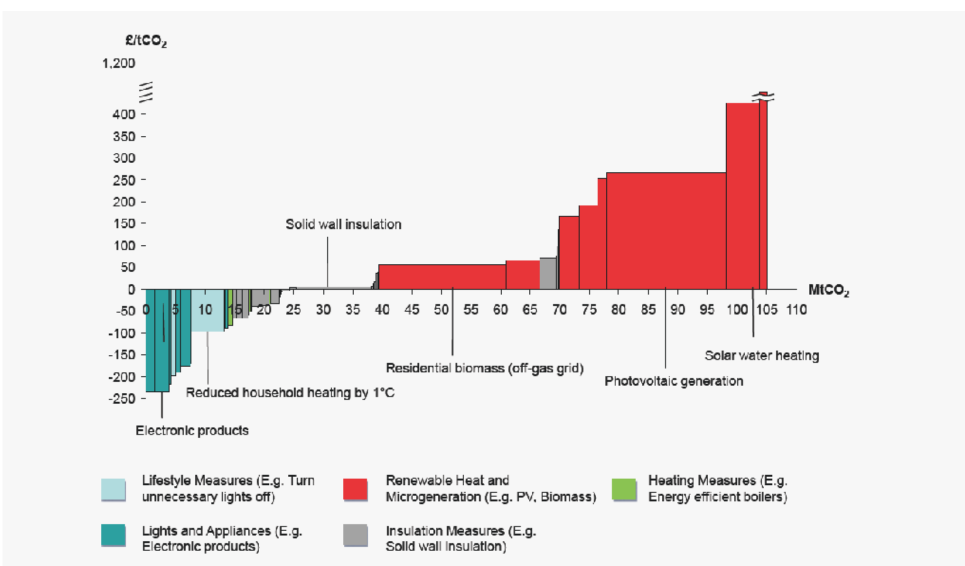
Even if the UK is on track to exceed its Kyoto targets by a significant amount[42], it is still a long way away from its ambitious 2050 national target. With regard to the power sector, decarbonisation has been described as slow and the renewables uptake limited (OECD, 2011). It is a small island with limited electricity interconnector capacity (though this is increasing), which increases the pressure on national generation capacity. The features of the building stock pose specific challenges as explained below. Also, there is a considerable and increasing share of households in fuel poverty, which may limit the type of policies that can be implemented.

One of the lessons learned from the previous sections is that UK energy policy should focus on the least cost achievement of UK decarbonisation, without "merging" the agenda with different objectives – such as "green jobs". Meeting the UK's decarbonisation targets would at most lead to a 1-2% reduction of world's CO2 emissions, which reveals that what matters is *how* UK decarbonisation is achieved. In this sense, the UK has the potential to lead by example. A key principle in the government's decarbonisation strategy regarding who should bear the costs is the "polluter pays" principle (DECC, 2010a, p.47).

8.1 Demand-side management

At the moment, the cheapest and most direct GHG abatement technologies are those which focus on demand reduction (Pollitt, 2010). There is potential for significant direct reduction of energy use in buildings, as discussed in the First Report of the CCC (CCC, 2008). This could involve combinations of renewable heat and micro-generation technologies. The CCC estimates a potential contribution of 14% reduction in carbon emissions from heat production via a combination of biomass, solar hot water, heat pumps and biogas by 2020, and further electricity savings from PV and other micro-generation technologies. This potential is illustrated in Figure 8.1.

Figure 8.1 Marginal Cost of Abatement Curve in Residential Buildings to 2020, Technical Potential



[42] However, one must be cautious interpreting this. It can be argued that the "dash for gas" and the recessions have had a more significant impact on the level of decarbonisation than any decarbonisation policy.

Source: CCC, 2008, p.221.

There are a few features of the UK building stock which significantly increase the energy used in residential buildings. First of all, the UK has some of the oldest building stock in Europe, with more than 40% of the houses built before 1945. 90% of the UK's building stock beyond 2030 will likely consist of buildings already existing today (Hinnells et al. 2008, CIBSE 2010). To meet the UK GHG target, more than one house would need to be refurbished every minute for the next 40 years (CIBSE, 2010), given the low quality of the buildings. Boardman et al. (2005), show that family size is declining, while population is increasing. This increases the total number of homes: from 24 million to 32 million or more by 2050. Also, detached homes form an increasing share of the stock since 1970, (from 10% to 22% in 2005, to an estimated 25% in 2050), which means higher levels of heat loss, at the same time as internal temperature (comfort) levels are increasing (from 12° in the 1970s to above 17° today).

A number of studies have shown that energy efficiency can deliver significant emissions reductions. Since, if successful, energy efficiency provides economic savings, it is essential that governments incentivize deployment of capital in this area (Deutsche Bank, 2009). The history of energy demand shows (see Platchkov and Pollitt, 2011) that any rise in energy efficiency must be accompanied by rises in unit prices to avoid rebound effects where higher aggregate demand for energy services offsets unit price impacts. Indeed, even if the exact magnitude is difficult to estimate, there is large agreement that rebound effects do occur (Sorrell, 2007, Sorrell and Dimitropoulos, 2008, Jenkins et al., 2011). A number of other demand related carbon reduction measures (e.g. load shifting to low carbon generation) also come at no economic costs.

As we have seen, one of the major risks of the policies put forward is the creation of windfall profits for utilities. Increases in costs for consumers could be mitigated through different options. As discussed in section 6, the "whole package" of different energy efficiency measures that are currently or will be soon available –i.e. Green Deal, FIT, RHI and smart meter roll-out - opens new opportunities for consumers' engagement. Such measures seek to involve the consumers directly through investment in demand reduction or micro-generation. Many consumers may therefore become producers or "pro-sumers" (Devine-Wright and Devine-Wright, 2004). The importance of consumers' role in the transition to a low-carbon economy is the theme of a growing literature (see for instance, MacNamara and Grubb, 2011).

8.2 Creating consumer markets for green energy

Consumers could also be involved in a more direct way in energy markets, and some suggest that this could create a market-pull for low-carbon investments. There is empirical evidence which shows that some consumers and businesses would value using low-carbon electricity (Laing and Grubb, 2010). As for "fair trade" products, some consumers are willing to pay for low-carbon energy (Roe et al., 2001, Longo et al., 2006). Green tariffs, for instance, are ways to capture this willingness to pay. Such tariffs are already offered in UK retail market - by the Big 6 and also by a few independent suppliers providing green electricity only (e.g. Ecotricity, Green Energy UK and Good Energy). The uptake is still marginal – 319,000 customers in 2009 (Ofgem, 2009a) - but this is in a context where the purchase of 'green electricity' makes very little contribution to the actual quantity of green electricity. Various rationales lead consumers to voluntarily choose more expensive tariff, but Laing and Grubb (2010) suggest that there might be further potential for harnessing this willingness to pay and creating a niche market in green electricity.

Although electricity is by nature a homogeneous good, there is scope for differentiating – at least on a contractual basis - the source of electricity and creating a differentiated green electricity market. There are certainly issues with such an idea, since differentiating the grid-based electricity supply is physically impossible, and the carbon intensity of the grid varies from minute to minute. For instance, the UK's Carbon Reduction Commitment – the UK emissions trading scheme covering organisations using more than 6,000MWh per year of electricity (Carbon Trust website) have to count their emissions based on the average grid carbon intensity. Purchases from green electricity tariffs are hence disregarded (Laing and Grubb, 2010). At present, only generation on-site can overcome the problem of tracking electricity source.

However, other options could be envisaged to create such a market-pull that would drive investment in low-carbon generation. Laing and Grubb (2010) suggest setting up a long term, zero carbon electricity contact market, a so called "GP contract", which would allow consumers to associate on a contractual basis with low-carbon investments, thus creating a market parallel to the conventional power market. The authors discuss the challenges associated with such a contract. At the household level, a substantial challenge is the unattractiveness of long-term contracts. A recent survey has shown that people are anxious about long-term contracts (Platchkov et al., 2011). Consumers might also be interested in innovative low carbon investment vehicles. An idea suggested in the context of nuclear is the issuing electricity price indexed bonds to finance nuclear investments (Newbery, 2010). Further research could shed some light on the possible remedies to the challenges associated with increased consumer engagement.

8.3 R&D support

The extent to which a low-carbon transition can be achieved cost-effectively depends on innovation, which in turn is driven by research and development (R&D). However, R&D funding in the electricity sector has been typically low, especially as compared to more innovative sectors such as the pharmaceuticals or IT (Laing and Grubb, 2010).

There is a tension between competition and investment, and research has shown that liberalisation of electricity markets in the UK has had a strong effect on innovative activities in the industry. The two key aspects observed are a reduction in R&D spending and an apparent increased commercialisation of innovation (Jamasb and Pollitt, 2008). This reveals a lower interest in the long-term benefits of R&D activities. There is a need for a framework to enhance R&D and support technological progress (Jamasb and Pollitt, 2010). A number of market failures – such as uncertainty and knowledge spillovers - are among the reasons advanced for this lack of investment (Goulder and Parry, 2008). The homogenous nature of electricity of also reduces incentives to innovate.

Several authors agree on the fact that rather than focusing on strategic roll out of subsidised renewables, it might be more cost effective to focus on R&D and innovation to reduce costs of technologies. Such costs, because they benefit society more generally, should be funded out of general taxes (or equivalently, hypothecated taxes). Thus they could be funded out of the extra revenue generated by a carbon tax and/or a full VAT on energy and R&D expenditures could be coordinated at the EU level to maximise benefits (Newbery, 2010, Newbery et al., 2011). Currently, in the UK, domestic energy is subject to a reduced VAT which distorts energy consumption relative to consumption of other goods. Charging full VAT - 20% rather than 5% - would raise about £3 billion per year, and offer an alternative way to fund R&D support (Newbery, 2010).

R&D measures have been implemented in various countries, as a complement to RES portfolios (Fisher and Preonas, 2010). The issue is therefore one of the optimal mix of support for a strategic roll out of renewables and support for R&D.

8.4 Other routes to carbon price certainty

Despite the economic downturn, in 2008, carbon trading globally exceeded the $120 billion, up from $64 billion in 2007 (Capoor and Ambrosi, 2009). By 2020, trading volumes could reach $1 trillion (Fankhauser and Hepburn, 2010). Despite all the weaknesses of emission trading systems, this gives a sense of the potential magnitude of carbon trading.

A long-term price on carbon is needed for meaningful climate change mitigation (Stern, 2007). This provides investors with clear signals about the economics of investments in different types of technologies. A spot-market alone is not enough given the long-term nature of such investments (Fankhauser and Hepburn, 2010). Less volatile carbon prices reduce risks and hence capital costs. Also, if the carbon price reflected the true societal costs associated with climate change, large additional support policies for renewables would lack economic rationale. The latter are a second-best indirect means to tackle CO2 emissions (Fisher and Preonas, 2010).

Hence, certainty and longevity are important features of meaningful carbon pricing, but flexibility is also needed. Flexibility can help firms to mitigate business cycles, manage their debt levels or take advantage of expected innovations (Fankhauser and Hepburn, 2010). Cost-effectiveness is crucial because people's willingness to pay is limited and low-carbon investments are extremely costly (Hepburn and Fankhauser, 2010). Different mechanisms have been suggested to improve carbon price signals.

Fankhauser and Hepburn (2010) examine the time consistency of policy, and discuss a number of mechanisms that could provide greater price predictability and credibility over time. The authors propose several routes to this. One of them is via longer-term commitments. As banking or borrowing CO2 allowances between trading periods is limited in the EU ETS[43], longer commitment periods would allow greater possibilities for price smoothing, increased liquidity and hence cost-reductions. A second possibility that could deliver the same benefits would be to give market players the opportunity to bank and borrow allowances across commitment periods. The lack of this opportunity opens up a great risk of price crash or spike – this happened in the EU ETS Phase I.[44] The authors argue that there are substantial advantages of such mechanism, and very few drawbacks. Banking has now been established in ETS Phase II and according to the authors, partly supports more stable prices.

[43] In the EU ETS, there is now banking, but only limited *de facto* borrowing within a particular commitment period, and no borrowing at all between commitment periods. In addition, as an increasing share of allowances is auctioned, the relative amount of borrowing decreases (Fankhauser and Hepburn, 2010). There is however no current guarantee that the market will exist after 2020.

[44] The market was slightly over allocated and the allowance price fell to almost 0.

A third possibility could be to smooth prices by binding carbon prices from below and above (Fankhauser et al., 2011). Fankhauser and Hepburn (2010) consider the advantages and drawbacks of a number of such "cap and floor" schemes: (1) setting reserve prices – i.e. floor prices to ensure that prices do not go below a certain level (see Hepburn et al., 2006); (2) creating an "allowance reserve" in case prices rise too high; or (3) setting rigid price ceilings and floors. Hence, as we can see, the volatility of carbon price is manageable within the existing EU ETS. However the issue of volatility is often confused with the issue of the long run average price of carbon permits. While volatility in the existing carbon market is an issue, it is a minor one because the long run moving average price is reasonably stable. The real issue for incentivising investment in a low carbon economy is the low average price around which the market price fluctuates.

8.5 Refocus on action at the EU level

Action at the EU level can take different forms. One of the most direct measures the UK could take to avoid carbon leakage due to increased UK levels of renewables and/or emissions reduction would be to advocate a tightening of EU ETS quotas (OECD, 2011). The effect of such measures is of course heavily dependent on political negotiations. Another specific action at the EU level that has been advanced would be to seek an agreement on a 'minimum reserve price' of the permit auctions. This would in fact amount to a carbon price floor, where permits would not be sold unless polluters paid the reserve price or higher (Fankhauser et al., 2011). A further amendment would adjust CO2 allowances in the EU ETS in relation to actual delivery of renewable across the EU. Currently, more subsidised renewable electricity means lower prices in the permit market, causing an undermining of incentives for non-subsidised low carbon electricity. This means that subsidy of renewables creates the need for more subsidy renewables, rather than moving towards a situation where renewable electricity is cost effective at reasonable carbon prices.

A second avenue for action at the EU level would involve the international trading of green energy. Given the ambition of UK targets, it will be extremely difficult to achieve significant reductions – not to say meet those targets - nationally at realistic costs. If additionality could be established, a sensible alternative could be to meet those targets through green energy purchases from abroad (Pollitt, 2010). The European RES Directive (Directive 2009/28/EC) actually provides a legal framework on which the necessary mechanisms could be built. The Directive introduces three "flexibility" or cooperation mechanisms that enable countries with expensive or low potential for renewables[45] to cooperate with other countries in achieving their targets[46] (Klessmann et al., 2010).

There is increasing interest in an international tradeable green certificate - TGC (Meyer, 2003). This would ensure more stable prices than in a national TGC. This would require some amount of harmonisation to ensure the avoidance of unfair competition. Early pilots show that this option offers potential. The Renewable Energy Certificate System International (RECS)[47] for instance, is an initiative by market players (electricity generation companies, traders, and consultancies and others) from Austria, Belgium, Holland, Italy, Norway and the UK that seek to promote a pan-European

[45] The national allocation of European RES targets does not necessarily match countries' potential.
[46] The three intra-European cooperation mechanisms are: statistical transfer, joint projects, and joint support schemes Governments have a key role in setting up statistical transfer and joint support systems. An additional option is the possibility of physically importing RES electricity from non EU countries. See Klessmann et al. (2010) for a discussion of the advantages and drawbacks of the different mechanisms.
[47] See http://www.recs.org/.

Renewable electricity market. RECS have established a voluntary market[48], where large volumes have already been generated, internationally traded and cancelled. However, an internal market for renewable energy needs to be established that would improve the process and ensure better cost efficiency. In 2009 RECS launched a discussion on the cooperation mechanisms (RECS International, 2009); and interest has been shown from part of member states, which have started to discuss the implementation. No results have been made public yet (Klessmann et al., 2010).

8.6 The importance of accompanying fiscal measures

According to some estimates (SKM, 2008), the UK support costs for renewables could be around £5.2-7.8 billion per year by 2020, i.e. between £60-90 per household. Newbery (2010) estimated that a CO2 tax of £15/tonne on electricity would raise £2.75 billion per year, based on current levels of electricity grid emissions, and a similar tax on final gas consumption could raise about £1.5 billion annually. This, in addition to the around £3 billion per year from raising VAT on energy, amounts to £7.3 billion per year. As emissions decrease, so do the revenues from CO2 tax. However, the carbon price should rise over time (Newbery, 2010). There is a strong case for such general taxation, due to the distortion of targeted taxes. Removing this artificial distortion lessens the deadweight costs of taxation, arising from over-consumption of energy and under-consumption of other goods (Newbery, 2010).

There is a fundamental point here: a high carbon price (or, equivalently, tight caps on auctioned CO2 allowances) increase brings revenue that can be recycled. Everybody is worse off compared to the non-tax scenario, via the induced higher energy prices. Higher tax-induced prices worsen social welfare (the so-called tax-distortion effect). However, the Treasury does get this revenue to recycle, and it can be redistributed, which allows other distorting taxes to be reduced and improves welfare (the revenue recycling effect). Goulder and Parry (2008) show that high prices on externalities should be accompanied by a recycling of the revenue back to consumers, to ensure that the net benefits to society are positive. This points to a key element of the EMR: the EMR is conducted by the DECC, but there are important fiscal mechanisms that could be developed and the Treasury should take a much greater role in reforming energy and carbon pricing.

The latest OECD report on the UK also argues in favour of harmonisation of carbon prices across sectors (OECD, 2011). This lack of harmonization, the reports says, is due to the way policies have been implemented (proliferated), and a simplified structure would be more efficient.

The UK government is reluctant to increase taxes on household energy use due to concerns about the impact on fuel poverty. A number of studies indeed show that flat energy taxes are regressive (e.g. Bull et al., 1994, Metcalf, 1999, Dinan and Rogers, 2002, West and Williams, 2004, Bento et al., 2009, Ekins and Dresner, 2004). They put a disproportionate burden on low-income households, as they use a higher proportion of income for energy bills. However, there are still advantages to a carbon tax - as compared to a cap-and-trade scheme - for instance. Indeed, in the latter, political reasons lead to inefficient grandfathering of permits, which is avoided in the case of carbon tax. There are two important aspects determining the extent of adverse impacts: (1) how tax revenue is reallocated is crucial to lessen the burden on the most vulnerable through compensation schemes;

[48] The voluntary market is driven by consumers willing to consume renewable electricity. It is based on certified renewable energy sources from which certificates are traded and cancelled on a voluntary basis.

and (2) the time perspective – i.e. whether household effects are examined with respect to annual income or lifetime income (Poterba, 1989 and 1991, Hassett et al., 2009, Metcalf et al., 2010).

Ekins and Dresner (2004) investigate the extent to which, in the UK, a compensatory scheme could lessen the burden of carbon taxation. Among their findings, they note a substantial level of heterogeneity in energy consumption patterns within income deciles. Those on low-incomes also pay much more per unit of energy than higher income households. Hence, higher taxes on energy would indeed be regressive. The authors examine different compensation mechanisms. Interestingly, they find that those in the lowest income decile – under a compensatory mechanism - could indeed end up being net gainers and it is hence possible to make the overall impact of the tax progressive. However, since the distribution of consumption of energy is highly skewed, some households within a particular income decile would become net losers, even if there was an average benefit within the decile. Hence, the introduction of such tax would be problematic (though no more so than any other poverty reduction scheme). However, the authors suggest some possibilities to address this. Reducing consumption through the kind of strategies described in Section 6 – i.e. directly addressing the cause - could mitigate the loss. To strengthen the uptake of energy efficiency measures, they propose a surcharge on those households that do not implement the cost-effective measures identified through an energy audit. They estimate that such schemes could save up to 4 million tonnes of carbon over 10 years, and £20 billion for an investment of £6.4 billion (Ekins and Dresner, 2004). Further research is needed to assess the extent to which such a tax (more akin to Redpoint's CPS50 scenario) and benefit scheme could yield better societal outcomes than the government's preferred EMR policy package.

9 Conclusion

The UK faces an 'impossible trinity' of energy policy objectives: decarbonisation, energy security and affordability.

Pushing forward with decarbonisation will be costly, especially, if the sources of decarbonisation are substantially based on immature renewable technologies. Energy security, especially with respect to electricity, is something which markets can manage well. However **energy security becomes more difficult if the government increasingly specifies energy technologies** whose primary aim is the achievement of environmental targets. The large amount of investment envisaged under government policy proposals must be paid for and ultimately this must be paid for by households, through a combination of higher taxation, higher household energy prices and/or higher prices more generally. **Affordability can be maintained for a few, via targeted assistance or subsidies, but the majority of households will have to pay more**.

<u>Faced with these competing policy objectives there are some clear ways forward.</u> Carbon emissions should face their full social cost, via taxation or via high CO2 permits prices. Immature generation technologies need to be efficiently subsidised via a judicious combination of R&D support and support for strategic roll out. The market should, as much as possible, be left to deliver energy security in the face of proper penalties for non-supply of energy. Wherever possible companies and technologies must compete for customers rather than look to governments for support. Attention must be paid to the distribution of welfare both between consumers, government and companies and within the income distribution of households. Measures to enhance the efficient delivery of

decarbonisation and energy security must be combined with appropriate redistributions of income and targeted intervention to increase energy efficiency.

Policies designed to meet the objectives must also create an environment where companies are likely to invest and compete in such a way as to keep energy prices as low as possible. We need to have policies which are consistent with one another and which give clear long term signals to investors. This is something which normal markets do well, because properly functioning markets give rise to predictable returns for investors and the expectation of political support for the legitimate pursuit of reasonable profits. Where governments do intervene in markets they need to do so in a consistent and predictable way. An important part of this is sufficient attention to the risk of unintended consequences in policy design and policy robustness in the face of new information. This usually involves having consistent and understandable policies.

Our analysis raises some serious questions about the EMR proposals as regards meeting the policy objectives, best practice policy design and policy consistency for investors.

On the policy objectives:

Two of the four elements of EMR are redundant. The EPS performs no role in hitting any of the environmental targets and is costly. The premature introduction of a targeted capacity mechanism is also costly and at variance with best practice learning from the US. Both of these elements have negative net present value with the government's own impact assessment of EMR policies.

The EMR envisages household bills rising by 32% by 2030 and by 47% per unit of electricity on average. If richer consumers subsidise the poorest consumers they will pay significantly more than this. A substantial part of this relates the UK's expensive renewable policy, which has proved difficult to get much traction on, except at very high cost, due to onshore planning difficulties. The preferred policy package transfers significant amounts of money to the private sector and the government from consumers, re-evaluating this at sensible social weights suggests other policy packages might be better.

The short term impact of the EMR on European carbon emissions is zero, given the existence of the EU Emissions Trading System. The long term impact depends on the extent to which the EMR bolsters or undermines EU emissions targets. From a game theoretic perspective, the EMR would seem to tie the UK's hands in future climate negotiations. This might well remove the UK as a credible player in determining the future of the EU ETS and European carbon policy more generally.

In short, on the face of it, residential consumers will be getting very little for the extra money they will be paying out.

On best practice policy design:

The EMR does not clearly move the UK towards a more comprehensive set of carbon taxes across the whole economy, though clearly the introduction of a CPS is a move in that direction.

UK procurement policy for large scale renewables needs to significantly address the issues of optimal subsidy paths for renewables and the correct balance between R&D expenditure and support for the strategic roll out of capacity. This is not done under EMR.

The EMR substantially interferes with market incentives for energy security via the flexible installation of gas-fired power plants or the market based choice of portfolios of generation plants. It shifts much of the responsibility for the maintenance of energy security in the electricity market to the government, mediated by the design of capacity markets.

EMR is about the proper pricing of a major environmental externality within our economy. Therefore it is as much about optimal tax policy as it is about optimal energy policy. It is not clear that there is sufficient joining up – between DECC and HM Treasury - of the analysis of how externalities should be priced and what should be done with the tax revenue.

From the perspective of individual households much more attention needs to given to the macro-efficiency and distributional consequences of EMR to mitigate the effect on their real incomes.

On policy consistency for investors:

The OECD (2011) has rightly criticised the UK for having an overly complicated and inconsistent set of energy policies. This creates inherent risks for investors, as individual policies are vulnerable criticism and prone to be short term and subject to revision.

The question for EMR is whether it contributes to a reduction in policy complexity and improvement in the investment environment for firms. The EMR certainly claims that this is its intended effect.

It is however unclear that it can do this via the creation of CFDs and the CPS, both of which seem prone to policy change. CFDs may provide certainty of returns for individual projects but they are not guaranteed over sets for projects. CFDs will not protect investors from windfall profits taxes, which have recently been observed in energy, if policies prove to be politically overly generous to investors.

The EMR's own risk analysis underplays the scope for policy failure in the detailed design and operation of the policy elements and the residual policy uncertainty facing investors with CFDs for nuclear.

While risks may not be reduced for investors, they are certainly increased for household consumers who will underwrite any CFDs and commit to pay for expensive renewables and nuclear plants regardless of world energy prices.

Ultimately, the costs imposed on consumers will be key in determining support for the government's energy policy. Strong grass-roots political opposition can lead to policy U-turns. It is possible that policy developments in the heat market (e.g. the Renewable Heat Incentive) and in demand reduction (e.g. the Green Deal) may mitigate some of the aggregate household energy cost impact of EMR. However, good policies elsewhere should not be used to obscure the potentially serious impacts of the EMR on unit electricity costs.

10 Documents reviewed

A. **CCC latest report on 4th Carbon Budget, December 2010**
http://www.theccc.org.uk/reports/fourth-carbon-budget

B. **DECC EMR – Impact assessment, December 2010**
http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx

C. **Redpoint Energy modelling**
http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx

D. **DECC "Estimated impacts of energy and climate change policies on energy prices and bills", July 2010**
http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/markets/impacts/impacts.aspx

E. **Ofgem, Project Discovery**
http://www.ofgem.gov.uk/markets/whlmkts/discovery/Documents1/Discovery_Scenarios_ConDoc_FINAL.pdf

F. **Ofgem Supply Probe – "State of the market report"**
http://www.ofgem.gov.uk/Markets/RetMkts/ensuppro/Pages/Energysupplyprobe.aspx

G. **Retail Market Review**
http://www.ofgem.gov.uk/Media/PressRel/Documents1/Retail%20Market%2026%20November.pdf

11 Annexes

11.1 CCC Fourth Carbon Report assumptions used

Table 11.1 CCC Fourth Carbon Report assumptions

Reference emissions scenario	
Investment in generation to replace retired capacity	Unabated gas fired
Emissions	250gCo2/kWh

Extended Ambition Scenario			
Category	**Element**	**Assumption**	***Source***
		Targets by 2020	
	Social discount rate	3.5%, declining over time	
Low carbon investment	Wind	23GW	*p.245*
	Non wind	4GW	*p.245*
	CCS	4 plants	*p.245*
	nuclear	3 plants by 2022	*p.245*
		Outcome of extended ambition scenario	
Emission intensity		300gCo2/kWh From 490gCo2/kWh (2009)	*p.245*
		Assumptions about technologies	
Conventional	Coal		*p.247*
	Coal CCS	11p/kWh in 2030	*p.260 (from Mott Mac Donalds, DECC central Fossil fuel price assumptions)*
	Gas CCS	40-50p/therm (2009) 76p/therm in 2030 11p/kWh (incl. CO2 costs)	*p.263 (DECC central case projection)*
	Gas	7p/kWh unabated or 12p/kWh with CO2 price	*p.247 , p.255 (DECC)*
Nuclear new built		Cost: 7p/kWh in 2030 (central case);	*p.255-8 (Mott Mac Donalds)*
RES	Onshore wind	Cost in 2030: 9p/kWh	*p.249, p.251*
	Offshore wind	Cost in 2030(?): 11-13p/kWh	*p.249*
	Tidal	16-20TWh/year	*p.25*
	Tidal stream	14-25p/kWh in 2020, down to 8-17p/kWh	*p.252 (DECC)*
	wave	18-25p/kWh in 2020, down to 7-11p/kWh in 2050	*p.253 Ernst and Young (2010)*
	Biomass	8-10p/kWh (solid) 5-10p/kWh (bioga, 2020)	*p.254*
	Geothermal	4-13p/kWh (2009) 5p/kWh (by 2030s)	*p.254 (IEA estimates for EU)*
	Solar	28p/kWh in 2020 (5MW) 45p/kWh (small residential scale)	*p.254*

Abatement scenarios			
Category	**Element**	**Assumption**	***Source***
Demand from current sectors		360TWh	*p.274 (DECC DUKES)*
Demand from new sectors	Heat	Up to 43TWh in 2030 (i.e. 12% of demand in 2030)	*p.275*
	transport	51TWh in 2030 (14% of demand from existing sectors)	*p.275*
DSR			*Box 6.10 analysis carried out by Poyry for CCC*
Technology costs		NOAK, 10% discount rates	*p.277 (Mott Macdonalds) Central*
Capacity (2020)	Nuclear	2 plants	*p.277*
Capacity (2020)	Wind	27GW	*p.277*
2020	RES	4GW	*p.277*
Throughout 2020s	Offshore	To keep RES at 30% of total generation	*p.277*
After 2025	CCS	5GW	*p.277*
	CCS coal	Retroffited in all scenarios	*p.277*
	Nuclear and		*p.277*
Interconnection	With NW Europe	6GW	*p.277*
	With Norway	2.5GW	*p.277*
	With Ireland	1.9GW	*p.277*
Storage		Remains same capacity	*p.277*
Others	Planning, Energy Efficiency		*p.277*
Low carbon investment			
(1) Low-investment scenario **(very limited demand growth from EV and heating, tight constraints on build rates of low-carbon plant)**			
Demand 2030	Heat	24 TWh	p.278
Demand 2030	Transport	15 TWh	p.278
Low-carbon generation		21GW through 2020s	p.275
Emissions		52MtCO2 in 2030	p.275
	Intensity	130g/kWh	p.278
(2) Medium investment **(demand growth from EV and heat from CCC medium scenarios, consistent with preferred economy-wide scenarios)**			
Demand 2030	Heat	51 TWh	p.278
Demand 2030	Transport	30TWh	p.278
Demand from new sector	EV (pure electric or plug-in)	60% of new cars and van	p.276
	Heat (heat pumps)	40% of total heat in buildings	p.276, CH 4&5

Build constraint		Average annual addition = 3-4GW	**Relaxed such that plants is added whenever it is cost-effective (more similar to Redpoint)**
Investment – low carbon		36 GW through the 2020s	
Emissions		16MtCO2 in 2030 (intensity: 50gCo2/kWh)	p.278
Panning			Preferred scenario for planning, most appropriate balance of risk
Total costs (% 2030 GDP) & absolute investment costs 2021-2030 (£ bn)	Central fossil fuel	0.4% & 94bn	p.281
	Low fossil fuel	0.7% & 94	p.281
	High fossil fuel	0.2% & 94	p.281
	Low capital costs (25% lower)	0.2% & 70	p.281
	High K costs (25% higher)	0.2% & 117	
Conclusions	*Develops important options for the path to 2050, delivers investment in mature low-carbon technologies, u to cost-effective levels given their best estimate of future demand and carbon prices* *Preferred economy-wide scenario for EV and heat, therefore appropriate for coordinated approach across sectors*		
High investment = high demand growth from EV and heat			
Demand – heat	Heat		
Demand	Transport		
Demand from new sector	EV	85% of new cars in 2030 10% hydrogen fuel cells	p.276, ch4&5
	Heat	55% of total heat in buildings	p.276, ch 4&%
Investment	Low carbon	37GW	p.276
Emissions	Emissions	13MtCO2 in 2030	p.276 p.278
	Emissions intensity	Average 40gCos/kWh	p.278
CCS	CCS gas		Only available in this scenario
Build constraint		Average addition 3-4GW	p.279
envisaged	unabated gas-fired generation	around 10-15GW to 2020	
	CCS demo	1.5GW	
	nuclear	3GW	
	Wind	23GW	

11.2 Redpoint assumptions used

Table 11.2 Redpoint BAU scenario

BAU "baseline" scenario assumptions, period considered: 2010-2030 Based on current policy, all prices 2009 real terms			
Category	**Commodity**	**Price**	**Source**
Fuel prices	Coal ARA ($/tonne)	2010: 110 2015: 80 2020: 80 2025: 80	p.21, C DECC UEP, June 2010, central price case, p.8
	Natural gas NBP[49] (p/therm)	2010: 58 2015: 63 2020: 67 2025: 71	p.21 DECC UEP, June 2010, central price case, p.8
	Crude oil $/bbl	2010: 70 2015: 75 2020: 80 2025: 85	DECC UEP, June 2010, central price case, p.8
Exchange rates	£/$	1.57	DECC UEP, June 2010, p.8
	Euro/£	0.890	
UEA prices	£/tonne	2010:14.1 2015: ? 2020: ? 2025: ? 2030:70	DECC central assumptions

[49] National Balancing Point (NBP) and Amsterdam-Rotteram-Antwerp (ARA), standard trading locations for gas and coal respectively.

Demand		2010: 2015:325.6 2020:337.3 2025:348.9 2030:360.5	p.21 DECC UEP, June 2010, central price case *Projected to grow by around 2% between 2009 and 2020, with growth restrained by EE. After 2020, slightly higher, because effect of economic growth is larger than EE.*		
Max. build rates			p.22 Annual build rates and total cumulative new build are limited		
Capital costs (CAPEX, real 2010, £/kWh)	**Capex, real 2010, £/kW**	**FOAK**	**NOAK**	**FOAK/NOAKswitch**	p.22 (Mott MacDonald UK Electricity)
	Gas - CCGT	823	731	2010	
	Gas - CCGT with CCS	1,396	1,111	2010	
	Coal - IGCC with CCS	3,244	2,487	2010	
	Coal - ASC with FGD and CCS	3,128	2,479	2010	
	Nuclear - PWR	3,812	2,966	2010	
	Wind - Onshore	1,731	1,547	2010	
	Wind - Offshore	3,110	2,840	2010	
	Wind - Offshore R3	3,625	3,087	2018	
	Small biomass power only	2,820	2,540	2015	
	Large biomass power only	2,230	1,950	2020	
	Large biomass CHP	4,160	3,730	2020	
	Wave	3,559	3,559	2010	
	Tidal Stream	3,812	3,812	2010	
	Hydro	2,070	1,954	2010	
	Energy from Waste	6,150	5,120	2010	
	OCGT	474	438	2010	
	AD on wastes	4,170	3,900	2010	
Learning		**2010**	**2020**	**2030**	
	Gas – CCGT	1	0.89	0.88	

	Gas - CCGT with CCS	1	0.9	0.89	
	Coal - IGCC with CCS	1	0.88	0.84	
	Coal - ASC with FGD and CCS	1	0.85	0.84	
	Nuclear – PWR	1	0.93	0.91	
	Wind – Onshore	1	0.9	0.89	
	Wind – Offshore	1	0.9	0.89	
	Wind - Offshore R3	1	0.9	0.89	
	Small biomass power only	1	0.88	0.86	
	Large biomass power only	1	0.95	0.87	
	Large biomass CHP	1	0.93	0.89	
	Wave	1.79	0.9	0.48	
	Tidal Stream	2.94	0.72	0.46	
	Hydro	1	1	1	
	Energy from Waste	1	1	1	
	AD on wastes	1	1	1	
	OCGT	1	1	1	
Planning & construction	**Type**	**Economic life (years)**	**Construction (years)**	**Planning(years)**	
	Gas – CCGT	20	3	2	
	Gas - CCGT with CCS	25	4	2	
	Coal - IGCC with CCS	25	4	4	
	Coal - ASC with FGD and CCS	25	5	4	
	Nuclear – PWR	30	5	4	
	Wind – Onshore	20	2	5	
	Wind – Offshore	20	2	5	
	Wind - Offshore R3	20	2	5	
	Small biomass power	20	2	2	

	only						
	Large biomass power only		20	4		2	
	Large biomass CHP		20	3		3	
	Wave		20	2		4	
	Tidal Stream		20	3		4	
	Hydro		20	5		5	
	Energy from Waste		20	3		3	
	AD on wastes		20	1		2	
	OCGT		20	2		2	
Capacity credits						*p.128/p.133*	
Hurdle rates	Detailed assumptions for: - cost of capital - technology and development risk - market and policy risk					*p.129*	
Renewable Obligation		**2010 - 2012**	**2013 -2016**	**2017 -2021**	**2022+**		
	Co-firing (regular)	0.5	0.5	0.5	0		
	Co-firing (energy crops)	1	1	1	0		
	Wind – Onshore	1	1.3	0.75	0.25		
	Wind – Offshore	2	2.35	1.75	1		
	Small biomass power only	1.5	1.5	1	0.25		
	Large biomass power only	1.5	1.5	1	0.25		
	Large biomass CHP	2	2	1	0.25		
	Wave	2	4	4	2		

	Tidal Stream	2	4	4	2	
	Hydro	1	1	1	0.25	
	Energy from Waste	1	1	1	0.25	
	AD on wastes	2	2	2	0.5	
RES –large scale (>5MW)			29% RES by 2020, figure consistent with DECC renewable energy strategy			p.22/23
RES – small scale (<5MW)		2.8 TWh by 2020, then levels off				
Inter-connection		+1.5GW				p.23
Large combustion plants						p.23
Nuclear plants	3 AGR	Plant	Capacity (MW)	Closure date	Annual availability	p.127
		Dungeness B	1,110	2018	70%	
		Hartlepool	1,210	2019	70%	
		Heysham 1	1,150	2019	70%	
		Heysham 2	1,250	2028	70%	
		Hinkley Point	820	2016	70%	
		Torness	1,250	2028	70%	
		Hunterston	820	2016	70%	
		Sizewell B	1,190	2045	87%	
		Oldbury	434	2010	75%	
		Wylfa	980	2010	75%	
	Wylfa Magnox Nuclear		Closed end of 2010			Agreed with DECC
	Oldbury magnox nuclear		Closed end of 2010			Agreed with DECC
CCS	Coal		4			p.24

CCS	Gas	N/A	p.24
VOLL		10,000/MWh	p.28
DSR		1GW (industrial and commercial)	p.30
Others factors (/constraints) – assumed to be addressed to a sufficient extent			
resource potential constraints			
Planning constraints			
Connections constraints			
supply chain constraints			

Table 11.3 Redpoint decarbonisation options

Decarbonisation options assumptions **All options meet an emissions intensity of 100g/kWh in 2030, as designed** **Results p.52 /key messages p.78/summary tables impacts p.79/risks, implementation issues discussed p.80-4/Summary p.84**					
Category		**Element**		**Assumption**	Source
Specific assumptions – Carbon Price Support scenario **introduced in 2013 and escalates annually with visibility to at least 2020**					
Gearing (increase, %)	CCGT	0	For every % reduction in earning risk, it is possible to increase the debt by 1%	Those are estimates and there are diverging views as to the extent to which carbon price support will be "bankable", i.e. whether financial institution are willing to increase lending projects on the back of it. Typically assume a gearing between 40-70% depending on investor type	p.33-4
	CCGT +CCS	7.5			
	Coal + CCS	5			
	Nuclear	5			
	Onshore wind	0			
	Offshore wind	0			
	Biomass	2.5			
	OCGT	0			
Specific assumptions – Premium Payment scenario **2 approaches: (1) premium tariffs paid directly to generators, set by government by technology or (2) competitive tenders (by technology), where investors bid for the premia they require above expected future electricity prices**					
Objectives	**RES**	**29% by 2020 & 35% by 2030**			

	Carbon intensity		**100g/kWh by 2030**		
Gearing (assumptions)	CCGT	0	*Those assumptions are made based on the results of simulating earning risk for different types of investments.* *Policy here is assumed to be administered tariffs set by government with the objective to promote a diverse range of low-carbon generation. 3 years of tariffs, the greater when construction or when becomes operational.* *Other details of design are made under DECC's guidance, (e.g. implemented in 2014 with 2 years notice, etc.)*		p.37-8
	CCGT +CCS	10			
	Coal + CCS	15			
	Nuclear	10			
	Onshore wind	0			
	Offshore wind	0			
	Biomass	0			
	OCGT	0			
Estimated Premium Payments	**Graph on p.39**		*Those premium payments result from the iterations and are inserted back hold constant under sensitivity modelling.* *Paid based on availability rather than output (unlike current RO).*		p.39
Targeted EPS			***This is included, applied to all new plant***		p.39
Specific assumptions – Fixed payments **2 alternative methods: (1) administered by tariffs set by the government according to technology or (2) competitive tenders organised by technology , where investors bid for the payment they need**					
Objectives	**RES**		**29% by 2020 & 35% by 2030**		
	Carbon intensity		**100g/kWh by 2030**		
Gearing	CCGT	**0**	*Those assumptions are made based on the results of simulating earning risk for different types of investments.*		
	CCGT +CCS	**15**			
	Coal + CCS	**25**			
	Nuclear	**25**			
	Onshore wind	**25**			
	Offshore wind	**25**			
	Biomass	**25**			
	OCGT	**0**			
Estimated fixed payments	**Graph on p.43**		*The required level of FP is also estimated from iteration.* *Assumed that based on availability rather than output.* *Includes tEPS to be applied to all new plant.*		**p.42-3**
Specific assumptions – Contract for Differences					

Gearing	CCGT	0		
	CCGT +CCS	10		
	Coal + CCS	20		
	Nuclear	25		
	Onshore wind	15		
	Offshore wind	15		
	Biomass	20		
	OCGT	0		
Estimated CfD			Assumed to (as FP): 1) Contract strike price and technology premia set by Gov and contract cover economic lifetime off the plant 2) diverse range of technologies is incentivised 3) implemented in 2014 with 2 years notice 4) combined contract strike price and technology premia based on LRMC of the different technologies rounded to nearest £5/MWh Includes tEPS to be applied to all new plant (600g/kWh at baseload)	
Specific assumptions – Strong Performance Standard **Different ways to implement: (1) rate basis or annual bubble; (2) new plant only or all plant; (3) specific plant types (4) individual plant level or generator's portfolio**				
Objectives				
Gearing				
EPS			Stronger than tEPS: introduced in 2018 at 2.39 t/KW, equivalent to 275g/kWh operating at baseload.	p.48
Options to enhance security of supply **Options set to achieve 10% de-rated capacity** **Key messages p.101/impact summary p.102/risk & implementations issues p.103-4/summary p.104**				
Capacity payments for all				
Target	10% de-rated capacity ma			
Gearing				

Capacity payments				Assumed low carbon generators receive CP under all decarbonisation options except fixed payments, where central buyer receives them and deduct them from costs of fixed payments recovered from customers.	
			Targeted capacity tender		
Target	10%	Targeted capacity tender are introduced when de-rated capacity margin is forecast to drop below 10%.			
Assumed to be addressed to a sufficient level		Resource potential constraints, Planning constraints, Connections constraints, Supply chain constraints			

11.3 EMR assumptions used

Table 11.4 EMR consultation document – assumptions

Element	**Assumption**	**Comments**	***Sources***
	BAU (No new policies, current set of policies as currently designed)		
	Reform policies		
Emission intensity power sector in 2030	100gCo2/kWh (indicative (not binding)	vs 200gCo2 BAU and 50gCo2/kWh CCC recommendations decision of level of reduction in power sector for period 2024-2028 will be taken in 2011	*p.39 Government*
Take-up of RES electricity	29% of total electricity generation in 2020 2035: when investors have perfect foresight of rising carbon price =35%	"This is different from the assumption of Carbon Price Support consultation, where level of renewable incentive is held constant across different scenarios, to isolate impact of carbon price support. All other assumptions are consistent"	*p.39-40*
Levelised costs			*p.40 (UEP June 2010)*
Electricity demand			*p.40 (UEP June 2010)*

Fossil fuel prices			*p.40 (UEP June 2010, central case)*
Limitations	Administrative costs, No short term impact, Incentives at correct level, No financing constraint, Liquid markets, Perfect competition		

11.4 DECC July 2010 assumptions used

Table 11.5 DECC July 2010, Estimated Impact of Energy and Climate Change Policies on Energy Prices and Bills, BAU scenario

BAU Scenario assumptions, period considered: 2010-2030 Based on current policy, all prices 2009 real terms				
Category	**Commodity/ Policy**	**Price/Detail**	***Comment***	***Source***
Fuel prices	Oil Price	\$80/bbl by 2020	*Uses "central prices" scenario from DECC. Also mentions \$60/bbl and \$150/bbl. Projections were made in May 2009, and reviewed in Jan 2010, but not changed.*	*DECC Central Assumption (UEP)*
	Gas Price	69 pence/therm by 2020	*Uses "central prices" scenario from DECC. UEP has price of 67 pence/therm in the main document, but of 69 pence/therm in the detailed annex.*	*DECC Central Assumption (UEP)*
UEA prices				*DECC central Assumptions*
<u>Policies Included:</u>				
CESP	Community Energy Saving Program			
CERT	Carbon Emissions	Runs till 2011	*Includes savings from measures of EEC1 and EEC2. Includes comfort factor of 15% for insulation measures for priority*	

	Reduction Target		*group (Low income households over 70 years old). Includes cost of suppliers for meeting these targets, and reduced demand from HH from these measures.*	
CERT Extension		Runs 2011-2012	*Savings from installed measures accrue in the following years. Analysis allows for comfort factor of 40% for insulation measures in the super priority group (15% in priority group), and 25% for heating measures in the super priority group (0% for priority group)*	
SO	Future Supplier Obligation	From 2012	*Likely continuation of CERT beyond 2012*	*Initial Assessment of Impact published March 2010*
Better Billing		Runs from 2009	*Suppliers have to include on bills and statements comparison with the same period last year (UK's implementation of Energy Services Directive). Net benefit of £315 million over 15 years, assuming that energy savings of 0.25% persist over this period.*	*Cost/benefit analysis by BERR, August 2007*
Smart Metering			*Expected price and bill impact from this prospectus*	*Smart Metering Prospectus, July 2010*
Products Policy			*EU Implementing Measures, such as minimum standards and labelling for domestic and non-domestic products. Includes EU Impact Assessment. In addition, DEFRA estimated impact of second trench of EU implementing measures that are in development in EU (Consultation in December 2009).*	*Impact Assessment, EU (July 2008 – April 2009)*
RHI	Renewable heat incentive	Will run from April 2011	*Includes the first set of detailed proposals on scheme design, including eligibility and tariffs.*	*Schemes were set out on Renewable Energy Strategy, IA February 2010*
Security Measures			*Includes costs recouped through Ofgem price control process for security upgrades within gas and electricity network, undertaken as part of the Government's National Security Strategy*	
EU ETS	EU Emissions		*Assume full cost pass through of the EUA.*	*DECC updated carbon*

	Trading System			*values June 2010 (UEP)*
Existing RO	Existing Renewable Obligation		*Subsidy costs of introduction technology banding that will result in Renewable electricity generation to 15% by 2020.*	*RO from Energy White Paper Reforms*
Extended RO	Extended RO		*Large scale renewable electricity generation to 29% in 2020.Subsidy costs and balancing costs pushing up consumer electricity bills. This does not include what impact RO may have on wholesale energy prices. Redpoint modelled this, and estimated reduction in wholesale electricity prices. But this is not included here.*	
CCS	Carbon Capture and Storage Demonstration			*Impact Assessment of Coal and Carbon Capture and Storage in Framework for Development of Clean Coal*
FiT	Feed-in-Tariffs	From April 2010	*Final Scheme design as announced and published in February*	
CCL	Climate Change Levy			
CRC	Carbon Reduction Commitment		*Price and bill impact from Impact Assessment published in January 2010*	
CCA	Climate Change Agreements		*Assumes new CCA scheme goes ahead as planned by previous government, but not assumed to be in place after the third carbon budget period.*	

Table 11.6 DECC Wholesale price assumptions £/MWh

Price of Oil	**\$60/bbl**	**\$80/bbl**	**\$150/bbl**

Year	Electricity	Gas	Electricity	Gas	Electricity	Gas
2010	37	11	56	20	77	29
2011	36	11	58	21	81	31
2012	38	11	60	21	87	33
2013	37	11	60	21	92	35
2014	38	11	61	22	97	37
2015	38	11	62	22	100	39
2016	38	11	62	22	104	41
2017	38	11	63	22	105	41
2018	38	12	63	23	101	41
2019	38	12	64	23	102	41
2020	38	12	64	23	102	41

Source: DECC (2010)
Figures in real 2009 prices

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