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Policies for decarbonizing a liberalized power sector

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Abstract
Given the agreed urgency of decarbonizing electricity and the need to guide decentralized private decisions, an adequate and credible carbon price appears essential. The paper models and quantifies the break-even carbon price for mature zero-carbon electricity investments. It appears an attractive alternative given the difficulty of measuring the social cost of carbon, but modelling shows it extremely sensitive to projected fuel prices, the rate of interest, and the capital cost of generation options, all of which are very uncertain. This has important implications, and justifies combining a carbon price floor with suitable long-term contracts for electricity investments.

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Keywords Carbon price; electricity; investment; renewables

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1 Introduction

The EU climate change targets set out in EC (2014) call for a 40% reduction in greenhouse gas (GHG) emissions by 2030 and an 80% reduction by 2050, relative to 1990. It is widely accepted that an efficient climate change mitigation strategy requires the rapid decarbonization of the power sector (IEA, 2012, 2015; CCC, 2009, 2014). The UK Government (DECC, 2009) with most other European countries and the European Commission (EC, 2015) recognize and intend to address the energy policy trilemma: to deliver reliability, sustainability (decarbonization) and affordability/competitiveness. Of these three, the hardest question is how best to incentivise the decarbonization of the power sector. There is considerable dispute as to whether it is sufficient to set a carbon cap (as under the EU Emissions Trading System, ETS), a carbon price/tax, and whether or not to supplement these with renewables targets, e.g. as specified in the EC *Renewables Directive* (EC, 2009), and/or emissions performance standards (EPS) of the kind introduced in the UK in the *Energy Act 2013* (HC, 2013). This paper examines the problems in setting a carbon price to guide low-carbon generation investment and possible solutions.

Setting a carbon price would seem the natural approach for a liberalized power sector, as standards are typically criticized for failing to equilibrate marginal abatement costs across technologies. The EU Emissions Trading System (ETS) was set up to deliver an EU-wide carbon price, at least for the covered sector, to guide efficient low-carbon choices for mature technologies, while the *Renewables Directive* would support the deployment of near-commercial renewable energy sources, and the Strategic Technologies Plan would identify and encourage greater ambition in Research and Development of immature low-carbon technologies. It is now widely accepted that the EU ETS has failed to deliver an adequate, durable or credible carbon price that would enable mature low and zero carbon price electricity generation investment to be commercially financed in the EU's liberalised electricity market (Newbery et al., 2018). While it is clearly desirable to reform the ETS to address these problems, and more generally, to encourage as wide a coalition of countries as possible to internalize the cost of GHG emissions, there is a more urgent need to ensure that highly durable investment decisions in the power sector avoid locking in an inappropriately carbon-intensive technology, as the lifetime of such investments made now takes us most of the way to the challenging 2050 targets. Indeed, on some views of the future, the 2Â°C capital stock for electricity may already have been reached, meaning that "even if other sectors reduce their emissions in line with a 2Â°C target, no new emitting electricity infrastructure can be built after 2017 for this target to be met" (Pfeiffer et al., 2016).

For setting the carbon price to be practical, its resulting value should not be too sensitive to fuel price and other uncertainties, given the considerable volatility and unpredictability of fuel prices. Unfortunately, this is not the case, as this paper demonstrates, which strengthens the case for multiple policies. This paper employs the useful concept of a break-even carbon price - the carbon price at which a zero or low-carbon technology (e.g. an on-shore wind turbine) has the same cost (*including* this carbon cost) as the most competitive carbon-intensive alternative (e.g. a combined cycle gas turbine, CCGT).[1] The break-even carbon price is useful in considering the

[1] The concept of a break-even price at which two competing technologies are equally profitable, given some set of prices and discount rates, has been employed in various contexts, e.g. for fuel cells in Brazil (Fukurozaki et al., 2015).

target-consistent carbon price, that is, the carbon price needed to meet some specified target GHG abatement, as in DECC (2009), CCC (2015), and Hepburn (2017). It is closely related to the Marginal Abatement Cost (MAC) but is a more direct route to the problem at hand of finding a suitable carbon price for the electricity sector. It also lends itself to exploring the sensitivity of this carbon price to key uncertain parameters, such as the fossil fuel price, the discount rate and capital costs (e.g. Roques et al., 2006; Green, 2008). This methodology can be readily applied to a wide range of comparisons, here illustrated with on-shore wind competing with a CCGT and a nuclear plant competing with an advanced combustion coal plant.

The next section reviews arguments for setting a carbon price rather than a quota, then considers the practical problem of setting a carbon price by developing and parameterizing a simple model for the break-even carbon price in the power sector. Section 3 then addresses the problem of designing suitable decarbonization policies for electricity. Section 4 concludes.

2 Carbon taxes, carbon caps and credibility

A carbon price can be either delivered by fixing the quantity (the cap) and then trading, as in the EU Emissions Trading System (ETS) (2003/87/EC), or fixing the price through some form of carbon tax or charge, such as the Carbon Price Support introduced in the 2011 UK Budget (HMT, 2011). The classic argument for setting a carbon price is based on Weitzman (1974), who noted that in the face of uncertainty, a price instrument (tax or charge) dominates a quantity instrument (a cap or quota) if the marginal benefit of reducing emissions is flatter than the marginal abatement cost schedule. The marginal damage of a tonne of CO_2 now is essentially the same as a tonne emitted in 10 years' time, as CO_2 is resident in the atmosphere and oceans for a century or more. Thus the marginal benefit of abatement is essentially flat in the *rate* of emissions, even if the marginal damage is steeply increasing in the *stock* of emissions (Grubb & Newbery, 2008).

Weitzman's original result was derived from a static model with uncertainty resolved immediately after abatement choices, and so only suitable for flow, not stock pollutants. It may be suitable for short-run operating decisions of existing capacity (whether to run coal or gas-fired plant more intensively), but is not well-suited to investment decisions in highly durable capacity. Nuclear and coal power stations have a life of 60+ years, even if gas-fired plant and wind turbines have shorter (20+) year lives, periods that commit to significant lock-in of cumulative emissions and hence a lock-in to a higher and more damaging stock of greenhouse gases (GHGs).

To deal with these lock-in and stock effects, one needs an intertemporal model in which damage depends on the stock of pollutant, not the flow. Pizer (2002) considered a modified DICE model (Nordhaus, 1994) in which the price or quantity is set in the base year. With his base calibration, the benefits of setting the optimal price are five times as large as those of setting the optimal quota. If the damage costs rise sufficiently rapidly with rising temperatures, then quotas become more attractive over a 50-year horizon. Such open-loop models in which agents fail to take account of future policy changes are unsatisfactory. As time passes we learn more about the likely future consequences of any stock of GHG, and hence the shape and level of the marginal damage (marginal abatement benefit) schedule. We also learn more about the costs of abatement and adaptation and need to adjust policies in light of this new information. While this simplification is understandable given the complexity of closed-loop models, sensible policy will respond to new information and this needs to be taken into account.

Hoel and Karp (2002) do this using feed-back optimal control in an intertemporal stochastic stock pollution model. Cost shocks are serially uncorrelated, the policy maker can periodically adjust policies in light of their development and investors take this into account when choosing their plans. Under parameter values that are plausible for GHG stocks and climate change, price policies are superior to quantity policies, confirming the one-period Weitzman intuition. Karp and Zhang (2006) allow for anticipated learning about future climate change damage and show that such learning favours the use of taxes rather than quotas. Subsequent more sophisticated dynamic models also tend to support this finding. Karp and Zhang (2012) point out that if, reasonably, investors have better cost information than policy makers, carbon taxes are potentially time-inconsistent while quotas are not in the face of cost shocks. Nevertheless, they find that in their linear-quadratic model with plausible parameters, taxes are still welfare superior to quotas. This does highlight a credibility problem with taxes, relevant to the policy choices considered below.

There is a related literature on whether learning is an argument for delay until we know more about damages (Karp and Zhang, 2006 and the extensive literature cited), whether this result is robust to irreversibilities (Chichilniski and Heal, 1993), or conversely, as much of the learning is learning-by-doing that affects abatement costs, whether the opposite is the case and investments should be advanced (Slechten, 2013). Athanassoglou & Xepapadeas (2012) show that an increase in Knightian uncertainty when choosing the least worst regrets option leads under plausible parameter values to an increase in precautionary policy.

2.1 Setting a carbon price

Setting a predictable carbon price trajectory or a carbon tax is, however, problematic, as would be setting the floor and ceiling for price collars. The social cost of carbon (SCC), explained in Stern (2006) and widely used by agencies such as the US EPA is difficult to estimate, as it involves computing the future damage imposed by the current emission of 1 tonne of CO_2 and discounting it back to the present. The US estimate for 2015 ranges from \$13/t CO_2 (5^{th} percentile) to \$121/t CO_2 (95^{th} percentile) with an average at 3% discount rate of \$42/t CO_2 (all uprated by the CPI to US\$2013) (US EPA, 2016).

The social cost of the damage is problematic as it involves weighting disparate and uncertain levels of future consumption, as is the discount rate, which should depend on the state of the future world in which the damage is incurred (Stern, 2006; Weitzman & Gollier, 2010, Guéant et al., 2012, Stern, 2013; Pindyck, 2013; Weitzman, 2013). It should be no surprise that the computed SCC is highly sensitive to the discount rate, as the following example shows. The majority of damage arising from climate change will occur after 50-100 years, and continue for thousands of years. (For example the time constant for ocean currents that convey cold salty water from the arctic to their eventual upwelling in the tropics before returning as a warm surface current is some 4,000 years.[2]) The present discounted value of \$1 million in 100 years time at 6% is \$2,950, at 3%

[2] See e.g., http://www.marbef.org/wiki/ocean_circulation

is \$52,000 and at 1.4% (the rate used in the Stern Review (Stern, 2006) is \$249,000, 84 times as large as at 6%. Not surprisingly, then, Waldhoff et al. (2014) start with a base case for the SCC of \$10/t-CO_2 discounting at 3% real, and including the benefits of CO_2 fertilization (without which the SCC rises to \$18/t-CO_2). (All values uplifted to 2013 US\$.) If they reduce the rate of pure time preference from 1% to 0.1% (lowering the discount rate to 2.1%) their SCC increases to \$42/t-CO_2. Taking some account of distribution (as the impacts are higher in poorer regions) can further raise it to \$135/t-CO_2. Other authors find a similarly wide range for the SCC. For example, Ackerman and Stanton (2012) find that the 2010 SCC could range from \$21/t CO_2 to \$800/t CO_2.

Allowing for the probability distribution of outcomes, including a small risk of catastrophic change, further magnifies the value of the SCC and increases the range of possible values for the SCC, leading Dietz (2011) to conclude that it is "impossible to come to useful conclusions about, for example, optimal rates of carbon taxation." This pessimism that the SCC is an operational concept leads Ackerman and Stanton (2012) to conclude that "the SCC is roughly equal to or greater than the cost of maximum feasible abatement." Following this line of argument, Dietz (2012) argues that "given the uncertainty about estimating the SCC, there is much to commend an approach whereby a quantitative, long-term emissions target is chosen (partly based on what we know about the SCC), and the price of carbon for regulatory impact analysis is then based on estimates of the marginal cost of abatement to achieve that very target." This in turn draws on earlier work in which Dietz and Fankhauser (2010) observe that at interest rate of 4% "the range of the present MAC (Marginal Abatement Cost) is ~\$0 to ~\$68/tCO2, which is a factor of 10 narrower than the uncertainty around the SCC."

Applying this insight to the electricity industry, one needs to find the carbon price above which mature zero-carbon generation becomes commercially viable, since the carbon targets cannot be met without an almost complete and early decarbonization of the power sector. The next section confirms that the MAC (and the break-even carbon price) for electricity is highly sensitive to fossil fuel prices, discount rates and capital costs, all of which are uncertain, making it difficult to set a suitable carbon price to guide generation investments, or to judge whether the price delivered by a cap-and-trade system is suitable. The range of uncertainty of the break-even carbon price, while less than that of the SCC, nevertheless remains substantial.

2.2 The model

There are two reasons for using a carbon price in a liberalized electricity supply industry (ESI) – in the short run to deliver an efficient merit order (the set of plant operating and their output levels) from the existing portfolio, and, the subject of this paper, to guide investment choices. At the time of investment for zero-carbon plant to be chosen, it must be more profitable than fossil-fueled alternatives, which requires a carbon price above the break-even price – the carbon price needed to make zero-carbon and fossil generation investments equally profitable. The break-even carbon price depends on the carbon intensity of the fuel, γ. If zero-carbon generation is competitive with fossil fuel, then a £1/MWh_{th} fall in the price of fuel would require an offsetting $1/\gamma$ increase in the price of CO_2 to maintain cost parity between zero-carbon and fossil generation.[3]

[3] The subscript $_{th}$ refers to the thermal energy content of the fuel, unsubscripted MWh refer to electricity output.

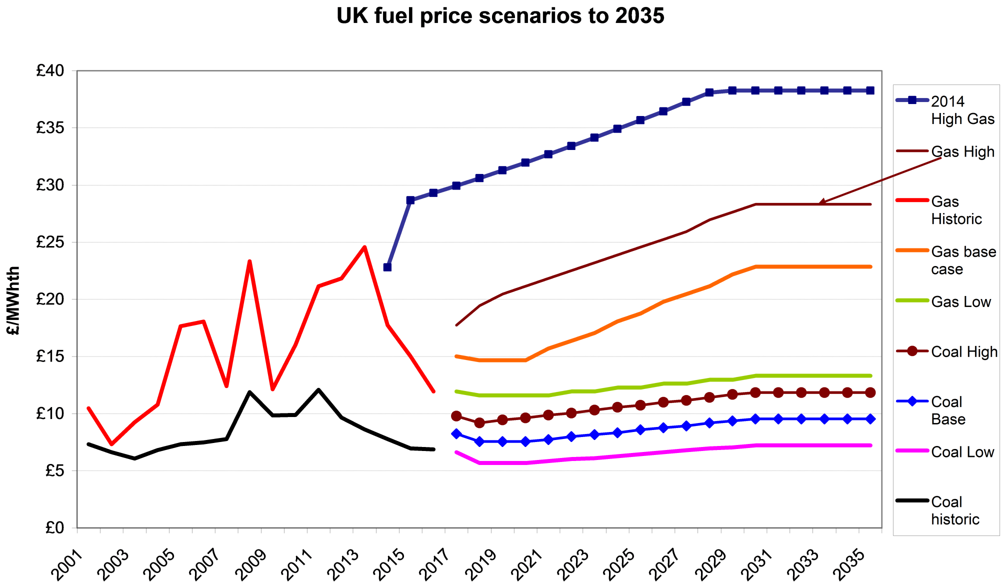

Figure 1: UK fuel prices past and future scenarios (DECC, 2015b)

The likely future competitive fuel in the ESI is gas. For delivered pipeline gas $\gamma = 0.19$ tonnes CO_2/MWh$_{th}$, so the multiplier for the CO_2 price is 5.24. This makes the break-even carbon price very sensitive to the gas price. This might not matter if the gas price were predictable and stable. Unfortunately, this is not the case as its price uncertainty is large, as shown in Fig. 1.[4] The forecast high gas price for 2030 made in 2014 (DECC, 2014) was £(2017)38.26/MWh$_{th}$ while that made in 2017 (BEIS, 2017) was £(2017)28.32/MWh$_{th}$ or 26% lower (both projections are shown in the figure). Even one year ahead the range between the UK's low and high wholesale gas price scenarios is 39% of the central forecast, rising to 65% by 2020 and thereafter remaining at that level.

The *difference* in UK projected high gas prices for 2020 made in 2014 and 2017 is £10.81/MWh$_{th}$ with an implied range in the required break-even CO_2 price of £57/tonne, which is nearly double the original UK 2020 (supported) carbon price of £(2017)33/tonne (DECC, 2010). Even taking just the 2017 forecasts for just three years ahead, the range for 2020 is £9.55/MWh$_{th}$ with an implied range in the required break-even CO_2 price of £50/tonne. In contrast, for coal, $\gamma = 0.341$, the multiplier is only 2.93 and the (2017 forecast) range of UK forecasted coal prices in 2020 is only £3.27/MWh$_{th}$ (although since 2001 the actual range has been £(2017)6.02/MWh$_{th}$). If coal were the competitive fuel, the uncertainty in the carbon price would be only £10/tonne (or £18/tonne using the historic range).

[4] The data for coal include £2/MWh$_{th}$ from the US$ price converted at the 2017 \$/£ exchange rate to cover transport to power stations. DECC (2014) projections have been uprated by 1.04 to 2017 prices. Historic coal prices before 2010 are derived from the cost of coal delivered to major power stations (hence the uplift of £2/MWh$_{th}$).

2.3 Sensitivity to parameters

Fossil generation and zero-carbon generation (wind, PV, nuclear power, etc.) differ in their cost and operating characteristics in important ways, which for present purposes it is convenient to measure by levelised costs.[5] To be clear on the meaning of levelised cost, as an example consider levelising the price. If p_{ht} is the wholesale price in hour h of year t, then if the time horizon is T and the discount rate is r, the levelised price p is defined first in terms of the base-load (time-weighted) price for that year, p_t, and then over the time horizon as the constant price giving the same present value as the actual stream of prices:

$$p\int_0^T e^{-rt}dt = \int_0^T p_t e^{-rt}dt, \;\; p_t \equiv \sum_h \frac{p_{ht}}{Y}, \;\; Y = 8760. \tag{1}$$

Suppose that the relevant lives of the most attractive fossil plant and zero-carbon plant are effectively the same (e.g. CCGT and on-shore wind) at T, and use upper case letters for the zero-carbon option and lower case letters for the fossil option.[6] K and k are respectively the capital cost in £/MW capacity of the two options, M and m are the fixed O&M costs, £/MW, (measured for convenience per hour, averaged over each of the $Y = 8760$ hours of the year), V and v are the variable O&M costs in £/MWh, f_t is the fuel cost in £/MWh$_{th}$, c_t is the carbon cost in £/tonne CO_2, e is the efficiency of the fossil generator, B and b_t are the capacity factors (e.g. for wind, the average fraction of equivalent full output hours per year, assumed constant from year to year for any specific wind farm).[7]

The gross profits per unit capacity in year t are respectively Π_t and π_t:

$$\begin{aligned}
\Pi_t &= \sum_h q_{ht}(p_{ht} - V) - MY = BY(\theta_t p_t - V) - MY, &(2)\\
\theta_t &\equiv \frac{\sum_h q_{ht} p_{ht}}{BY p_t}, \;\; \text{where } q_{ht} \text{ is output in hour } h.\\
\pi_t &= \sum_h \max(p_{ht} - v - \frac{f_t}{e} - \frac{\gamma c_t}{e}, 0) - mY,\\
\pi_t &= b_t Y(\phi_t p_t - v - \frac{f_t}{e} - \frac{\gamma c_t}{e}) - mY. &(3)
\end{aligned}$$

Here q_{ht} is the output per MW capacity in hour h and year t of the zero-carbon plant (e.g. wind) and θ_t measures ratio of the average revenue per MWh earned by the, possibly intermittent, zero-carbon generator and the base load average price in that year. Thus in Britain, wind output is positively correlated with price at low levels of wind penetration, so $\theta > 1$, but as wind penetration increases, it becomes more dominant in hours of high wind and depresses the price, eventually causing $\theta < 1$ (Green & Vasilakos, 2010). For the fossil plant, b_t is the fraction of the time that the spot price is above the avoidable cost, equal to its capacity factor (CF), while $\phi_t > 1$ is the ratio

[5] Recognising that levelised costs are misleading for plant with low or variable load factors, for which investment appraisals need output and price profiles. The required corrections for output profiles are explained below.

[6] A glossary of terms is provided at the end, and teh main terms are listed in Table 1).

[7] Although actual output varies from year to year the expected output used for investment analysis is normally taken as constant. Any decline in output from a given turbine over time can be addressed by taking a suitable levelised average value.

of output-weighted price to the base load (or time-weighted) price, defined similarly to θ_t. $\phi_t > 1$ as positive fuel costs mean that plant will not supply when the price falls below variable operating costs and will therefore supply in the higher-priced hours. Both b_t and ϕ_t are influenced by low-carbon penetration, with b_t falling but ϕ_t rising as zero-carbon low variable cost plant sets low prices in an increasing number of hours. For a given fossil plant technology, their product will fall over time as this type of plant becomes less profitable.

The electricity system also has to meet the reliability standard (in many countries set as a Loss of Load Expectation, and in many European countries this is 3 hrs/yr). With increasing renewables penetration this requires back-up controllable (usually fossil, but in favoured locations storage hydro) plant. As the contribution selling at the wholesale price falls for fossil plant, it will become necessary to provide a capacity payment, P/MWhr,[8] set at the efficient level, either through a capacity auction (as in GB) or conceivably through competitive scarcity pricing in energy-only markets (Newbery, 2017c). Plant eligible for capacity payments are derated to give their equivalent firm capacity factor, Γ for wind (which, in Northern Europe, might be as much as 50% of B, and τ for fossil (typically 85-90%). These capacity credits reduce the annualized capital cost and are assumed constant (or levelized).

The annualization factor to convert the capital cost into an hourly cost is $\xi \equiv \frac{r}{Y(1-e^{-rT})}$. The break-even levelised carbon price, c, equates the profitability of the competing technologies:

$$\Pi = B(\theta p - V) - (M + \xi K - \Gamma P) = \pi = b(\phi p - v - \frac{f+\gamma c}{e}) - (m + \xi k - \tau P). \tag{4}$$

Here f is the levelised forecast fuel price, b, θ, ϕ, Π and π are the levelised forecast values of the CF, price multipliers and net (annual) profits. If the carbon price c is adjusted to remain at the break-even level and each technology (fossil and zero-carbon) is the most profitable currently available, then in competitive equilibrium, the price p adjusts to make both (excess) net profits zero. Set (4) to zero and eliminate p to give the levelised break-even carbon price:

$$\frac{\gamma c}{e} = \frac{\phi}{\theta}(\frac{M + \xi K - \Gamma P}{B} + V) - (\frac{m + \xi k - \tau P}{b} + v) - \frac{f}{e}. \tag{5}$$

Partially differentiating (5) confirms that $\partial c/\partial f = -1/\gamma$, except that the fuel and carbon prices are now their levelised values.[9] The break-even carbon price rises with efficiency, e, of the marginal entrant fossil plant and with the fixed and variable excess cost of the zero-carbon plant over the fossil plant (suitably adjusted for price and capacity factors). Similarly, $\partial c/\partial v = -e/\gamma$ and $\partial c/\partial V = e\phi/(\theta\gamma)$, both smaller in absolute size than $\partial c/\partial f$ with ϕ/θ normally >1 for on-shore wind.

If $A \equiv M + \xi K - \Gamma P$, $a \equiv m + \xi k - \tau P$, are the total fixed and capital costs per hour, then $\partial c/\partial v = -e/\gamma$, $\partial c/\partial a = b^{-1}\partial c/\partial v$, $\partial c/\partial V = e\phi/(\gamma\theta)$, and $\partial c/\partial A = B^{-1}\partial c/\partial V$. For fossil plant all these parameters are fixed except for b, which will be lower the higher is the capacity

8 The GB auction cleared at about £20/kWyr which would be £2.283/MWhr for our $Y = 8,760$ hrs, but this is low partly because of additional ancillary service revenue left out of this model. A typical US adminsitratively set capacity payment of \$75,000/MWyr or \$8.76.MWhr. Note that the actual payment would only be made in hours of stress, not equally over the year, but for levelising purposes this is the appropriate formulation.

9 Table 3 gives the signs of the various derivatives.

share of zero-carbon plant relative to the higher variable cost fossil plant. For wind turbines, B may be fixed but the relative price factor ϕ/θ is likely to rise over time with increased penetration. Over time the value of e/γ will fall as cheaper but less efficient peaking plant is increasingly installed in place of baseload fossil plant, given the lower value of b, so the carbon price will become less sensitive to excess fixed costs, and as γ rises, so the sensitivity of the carbon price to fuel prices will fall. Thus the sensitivity of the carbon price falls over time with decarbonization.[10]

If we ignore the (lower) dependency of the levelised fuel and carbon costs on the rate of discount, and concentrate instead on the more sensitive amortization factor, ξ, holding everything else constant, then

$$\frac{r\partial c}{\partial r} = \frac{e\xi}{\gamma}\left(\frac{\phi K}{\theta B} - \frac{k}{b}\right)\frac{d\xi}{dr} = \frac{e\xi}{\gamma}\left(\frac{\phi K}{\theta B} - \frac{k}{b}\right)\left(1 - \frac{rTe^{-rT}}{(1-e^{-rT})}\right). \tag{6}$$

To gain an order of magnitude of the carbon price sensitivities, Table 1 provides cost and technology estimates and Table 2 gives the levelised fuel prices.

These data can be used to compute the equilibrium levelised carbon and time-weighted electricity prices for either on-shore wind and a gas-fired combined cycle gas turbine (CCGT) or for base-loaded nuclear power and Advanced Supercritical Coal (ASC) with flue gas desulphurisation. At these equilibrium prices the various sensitivities can be calculated, assuming for present purposes an interest rate of 5% (real) and the central values in Table 1, with the High gas price discounted over 20 years but the Medium coal price discounted over 40 years. Table 3 shows in the column headed "factors, m" the values of $\partial c/\partial x$, where x is variously f, v, a, etc., estimated at equilibrium values of c, the full range of uncertainty of each of the parameters, Δx, from Tables 1 and 2, and the resulting change in c, Δc, from multiplying the multiplier with the range. Fig. 2 illustrates this sensitivity graphically comparing gas CCGT with on-shore wind, and, given the prices of gas from fig. 1, can be used to assess the required break-even price of carbon for vary-

Table 1: Cost and technology parameters

units	symbol	on-shore wind	CCGT	Nuclear	ASC Coal
£/MW/8760	K,k	183 ± 50	70 ± 12	580 ± 145	190 ± 20
£/MW/8760	M,m	3 ± 1.5	2.7 ± 0.6	10 ± 2	5 ± 1
£/MWh	V,v	4 ± 1	1.6 ± 0.4	2 ± 1	2 ± 1
Lifetime yrs	T	20 ± 5	25 ± 5	60	50 ± 10
Capacity factor	B,b	$25\% \pm 3\%$	$40\% \pm 10\%$	$90\% \pm 2\%$	$88\% \pm 2\%$
HHV %	e		$53\% \pm 1\%$		$41\% \pm 2\%$
t. CO_2/MWh_{th}	γ	0	0.19	0	0.341
price factor	θ,ϕ	1 ± 0.1	1.2 ± 0.1	1	1

Source: DECC (2013), NREL (2010)

[10] The simple model here assumes just one fossil plant, but in long-run equilibrium it is likely that a range of fossil plant (mid-merit CCGTs, peaking open-cycle gas turbines) will be needed to deliver power at least cost. Each technology will have likely different e/γ but each will need to cover its cost on average. A full systems analysis would require a more complex model.

Table 2: levelised fuel prices for varying time horizons and discount rates

r, T	Gas H	Gas L
5%, 20yrs	£32.6	£15.0
10%, 20yrs	£31.7	£15.1
5%, 25 yrs	£33.0	£15.0
	Coal H	Coal M
5%, 40 yrs	£15.4	£12.3
10%, 40 yrs	£8.3	£6.8
5%, 60 yrs	£17.2	£13.6

Source: DECC (2014)

Table 3: Sensitivities and impacts on the break-even carbon price

	Factors, m	Range	Response	Factors, m	Range	Response
	gas v. wind	Δx	Δc	Coal v. Nuc.	Δx	Δc
$\partial c/\partial f$	-5.3	£17.6	-£93	-2.9	£6.6	-£19
$\partial c/\partial v$	-2.8	£0.8	-£2	-1.2	£2	-£2
$\partial c/\partial V$	2.3	£2	£5	1.2	£2	£2
$\partial c/\partial a$	-7	£3	-£21	-1.3	£3	-£4
$\partial c/\partial A$	9.2	£11	£100	1.4	£20	£28
$r\partial c/\partial r$	35	5%	£35	31	5%	£31

Source: Tables 1, 2

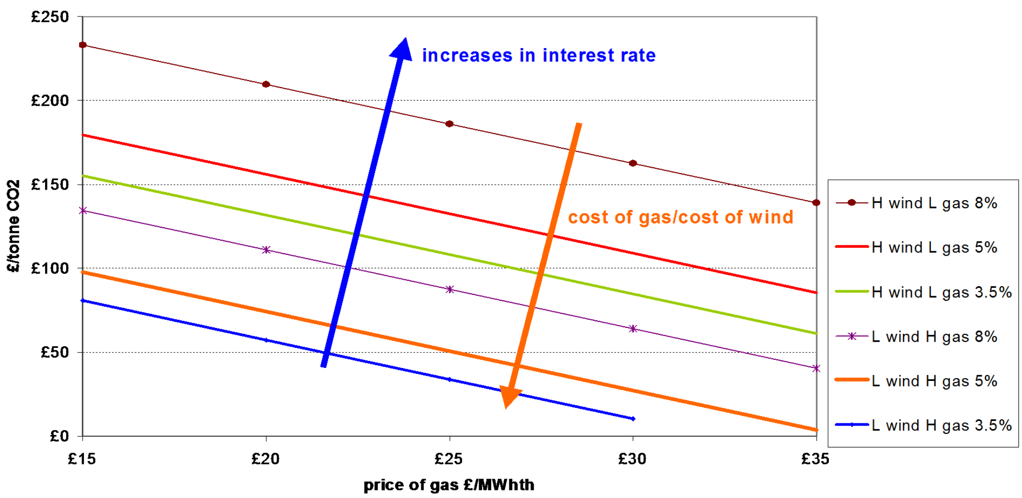

Figure 2: Break-even CO_2 prices vs. the gas price

ing assumptions about costs and discount rates. As the price of gas rises along the x-axis, for any set of other parameters the break-even price of CO_2 falls (the break-even lines slope down). As the interest rate rises for any gas price the lines move vertically up and with them the required break-even CO_2 price, while as the capital cost of CCGT rises relative to the wind turbine, so the lines move down, as does the break-even CO_2 price. In Table 3, if the gas price were Low instead of High, c would have to increase by $\Delta c = m \cdot \Delta x = -5.3 \times -£17.6 = £93$/tonne CO_2, and if the total fixed cost per MW of wind, A, were to rise by £11/hr, c would need to rise by £100/t. In contrast if nuclear and ASC coal are both the marginal technologies, the sensitivities are far lower and even a change in the total fixed cost per hour per MW of nuclear, A, were to rise by £20/hr, c would need to rise by only £28/t (at these perhaps optimistic values for the capital cost of nuclear stations). Similarly if the rate of interest were to rise from 5% to 10% (i.e. doubling) c would need to increase by £35/t (wind) or £31/t (nuclear) as the zero-carbon options are more capital intensive and so more impacted by a rise in the WACC, r.

2.4 Other applications and implications

The range of possible low-carbon generation options is wider than just on-shore wind and nuclear power, and includes solar PV, off-shore wind, biomass, and carbon capture and storage (CCS), applied either pre- or post-combustion to coal or CCGTs. Some, such as biomass and arguably CCS, are mature (at least in their component parts) and for these the same method can be applied to compare any of these with the least-cost fossil option. Others are less mature and investments deliver a learning benefit of uncertain but potentially important value (Newbery, 2017a, 2018b). This can be treated as a credit to the investment (almost all learning is delivered in the supply chain up to the point of commissioning, although some may derive from its operation), and can thus be considered as an uncertainty about the *attributable* capital cost (i.e. the gross cost *less* the learning benefit). A more sophisticated extension would recognize that the optimal decarbonization strategy is likely to require a portfolio of technologies, as their performance will be imperfectly correlated with uncertain parameters (fossil fuel prices, discount rates, capital costs). At each combination of generation plant on the efficient risk-reward frontier, there is a weighted average response of the break-even carbon price allowing for these cross correlations (Roques et al., 2008).

It is also quite standard to compute the implied cost of saving a tonne of CO_2 when examining various policy options such as improving building insulation standards, some of which are directly observed on auction markets, such as that for the Energy Company Obligation.[11] In some cases the numbers are given with spurious precision, but this paper shows there is huge uncertainty attached to these figures, primarily, but not exclusively, through their dependence on the future price of fossil fuels, which for gas is highly uncertain.

One of the most attractive ways to mitigate climate change damage is to stop subsidizing fossil fuels. The IEA publishes annual estimates of the global level of these subsidies, which in 2013 were \$548 billion, 54% due to underpricing oil but only 1% from underpricing coal.[12] These estimates exclude the cost of CO_2, while those prepared for the EC by Ecofys include a SCC of €50/tCO_{2e} in 2012. At this price, climate damage in the EU-28 in 2012 is estimated at €100 billion, double the other external costs (Ecofys, 2014, Fig. 3.13 but ignoring resource depletion costs, which are a pecuniary externality). Ecofys recognizes that the SCC is highly uncertain and

[11] See http://www.insidehousing.co.uk/home/home/price-of-carbon-soars-to-120-per-tonne-at-auction-34750
[12] See http://www.worldenergyoutlook.org/resources/energysubsidies/fossilfuelsubsidydatabase/; see also Newbery (2017b)

cites a range of studies, suggesting a range from €10-100/tCO_{2e} in 2012, although Ecofys itself considers a narrower range from €30-100/tCO_{2e}. If instead the break-even carbon cost is used, the range would if anything increase.

3 Designing suitable decarbonization policies

Although it is very attractive to work back and find a carbon price that supports mature renewable generation, this paper suggests that the resulting value for the required carbon price is highly sensitive to capital costs, the discount rate, and especially the price of fuel. These sensitivities decrease with increased zero-carbon penetration, but that is little comfort in the early investment stage. This creates a dilemma for policy design, as ideally the carbon price should be predictable to create credible investment decisions, and uniform across the economy(ies) at each date to deliver decarbonization at least cost. Certainly in the near term it seems unlikely that the consensus forecast of carbon prices will give the right signals for long-term highly durable investment decisions in the ESI. It also seems reasonable that, given the current consensus on the urgency of avoiding further carbon lock-in from such durable investment decisions, the objective is to decarbonize the ESI rapidly as the least worst regrets strategy. If that is accepted, then an immediate implication is that there should be no new unabated coal generation built, a requirement of UK's *Energy Act, 2013*. In January, 2018, the UK Government announced its intention to phase out all unabated coal-fired generation by 2025.[13] That leaves gas as the only acceptable fossil fuel for generation in the short and medium run. This is consistent with National Grid's (2017) *Two Degrees* scenario (which is the most aggressive decarbonization scenario), shown in Fig. 3. (Notice that the graph shows output, not capacity, which for gas may need to rise as its capacity factor falls.)

New investment will need to be that most suited to the evolving portfolio of low-carbon power stations. Storage hydro has the ideal combination of zero carbon and the ability to vary output across time in response to intermittent renewables but there is hardly any left unexploited in Europe. Most renewables except biomass (which has other sustainability problems) are intermittent and require demand *less* uncontrollable supply to be able to accommodate large and rapid changes. That can be delivered through a combination of trading over wide areas, flexible generation, demand side response, and/or storage (Newbery, 2018a). All options require additional investment in the appropriate technologies and efficient price signals to make the investments profitable and their instantaneous operation efficient. The test of energy policies is whether they can deliver these objectives and decarbonization in a liberalized ESI.

3.1 Comparing policies

The range of policies for decarbonizing electricity include: (1) agreeing (usually internationally, as in the EU) a sequence of caps under a cap-and-trade system, (2) setting a carbon price (directly as a tax, or through a carbon price floor, as in Britain), (3) setting an emissions performance standard (EPS) as in the UK *Energy Act, 2013* (HC, 2013) or (4) providing long-term contracts (as for renewables in many jurisdictions, and as set out in the UK *Energy Act, 2013*). Designing and

[13] http://uk.reuters.com/article/uk-britain-coal-phase-out/britain-outlines-plans-for-2025-coal-power-phase-out-idukkbn1eu15p

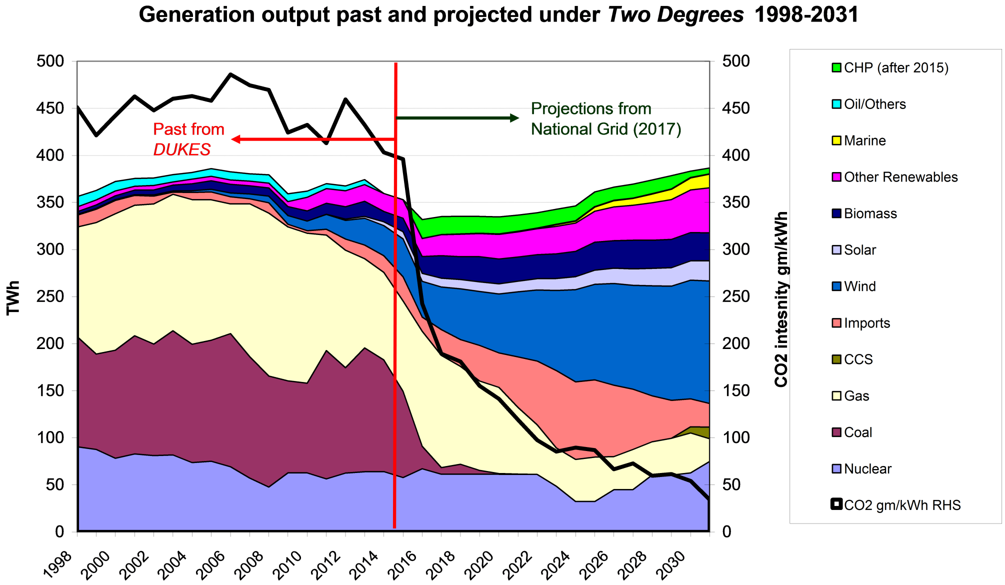

Figure 3: Generation by fuel. Sources: *DUKES*, National Grid (2017)

allocating such contracts opens up an additional and quite wide range of options. All four options (and several contractual variants) have been employed in the UK. Their respective merits should be judged against whether they are the least-cost solution to the market failures identified (biassed views on future carbon prices, missing risk and futures markets, learning spill-overs, etc., see Newbery, 2017c), whether they minimize distortions to efficient trade between technologies at home and internationally, whether they are perceived as credible by investors and thus reduce the cost of borrowing, whether or not they create political lock-in that reduces future flexibility, and what incentives they provide for desirable learning and innovation.

Agreeing caps for cap-and-trade

The fundamental objection to quotas discussed above remains, given that CO_2 is a highly persistent global stock pollutant. It is, however, politically the simplest instrument for putting a carbon price in place within a country and agreeing to coordinate between countries. The challenge is to transform it to deliver an adequate, credible and durable price, which requires modifying its form (e.g. through possibly soft collars, see e.g. Newbery et al., 2018)). It is therefore tempting to leave the carbon price to the existing EU ETS and concentrate on its reform. Apart from the obvious objection that the current ETS price is too low and so fails to give suitable long-run investment signals, it faces additional problems. Until low-carbon generation dominates price determination, the electricity price will be set by fossil generation most of the time. That means fossil generation enjoys a natural hedge against fuel price uncertainty, and hence will appear lower risk and more attractive than equal expected value zero-carbon plant (Roques et al. 2008). Given the pressure to reform the ETS and raise the carbon price, the consequential risks facing coal-fired investment may be a sufficient deterrent, and so it may provide a transition from largely coal-based ESIs to a fuel mix that has a large share of gas for some time while retaining old coal for its useful balancing capability. In addition, a more aggressive low-carbon deployment strategy of the sort that makes sense in the ESI will lower the price of carbon facing the remaining sectors in the ETS, as the *Renewables Directive* demonstrated, and will not reduce the total emissions of CO_2.

Clearly the current ETS does not give good signals on the kinds of investment needed for the future fuel mix (flexible generation, interconnectors, etc.). The spot price of carbon is also critical in determining whether existing coal or gas generation is favoured. Thus the capacity factor of coal plant in the island of Ireland has varied between below 40% and above 95% since Jan 2012 as the relative carbon-inclusive prices of coal and gas have varied.[14] Short-run efficiency between sectors and across trading partners needs a uniform but also adequate carbon price (and there is agreement that the EU ETS has failed to deliver an adequate price since 2008). Britain with its Carbon Price Floor (in 2018 at £18/tonne CO_2) has dramatically reduced the coal share of generation. In the second quarter of 2017, "gas accounted for 41.3 per cent, whilst coal accounted for a record low of only 2.1 per cent".[15]

Raising the ETS price requires agreement to tighten the cap. The difficulty is that the national caps are valuable and agreeing to reduce them is perceived as harming domestic interests. If future allocations are uniformly scaled back, and if each Member State auctions off a sufficient fraction of its allocation, these states will receive much needed fiscal revenue which might form the motive for collective agreement, but evidence for success here is lacking, and the route in which individual Member States impose their own Carbon Price Floors may be the default option.

Setting a carbon price

The carbon price could be the break-even price defined above and backed out of the abatement cost side, or the social cost of carbon (SCC) based on some view of future damages, as in the *Stern Review* (Stern, 2006). The break-even carbon price is too dependent on future forecasts to be credible by itself as forecasts can be easily manipulated, while the SCC is quantitatively too ill-defined, as argued above. If one EU Member State (MS) sets a high Carbon Price Floor (as the UK considered) it will distort trade and be perceived as harming its competitiveness, although the new rules for the Market Stability Reserve (MSR) which will 'limit the validity of allowances in the MSR' from 2023 onward (EC, 2018), ratified by the European Parliament in January 2018, emissions reductions secured by a CPF in any one Member State lead to 50-85% reduction in total EU emissions. This may encourage more countries to impose a CPF, as seems to be happening in the Netherlands (Newbery et al., 2018).

Setting Emissions Performance Standards

The UK set an EPS for new power stations in the *Energy Act 2013* of 450gm/kWh averaged over 7,000 hours or 3,150 tonnes CO_2 per MW capacity (with some exemptions for part CCS plant). The intention is to make it uneconomic to build new unabated coal or oil-fired generation operating

[14] *The Single Electricity Market Update (Q2 2015)* at http://www.allislandproject.org/en/homepage.aspx

[15] UK *Energy Statistics Q2 2017* at http://www.gov.uk/government/uploads/system/uploads/attachment_data/file/647750/Press_Notice_September_2017.pdf

at base-load (which is the natural configuration for thermal plant) as such plant has roughly twice this emission factor. Existing coal plant could continue to operate a reduced number of hours per year to provide balancing services more cheaply than new peaking plant, at least until 2025. Efficient new CCGT would qualify, as would less efficient peaking plant with an instantaneous emission factor above this level as it would only operate for less than 1,000 hours/yr. An EPS would thus allow gas to remain an attractive option but might discourage zero-carbon options for too long unless the EPS were progressively tightened. Announcing a future path of EPS that applied to all new investment (i.e., not grandfathering the EPS ruling at the date of investment) might encourage better adaptation to the future desired fuel mix, but might also have unintended consequences if it did not deliver sensible short (time-varying) and longer run prices. It would also be hard to make it credible to investors.

Long-term contracts

The final option is to provide long-term capacity contracts for zero-carbon plant. Most of these technologies have high capital but low variable costs (CCS and biomass are exceptions with high variable cost). The least-cost way of procuring these would be through a Single Buyer offering a capacity and energy Power Purchase Agreement (PPA). The capacity payment would be paid if available, and determined (assuming adequate competition) in an auction, in which the incentive-compatible PPA is one in which the generator offers the energy element at the avoidable short-run marginal cost (SRMC, typically indexed to suitable prices),[16] with the fixed costs covered through the capacity payment. For technologies (renewables in particular) that have significant unremunerated spillovers, the auction would either be sub-divided into groups of technologies with similar learning rates, with caps (relative to mature technologies) determined by the value of these spillovers (Newbery, 2017a, 2018b).

Auctions work well given adequate competition but there are too few bidders for a new nuclear plant, for which an optimal procurement contract is more suited. The assured capacity payments should allow the capital cost to be financed cheaply from debt. Under the PPA, the Single Buyer would choose the least cost plants to run, and the SRMC of the most expensive plant would determine the System Marginal Cost (SMC), as in a competitive liberalised market (or one with mandated cost-reflective bidding, as in the Single Electricity Market of the island of Ireland.[17] An alternative is to allow all generators to receive the SMC, and any other ancillary service income, and leave them to determine the missing money they would need to cover the remaining fixed costs, as with the British fossil plant capacity auction (National Grid, 2014). This has the advantage of exposing generators to the correct short-run price signals for energy and balancing to determine B, θ and ϕ, but for this to be a decisive advantage the ability of the generator to manage these risks would need to outweigh the extra cost of bearing such risks.

In the daily operation for intermittent plant that may not be an advantage, and the main choice with significant system cost implications is that of location. Good location signals are therefore critical in decentralized markets, although a Single Buyer could pre-determine locations and

[16] E.g. an index for maintenance costs, and for nuclear, CCS and biomass, for spot (or contract) fuel prices.
[17] See e.g. http://www.semcommittee.com/news-centre/sem-09-114-market-monitoring-unit-market-report

auction the right to build in specified sites if the locational signals are unreliable (as in most European markets). The best (short-run) locational signals are Locational Marginal Prices or nodal spot pricing, as in the US Standard Market Design and in operation over wide areas in the USA. Nodal pricing determines the value of electricity at each grid connection point, reflecting transmission losses and congestion in the network. Thus if export from a zone is constrained, prices fall to match supply and demand within the zone, but if a more expensive generator is needed to relieve import constraints, prices rise encouraging more local supply. Nodal prices with suitable long-term hedging contracts on a reference node or hub (such as financial transmission rights), leaving basis risk to encourage efficient location decisions, and in a liberalised wholesale electricity market, they could also guide short-run operations, curtailing output by paying lower prices in export-constrained areas.

Long-term hedging contracts at the hub would also discourage excessive volumes of wind and solar PV connecting in high wind or insolation zones and unduly depressing local prices. Efficient locational spot pricing gives guidance for grid investments and interconnectors, which connect regions with lower correlated renewables outputs.

4 Conclusions

If ESI investment decisions are to be left to the market, then a number of market failures will need to be addressed. The most obvious is that CO_2 emissions should be properly priced to internalize that externality, but that is not the only externality, as RDD&D creates valuable public knowledge that is not reflected in the returns to developers. In addition to the difficulty of determining the right carbon price, the problem is amplified by a number of missing markets. ESI investments are highly durable and futures markets for more than a few years ahead are lacking. That might not matter if the policy environment were predictable, but that is far from the case. Perhaps more important, suitable risk markets are lacking. Fossil generators enjoy a natural hedge as they set the electricity price, and shift the volatility in fuel, carbon and electricity prices on to consumers and most zero-carbon generators, whose variable costs are close to zero. Consumers are denied the option of insuring through future climate change mitigation in the existing markets, and the risks are asymmetric.

Decarbonizing electricity is an attractive insurance policy against an increasingly likely high cost of future climate change damage (Arrow, 2007) but not one consumers can purchase, except via public policy. This is recognized both in international climate change negotiations and within the EU in the ETS. While cap-and-trade solutions are politically attractive as coordination mechanisms, they fail the test of resilience to shocks that underlies the literature on addressing persistent global stock externalities like GHGs. They need to be reformed to give credible, durable and adequate price signals. The social cost of carbon is highly uncertain, and as there is widespread agreement that the ESI should lead in decarbonizing, it appears operational and therefore attractive to set the carbon price at the break-even level at which zero-carbon options become commercially viable. Unfortunately, this break-even price is highly sensitive to fuel price and other uncertainties. If, for example, gas generation is to be outcompeted by wind, then a fall of \$10/MWh$_{th}$ (\$2.93/mmBTU) in the price of gas requires an increase of \$53/tonne CO_2 to restore parity.

Given the volatility in the forecast price of gas (and other risks), it would be difficult to set a carbon price now that would give credible signals over the life of new investment. Setting an EPS has the merits of ruling out some obviously unattractive choices like coal-fired generation, but is unlikely by itself to signal the kinds of investment needed for a low-carbon ESI with growing intermittent renewable power and (commercially) inflexible nuclear power. A carbon price floor is valuable in guiding short-run operating decisions (raising the cost of higher carbon plant and reducing its capacity factor), and if periodically re-set in the light of objective assessments (of the kind the UK's Committee on Climate Change provides through its carbon budgets and advice to government) they might reduce investment risk. Long-term contracts have the advantage of addressing missing market problems (risk and futures markets) and can be designed to select enough zero-carbon capacity. Auctions offer the benefits of competitive pressure and some inducements to innovation, but the contract design (supplemented by other market and regulatory signals for e.g. balancing and transmission charging) needs to ensure efficient short-run operation, long-term locational guidance and adequate incentives for RDD&D. The design problem is to retain the benefits of competition in and for the market while balancing risk and incentives, as in the classic Principal-Agent problem, while allowing investors to express their diversity of views about the best route for decarbonization and properly rewarding learning spill-overs. Standard arguments suggest that it is preferable to separately identify and provide any innovation support. That can also be subject to a competitive allocation (Newbery, 2018c). It might also be possible to allow less mature supported technologies to compete with mature technologies through a more complex package auction.

The extreme form of a risk-reducing contract would be a Single Buyer auctioning Power Purchase Agreements, typically 20-25 years, with an energy and capacity availability payment. The optimal energy payment is marginally above the short-run avoidable cost, and competition is for the capacity payment. This transfers all the risk to final consumers, minimizing risk costs, but at the expense of relying on the competence of an uncontestable single agent to make the right technology and innovation choices.

What this paper demonstrates is that climate mitigation strategies need to be tailored to each sector. In the critical power sector, policies need to address a whole set of missing markets in the face of the high level of uncertainty that make simple carbon pricing problematic, and in need of contractual support. The combination of an adequate carbon price to guide short-run operational decisions combined with long-run competitively allocated contracts and a better system of rewarding learning spill-overs is the implied package, close to that set out in the *Energy Act 2013* (HC, 2013).

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Glossary

List of acronyms

ASC Advanced supercritical coal
CCGT Combined Cycle Gas Turbine
CCS Carbon Capture and Storage
CPI Consumer Price Index
DECC Department of Energy and Climate Change
DUKES *Digest of UK Energy Statistics*
EPS Emissions performance standard
ESI Electricity Supply Industry
ETS: Emissions Trading System
EU European Union
GHG Greenhouse gases
MAC Marginal Abatement Cost
MS Member State (of the EU)
MWh_e Megawat hour of electrical output
MWh_{th} Megawat hour of energy content of the fuel
PPA Power Purchase Agreement
PV (solar) photovoltaic
RDD&D Research, Development Demonstration and Deployment
SCC Social Cost of Carbon
SMC System Marginal Cost
SRMC short-run marginal cost

List of symbols in order of appearence

γ is the carbon intensity of the fuel,
p_{ht} is the wholesale price in hour h of year t
p_t is the base-load (time-weighted) wholesale price in year t
r is the discount rate
T is the time horizon
K and k are respectively the capital cost in Â£/MW capacity of the two options,
M is the zero-carbon fixed O&M costs, Â£/MW, (average per hour),
m is the fossil fixed O&M costs, Â£/MW, (average per hour),
V is the zero-carbon variable O&M costs in Â£/MWh,
v is the fossil variable O&M costs in Â£/MWh
f_t is the fuel cost in Â£/MWh_{th},
f is the levelised forecast fuel price,
c_t is the carbon cost in Â£/tonne CO_2,
c is the break-even levelised carbon price,
e is the efficiency of the fossil generator,

B is the capacity factor (CF) of zero-carbon plant
b_t is the capacity factor (CF) of fossil plant,
b is the levelised forecast CF
Π_t and π_t are the gross profits per unit capacity in year t are respectively,
Π is the levelised forecast gross zero-carbon profits,
π is the levelised forecast gross fossil profits,
q_{ht} is the output per MW capacity in hour h and year t of the zero-carbon plant,
θ_t is the ratio of average revenue/MWh of zero-carbon generator to p_t,
θ is the levelised forecast value of θ_t
$\phi_t > 1$ is the ratio of output-weighted price of fossil plant to p_t,
ϕ is the levelised forecast value of ϕ_t
P/MWhr is the capacity payment paid for the equivalent firm capacity,
Γ is equivalent firm capacity factor for wind,
τ is equivalent firm capacity factor for fossil,
$\xi \equiv \frac{r}{Y(1-e^{-rT})}$ converts the capital cost into an hourly cost,
$A \equiv M + \xi K - \Gamma P$ is the total zero-carbon fixed and capital costs per hour,
$a \equiv m + \xi k - \tau P$ is the total fossil fixed and capital costs per hour.