# Reforming Renewable Electricity Support Schemes

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- The UK plans to build as much renewable electricity (RE) by 2030 as it has to date
- Current supports (ROCs and CfDs with FiTs) distort location and operating decisions
- While it is desirable to confront developers with marker prices they need a hedge against their future uncertainty (of policy change, cannibalisation, etc.) to lower finance costs
- This note provides the contract design for an auctioned yardstick premium CfD that avoids all these problems and enables a seamless transition to "subsidy-free" RE

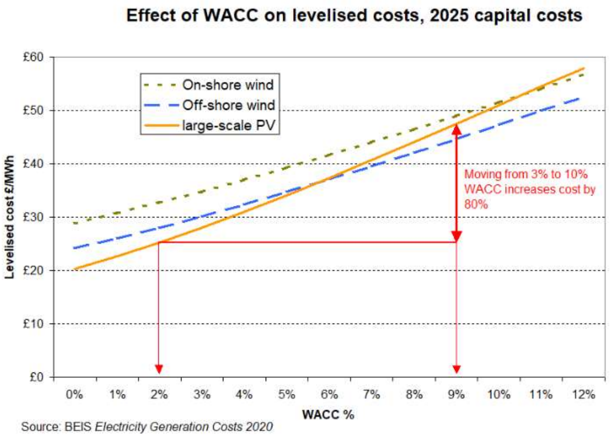
**Background**

The UK proposes to more than double installed variable renewable electricity (VRE, i.e. wind and solar) between 2020 and 2030.[1] Even at the future, lower, 2030 installation costs the average across all National Grid's *Future Energy Scenarios* (FES) is £61 bn.[2] The Government has recently published its report *Enabling a High Renewables, Net Zero Electricity System: Call for Evidence; Government response*. It reported that "Most respondents felt there was not a viable route to market for renewable projects based principally on future wholesale market prices. Primarily, this was because the wholesale market is not deemed investable by investors due to future price risk, price volatility, the likelihood of more frequent occurrences of price cannibalisation, and the lack of mitigations to protect investors from these risks. …the current CfD design exacerbates the issues of price volatility and price cannibalisation. This is because projects are insulated from market signals and this becomes a barrier to the deployment of renewable projects without government support. … increasing exposure of renewable projects to market signals would add to the cost of financing renewable projects." (pp8-9).

The main future sources of renewable electricity are wind and solar PV. They have high capital costs but low running costs. Variable running costs for PV are zero, while for wind they are modest. It follows that their major cost is the financing cost – the weighted average cost of capital, WACC. The more predictable and certain are the costs and revenue streams at the time of final investment decision, the higher the share of debt: equity and the lower the WACC. Risk increases the WACC, so reducing risk is the most effective way of lowering RE costs. The figure

[1] FES 2021 shows VRE in 2020 at 36 GW, and scenarios for 2030 ranging from 70 GW (Steady Progression) to 113 GW (Leading the Way).

[2] BEIS *Electricity Generation Costs 2020*




shows the dramatic effect on levelized cost (not the same as the value) of lowering the WACC. Between the BEIS generation cost estimates of 2016 and 2020 the hurdle rate (i.e. the WACC) for offshore wind was reduced from 8.9% to 6.3% (both real before tax). This is still high compared to the social discount rate of the Government's Appraisal Manual used for climate change mitigation evaluation.

The need to respond to wholesale price signals while also reducing risk to lower the cost of finance recurs, but without resolution in the *Response*. The need for market signals includes "altering the location of sites, specifically to avoid a correlation of generation with similar technology types." Exposure to real-time prices has additional value, hence the "focus should be on ensuring CfD generators can take part in balancing services". (p12.)

There is therefore widespread acceptance that existing renewables support schemes (certainly the previous RO scheme but also its replacement, the Contract-for- Difference with Feed-in-Tariff (CfD with FiT) distort location and dispatch decisions. While the RO scheme imposed unnecessary risk on developers, it only partly exposed renewables to wholesale prices. It encouraged developers to choose sites uncorrelated with other price-depressing VRE, but it still over-rewarded high resource sites. CfDs with FiTs successfully removed price risks but at the expense of removing market signals and hence failing to address both distortions (of locating and operating).

The EU *Clean Energy Package* (EU 2018/20010, §19) requires that "Electricity from renewable sources should be deployed at the lowest possible cost to consumers and taxpayers. … Market-based mechanisms, such as tendering procedures, have been demonstrated to reduce support cost effectively in competitive markets in many circumstances." Well-designed auctions dramatically reduced the clearing prices of successive auctions for off-shore wind in the North Sea. This note outlines a design for an auctioned contract to deliver Variable Renewable Electricity (VRE) "at the lowest possible cost to consumers and taxpayers". Perhaps the most significant change in the *Clean Energy Package* was to remove the country-specific targets of renewable energy output shares, which directly encouraged *output* subsidies.

The first step in designing a renewable electricity support scheme (RESS) is to identify the market failures that need correction. If carbon is properly priced the only externality to address is the learning spill-over – investment creates demand that stimulates R&D, developing supply chains and scaling up production, all driving down future costs. That benefit is not captured by current investors or manufacturers unless subsidized. As June 2021 carbon price levels in the EU and UK were over €50/t $CO_2$, within the required Paris target-consistent carbon price range, there is no remaining case for subsidizing output rather than investment.

Least system cost requires that new VRE is the right design (able to offer some balancing services), locates in the right place and is dispatched optimally. Least cost to consumers includes the cost of any subsidies to persuade VRE of the commercial case to enter. Auctions are the best way to deliver least cost procurement, while giving control over the volumes of RE or the cost of RESS. For auctions to work well, bidders need clarity on factors that affect their future revenue streams (for ancillary services, the route to market and system operating rules or Grid Codes (including differential locational transmission charges). Many respondents to the consultation argued “to hold the CfD auctions on a more frequent basis (e.g. yearly)” (p9). A predictable future timetable of auctions with indicative volumes would create confidence to build up capacity in developing, manufacturing, and installing VRE.

**Current distortions**

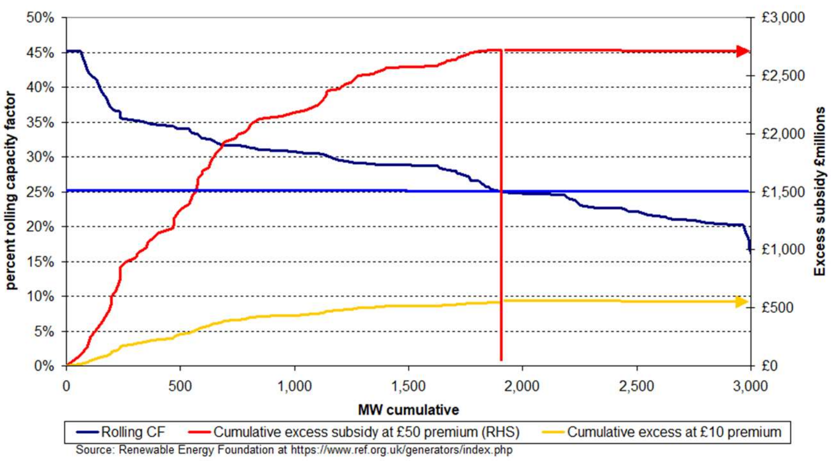
The present renewable electricity support schemes (RESSs) provide a subsidy conditional on delivering electricity for a fixed number of years. This conditionality is the root cause of location and operating distortions, as well as unnecessarily raising the cost of support. The location distortion is simply illustrated. Suppose there is a windy but distant location with on average 2,500 full operating hours per year and a less windy but central location (close to demand) with 2,000 full operating hours. Suppose the average wholesale price is £40/MWh and the support scheme (e.g. the ROC) provides a premium of £40/MWh on the market price of £40/MWh (or the CfD with FiT has a strike price of £80/MWh). Suppose also that the extra system costs of the windy compared to the central location are £25/kWyr.

The net *economic* value of the electricity produced at the windy location is £40/MWh x 2,500 hrs - £25,000/MWyr = £75,000/MWyr and of the central location is £40 x 2,000 = £80,000/MWyr. From a system cost perspective it is better to locate centrally. Under the RESS, however, the windy location will earn net revenue of £80 x 2,500 - £25,000/MWyr = £175,000/MWyr and the central location will earn £80 x 2,000 = £160,000/MWyr, an advantage of £15,000/MWyr. The developer prefers the inefficient windy location.

This can be avoided by specifying the length of support not in years but in full operating hours, e.g. 30,000 MWh/MW. In the previous example, the windy location would cease receiving above market support after 12 years, while the central location will receive support for 15 years. Discounting at 5% real, the present discounted value of the subsidy is only 6.7% higher in the windy location, not enough to offset the extra system costs.

The second effect of over-rewarding high resource locations becomes clear in an auction where the subsidy is set by the least profitable offer (the one needing the highest subsidy). Figure 2 shows the result of running an auction for two values of the premium (over market price) of either £50/MWh or £10/MWh (the former is closer to the earlier ROC value). It shows the average capacity (or load) factor

**Fig. 2 Rolling CF of recently ROC-supported GB wind farms**



Source: Renewable Energy Foundation at https://www.ref.org.uk/generators/index.php

(CF) since installation for wind farms of above 1.4 MW installed after 1/1/15 in England and 1/1/16 in Scotland (to give comparable numbers for each nation). Now suppose that support had been auctioned for a fixed number of MWh/MW (i.e. for 15 years at a 25% CF or just under 33,000 full operating hours). If the marginal wind farm had bid for a ROC price of £50/MWh (or a CfD with FiT at £50/MW above the expected market price) and cleared at a CF of 25%, then the rising line shows the cumulative excess subsidy paid out to infra-marginal wind farms. For the 1,900 MW that would have been accepted, the excess subsidy amounts to £2,720 million (undiscounted over the number of subsidised full operating hours) in the high subsidy case and £544 million (20% as high) in the lower (future?) subsidy case.

The operating distortion arises because the VRE will be willing to offer even negative prices to be dispatched, or else risk losing the subsidy for that hour. Thus if the variable operating cost of on-shore wind is £6/MWh and the strike price under the CfD with FiT is £80/MWh (Round 1), the wind farm would be willing to accept any price above *minus* £74/MWh. As such they would not be accepted for constraining-off to deal with congestion, and they would need to be paid a lost profit of £74/MWh to reduce output in the balancing market.

The distortion arises because of the form of the hedge. A normal Contract-for-Difference (CfD) is a purely financial hedge on a fixed volume independent of actual generation, but a CfD with FiT for wind and solar is a hedge on metered output. Consider a fossil generator with avoidable operating costs of £40/MWh and a CfD for 1 MW at strike price of £50/MWh. If the wholesale price is £5/MWh, the generator receives £50-£5 = £45 from the CfD, regardless of whether she chooses to operate or not. Not generating avoids the operating cost of £40/MWh, leaving the financial hedge revenue of £45/MWh.  Generating provides £5/MWh from the market, *less* £40/MWh operating cost, or a *loss* of £35/MWh to offset against the hedge of £45/MWh. The generator chooses not to be dispatched, and is guided by the market price.

In contrast the VRE with a CfD with FiT at a strike price of £50/MWh payable only on delivery, can either make zero by not operating, or offer into the market at a large negative price (up to *minus* £44/MWh). Such an offer will be accepted and paid the market price of £5/MWh, which will be made up to £50/MWh by an additional payment of £45/MWh under the terms of the CfD with FiT, producing a profit of £50 - £6 (operating cost) = £42/MWh, even though its avoidable cost is above the wholesale price, so the VRE should not operate.

VRE has a peak output that is a considerable multiple of its average output. For wind this might be 3:1; for Northern solar PV 10:1. As VRE penetration increases the surplus output will need to be curtailed. An efficient RESS should encourage VRE to choose not to generate if the value of its output is less than its avoidable cost. With PV with zero variable operating cost this can be ruled out by prohibiting negative offers. With wind a similar prohibition would cause only minor operating distortions. A better solution is set out and explained below.

**Saturation and encouraging diversity of location**

The responses to the BEIS consultation considered it desirable to alter “the location of sites, specifically to avoid a correlation of generation with similar technology types.” (p11). Once VRE penetration becomes high enough to cause significant reductions in wholesale prices in high capacity factor (CF) hours finding sites with a lower correlation with the system-wide CF becomes important. If VRE faced market prices they would (other things equal) prefer sites with higher average wholesale prices, which means avoiding low price hours caused by VRE saturation and hence finding sites with lower correlations with the system CF.

Fig. 3 Revenue per MW and per MWh by UK region

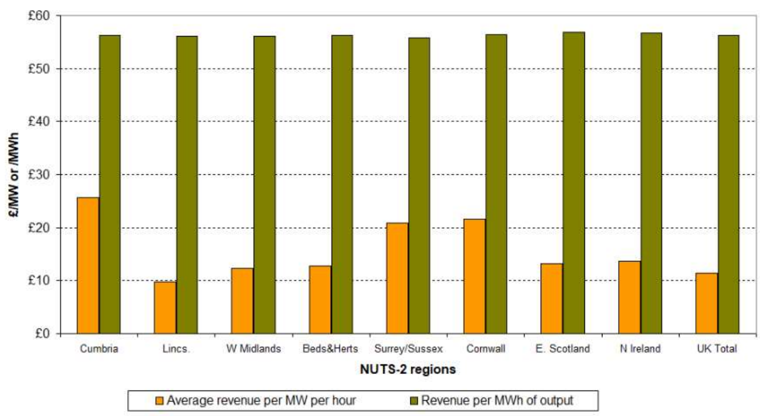



Figure 3 illustrates this using the MERRA-2 capacity factors for the average wind year 2018 but scaling up market prices and wind output to give many hours of zero price for a simulated year (2025). The price forecast is admittedly simplistic in which wholesale prices are either zero when there is excess wind (16% of the projected future year), or otherwise scaled up from 2018 spot prices to give the average forecast price of £56.9/MWh over the whole year.[3] The value of output per MW capacity varies from a low in Lincolnshire of £9.73/MW (averaged over every hour of the year) to a high in Cumbria of £25.62/MW. In contrast, the market revenue per MWh delivered is far more uniform across the country.

The guiding principle in designing a suitable RESS is to start from market prices, particularly now that VRE costs have fallen to the point that they are almost “subsidy free”. The trick is to make average revenue stable, but to provide a suitable hedge against the fear that developers have of future cannibalization or other threats to market prices. The starting point is for the contract counter-party to estimate the time path of the region-specific VRE output-weighted wholesale price, much as is done at present in forecasting future energy prices (e.g. BEIS, 2020b). The regional value of output per MWh ranges from a low of £56.05/MWh in Lincolnshire to a high of £56.86/MWh in Cumbria in the simulations reported above. The logical hedge is to set the base strike price at the expected regional VRE output-weighted average per MWh, and then for the auction to set a premium to this base price, to create a Premium CfD. Thus if the premium is £10/MWh, the strike price in Lincolnshire would be £66.05/MWh and £66.86/MWh in Cumbria. Admittedly, the variation is not that large (overall less than 2%), in part because solar PV output is negatively correlated with wind, reducing overall VRE cross-region output diversity. It may become more significant as excess VRE drives prices down in some hours, while the high cost of meeting shortages of VRE drives up wholesale prices on windless dark winter evenings.

**An hour-limited yardstick Premium CfD for VRE**

Putting all these elements together, the proposed solution is a novel auctioned contract to address both location and dispatch distortions: a financial Premium CfD (PCfD) with hourly contracted volume proportional to the *forecast* local output/MW, with a life specified in full operating hours (e.g. 30,000 MWh/MW). The auction would set a Feed-in-Premium, *f*, to be paid

[3] Baseline projections for 2025 are £56.90/MWh baseload. See Annex M

on top of a regionally VRE-weighted wholesale price, equal to a projected average regional revenue/hr per MW over the expected life of the contract. Thus if the forecast future price in hour *h* and year *y* is $P_{yh}$ and the regional average capacity factor is $\theta_{rh}$ in region *r*, then $EP_{yh}\theta_{rh}$ is the expected wholesale hourly revenue, and the expectation E is on the future forecast prices and the time period is comparable to debt tenors (10-15 years). The regional base price is $b_r = EP_{yh}\theta_{rh}/\theta_r$, where $\theta_r$ is the annual average CF, so the regional strike price would be $s_r = f + b_r$. The formula for the yardstick PCfD would be $(s_r - p_h).\theta_{rh}$, where the capacity factor $\theta_{rh}$ (CF, MWh/MW) in that hour is *forecast* by the contract counterparty day-ahead and $p_h$ is the hourly day-ahead wholesale price, as illustrated above.[4]

This rather complicated formula is performing a number of functions at the same time. First, as $\theta_{rh}$ is the *forecast* output per MW in that region, payment is independent of the actual output, ensuring efficient dispatch. Second, the base price encourages VRE to locate in areas which have higher average wholesale value for the particular output pattern of the VRE, notably where the CF has a low correlation with the system VRE CF. As high VRE will drive prices down as penetration reaches higher levels, a low correlation with the system VRE translates into avoiding periods of low prices, and raises the average value. While the forecast prices will reflect the best modelling available, in practical terms the price adjustment steers new investment to where it is considered most valuable. Each auction round can re-compute the price adjustment in the light of emerging evidence of local saturation. Finally, fixing the contract in full hours (MWh/MW) means that the full auction premium needed to attract entry will pay the same amount per MW regardless of location.

As an example, consider a windfarm located in Cumbria. Suppose the local forecast for 3pm the next day is 0.40 MWh/MW and the windfarm contracts to sell this amount in the day-ahead market (DAM), where the DAM hourly price is £45/MWh. If the regional strike price is £65/MWh and the PCfD is settled on the day-ahead price, the windfarm will receive £(65-45)*0.4 per MW from the PCfD and £45*0.4 from the DAM, or £26/MW (= £65*0.4). On the day, suppose that by the time the balancing market opens the wind has dramatically increased (by 25% to 0.5 MWh/MW) and the balancing price has fallen in response to £4/MWh, below the variable cost of the windfarm (£6/MWh). In response, the windfarm chooses not to generate, pays imbalance charges on its DAM sales of 0.4*£4 = £1.6/MW. It avoids 0.5*£6 = £3/MW in operating cost if it had generated its full output, and so is £1.4/MW better off not generating, while still enjoying the CfD payment of £26/MW. (The contract payment would of course count against the allowed number of supported MWh/MW.)

If the forecast is unbiased, then on average the windfarm will receive its actual output times the strike price for the contracted number of full operating hours. As the actual output does not depend on the forecast (provided by the counterparty to the hedge), output decisions will be guided as with a normal CfD by the actual spot price. That hedges price risk and the problem of over-rewarding high resource costly locations but removes the incentive to locate where local RE output has a high correlation with national RE output and hence lower value.

[4] Fuller details are available in the underlying paper, Newbery (2021).

While correcting for correlations is important for addressing curtailment and zero prices, locational network use-of-system charges are also important for managing local congestion: “The majority of respondents identified the locational nature of transmission charges as one of the key factors in incentivising a CfD project’s location” (p13). The appropriate network charge is a long-term transferrable transmission contract based on projected nodal prices (as the current zonal transmission use-of-system charges are set to reflect congestion and losses). That transfers risk from commercial VRE developers to the regulated network companies, whose revenues from such contracts are guaranteed by the regulatory contracts they hold. Developers could also be offered non-firm contracts which do not guarantee dispatch until it is economic to reinforce the network.[5]

**What if VRE costs are “subsidy-free”?**

Projected VRE costs appear to be below forecast wholesale electricity prices at low WACCs (at least, ignoring any additional system costs and transmission investment needed to accommodate the planned VRE increases). Nevertheless, as the responses to the consultation kept stressing, “increasing exposure of renewable projects to market signals would add to the cost of financing renewable projects.” (p11.) The contract developed above has the agreeable property that it automatically deals with falling VRE costs. Successive auctions should reveal falling premia, which could even go negative, reflecting the value of the hedge compared to risking volatile wholesale prices. At the end of the contract one-year Premium CfDs can be offered, again with regional strike prices.

**Conclusion**

This volume-limited yardstick PCfD delivers efficient dispatch while assuring but limiting the total amount of subsidy, providing efficient location and operating signals. The revenue assurance, with a government-backed counterparty, allows a high debt share, dramatically lowering the subsidy cost when subsidies are needed, and facilitating the entry of “subsidy-free” VRE when that time arrives.

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[5] As successfully introduced on distribution networks, see https://www.ofgem.gov.uk/publications/flexible-plug-plays-successful-delivery-reward-application