Transferrable long-term contracts for electricity investment

Response to DECC
Call for Evidence on Energy Market Reform

[redacted]

Summary

Moving to a very low carbon electricity system is central to meeting the goals of UK energy policy, and indeed to the wider global challenge of tackling climate change. This will require massive investment in low carbon electricity sources. Part 1 of this submission summarises briefly four of the difficulties facing the current mainstream approach of relying on the impact of the EU ETS in the present liberalised electricity market, supplemented with additional incentive mechanisms like renewable obligation certificates and feed-in tariffs.

Part 2 offers some observations on some of the alternative or complementary approaches set out in the EMR Consultation document, with a brief look at strategic dimensions of a carbon floor price, and then a more detailed look at the design of long-term contracts. In this, I outline a case for a distinct approach to long term low-carbon contracts, which focuses upon engaging a diversity of potential buyers. The aim would be to retain a greater role for competition on demand as well as supply side, in the form of long-term 'Green Power' contracts that operate in a separate, differentiated contract market. It could thereby harness the potential interest and capital of electricity consumers, large and small, directly in funding low carbon electricity investments.

Introduction

The UK has been amongst Europe's leaders on both electricity liberalisation and climate change. In electricity regulation, the UK blazed a trail in unbundling previously centralised systems to inject competition wherever it seemed viable. The short term result was a radical reduction in costs (including unfortunately R&D), a surge of investment in combined cycle gas turbines, and a proliferation of suppliers competing for customers followed by consolidation. Reduction in CO_2, driven by the displacement of old coal plants and some increased plant efficiency, was a significant side benefit. The basic idea of liberalisation and competition has spread more widely across the EU, albeit with complex variants.

The UK also aspired to be among Europe's leaders on climate change, pushing to strengthen the EU ETS, together with its ROC scheme to support renewable generation and a strengthening range of demand-side policies. This would seem to a good environmental combination. It is, however, now recognised to be inadequate, for a combination of technical issues in design and implementation - and for more fundamental reasons.

PART I: PRESENT POLICIES AND CHALLENGES

The situation we now find ourselves in, the UK and Continental Europe, is a mix of carbon pricing, technology-specific support mechanisms and targets for renewable power. The interaction between these instruments and electricity market design can be troublesome, and there are at least four specific challenges associated that arise with this policy mix.

1. Reprise: low-carbon electricity and investment

Creating a low-carbon electricity system requires a huge capital investment over the coming decades. The liberalisation of electricity systems has been very effective in driving down the costs and prices associated with operating existing systems, but less effective in attracting new investment, except into low capital CCGTs.

Zero carbon sources are very different: most renewables, and nuclear power, are very capital intensive, with relatively low operating costs. The scale of the different shares of investment, O&M and fuel costs between fossil-fuel based generation and some low-carbon options are shown in 1: capital accounts for more than half the levelised costs for nuclear, wind and solar alike, in sharp contrast to conventional options. A move toward any of these low-carbon generation options implies a radically greater capital intensity.

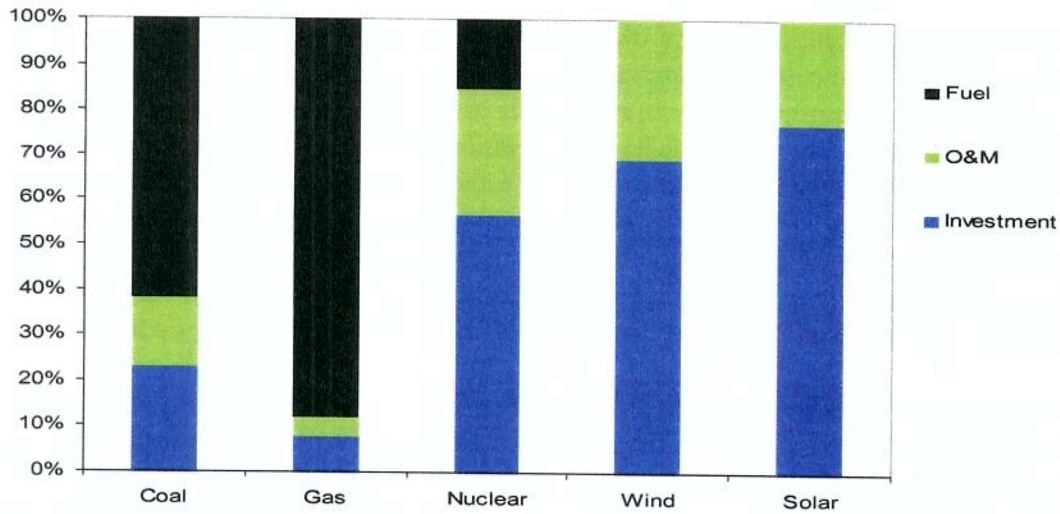

Figure 1: Composition of levelised generation costs at 5% discount rate Source: (IEA 2005)[1]

At the risk of repeating now well-known issues, this has two crucial implications:

- Zero carbon sources will tend to operate as baseload, ahead of fossil fuel sources, because they are cheaper to run and need to run as much as possible to recover the cost of capital;
- The cost of capital is all-important to developers and is crucial to determining the cost of, and our ability to move towards, a low-carbon electricity system.

Returns to investment in low-carbon electricity generation at present depend upon the electricity price, along with any additional support policies. In competitive wholesale electricity markets, such as that that exists in the UK, the price is set mainly by the marginal unit of generation. In the UK this is predominantly gas or coal-fired generation, as determined by the combination of fuel and carbon prices. Crucially, this means that in the mainstream market ***the price at which a low-carbon investor can sell its product bears little or no relation to its own costs.*** It depends instead upon the volatile prices of coal, gas and carbon faced by the fossil fuels generators.[2]

In the absence of other targeted support, this amplifies risks to investors in low carbon plant and raises the cost of capital - increasing overall costs and reducing incentives to invest, for the very sources that are central to low-carbon futures. Doubling the cost of capital (effective discount rate) from 5 to 10% can increase the cost of nuclear and wind by around 50%, with far less impact on the cost of fossil fuel generation. At 5% discount rate, nuclear and (onshore) wind can compete comfortably; at 10%, they are uncompetitive – and the cost of transforming to a low carbon electricity system would itself be about 50% higher. An investment environment that minimises the cost of capital will be crucial; the current structure does not do this.

[1] See also various reports by UKERC for cost structures of different specific UK generating options

[2] In economic terms, zero carbon sources are all infra-marginal, but in the absence of other measures will receive a price set at the margin over which they have no control – and limited capacity to predict. In practice, most renewables are covered by other support schemes, reducing the role of the electricity market itself. This submission does not address directly the pros and cons of the UK ROC scheme *vs* feed-in tariffs, but does argue the need for some vision of when and how to integrate renewables investment into mainstream electricity regulation in the long term.

UK scenarios for decarbonising the power sector imply that the UK system should get about 90% of its electricity from zero carbon sources within 20 years, from a massive investment programme mainly in renewable and nuclear costing potentially over £100bn. This is a staggering scale of investment, and yet the existing approach implies *that this should be financed on the basis of future electricity sales at a price that has little to do with the cost of all that investment,* but is a function of gas, coal and carbon prices – with added incentives eg. for renewables over which the investors limited foresight or control. This is likely to prove a very expensive way of funding £100bn of investment, if indeed it delivers at all, which is clearly in doubt.

Acceptance of this basic insight underlies the EMR. It bears repeating, simply to underline not only the scale of the challenges, but its two distinct components: capital intensity, *and* the fact that the investments sought would be 'price takers', from fossil fuel and carbon markets. A structure to provide greater stability and security for the long-term infrastructure-type investments required might need to look very different from the spot market system we have today. The main solutions considered to date largely take the incentives out of the hands of any market.

Whilst this forms the central challenge, there are three other difficulties that also inform the reasoning behind this submission's approach to long term contracts.

2. Innovation in electricity

We require innovation across a range of technologies, yet private R&D expenditure in electricity (per unit turnover) has been just a tiny fraction of that in the most innovative sector of pharmaceuticals and software and computer services (Figure 2).[3] Much of the current technology embodied in generation, transmission and distribution is based upon the technology used a century ago.

The reasons for this are still inadequately appreciated, but comprise several mutually reinforcing explanations. One is the sheer scale and technological risk associated with the heavy engineering implied in converting large amounts of power. Another plausible factor is that for most of last century, power systems were run as regulated monopolies. It was hoped that liberalisation would inject more innovation. In terms of operating practices, it has; and yet liberalisation has been accompanied by further collapse of R&D expenditure, as investors sought quick returns.

Overlaying these is the fact that electricity is the ultimate homogenous good. At the point of consumption, all electricity is the same. This means that there is little product differentiation in electricity: the only differentiator is price. This greatly reduces the incentive to innovate. A new way of generating electricity has to compete purely on price against incumbent technologies that have benefited from decades of development, economies-of-scale, and regulatory adaptation. They might be aided by a carbon price, but that – a price differential, driven and constrained by politics – is

[3] Although it depends on the definition of the electricity sector, for example Siemens are classified in the Electronics sector, yet some of their products may be applicable to the electricity sector.

the sole basis on which low carbon innovation has to recover all of the costs and risks of its R&D. Thus new innovations in electricity can't command a large economic margin by offering consumers products with unique characteristics, protected by the monopoly guaranteed by patents (as with pharmaceutical), and/or consumers chasing the latest gadget (as with IT).

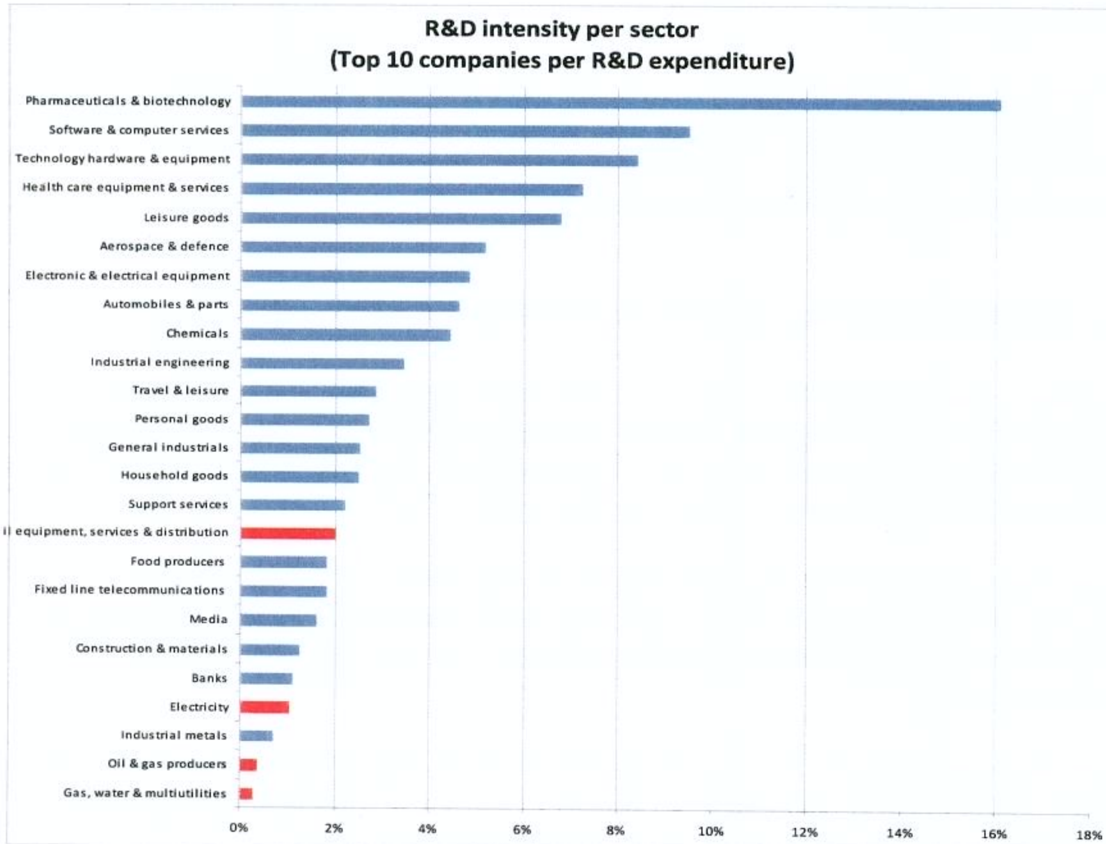

Figure 2: R&D intensity per sector (Department of Innovation, Universities and Skills 2008)

Ofgem's low carbon network fund is an ambitious effort to fill the gap, but cannot wholly compensate for the weak market incentives for innovation. Yet innovation on the scale of IT or pharmaceuticals is what we really want for the challenges ahead. The suggestion in this submission offers an attempt to strengthen the potential for consumer-driven innovation for low carbon electricity.

3. Consumer interest in low carbon electricity

Some consumers, groups, and companies would value the potential to use low-carbon electricity. Finding ways to harness consumer purchasing power more directly in the transition to a low-carbon electricity system could help drive the innovation required and raise the political acceptability of the undertaking. In the UK consumers have a range of 'green tariffs,' but as noted below these are somewhat problematic and uptake has been modest, just 319,000 in 2009 (OfGem 2009). Empirical evidence of the willingness of individual consumers to pay for green energy is mixed.
Interest in purchasing 'green energy' is however not confined to households. Several major UK companies, accounting for a significant fraction of UK electricity demand, have pursued a strategy of wanting to buy green power often for CSR reasons.

However in June 2008, DEFRA prohibited companies from claiming credit for purchasing electricity through the present green tariffs in carbon accounting or environmental reporting, due to problems with double-counting given the regulatory structure. This extends to companies under the UK's Carbon Reduction Commitment (CRC) which have to count all their electricity purchased from the grid at a single emissions grid average. Only on-site renewable generation can avoid this, creating an obvious distortion.

The reality is not that all customers treat all electricity the same. There is a diversity of electricity customers, with varied willingness-to-pay for a product they believe to be "environmentally clean". The present market structure makes it hard and/or unnecessarily expensive for them to exercise that preference.

4. Electricity prices, carbon leakage and carbon attribution

Carbon prices increase the cost of fossil-fuel based generation and in competitive markets this passes through to wholesale electricity prices, increasing tariffs for both households and industries. In terms of economic incentives the pass-through of carbon prices is desirable, but gives rise to two kinds of problems.

One obviously is the distributional impact on consumers – individual, and corporate - and the political resistance this creates. The resistance may be magnified if they do not have a clear alternative to consider of buying low carbon power that is free from the carbon price.

The other is the concern about 'carbon leakage' from impact on industrial costs. The most extreme case is aluminium. Over 80% of emissions from aluminium are from electricity, and they represent about 4% of total emissions from the EU ETS. Aluminium firms could relocate if the indirect cost they face from carbon pricing is high enough. For many energy-intensive industries, these indirect costs from electricity prices are small relative to the direct costs from emitting CO_2, but are not insignificant: the electricity-related costs associated with paying €30/tCO2 would add more than 4% of Value Added to the cost of industrial gases, inorganic basic chemicals, paper and paperboard, and steel electric arc furnaces.

Free allocation is being used to 'protect' most energy intensive industries in the EU. This in itself a highly imperfect approach. Border-levelling of carbon costs (charging embodied carbon on imports, and repaying carbon costs on export) would, from an economic and environmental perspective, be far better. For compensating direct emissions, numerous analysts (including by the present author) have argued that border levelling can be implemented in ways compatible with WTO rules; the WTO itself emphasises that various forms of border levelling can meet criteria to ensure they are compatible with world trade law.

However this requires attributing emissions to products, which is much more difficult – to the point of almost impossible - for electricity-related costs. Trying to attribute to a specific product the carbon intensity of electricity drawn from a power grid would be replete with scope for dispute.[4] No amount of supply-side incentives – carbon prices, feed-in tariffs, etc – can overcome this problem, they just add to the costs.

These four factors – structures that seem inadequate in terms of investment incentives, innovation incentives, consumer engagement or carbon attribution to industrial products – add up to a powerful and difficult set of challenges. A key point of this submission is that alternatives should be evaluated not only with respect to the first, which is driving force behind the EMR, but in relation to all.

PART II: ON PRICING AND LONG-TERM CONTRACTS: PRESERVING A ROLE FOR THE BUYER

5. Overview: the recentralisation of electricity policy?

Part II of the submission considers the challenge of developing investment incentive structures that could rise to the considerable challenges identified in Part I. The EMR identifies several options, and this submission does not attempt to cover the span. It touches briefly upon the role of, and architectures for, a carbon floor price; and then concentrates on the case for a specific approach to long-term contracts.

First an important word of context. One effect of the developments during the 2000s is an apparent emerging conflict between the agendas of liberalisation, and the environmental agenda. Fundamentally, it seems the government needs increasingly to try and engineer investment that would not otherwise happen in the short-run, competitive market that it has created, by adding more rules, special incentives, and constraints. There seems to be an increasing risk of the environmental agenda unrolling the liberalisation agenda and pushing us back towards centrally planned power systems (a concern articulated for example by Malcolm Keay among others). When we reflect on the nature of the UK electricity market – aimed to minimise costs and risks on short term financial perspective, driven by shareholder interests, and with rules designed to force competition through regulatory oversight and limiting the scope for long-term consumer commitments (eg. through switching provisions) – this is not so surprising. It suggests a deeper level of challenge that needs to be considered.

Some, pointing to the environmental and other inadequacies of the current system, welcome this. I 'cut my research teeth' in the days of the Central Electricity Generating Board, which clung to coal and nuclear generation as the only serious options. One does not need an ideological approach to free markets to be uneasy about a trend towards greater State determination of energy investment choices.

---

[4] The most inherently WTO-compatible approach to border levelling suggests starting with a fixed "benchmark" based on the carbon intensity of the best available technology. However for electricity-intensive products, the best available technology from a carbon emissions perspective would involve zero carbon power, with no carbon costs - negating the point of the border levelling. And for export adjustments, it would be similarly hard or impossible to get consensus on the level of adjustment, unless a producer could plausibly demonstrate direct association with a specific power source and a trail of the carbon costs incurred. This is impossible under our current regulatory structures, because it is impossible to associate a given power source with a given electricity consumer.

To date, UK efforts to promote environmental goals in the market framework have led to growing complexity, and/or reduced flexibility. The ROCs scheme has evolved closer to central direction, set to operate at the "capped" price and with technology-based banding to support the growth of diverse technologies. 'Green power' tariffs have to pass a complex set of assessment criteria to try and avoid double counting of renewable energy with the ROCs support and Levy Exemption Certificates. Obviously, their 'additionality' could be ensured if suppliers of green tariffs had to retire ROCs, but the price of ROCs reflects the cap price including the many elements of market risk premium that others have noted, not the actual cost of most renewables – thereby making this approach to 'green tariffs' prohibitively expensive.

An important option in the debate is to set a floor price to carbon. This submission does not address this in detail, but in my view much depends upon the form a price floor might take. A floor price set by an EU-wide reserve price on allowance auctions is *not* in itself an interference in the market. In principle, it is a simple mechanism that can reduce the cost of capital, by reducing downside risks in the face of inherent economic uncertainties: it offers an automatic self-correction of the target if events prove the initial level of ambition to have been weaker than expected. However this is different from a floor price that *takes the place* of an inadequate level of ambition in the EU wide emissions cap.

In turn, achieving an EU floor price – whether a genuine hedge against uncertainty or a substitute for an inadequate cap - would be preferable to a UK-alone solution. The current focus on a UK-specific floor price is second-best: it reflects the relatively weak nature of the EU's current 2020 ambition, the related lack of serious EU debate on a floor price - and the now-limited timespan of EU ETS Phase III. It may be useful for specific UK investment purposes, but will in turn face limitations on the level that may be contemplated, not least arising from concerns about *inta-European* competitiveness impacts on downstream industry.

Against that background a carbon floor price may be useful but does not in itself address all the obstacles to capital-intensive, low carbon investment noted in Part 1 above.

Another option set out in the EMR is for long term contracts. Carbon Contracts have been proposed separately for example by both Newbery and by Helm. As initially conceived these would be project-specific contracts in which the Treasury would sign a contracts-for-differences on the carbon price, in effect guaranteeing a minimum carbon price to project investors. The economic logic is impeccable: carbon price risk is driven by politics, it makes sense for the political system to underwrite the risks if it wants private sector investors to assume a particular level of ambition.

An extension, which would further reduce market risks, is for direct long-term power contracts. These could take the form of mandated feed-in tariffs, or could be established between the government and investors through some kind of auction mechanism. Such approaches could address many of the obstacles to capital-intensive investment and are rightly now the topic of extensive debate around the EMR.
There are implementation challenges arising from the project-specific nature of the 'contract-for-difference' proposals, concentration in the power market undermining

auctions, and the understandable reluctance of the UK Treasury to take on the liabilities or costs that most contract proposals would imply. The Treasury may desire an adequate price for investors, but not to the extent of being keen to underwrite a price largely outside its control using UK taxpayers money.

Moreover, most of these proposals place the government in a much more central position in the power markets. The fundamental tension is that the government would be – rightly in my view - trying to facilitate long-term, low carbon investment by reducing the political risks, for which it seems that placing the government as determining or underwriting the price is the only option.

6. Transferrable long-term, low-carbon electricity contracts

Most of these improvements – carbon floor prices / FITs / auctioned contracts, are targeted at the first of four issues surveyed in Part 1: investment. Differentiation between technologies may support 'learning by doing' but they do little for innovation *per se* – a lack of which has resulted in the UK and EU launching major publicly-funded innovation programmes to try and compensate for the lack of private R&D. And they do nothing for the accounting of carbon or carbon costs in industrial products, or engagement of consumers. Indeed, on the last of these most policies have achieve exactly the opposite, leaving the consumer faced with one metric - a cost per kWh - in which suppliers, in their different ways, subsume together all the different kinds of support and incentive costs.

This submission, based on a Working Paper published last year with the Cambridge Electricity Policy Research Group, offers a case for a different way of conceiving long-term contracts. The basic proposal is that the emphasis should be on facilitating long-term, low-carbon electricity contracts between private sector producers and consumers. The government's role would be to create the *market structure,* which would have to operate alongside the existing (or altered) structure of electricity generation and supplier markets, and to the extent necessary *underwrite* contracts. One way into this could indeed be for the government to be an initial purchaser, but with the aim of selling contracts on to third party buyers.

Specifically, this would require the government to facilitate the development of a *market* for long-term, zero-carbon power contracts – a specific, regulated contracted 'green power' market, which could operate alongside the mainstream conventional power market. A core feature would be to allow final consumers to associate in consistent ways with zero carbon electricity production, from sources that their contracts would help to fund.

This would require active regulatory and policy decisions in several dimensions. To secure investment, such contracts would have to be long term; current regulations at the consumer end seek the opposite. However, a long-term contract on the generator side does not necessarily preclude the ability to trade contracts (which might be particularly relevant as an option on the consumer side). Over time, driven in part by a rising carbon price, more investment might be contracted through what might best be termed a 'Green Power (GP) Contracts Market'.

To be clean, the entire accounting framework would need to clearly delineate such GP contracts from the rest of the power system, including in terms of its carbon intensity. Such a differentiation would allow holders of such GP contracts to claim credit for purchasing low-carbon power in calculating their carbon emissions, either for regulatory (eg. CRC) or voluntary purposes. This would increase the incentive for firms to purchase and invest in low-carbon power, and allow those who would like to, to purchase and claim credit for it. It could provide a means for those consumers who wish to pay extra for renewable power to make the purchases they desire. It is thus an extension of market principles – not the reverse.[5]

In some respects this has much in common with established contract proposals: unless and until an adequate carbon price is attained, the government would probably still need to underwrite the contracts. In other respects it is a radical proposal: it would in effect imply creating a separate kind of electricity at point of consumption – one directly associated with zero emissions, high capital and low operating cost plant – and designing contract structures accordingly. The structure might have more in common with mortgages, than with the current spot price, and would not necessarily be per kWh: it could be a fixed payment charge, conferring entitlement to a maximum kW, or a total kWh.

Some consumers might wish to purchase both 'kinds' of electricity – a GP contract for a basic level of use, topped up with purchases per kWh (maybe from another supplier) that would reflect the marginal operating cost of the system. The combined economic structure would then be akin to a fixed + variable charge, or other 'rising block' tariff - except that the size of the 'base' component (if any) would be entirely in the hands of the purchaser.

Note that the carbon market remains central to the economics of this approach. As the carbon price rises, the *relative value* of GP contracts would correspondingly increase. It is this that makes a growing non-governmental role in a GP contract market economically plausible. But the financing of the power investments would not be at the mercy of the fluctuating markets in coal, gas and carbon; they would be securitised through long term contracts that reflect the cost structure of the generating sources in that GP contract market, not the fluctuating spot price determined by current fossil fuel and carbon prices.

Thus, in terms of the four challenges discussed in Part 1:

- Establishing such a GP contract market would reduce the financing costs, and thereby reduce the cost of *investment* in low-carbon electricity. To use Walt Patterson's term, this parallel market would be better suited to the 'infrastructure

[5] This would also facilitate (though not resolve entirely) the dilemma that any cap on generator emissions "disenfranchises" consumers from claiming any carbon reductions from reducing their electricity consumption. The EU ETS cap for post 2020, for example, could be explicitly debated in terms of electricity sector emissions *net of the volume of GP contracts*; such contracts could thus legitimately claim to be contributing to ongoing carbon emissions, by reducing the demand for carbon-based generation and thus facilitating tougher carbon caps on the rest of the system over time.

electricity' that new green power will supply. Long-term contracts for green power could be based on their own costs, and allow more certainty in repayment of the large initial capital costs, reducing the cost of capital. From a Treasury standpoint, it would presumably be welcome to bring new sources of private capital to help finance the UK electricity sectors' transition

- The product differentiation from such a division could create extra incentives for *innovation* into low-carbon power, and help to create the missing demand-pull for low-carbon technologies from consumers, both large and small.
- Such differentiation could also help create a system in which major industrial consumers, such as Aluminium, could accurately and legitimately establish a basis for avoiding carbon costs. Adopted more widely, this might provide a way for any border attribution to legitimately focus on carbon-related costs: charging imports, unless producers could produce evidence that they were drawing power from zero carbon electricity contracts, in which case they could be exempt.
- Finally, this would provide a way in which diverse, large-scale electricity consumers could express their potential preference for low carbon power in the market - without the extraordinary and unsatisfactory hoops that have emerged to avoid double counting for existing schemes to small consumers, and the de facto ban on large consumers entering at all. It would thus provide a ready alternative to the bizarre situation in which the UK, whilst extolling the need for a rapid and costly transition to zero carbon sources, specifically prevents the major companies participating in the Carbon Reduction Commitment from claiming any credit for investing in zero carbon generation.

7. Challenges and Precedents

Given these potential advantages, is it possible to create such a structure, and could this be done in the context of our current regulatory regimes?
There are a number of hurdles that would need to be overcome.

'Green power' contracts would need to ensure that low-carbon power sold is matched by low-carbon generation average over a suitable time period, to account for variability. The UK already has models for this, in terms of rules around Levy Exemption Certificates. The creation of a separate low-carbon product alongside standard grid electricity would require the carbon intensity of the mainstream electricity market to be calculated separately for use in regulatory instruments like the CRC, or in voluntary carbon footprinting – with separate accounting for the electricity denominated in GP contracts.

Of course, long-term contracts are nothing new. Indeed, they already exist in the electricity arena. The Finnish contract under which pulp & paper industry contracted to a new nuclear power plant, underwritten by AREVA, is the most famous recent example – though not an encouraging one, given the scale of delays and cost overruns. This reflects one reason why such arrangements are rare. A contract between an individual buyer (or a fixed consortium) and a single power plant poses big risks for both sides. A generating company that builds and operates the plant faces the risk of having a single purchaser, while the counterparty is dependent on one single power source, with the inherent risks involved:

- If the buyer goes bust, the power plant is exposed – this has been a major reason cited why most generators have not pursued long term contracts with some of

Europe's major industrial consumers. In a globalising world, and witnessing the struggles of European heavy industry, the longevity of a specific industrial plant is just considered too risky to finance a major power plant construction;
- If the contract is focused on a single huge new power plant, the buyer is exposed if that goes wrong – as with the Finnish reactor.

That is why transferability, and government underwriting, would be important to lower the risks.

There is at least one other major example in Europe, which seems more relevant, namely the French Exeltium contract (see box). However, even this reflects rather special circumstances and it may be neither feasible, nor necessarily desirable, for this exact model to be more widely replicated.

The French Exeltium contract.*

In this contract, a consortium of electricity intensive industries combined to structure a long-term partnership with energy producers. The total value is €4bn, funding a 24-year contract with EdF. Four French banks led a consortium of ten banks to provide a €1.7bn loan, supplying electricity to the syndicated consortium of about three dozen heavy electricity consuming industries. The deal reached financial closure in April 2010.

The cost to the consuming industries are differentiated between a fixed part at the start of the contract reflecting the investment cost, and a variable part in line with operating costs of the plant. Thus, the cost structure of the Exeltium contract broadly matches that of the generating plant, considerably reducing the cost of capital.

By some pooling of demand (with a consortium of consumers), some of these risks are reduced; the electricity supply risk is underwritten through EdF.

However, there seem to be major obstacles to the wider use of such contracts.

One relates to political and legal acceptability. The Exeltium contract required approval from the European Commission, which was granted after considerable negotiation. However there was strong indication that this was considered to be an exception (presumably aided by strong support from the French government) and that in general such contracts would face difficulties as they are perceived as potentially anti-competitive.

Another obstacle is that the conditions themselves are not so easily replicable, reflecting as it does the nature of the relationship between French industry, banks, and EdF, mediated to a large degree by the French government.

The proposal in this paper is not that the Exeltium experience should itself be replicated, but rather that the underlying objective –long term contracts between suppliers and consumers of electricity – has potentially multiple benefits. Policy can learn from such experience, and rather than impede should facilitate more generic tradeable long-term contractual structures, and engage a wider group of electricity consuming organisations, more explicitly linked to the huge task of decarbonising European power generation.

*Sources: Reuters, 13 Apr 2010; Simon Cotterill, Presentation to CBI Energy Conference, 2009.

The core argument of this paper is that long-term contracts are desirable, but that they need to be embedded in a structure that would facilitate transfer of such contracts. Structured in the right way, making long-term contracts transferrable can reduce risk to both generators and consuming parties.

Creating a transferrable contractual structure would be crucial to such arrangements, allowing aggregation of buyers to finance large investments, for example, and allowing firms to acquire or divest such contracts as their financial situation (and CSR policy) dictates, within prescribed rules that protect the underlying financing commitments. The great difficulty with such an idea is the potential diversity of such contracts – how would one trade a 15-year contract with one finance and risk structure with another of 20 years and a completely different finance and risk structure? This is why it cannot emerge on its own. Some degree of diversity is probably necessary and healthy, but the need for some liquidity in such a contract market would imply two things: a need for a publicly defined framework for a limited number of "qualifying" contract types; and as wide a market as possible. More specifically, there needs to be a government-led process that establishes a basic structure of such contracts, and that facilitates competition *between those entities that are interested in securing stable, zero carbon long term power contracts.*

Why link the long-term contract market to zero carbon power? Fundamentally, because of all the reasons set out earlier in this paper:

- decarbonising power generation is one of the major public policy challenges of our times, and low carbon generation is almost all very capital intensive and infra-marginal;
- the electricity system suffers from insufficient innovation in general, and specifically in relation to low carbon innovation given the industrial discounting of political uncertainties around the carbon market; a market for long term contracts could widen the space and incentives for innovative approaches,
- the ability to demonstrate zero carbon generation in legally secure, verifiable and trackable ways is crucial to attributable power-related emissions in any system of border leveling; and
- there are a substantial body of electricity consumers whose interest might be driven partly by the desire for low carbon power and/or long term stability separate from the fluctuations of fossil fuel and carbon prices – considered further below

One open question is how to design such a market interface in open competition with standard grid electricity, where consumer switching of suppliers is strongly encouraged. Individual consumers seem unlikely to be the main participants in long term contracts anyway, but there may need to be some re-examination of the rules if consumers were interested in long-term contracts. At some scale, preventing or impeding mutually assenting parties from entering long-term contracts can no longer be presented as a way of preventing market abuse, but risks instead impeding another sort of competition – one which might be far better suited to fostering the investments required. These are big questions and I do not pretend to have all the answers, but the issues need examining.

Another key question is how such a GP contract market would relate to existing support structures, notably for renewable electricity. Clearly, if a country has a mandated renewable energy cap (as in theory does the UK) that it is set to achieve, then GP contracts could only increase the renewable energy investment if they retire credits (ROCs in the UK case). However even in the UK the system is subject to a "cap price". With feed-in tariffs, the question is whether any investor would wish to sign such a contract, compared to the returns available under a feed-in tariff. This is an empirical question, not a fundamental conflict.

Moreover, a key goal of GP contracts would be to provide a more secure "convergence point" for a sector if and as technology-specific supports phase down. At present, the proposition appears to be that low carbon technologies will benefit from an extended period of support, whilst there is an 'industry-building' case for supporting the implicit innovation, or compensating for an inadequate carbon price – but will then have to fend for themselves on the basis of a market determined entirely by short-run marginal prices of fossil fuels and carbon. After supports expire, leaving many GW of capital-intensive plant, this is a recipe either for windfall profits or eternal financial restructuring of bankrupt projects that cannot cover their loans.

GP contracts could offer a much more robust answer to the question of whether and how we could ultimately move beyond current technology-specific supports. The carbon price would still be crucial – but alongside it, there would be a market structure more appropriate for existing 'infrastructure' generation - and for supporting continued investment in low carbon technologies if and as other supports expire.

8. Potential purchasers

A key question is who might want to buy such long-term, zero-carbon power contracts. There are three broad approaches to answering this question.

One is to speculate, based on current indications and possibilities. Many consumer-facing companies already have clear environmental goals, and have expressed frustration at the current rules that make it so difficult for them to purchase genuinely low carbon electricity. Examples exist in telecoms, supermarket chains, and financial services; companies like TESCOs and Marks & Spencer are also starting to market electricity to consumers under their own brand, and might prefer to be able to offer genuinely zero-carbon electricity. CRC participants, that currently have to pay for carbon in their electricity even if they might pay for zero carbon electricity, is an obvious place to look. Depending on cost differentials, some electricity-intensive industries might welcome the certainty of moving to such contracts as their current contracts expire. In addition, the recent government move to allow local councils to sell electricity might open up a whole new kind of purchaser, more closely aligned to domestic markets, that might sell 'clean power' on to local consumers.

Each of these might inject preferences for different kinds of zero carbon power; several might also help to engage citizens more in the choices about low carbon investment, reducing some of the political obstacles that emerge (eg. opposition to onshore wind energy, despite its cheapness) when the incentives for investment become too disconnected from civil society. Indeed, underlying the thinking there lies a strong element of organisational and behavioural economics, in which the degree of control that people have over their choices is an important motivating factor. There are obvious parallels with the various proposals for 'green bonds', and buyers could of course include pension companies, for example. However its distinctive feature is its potential to help electricity consumers of different sorts connect with – and help to fund - electricity sources of their choice, through the electricity they purchase.

A second approach is simply to wait and see: to argue that one never knows, until one tries, what the demand for a new product might be. 'Green tariffs' to date have been presented as a green version of conventional energy, set purely at a price per kWh –

not presented in the form of a long-term offering more akin to a mortgage. Discovering the scale of demand could itself be valuable.

The third approach notes that ultimately, the leverage of carbon price remains in State hands. If there is insufficient investment in low carbon electricity sources, in addition to contracting more itself, the government could increase the carbon price, to improve the competitiveness of the 'GP contracts market'. And that, indeed, is one additional advantage. Many of the proposals for support mechanisms, including long-term contracts with government as the purchaser, marginalise the role of the carbon price. Having put huge political effort into creating a carbon price, for sound reasons, it would seem very strange to then sideline its role in long-term electricity investments. By creating zero-carbon electricity contracts as a separate commodity, in competition with 'normal', high carbon electricity at the point of end users, the carbon price would remain a key driver of a market-based switch to low carbon investment.

9. Conclusions

Creating a low-carbon power system is a cornerstone of the move towards a low-carbon economy. This requires huge investment and extensive innovation. Our current electricity market structures create large uncertainties for investors, and have incentivised little private innovation and R&D. We have put in place policy instruments to try and address these problems. ROCs and feed-in-tariffs create greater certainty over returns to investment, and boost demand for renewable power. Both of these policies have had their successes, but also face long-term limitations.

Harnessing consumer, business and industry demand for zero-carbon electricity can help raise investment in low-carbon power, and also increase the political acceptability of the endeavour. Our current market structures do not harness this demand, and the systems we currently have in place struggle to provide clearly additional zero-carbon electricity to consumers. Creating a clearly defined separate low-carbon electricity product could help to harness this demand and capital, and could carry a number of other benefits as indicated.

The idea is only presented for consideration: it is not a proposal that has been rigorously explored and debated. Closer examination might reveal insuperable obstacles, or show advantages to be less than they seem. With the EMR process, however, the UK is at a major juncture, and has the kind of opportunity for major reform that only arises every couple of decades. Whether and how to create a separate contractual market that allows end-user competition between zero-carbon electricity and the rest of the system requires more research and analysis, but it is surely an option that should be seriously debated in the EMR process

*

[redacted]