

# Reforming Competitive Electricity Markets to Meet Environmental Targets

David Newbery

August 2011

CWPE 1154 & EPRG 1126

# Reforming Competitive Electricity Markets to Meet Environmental Targets

EPRG Working Paper 1126

Cambridge Working Paper in Economics 1154

**David Newbery**

**Abstract** The UK and other EU countries are concerned to deliver secure, sustainable and affordable electricity, to meet challenging targets for decarbonisation and renewable energy. The UK Government has consulted and concluded that the present electricity market arrangements will not deliver all three goals, and has proposed a major Electricity Market Reform (EMR). This article describes the reasons for, and the nature of, the EMR, pointing to the need for further market and institutional reforms.

**Keywords** Electricity market reform, environment, low-carbon generation

**JEL Classification** Q48, Q42, L94

Contact  
Publication  
Financial Support

dmgn@cam.ac.uk  
August 2011  
ESRC RES-189-25-0155



# Reforming Competitive Electricity Markets to Meet Environmental Targets

*David M Newbery*<sup>1</sup>

Director of Research, Electricity Policy Research Group,  
University of Cambridge

*30 August 2011*

## Abstract

The UK and other EU countries are concerned to deliver secure, sustainable and affordable electricity, to meet challenging targets for decarbonisation and renewable energy. The UK Government has consulted and concluded that the present electricity market arrangements will not deliver all three goals, and has proposed a major Electricity Market Reform (EMR). This article describes the reasons for, and the nature of, the EMR, pointing to the need for further market and institutional reforms.

**Key words:** Electricity market reform, environment, low-carbon generation

## Introduction

The reform of electricity markets set out in the latest UK Energy *White Paper* (DECC, 2011, hereafter the *White Paper*) announces the third major reform since the end of the nationalized era (and the fourth *Energy White Paper* since 2003). It was prompted by the growing realization that the current electricity market design was unlikely to meet the Government's challenging targets for reducing greenhouse gas emissions and increasing the share of renewable energy. In addition, generation capacity equal to more than a quarter of peak demand will be decommissioned by 2016, either because of tightened air quality standards in the case of old coal stations, or life expiry for the older nuclear power stations. Uncertainty about future energy policy has made companies reluctant to invest in new capacity, so there is a looming security of supply issue, while the European Emissions Trading System (ETS) is failing to give adequate and credible signals for investing in the low-carbon generation that is needed to meet

---

<sup>1</sup> [dmg@cam.ac.uk](mailto:dmg@cam.ac.uk) +44 1223 335248. I am greatly indebted to an anonymous EPRG referee for extensive and helpful comments, with the usual disclaimer that I have considered them carefully, but not always accepted them.

climate change targets. In response, the Government launched a consultation on Electricity Market Reform (EMR) in December 2010 (DECC, 2010) and has now published the *White Paper*. This article describes the reasons for, and the nature of, the EMR, pointing to the need for further market and institutional reforms.

## **Electricity market design**

The EMR will be the third major reform since the end of the nationalized era, and in part has to deal with the unsatisfactory electricity market reform of 2001, so a brief history of earlier electricity market designs is helpful in explaining the present market context for the reform. In 1990 the Government restructured and privatized the British electricity supply industry, with the exception of the nuclear power stations, where the newer stations were sold in 1995. The centre piece of the restructuring was the creation of a wholesale electricity market, the Electricity Pool. All but the smallest generators were required to offer supply schedules that determined the central dispatch and the market clearing price for each half hour. Although the initial market structure was very concentrated, with two fossil generators setting the price in England and Wales almost all the time, it was open to entry, as any merchant generator could offer its power and receive the same price as the incumbents.

The timing of the privatization was fortunate, in that efficient and relatively cheap combined cycle gas turbines (CCGTs) became available at modest scales, while rapid expansion of North Sea gas offered attractive fuel prices, particularly when compared with expensive British coal. Over the next decade, new gas-fired entry and the incumbents' sale of older coal-fired plant created a workably competitive industry that was considered an ideal model by many observers, and was influential in stimulating European electricity liberalization through a sequence of EU Directives. However, UK regulatory concerns over market power and political worries over the displacement of coal by what some thought were artificially favourable entry conditions for gas-fired plant (attractive long-term contracts by the Regional Electricity Companies who could pass on the costs to captive domestic customers until 1998) led to pressures for market reform.

In response, the Government and Ofgem (the energy regulator) introduced the New Electricity Trading Arrangements (NETA) in 2001, replacing the mandatory gross pool and central dispatch with a model of voluntary bilateral contracting, self-dispatch, and an opaque two-price balancing mechanism that by penalizing both long and short positions was designed to encourage forward contracting before dispatch. The theory was that contracting privately and fully ahead of time would encourage more competitive behavior, and address concerns over market power. The theory had already been criticized (Newbery, 1998) and the post-2001 evidence suggested that the fall in wholesale prices claimed as a major NETA success was a result of reduced concentration that occurred *before* NETA (Bower, 2002; Evans and Green, 2005; Newbery, 2005). The lack of a liquid wholesale market and the penal imbalance charges adversely affected wind generators and CHP plant and strengthened the case for vertical integration between generators and supply (retail) companies, so that in

short order the British electricity market had consolidated into the Big Six<sup>2</sup> vertically integrated utilities, who between them supplied 99% of the domestic retail market. NETA was replaced in a further reform by the British Electricity Trading and Transmission Arrangements (BETTA) that put Scottish transmission under NGET, the GB System Operator. It created a single price area for the whole of GB, despite serious congestion on the border between England and Scotland that significantly raised redispatch costs.

Nevertheless, by comparison with the Continent, the British electricity market seemed to signal the success of the liberalized, unbundled and competitive model for wholesale electricity markets, notably in comparison with some countries whose energy markets were investigated by the European Commission in its Energy Sector Inquiry (DG Comp, 2007).

## Environmental challenges

Meanwhile, concerns over climate change were rapidly moving up the political agenda both in the UK and Europe, resulting in the creation of the EU Emissions Trading System (ETS), a cap-and-trade system designed to limit emissions of CO<sub>2</sub> from the covered sectors (about half the total, but notably including the power sector). Trade in the EU Allowances (EUAs) put a price on CO<sub>2</sub>, but uncertainty about demand for the EUAs led to initially high volatility. The first period did not allow banking of EUAs beyond 2007, and the growing realization that their allocation had been over-generous led to a collapse in the carbon price from late 2006, which fell to zero by mid 2007, as shown in figure 1.

### EUA price October 2004-August 2011

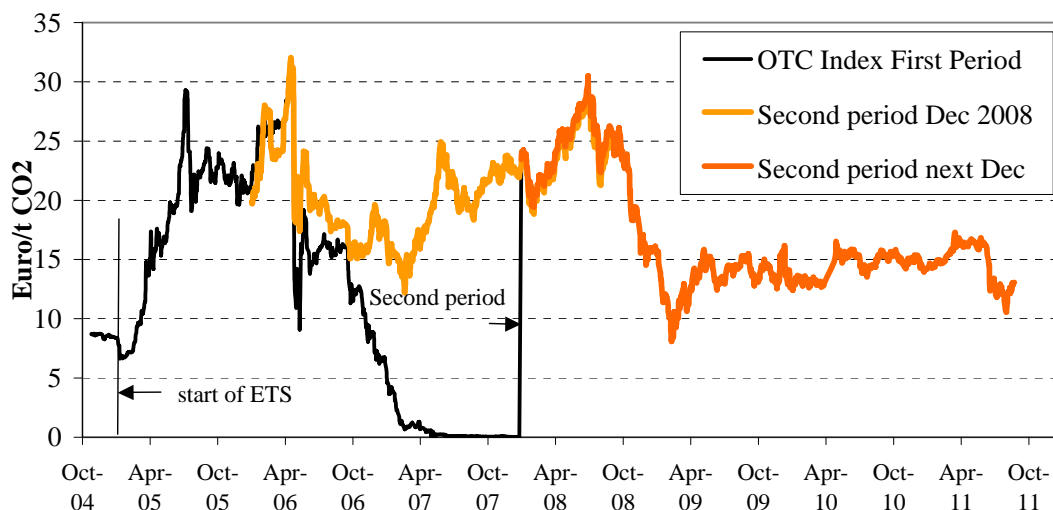


Figure 1 Evolution of the CO<sub>2</sub> price.

Source: EEX

Note: EUAs for the second period are for delivery either in Dec 2008 (the end of the first year in the second period) or for the next December

<sup>2</sup> British Gas, npower, Scottish and Southern, Scottish Power, EDF and E.ON

The second period did allow banking (and their EUAs could be traded ahead of the start of the second period) and initially their price rose to over €25/tonne CO<sub>2</sub>. In December 2008 the EU introduced the 20-20-20 Renewables Directive that increased the share of EU *energy* (not electricity) that must be generated from Renewables by 2020 from 12.5% to 20%, but without reducing the cap on CO<sub>2</sub> emissions. Each Member State was given an individual target that reflected a balance between efficiency (to result in the same marginal costs everywhere) and equity (with richer countries shouldering more of the burden). The resulting expected increase in the supply of zero carbon electricity reduced the demand for EUAs and led to an estimated forecast fall in the 2020 EUA price from €60 to €50/EUA (CCC, 2009). At the same time the financial crisis and the predicted fall in future carbon intensive industry and electricity demand further undermined the 2020 forecast price to €20/EUA, at which level low-carbon generation was not profitable without support.

British renewable electricity supply has also lagged far behind Germany and Spain (and in 2010 UK wind capacity was only 19% of that in Germany, despite having a better wind resource). By mid-2011 the UK had 5.5 GW installed capacity (of which 1.3 GW was off-shore), which, because of its lower capacity factor, is only equivalent to 1.8 GW of a base-load station operating at 85% capacity factor.<sup>3</sup> Given that meeting the UK's 2020 target may require 27-35 GW of wind, there were increasing doubts that the UK would be able to meet its renewables target (although Germany had installed 27 GW wind by 2010 starting from the UK's 2010 level a decade earlier, so matching Germany's roll-out rate would deliver the lower end of UK's aspirations).

The final pressure on the sector was the increasingly tight air pollution limits placed on generators through the Large Combustion Plant Directive (LCPD) that would require major refits or massive plant closure before 2016. In the UK, some 12 GW of the older coal-fired plant (about 20% of peak demand) will close by the end of 2015, while an additional 6.3 GW of aging nuclear plant will also close by 2016. The *White Paper* notes that one quarter of generation capacity will need to be replaced by 2020. Despite the need for new investment, uncertainty over future energy policy has encouraged utilities to delay new build, further raising concerns over security of supply.

## **Policy environment and the Government's response**

In October 2008 the then UK Labour Government established the Department of Energy and Climate Change (DECC), shortly before the Climate Change Act received Royal Assent in November 2008. The Act provides a legal framework for ensuring that Government meets its commitments to tackle climate change. It also set up the Committee on Climate Change (CCC) as an independent body to advise and monitor the Government's carbon commitment. The Act requires that emissions are reduced by at least 80% by 2050 compared to 1990 levels, and that the Government commit to a series of 5-year carbon budgets.<sup>4</sup> One might

<sup>3</sup> <http://www.bwea.com/statistics/>

<sup>4</sup> <http://www.theccc.org.uk/about-the-ccc/climate-change-act>

have expected DECC to take the lead in examining the ability of the energy market to deliver these targets but it was the regulator, Ofgem, that launched Project Discovery in June 2009 in its scrutiny of security of GB energy supply.<sup>5</sup> Ofgem reported on 3<sup>rd</sup> Feb 2010 recommending “far reaching energy market reforms to consumers, industry and government” and concluded that “The unprecedented combination of the global financial crisis, tough environmental targets, increasing gas import dependency and the closure of ageing power stations has combined to cast reasonable doubt over whether the current energy arrangements will deliver secure and sustainable energy supplies.”

After a pause and a change of government to the Conservative and Liberal Democrat coalition on 6 May 2010, DECC launched its consultation on Electricity Market Reform in December 2010 (DECC, 2010). Its diagnosis was similar to that of Project Discovery (and the CCC) - the carbon price was now too low to support unsubsidized nuclear power while the wholesale electricity price was set by fossil fuel prices (and the ETS). Fossil generators thus had a natural hedge (as shown in figure 2) – the difference between the electricity sales price and the cost of fuel is reasonably stable, while that for non-fossil generation is very volatile as their variable costs are low and constant. Looking forward, non-fossil generation faces volatile carbon prices that are low and sensitive to political intervention, thus undermining its future credibility.

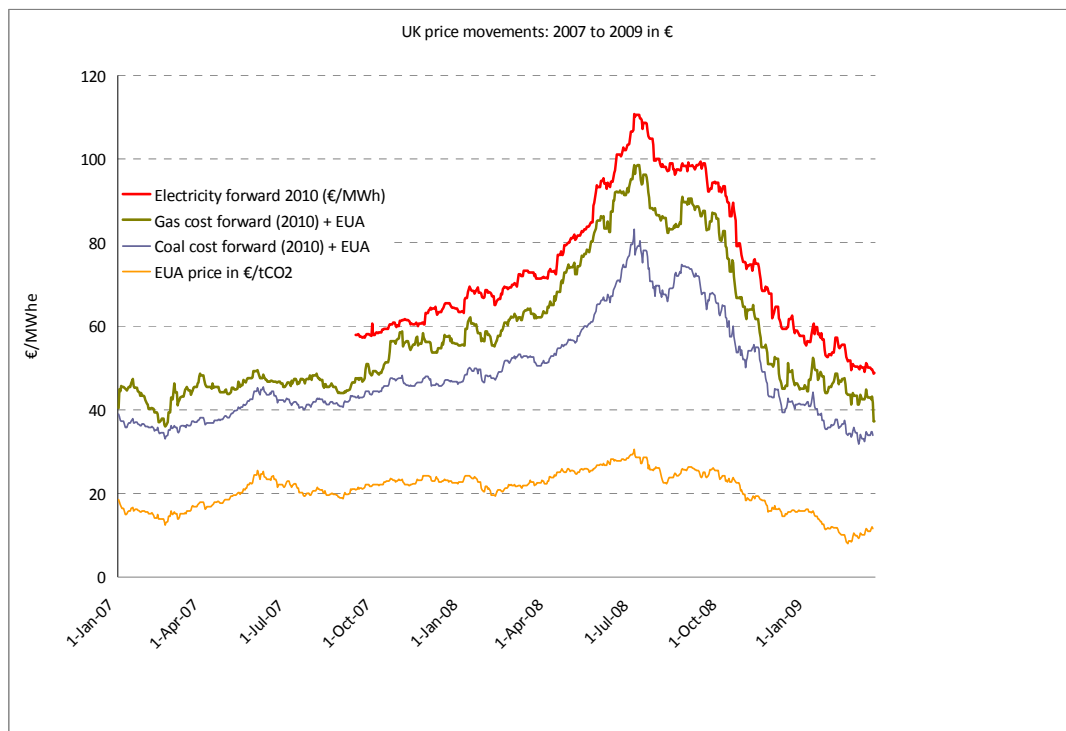


Figure 2 Forward electricity, fuel and carbon prices for 2010 delivery  
Source: Bloomberg

The DECC consultation noted that adequacy and security of supply was rapidly becoming an issue with rapidly approaching generating plant decommissioning,

<sup>5</sup> <http://www.ofgem.gov.uk/markets/whlmarkets/discovery/Pages/ProjectDiscovery.aspx>

and that the market did not seem to be delivering the required volume of renewables, all suggesting that the electricity market was not well suited to delivering secure, sustainable and affordable electricity – the three key Government objectives.

The estimated cost of meeting the Government’s carbon and renewables targets by 2020 in electricity alone amounted to £120 billion, or over £12 billion per year compared with less than £5 billion in 2008 (itself nearly 80% above the previous decade average),<sup>6</sup> and considerably above financial analysts’ estimates of the capacity of the Big Six to finance on its own, indicating the need to access new sources of finance. Given the high capital cost of most low-carbon options, anything to de-risk investments and lower the Weighted Average Cost of Capital (WACC) would have significant benefits in terms of lower costs and prices. A reduction in the equity risk premium and an increase in the debt share might reduce the WACC by 1% (or even more for smaller entrants), which would reduce the capital cost by £1.2 billion each year by 2020, or nearly £45/year per household, compared with current electricity bills of £450/yr (although domestic consumers consume about 40% of the total, electricity prices feed through into other goods ultimately consumed).

The consultation proposed a Carbon Price Floor (CPF) to ensure that the carbon price moved on a trajectory that would ensure the commercial viability of nuclear power without further support, and this was the subject of a separate and rather hasty consultation by HM Treasury, with draft legislation published on 11 Jan 2011. The levels announced in the Budget in March 2011 would support the price of CO<sub>2</sub> starting at £16/tonne in 2013, rising to £30/tonne (€35/tonne) in 2020, and projected to rise to £70/tonne by 2030 (all at 2009 prices).<sup>7</sup> By itself, any tax, and particularly a carbon tax that might adversely impact British competitiveness, would not be credible, as it could be reversed in any Budget. Indeed, past protests have reversed a similar road fuel tax escalator that was intended to steadily increase the real tax on motor fuel. The central element in the consultation, endorsed in the resulting *White Paper* published in July, was therefore to offer long-term contracts for low-carbon generation. These would be further bolstered by an Emissions Performance Standard (EPS) that would limit emissions from any new power station to 450gm/kWh “at base load”, intended to rule out any unabated coal-fired station (with exemptions for the demonstration Carbon Capture and Storage, CCS, stations which would only require a third or less of output to be subject to carbon capture).<sup>8</sup>

The final component of the EMR is a proposal to introduce a Capacity Mechanism to encourage an adequate supply of flexible peaking plant to ensure

---

<sup>6</sup> £4.3 billion at 2005 prices (Office of National Statistics)

<sup>7</sup> HM Treasury, *Budget 2011*, HC 836, March 2011

<sup>8</sup> If “base load” is taken as 8760 hrs per year, then a conventional coal-fired station with emissions of 900gm/kWh could operate at a capacity factor of 50%, and if the CCS element emitted 90gm/kWh on 400MW (gross, 300 MW net) of a 1,600MW (gross) supercritical station (44% efficient), the remaining 1,200 MW might be able to operate at a capacity factor of 78%, below its normal design rating. The *White Paper* (at 1.22) therefore allows for exemptions for such demonstration plant.



security of supply. As the volume of intermittent wind connected to the system increases (and the 2020 targets are for 27-35 GW of on- and off-shore wind) so the risk of sudden drops in wind power increase. If we take as an example wind power simulated over Britain from 9-11 October 2003 (using data from Green and Vasilakos, 2010) the wind output fell from a capacity factor of over 85% to less than 5% over a period of 24 hours, and by 65% in the first 10 hours. If the UK succeeds in building 27 GW of wind, this would require the rapid start up of nearly 18 GW of capacity over 10 hours (assuming that the system had been able to accommodate the previous peak wind output of 23 GW compared to demand then of 34 GW). In the past, peaking capacity was supplied by older power stations with high variable costs, but the LCPD and the EU Industrial Emissions Directive will force most such plant off the system (except perhaps for some older CCGTs). This requires new peaking plant to be built to run a modest and rather variable number of hours per year, for prices that would be hard to predict. Exactly how this reserve capacity is to be procured has proven difficult to decide, and has been left for a “technical update” at the end of 2011 (DECC, 2011, 3.2.41).

## **Contracting for low-carbon power**

Most projections of how Britain will meet its challenging low-carbon objective require the almost complete decarbonisation of the electricity sector by 2030. The Committee on Climate Change (CCC, 2010) and the Select Committee report on the EMR (HC, 2011) both call for *average* emissions no higher than 50gm/kWh by 2030 (compared with the current intensity of about 500gm/kWh), although the *White Paper*, while mentioning the 50gm/kWh target (7.13, fig 19) does not advocate any specific target. Nevertheless, the implication is that apart from flexible peaking plant, all new generation should be low or zero-carbon – nuclear power, renewables, or fossil plant with CCS. That rules out CCGT as a base load option, although 3.9GW of new CCGT plant is under construction and a further 8GW has consent to build (National Grid, 2011). Already, some of the consented plant has been delayed, and the rest can expect to operate at lower capacity factors in the 2020’s if it goes ahead. Although the Carbon Price Floor (CPF) would make nuclear and on-shore wind economic (but not PV, CCS or off-shore wind, at least until after 2020), the CPF by itself is hardly bankable, and the aim is to increase the share of debt in financing new generation to lower its annual capital cost.

The Government’s solution is therefore long-term contracts that remove electricity market price risk, and are legally enforceable and hence credible in a way that the CPF is not. The *White Paper’s* preferred option is for a Feed-in Tariff (FiT) with Contracts-for-Difference (CfD). The standard two-sided CfD entitles the generator to receive (or pay) the strike price *less* a reference price (an amount that could be negative, requiring the generator to make a payment), but the generator must sell the power for whatever price can be secured in the market place. There is some discussion about the appropriate reference price and some recognition (DECC, 2011, 2.3.17) that this should be technology specific. Thus nuclear power, which can schedule refueling to occur at seasonally

low-price periods, would likely have a reference price based on the forward base-load price, while intermittent generation might have the day-ahead average price (DECC, 2011, fig 8). The CPF is then seen as an important counter-part that ensures that over the life of (most?) contracts they are “in-the-money” and hence represent credible financial instruments and good value for consumers (at least, relative to the counterfactual of having the CPF and not having the contracts).

This raises a number of points, of which the most important is how the contracts are to be designed and financed. The need for a suitable institution to design, negotiate, finance and settle the contracts for each new vintage of plant was not included in the original consultation, but was emphasized by the Parliamentary Select Committee (HC, 2011) and other respondents. In response, chapter 4 of the *White Paper* recognizes this need and lays down criteria any such institution should satisfy. The details are to be left for further consultation, and there will be considerable delay before the enabling law is passed in 2013. It is sensible to put as little detail as possible into the legislation, which should be enabling, with the details written into the mandate of the contracting institution and subsequently into the contracts. That was the approach taken at privatization, where the enabling legislation was very brief, requiring licences and setting up the regulator with a defined remit and powers, leaving all the important detail to the licences, which are legally enforceable contracts. There are fortunately good precedents for such a contracting agency, as the Non-Fossil Purchasing Agency<sup>9</sup> was set up to administer the renewable electricity contracts auctioned off under the Non Fossil Fuel Obligation.

Assuming that a contracting agency is set up, the next question will be how to design the contracts. In the case of a CfD, the definition of a suitable reference price is important, and the *White Paper* recognizes that the current spot and contract markets are not very liquid, creating basis risk (the difference between the reference price and the price actually secured in the market). The EU has recently enacted the Third Energy package, creating ACER as its regulatory agency and issuing framework guidelines (the Target Electricity Model) to deliver the single electricity market. This will require market coupling for day-ahead dispatch of interconnectors, intra-day rebalancing and forward contracting. The current preferred model is for energy-only markets linking price zones, where the boundaries of these zones are to be defined by significant congestion, not national borders. As the Scottish-English boundary is heavily congested and likely to become more so with additional wind power in Scotland, Scotland will become a separate price zone, requiring presumably a different reference price, if generation is required to sell in its local market. It will be important to ensure that contracts are robust to such changes in market price definition. It is also unlikely that the choice of zones will be left to national authorities. DG Comp was asked to investigate the Swedish TSO’s handling of internal congestion that had repercussions for trading over the interconnector to Denmark.<sup>10</sup> As a result of the decision (April 2010) Sweden was required to

---

<sup>9</sup> See <http://www.nfpa.co.uk/> and Mitchell (2000).

<sup>10</sup> See e.g. [http://ec.europa.eu/competition/antitrust/cases/dec\\_docs/39351/39351\\_1211\\_8.pdf](http://ec.europa.eu/competition/antitrust/cases/dec_docs/39351/39351_1211_8.pdf)

move to at least two internal price zones – in practice it will have four zones – and reinforce its internal network.

Perhaps a more dramatic market design change would be a move to nodal pricing or Locational Marginal Pricing (LMP). LMP has been successfully implemented in a wide range of electricity markets, most notably in the PJM Interconnect, a market that has evolved from its original Pennsylvania, New Jersey and Maryland base to cover an area with three times the GB installed capacity (see Newbery, 2011a). The move from zonal to nodal pricing in PJM was precipitated in very short order by the escalating costs of redispatch, as generators were free in the newly liberalised market to offer to inject power at nodes that would create congestion, and would then have to be paid not to generate. This “inc-dec” game would have bankrupted the system unless ended by offering generators their nodal price, equal to the scarcity value of power at the node. It is therefore worth contemplating the possibility that the EU’s Target Electricity Model for zonal pricing and market coupling may collapse into nodal pricing, and to consider what that would mean for contracting and renewables. It appears that Poland is already anticipating the need for such a change. Certainly nodal pricing would give considerably better market signals for short-term storage and local demand side management.

While a standard two-sided CfD looks appropriate for controllable generation (nuclear, CCS, bio-mass), it makes less sense for intermittent generation such as wind, where output is determined by the vagaries of wind, and not accurately predictable until shortly before dispatch. Newbery (2011b) argues that the logical contract is a fixed FiT that guarantees a price per metered MWh of output, with dispatch entrusted to the System Operator or another aggregator that can afford to invest in the necessary local short-term wind forecasting expertise. That would avoid forcing every wind farm to make its own forecasts, negotiate for off-take contracts and be exposed to the poorly designed GB Balancing Mechanism for inevitable mismatches between contract and delivery. The *White Paper* accepts that the current balancing design needs improvement (at 3.2.24) and this is currently a subject of an Ofgem consultation and possible Significant Code Review.<sup>11</sup>

A closely related issue is that the massive wind investment required by the EU 20-20-20 Renewables Directive (2009/28/EC)<sup>12</sup> will require substantial investments in electricity networks (some £35 billion by 2020 in the UK alone). In response to concerns about the suitability of the present transmission access arrangements for connecting wind power, Ofgem launched project TransmiT to review GB transmission charging and associated connection arrangements, and to seek advice on any changes needed to efficiently support the transition to a low-carbon energy sector.<sup>13</sup> Ofgem invited three academic groups to propose high level principles on how transmission charging might be improved. The

---

<sup>11</sup>

<http://www.ofgem.gov.uk/Markets/WhlMkts/CompanEff/CashoutRev/Pages/CashoutRev.aspx>

<sup>12</sup> <http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32009L0028:EN:NOT>

<sup>13</sup> <http://www.ofgem.gov.uk/Networks/Trans/PT/Pages/ProjectTransmiT.aspx>

leading candidate was, unsurprisingly, nodal pricing to encourage efficient use of the system once built, coupled with deep connection charges to provide the right long-run locational guidance for new generation, and delivered in the form of long-term Financial Transmission Rights (see e.g. Newbery, 2011a).

Transmission charging reforms will have implications for contract design. At present National Grid Electricity Transmission, NGET, can change the annual Transmission Network Use of System (TNUoS) and Balancing Services Use of System (BSUoS) charges levied on generators at relatively short notice, and does not offer long-term contracts for connection. The logical solution is for the FiT to cover all the connection charges, so that the wind farm is insulated from future possibly large changes in the annual charge (which, after investment, will have no impact on the location decision that they are intended to guide). The contracting institution would then recover these charges from the counterparty to the contract – consumers or the Government, yet to be determined.

The advantage of a FiT is that the contracting institution can in principle choose the least system cost wind farm proposals (taking account of the cost of the power and the transmission services) and then pay the least amount needed to induce these proposals to go ahead, perhaps using the *White Paper's* suggested technology-specific tender auctions (para 12 and 2.3.21). This would emulate the German FiTs that differentiate by wind resource so that they do not over-reward windy locations, in contrast to the current British approach that pays the same wholesale price and Renewable Obligation Certificate (ROC) price to all wind farms no matter where they are located.

## **How to support renewable**

That leads to the third and arguably most fundamental question, and the question implicitly raised in the title to this paper. The drive for accelerated renewable electricity comes from the EU 20-20-20 Renewables Directive. This requires the UK to deliver 15% of total energy from renewable sources by 2020. The least-cost way of achieving this is to deliver a high (30-35%) share of electricity from renewable sources, largely wind. The logic of the 20-20-20 Directive is not to reduce the EU's CO<sub>2</sub> emissions, whose level is already predetermined by the ETS cap. Instead it is primarily designed as a demand-pull instrument to encourage a substantial increase in investment in renewable energy, which is expected to lower the cost of future renewables through learning-by-doing and induced innovation. Companies investing in renewables will create new knowledge that is a public good and therefore a legitimate reason for public support. The case for EU action is that if successful it will encourage other countries to adopt these technologies when their costs fall sufficiently, thereby mitigating CO<sub>2</sub> emissions with universal benefit. While it can be argued that all such learning and R&D creates market failures that justify public intervention, the standard mechanism of patents have obvious drawbacks when the aim is to encourage other countries to deploy the resulting low-carbon technologies and help mitigate climate damage, to the benefit of all.

The Directive shares the burden of the extra renewables cost by specifying targets for each Member State that balance equity and efficiency – richer countries have a higher share than indicated on overall cost minimization grounds. Given that objective, the obvious question is how policy instruments should be designed to achieve the targets at least social cost. In the case of on-shore wind, which is a reasonably mature technology, future cost reductions are likely to come from scaling up production, improving reliability, developing better materials for blades and towers, and better site location (including experience at handling environmental and social objections). Almost all of these benefits derive from the original investment, rather than the subsequent operation of the wind turbine, which suggests targeting the support on that investment, rather than the output. If so, then the logical contract is a payment per MW of *available* connected capacity, and a fixed payment per metered MWh equal to the expected average local wholesale price.<sup>14</sup> To the extent that there is a case for incentivizing improved reliability, the output payment could be set at a higher level than the expected electricity price, although if the CPF is intended to run to 2030 the average price will be considerably above the current price. Firms like GE and Siemens are likely to offer reliability guarantees as part of their market positioning, capturing the knowledge externalities and reducing the need for this extra output support.

The consequences of this change are potentially profound, because the present system of paying a premium to the market price is through a Renewable Obligation Certificate, ROC. Under the ROC scheme an on-shore wind generator would be issued one ROC per MWh that they could sell in the market for ROCs, as well as selling their power. A wind farm that locates in the North of Scotland might access a considerably stronger wind resource than one in the Midlands, for example, perhaps generating 400 hours per year more.<sup>15</sup> With a ROC value of £50/MWh and a wholesale price of £50/MWh, the extra 400 hours would be worth an extra  $(£50+£50) \times 400$  per MW/yr or £40/kW/yr, which is large compared with the spatial variation in TNUoS charges, which in 2001 differed between North Scotland and the Midlands by £20/kW/yr. The wind farm would therefore prefer to locate in Scotland rather than in the Midlands under the current system of TNUoS charging and the ROC form of support. However, the TNUoS charges fail to capture the full extra cost of reinforcing the system to accommodate extra wind in Scotland, which might lead to a substantially higher differential if properly charged (through, e.g. deep connection charges). Equivalently, nodal pricing would lead to considerably lower prices in the North of Scotland whenever the wind blows strongly. The combination of proper access charging to the grid and payment for available capacity rather than output might lead to considerably less wind power in Scotland and more in areas with less

---

<sup>14</sup> Availability is easy to monitor given the extensive instrumentation on wind turbines that can deliver information to the System Operator.

<sup>15</sup> Individual wind farm capacity factors (CF) are available from the very informative REF web site at <http://www.ref.org.uk/roc-generators/> which shows a rolling average CF for e.g. Aikengall's 48 MW site in Scotland of 32.6% compared with the excellent Deeping St Nicholas 16 MW site in Lincolnshire with 26.3%. The difference between these is 550 hrs per year. There are many sites in Scotland with less than 25% CF (Whitelee Windfarm has 322 MW and a CF of 20.4%) and the average in England is less than 25% so the typical difference is smaller.

transmission congestion, saving potentially many £ billions in transmission investment. Paying for availability rather than generation also avoids the current distortion in which wind farms are willing to offer at negative prices (up to the value of the ROC) in order to be dispatched and earn their ROC.

To be consistent with the underlying objectives of the 20-20-20 Directive, the EU should modify the targets in terms of equivalent installed capacity (and might go further and differentiate by technology, perhaps weighting them by estimates of the cost per kW and the prospects for future market penetration). That would encourage the development and deployment of renewables while reducing inefficient location decisions and avoiding adverse market impacts such as negative prices that are already a problem in Denmark. This, however, is likely to be politically hard to achieve, while the current set of targets has the great merit of simplicity – member states merely have to accept the overall target and the resulting allocations. Perhaps it might be possible allow individual member states to make their case for a specific interpretation of how they will meet their target, allowing capacity based measures as suitable proxies for output.

### **Will the EMR undermine the competitive market?**

Reforming liberalised electricity markets to meet environmental targets is challenging for several reasons. Under the old model of state-owned vertically integrated franchise monopolies, governments could instruct the utility to install the preferred portfolio of assets to meet the targets, much as Britain and France instructed their utilities to build nuclear power stations at an earlier date. With privately owned generating companies operating in liberalised markets, investment choices have to be market driven. Logically, environmental costs should be reflected in suitable charges, and the EMR's Carbon Price Floor is designed to supplement the EU ETS carbon price to achieve this end in a market friendly way. However, there are political as well as market failures, and such instruments by themselves lack credibility and need some contractual underpinning if markets are to finance low-carbon generation at a reasonable cost of capital. Hence the EMR is driven to propose long-term legally enforceable contracts to de-risk these investments. It may similarly require contracts for reserve capacity to deliver security of supply, although there may be more market friendly solutions if the balancing market is made fit for purpose and the System Operator given somewhat broader powers.

While these contracts address some market and political failures, they risk removing large fractions of supply from market forces. The case for liberalization was that decentralising investment decisions would deliver better outcomes at less risk to consumers, while competition in the wholesale market would deliver more efficient operation, both of which might appear to be at risk from the proposed reforms. The main line of criticism of the EMR is that these long-term contracts effectively replace the UK liberalized market model with the derided and rejected Single Buyer Model.

There are several responses to this criticism. The first is that the apparent success of the liberalized market in stimulating massive generation investment

in its first decade (entirely in new gas CCGTs) was based on two factors – all the so-called Independent Power Producers held long-term contracts with their partner distribution/retailers, as well as long-term gas contracts that together de-risked the investment and made them easy to finance with a large share of debt. The other source of CCGT investment was from the incumbent duopolists, with their strong balance sheets and a need to diversify away from their obsolescing coal plant. Neither of those factors operates now, and notably, past new entrants needed the assurance of long-term contracts. Second, most of the evidence of the success of liberalisation points to the incentive effect of ensuring availability to generate in order to be paid, and any sensible contract should ensure that.

Moreover, the electricity market still has a potentially important role to play, although to fully deliver that will require some additional reforms, curiously the one aspect that the EMR does not address. Efficient operation and investment decisions need efficient short and long-run locational price signals, which the current market design notably fails to deliver. Efficient dispatch requires a liquid intra-day and balancing market, again lacking in Britain. There are models that might work considerably better than GB's market design.

One potentially attractive model might be the Single Electricity Market (SEM) of Ireland, combined with nodal pricing (perhaps implicitly in the dispatch algorithm). Generators in the SEM are bound by the Wholesale Bidding Code of Practice, which requires generators to offer supply at their (audited) short-run marginal cost and determines a System Marginal Price (SMP) much like the former English Pool, with a capacity payment added in tight hours. The attraction of a pool model is ease of entry for new generators, the simultaneous provision of balancing and dispatch services, a highly liquid reference price, and the option for managing wind farms better (as in Portugal, which combines forecasting, individual wind farm monitoring and control). For the period up until probably the mid 2020s there should be enough high variable cost fossil, bio-mass or CCS on the system enough of the time to produce an adequate SMP, particularly if combined with a locational capacity price related to the Loss of Load Probability (again, as in the former Electricity Pool). Flexible generators and those with conventional CfDs should face adequate incentives for efficient dispatch in such a market.

When it comes to using markets to guide investment, apart from improving locational signals, there is a case for using technology specific auctions where there are sufficiently many potential suppliers, as the *White Paper* recognises (para 12 and 2.3.21). At present, securing local planning permission has proven difficult, while suitable grid connections and the right wind conditions all need to be identified for successful sites. One possibility that might address several obstacles at once is to empower an institution to seek out and secure site permission for on-shore wind farms and then to auction off the FiTs.

## Conclusions

This paper has argued that the diagnosis in the EMR *White Paper* is largely sound, in contrast to many who have claimed that it is “focused on simply shifting risk around” (Yarrow, 2011). The cost of risk depends on how it is allocated, and risk sharing (through contracts passed through to consumers or tax payers) can greatly reduce the cost of risk – the real problem is the well known Principal-Agent problem of retaining incentives while reducing the risk, where markets, auctions or benchmarking can all play their part. If that is appreciated, it ought to be possible to reduce risk and the resulting cost of capital while retaining and possibly even improving the incentive properties of the current electricity market. The intensity of disagreement with this will doubtless be high, as many benefit from the lack of contestability in the present opaque and illiquid British market, and enjoy the rents that derive from a mismatch between targets, reflected in ROC premia, and the ability of the current system to deliver on those targets.

In conclusion, the EMR *White Paper* was correct in confirming that the present GB electricity market design will not deliver secure and sustainable (low-carbon) electricity at an affordable price, and has put in place solutions, notably contracts, that should reduce political uncertainty and market risk. The *White Paper* responds to the problem of the credibility of current climate change and energy policy, and attempts to reduce political failures while addressing various market failures, while paying considerable (perhaps excessive) regard to using market mechanisms (such as CfDs). However, it fails to make the more fundamental market reforms that would allow a liberalized market to deliver these objectives at least cost, and it remains to be seen whether the contract design and procurement process will work well for the varying types of plant required (wind, nuclear, CCS, and flexible reserve capacity).



## References

- Bower, J. (2002). "Why Did Electricity Prices Fall in England and Wales?: Market Mechanism of Market Structure?" Oxford Institute for Energy Studies Working Paper, EL O2.
- CCC (2009). *Meeting Carbon Budgets - the need for a step change*. Committee on Climate Change, at <http://www.theccc.org.uk/reports/1st-progress-report>
- CCC (2010). *The Fourth Carbon Budget - Reducing emissions through the 2020s*. at <http://www.theccc.org.uk/reports/fourth-carbon-budget>
- DECC (2010). *Electricity Market Reform: A consultation document*. Dec, available at <http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx>
- DECC (2011). *Planning our electric future: a White Paper for secure, affordable and low-carbon electricity*. 12 July, available at [http://www.decc.gov.uk/en/content/cms/legislation/white\\_papers/emr\\_wp\\_2011/emr\\_wp\\_2011.aspx](http://www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/emr_wp_2011.aspx)
- DG Comp (2007). *DG Competition Report On Energy Sector Inquiry*. Brussels SEC(2006) 1724 at [http://ec.europa.eu/competition/sectors/energy/inquiry/full\\_report\\_part1.pdf](http://ec.europa.eu/competition/sectors/energy/inquiry/full_report_part1.pdf)
- Evans, J. and R. Green (2005) "Why did British electricity prices fall after 1998?" Department of Economics, University of Birmingham, Discussion paper 05-13. Available at <http://ideas.repec.org/p/bir/birmec/05-13.htm>
- Green, R.J. and N. Vasilakos (2010). "Market Behaviour with Large Amounts of Intermittent Generation." *Energy Policy* 38 (7), July 2010, Pages 3211-3220 <http://dx.doi.org/10.1016/j.enpol.2009.07.038>
- HC (2011). *Electricity Market Reform*. House of Commons Energy and Climate Change Committee fourth report of session 2010-12, HC 742, 16 May, Vol 1
- Mitchell, C (2000). "The England and Wales Non-Fossil Fuel Obligation: History and Lessons." *Annual Review of Energy and the Environment*, Vol. 25: 285-312
- National Grid (2011). *2011 National Electricity Transmission System (NETS) Seven Year Statement*. at <http://www.nationalgrid.com/uk/Electricity/SYS/current/>

Newbery, D. M. (1998). "The Regulator's Review of the English Electricity Pool." *Utilities Policy*, 7(3), 129-41

Newbery, D.M. (2005). "Electricity liberalisation in Britain: the quest for a satisfactory wholesale market design." *Energy Journal*, Special Issue on European Electricity Liberalisation, ed. D Newbery, 43-70

Newbery, D.M. (2011a). *High level principles for guiding GB transmission charging and some of the practical problems of transition to an enduring regime*. Report for Ofgem, at <http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=93&refer=Networks/Trans/PT>

Newbery, D.M. (2011b). "Contracting for wind generation." EPRG Working Paper 1120 at <http://www.eprg.group.cam.ac.uk/wp-content/uploads/2011/07/EPRG1120 Complete.pdf>

Yarrow, G (2011) "Response to the Electricity Market Reform Consultation" available at <http://www.rpieurope.org/publications/2011/G Yarrow Response to the Electricity Market Reform Consultation.pdf>