Powering Net Zero

Appendix 2 & 3

Policy Exchange

Contents

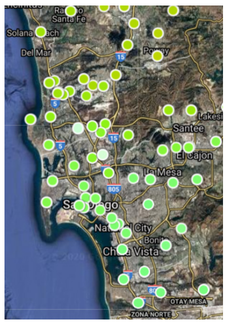
Appendix 2: Detailed policy options

This appendix explores policy options for the GB electricity market in more detail.

Policy options for the wholesale electricity market

There are three major design options for the wholesale electricity market, which are summarised in Table 10. The GB electricity market currently uses national pricing. Regional pricing and local pricing are explored in detail below.

Table 10: Summary of policy options for the wholesale electricity market.

Policy Option:	National pricing (Current policy)	Regional pricing	Local pricing
Technical name	Uniform pricing	Zonal pricing	Nodal pricing
Example	Great Britain	Italy.[1]	California.[2]
# of zones	1 zone	6 zones	c.10,000 nodes
Map			
Advantages	Maximises liquidity, which reduces hedging costs.	Considers the most important transmission constraints, whilst retaining liquidity.	Considers almost all network constraints, rewarding customers and generators who react to market prices.
Disadvantages	Ignores physical network constraints, leading to higher 'constraint costs'.	Does not consider network constraints within zones, which can be substantial.	Lower liquidity, high volatility at individual nodes. Risk of a 'postcode lottery' for customers.

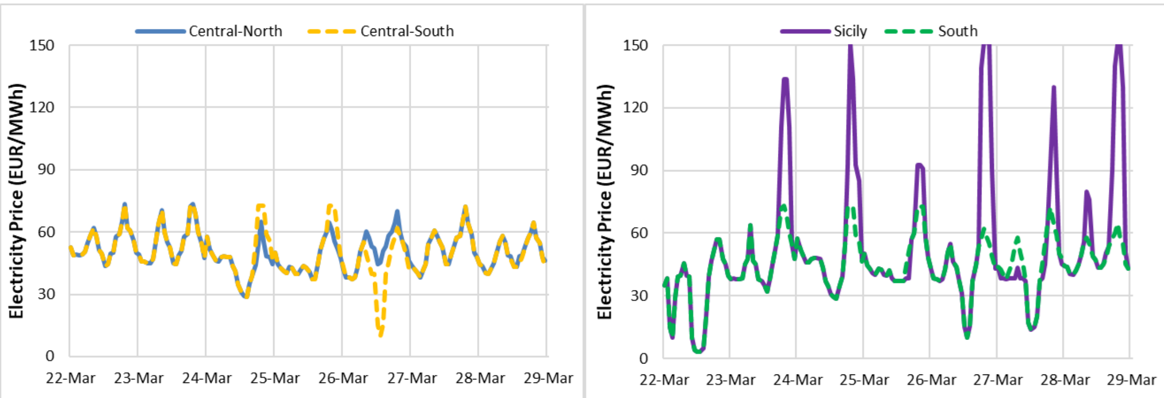
1. Image link
2. Image link

Regional pricing (zonal pricing) splits electricity markets into smaller pricing zones.

In a regional electricity market, there is a separate wholesale electricity price in each region, known as zones. When the network capacity between two zones is not fully utilised, demand can be met by a generator in either zone. This means that the neighbouring zones will have the same price, which happens most of the time. However, at other times, there will be a surplus of generation in one zone, for example 'Zone A', that is greater than the network capacity between Zone A and neighbouring Zone B. In this case, the network is said to be 'congested' and Zone A will have a lower price than Zone B. Regional pricing automatically resolves network constraints between zones, rather than relying on the electricity system operator (ESO), as we do in Great Britain. Examples of regional electricity markets include Italy, Denmark, Sweden and Norway.

The Italian electricity market has six zones: North, Central-North, Central-South, South, Sardinia and Sicily. There is a limit on how much electricity can be transmitted between each zone, based on the technical parameters of the network. Figure 22 shows electricity prices in selected zones for one week in spring 2019. The left panel shows that prices in the Central-North and Central-South zones were the same in almost all hours. In 2019, these zones had the same price in 80% of hours. The right panel shows electricity prices in the South and Sicily zones over the same period. These zones had different prices in more hours, especially at peak times. This reflects the limited network capacity between Sicily and the Italian mainland, as well as the higher cost of generating electricity on Sicily. In 2019, these two zones only had the same price 50% of the time.

Figure 22: Italian electricity prices in the day-ahead market for one week in spring 2019. (Left) Central-North and Central-South zones. (Right) South and Sicily zones.[3]



Without regional electricity pricing to resolve the network constraint between Sicily and the mainland, the Italian electricity system operator would regularly have to pay generators on Sicily to increase their output, whilst paying generators on the Italian mainland to reduce their output. Regional electricity pricing also sends a clear signal to developers of power

3. Policy Exchange analysis of data from Gestore Mercati Energetici (Italian electricity market operator). Link

stations and battery storage that, if they want to capture high peak prices, they should build their projects on Sicily.

It is not only renewable generators that can cause network constraints. In Ireland, which uses national pricing, technology companies have recently connected several new data centres in Dublin. This has started to create problems for the system operator, which could be mitigated by moving to regional pricing.[4]

However, even markets with regional pricing can suffer from rising constraint costs as the share of renewables increases. Analysis of the Italian electricity market shows that, during the peak of the coronavirus lockdown, constraint costs doubled relative to the same period in previous years.[5] Constraint costs arise in regional electricity markets because regional pricing only takes into account transmission constraints between zones, and ignores constraints within zones.

4. Eirgrid (July 2020). *Consultation on data centre connection offer process and policy.* Link. See page 4.
5. Graf, C. Quaglia, F. Wolak, F. (June 2020). *Learning about electricity market performance with a large share of renewables from the COVID-19 lock-down.* Link

Local pricing (nodal pricing) creates thousands of pricing nodes, all of which could have a different price.

Regional pricing helps to reduce the impact of major network constraints between zones, as shown by the example of Italy above. However, there can still be constraints within a zone. For example, if there are a large number of solar generators in a local area, then this can cause network constraints when it is sunny and when demand is low. This may be one factor that contributed to higher constraint costs in the regional Italian electricity market during the coronavirus lockdown.

Local pricing accounts for local network constraints by splitting the electricity market into a large number of pricing 'nodes'. For example, the main electricity market in Texas (ERCOT) had four price zones until December 2010, when it was split into around 4,000 nodes.[6] By moving to local pricing, the ERCOT electricity market now more accurately reflects the constraints on the network. This reduces the need for the electricity system operator to resolve constraints, because constraints are included in the market. It also encourages generators, energy storage and customers to react to local prices, which reflect local supply and demand for electricity. In the United States, local electricity markets also operate in almost all competitive wholesale electricity markets, including California, New England, New York State, Texas and the eastern United States (PJM). Mexico, Chile, New Zealand and Singapore also using local pricing.

Even under local pricing there can still be network constraints within each node, although constraints are much less frequent than in national or regional pricing. The ESO, or a local system operator, is still needed to resolve these local constraints. For example, as customers adopt EVs and heat pumps, there could be constraints in some streets but not in others.

Alongside local pricing, the ERCOT market in Texas schedules some system balancing services as part of the wholesale electricity market. This is relatively easy in ERCOT because local pricing requires all generators to use the system operator's scheduling software. By contrast, the GB electricity market currently allows generators to trade bilaterally.

In Europe, there are no markets that use local pricing; however, the Polish system operator, PSE, is proposing to move to local pricing from as early as 2023.[7] Political leaders in Europe are often wary of local pricing, in part due to concerns about creating a 'postcode lottery', with some customers facing higher prices than others just because of where they live. These distributional concerns can be addressed using fixed financial transfers between customers in high-priced and low-priced regions, as discussed later in this report.

Local pricing is sometimes criticised as expensive and detrimental to market liquidity.

Energy economists typically favour local pricing because it results in a more efficient use of resources and it encourages generators and customers to react to local supply and demand for electricity. Some criticise regional and local pricing as expensive to operate and argue that local pricing both

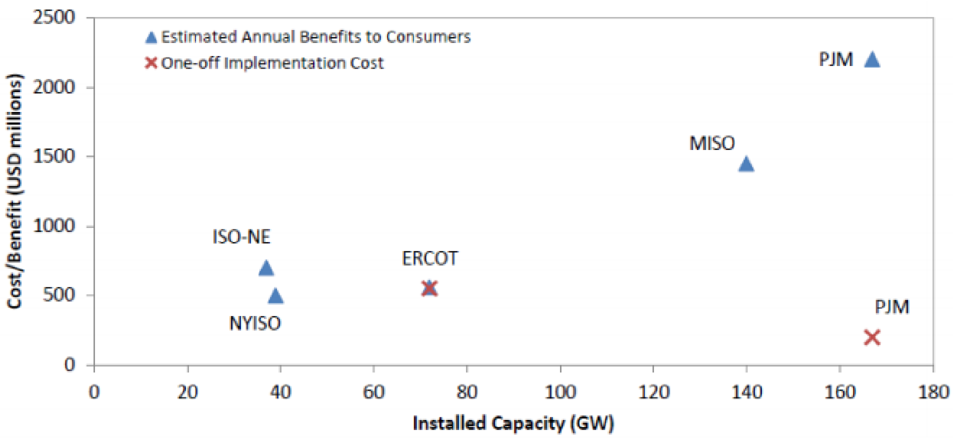
6. Potomac Economics for Texas PUC (July 2012). *2011 State of the market report for ERCOT...* Link
7. Simon, F. Euractiv (July 2019). *100% renewable power requires radical EU market fix, Poles argue.* Link

reduces liquidity and leads to local market power. It is worth addressing each of these criticisms in turn.

Criticism 1: It is expensive to implement local pricing.

Local pricing requires a complicated market algorithm that considers the physical constraints on the electricity network. In 2008, the cost of the Texas Nodal Market project, which implemented local pricing, was estimated to be $220m (£170m). The benefit to consumers was estimated to be twenty times higher than the costs over the first 10 years of the market's operation.[8] Other research suggests that, in various US markets, one year of the annual benefit to customers is higher than the one-off cost of implementing local pricing (i.e. local pricing has a one-year payback period for customers).[9]

Figure 23: Estimated one-off implementation cost of local pricing (crosses) compared to annual benefits to customers (triangles) in various US markets.



Source: (Neuhoff, et al., 2011), 2011.

Before introducing local pricing in Great Britain, the Government and Ofgem would have to consider a market-wide cost-benefit analysis. However, based on the experience of Texas and others, it is unlikely that local pricing would increase customer prices, especially because the benefits grow as more renewables are connected.

Criticism 2: Local pricing reduces liquidity.

The European Federation of Energy Traders (EFET), a trade body, argues that "*liquid markets are indispensable to manage and reduce risks for market participants, and thus to support timely investments in generation, storage and demand response.*" They note that Sweden's move to regional pricing in 2011 was associated with a drop in market liquidity, which tends to increase hedging costs for electricity traders. Also, the prices in three of Sweden's bidding zones are the same 95% of the time, which the EFET argues means that the Swedish Government should consider merging these zones.[10]

Local pricing would lead to lower headline measures of market liquidity

8. CRA International and Resero Consulting (December 2008). *Update on the ERCOT Nodal Market Cost-Benefit Analysis.* Link. Page 7. *Note: the estimated benefits to customers were largely a welfare transfer from generators to customers, rather than a pure improvement in system-wide costs.*
9. European Commission (April 2020). *Nodal pricing in the European Internal Electricity Market.* Link. Page 15.
10. EFET (September 2019) *Bidding zones delineation in Europe: Lessons from the past & recommendations for the future.* Link

and is likely to increase hedging costs. However, traders can use 'Financial Transmission Rights' (FTRs) to hedge against cost differences between nodes due to network constraints. FTRs are a well-established feature of US electricity markets.[11]

Also, arguably the liquidity in a market with national pricing is an illusion. For example, market participants in Texas accept that electricity delivered in Houston is a separate product to electricity delivered in El Paso, and therefore has different prices. On the other hand, in Great Britain, the market currently treats electricity delivered to customers in Aberdeen the same as electricity delivered to customers in Cornwall. Whilst this creates an illusion of liquidity, the Electricity System Operator is left to resolve network constraints in the real-time balancing markets, which may be highly illiquid.

Criticism 3: Local pricing gives some generators market power to raise prices locally.

Under local pricing, very high prices can occur at a small number of nodes. There may be only one or two generators who can generate electricity to meet demand at those nodes, which leads to concerns about market power. These generators could abuse their market power by charging excessive prices for the electricity that they generate.

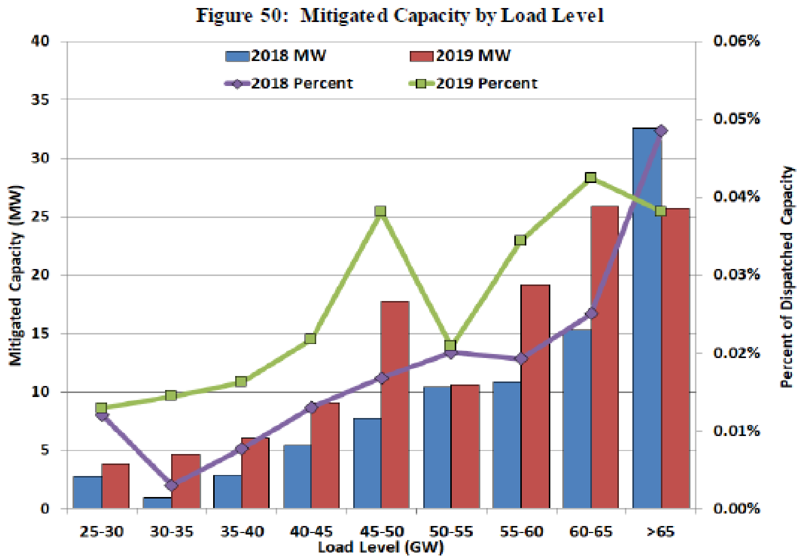
Regulators that operate local electricity markets are aware of this risk, so they impose market power mitigation measures on a few generators, and only at times that they have market power. For example, in Texas, the market scheduling software automatically caps a generator's bid when it is the only generator available to meet demand at a node. In 2019, on average only 20 MW (0.03% of the market) was produced by generators subject to market power mitigation measures (Figure 24: ERCOT capacity subject to market power mitigation measures, by load level. Source: ERCOT 2019 state of the market report.12).

The GB electricity market is a similar size to ERCOT, although the level of required market power mitigation will depend on the specifics of the capacity mix and electricity network. In the GB electricity market, national pricing means that generators are generally unable to exercise market power in the day-ahead and intra-day markets, where network constraints are ignored. Instead, market power appears when the ESO has to resolve network constraints through the Balancing Mechanism.

National pricing is therefore not immune to market power, it merely ensures that it appears in the ESO's balancing market (which considers network constraints) rather than in the day-ahead and intra-day markets (which ignore network constraints). Local pricing exposes market power in all markets, which makes it easier to resolve through mitigation processes that have been well tested in local electricity markets.

11. PJM Market Simulation Department (December 2018). *PJM Manual 06: Financial Transmission Rights.* Link

Figure 24: ERCOT capacity subject to market power mitigation measures, by load level. Source: ERCOT 2019 state of the market report.[12]



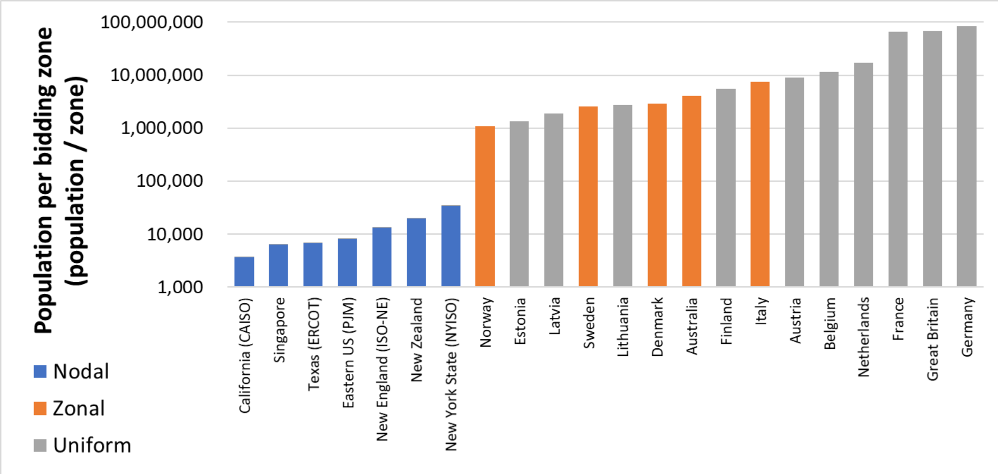
What would regional or local electricity pricing look like in Great Britain?

The GB electricity market has a single bidding zone with a single national price. If the GB electricity market moved to regional or local pricing, there would be more bidding zones. Using international examples as a guide, Figure 25: Population per electricity bidding zone in selected electricity markets.14 shows that markets with local pricing have approximately one node per 10,000 people, whereas markets that use regional pricing have one zone per 3 million people. Markets with national pricing, such as Great Britain, can have over 50 million people per bidding zone.

Assuming that this sample is representative, **if Great Britain adopted regional pricing there would be up to 25 bidding zones.** The location and size of these zones would reflect major network constraints, rather than having an equal population in each zone. There are currently 27 zones for transmission charging in Great Britain, of which 11 zones are in Scotland due to higher network constraints in the north of the UK.[13] Similarly, a regional GB electricity market would have more zones in Scotland per head of population. **If Great Britain adopted local pricing, there would be approximately 7,000 nodes.** This would mean a separate electricity pricing node for mid-sized towns such as Stonehaven in Aberdeenshire, Ilfracombe in Devon, and Monmouth in Gwent.

12. Potomac Economics for Texas PUC (May 2020). *2019 State of the market report for the ERCOT electricity markets.* Link (Page 118).
13. National Grid ESO (April 2019). *TNUoS guidance for generators.* Link (Page 10).

Figure 25: Population per electricity bidding zone in selected electricity markets.[14]



14. Source: Policy Exchange analysis. Note: New York state is nodal for generation (as shown above) but zonal for demand.

Policy options to support renewable energy generators

Aside from the current UK CfD scheme, there are three main options to support renewable energy generators. These options are summarised in Table 11.

Table 11: Summary of policy options for supporting renewable energy generators.

Policy Option	Examples	Description
Carbon pricing	EU, UK	Increases the cost of high-carbon resources like coal and natural gas, raising the wholesale electricity price and incentivising investment in renewables. However, carbon pricing alone may not provide sufficient long-term price certainty for investors in renewable energy projects.
Floor-price CfD	Spain	Guarantees investors a minimum price for the electricity that they generate. This encourages developers to try to capture the highest power prices by building projects in places where they will be most valuable. However, under a floor price, investors do not pay customers back if power prices are higher than expected.
Renewables Portfolio Standard (RPS)	US states	Requires suppliers to contract with an increasing proportion of renewable energy resources. Depending on the financial viability of electricity suppliers, this model creates 'counterparty risk' for owners of renewable energy project, which may increase overall costs.

The EU and the UK both have a carbon price in the electricity sector. However, to date, carbon pricing has rarely supported investment in renewables without other subsidies.

By applying a carbon price in the electricity sector, wholesale electricity prices in both the UK and the EU are higher than they would be otherwise. This encourages investors to build renewable energy projects, which do not pay the carbon price (because they are low carbon) and benefit from higher wholesale electricity prices. However, to date the vast majority of renewable energy projects in the UK and in the EU have been supported by long-term contracts backed by national Governments. This is in part because investors will tend to prefer a long-term contract if it is available, and in part because Government subsidies for renewables have worked to suppress carbon prices by pushing more low-carbon electricity generation into the market.

More recently, investors are starting to build solar farms without subsidies in Italy,[15] Spain,[16] and the UK.[17] This investment in 'subsidy-free' projects has been supported by higher carbon prices, falling technology costs, and the closure of previous renewable energy support schemes. However, there is a question over whether governments will allow carbon prices to rise sufficiently to incentivise wide-scale deployment of renewable energy projects.

Professor Dieter Helm has called for the responsibility for advising on the carbon price to be transferred to an independent body such as the UK's Committee on Climate Change.[18] This body would recommended adjustments to the carbon price to achieve an overarching carbon budget, similar to how Central Banks adjust interest rates based on inflation and other monetary policies objectives.

Even if national Governments agreed to let an independent body set or advise on their carbon price, investors would still not have complete certainty over their future revenues because electricity prices can change. The UK's CfD scheme insulates investors from changes in electricity prices. This increased risk would raise investors' cost of finance, potentially raising prices for customers. Also, a carbon price would not necessarily have supported the development of technologies like offshore wind, which were originally expensive but are now increasingly competitive with existing gas- and coal-fired power stations.

15. Shrestha, P. Energy Live News (December 2019). *Seven new subsidy-free solar power plants switched on in Italy.* Link
16. Renews (September 2020). *Foresight acquires Spanish subsidy-free solar project.* Link
17. Edie.net (August 2020). *Gridserve buys UK's first subsidy-free solar farm to power EV forecourts.* Link
18. BEIS (October 2017). *Cost of energy: independent review.* Link

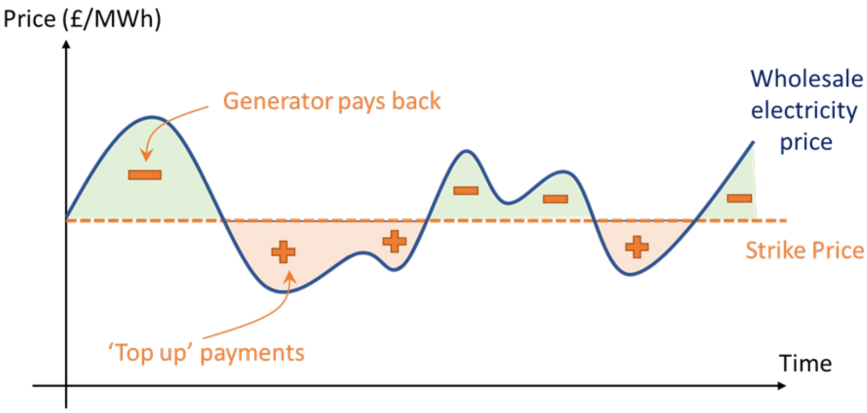
In 2017, the Spanish Government ran an auction that offered generators a long-term minimum revenue guarantee, similar to a 'floor-price CfD'.

The current UK CfD scheme guarantees generators a fixed price for their electricity (Figure 26). By contrast, a floor-price CfD provides investors a guaranteed minimal revenue for the electricity that they generate (Figure 27). A floor price CfD would therefore only be minor change to the UK's current CfD regime.

Under a floor-price CfD, investors can retain any upside from higher electricity prices, which encourages them to locate and to design their projects so that they generate when electricity prices are higher. This is an important difference from the current UK CfD, where generators are only encouraged to generate as much electricity as possible. Because they have the potential for upside, investors will likely be prepared to accept a lower floor price compared to the current strike prices for CfDs.

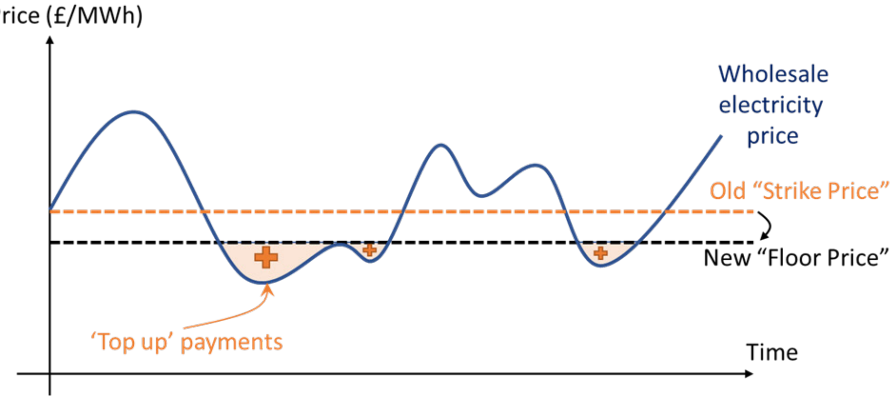
In Spain, the Government conducted an auction in 2017 that effectively provided a floor price to investors in wind and solar projects.[19] However, the Spanish auction was incredibly complicated, and was in part based on a Regulated Asset Base (RAB) model, which means that the floor price could be adjusted by the Government throughout the project's life. Whilst the idea behind Spain's 2017 auction was good, in practice the scheme was designed poorly, so it is not a good guide for the detailed design of any floor-price CfD in the UK.[20]

Figure 26: Schematic of the current 'two-way CfD'.



19. Spanish Government (undated). *Renewable energy auction 2,000 MW.* Link
20. Del Rio, P. (April 2017). *Assessing the design elements in the Spanish renewable electricity auction: an international comparison.* Link

Figure 27: Schematic of a 'floor-price CfD'.



Many US states use a Renewables Portfolio Standard (RPS) that requires electricity companies to increase their share of renewable energy.

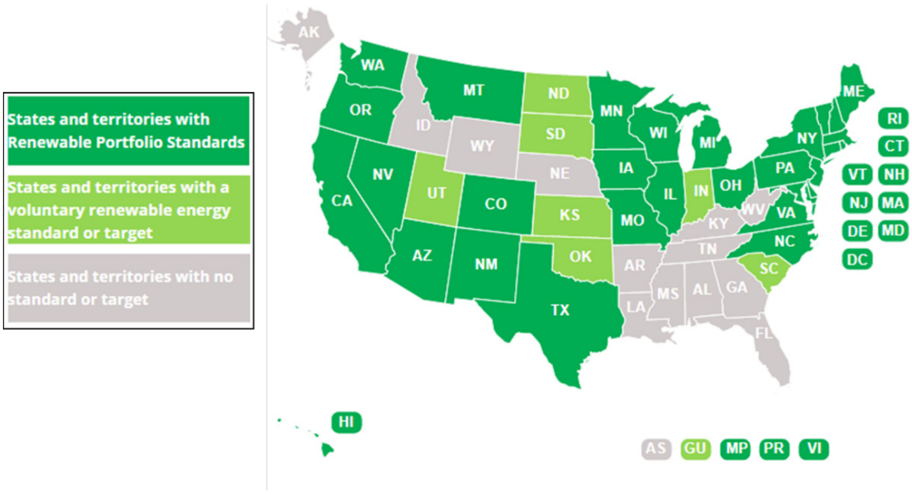
A 'Renewable Portfolio Standard' (RPS) puts an obligation on electricity suppliers to supply more of the electricity from renewable energy resources each year. Energy suppliers are therefore responsible for contracting with new and existing renewable energy resources like wind and solar. As of April 2020, thirty US states had implemented an RPS.

One downside of an RPS is that it may not provide new wind and solar projects with long-term fixed-price contracts, something that has been incredibly important in lowering the cost of offshore wind in the UK. Also, an RPS does not necessarily encourage sufficient innovation.

For example, if the UK introduced an RPS, energy suppliers are likely to contract established technologies like solar, onshore wind and traditional offshore wind farms. Suppliers would have little incentive to contract with a floating offshore wind farm, which would be more expensive than traditional offshore wind farms today but may be cheaper in the long term. To address this, and to ensure innovation and a diversity of resources, some US states apply multipliers or carve-outs for specific technologies.

As with supplier-led capacity markets, a supplier-led RPS in the UK would also need to consider the financial health of the UK's electricity suppliers. The UK energy sector has seen many bankruptcies in recent years. If this trend continued, renewable energy generators could not be uncertain about whether they would get paid by the electricity supplier.

Figure 28: US states and territories with Renewable Portfolio Standards. Source: National Conference of State Legislatures.[21]



21. National Conference of State Legislatures (April 2020). *States Renewable Portfolio Standards and Goals.* Link

Policy options for the Capacity Market

There are a number of policy options for the GB Capacity Market, several of which could be applied in combination. These options are summarised in Table 11: Summary of policy options for the GB Capacity Market. and are explored in more detail below.

Table 11: Summary of policy options for the GB Capacity Market.

Market design	Examples	Description
No capacity market	Texas	Texas (ERCOT) operates a secure electricity system without a capacity market. This is known as an 'energy-only' market. However, customers experience short periods of very high electricity prices in some regions.
Regional (zonal) capacity market	New York State	New York State operates a regional (zonal) capacity market, with different capacity prices in each zone. This is similar to the GB Capacity Market but split into regions (zones) that can have different prices. The market monitor for New York State recommends moving to local (nodal) pricing for capacity).
Obligation on electricity suppliers	Australia	Australia puts more responsibility on electricity suppliers to ensure security of supply. Suppliers are required to contract with generators, energy storage and DSR to meet their customers' demand. The argument in favour of this approach is that suppliers are well-placed to interact with their customers. This model creates 'counterparty risk' for generators, which may raise overall costs. It also requires the Government to give up some control over security of supply, which may be politically unattractive.
Strategic Reserve	Belgium, Germany	Germany and Belgium operate strategic reserves that can only be used in an emergency. Generators are paid to wait in reserve and can only generate during an emergency. This model can create a 'slippery slope', with more generators petitioning to be included in the strategic reserve over time. This is why GB moved to a full capacity market. Belgium is also now moving to a full capacity market, similar to GB.
Reliability Option (RO)	Ireland & Northern Ireland	Ireland and Northern Ireland charge higher penalties to resources that do not deliver. Under an RO, generators pay a financial penalty if they do not generate during periods of high prices. This creates a bigger incentive to deliver but is likely to raise capacity prices as there is more risk for generators.
Mandates for energy storage	California Public Utilities Commission (CPUC)	CPUC directs energy companies to sign contracts with firm low-carbon resources such as battery storage. This is a very direct government/state intervention in the electricity market to support a specific technology. The UK Government generally prefers technology-neutral approaches, although it has heavily supported offshore wind.

Texas (ERCOT) operates a secure electricity system without a capacity market. However, customers experience short periods of very high electricity prices.

The Electricity Reliability Council of Texas (ERCOT), which serves 90% of Texas, operates an 'energy-only' market with no capacity market. This means that market prices, rather than a government or a regulator, determine the capacity mix. Markets without a capacity market tend to have a lower 'reserve margin', which means that there is a smaller buffer of spare capacity available to meet peak demand. For example, Texas has a reserve margin of 14% compared to 21% in the PJM market in the eastern US, which has a capacity market.[22]

Because of its lower reserve margin, electricity prices in Texas are more likely to spike to the price cap of 9,000 $/MWh (7,000 £/MWh) at times of system stress. Texas uses local pricing, so these prices spikes tend to happen only in a few locations. These short periods of high prices encourage generators to be available at peak times and also encourage residents and businesses to participate in demand-side response, for example by scheduling their air conditioners to run at off-peak times.

The obvious limitation of having no capacity market is that there could be insufficient generation to meet demand and customers may face rolling blackouts at peak times. The experience in Texas is that, by allowing very high electricity prices in some hours, enough generators will be built to meet demand. Also, customers in Texas have strong incentives to provide DSR.

For the UK, there is a question over whether the Government would be prepared to accept giving up control of security of supply, in light of the likely media and political backlash if customers were to experience blackouts.

22. Hourihan, M. CPower. (April 2019). *Why doesn't Texas have a capacity market.* Link

New York State operates a regional (zonal) capacity market, with different capacity market prices in each zone.

A regional capacity market is very similar to a regional wholesale electricity market. Prices in neighbouring zones will be different if the network capacity between zones is constrained. Regional capacity markets help to ensure a more uniform distribution of capacity across the market, which makes it easier for the ESO to operate the electricity system.

The New York State Installed Capacity (ICAP) market has four price zones: New York City, Long Island, South-eastern New York (G-J Locality), and Upstate New York (New York Control Area). These zones were chosen to reflect the major constraints on the electricity network in New York State. Prices are generally highest in New York City, where generators face higher underlying costs including land value, fuel costs, and tighter restrictions on air pollutants such as ozone.[23] In 2019/20, capacity prices in New York City were 104 $/kW/year (£81/kW/year) compared to just 8 $/kW/year (£7/kW/year) in Upstate New York.[24] The difference between these prices reflects both the transmission constraints on the New York electricity network and the differing supply and demand characteristics in each region.

In the '2019 State of the Market Report', the Market Monitoring Unit made a number of suggestions to improve the New York capacity market. These included moving to local (nodal) prices, based on similar arguments to those for local wholesale markets.[25] This would allow capacity prices to change at each node when conditions change, for example to reflect a deficit in local capacity when a large nuclear power station retires. The report also suggested changes that would allow new power lines to receive payments if they reduced prices in the capacity market. In the New York example, this could include rewarding a new power line for resolving the constraint between Long Island and New York City.

23. See page 80 of the 2019 market report.

24. Potomac Economics (May 2020). *2019 State of the Market Report for New York ISO Markets.* Link. Page 77.

25. Ibid (2019 market report for NYISO).

Australia puts more responsibility on electricity suppliers to ensure security of supply.

Under a supplier obligation, electricity suppliers are required to sign contracts with enough resources to meet their customers' electricity demand. This is a big difference from the GB Capacity Market, where the Government is responsible for procuring firm capacity.

In 2019, the Australian Government introduced a Retailer Reliability Option (RRO), which requires electricity suppliers (Retailers) to demonstrate that they have signed contracts with enough resources. The Australian electricity market operator and regulator set the level of the obligation three years ahead of delivery. They also set the capacity credit for each type of resource.[26] If suppliers do not purchase enough resources, then the market operator can buy more resources as a 'Procurer of Last Resort'.[27]

The advantage of a supplier obligation is that it puts the responsibility on electricity suppliers, who are party that has the closest relationship with electricity customers. Suppliers have both the incentive and the means to engage their customers, possibly finding cheaper solutions like paying customers to shift their demand away from peak periods. This will become more important as customers purchase electric vehicles and charge them at home.

One downside of a supplier obligation, from a Government perspective, is that it cedes more control to suppliers. The Government would need to get comfortable relying more on electricity suppliers to ensure security of supply; the Government would retain the ability to intervene as a last resort. The detailed design of the supplier option would determine the roles and responsibilities of generators, suppliers, the Government and the ESO.[28]

In Great Britain, electricity suppliers are going bust at a record rate, due to a large number of new entrants to the market who were either poorly capitalised or did not understand the market.[29] This would need to be addressed before the Government could credibly give electricity suppliers more responsibility for security of supply.

26. Forster, C. Murphy, R. Norton Rose Fulbright (August 2019). *A guide to Australia's Retailer Reliability Obligation*. Link
27. Australian Government. Department of the Environment and Energy (2019). *Retailer Reliability Obligation Factsheet*. Link
28. ESC (November 2019). *Broad model for a capacity remuneration mechanism in an Energy Service Provider-led market*. Link
29. Gausden G. This is Money (April 2020). *Record number of energy firms collapsed in 2019*. Link

Germany and Belgium operate strategic reserves that can only be used in emergency situations.

One criticism of the GB Capacity Market is that all generators receive the capacity payments, even though only some generators actually require them. Other jurisdictions use a 'strategic reserve', which aims to restrict capacity payments to generators that are at risk of closing. A strategic reserve risks creating an uneven playing field between generators that receive payments, and those who do not. To minimise the impact of the strategic reserve on the wholesale market, it can only be called on at times of extreme system stress, for example if market prices are very high or if there is an imminent risk of blackouts.

Great Britain used a strategic reserve between 2014 and 2017, known as the 'Contingency Balancing Reserve' or CBR.[30] One problem with the CBR was that generators saw it as an attractive revenue stream relative to their profits (or lack thereof) in the wholesale market. Generators had an incentivise to announce plans to close, in the hope of securing a contract in the CBR. The strategic reserve grew each year, from 1.6 GW in 2014/15 to 3.5 GW in 2016/17. In winter 2017, the CBR was replaced with the GB Capacity Market. Unlike the CBR, the Capacity Market allowed both new and existing generators to compete to provide firm capacity.

Belgium has followed a similar path to Great Britain. The Belgian electricity system operator, Elia, currently procures around 750 MW of strategic reserve each winter.[31] However, the Belgian Government is now planning to replace the strategic reserve with a capacity market that is similar to the GB Capacity Market. Belgium's planned capacity market is currently being investigated by the European Commission under EU State Aid rules, which is concerned that the capacity market may not be needed.[32] The European Commission is generally sceptical of capacity markets due to the risk of market distortions and the difficulty in ensuring a level playing field between capacity providers in different EU Member States.

Germany also operates a strategic reserve, known as the 'capacity reserve', which is procured by the four German system operators. Generators in the capacity reserve cannot participate in the electricity market, and the system operators can only call on them if electricity prices reach the price cap.[33] The German capacity reserve has a maximum capacity of 2,000 MW.[34] Germany also operates a 'network reserve', which procures capacity on a regional basis to ensure that there is always sufficient local generation to meet local demand. The network reserve is expected to grow from 5,100 MW in winter 2019/20 to 8,000 MW in winter 2024/25.[35] The German energy regulator hopes that this network reserve will eventually shrink as new power lines are built to reduce network constraints.

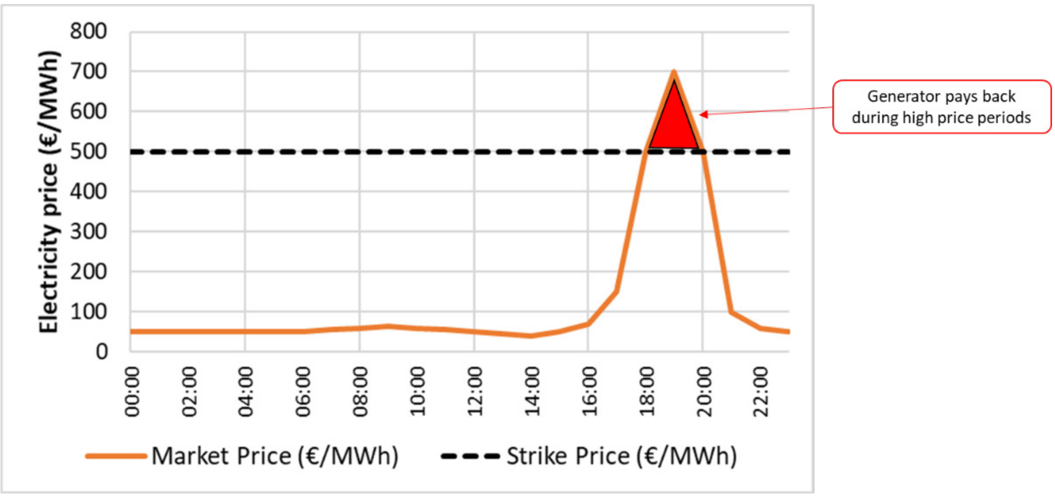
30. BEIS and Ofgem (October 2016). *Statutory Security of Supply Report 2016.* Link
31. Elia (undated). *Strategic Reserve: Volumes & Prices.* Link
32. European Commission (September 2020). *State aid: Commission opens in-depth investigation into Belgian capacity mechanism.* Link
33. German Federal Ministry for Justice and Consumer Protection (undated). *Ordinance regulating the procurement, use and billing of a capacity reserve. Section 25: activation.* Link (in German).
34. Reuters (February 2020). *Germany adds 1,056 MW to electricity reserve capacity from October.* Link
35. Eriksen, F. Clean Energy Wire (May 2020). *Germany raises grid stability reserve as network expansion lags behind.* Link

Ireland and Northern Ireland charge higher penalties to resources that do not deliver.

Some capacity markets include higher penalties for generators who do not deliver when they are needed, something that BEIS has identified as a weakness in the current GB Capacity Market. Ireland and Northern Ireland operate a joint capacity market that places a financial penalty on those who do not generate when wholesale electricity prices are above a threshold. It does this through a financial instrument known as a 'Reliability Option' (RO). Under an RO, a generator commits to be available to generate electricity when there is system stress, reflected by high prices. The generator must make payments to the market operator when prices exceed the 'strike price', which in Ireland and Northern Ireland is €500/MWh (£450/MWh). This effectively caps the price that a generator can receive at the strike price and provides a financial incentive for the generator to be available when prices are high.[36]

A Reliability Option also addresses the concern that, under a capacity markets, customers are paying generators whilst getting almost nothing in return, because prices can still be high at times of system stress. Under an RO, customers make annual payments to generators, through their suppliers, but should benefit from lower market prices due to the RO strike price. Also, unlike the GB Capacity Market, RO holders in Ireland and Northern Ireland lose money over the course of a year if they do not deliver when needed.[37]

Figure 29: Example of a generator making payments under a Reliability Option during periods of high electricity prices.



36. Single Electricity Market Operator (September 2017). *I-SEM Training Capacity Market Settlement.* Link

37. The annual stop loss limit is 150%, which means a net loss of 50%. For example, if the capacity market price is 20 EUR/kW/year, the maximum annual net loss is 10 EUR/kW/year.

The California Public Utilities Commission (CPUC) directs energy companies to procure firm low-carbon resources such as battery storage.

Like many jurisdictions, California uses a capacity mechanism to ensure that there are enough resources to meet customer demand. California has a Capacity Procurement Mechanism that procures capacity up to three years ahead of delivery, and Reliability Must Run contracts, which are used to resolve local capacity deficits.[38]

As in Great Britain, the majority of firm capacity in California is provided by natural gas-fired power stations. In 2010, the California legislature recognised this as a barrier to decarbonisation and gave the California Public Utility Commission (CPUC) the power to mandate more energy storage in the California electricity system.[39] This type of mandate is possible in California because the majority of power stations are owned by three regional electricity companies, known as Investor-Owned Utilities or IOUs. The mandate requires Pacific Gas & Electricity (PG&E), Southern California Edison (SCE), and San Diego Gas & Electricity (SDG&E) to sign contracts with more energy storage projects each year, which can be built by them or by independent developers. California has a mandate for 1,325 MW of energy storage by the end of 2020.[40]

The California energy storage mandate effectively creates a separate capacity market for storage. This means that energy storage can receive a higher price for providing capacity compared to traditional fossil fuel resources such as gas-fired power stations. This recognises that the cost of energy storage is currently higher than gas-fired power stations, but also that firm low-carbon resources such as energy storage will be critical to delivering on California's climate goals.

38. California ISO (May 2019). *2018 Annual Report on market issues and performance.* Link.

39. The Climate Group (April 2017). *How California is driving the energy storage market through state legislation.* Link

40. California Public Utilities Commission (CPUC) (undated). *Energy storage.* Link

Other policy options: Equivalent Firm Power auctions or a retail-led market

There are two main models for the Government to reduce its role in the electricity sector. These are summarised in Table 12: Summary of other policy options. and are explored in more detail below.

Table 12: Summary of other policy options.

Policy Option	Description
Equivalent Firm Power Auctions ('EFP auctions')	In the 2017 Cost of Energy Review, Professor Dieter Helm proposed a unified framework for procuring firm capacity and clean energy, known as an Equivalent Firm Power auction ('EFP auction').[41] EFP auctions would be run by an independent system operator, so they would be independent from the Government. EFP could help to properly price the intermittency of wind farms and solar farms. However, the EFP auction risks undervaluing clean energy resources like wind and solar, because it focusses on firm capacity. It is not entirely clear how wind and solar projects would be supported, except through a carbon tax that rises to levels that may not be politically viable.
Retail-led market	As part of the *'Rethinking Electricity Markets'* initiative, the Energy System Catapult (ESC) is developing proposals that would make energy retailers and customers more responsible for ensuring decarbonisation and security of supply, rather than the Government.[42,43] The ESC argues that energy retailers and customers are best placed to understand the needs of customers, as well as to encourage customers to react to local supply and demand for electricity, for example by scheduling EV charging in off-peak hours. This model would put a lot of new responsibility on retailers and customers. Generators would rely on retailers for more of their revenue than they do today. This creates a new financial risk for generators, particularly because energy suppliers in Great Britain are going bust at a record rate.

41. BEIS (October 2017). *Cost of energy: independent review.* Link
42. Energy Systems Catapult (November 2019). *Towards a new framework for electricity markets.* Link
43. Energy Systems Catapult (Forthcoming). *The Case for EMR2.0.* Link

Professor Helm proposes an Equivalent Firm Power auction that would combine the CfD and CM schemes.

As part of the 2017 Cost of Energy Review, Professor Dieter Helm proposed a unified framework for procuring firm capacity and clean energy, known as an Equivalent Firm Power auction ('EFP auction').[44]

Professor Helm argues that the current CfD scheme for renewables is badly designed,[45] in part because the CfD doesn't distinguish between intermittent generators (wind and solar) and dispatch generators like biomass that can provide firm capacity as well as clean energy.[46]

Helm also argues that neither wind nor solar pay "*the full costs to the system of its intermittence*", although he notes that the implications of intermittency for system costs is hotly debated.[47]

Helm argues that EFP auctions and a carbon price will deliver firm capacity and clean energy at the lowest cost.

Helm proposes a "*proper cost of carbon and an auction system, which merges the capacity market and the [CfD scheme] on a common Equivalent Firm Capacity basis*".[48]

Helm argues that the Government should ask the Committee on Climate Change to advise on the level of the carbon price to meet the UK's decarbonisation targets, similar to how the Bank of England's Monetary Policy Committee sets interest rates to achieve an inflation target.[49] If the carbon price is not high enough to deliver a decarbonised electricity system, then Helm argues that the System Operator should take into account carbon emissions when allocating contracts, i.e. there should be a carbon constraint in the EFP auction.[50]

One advantage of EFP auctions is that they would be run by an Independent System Operator. This should help to de-politicise UK energy policy, because the Government would pass more control to an independent body. Helm argues that this would reduce the potential for vested interests to capture UK energy policy.[51]

EFP auctions could undervalue wind and solar, particularly if the carbon price is too low.

One potential downside of the EFP auction is that it risks undervaluing clean energy resources like wind and solar. These resources make at best a limited contribution to firm capacity because there are days when there is no wind, and there is no solar power at night.

Wind and solar still contribute to the electricity system, as they allow conventional power stations to switch off when it's windy or sunny, reducing carbon emissions. In an EFP auction, it is not entirely clear how wind and solar could receive credit, as there is little incentive for a provider of firm capacity to pair up with a wind or solar farm. Providers of firm capacity, for example a gas-fired power station, will already receive a full credit for providing firm power, as they are almost always available.

Helm's proposals therefore rely heavily on either: having a carbon price that is high enough, which may politically difficult; or on the second stage EFP auction, which includes a carbon constraint. This carbon-constrained

44. BEIS (October 2017). *Cost of energy: independent review.* Link
45. Ibid (Cost of Energy Review). Page 107, paragraph 91.
46. Ibid (Cost of Energy Review). Page 107, paragraph 92.
47. Ibid (Cost of Energy Review). Page 109, paragraph 96.
48. Ibid (Cost of Energy Review). Page 109, paragraph 99.
49. Ibid (Cost of Energy Review). Page 114, paragraph 113.
50. Ibid (Cost of Energy Review). Page 120.
51. Ibid (Cost of Energy Review). Page 211, paragraph 8.

second auction starts to look a bit like a CfD auction, with low-carbon resources competing to provide clean energy at the lowest cost.

The EFP auction would also introduce bilateral contracting between clean energy resources and firm capacity resources, to improve the EFP credit of wind and solar farms. However, Helm also argues that the NETA and BETTA reforms, which moved away from the centralised Pool, were bad because they introduced bilateral contracting, which reduces liquidity and favours vertically integrated utilities.[52] There is a risk that EFP auctions could see a return to vertical integration and less market transparency.

There is also a question over whether EFP auctions would have delivered the 'deployment-led innovation' that has contributed to the falling costs of offshore wind. The UK Government was prepared to pay high prices for the first offshore wind projects, in the hope of prices falling. Helm argues for increased spending on R&D; however, R&D alone may not have been enough to bring down the costs of offshore wind.

52. Ibid (Cost of Energy Review). Page 109.

The Energy Systems Catapult (ESC) argues for a retail-led market to deliver decarbonisation and security of supply.

The Energy System Catapult's *'Rethinking Electricity Markets'* initiative is developing proposals to reform the GB electricity market, with a focus on a decentralised policy framework for reducing carbon emissions and ensuring reliability. In practice, this would make electricity retailers and customers responsible for ensuring decarbonisation and security of supply, rather than the Government.[53]

The Energy Systems Catapult argues that current market arrangements are complex, highly fragmented, and do not fully reflect the value that different energy resources can provide to the system. They argue that policymakers need to address policy fragmentation; the integration of electricity, heat and transport; and the interaction between markets and regulation (led by Ofgem), policy (led by BEIS), and the Electricity System Operator (ESO).[54]

A decentralised market could deliver decarbonisation and security of supply.

The ESC proposes a decentralised energy system with customers and retailers at its heart. This could be delivered by beefed-up versions of today's energy suppliers; alternatively, entirely new business models could emerge. Retails would offer customers a range of energy services across electricity, heat and energy efficiency. These services could be measured in the metrics that matter to customers like warmth, reliability, and controllability, rather than the current approach of selling kilowatt hours (kWh).

Retailers would be responsible for ensuring decarbonisation and security of supply, reducing the role of the Government. This would mean an end to the GB Capacity Market, which would be replaced with a decentralised capacity mechanism (either a decentralised Reliability Obligation or a decentralised Reliability Option). If retailers do not buy enough capacity (i.e. the market does not clear), then ESO would procure additional capacity using strategic reserves, giving the Government extra assurances over security of supply. A Reliability Obligation could be modelled on Australia's Retailer Reliability Option, which was described earlier in this section.

The UK's Contracts for Difference scheme would be replaced with a carbon intensity obligation applied to a retailer's portfolio of energy resources.

The benefit of this system is that it puts more responsibility on energy retailers – who are the closest parties to their customers – and on customers themselves. Energy retailers and customers are best-placed to think about what services customers actually need and how much they can flex their energy consumption based on real-time supply and demand for electricity.

53. Energy Systems Catapult (November 2019). *Towards a new framework for electricity markets.* Link

54. Energy Systems Catapult (undated). *Rethinking Electricity Markets.* Link

A retail-led market could increase financing costs, depending on how it is implemented.

The ESC's vision for a decentralised market led by retailers and customers is both coherent and compelling. However, it would be a major change from the current system, and it would require more sophisticated regulation, not least to prevent mis-selling.

Current UK energy policy recognises the benefit of the Government providing long-term contracts that de-risk private investment; this is the fundamental principle of the CM and CfD schemes. The ESC's proposals would end these long-term, Government-backed contracts, and would instead require investors to sign contracts with energy retailers and customers. This introduces more counterparty risk for investors,[55] which is likely to increase financing costs. Higher financing costs must be weighed up against the likelihood of procuring a more optimal capacity mix and unlocking the value of local energy and demand-side resources.

If such a system is implemented badly, then there is a risk that investors will stop investing in clean energy projects like offshore wind. This could put the UK's Net Zero target at risk. On the other hand, if implemented well, this system could lead to a truly smart UK energy system with engaged customers and ultimately lower costs.

55. I.e. the risk that the counterparty to the contract (the energy supplier) goes bust, and the contract is cancelled.

Appendix 3: Detailed arrangements for firm low-carbon resources in the CfD scheme

We recommend that firm low-carbon resources in the CfD scheme should commit to generating clean energy for a minimum number of hours per year. They should be incentivised to generate when electricity prices are highest. *This appendix describes how this could be achieved.*

Today, firm low-carbon resources that hold a CfD are encouraged to generate all the time, regardless of the underlying electricity price. In the early years of the CfD scheme, this was not an issue because the Government wanted biomass generators to run all the time to reduce carbon emissions. However, as the share of wind and solar grows, firm low-carbon resources will need to operate flexibly, mainly generating electricity when it's not windy or sunny. For example, a hydrogen electrolyser could be used to make hydrogen from electricity when it's windy and electricity prices are low. When wind and solar output is low and electricity prices are higher, a hydrogen-fired power station could use the hydrogen to generate electricity.

The Government has recognised the need for firm low-carbon resources to generate flexibly. The Government's preferred position on supporting CCUS in the electricity sector ('Power CCUS') is to offer generators both an 'availability payment' (for firm capacity) and a 'variable payment' (for clean energy).[56] The Government plans to index the variable payment to the cost of fuel and carbon, relative to an "*equivalent unabated reference plant*", in this case a conventional gas-fired power station.

This approach could work for Power CCUS; however, the Government would need to take a different approach for technologies like low-carbon hydrogen and ultra-long duration storage, for which there is no equivalent reference. This will make it hard to compare across technologies.

Where possible, the Government should take a consistent approach across technologies, requiring firm low-carbon resources to generate clean energy for a minimum number of hours each year in return for a floor-price CfD. For example, a hydrogen-fired power station might commit to generating for at least 1,000 hours per year, in return for a floor-price guarantee of £100/MWh.

56. BEIS (August 2020). *A Government Response on potential business models for CCUS.* Link. Pages 30-36.

To ensure that firm low-carbon resources generate at times of high prices, the index price for the floor-price CfD should be the higher of: the generator's achieved market price, and the average of the highest electricity prices in the year (known as the Market Reference Price).

Table 8: Floor-price CfD (Scenario 1). Firm low-carbon resource exceeds the Market Reference Price. and Table 9 respectively show examples where a firm low-carbon resource does and does not exceed the Market Reference Price (MRP). The MRP is calculated as the average of the highest electricity prices in the year, calculated for the generator's nominated hours (1,000 hours), plus a buffer. A buffer is needed because generators cannot know in advance which hours in the year will have the highest prices. In this indicative example, we have used a buffer of 150%.

This approach would allow the Government to compare between projects and technologies. It would also allow the Government to more effectively value clean energy projects that only generate for a small number of hours per year, for example on cold winter evenings.

Table 8: Floor-price CfD (Scenario 1). Firm low-carbon resource exceeds the Market Reference Price.

Category	Item	Units	Value
CfD terms			
	Nominated Hours	Hours / year	1,000
	Strike Price	£/MWh	100
Average wholesale electricity price			
	Achieved by generator (achieved market price)	£/MWh	80
	Top 1,500 hours in the year (Market Reference Price)	£/MWh	70
CfD calculations			
	Index price for floor-price CfD	£/MWh	80
	Top up payment (CfD top up)	£/MWh	20
Total			
	Generator total revenue (achieved market price + CfD top up)	£/MWh	100

Table 9: Floor-price CfD (Scenario 2). Firm low-carbon resource does not exceed the Market Reference Price.

Category	Item	Units	Value
CfD terms			
	Nominated Hours	Hours / year	1,000
	Strike Price	£/MWh	100
Average wholesale electricity price			
	Achieved by generator (achieved market price)	£/MWh	50
	Top 1,500 hours in the year (Market Reference Price)	£/MWh	70
CfD calculations			
	Index price for floor-price CfD	£/MWh	70
	Top up payment (CfD top up)	£/MWh	30
Total			
	Generator total revenue (achieved market price + CfD top up)	£/MWh	80