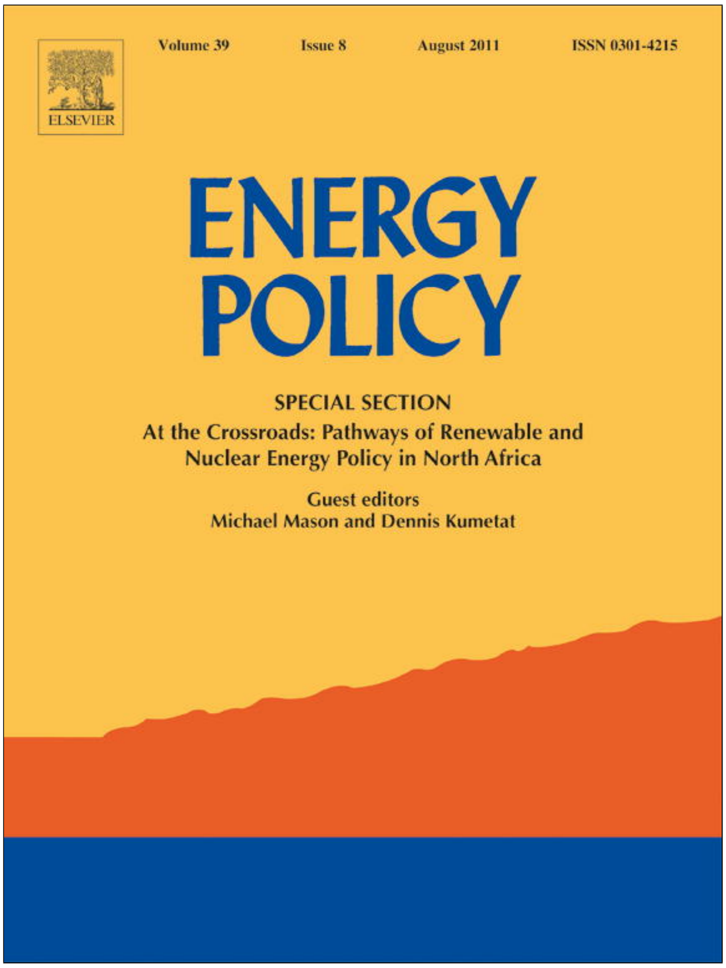

Volume 39 Issue 8 August 2011 ISSN 0301-4215

ENERGY POLICY

SPECIAL SECTION
At the Crossroads: Pathways of Renewable and Nuclear Energy Policy in North Africa

Guest editors
Michael Mason and Dennis Kumetat

Energy Policy 39 (2011) 4578–4593

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Coevolution of policy, market and technical price risks in the EU ETS

William Blyth [a,b,c,*], Derek Bunn [b]

[a] Oxford Energy Associates, Forest Hill, Oxford OX33 1EH, UK
[b] London Business School, Regent's Park, London NW1 4SA, UK
[c] The Royal Institute of International Affairs, Chatham House, 10 St. James's Square, London SW1Y 4LE, UK

ARTICLE INFO

Article history:
Received 30 July 2010
Accepted 26 April 2011
Available online 23 May 2011

Keywords:
Policy uncertainty
EU–ETS
Carbon price risk

ABSTRACT

Within the EU, there have been calls for governments to provide greater certainty over carbon prices, even though it is evident that their price risk is not entirely due to policy uncertainty. We develop a stochastic simulation model of price formation in the EU ETS to analyse the coevolution of policy, market and technology risks under different initiatives. The current situation of a weak (20%) overall abatement target motivates various technology-support interventions, elevating policy uncertainty as the major source of carbon price risk. In contrast, taking a firm decision to move to a more stringent 30% cap would leave the EU–ETS price formation driven much more by market forces than by policy risks. This leads to considerations of how much risk mitigation by governments would be appropriate, and how much should be taken as business risk by the market participants.

1. Introduction

Whilst there have been consistent requests from the business sector for governments to provide greater certainty over climate policy in order to help reduce investment risk (IIGCC, 2010; Reuters, 2010; Resources for the Future, 2007; UNFCCC, 2008), it is an open question how far governments can, or should, limit exposure to the actual carbon price risk. Although carbon prices are ultimately institutional artefacts and therefore policy risk is foundational, market-based mechanisms with quantity targets are chosen to promote efficiency in price discovery and innovation in the management of risks by the private sector in ways that policy-makers cannot fully anticipate. Once created the nature of the risks that emerge in cap-and-trade emissions markets become a coevolution of regulatory interventions, economic activities, commodity prices and technological innovation. In calling for price stability beyond that of a clear policy framework, it appears that there may be a confounding of these separate risk drivers, which, as a consequence, motivates a confused demarcation of responsibilities for risk taking and mitigation between the private sector and the government.

Thus, one of the concerns of power companies, especially those seeking to invest in nuclear power, is that the price of carbon might fall below a level that makes their decarbonising investments cost-effective (EdF, 2010; Centrica, 2010). This has led to a number of proposals including a guarantee for the price of carbon for these companies (Helm and Hepburn, 2005), a firm floor to the price of carbon (Ismer and Neuhoff, 2006), or a softer "price cushion" in the event that it falls below a pre-determined level by withholding allowances from auction (Hepburn et al., 2006). Pizer (2002) showed how price instruments (taxes) and quantity instruments (caps) could be combined by introducing a floor and a ceiling on the price of carbon in a cap-an-trade scheme to achieve the benefits of both types of regulation. The UK government (DECC, 2010) has proposed the unilateral introduction of a carbon price floor via a new carbon tax supplementary to the EU–ETS carbon price, largely in response to power companies and others arguing that the current EU–ETS price is too low. The extent to which such proposals lead to an efficient allocation of risk is still an open question. Relatively little attention has been paid to whether the risks to be underwritten through such interventions would be policy-based or market-based risks. Arguably, the former would be an appropriate reason for government intervention, whereas the latter would not.

The aim of this paper is therefore to quantify the key risk factors that affect the price of carbon in the EU emissions trading scheme (EU–ETS) over different time periods in order to help shed some light on these considerations. The results indicate that policy risks tend to dominate when carbon prices are low, whereas market risks tend to dominate when carbon prices are high. Under current weak targets, this suggests a case for intervention through a price floor, but, alternatively, with a tighter cap in the EU–ETS, policy risks would be reduced and the EU–ETS rebalanced towards market-driven prices.

2. Analytical approach

The research literature on price behaviour and risk in carbon markets has proceeded along two distinct approaches. One

---

[*] Corresponding author at: Oxford Energy Associates, Forest Hill, Oxford OX33 1EH, UK.
E-mail address: william.blyth@oxfordenergy.com (W. Blyth).

0301-4215/$ - see front matter © 2011 Elsevier Ltd. All rights reserved.
doi:10.1016/j.enpol.2011.04.061

approach is based on econometric analyses of historic behaviour in the market (see e.g. Taschini and Paolella, 2008; Daskalakis et al., 2009; Wagner and Uhrig-Homburg, 2009), whilst more forward-looking models examine the abatement options, which are expected to be the key drivers of the carbon price in the future. For example Seifert et al. (2008) and Chesney and Taschini (2008) consider carbon prices to be determined by the marginal cost of switching fuel, and so model variability as a function of gas and coal price variability. In contrast, because current carbon allowances are bankable in the EU–ETS, Lewis (2008) assumes future prices will ultimately be determined by the cost of clean coal technology, and uses discounting to arrive at an estimate of the current value of allowances.

The analysis in this paper follows this second approach. It is based on an abatement supply function model of the EU–ETS, where risk is included through the stochastic simulation of the key input parameters. The model builds on the approaches of Seifert et al. (2008), Chesney and Taschini (2008) and Lewis (2008) by including a more complete description of the different abatement technologies within the EU–ETS, and including the impact of technology cost dynamics and policy uncertainty. It is designed to analyse probability distributions in the carbon price, taking account of key sources of risk and uncertainty in the carbon market. The model is based on a marginal abatement cost (MAC) curve incorporating the various sources of abatement covered by the scheme. Uncertainty is represented in the model by allowing the marginal cost and quantity of abatement from each abatement option in the MAC curve to vary stochastically. This approach has the advantage that uncertainty in each element of the cost curve can be defined individually. This gives a richer characterisation of uncertainty than can be achieved by modelling uncertainty across the MAC curve as a whole. The model calibrates ranges of cost and quantities for each abatement option according to values derived from the published literature for those options. The assumptions on expected costs and the assumed stochastic variations are to be found in Appendix A.

This model has previously been applied to a general analysis of the potentially wide variation of marginal abatement costs that uncertainties in the EU–ETS mechanism imply (Blyth et al., 2009), but without any identification of the sources of risk. Since the 2009 paper, the authors have updated the model to take account of the following:

- Updated baseline energy and emissions scenario (based on the PRIMES model as reported in European Commission, 2008a) to take account of revised expectations following the financial crisis, calibrated to IEA's World Energy Outlook 2010 (IEA, 2010).
- Updated energy price forecasts based on IEA (2010).
- Updated technology cost estimates based on the various sources (see Appendix A).

The revised baseline, since the recession has substantially reduced the abatement cost estimates, is explored in a separate section below. The MAC curve for 2030 based on expected values for technology costs and abatement quantities is shown in Fig. 1. (Table 1).

It can be seen that in the model, technologies are not strictly in order of marginal cost, as in a conventional theoretical MAC curve. This is because some abatement options are assumed to be contingent on the prior implementation of other options. This is the case with off-shore wind power, carbon capture and storage, and solar PV. For each of these technologies, where technological learning is assumed to be a significant factor, the abatement option is split into more than one tranche. Early-stage implementation of the technology is taken to be more expensive than the mature stage of the technology. Each stage is represented by a different tranche in the MAC curve. Since the mature stages of the technology cannot be undertaken until the learning stages have been undertaken, they appear further to the right in the MAC curve than they would do if they were to take their normal place based on marginal cost. In practise, governments often introduce additional policy measures, which bring forward the expensive learning stage through support for the early-stage technologies (e.g. demonstration projects, subsidies, etc.). In our model such support can be represented by bringing those technologies to the front of the MAC curve, so that they are assumed to be rewarded and implemented outside the carbon market, whilst still contributing abatement savings that will help to meet the EU–ETS target. An important example of this is the EU's renewable energy target, discussed in the Section 2.1.

The stochastic MAC curve is constructed through Monte Carlo's simulations. For each realisation in the simulation, a new value is selected for the cost and quantity of abatement for each of 26 abatement options included in the model. These values are

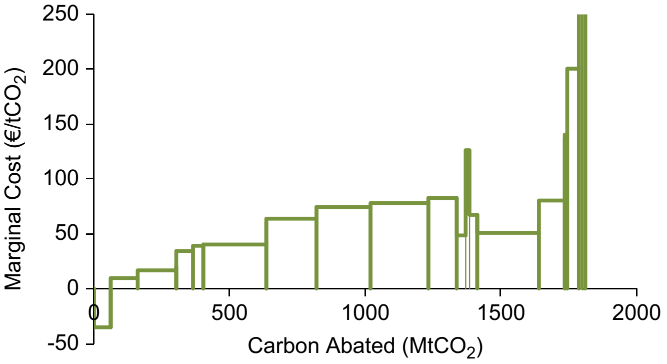

Fig. 1. MAC curve for 2030 based on expected marginal costs and abatement quantities.

Table 1
Parameters underlying the MAC curve in Fig. 1.

	Price (€/tCO$_2$)	Quantity (MtCO$_2$)	Cum'tive Q (MtCO$_2$)	Cumulative total (€m)
Demand variation	0	0	0	0
IGCC	−34	64	64	−2196
En Eff Industry	10	100	163	−1200
Nuclear	17	141	305	1204
Hydro	20	1	306	1229
FuelSwGas 1	20	0	306	1229
Energy efficiency 1	35	60	366	3335
Onshore wind	39	39	405	4872
FuelSwGas 2	40	0	405	4872
CCGT vs. lignite	40	230	636	14,120
FuelSwGas 3	60	0	636	14,120
CCGT vs. coal 1	64	184	820	25,890
Biomass	74	200	1020	40,713
Energy efficiency 2	75	0	1020	40,713
CDM credits	78	215	1235	57,570
Offshore wind 1	83	103	1339	66,175
Offshore wind 2	49	32	1371	67,740
CCS 1st tranche	127	14	1385	69,520
CCS 2nd tranche	68	28	1413	71,420
CCS 3rd tranche	51	229	1642	82,997
CCS industry	80	95	1737	90,588
CCGT vs. coal 2	137	0	1737	90,588
CSP	141	7	1744	91,595
Biomass industry	200	43	1786	100,135
Solar 1	426	17	1803	107,279
Solar 2	302	7	1810	109,358

selected from the probability distributions as described in Appendix A. For each realisation in the Monte Carlo simulation, the MAC curve is reassembled, enabling a calculation of the overall marginal cost of achieving a given emission reduction goal for that particular set of technology costs and abatement quantities. This overall marginal cost of reaching the abatement target is taken to be the fundamental driver of carbon price in the EU–ETS. Over several thousand runs, a probability distribution of marginal costs can be determined for any given level of abatement target taking account of the uncertainties in the values of the underlying variables. For the purpose of this paper, the uncertain variables in the model are aggregated into 3 risk categories: policy risks, market risks and technology risks.

2.1. Policy-based risks

The key policy-based risks incorporated into the model are those represented by the EU's headline climate policy objectives (European Commission, 2008b). This was a package of climate and energy policy measures adopted by the EU, which sets a goal for 2020 of 20% economy-wide greenhouse gas emission reduction target relative to 1990, a separate commitment to meet 20% of the EU's final energy demand from renewable sources and a 20% target for savings through energy efficiency measures. The package also commits a support for the development and demonstration of carbon capture and storage (CCS) technologies. Uncertainties arise from all these commitments and targets. In terms of the cap, the EU has pledged to increase the stringency of the overall emissions reduction goal to 30% by 2020 if other major economies join an ambitious international agreement (European Commission, 2008b). Although further analysis of the option to move to a 30% reduction target was published (EU Commission, 2010), the outcome of international negotiations remains highly uncertain. On the other hand, achievement of the 20% renewable energy commitment is largely dependent on regulations determined at the Member State level, since it is here that the subsidy regimes for renewables are set. These subsidies for renewables also reduce the price of carbon, because they result in emission reductions that are paid for through other mechanisms, displacing abatement options that would otherwise have to be paid through the carbon price. Therefore, uncertainty over the achievement of the renewable energy targets is a risk factor for carbon prices. The key EU-level policy risks modelled here can therefore be summarised as follows:

(i) *Level of the cap*: Uncertainty over whether the overall EU abatement target for 2020 will be set at 20% or 30%. This is modelled as a binary choice, so that the model is run separately under a 20% and a 30% abatement scenarios. The choice for 2020 is assumed also to affect the post-2020 targets: it is assumed that the greater annual rate of emissions reduction required to meet the 30% reduction by 2020 is continued at the same rate up to 2030.

(ii) *Level of technology support*: Uncertainty over the level of renewable energy implementation. Whilst ambitious targets have been set to meet 20% of overall energy from renewable sources, actual achievement of these targets is assumed in the model to remain uncertain and therefore remains a policy-based risk factor from the point of view of carbon markets. The lower limit of renewable energy penetration is assumed to be a continuation of baseline levels of renewables under the PRIMES model (which already assumes significant increases), whilst achievement of the 20% target is taken to be an upper limit. Combined with these uncertainties over renewables is uncertainty over support for CCS. The lower-bound assumption is that no CCS support is forthcoming before 2020, so that the mature-phase technology is not available by 2030. The upper-bound assumption is that support for demonstration projects is made available according to EU Commission proposals, and that this is sufficient to stimulate CCS development and availability by 2030. These policy support scenarios are again modelled as binary (on/off) outcomes. The actual cost of abatement of the various renewable and CCS options however are treated as technology risks as described below.

(iii) *Energy Efficiency target*: EU has set a target of improving energy efficiency by 20% by 2020 as part of the policy package set out in January 2008, although the lack of any additional legislative package to enforce the target makes the target rather weaker than the renewables and overall GHG commitment. Nevertheless, further measures may be introduced. Such policies would indirectly reduce power sector emissions, reducing the need for emission reductions to be made by participants in the EU–ETS. The regulatory impact assessment for the EU energy efficiency action plan estimated that about 100 Mtoe could be saved through electrical energy efficiency measures in downstream sectors outside the EU–ETS. Whether or not these savings are realised is treated in this analysis as a policy risk that would affect the carbon price in the EU–ETS.

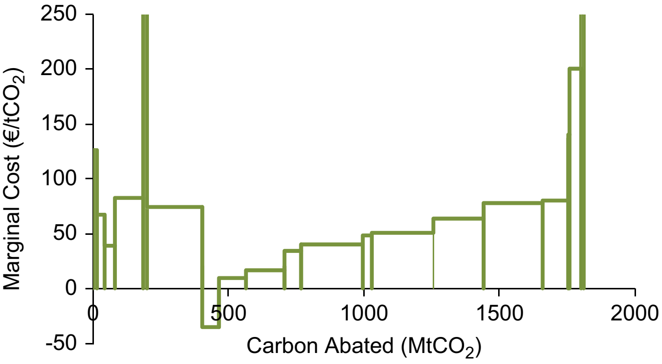

Fig. 2. MAC curve for 2030 based on expected costs and quantities, with renewable energy and CCS demonstration plant brought to the front of the curve.

The effects of supporting renewable energy and CCS technologies through additional subsidies and demonstration projects are to bring these options to the front of the MAC curve. The assumption here is that these options will be implemented independently of the carbon price, although emissions reductions will still contribute to meeting the EU–ETS target. This has the effect of shifting the rest of the curve to the right, and reducing the marginal cost at which the EU–ETS target would be met. The MAC curve based on expected values for cost and quantity, assuming the 20% renewables and CCS demonstration projects (but not additional end-use energy efficiency policy implementation), is shown in Fig. 2. (Table 2).

2.2. Market-based risks

The two key market risks included in the model are:

(i) *Uncertainty in the level of demand for electricity*[1] (related to overall economic uncertainty): This is calibrated by taking the difference between two different published estimates for the

---

[1] *Note*: only the impact on electricity demand is included, not the impact on direct emissions from industry, which account for around 40% of EU–ETS emissions. This probably leads to an underestimate of the contribution of economic demand uncertainty in the model.

Table 2
Parameters underlying the MAC curve in Fig. 2.

	Price (€/tCO$_2$)	Quantity (MtCO$_2$)	Cum'tive Q (MtCO$_2$)	Cumulative total (€m)
Demand variation	0	0	0	
CCS 1st tranche	127	14	14	1781
CCS 2nd tranche	68	28	42	3680
Onshore wind	39	39	82	5218
Offshore wind 1	83	103	185	13,823
Solar 1	426	17	202	20,967
Biomass	74	200	401	35,790
Hydro	20	1	403	35,815
IGCC	−34	64	466	33,619
En eff industry	10	100	566	34,615
Nuclear	17	141	707	37,019
FuelSwGas 1	20	0	707	37,019
Energy efficiency 1	35	60	768	39,125
FuelSwGas 2	40	0	768	39,125
CCGT vs. lignite	40	230	998	48,373
Offshore wind 2	49	32	1030	49,937
CCS 3rd tranche	51	229	1259	61,515
FuelSwGas 3	60	0	1259	61,515
CCGT vs. coal 1	64	184	1443	73,284
Energy efficiency 2	75	0	1443	73,284
CDM credits	78	215	1658	90,141
CCS industry	80	95	1753	97,732
CCGT vs. coal 2	137	0	1753	97,732
CSP	141	7	1760	98,739
Biomass industry	200	43	1803	107,279
Solar 2	302	7	1810	109,358

level of electricity demand in 2030, namely the World Energy Outlook reference scenario from 2007 (IEA, 2007) and PRIMES baseline scenario. These two scenarios projected a 20% difference over the 25 years. Demand uncertainty is modelled as an 'abatement option' that has a zero abatement cost, contributing a quantity of abatement that can be positive or negative. It is always assumed to be the first element in the MAC curve, either making the task of meeting a particular target easier (in the case of a drop in demand) or harder (in the case of an increase in demand). These variations are modelled as a geometric Brownian motion random walk over time.

(ii) *Uncertainty over fuel prices*: In modelling uncertainty over future fuel prices, we follow the arguments of Pindyck (1999) in assuming that long-run price uncertainty can best be modelled using the geometric Brownian motion processes. Thus, gas prices in any given year are related to those in previous years according to an expected price escalation factor, but with a random walk element added. Note that this random walk is intended to represent a long-term uncertainty rather than a short-term volatility, which might expect to be mean-reverting and is not included in the model. Coal prices are similarly modelled as a geometric Brownian motion random walk, but with a smaller variance than for gas price. The variance (i.e. the size of the random component of price variation) is calibrated so that the standard deviation of the price distributions after 10 years match high and low energy price scenarios used in the UK government forecasts. Fuel price uncertainty gives rise to a wide variation in the marginal cost of switching between fossil fuels (coal to gas), and also affects the marginal cost of shifting to low carbon technologies.

2.3. *Technology-based risks*

Technology risks included in the model comprise of uncertainties over the marginal cost of abatement for each of the abatement options in the MAC curve, as well as the quantity of abatement available from each option. Assumptions about these costs are drawn from various published studies as summarised in Appendix A, and the resulting marginal cost distributions for some of the more significant abatement options are illustrated in Appendix B.

Uncertainty over the quantity of abatement from each option is modelled in different ways. In some cases, values are picked from a normal distribution around a central expected value. The contribution of different renewable energy sources however are modelled slightly differently. Uncertainty in these options is based on differences between two published sets of projections regarding the amount of each kind of renewable energy that will be installed to satisfy the EU's 2020 target (European Commission, 2008a, b; Pöyry, 2008). In this case, we have assumed that both estimates are equally likely, so that the model picks values according to a uniform probability distribution within this range.

Technological learning is assumed to occur in the model through two separate mechanisms. Spill-over effects (i.e. technological learning through developments outside of the EU or through developments unrelated to energy-sector applications) are represented by allowing technology costs to fall over time irrespective of assumptions about implementation levels. Learning by doing on the other hand is reflected in the model by incorporating multiple tranches for particular technologies. Early-stage (more expensive) plant may be required to occur first in the MAC curve before the cheaper mature-stage abatement options can be at a later date. The extent to which the early-stage plant gets implemented may be dependent on policy (e.g. in the case of provision of funding for the demonstration of CCS plant). In this case, uncertainty over whether or not such demonstration plants go ahead are included in the category of policy risk for the purposes of this analysis as described above.

Uncertainty over international offsets (clean development mechanism CDM credits) is included both in terms of the quantity and price of credits available in the market. CDM prices are calibrated to assumptions used by DECC for policy appraisal, as described in Appendix A. The quantity of CDM credits are assumed to be dependent on the choice of 20% vs. 30% abatement target. The EU constraints on usage of CDM credits under the EU's current unilateral target of 20% greenhouse gas abatement by 2020 is assumed to be relaxed if the abatement target is tightened to a 30% reduction, allowing double the number of credits to be used compared to the 20% target scenario.

3. Impact of policy interactions

The results of the Monte Carlo simulations are shown in Fig. 3. Marginal and total abatement cost distributions are shown separately for 2020 and 2030, and for the 20% and 30% EU-wide emissions caps under different assumptions about policy support for renewables, CCS and energy efficiency in end-use sectors:

(1) **All off** indicates that no additional policy support for renewables, CCS demonstration or energy efficiency is provided outside of the EU–ETS.
(2) **RE CCS on** indicates that support for renewable energy is adequate to meet the EU 20% renewable energy target, and that sufficient support for CCS demonstration is provided to allow mature-phase CCS to be commercially available.
(3) **RE CCS EE on** indicates that in addition to case 2, policies are put in place to meet the EU target of an increase in energy efficiency of 20% by 2020.

The introduction of these additional policies to support renewables, CCS and energy efficiency all tend to reduce the marginal cost at which the EU ETS cap is met. This can be seen from the

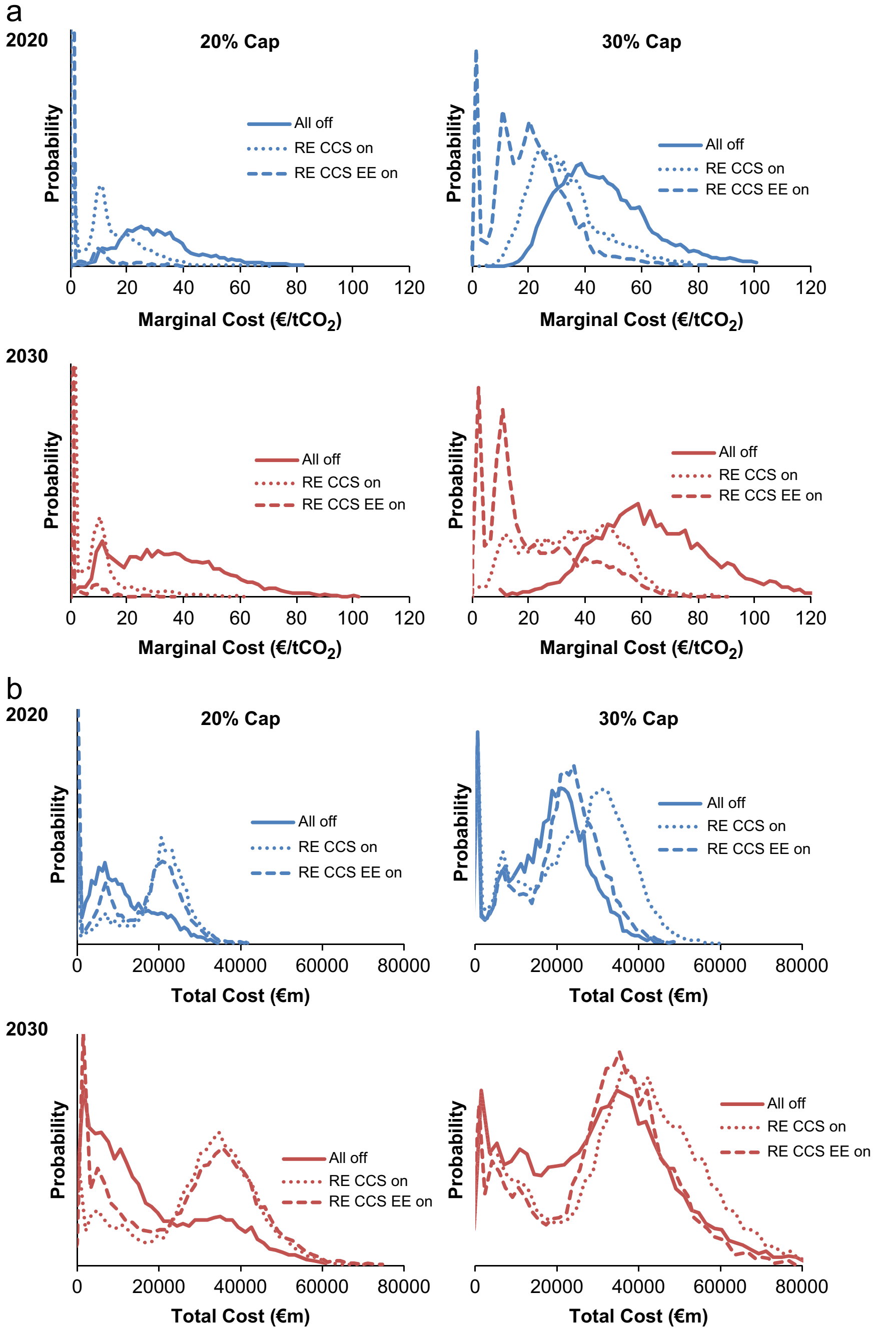

Fig. 3. (a) Results of the Monte Carlo simulations: marginal abatement cost distributions and (b) results of the Monte Carlo simulations: total abatement cost distributions.

leftward-shift in the marginal cost distributions in Fig. 3a. Under the weaker cap scenario of 20% in 2020, the introduction of additional policies leads to a significant suppression of the marginal costs with an 80% probability of marginal costs collapsing below €5/tCO_2 in the "RE CCS EE on" case, and to a 30% probability under the "RE CCS on" case. This risk of low prices is still evident in 2030 under the weaker 20% cap scenario, with a 90% chance of marginal costs below €5/tCO_2 in the "RE CCS EE on" case, and to a 70% probability under the "RE CCS on" case.

These high probabilities of low marginal costs pose a risk to investors in low-carbon generation if they are relying on the carbon price to make the investment cost-effective. The next section identifies some of the key drivers of these risks. However, it can be seen in Fig. 3a that the level of the cap has a significant influence. Under the more stringent 30% target case in 2020, there is a 20% probability of marginal costs falling below €5/tCO_2 in the "RE CCS EE on" case, whilst the probability of such low marginal costs falls below 1% in the "RE CCS on" case.

The impact of policy interactions on the total cost of meeting the cap depends on which additional technologies are introduced. In the model, the renewable energy technologies tend to be more expensive than the marginal technologies in the abatement curve, and so increase the total cost of meeting the cap relative to the 'All off' scenario. The energy efficiency options on the other hand are assumed not to add any additional costs (i.e. they can be achieved by overcoming barriers without incurring net social costs), and so these tend to reduce the total cost of meeting the ETS cap. It should be noted that this paper does not provide detailed analysis of whether or not such 'free' energy efficiency measures can be undertaken in practise. Such discussions on the existence or otherwise of low cost energy efficiency options are available in the literature (see e.g. McKinsey, 2010; Gayer, 2009).

In 2030, the differences in total cost of abatement between the different scenarios is less pronounced under the 30% cap than under the 20% cap. This is because under the more stringent cap, a greater degree of abatement is required with higher marginal costs. The difference in cost between the additional renewable energy options brought in under the RE policy scenario and the marginal costs that are required under the "All off" scenario are therefore reduced compared to the weaker 20% cap scenario. In addition, supporting CCS demonstration in the "RE CCS on" case enables mature phase CCS to enter the cost-curve, which helps to reduce total abatement costs.

4. Comparison with pre-recession scenarios

The model used to generate the cost distributions presented in the previous section has been updated by Blyth et al. (2009) in a number of ways, in particular to include revised baseline assumptions for CO_2 emissions in the EU. Whilst the earlier analysis was based on assumptions presented in WEO 2008, the results here are based on WEO 2010 reference scenario assumptions. The biggest single change between the two has been the downward revisions to expected CO_2 emissions as a result of the recession since 2008. A comparison of the marginal and total cost distributions with the previous published version is presented in Fig. 4.

Compared to the pre-recession results, these distributions are shifted quite significantly to lower marginal and total abatement costs. This is in large part due to the downward revision in electricity demand expectations. Other revisions to the model have also affected the results in different ways. For example, a significant upward revision in fossil fuel price projections in WEO 2010 compared to 2008 lead to increases in the marginal abatement cost of fuel switching, and reductions in the implied cost of switching to low carbon technologies such as nuclear and renewables. However, the capital cost estimates for nuclear power have been revised upwards significantly, since the previous paper based on recent estimates literature, offsetting much of this cost advantage compared to fossil-based plant. Nuclear capital and operating costs have also been made stochastic in the model to reflect the relatively wide range of estimates in the literature for the costs of new nuclear plant.

5. Risk factors under 20% and 30% cap scenarios

This section explores which stochastic variables are most responsible for the distributions in abatement cost shown in the previous sections. We are interested in exploring the relative roles of policy, market and technical risks. Policy risks in this section comprise uncertainty over implementation of renewable energy, CCS and energy efficiency policies. We therefore combine the Monte Carlo runs from each of these scenarios into a single population for which to carry out the sensitivity analysis. In this context the decision over whether the overall GHG target is a 20% or 30% reduction is assumed to have already been made (i.e. it is not treated as a policy risk), so that the analysis focuses on the risk factors within each cap scenario. The next section looks at the implication of considering the choice between 20% and 30% as an additional policy risk factor.

The mean and standard deviations for abatement costs across the range of technology policy scenarios is shown in Table 3.

Table 3
Standard deviations in cost distributions.

	Marginal cost (€/tCO_2)				Total cost (€m)			
	20% cap		30% cap		20% cap		30% cap	
	Mean	Std dev	Mean	Std dev	Mean	Std dev	Mean	Std dev
2020	12.6	15.8	30.4	15.3	11,962	8639	23,418	9555
2030	9.5	22.4	37.8	25.8	19,103	15,761	35,031	17,067

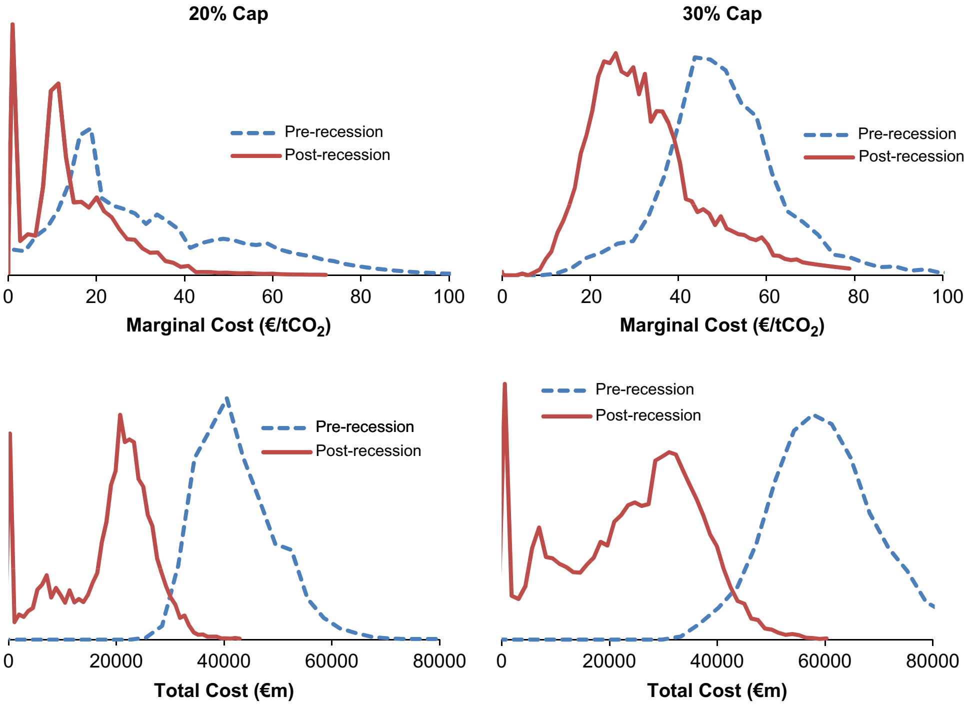

Fig. 4. Effects of the recession on abatement costs in EU–ETS in 2020.

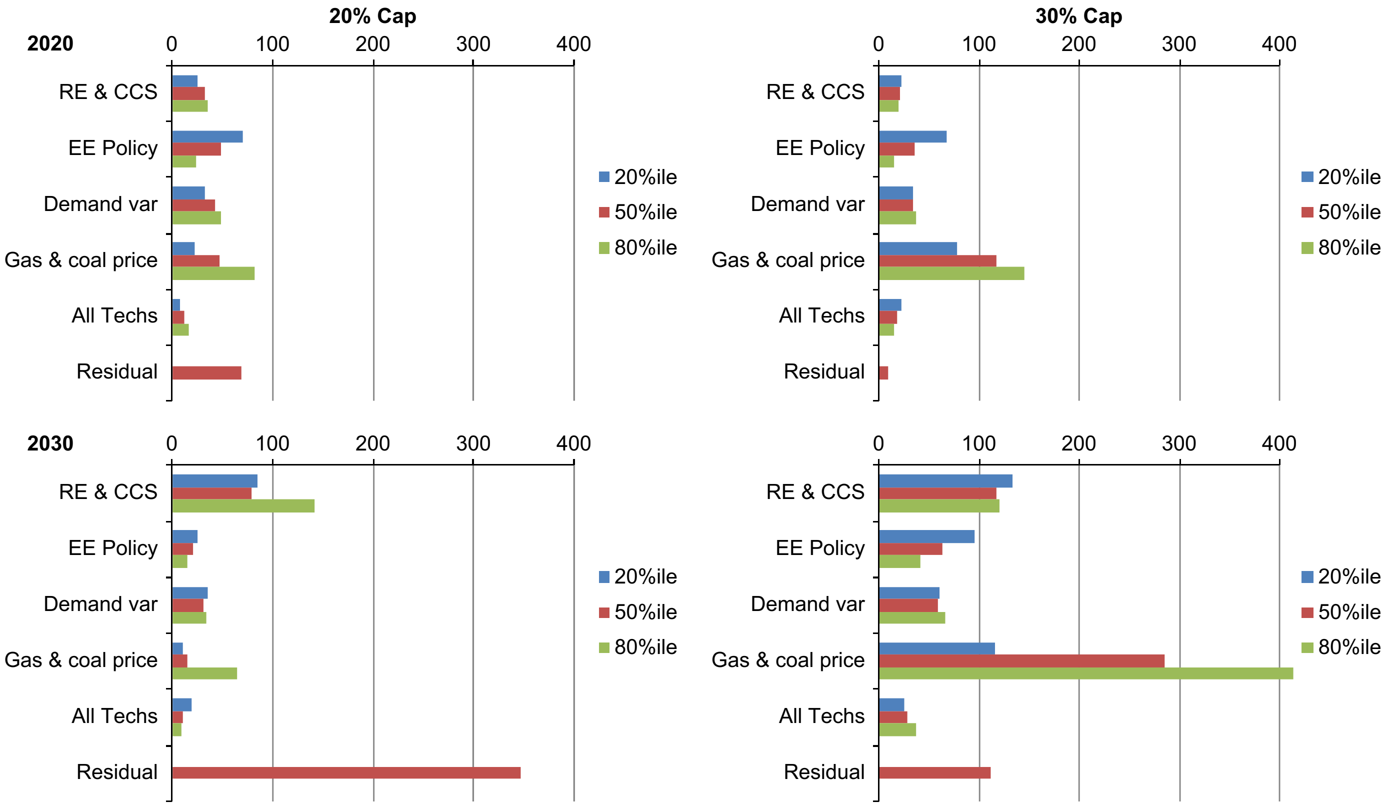

Fig. 5. Risk factors driving the marginal cost distribution.

It can be seen that although abatement costs increase under the more stringent cap, the standard deviation in abatement costs does not differ significantly between the 20% cap case and the 30% cap case.

In order to see the factors that are driving these cost distributions, a quantile regression analysis was carried out. Quantile regression allows coefficients to be calculated that show the sensitivity at different percentiles in the abatement cost distribution to each of the variables in the model. This allows us to identify how different drivers affect high or low scenarios for costs.

The quantile regressions were carried out by importing the results of the Monte Carlo analysis into the Gretl econometrics interface.[2] Most of the variables described in Appendix A were included as variables in the regression. The exception is that fuel switching options were treated as endogenous to energy price variations and thus all of the variations in abatement costs from these technical options were associated with the exogenous fuel price variables. The coefficients resulting from the quantile regression are presented in Appendix C. It is clear that there are significant differences in the coefficients or each variable at different percentiles of the cost distribution.

In order to identify the importance of each variable in contributing to risk in overall abatement cost, we computed individual risk factors as follows. The coefficients resulting from the quantile regressions were multiplied by the standard deviation of each variable; these were then squared in order to become variance components to provide additivity. This simple additivity is robust since there are no correlation effects between the different categories of risk, by construction, as they are created in the simulations by independent stochastic processes. The stochastic drivers for different technologies are also separate, again allowing the technology variables identified in Appendix A to be summed together under the 'all techs' category in Fig. 5. The 'residual' measures the additional variance that is not explained by the variables included in the regression.

The results are shown in Figs. 5 and 6 for marginal and total abatement costs, respectively. The values are the contributions to cost variance, meaning that taking the square root of the values shown would give the implied contribution to the standard deviation in cost (e.g. a value of 100 shown in Fig. 5 corresponds to a contribution to the standard deviation of €10/tCO$_2$).

The explanatory variables included in the regression analysis account for most ($>70\%$) of the variation in costs identified in the Monte Carlo runs, except in the 20% abatement scenario in 2030. In this case, the regression analysis is less successful, with the explanatory variables accounting for only 30% of the variance due to the standard deviation being significantly higher than the mean (see Table 3) and a high probability of zero carbon prices.

The clearest result that emerges from Fig. 5 is the shift in risk factors that occurs between the 20% and 30% cap scenarios. Under all the scenarios and time frames, technology risks are relatively unimportant as a driver of marginal cost, with policy and market risks playing a more substantial role. Under the weaker 20% cap, the combined influence of the policy risk factors (RE, CCS and EE policy) on median marginal abatement cost variance is approximately the same as the combined influence of the market risk factors (demand variance and gas and coal prices) in 2020. In 2030, the balance shifts markedly towards a greater influence of policy risk factors.

However, under a more stringent 30% cap, policy risk factors reduce slightly in 2020, whilst market risk factors increase quite

---

[2] Gnu Regression, Econometrics and Time-series Library. This is an open source econometrics tool available at http://gretl.sourceforge.net/

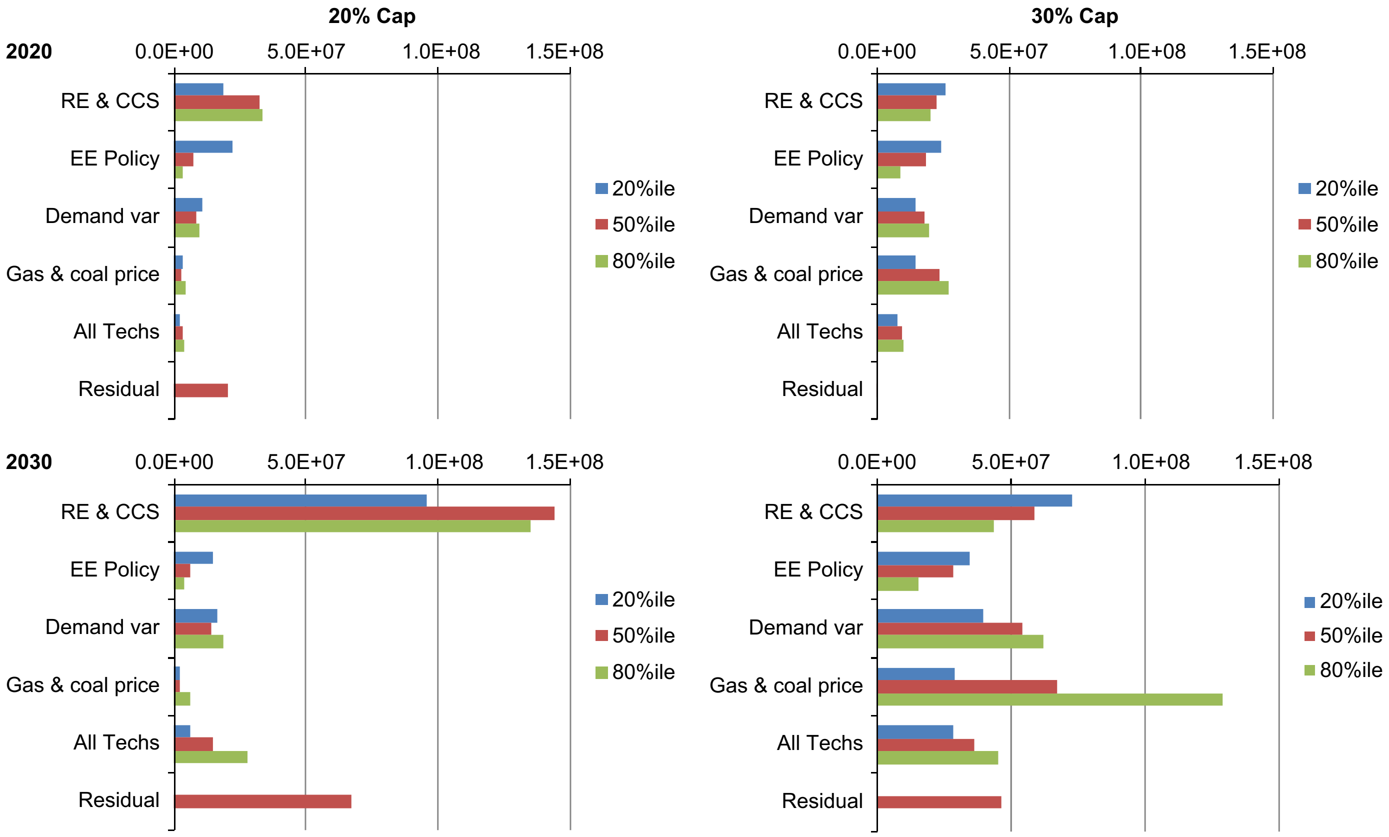

Fig. 6. Risk factors driving the total cost distribution.

significantly, so that market risk factors contribution to variance is more than 2.5 times greater than the combined policy risk factors. In the 30% cap scenario in 2030, market risk factors again become significant, accounting for around twice as much of the variance as the policy risk factors.

The second notable result from Fig. 5 is that the risk factors vary considerably for the different percentiles of the marginal cost probability distribution. Risks associated with the impact of implementation of energy efficiency policy are particularly strong at the 20th percentile (i.e. when prices are low). This is because the EE policy is a significant causal factor for prices dropping to very low values when other price drivers are weak and little abatement is required to meet the cap. Fuel price risks on the other hand are significantly stronger at the 80th percentile (when prices are high) because fuel switching is often the marginal technology when caps are biting, and so carbon prices will go high when gas prices are high.

Fig. 6 shows the risk factors affecting the total costs of abatement, again showing how these vary at different percentiles in the cost distribution. A similar pattern emerges for total abatement costs as for marginal abatement costs. Policy risks dominate under the weaker 20% cap scenario, but are more balanced between policy and market risks under the 30% cap. Again, the policy risks are particularly prevalent at the lower cost percentiles, whereas market risks tend to be stronger at the high cost percentiles.

6. Uncertain cap as a risk factor

In this section, the decision over a 20% vs. 30% cap is assumed not to have taken place yet, so that the choice of cap is treated as another policy risk factor (arguably the situation, which currently pertains to the EU–ETS). For this analysis, the results of the 20% and 30% cap Monte Carlo scenario runs were aggregated into a single data set, and a new quantile regression analysis was carried out, with the choice of cap specified as an explanatory variable.

The results are shown in Fig. 7, which show that the key risk factors are policy and market factors, not technology risks. In particular, the choice of cap is one of the key drivers of the marginal cost, and therefore of carbon prices in the market.

The variation in risks across the different percentiles shows a similar pattern to that shown in the results of the previous section. The 20% percentile figures show a stronger impact of introducing additional energy efficiency policies than for the median. This implies that when carbon prices are already low, the risks associated with these policy interactions are particularly high.

Conversely, when carbon prices are high (in the 80 percentile case), gas price risk becomes much more significant, since this tends to be a driver of high prices.

Fig. 8 shows the impact of these same drivers on variance in total abatement cost. These show a relatively greater importance of the RE and CCS Support factor than is the case for the marginal costs, because of the additional total abatement costs incurred when these options are brought to the front of the MAC curve. Technology risks are more significant for total costs than for marginal costs, again reflecting the fact that total abatement costs are affected by the costs of every infra-marginal technology in the MAC curve, not just the ones, which tend to be at the margin. In particular, when RE support is switched on in the model, renewable technologies that have relative high levels of uncertainty in cost (particularly in the 2030 timeframe) become inframarginal,

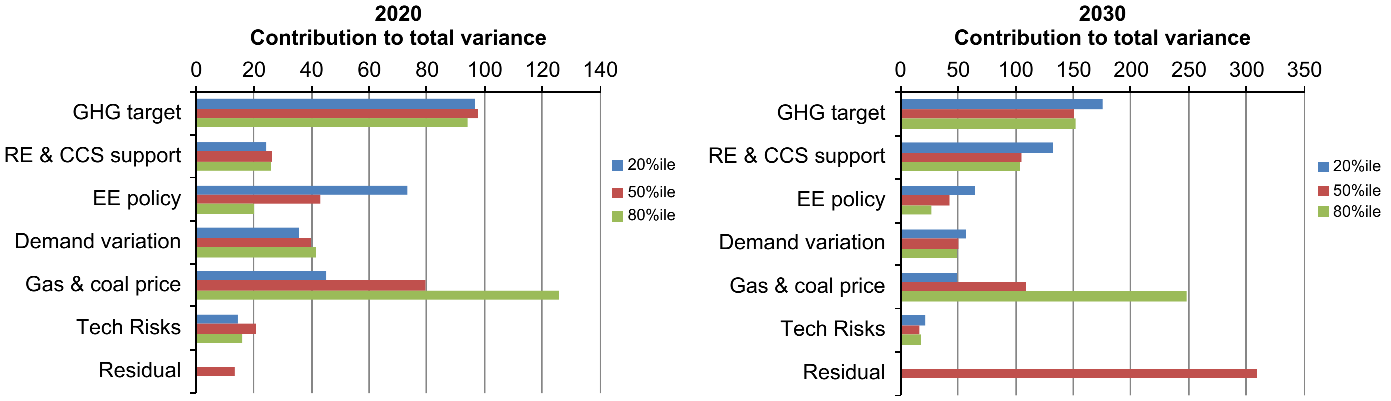

Fig. 7. Contribution of different risk factors to the variance in marginal cost.

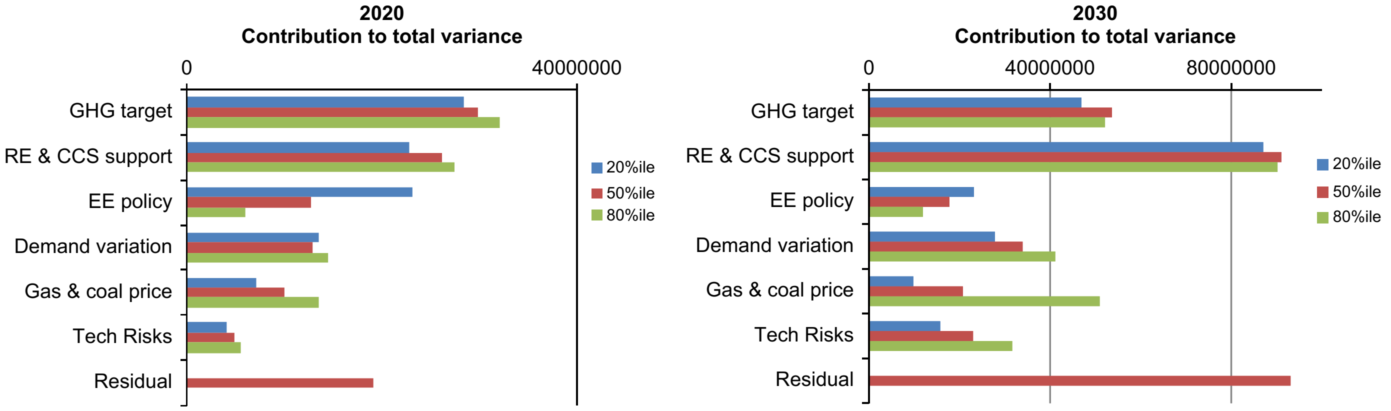

Fig. 8. Contribution of different risk factors to the variance in total cost.

and contribute to variance in total abatement cost.[3] A similar pattern can be observed in Fig. 8 as in Fig. 7 in the way that fuel price risks tend to be a stronger driver when total costs are high, whereas energy efficiency policy tends to be a stronger driver when total abatement costs are low. Overall however, policy risks appear to be a stronger risk factor than market risks across the whole cost distribution for both 2020 and 2030.

7. Conclusion

This paper presents an analysis of the key drivers of carbon price risk in a cap and trade emission market using a stochastic marginal abatement curve model. Understanding the sources of price risk is important not only for hedging decisions at the market participant level, but also at the energy policy level in terms of how much risk mitigation, if any, governments should provide.

Our simulations on the EU–ETS show that policy risk, market risk and technology risk coevolve in an inter-related way, with a level of complexity that suggests that detailed modelling of the kind presented here is necessary to identify their relative importance under various scenarios. Policy risks in this application included: (i) uncertainty over whether the EU unilateral abatement target is set at a 20% or 30% reduction by 2020 relative to 2005, (ii) uncertainty over policy support to meet EU targets for 20% of energy to come from renewable sources and for CCS demonstration and (iii) uncertainty over achievement of EU targets for a 20% improvement in energy efficiency by 2020. Market risks modelled here include: (i) variations in gas and coal prices and (ii) variations in demand for electricity in the economy. Technical risks include uncertainty over the price and quantity of abatement available for over 20 different abatement options included in the marginal abatement curve. The key conclusions are as follows:

- Resolving the 20% vs. 30% cap uncertainty would significantly reduce policy risk.
- Policy risks in a 30% cap scenario are slightly lower than in a 20% cap scenario in absolute terms, and very much lower in relative terms.
- Policy risks are particularly strong when carbon prices are low.
- Market drivers (fuel prices and electricity demand) tend to dominate the risk factors when carbon prices are higher.
- Policy interactions of other technology policies tend to further suppress carbon prices in the EU–ETS.
- The recession has led to a considerable downward revision in likely carbon prices in the EU–ETS.

---

[3] Note that if a weak cap is met through implementation of energy efficiency and renewable policy, then the marginal cost of meeting the cap is deemed to be zero as no additional effort is required (implying a zero carbon price), whereas the total abatement cost includes the abatement costs of the renewable energy abatement. This explains why technology risks appear higher for the total abatement costs in Fig. 8 than the marginal costs in Fig. 7.

Table A1
Assumptions for policy, market and technology variables in the model.

Policy variable	Description	Modelling method
20% vs. 30%	The EU has set a unilateral target of an economy-wide 20% GHG reduction target by 2020 relative to 1990. It may choose to increase this to a 30% target as part of its international commitments. The EU–ETS target is assumed to also reflect this choice.	The choice between 20% and 30% is modelled as a binary choice, which continues to affect the rate of reduction of the emissions cap in the EU–ETS, assuming a constant per annum reduction in the cap between 2020 and 2030 continuing the rate of the previous decade. An increase to 30% simply increases the abatement required to meet the cap, thereby increasing the cost of abatement. Most other variables in the model assumed to be independent of this choice, apart from the supply of CDM credits (see separate entry in abatement options table).
Implementation of RE targets	Implementation of the EU 20% renewable energy target will require additional policy measures to be undertaken. The success of these additional policies is taken to be a policy variable reflecting uncertainty over delivery of the target.	Achievement of the 20% renewable energy target is modelled as a binary (on/off) switch in the model. If the renewables option is switched 'on', then the required amount of renewables are brought to the front of the abatement curve in advance of any other abatement options required to meet the EU–ETS target. If the renewables option is switched 'off', then no additional renewable support is assumed to occur, and renewable energy options take their place in the abatement curve.
Implementation of EE targets	The EU has adopted a target of a 20% improvement in energy efficiency by 2020, although unlike the renewables target it does not have any binding legislation to back this target up.	Similar to the modelling of renewable energy targets, this is modelled as a binary 'on' or 'off' variable. When it is off, energy efficiency improvements revert to those included in the baseline. When it is switched on, baseline electricity demand is reduced by up to 100 Mtoe, the amount of electrical energy efficiency estimated by the EC's impact assessment of the energy efficiency action plan.
Demonstration of CCS	CCS requires full-scale demonstration before it becomes commercially viable. The EU has stated its willingness to support such demonstration plant, but whether or not the necessary support materialises to achieve an adequate level of technology learning is treated as a policy variable.	The model constrains CCS so that demonstration plant have to be implemented before the mature phase of the technology becomes available for abatement. Like the RE targets, CCS demonstration is treated as an 'on' or 'off' variable. When it is 'on', both 1st and 2nd demonstration tranches are assumed to be fully realised, allowing the mature phase technology to enter the abatement curve in the order determined by its marginal cost. When it is off, no demonstration plant are assumed to be undertaken, except in rare cases, where the carbon price is adequately high.

	Description	Expected values $E[P]$ expected price $E[Q]$ expected quantity		Standard deviation (annual)	Uncertainty assumptions
		2020	2030		
Market uncertainties					
Demand	Uncertainty in electricity demand is modelled as a stochastic variable leading to positive or negative contributions to the total abatement requirements to meet a given target. This contribution to emissions reductions is calculated by taking stochastic variations in electricity demand in the baseline against which the cost curve is calculated.	Electricity demand 3713 TWh.	Electricity demand 3936 TWh.	$\sigma_{\text{demand}}=1.9\%$	Total electricity demand uncertainty calibrated to the annualised differences in forecasting 2020 electricity sales by EIA forecasts made over the past 8 years
Fuel price	Fuel price expectations based on WEO 2010 'New Policies' scenario fuel price assumptions. Uncertainty calibrated to UK high and low energy price scenarios as described in Blyth et al. (2009).	Prices: Gas \$11.6/MBtu Coal \$102/t	Prices: Gas \$12.9/MBtu Coal \$106/t	$\sigma_p=6.7\%$ (gas price) $\sigma_p=3.3\%$ (coal price)	Uncertainty maintained at same level as Blyth et al. (2009).
CDM	Values for traded prices based on DECC assumptions about traded price in 2020 in their guidance document "Carbon Valuation in Policy Appraisal" DECC (2009). Quantity available based on limits set for EU–ETS by European Commission. Quantity assumed to increase by factor of two under a 30% EU-wide abatement target scenario.	$E[P]$ €25/tCO_2, range €14-31/tCO_2. $E[Q]$ 108 MtCO_2 under 20% scenario, 215 MtCO_2 under 30% scenario	$E[P]$ €78/tCO_2, range €32-124/tCO_2. $E[Q]$ 108 MtCO_2 under 20% scenario, 215 MtCO_2 under 30% scenario	$\sigma_p=15\%$ in 2020, 25% in 2030 $\sigma_q=4.5\%$	Uncertainty in price calibrated to the ranges given in DECC (2009), so vary by year.
Technology uncertainties					
Electricity end use efficiency	Electricity demand reduction through energy efficiency. Split into two tranches, representing the additional savings in the IEA's ACT and BLUE scenarios compared to the PRIMES reference scenario. Results post-processed to provide a smooth distribution of prices for energy efficiency savings.	$E[P]$ €35/tCO_2 tranche 1 €75/tCO_2 tranche 2. $E[Q]$ 36 MtCO_2 tranche1 and 54 MtCO_2 tranche 2	$E[P]$ €35/tCO_2 tranche 1 €75/tCO_2 tranche 2. $E[Q]$ 60 MtCO_2 tranche1 and 89 MtCO_2 tranche 2	$\sigma_q=4.5\%$	Quantity of available abatement assumed to vary as GBM process.
Industrial energy efficiency	Direct emission reductions from industry covered by the EU–ETS. Savings potential and marginal cost calibrated to ETP 2010 industrial savings potential.	$E[P]$ €10/tCO_2, $E[Q]$ 65 MtCO_2	$E[P]$ €10/tCO_2, $E[Q]$ 100 MtCO_2	$\sigma_p==4.5\%$ $\sigma_q=4.5\%$	Quantity of available abatement assumed to vary as GBM process.
Build new gas instead of coal	Carbon price calculated as the price required to equalise the long-run marginal cost of new coal and gas plant. The quantity of new coal that can be switched to gas is assumed to be constrained to a maximum of 50% of total baseline coal build for policy reasons relating to diversity of supply.	$E[P]$ €52/tCO_2 $E[Q]$ 150 MtCO_2	$E[P]$ €64/tCO_2 $E[Q]$ 240 MtCO_2	$\sigma_q=4.5\%$	Carbon price variability for this option derives largely from fuel price uncertainty, and has a large range because it is based on taking a differential between two sets of stochastic variables.

Table A1 (*continued*)

	Description	Expected values $E[P]$ expected price $E[Q]$ expected quantity		Standard deviation (annual)	Uncertainty assumptions
		2020	2030		
Build new gas instead of lignite	Modelled in similar way to building gas instead of coal. Prices are lower because of lower efficiency of lignite plant.	$E[P]$ €31/tCO$_2$ $E[Q]$ 125 MtCO$_2$	$E[P]$ €40/tCO$_2$ $E[Q]$ 230 MtCO$_2$	$\sigma_q=4.5\%$	Price variability driven largely by fuel price variability (see comment above).
CCS tranche 1	1st generation demonstration plant. These are required before tranche 2 can be built. Expected price based on assumed factor of 3 increase in price compared to mature phase technology. Expected quantity based on 12 demonstration plant planned for EU. Learning assumed to reduce expected costs over time.	$E[P]$ €166/tCO$_2$ $E[Q]$ 18 MtCO$_2$	$E[P]$ €127/tCO$_2$ $E[Q]$ 18 MtCO$_2$	$\sigma_p=4.5\%$ $\sigma_q=15\%$	Uncertainty associated with the amount of CCS demonstration required in this tranche before the next (lower cost) tranche can be accessed.
CCS tranche 2	2nd generation demonstration plant. These are required before tranche 3 can be built. Expected price based on assumed factor 1.5 times cost of mature technology. Quantity based on assumed doubling of the size of tranche 1.	$E[P]$ €83/tCO$_2$ $E[Q]$ 36 MtCO$_2$	$E[P]$ €68/tCO$_2$ $E[Q]$ 36 MtCO$_2$	$\sigma_p=4.5\%$ $\sigma_q=15\%$	Uncertainty associated with the amount of CCS demonstration required in this tranche before the next (lower cost) tranche can be accessed.
CCS tranche 3	Mature stage technology. Expected costs based on average of estimates by EPRI and special report by IPCC on CCS. Technology cost reductions of 1.1% per year assumed based on study by Redpoint for UK Gov't. Price based on breakeven cost of carbon required to equalise new coal +CCS with new coal. Quantity based on assumption that approx 25% of new coal could be built with CCS by 2025 / 2030, calibrated to ETP ACT scenario. CCS tranche 3 can only be implemented if other two tranches have already been implemented.	$E[P]$ €55/tCO$_2$ $E[Q]$ 23 MtCO$_2$	$E[P]$ €50/tCO$_2$ $E[Q]$ 295 MtCO$_2$	$\sigma_{\text{capital}}=9\%$ $\sigma_q==4.5\%$	Capital cost uncertainty for CCS based on range of costs between the EPRI and IPCC studies.
CCS Industry	CCS to abate direct industrial emissions. Price and quantity based on estimates in ETP 2010. Assumed not to be available until after 2020, and dependent on demonstration of CCS tranche 1 and tranche 2.	$E[Q]=0$	$E[P]$ €80/tCO$_2$ $E[Q]$ 95 MtCO$_2$	$\sigma_p=4.5\%$ $\sigma_q=4.5\%$	Price and quantities assumed to be GBM processes
IGCC	Build integrated gasification combined cycle plant in place of ultra-supercritical coal plant. Higher efficiency leads to emissions reductions. Cost of carbon based on breakeven required to equalise long-run marginal costs. Leads to negative expected carbon cost. Quantity assumes that up to 30% of new coal could be IGCC rather than USC.	$E[P]$ €20/tCO$_2$ $E[Q]$ 42 MtCO$_2$	$E[P]$ €34/tCO$_2$ $E[Q]$ 82 MtCO$_2$	$\sigma_q=4.5\%$	Cost of abatement uncertainty driven by fuel price uncertainty because of the different efficiency levels of the two technologies (4% points difference in 2030).
Switch existing coal to existing gas	Fuel switching to gas split into three tranches, at €20, €40 and €60/tCO$_2$. Amount available to switch in each tranche depends on gas price, and is calibrated to a study of fuel switching potential across Europe carried out by Powry for DECC. Results are post-processed after the Monte Carlo run to give a smooth distribution of fuel switching potential at different prices. The potential for fuel switching existing plant declines over time as existing plant retire.	€20/tCO$_2$: $E[Q]=0$ €40/tCO$_2$: $E[Q]=220$ €60/tCO$_2$: $E[Q]=140$	€20/tCO$_2$: $E[Q]=0$ €40/tCO$_2$: $E[Q]=185$ €60/tCO$_2$: $E[Q]=115$		Quantity of abatement depends on fuel price. When gas price low, more abatement available, particularly in lower price tranches.
Early closure of coal plant, replace with gas	This option allows for early closure of existing coal to be replaced with gas-fired CCGT plant. Expected costs based on breakeven carbon required to equalise short-run marginal cost of existing coal with long-run marginal cost of new gas. Quantity available constrained by availability of existing coal that has not already been switched to existing gas plant. This option only relevant in earlier time periods. In 2020, expected quantity zero, although stochastic values can be significant in 2020.	$E[P]$ €126/tCO$_2$ $E[Q]$ 0 MtCO$_2$	$E[P]$ €137/tCO$_2$ $E[Q]$ 0 MtCO$_2$		Uncertainty in price driven by fuel price uncertainties. Uncertainty in volume driven by uncertainty in degree of fuel switching of existing coal to existing gas (early closure picks up the remaining existing coal plant potential).
Nuclear	Abatement assumes new nuclear plant replaces new coal plant. Expected price based on breakeven carbon price required to equalise long-run marginal costs of nuclear and coal. Nuclear capital costs and uncertainty based on average and range of values quoted in Redpoint (2009), EIA (2010), EC (2008a,b), EIA NEMS (2010), MIT (2009), IEA/NEA (2010). Quantity available from new nuclear based on additional 10% (above baseline) of total generation mix coming from nuclear based on ETP 2010 BLUE scenario.	$E[P]$ €16/tCO$_2$ $E[Q]$ 62 MtCO$_2$	$E[P]$ €17/tCO$_2$ $E[Q]$ 128 MtCO$_2$	$\sigma_{\text{capital}}=7\%$ $\sigma_q=4.5\%$	Carbon price uncertainty driven largely by capital cost uncertainty, but also coal price uncertainty.
Onshore wind	Expected values and ranges for abatement cost based on electricity generation cost estimates in EC (2008a,b). Carbon costs calculated as value required to breakeven with long-run marginal cost of new coal plant. Abatement assumes wind replaces coal in the generation mix. No allowance is made for reserve requirements or decreases in operating efficiency of fossil plant on the system.	$E[P]$ €47/tCO$_2$ $E[Q]$ 15 MtCO$_2$ Q_{high} 17 MtCO$_2$ Q_{low} 14 MtCO$_2$	$E[P]$ €39/tCO$_2$ $E[Q]$ 39 MtCO$_2$ Q_{high} 44 MtCO$_2$ Q_{low} 35 MtCO$_2$	$\sigma_{\text{elec}}=4.1\%$	Uncertainty range for electricity cost based on range in EC (2008a,b). Uncertainty in abatement cost of carbon also depends on coal price uncertainty. Quantity of abatement assumed to lie with equal probability within the range indicated.

	Quantity based on Pöyry (2008) estimates of contribution of wind to Europe's RE target.				
Offshore wind 1	Learning phase of offshore wind development. This tranche needs to be implemented before lower cost second tranche. Expected cost based on upper half of the range given in EC (2008a,b). Expected quantity based on Powry estimates of contribution of offshore wind to Europe's RE target. Assumed to replace new coal build. No account taken for reductions in fossil efficiency / back-up requirements.	*E*[*P*] €101/tCO$_2$ *E*[*Q*] 40 MtCO$_2$ Q_{high} 46 MtCO$_2$ Q_{low} 36 MtCO$_2$	*E*[*P*] €83/tCO$_2$ *E*[*Q*] 103 MtCO$_2$ Q_{high} 116 MtCO$_2$ Q_{low} 91 MtCO$_2$	$\sigma_{elec}=4.8\%$	As above.
Offshore wind 2	Mature phase of offshore wind. This tranche only accessible after 1st tranche has been implemented. Expected cost based on lower half of the range given in EC (2008a,b). Expected quantity based additional wind in ETP BLUE scenario over and above EU's RE target implementation. Assumed to replace new coal build. No account taken for reductions in fossil efficiency / back-up requirements.	*E*[*P*] €81/tCO$_2$ *E*[*Q*] 19 MtCO$_2$	*E*[*P*] €49/tCO$_2$ *E*[*Q*] 32 MtCO$_2$	$\sigma_{elec}=4.8\%$ $\sigma_q=4.5\%$	Uncertainty range for electricity cost based on range in EC (2008a,b). Uncertainty in abatement cost of carbon also depends on coal price uncertainty. Uncertainty in quantity assumed to be a GBM process.
Solar PV 1	Learning phase of solar development. This tranche needs to be implemented before lower cost second tranche. Expected cost based on upper half of the range given in EC (2008a,b). Expected quantity based on Powry estimates of contribution of offshore wind to Europe's RE target. Assumed to replace new coal build. No account taken for reductions in fossil efficiency / back-up requirements.	*E*[*P*] €705/tCO$_2$ *E*[*Q*] 3 MtCO$_2$ Q_{high} 4 MtCO$_2$ Q_{low} 3 MtCO$_2$	*E*[*P*] €425/tCO$_2$ *E*[*Q*] 17 MtCO$_2$ Q_{high} 19 MtCO$_2$ Q_{low} 15 MtCO$_2$	$\sigma_{elec}=4.3\%$	As for offshore wind 1.
Solar PV 2	Mature phase of solar PV. This tranche only accessible after 1st tranche has been implemented. Expected cost based on lower half of the range given in EC (2008a,b). Expected quantity based additional wind in ETP BLUE scenario over and above EU's RE target implementation. Assumed to replace new coal build. No account taken for reductions in fossil efficiency/back-up requirements.	*E*[*P*] €523/tCO$_2$ *E*[*Q*] 4 MtCO$_2$	*E*[*P*] €302/tCO$_2$ *E*[*Q*] 7 MtCO$_2$	$\sigma_{elec}=4.8\%$ $\sigma_q=4.5\%$	As for offshore wind 2.
Concentrating solar power	Cost estimates and range based on EC(2008). Assumed to replace new coal build. No account taken for reductions in fossil efficiency / back-up requirements. Expected quantity based additional wind in ETP BLUE scenario over and above EU's RE target implementation.	*E*[*P*] €168/tCO$_2$ *E*[*Q*] 4 MtCO$_2$	*E*[*P*] €140/tCO$_2$ *E*[*Q*] 7 MtCO$_2$	$\sigma_{elec}=2.6\%$ $\sigma_q=4.5\%$	As for offshore wind 2.
Biomass	Build dedicated new biomass plant instead of new coal. Capital operating costs and fuel costs based on estimates in Powry (2007). Costs based on breakeven carbon price required to equalise long-run marginal cost of biomass and new coal plant.	*E*[*P*] €76/tCO$_2$ *E*[*Q*] 104 MtCO$_2$ Q_{high} 117 MtCO$_2$ Q_{low} 91 MtCO$_2$	*E*[*P*] €74/tCO$_2$ *E*[*Q*] 200 MtCO$_2$ Q_{high} 224 MtCO$_2$ Q_{low} 175 MtCO$_2$	$\sigma_q=7.4\%$	Variability in price driven largely by uncertainty in biomass fuel price, but also coal price uncertainty. Quantity of abatement assumed to lie with equal probability within the range indicated.
Biomass in industry	Potential for industry-based biomass fuel switching based on ETP 2010 prices and quantities.	*E*[*P*] €200/tCO$_2$ *E*[*Q*] 30 MtCO$_2$	*E*[*P*] €200/tCO$_2$ *E*[*Q*] 43 MtCO$_2$	$\sigma_p=4.5\%$ $\sigma_q=4.5\%$	Price and quantity variation assumed to follow GBM stochastic process.
Hydro	Prices and quantities based on Powry 2007 report on meeting EU 20% renewables target. Assumed to replace new coal plant. Relatively low additional potential assumed for hydro plant in Europe.	*E*[*P*] €20/tCO$_2$ *E*[*Q*] 7 MtCO$_2$ Q_{high} 8 MtCO$_2$ Q_{low} 6 MtCO$_2$	*E*[*P*] €20/tCO$_2$ *E*[*Q*] 1 MtCO$_2$ Q_{high} 1 MtCO$_2$ Q_{low} 1 MtCO$_2$	$\sigma_p=4.5\%$ $\sigma_q=4.5\%$	Price variation assumed to follow GBM stochastic process. Quantity of abatement assumed to lie with equal probability within the range indicated.
Market uncertainties					
Demand	Uncertainty in electricity demand is modelled as a stochastic variable leading to positive or negative contributions to the total abatement requirements to meet a given target. This contribution to emissions reductions is calculated by taking stochastic variations in electricity demand in the baseline against which the cost curve is calculated.	Electricity demand 3713 TWh.	Electricity demand 3936 TWh.	$\sigma_{demand}=1.9\%$	Total electricity demand uncertainty calibrated to the annualised differences in forecasting 2020 electricity sales by EIA forecasts made over the past 8 years
Fuel price	Fuel price expectations based on WEO 2010 'New Policies'scenario fuel price assumptions. Uncertainty calibrated to UK high and low energy price scenarios as described in Blyth et al. (2009).	Prices: Gas $11.6/MBtu Coal $102/t	Prices: Gas $12.9/MBtu Coal $106/t	$\sigma_p=6.7\%$ (gas price) $\sigma_p=3.3\%$ (coal price)	Uncertainty maintained at same level as Blyth et al. (2009).
CDM	Values for traded prices based on DECC assumptions about traded price in 2020 in their guidance document "Carbon Valuation in Policy Appraisal" DECC (2009). Quantity available based on limits set for EU–ETS by European Commission. Quantity assumed to increase by factor of two under a 30% EU-wide abatement target scenario.	*E*[*P*] €25/tCO$_2$, range €14-31/tCO$_2$. *E*[*Q*] 108 MtCO$_2$ under 20% scenario, 215 MtCO$_2$ under 30% scenario	*E*[*P*] €78/tCO$_2$, range €32-124/tCO$_2$. *E*[*Q*] 108 MtCO$_2$ under 20% scenario, 215 MtCO$_2$ under 30% scenario	$\sigma_p=15\%$ in 2020, 25% in 2030 $\sigma_q=4.5\%$	Uncertainty in price calibrated to the ranges given in DECC (2009), so vary by year.

These results illustrate the different risks that investors face when they are exposed to uncertain carbon prices. For investors exposed to downside risk from low carbon prices policy risks tend to dominate as a price driver. On the other hand, investors exposed to downside risk from high carbon prices will be mostly exposed to market risks.

Policy-based risks are of a different nature to market-based risks. The lack of private sector counter-parties makes policy-based risks difficult to hedge. Combined with the dominance of policy-based risks when carbon prices are low, this fact tends to support the case for providing a carbon price floor, particularly under current conditions in the EU–ETS, which appears to be dominated by policy-risk because of weak prevailing targets. An alternative, prescription would be to increase the stringency of the cap to 30%. This would increase carbon prices, creating greater incentives for low-carbon investment, and would reduce policy-based risks, rebalancing the EU–ETS to become more market-driven, and largely precluding the need for further government interventions, such as carbon price floors.

Finally, these results have implications for the early stages of implementation of cap-and-trade schemes. When they are first set up, caps are typically relatively weak because of the need to phase-in targets, and schemes will often be introduced into a regulatory environment where other policy interventions are already in place (such as targets for renewable energy, energy efficiency, etc.). Our modelling suggests that it is precisely under these conditions that policy risks are most acute. Policy-makers may therefore need to be most alert to the need to alleviate policy risk in the early stages of cap-and-trade schemes.

Acknowledgements

The authors would like to thank the ESRC and EPRI for providing research grants for the development of the model underpinning this study.

Appendix A

See Table A1.

Appendix B

See Fig. B1.

Appendix C

See Table C1.

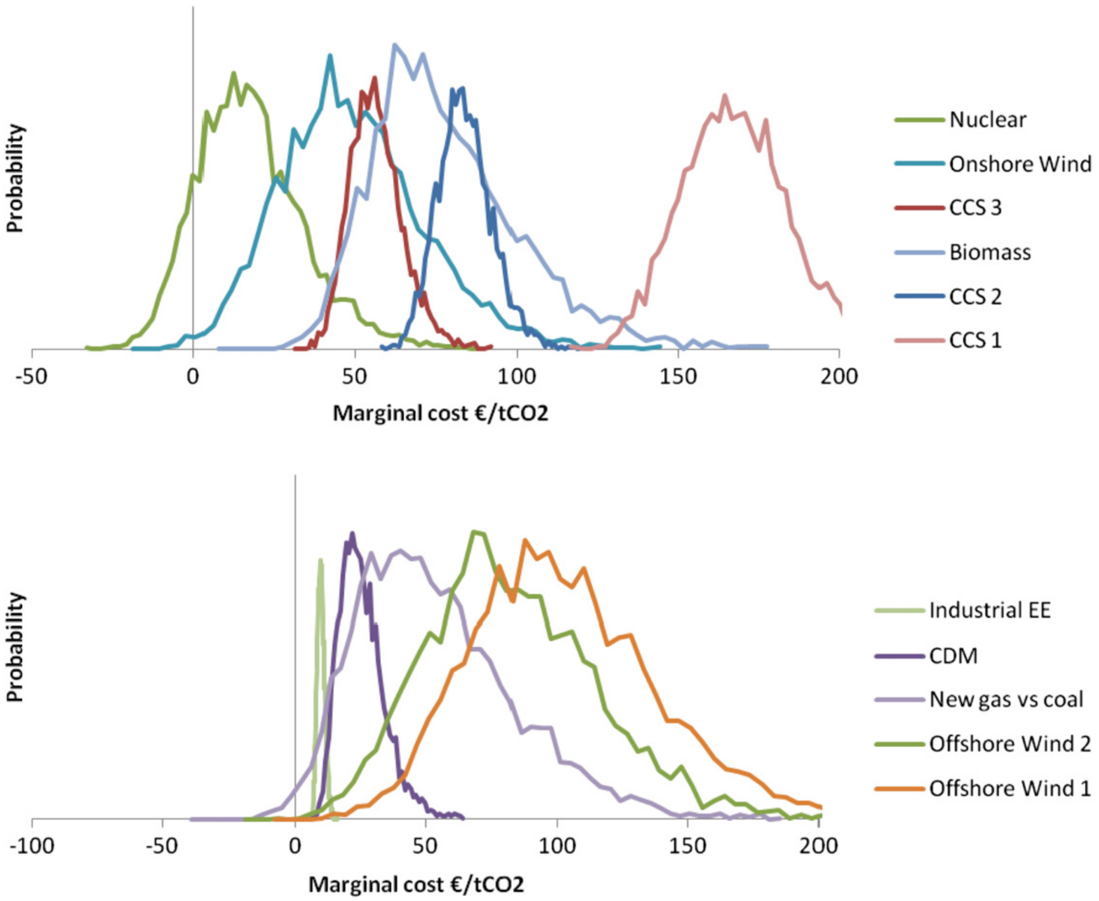

Fig. B1. Marginal cost distributions for some of the larger contributing options included in the EU–ETS MAC curve.

Table C1
Coefficients from the quantile regression analysis.

	%ile	20% 2020		20% 2030		30% 2020		30% 2030	
		Coeff	*t*-Ratio	Coeff	*t*-Ratio	Coeff	*t*-Ratio	Coeff	*t*-Ratio
Const	0.2	13.87	0.8	7.71	0.7	24.99	6.0	36.32	4.6
	0.5	29.08	2.1	16.65	2.6	42.10	11.2	42.59	6.4
	0.8	50.85	4.4	33.12	4.8	46.28	10.9	56.67	7.7
Policy variables									
Renewables	0.2	−9.42	−37.7	−18.36	−37.4	−8.93	−47.3	−22.46	−65.1
	0.5	−10.78	−53.6	−17.69	−63.6	−8.55	−50.1	−20.42	−70.2
	0.8	−11.42	−67.5	−23.71	−79.3	−8.26	−42.7	−19.59	−60.8
CCS on	0.2	−3.20	−12.8	−1.55	−3.2	−2.78	−14.7	−5.64	−16.3
	0.5	−3.40	−16.9	−1.50	−5.4	−3.07	−18.0	−7.24	−24.9
	0.8	−3.41	−20.1	−2.54	−8.5	−2.95	−15.2	−9.73	−30.2
Ee on	0.2	−16.73	−66.8	−10.14	−20.7	−16.44	−87.1	−19.48	−56.5
	0.5	−13.95	−69.4	−9.04	−32.5	−11.85	−69.4	−15.89	−54.6
	0.8	−9.63	−56.9	−7.66	−25.6	−7.97	−41.2	−12.97	−40.2
Market risks									
Gas price	0.2	0.28	14.9	0.13	5.8	0.53	38.0	0.44	28.5
	0.5	0.40	26.9	0.16	12.6	0.64	51.1	0.69	52.4
	0.8	0.52	41.9	0.32	24.0	0.71	50.2	0.82	56.5
Coal price	0.2	−0.21	−2.4	0.13	1.0	−0.37	−5.7	−0.21	−2.5
	0.5	−0.32	−4.7	0.05	0.7	−0.66	−11.2	−0.73	−10.0
	0.8	−0.49	−8.4	−0.38	−5.2	−0.75	−11.3	−1.02	−12.7
Demand	0.2	−0.05	−24.5	− −0.04	−16.9	−0.05	−32.9	−0.05	−31.2
	0.5	-0.06	−34.5	−0.04	−27.4	−0.05	−36.3	−0.05	−36.5
	0.8	−0.07	−43.8	−0.04	−26.6	−0.06	−33.5	−0.06	−35.1
Technical risks (cost of abatement)									
Energy eff	0.2	0.26	3.6	0.11	1.0	0.00	0.1	0.13	1.7
	0.5	0.19	3.3	0.19	3.0	0.00	−0.1	0.09	1.4
	0.8	0.03	0.7	0.03	0.5	−0.01	−0.2	−0.03	−0.4
CDM	0.2	0.04	2.2	0.00	0.5	0.34	27.1	0.02	2.8
	0.5	0.17	12.6	0.00	−0.5	0.32	28.1	0.04	7.8
	0.8	0.23	20.8	0.01	2.4	0.32	24.7	0.08	12.7
CCS tranche 1	0.2	−0.03	−2.2	−0.03	−1.0	0.00	−0.2	0.03	1.3
	0.5	0.00	0.0	−0.03	−1.5	0.00	0.2	0.03	1.5
	0.8	−0.01	−1.2	−0.04	−1.9	0.02	1.6	0.03	1.6
CCS tranche 2	0.2	0.05	2.0	0.07	1.1	0.01	0.7	0.00	0.0
	0.5	0.01	0.3	0.01	0.2	0.00	−0.1	−0.05	−1.4
	0.8	0.02	1.4	−0.02	−0.5	−0.04	−2.0	−0.05	−1.4
CCS tranche 3	0.2	0.03	1.1	0.00	0.0	0.00	−0.1	0.03	0.7
	0.5	0.00	−0.2	0.02	0.7	−0.01	−0.6	0.09	2.8
	0.8	−0.03	−1.6	0.07	2.1	0.01	0.7	0.14	3.8
CCS industry	0.2	0.00	−0.2	0.00	0.1	0.01	1.8	0.03	3.2
	0.5	−0.01	−1.5	−0.01	−1.9	0.01	1.6	0.03	4.3
	0.8	−0.01	−2.3	−0.02	−2.0	0.01	1.1	0.03	3.0
Nuclear	0.2	0.10	10.5	0.15	11.5	0.06	8.1	0.11	12.8
	0.5	0.09	12.1	0.12	16.0	0.05	7.9	0.11	14.4
	0.8	0.09	13.6	0.09	11.3	0.05	6.4	0.09	11.4
onshore w	0.2	0.00	0.4	0.00	0.3	0.01	2.5	0.02	3.6
	0.5	0.00	0.5	0.01	1.9	0.01	1.5	0.02	3.5
	0.8	0.00	0.6	0.02	2.7	0.00	0.8	0.01	1.4
Offshore w	0.2	−0.01	−1.6	0.00	0.2	0.00	1.7	0.03	6.8
	0.5	0.00	−1.8	0.00	1.4	0.00	1.4	0.02	6.7
	0.8	0.00	−1.0	0.01	3.0	0.01	2.2	0.03	6.9
Offshore w 2	0.2	0.00	−1.2	0.01	1.6	0.01	1.8	0.01	3.0
	0.5	0.00	0.7	0.01	1.4	0.00	−0.6	0.01	3.0
	0.8	0.00	−0.1	0.01	2.6	0.00	0.1	0.02	3.2
Solar 1	0.2	n/a	n/a	0.00	1.8	0.00	1.1	0.00	0.8
	0.5	n/a	n/a	0.00	1.2	0.00	0.2	0.00	0.8
	0.8	n/a	n/a	0.00	0.7	0.00	0.0	0.00	0.2
CSP	0.2	0.00	0.3	0.01	0.9	0.01	2.4	0.01	1.0
	0.5	0.00	−0.3	0.00	−0.6	0.00	0.9	0.00	0.7
	0.8	0.00	0.5	−0.01	−1.5	0.00	0.5	0.00	0.3
Biomass elec	0.2	−0.02	−2.8	0.00	−0.4	0.00	0.3	0.04	6.0
	0.5	0.00	−0.8	0.00	−0.2	0.00	0.7	0.05	9.7
	0.8	0.00	−0.9	0.01	2.3	0.01	1.5	0.07	12.2
Biomass ind.	0.2	0.00	−0.5	0.01	2.7	0.00	−1.2	−0.01	−1.8
	0.5	0.00	0.3	0.00	0.6	−0.01	−2.4	−0.01	−2.0
	0.8	0.00	0.6	0.00	1.3	0.00	−0.9	−0.01	−1.8

Table C1 (*continued*)

	%ile	20% 2020		20% 2030		30% 2020		30% 2030	
		Coeff	*t*-Ratio	Coeff	*t*-Ratio	Coeff	*t*-Ratio	Coeff	*t*-Ratio
Hydro	0.2	−0.03	−0.5	0.00	0.0	−0.01	−0.2	−0.07	−1.0
	0.5	−0.05	−1.0	0.00	−0.1	−0.02	−0.5	−0.03	−0.6
	0.8	−0.01	−0.1	−0.03	−0.5	0.00	0.1	−0.07	−1.1
Technology risk (quantity of abatement)									
Energy eff	0.2	0.00	0.0	−0.05	−3.3	−0.01	−0.5	0.00	0.1
	0.5	0.00	0.1	−0.01	−0.8	−0.02	−1.6	−0.03	−2.9
	0.8	0.00	−0.3	−0.02	−2.4	−0.05	−3.6	−0.03	−3.2
EE industry	0.2	−0.04	−3.9	−0.02	−1.8	−0.03	−3.8	−0.06	−7.5
	0.5	−0.05	−5.5	−0.03	−4.6	−0.05	−6.5	−0.07	−10.6
	0.8	−0.06	−8.2	−0.04	−5.3	−0.05	−5.4	−0.08	−10.6
CDM	0.2	0.00	0.6	−0.01	−1.0	−0.03	−13.4	0.00	0.9
	0.5	−0.02	−3.0	0.00	0.4	−0.04	−17.0	0.00	0.2
	0.8	−0.03	−7.5	0.00	−0.4	−0.04	−14.8	0.00	0.4
Gas instead coal	0.2	0.00	0.1	0.01	1.7	−0.01	−4.5	−0.01	−2.1
	0.5	0.00	0.4	0.00	1.5	−0.01	−2.8	0.00	1.1
	0.8	0.00	−0.7	0.01	2.1	−0.01	−4.3	0.00	−0.6
Gas instead lignite	0.2	−0.01	−2.7	−0.01	−3.3	−0.03	−8.3	−0.04	−13.9
	0.5	−0.02	−5.3	−0.01	−4.2	−0.03	−10.8	−0.04	−17.6
	0.8	−0.01	−4.3	0.00	−1.1	−0.04	−11.4	−0.05	−17.3
CCS tranche 1	0.2	−0.03	−1.8	0.00	−0.1	−0.01	−0.5	0.03	1.1
	0.5	−0.02	−1.5	0.03	1.4	0.00	0.1	0.02	1.0
	0.8	0.00	0.2	0.04	1.8	0.02	1.3	0.06	2.7
CCS tranche 2	0.2	−0.02	−1.8	0.01	0.4	0.00	−0.6	0.02	1.8
	0.5	−0.01	−1.3	0.00	−0.1	0.00	−0.2	0.02	1.9
	0.8	−0.01	−1.8	0.01	1.2	−0.01	−0.8	0.02	2.0
CCS tranche 3	0.2	0.01	0.5	0.01	3.4	0.03	1.5	0.01	5.8
	0.5	0.06	2.6	0.01	6.2	−0.01	−0.4	0.01	5.9
	0.8	0.01	0.5	0.01	4.7	−0.04	−1.7	0.02	7.0
CCS industry	0.2	n/a	n/a	0.01	0.6	n/a	n/a	0.00	0.1
	0.5	n/a	n/a	0.00	−0.2	n/a	n/a	−0.01	−1.3
	0.8	n/a	n/a	0.01	0.9	n/a	n/a	0.01	0.6
IGCC	0.2	−0.06	−4.3	−0.08	−7.0	−0.04	−4.0	−0.03	−3.7
	0.5	−0.06	−5.0	−0.03	−5.1	−0.07	−6.8	−0.03	−4.8
	0.8	−0.07	−7.1	−0.03	−4.6	−0.07	−6.1	−0.05	−5.9
Retire coal	0.2	−0.13	−11.9	−31.42	−0.6	−0.23	−24.6	−18.75	−0.5
	0.5	−0.17	−19.2	−51.23	−1.8	−0.14	−16.8	−5.02	−0.2
	0.8	−0.19	−25.2	−53.35	−1.7	−0.06	−6.8	−18.03	−0.5
Nuclear	0.2	−0.01	−1.5	−0.03	−4.1	−0.06	−8.0	−0.05	−9.3
	0.5	−0.02	−3.1	−0.02	−4.1	−0.05	−7.7	−0.04	−10.9
	0.8	−0.04	−6.1	−0.02	−4.8	−0.05	−6.4	−0.04	−9.4
Onshore W	0.2	−0.16	−1.4	0.00	0.0	0.00	0.0	0.04	0.6
	0.5	0.13	1.4	−0.03	−0.7	−0.01	−0.1	0.05	1.0
	0.8	−0.09	−1.1	−0.03	−0.6	−0.06	−0.7	−0.02	−0.3
Offshore W	0.2	−0.04	−0.8	0.01	0.1	−0.03	−0.8	−0.02	−0.8
	0.5	−0.05	−1.1	0.00	0.1	−0.01	−0.2	−0.03	−1.2
	0.8	−0.08	−2.4	−0.01	−0.3	−0.08	−1.9	−0.02	−0.6
Offshore W 2	0.2	0.03	0.7	−0.03	−0.8	−0.05	−1.6	0.01	0.5
	0.5	0.04	1.3	0.03	1.4	−0.01	−0.4	0.02	0.8
	0.8	−0.02	−0.6	0.00	−0.1	0.03	1.2	0.01	0.6
Solar 1	0.2	0.22	0.4	0.23	1.1	0.39	0.9	0.05	0.4
	0.5	−0.78	−1.7	0.15	1.2	−0.56	−1.4	0.19	1.5
	0.8	−1.09	−2.8	0.09	0.7	−0.33	−0.7	−0.20	−1.4
Solar2	0.2	0.04	0.2	0.03	0.2	−0.08	−0.6	0.17	1.5
	0.5	0.00	0.0	0.06	0.7	−0.02	−0.2	0.00	0.0
	0.8	−0.06	−0.5	−0.05	−0.5	0.11	0.8	0.07	0.7
Biomass elec	0.2	−0.01	−0.9	0.00	0.0	0.00	−0.3	−0.04	−3.5
	0.5	−0.03	−2.4	−0.01	−1.1	−0.03	−2.8	−0.04	−3.9
	0.8	−0.03	−2.2	−0.01	−1.2	−0.03	−2.6	−0.04	−3.4
Biomass ind.	0.2	−0.06	−2.3	0.02	0.8	−0.03	−1.9	−0.02	−1.0
	0.5	−0.03	−1.5	0.01	0.4	−0.01	−0.3	0.00	0.2
	0.8	−0.03	−1.6	−0.01	−0.9	−0.03	−1.5	−0.02	−1.0
Hydro	0.2	−0.09	−0.4	−2.46	−0.9	− −0.16	−0.9	−0.62	−0.3
	0.5	0.14	0.7	3.75	2.3	−0.26	−1.6	−1.79	−1.1
	0.8	0.19	1.2	5.17	3.0	−0.12	−0.6	−1.45	−0.8

References

Blyth, W., Bunn, D., Kettunen, J., Wilson, T., 2009. Policy interactions, risk and price formation in carbon markets. Energy Policy 37, 5192–5207.

Centrica, 2010. Centrica says alternatives to gas are vital for the UK, Comments attributed to Sam Laidlaw, CEO of Centrica, Reported in Financial Times February 26, 2010.

Chesney, M., Taschini, L., 2008. The Endogenous Price Dynamics of Emission Allowances: An Application to CO_2 Option Pricing, Swiss Finance Institute Research Paper Series No. 08–02.

Daskalakis, George, Psychoyios, Dimitris, Markellos, Raphael N, 2009. Modeling CO_2 emission allowance prices and derivatives: evidence from the European trading scheme. Journal of Banking and Finance 33 (7), 1230–1241.

DECC, 2009. Carbon Valuation in Policy Appraisal. UK Department of Energy and Climate Change.

DECC, 2010. Consultation on Electricity Market Reform, Department of Energy and Climate Change.

EdF, 2010. "Why Britain must take the nuclear path" by Vincent de Rivaz, Chief Executive EdF Energy, published Financial Times, London January 7, 2010.

EIA, 2010. Updated Capital Cost Estimates for Electricity Generation Plants. US Energy Information Administration, Washington, DC.

EIA NEMS, 2010. Assumptions to the Annual Energy Outlook 2010. National Energy Modelling System. US Energy Information Administration, 〈www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity_tbls.pdf〉.

European Commission, 2008b. 20 20 by 2020: Europe's climate change opportunity, Communication from the Commission COM(2008) 30 final.

European Commission, 2008a. European Energy and Transport; Trends to 2030–2007 Update. Belgium: European Commission Directorate General for Energy and Transport.

European Commission, 2010. Analysis of options to move beyond 20% greenhouse gas emission reductions and assessing the risk of carbon leakage, Communication from the Commission COM(2010) 265 final.

Helm, D., Hepburn, C., 2005. Carbon contracts and energy policy: an outline proposal, October 2005 available at 〈www.dieterhelm.co.uk〉.

Hepburn, C., Grubb, M., Neuhoff, K., Matthes, F., Tse, M., 2006. Auctioning of EU ETS phase II allowances: how and why? Climate Policy 6, 137–160.

IEA. 2007. World Energy Outlook 2007, OECD/IEA Publications, Paris.

IEA, 2010. World Energy Outlook 2010, OECD/IEA Publications, Paris.

IEA/NEA, 2010, Projected Costs of Generating Electricity. Joint Report by the International Energy Agency and the OECD Nuclear Energy Agency.

IIGCC, 2010. 2010 Investor Statement on Catalyzing Investment in a Low-Carbon Economy, Institutional Investors Group on Climate Change.

Ismer, R., Neuhoff, K., 2006. Commitments through financial options, Electricity Policy Research Group working paper available at 〈http://www.eprg.group.cam.ac.uk/〉.

Lewis, M., 2008. It Takes CO_2 to Contango, Deutsche Bank Report.

McKinsey, 2010. Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve, McKinsey & Company 〈http://www.mckinsey.com/clientservice/sustainability/pdf/Impact_Financial_Crisis_Carbon_Economics_GHGcostcurveV2.1.pdf〉.

MIT, 2009. Update of the 2003 Future of Nuclear Power. Massachusetts Institute of Technology.

Pindyck, R., 1999. The long-run evolution of energy prices. The Energy Journal 20, 2.

Pizer, W.A., 2002. Combining price and quantity controls to mitigate global climate change. Journal of Public Economics 85, 409–434.

Pöyry, 2008. Compliance Costs of Meeting the 20% Renewable Energy Target in 2020. Report to UK Department for Business Enterprise and Regulatory Reform by *Pöyry* Energy Consulting.

Redpoint, 2009. Implementation of the EU 2020 Renewables Target in the UK Electricity Sector: RO Reform. Report for the Department of Energy and Climate Change, June 2009 — URN 09D/702.

Resources for the Future, 2007. Assessing U.S. Climate Policy Options: A Report Summarizing Work at RFF as Part of the Inter-industry U.S. Climate Policy Forum.

Reuters, 2010. CEOs seek firm signal on climate policy, 〈www.reuters.com/article/idUSTRE6242IQ20100305〉.

Seifert, J., Uhrig-Homburg, M., Wagner, M.W., 2008. Dynamic behavior of CO_2 spot prices. Journal of Environmental Economics and Management 56 (2), 180–194.

Taschini, Luca, Paolella, Marc S., 2008. An econometric analysis of emission trading allowances. Journal of Banking and Finance 32 (10).

UNFCCC, 2008. Financing Climate Change Action; Investment and Financial Flows for a Strengthened Response to Climate Change, Fact sheet.

Wagner, M.W., Uhrig-Homburg, M., 2009. Futures price dynamics of CO_2 emission certificates—an empirical analysis. Journal of Derivatives 17 (2), 73–88.