UK Electricity Market Reform and the Energy Transition:

Emerging Lessons

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He has combined research and applied roles for many years, bringing research insights into policymaking, and bringing practical experience to bear upon academic studies: before taking up his post at UCL he was part-time Senior Research Associate in Economics at Cambridge University, combined with (prior to joining Ofgem) Chief Economist at the Carbon Trust.

Professor Grubb is author of eight books and, sixty journal research articles, and numerous other publications. His most recent book, *Planetary Economics: energy, climate change and the Three Domains of Sustainable Development* (Routledge 2014), brought together insights from 25 years of research and implementation of energy and climate policies. He was also founding Editor-in-Chief of the journal *Climate Policy*, and from 2008-11 served on the UK Climate Change Committee, established under the UK Climate Change Act to advise the government on future carbon budgets and to report to Parliament on their implementation.

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Occasional economic advisor to Ofgem, former chairman of the Dutch Electricity Market Surveillance Committee, member of the Panel of Technical Experts offering quality assurance on the delivery of the UK's Electricity Market Reform (2014-16). He is currently an independent member of the Single Electricity Market Committee of the island of Ireland and a panel member of Ofgem's Network Innovation Competition**.**

Professor Newbery is author of eight books, over one hundred and thirty research articles and numerous other publications. His book, *Privatization, Restructuring and Regulation of Network Utilities*, published by MIT press provides a definitive empirical cross-country study of de-regulation, liberalization and privatization in electricity, telecoms and gas to assess how structural reforms can enhance productivity.

Both the authors are writing in their independent academic capacities, and drawing only on published materials.

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Summary

Until 1990, the UK - like many other countries - had an electricity system that was centralised, state-owned, and dominated almost entirely by coal and nuclear power generation. The privatisation of the system that year and its creation of a competitive electricity market attracted global interest, helping to set a path which many have followed.

Two decades later, however, the UK government embarked on a radical reform which some critics described as a return to central planning. The UK's Electricity Market Reform (EMR), enacted in 2013, has correspondingly been a topic of intense debate, and global interest in the motivations, components, and consequences.

This report summarises the evolution of UK electricity policy since 1990 and explains the EMR in context: its origins, rationales, characteristics, and results to date. We explain why the EMR is a consequence of fundamental and growing problems with the form of liberalisation adopted, particularly after 2000, combined with the growing imperative to maintain system security and cut CO2 emissions, whilst delivering affordable electricity prices.

The fifteen years after privatisation, coinciding with the era of low fossil fuel prices, had seen mostly falling electricity bills; from about 2004 they started to rise sharply, for multiple reasons including increasing fossil fuel prices, the need for new investment in both generation and transmission, and inefficient renewables policies.

The four instruments of the EMR have indeed combined to revolutionise the sector; they have also both drawn on, and helped to spur, a period of unprecedented technological and structural change. Competitive auctions for both firm capacity and renewable energy have seen prices far lower than predicted, with the fixed-price auctions for renewable sources estimated to save over £2bn/yr in the cost of financing the projected renewables investments, compared to the previous support system. A minimum carbon price level has brought cleaner gas to the fore, displacing coal. Electricity prices may have peaked from 2015, with energy efficiency helping to lower overall consumer bills.

New forms of generation have expanded rapidly at all scales of the system. Renewable electricity in particular has grown from under 5% of generation in 2010, to almost 25% by 2016, and is projected to reach over 30% by 2020 despite a political de-facto ban on the cheapest bulk renewable, of onshore wind energy. The environmental consequences overall have been dramatic: coal generation has shrunk from about 2/3rd of generation in 1990, to 35% in 2000, to 10% in 2016, halving CO2 emissions from power generation over the quarter century.

Neither the technological nor regulatory transitions are complete, and the results to date highlight other challenges. The Capacity mechanism has proved ill-suited to encouraging demand-side response, and in combination with the growing share of renewables, has underlined problems in transmission pricing. As the share of variable renewables grows further, the associated contracts will require reform to improve siting efficiency and avoid adverse impacts on the wholesale market. The results to date show that EMR is a step forwards, not backwards; but it is not the end of the story.

Acronyms

BEIS	Department for Business, Energy and Industrial Strategy (successor to DECC, established in 2016)
BETTA	British Electricity Trading and Transmission Arrangements (extension of NETA to include Scotland from 2005)
CfD	Contracts for Difference (a fixed-price electricity contract)
CCGT	Combined Cycle Gas Turbine
DECC	Department of Energy and Climate Change
DSR	Demand-side Response
EMR	Electricity Market Reform
IPP	Independent Power Producers
NETA	New Electricity Trading Arrangements (adopted in 2001)
ROC	Renewables Obligation Certificate
PTE	Panel of Technical Experts (independent advisory committee established under the Electricity Market Reform legislation
RECs	Regional Electricity Companies (RECs), established after privatisation
WACC	Weighted Average Cost of Capital

1. Introduction: 'Model or Warning?'

The UK was widely seen as one of the world's leaders on electricity deregulation in the early 1990s. Though the model of liberalisation 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 regulation. To many, it seems like abandoning the principles of market competition that had been seen as defining the UK approach.

The Electricity Market Reform legislation did indeed represent a radical change. Prompted by underlying concerns about a lack of investment that threatened to undermine both security and decarbonisation goals, and politically galvanised also 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 liberalisation of electricity was widely seen as a radical experiment, attracting worldwide interest. The UK's Electricity Market Reform has, similarly, sparked widespread interest, 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 electricity.

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

- Summarise briefly the evolution of the UK electricity system including the underlying institutional and political context;
- explain the basic reasons why the UK embarked on its Electricity Market Reform – the key intellectual debates and institutional proponents;
- explain the basic structure of the EMR package as finally defined in the 2013 legislation;
- present the results to date, focusing primarily on the results of contracts issued and auctions held through to mid-2017;
- draw initial lessons, addressing concerns that the EMR represents a 'return to central planning'.

Finally, we reflect on the future challenges and prospects for evolution of the UK electricity market structure.

2. UK Electricity in context

2.1 The evolution of the UK electricity supply industry – the origins

In England and Wales from 1947 when the electricity supply industry was nationalised, generation and transmission were owned by the public Central Electricity Generating Board. 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.

Figure 1 shows generation output by fuel from 1970. Until 1955 almost the entire output was generated from coal, supplied by the National Coal Board, but, under pressure from the Treasury, oil-fired power stations were built and 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 until by the end of the century it was down to 1%.

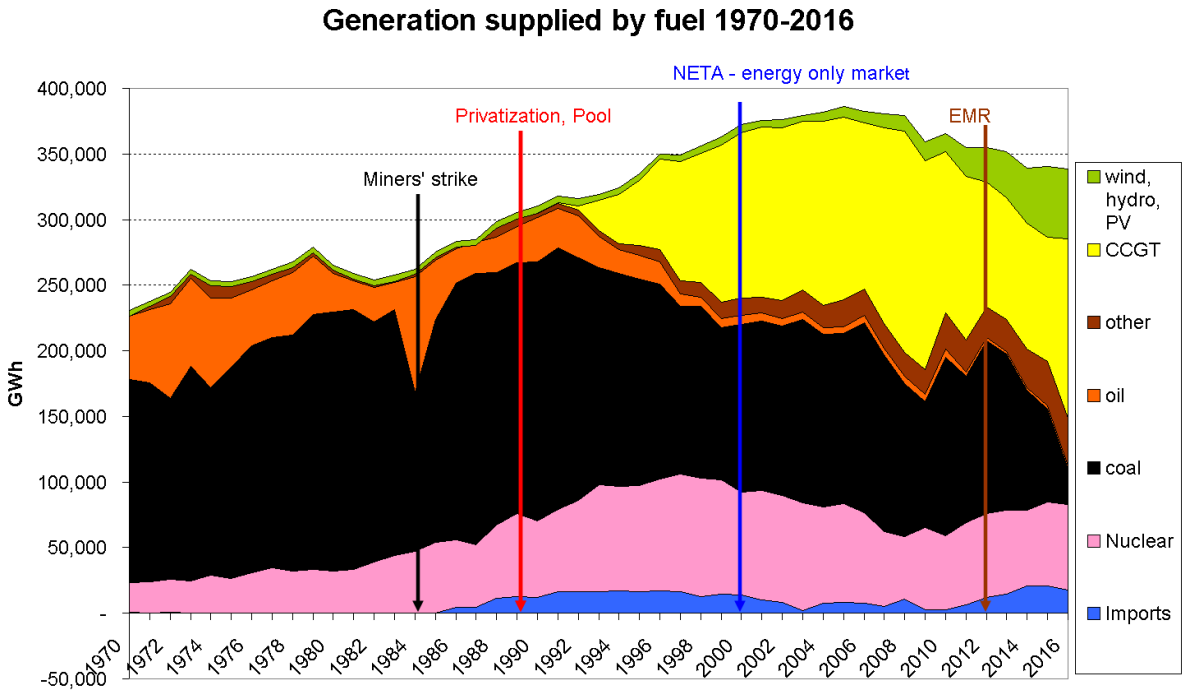


Figure 1: UK electricity generation by fuel, 1970-2016
Source: BEIS (2017)
Note: "other" is all thermal generation from other generators (i.e. not the public supply companies), non-CCGT gas and thermal renewables. Pumped storage (net negative) is not shown. See notes to BEIS (2017)

The Conservative Government under Margaret Thatcher came to power in 1979 after a "winter of discontent", strikes, stagnation and a drastic reduction in public investment following the oil shocks and a visit of the IMF urging austerity in 1976. Her manifesto pledge was to reverse economic decline, roll back the frontiers of the state, and reduce the power of organised labour. Privatizing state-owned enterprises started cautiously, but between 1979-92 some 39 companies were privatized, so that by 1992 the top 100 companies included 17 formerly state-owned companies (Newbery, 1999). The first public utility to be sold was British Telecom (in 1984) followed by British Gas, the water companies (1989) and finally the

electricity utilities through the *Electricity Act 1989* (from 1990 on, ending with the sale of the more modern nuclear plant in 1995).

By 1989, just before restructuring for privatisation, around 90% of the conventional thermal generation was from coal, and the share of oil fell rapidly from 7% to 1% in 2002 (the remainder of thermal generation is largely from by-product gases from iron, coke and chemicals). The story is quickly told: the miners' strike in 1984 was accommodated by a short-lived switch back to oil using plant built in the 1960's but displaced by cheaper coal after the oil shocks of the 1970s. At privatization in 1990 the UK was supplied by coal and nuclear power with some imports. Shortly after privatization the coal share rapidly declined as nuclear power improved its performance, and 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 (E&W), two fossil and one nuclear (initially state-owned) generation companies, with an unbundled National Grid (initially collectively owned by the regional privatized 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 (PPAs). 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. 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 (see Box 1). One of the most dramatic developments after privatisation was the 'dash for gas'; investment poured in to new gas generating plants, and as shown in Figure 1, gas generation grew from next to nothing in 1992, to almost a third of generation by 2000.

Multiple factors underpinned this. Outside the electricity market itself, North Sea gas had largely saturated domestic markets whilst production was still growing, with low and falling gas prices. A legal ban on using gas for power generation had been lifted and the new generation of Combined Cycle Gas Turbines (CCGTs) promised far greater efficiency than existing plant. Given its political history the conservative government was happy to encourage the decline of coal, whilst the breaking up of the CEGB, which had seen the world largely in terms of ever bigger coal and nuclear generation, introduced players interested in new approaches.

Box 1: Pricing and capacity payment in the Electricity Pool

The operation of the electricity pool established after privatisation was defined in terms of a single price for electricity purchased 'by the pool' from generators (Pool Purchase Price). The System Operator (owned by National Grid) received offers from all individual generating sets the day before. To meet projected demand, National Grid established a System Marginal Price (SMP) from the schedule of generation offers, dispatching the generators accordingly up to the marginal offer which defined the SMP.

To this was added a Capacity Payment, which was designed to compensate for the 'missing money' in a system based purely on short-run marginal generating costs:

$$\text{Capacity Payment} = \text{LoLP}*(\text{VoLL} - \text{SMP}), \quad (1)$$

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 give the efficient scarcity price of electricity if the SMP were the system marginal cost, but generators were free to offer any price, only constrained by the threat of anti-competitive behaviour.

SMP + Capacity Payment is the Pool Purchase Price,, which, with additional ancillary service and constraint costs made up the Pool Selling Price. The day-ahead bids received by National Grid were complex multi-part offers with a raft of additional constraints and characteristics. National Grid used the old scheduling algorithm to determine a feasible dispatch. Adjustments during the day were called off the previous day's offers and charged out to consumers in the selling price (Green and Newbery, 1993).

In the market itself, the low and falling gas prices were aided by high Pool prices, and rapidly improving and low capital cost Combined Cycle Gas Turbines (CCGTs). With energy policy left to 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.

Thus 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 centralised generation. The two fossil generators dominated the England & Wales Pool and clearly had considerable market power (Newbery, 1995), which the regulator negotiated down by encouraging them to divest 6 GW of coal plant 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 plant the generation companies were free to buy the supply businesses originally integrated with the RECs. The market evolved towards the current Big Six generators[1] plus retailers. The market power of the triopoly lead 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 represent a further step towards competition. To meet the physical need to balance supply and demand, NETA created a two-priced Balancing Mechanism. The claimed logic for the reform was that self-dispatch required generators to submit a balanced offer (i.e. output matched by contracts to purchase bys buyers) and that required them to contract all output ahead of time, 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 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 protected both ways 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 – at least - of the electricity system as an oligopoly of major power companies controlling the entire system from generation to consumption.

Without heed to these concerns, 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.[2] This created a single price zone despite serious congestion on the Scottish border, with its resulting high redispatch costs (which grew further 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

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

[2] Leading also to the strange situation that National Grid, as Transmission System Owner and Operator in England and Wales, became the System Operator of the Scottish grids that remained under the ownership of the two vertically integrated companies.

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 (admittedly high cost) month.[3]

2.4 Electricity demand and the retail market

The pattern of electricity consumption has been far more stable that the pattern of fuel use in production (figure 2): initially dominated by industry and domestic use, the former since the 1970s has declined relatively in favour of "other" (particularly services), whilst over the past decade, overall demand on the national grid has declined.

Industrial electricity demand in particular stabilised 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 GB population growing 10% over the period.[4] This reflected a combination of improved energy efficiency (driven by stronger efficiency standards on building and appliances, and various government programmes), slowed economic growth after the financial crisis, and the direct impact of rising prices, which also accelerated structural change in industry.

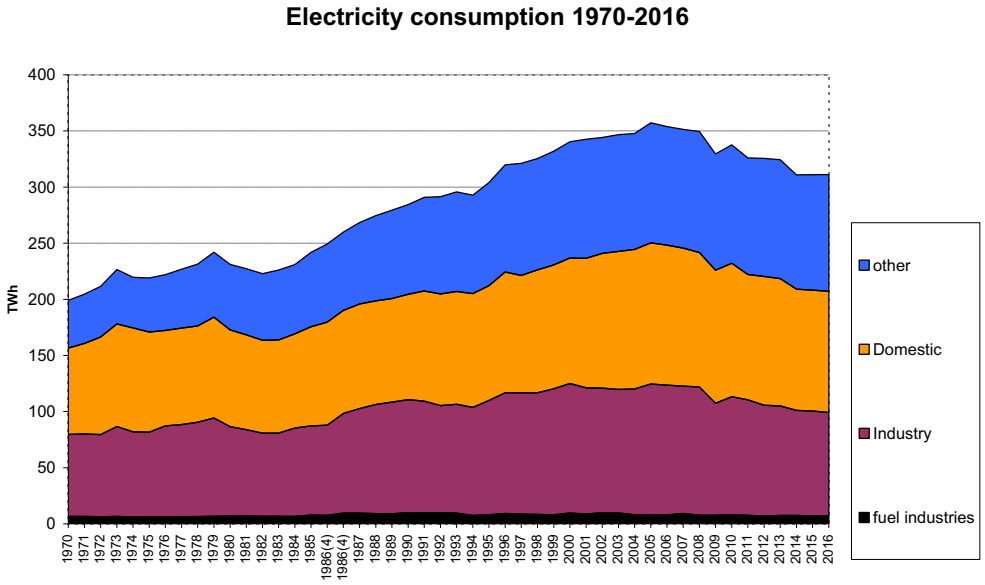


Figure 2: UK electricity consumption by end use

Source: BEIS (2017)

Note: "other" includes Public administration, transport, agricultural and commercial sectors.

[3] National Grid *Operational and System Cost Update* 2015 at www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=40206

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

In contrast, electricity prices (measured in terms of average bill paid for 3,800 kWh, to capture fixed charges) have been considerably more volatile (Figure 3). Once the big wave of gas investments in the early 1990s had been completed, there was no need for more capacity. With surplus capacity, increasing competition and falling fossil fuel prices, the price declined steadily from the mid-1990s. When fossil fuel prices started to soar from 2004, electricity prices naturally followed in the now competitive wholesale market.

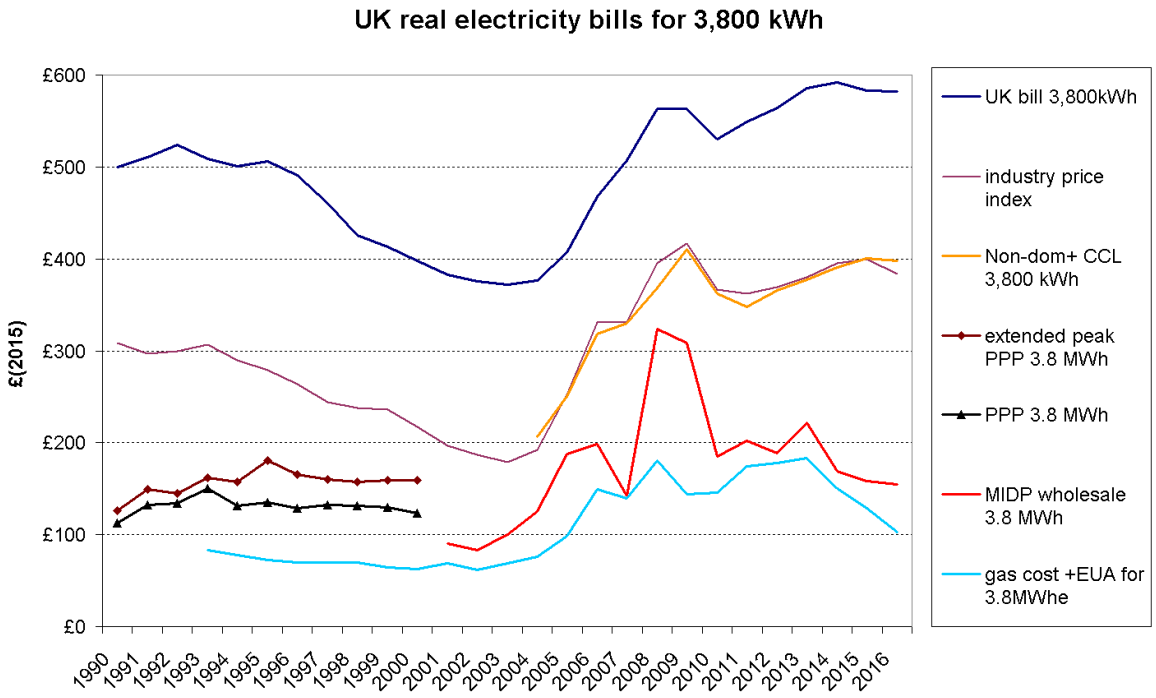


Figure 3 Real Industrial and domestic bills for standardized consumption level
Source: BEIS (2017)
*Notes: **CCL** is climate change levy, **PPP** is the Pool Purchase Price (i.e. the wholesale spot price), **MIDP** is the Market Index Data Provider prompt wholesale price after 2001, EUA is European (CO_2) emission allowance price. The figure shows in real terms -£(2015, deflated by the Consumer Price Index) the bills for 'standard' domestic customers consuming 3,800kWh,that for industrial customers but using industrial prices for 3,800 kWh, the wholesale cost of purchasing the domestic demand profile and the variable cost of generating that power (the gas cost for a 50% efficient gas turbine plus its carbon cost). See appendix for details.*

The decline in electricity demand (in 2013 Ofgem had to revise down its definition of "standard" domestic consumption to 3300kWh3,300kWh/yr per household) helped to contain electricity *bills* (the same was true for gas consumption) but of course this was confined to homes that benefited from such measures. Electricity prices, and in particular the impact on poor households and industry, became a big political issue at just about the same time that the government was embarking on EMR.

Ofgem, the energy regulator, does not control wholesale or supplier prices, but does regulate the transmission and distribution tariffs through incentive regulation, initially proposing 5-year price caps for a basket of goods that are indexed to the retail price index (RPI) and include an efficiency ('X') factor, hence RPI-X. This has evolved into RIIO – (Revenue=Incentives+ Innovation+Outputs) lasting for 8 years and starting in 2013 for the transmission network. Ofgem has oversight of the 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*, reporting initially later that year.[5] This was 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 that the wholesale market was workably competitive, they expressed concern over the retail markets, and proposed various remedies.[6] By then, however the UK was already moving on to yet another round of fundamental reform.

3. The intellectual and political evolution of UK Electricity Market Reform

The Electricity Market Reform (EMR) that took effect in 2013 was, with hindsight, a long time in intellectual gestation, and fed from multiple strands of intertwined concerns about investment, environment, and energy prices.[7]

The first was a growing concern about investment and security. Theoretically, an energy-only market would encourage generators to mark-up their offer prices during periods of scarcity, reflecting the previous capacity element in the pool price. Also theoretically, investors would predict future scarcity and anticipate higher (scarcity) prices, which would encourage them to start investments now for delivery at the time of predicted higher prices.

Several factors undermine this theoretical hope. The first is that futures markets for electricity 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 conditions (Newbery, 2015). 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,

[5] See https://www.ofgem.gov.uk/publications-and-updates/energy-supply-probe-initial-findings-report
[6] See https://www.gov.uk/cma-cases/energy-market-investigation
[7] For an overview of many debates and perspectives at the time, see various chapters in Grubb, Jamasb and Pollitt (2007).

but set against the predictable political pressures that would arise to 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.

This problem was, however, amplified in multiple ways by additional considerations. 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.

First, UK energy policy had been in turmoil for most of the post 1997 period when the Labour Party came to power, with arguments over 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 the likely future prices.

Second, in theory, the growing imperative towards environment and particularly decarbonisation was to be reflected through carbon pricing. The UK model of wholesale electricity market competition had begun to dominate discourse in Europe, and the natural complement of a market approach to electricity was the need to price the CO_2 externality. The European Commission moved deftly to exploit the mood of the times and introduce the European Emissions Trading System (ETS), designed to deliver the EU's Kyoto emission targets with an EU-wide carbon price covering about half of total emissions.

However, the EU ETS has signally failed to deliver an adequate, durable and credible carbon price signal: it was indeed driven by policymakers creating a system in the image of the US sulphur trading system,[8] and for whom the imperative seemed to be delivering a relatively short-term emissions target based on ideas of static efficiency rather than providing anything that investors could rely on for major investments. By the end of the first trading period in December 2007 the emissions allowance price had fallen to zero, and although it reached at a credible €30/tonne CO_2 in the second period in early 2008, it crashed to €15/tonne with the financial crises, oscillated around that for two years, and then sank further to well below €10/tonne, from which it has yet to recover. 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 as the EU carbon price collapsed three times within the span of 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)[9] raised the required share of renewable *energy* (not just electricity) from 12% in 2010 to 20% of *final*

[8] The US system had a long-term stable plan and allowed banking of permits to encourage investments, with considerable success (Schmalensee et al. 1998)

[9] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32009L0028:EN:NOT

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 renewables from the EU ETS, putting downward pressure on the carbon price. To these conflicting signals was added a slowly growing realisation that massive renewables entry would, if delivered, crash the wholesale market *electricity* price (an outcome predicted in falling utility share prices and realised most obviously In the German wholesale market). 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*[10] was passed and provides a legal framework for ensuring that Government meets its commitments to tackle climate change. The Act requires that emissions are reduced by at least 80% by 2050 compared to 1990 levels, and that the Government commit to a series of 5-year carbon budgets.[11] Yet, UK renewables support policy was a shambles (see box), 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.

For Britain faced two additional problems. First the *Large Combustion Plant Directive* (LCPD) and then the EU *Industrial Emissions Directive* set tighter emissions limits that would force the retirement of older coal plant unless refurbished – a prospect that for many 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. By the end of the 2000s, it was expected that some 12 GW of the older coal-fired plant (about 20% of peak demand) would close by the end of 2015, while an additional 6.3 GW of aging nuclear plant would also close by 2016.

As fossil fuel prices soared towards their peak of 2008, therefore, 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 (CCC 2008) that a market structure built purely around competition for buying and selling electrons could not deliver low carbon investment. 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 conceivably support the capital intensive but cheap-to-run investments that characterised low carbon sources, whether renewables or nuclear. Gas investments would at least be hedged by being able to pass 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

[10] https://www.legislation.gov.uk/ukpga/2008/27/contents
[11] http://www.theccc.org.uk/about-the-ccc/climate-change-act

conflict with the fundamental aim of the *Climate Change Act*, whose core rationale was to give strategic certainty for low carbon investments.

Box 2: The history of UK renewables policy before EMR

The UK government first embraced 'non-fossil' energy in 1990 when the nuclear power stations were separated from the CEGB at privatisation but before it became clear that the markets could not be persuaded to buy nuclear power. An enterprising civil servant slipped renewable energy under the banner of support for 'non-fossil energy'. Nuclear power was subsequently withdrawn from the Non-Fossil Fuel Obligation, leaving the NFFO as a mechanism to ensure premium payments for electricity generated from renewable energy.

The NFFO invited companies to tender bids in different technology categories. Such auctions run the risk of "winner's curse": projects that used the most optimistic assumptions won bids, but then had to face the reality of risking hard money on construction. A significant number of winners never proceeded to completion. This could have been resolved by rerunning auctions, but UK renewables increasingly lagged the Continent, fuelling the desire for change.

In 2002, the government switched policy to undifferentiated Renewable Obligation Certificates (ROCs). Similar to US 'Portfolio Standards', this mandated a fixed and increasing share of renewable generation. Retailers were obliged to source an increasing share of their sales from renewables, an obligation discharged either by buying ROCs or paying a buy-out price of £30/MWh (to assuage fears of excessive costs), with revenue recycled back to the renewable generators. The renewable generators were responsible for selling their output in a market and being responsible for imbalances, so developers needed to predict wholesale prices, imbalance payments and ROC prices over the future life of their investment. Given that the RO scheme was widely criticised (Newbery, 2012b and references therein) investors would furthermore expect that it would be reformed and hence was not a very durable commitment.

Finally, since all renewables competed equally, most of the support ended up going to the least risky, best-established technologies – mainly onshore wind projects and co-firing biomass in existing power stations. The fact that the UK domestic renewables manufacturing had lost out in the 1990s meant that foreign manufacturers were the main beneficiaries. The focus on onshore wind combined with lack of any visible industrial or innovation benefits weakened public support, and opposition to planning consents grew. By 2008, UK renewable capacity ranked almost bottom amongst European countries, despite the UK having some of the best resources.

Faced with overwhelming evidence of these problems, the government had announced in 2006 intent to reform the system and in 2009 introduced 'banding' – in which the less developed renewables received multiple credits to foster innovation – and complemented the price cap with a 'ski-slope' that ensured ROC values would be maintained should targets be overachieved, to give investors the price confidence they had been saying all along was needed. The UK had in effect been dragged into the messiest, most complicated, and most expensive way of delivering feed-in tariffs yet conceived.

Source: adapted from Grubb et al (2014), Chapter 9: *Pushing further, Pulling deeper: Bridging the technology valley of death*

Then Ofgem, the energy regulator, concerned over the impending threat to energy security, launched *Project Discovery* in June 2009.[12] The institution seen by many as the champion and guardian of the liberalized energy model concluded (Ofgem 2010) that "The unprecedented combination of the global financial crisis, tough environmental targets, increasing gas import dependency and the closure of ageing power stations has combined to cast reasonable doubt over whether the current energy arrangements will deliver secure and sustainable energy supplies". 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 Electricity Market Reform in December 2010 (DECC, 2010). It concurred with *Project Discovery* that the carbon price was now too low to support unsubsidized nuclear power; 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 ROC prices. It was similarly concerned that security of supply was rapidly becoming an issue while 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 3), and industry warned about the high financing costs arising from the multiple risks surrounding the sector. The UK's much-vaunted model of liberalisation 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 (EMR), through a combination of four mechanisms as illustrated in Figure 4. 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).[13]

[12] http://www.ofgem.gov.uk/markets/whlmkts/discovery/Pages/ProjectDiscovery.aspx
[13] HM Treasury, *Budget 2011*, HC 836, March 2011

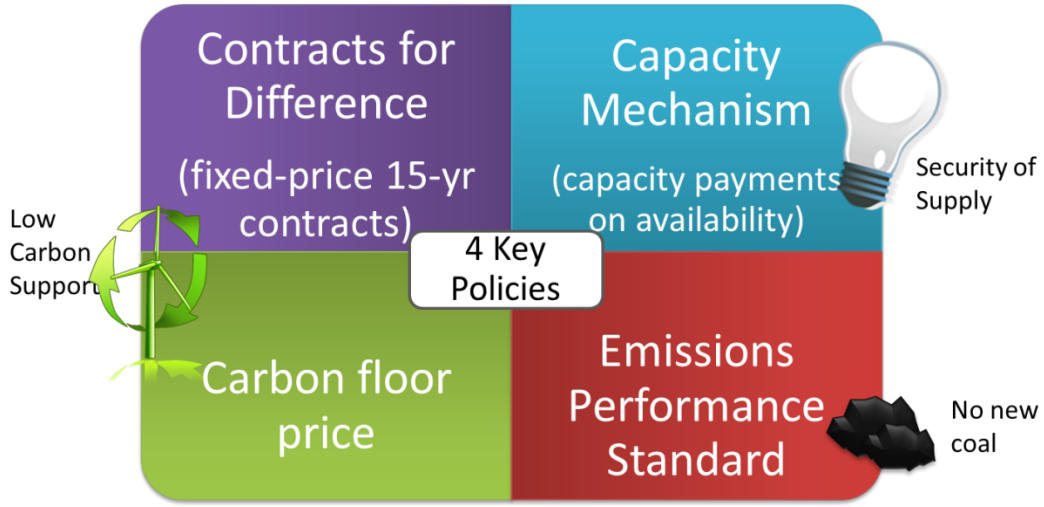


Figure 4 The four pillars of UK Electricity Market Reform
Source: Ofgem

When the EMR legislation was first being developed in 2010-11, the EU ETS price had hovered around €12/tCO2 (£10/tCO2) for about two years, and the rate was set in relation to levels two years before. This implied a top-up of just a few £/tCO2 in 2013, with initial expectation that this would rise slowly (Figure 5). 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.

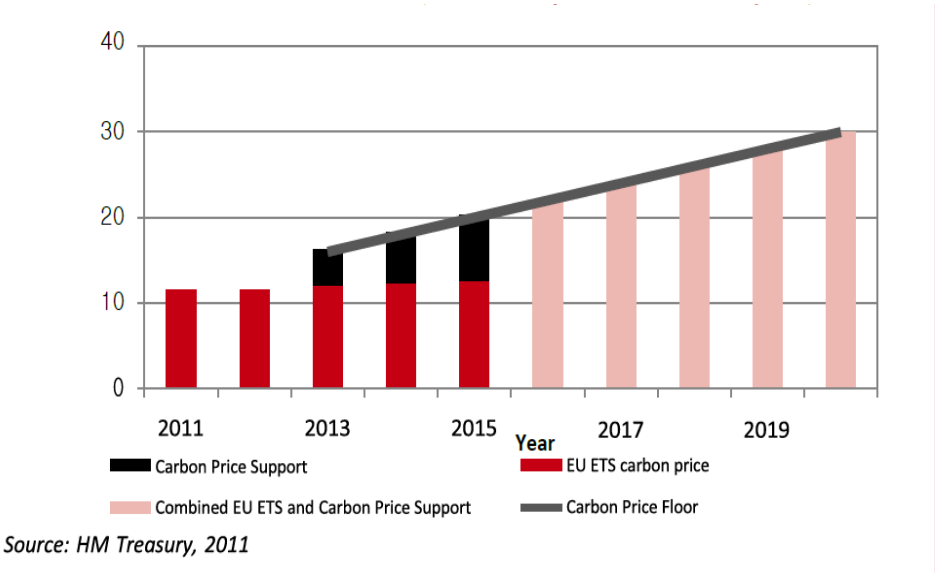


Figure 5: Carbon price support, as seen by the UK Treasury in initial development of the EMR

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 Performance Standard (EPS)** that would limit emissions from any new power station to

450gm/kWh "at base load", intended to rule out any unabated coal-fired station (with exemptions for the demonstration Carbon Capture and Storage, CCS, stations which would only require a third or less of output to be subject to carbon capture).[14] The Emissions Performance Standard 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.[15]

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, which was nearly 80% above the previous decade average).[16] This was considerably above financial analysts' estimates of the capacity of the Big Six to finance and so new sources of finance were needed. All zero-carbon generation has very high capital costs and very low variable costs, which makes 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 RO 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.

[14] The force of "base load" is somewhat unclear. If it is taken as 8760 hrs per year, then a conventional coal-fired station with emissions of 900gm/kWh could operate at a capacity factor of 50%, and if the CCS element emitted 90gm/kWh on 400MW (gross, 300 MW net) of a 1,600MW (gross) supercritical station (44% efficient), the remaining 1,200 MW might be able to operate at a capacity factor of 78%, below its normal design rating. The *White Paper* (at 1.22) therefore allows for exemptions for such demonstration plant. Other government documents state that the Performance Standard is intended to rule out any new coal without CCS, and the National Policy Statement for Fossil Fuel Electricity Generating Infrastructure (EN-2) states that any new coal-fired power plant demonstrate CCS on at least 300MW (net) of the proposed generating capacity as a condition of its consent (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266882/EPS_Policy_Brief_RA.pdf).

[15] E.On argued that a new coal plant would reduce emissions by displacing older, less effect plant; and later, that it would be build "capture ready" (ie. 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, with recognition of its incompatibility with the essential thrust of UK policy and the Climate Change Act.

[16] £4.3 billion at 2005 prices (Office of National Statistics)

The UK was reluctant to adopt the relative simplicity of the technology-specific German feed-in-tariff model except for very small scale renewables,[17] but achieved the same basic risk reduction through a '**Contract-for-Difference'** structure (indeed described in the White Paper as a 'CfD with FiT'). Government would pay the difference between the reference wholesale electricity price and an agreed 'strike price' (Figure 6).

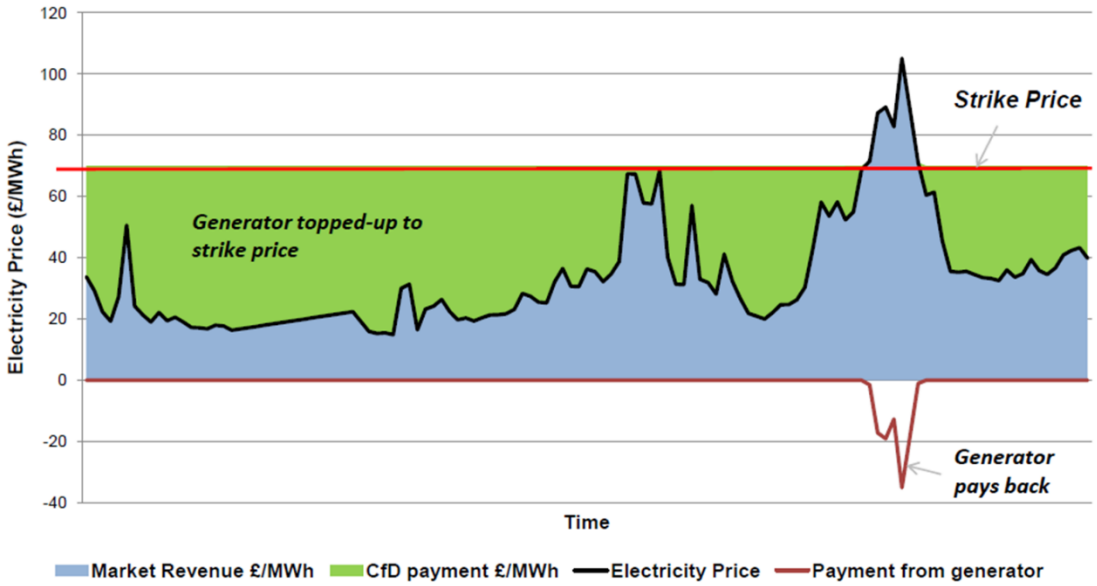


Figure 6: Structure of the Contracts-for-Difference
Source: Ofgem

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 a Panel of Technical Experts (PTE) to comment on the delivery of policies. The PTE's first report (DECC, 2014a) criticized the over-generous hurdle rate that resulted in high strike prices. This applied to 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 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 restrictions on allowed State Aid), after this initial round of 'administered' contracts, DECC moved to auctions for allocating specified volumes of

[17] The government had separately moved to adopt feed-in-tariffs for solar and wind technologies below a certain scale, on the (reasonable) grounds that the transaction costs of the CfD allocation processes would be unjustifiable, and indeed that small investors would be unable to handle the complexity.

renewables, divided into one 'pot' for developed technologies, and one for less developed technologies. As described in the next section, Newbery (2016a) estimates that the resulting clearing prices for on-shore wind lowered the WACC by 3% real. Unfortunately, the Conservative Government, in its bid for re-election in 2015 and to appeal 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 fourth and final strand of EMR was directed to ensuring security of supply, through introduction of 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 'lights going out', DECC overcame Treasury scepticism 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 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 the UK's main need was for new 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 UK's security standard - of a Loss of Load Expectation of 3hrs 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. To provide added scrutiny and address fears of conflicts of interest, an independent Panel of Technical Experts (PTE) was established, initially to advise on the detailed design, and then to scrutinise and challenge in particular National Grid's advice on capacity procurement. The process was underpinned with an effort to ensure transparency, with for example the analysis for capacity procurement of both National Grid and the PTE published each year (for example in the first year as National Grid (2014) and DECC (2014)). The Minister would then choose the amount of de-rated capacity to procure in a December auction that year for delivery in four years' time (hence the "T-4 auction"), supplemented by year-ahead auctions for additional resources (including demand-side response)

5. Results to date

This report is written (late 2017) some four years after the UK's Electricity Market Reform was enacted and the first administered contracts awarded, and almost three years after the first auctions. This section summarises the main results to date.

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 legislative adoption, the government was thus already negotiating the first round of contracts, both for renewables, and what was intended to be the first of a fleet of new nuclear power stations.

The first 'Administered contracts' for renewables, as summarised for Table 1, involved 15-year contracts for wind energy at strike prices of £95/MWh (onshore) and 140/MWh (offshore). The latter was almost 3 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 scepticism.

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).

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 3.2GW Hinkley Point C nuclear station. This finally emerged (see box) 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 cited in the course of persuading the UK to re-embrace nuclear

power, and assumed by the Climate Change Committee in recommending a new fleet of nuclear as part of its decarbonisation strategy.[18]

Box 3 The (almost) 'most expensive object on the planet?' – the Hinkley Point C nuclear contract

The UK's 1980s effort to develop a 'new nuclear family', based on French Pressurised Water Reactor technology, was one of the major victims of privatisation in 1990, with only the one already committed new plant (the Sizewell 'B' reactor) proceeding. Aside from any environment or safety concerns, nuclear power was acknowledged to be uncompetitive in a liberalised electricity market and fell into public disrepute.

The political rehabilitation of nuclear power took a full decade from Tony Blair's election in 1997, and culminated the first nuclear contract for a generation, a story detailed elsewhere (Taylor, 2016). The need to reduce CO2 emissions, combined with the promise of economic baseload power, formed the twin planks of the long 'charm offensive.' The Climate Change Committee, a body generally welcomed also by the environmental movement, argued in 2008 that the country at minimum needed to re-establish nuclear power capabilities as one of the three core technology options for deep decarbonisation (along with renewables and CCS). The new European Pressurised Water Reactor, of which two were under construction, was expected to cost around £50-60/MWh.

Public opinion gradually shifted and nuclear was firmly on the agenda of the EMR legislation. Having been burnt by construction cost overruns in the past, the structure of Contracts for Difference was seen as ideal. History had made everyone leery of direct government funding for such risky projects and the CfD structure enabled the government to side-step debates about whether this would be a subsidy (or how big) – that would depend on future wholesale electricity prices. The private sector would have to bear all the construction risks, in return for the guaranteed electricity price.

Hinkley Point C, with the EPR design, was chosen to be the first of the new family. With various industrial turmoil amongst the companies involved, the UK government brokered Chinese involvement to inject additional capital (with the promise of future nuclear construction contracts). By then, both of the European 'demonstration' projects were in trouble. During 2013, varied leaks from the negotiations between the government and the EdF-led consortium pointed to prices far higher than expected. The final contract offered landed at £92.50/MWh, index-linked and guaranteed for 35 years, with the plant expected to start generating in the mid-2020s – implying a contract worth over £70bn (over $100bn) undiscounted, running to almost 2060.

Critics soon dubbed it 'the most expensive object on the planet', a claim disputed by EdF pointing to Australia's massive liquefied gas (LNG) terminal developments. The extent to which the contract amounts to a subsidy of course depended on wholesale electricity prices projected out over coming decades; with gas and wholesale prices declining, along with declining renewable energy costs, successive Parliamentary enquiries ratcheted up the estimated implied subsidy to £30bn, and even more in most recent estimates. It remains to be seen whether and when Hinkley Point C does enter operation, and whether it, like Sizewell B a generation before, it turns out to be a solitary member of the promised 'family.'

The perception that the main proponent, Electricité de France (EdF), had run rings around the government and secured an overpriced contract (Box 3) received a knocking when –

[18] 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.

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 the plant began to generate – along with the complete implausibility of any private entity building nuclear without massive government involvement.

For the EMR itself however, better news was around the corner 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) argues 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, as indicated previously. 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 ROCs system. Using the results in Table 1, Newbery estimates that the move to competitive auctions lowered the cost of capital from about 6% to 3% - which, translated to the £75+bn expected investment required over the decade, would translate into a £2.25bn annual saving for 15 years. [19]

Levy control, the hiatus, and Second Auction

Shortly after these first renewables auction contracts were awarded, however, a General Election ushered in renewed uncertainty. Under the coalition government, the Chancellor George Osborne had placed a cap on the overall levy that could be charged on to consumers amounting to £7.6bn/yr (2011/12 prices) by 2020/21. He retained his post, and along with colleagues in the Conservative party was not amused as it became clear that this cap was going to be breached, for multiple reasons. Overly generous PV feed-in-tariffs had led to an unexpected explosive growth (almost 10GW compared to an expected 1.5GW), before tariff reductions could kick in. The post-2014 fall in gas and hence wholesale electricity prices increased the subsidy element in the CfD contracts. And the offshore wind farms, in particular, were generating substantially more output than expected, increasing of course the payouts to them (Grubb, 2015).

[19] Specifically: "The differences from varying the technology assumptions are small, suggesting that the lowering of the WACC of some 3% real per year is robust. This is material as DECC [49] estimated that the WACC for on-shore wind might fall from 8.3% under the RO scheme to 7.9% with a CfD, or by 0.4% (all real). If the implied WACC is reduced by 3.3% through auctions then the saving on generation investment of £75 billion up to 2020 [35] would be £2.5 billion per year by 2020, continuing for 15 years. The contrary view that the RO provides a better hedge than CfDs [50] might be true for portfolio utilities but the EMR was intended to encourage new sources of finance and appears successful, consistent with the experience elsewhere" (Newbery 2016a, p.1325)

There followed a major struggle and long hiaitus, 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 had led to the EMR won out, buttressed by the fact that to an important degree, the breaching of the levy cap was itself a sign of success in terms of the unexpected surge in renewables output (solar capacity and offshore wind performance). Indeed, the renewable energy target for electricity (30% by 2020), which had initially been widely viewed as impossibly ambitious, was looking increasingly plausible. Figure 7 shows the percentage *increase* in the share of generation from renewables since 2005, for the 10 EU countries whose increase was higher than the EU as a whole. Between 2010-15 the UK lagged this pack but has since accelerated.

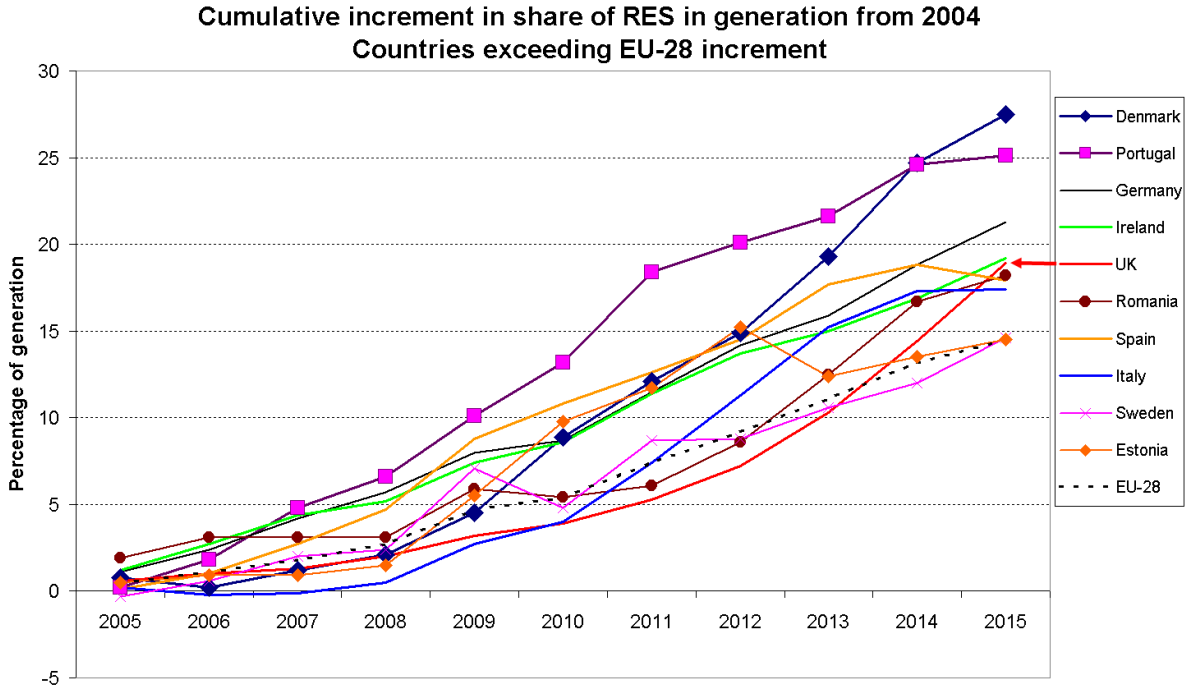


Figure 7 Growth of renewable electricity generation in EU countries since 2005
Source: Eurostat

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 intent to continue. Nevertheless, after the first CfD auction of January 2015, it was over two and half years before the next, 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.

The outcome, as one senior civil servant admitted, came as a 'complete shock – of the best kind'. As illustrated in , two major wind farms bid down to 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.[20] And, to add further political sweetening, a report estimated that the UK had regained ground in the associated industries, with almost 50% of the supply chain value expected to accrue to British business (Renewable UK, 2017).

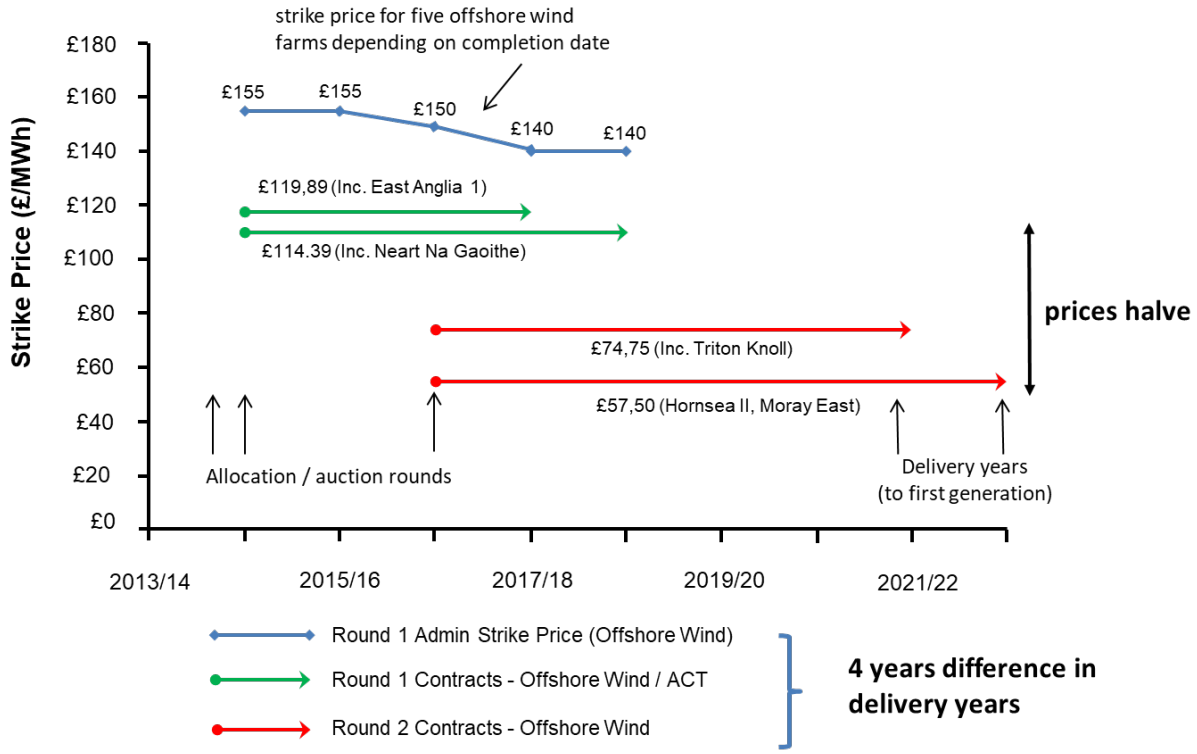


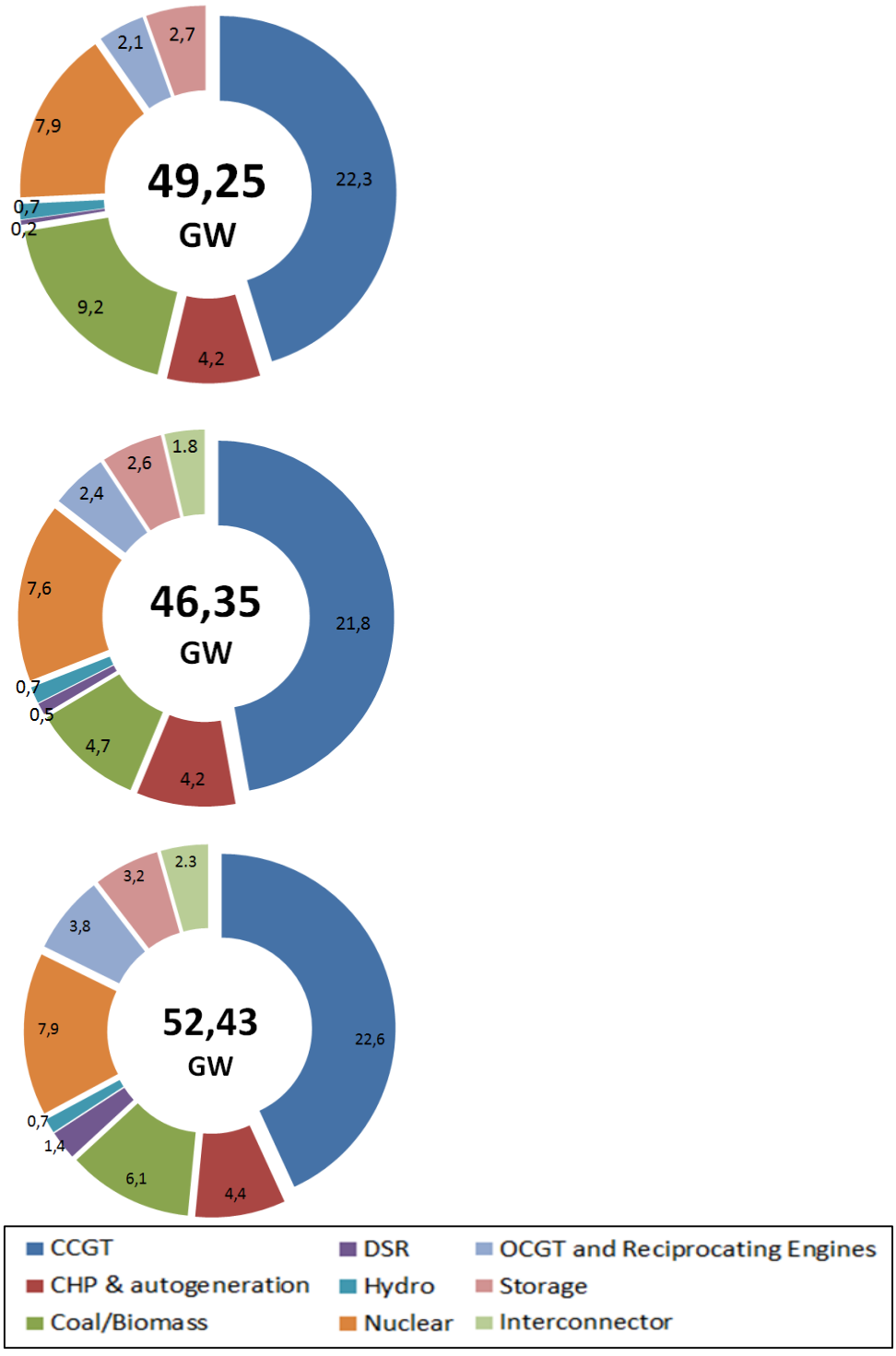
Figure 8 UK offshore wind cost reduction across allocation and auction rounds
Source: Author, adapted from graphic in KPMG (2017)

5.2 Capacity Market

The Capacity Mechanism – or Capacity Market, as it began to be called – may be considered as testament to the old saying: 'be careful what you ask for, you might get it.'

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

Results from **the first three main (4-year ahead) UK Capacity Auctions, 2014-2016**



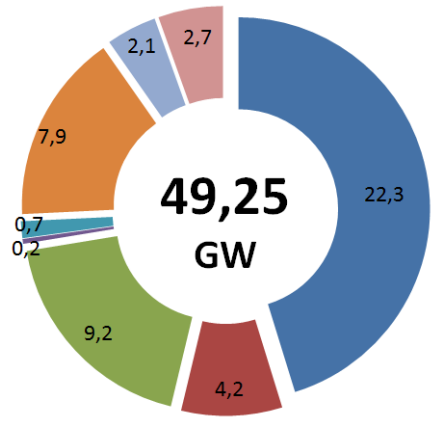
**Note: An auction price of £20/kw/yr for 50GW capacity corresponds to around £1bn/yr, under half initial estimates, around £11 per average household. The market is expected to react with lower wholesale prices, so the net impact lower, estimated by DECC at c. £2 per household.*

All plant capacity values are 'derated' according to statistically expected availability when needed

Figure 9 shows the results of the main capacity auctions, held for delivery of capacity four-years

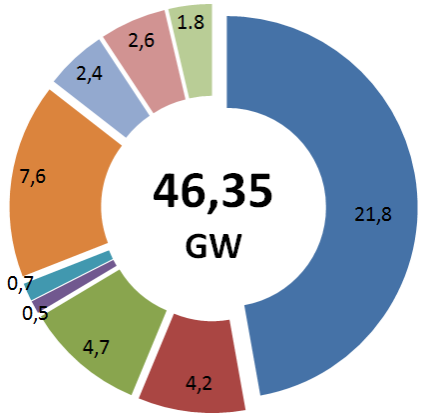
ahead (“T-4”) over the first three years` of the EMR.

Results from the first three main (4-year ahead) UK Capacity Auctions, 2014-2016



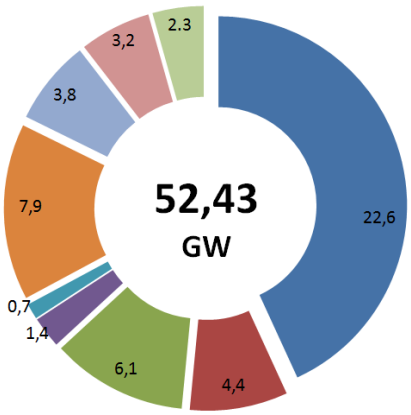
First main capacity auction (December 2014)

- Almost 50GW awarded, clearing price **19.40**/kW/year*
- Mix of 1-year, 3-year (refurbishment) and 15 year (2.5GW of new build) contracts
- Mainly existing nuclear, gas and coal generators successful
- One new CCGT (1,650MW) wins an agreement – but failed to raise final investment
- Only 174MW of demand side response
- 2.5GW of capacity reserved for the 2017 1-year ahead auction, so existing plant and demand-side response that missed out had another chance…



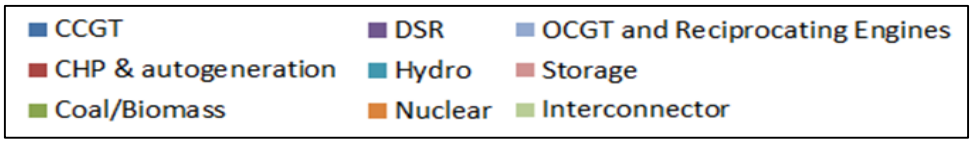
Second main capacity auction (December 2015)

- 46.35GW awarded, including 2.5 GW new capacity
- Interconnectors included
- Clearing price £**18.00**/kW/year



Third main capacity auction (December 2016)

- 52.43GW awarded, including 3.4 GW new capacity
- New diesel largely excluded
- Clearing price £**22.50**/kW/year



**Note: An auction price of £20/kw/yr for 50GW capacity corresponds to around £1bn/yr, under half initial estimates, around £11 per average household. The market is expected to react with lower wholesale prices, so the net impact lower, estimated by DECC at c. £2 per household.*

All plant capacity values are 'derated' according to statistically expected availability when needed

Figure 9: Results of main capacity (four-year ahead) auctions

The first auction, held in December 2014, was for delivery of 50GW committed capacity by winter 2018/19.[21] Based on the estimated 'net Cost of New Entry' – 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 to be £49/kW, and from this derived an estimated demand curve, and set a price cap of £75/kW (1.5 x net CoNE).

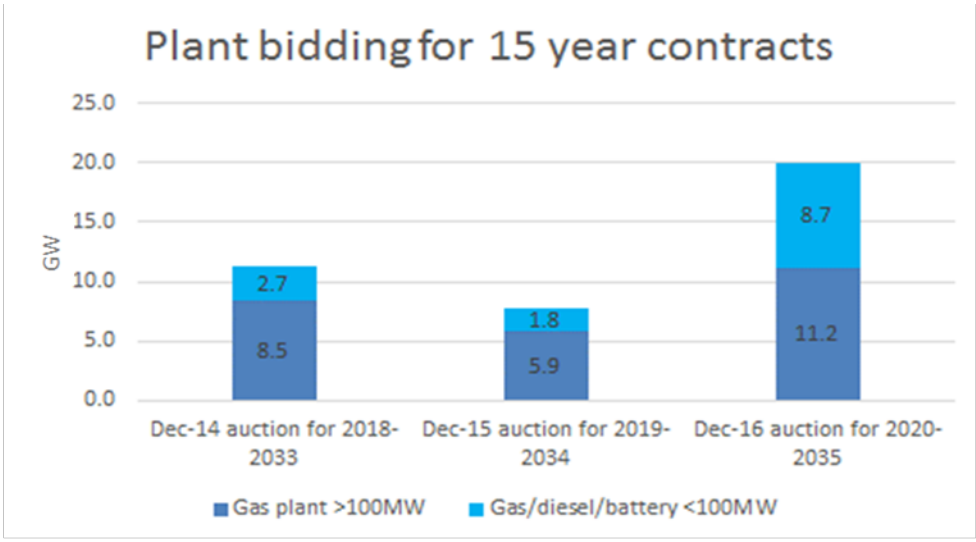
In the event, the auction cleared at £19.40/kW, and only one CCGT company (with two turbines) stayed in to be offered such a contract (after two years of struggling to raise finance, it finally withdrew in December 2016). The major beneficiaries were, of course, existing coal, gas and nuclear generators. This was as expected by those involved, but was the first dawning of reality for those who had not understood the full implications of a system-wide auction, and led to a storm of protest about the government subsidising precisely the type of plant (coal) that it claimed to be trying to get rid of.

Another source of more internal disquiet was that Interconnectors (the UK had about 4GW of connections to continental Europe and more was being investigated) were not included.[22] This became a source of strong debate within all the bodies concerned – the evidence was unambiguous that interconnectors were not only predominantly a source of imports, thus contributing to security, but that imports would be even more likely in times of system stress when UK wholesale prices would be very high (Newbery and Grubb, 2015). A decisive intervention then came from the European Commission which ruled that excluding interconnection was clearly against EU market principles of non-discrimination, and only gave state-aid approval for the first capacity auction provided interconnectors were included in subsequent rounds. Their absence in the calculation but their contribution made up for the shortfall from the withdrawn new CCGT plant.

The next year confirmed again that UK electricity demand was actually falling not rising (at least at transmission level), and the capacity procured for the second auction was lower. However, coal plant was beginning to close at pace, for reasons indicated later (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, and increasing the volume to be procured in the next 1-year-ahead auction to cover for cancelled capacity contracts.

[21] Of the total projected need for around 52.5GW, 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.

[22] More precisely, National Grid took the high end of its capacity range of 53.3 GW on the basis that imports could not be relied upon (National Grid, 2014, p10-11).



(b) Successful New Build capacity by fuel and technology type in the T-4 auctions

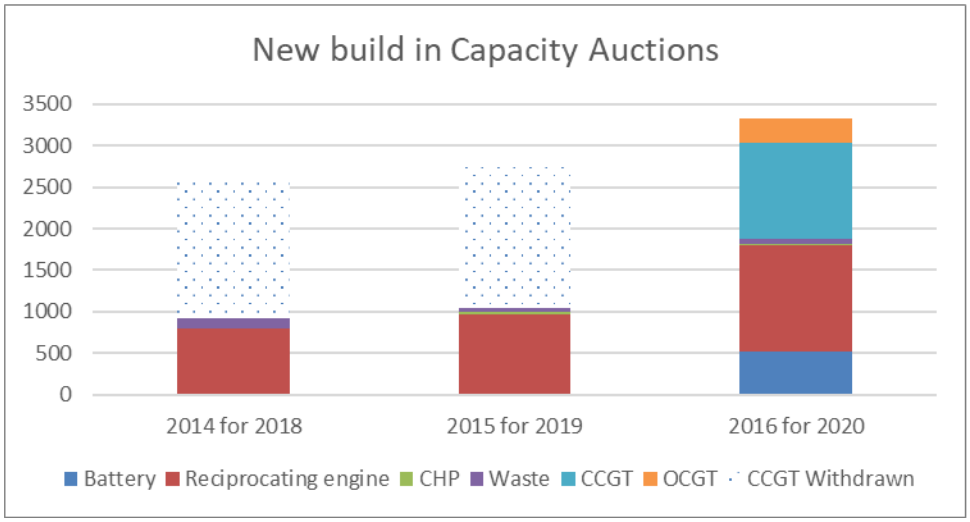


Figure 10: New capacity in the Capacity market, bids and approved, 2014-2016

Note: The upper panel (a) shows the new-build capacity bidding for 15 year contracts, divided between plants bigger or smaller than 100MW. The lower panel (b) shows the types of generation awarded contracts, excluding a 1.65GW CCGT plant from the first auction which abandoned efforts to secure funding two years later, and about 95MW of OCGT and reciprocating engine plants from the first two auctions which also did not proceed. Some of the latest new build opted to take just one-year contracts for 2020, hoping that subsequent capacity market auctions will yield higher prices.

By this time, many more smaller generators had realised the opportunity of the capacity mechanism, and along with interconnectors, the second auction saw many contracts going to small-scale generators (Figure 10b) – notably, reciprocating engines powered by gas or diesel, with an even lower clearing price of £18/kW.yr.

Diesel was clearly a carbon-intensive fuel and its image was further worsened by the VW vehicles scandal. In principle, these plants are unlikely to be used much – most of this new build is of the cheap capital,[23] high running cost plant appropriate to a role of just meeting extreme system needs, though this couldn't be guaranteed. Politically, the fact of being seen to subsidise diesel power stations, instead of the relatively clean and efficient CCGTs expected, was highly problematic.

The experience 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 and the 'latent capacity' of the system to handle stress events, to get a better balance of costs and hence reduce the inevitable institutional and political pressures to over-procure.

Moreover, a major anomaly soon became apparent, arising from the fact that generation connected at distribution level (i.e. not feeding directly into the main transmission network) avoided both generation and load transmission charges. In the previous era of relatively low transmission charges and a small volume of such 'embedded generation' this had been seen as both rational, and positive as an encouragement to new, localised generation. As transmission charges grew, as the volumes grew, and with the Capacity Mechanism paying centrally for sources intended to be used nationally in event of need, wherever connected, it rapidly came to be seen as a distortion that accounted for the dominance of small-scale sources at unrealistically low prices (see Box). The concerns reached crescendo when a staggering 8.7GW of 'embedded generation' registered for the 3rd Capacity Auction (Figure 10a).

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. 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 hasn't). And the incumbent industry cried foul (with reason) at the competition from decentralised generation which was effectively subsidised due to the exemption from the now very high residual transmission charges.

[23] Reciprocating engines are typically more costly per kW than open cycle gas turbines

Box 4 Transmission charging and 'embedded benefits' in the Capacity Mechanism

UK Transmission charges are levied on plants connected to the transmission system, and distribution companies pay a Load tariff for taking power from the grid, that they pass on to their customers. Both generation and load tariffs have an efficiency element designed to guide location decisions, and a residual element to make up the initially small shortfall and provide the regulated total transmission revenue.[1] Generators connected to the distribution network therefore reduce the Load taken from the grid, and so apparently reduce the charge to the distribution networks, who pass this reduction on as an "embedded benefit". When the capacity of distributed generation was small, unsubsidised, and consisting mostly of industrial backup and co-generation of heat and power, and while the residual element in the tariff was small, this seemed reasonable. Decentralised generation was also very much in vogue, being associated in particular with household or farm level self-generation.

However, as the residual element of transmission charges rose rapidly (from about £10/kW.yr in 2006 to about £50/kW.yr in 2016 and projected to rise to £80/kW.yr in 2020)[1] it became clear that the "embedded benefits" were largely avoided contributions to the public good nature of the networks, not properly avoided marginal costs. In some cases the embedded generation, notably PV in the south-west of English grew so rapidly it exceeded the local export capacity of the grid and had to be curtailed. As the whole point of capacity procured under the Capacity Mechanism was to be able to supply national demand when needed such curtailment rendered such embedded capacity problematic.[1] Analysis soon showed that the exemption from transmission charges could represent a major distortion, equivalent to anything up to £50/kW.yr of capacity. It turned out there was a strong commercial (if not economic) reason why the Capacity Mechanism was seeing so much decentralised generation – and at such low prices.

Concerns expressed about embedded benefits were already clear in December 2015 and officially acknowledged in June 2016 (DECC, 2016, §33-34), Ofgem finally implemented changes to the charging regime in June 2017, phasing in over the subsequent three years requirements for distribution-connected generation to pay transmission charges. The outcome of a legal challenge, and the impact on Capacity Market volumes and prices, remains (Dec 2017) to be seen.

The government moved to effectively bar diesel from the third auction using environmental regulation, and the price in that (Dec 2016 auction) rose somewhat, bringing another surprise with the scale of storage coming forth. Embedded generation still dominated the winning bids, but despite higher procurement volumes, cleared at a price again much too

low to support new CCGTs, which many still regarded as needed for providing bulk power through the 2020s and beyond. Despite concerns expressed about embedded benefits (DECC, 2016, §33-34) in June, 2016 (and the evidence of a problem already clear in December 2015), it took Ofgem until June 2017 to remove this embedded benefit for distribution-connected generation with capacity agreements,[24] with consequences yet to be seen, but presumably likely to raise prices further.

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 Minister and National Grid are to over-procure capacity - no-one wants to be held responsible if the "lights go out", as the tabloid newspapers 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 paying for capacity (particularly with overprocurement). If generators do not pass the capacity payments through in reduced wholesale prices, they effectively gain windfall profits. And if they do, the lower wholesale price drives up the Capacity payments required to support new investment[25] – and, moreover, the net cost of the other big 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.

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.

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 operation of 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. At the time of its introduction, in April 2013, the resulting price floor was still too low to have much impact, given the high gas prices which maintained coal as the economic choice for baseload generation. But two things soon changed.

[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

[25] The evidence so far is that capacity payments are passed on in lower wholesale prices – see the interesting econometric study undertaken for Ofgem at https://www.ofgem.gov.uk/system/files/docs/2017/10/final_version_-_technical_appendix.pdf

First, the further collapse of EU ETS price alongside the rising floor increased the gap between UK and EU carbon prices dramatically: the top-up written in with the final EMR legislation rose from £4.94/tCO2 in the year of adoption (2013) to £18.08 in 2015-16, with 'indicative' projections then rising above £20/tCO2. UK industry, whilst supporting the floor in principle, became alarmed at the scale of the differential. In the subsequent (2014) budget, the Chancellor bowed to the pressure and froze the maximum level of 'carbon price support' at an £18 add-on to the EU ETS price.[26] Given the 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 economic to start base-loading gas instead of coal. Figure 11 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 11), prompting a raft of coal plant closures.

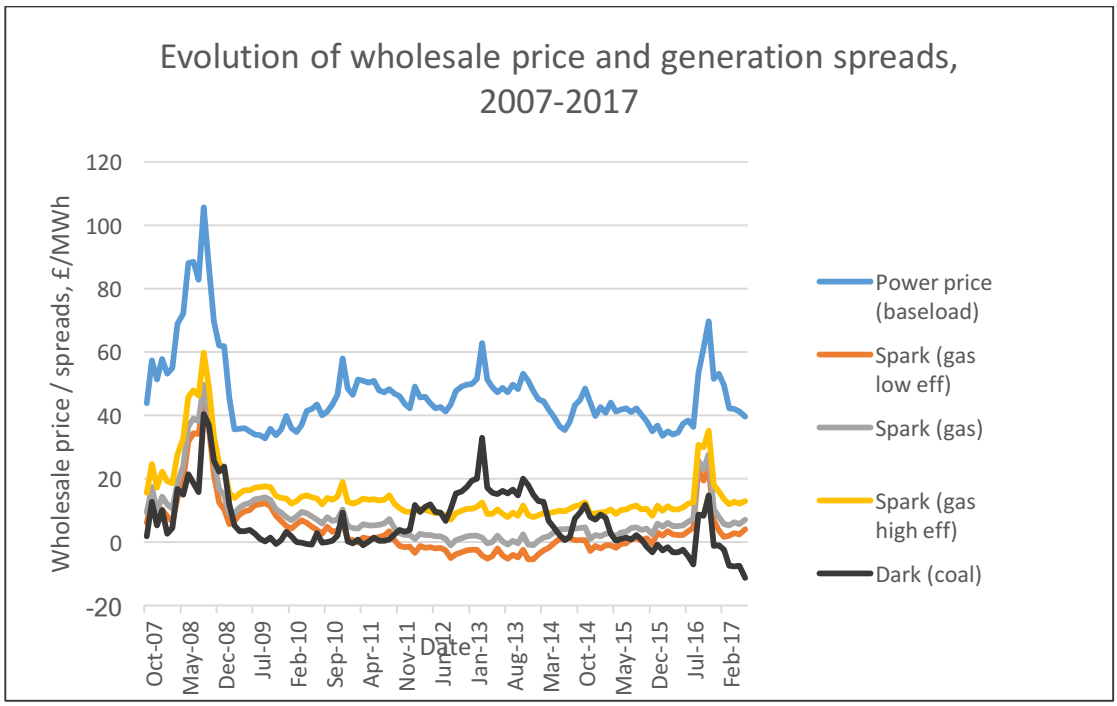


Figure 11 GB wholesale electricity price and the cost of generation, 2007-17 at 2011/12 prices

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

Note: 'Spark spread' is the utility term for the difference between the operating cost of a gas plant and the wholesale electricity price. 'Dark spread' is the corresponding term for coal. . Costs include the GB carbon price.

[26] For an excellent concise briefing see http://researchbriefings.files.parliament.uk/documents/SN05927/SN05927.pdf

As illustrated in Figure 12 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 maximises the impact of the carbon price on electricity prices. 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 industry, along with the 'climate-sceptic' wing of the conservative party, to cancel the floor price entirely on grounds of industrial competitiveness. However, strong counter- lobbying – including the gas industry alongside larger swathes of UK business pleading for stability in the policy environment – merged with the evident self-interest of the UK Treasury to maintain the auction revenues.

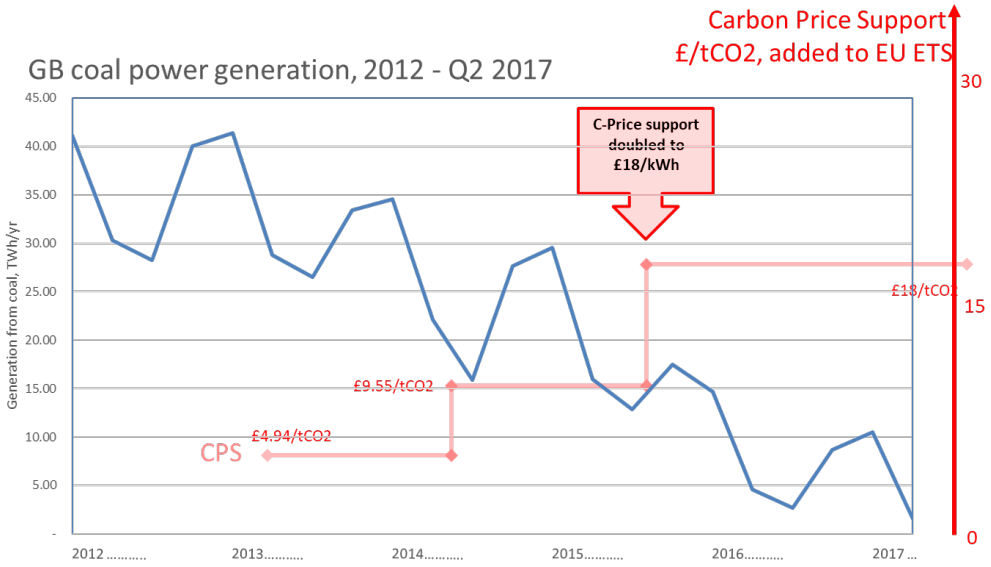


Figure 12 Carbon Price Support and impact on coal generation, 2012-2017 (Q2)

As the combination of fuel and carbon prices increasingly made gas plants cheaper than coal to run, this 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

thus 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."[27]

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 similarly procured by a bilateral contract with the Government, 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 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 liberalised 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.[28] 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 which as 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 recognising there were big gaps that had to be filled if the national objectives were to be met.

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[27] Nigel Lawson, quoted at https://publications.parliament.uk/pa/ld201617/ldselect/ldeconaf/113/11305.htm

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

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 decarbonise the power system, well before 2050, without it.

It is also worth remembering that the massive entry of new Combined Cycle Gas Turbines in the 1990s by Independent Power Producers 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 (partly as a way of reducing their reliance on the duopoly generating companies). 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 multi-lateral contract that was intended to be hard to change in order to offer greater credibility to the basis of 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 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 has already been solved by the time the reforms took place. The problems of the 'New Electricity Trading Arrangements' were exacerbated by the expansion to the 'British Energy Transmission and Trading Arrangements', 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 support scheme, and the alphabet soup of interventions to enhance energy efficiency, stimulate new technologies, and reduce CO2 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, 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. Conclusions: the collapse of coal, lessons of contracting and future challenges

The impact of more than 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. Figure 13 shows in finer grain the impact over the past two decades. With the dash-for-gas, the UK during the 1990s 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.

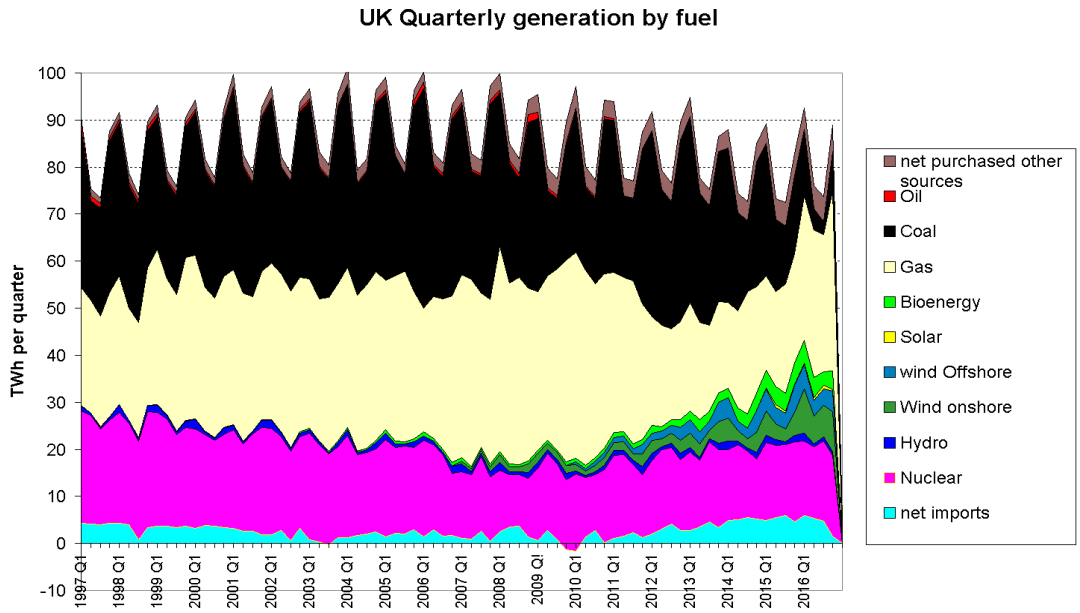

Figure 13 UK quarterly electricity generation by fuel type, 1997-2017
Source: *Energy Trends* various years[29]

[29] At https://www.gov.uk/government/statistics/electricity-section-5-energy-trends

Over the full period since privatisation, coal fell from 2/3rd of generation in 1990, to 35% in 2000, to 10% in 2016, halving CO2 emissions from power generation over the quarter century.[30] Over the next few years, coal will be increasingly confined to meeting winter needs.

But renewables – including conversation 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 contracts for the large. Electricity demand began to fall for the reasons indicated in section 1, and by 2015 the carbon price at last began to bite, driving coal to the margin of what remained. In 2015 the UK, an 'island of coal in a sea of oil and gas', saw its first hours without coal fired power generation for over a century, and in 2016 that become the first full day.

Over the full period since privatisation, coal fell from two-thirds of generation in 1990, to 35% in 2000, to 10% in 2016, halving CO_2 emissions from power generation over the quarter century.[31] Over the next few years, coal will be increasingly confined to meeting winter needs. The Government recently consulted on the future of coal and is minded to phase out coal-fired generation entirely by 2025[32] – 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 carbon capture and storage (CCS) appears to be waning, as is hostility to on-shore wind (which, on good Conservative principles, should be up to local authorities to accept or deny).

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 now beloved by the EU is demonstrably unsuited to cost-effective new investment, while capacity auctions clearly can work - if the remaining regulated prices are correctly set. Transmission pricing policy is also slowly adapting to the need to give better signals for the decentralised world of smaller generating units that can connect rapidly, but not necessarily in the right place.

At the heart of all these is the need for, and gradual acceptance of, credible stable policies that encourage development and deployment and creates learning-by-doing, with, in some cases, impressive cost reductions. Yet the regulatory journey 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

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

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

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

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 added value will thus increasingly be offset against rising system balancing and management costs.

Similarly, the problems of the Capacity Mechanism are only partially resolved and some may be unfixable, implying more focus on other market developments for distributed energy supply and demand resources that could deliver multiple benefits. Along with the small renewables feed-in-tariffs, 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.

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 there remains a considerable journey ahead.

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Data appendix: Notes on construction of electricity bills

Household bills are based on 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 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 (see box 1), and hence understates the selling price paid by suppliers.