How do we get to an electricity market with government making as few decisions as possible by 2025?

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Executive summary

The Secretary of State for Energy and Climate Change has set a target to deliver a competitive electricity market, with minimal government intervention by 2025. DECC would also like to have enough freedom within the market to drive innovation in energy and energy services, and position the UK for the significant changes that might occur between now and 2050 in our electricity markets, including how to reduce carbon emissions most cost effectively. The claim is that *current electricity market is too government directed and that no form of generation can be built without a government-backed contract. DECC would like to get away from that and allow the market to decide what gets built.*

This paper argues that the criterion should not be to minimize intervention but to deliver secure, sustainable electricity at least cost, which will almost certainly require long-term contracts for a growing fraction of new generation. The first part of the paper lays out the principles needed to address the questions, the distinction between those aspects of the industry that necessarily require regulation (wires, safety, and some environmental standards) and those that might be left to the market, pointing out how to address the problem of missing futures market in what is inevitably a highly politicized industry. It then places the British electricity industry in its historical context since privatization, to draw lessons from earlier market designs and the experience of the EMR, particularly the impact of auctions on the procurement cost.

DECC has posed the following bulleted questions and summary answers are given after the questions. The paper amplifies the answers with relevant evidence from p 12 on.

- How would technologies with different characteristics (intermittent, higher carbon, storage) be able to compete on a level playing field?

The key problem is to ensure that all services supplied by generators (capacity, flexibility, ancillary services, etc.) are properly priced, and that investors can make confident forecasts of their value when investing. Where future prices are robustly predictable, they do not need to be included in contracts. Otherwise a package auction for contracts in which generators offer packages of services (for 10+ years for new entrants, 1 year for existing generators) can alleviate the missing futures market problem. Where

[1] The author is responding to a personal invitation by the Chief Economist of DECC. He is a member of the Panel of Technical Experts advising DECC on the delivery of the EMR, but writes this in his academic capacity alone, using only publicly available documents and data. DECC is not responsible for any of the views expressed here, nor should they be taken as reflecting the views of other members of EPRG, although I am indebted to their comments on an earlier draft.

there are currently un- or under-priced externalities, these should be quantified, announced and included as shadow penalties in procurement. The evidence of recent EMR auctions is that they were technology neutral and highly cost-effective. If they failed to deliver the "right" outcome that was largely due to an absence of corrective shadow penalties and inefficient regulated tariffs, particularly transmission charges.

- What are steps needed to get from the current system to your desired power market?

The EMR capacity auction was proposed as an enduring solution to the "missing money" problem, and tweaking its design to meet criticisms should not present insuperable difficulties. The main problem is the perverse impact of the LCF. As electricity becomes more affordable, so the Government is less willing to use that opportunity to make investments that will stand in good stead for later carbon targets.

- How would your proposed market arrangements cope with the potential need for new nuclear power stations?

The current approach of forcing the private sector to bear the enormous construction risk for a project that costs more than the market value of EdF is doomed to either fail or be unnecessarily costly to future consumers. No nuclear power plant has ever been built except with either strong state support or the ability to pass all construction risks on to current consumers via cost-of-service regulation (and even that had a high failure rate). A better approach is a Government procurement construction contract followed by an auction for the operation and maintenance at commissioning.

- Would you be able to use or improve current instruments (CFD, ETS, capacity market) or would you need replacements?

There are possible improvements that can be made to CfDs and capacity agreements, but the major improvement that EMR delivered was to demonstrate the power of procurement auctions. The ETS is a failed instrument and will need reform, failing which the carbon price floor is needed to deliver efficient short-run dispatch. It is inadequate for long-term credibility, which will need contracts. There is little conceptual difficulty in evolving the present structure with suitable modifications, although the transmission charging regime needs reform. Financing nuclear power needs reform.

- Does any market-based, low carbon system rely on a steadily rising carbon price?

Theoretically the answer is that the carbon price should rise at the rate of interest, which is conveniently delivered through a banking scheme. In practice, investors prefer front-end loaded support, which argues for a constant nominal strike price that converges on the expected future market price. The practical case for an escalating carbon price is that it is politically expedient to introduce taxes gradually, as with past road excise taxes, although this has to be balanced against the mismatch with carbon pricing in neighbouring jurisdictions (not least, Northern Ireland).

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1. The Brief

The Secretary of State for Energy and Climate Change, Amber Rudd, has set a target for the present government to deliver a competitive electricity market, with minimal government intervention by 2025.

The energy market is complex, and electricity is a product unlike any others. There are many ways the government could reduce its role in the electricity market, but DECC and the Minister are interested in how to do this and at the same time achieve DECC's stated primary objective of security of supply, emotively termed keeping the "lights on". DECC would also like to have enough freedom within the market to drive innovation in energy and energy services, and position the UK for the significant changes that might occur between now and 2050 in our electricity markets, including how to reduce carbon emissions most cost effectively.

Current electricity market is too government directed. The current perception is that no form of generation can get built unless it is with a government-backed contract. DECC would like to get away from that and allow the market to decide what gets built. In addition DECC has posed a number of sub questions:

- How would technologies with different characteristics (intermittent, higher carbon, storage) be able to compete on a level playing field?
- What are the steps needed to get from the current system to your desired power market?
- How would your proposed market arrangements cope with the potential need for new nuclear power stations?
- Would you be able to use or improve current instruments (CFD, ETS, capacity market) or would you need replacements?
- Does any market-based, low carbon system rely on a steadily rising carbon price?

1.1 Comment

The request contains a challengeable statement: "*Current electricity market is too government directed. The current perception is that no form of generation can get built unless it is with a government-backed contract. DECC would like to get away from that and allow the market to decide what gets built.*" The original statement of the (admittedly previous) Government's objective was to deliver secure, affordable and sustainable energy. This trilemma can be interpreted as delivering security of supply while ensuring cost effective delivery of the 2020 renewables obligation and the climate change budgets leading to the 2050 climate change target, at least cost. This new requirement seems to replace least cost or efficiency with “allowing the market to decide” – an objective that raises obvious questions and would require considerable qualifications before it can be accepted.

Competitive markets may be one way to deliver cost reductions, but the natural monopoly parts of the industry (the wires and pipes) cannot plausibly be left to the unregulated free market. In addition, there are major market and policy failures that make the unsupported and very short-term markets for the potentially competitive elements of generation and supply unlikely to deliver the underlying trilemma objectives. The first capacity auction demonstrated by the wide range of technologies accepted that it was technology neutral, but at least some in the Government who were unhappy that their preferred technology choices were not as successful as others of which they disapproved. Auctions for renewables also demonstrated that on-shore wind was strongly favoured but again that ran up against Government opposition to more on-shore wind, and shortly after that auction, all subsidies for on-shore wind were withdrawn.

Current concerns about the need for contractual assurance in considerable part derives from a lack of confidence that without contractual assurance, the Government will whimsically change the rules of engagement, undermine previously commercially viable investment choices, and change the market design without adequate consultation, impact assessments or justification. The recent breach of a manifesto commitment to support CCS is just one of many incidents that have made investors wary of relying on promises unbacked by contractual assurance, given that the “free” market and policy promises have been subject to so many reversals of direction or failure in delivery.

2. Background

The original goal of the Conservative Government that privatized the electricity supply industry, ESI, in 1989 was to replace state-owned enterprises by unbundled utilities, in which the networks were regulated but the potentially competitive activities of generation and supply (retailing) were separated out, liberalized, and subject to *ex post* oversight by the competition authorities, in the expectation that once competition had become established, market signals, not ministerial guidance, would dictate investment and output decisions. Generation investment responded rapidly with the massive entry of gas-fired generation threatening the economics of the old coal stations buying coal on high price vesting contracts, which, as they expired, lead to a replacement of domestic coal by gas and imported coal – see figure 1 (which covers a much longer period and also shows the recent resurgence of coal as nuclear declines, gas prices rise and coal prices crash). In the first decade after privatization, the market signaled the cheapest option (gas), and the Government immediately responded to the threat to state-owned coal mines with a public inquiry and a further set of transitional coal contracts.

Electricity supplied by major UK generators by fuel, 1990-2014

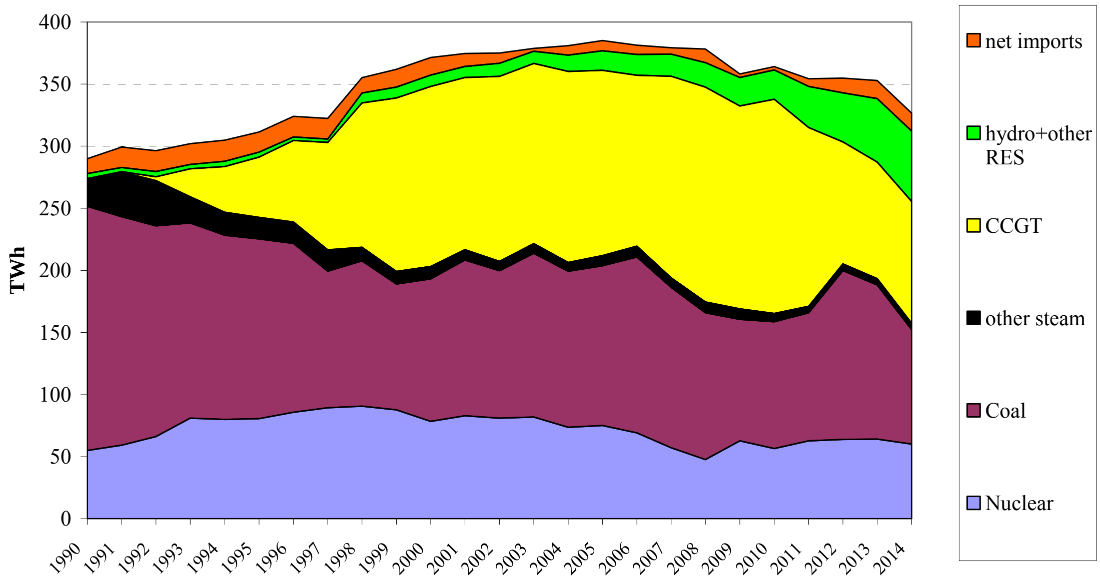

Figure 1 The dash for gas, the decline of coal, and the delivery of a competitive market
Source: DUKES, various years

If investment was guided by the market, there was less confidence that the wholesale market was competitive. The transition to workable competition took a decade. The ESI was privatized as an effective price-setting duopoly, only restrained from exercising unreasonable market power by the threat of a reference to the Monopolies and Mergers Commission. Figure 2 shows the initial rapid rise in the price-cost margin, the period of price control, the subsequent agreed divestment to create a triopoly, and the dash to sell off old generation sets at high prices (see fig 4 below) before entry and competition crashed the margin (which it did before NETA go-live in 2001). By then the wholesale market was workably competitive, and has remained so since then.

Entry by new gas-fired "independent" power producers was facilitated by long-term power purchase agreements (PPAs) with the retailing companies that originally were separated from generation (but later allowed to merge to create what became the vertically integrated Big Six). These PPAs removed revenue risk, and were combined with long-term gas purchase contracts and maintenance contracts and warranties that effectively derisked investments and allowed cheap financing. The resulting "dash for gas" combined with free imports destroyed the UK deep mined coal industry.

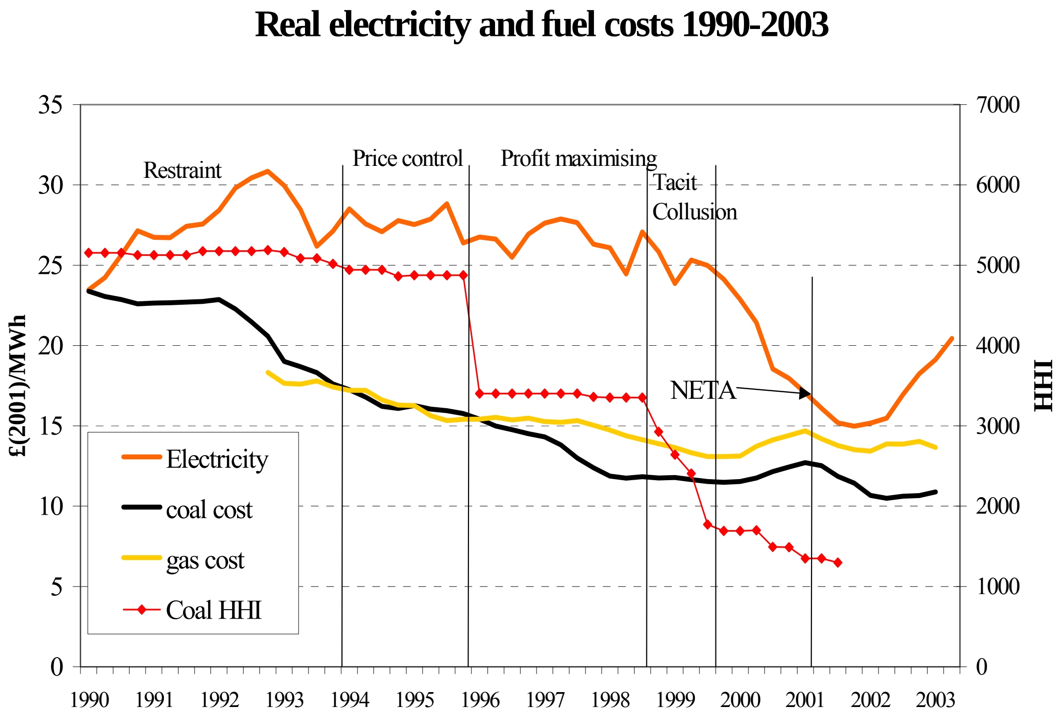

Figure 2 Evolution of wholesale prices in the pool and at the start of NETA

The wholesale market was an intelligently designed mandatory electricity pool, delivering a single price in each half-hour (with constraint payments for out-of-merit gensets) and hence great liquidity on which contracts-for-difference (CfDs) could be struck and on which PPAs could be designed. Its major flaws were the lack of competition (gradually addressed as noted above and shown by the HHI concentration index in figure 2 and the divestment in figure 4 below) and a cumbersome trading and settlement agreement that was (deliberately) hard to modify, creating contractual assurance but inflexibility. The response was to abolish the Pool, just at the time when its major competitive failings had been addressed, and create an energy-only market (first NETA, then BETTA). Unsurprisingly (at least for those half-awake), as plant retired and margins began to tighten, this market redesign was deemed unlikely to support adequate new investment when needed, as diagnosed by the discussions preceding Electricity Market Reform (EMR). Meanwhile, the abolition of the Pool put at risk these early PPAs which were written on the back of the Pool price, and whose disappearance rendered the contracts legally questionable. Investments of a long-term nature predicated on the continuance of a particular market design for such a politically contentious activity as energy and security of supply was demonstrated to be fraught with political and regulatory risk, as well as the commercially understood, but still risky, fuel price volatility and technical change.

Regulation of the grid and distribution networks was intended to mimic the effect of a competitive market by setting price caps and allowing companies to retain excess profits until the next regulatory review, which could be thought of as simulating the entry of new competitors setting a lower price for the industry. By most measures regulation has been successful in delivering high levels of investment, improved reliability and quality of service and in driving down costs.

Innovation is always problematic in a market environment. In some industries, ICT and pharma, patent or copy-right establish temporary monopolies whose distortions are compensated by the returns that motivate and reward R&D. In other sectors state monopoly can deliver the funding and capture the benefits, but the evidence of liberalizing the ESI has been a collapse in R&D.

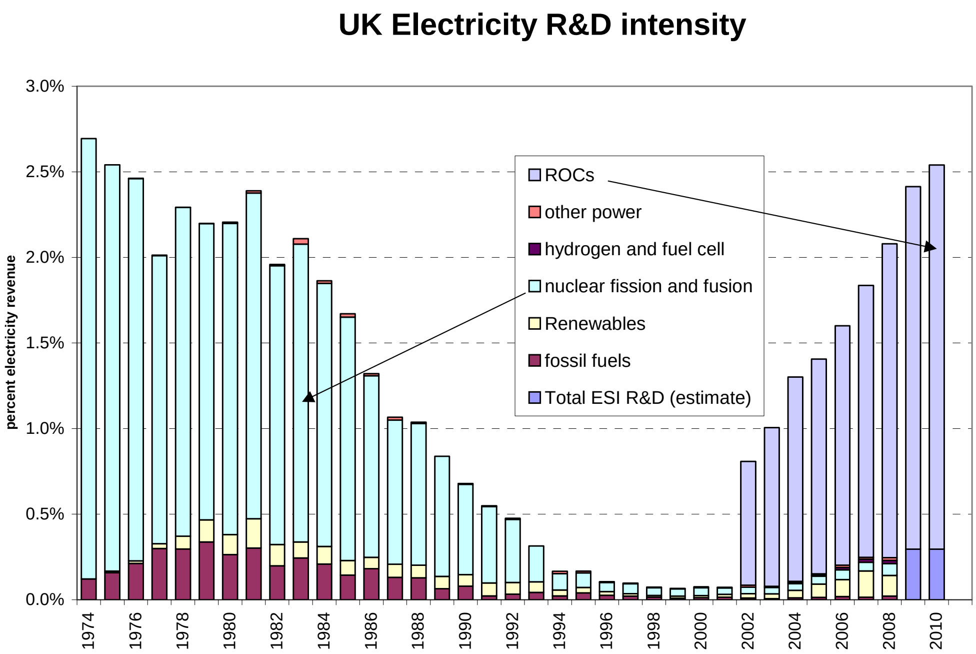

Figure 3 The collapse of electricity R&D with liberalization

Figure 3 shows that the move to liberalization under the Thatcher government coincided with (and arguably caused) the collapse of ESI R&D. This was redressed by targeted support for renewables, demonstrating that deployment, if not R&D, can be supported by subsidies to the technology to be deployed, and that can induce R&D, as has been demonstrated by the dramatic fall in solar PV costs.

3. Market and policy failures

The claim that markets will deliver efficient solutions rests on a number of assumptions which need to be carefully examined. The proposition requires that the markets are competitive, complete, all relevant information is available to all relevant parties, and there are no externalities and public goods. Natural monopolies clearly fail to meet the first condition and may be dealt with by incentive regulation, as noted above. Externalities can be addressed to some extent by corrective taxes and subsidies, and the ETS attempts, largely unsuccessfully, to use market mechanisms for CO_2. The UK (more correctly GB) has addressed this policy failure with the Carbon Price Floor, itself a flawed instrument lacking credible durability. Other air pollutants are addressed with potentially less efficient, but more credible and durable standards (LCPD, IED, etc.). The public good of innovation and learning-by-doing for renewables is addressed, again with mixed success, though target renewable energy shares by 2020 under the *Renewables Directive*.

Market advocates tend to overlook the failure of market completeness. Pareto efficiency requires either a full set of competitive risk and futures markets or rational expectations and risk neutrality. Fuels and electricity are at least sufficiently homogenous to support futures markets but they are highly illiquid more than two years out. Risk markets are even more problematic, although the early dash for gas used contracts to mitigate price risk in the fuel and electricity markets, and supplier guarantees for technical performance risk. We have seen that these risks were incompletely covered when policy intervention ended the Pool and removed the basis on which the contracts were written.

Clearly, missing futures and risk markets are not confined to electricity but pervasive for all goods and services. Absent market completeness, policy makers may be happy with the assumption that the combination of reasonably rational expectations and other risk-sharing instruments such as equity diversification can deliver acceptable outcomes. Thus the practical issue is whether there are special features of electricity that make these missing market problems more serious than in other markets. Moreover, it is not sufficient to point to a market failure as a justification for an intervention. It must also be the case that the intervention is sufficiently better than the market failure to justify the market chilling impact that policy interventions create for those operating in these markets.

The most obvious difference between electricity and most other goods and services is that it has always been highly politicized, and if anything has become more so. Farrer's (1902) lists product characteristics that predispose for public ownership and/or control (he was concerned with natural monopolies):

1. economies of scale with immobile assets
2. capital-intensity
3. non-storability with fluctuating demand
4. locational specificity generating location rents
5. producing necessities or essential for the community
6. involving direct connections to customers

A more modern definition of natural monopoly is restricted to the first characteristic, but the sources of legitimate public concerns and the felt need for public control are captured by the other characteristics, particularly the final two. Electricity fits Farrer's catalogue perfectly, which suggest a richer set of reasons for public concern over the activities of these utilities than just the potential for the exercise of market power.

In normal markets, commercial decisions are based on the expectation of competition with similarly placed companies and under a rule of law in which anti-competitive practices are illegal, so that the players understand the rules of the game, can expect redress against sharp practices or obstructive behaviour by rivals, and do not expect arbitrary regulatory intervention. Where environmental standards are tightened, they are usually industry wide, so the costs that each firm will face can be passed on to consumers in higher prices. Where there are differential impacts, the regulations and standards are usually phased in over a lengthy period. Of course, firms face disruption – from new technologies, from new foreign competitors, and from changing patterns of demand and cost shocks to some parts of supply chains: normal commercial risks that are addressed by suitable equity gearing, product diversification and market intelligence.

Few of these commercial stabilities remain in the ESI, given the policy turbulence since 2000, but before examining the challenges now faced, it is important to place recent GB experience of liberalized electricity markets in a proper historic context. Liberalization, at least in GB, took place in a very benign economic climate. The CEGB had adequate spare capacity, and was privatized at a moment when new technology, CCGTs, made entry easy – the scale and unit cost of CCGTs, as well as their speed of build, made entry by new independent power producers (IPPs) feasible, especially as they were competing with cheap fuel against incumbents locked into comparably expensive coal (fig 1). Gas prices were unexpectedly low as a result of rapid development of North Sea gas. Until the Bacton Interconnector allowed exports, gas prices were depressed by supply tending to outstrip demand and depress prices. These favourable circumstances should be contrasted with the far more challenging investment climate of today.

Even so, the entry of new CCGTs needed the encouragement that prices would likely be kept up by a duopoly, combined with what some termed “sweetheart deals” with the supply companies (the Regional Electricity Companies that still owned the local distribution networks), who often held an equity stake in the “independent” power producers. In addition, they were selling into a franchise market, and all they needed for commercial security was to receive the approval of the Director General of Electricity Supply (the regulator) of the contracts the supply companies had signed. Generation investment was not actually needed for security of supply, but was nevertheless facilitated by attractive contractual conditions.

3.1 The energy-only market post 2001

The New Electricity Trading Arrangements (NETA) replaced the Pool with bilateral contracting, a two-priced pay-as-bid balancing mechanism (NOT a market) and illiquid spot and forward markets, designed to force generators to contract with suppliers in the expectation that bilateral bargaining ahead of delivery in opaque markets would impair market power. The reasoning has some logic, as a fully contracted generator has an incentive to offer electricity into the spot market at marginal cost, but at the risk of higher contracting and certainly higher balancing costs (balancing was automatically provided through the offer stack in the Pool).

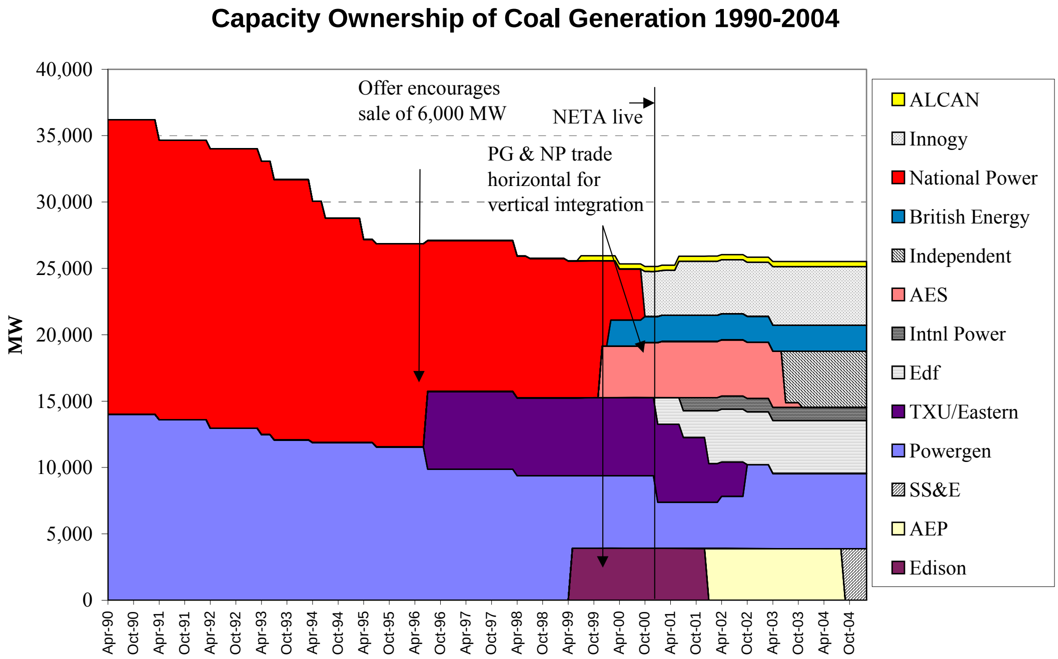

Figure 4 Duopoly sales of their old coal stations reduced concentration before NETA

Figure 4 shows that the incumbent coal-based duopoly had fragmented and reached a competitive state before NETA. Figure 1 showed that gas-fired generation was responsible for one-third of total output by 2001, and was widely owned. The baseload nuclear power accounted for up to one-quarter of output, and was not price-setting but by pre-empting market share made the remaining market more competitive. The British ESI was then diversified in fuel and ownership and hence structurally workably competitive, an assessment that the recent CMA inquiry has endorsed. Consequently, the remedy of quasi-enforced contracting was not needed to create competitive pressure, and only the adverse effects of NETA were left to be addressed by EMR.

4. Why do we need contracts and how should they be procured?

As the IPP episode demonstrated, contracts can be an excellent surrogate for missing futures and risk markets and a hedge (if properly designed and underwritten) against future policy reversals. The logic of the EMR and the capacity auctions was that contracts would reduce these risks and hence lower the weighted average cost of capital (WACC). As the capital cost is a large part of the cost of generation for many technologies, this would lower the cost of delivering the trilemma objectives. Auctions have the property of creating competition for the market, while for those holding capacity agreements, the spot and short-term forward markets should ensure efficient and least cost generation. The experience of the two capacity auctions is that they delivered prices well below the price that bureaucrats might have set, while the CfD action for renewables was similarly effective in lowering strike prices. Table 1 shows the results of the first CfD auction round that was declared on 26 February 2015.

Table 1 CfD Auction Allocation: Round 1

Technology		admin price	lowest clearing price	2015/16	2016/17	2017/18	2018/19	Total Capacity (MW)
Advanced Conversion	£/MWh	£140	£114.39			£119.89	£114.39	
Technologies	MW					36	26	62
Energy from Waste with	£/MWh	£80	£80				£80.00	
Combined Heat and Power	MW						94.75	94.75
Offshore wind	£/MWh	£140	£114.39			£119.89	£114.39	
	MW					714	448	1162
Onshore wind	£/MWh	£95	£79.23		£79.23	£79.99	£82.50	
	MW				45	77.5	626.05	748.55
Solar PV	£/MWh	£120	£50.00	£50.00	£79.23			
	MW			32.88	36.67			69.55

Source: DECC (2015a)
Note: the £50 bid for solar PV in 2015/16 was withdrawn

Table 1 shows the clearing prices were often substantially below the administered prices (now price caps). The excess level of the WACC can be computed from Table 1 using cost estimates (National Grid, 2013) and price forecasts (DECC, 2014). The differences in the internal rate of return for on-shore wind for varying values of the capacity factor (CF), capital cost (capex), and opex are shown in table 2 as "IRR delta", where changes in assumptions are italicized.

Table 2 Differences in the internal rate of return for on-shore wind

CF	capex £/kW	fixed opex £kWyr	var opex £/MWh	IRR delta
25%	£1,600	£30	£5	3.30%
25%	*£1,800*	£30	£5	3.10%
28%	£1,600	£30	£5	3.40%
25%	£1,600	*£45*	£5	3.50%
25%	£1,600	*£20*	£5	3.20%
25%	£1,600	£30	*£2*	3.20%

Source: own calculations

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 (2013a) 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 (DECC, 2011) 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 (Bunn and Yusupov, 2015) 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 (Criscuolo and Menon, 2015).

The capacity auction similarly delivered lower than expected clearing prices, but aroused fears that the large CCGT awarded an agreement might not proceed to financial closure, raising doubts about the effectiveness of the penalty for non-delivery. The Panel of Technical Experts (DECC, 2013b) argued that given the uncertainty in forecasting requirements four years ahead it might be desirable to retain the option of an earlier (e.g. T-2 auction) if events (such as this) justified. There is potential low-cost option value in anticipating the need for grid connections and site permissions ahead of committing to build. Nevertheless, the auction demonstrated substantial new entry and the range of technologies accepted suggested that it was indeed technology neutral.

5. The specific questions

The specific questions can now be addressed in turn:

1. How would technologies with different characteristics (intermittent, higher carbon, storage) be able to compete on a level playing field?

This needs to be considered in two parts. For mature technologies that are needed to address current market problems such as intermittency and inertia, the solution is to define the ancillary service products needed and then secure them in the most competitive way, ideally by package auctions, discussed below. For technologies that require support (either because of an inefficiently low carbon price, or because of learning spillovers, or both), again they should be procured through an auction, as with the first CfD auction of table 1 above, but this would not be the same as the security of supply auction.

Ancillary services and security of supply

The Single Electricity Market (SEM) of the island of Ireland provides some useful examples for a number of reasons. It is a moderately small, moderately isolated system with a range of fossil generation, with individual units that are large compared to demand. It has already high wind penetration, and currently experiences occasions with more than 50% system non-synchronous penetration (SNSP), at which point curtailment is currently required to maintain system stability. The ambition is to develop new ancillary and flexibility services under the project *Delivering a Secure and Sustainable electricity System* (DS3) to cope with 75% SNSP, while at the same time transforming the centrally dispatched pool into a model compatible with the EU Target Electricity Model in which bids and offers are submitted to the European auction platform, EUPHEMIA, to determine market clearing prices and interconnector use.

The System Services needed for DS3 are “those services, aside from energy, that are necessary for the secure operation of the power system. These services are also referred to as Ancillary Services and System Support Services. The All Island Energy Market Development Framework (Nov 2004) included, as a goal, the harmonization of Ancillary Services (AS) arrangements. The Harmonized AS (HAS) project, which began in January 2008, culminated in the successful implementation of harmonized arrangements in February 20101. …The Harmonized AS arrangements and GPIs (Generator Performance Incentives) provide a platform for a comprehensive review to be undertaken of the types and amounts of System Services required. … Under the HAS arrangements, service providers are remunerated based on regulated rates, which are reviewed annually. The total AS allowance for the period October 2011 to September 2012 is approximately €50m...” (Eirgrid/SONI, 2011).

Table 3 lists the existing services with their abbreviations on the right hand side, and also a list of proposed new services that are considered necessary to manage future SNSP. The percentages show the extent to which current plant can provide the services needed by 2020, as discussed below. A fuller description of these services is given in the source SEM-13-060.

Table 3 Proposed new and existing System Services

	New Services	Now		Existing Services	Now
SIR	Synchronous Inertial Response	65%	SRP	Steady-state reactive power	69%
FFR	Fast Frequency Response	54%	POR	Primary Operating Reserve	87%
DRR	Dynamic Reactive Response	82%	SOR	Secondary Operating Reserve	90%
RM1	Ramping Margin 1 hour	88%	TOR1	Tertiary Operating Reserve 1	91%
RM3	Ramping Margin 3 hours	88%	TOR2	Tertiary Operating Reserve 2	89%
RM8	Ramping Margin 8 hours	66%	RRD	Replacement Reserve (De-Synchronised)	83%
FPFAPR	Fast Post Fault Active Power Recovery	88%	RRS	Replacement Reserve (Synchronised)	93%

Source: SEM-13-060

Fig. 5 shows the most recently available full year payments under various categories. Incentive payments amount to only 3% of the total. Operating reserves (OR, Primary, Secondary and Tertiary) account for half, with replacement reserves (RR) accounting for an additional 14%. Reactive power in total accounts for 18% of the €61 million.

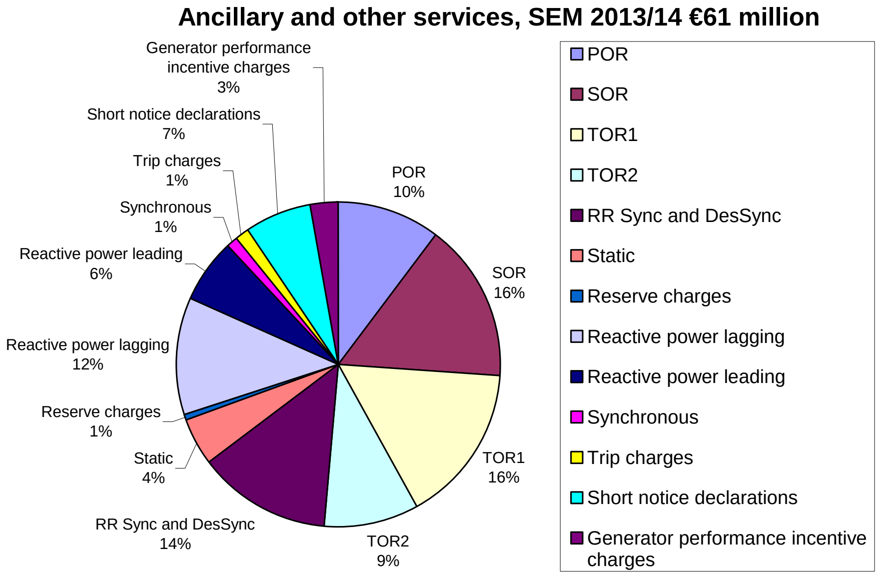

Figure 5 Payments for various System Services, 2013/14
Source: http://www.eirgrid.com/operations/ancillaryservicesothersystemcharges/

To interpret these services, fig. 6 shows the full range of existing and proposed frequency control services, with descriptions given in the source.

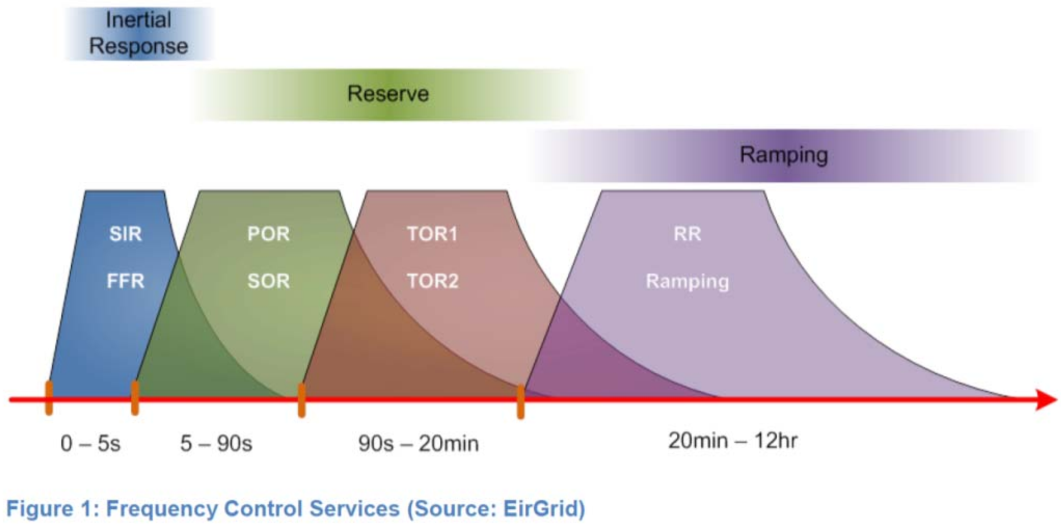

Figure 6 The existing and proposed Frequency Control Services
Source: SEM-13-060

In addition to these Frequency Control services there are voltage response products shown in Fig. 7.

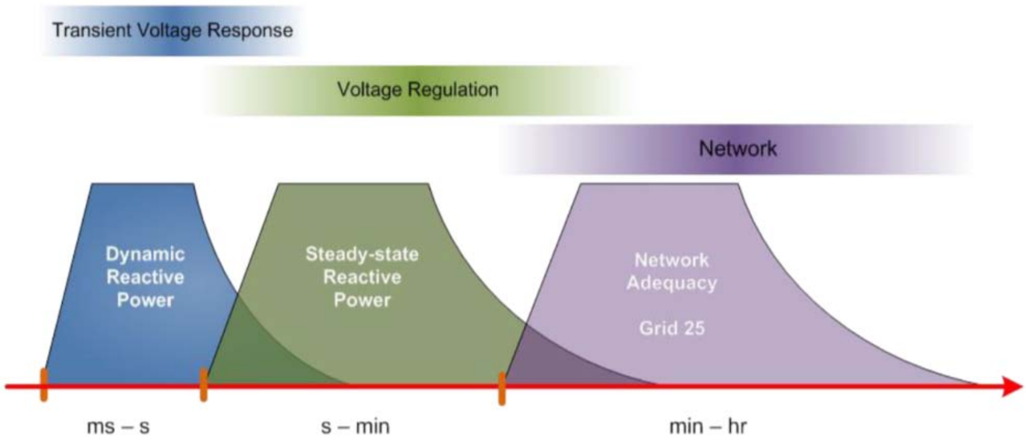

Figure 5: Voltage Control Services (Source: EirGrid)
Figure 7 Voltage Control Services
Source: SEM-13-060

Ideally, as these services can be supplied in different combinations by different technologies, along with capacity, they should be procured in a simultaneous package auction. The offers would state the minimum amounts of annual payments for the package of services offered (for e.g. 10 years for new entrants, for one year for existing plant) and the auction platform would establish the clearing prices for each service that would combine to give the required revenue for each accepted offer. In practice, especially in a small and concentrated market like the SEM, concerns over market power may require price caps on some of the services, and price taking behaviour by larger incumbents, but these are details for the auction design. Price caps may also be needed where the value of the service if limited (e.g. by the cost of curtailing wind).

Provided the services have been properly defined and their value (i.e. the willingness to pay for them) established, different technologies would be enabled to compete on a "level playing field". If some technologies have egregious externalities (air pollution, CO_2) then absent a proper tax or price for them, the auctioneer can announce that these characteristics would be penalized appropriately in determining winners. That might, for example, encourage diesel gensets to adapt to run on natural gas.

Storage, to take a specific technology, may be able to provide a range of new and existing services identified in Table 3. Batteries have very fast response times, pumped storage in spinning mode almost as fast, etc. Dinorwig pumped storage in Wales derives about three-quarters of its revenue from ancillary services, and only one quarter from price arbitrage (buying cheap and pumping, discharging in high price hours).

It is critical for new capacity to be able to value all the services they can provide (DS3 and energy as well as capacity), as it is the sum of all these revenue streams that will determine what price they need to offer into a capacity auction. The problem is not just one of "missing money" but also of "missing markets" for these services now and in the future (Newbery, 2015a).

The problems facing the SEM in its transition to the EU compliant I-SEM are greater than those facing GB, as they are creating new ancillary services whose price is as yet unclear at the same time as moving to a capacity auction from the previously bureaucratically set capacity remuneration model. In GB, investors can make reasonable estimates of future ancillary service (AS) revenue when deciding how much money remains missing. Nevertheless, the greater the clarity and confidence that can be given to future AS prices and likely energy receipts, the more confidently investors can assess the required offer to make to the capacity auction.

For existing generators the problem is simpler – is the revenue with the capacity payment enough to cover enduring costs or should they exit. Here one of the main unsatisfactory features of the energy market is the annual TNUoS charges (Newbery, 2011). For generators such as Longannet (and many of the northern coal-fired stations) these annual payments are of the same order as the annual capacity payment and hence hugely material to the exit decision. Ideally, these TNUoS charges should reflect the expected average nodal price differential from the reference bus bar (or more precisely, so that the sum from all TNUoS G charges allocates the regulated revenue appropriately between generation and load). The TNUoS charges are currently determined using the ICRF methodology, which assesses the cost of connecting new generation at that connection point. It is not clear that it reflects the value of an existing connection, which, for an old coal station, will likely have recovered the initial reinforcement costs over its life to date. The proper question to ask is what increase in transmission costs would be caused by the exit of the station, or what value exit would create by allowing new connections. As a matter of urgency, National Grid should be asked to answer these questions for all existing stations contemplating exit.

6. Renewable and low-carbon capacity

The CfD auction set out in table 1 created three different tranches for technologies of three different stages of maturity, corresponding, presumably to three different levels of credit for these beneficial learning externalities. One criticism of that auction is that it offered CfDs for output, not capacity, although arguably the main obstacle they face is excessive current investment cost, as once they have been built, their output is primarily determined by the resource (wind, wave or sun). Paying higher prices for output can be justified to some extent as compensation for an inadequate carbon price, while if the purpose is to encourage the learning-by-doing externalities it would be better to subsidize capacity, as the learning is derived from the creation of the equipment, site procurement and construction, and less from operation (where the electricity price provides an incentive for reliable operation).

The EMR phased the replacement of ROCs by CfDs, reducing risk and lowering cost (as shown in tables 1 and 2) but still confronting generators with marketing and balancing risk (Newbery, 2012a). Just after the first CfD auction the *Energy Union Package* was launched (COM(2015) 80), stating that:

> "… renewable production needs to be supported through market-based schemes that address market failures, ensure cost-effectiveness and avoid overcompensation or distortion. Low-cost financing for capital intensive renewables depends on having a stable investment framework that reduces regulatory risk." (EC, 2015)

Action Point 5 reiterated the aim of "integrating renewables in the market …" and proposing "a new European electricity market design in 2015, which will be followed by legislative proposals in 2016." This Commission proposal would seem to reverse the logic, painfully learned in the UK, of moving from Premium Feed-in-tariffs (PFiTs) to FiTs with their revenue guarantee and hence reduced risk and WACC. German, Danish Spanish and Italian case studies (Criscuolo and Menon, 2015; Laleman and Albrecht, 2014; Lipp 2007) all demonstrate that a well-designed FiT can be cost-effective (with suitable degression tracking falling costs), can deliver rapid deployment, and encourage the cost reductions that are the logic behind the *Renewables Directive,* as figure 7 shows. Why then abandon what seems to be an effective instrument?

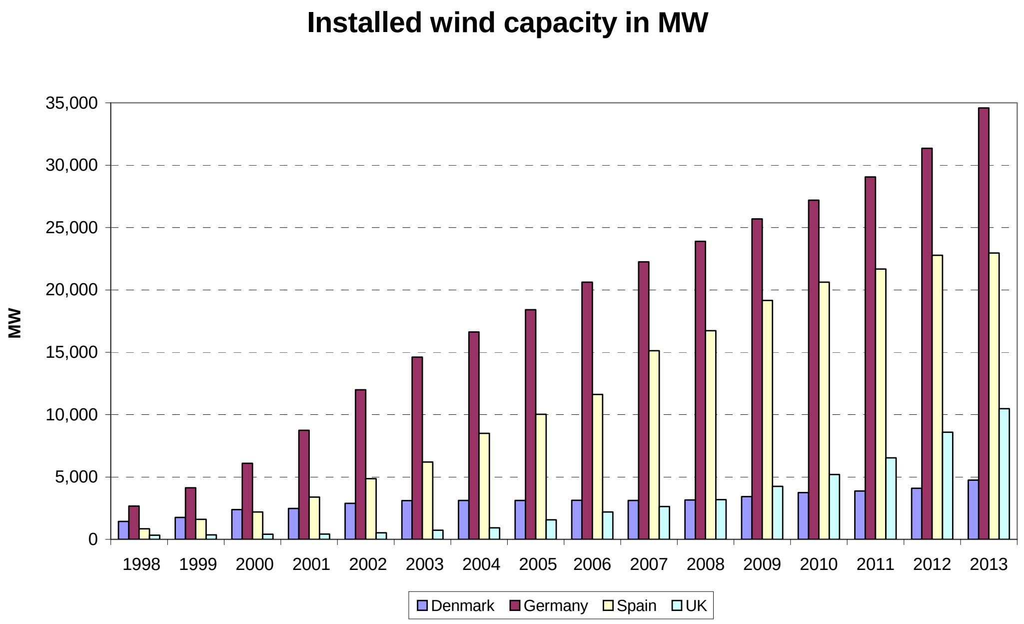

Figure 7 Progress with deploying wind 1998-2013
Sources: IEA to 2011, EWEA 2011-13

There are two good reasons for linking payments to wholesale prices and requiring renewable energy supply for electricity (RES-E) to pay for balancing services. As the volume of a specific type of RES-E increases in a local market area (South German PV is an excellent example)[2] so the output in favourable conditions will increase, depressing wholesale prices in those hours (Green and Vasilakos, 2010). This fall in prices should lead developers to choose better locations (higher local prices offsetting less sun or wind). A contract price independent of the spot price suppresses efficient signals, raising deployment costs. PV has a rapid afternoon fall-off, requiring rapid ramp rates from back-up plant.[3] High RES-E penetration requires new and costly ancillary services (ramping, frequency response, inertia) and needs to be reflected in support costs, logically by requiring operators to purchase them.

The counter argument is that exposing RES-E to uncertain market conditions undermines the risk and cost-reducing properties of the classic FiT, reallocating risk to those less able to bear it. It does, however, raise the question of how best to support RES-E. The logic of the *Renewables Directive* is to solve the club good problem of financing deployment to reap the dynamic economies of scale (learning-by-doing), which is primarily about the design, location and installation of the RES-E plant, and less about its operation (which, if it is mature enough to warrant mass deployment, should primarily depend on the resource, wind or sun). This suggests paying for availability rather than output, per MW, not per MWh, with developers receiving the local, ideally nodal, price.

Successful bidders in the RES-E auction would receive a nominal payment per MW of capacity available for some period, and be responsible for selling power at the spot price, avoiding the location distortion that high RES-E prices cause (Newbery, 2011). Such auctions would remove the risk that future support payments would breach the LCF (see fig. 10 below; note that capping support risks breaching the RES target).

This might seem to recreate the risk of the PFiT, although the contractual guarantee of capacity payments should allow a higher fraction of debt finance that the less predictable ROC value. To reduce risk further, balancing and other ancillary services could be procured competitively by the System Operator (SO) and offered in a cost-reflective contract, whose cost would be factored into the auction for capacity availability. Other aggregators or supply companies could offer PPAs for the metered output, based on a prediction of the local wholesale price, further reducing transaction costs and risks. Finally, RES-E (and indeed all generation) should ideally pay the deep connection charge amortized over a suitable period to ensure efficient location and exit decisions (Newbery, 2011).

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[2] "Wholesale electricity costs in Germany decrease in 2012 vs. 2008 by a total of €6.145b driven by increased solar PV generation" according to Renewable Analytics at http://www.qualenergia.it/sites/default/files/articolo-doc/RA-January-2013_Germany-Wholesale-Power-Report-3.pdf

[3] See e.g. https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

While this capacity support addresses the reason for the *Renewables Directive*, there is a case for an additional output support to reflect the inadequately priced carbon saved, although there is the obvious concern that the total volume of RES-E has no impact on the EU's carbon emissions, which are fixed by the ETS cap. Another practical reason for an element of output support is that the target is, inappropriately given the underlying logic of the *Renewables Directive*, based on output, not installed capacity, and as such there is a shadow value to meeting that output target.

7. Transition to an enduring capacity procurement regime

- What are the steps needed to get from the current system to your desired power market?

The EMR capacity auction was proposed as an enduring solution to the "missing money" problem, and tweaking its design to meet criticisms should not present any insuperable difficulties. There are recognized problems of ensuring the right incentives for delivery, and a more intractable bias towards over-procurement (Newbery and Grubb, 2015). (Intractable as National Grid and the Minister, who do not have to pay, are encouraged to over-procure to avoid scare-mongering stories in the media. The cost falls on future consumers who will not feel the extra cost until many years later.)

7.1 Transitions for renewable electricity support schemes

The major problem lies with RES-E (nuclear power is addressed separately below). The remaining questions are relevant here:

- Would you be able to use or improve current instruments (CFD, ETS, capacity market) or would you need replacements?
- Does any market-based, low carbon system rely on a steadily rising carbon price?

On the assumption that additional investment in RES-E will be required to meet the 2020 targets and looking forward to the post 2020 world in which the UK has no binding RES targets, the transitional question has three parts: how to deliver the 2020 target, how to make the transition for RES-E that by 2025 will be economic (allowing for a proper carbon price) and how to support innovation for less mature low-carbon technologies.

Delivering the 2020 target is best achieved by CfD auctions and needs no legislative action except to address the LCF cap, which, as gas prices fall, looks set to be breached (fig. 10). It seems perverse that cheaper electricity is interpreted as implying we can less well afford the low-carbon options. The present, when interest rates are low and the macro-economy is suffering from deficient demand, is the right time to invest and accelerate the transition to the decarbonized ESI we need by the early 2030s.

One key barrier facing the decarbonization of electricity is the lack of an adequate, credible and durable carbon price. The ETS delivers prices that are too low, and the evident need for its reform makes its future neither durable nor credible. The GB Carbon Price Support is evidently neither credible (it was frozen shortly after launch) nor durable (it has no assurance beyond any annual budget). If we are serious in delivering our carbon budgets the ESI has to rapidly decarbonize, which means that all new base-load power (i.e. power that is dispatched as least cost) should be zero carbon (in operation). The only new unabated fossil plant that should be procured is that needed to deliver system security (flexibility, meeting shortfalls in RES-E, etc.). Some but not all of that can be delivered by the demand side, some from storage (although the cost of bulk multi-day storage will have to come down appreciably to compete with flexible gas generation). The shortfall in flexible capacity should be chosen with adequate penalties for excessive carbon and air pollutants.

But what is the carbon price needed to make mature RES-E (on-shore wind and some grid-scale solar PV) commercially viable without additional subsidy? One apparently natural way to answer this is to ask what carbon price is needed to make these technologies competitive against the least-cost fossil option, which is gas-fired generation. Unfortunately that depends critically on the price of gas. At the final investment decision date for zero-carbon plant, it must be more profitable than fossil-fueled alternatives, which requires a carbon price above the break-even price - the carbon price needed to make zero-carbon and fossil generation investments equally profitable. The break-even carbon price depends on the carbon intensity of the fuel, γ, (tonnes CO_2/MWh_{th}).[4] If zero-carbon generation is competitive at some fuel and CO_2 price, then a £1/MWh_{th} fall in the price of fuel would require an offsetting $1/\gamma$ increase in the price of CO_2 to maintain cost parity between zero-carbon and fossil generation.

The likely future competitive fuel in the ESI is gas. For delivered pipeline gas γ=0.19 tonnes CO_2/MWh_{th}, so the multiplier for the CO_2 price is 5.24. This makes the break-even carbon price very sensitive to the gas price. This might not matter if the gas price were predictable and stable. Unfortunately, this is not the case as its price uncertainty is large, as shown in Fig. 8. The range between the UK's low and high wholesale gas price scenarios for 2017 made at the end of 2015 (DECC, 2015b) is from £12.3/MWh_{th} to £23.4 MWh_{th}, or £11.1/MWh_{th}.[5] The range in UK projected 2020 gas prices is £15.7/MWh_{th} with an implied range in the required break-even CO_2 price of £82/tonne, which is more than 100% of the original UK 2030 (supported) carbon price (DECC, 2010).

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[4] The subscript *th* refers to the thermal energy content of the fuel, unsubscripted MWh refer to electricity output.

[5] DECC publishes wholesale fuel price forecasts (for gas at the trading hub, for coal cif ARA in $/tonne. The figures are adjusted to include the observed past margin into power stations, from https://www.gov.uk/government/statistical-data-sets/prices-of-fuels-purchased-by-major-power-producers

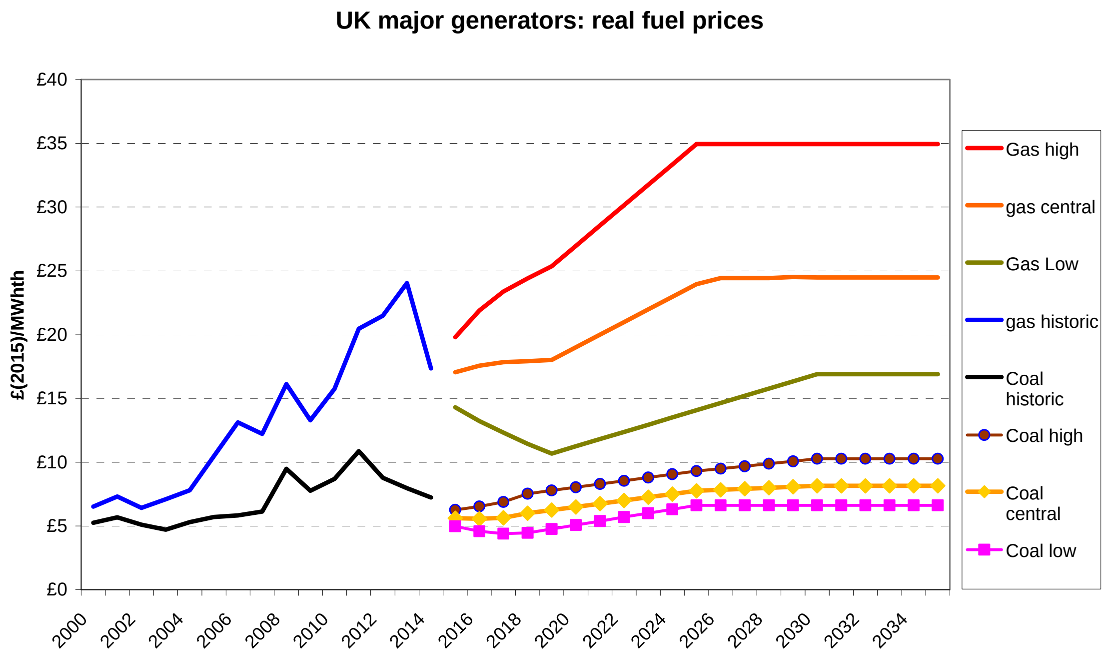

Figure 8. UK fuel prices past and future scenarios (DECC, 2015b)

It follows that a spot and fluctuating carbon price is an inadequate instrument for supporting RES-E, and that contracts will continue to be needed. The CfD is an improvement on the pFIT of the previous ROC, as it removes the fuel price risk inherent in the carbon pricing problem, at least while fossil fuels set the electricity price. An auction is the most competitive way of delivering the RES-E, and if aggregators do not appear in sufficiently competitive volumes to off-load the marketing and balancing risk, there is a case for the SO to offer such services.

Given the carbon budgets and their implied electricity demand, that implies a specific volume of new zero-carbon capacity to be procured through the auctions, much as the volume of security capacity is currently specified and procured.

The question of supporting immature technologies is deferred to section 8, which addresses the wider question of innovation support.

7.2 The carbon price trajectory

The theoretical case for a carbon price rising at the rate of interest is that the present value of the future damage rises at that rate. It has the agreeable implication that a trading scheme with banking would, if credible and supported by a liquid and efficient capital market, have prices also rising at the rate of interest. There are good political arguments for a gradually rising carbon price, as previous experience with a fuel price escalator for road fuel demonstrated. Arguing against that, sceptical investors prefer front-end loaded contractual support, which Germany provides by not indexing but fixing FiT contracts in nominal terms (consistent with nominal bond financing). That does not mean that the social cost of carbon should not rise with the rate of interest, which translates into a reduced subsidy, counting the carbon price as a corrective tax that will increasingly make low-carbon options more economically attractive.

7.3 Financing new nuclear power

- How would your proposed market arrangements cope with the potential need for new nuclear power stations?

Nuclear power has been treated as a special case, although perhaps the Carbon Price Floor was an attempt to address the market failure of carbon pricing that makes nuclear uncommercial and to avoid the state aids issue. Putting state aids on one side, several points can be made:

1. Nuclear power is essential for the massive decarbonization of the ESI, unless CCS and/or storage makes rapid and major progress
2. Almost all the costs of nuclear power lie in the construction phase, although it remains critical for public acceptance that the decommissioning end is securely addressed, even if its present discounted cost is low
3. The scale and cost of new build makes it extremely risky and hence costly for private firms to bear the construction risk
4. Public funding is currently very cheap
5. Arguably the EPR is the wrong choice

Figure 9 shows that France moved from the current GB carbon intensity to GB's 2030 target between 1979 and 1987 by a massive programme of nuclear power station construction. France was fortunate in choosing a viable design (PWRs) and replicating that design at scale through massive state funding. The world currently lacks an agreed design with evidence of successful replication at an acceptable cost. The chosen EPR suffers from massive cost and time over-runs in its first two European projects, and is currently under investigation for safety concerns at Flamanville.[6] Even had the design been appropriate, the choice of funding method appears to be the most expensive procurement contract imaginable. Once a nuclear power station is successfully commissioned, its operating cost should be very low and its expected reliability and availability very high, meaning that it has more in common with infrastructure like the national grid than a conventional generating plant. It would therefore lend itself to

[6] "French regulators are to demand another lengthy round of tests on its flawed reactor vessel." at http://www.theecologist.org/News/news_analysis/2985650/flamanville_nuclear_safety_fail_sounds_death_knell_for_hinkley_c.html

financing the operation and maintenance with a contract akin to the OFTO contracts that have attracted bank finance at very low rates of interest for off-shore wind infrastructure.

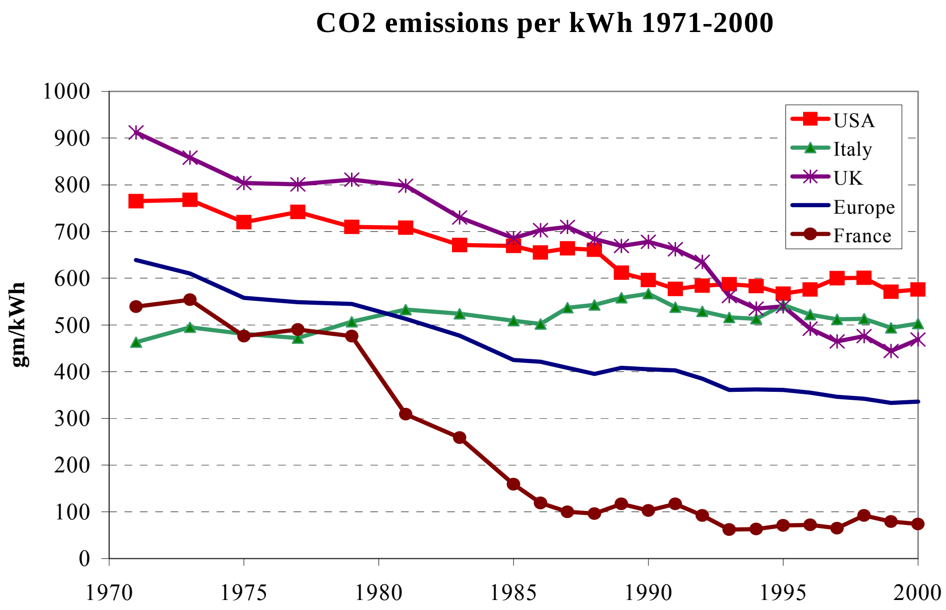

Figure 9 France decarbonized through nuclear power in a decade

Almost all the risk lies in the construction and overcoming technical design problems (of which metallurgical flaws in the reactor vessel and lid are probably the most concerning). That part of the process has more in common with Crossrail or HS2 or similarly lengthy and costly projects, although with higher technical/design risk. The State is the logical source of both finance and risk-bearing, and most nuclear programmes have been so funded. The US is an interesting and instructive exception, although the risk-sharing properties of cost-of-service regulation encouraged an ambitious programme. WPPSS in Washington State ran into serious problems with its nuclear build,[7] as did LILCO and many others. According to Gore (2009, p. 157) "Of the 253 nuclear power reactors originally ordered in the United States from 1953 to 2008, 48 percent were canceled, 11 percent were prematurely shut down, 14 percent experienced at least a one-year-or-more outage, and 27 percent are operating without having a year-plus outage. Thus, only about one fourth of those ordered, or about half of those completed, are still operating and have proved relatively reliable."[8]

I am no expert in nuclear design engineering, but if a way could be found of identifying the most promising design,[9] ideally one that has been successfully

[7] http://content.time.com/time/magazine/article/0,9171,955183,00.html
[8] Wikipedia gives a list of the cancelled nuclear power stations at https://en.wikipedia.org/wiki/List_of_canceled_nuclear_plants_in_the_United_States
[9] D'haeseleer (2013) provides a helpful guide to lessons learned, particularly from the recent Fench experience of cost escalation.

commissioned, and then finding the best construction consortium to build it, the remaining problem would be to design a suitable incentive procurement contract for its delivery, bearing as much risk on the public exchequer that is consistent with efficient incentives (i.e. solving the classic Principal-Agent problem in this specific case). Once commissioned, the contract to operate, maintain and decommission (not necessarily all by the same company) can be tendered or auctioned as a classic PPA: with a capacity availability payment and an energy payment, somewhat akin to the French virtual power plant concept.

8. Innovation, CCS, and next generation nuclear power

We still lack cost-effective reliable low carbon options suitable for scale generation. The innovations that need to be explored include modular nuclear reactors (where the benefits of replicability and factory assembly may outweigh the scale diseconomies – see Kessides & Kuznetsov, 2012), CCS, and storage (which, if cost effective, would enable a higher share of intermittent power). As innovation is a public good, it would be desirable to seek partners to co-fund it, and that was the intention behind the EU Strategic Energy Technologies (SET) Plan. The Energy Union claims to emphasize innovation, and clearly the 2020 Horizon plan will help, but both suffer from a secure source of large scale funding, compared with the resources spent on supporting renewables, demonstrated in fig.3.

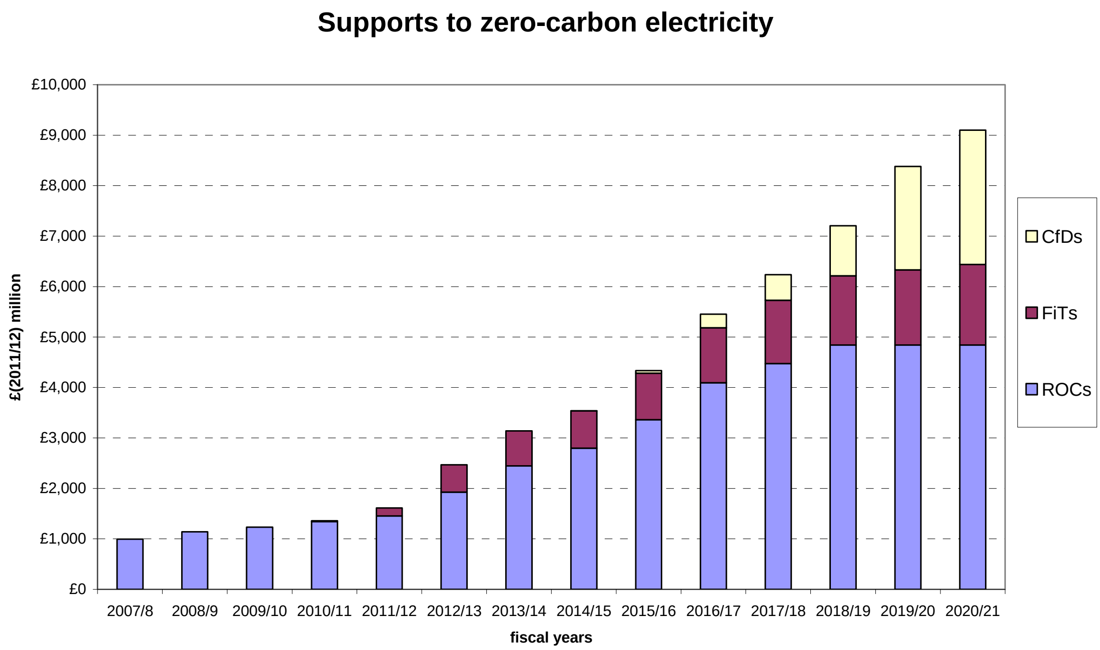

Figure 10. Past and projected expenditure on zero-carbon electricity support
Sources: past FiTs and ROCs from Ofgem annual reports, projections: DECC (2015b)

One ambition might be to suggest to the EU that the club funding model of the *Renewables Directive* be modified to allow support to either renewables or competitive innovation projects. That would require monetizing the efficient level of support that each Member State agreed to meet when accepting its renewables target, and then valuing renewables equally with sums offered for innovation support, provided the competition for selecting the project were run by an independent body and open to all Member States. The UK's support for renewables is already significant and rising, as figure 10 shows.

The Ofgem LCNF and Network Innovation Competitions are good examples of how this might operate, although the LCNF budget of £500 million over four years is modest by comparison with that needed for the industry as a whole. Network owners submit project proposals which meet the required criteria, have a well-defined business plan, define satisfactory success criteria, and estimate the benefits and costs if successful. A panel of independent experts chooses which to support up to the agreed budget.

Supporting demonstration CCS or next generation nuclear power would require an order-of-magnitude increase in funds, in line with the ambitions of the proposed Apollo Programme (King et al, n.d.). To quote from that report "the original Apollo Programme (which was mainly concentrated in the 10 years 1960-69) … cost about $150 billion in today's dollars … So we consider $15 billion a minimum acceptable scale for the Programme in its early years, rising thereafter in line with GDP growth. This would amount to 0.02% of world GDP."

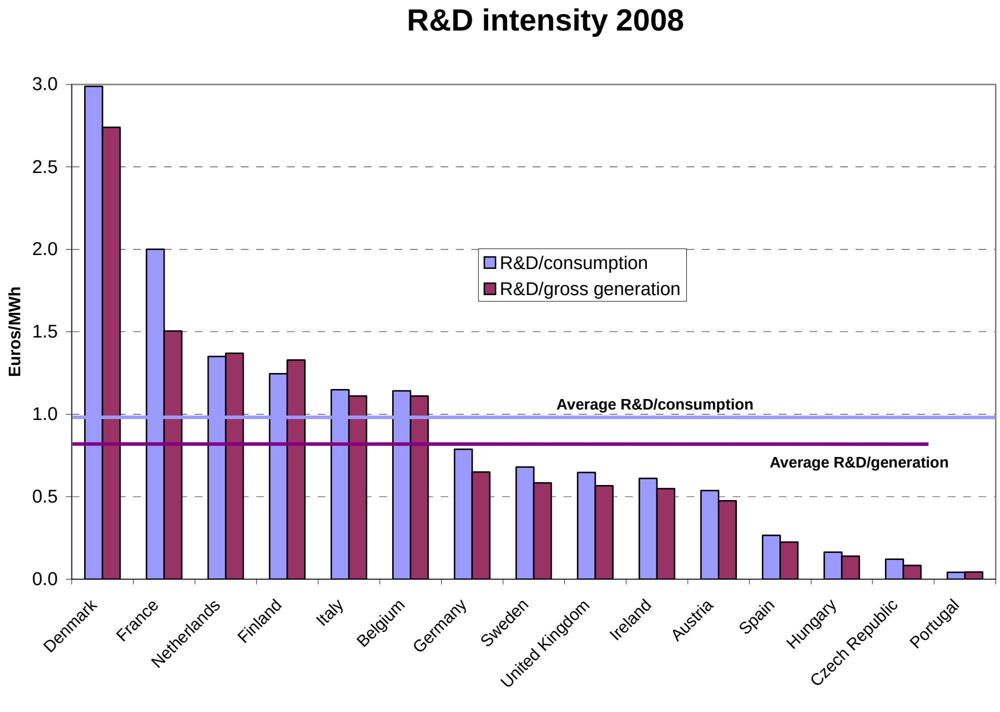

Figure 11 R&D intensity in the ESI
Sources: COM(2009) 519, Eurostat

If the UK's 2016 GDP is estimated at £2,200 billion then 0.02% would be £440 million per year. If the wholesale value of electricity is £13.5 billion (£45 x 300 TWh) that would amount to 3.3% of wholesale value, substantially less than the LCF of £7.5 bn (and one might expect rich countries to pay relatively more than the global average). Applied to the EU's GDP of €14,300 billion would imply innovation funds of €2.9 billion/yr, which is less than the 2007 SET R&D expenditure, and less than half the SET target of about €6 bn/yr. Thus the Apollo Climate Change programme is actually rather modest when compared to either UK's LCF limit on subsidies or the (unfunded) SET plan. It is, however, 50% more than the UK spends on energy R&D.

The choice of optimal allocation of funds between learning by doing and learning by research and demonstration is complex (Rubin et al. 2015) but it is hard to escape the conclusion that favourable funding streams for deployment and the absence of comparable support for RD&D has biased the allocation too heavily towards deployment.

To conclude, there is a strong case for a substantial increase in low-carbon electricity R&D, and a suspicion that the balance between deployment support for RES-E and R&D and demonstration projects is skewed too far towards deployment. It would obviously help if we could persuade the Energy Union to take this to heart.

9. Reforming energy subsidies and taxes

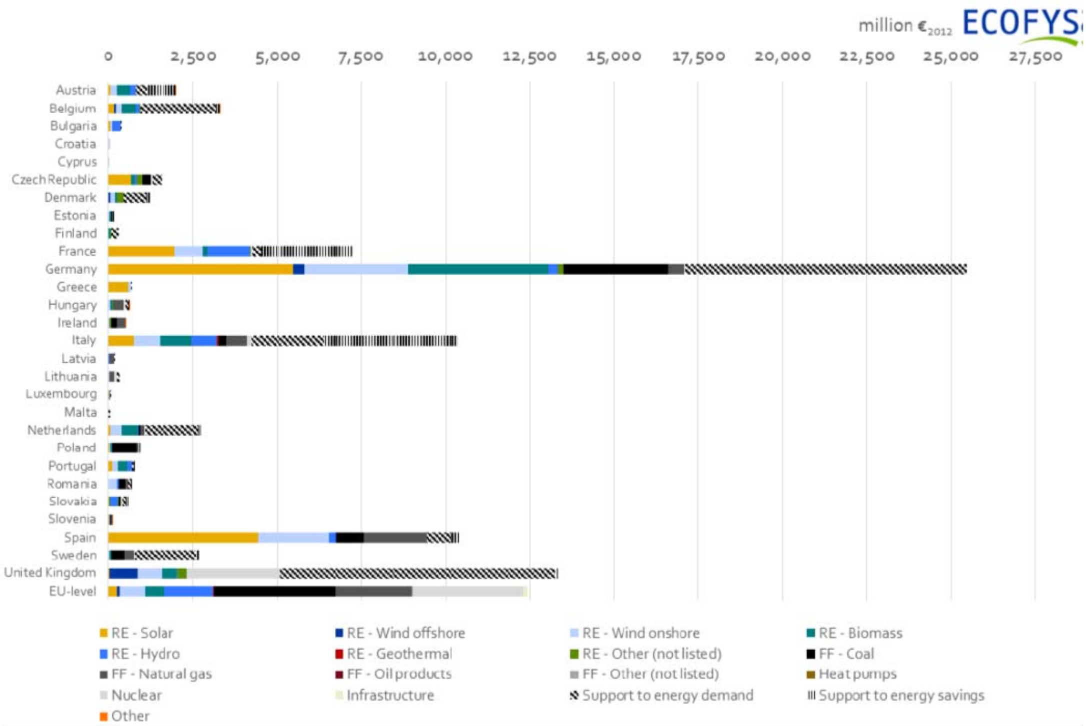

Figure S - 3 Interventions per Member State in 2012 (in million €2012)
Note: The EU-level intervention refers to interventions financed by the EU and not by individual Member States.

Figure 12 Energy subsidies for EU member states in 2012
Source: Ecofys (2014).

Newbery (2015b) sets out an agenda for reforming energy taxes and subsidies to provide a more efficient tax and support system. To single out one sensible reform, imposing VAT on energy at the standard rate would reduce our energy subsidies substantially (itemized in Figure 12 as “support to energy demand”) and remove that embarrassment. The increased revenue would allow all charges on electricity bills to pay for RES-E and efficiency measures to be allocated to general taxation, as is appropriate for the funding of public goods.

10. Conclusion

EMR has delivered at least three valuable reforms. It has made the case for, and delivered, a capacity payment, it has demonstrated that a CfD is a cost-effective way of supporting renewables, and finally, and most important, it has demonstrated the efficacy of auctions for delivering capacity and RES-E. There have been flaws (in the delay to ending the RO Scheme, in the over-generous FIDER contracts (NAO, 2014), in ignoring interconnectors and over-procuring in the first capacity auction) but that is water under the bridge and need not prevent sensible future implementation. The frequent reversals of energy policy has contributed to unsettling markets, raising the cost of finance and removing lower cost options, but electricity is an inevitably politically contentious topic, critical to economic survival, affecting all voters, and involving substantial charges on the budget.

The lessons from the recent past are to press for auctions as procurement where there is adequate competition (everything except nuclear power), remove tax and subsidy distortions where politically possible, internalize externality costs through additional (possibly shadow) taxes on carbon and air pollutants in procurement auctions, and recognize that missing futures markets combined with the ever-present threat of political intervention require contracts with sound counter-parties, aka the state, and think more carefully about lower cost state funding for nuclear power, at least in the construction phase. Encouraging a properly funded EU innovation policy can then address the critical requirements of cheaper nuclear power, viable CCS, cheaper storage, and various other technologies outlined in the new Apollo Programme.

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