EPRG WORKING PAPER

UK Electricity Market Reform and the Energy Transition: Emerging Lessons

EPRG Working Paper 1817

Cambridge Working Paper in Economics 1834

Michael Grubb and David Newbery

Abstract The 2013 Electricity Market Reform (EMR) was a response to problems of delivering reliability with a growing share of renewables in its energy only market. Four EMR instruments combined to revolutionise the sector; stimulating unprecedented technological and structural change. Competitive auctions for both firm capacity and renewable energy have seen prices far lower than predicted and the entry of unexpected new technologies. A carbon price floor displaced coal, whose share fell from 46% in 1995 to 7% in 2017, halving CO2. Renewables grew from under 4% in 2008 to 22% by 2017, projected at 30+% by 2020 despite a political ban on onshore wind. Neither the technological nor regulatory transitions are complete, and the results to date highlight other challenges, notably to transmission pricing and locational signals. EMR is a step forwards, not backwards; but it is not the end of the story.

Keywords Electricity market design, capacity auctions, renewables support

JEL Classification L94, D44

Contact dmgn@cam.ac.uk
Publication June 2018
Financial Support Support from MIT CEEPR is gratefully acknowledged. A fuller and earlier version of this paper was published as CEEPR WP 2018-4 at http://ceepr.mit.edu/files/papers/2018-004.pdf

UK Electricity Market Reform and the Energy Transition: Emerging Lessons

13 April 2018

1. INTRODUCTION: 'MODEL OR WARNING?'

The UK was widely seen as one of the world's leaders in electricity deregulation in the early 1990s. Though the model of liberalization went through significant changes, many international observers were surprised when in 2010 the new UK government embarked on a fundamental reform to the architecture of UK electricity markets. To many, it seemed like abandoning the principles of market competition seen as defining the UK approach (e.g. Darwell, 2015), with widely divergent views as to whether it represents a potential model which others could follow, or a warning of the perils of – apparently – returning to greater state involvement in the market.

The Electricity Market Reform (EMR) legislation represented a radical change. Prompted by concerns about a lack of investment that threatened to undermine both security and decarbonization goals, and politically galvanized by rising energy prices, it nevertheless proved highly controversial. The legislation took most of the 5-year Parliamentary term to complete, and the first auctions under the new system only took place in December 2014. The UK's original liberalization of electricity was widely seen as a radical experiment, attracting worldwide interest. EMR has similarly attracted widespread interest,

It is still relatively early, but many lessons can already be drawn. This paper:

- summarizes the evolution of the UK electricity system, including the underlying institutional and political context;
- explains the reasons for EMR – the key intellectual debates and institutional proponents;
- explains the legislated structure of EMR;
- presents results to early 2018 and draws lessons, addressing concerns that the EMR represents a 'return to central planning'.

Finally, we reflect on future challenges and prospects facing the GB electricity market.

2. UK ELECTRICITY IN CONTEXT

2.1 The Evolution of the UK Electricity Supply Industry under State ownership

In England and Wales from 1947 when the electricity supply industry was nationalized, generation and transmission were owned by the public Central Electricity Generating Board (CEGB). The CEGB sold to the 12 Area Boards (the distribution and retailing) companies under a Bulk Supply Tariff (for energy and peak demand). In Scotland, the industry comprised two regional vertically integrated companies, and in Northern Ireland just one vertically integrated company. The Conservative Government under Margaret Thatcher came to power in 1979 with a manifesto pledge to reverse economic decline, roll back the frontiers of the state, and reduce the power of organized labour. Privatizing state-owned enterprises started cautiously, but between

1979-92 some 39 companies were privatized, culminating with the electricity utilities from 1990 that ended in 1995 with the sale of the more modern nuclear plant (Newbery, 2000).

Figure 1 shows generation output by fuel from 1970 with some of the key events. Until 1955, almost the entire output was generated from coal, supplied by the state-owned National Coal Board, but, under pressure from the Treasury, oil-fired power stations were built, the first generation of gas-cooled Magnox nuclear power stations started producing, and the nuclear share rose to 20% by 1990. The share of oil peaked at 34% just before the oil shock in 1972, and thereafter coal and nuclear power gradually replaced oil.

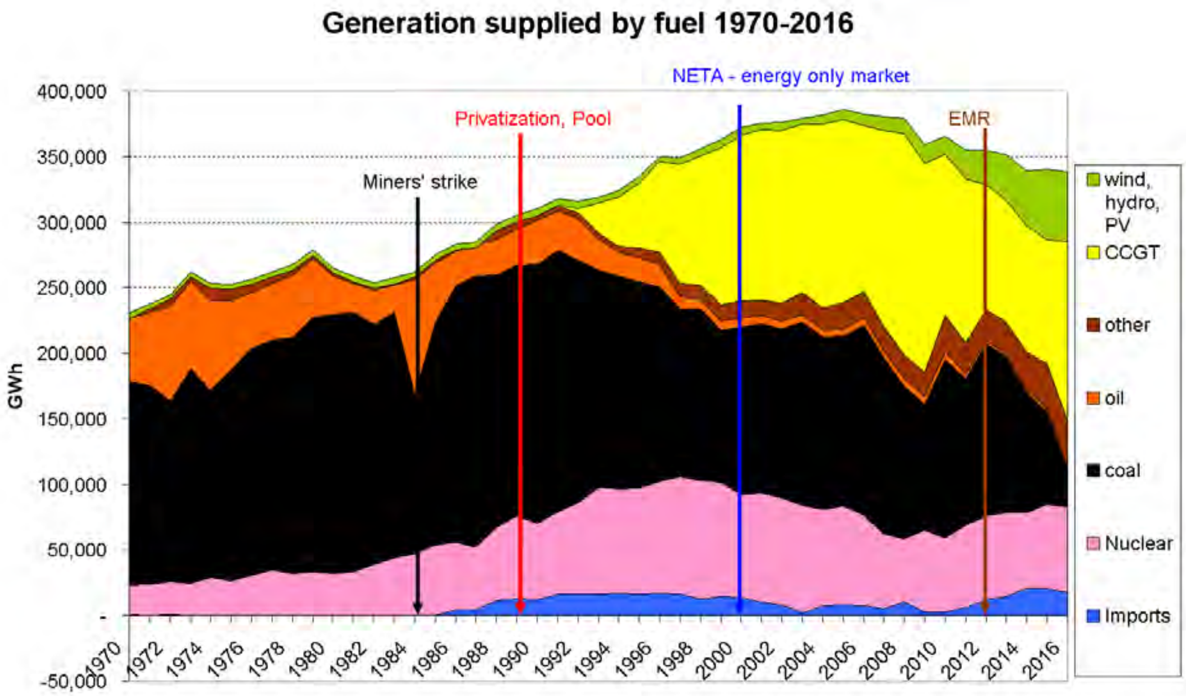


Figure 1: UK Electricity Generation by Fuel, 1970-2016

Source: BEIS (2017)

Note: "other" is all thermal generation from other generators (i.e. not the public supply companies), non-CCGT gas and thermal renewables. Pumped storage (net negative) is not shown.

By 1989, just before restructuring for privatization, around 90% of the conventional thermal generation was from coal, and thereafter the share of oil fell from 7% to 1% in 2002 (the remainder of thermal generation is largely from industrial by-product gases). Shortly after privatization, the coal share rapidly declined as imported electricity and nuclear power increased. It continued declining with the 'dash for gas', which was all new entry despite the considerable spare capacity. At the end of the century, consumption fell with deindustrialization and increased demand efficiency, while renewables displaced gas and/or coal, whose shares depended on the very volatile clean (gas) and dark green (coal) spark spreads (the margin between the wholesale price and the fuel plus CO_2 cost).

2.2 The Electricity Industry Structure 1990-2001: The Pool and the ‘Dash-for-Gas’

The state-owned companies were replaced by, in England and Wales, two fossil and one nuclear (initially state-owned) generation companies, with an unbundled National Grid (initially collectively owned by the privatized distribution and supply Regional Electricity Companies, RECs). In Scotland the two vertically integrated companies were sold bundled, while in Northern Island three generation companies were sold with long-term power purchase agreements.

National Grid and the RECs were regulated, and large customers were free to buy directly from the wholesale market, which took the form of the mandatory gross Electricity Pool, into which all plant had to be offered (with sub 50 MW exceptions). This was centrally dispatched with a System Marginal Price (SMP) set by the marginal price offered by the most expensive unconstrained generator required, to which was added a capacity payment, equal to LoLP*(VoLL – SMP), where LoLP is the Loss of Load Probability in that half-hour and VoLL is the Value of Lost Load (£5,000/MWh in 2016£). This would have been the efficient price if the SMP were equal to the System Marginal Cost (SMC), but the restructuring had left two large fossil companies (National Power and PowerGen) setting the price in the Pool with the ability to raise the wholesale price above the SMC.

Figure 1 shows the dramatic ‘dash for gas’ with its share growing from next to nothing in 1992 to almost a third of generation by 2000. Multiple factors underpinned this. A legal ban on using gas for power generation had been lifted and the newly developed Combined Cycle Gas Turbines (CCGTs) were cheap, quick to build and offered high efficiencies, which, with falling gas prices, offered low average costs. The Pool allowed new entrants to sell at the same price as incumbents and the transparent system-wide price facilitated contracts. With energy policy leaving the market to guide choices, political risk was considered low and substantial entry by ‘Independent’ Power Producers (IPPs) occurred. These entered on the back of long-term fixed-price contracts (and often share ownership) with the RECs, who could pass on their costs to the captive franchise domestic market.

The combination of long-term gas contracts, long term IPP contracts, regulated pass-through and performance guarantees on the CCGTs all reduced risk, whilst an added incentive for the RECs to sign such contracts was to exploit their new independence from centralized generation. The two fossil generators dominated the England & Wales Pool and clearly had considerable market power (Newbery, 1995; Tashpulatov, 2015), which the regulator negotiated down by encouraging them to divest 6 GW of coal plants to a third generator in 1996. The resulting triopoly was less constrained in exercising market power, with an incentive to do so as they wished to divest coal plant before the dash for gas eroded their market share too drastically (Sweeting, 2007). Indeed, by 2000, coal-based generation had shrunk by more than a third (and increasing amounts of coal were imported rather than domestically produced).

2.3 The Electricity Industry Structure after 2001

Once they had divested enough plants, the generation companies were free to buy the supply (retailing) businesses originally integrated with distribution in the RECs. The market evolved towards the current Big Six generators plus retailers.[1] The market power of the triopoly led to an increasing gap between cost and price in the Pool between 1996-2000, and encouraged the Government to replace the Pool with *New Electricity Trading Arrangements* (NETA) – just at the date (2001) when the price-cost margin collapsed under the weight of competition and excess capacity (Newbery, 1998; 2005).

NETA replaced central dispatch and the Pool with a self-dispatched energy-only market (abolishing capacity payments). The argument put forward was that getting rid of the Pool in favour of direct bilateral trading would encourage competition. To meet the physical need to balance supply and demand, NETA created a penal two-priced Balancing Mechanism. The claimed logic for the reform was that self-dispatch required generators to submit a balanced offer (output matched by contracts to purchase), requiring them to contract all output, thus removing the incentive to manipulate the spot market (under-contracting encourages sellers to increase the spot price above the marginal cost, over-contracting to reduce the price below marginal cost, Newbery, 1995).

In practice, the balancing mechanism was so flawed that it has required many hundreds of painfully negotiated modifications to approximate an efficient balancing market. In addition, the risk of incentives to manipulate the spot market was replaced by a clear incentive to vertical integration: the merger of retailing and generation companies ensured that they were automatically hedged against electricity price uncertainties, since they would then be selling wholesale to themselves. However, this in turn created major barriers to entry, and a perception of the electricity system as an oligopoly of major power companies controlling the entire system from generation to consumption.

Despite evidence that transmission constraints requiring expensive redispatch could be exploited by generators, in 2005 the retrogressive principles of NETA were expanded to incorporate Scotland in BETTA – *British Electricity Trading and Transmission Arrangements*, creating a single Great Britain electricity market. National Grid acted as the National Electricity Transmission System Operator (NETSO) for GB, owning transmission south of the border but acting as an Independent System Operator in Scotland, where the two incumbents remain Transmission Owners. BETTA created a single price zone despite serious congestion on the Scottish border, where redispatch costs were high and growing as wind energy was increasingly deployed in Scotland. The EU Target Electricity Model that came into effect in 2014 mandates that separate price zones are created when there are significant boundary constraints. Had this been followed, Scottish consumers would frequently enjoy lower prices than the rest of GB, and the costs of redispatch would have been avoided. These costs rose to hundreds of millions of pounds annually, amounting to £60 million in October, 2014, for a single (high cost) month.[2]

---

[1] Centrica, SSE plc, RWE npower, E.ON, Scottish Power and EDF Energy.

[2] National Grid *October 2014 Monthly Balancing Services Summary,* Table 5.1.1, at https://www.nationalgrid.com/sites/default/files/documents/37743-MBSS_OCTOBER_2014.pdf.

2.4 Electricity Demand and the Retail Market

The pattern of electricity consumption has been far more stable than the pattern of fuel use in generation. Industrial demand stabilized from about 2000, and domestic (household) electricity demand peaked in 2005. By 2016, industrial and domestic electricity demand were respectively 21% and 14% below the levels a decade earlier, despite the GB population growing 10% over the period.[3] This reflected improved stronger efficiency standards on buildings and appliances, slowed economic growth after the 2008 financial crisis, and the impact of rising prices, which also accelerated structural change and industrial off-shoring.

In contrast, Figure 2 shows that electricity prices have been considerably more volatile. After the 'dash for gas' of the 1990s, there was considerable spare capacity. With increasing competition, and falling fossil fuel prices, the price declined steadily from the mid-1990s. When fossil fuel prices rose sharply in 2004, electricity prices followed in the now competitive wholesale market, where prices are set by marginal, not average costs.

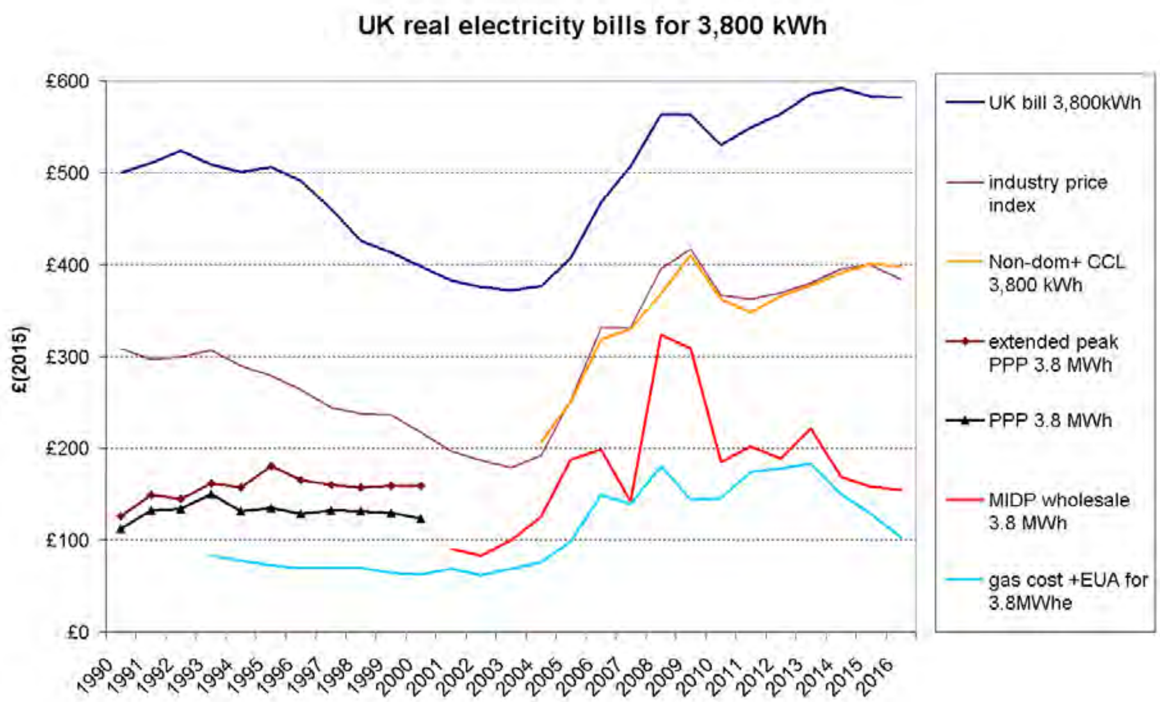


Figure 2: Real Industrial and Domestic Bills for Standardized Consumption Level

Source: BEIS (2017)

Notes: CCL is climate change levy, PPP the Pool Purchase Price (wholesale spot price), MIDP the Market Index Data Provider prompt wholesale price after 2001 (weighted by the household demand profile), EUA the European (CO_2) emission allowance price. The UK bill is for

[3] *Digest of UK Energy Statistics* (2017 Table 5.1.2); Population data: https://www.ons.gov.uk/peoplepopulationandcommunity/populationandmigration/populationestimates/datasets/populationestimatestimeseriesdataset

'standard' domestic customers consuming 3,800kWh including fixed charges. See appendix for details.

The decline in electricity demand (in 2013 Ofgem revised down its definition of 'standard' domestic consumption to 3,300 kWh/yr) helped to contain electricity *bills* for homes that invested in efficiency measures. Electricity prices and their impact on poor households and industry became a political issue at the time the government was embarking on EMR.

Ofgem, the energy regulator, regulates transmission and distribution tariffs and has oversight of wholesale and retail markets, but prefers to leave them to competition to deliver efficiency improvements and to pass these through to final customers. Periodically, as domestic retail prices rise, politicians, reflecting tabloid headlines, call for intervention, price caps or even renationalization, and in response Ofgem initiates an investigation – in 2008 the *Energy Supply Probe*,[4] followed in 2014 by a Competition and Markets Authority (CMA) investigation into the trading practices and competitiveness of the country's 'Big Six' energy companies. While the CMA found the wholesale market workably competitive, it expressed concern over the retail markets, and proposed various remedies.[5] By then, however, the UK was already embarking on yet another round of fundamental reform.

3. THE INTELLECTUAL AND POLITICAL EVOLUTION OF GB[6] ELECTRICITY MARKET REFORM

The Electricity Market Reform (EMR) that took effect in 2013 was a long time in intellectual gestation, responding to multiple concerns about investment, environment, and energy prices.[7] The most important was a growing concern about investment and security. An energy-only market encourages generators to mark-up their offer prices during periods of scarcity. Theoretically investors would predict future scarcity with higher prices, which would encourage them to start investments now for delivery at the time of predicted higher prices (if they could sell forward on sufficiently distant futures markets).

Several factors undermine this theoretical hope. The first is that electricity futures markets are either very illiquid or absent for much more than a year ahead, while it takes 4-8+ years from final investment decision to plant commissioning. Investors therefore need to be confident that the market conditions over the next 20-30 years are moderately predictable on the basis of existing laws and policies, and that demand and supply conditions are set by commercial, not political factors (Newbery, 2015). The alternative to futures markets are long-term Power Purchase Agreements (typically of 15-25 years tenor) but with the ending of the domestic retail franchise, there were no willing counterparties to sign such contracts, as there had been in the early days of the Pool.

---

[4] See https://www.ofgem.gov.uk/publications-and-updates/energy-supply-probe-initial-findings-report.
[5] See https://www.gov.uk/cma-cases/energy-market-investigation.
[6] EMR does not apply to Northern Ireland
[7] Grubb, Jamasb and Pollitt (2007) gives an overview of earlier debates.

Even without other considerations, it would be a brave investor to commit billions of pounds to a project against the prospect of electricity prices rising to reflect growing scarcity, on highly uncertain timescales, to unknowable levels, but set against the predictable political pressures that would likely curtail price rises. The early 2000s already saw a growing debate between economists, largely cast between abstract theory and the practical realities of likely 'missing money' in the calculations of cautious and risk-averse investors.[8] This problem was, however, amplified in multiple ways. Investment required some confidence in the political landscape and the determinants of market-driven fossil fuel prices, against which one could at least plausibly estimate or hedge. But UK energy policy had been in turmoil for most of the post-1997 period when the Labour Party came to power, with arguments over the role of coal, gas, renewables, and especially nuclear power. There were four Energy *White Papers* from 2003-2011 (the last being the precursor to EMR). Given such policy uncertainty, it would take a brave investor to predict the constraints on and interventions in future electricity markets, and hence likely future prices.

Second, in theory, the growing imperative towards environment and particularly decarbonization was to be reflected through carbon pricing. The European Commission, persuaded by the success of the US sulphur cap-and-trade scheme,[9] created the European Emissions Trading System (ETS) to deliver the EU's Kyoto targets with an EU-wide carbon price covering half total emissions. However, the EU ETS has signally failed to deliver an adequate, durable and credible carbon price signal. By the end of the first trading period in December 2007 the emissions allowance price had fallen to zero, and although it reached a more realistic €30/tonne CO_2 in the second period in early 2008, it crashed to €15/tonne with the financial crisis, oscillated around that for two years, and then sank further to well below €10/tonne, from which it has yet to recover (the March 2018 price was still only €11/tonne). The emission targets were achieved, but the economic choice between coal, gas and zero-carbon generation (renewables and nuclear) investment depends critically on the level of the carbon price over coming decades, and investors had watched the EU carbon price collapse three times within five years.

Third, broader environmental policy, particularly at the domestic (UK) level, was similarly unstable and hard to predict. The EU's *Renewables Directive* (2009/28/EC)[10] raised the required share of renewable *energy* (not just electricity) from 12% in 2010 to 20% of *final energy demand* by 2020, with each country agreeing its target share. The UK signed up to a particularly challenging share; starting from one of the lowest contributions (barely 1%), its target of 15% implied a dramatic growth of renewables. With electricity the easiest sector to tackle, this implied foreclosing much of the electricity market to conventional generation (at least, measured by output). The Directive also failed to remove allowances now displaced by

[8] See e.g. Symposium on 'Capacity Markets' (Joskow, 2103), particularly Cramton, Ockenfels and Stoft (2013), and earlier papers by Joskow (2008), and Joskow and Tirole (2007).
[9] The US system had a long-term stable plan and allowed banking of permits to encourage investments, with considerable success (Schmalensee et al. 1998), features that the ETS signally lacked.
[10] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32009L0028:EN:NOT.

renewables from the EU ETS, putting downward pressure on the carbon price. To these conflicting signals was added a slowly growing realization that massive renewables entry would, if delivered, crash the wholesale market *electricity* price (an outcome predicted in falling utility share prices and realized most obviously in the German wholesale market, see Hirth, 2018). The case for conventional investment was thus further undermined and mired in uncertainty.

The growing imperative for low carbon investment became the other driving concern. Domestically, the *UK Climate Change Act 2008*[11] was passed and provides a legal framework for ensuring that Government meets its climate change commitments. The Act requires that emissions be reduced by at least 80% by 2050 compared to 1990 levels with the Government committed to a series of 5-year carbon budgets.[12] Yet UK renewables support policy was a shambles (Gross and Heptonstall, 2010; Grubb et al., 2014, box 9.3), and after a decade of political efforts to rehabilitate the reputation of nuclear power, the government also wanted to find a way to get nuclear stations built.

Britain faced two additional problems. First, the EU *Large Combustion Plant Directive* and then the *Industrial Emissions Directive* set tighter emissions limits that would force the retirement of older coal plant unless refurbished – a prospect that seemed risky and uneconomic. Second, Britain's first two generations of nuclear power stations (the Magnox and Advanced Gas-cooled Reactors) were coming to the end of their lives. It was expected that some 12 GW of the older coal-fired plant (about 20% of peak demand) would close by 2015 and an additional 6.3 GW of nuclear plant by 2016.

As fossil fuel prices soared towards their peak of 2008, the UK electricity model seemed increasingly untenable, as underlined by two official assessments. First, the UK Climate Change Committee – the body set up to guide implementation of the *Climate Change Act* – concluded that a market structure built purely around competition for buying and selling electrons could not deliver low carbon investment (CCC, 2008). Added to the generic concerns about investability of the market at all, and the inadequacy of carbon pricing, electricity prices driven by short-run generating costs could not support the capital-intensive but cheap-to-run investments that characterized low carbon sources, whether renewables or nuclear. Gas generation investments would be hedged by passing through fuel prices into the market; zero carbon investments in contrast would take all the price risk of both fossil fuel and carbon price uncertainties. The NETA/BETTA model, in other words, was in direct conflict with the fundamental aim of the *Climate Change Act*, whose core rationale was to give strategic certainty for low carbon investments.

Then Ofgem, concerned over the impending threat to energy security, launched *Project Discovery* in June 2009.[13] The institution seen by many as the champion and guardian of the liberalized energy model concluded that that '[t]he unprecedented combination of the global financial crisis, tough environmental targets, increasing gas import dependency and the closure

[11] https://www.legislation.gov.uk/ukpga/2008/27/contents.
[12] https://www.theccc.org.uk/tackling-climate-change/the-legal-landscape/the-climate-change-act/.
[13] http://www.ofgem.gov.uk/markets/whlmkts/discovery/Pages/ProjectDiscovery.aspx.

of ageing power stations has combined to cast reasonable doubt over whether the current energy arrangements will deliver secure and sustainable energy supplies.' (Ofgem, 2010). Leaving metaphorical blood on the boardroom floor as some directors resigned in protest, Ofgem recommended 'far reaching energy market reforms to consumers, industry and government.'

Shortly thereafter, the Labour Government lost to a Conservative and Liberal Democrat coalition, and the newly formed Department of Energy and Climate Change consulted on EMR (DECC, 2010). It concurred with *Project Discovery* that the carbon price was now too low to support unsubsidized nuclear power and the wholesale electricity price was set by fossil fuel prices (and the ETS) that ensured that fossil generators had a natural hedge in that electricity prices mirrored gas and coal prices while non-fossil generation faced volatile wholesale and renewable obligation certificate (ROC) prices. It was concerned about security of supply and that the market was not delivering the required volume of renewables.

In conclusion, the electricity market was not well suited to delivering either secure or sustainable electricity – and even 'affordable' rang hollow politically as retail electricity prices continued to rise (figure 2), while industry warned about the high financing costs from the multiple risks facing the sector. Britain's vaunted model of liberalization was seen to be failing on all three key Government objectives.

4. A FOUR-LEGGED BEAST? THE EMR PACKAGE

The resulting *White Paper* (DECC, 2011) set out an intellectually coherent basis for electricity market reform through a combination of four mechanisms. The lack of a credible carbon price would be addressed by a Carbon Price Floor, almost immediately enacted by HM Treasury in the Budget in March 2011. Fossil fuel used to generate electricity would be taxed to bring the minimum price of CO_2 up to £16/tonne in 2013, rising linearly to £30/tonne in 2020, and projected to rise to £70/tonne by 2030 (all at 2009 prices).[14]

When EMR legislation was being developed in 2010-11, the ETS forward price had hovered around €15/tCO_2 (£12/tCO_2) for about two years, and the rate was set in relation to these levels. This implied a top-up of just a few £/tCO_2 in 2013, expected to rise slowly. However, with the collapse of the ETS price during 2011, the top-up required when written in to the legislation by 2013 actually escalated very rapidly.

As any tax could be changed with every budget (and the Carbon Price Floor was indeed subsequently capped, as explained later), this policy was buttressed by an Emissions

[14] HM Treasury, *Budget 2011*, HC 836, March 2011. The government had adopted a Social Cost of Carbon (SCC) for public policy evaluation, following the *Stern Report* of 2006, expecting that the EU ETS would provide a carbon price in this range. As the ETS price sank the government in 2009 shifted to a *shadow price of carbon.* The shadow price of emission savings outside the ETS (like households and transport) would be the SCC, that covered by the ETS would be a shadow price starting closer to the 2009 ETS price (£12/tCO_2), but risings to converge with the SCC at £70/tCO_2 (c. £ 250t/C) in 2030. The carbon floor price was thus targeted to make this 'shadow price' real in the electricity sector. For the subsequent evolution see section 3.5.

Performance Standard (EPS) that would limit CO_2 emissions from any new power station to 450 gm/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).[15] The EPS had followed on from experience of a long battle over plans for a new coal plant at Kingsnorth in Kent, which E.On had proposed in 2006, and served to remove any ambiguity about UK policy towards coal.[16]

In terms of policy design, these two steps were relatively straightforward. The thorny issues concerned how best to support low carbon investment, and how to ensure system security. The UK's carbon and renewables targets were estimated to require over £12 billion investment per year (compared with less than £5 billion in 2008).[17] This was considerably above financial analysts' estimates of the capacity of the Big Six (see footnote 1) to finance, requiring new sources of finance. All zero-carbon generation has high capital costs and low variable costs, making their cost highly sensitive to the Weighted Average Cost of Capital (WACC). By 2020 the cumulative investment in generation alone would amount to £75 billion (DECC, 2011) and if the WACC could be reduced by 3% (as the auction discussed below demonstrated), the consumer cost would be reduced by £2.25 billion *per year* (if all attributed to households, this is about 15% of a typical electricity bill). Lower risk enabling higher debt made this eminently feasible. As the Renewable Obligation scheme placed all the market price and policy risk on developers, replacing this by a fixed-price contract would considerably reduce risk and hence encourage new finance and entry.

The UK was reluctant to adopt the relative simplicity of the technology-specific German feed-in-tariff (FiT) model except for very small scale renewables (for which anything else would be unreasonably burdensome) but achieved the same risk reduction with 'Contracts-for-Difference' (described as a 'CfD with FiT'). Government would pay the difference between the reference wholesale electricity price and an agreed 'strike price'. This was initially done by publishing a set of strike prices for the CfDs based on inflated estimates of the required hurdle rate of return (i.e. the WACC) derived by asking the financial sector what they needed (DECC, 2013), combined with estimates of costs for different technology bands. Unsurprisingly, there was an enthusiastic uptake. As part of EMR, DECC had appointed an independent Panel of Technical Experts (PTE) to comment on the delivery of policies.[18] The PTE's first report (DECC, 2014) criticized the over-generous hurdle rate that resulted in high strike prices for the 15-year contracts offered to renewable generators. The stakes were even higher for nuclear power, in which the first (and possibly only) contract was awarded for the Hinkley Point nuclear

---

[15] The force of 'base load' effectively grants an emissions allowance per MW of capacity, but would force coal-fired stations to operate at a capacity factor of 50% or less.
[16] E.On argued that a new coal plant would reduce emissions by displacing older, less efficient plants; and later, that it would be built 'capture ready' (i.e. to include CCS technology as and when it became commercially viable). After three years of intense controversy, the UK government 'deferred' a planning decision, and shortly afterwards the project was abandoned.
[17] £(2005) 4.3 billion (Office of National Statistics).
[18] Both authors have been members of the PTE but this paper only draws on published evidence.

station on eye-watering terms of a 35-year contract at £92.5/MWh, roughly twice the then wholesale price.

For multiple reasons (including pressure from the EU Directorate-General for Competition concerning State Aids), after this initial round of 'administered' contracts, DECC moved to auctions for allocating specified volumes of renewables, divided into one 'pot' for developed technologies, and one for less developed technologies. As described below, Newbery (2016a) estimated the resulting clearing prices for on-shore wind lowered the WACC by 3% real. Unfortunately, the Conservative Government, in its 2015 election manifesto appealing to its rural constituencies, ruled out supporting on-shore wind – and along with it, all the other developed 'pot 1' renewable technologies - so the dramatic reduction in support prices for on-shore wind only survived one auction round.

The final and most important strand of EMR was directed at security of supply through a Capacity Mechanism. After extensive internal debate and exploration of international experience, the government rejected the idea of payments targeted to new entrants (a 'Strategic Reserve'), in favour of system-wide payments to all generators who could contract to generate whenever called upon by the System Operator, National Grid. Wielding the fear of 'the lights going out', DECC overcame Treasury skepticism about the need for any capacity mechanism, whilst Ofgem amongst others argued that targeted supports for new entrants would create perverse incentives, for example, for a company to close down one plant (and many fossil plant were near life-expired but still useful to meet occasional peaks) in order to get subsidies to open another. The prevailing view became that capacity payments would in effect be a market for reliable capacity, with a fixed payment (the clearing price of the 'descending clock reverse auction') to all who could provide it. The assumption behind the design, however, was that GB's main need was for new efficient flexible CCGTs, and the system was designed accordingly with auctions held for delivery 4-years ahead – allowing both for major refurbishment and new plant, with the latter being offered 15-year capacity contracts.

The auction volumes would be decided by the Minister on the basis of advice from National Grid on the capacity needed to meet the GB security standard – of a Loss of Load Expectation of 3 hrs per year (on average over a large number of years) – together with estimates of the 'de-rating factor' to reflect technology-specific plant availability.

The institutional set-up behind this structure was itself a challenge. The government created a separate, government-backed body (the Low Carbon Contracts Company) to be the counterparty for CfD contracts, whilst National Grid is charged with both running the Capacity and the CfD auctions. Transparency was underpinned by publishing National Grid's analysis and the PTE's critique annually (see e.g. National Grid, 2016; DECC, 2014). The Minister chooses the de-rated capacity to procure in a December auction for delivery four years' hence (hence the 'T-4 auction'), supplemented by year-ahead ('T-1') auctions for additional resources (including demand-side response), and, critically, to allow otherwise retiring plant to remain available for a further year.

5. RESULTS TO DATE

This paper is written (early 2018) four years after the UK's EMR was enacted and the first administered contracts awarded, and three years after the first auctions.

5.1 CfD Allocation and Auctions

With the legislation so long in the making, by the time it was in the final stages in 2013, both the nuclear and renewables industries were impatient and warning of waning confidence, interest and capabilities in the UK market. In parallel with the legislative timetable, the government negotiated a preliminary round of contracts for renewables and what was intended to be the first of a fleet of new nuclear power stations.

5.1.1. From negotiated contracts to competitive auctions

The first 'Administered contracts' for renewables summarized for Table 1 involved 15-year contracts for wind energy at strike prices of £95/MWh (onshore) and £140/MWh (offshore).[19] The latter was almost three times the estimated cost of CCGT generation, and divided opinion deeply between those who saw offshore wind as the UK's great zero carbon prospect – with almost unlimited resource – and those who saw it as a ludicrously expensive way to cut emissions. At this price, the contract value for each GW of offshore wind was over £7bn (and they were expected to generate at load factors of only around 35%). The industry argued that given scale and commitment, it would be able to engineer costs down to £100/MWh by 2020 – a claim greeted with considerable skepticism.

The scale of stakes in the EMR – and the low-carbon transition overall – were becoming very clear, and became even more so with the long saga of the contract for the 3.2 GW Hinkley Point C nuclear station. This finally emerged at a price of £(2012) 92.5/MWh indexed for a *35-year* contract – with a total value (in present money, undiscounted) over £70bn – along with extensive underwriting of some key risks (mainly of the CfD). This was substantially above most estimates of the generating cost assumed by the Climate Change Committee in recommending a new fleet of nuclear as part of its decarbonization strategy.[20] The perception that the main proponent, Electricité de France (EdF), had out-maneuvered the government to secure an overpriced contract was cast in doubt when – despite major financial injection from a Chinese partner on the project – it split the EdF Board, with two Directors (including the Finance director) resigning, and final approval only carrying a 10:7 majority. More than anything else, it all underlined the centrality of the finance challenge – those opposing feared that the £15-20bn construction cost would bankrupt the company before commissioning – along with the complete implausibility of any private entity building nuclear without massive government involvement.

---

[19] Heavily criticized by the National Audit Office (NAO, 2014).

[20] See https://www.theccc.org.uk/2011/08/09/confused-about-costs-of-nuclear-v-renewables-read-on, where the range of costs was given as £40-100/MWh by 2030, whereas renewables were expected to cost £75-135/MWh.

Table 1: Administered Renewable Energy Prices Compared to First CfD Auction

	Capacity (MW)	Admin Strike price 2014 (£/MWh)	Lowest auction clearing price Jan 2015	Maximum % saving
Large solar PV	72	£120	**£79**	**34%**
Onshore Wind	1162	£95	**£79**	**17%**
Energy from Waste CHP	95	£80	**£80**	**0%**
Offshore Wind	750	£140	**£114**	**18%**
Advanced Conversion Technologies	62	£140	**£114**	**18%**

Source: Simplified from Newbery (2016a, Table 1).

EMR, however, delivered a considerably better outcome with the first competitive auction of renewable CfD contracts, held barely six months after the administered contracts, with the results shown in the final columns of Table 1. Newbery (2016a) argued that the close juxtaposition of these contracts provides an ideal natural experiment. Although both involved 15-year contracts, the first were conducted in parallel with the operation of the ROCs system, and companies could use projects constructed under this regime as their evidence for costs and required rates of return. With the move to auctions, this no longer applied; the contracts would go to those offering the best value, including lowest cost of capital, irrespective of costs under the far more volatile and uncertain ROC system. Using the results in Table 1, Newbery estimated the move to competitive auctions lowered the cost of capital from about 6% to 3% - which, applied to the £75+bn expected investment required, translates into £2.25bn annual saving for 15 years.

5.1.2 Levy Control, the Hiatus, and the Second Auction

Shortly after these first renewables auction contracts were awarded, however, a General Election ushered in renewed uncertainty. Under the coalition government, Chancellor Osborne had placed a cap on the overall levy that could be charged to consumers rising to £7.6bn/yr (2011/12 prices) by 2020/21. He retained his post, and along with Conservative colleagues was not amused as it became clear that this cap was going to be breached. Overly generous PV feed-in-tariffs had led to an unexpected explosive growth (almost 10GW compared to an expected 1.5GW) before future tariff reductions were finally imposed. The post-2014 fall in gas and hence wholesale electricity prices increased the subsidy element in the CfD contracts. Finally, the offshore wind farms were generating substantially more output than expected, increasing their payouts, and underlying the undesirable way of paying subsidies per MWh rather than on capacity (Grubb, 2015; Newbery et al., 2017).

There followed a major struggle and long hiatus, with the energy transition, the EMR framework that had been designed around it, and particularly, the CfD contracts for offshore wind, under major political pressure. Gradually, however, the arguments that led to the EMR won out, buttressed by the fact that breaching the levy cap was a sign of success in delivering renewables. Indeed, the renewable energy target for electricity (30% by 2020), which had initially been widely viewed as impossibly ambitious, was looking increasingly plausible. Figure 3 shows the percentage *increase* in the share of generation from renewables since 2005 (the starting points were very different, due partly to pre-existing levels of hydro and biomass), for the 10 EU countries whose increase was higher than the EU as a whole. Until 2020 the UK lagged most of this pack but has since accelerated.

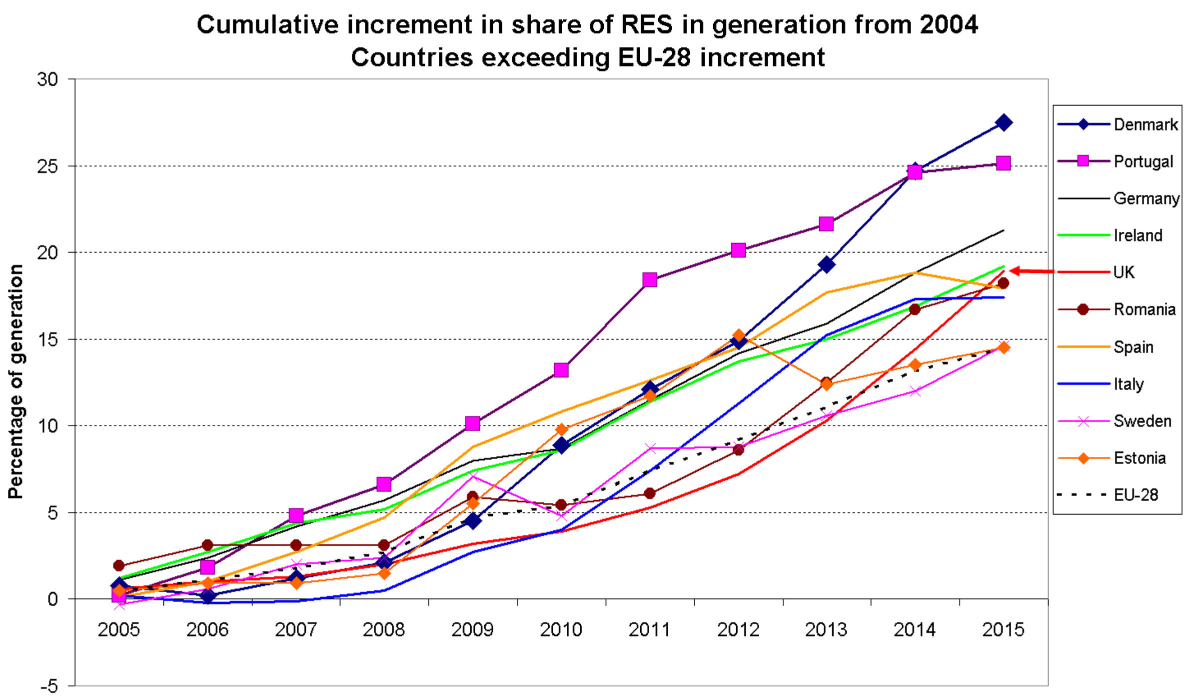


Figure 3: Growth of Renewable Electricity Generation in EU Countries since 2005
Source: Eurostat

With the *de-facto* ban on onshore wind appeasing some of the internal politics of the now-ruling Conservative party, the political context for energy gradually calmed. With industry pleading for stability in the policy framework and no credible alternative to EMR on offer, the government finally announced its intent to continue. Nevertheless, after the first CfD auction of January 2015, it was over two and half years before the next took place, in September 2017. The 'pot 1' auctions for developed technologies legally had to include onshore wind (due to the 'technology neutral' principles embodied in the State Aid clearance), so the government adopted the simple if ironic fix of declaring that no money would be made available in auctions for the cheapest renewables, and the second auction would focus entirely on the less developed 'pot 2' – with all eyes on offshore wind.

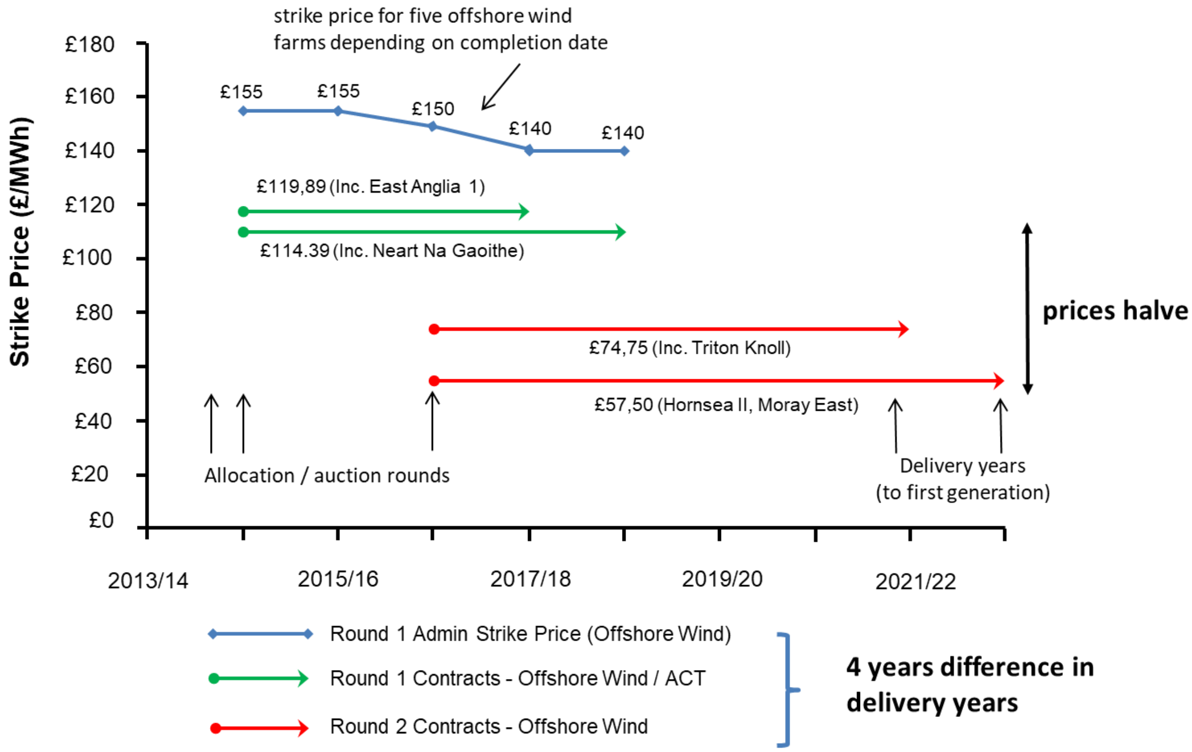


Figure 4: UK Offshore Wind Cost Reduction across Allocation and Auction Rounds
Source: Authors, adapted from graphic in KPMG (2017).

The outcome, as one senior civil servant admitted, came as a 'complete shock – of the best kind'. Figure 4 contrasts the administered prices and first auctioned prices (of summer 2014 and Jan 2015 respectively), with the prices obtained in the September 2017 auction for three major offshore wind farms. The headlines were dominated by two, totaling 2,300MW capacity, scheduled for delivery by 2022/23 at a contract price of just £57.50/MWh – way below any expectations, at half the price in the first auction, and allowing the government to secure 57% more capacity, for 44% less estimated subsidy, compared to round 1.[21] To add further political sweetening, Renewable UK (2017) estimated the UK had regained ground in the associated industries, with almost 50% of the supply chain value expected to accrue to British business.

[21] Author calculations, based on data for Round 2 vs Round 1 auctions: Capacity 3.3 GW vs 2.1 GW, and annual subsidy £176m *vs* £315m, given assumed electricity wholesale price of £45.61/MWh. Source: BEIS, CfD Round 2 Auction results.

Of course this was not a simple story, nor one for the UK only; the UK auction was the culmination of several such auctions by countries bordering the North Sea over the previous year, which had yielded declining costs based on multiple factors. The UK auction was a dramatic culmination of this trend, symbolically also important for a country in which the move to support large-scale renewables at high initial cost had been so controversial, but which was facing rapid decline of its existing North Sea gas industry, and dilemmas on how to meet the ambitious carbon budgets set for the 2020s under the Climate Change Act. Given the huge scale of the UK offshore wind resource, it seemed that the gamble of committing to North Sea wind development, based on initial government contracts followed by competitive auctions, had paid off, and opened up a major new and zero-carbon national (and regional) energy resource.

5.2 Capacity Market

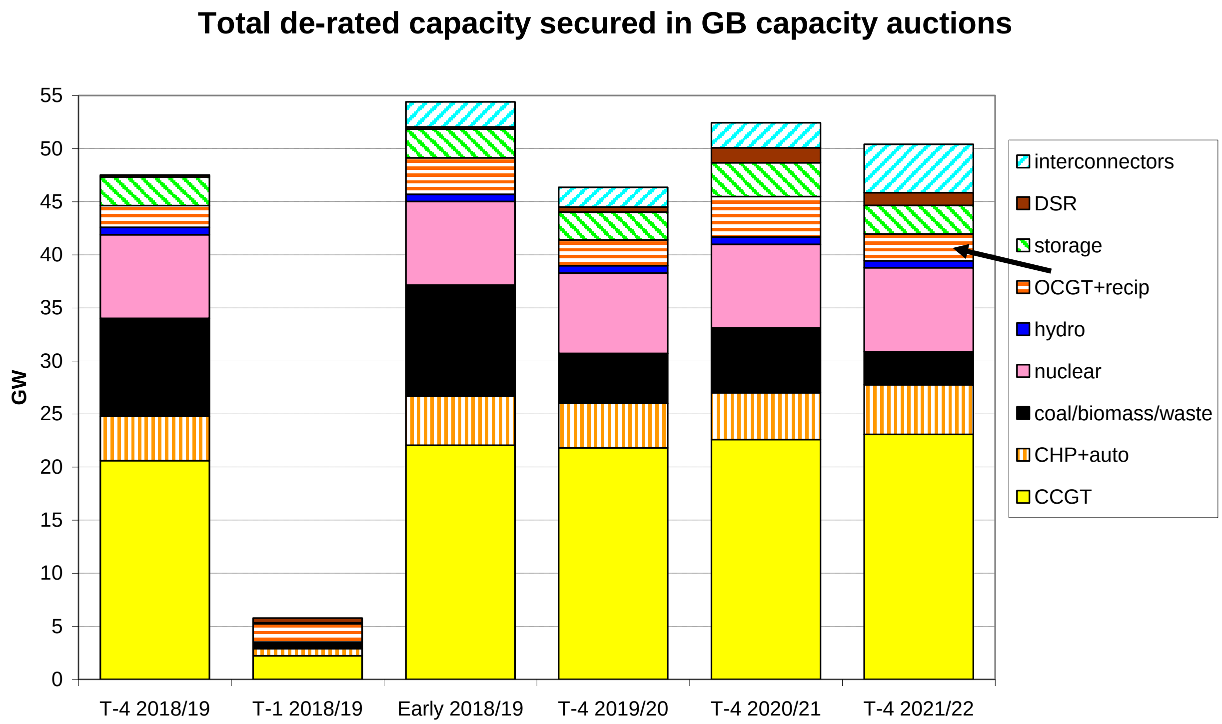
The first capacity auction held in December 2014 was for almost 50 GW de-rated capacity by winter 2018/19.[22] Figure 5 top shows the types of all (existing, refurbished and new) capacity procured in the first four annual auctions by delivery year (essentially the winter periods), including the "Early Capacity Auction" (i.e. T-1) held in Feb 2018 for delivery the following winter, with the resulting total capacity secured for winter 2018/19 ("Early 2018/19"). Based on the estimated 'net Cost of New Entry' (net CoNE) – which was interpreted as the price required to support a new CCGT investment above the revenue earned in the market – the government projected the likely clearing price in the first T- 4 auction to be £49/kWyr, which set the kink in the demand curve, with a price cap of £75/kWyr (1.5 x net CoNE).

In the event, the first T-4 auction cleared at £19.40/kWyr (figure 5 lower). Only one CCGT company (with two turbines) won a contract (but withdrew after failing to raise finance. Figure 5 top shows the amount surviving, hence the need to procure more in the T-1 auction for 2018/19, whose clearing price is the single diamond). The major beneficiaries were existing coal, gas and nuclear generators. This was as expected, but was the first dawning of reality for those not understanding the implications of a system-wide auction, and led to protests about the government subsidizing the type of plant (coal) that it claimed to be trying to phase out.

More concerning was that interconnectors were excluded (the UK had about 3 GW of connections to continental Europe, with more planned).[23] The evidence was unambiguous that interconnectors contributed to security, with imports even more likely in stress periods when UK wholesale prices would be very high (Newbery and Grubb, 2015). The European Commission intervened, ruling that excluding interconnection was discriminatory, and only gave state-aid approval for the first auction provided interconnectors were included in subsequent rounds.

[22] Of the total projected need for around 52.5 GW, 2.5 GW was held aside to ensure some room for a 1-year ahead auction in 2017, to provide scope for nearer-term adjustment, and shorter-term options like demand-side response (DSR).
[23] National Grid took the high end of 53.3 GW on the basis that imports could not be relied upon (National Grid, 2014, p10-11).

(Figures 5 top). Although absent in the calculation, their contribution made up for the shortfall from the withdrawn new CCGT plant, and they were included in the Early Auction for 2018/19



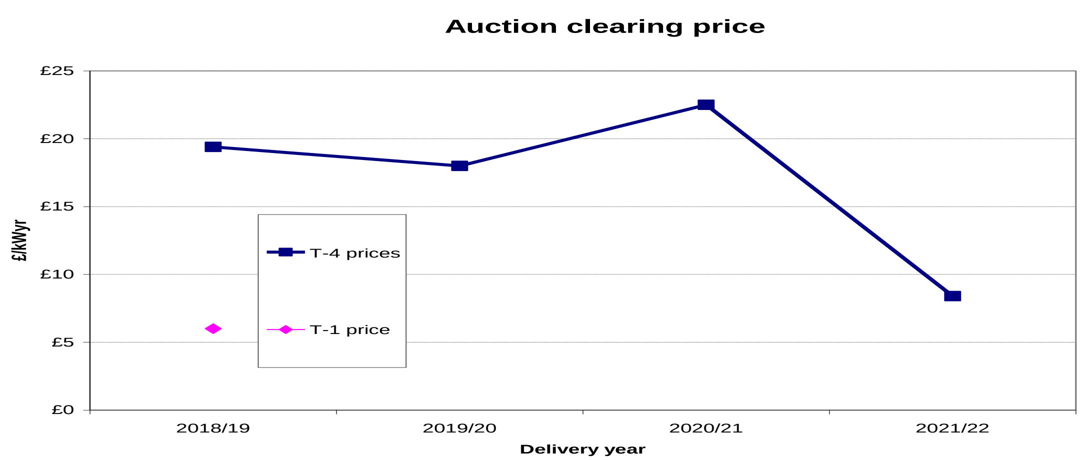


Figure 5 top: Results of Capacity Auctions; lower: clearing prices by delivery year
Source: National Grid *Provisional Auction Results*, various years

More problematic still was the large volume of small open cycle gas turbines (OCGT) and reciprocating diesel generators (arrowed in figure 5), with an average size of about 10 MW, connected to the distribution network. Diesel was clearly both a carbon-intensive fuel and one with dangerous air pollutants like nitrogen oxides and particulates, which came into sharp public focus with the VW vehicles scandal. In principle, these plants are unlikely to be used much – most of this new build is of the cheap capital (BEIS, 2016), high running cost plant appropriate to a role of just meeting extreme system needs, though this could not be guaranteed. Politically, the fact of being seen to subsidize diesel power stations instead of the relatively clean and efficient CCGTs expected was highly problematic.

The reason for the rush to connect small generators to distribution networks was, after the event, immediately obvious. Transmission-connected generation pays a Transmission Network Use-of System (TNUoS) G (for generation) charge that varied in 2017 across the country from about £20/kWyr in the far North to -£5/kWyr in London (i.e. paid to deliver peak power), signaling where new generation is encouraged or discouraged. In addition Load (actually the Distribution networks that pass it through to final consumers) pays TNUoS on peak demands, lower where G charges are high, higher where G charges are low, so that the sum of the two is roughly constant across the country at about £50/kWyr.

A small part of the TNUoS charge represents the marginal cost of expanding the grid, but the overwhelming part is the residual charge to collect the regulated transmission revenue set in the periodic price controls. This residual was low (about £10/kWyr in 2006) but was projected to rise to over £60/kWyr by 2020.

Distribution-connected generation was credited with the avoided TNUoS charge, and hence gained a relative advantage of about £50/kWyr compared to transmission-connected generation, so that the £20/kWyr auction price translated into a £70/kWyr benefit for these small generators. The efficient saving in transmission they deliver is not the average but the marginal cost of grid expansion, and, worse, the lost revenue by reducing peak demand on the grid must be recovered from the remaining grid users, further encouraging generators to migrate to local networks. The concerns over these local polluting small generators reached a crescendo when a staggering 8.7 GW of 'embedded generation' registered for the third Capacity Auction. Despite early concerns expressed about embedded benefits (DECC, 2016, §33-34) and the evidence of a problem already clear in December 2015, it took Ofgem, charged with ensuring the transmission tariffs are cost-reflective, nearly three years to remove this biased embedded benefit,[24] and even now this is subject to litigation, although tariffs are routinely revised every year and have no long-term durability. Auctions that offer 15-year contracts in one afternoon of bidding really need all the regulated price signals to be functioning well before the auction, not changed several years later, after investments have been committed.

The second T-4 auction in December 2015 confirmed that UK electricity demand was falling, not rising (at least at transmission level), and the capacity procured for the second auction was lower (wind is excluded as it has already been paid for its capacity, but its equivalent firm capacity contribution is netted from total demand to determine the amount to procure). However, coal plants were beginning to close apace, for reasons indicated below (in addition to the low value of capacity payments) – including some which had capacity contracts, thus prompting the government into holding a 1-year-ahead auction earlier than planned (the Early

[24] At https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-impact-assessment-and-decision-industry-proposals-cmp264-and-cmp265-change-electricity-transmission-charging-arrangements-embedded-generators.

Auction), and increasing the volume to be procured in the next 1-year-ahead auction to cover for cancelled capacity contracts (Figure 5).

The experience after these auctions underlined the unexpected: gross capacity requirements so far have turned out lower than the auction volumes set, and yet the system had become somewhat more dependent on year-ahead auctions than originally envisaged because of cancelled contracts for new build. The 2017 PTE report (DECC, 2017) argued there needed to be more attention to demand side response (DSR) and the 'latent capacity' of the system to handle stress events (Newbery and Grubb, 2015),[25] to get a better balance of costs, and hence reduce the inevitable institutional and political pressures to over-procure.

The government had designed the Capacity Mechanism to deliver reliable generating capacity at the cheapest *price*, given existing conditions. That is exactly what it has delivered. That might have been fine if price and true *economic cost* were aligned, but they were not, as transmission and distribution tariffs failed to give efficient location decisions. The environmental NGOs were aghast to see old coal plants receiving payments, and hated diesel even more. The nascent demand-side management industry sees the Capacity Mechanism as unbalanced (which it is) and undermining their main potential market of responding to scarcity pricing in the wholesale market (they are mounting a legal challenge). The government really wanted and expected the Capacity Mechanism to bring forth large flexible gas-fired generation (which it has not). And the incumbent industry cried foul (with reason) at the competition from decentralized generation, which was effectively subsidized due to the exemption from the now very high residual transmission charges.

The government moved to effectively bar diesel from the third auction using environmental regulation, and the price in that auction (Dec. 2016) rose somewhat, bringing another surprise with the scale of storage coming forth. Embedded generation still dominated the winning bids (Ofgem had not yet published its intention to end embedded benefits), but despite higher procurement volumes, cleared at a price again much too low to support new CCGTs, which many still regarded as necessary for providing flexible bulk power through the 2020s and beyond. Moreover, it also became clear that much of the 500MW of battery storage in the most recent auction has storage lifetime much shorter than the potential duration of 'stress events', but was being accredited as if firm – leading to another revision of rules.[26]

Aside from the many dimensions of concern about the lack of a 'level playing field', the Capacity Mechanism faces two other, intertwined, worries. One is that the incentives on the

[25] Part of the problem is that a "Loss of Load Event" is not actually a situation in which load is disconnected, but one in which the system operator can invoke measures from voltage reduction, requesting generators to exceed their rated capacity for short periods, emergency imports, etc., none of which causes the lights to go out.

[26] Batteries were previously treated with high (96%) availabilities derived from pumped storage. National Grid (2017) published new derating factors so that storage with half (or one) hour has a derating factor a quarter (or half) of that previously, rising to 'firm' (96%) for 4-hour storage. The System Operator of the island of Ireland, using the appropriate concept of equivalent firm capacity, avoided such an egregious mistake.

Minister and National Grid are to over-procure capacity – no-one wants to be held responsible for the 'lights going out', as the tabloids frequently announce is imminent. As they do not pay (and National Grid may benefit if more transmission investment is required), and consumers do not see the capacity payment in their bills, there is an additional bias to over-procurement.

This, in turn, exacerbates the other worry, about the potential perverse consequences of over-procuring capacity. If existing generators pass the capacity payments through in reduced wholesale prices (as they do, see Ofgem, 2017), these lower prices drives up the Capacity payments required to support new investment – and, moreover, the net cost of the other major pillar of EMR, the CfD supports – whilst the dampening effect on peak-load pricing in particular robs demand-side management of its primary potential market, for which the Capacity Mechanism as it stands is simply not a credible substitute. The Irish model discussed in 7.2 avoids many of these problems.

Thus, the judgement is mixed. The positive case is that the Capacity Mechanism is delivering capacity to maintain security, and has uncovered many options previously not seriously considered, at prices far lower than expected. In doing so, however, it has raised a host of challenges, of which only some are, slowly, being resolved. A more positive assessment is that running annual auctions allows the system to be fine-tuned to avoid future problems. A more skeptical view is that Ofgem has repeatedly failed to adequately address failures in the locational element of network charges, in large part as it is unwilling to grandfather charges to existing power stations (which cannot relocate, but can exit) and confine tariff revisions to future connections.

The final observation concerns the remarkably low (and falling) auction clearing prices, despite concerns over massive plant retirements and tightening margins. One explanation is that the System Operator is increasingly procuring various balancing services, most recently enhanced frequency response for plant "capable of responding within one second to frequency deviations and operate in frequency sensitive mode".[27] These additional ancillary services do much to alleviate the "missing market" problem (Newbery, 2015b), and in part are also responsible for the entry of batteries capable of providing such fast response.

5.3 Carbon Price Floor and Emissions Performance Standard

As described, the other two elements of the EMR targeted coal more directly. With the Performance Standard effectively removing any prospects of new coal investment, the issue really concerned the existing fleet and the incentives for keeping coal power stations open. Before the introduction of the carbon price support (CPS), the carbon price was insufficient to have much operational impact. However, the legislated top-up rose from £4.94/tCO_2 in the 2013 to £18.08 in 2015-16, but then frozen at an £18 add-on to the EU ETS price.[28] Given the

---

[27] https://www.nationalgrid.com/uk/electricity/balancing-services/frequency-response-services/enhanced-frequency-response-efr

[28] For an excellent concise briefing on the UK carbon floor price see http://researchbriefings.files.parliament.uk/documents/SN05927/SN05927.pdf.

persistently low EU ETS price, this in effect became a top-up tax at this level, raising around £1.5bn/yr.

The other factor was that gas prices began to decrease at last. The combination made it economical to start base-loading gas instead of coal. Figure 6 shows that the carbon-inclusive cost of gas-fired generation fell below that of coal from April 2014 and, for high efficiency CCGTs, has remained below since. Indeed, coal has been frequently unprofitable to operate since mid-2015 (below zero in figure 6), prompting a raft of coal plant closures.

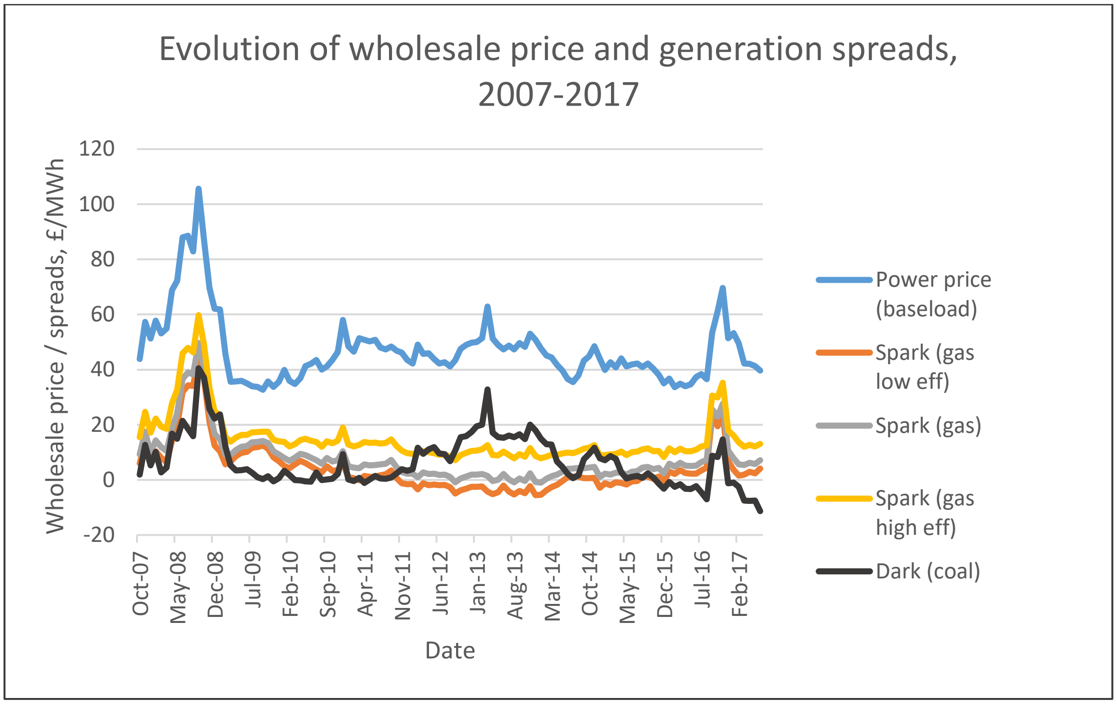


Figure 6: Wholesale Electricity Price and Spark Spreads, 2007-17 (at 2011/12 Prices)

Source: https://www.ofgem.gov.uk/data-portal/spark-and-dark-spreads-gb

Note: 'Spark spread' is the he difference between the cost of fuel and carbon for a gas plant and the wholesale electricity price. 'Dark spread' is the corresponding term for coal.

As illustrated in Figure 6 and described further in the conclusions, the overall impacts on the GB electricity system and its emissions have been dramatic. As the combination of fuel and carbon prices increasingly made gas plants cheaper than coal to run, this made coal the marginal plant, which maximizes the impact of the carbon price on electricity prices. Gas increasingly displaced coal, as figure 1 illustrates, and on several days there has been no coal generating for the first time since the 1890s. Coal burn has now decreased dramatically from 41% of UK generation in 2013 to less than 8% in 2017, so that total UK emissions are now lower than a century ago.[29]

Domestic electricity prices were already politically charged and, in 2015, the differential with the rest of the EU, exacerbated by a high exchange rate, pushed comparative industrial electricity prices also high on the political agenda. After the general election of 2015, there was a concerted push from some electro-intensive industries, along with the ‘climate-sceptic’ wing of the Conservative party, to cancel the floor price on grounds of industrial competitiveness. However, strong counter- lobbying – including the gas industry alongside UK business pleading for policy stability – combined with Treasury self-interest to maintain auction revenues.

As the combination of fuel and carbon prices increasingly made gas plants cheaper than coal to run, the Treasury duly announced that the Carbon Price Support would remain, frozen at the same level, at least through to 2021. The rapid decline of coal started to create periods with gas as the marginal fuel, starting to temper the impact of the carbon price on wholesale prices, whilst the collapse of the UK exchange rate after the EU referendum did much to remove the price gap with the rest of Europe for many industrial consumers. In autumn 2017, the government announced it considered that the overall carbon price was at about the right level – precluding significant near-term increase, but also protecting the market price against the possible loss of the EU ETS after Brexit – and would be reviewed once coal was removed from the system. As the dust began to settle, therefore, all four planks of the EMR had survived the political turmoil – but at the price of sacrificing the intended strategic signal of a steadily rising carbon price to guide all low carbon investment.

6. POPULAR CARICATURE: RETURN OF THE “CENTRAL ELECTRICITY GENERATING BOARD”?

The original vision that motivated privatization was, to quote the then energy minister Lawson: ‘the business of Government is not the government of business’ (Lawson, 1992, p211). As to energy policy, Lawson stated at a BIEE conference in 1982 ‘I do not see the government’s task as being to try and plan the future shape of energy production and consumption. It is not even primarily to try to balance UK demand and supply for energy. Our task is rather to set a framework which will ensure that the market operates in the energy sector with a minimum of distortion and energy is produced and consumed efficiently.’[30]

Critics have argued that EMR represents a reversal of this ideal, with the Government now planning the future shape of energy production and consumption. Specific renewable technologies are procured through CfD auctions, nuclear power is procured by a bilateral contract with the Government, and the amount of fossil capacity considered to be needed to deliver the reliability target is set by the minister, while the regulator, Ofgem, is subject to strong political pressure to deliver cheaper domestic electricity prices. Critics further argue that long-term contracts are replacing the market as a mechanism to attract new investment into the

[29] https://www.carbonbrief.org/analysis-uk-cuts-carbon-record-coal-drop
[30] quoted at https://publications.parliament.uk/pa/ld201617/ldselect/ldeconaf/113/11305.htm.

industry, seemingly moving back to the Single Buyer Model that the French, with their state-owned electricity industry, pressed unsuccessfully for in the first EU *Electricity Directive*.

So, is EMR an admission of a failure of the liberalized electricity market model, or is the Government, though the *Energy Bill 2013*, attempting instead to better correct market failures? We would argue the latter. Long-term contracts (only for new investment) replace the absent futures markets, all the more necessary given the unpredictability of future energy policy. Most renewables create learning spill-overs that are unrewarded by the market, which justify subsidy.[31] As learning spill-overs depend on technology and the state of the technology's maturity, the subsidies should also be technology specific (although the form of subsidy provided by EMR is not particularly well-directed to addressing the learning market failure).

It is moreover wrong to confuse government-led auctions with central planning. As an official remarked in 2013, it felt strange to be accused of central planning when they were as uncertain about the results of the impending auctions as everyone else. The auctions created new markets, and, as is common with new markets, both unearthed and stimulated the unexpected. But the new markets – and investments and learning – could not have occurred without the government recognizing there were market failures that had to be corrected.

Providing a long-term contract for nuclear power also reflects the lack of a durable credible carbon price, as well as the lack of insurance markets for future power prices and nuclear policy changes (such as the *Energiewende* in Germany). While the particular form of underwriting for Hinkley Point is highly unsatisfactory, it seems inconceivable that private companies would take on nuclear risk without some Government-backed guarantee to facilitate financing. The UK, like many other countries, has struggled to find cost-effective ways to support nuclear power, and yet it remains unclear whether or how the UK will meet its ambitious goals to almost entirely decarbonize the power system, well before 2050, without it.

It is also worth remembering that the massive entry of new CCGTs in the 1990s by IPPs was based on long-term power purchase agreements with the Regional Electricity (distribution) Companies, many of whom were co-sponsors and shareholders in the projects. The development of those CCGTs was in turn heavily subsidized by the defence industry supporting jet engines.

The important difference with the new contracts is they are competitively secured at auction, and so market tested in a way that is central to the idea of a liberalized market. Holding periodic auctions also allows flaws in the market design to be detected and corrected in a timely fashion. In contrast, the period of the Electricity Pool from 1989-2001 was marked with great difficulties in reforming the Pool, a multilateral contract that was intended to be hard to change in order to offer greater stability to the liberalized market.

Recent interventions by the Government (such as banning any subsidies for on-shore wind to appease Conservative rural voters) can also be contrasted with the earlier period of the intended 'hands-off' energy policy. In the 1990s, the coal industry had to be saved with coal-backed contracts forced on the retailers. The incoming Labour Government imposed

[31] Tidal lagoons are presumably an exception, as building dams in a millennium-old skill.

retrospective windfall taxes on the privatized utilities. Gas-fired generation was also proscribed for a period, again to save the coal industry.

The reform of trading arrangements that ended the Pool was a blunt market redesign to address market power – a problem that had already been solved by the time the reforms took place. The problems of NETA were exacerbated by the expansion to BETTA, which was partially a political fix to appease Scottish power generators (at the expense of both Scottish and English consumers). The Renewables Obligation Scheme was a poor substitute for the earlier auctioned Feed-in Tariff (NFFO) support scheme, and the alphabet soup of interventions to enhance energy efficiency, stimulate new technologies, and reduce CO_2 emissions at various levels in the system were poorly coordinated, lacking a clear consistent intellectual framework to guide their choice, design and relationships.

Electricity, delivered to each voter's home and critical to modern existence, is inevitably politicized. The main question is how to reduce the adverse effects of inevitable interventions. The move to auctions, fixed price contracts with the price set at auction for renewables and firm capacity, backed by a government-guaranteed credible counter-party, and even the Carbon Price Support, seem steps in the right direction. Compared to most of their predecessors, they are arguably better policies to address market failures, and do more to shape the evolution of the electricity system in directions consistent with the multiple goals of public policy.

7. FUTURE CHALLENGES

7.1 The limits of fixed price contracts for renewables

After two decades of being seen as amongst the 'worst in class' on renewable energy in Europe, the turnaround in UK renewables is remarkable, as is the policy progression from rather ineffective, through inefficient, to the effective and relatively low-cost structures of the EMR. The irony is, however, that the apparent success is likely to more rapidly highlight the limitations of the approach, and the need for further, and complex, reform.

For as renewables mature, the objectives and conditions change. The fixed price auctioned contracts embodied in the EMR have helped to reduce the cost of capital and attract investment to emergent and potentially risky new industries. However, this simple attraction is also their strategic Achilles' Heel, for several reasons.

First, the subsidy element amplifies incentives to inefficient siting. Going to resource-rich regions makes sense, but the windiest locations get a full 15 years of guaranteed income at a rate defined by the most costly plant in the auction – much more than they need. The windiest places, which are inherently the cheapest to developers, get the biggest share of subsidy. A move to contracts which guarantee a strike price for a given volume of total output, rather than for a given number of years, could solve this problem.

Second, within about a decade, the UK power system may have growing periods in which zero carbon sources with such contracts are able to meet all the power needs (e.g. on sunny weekend days, or windy winter nights). In these conditions, the existing holders of ROCs (that pay a premium on the wholesale price only if generating) will bid down wholesale prices to deeply negative levels to keep receiving a subsidy – with adverse effects on other zero-carbon generation such as nuclear power.

As renewable volumes grow, policy will have to confront the fact that the value of power is not constant in either time or space, so that a support system based on fixed prices will be increasingly at variance with the underlying economics. The need will be less for subsidy, and more for pricing which is capital-efficient but better reflects system value. There is consequently a resurgent debate on the 'system costs' associated with rising shares of variable renewable electricity sources. Defining such system costs is in fact complex and most estimates suggest they are modest at present (Heptonstall, Gross, & Steiner, 2016), but the problem is that the EMR system provides little incentive to manage these sensibly as capacities rise.

Under the EMR, renewables do face short-run balancing costs – the contract strike price is averaged in relation to the wholesale price, and generators pay imbalance prices in the balancing mechanism. This however is not the same as pricing that reflects the overall value to the system, and its dependence on location and time of generation. The real value depends on location including transmission costs / constraints, which are not adequately reflected in the CfD system, amplifying the incentive to inefficient siting. And ever more strongly as capacities rise, system value will reflect time of operation: more PV added to a system which already has enough to meet demand on sunny days; or wind expanding in existing regions to feed more power at the same time into a system which already has enough to meet demand on windy nights, is obviously of declining economic (and even environmental) value.

Fixed price contracts do not reflect these factors, and the question of how to include space- and time-varying values whilst retaining the economic benefits of investor risk reduction will increasingly come to the fore during the 2020s. Newbery et al., (2017) argue for paying an auctioned price for a fixed number of full operating hours while confronting developers with nodal prices, hedge with contracts. Another option could be for unsubsidized renewables to be financed through a long-term "contracts pool" selling power to bulk consumers, and buying balancing and backup services from the spot market (Grubb and Drummond, 2018). As in other countries, once renewables penetration reaches very high levels, further reforms will be needed if costs are to be restrained.

7.2 Capacity auctions and reliability markets: the Irish example

Whilst there is no obvious international example of a market structure fully appropriate for variable renewables at scale, there are many examples of approaches to system reliability which might offer improvements to the UK capacity market, and one is on Britain's doorstep. The Single Electricity Market (SEM) of the island of Ireland (comprising Northern Ireland, part of the UK, and the Republic of Ireland) is transiting to the Integrated SEM, or I-SEM, under the requirement to adopt the EU Target Electricity Model. That requires replacing the centrally dispatched pool with its mandatory requirement to bid short-run marginal costs (to which is added a regulated capacity payment) with bidding into the European auction platform, EUPHEMIA.

The SEM had a Capacity Remuneration Mechanism (CRM), which offered the Best New Entrant price that in 2017 was set at €70.99/kWyr, but this has now been replaced by auctioned Reliability Options, (ROs). An RO is a one-sided CfD, in which the holder pays back the excess of the market price over the strike price (set in the first auction at €500/MWh). To ensure that the market price signals the correct scarcity price for trading across borders (i.e. to GB), the system operator sets an Administered Scarcity Price as a floor price. This is currently limited to the EUPHEMIA price cap of €3,000/MWh but with the intention of moving towards the VoLL*LoLP to ensure efficient scarcity pricing over I-SEM's interconnectors. Reliability options are arguably a better alternative to capacity payments, as they address missing money problems, hedge high and uncertain prices for generators and consumers while ensuring that the wholesale market and international trade clear at efficient prices (Newbery, 2016b).

The first (T-1) Irish RO auction cleared at €41.8 (£38.10)/kWyr on 15th December 2017,[32] although several stations received higher (regulated) prices to meet transmission constraints. Of the 147 Candidate Units offering 9.42 GW, 104 were successful, offering 9.07 GW of de-rated capacity; over 80% thermal (53% CCGT, 30% steam turbines (mainly coal)), 7% DSR (half new entry), 5% interconnectors, 5% pumped storage and hydro, and 0.2% wind (which did not need to offer and can enjoy the high scarcity prices). The previous CRM paid out €70.99/kWyr on 7,267 MW (the required capacity) to give a CRM 'pot' of €515.9 million to be spread over all available and eligible generation,[33] whereas the new RO auction will pay out €379 million, saving €137 million/yr.

The obvious question to ask is why the I-SEM capacity price is so much higher than the GB price (although considerably below the previous CRM payment) in the presence of so much excess capacity (crudely comparing the 9.1 GW accepted against the previous 7.8 GW - after adding excluded interconnectors - thought sufficient for the CRM). This is despite the range of new ancillary services (under the DS3[34] programme) to address the missing market and hence missing money problem.

One immediate difference with the GB auction is that holders of the auctioned RO contracts have their prices capped at €500/MWh, and forego the upside enjoyed by GB capacity agreements. At present, wholesale prices in the un-reformed SEM are capped at €1,000/MWh but capacity payments are higher. Allowing for this cap arguably reduces the net amount to €21.8 (£19.9)/kWyr, very close to the first GB auction price.[35] In addition there is uncertainty about how prices will be set in the I-SEM, as yet untested, and once the new I-SEM market has bedded down auction prices may fall, as was the case in GB.

---

[32] http://www.sem-o.com/ISEM/General/Capacity%20Market%20-%20Final%20Capacity%20Auction%20Results%20Report.pdf
[33] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-16-026%20ACPS%202017%20Consultation%20Paper%20for%20Publication_0.pdf
[34] http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/
[35] Prices are currently capped at €3,000/MWh. As the reliability standard is 8 hrs/yr, the missing money is (€3,000-€500)/MWh x 8 hrs/yr = €20/kWyr,

One conclusion is that if the EMR capacity auction is to be reformed, this RO auction has obvious attractions.

8. CONCLUSIONS

The impact of more than a quarter of a century of reforms in UK electricity policy have been profound, as was already evident from the long-term evolution of fuel mix and demand in Figure 1. With the dash-for-gas during the 1990s, the UK had moved to a roughly equal mix of coal, gas, and nuclear. As the oldest nuclear plants were retired in the 2000s, the system was kept supplied by the abundance of gas, steadying demand, and the slow emergence of renewables – still barely visible in the overall statistics – whilst coal remained the mainstay of baseload demand and seasonal scheduling. Over the full period since privatization, coal fell from two-thirds of generation in 1990 to 35% in 2000, to 7% in 2017, halving CO_2 emissions from power generation over the quarter century.[36] Over the next few years, coal will be increasingly confined to meeting winter peaks.

Renewables – including conversion of some coal to biomass – began to surge after 2010, at a greater rate with the advent of feed-in-tariffs for the small sources and long-term CfD contracts for the large. Electricity demand began to fall and by 2015 the carbon price support drove coal to the margin of what remained. In 2015, the UK, an 'island of coal in a sea of oil and gas', saw the first full day without coal-fired generation for over a century. The Government is minded to phase out coal-fired generation entirely by 2025[37] – if there is any left by then, given carbon, gas and coal price trends, and the tightening emissions standards. In the short-run, that leaves gas as the flexible dispatchable fuel to manage renewables intermittency. The earlier hostility to CCS appears to be waning, as is hostility to on-shore wind.

Competitive auctions have proven their worth not only in revealing costs and options, but in driving down costs and prices for both renewables and firm capacity. The commitment to off-shore wind, originally seen as a costly white elephant, now appears to be a way of encouraging a coherent supply chain with its cost reductions to develop and deliver. The energy-only market beloved by the EU is demonstrably unsuited to cost-effective new investment, while capacity auctions clearly can work – if the remaining regulated network tariffs are correctly set. Transmission pricing policy is also slowly adapting to the need to give better signals for the decentralized world of smaller generating units that can connect rapidly, but need good price guidance to locate in the right place.

At the heart of all these trends is the need for, and gradual acceptance of, credible, stable policies that encourage development and deployment, and that support learning-by-doing in collaboration with the widest group of countries, as in *Mission Innovation*,[38] to continue to reap what continue to be impressive cost reductions for some technologies. Yet the regulatory journey

[36] https://www.gov.uk/government/statistics/final-uk-greenhouse-gas-emissions-national-statistics-1990-2015.

[37] https://www.gov.uk/government/consultations/coal-generation-in-great-britain-the-pathway-to-a-low-carbon-future.

[38] http://mission-innovation.net/

is by no means over. The fixed-price contracts for renewables have been effective in reducing financing and technology costs, but create perverse impacts on the wholesale market, and lack any incentive to site renewables efficiently with respect to either place or generation timing, and hence the 'systems costs' they create. This mattered little when the capacities were small; it will matter far more over the next decade, when adding more renewables will increasingly serve to generate power when it is least needed, and conflict with other contracted sources (nuclear and biomass); declining costs will be increasingly offset by rising system costs.

Similarly, the problems of the Capacity Mechanism are gradually being resolved, although arguably a Reliability Option auction would be preferable, and including demand side response remains a work in progress. Along with the small renewables feed-in-tariffs, the combination of the Capacity Mechanism and the 'embedded benefits' distortion may unwittingly have helped to launch a revolution in distributed energy resources, but the fixes to date are probably inadequate for dealing with the wider consequences and opportunities of such decentralization.

The balance between the state and private sectors is being revisited, not without dispute, and we are a long way from a credible nuclear (or even CCS) strategy. The way we support zero and low-carbon generation could benefit from further changes (supporting the learning externalities as well as the carbon saved), and better location signals are still needed for investment and dispatch. The evidence suggests that UK's Electricity Market Reform has been a major step forward, but a considerable journey remains ahead.

References

BEIS, (2016). *Electricity Generation Costs*, at https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016

BEIS, (2017). *Historical electricity data: 1920 to 2016*. Available at https://www.gov.uk/government/statistical-data-sets/historical-electricity-data-1920-to-2011.

Cramton, P., A. Ockenfels, and S. Stoft (2013). "Capacity Market Fundamentals." *Economics of Energy and Environmental Policy*, 2(2). 27-46.

Darwell, R., (2015). *Central Planning with Market Features: how renewable subsidies destroyed the UK electricity market*, Centre for Policy Studies, at http://euanmearns.com/renewable-energy-the-most-expensive-policy-disaster-in-modern-british-history/

DECC, (2010). *Electricity Market Reform: A consultation document*. Dec., 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* , at http://www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/emr_wp_2011.aspx.

DECC, (2013). *Annex F: EMR Panel of Technical Experts Final Report for DECC*. July, at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223656/emr_consultation_annex_f.pdf.

DECC, (2014). *EMR Panel of Technical Experts' Final Report on National Grid's Electricity Capacity Report*, at http://www.eprg.group.cam.ac.uk/wp-content/uploads/2014/07/EMR_Panel_s_Final_Report_on_National_Grid_s_ECR.pdf.

DECC, (2016). *Electricity Market Reform Panel of Technical Experts 2016, final report on National Grid's Electricity Capacity Report 2016*, at https://www.gov.uk/government/publications/electricity-market-reform-panel-of-technical-experts-2016-final-report-on-national-grids-electricity-capacity-report-2016.

DECC, (2017). *Electricity Market Reform Panel of Technical Experts 2017 final report on National Grid's Electricity Capacity Report 2017*, at https://www.gov.uk/government/publications/electricity-market-reform-panel-of-technical-experts-2017-final-report-on-national-grids-electricity-capacity-report-2017.

HM Treasury, (2011). *Carbon price floor consultation: The Government response*, at http://webarchive.nationalarchives.gov.uk/20130103021036/http://www.hm-treasury.gov.uk/d/carbon_price_floor_consultation_govt_response.pdf.

Grubb, M., Jamasb, T., and Pollitt, M. (eds), (2007). *A low carbon electricity system for the UK: technology, economics, and policy*, Cambridge: Cambridge University Press.

Grubb, M., with Hourcade, J.C., and Neuhoff, K., (2014). *Planetary Economics: Energy, Climate and the Three Domains of Sustainable Development*, Routledge / Taylor and Francis.

Grubb M. and P.Drummond (2018), 'UK Industrial Electricity Prices: Competitiveness in a low carbon world', UCL Institute of Sustainable Resources, www.ucl.ac.uk/bartlett/sustainable

Gross, R. and P. Heptonstall, (2010). Time to stop experimenting with UK renewable energy policy, ICEPT working paper, Imperial College London, at https://pdfs.semanticscholar.org/e932/cbb447c994372339a484eba7b1661d6efd7f.pdf

Heptonstall, P., Gross, R., Steiner, F. (2017) "The costs and impacts of intermittency – 2016 update: A systematic Review of the evidence on the costs and impacts of intermittent electricity generation technologies," UK Energy Research Centre, London

Joskow, P.L. (2008). "Capacity Payments in Imperfect Electricity Markets: Need and Design," *Utilities Policy*, 16(3): 159-70. http://dx.doi.org/10.1016/j.jup.2007.10.003.

Joskow, P. (2013). "Symposium on 'Capacity Markets'." *Economics of Energy and Environmental Policy*, 2(2). v-vi.

Joskow, P.L. and J. Tirole (2007). "Reliability and Competitive Electricity Markets," *Rand Journal of Economics*, 38(1): 68-84. http://dx.doi.org/10.1111/j.1756-2171.2007.tb00044.x .

KPMG (2017), *Results that will blow you away: CfD allocation round two*. September 2017, at https://assets.kpmg.com/content/dam/kpmg/uk/pdf/2017/09/cfd-allocation-round-two-energy-update.pdf.

Lawson, N., (1992). *The view from No. 11: Memoirs of a Tory Radical*, London: Bantam.

NAO, (2014). Early contracts for renewable electricity, National Audit Office, HC 172, at http://www.nao.org.uk/report/early-contracts-for-renewable-electricity/ last accessed 20/7/15.

National Grid, (2016). *EMR Electricity Capacity Report*, at https://www.emrdeliverybody.com/lists/latest%20news/attachments/47/electricity%20capacity%20report%202016_final_080716.pdf.

National Grid, (2017). *Duration-Limited Storage De-Rating Factor Assessment: Final Report*, at https://www.emrdeliverybody.com/SitePages/Home.aspx.

National Grid, (2018). *Provisional Auction Results; T-4 Capacity Market Auction for 2021/22*, at https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Provisional%20T-4%20Results%20DY%202021-22.pdf

Newbery, D.M., (1995). 'Power Markets and Market Power.' *The Energy Journal*, 163, 41-66.

Newbery, D. M., (1998). "The Regulator's Review of the English Electricity Pool." *Util. Pol.* 7(3), 129-41, at https://www.semanticscholar.org/paper/The-Regulator%E2%80%99s-Review-of-the-English-Electricity-Newbery/5b58c0ba27ed022045c4e703085332d7d7fd1461 .

Newbery, D.M. (2000), *Privatization, Restructuring and Regulation of Network Utilities*, (The Walras-Pareto Lectures, 1995), MIT Press, 2000, ISBN 0-262-14068-3.

Newbery, D.M., (2012a). "Contracting for wind generation." *Economics of Energy & Environmental Policy*, 1(2), 19-36. Available at http://dx.doi.org/10.5547/2160-5890.1.2.2.

Newbery, D.M., (2012b). "Reforming Competitive Electricity Markets to Meet Environmental Targets." *Economics of Energy & Environmental Policy*, 1(1), 69-82.

Newbery, D.M., (2015b). "Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors." *Energy Policy*, 94, 401–410. Available at http://dx.doi.org/10.1016/j.enpol.2015.10.028.

Newbery, D.M., (2016a). "Towards a green energy economy? The EU Energy Union's transition to a low-carbon zero subsidy electricity system - lessons from the UK's Electricity

Market Reform." *Applied Energy*, 179, 1321–1330, at http://dx.doi.org/10.1016/j.apenergy.2016.01.046.

Newbery, D.M., (2016b). "Tales of Two Islands - Lessons for EU Energy Policy from Electricity Market Reforms in Britain and Ireland." *Energy Policy*, 105, 597–607, at http://doi.org/10.1016/j.enpol.2016.10.015.

Newbery, D.M., M. Pollitt, R. Ritz, and W. Strielkowski, (2017). "Market design for a high-renewables European electricity system", EPRG Working Paper 1711, at https://www.eprg.group.cam.ac.uk/wp-content/uploads/2017/06/1711-Text.pdf

Newbery D.M., and Grubb, M., (2015). "Security of Supply, the Role of Interconnectors and Option Values: Insights from the GB Capacity Auction." *Economics of Energy & Environmental Policy*, Vol. 4, No. 2. Available at http://dx.doi.org/10.5547/2160-5890.4.2.dnew.

Ofgem, (2010). *Project Discovery: Options for delivering secure and sustainable energy supplies*. February, at https://www.ofgem.gov.uk/ofgem-publications/40354/projectdiscoveryfebcondocfinal.pdf.

Ofgem, (2017). *The impact of the Early Capacity Market Auction announcement on wholesale electricity prices and revenues*, at https://www.ofgem.gov.uk/ofgem-publications/124340

Renewable UK, (2017). *Offshore Wind Industry Investment in the UK 2017 Report on Offshore Wind UK Content*, at http://c.ymcdn.com/sites/www.renewableuk.com/resource/resmgr/publications/Offshore_Wind_Investment_V4.pdf.

Schmalensee, R., Joskow, P.L., Ellerman, A.D., and Montero, J.P., (1998). "An Interim Evaluation of Sulfur Dioxide Emissions Trading." *Journal of Economic Perspectives*, 12(3), 53-68.

Tashpulatov,S.N., (2015). "Analysis of electricity industry liberalization in Great Britain: How did the bidding behavior of electricity producers change?". *Utilities Policy*, 36, 24-34, https://doi.org/10.1016/j.jup.2015.07.004 .

Taylor, S., (2016). *The Fall and Rise of Nuclear Power in Britain: A history*. Cambridge: UIT Press.

Data appendix: Notes on Construction of Electricity Bills

Household bills are based on annual consumption of 3,800 kWh, nominal expenditure is from Table 2.2.1 ('Average annual domestic standard electricity bills by home and non-home supplier based on consumption of 3,800kWh/year') in BEIS *Quarterly Energy Prices* (March 2017), deflated by the CPI to 2015. Industrial prices from Table 3.4.2 ('Prices of fuels purchased by non-domestic consumers in the UK'), also in BEIS *Quarterly Energy Prices* (March 2017). The data are the average for all firms, available in nominal £/kWh and multiplied by 3,800 to give the same notional bill (but industrial prices are lower for higher volumes, so this is a purely notional comparison). Industrial prices from BEIS' *Industrial Energy Price Statistics* are given in index number form from 1990. The price index series is recalibrated to yield the same nominal bill in 2015 (£400). Wholesale prices are available from the Elexon Portal by half-hour as MIDP (Market Index Data Provider prompt wholesale price). The domestic customer profile is also available for weekdays, Saturdays and Sundays for seasons from Elexon. The weighting to apply to each half-hour is based on seasonal weekdays (weekends are fairly similar) adjusted to 1 MWh over all hours for all seasons (so a higher weight on winter peak hours). The resulting weighted average wholesale price in £/MWh is multiplied by 3.8 to give the wholesale energy cost of the retail bill, the difference being transmission, distribution and the retailing margin. Wholesale prices before 2001 are derived from the electricity Pool Purchase Price and hence understate the selling price paid by suppliers. The gas cost is the variable cost of generating in a 50% efficient CCGT, including the carbon cost.