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Keywords renewables, market failures, locational signals, contract design

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Designing an electricity wholesale market to accommodate significant renewables penetration: Lessons from Britain

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Abstract

The wholesale market has to address two major market failures – inadequate carbon prices in the EU ETS, and the learning externalities and missing futures markets for energy and ancillary services needed to guide flexible dispatchable plant. The paper discusses the importance of locational price signals to guide investment, the need to reform transmission pricing and renewables support. the case for capacity auctions for renewables and quantifies the justifiable level of renewables support. These proposals are consistent with the EU Clean Energy Package, but the nature of the renewables target and its financing should change.

1. Introduction

The European Union has committed itself to a 27% share of renewable energy in total gross energy production by 2030. As it is much easier to adopt renewable energy sources in the electricity sector (RES-E), it is likely that its share of electricity will be 40%, or possibly more in hydro rich countries like Norway and Spain. More ambitiously, the Single Electricity Market (SEM) of the island of Ireland has a RES-E target of 40% of electricity by 2020, despite the small and isolated size of the market and its lack of storage hydro. In anticipation of this high RES-E penetration, and to comply with the EU Target Electricity Market design, the SEM is redesigning its wholesale market to become the Integrated SEM or I-SEM. A large part of that redesign involves developing new products for system balancing and voltage support to handle intermittency (Newbery, 2017a).

To be fit for purpose, the market design should ensure that the right investments are made in generation, transmission and distribution, at the right time and at least cost, that due account is taken of the climate change benefits of low-carbon technologies, and that learning spill-overs from immature renewable energy in the electricity sector (RES-E) are properly included in determining the optimal investment portfolio.[2] These last two considerations are problematic in a liberalized electricity market, as they both involve externalities that, unless properly addressed, will be under-supplied by the market. Further, if CO_2 is not adequately priced, the more carbon-intensive fossil generation (like coal) will be over-supplied and wholesale prices depressed below their efficient (carbon-inclusive) levels, further discouraging lower or zero carbon options.

This paper addresses the question of how best to deliver a secure, sustainable and affordable electricity supply system in the context of private ownership and a liberalized

[1] dmgn@cam.ac.uk . I was a member of the Panel of Technical Experts advising DECC on capacity auctions, and am an independent member of the Single Electricity Market Committee of the island of Ireland, but the views expressed here are mine alone and rely solely on publicly available information. I am indebted to Pedro Linares for helpful comments as well as from members of EPRG, whose views this paper does not necessarily represent.

[2] See Newbery et al., 2017, on which this paper draws heavily.

market, both at the individual Member State Level and for the EU when it comes to design its energy Directives, targets and mandates. Clearly if externalities are global, as most are in the case of electricity, there needs to be harmonization of carbon taxes and RES-E subsidies across the EU if the ideals of the single market are to be achieved, and globally to the extent possible. Deciding what decisions to leave to Member States and what degree of harmonization is desirable is one of the central issues to resolve in designing EU energy policy, but is not the major task of this paper.

2. The relevant characteristics of electricity supply

One of the concerns exercising generation companies is that wholesale prices seem to have been unreasonably depressed by mandated or heavily subsidized RES-E, while a failure to properly price carbon makes new lower carbon gas generation unattractive. As a result the new investment needed to deliver the required flexibility and reliability is prejudiced. If the aim is to move to an electricity system whose capacity is not to be solely centrally determined and financed, this concern must be addressed. Part of the problem arises from extrapolating the central idea of the EU Target Electricity Market design of an energy-only market to inferring that the only relevant characteristic of electricity is its energy content, MWh.

That is, however, very misleading, and it is better to separately distinguish energy (MWh), capacity (MW, that determines reliability measured by the Loss of Load Probability), and Quality of Service (measured by a range of indicators, such as frequency, voltage, and phase angle) (Newbery et al., 2017). Electricity delivery at any node on the network is also constrained by the capacity of links on that network (and Kirchoff's Laws that determine how these impact the amounts that can be injected or withdrawn from each node). It follows that the values of these different products will likely vary across space and over time, and the relevant time period may be anything from milli-seconds up to hours, days and years, depending on whether we are discussing automatic pre-contracted control actions or real-time, day-ahead and intra-day markets for dispatch, or futures markets in the longer term for investment.

These product differences matter at the consumer level. Capacity is relevant for deciding the maximum amount that the consumer is allowed to draw (and will in turn determine the capacity of the connection to the end user, and of the fuse to protect against current surges). The option of taking power is valuable, and even for a consumer with a large array of solar PV cells that generate over the year more than is consumed on the premises, it is clearly valuable to be able to export surplus day-time power and take night-time power from the system. This requires both a connection of the right capacity and the necessary back-up generating assets to deliver replacement power when needed. The capacity on the wires and of generation can be paid for either by declaring a maximum demand, or paying a capacity element that depends on the state of the supply-demand balance (much higher when scarce, zero at times of surplus).

Energy is the default product, whose quality is assured by the System Operator, and is sold as such, often with compensation if the quality or continuity of service is compromised. It is also normally bundled with transmission and distribution charges (although these may be separately identified in the bill) and for retail consumers, also bundled with retailing services. The structure of these various components is normally more cost-reflective the higher the voltage and capacity taken, but smart metering at the household level offers the opportunity to make all tariffs cost-reflective and avoiding the kinds of distortions discussed below.

When it comes to remunerating generators, these different aspects of electricity are even more important. There is an increasing mismatch between the traditional model of a wholesale market that emerged in the early 1990s under the early EU *Electricity Directives* and that required to meet high RES-E penetration. As with the earlier unbundling and market liberalization, Britain has paved the way with its Electricity Market Reform (EMR), which became law as the *Energy Act 2013* (HC, 2013). The EMR re-introduced a capacity remuneration mechanism after the original capacity payment of the 1990 electricity pool was replaced by an energy-only wholesale market in 2001. Combined with National Grid's new ancillary services such as enhanced frequency response, annual capacity auctions that offer capacity contracts for new and existing plant provide greater investment assurance and encourage the new flexible generation needed to address the intermittency of wind and solar PV.[3] EMR also changed the form of RES-E support from a Green Certificate scheme (the Renewables Obligation Scheme, similar to a Premium Feed-in Tariff, PFiT) to something closer to a classic Feed-in Tariff (FiT) paying a fixed price per MWh. In the EU as a whole in 2013, FiTs accounted for about 58% of supported output, green certificates for 26% and PFiTs for 16%.[4]

The changes needed to address high RES-E are recognised in the 2015 *Energy Union Package* (EC, 2015), clarified and updated in the 2016 *Clean Energy Package* (EC, 2016a).[5] This recognises the importance of a stable investment framework that reduces regulatory risk for investors and achieves security of supply, and proposes integrating RES-E through market-based schemes that are more like PFiTs. The next section sets out the logic behind the changes made by EMR, the lessons learned from their implementation, and the relevance of the *Clean Energy Package*.

3. Electricity Market Reform, Capacity Auctions and the British experience

The British Electricity Market Reform (EMR) was motivated by the failure of the energy-only market to deliver adequate investment in the flexible gas-fired generation needed to deliver the reliability standard of a Loss of Load Expectation of 3 hrs/yr. This failure was a result of considerable policy uncertainty causing investors to delay investing until either some consistency, or better, long-term contracts emerged to reduce or hedge against policy uncertainty. In the period after the New Electricity Trading Arrangements that introduced the energy-only market in 2001, there were four *White Papers* on Energy Policy, reflecting uncertainty over the role of nuclear power, poor delivery of RES-E, and the pending retirement of most coal-fired power stations threatened with tightening pollution standards (Newbery, 2012). Unless investors feel confident that they can forecast future wholesale and ancillary service revenues, they would logically delay investing until either futures prices rise

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[3] See also Pollitt and Anaya (2016) for a comparison between the GB approach to accommodating high RES-E with that in Germany and the State of New York.

[4] Figures based on CEER (2015, Annex 9).

[5] https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition

enough to ensure a high enough rate of return to compensate for the perceived risk, or markets are reformed to reduce uncertainty.

3.1. Capacity auctions for reliability

EMR recognised the need to provide more investor confidence by offering 15-year contracts to pay per kW of de-rated capacity (de-rated to reflect its reliable availability) of new plant. In order to procure the required amount of capacity to meet the reliability standard, EMR proposed auctions four years ahead of delivery for new plant (the T-4 auction) and one year ahead (T-1) at which existing plant could be offered a 1-year contract to allow them to decide whether to accept the contract and remain in the market or to exit (i.e. disconnect). The auction design was much influenced by US experience, particularly that of PJM (Bowring, 2013) and involved a downward-sloping demand schedule for capacity, passing through the desired amount at the net Cost of New Entry (CoNE).[6] The auction clearing price (in £/kWyr) is paid to all successful plant (new and existing) for the length of the contract, and was intended to make up the missing money – the amount needed to cover the full cost including transmission charges (for new plant) less the revenue they would earn in the energy and ancillary service markets. Existing plant could not bid above half net CoNE (to prevent gaming and the exercise of market power),[7] but if new plant were required that would likely set a higher price. The auction was a descending clock auction, stopped when the supply met the demand schedule. If more capacity was available at a price below the net CoNE (set initially at £49/kWyr), then more would be purchased, the reliability would exceed the target, and conversely if the cost of reliability were shown to be too high.

These contracts would require the holders to be available to be dispatched at four hours' notice in the event of a "stress event" or pay a penalty. De-rating would estimate the proportion of the time that the plant was available, allowing for forced outages and plant maintenance (although the latter should be scheduled for seasons with lower demand). The philosophy behind the capacity auction assumed that all other prices (apart from capacity) were correctly set and appropriately rewarded the various services provided (energy, flexibility, fast ramp-up, etc.). The island of Ireland has already had to address the problem of first defining, and then pricing, the new flexibility services needed for high renewables penetration, ahead of reforming its capacity remuneration mechanism, and will be discussed briefly below (and see also Newbery, 2017a). The next section discusses the first two British auctions, which revealed a serious short-coming in the way generation pays for or is paid to use the transmission and distribution system. To understand the critical role of location signals the next section explains what is needed, how the British system works, and what problems the capacity auction exposed.

[6] For a more sceptical view of EMR and capacity auctions, see Pollitt and Haney (2013).

[7] Plant not bidding but expected to be present in the delivery year had their de-rated capacity subtracted from the demand to procure. RES-E with existing support contracts would similarly have their de-rated (i.e. equivalent firm output in stress periods) deducted.

3.2 *Location signals and network charges*[8]

Transmission links have limited capacity that must be respected by the System Operator (SO) when managing dispatch and redispatch. The Target Electricity Model is an energy-only market in which all generators are free to offer to supply amounts at specified prices and others bid amounts and prices at which they are willing to buy. Importantly, the aim is to integrate markets across the whole of the EU in a way that couples the markets controlled by different SO's and makes efficient use of the interconnectors between these different market areas. This market coupling relies on the auction platform EUPHEMIA[9] to match demand and supply, given the available transfer capacity (ATC) on the interconnectors that link different dispatch zones within the EU Integrated Electricity Market. If the initial set of offers to supply and bids to buy leads to an infeasible solution that would exceed some ATCs, the flows on these interconnectors are set at their ATC values, and the auction re-run for separate zones on each side of the constrained link to find zonal market clearing prices that satisfy all interconnector constraints.[10] The price difference between constrained zones measures the value of increasing interconnection capacity and acts as a valuable market signal for investment, while the zonal prices indicate the value of electricity in each dispatch zone.

The obvious problem with this dispatch system is that only major interconnectors are included in EUPHEMIA. Within each dispatch zone there may be many critical transmission links that require the local SO to redispatch plant to ensure that the actual dispatch will continue to respect all constraints, even if one of the generators or links fails (the N-1 condition). This feasible security-constrained dispatch requires the SO to issue balancing commands to well-placed generators to increase or reduce supply after all the commercial transactions have been accepted by EUPHEMIA and bilateral contracts have been notified to the SO. These balancing actions (which also include actions to address departures from the announced generation and demand plans submitted before dispatch) can be costly. Failures to meet announced positions are charged to those out of balance but redispatch costs must be recovered from consumers.

The theoretically correct way to handle transmission constraints in the short run is through Locational Marginal Pricing (LMP) or nodal pricing, in which each node on the network has a potentially different price, reflecting either the marginal cost of delivering an extra unit to that location, or the marginal value of the last unit (Schweppe et al., 1988). LMP has been widely introduced via the Standard Market Design in the US, and demonstrated to work in practice as well as in theory, although there is little appetite at present for introducing in in the EU. Nevertheless, when the inefficiencies of the current model become too large to ignore (as they did in the early days of PJM), there may be pressure to revisit this position. One advantage of LMPs is that there is no need to redispatch plant for reliability (N-1) purposes, as the SO computes a feasible security-constrained dispatch and its associated LMP

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[8] See also Newbery (2011), Pollitt (2016) and Strbac et al., (2013)

[9] Pan-European Hybrid Electricity Market Integration Algorithm described in https://www.nordpoolspot.com/globalassets/download-center/pcr/euphemia-public-documentation.pdf

[10] This is a simplification as the system is moving towards more efficient flow-based coupling. See e.g. https://www.tennet.eu/news/detail/flow-based-methodology-for-cwe-market-coupling-successfully-launched/ .

for each node. The only balancing actions required are those to address errors or failures, which are charged to those causing the balancing actions.

The more significant benefit of giving good locational signals comes from long run investment decisions in transmission and generation location. Good locational decisions can avoid costly and continuing redispatch costs and deliver a pattern of investment that minimizes total system costs. One theoretical advantage of LMPs is that they give clearer signals of where to locate new generation (where LMPs are high indicating the need for more supply) and demand (where they are low, indicating ample availability). It also signals where to increase transmission capacity, and provides a revenue stream to transmission owners. However, to be credible for making long-term investment decisions, these LMPs need to be known in the future, or at least subject to longer-term contracting.

In the absence of LMPs some other means are needed to guide location decisions within each EUPHEMIA price zone – and Britain is a single price zone requiring expensive redispatch to handle the Scottish border constraint. The British solution is to define different tariff zones each of which has a different Transmission Network Use of System (TNUoS) charge. Generators pay Generation (G) TNUoS annually on their Transmission Entry Capacity – the maximum amount they wish to export – while the demand side pays Load (L) TNUoS on the amount taken from the grid in Triad half-hours – the three half-hours of system maximum demand separated by 10 days in the year (in the winter).[11] Figure 1 shows these annual charges across the different zones in GB. The difference between the G TNUoS charges across zones is about £25/kWyr and signals where to locate (near London, where the charges are low) and where not to locate (in the North where the charges are high).

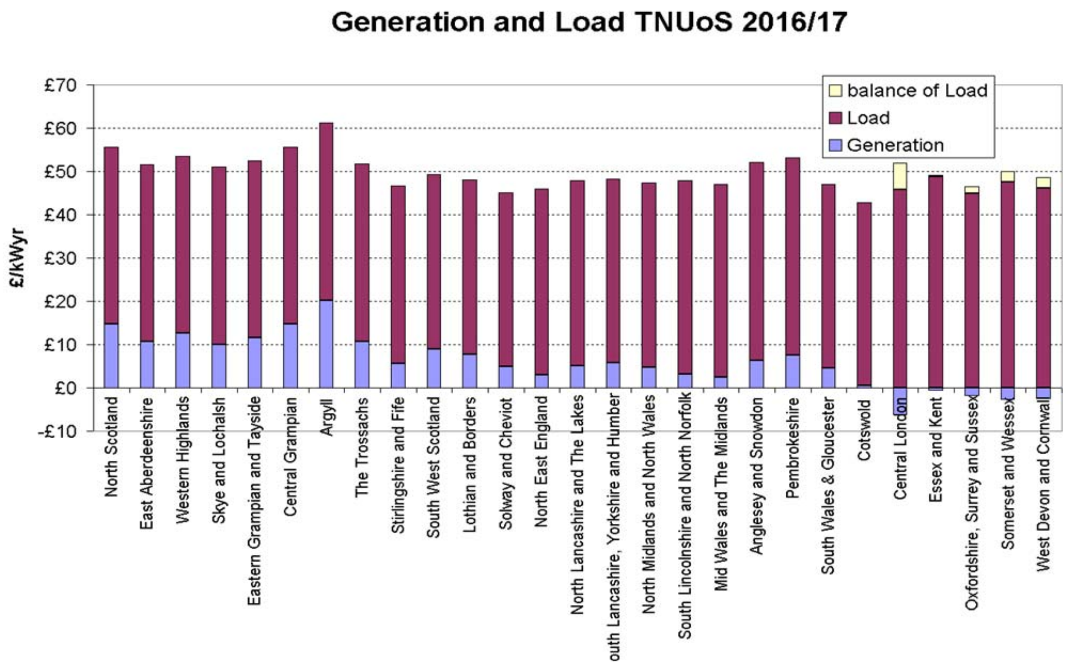

Figure 1 Transmission Network Use of System charges in GB for 2016/17
Source: National Grid (2016)

[11] The distribution company pays the grid for Triad load at the grid supply point, and passes these costs on in full at the Triad to large customers. Domestic customers pay a fixed fee and a variable energy charge that does not distinguish demand at the peak.

The sum of the two charges is in principle passed through to final consumers (and note that their sum is fairly uniform across GB, despite large differences in each element), so in an isolated system the balance between the average G and L charge would not matter. However, in an interconnected market where imported power can compete with domestic generation, the level of the G charges does matter. To improve the efficiency of cross-border trade, the EU has mandated[12] that the *average* G charge should be no higher than €2.50/MWh, and in order to comply with this, G TNUoS charges in areas needing most extra supply are set to be negative. Generators there are paid if they deliver during Triad periods, thus relieving local shortages.

If annual charges are to guide location decisions they should reflect the *marginal* cost that generating at each location imposes on the total system – as LMPs do, and as zonally varying annual charges can to a lesser extent. Different generation location choices can impose very different costs on the network. These costs include reinforcing the network, incurring differential losses, and from the constraints injections may cause. It is therefore surprising that only the UK, Ireland, Norway, Sweden and Romania differentiate G charges by location (ENTSO-E, 2017, table 4.1, chart 7.5). Of these, only Britain, Norway and Sweden have any significant variation; Ireland, with significant constraints, has hardly any locational variation. In addition to providing efficient annual price signals, it would seem desirable to offer long-term contracts at the time of investment to signal not just current local opportunities but those likely in the foreseeable future, as discussed in the next section.

The transmission system is a natural monopoly for which the marginal cost (mainly transmission losses and the shadow values of constraints) falls far below the average cost of an efficiently configured system – Perez Arriaga et al. (1988) estimate that at best marginal costs are 30% of average costs. The difference between the average and marginal cost is akin to a tax required to collect revenue, rather than a price to guide location and use decisions. As such, it needs to be recovered in the least distorting way possible, which, if we leave issues of distributional justice to the Government's tax and expenditure policies, means charging users who would change their supplies or demands the least in response to tariff changes. That probably means levying the fixed costs on final consumers' pre-stated maximum demands. Triad charging may approximate this provided consumers do not install expensive generation behind the off-take metering point, otherwise the L triad charge would over-encourage inefficient local generation merely to avoid a quasi-tax, as explained below. The L TNUoS charges are now high largely to collect the revenue shortfall, and only a small part reflects locational signals. This residual charge has grown from about £10/kWyr in 2005/6 to about £50/kWyr in 2015/16, and is set to go on increasing.[13]

3.3. *Capacity auction results*

The first capacity auction in December 2014 was expected to encourage large efficient and flexible combined cycle gas turbines (CCGTs) to secure capacity agreements, for which it

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[12] Via European Commission Regulation (EU) No 838/2010 at http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:250:0005:0011:EN:PDF

[13] See 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

was estimated that the net CoNE would be £49/kWyr. This was the estimated shortfall after earning revenue in the wholesale energy and ancillary service markets, and paying G TNUoS charges (which in Argyll could be £25/kWyr more expensive than in Central London). The auction in December 2014 cleared at just under £20/kWyr. About 1,600 MW (two turbines) of CCGTs secured agreements but their bankers declined to finance them and they withdrew (paying a modest non-delivery penalty). Instead a large number of small (11 MW) generating units (many diesel) secured agreements, based on the "embedded benefit" they received from Distribution Network Operators for relieving them of paying L TNUoS charges. As argued above, most of this is the revenue-raising or residual element which should not be side-stepped. The net effect of this embedded benefit was worth about £50/kWyr to distribution-connected generators, giving them potentially £70/kWyr compared to just £20/kWyr for grid connected generators.

It took until early 2017 for the regulator, Ofgem, to remove this distortion and ensure that distribution-connected generation would not receive this embedded "benefit" (of avoided revenue collection). Whether this will result in the earlier successful smaller units not connecting (and paying the non-delivery penalty) and prejudicing the aims of the auction to procure adequate capacity remains to be seen, although National Grid has announced an adequate reserve margin for winter 2017/18 (the first delivery period of the EMR capacity auction) with a Loss of Load Expectation of 0.01 hrs/yr.[14] The early exits of the two CCGTs were fortunately counterbalanced by ignoring the contribution interconnectors would make (Newbery and Grubb, 2015).

The other flaw revealed by the capacity auction was that TNUoS charges are set (and potentially changed) annually, so that generators can disconnect and escape the charges by giving a year's notice. A large coal-fired generator chose to do so, and avoided paying G TNUoS charges comparable in size to the capacity payment. The decision to build a new power station is a sunk commitment lasting for decades, and the investment in transmission to deliver that power lasts even longer. Logically the cost of upgrading the network to accept the new power station would be an obligation to pay the full cost of that upgrade, amortized over perhaps 15-20 years, and inescapable on early exit. If the station pays the full (or "deep") cost in this way, it would on the same logic receive the property right to inject the specified capacity at that point for as long as the network links survived, with the freedom to reassign ownership to other entrants if the value to them exceeded the value to the incumbent. This would ensure efficient rather than premature exit signals that might be caused if the TNUoS charge overstated the local value of the capacity released.

3.4 Locational capacity payments

One question that did not need to be addressed in GB was whether the capacity auction should be (GB) market-wide or zonal. Capacity for reliability needs to be deliverable to where the shortage occurs, and transmission constraints may prevent poorly located capacity from providing this service. In GB the main constraint is at the Scottish-English border and Scotland normally exports to England, so this could be a problem. G TNUoS makes it more costly for generators to locate in Scotland, but the main reason for high exports from Scotland

[14] At http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/

is high wind capacity there. Stress events are more likely when the wind does not blow, in which case dispatchable power in Scotland should be able to export and provide reliability services without exceeding the export constraints. In other jurisdictions, like the I-SEM or PJM,[15] these constraints may be important, requiring that there is enough dispatchable capacity capable of delivering to each constrained zone. This may be addressed either by finding the market clearing price in each zone (as in the day-ahead EUPHEMIA auction) if there are enough competitors in each zone, or by paying a must-run or similar reliability premium (above the market-wide capacity auction price) for plant that is essential but faces few competitors, as proposed in the I-SEM.[16]

3.5 Alternatives to capacity auctions

The proposed capacity remuneration mechanism in the island of Ireland involves auctioning a Reliability Option (RO). The winners in the auction receive an annual payment per de-rated kW in exchange for a one-sided Contract-for-difference on the reference price (normally the day-ahead price). The strike price is set higher than the most expensive variable cost plant (e.g. at €500/MWh), and if the market price exceeds that, the holder of the RO pays the counterparty the excess over the strike price (if available) or the whole reference price (if not available). This design has a number of attractive features (Batlle et al., 2005; 2007, Bidwell, 2005). It provides insurance to consumers against high prices while allowing the market price to signal appropriate scarcity (and the proposal is that the System Operator will ensure that there is a floor price in the relevant market set at the Loss of Load Probability times the Value of Lost Load). That means that trade over interconnectors reflects the value in the I-SEM, while confining the insurance to the beneficiaries of the RO, namely just the I-SEM consumers. It is a way of devolving reliability to each Member State without distorting trade between them, and allows each to decide how to best deliver reliability.

3.6 *The carbon price support*

In order to compensate for the inadequate carbon price set by the EU Emissions Trading System the Treasury (Ministry of Finance) legislated (HMT, 2011) a carbon price support to bring the EU ETS allowance price up to "£16 per tonne of carbon dioxide in 2013, rising to £30 by 2020 in 2009 prices. The starting price would be equivalent to £19.16 in estimated 2013-14 prices. The Treasury estimates that the new tax will raise £3.2bn in the three tax years from 2013. In the 2014 Budget, the Chancellor announced that the UK-only element of the carbon price floor will be capped at £18 per tonne of carbon dioxide (tCO2) from 2016-17 to 2019-20."[17]

Figure 2 shows that until April 2014 it was cheaper to generate electricity using coal but thereafter it became cheaper to use gas. The effect of the carbon price support was to displace cheap coal in the merit order, as can be seen in Figure 3, where gas (and increasingly RES-E) have displaced coal, to such an extent that there have been days in the summer with

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[15] See https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx

[16] See https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-17-022%20CRM%20Parameters%20Decision%20Paper_1.pdf

[17] Quotation from http://www.gov.scot/Topics/Environment/climatechange/ukandeuclimatechange/Carbon-Price-Floor

no coal generation (for the first time in over a century). Subsequent announcements prevent any new coal generation entering, as part of the plan to meet the legally binding carbon targets set by the Committee on Climate Change.[18]

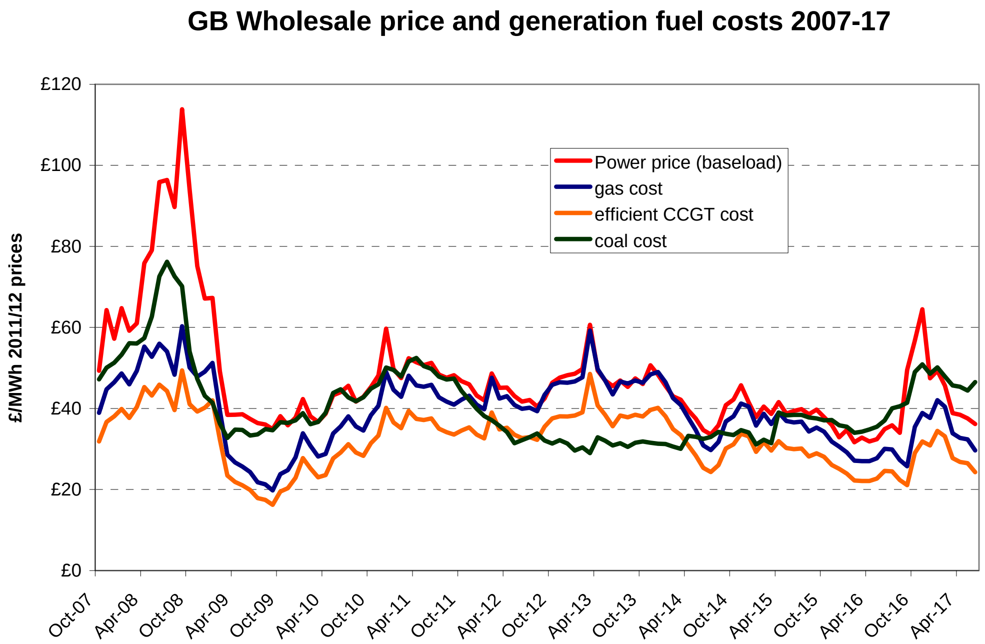

Figure 2 GB wholesale electricity price and the cost of generation, 2007-17 at 2011/12 prices
Source: https://www.ofgem.gov.uk/data-portal/spark-and-dark-spreads-gb
Note: gas cost is for an average efficiency CCGT. Costs include the GB carbon price.

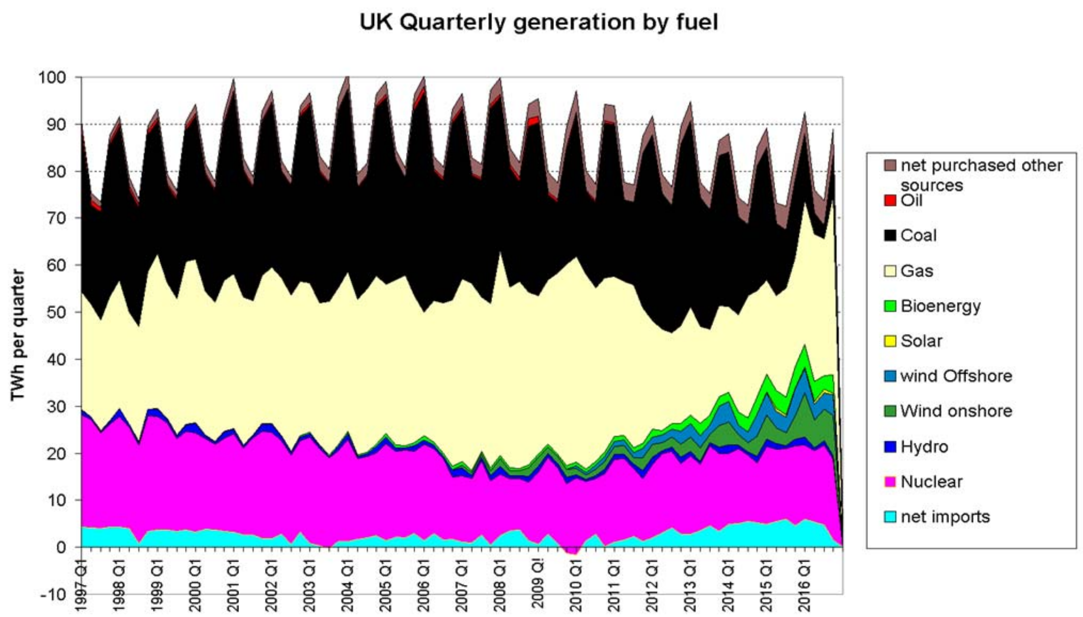

Figure 3 UK quarterly generation by fuel type

Source: *Energy Trends* various years[19]

[18] See https://www.theccc.org.uk/tackling-climate-change/reducing-carbon-emissions/carbon-budgets-and-targets/

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

3.7 *Renewables Support*

EMR introduced Contracts-for-Difference with Feed-in Tariffs (CfD FiTs, CfDs for short) for renewables. This is a contract with the Low Carbon Contract Company (backed by the Government) that fixes the strike price of sales. RES producers sell in the market and either receive the shortfall of the Market Reference Price from the strike price or pay the excess above the strike price. Initially the strike price was set by the Government for each technology after asking financiers what rate of return they would like. Under pressure from the Panel of Technical Experts (DECC, 2013, §79) and subsequently DG COMP, later rounds were offered at auction, starting in February 2015. The results are shown in Table 1 where the administered price was the previously set strike price (now treated as a price ceiling in the auction). The auction clearing prices depend on the year of delivery. Newbery (2016a) shows that the auction reduced prices for on-shore wind by the equivalent of reducing the weighted average cost of capital by 3%. If auctions for all new generation were to have the same effect on the financing cost, the cost saving on the estimated £75 billion of generation investment needed to 2020 would be £2.25 billion per year for 15 years, or a cumulative undiscounted sum of over £1,000 per household.

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 & 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 (2015)

Note: the Solar PV bid of £50/MWh for 2015/16 was withdrawn

Subsequent renewables auctions have produced even more dramatic price reductions, although the Government prevented on-shore wind competing for CfDs after 2015. Table 2 shows that off-shore wind, which had a 2014 administered price of £140/MWh, had auction clearing prices of £74.75 (for 2021/2 when it competed with other RES) and £57.50/MWh for 2022/23, well under half the administered price.

Table 1 CfD Auction Allocation: Round 2

Year		**2021/22**	**2022/23**	**Total Capacity (MW)**
Advanced Conversion Technologies	£/MWh	£74.75	£40.00	
	MW	56.31	8	64.31
Dedicated Biomass with CHP	£/MWh	£74.75	N/A	
	MW	85.64	0	85.64
Offshore Wind	£/MWh	£74.75	£57.50	
	MW	860	2,336	3,196

Source: BEIS (2017)

Figure 4 shows the impact of the change of support policies to RES-E. Progress until 2010 was unimpressive compared with the challenging commitments the UK accepted under the *Renewables Directive* (EC, 2009).

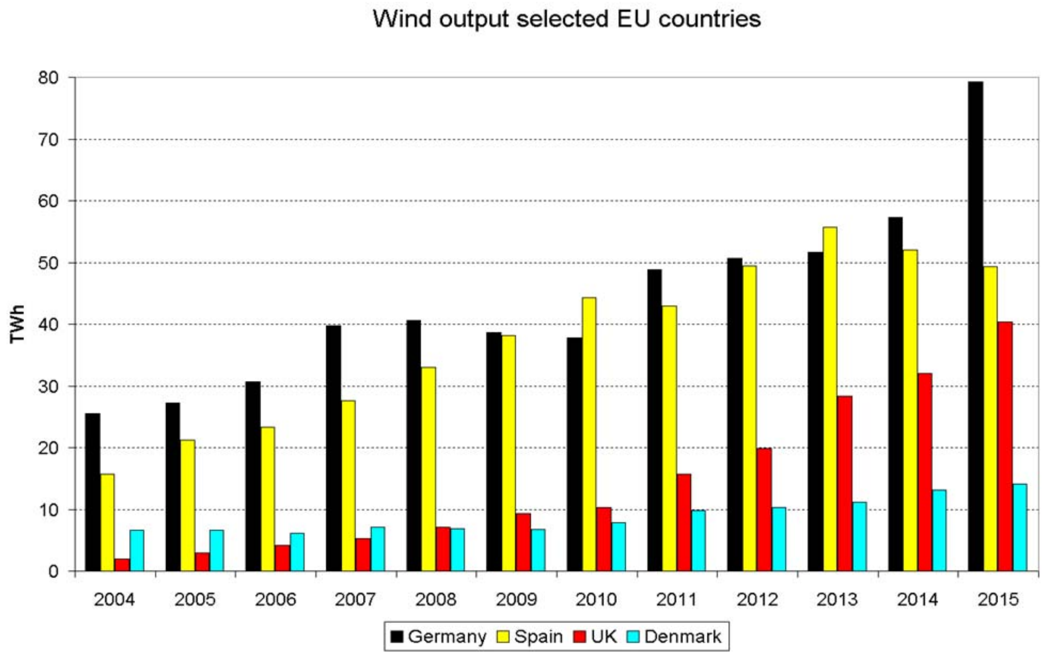

Figure 4 Wind output in UK compared with leading EU wind countries
Source: Eurostat

Figure 5 shows the cumulative *increase* of output of RES as a share of total generation from 2004, for those countries that had a higher increment than the EU average.

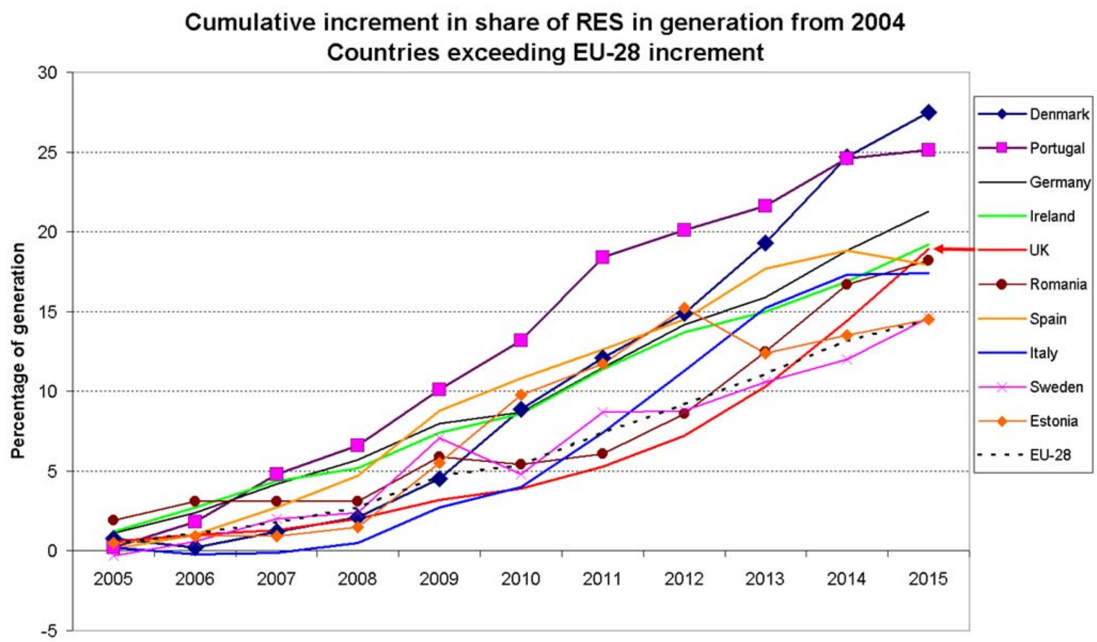

Figure 5 Cumulative increment in share of RES-E in generation in those EU countries with higher final shares than the EU average
Source: Eurostat

The UK lagged this group of countries until 2013, after which it accelerated relative to these countries. Part of this acceleration was probably a result of falling borrowing costs, falling RES costs and over-generous CfD prices set before they were auctioned. Certainly the National Audit Office criticized the excessive cost of transitional (FIDeR) contracts paying these prices (NAO, 2014).

Renewables support policy has now come full circle. In the 1990s RES-E contracts were auctioned, delivering rapidly falling prices, but an increasing failure to deliver (as there were no non-delivery penalties). The obvious solution was to require evidence of progress, which if not provided, would allow the shortfall to be re-auctioned to meet the targets (that were in any case set for some distant future). Instead the system was replaced by the Renewables Obligation Scheme which placed a strong (but costly) demand pull on the suppliers, who had to meet increasing shares of sales from renewables. Initially the scheme was technology neutral, but from 2011 it provided more generous support for less mature technologies. This scheme will end in 2018, despite a preferable alternative available from 2014 from the EMR's CfD scheme, delaying the move to the lower cost auctioned option.

3.8 *The cost of renewables support*

CCC (2015) estimated that the annual support cost in 2020 (at 2011/12 prices) would be £8,275 million, of which the first auction round of CfDs accounts for £338 million, and the FIDeR contracts criticized by NAO for fixing too high a strike price accounts for £1,626 million. Helm (2017) estimates that the total support cost of decarbonising electricity by 2030 could exceed £100 billion, although part of that results from failing to properly charge for carbon, and much of the rest is support for learning externalities, discussed below. The cumulative cost of support (primarily for ROCs and small-scale FiTs) between 2011/12 to 2015/16 is given by BEIS (2016a) as £14.84 billion in 2011/12 prices, during which period 260 TWh of wind, solar and bioenergy were generated (*Energy Trends*. 2016, table 5.7), suggesting an average past support for these technologies of £57/MWh, when the average real wholesale price (shown in figure 2) was £43/MWh.

This support cost needs adjusting in several ways. First, during this period the average EU ETS price of carbon was £9.31/tonne CO_2 but from April 2013 the Government imposed a Carbon Price Support, bringing the average CO_2 price for GB electricity generators up to £14.36/t CO_2 (over the period 2013-16). The UK Government originally argued for a carbon price floor of £30/tonne CO_2 by 2020 and £70/tonne by 2030 (HMT, 2011), but then capped the level until 2020. Taking a compromise value of £25/tonne, the shortfall in the carbon price over this period was about £10/tonne. If the marginal fuel displaced by RES were coal, the value would be £9/MWh, reducing the RES-E support element to £48/MWh. Whether this is high or low will be discussed below in §4.2.

The second adjustment is harder to estimate, and it is the extra system costs (balancing, ancillary services and reliability reserves) needed to accommodate the extra RES. It will depend on the way in which RES-E is paid. In a classic Feed-in-Tariff (FiT), RES-E is given priority dispatch and paid the fixed tariff on metered output, regardless of any balancing and other costs imposed on the system. Watson & Gross (2017) estimated the system cost of RES-E at about £10/MWh up to 30% RES-E penetration, about the same as the shortfall in carbon saving, so in classic FiT systems this should be added to the excess of the FiT over the market price.

In the GB approach, RES-E producers remain responsible for paying imbalance charges and locational TNUoS charges. If both were set equal to the efficient price, their sales value would already include their system costs. As a result, many smaller RES-E producers sign Power Purchase Agreements with aggregators or larger integrated utilities and receive a lower net price per MWh. The auction prices in Tables 1 and 2 are the gross revenue before deducting any of these system costs. While the incremental transmission costs imposed by RES-E may not be fully attributed to them (as it would with deep connection charging) as a rough approximation the RES-E subsidy just needs the deduction for the shortfall in carbon price discussed above. Tables 1 and 2 suggest that the next increment of RES-E could be almost competitive with a properly carbon-adjusted new generation cost. BEIS (2016b) gives the 2020 CCGT levelized cost at £65-68/MWh for the central gas price forecast (with a carbon cost at £18/t CO_2) +/- £10/MWh for high and low gas prices - close to the adjusted cost of on-shore wind of £79 - £9 (for carbon) = £70/MWh.

4. A better way to support and integrate renewables

One of the main problems with the current renewables support scheme is that it rewards output rather than capacity. The main case for providing additional support to RES-E is that increasing the cumulative *capacity* installed drives down costs, benefitting future investors.

4.1 Support for learning spill-overs

Figure 6 shows that for every doubling of cumulative production of PV modules, the price falls by 20-23% as a result of learning-by-doing. As current production is growing by over 30% p.a. the annual cost fall is some 7% p.a (IRENA, 2016). On-shore wind also creates unremunerated learning spill-overs, but the learning rate is lower than for PV, at 7%. The cumulative installed capacity is 487 GW, growing at 12% in the recent past (although now accelerating), implying a cost reduction of about 1% p.a.

This learning spill-over is a global public good, arguing for a collective agreement to compensate installers for the value of this spill-over, e.g. via the *Global Apollo Programme* (King et al., 2015), now re-branded as *Mission Innovation*.[20] The *Renewables Directive* (EC, 2009) mandates shares of renewable energy for each Member State and as such treats the support of RES-E as a club good, in which members collectively fund an agreed amount of total deployment. However, the way the *Directive* set the target, and the way most Member States support renewables, is on renewables output (as a share of total energy), not on installed capacity, which is the driver for the learning and cost reduction.

Ideally, support to RES would be provided on the basis of installed capacity (suitably re-rated to reflect the size of the learning spill-over, larger for solar PV than wind). This could be achieved most efficiently by an EU-wide auction in which Member States offer to support installations in the most cost-effective location. Instead of agreeing shares of renewable energy, Member States could contribute to a central budget on the base of GDP (perhaps progressively, and perhaps with some recognition of past renewable investment).

[20] http://mission-innovation.net/wp-content/uploads/2017/06/MI-Action-Plan.pdf

Taking this idea further in the direction of *Mission Innovation*, the funds to support learning could also be used to support R&D and demonstration, thereby dealing with the missing element of the EC 2016 *Clean Energy Package*,[21] which only partly addresses the problem of funding clean innovation. Again, allocating RD&D funds competitively at the EU level would ensure efficiency (and solidarity), building on the experience of the Ofgem Network Innovation Competitions.[22]

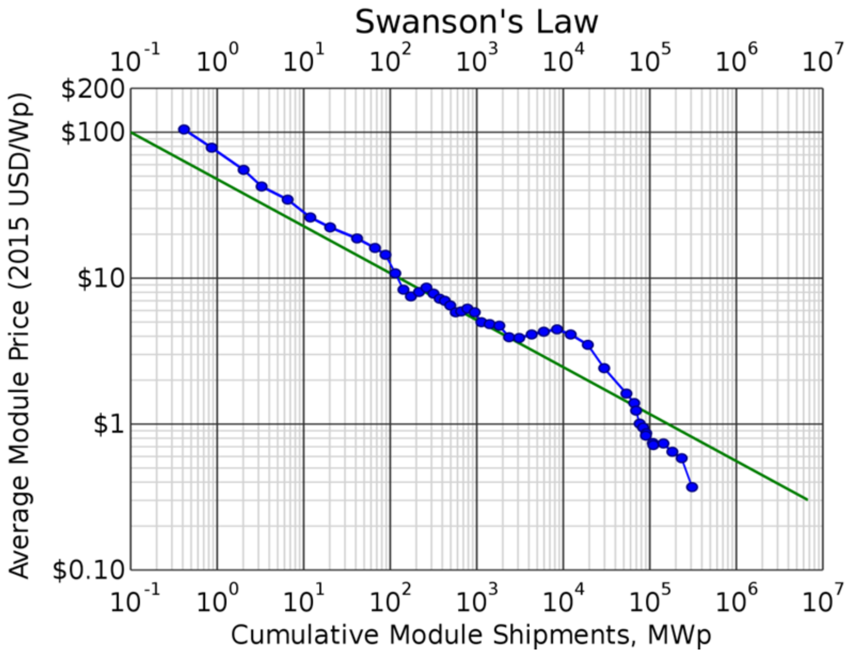

Figure 6 Cost reductions from doubling cumulative PV module shipments
Source: https://commons.wikimedia.org/wiki/File:Swansons-law.svg
Note: The straight (green) trend line represents a learning rate of 20%; the actual rate is slightly higher.

The proposed RES-E capacity auction would invite bids for the support needed per MW of installed capacity, but in order to ensure appropriate delivery, this would be paid per MWh for the first 20,000 MWh per MW of installed capacity (i.e. for 20,000 full output hours). This would be very close to a capacity subsidy, with only a very slight advantage to locating in high resource areas, in that the subsidy would be earned more quickly, and hence have a slightly higher present value. The value of the electricity produced would be effectively the (local) market value, and would thus be on a par with other forms of generation, avoiding locational distortions.

The objection to paying the subsidy per MWh is not only does it over-reward high resource locations, but it also distorts location decisions, even if the transmission charges have been suitably designed to indicate the value of power at each location. Thus a subsidy of

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[21] At https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition

[22] See https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/gas-network-innovation-competition

£50/MWh when the market price is £50/MWh gives a windfarm enjoying 2,500 hrs/yr a revenue of £250,000/MW, whereas one enjoying 2,000 hrs/yr receives £200,000/MW, an advantage of £50,000/MW while the value of the electricity produced is only £25,000/MW higher (£25/kWyr). This difference is more than the difference in G TNUoS across GB and over-encourages wind to locate in Scotland, unnecessarily adding to congestion on the Scottish border.

The 2016 *Clean Energy Package* sets out some details of desirable support schemes in EC (2016b): under (i) Options to increase renewable energy in the electricity sector (RES-E): "A common European framework for support schemes: (1) sole use of market mechanisms; (2) European framework for market-based and cost-effective support; (3) mandatory move towards investments aid." A generous interpretation of this framework would use auctions (thus meeting State Aid requirements) to support installation (i.e., per MW, providing *investment aid* to capacity) and then requiring output to be sold in the wholesale market (satisfying (1) above). Balancing and marketing risk could be covered by suitable contracts to reduce the weighted average cost of capital, while if the market gives good locational and temporal signals, developers will choose higher value locations and avoid saturating local networks. Moving to locational marginal prices (LMPs) is the cleanest way of ensuring that.

4.2 Estimating the justifiable learning subsidy

Newbery (2017b) provides a method for estimating the global value of the learning-benefit of low-carbon technologies, on the assumption that they will eventually become economically viable (i.e. would no longer need any support). In the case of solar PV, the combination of rapid growth and significant problems of market saturation limits the period during which support is either necessary or desirable. At some time before the date of reaching the final market size for solar PV further subsidies are no longer warranted as all they do is advance the date of saturation and do not affect the cumulative amount of remaining capacity to install and hence the future cost reductions, merely when it happens. Current subsidy costs can then outweigh the present value of future benefits.

Different technologies are at different stages of maturity and create different levels of learning spill-overs, arguing for different levels of support. As auctions are the most cost-effective procurement mechanism, this would probably involve grouping technologies into different pots (as in the GB CfD auctions), although in many locations wind and solar PV appear roughly competitive against each other and might be grouped together (even though they have different spill-over benefits).

For solar PV, Newbery (2017b) estimates the spill-over benefit at about 38% of the 2015 PV cost of \$1,050/kW$_p$. At a Spanish location delivering 1,800 MWh/MW$_p$yr it would take just over 11 years to be fully compensated for the capacity subsidy in the auction described above, and the subsidy should then be worth \$400,000/MW$_p$. At a real discount rate of 3%, a payment of \$24 (€22, £16)/MWh (in addition to the wholesale price) would recover that sum over 20,000 MWh (in present value terms). Table 1 shows that the auction price for GB solar in 2016/17 is £79.23/MWh. Even with a low cost of capital, the BEIS (2016) CCGT levelized cost (including carbon) is £65/MWh, only £14/MWh below the auction price for PV in 2016, less than the spill-over benefit.

The formula presented in Newbery (2017b) can be adapted to the case in which there is no clear date of saturation, merely a slowdown in the rate of growth on RES-E in line with electricity demand growth. The fraction of installation cost equal to the present value of future cost reductions is

$$S_t/c_t = bg\,(1-\varphi)\{(e^{-(bg+r)t} - e^{-(bg+r)T})/(bg+r) + e^{-(bm+r)T}/(bm+r)\},$$

where S_t is the learning benefit, c_t is the unit cost of the current installation, at date t, $1-\varphi$ is the share of the cost that enjoys learning spill-overs, r is the social discount rate, b is the coefficient of cost decline in the expression $c_t/c_0 = (K_t/K_0)^{-b}$ where K_t is the cumulative installations at t, and is related to the learning rate λ by $b = -\ln(1-\lambda)/\ln(2)$, g is the rate of growth of the installed base, and T is the time at which the growth of the RES falls to that of the whole market, growing at rate m. Note that this is decreasing in t, the date of the subsidy calculation, so that past subsidy rates would be higher and could justify past more generous rates.

If we assume a learning rate for on-shore wind of 7%, $b = 0.1$, and if $g = 12\%$,[23] $r = 3\%$, $T = 15$ yrs (suggesting a rather high ultimate wind capacity 6 times the current amount, or about 3,000 GW),[24] $1-\varphi = 75\%$,[25] and a (low) installation cost of €1,000/kW (IRENA, 2012), then the justified subsidy could be as high as 28% of €1,000/kW or €280,000/MW, or €17 (£15)/MWh for the first 20,000 full hours (MWh/MW). The latest GB auction price for on-shore wind was £79.23/MWh for the more competitive 2016/17 delivery date, rising to £82.50/MWh in 2018/19 (Table 1) but this higher value may reflect the anticipated hostility to supporting on-shore wind. In contrast off-shore wind costs have fallen to £57.50/MWh, below the levelized cost of CCGT and therefore apparently requiring no subsidy. Even at the low cost of capital for the CCGT, the 2016/17 on-shore wind subsidy is about the same as the learning spillover.

4.3 Addressing carbon price short-falls

There remains a case for a subsidy per MWh reflecting the shortfall in the appropriate carbon price, given that for international trading reasons the Treasury has frozen the carbon price support (and other EU countries lack even that support). Depending on the marginal fuel displaced (averaged over perhaps a year) and the EU ETS price this could be somewhere between £5-10/MWh, and would be payable not just to RES-E but also to nuclear power and plant with Carbon Capture and Storage (for its carbon credit).

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[23] Recent growth rates have been 16-17% p.a. (WEC, 2016).

[24] https://www.statista.com/statistics/238610/projected-world-electricity-generation-by-energy-source/ projects world RES-E output in 2030 about 9,000 TWh. At 2,500 full hrs/yr this would deliver about 7,400 TWh, close to the total RES-E limit.

[25] Share of turbine in installed cost from IRENA (2012). IRENA (2016) reports a global average (not low cost) installation cost for on-shore wind of US$ 1,560/kW

4.4 *Flexibility services*[26]

All RES-E except storage hydro and biomass are intermittent, and if quality of service and security of supply are to be ensured, additional flexibility services (as well as reserves) will be needed to manage this intermittency. High levels of intermittent generation reduce the amount of system inertia (the spinning mass of conventional synchronised turbines and rotating equipment) and make the system less resilient to fluctuations in supply or demand. Wind can be reasonably well forecast a few hours ahead, giving time for conventional plant to ramp up if warm, and for some plant to start from cold. Sudden cut-outs of wind from excessive gusts (or failure to ride through faults and frequency fluctuations) and more so from solar PV experiencing cloud cover require more rapid responses, in an extreme, measured in milli-seconds if frequency is to be maintained, particularly with low system inertia.[27]

The island of Ireland is at the forefront of adapting its system to accommodate up to 75% non-synchronous (i.e. intermittent) generation through its DS3 (*D*elivering a *S*ecure *S*ustainable Electricity *S*ystem) programme.[28] This programme proposed seven new System Services for frequency control (such as Synchronous Inertial Response and Fast Frequency Response) and voltage support (such as Dynamic Reactive Response) to complement the existing seven services, described in more detail in Newbery (2017a). GB is addressing this need for more flexibility through procuring additional enhanced frequency response.[29] Distribution-connected large batteries have been successful tendering this service, as they can deliver the required 100% of specified capacity within one second.

Batteries are often claimed as a solution to intermittency, as they can store surplus power (e.g. in the day-time) for release later (e.g. at night) and for off-grid such batteries (or back-up generation) are necessary. However, their cost is still very high. Lazard (2016) surveys a range of chemical and other storage formats. The preferred chemical batteries (Lithium-ion and Sodium-Sulphur) still cost more than $250/MWh levelised cost, so that even if the purchased electricity is free, it requires a value or selling price higher than this to cover its cost. To date their value has been primarily derived from delaying expensive upgrades to transformers or distribution networks, followed by short-term flexibility responses, with only a small part coming from arbitraging prices (Newbery, 2016b).

Flexibility is often more cheaply provided by strengthening networks so that local imbalances in supply and demand can be managed by importing or exporting power from more distant locations experiencing different local conditions. Pumped storage plant (PSP), and more significant in scale, storage hydro, can similarly accommodate fluctuations in demand and supply, and their scale dwarfs chemical storage. Globally chemical battery storage is only 0.1% of pumped storage capacity - PSP has about 1.7 TWh - while global storage hydro systems provide 2,700 times the global PSP capacity (Newbery, 2016b). For

[26] See also Imperial College London (2015).
[27] One measure is to increase the default settings for Rate of Change of Frequency (RoCoF) above which generators and some equipment disconnects to protect itself, allowing the system more time to correct frequency fluctuations, but this is not costless.
[28] http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/
[29] http://www2.nationalgrid.com/Enhanced-Frequency-Response.aspx. The site gives the definition and the tender prices for the service.

the Continent accessing this storage hydro by interconnection is therefore very attractive. Norway can store up to 82 TWh and averages just under 70 TWh while Spain has about 25 TWh, many orders of magnitude greater than PSPs.

The simplest way to find the least-cost way of providing the necessary solutions to deliver the reliability standard is to run a capacity auction, as in GB, with the proviso that local reliability may need targeted local solutions as discussed in §3.4. Recent auctions have procured new generating capacity, batteries and demand side response, all competing to receive the same price per de-rated kW. As discussed above, different technologies can only be properly compared if the network tariffs are efficient and the various flexibility services are properly priced. In the 2016 GB capacity auction 500 MW of batteries won capacity agreements, but all storage was de-rated as though it were pumped storage, which typically can supply power for at least 6-8 hours. Batteries may only be able to deliver their rated output for 30 minutes. If in stress periods power is needed for several hours, they should properly be derated accordingly – in Ireland they would be derated to 25% of their nominal output, while Britain has recently published a new set of more realistic derating factors for batteries.[30]

5 Conclusions and policy implications

Designing the wholesale market to accommodate significant RES-E penetration also requires other reforms to transmission pricing and the form of support if RES-E is to be delivered at least cost. The wholesale market redesign has to address two major market failures – the inadequacy of and lack of credibility of current and future carbon prices in the EU ETS, and the need to compensate developers for the learning spill-overs that wind and solar PV currently create. In addition, there are important markets that are missing, notably futures markets for energy and ancillary services. Future price expectations of both energy and ancillary services are critically important for guiding the right choice of suitably flexible generation (and demand response) to accommodate growing levels of intermittency and falling levels of system inertia.

Some flexibility services (notably very fast frequency response and rapid ramping) may lack price signals in many markets, although SO's are increasingly recognising the need to create such markets or contract for these new services. Rapid developments in ICT, smarter grids and distribution networks, active network management and the emergence of aggregators may, however, alter the value and prices of these flexibility services quite rapidly, making current price signals an unreliable good guide to their future value.

Transmission and distribution networks will need to accommodate very different patterns of connection and flows, leading to the need to better coordinate investment in wires and generation. If tariffs are relied upon to give good price signals, they will need to ensure that the efficient price signals based on marginal costs are not distorted by the need to recover average costs. The difficulty of ensuring that may require a central planning body that designs network expansion and makes suitable RES-E sites with access to networks available for auction. If markets are preferred to planning, then nodal pricing looks increasingly

[30] At https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/664272/capacity-market-consultation-improving-framework-response.pdf

attractive in giving better dispatch signals in the short run and potentially better location guidance in the longer run (when combined with longer term hedging contracts).

RES-E support is justified partly by the inadequate carbon price, for which an additional premium per MWh reflecting the value of carbon saved is appropriate, and partly by the learning spill-overs. A better EU-wide RES-E support system would collect funds from Member States and then auction off capacity supports (e.g. for a specified number of full hours operation) EU-wide, ensuring the RES-E connected where the value of the resource and the cost of delivery delivered least system cost. The funds could also be used to support EU-wide low carbon innovation.

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