Powering Net Zero

Policy Exchange

Why local electricity pricing holds the key to a Net Zero energy system.

By Ed Birkett

Foreword by Bim Afolami MP

Edited by Benedict McAleenan

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Foreword

By Bim Afolami MP

The Prime Minister's 10-Point Plan for a Green Industrial Revolution has sparked interest right across Parliament, galvanising colleagues who previously saw only the costs and not the opportunities of reaching Net Zero. The Plan is an exciting environmental and economic opportunity for this country as we emerge from Covid 19.

A key part of the Prime Minister's plan is to deliver 40 gigawatts (GW) of offshore wind by 2030, four times today's capacity. However, to deliver on this ambition we need to deal with intermittent supply and to develop large-scale energy storage solutions. With this in mind, I welcome this new report from Policy Exchange, which looks at how our electricity market needs to change to accommodate the UK's increasingly ambitious action on climate change.

I am particularly struck by this report's recommendation for 'local electricity pricing' as a way to integrate further renewable and sustainable energy resources, something that's close to my heart as the Chair of the UK's Parliamentary Renewable and Sustainable Energy Group (PRASEG). I am excited by the potential for local pricing to revitalise the UK's coastal industrial hubs by giving them access to cheap, low-carbon energy from offshore wind farms. Cheaper energy in these regions could make a big contribution to delivering a greener and more productive economy whilst helping to level up the UK's coastal regions.

With so much offshore wind set to come online in the 2020s, it's absolutely right that the Government looks again at the design of the electricity market to ensure that it's fit for purpose. With an Energy White Paper expected imminently, the debate is already beginning about how to achieve this. I'm sure that this report will make an important contribution to that debate.

Like many others, I hope the White Paper will highlight the role of competitive markets and private sector investment to deliver a secure, affordable, low-carbon energy system. We will only deliver Net Zero by mobilising the expertise, innovation and resources of the private sector. The UK's Contracts for Difference (CfD) scheme for renewables is a leading example of what we can achieve when the Government and the private sector work together. It has slashed the costs of wind power and we need to build on its success. Any changes to the CfD scheme must maintain the confidence of investors whilst ensuring that it continues to deliver for customers. Policy Exchange's recommendation for a 'floor-price CfD' might be the answer, or at least part of it, and I hope that the Government will consider it carefully.

A dynamic, low-carbon electricity system will be central to our fight against climate change, helping us to cut the emissions of our homes, our vehicles and our industry. As this report shows, the right electricity market design can help us take the crucial next steps on the path to Net Zero.

Bim Afolami is the Member of Parliament for Hitchin & Harpenden and the Chair of the All-Party Parliamentary Group for Renewable and Sustainable Energy.

Glossary of Terms

Term	Definition
Balancing Mechanism (BM)	Market that the ESO uses to balance supply and demand for electricity in real-time. The ESO uses the BM to resolve network constraints.
BECCS	Bioenergy with carbon capture and storage. A biomass-fired power station equipped with carbon capture and storage.
BEIS	Department for Business, Energy & Industrial Strategy. UK Government department responsible for business, energy and industrial strategy.
Capacity credit	See *de-rated capacity*.
Capacity Market	Market for firm capacity. Ensures that there are always sufficient generators available to meet electricity demand.
Clean energy	MWh of generation from low-carbon generation sources. Includes wind, solar, nuclear and others.
Climate Change Committee (CCC)	Independent statutory body advising the UK and devolved governments on emissions targets and preparing progress reports to Parliament.
Carbon dioxide (CO_2)	Carbon dioxide (CO_2) is the main greenhouse gas. The vast majority of man-made CO_2 emissions come from the burning of fossil fuels.
Carbon Emissions Tax (CET)	A tax on greenhouse gas emissions, measured in pounds per tonne of carbon dioxide equivalent (£/t CO_2).
Constraint costs	Constraints on the electricity network occur when a power line cannot transmit any more electricity. When this happens, the network is said to be ‘constrained’. To resolve constraints, the ESO pays generators to turn down. These costs are called ‘constraint costs’.
Contracts for Difference (CfD)	Main support scheme for renewable energy generators in Great Britain. Generators receive a fixed price for their electricity, with payments based on the different between the wholesale price and a fixed ‘Strike Price’.
De-rated capacity	Measure of firm capacity for generators, used in the GB Capacity Market. Wind and solar generators depend on the weather and therefore have a low de-rated capacity, whereas firm resources like gas-fired power stations have a de-rated capacity that is close to their installed capacity.
Electricity System Operator (ESO)	The GB Electricity System Operator, a company within the National Grid group, is responsible for balancing the electricity system’s supply and demand to ensure a stable, high-quality supply of electricity. The ESO procures a range of ‘system balancing services’ on behalf of energy users.
Electricity Market Reform (EMR)	A significant recent programme of electricity market reform in Great Britain. Implemented through the Energy Act 2013.

Emissions Trading Scheme (ETS)	A scheme that sets a cap on the maximum level of emissions from particular industries in a region. Emitters must purchase 'ETS permits' and the number of these available declines over time, in order to reduce overall emissions in that region. Companies can trade emissions permits. The EU operates an ETS.
Energy trilemma	Describes the triple challenge of operating a secure, affordable, low-carbon electricity market (hence 'trilemma').
Firm capacity	Capacity that is always available to generate electricity, regardless of weather conditions. Wind and solar make only a small contribution to firm capacity.
Firm low-carbon resources	Resources that can provide both firm capacity and low-carbon energy (or clean energy). Includes BECCS, Power CCUS, geothermal, ultra-long duration energy storage and others.
Floor-price CfD	A proposed amendment to the current CfD regime in Great Britain. Would top-up generators when the wholesale price is below the Strike Price. Generators would not pay back when prices are high.
Gas CCUS	See *Power CCUS*.
GB electricity market	The electricity market covering Great Britain (England, Scotland and Wales).
Green hydrogen	The production of hydrogen using renewable electricity sources. In the UK, the term 'green hydrogen' is typically used to describe all hydrogen produced with electricity.
Hydrogen	A clear, odourless gas which is highly flammable, the most common element in the universe which can be used as a low emission alternative fuel for power, heating and transport.
Local pricing	A wholesale electricity market split into a large number of nodes. For example, the California electricity market has approximately 10,000 pricing nodes.
Net Zero	A target of zero overall greenhouse gas emissions across an economy or for a company. For example, the UK Government has committed to Net Zero emissions across the UK by 2050. The "Net" in Net Zero refers to a balance between positive emissions (e.g. from burning fossil fuels) and negative emissions (e.g. from planting trees or capturing carbon dioxide from the air).
Market coupling	A system that automatically schedules electricity flows on interconnectors, minimising the cost of meeting electricity demand across the coupled region.
Megawatt (MW)	Measure of installed capacity. The maximum instantaneous output of a generator.
Megawatt hour (MWh)	Measure of energy. For example, if a generator generates 1 MW of electricity for one hour then they generate 1 MWh of energy.
National pricing	A wholesale electricity market with the same price in all locations in each time period (i.e. a single bidding zone). For example, Great Britain uses national pricing.
Nodal pricing	See *Local pricing*.
Ofgem	The Office for Gas and Electricity Markets (Ofgem) is the regulator for gas and electricity in Great Britain.
Power CCUS	A gas-fired power station equipped with carbon capture, utilisation and storage.

Regional pricing	A wholesale electricity market split into a number of zones that cover a geographical region of that market. For example, the Italian electricity market has 6 zones.
Retail electricity market	Supply of electricity to end customers, particularly domestic customers and small businesses. Retail electricity is more expensive than wholesale electricity because it includes network charges and the cost of subsidies and fuel poverty obligations.
Single Electricity Market (SEM)	A joint electricity market on the island of Ireland, covering the Republic of Ireland (ROI) and Northern Ireland (NI).
System balancing services	The ESO procures system balancing services to manage the technical parameters of the electricity network to prevent blackouts. These services include frequency regulation, voltage control, inertia, and constraint management.
Uniform pricing	See *National pricing*.
Wholesale electricity market	Main market for generators and suppliers to buy and sell electricity. Only take into account energy costs, not network charges and the cost of subsidies (see *retail electricity market*).
Zonal pricing	See *Regional pricing*.

Executive Summary

The UK is on the cusp of a clean energy revolution, underpinned by the Government's commitment to 40 GW of offshore wind by 2030. However, cost increases during the coronavirus lockdown showed that Great Britain's electricity market won't allow customers to benefit from the falling costs of wind and solar. Without reform, the cost of operating the electricity system will rise, adding billions to bills every year.[1] To take advantage of the UK's full potential for offshore wind, **the Government should introduce 'local electricity pricing', based on markets that operate successfully in Texas and California. This could reduce electricity bills by £2.1bn per year.**

Cost rises during lockdown were a preview of a Net Zero future, but 'local pricing' can reduce costs.

Electricity demand fell sharply during the coronavirus lockdown in summer 2020, which meant that offshore wind farms generated more of the UK's electricity and supply was more dependent on the weather. It is the responsibility of the Electricity System Operator (National Grid ESO) to 'balance' the system every second, smoothing out the peaks and troughs in supply and demand, which is then paid for by all bill payers.

The higher than expected share of wind power in 2020 has created challenges for the ESO. The ESO had to pay to turn off nuclear power stations and wind farms, and had to pay to turn on gas-fired power stations. These 'system balancing' actions ensured a highly reliable supply of electricity, but system balancing costs rose by two-thirds (£220m) compared to the same period in 2019. Without reforms, these higher costs could become a new normal.

Today, everyone in Great Britain pays roughly the same price for electricity, a system known as 'national pricing'. Local electricity pricing is an alternative that would allow electricity prices to vary across Great Britain, depending on local supply and demand. This would encourage electric car drivers in Cornwall to charge their vehicle when it's sunny and those in Aberdeenshire to charge when it's windy, reflecting local sources of electricity. Local pricing would also encourage energy intensive industries to build factories and data centres in the UK's coastal industrial hubs, where they can benefit from the UK's abundant offshore wind resources. **Lower local energy prices could be a catalyst for the UK's green manufacturing sector in places like Aberdeen, Grangemouth, Teesside, Humberside, Merseyside, East Anglia and South Wales.**

Switching to local pricing could reduce total system costs by £2.1bn

1. Source: Modelling by Aurora Energy Research, commissioned as part of this project, see Appendix 1 for details. System balancing costs could rise from ~£1.5bn per year in 2020 to £4bn by 2030 and to £6bn by 2050.

per year, saving the average household £37 every year, according to modelling by Aurora Energy Research, commissioned by Policy Exchange. **If the Government implements local pricing by 2026, then customers could save £50bn by 2050.** To put this in context, the Electricity System Operator's plan for an integrated offshore grid could save customers £6bn by 2050.[2,3]

A smart energy system is within reach, underpinned by local pricing and offshore wind.

We can't yet know the right market design for 2050 and we shouldn't expect the upcoming Energy White Paper to have all the answers. However, we can say that local electricity pricing will provide the foundation for a truly smart energy system and save customers money. This will keep the UK powering ahead to Net Zero whilst continuing to deliver a secure, affordable and low-carbon electricity system.

History of the GB electricity market

Following privatisation in the 1990s, Great Britain has operated a competitive electricity market covering England, Scotland and Wales (the 'GB electricity market'). On top of the competitive electricity market, the Government has added policies to deliver certain outcomes. These extra policies are designed to ensure energy security (i.e.to keep the lights on) and decarbonisation (i.e. to limit climate change).

Since the early 2010s, the Government's programme of Electricity Market Reform (EMR) has delivered falling costs for offshore wind, through subsidies like the Contracts for Difference, and has allayed fears of blackouts through the Capacity market. Over the last decade, carbon emissions from the UK's electricity sector have fallen by 60%, whilst household electricity bills have stayed about the same in real terms. Despite this success, some areas of the market now need further reform.

The wholesale electricity market (the main market used by generators and suppliers) was last reformed through the BETTA reforms in 2005, which saw Scotland join England and Wales to form the GB electricity market. Market conditions during the coronavirus lockdown in summer 2020 exposed flaws in the GB electricity market, which is not prepared for a future dominated by offshore wind and other renewables, as well as increases in electric vehicles and electric heating.

Limitations of the GB electricity market

Summer 2020 was a preview of the electricity system of the future.

During the coronavirus lockdown, electricity demand fell by 15%. This meant that offshore wind farms and nuclear power stations generated more of the UK's electricity. The Electricity System Operator (ESO) faced extraordinary challenges to keep the grid running safely. To manage the system, the ESO had to pay nuclear power stations and wind farms to turn off and had to pay gas-fired power stations to turn back on. This

2. NG ESO (September 2020). *Latest report on consultation in Offshore Coordination project released.* Link
3. Of course, the Government can pursue local pricing and an integrated offshore grid in parallel.

led to higher 'system balancing costs', which were two-thirds (£220m) more than the same period in 2019. These cost rises were offset by lower wholesale electricity prices; however, it's clear that the current market makes bills higher than they should be.

Offshore wind capacity is expected to double by 2025 and to quadruple by 2030, which means that this summer was a preview of the future electricity system. Without further reforms to the GB electricity market, these higher costs will become the norm, and customers won't fully benefit from the falling costs of wind and solar.

The Government needs to develop policies that support renewables and keep the lights on.

The Government's main schemes to support new renewable energy projects (Contracts for Difference) and to keep the lights on (the Capacity Market) were both designed about a decade ago. These schemes have delivered against their original objectives; however, the Government now needs to evolve them to keep the UK on track for Net Zero.

The Contracts for Difference (CfD) scheme has delivered incredible reductions in the cost of offshore wind, but it distorts the electricity market by insulating investors from the wholesale electricity price. One symptom of this is negative prices, which are increasingly common in GB. Without reform, the CfD scheme will drive higher costs in other areas of the GB electricity market, including higher system balancing costs.

The Capacity Market (CM) has averted fears of blackouts in Great Britain by paying for reliable ('firm') back-up power supplies. However, the CM mainly supports high-carbon resources, particularly gas-fired power stations. As the UK transitions to Net Zero, the CM will increasingly need to support low-carbon resources that can deliver firm power like low-carbon hydrogen, gas or bioenergy with carbon capture and storage, geothermal and others.

The GB electricity market in 2050

By 2050, the GB electricity market will be at the heart of a Net Zero UK. Wind and solar could provide as much as two-thirds of electricity in Great Britain, complemented by nuclear, energy storage and other low-carbon resources. Customers and energy suppliers will work together to balance the fluctuations of wind and solar, helped by smart electric vehicle charging and smart electric heating. Security of supply will be more important than ever, as customers will be more reliant on electricity for heating and transport.

The Government needs to deliver this new energy system at a price that's affordable for customers, which means harnessing market competition to bring down costs. Policymakers must take advantage of the tumbling cost of offshore wind, solar PV and battery storage, as well as driving innovation to develop new low-carbon resources like hydrogen and carbon capture and storage.

Key principles

This report proposes four key principles to guide the next stage of electricity market reform in Great Britain:

Table 1: Recommended Principles”

Recommended principles	
1.	Keep the three priorities expressed in the ‘energy trilemma’ at the heart of UK energy policy.
2.	The Government’s reforms need to be ambitious to keep the UK on track for Net Zero, but they must retain the confidence of investors.
3.	In the medium-term, market competition should play a bigger role in the electricity system, reducing the role of the Government and Ofgem.
4.	The Government should support innovation and early deployment of all types of low-carbon resources, not just renewables.

Policy recommendations

This report makes 15 specific policy recommendations for the UK Government (Table 2), grouped into three themes:

- **Introduce local electricity pricing in Great Britain:** This will encourage generators and customers to balance supply and demand in their local area. Modelling by Aurora Energy Research shows that local pricing could reduce total system costs by £2.1bn per year from 2030 onwards. This would reduce the average household electricity bill by £37 per year.[4]
- **Reform the CfD scheme to offer a simplified ‘floor-price CfD’:** This will encourage developers to build projects in places that reduce costs for customers. To speed up deployment, the Government should run CfD auctions annually as well as radically simplifying the CfD scheme.
- **Reform the Capacity Market to include a ‘low-carbon quota’ for firm low-carbon resources:** This will ensure that the CM doesn’t ‘lock in’ gas-fired power stations for the long term.

In the medium term, there are good arguments for the market to play a bigger role in the electricity sector, reducing the role of the Government and Ofgem. The recommendations in this report will put the Government on a path to less intervention in the electricity sector without risking much-needed investment in the UK’s renewables sector.

4. See Appendix 1 for details.

Table 2: Specific policy recommendations for reforms to the GB electricity market.

Introduce local (nodal) electricity pricing in Great Britain.	
1.	The Government should introduce local pricing in the GB wholesale electricity market, modelled on US markets such as Texas.
2.	Initially, residential and small business customers should be charged a regional (zonal) electricity price unless they opt in to local (nodal) pricing. Over time, the Government should aim to extend local pricing to all customers.
3.	The Government should offset differences in electricity prices in different regions of Great Britain using fixed credits and charges on customer bills. This should apply to residential and small business customers only.
4.	Local pricing in the GB electricity market should start in April 2026.
The CfD scheme should offer a simplified 'floor-price CfD', rather than a long-term fixed price.	
5.	The Government should amend the CfD scheme to offer generators a guaranteed annual minimum payment ('floor-price CfD'), based on approaches used in Spain.
6.	CfD auctions should be held annually, at the same time as the Capacity Market auctions. This could make it easier to combine the CM and the CfD in future.
7.	Project developers should be required to submit bid bonds when entering the CfD auction, as they do in the Capacity Market. This will help to ensure that clean energy projects are delivered.
8.	Existing renewable energy generators should be allowed to compete for 1-year CfDs once their existing support contracts end. This will ensure that existing generators are not decommissioned prematurely and will align the treatment of existing generators between the CM and CfD schemes.
9.	The Government should radically simplify the Contracts for Difference scheme by scrapping Delivery Years and price caps for established technologies, and by allowing project developers to nominate their own 'load factor'.
10.	The CfD auction planned for 2021 should be the last one held under the current rules. The first CfD auction for 'floor-price CfDs' should be held in Q4 2023.
The Capacity Market should include a 'low-carbon quota' to support firm low-carbon resources.	
11.	The Capacity Market should include a 'low-carbon quota' for firm low-carbon resources. This quota should grow over time to increase the participation of low-carbon generators.
12.	The Government should allow firm low-carbon resources to receive contracts in both the Capacity Market and the CfD scheme.
13.	The Government should amend the Capacity Market to include regional (zonal) capacity pricing. This should be modelled on markets like New York State.

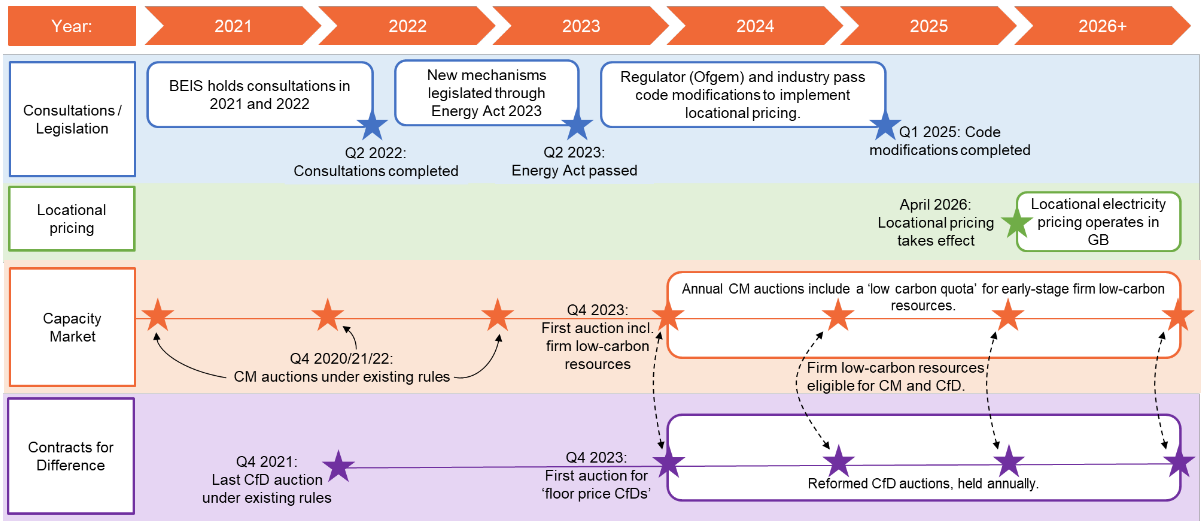
14.	The Government should introduce a stricter testing regime and higher penalties for non-delivery in the GB Capacity Market.
15.	The first CM auction including a 'Low Carbon Quota' should be the T-4 auction for 2027/28, held in Q4 2023.

Recommended policy timeline

Some of these recommendations in this report are incremental, whereas others are more substantial. We recommend that the Government legislate for these changes through an Energy Act in 2023 (Figure 1: Recommended policy timeline, including legislative and regulatory timelines.).

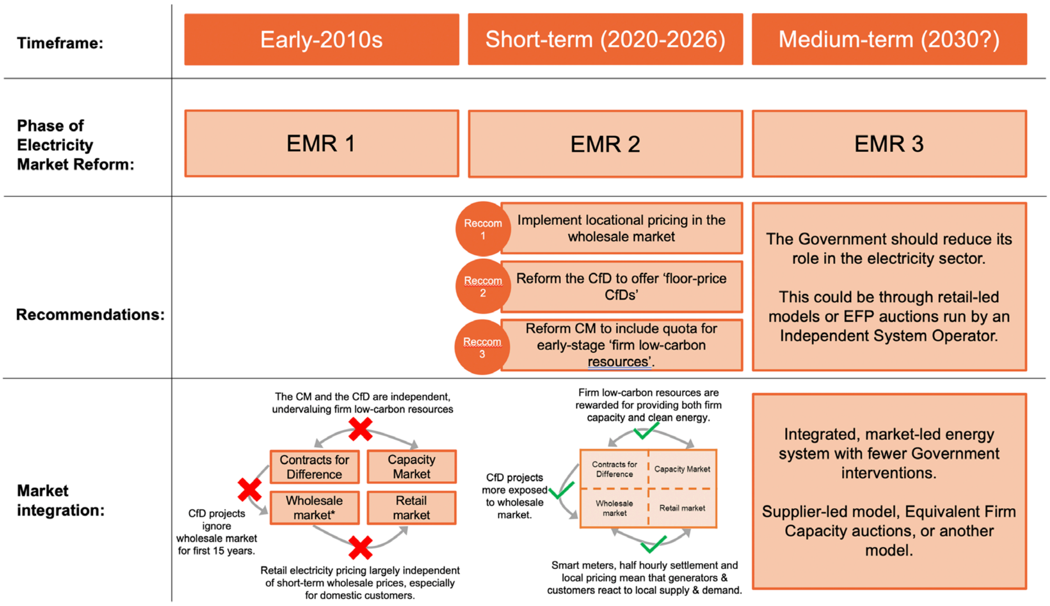
Changes to the Capacity Market and Contracts for Difference schemes can be implemented relatively quickly, so the first auctions under the new rules should be held in late 2023. For local pricing, legislation is only a starting point and Ofgem and industry will need around two years to implement the code modifications required to make locational pricing work. The Government should see locational pricing as approximately a five-year programme, going live in April 2026. This timeline is likely to align with the wide-scale deployment of smart meters and half-hourly settlement for domestic electricity customers. Together, these changes have the potential to unlock flexible demand, which will dramatically reduce the cost of integrating further offshore wind to the GB electricity system.

Figure 1: Recommended policy timeline, including legislative and regulatory timelines.



The recommendations in this report are intended to act as the second phase of Electricity Market Reform ('EMR 2'), building on successful reforms in the early-2010s ('EMR 1'). Once these reforms are implemented, the Government could consider a third, more radical, phase of Electricity Market Reform that could deliver a Net Zero-ready electricity system ('EMR 3') (Figure 2).

Figure 2: Conceptual model of the three phases of Electricity Market Reform (EMR 1, EMR 2, EMR 3).



It is tempting to try to move straight to the perfect electricity market design, along the lines of 'EMR 3' above. However, history shows that the evolution of electricity markets is a continual process of trial and error. If the Government tries to move too fast and too radically, then there's a risk of a botched implementation and a loss of confidence amongst investors and market participants, which would ultimately lead to less investment and an electricity system that is less secure, higher carbon and with higher electricity bills.

Our judgement is that local pricing is a fundamental building block of any long-term, efficient electricity market design, so the Government should prioritise local pricing over the next 5 years. Alongside local pricing, the Government needs to evolve the CfD and CM schemes to ensure continued decarbonisation and value for money. We recognise that the CfD and the CM are not perfect and won't be perfect even after these proposed reforms, but they remain useful for the medium term.

Once the Government has implemented these recommendations, the GB electricity market will have firm foundations that will allow the Government to consider longer-term policy options for the GB energy system.

1. Introduction

This section provides a short history of the GB electricity market, from privatisation in the early-1990s, to the scrapping of the 'England and Wales Pool' in 2001, and lastly the Electricity Market Reform (EMR) programme in the early-2010s. This section also summarises the impact of the COVID-19 pandemic on the GB electricity market, including the lessons that should be learnt from how the electricity system reacted to lower demand during the national lockdown.

History of the GB electricity market

Privatisation (1990s)

Electricity generation, transmission and supply in England and Wales was under public ownership until 1990, when the Central Electricity Generating Board (CEGB) was privatised. The CEGB owned and operated all electricity generation and transmission assets.[5,6] Post-privatisation, electricity generation has operated as a competitive market, known as the 'Electricity Pool of England and Wales' or just 'the Pool'.[7] Generators submitted bids into the Pool, which set the electricity price in each half-hourly trading period.

All electricity networks in Great Britain are now privately-owned and are regulated as regional monopolies. By 2000, the supply of electricity to customers was fully liberalised, allowing customers to choose their electricity supplier.

NETA and BETTA reforms (2000s)

In 2001, the Pool was replaced by the New Electricity Trading Arrangements (NETA), under which generators and suppliers could either trade bilaterally or submit bids and offers on power exchanges to buy and sell wholesale electricity.[8] This created a two-sided market with decentralised trading, in contrast to the centralised trading in the Pool. Under NETA, electricity suppliers fully participated in the market for the first time, encouraging customers to vary their electricity demand in response to changes in the underlying electricity price. The NETA reforms also removed capacity payments, which had faced accusations of inefficiency and gaming by generators.[9]

Critics of the NETA reforms argued that the move to decentralised trading would increase the market power of large generators due to a loss of transparency. The NETA reforms were also criticised for failing to incorporate transmission constraints by maintaining a single price for

5. Newbery, D. and Pollitt, M. (September 1997). Public policy for the private sector (Note 124). *The restructuring and privatization of the UK electricity supply – was it worth it?*
6. Electricity generation = Power stations. Electricity transmission = Power lines and substations.
7. Newbery, D. (November 1997). *Pool Reform and Competition in Electricity.* Link
8. Cui, C. (2010). Doctoral Thesis, University of Sterling. *The UK Electricity Markets: Its Evolution, Wholesale Prices and Challenge of Wind Energy.* Link (Chapter 2).
9. OFFER (February 1998). *Review of Electricity Trading Arrangements: background paper 1: electricity trading arrangements in England and Wales* .(Page 25) Link

electricity sold across England and Wales.[10] Although there were relatively few transmission constraints at the time of the NETA reforms, the cost of constraints is now significant, as described later in this report.

In 2005, the NETA arrangements were extended to Scotland and renamed the British Electricity Trading and Transmission Arrangements (BETTA). BETTA governs electricity trading arrangements across the whole of Great Britain, creating the 'GB electricity market'.

Post-BETTA, all generators in England, Scotland and Wales can sell electricity to suppliers across Great Britain. This trading system does not consider the physical limitations of the electricity network. For example, on a windy day, wind farms in Scotland may have sold their electricity to customers based in London, even if the electricity network cannot physically transmit this electricity. It is the responsibility of the Electricity System Operator, *National Grid ESO*, to resolve these physical 'constraints'.

The ESO resolves constraints by paying some generators to turn down (typically wind generators in Scotland) and other generators to turn up (typically gas-fired power stations in England and Wales). Constraints are also caused by solar farms, nuclear power stations and interconnectors. The cost of resolving these constraints is socialised and recovered from all electricity customers in Great Britain.[11]

Northern Ireland has separate electricity trading arrangements as part of the 'Single Electricity Market' on the island of Ireland, comprising both the Republic of Ireland and Northern Ireland.[12]

Electricity Market Reform (2010s)

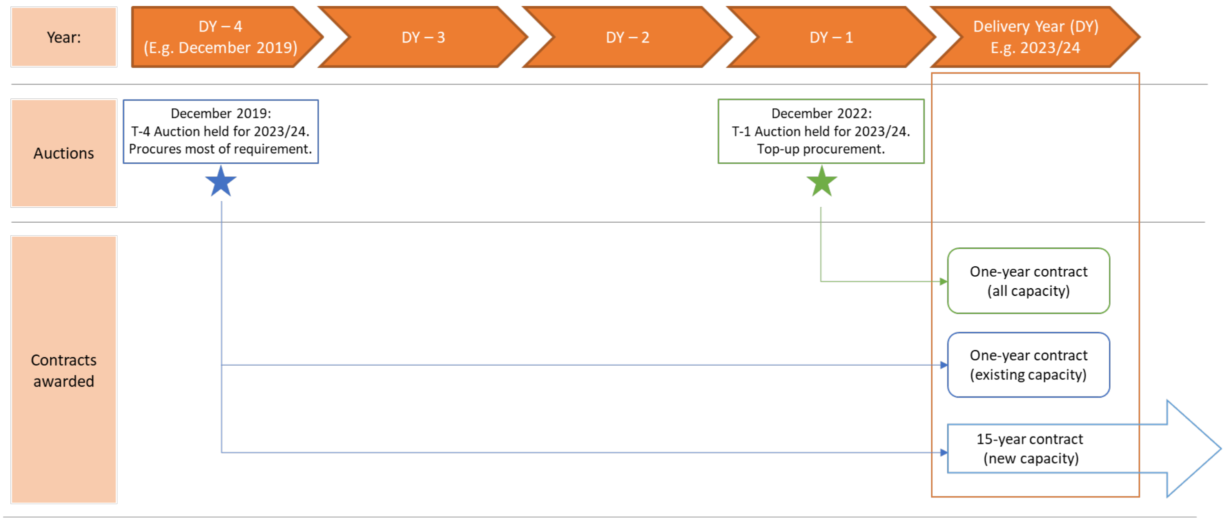
The Energy Act 2013 made significant changes to the GB electricity market through a programme known as Electricity Market Reform (EMR). However, EMR did not change the wholesale electricity market, which is still governed by the BETTA arrangements. EMR introduced two major changes: The Capacity Market (CM) to promote security of supply, and the Contracts for Difference (CfD) scheme for renewable energy generators such as wind and solar.[13]

The Capacity Market (CM) pays generators to be available at times of system stress, for example on a cold winter evening when there is little wind generation. The CM requires generators to be available when demand is highest and supply is lowest, which means that intermittent generators like wind and solar are generally either not eligible for contracts or receive much reduced payments. Most CM contracts are awarded to gas-fired power stations and nuclear power stations. In recent years, battery storage and electricity interconnectors have become increasingly competitive. New generators are eligible for 15-year CM contracts to support upfront capital investment, whereas existing generators are only eligible to receive one-year contracts.

Two CM auctions are held each year: Most capacity is procured four years ahead of time through the 'T-4' auction; if required, additional capacity is procured one-year ahead of time through the 'T-1' auction (Figure 3).

10. Sweeting, A. MIT CEEPR Working Paper. *The Wholesale Market for Electricity in England and Wales: Recent Developments and Future Reforms.* Link
11. Constraint costs are socialised and recovered through the Balancing Services Use of System (BSUoS) charge that is paid by all final demand customers.
12. SEM Committee (undated). *SEM.* Link
13. Ofgem (undated). *Electricity Market Reform (EMR).* Link

Figure 3: Example timetable for Capacity Market auctions (Delivery Year 2023/24).[14]



The Contracts for Difference (CfD) scheme offers renewable energy generators long-term contracts that guarantee them a fixed price for the electricity that they generate. CfD contracts for wind and solar run for fifteen years and are instrumental in supporting the financing of renewable energy projects, which have high upfront costs but low operating costs. CfD contracts are allocated through a competitive auction process, in which generators compete to secure contracts. The CfD scheme has encouraged steep reductions in the prices offered by developers of offshore wind farms, which have fallen by two-thirds since the first auction in 2015.[15] The next CfD auction is planned for late-2021.[16]

The CfD scheme has also supported the new nuclear power station at Hinkley Point C, which is currently under construction. Unlike the CfDs for wind and solar, this contract runs for 35 years and was bilaterally negotiated between the Government and the project owner, EDF, rather than auctioned.[17]

Despite the CfD and the CM both creating additional costs that have to be paid by customers, average bills have remained relatively unchanged over the last decade. In 2019, the average electricity bill was £544, compared to £509 in 2010 (in real terms).[18] Over the same period, carbon emissions in the electricity sector have fallen by over 60%.[19] Bills are relatively unchanged despite nearly a quarter of customer bills now going to pay for environmental and social obligations, including subsidies for wind and solar and financial protection for the poorest customers.[20] Energy efficiency has been a major driver of cost savings for customers, with average domestic electricity consumption falling 20% since 2010. The cost of new offshore wind farms has now fallen so far that the Government does not expect them to increase customer bills.[21]

14. Delivery years run from 01 October to 31 September. E.g. Delivery Year 2023/24 runs from 01 October 2023 to 31 September 2024.
15. KPMG (September 2019). *Blown away: CfD round 3 delivers record low prices for offshore wind.* Link
16. BEIS (March 2020). *Contracts for Difference (CfD): Allocation Round 4.* Link
17. BEIS (Updated July 2018). Collection: Hinkley Point C. Link
18. BEIS (March 2020). *Average annual domestic electricity bills by various consumption levels (Table 2.2.5).*
19. CCC (July 2019). *Reducing UK emissions: 2019 Progress Report to Parliament.* Link
20. Ofgem (September 2020). *Infographic: Bills, prices and profits.* Link
21. BEIS (Updated October 2019). *CfD Allocation Round 3: results.* Link. *(C) Estimated actual monetary budget impact.*

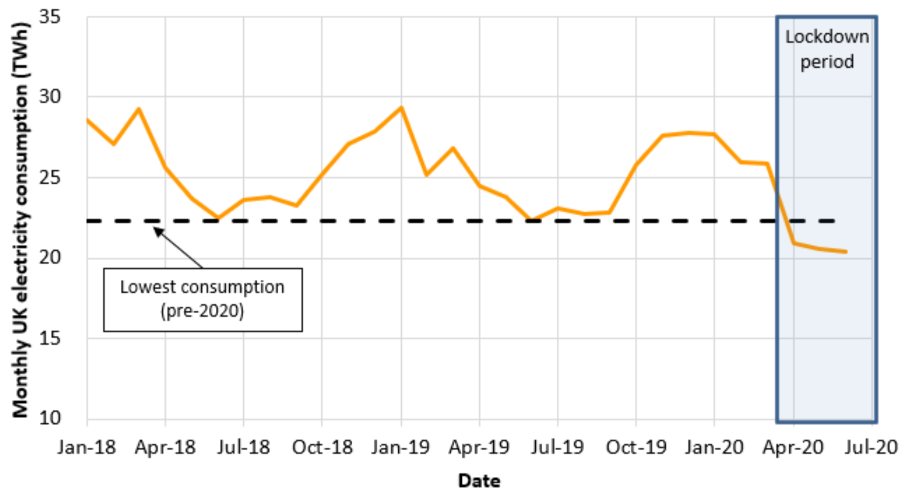
The impact of COVID-19 on the GB electricity market

The national lockdown in summer 2020 associated with COVID-19 created new challenges for electricity markets.[22] Falling economic activity led to record low electricity demand, which caused problems for the Electricity System Operator (ESO), who incurred higher than normal costs to run the electricity system, as explained below.

Falling electricity demand made operating the electricity system more difficult.

During the national lockdown, UK GDP fell by 20% (Q2 2020).[23] This led to a sharp reduction in electricity demand as factories, offices and shops closed their doors. Demand fell by an estimated 15% during April and then remained suppressed compared to previous summers (Figure 4: UK monthly electricity consumption. Source: BEIS energy trends.24).

Figure 4: UK monthly electricity consumption. Source: BEIS energy trends.[24]



Falling demand led to a significant reduction in carbon emissions from the electricity sector, which fell by as much as 40% across Europe during April.[25] However, low demand caused difficulties for the ESO. The ESO is responsible for balancing electricity supply and demand in real-time, as well as ensuring that the lights stay on in the event of faults on the network. To do this, the ESO pay generators to increase or decrease their output, depending on the local balance of supply and demand in their area. These instructions are collectively known as 'system balancing services'. For example, when it is windy in Scotland, the ESO often pay Scottish wind generators to decrease their output so that the local electricity network is not overloaded. The ESO must also manage system technical parameters including frequency, inertia and voltage.

The ESO has traditionally relied on gas- and coal-fired power stations to vary their output to manage these technical parameters. However, these power stations can only vary their output when they are already running.

22. Birkett, E. Policy Exchange (June 2020). *Electricity Markets Under Pressure.* Link
23. ONS (August 2020). *GDP first quarterly estimate, UK: April to June 2020.* Link
24. BEIS (updated August 2020). *Energy Trends: UK electricity*. Link. Note: includes Northern Ireland.
25. Jones, D. Carbon Brief (April 2020). *Analysis: Coronavirus has cut CO2 from Europe's electricity system by 39%.* Link

During the national lockdown, many power stations were not planning to operate due to low demand and correspondingly low electricity prices. This removed the ESO's traditional source of balancing services. The ESO therefore had to pay power stations to turn on so that they could be available to provide balancing services, incurring significant costs.

The ESO has pledged that it will be able to operate a zero-carbon electricity system by 2025, which means that the system will be able to operate with only zero-carbon electricity generators such as wind, nuclear, solar, biomass and hydro.[26] The ESO will be able to balance the system without having to pay to switch on gas- and coal-fired power stations, reducing the need to pay to switch off low-carbon generators like wind and solar. However, based on the ESO's target, this capability is still five years away.

Over this summer, system balancing costs increased by two-thirds.

To manage lower demand this summer, the ESO introduced new services, including paying the Sizewell B nuclear power station to reduce its output.[27] In May 2020, the ESO forecasted that system balancing costs for May-August 2020 would be more than double the same period in 2019 (£830m vs. £330m).[28] As it has turned out, balancing costs for summer 2020 only increased by two-thirds (£220m) compared to the same period in 2019 (Table 3: 'Balancing Services Use of System Cost' (BSUoS) for summer 2019 and summer 2020 (May to August).).

Table 3: 'Balancing Services Use of System Cost' (BSUoS) for summer 2019 and summer 2020 (May to August).

Month	Summer 2019 BSUoS (£m)	Summer 2020 BSUoS (£m)
May	£64m	£162m
June	£89m	£139m
July	£71m	£139m
August	£109m	£118m
Total	£333m	£557m
Increase vs. 2019 (%)	-	**+67%**

Source: National Grid ESO.[29]

Summer 2020 was a preview of the future, high renewables, GB electricity market.

In many ways, summer 2020 was a preview of the future electricity system, with renewable energy generators making up a larger share of generation, and gas- and coal-fired power stations available less often to provide system balancing services. To limit rising balancing costs, the ESO will need to continue to innovate and to introduce new services. However, the ESO cannot do this on its own.

26. National Grid ESO (undated). *Zero-carbon explained.* Link.
27. National Grid ESO (May 2020). *The actions we're taking to manage reduced demand for electricity this summer.* Link
28. National Grid ESO (May 2020). *A note on our BSUoS updates published 15th May 2020.* Link
29. Policy Exchange analysis. Based on data from National Grid ESO monthly BSUoS forecasts and reports. Link

Electricity market design influences where developers build new projects, how customers react to electricity prices, and ultimately how much system balancing the ESO needs to do. The challenges for the ESO are only expected to grow. UK offshore wind capacity is expected to double by 2025 and to quadruple by 2030. Without further reforms to the GB electricity market, costs will rise, and customers will not fully benefit from the falling costs of wind and solar. Modelling from Aurora Energy Research shows that, without reform, system balancing costs could be four times higher by 2050 (£6bn per year).[30]

30. See Appendix 1 for details.

2. The GB electricity market in 2050

The GB electricity market has already undergone a decade of rapid change, with the market share of coal generation falling from 28% in 2010 to 2% in 2019 (Figure 5: GB electricity market generation mix. Historical (Source: DUKES). Projection (Aurora).31). Coal has been replaced by a combination of wind, solar and gas. Modelling from Aurora Energy Research shows that the 2020s will be about replacing gas with more renewables, particularly offshore wind.

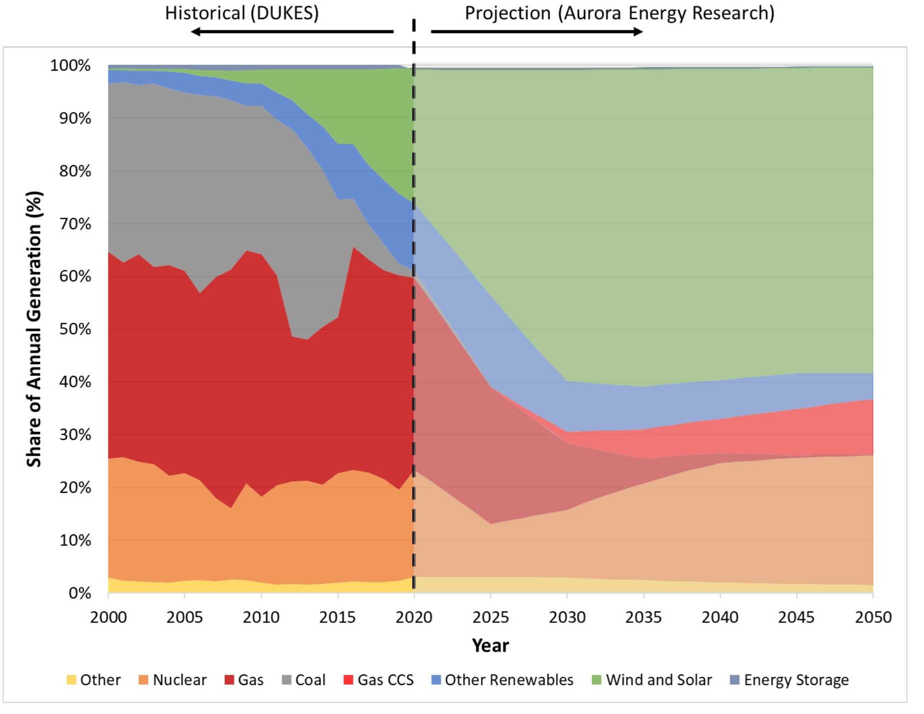
In the long-term, the GB electricity system is expected to be dominated by wind and solar (c.60% of generation) and nuclear (c.25%). Great Britain will also rely on gas with carbon capture and storage, as well as cheap gas-fired 'reciprocating engines', which will provide back-up at times of low wind but will only operate very rarely.

The 2050 electricity system will pose challenges for grid operators, unless energy storage or other flexible technologies are developed, and unless customers are encouraged to shift their demand to coincide with periods of high wind and solar generation. The future electricity system will harness flexible demand, which will use excess wind and solar power to produce green hydrogen, charge electric vehicles and heat homes.

The remainder of this report proposes policies to ensure that the GB electricity market continues to operate effectively as the UK heads for Net Zero.

Figure 5: GB electricity market generation mix. Historical (Source: DUKES). Projection (Aurora).[31]

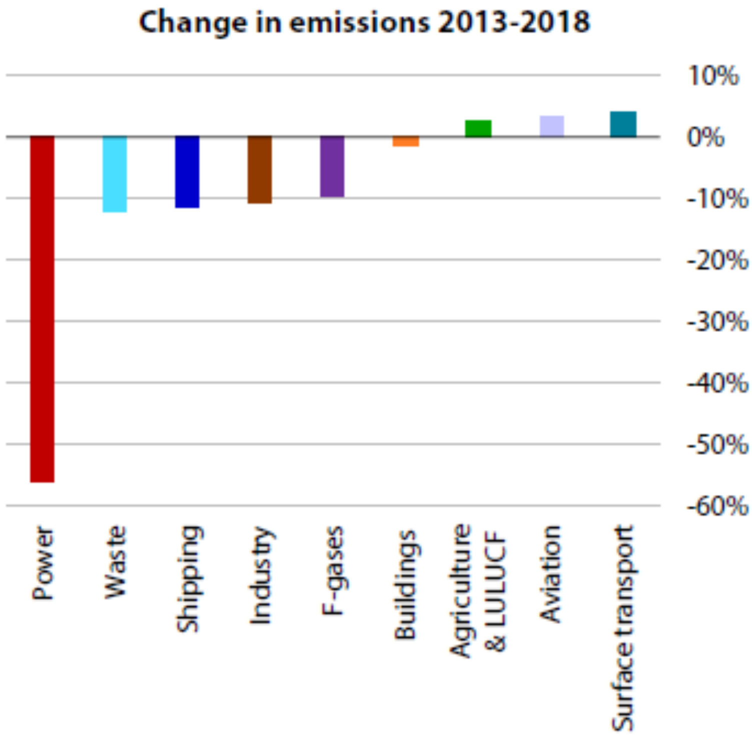
31. Note: Does not include interconnector imports and exports. Historical data includes Northern Ireland, whereas projection is Great Britain only.


Historical (DUKES)
Projection (Aurora Energy Research)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Share of Annual Generation (%)
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year
Other
Nuclear
Gas
Coal
Gas CCS
Other Renewables
Wind and Solar
Energy Storage

3. Limitations of the current GB electricity market design

Since Electricity Market Reform, carbon emissions reduced significantly in the electricity sector, more than any other part of the UK economy (Figure 6: Percentage change in UK greenhouse gas emissions by sector (2013-2018).). Despite this success, there are clear signs that the Government will need to make further reforms to the GB electricity market. In particular, the costs of balancing the system are rising year-on-year, as described in the previous section. There are also questions over whether the current Capacity Market will 'lock-in' gas-fired power stations and become a barrier to the deep decarbonisation of the electricity system. Finally, the CfD scheme undoubtedly distorts the wholesale electricity market, as evidenced by increasing periods of negative electricity prices. This section explores these issues in detail.

Figure 6: Percentage change in UK greenhouse gas emissions by sector (2013-2018).



Source: CCC.[32]

32. CCC (July 2019). *Reducing UK emissions: 2019 Progress Report to Parliament 2019.*

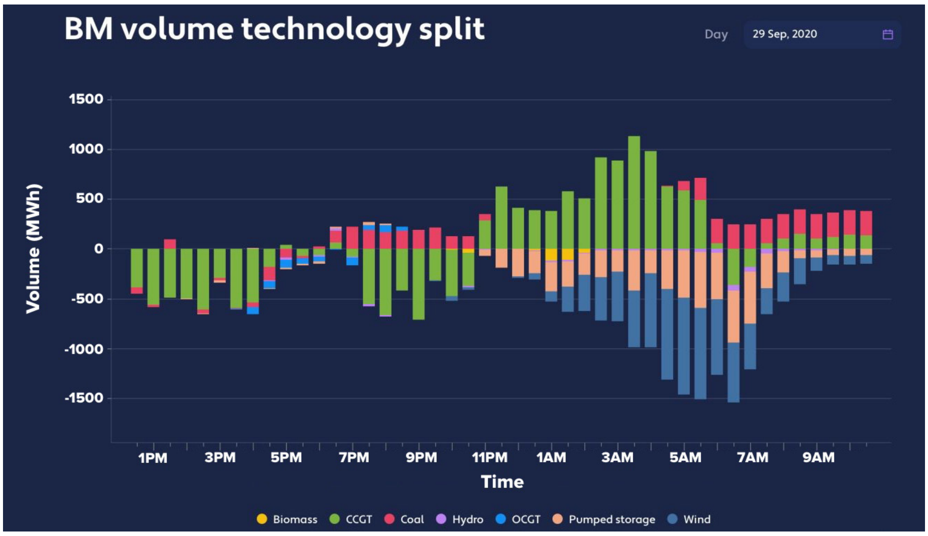
Limitations of the GB wholesale electricity market

The GB electricity market is structured so that, at any given time, all generators and customers receive or pay the same price for wholesale electricity in all locations in Great Britain. This system is known as 'national pricing' or 'uniform pricing'.[33] National pricing effectively ignores the physical limitations of the electricity network. For example, the electricity cables between Scotland and England have a limited capacity, currently 5.7 gigawatts (GW).[34] When it is windy in Scotland, the ESO often has to pay Scottish wind generators to turn off, so that they do not overload the electricity cables to England. Similarly, there are days when solar generators, typically located in the South of England, generate more electricity than the local network can handle. In both these cases, the electricity network is 'constrained'.

The rise of renewable energy is leading to higher constraint costs. This is exacerbated by national pricing.

When the electricity network is constrained, the ESO has to pay generators in the constrained area to turn down and other generators to turn up. To do this, the ESO accepts bids (to turn down) and offers (to turn up) in the Balancing Mechanism. Figure 7: Volume of accepted bids and offers in the Balancing Mechanism (BM). 29 September 2020. shows 24 hours of accepted bids and offers in the Balancing Mechanism in September 2020. During the night, the ESO paid to turn down wind generators, typically located in Scotland, and to turn up gas-fired power stations, typically located in England and Wales. The ESO also paid pumped storage facilities to absorb excess electricity by pumping water up hill. These payments are known as 'constraint costs'.

Figure 7: Volume of accepted bids and offers in the Balancing Mechanism (BM). 29 September 2020.



Source: Modo Energy.

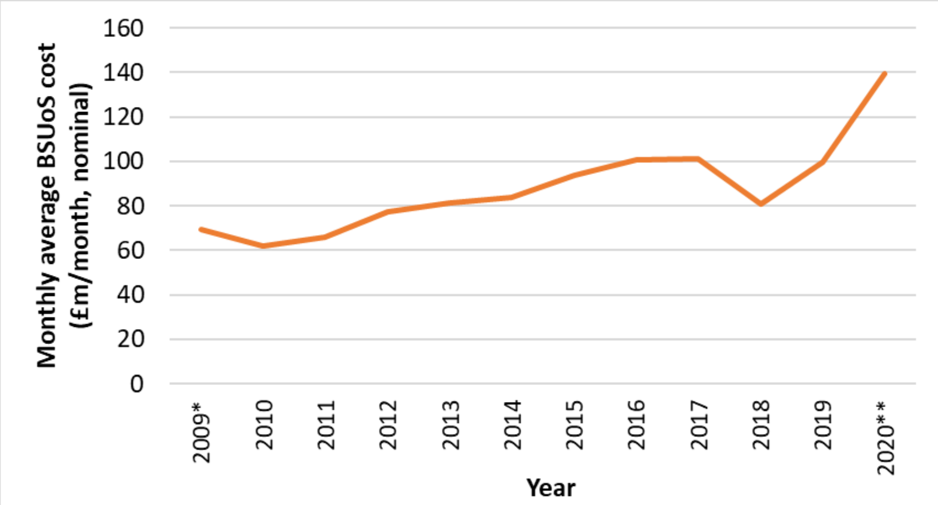
33. The electricity price does change every 30 minutes, known as a 'settlement period'. In each 30-minute period, the price is uniform across Great Britain.
34. National Grid ESO (2019). *ETYS 2019 (page 40-41: Boundary B6 – SP Transmission to NGET).*

Constraint costs are socialised across all electricity customers as part of the Balancing Services Use of System (BSUoS) charge, which has risen sharply in 2020 (Figure 8: Monthly average system balancing costs in the GB electricity market.35). Because constraint costs are socialised, all customers pay an equal share even though constraints are caused by a limited number of generators.

Customers can help to reduce constraints by increasing their demand when there is excess generation in their local area. For example, EV owners in Aberdeenshire could charge their car when it's windy and EV owners in Cornwall could charge when it's sunny.

National pricing discourages this behaviour because all customers are charged the same price, regardless of local supply and demand, so they have no incentive to help reduce constraints through different approaches to energy use. As the market share of wind and solar grows, national pricing will make electricity bills higher than they need to be.

Figure 8: Monthly average system balancing costs in the GB electricity market.[35]



Renewables also make operating the electricity system more difficult, which contributes to rising system balancing costs.

As well as constraints, renewables cause other problems for the ESO. For example, gas-fired power stations provide significant 'inertia', which stabilises the electricity system and helps the ESO to respond to faults on the network.[36] To keep the system stable, the ESO increasingly has to turn off renewable energy generators, like wind and solar, so that it can turn on gas-fired power stations to provide inertia and to manage voltage fluctuations.

The ESO procures system balancing services through a mixture of short-term and long-term contracts. Traditionally, the ESO has not paid for inertia because large power stations provided it for free. Now that inertia is scarcer, the ESO has started to introduce new markets for inertia and voltage control through a combination of 'pathfinder' projects and

35. Source: Policy Exchange analysis of NG ESO historical BSUoS data. Settlement Final (SF) data. * 2009 = April-Dec only. ** 2020 = Jan-Aug only. Link.

36. National Grid ESO (January 2020). *Our new approach to inertia and other stability services.* Link

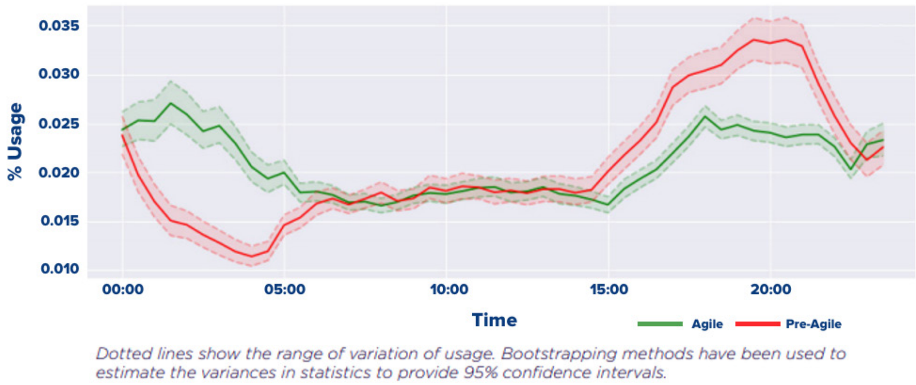
trials using distributed energy resources including small solar farms and battery storage facilities.[37,38]

A full review of the ESO's contracting strategy is beyond the scope of this report. However, system conditions this summer mean that there will be renewed scrutiny of the ESO's plan to be able to operate a zero-carbon electricity system by 2025.[39]

We also know that customers can reduce the need for system balancing services by responding to local demand and supply for electricity. For example, if more customers charged their electric vehicles at times of high wind generation, then more power stations would be operating and the ESO would have access to more system balancing services at a lower cost.

Octopus Energy's *Agile* tariff charges customers the real-time wholesale electricity price, which changes every 30 minutes. Early research using the Agile tariff shows that customers will respond to price signals (Figure 9: Electricity usage for customers on Octopus Energy's Agile tariff. (Red) standard tariff. (Green) Agile tariff.). At the moment, all Agile customers see broadly the same tariff, regardless of where they live. With locational pricing, customers in Scotland would see the lowest prices when it's windy, encouraging them to increase their demand and reducing costs for the ESO.

Figure 9: Electricity usage for customers on Octopus Energy's *Agile* tariff. (Red) standard tariff. (Green) Agile tariff.



Source: Octopus Energy.[41]

Large industrial users are also well-placed to balance local supply and demand by shifting their load to times when it's windy and prices are low. Industrial customers can also help to provide inertia, which is provided by rotating machines. Demand currently provides up to 30% of inertia in GB, particularly from industrial motors.[41]

Locational network charges and transmissions losses provide some locational signals. However, this approach has two major

37. National Grid ESO (undated). *Network Development Roadmap*. Link
38. National Grid ESO (undated). *Power potential*. Link
39. ESO (April 2019). *Zero carbon operation of Great Britain's electricity system by 2025*. Link
40. Octopus Energy (undated). *Agile Octopus: A consumer-led shift to a low-carbon future*. Link
41. Berry, BB. Reactive Technologies (June 2019). *Inertia Estimation Methodologies vs Measure Methodology*. Link. Page 4. *"In the UK, demand side inertia can currently be up to about 30% of the total inertia of the system…"*

drawbacks.

There are some locational signals in the GB electricity market. Network charges are higher in Scotland, reflecting an excess of generation that needs to be exported to England and Wales.[42] Network charges encourage project developers to build projects further south in Great Britain, which contributes to reducing network constraints. The GB electricity market also includes transmission losses that vary by region. This encourages generation and demand to locate closer to each other. Regional transmission losses were introduced in April 2018,[43] following an investigation by the Competition and Markets Authority.[44]

Network charges and transmission losses both provide locational signals to generators and demand. However, there are two major limitations of this approach:

1. Locational network charges do not encourage generators and demand to react to local supply and demand for electricity, because they are mostly fixed charges.[45] For example, battery storage in Scotland sees the same wholesale price as battery storage in the southwest of England, even though local supply and demand could be very different.
2. The current network charging regime discourages developers from building energy storage projects in Scotland, even though storage could help to reduce transmission constraints. Ofgem's ongoing Significant Code Review could resolve this issue with energy storage;[46] however, it will remain inefficient to use network charges, which are set ahead of time, to resolve network constraints, which occur in real time and vary from hour to hour.

It is clear that the GB electricity market would benefit from stronger signals for all market participants to balance supply and demand on a regional and local level. **Without further market reform, system balancing costs will continue to rise and customers will not fully benefit from the falling cost of wind and solar.**

Limitations of the Contracts for Difference (CfD) scheme

Before the CfD was introduced, renewable energy generators were subsidised through the Renewables Obligation (RO) scheme, which awarded Renewables Obligations Certificates (ROCs) to generators for each megawatt-hour (MWh) of electricity generated. ROCs give developers a fixed top-up to the variable wholesale electricity price. Ministers set the number of ROCs per MWh awarded to each technology, with more ROCs awarded to newer technologies like offshore wind.

One issue with this approach is that, as the cost of wind and solar fell, Ministers had to reduce the number of ROCs awarded to each technology. This created boom-and-bust cycles of project development,

43. Elexon (undated). *Glossary: Transmission Losses.* Link
44. Competition and Markets Authority (June 2016). *Energy market investigation: final report.* Link
45. I.e. there is poor 'dispatch efficiency'.
42. National Grid ESO (undated). *TNUoS guides for generators.* Link
46. Ofgem (April 2019). *Reform of network access and forward-looking charges.* Link

with developers constantly chasing cliff-edge deadlines to complete their projects and to secure more ROCs. This led to almost farcical scenes of solar farm developers building in the mud and through the night in February and March to energise their projects before the cliff-edge on the first of April.

The CfD scheme has used competition to drive down the cost of renewables.

Under the CfD scheme, politicians and civil servants have far less responsibility for setting prices, which are instead set via competitive auctions. There is also far less pressure on developers to build before cliff-edge deadlines, because CfD contracts have a flexible period for construction. This means that developers and investors can instead focus on lowering the overall cost of their projects. Since 2015, the CfD scheme has awarded contracts to 13 GW of offshore wind, with prices falling by two-thirds since the first auction.[47]

However, costs have not fallen for all technologies. The UK Government has only awarded a CfD to one nuclear power station, Hinkley Point C, at a price of 92.50 £/MWh (2012 prices).[48] The Government expected this contract to be the first of many, with future projects including Sizewell C (EDF), Moorside (NuGen), Wylfa (Hitachi), and Bradwell B (CGN and EDF). In theory, the Government should have been able to create competition between new nuclear projects, further driving down costs. However, following Hitachi's withdrawal from the Wylfa project in September 2020, only EDF Energy and China General Nuclear (CGN), acting in partnership, are developing new large-scale nuclear power stations in the UK.

The failure of the CfD model to deliver new nuclear power stations means that the Government is now considering a Regulated Asset Base (RAB) model for new projects.[49] Under a RAB model, more risk is transferred to customers. If the nuclear power station doesn't work properly, or if costs rise, then customers will pay more, rather than the project's owners. This model significantly reduces the cost of financing for new nuclear power stations, which should reduce the overall cost to customers. Some US states have used variations of a RAB model for new nuclear power stations; several of these projects experienced cost overruns, leading to higher costs for customers.[50]

Early CfDs also supported a new class of technologies that generate electricity from waste via gasification or pyrolysis. Collectively, these technologies are known as 'Advanced Conversion Technologies' (ACT). The technical and economic performance of ACT plants has generally disappointed, with the industry reverting to conventional waste-to-energy designs (incinerators).[51] In the last CfD auction, ACT plants were awarded just 35 MW of contracts. Arguably, this demonstrates the CfD mechanism working as intended, finding the cheapest technologies (offshore wind) and rejecting others (ACT, wave and tidal).

47. Source: BEIS.
48. BEIS (updated July 2018). *Collection: Hinkley Point C*. Link
49. BEIS (July 2019). *Consultation: Regulated Asset Base (RAB) model for nuclear*. Link
50. Newberry, D. et al. (University of Cambridge, Energy Policy Research Group). *Financing low-carbon generation in the UK: The hybrid RAB model*. Link. Page 13.
51. Peake, L. Resource Magazine. (November 2016). *Advanced Conversion Technologies: A heated debate*. Link

The Government retains the flexibility to incentivise a broader capacity mix through the dedicated 'Pot 2' for 'less established technologies'. In the next CfD auction, the Government plans to use Pot 2 to use to support floating offshore wind, which is an early-stage technology.[52]

Under the CfD scheme, the Government is largely in control of which technologies get built.

Nearly all new renewable energy projects built in Great Britain are supported by the Government-backed CfD scheme. We have started to see a few 'subsidy-free' onshore wind and solar projects, although this is mainly because these technologies were excluded from the last two CfD auctions.[53] There is both a philosophical and economic question about whether the Government should be playing such a large role in determining the UK's capacity mix.

On the one hand, by providing long-term contracts, the Government significantly reduces risk for investors, reducing financing costs and therefore securing the best prices for customers. On the other hand, no entity, whether a Government or a private company, could possibly procure the optimal capacity mix. This means that the Government is inevitably procuring some projects that are not in the best interests of customers. Project developers are also reliant on the whim of changing Government preferences. For example, the Government has used its control of the CfD process to hold back the deployment of onshore wind and solar at a time when these types of projects were causing political difficulties.

As with the Capacity Market, there are other policy options to support renewable energy projects that would reduce the influence of the Government, leaving more to the market.

The CfD scheme distorts the wholesale market by insulating developers from the wholesale market.

Another limitation of the CfD mechanism is that it pays generators a fixed price per megawatt-hour (MWh) generated, regardless of whether it is needed by the electricity system. Because CfD generators receive a fixed price for their electricity, they will continue generating even when there is a surplus of electricity. When the electricity system cannot accommodate any more wind generation, the ESO must pay wind farms to switch off. This increasingly leads to negative electricity prices in the wholesale market, putting further pressure on conventional power stations and nuclear generators, who must either switch off or pay to continue operating. This risks undermining investment in the electricity system.

In 2020, there have been more periods of negative pricing in the UK and across Europe. [54,55] This is in part due to lower demand during the Coronavirus lockdowns and in part due to a rising share of renewable energy generation. As with system balancing costs, there is a risk that

53. Stoker, L. Solar Power Portal (September 2017). *Anesco lays claim to UK's first subsidy-free solar farm.* Link
54. Elexon (June 2020). *Negative System Prices during COVID-19.* Link.
55. Grundy, A. Current News (October 2020). *Instances of negative pricing more than double across Europe in 2020.* Link
52. BEIS (accessed 21 September 2020). *Consultation: CfD: proposed amendments to the scheme 2020.* Link

the periods of negative pricing experienced in 2020 are a preview of the electricity system of the future.

To minimise the impact of the CfD scheme on the wholesale electricity market, and under pressure from the European Commission, the CfD scheme includes a 'six-hour rule'. This means that the Government will not pay generators if the day-ahead electricity price is negative for six hours or more.[56] This year, the Government has consulted on eliminating payments to generators whenever the day-ahead electricity price is negative, a recognition that prices could be negative more often than previously thought.[57,58] This rule change will increase uncertainty for investors, who will need to forecast the number of periods of negative prices, and is therefore likely to put upwards pressure on CfD prices.[59]

For future CfD rounds, **the Government must consider reforms to the CfD mechanism to reduce its distortionary impact on the wholesale electricity market.**

Limitations of the Capacity Market (CM)

During the mid-2010s, there was a risk of supply shortages as gas- and coal-fired power stations closed. Some of these power stations had reached the end of their planned operating lifetime, particularly large coal-fired power stations commissioned in the 1960s and early gas-fired power stations commissioned in the 1990s. In theory, these closures should have led developers to anticipate rising prices due to falling supply, allowing them to finance and build replacement power stations.

However, the Government was concerned that developers were not building enough new power stations despite impending supply shortages. This was in part due to a 'missing money' problem, with power station owners unable to make enough money in the short-term wholesale electricity market to cover the cost of building and operating their power stations. There is significant academic debate over the existence of 'missing money' and how to address it.[60]

Many energy economists argue that the Government should not intervene, even if it believes that there could be supply shortages. Instead, they argue that the Government should allow prices to rise to very high levels for short periods (perhaps 100 times higher than the average price), which will encourage investors to build more generators and will encourage customers to be more flexible to avoid price spikes. The counterargument is that it is not politically acceptable for prices to rise to very high levels, even for short periods, and that it is in the best interests of customers for the Government to ensure that there is always sufficient electricity generation available. Whatever the merits of these arguments, the UK Government saw an impending supply shortage and decided that something needed to be done.

The first Capacity Market auction was held in 2014 for delivery in October 2018 (Delivery Year 2018/19). The CM replaced the 'Contingency Balancing Reserve' that was used between 2014 and 2017, under which the Government bilaterally negotiated contracts with generators.[61] The

57. BEIS (accessed 21 September 2020). *Consultation: CfD: proposed amendments to the scheme 2020.* Link
58. BEIS (November 2020). *CfD for Low Carbon Electricity Generation: Government response to consultation on proposed amendments to the scheme.* Link
59. Also, the negative pricing rule only applies to the day-ahead market, which means it may not resolve negative prices in the intra-day market and in the real-time balancing mechanism, which the ESO uses to turn down and switch off generators when there is excess supply.
60. Newbery, D. (July 2015). *Missing Money and Missing Markets (working paper).* Link
61. BEIS and Ofgem (October 2016). *Statutory Security of Supply Report 2016.* Link

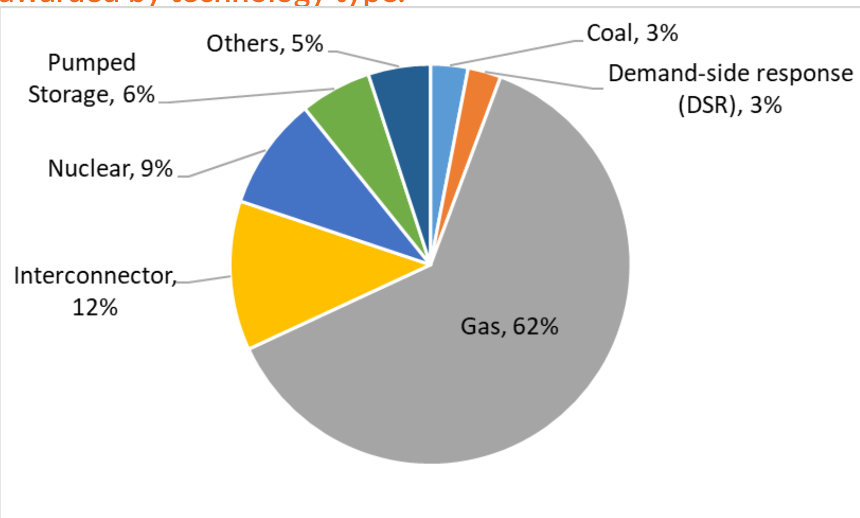
56. Baringa (2015). *Negative pricing in the GB wholesale electricity market.* Link

Capacity Market costs customers around £1bn per year, depending on the annual auction prices.[62] This cost is lower than many expected, in part because the Government has run competitive auctions to drive down costs. The Capacity Market has largely allayed fears of supply shortages and blackouts in the UK.

The Capacity Market risks 'locking in' gas-fired power stations for the long term.

One valid concern with the Capacity Market is that it tends to support fossil fuel power stations, particularly gas-fired power stations, which more readily provide firm capacity. In the most recent auction (for 2023-24), gas-fired power stations comprised nearly two-thirds of the awarded capacity (Figure 10: Capacity Market (T-4) for 2023-24. De-rated capacity awarded by technology type.63). Wind and solar generators are eligible for contracts; however, their contribution is 'de-rated' because they are not guaranteed to be available at times of system stress, which are typically cold winter evenings when the wind is not blowing. Support for new gas-fired power stations is particularly controversial, as new generators receive 15-year contracts. This raises concerns over 'locking in' fossil fuel generation at the expense of low-carbon alternatives.

Figure 10: Capacity Market (T-4) for 2023-24. De-rated capacity awarded by technology type.[63]



One obvious suggestion is that the Capacity Market should exclude new gas-fired power stations. However, this ignores the very real energy security challenge posed by cold, still winter evenings when wind and solar cannot make a significant contribution to the UK's electricity supply. In recent CM auctions, developers of battery storage have won more contracts due to the falling cost of batteries. However, like wind and solar, the contribution of battery storage is 'de-rated' as these battery projects can typically only generate for one or two hours before they need to be

62. E.g. Cost of the T-4 2023/24 auction: 43,749 MW (de-rated) @ £15.97/kW/year (de-rated) = £700m/year.

63. Source: NG ESO (March 2020), Final Auction Report (T-4): Link

recharged. This limits the potential for battery storage to contribute to security of supply, in the absence of dramatic cost reductions and/or technological breakthroughs.

Firm low-carbon resources will have to keep the lights on in a low-carbon electricity system.

There is a class of technologies that have the potential to replace gas-fired power stations, known as 'firm low-carbon resources' (Box 1).

Box 1: What are 'Firm low-carbon resources'?

Traditionally, electricity systems have relied on two types of resources:

1. **'Firm resources'** such as gas- and coal-fired power stations, which can generate at any time but have significant greenhouse gas emissions.
2. **'Intermittent low-carbon resources'** such as wind and solar, which only generate in favourable weather conditions.

There is a third class of resources, **'firm low-carbon resources'**, which can generate at any time and have low or zero greenhouse gas emissions. Nuclear is the typical 'firm low-carbon resource'. However, nuclear power is relatively inflexible, making it a relatively poor complement to wind and solar. Also, new nuclear power stations are proving expensive to build in Europe.

Demand-side response (DSR) and lithium-ion battery storage are examples of low-carbon resources; however, they can typically only deliver for a few hours and are therefore rarely truly 'firm'. Some researchers instead classify battery storage and DSR as 'fast burst' balancing resources.[64]

Examples of 'firm low-carbon resources' include:

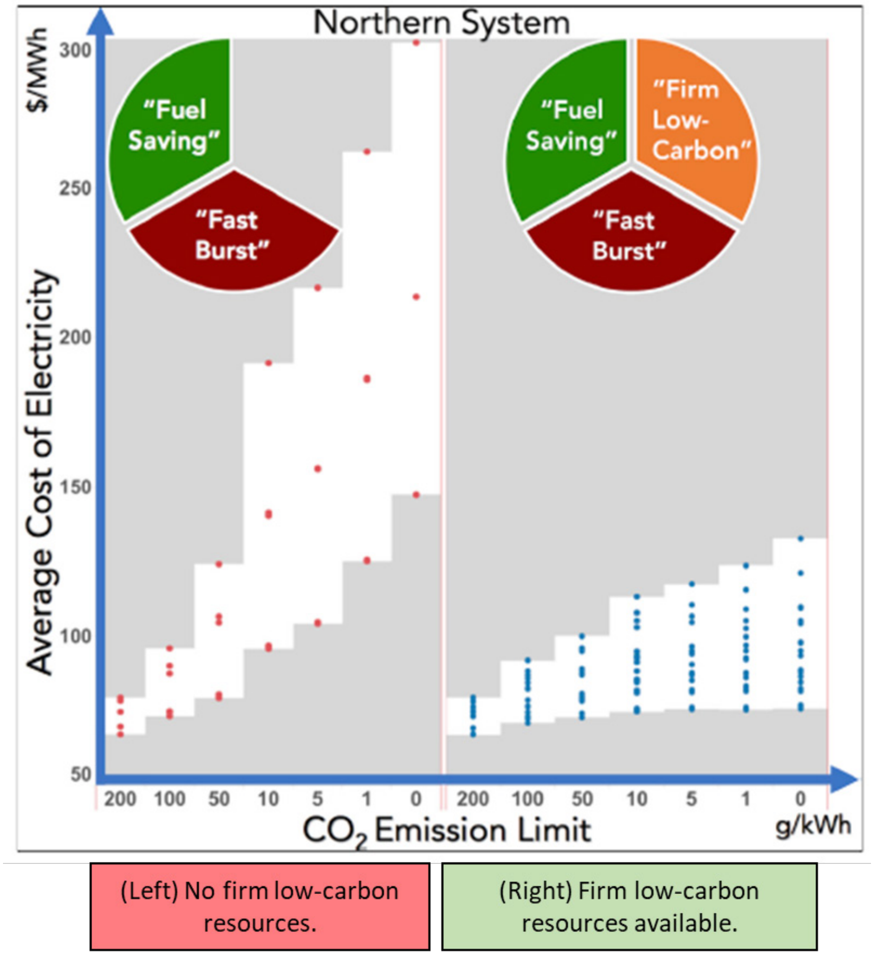
1. Nuclear power stations.
2. Natural gas with carbon capture and storage (Power CCUS).
3. Low-carbon hydrogen.
4. Biogas and biomass.
5. Hydro power plants, including long-duration hydro pumped storage.
6. Geothermal.
7. Ultra-long duration energy storage (measured in weeks or months).[65]
8. Renewable energy projects combined with storage energy storage.

These technologies are in various stages of development and each has its own challenges.

Research shows that, without firm low-carbon resources, electricity costs are likely to increase substantially as countries move to zero-carbon electricity sectors. This is because, in the absence of firm low-carbon resources, countries will need to build substantially more wind, solar and battery storage projects to ensure that electricity is available in all weather conditions. However, if firm-low carbon resources are available, cost rises are relatively modest even in a fully decarbonised electricity sector ( ).

64. Sepulveda N., Jenkins J., de Sisternes F., and Lester R. (November 2018). *The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation*. Link.
65. Could include batteries (e.g. flow batteries), heat batteries, compressed air energy storage (CAES), long-duration pumped hydro storage, and others.

Figure 11: Simulated electricity costs in a very low-carbon electricity system. Based on resources available in the north-eastern United States. Dots represent scenarios with different technology costs.[66]



The Capacity Market has never penalised a generator for being unavailable at a time of system stress.

Generators who hold Capacity Market contracts must be available to generate electricity when there is not enough supply to meet demand, known as 'System Stress Events'. A System Stress Event occurs when the ESO forcibly disconnects some customers for 15 minutes or more through a process known as 'Demand Control'.[67] If a generator does not provide electricity during a System Stress Event then they will face penalties. However, these penalties are relatively mild. The maximum monthly penalty for a generator is double that month's Capacity Market payment, and the annual penalties are capped at the annual value of the generator's Capacity Market contract.[68] This means that a generator cannot lose money from holding a CM contract.

The first Delivery Year for the Capacity Market started in October 2017.[69] In the three years since the CM started, there has not been a single System Stress Event, meaning that no generators have been penalised for failing to deliver at a time of system stress.

66. Ibid (The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation).
67. Ofgem (September 2020). *Publication of Consolidated Capacity Market Rules 2020.* Link. Ch.8, Para.8.4.
68. See columns "CH" and "CI" of the Capacity Market register. Link
69. The Delivery Year for the T-1 2017-18 Capacity Market Early Auction was Oct. 2017 to Sep. 2018. Link

During times of system stress, electricity prices are higher, which encourages resources to deliver. In the last five years, Ofgem has reformed the balancing market to increase prices when the demand is high, and supply is low.[70] In 2016, the Government strengthened penalties for resources that do not deliver in CM by raising termination fees.[71] Despite these reforms, there's a sense in industry that the Capacity Market is largely a one-way bet for generators.

In July 2019, the Government's five-year review of the Capacity Market concluded that *"the penalty regime needs to be strengthened"*.[72] However, as yet, no changes have been proposed. A consultation published in February 2020 noted that the Government intends, *"in due course, to publish a call for evidence on [...] issues related to the penalty regime"*.[73] Given that the Capacity Market is central to security of supply, the Government must prioritise implementing stronger alternatives to the current penalty regime.

National pricing means that the Capacity Market does not encourage a spread of generators across Great Britain.

The GB Capacity Market has a single national price for all generators in Great Britain, mirroring the wholesale electricity market. This has the advantage of simplicity. However, as with national pricing in the wholesale market, it ignores the need to have generators located across the market to overcome network constraints. For example, if Scotland only has wind farms, transmission constraints mean that, at times of low wind, it may not be possible to meet Scottish electricity demand solely with imports from England and Wales.

In addition to network constraints, the Electricity System Operator (ESO) needs access to generators across the whole of GB to safely operate the electricity system. This includes ensuring that limits on voltage, inertia and frequency are respected both nationally and regionally. Also, in the event of a market-wide blackout, the ESO would first restore power to small regions of the network, before restoring power nationwide; this process is known as a 'black start' and thankfully it has never been needed in Great Britain.[74] A black start is only possible if generators are distributed around the network, rather than concentrated in certain regions.[75]

Government decisions now largely determine which projects get built.

In the Capacity Market, Government decisions influence which generators win contracts, and ultimately which projects are built. For example, the Government sets a 'de-rating factor' for each technology, which determines the 'capacity credit' received by 1 MW of each technology type. For energy storage, the de-rating factor depends on how long the storage system can operate for before recharging. This means that the Government is playing a direct role in assessing the relative value of a one-hour energy storage system compared to a system with two hours or four hours of storage. Other models are possible, for example a model where energy suppliers are responsible for contracting with sufficient capacity to

70. Ofgem (undated). *Electricity Balancing Significant Code Review (EBSCR).* Link
71. DECC (now BEIS) (May 2016). *Government Response to the March 2016 consultation on further reforms to the Capacity Market.* Link. Page 16
72. BEIS (July 2019). *Capacity Market review (2014-2019).* Link. Paragraph 159.
73. BEIS (February 2020). *Capacity Market: Consultation on future improvements.* Link. Page 5.
74. National Grid ESO (undated). *Black Start.* Link
75. There are trials for wind farms to provide Black Start capability; however, these are at an early stage. See: Renews.biz (November 2020). *SPR delivers 'black start' from onshore wind.* Link

meet their customers' demand at all times. These models are explored in the next section.

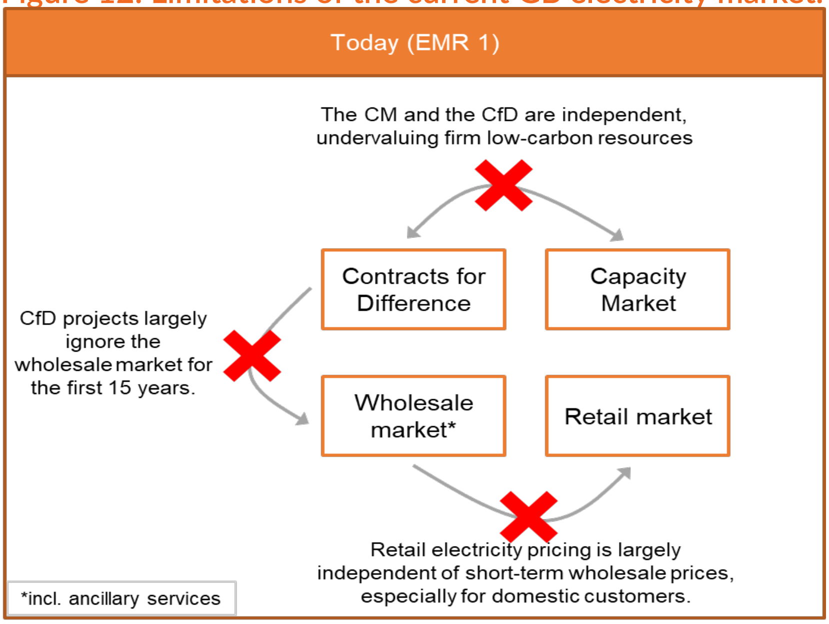
Regardless of whether the UK continues to rely on a Capacity Market led by the Government, the UK needs to confront the fact that the majority of firm capacity is currently provided by gas-fired power stations. **As the UK transitions to Net Zero, firm capacity must increasingly be provided by 'firm low-carbon resources'.**

How different parts of the GB electricity market operate in siloes

As described above, there are limitations of the individual parts of the GB electricity market. When considering the GB electricity market as a whole, one major limitation is how the different parts of the market interact with other (Figure 12: Limitations of the current GB electricity market.). For example, new offshore wind farms that hold CfD contracts largely ignore the wholesale market for the duration of their 15-year contract. Similarly, the retail market is largely independent of short-term price changes in the wholesale market. Finally, and as described above, the CfD and CM operate independently, undervaluing firm low-carbon resources.

As well as addressing the limitations of the individual elements of the market, this report aims to improve the interactions between each element to create a more integrated GB electricity market.

Figure 12: Limitations of the current GB electricity market.



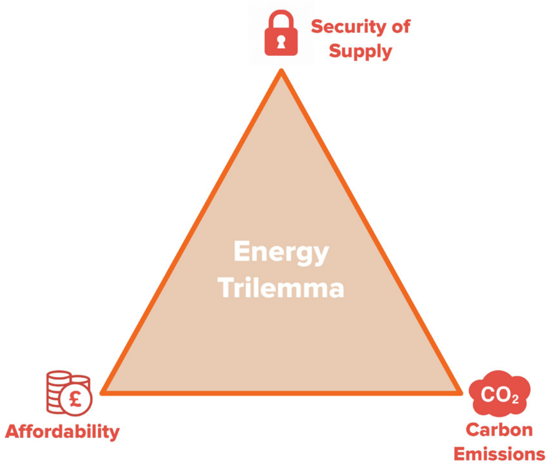
4. Key Principles

As set out in previous sections, there is now an overwhelming need for further reforms to the GB electricity market. We have found four key principles to guide the Government's approach to market reform, which are described below

Principle 1: Keep the three priorities expressed in the 'energy trilemma' at the heart of UK energy policy.

The energy trilemma describes the triple challenge of delivering a secure, affordable and low-carbon energy system (Figure 13). This trilemma was at the heart of the UK's Electricity Market Reform programme in the early-2010s. However, more recently, the Government has shied away from the energy trilemma. In 2018, then-Secretary of State for BEIS, The Rt Hon Greg Clark MP, declared that the energy trilemma was "*well and truly over*" due to the falling cost of renewable energy projects.[76]

Figure 13: The energy trilemma.



Unfortunately, even if renewables are the cheapest way to provide clean energy (measured in MWh), this doesn't address the need for firm capacity (measured in MW). The post-trilemma world also fails to address rising system balancing costs, which are in part due to the Government focusing on reducing the headline cost of renewables through lower CfD strike prices.

For example, offshore wind farms in Scotland and East Anglia may have low headline costs, but they are leading to more network constraints.

76. BEIS (November 2018). *After the trilemma – 4 principles for the power sector. Speech by Business Secretary Greg Clark.* Link

When considering all costs,[77] it may be better to pay more for a floating offshore wind farm off South Wales rather than a traditional offshore wind farm off Scotland or East Anglia. As the Government targets 40 GW of offshore wind by 2030, it must put in place markets that correctly value different resources in different locations.

Abandoning the energy trilemma *could* put security of supply at risk. Recent events in California show that any blackouts will be blamed on renewables even if the underlying cause is more complex.[78] This means that, as UK relies more on offshore wind, the Government must put extra emphasis on security of supply so that there is no basis for sceptics to argue that renewables will make the lights go out.

The GB electricity market can continue to be secure, low-carbon and affordable, but the Government needs to ensure that the market has the right mix of resources to provide both clean energy and firm capacity.[79] The term 'trilemma' wrongly implies that this challenge is unsolvable; however, it still provides a useful framing of the three, sometimes conflicting, imperatives of the energy system. This means that the Government should keep the energy trilemma at the heart of UK energy policy, focusing on reducing total costs whilst operating a secure and low-carbon electricity system.

Principle 2: The Government's reforms need to be ambitious to keep the UK on track for Net Zero, but they must also retain the confidence of investors.

The UK's programme of Electricity Market Reform is widely viewed as successful, reducing the cost of offshore wind whilst ensuring security of supply. The CM and the CfD are at the heart of this success, as is the central role played by private sector investors. As described in earlier sections, there are good arguments for why the Government now needs to reform both the CfD and the CM. However, in the 2020s, the UK must rapidly deploy a large volume of low-carbon energy projects like offshore wind farms whilst making sure that security of supply is maintained. Therefore, any changes to the CfD and the CM should be calibrated to maintain investor confidence, ensuring that there is no gap in investment.

Principle 3: In the medium-term, the market should play a bigger role in the electricity sector, reducing the role of the Government and Ofgem.

Electricity Market Reform did a lot of good things. However, it also put the Government in charge of procuring almost all clean energy resources through the CfD scheme, and in charge of procuring almost all firm capacity resources through the GB Capacity Market. There is still market competition between developers to determine the mix of clean energy and firm capacity resources; however, with the Government so involved in the electricity sector, it is taking on a lot of risk on behalf of customers.

77. Sometimes known as 'full system costs'.
78. Kahn, D. Bermel C. Politico (August 2020). *California has first rolling blackouts in 19 years – and everyone faces blame.* Link
79. Policy Exchange (October 2020). *No, more wind power doesn't mean the lights will go out.* Link

Ultimately, if the Government procures the wrong capacity mix, then this feeds through into higher customer bills.

The Government can, and probably should, reduce its involvement in the electricity sector. There are two main models that the Government could pursue. The Government could transfer responsibility for security of supply and decarbonisation to an Independent System Operator that would run Equivalent Firm Power auctions, as argued for by Professor Dieter Helm in the 2017 Cost of Energy Review.[80] Alternatively, the Government could transfer more responsibility to electricity customers and energy retailers to drive innovation, as argued for by the Energy Systems Catapult.[81] Both of these models would significantly change UK energy policy, so the Government needs to tread carefully to maintain investor confidence.

Before embarking on an energy policy revolution, the Government must reform the wholesale market to expose generators and customers to the costs that they cause, including network constraints. This will improve the flexibility and the efficiency of the GB electricity market, as well as laying the foundations for more major policy changes.

Policymakers also need to make sure that all resources can participate in the market, particularly demand-side response. Some of this demand-side flexibility will be achieved through smart meters and by reforming residential electricity tariffs, but this will be a gradual process.

Principle 4: The Government should support innovation and deployment of all types of low-carbon resources, not just renewables.

The Government's CfD programme has made a significant contribution to reducing the cost of offshore wind farms. It did this by supporting offshore wind at a time when it was both innovative and expensive, leading to 'deployment-led innovation'. However, there are serious questions about what resources will provide firm capacity in a Net Zero electricity system. The UK needs access to affordable firm low-carbon resources. [82]

Without firm low-carbon resources, the GB electricity market will continue to rely on gas-fired power stations to provide firm capacity. Modelling from Aurora Energy Research shows that, by 2050, firm low-carbon resources need to provide two-thirds of firm capacity in Great Britain, up from one-third today.[83]

Alongside supporting renewables like offshore wind, the UK Government should now apply the same deployment-led innovation to early-stage firm low-carbon resources like low-carbon hydrogen, geothermal, ultra-long duration energy storage, BECCS, gas with CCUS and others. If the Government can drive down the cost of these technologies, then a secure, affordable and low-carbon electricity system will be within reach.

The next phase of market reform must present a clear path to an electricity system where security of supply is provided by firm low-carbon resources.

80. BEIS (October 2017). *Cost of energy: independent review.* Link
81. Energy Systems Catapult (undated). *Rethinking Electricity Markets.* Link
82. Ibid (The Role of Firm Low-Carbon Electricity Resources).
83. See Appendix 1 for details.

5. Policy Options

This section summarises policy options for the wholesale market, the Contracts for Difference (CfD) scheme and the Capacity Market (CM), based on international examples. This section also summarises more radical options to overhaul the design of the GB electricity market.

These policy options are explored in detail in Appendix 2.

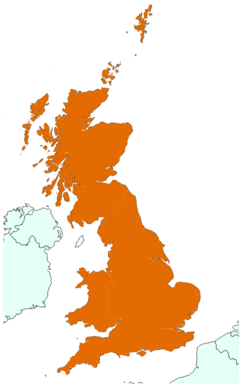
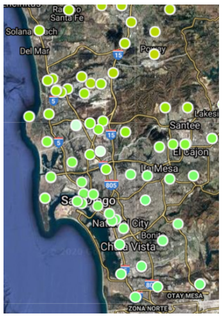
Policy options for the wholesale electricity market

There are three main policy options for the wholesale electricity market:

1. **National pricing** (uniform pricing): The GB electricity market uses national pricing, which is common across Europe. National pricing means that the electricity price is the same across the whole market in each time period.
2. **Regional pricing** (zonal pricing): Scandinavia and Italy split their markets into a number of bidding zones, a system known as regional pricing. The wholesale electricity price can be different in each zone, depending on the supply and demand for electricity in each zone and the network capacity between zones.
3. **Local pricing** (nodal pricing): In the United States, almost all competitive wholesale electricity markets are divided into significantly smaller bidding zones, known as 'nodes'. With local pricing, the electricity price can be different in neighbouring towns or in different parts of the same city.

These policy options are summarised in Table 4 and are explored in more detail in Appendix 2.

Table 4: 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.[84]	California.[85]
# of zones	1 zone	6 zones	~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. Risks a 'postcode lottery' for customers.

National, regional and local pricing each have pluses and minuses, and any move to regional or local pricing would be a major change to the GB electricity market. However, it is clear that national pricing is unsustainable in a world of more generation from renewable energy sources. The energy trilemma demands that the Government focus on reducing whole system costs, not just the headline cost of offshore wind farms. Regional and local pricing reduce socialised 'constraint costs', which will reduce whole system costs and therefore customer bills.

Markets with regional and local pricing have operated successfully for decades, so the UK Government should not be nervous about implementing either of these models.

84. Image link
85. Image link

Policy options to support renewable energy generators

The UK's Contracts for Difference (CfD) scheme is a marked improvement on the previous 'ROC' regime, which was characterised by boom and bust investment cycles and required Ministers to set support levels for different technologies. However, the CfD regime is increasingly distorting the wholesale electricity market by insulating project owners from the wholesale market, which is increasingly leading to negative prices.

In place of the UK's CfD scheme, the Government could instead rely on robust carbon pricing to deliver renewable energy projects. Alternatively, the Government could follow Spain by introducing a 'floor-price CfD', which offers investors a guaranteed minimal annual revenue. Many US states take a different approach, putting more responsibility on electricity suppliers through a Renewables Portfolio Standard. These policy options are summarised in Table 5: Summary of policy options for supporting renewable energy generators. and are explored in more detail in Appendix 2.

Table 5: 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 back to customers 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 projects, which may increase overall costs.

As described above, the UK Government has a number of options to reform the CfD scheme. The Government is unlikely to rely solely on carbon pricing to deliver new renewable energy projects because this could slow the rate of deployment and put Net Zero at risk.

The Government could consider a Renewable Portfolio Standard (RPS), and this might be the optimal solution in the longer term. However, the Government must ensure that the UK continues to deploy renewable energy quickly and cost-effectively. An RPS would be a major change that could undermine investor confidence. The Government's commitment to 40 GW of offshore wind by 2030 means changes to the CfD scheme must not delay investment in new projects.

Policy options for the Capacity Market

The Government's five-year review of the GB Capacity Market (CM), published in 2019, concluded that the CM is operating as intended.[86] However, the CM primarily supports gas-fired power stations, which creates a risk that it will become a barrier to the deep decarbonisation of the GB electricity market. Internationally, there are electricity markets that operate either without a capacity market or with a different market design.

One alternative is to place more responsibility on electricity suppliers to contract with generators, energy storage and demand-side response to meet their customers' demand at all times; Australia uses a variation of this model. Alternatively, the ESO could procure a 'strategic reserve' of generators, which are not allowed to participate in the electricity market and are only called on if there is a system emergency; Germany and Belgium have adopted this approach. California uses a hybrid model, comprising a capacity market and a mandate on energy companies to sign contracts with energy storage projects. California's policy aims to prevent blackouts whilst also pulling energy storage into the market to replace gas-fired power stations.

These policy options are summarised in Table 6 and are explored in more detail in Appendix 2.

86. BEIS (July 2019). *Capacity Market: Five-year review (2014-2019).* Link

Table 6: Summary of policy options for the GB Capacity Market.

Policy option	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 put 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 benefit of this approach is that suppliers are well-placed to interact with their customers. However, 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 one reason 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. The 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 like 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.

As described above, a wide range of capacity market designs operate around the world, including markets that operate without a capacity market. This shows that the UK Government could choose to significantly redesign the GB Capacity Market without risking security of supply. However, if the UK Government changed or removed the CM, then it would need to be prepared to accept criticism when wholesale prices spike or when there is a perceived risk of the lights flickering.

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

If the Government wants to take a more radical approach to reforming the Capacity Market and the Contracts for Difference scheme, then it could consider one of the following two options. The Government could implement Professor Dieter Helm's proposals to combine the CfD and CM schemes into an auction for 'Equivalent Firm Power' (EFP). Alternatively, the Government could make retailers and customers responsible for decarbonisation and security of supply. These competing models are summarised in and are explored in more detail in Appendix 2.

Table 7: 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').[87] EFP auctions would be run by an independent system operator, so they would be independent from the Government. EFP auctions could help to 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.[88,89] 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 more responsibility on retailers and customers. Generators would rely on retailers for more of their revenue than they do today. This creates new a financial risk for generators, particularly because energy suppliers in Great Britain are going bust at a record rate.

These two options are radically different visions for the long-term design of the energy system. It is hard to see the Government implementing either of these models in the short-term, not least because they would require the Government to give up control of key areas of UK energy policy. However, in the medium-term, there are good arguments for why the Government should look at aspects of both of these models. This will need to be a gradual process to ensure that customers, investors and politicians are comfortable with the direction of travel, which is crucial to keep Net Zero on track.

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

6. Policy recommendations

We have grouped our policy recommendations into three themes, based on the key principles set out in the previous section:

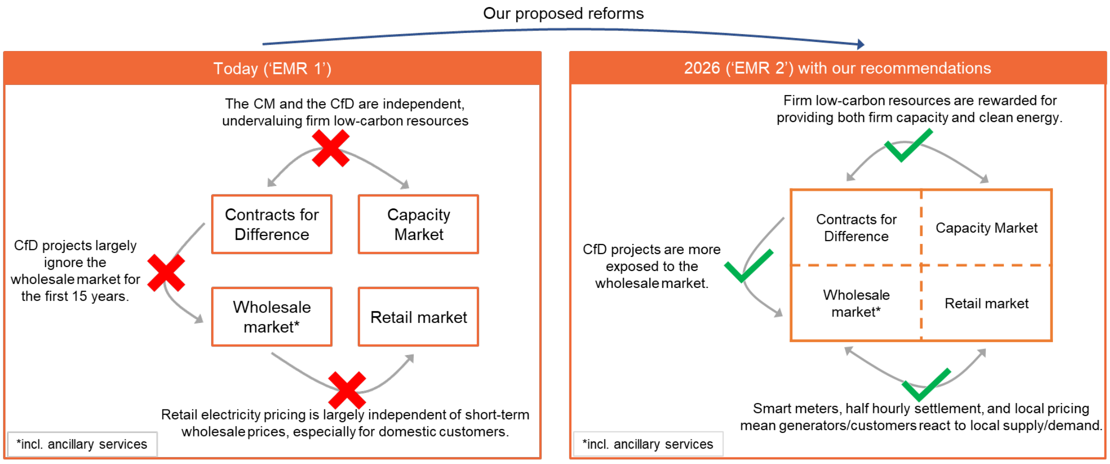
1. Introduce local (nodal) electricity pricing in Great Britain.
2. The CfD scheme should offer a simplified 'floor-price CfD', rather than a long-term fixed price.
3. The Capacity Market should include a 'low-carbon quota' to support early-stage firm low-carbon resources.

If the Government follows these recommendations, then it will put the GB electricity market on the path to delivering a secure, low-carbon electricity system at the lowest cost. These recommendations will also lay the foundations for the Government to reduce its role in the electricity sector over time.

These proposals aim to improve the operation of the wholesale electricity market, the CfD scheme and the GB Capacity Market. They will also improve the integration of the different parts of the electricity market ( ). Once these proposals are implemented, CfD projects will be more exposed to the wholesale electricity market, and the CM and the CfD schemes will work together to support firm low-carbon resources.

Local pricing will have a profound impact on all aspects of the GB electricity market, including the retail market. Combined with half-hourly settlement and smart meters, local pricing will reward customers and generators for working together to balance local supply and demand.

Figure 14: Impact of the proposals in this report on the integration of the GB electricity market.



Theme 1: Introduce local (nodal) electricity pricing in Great Britain.

Recommendation 1: The Government should introduce local pricing in the GB wholesale electricity market, modelled on US markets such as Texas.

Falling electricity demand during the COVID-19 lockdown made operating the GB electricity system both more difficult and more expensive. There is a risk that these higher system balancing costs will become a new normal as the UK builds more offshore wind farms, leading to more network constraints. The current GB electricity market ignores the physical reality of the electricity network. Increasingly, this leaves the Electricity System Operator (ESO) to pick up the pieces, incurring higher costs to resolve network constraints and to operate the system safely.

At a minimum, the Government must split the GB wholesale electricity market into a number of 'zones' based on major transmission constraints, for example between England and Scotland. However, experience from Italy, Texas and others shows that this is unlikely to be enough to cope with more generation from renewable energy sources, particularly offshore wind.

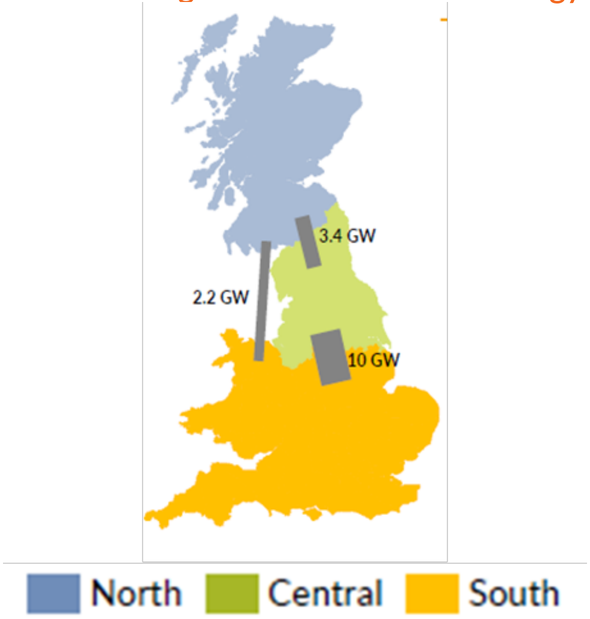
To fully integrate renewables, the Government should therefore implement local pricing, creating thousands of electricity price nodes across Great Britain. This will encourage generators, energy storage and customers to respond to local changes in supply and demand for electricity, leading to a truly smart, flexible energy system.[90]

90. BEIS and Ofgem (Last updated July 2017). A *smart, flexible energy system: call for evidence.* Link

Modelling from Aurora Energy Research shows that locational pricing could reduce total system costs by £2.1bn per year, reducing the average household bill by £37 per year.

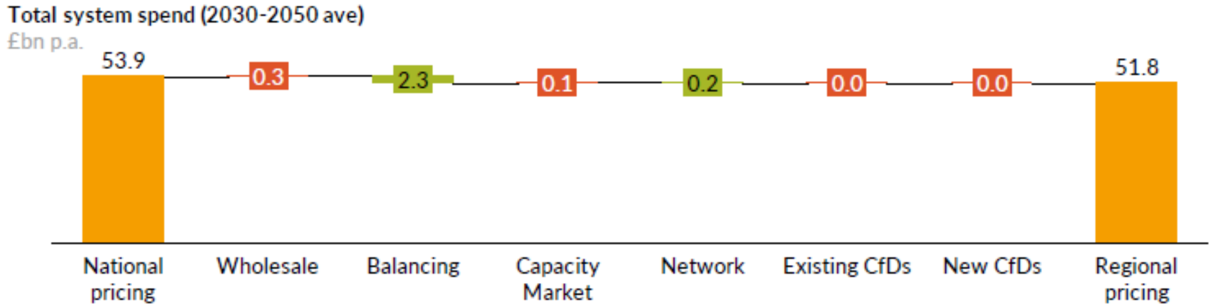
As part of this project, Policy Exchange commissioned modelling from Aurora Energy Research to assess the impact of locational pricing in Great Britain. Aurora modelled regional pricing, splitting Great Britain into three zones (Figure 15: Aurora electricity market modelling. Great Britain split into three regions. Source: Aurora Energy Research.). Modelling local pricing was beyond the scope of this project; however, there is ample evidence from other markets this would have even greater benefits.

Figure 15: Aurora electricity market modelling. Great Britain split into three regions. Source: Aurora Energy Research.



Aurora's modelling shows that locational pricing could reduce total system costs by £2.1bn per year (Figure 16: Total annual electricity system spend (2030-2050). Source: Aurora Energy Research.91) and could reduce the average household electricity bill by £37 per year. Locational pricing encourages generators and customers to react to local prices, as well as encouraging project developers to build projects in places that provide the most benefit to customers. Aurora's analysis showed that locational pricing could reduce system balancing costs by one third.

Figure 16: Total annual electricity system spend (2030-2050). Source: Aurora Energy Research.[91]



Policy Exchange previously called for the Government to explore local (nodal) pricing in a 2016 paper, *Power* 2.0. This modelling from Aurora Energy Research is a significant contribution to the evidence base for local pricing in Great Britain, supplementing evidence from markets around the world that have used local pricing for decades.[92]

Generators and suppliers should be required to submit all bids and offers to the GB market operator and Electricity System Operator (ESO).

For local pricing to work, the Government and Ofgem will need to make other changes to the market. For example, in local electricity markets, generators and suppliers are typically required to submit all bids and offers to the market operator and to the ESO. This maximises liquidity and allows regulators to automatically impose market power mitigation measures when required. This change would also allow the ESO to procure system balancing services through the wholesale market, following the examples of Australia and many US states.[93] The ESO will be able to procure system balancing services more transparently, more efficiently, and closer to real-time, further lowering the cost of operating a low-carbon electricity system.

Today, the ESO is a gatekeeper for flexibility resources like electricity vehicles and battery storage. These resources can only get paid for providing locational value by selling services to the ESO or to their local network operator (DNO). Local pricing allows resources to monetise more of their value in the wholesale electricity market, reducing the role of the ESO. This will allow suppliers to develop increasingly innovative offerings for customers. For example, a data centre, a green hydrogen producer and a green steel producer could work together to share the network capacity that is available in their local area.

Ofgem and industry will also need to make changes to the real-time balancing market (the Balancing Mechanism) and to the methodology used to set network charges (Box 2). These reforms should be taken forward by Ofgem and industry through with existing code governance procedures.

91. See Appendix 1 for details.
92. Harvey, S. and Pope, S. (undated). *Locational Marginal Pricing (LMP), Price Formation and Competitive Electricity Markets.* Link
93. AEMO (April 2015). *Guide to ancillary services in the National Electricity Market.* Link

Box 2: How should network charges work under local pricing?

In Great Britain, locational signals are mainly provided by network charges, which are highest for generators in Scotland and for demand customers in London. In markets with locational pricing, for example New York State, locational signals are mainly provided by differences in the wholesale price in different regions. The grid operator raises money to pay for the electricity network through congestion revenue (which arises when prices are different between nodes) and from a Transmission Service Charge on demand customers.[94]

If the Government adopted local pricing in Great Britain, there would be significant implications for network charges, including for Ofgem's ongoing Significant Code Review.[95] Ofgem would also need to make changes to the process for planning network upgrades.

Today, Ofgem decides whether or not to approve a new power line based on whether it will reduce costs for customers. For example, a new power line between Scotland and England will reduce the ESO's spending on network constraints. With local pricing, most network constraints are resolved by the market. Ofgem can adapt its process to consider local pricing; however, this will need to be clearly communicated to the market because new power lines will have a big impact on local prices and therefore on investors.

Ofgem will also need to adapt regulations governing electricity market coupling and trading on interconnectors. Policy Exchange's recent paper, The Future of UK-EU energy cooperation, called for the UK and the EU to seek a long-term 'Energy Partnership' based on mutual interests including competitive energy markets, carbon pricing and sharing renewable energy resources across borders.[96] Any long-term Energy Partnership must allow the Government to introduce local (nodal) pricing in Great Britain.

Recommendation 2: Initially, residential and small business customers should be charged a regional (zonal) electricity price unless they opt-in to local (nodal) pricing. Over time, the Government should aim to extend local pricing to all customers.

Under local pricing, prices at individual nodes can be highly volatile. There are valid concerns over whether residential and small business customers are well-placed to respond to this volatility. However, even with local pricing it is unlikely that customers will have to directly respond to price signals. Instead, electricity suppliers will control customers' devices (with their permission) to minimise electricity bills. For example, most customers will only need to charge their EV for an hour or two overnight and they don't care when this happens. Electricity suppliers can control EV charging to minimise the cost to the customer, which means that customers won't need to become energy traders to take advantage of local pricing.

As customers buy more EVs and install more electric heating systems, they will be more able to respond to price signals. If a customer has smart

96. Policy Exchange (September 2020). *The Future of UK-EU Energy Cooperation.* Link
94. NY ISO (2005). *Transmission Services Manual.* Link (page 24). The Transmission Services Charge is broadly equivalent to the 'demand residual' network charge in Great Britain.
95. Ofgem (undated). *Reform of access and forward-looking charges.* Link

charging and smart heating controls, then they will be able to provide significant flexibility to the electricity grid with minimal effort. Customers won't be expected to get up in the middle of the night to do their washing or to cook during the middle of the day and when it's sunny.

One way to address price volatility at individual nodes is to charge residential and small business customers the average price in their region, i.e. to use regional pricing for the smallest customers. These small customers would face less volatility than under local pricing, but they will still be exposed to the general shape of prices in their region. New York State uses a variation of this approach.[97]

Some customers will be happy to be exposed to local prices, for example those who have smart devices and who have flexibility over when they need to charge their Electric Vehicle. Initially, the Government should make local pricing opt-in for residential and small business customers. This would mirror Ofgem's approach to real-time settlement, known as 'Half Hourly Settlement', where the smallest customers currently have to opt-in to real-time settlement.[98] Ofgem is now consulting on moving all customers to real-time settlement as part of a gradual process to extend real-time settlement to the whole market.[99]

In the long term, full local pricing is needed to encourage maximum demand-side participation. Texas already follows the fully local approach. Even if customers face full local pricing, they are still likely to have a contract with an electricity supplier for a fixed price or a static 'time of use tariff' (which follows a predictable price shape). To accommodate local pricing, the Government and Ofgem should consider changes to the electricity price cap and to the structure of default electricity tariffs.[100]

Large energy users make up one third of demand and have the strongest incentives to react to locational pricing, so they should be exposed to local prices from the start.[101] For example, a data centre may be able to operate flexibly, so that it consumes more power when prices are low. In the longer-term, local pricing will encourage energy intensive industry to locate in the UK's coastal industrial hubs along the North Sea, in Merseyside and in South Wales. These industrial hubs are close to the UK's abundant offshore wind resources and are likely to have lower electricity prices under local pricing.

Large energy users can still hedge their electricity costs through Financial Transmission Rights (FTRs), which allow market participants to hedge against price differences between locations. Ofgem should develop and regulate the market for FTRs (Box 3).

97. In New York State, all demand is charged a regional (zonal) price, whereas generators receive a local (nodal) price.

98. From Ofgem (Link): *"Settlement reconciles differences between a supplier's contractual purchases of electricity and the demand of its customers". "Currently, most customers are settled on a 'non-half-hourly' basis using estimates of when they use electricity, based on a profile of the average consumer usage and their own meter reads (taken over weeks and months)."* Half-hourly settlement means that suppliers will be charged for their customers actual consumption in each period. This encourages suppliers to offer 'time-of-use' tariffs to their customers, which better reflect the underlying costs of electricity.

99. Ofgem (undated). *Electricity Settlement Reform.* Link

100. Ofgem (undated). *About energy price caps.* Link

101. Source: National Statistics (September 2020). *Energy Trends: UK electricity (Table 5.5).* Link. Based on category 'Industrial consumers).

Box 3: Local pricing and Financial Transmission Rights (FTRs)

In markets with national pricing, generators and suppliers can agree to buy and sell electricity far into the future. For example, in Great Britain, the operator of the railway network, Network Rail, has a long-term contract with EDF to buy electricity produced by its nuclear power stations.[102] If, due to network constraints, the nuclear power stations cannot actually supply all of the railway network, then it is up to the ESO to resolve these constraints through the Balancing Mechanism.

By contrast, in a local electricity market, participants can only buy and sell electricity through the market operator and the ESO. The market operator will typically operate a day-ahead market, a number of intra-day markets and a real-time market. This means that generators and suppliers cannot agree to physically buy and sell electricity to each other far into the future, but they can still come to a financial hedging agreement.

In the example above, Network Rail could agree to pay EDF the difference between the real time electricity price and a fixed price agreed in advance, providing a financial hedge for both parties. Unfortunately, local pricing further complicates this picture because the wholesale electricity prices at EDF's generators (the nuclear power stations) may be different to the prices at Network Rail's sites (the railway substations). This is where Financial Transmission Rights (FTRs) come in.

An FTR is a financial product that is used to hedge differences in wholesale electricity prices between nodes. FTRs can be bought and sold by generators, suppliers and even financial participants such as banks. In New York State, the ESO organises monthly and six-monthly auctions for FTRs, known as Transmission Constraint Contracts.[103] In Great Britain, Ofgem should introduce a similar system of FTRs.

Recommendation 3: The Government should offset the differences between electricity prices in different regions of Great Britain using fixed credits and charges on customer bills. This should apply to residential and small business customers only.

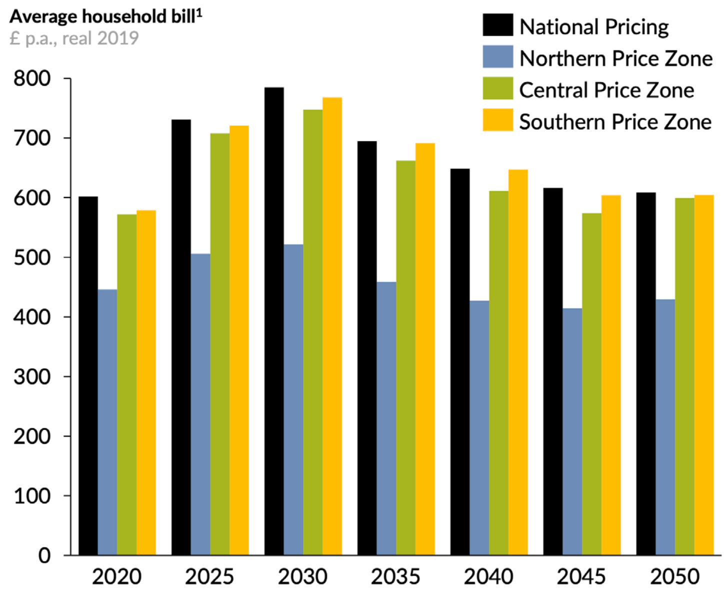
With local pricing, customer bills will be higher in some places than in others. In Great Britain, prices would likely fall in Scotland and would likely rise in the South of England, particularly in London. This means that, if the GB electricity market moves to local pricing, policymakers will need to address the argument that it is unfair for some people to pay higher prices than others. If the Government allows prices to vary significantly across GB, then it could face a backlash from customers against local pricing.

Modelling from Aurora Energy Research shows that, with regional pricing, electricity bills in Scotland could be 30% (£200 per year) lower than those in England and Wales (Figure 17: Average household electricity bill in each of the three modelled regions.). With local pricing, prices could vary between neighbouring towns, depending on network constraints.

102. Railway Gazette (January 2013). *Network Rail awards 10-year electricity supply contract.* Link

103. Ibid (NYISO State of the Market Report 2019). Page 144.

Figure 17: Average household electricity bill in each of the three modelled regions.



Source: Aurora Energy Research. [105]

To address concerns over fairness, the Government should compensate customers for differences in average electricity prices in different regions. This compensation should take the form of fixed credits and charges on customers' bills. Customers already pay fixed charges, known as 'standing charges'.[104] These standing charges should be adjusted depending on the average electricity price in each region. For example, customers in the north of Great Britain would face higher fixed charges but lower variable charges, whereas customers in the south of Great Britain would face lower fixed chargers and higher variable charges.

This will ensure that the average residential customer pays the same average price for electricity in each part of Great Britain. Importantly, customers will still be exposed to the real-time wholesale price in their local area through variable charges. This will ensure that the short-term price signal remains intact, so customers will still be encouraged to help to balance supply and demand in their local area.

This approach should be targeted at residential and small business customers, who have little choice over where they live and work. However, it is very important that large energy users react to local supply and demand for electricity and therefore face local prices.

The Government should also consider measures to increase access to smart technologies.

Local pricing will benefit customers who are able to respond. Wealthier customers are more likely to have the money to invest in smart technologies, which will allow them to respond to local prices, whereas

104. Ofgem (undated). *Standing charge.* Link

poorer customers have fewer options. However, this should not prevent the Government from introducing local pricing. Local pricing is a more efficient market design that can substantially reduce customer bills. The distributional impacts are important and should be addressed, but they are not a reason to persist with an inefficient and more expensive market design.

To mitigate the distributional impacts of local pricing, the Government should consider measures to allow poorer customers to install smart technologies. Some of this can be achieved through regulation, including the UK Government's plan to require all EV chargers to have smart functionality.[105] The Government should also consider whether schemes to tackle fuel poverty, such as ECO,[106] could be supplemented with schemes to install smart technologies in the homes of the poorest customers.

Recommendation 4: Local pricing in the GB electricity market should start in April 2026.

Local pricing can provide major benefits to the GB electricity market. However, it will be a big change and market participants will need time to adapt. Ofgem and industry will need to make changes to market rules and suppliers will need to implement new systems and introduce new products. The start of local pricing should be aligned with the charging year for network charges, which starts on 1st April.[107]

The Government should see locational pricing as a five-year programme, which means that **locational pricing in the GB electricity market should start in April 2026**.

Theme 2: The CfD scheme should offer a simplified 'floor-price CfD', rather than a long-term fixed price.

Recommendation 5: The Government should amend the CfD scheme to offer generators a guaranteed annual minimum payment ('floor-price CfD'), based on approaches used in Spain.

The current CfD scheme has delivered major cost reductions for offshore wind and other renewables. However, it is distorting the wholesale electricity market and it does not encourage generators to react to the wholesale electricity price. A floor-price CfD could address both of these problems, whilst preparing renewable energy generators for a future with less Government support.

Under a floor-price CfD, generators commit to generating a minimum volume of clean energy each year, measured in MWh, in return for a guaranteed minimum price, measured in £/MWh. For example, a 10 MW solar farm could commit to generating 10,000 MWh per year in return for a minimum price guarantee of 25 £/MWh. The solar farm is therefore guaranteed a minimum revenue of £250,000 per year for the duration of the contract. If the project produces more than its minimum

105. DfT (updated May 2020). *Closed consultation: EV smart charging.* Link

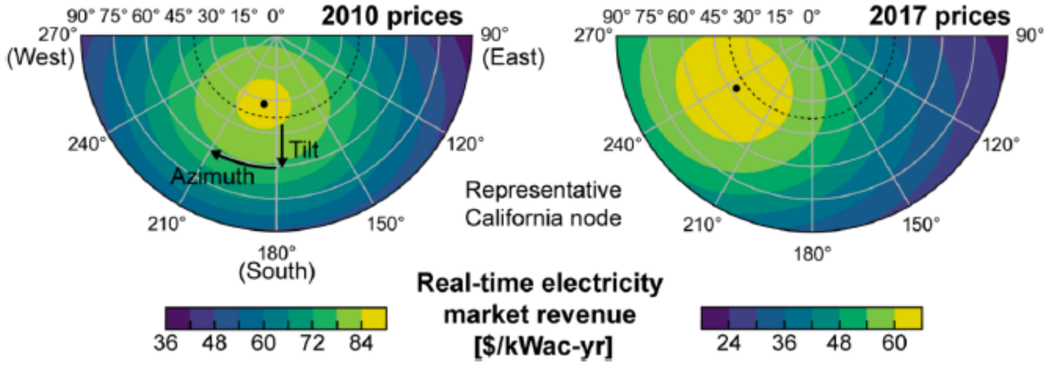
106. Ofgem (undated). *About the ECO (Energy Company Obligation) scheme.* Link

107. The GB electricity market year runs from 1st April to 31st March.

generation or captures a higher price, then the project's owners keep the additional revenue. However, if the project generates less than the declared generation (in this example 10,000 MWh per year) then the revenue floor should be reduced accordingly.[108]

The current CfD scheme encourages developers of wind farms and solar farms to maximise their annual production, but not to try to capture peak prices. As more wind farms and solar farms are built, electricity prices will fall when it is windy or when it is sunny (particularly in the middle of the day). In California, this effect is now so stark that, to maximise returns, project developers should build solar farms that face southwest to capture higher prices in the evening, rather than facing south to maximise generation (Figure 18: 'Revenue optimised PV array orientation'. This chart shows that, in California in 2017, solar farms that point southwest had the highest revenue.109). A floor-price CfD encourages solar generators to think about changing market dynamics, reducing total system costs.

Figure 18: 'Revenue optimised PV array orientation'. This chart shows that, in California in 2017, solar farms that point southwest had the highest revenue.[109]



Another benefit of a floor-price CfD is that it encourages project owners to seek additional contracts with large energy users. Consider a wind farm that holds a 15-year floor-price CfD with the UK Government at 30 £/MWh. The wind farm may be able to secure an additional 5year fixed price agreement (a PPA) with a data centre or a large corporate at a higher price, for example 40 £/MWh. A floor-price CfD is compatible with these 'Corporate PPAs', encouraging greater innovation and preparing market participants for a future without Government-backed long-term contracts.

A floor-price CfD also encourages project owners to think about how they can limit their risk from changes in the wholesale price by owning a portfolio of projects that have different risks. For example, an investor could own both solar projects and battery storage projects. If prices fall sharply during the middle of the day, then the solar project will make lower returns, but the battery storage project will benefit from increased volatility. The current CfD regime almost entirely removes the incentive for investors to think like this.

Under the current CfD regime, project owners make payments to

108. The reduction in the floor should be more than a straight pro-rata of the annual minimum revenue. This will encourage generators to commit to a minimum generation that they are confident in.

109. Brown, P. O'Sullivan, F. (September 2019). *Shaping photovoltaic array output to align with changing wholesale electricity price profiles.* Link

customers when electricity prices are higher than the Strike Price. Under a floor-price CfD, project owners would retain any upside if electricity prices are higher than the floor price. This could lead to concerns that, under a floor-price CfD, customers are taking all of the downside (by guaranteeing a floor) by not capturing any upside (because they aren't paid back when prices are high). This is a fair concern, especially because CfD Strike Prices are now similar to the current wholesale electricity price, so there's a realistic prospect of project owners making payments to customers (through their supplier) over the project's lifetime.[110]

The counterargument is that, under a floor-price CfD, project developers will bid lower floor prices into the CfD auction in the hope and expectation of capturing upside when electricity prices are high. A floor-price CfD can also reduce the distortions caused by the current CfD scheme (see below). Our judgement is that floor-price CfDs are more likely to result in lower total system costs and therefore lower customer bills.

A floor-price CfD can minimise the market distortions that cause negative prices.

To reduce distortions to the wholesale electricity market, floor-price CfDs should not compensate generators for negative prices. This means that, during negative price periods, renewable energy generators will need to either switch off or accept negative prices. If the generators switch off, then they may generate less than required by their floor-price CfD and may face penalties.

To mitigate this risk, the Government should credit generators for energy that is curtailed during negative price periods. For example, the solar generator in the example above might only generate 9,500 MWh in a year because 500 MWh was curtailed. The Government should still credit the solar farm for the 500 MWh that was curtailed, so that the solar farm is still judged to have produced the promised 10,000 MWh. One downside of this approach is that it is open to gaming by generators, who could exaggerate the volume of curtailed energy.

The Government needs to consider carefully whether the risk of curtailment sits best with renewable energy investors, who are typically low-risk investors like pension funds, or whether it should sit with the Government and by extension with customers. Our view is that the Government and customers are currently best placed to bear this risk.

The floor-price CfD should encourage projects to participate in system balancing services if these provide more value to the electricity system.

The current CfD regime pays generators for generating megawatt-hours (MWh) of clean energy. The CfD is primarily designed to deliver clean energy resources, so this seems sensible. However, clean energy resources like wind and solar can also provide system balancing services.

For example, the ESO and UK Power Networks (a DNO) are currently running a pilot project to test whether small-scale projects can provide

110. BEIS (Update 11 October 2019). *CfD AR3 results.* Link. *Section B (Estimated notional monetary budget impact) shows that BEIS expects the most-recently awarded CfD projects to pay back to customers over the lifetime of the projects.*

reactive power, a system balancing service.[111] Many of the trial's participants are solar farms, some of which may hold a CfD contract. Some solar farms may be able to provide reactive power services without reducing their output. However, for some projects and for some balancing services, there is a trade-off between providing system balancing services and generating clean energy. The current CfD regime discourages generators from participating in system balancing services, even if prices are higher than in the wholesale electricity market. This means that CfD projects are encouraged to act in a way that raises overall system costs.

To overcome this problem, floor-price CfDs should be based on the total revenue of the project including both wholesale market sales and revenue from system balancing services. As with curtailment due to negative prices (see above), projects should be credited with output that they curtail in order to provide system balancing services.

The Government should award floor-price CfDs based on the expected cost of supporting each project. The Government should take into account the wholesale electricity price that each project is expected to capture, which will depend on the technology and location.

Under the current CfD scheme, bids are ranked in order of 'strike price', with the cheapest bids accepted first. This is based on assumption that projects with the lowest strike prices will deliver clean energy at the lowest cost. However, projects with the lowest strike price do not always offer the best value for money. This is because some technologies will capture a lower wholesale electricity price, leading to a bigger top-up payment from customers. For example, a nuclear power station that operates all the time (baseload) is likely to capture a higher average price than a wind farm that only generates when it is windy. This is because, when it is windy, higher supply from wind farms leads to lower electricity prices.

Locational pricing will make this problem worse because an onshore wind farm in Scotland will capture much lower prices than, for example, a floating offshore wind farm off the coast of South Wales, where there are currently few wind farms. The Government already recognises that intermittent technologies such as wind and solar capture lower wholesale prices than baseload technologies such as nuclear and waste-to-energy. In the 2019 CfD auction, the Government introduced separate 'reference prices' for baseload and intermittent technologies.[112] However, these reference prices are only used to calculate the expected impact of projects on the overall CfD budget and are not used to assess the relative value of different projects.

For future CfD rounds, the Government should award floor-price CfDs based on the difference between each project's bid and the expected wholesale electricity price captured by that technology in that location. This means that a solar farm will be expected to capture a different price to an offshore wind farm. Figure 19: Indicative impact of different ranking

111. National Grid ESO (May 2019). *Power Potential*. Link.

112. BEIS (May 2019). *CfD Allocation Round 3: Allocation Framework (updated)*. Link. Page 40 (Appendix 2).

systems for CfD bids. (Left) Project details. (Right) Ranked bids. Top three bids highlighted in green in each case. shows how these changes could lead to very different outcomes in the CfD auction, lowering overall costs for customers.

Modelling by Aurora Energy Research show that, with locational pricing, there could be 60% more offshore wind in the South of Great Britain compared to a scenario with national pricing. Locational pricing will particularly favour floating offshore wind in the south of Great Britain, including off the coast of Wales.[113] The Government must ensure that the CfD scheme correctly values projects in different areas of the country.

Figure 19: Indicative impact of different ranking systems for CfD bids. (Left) Project details. (Right) Ranked bids. Top three bids highlighted in green in each case.

Technology	Location	Bid Price (£/MWh)	Expected Price (£/MWh)	Difference (£/MWh)	Rank (Current)	Rank (Proposed)
Solar PV	Midlands	45	45	0	2=	1
Offshore Wind	East Anglia	50	45	+5	4	2
Floating Offshore	South Wales	65	55	+10	6	3
Solar PV	Scotland	60	45	+15	5	4
Solar PV	Cornwall	40	20	+20	1	5
Offshore Wind	Scotland	45	20	+25	2=	6

Note: numbers are indicative.

The market monitor for New York State explains how locational pricing brings forward projects that reduce total system costs, even when most projects are supported by long-term Government-backed contracts like CfDs:

> *"When NYSERDA (New York State Government) and other entities contract for resources to help satisfy state mandates, the most economic projects are likely to submit the lowest-cost proposals and more likely to be selected. Hence, even though these projects are ostensibly developed to satisfy state policy objectives, the NYISO market provides incentives that will channel investment towards the most effective and efficient uses."*
>
> *Source: 2019 State of the Market Report for the NY ISO markets (page 96).*

Recommendation 6: CfD auctions should be held annually, at the same time as the Capacity Market auction. This could make it easier to combine the CM and the CfD in future.

The first CfD auction was held in winter 2014/15, followed by a two-and-a-half-year gap until the second auction in Summer 2017. In future, the Government expects to hold auctions around every two years, although the exact timing is not published in advance. The next auction is now expected to open in "late-2021", two and a half years since the last auction opened.[114]

113. See Appendix 1 for details
114. BEIS (October 2020). *CCC's 2020 progress report: government response.* Link. Page 18.

The Government currently has significant flexibility over when CfD auctions are held. One advantage of this approach is that it allows the Government to align auction timelines with significant industry events. For example, the Government could delay the next CfD auction until multiple offshore wind farms have been granted planning permission or until the Government and Ofgem have introduced a new coordinated approach to grid connections for offshore wind farms. However, this creates uncertainty for project developers, who need to align their project timelines with the auctions. For example, project developers may lose their grid connection offers if they are still waiting to receive a CfD contract, and therefore cannot demonstrate that they are proceeding with their project.

If the Government holds auctions annually, project developers will know when the auctions will be held, which will ensure that there is a steady stream of projects coming through the system. The Government will be concerned that annual auctions reduces competition between projects, raising prices. This risk can be mitigated by setting the annual procurement target based on the capacity of prequalified projects. In a recent consultation response, BEIS indicated that the Government is open to the possibility of more frequent auctions.[115]

BEIS has to dedicate significant resources to administering CfD auctions and we understand that this is seen as a barrier to annual CfD auctions. However, regular CfD auctions are crucial to delivering Net Zero, so they must be a priority for the Government. Also, by aligning the timelines of the CM and CfD auctions, the Government opens up the possibility of combining these schemes into a single auction for 'Equivalent Firm Capacity'.

Recommendation 7: Project developers should be required to submit bid bonds when entering the CfD auction, as they do in the Capacity Market. This will help to ensure that clean energy projects are delivered.

When the Government awards CfD contracts, it expects projects to be built. However, there are various reasons why this might not happen. Technology costs might not fall as expected, developers might misunderstand the CfD rules or encounter unforeseen technology and financing risks. If projects are not delivered, then the Government will fall behind on its progress to Net Zero.

To encourage developers to build their projects, the CfD scheme includes a 'Non-Delivery Disincentive' (NDD). If a developer does not deliver on a CfD contract, then that project is banned from entering a further CfD auction for at least 24 months.[116]

There is now a good argument for the Government to strengthen the NDD in future CfD auctions. The auctions are now being held less frequently,[117] and the Government is planning to procure up to twice as much capacity in the next auction, scheduled to open in late-2021.[118] This

115. BEIS (November 2020). *CfD for Low Carbon Electricity Generation. Government response to consultation on proposed amendments to the scheme.* Link. Page 70.

116. BEIS (October 2016). *Contracts for Difference: Government response to the consultation on changes to the Non-Delivery Disincentive for CFD allocation.* Link

117. The last auction (AR3) opened in Spring 2019, and the next auction (AR4) is expected to open in late-2021. This would be 2.5 years between auctions vs. Government aim of 2 years.

118. Prime Minister's Office (October 2020). *New plans to make UK world leader in green energy.* Link. *"Setting a target to support up to double the capacity of renewable energy in the next [CfD] auction…".*

concentration of projects makes it even more important that projects that are successful in the 2021 auction are delivered. One option to strengthen incentives is 'bid bonds'.

Bid bonds are a cash (or cash equivalent) deposit that would be submitted by developers in advance of the auction.[119] If developers are awarded a CfD, but do not build their project, then they forfeit the bond. The bond could be set based on installed capacity, for example £10,000 per MW, to align with the Capacity Market. Alternatively, the Government could set the bond based on expected annual generation, for example 2 £/MWh of expected generation, which would recognise that 1 MW of offshore wind is significantly more productive than 1 MW of solar PV.[120] The Government has decided not to introduce bid bonds in the 2021 auction, but intends to carry out further work on how bid bonds could be used in future rounds.[121]

Recommendation 8: Existing renewable energy generators should be allowed to compete for 1-year CfDs once their existing support contracts end. This will ensure that existing generators are not decommissioned prematurely and will align the treatment of existing generators between the CM and CfD schemes.

Today, only new renewable energy generators are eligible to receive CfD contracts, which last 15 years. Once this initial contract ends, generators cannot receive another contract. This rule exists because the CfD was designed as a subsidy to support upfront capital investment.

However, as more renewables are built, wholesale electricity prices are expected to fall during hours with high wind or solar generation, a process known as 'price cannibalisation'. This creates a risk that, after the 15-year CfD expires, project owners may be unable to raise the funds required to maintain or refurb their wind or solar farms and will therefore stop operating. If these renewable energy projects are decommissioned, then the Government will need to procure additional renewable energy resources through the CfD mechanism, even though this might be more expensive than extending the lifetime of existing projects.

Today, there are very few renewable energy projects that have reached the end of their subsidy contract. However, this will change quickly in the early 2030s, when generators supported under the Renewables Obligation (20year contracts) and CfD scheme (15year contracts) reach the end of their contracts.

The Government will be wary of extending the CfD to existing generators because they don't want to pay twice for the same wind and solar farms, i.e. paying once for the first 15-years and then again for additional contracts. However, reducing carbon and minimising costs means that the Government should support the lowest cost clean energy resources, whether they are new and existing projects. The Government already recognises this principle in the Capacity Market, where new generators can receive a 15-year contract initially and can receive one-

119. BEIS (March 2020). *CfD: Consultation on proposed amendments to the scheme.* Link

120. 1 MW of solar is expected to generate c. 1,000 MWh/year, whereas 1 MW of offshore wind is expected to generate 4,000 – 5,000 MWh/year.

121. Ibid (CfD: Response to consultation on proposed amendments). Page 42.

year contracts thereafter.

Recommendation 9: The Government should radically simplify the Contracts for Difference scheme. This should include scrapping Delivery Years and price caps for established technologies, and by allowing project developers to nominate their own 'load factor'.

The Contracts for Difference scheme is complicated, with multiple technology pots, various price caps and a complex system of Delivery Years. We recommend that the Government runs CfD auctions annually; however, we recognise that this is a significant resourcing challenge. One way to address this is to radically simplify the CfD scheme.

In March 2020, the Government launched a consultation on amending the CfD scheme. In this consultation, the Government suggested that it is considering setting a single clearing price for all 'Delivery Years' in the auction.[122] Today, the CfD auction can produce very different prices for projects delivered in one year (e.g. 2021/22), compared to the next year (e.g. 2022/23). This distinction made sense in earlier years when technology costs were falling rapidly. However, offshore wind, onshore wind and solar PV are now established technologies with less potential for large price falls from year-to-year. The Government is now proposing to set a single clearing price for all delivery years in the 2021 auction, subject to further consultation with independent auction experts.[123]

To simplify the CfD scheme, the Government should run an auction for all established technologies (offshore wind, onshore wind and solar) in a single pot (Pot 1) and should do away with the concept of Delivery Years. Instead, the Government should set a technology-specific longstop date for project delivery, based on likely construction time. By default, this should be two years for onshore wind and solar PV, and five years for offshore wind. Before the auction, individual project developers should have the option to apply for a longer build period, if they can provide evidence that this is needed.

The Government should also abolish 'Administrative Strike Prices' (ASPs) for established technologies. ASPs put a cap on the bid price of each technology, based on the Government's estimates of underlying technology costs. For established technologies, it is not clear why the Government needs to estimate technology costs, particular as project developers have much better information than the Government. The Government should instead rely on competition to keep prices low.

Finally, the Government should allow project developers to declare how much clean energy their projects will produce each year. At the moment, the Government calculates an annual load factor for each technology type. Under the current CfD system, this load factor is needed to calculate the impact of each project on the overall CfD budget.

Under our proposed floor-price CfD, generators should nominate their own minimum annual generation. If a project generates more than the minimum then the project's owners will keep the additional

122. Ibid (CfD: Consultation on proposed amendments).

123. Ibid (CfD: Response to consultation on proposed amendments). Page 44.

revenue, whereas if it generates less, then the floor-price will be reduced accordingly. With this structure, project developers will have a stronger incentive to accurately forecast their annual generation, which could be very different depending on where the project is located. As with project costs, developers have much better information than the Government.

The Government has decided to auction offshore wind in a dedicated Pot 3, rather than in Pot 1 alongside onshore wind and solar PV.[124] The Government is concerned that a single Pot for established technologies could lead to less diversity in the types of projects coming forward. This is a valid concern; however, as described in Recommendation 5, an updated system for ranking CfD bids will lead to a diverse range of resources, geographically spread across Great Britain.

Combined with the other changes proposed in this report, these recommendations would transform the CfD scheme into a proper 'market for clean energy resources', in the same way that the Capacity Market is a market for firm capacity resources.

Recommendation 10: The CfD auction planned for 2021 should be the last one held under the current rules. The first CfD auction for 'floor-price CfDs' should be held in Q4 2023.

These proposed changes are an evolution of the existing CfD scheme and can be implemented relatively quickly. It may not be possible to introduce locational reference prices until locational pricing is established in the GB electricity market. However, this should not delay the transition to floor-price CfDs. We recommend that the next CfD auction, planned for 2021, is the last one held under current rules. This means that the first auction for floor-price CfDs should be held in Q4 2023, alongside the T-4 Capacity Market auction for 2027/28.

If the Government introduces locational pricing in the wholesale market (Recommendations 1-4), then projects owners will face more volatile wholesale electricity prices. By retaining a reform CfD scheme, the Government will reduce the cost of integrating more wind and solar, whilst maintaining revenue certainty for generators, which will help to keep costs low for customers.

Theme 3: The Capacity Market should include a 'low-carbon quota' to support early-stage firm low-carbon resources.

Recommendation 11: The Capacity Market should include a 'low-carbon quota' for firm low-carbon resources. This quota should grow over time to increase the participation of low-carbon generators.

Today, the only resources that are ineligible for contracts in the GB Capacity Market are those with an emissions intensity of over 550 gCO_2/kWh. This is because the European Union prohibits Member States from supporting these very high-emitting power stations, predominantly coal-

124. Ibid (CfD: Response to consultation of proposed amendments). The Government also argues that multiple pots will allow auction parameters to better reflect the characteristics of the projects in each pot, for example project size and project cost.

fired, in their capacity markets.[125] To decarbonise the GB Capacity Market, the Government could reduce this emissions limit over time. However, this would encourage investors to build new high-efficiency gas-fired power stations, rather than moving straight to firm low-carbon resources. This would risk 'locking-in' new gas-fired power stations and would likely raise overall costs, because high efficiency gas-fired power stations are expensive to build.

Firm low-carbon resources provide both firm capacity and clean energy. Today, firm low-carbon resources are dominated by nuclear, biomass and short-duration energy storage (pumped storage and battery storage). To reduce the cost of reaching Net Zero, the UK should develop a range of firm low-carbon resources, which could include gas-fired power stations with CCUS (Power CCUS), bioenergy with CCUS (BECCS), low-carbon hydrogen (blue or green), biogas, geothermal, or ultra-long duration energy storage. To bring down costs, the Government should reform the Capacity Market to encourage the deployment of these early-stage technologies.

Initially there should be two 'Pots' in the CM. Pot 1 should be for established technologies like gas-fired power stations, short-duration battery storage, hydro pumped storage and DSR. Pot 2 should be reserved for early-stage 'firm low-carbon resources'.

The UK CfD scheme has two 'Pots'. Pot 1 is for 'established technologies' like onshore wind and solar PV. Pot 2 is for 'less-established technologies' like offshore wind, wave energy and tidal energy. This split approach allows the Government to reserve funding to support early-stage technologies, which are typically more expensive. This approach has helped to reduce the cost of offshore wind, which is now broadly cost competitive with onshore wind and solar PV in the UK.[126] The Government now considers offshore wind to be an established technology, and plans to move it into either Pot 1 or a dedicated Pot 3 in the next CfD auction. This will also give other less-established technologies like floating offshore wind, wave and tidal a better chance of winning contracts in the next auction.

The Government should implement a separate pot in the Capacity Market for firm low-carbon resources. Pot 1 should contain established technologies, whereas Pot 2 should be reserved for early-stage firm low-carbon resources. As with the CfD scheme, Ministers should retain the ability to create additional pots and to reallocate technologies between pots. To preserve liquidity in each pot, the CM should only have two or three pots, in line with the CfD scheme.

Recommendation 12: The Government should allow firm low-carbon resources to receive contracts in both the Capacity Market and the CfD scheme.

Today, projects that hold a CfD are not eligible for the Capacity Market, and vice versa. This is so that projects cannot receive a 'double subsidy'.[127]

126. BEIS (August 2020). *BEIS electricity generation cost report (2020)*. Link. Page 27.

125. BEIS (May 2020). *Consultation on Capacity Market proposals for future improvements*. Link

127. Both the CM and the CfD are considered State Aid (subsidies) by the European Commission.

This approach undervalues firm low-carbon resources, because these technologies provide both firm capacity and clean energy.

The current arrangements cause two problems:

1. Firm low-carbon resources have to choose between the CM and the CfD. These resources are therefore not fully rewarded for the value they provide to the electricity system.
2. If firm low-carbon resources hold a CfD contract, then they have no incentive to vary their output to capture higher electricity prices. For example, one of the biomass units at Drax power station holds a CfD.[128] This unit is incentivised to generate in all hours regardless of the electricity price.

Once the Government has aligned the timelines of the CfD and CM auctions, it should allow firm low-carbon resources to receive contracts through both schemes. This will value firm low-carbon resources more fairly. It also allows a more direct comparison between a firm low-carbon resource, like nuclear, and a combination of a firm resource and a clean energy resource (e.g. a gas-fired power station plus an offshore wind farm).

Allowing firm low-carbon resources to enter both the CM and the CfD would be a step towards the design of an Equivalent Firm Power (EFP) auction, as proposed by Professor Dieter Helm in the 2017 Cost of Energy Review.[129] In the longer term, the Government could combine the CfD and CM auctions.

Firm low-carbon resources should be incentivised to generate when electricity prices are highest. Appendix 3 provides details for how this could work.

The Government is unlikely to auction contracts for the first BECCS and Power CCUS projects.

History shows that competitive procurement is the key to delivering cost reductions for early-stage clean energy resources, as we have seen with offshore wind, onshore wind and solar. This recommendation sets out a pathway to integrate firm low-carbon resources into the Government's framework for competitively procuring firm capacity (through the CM) and clean energy (through the CfD). However, for the first projects with new technologies, it may not be possible to use competitive procurement.

For example, the first BECCS and Power CCUS projects will be highly dependent on the Government's plans to establish at least two operational CCUS clusters in the UK by 2030, including the associated CO_2 transport and storage infrastructure.[130] The Government is likely to procure these projects through bilateral negotiations that include the development of wider infrastructure. However, this does not remove the need for the Government to integrate firm low-carbon resources into the CM and the CfD.

If the Government provides opportunities for early-stage firm low-

128. Low Carbon Contracts Company (undated). *CfD register: Drax 3rd conversion unit (unit 1).* Link

129. BEIS (October 2017). *Cost of energy: independent review.* Link

130. BEIS (August 2020). *CCUS: Government response on potential business models for CCUS.* Link. Page 12 (The CCS Infrastructure Fund).

carbon resources in the CM and the CfD, then project developers will bring forward innovative projects, potentially at much lower costs than the Government expects. This could include low-carbon hydrogen projects, compressed air energy storage, ultra-long duration flow batteries, or technologies that the Government hasn't considered. Project developers have much more information than the Government about the costs and risks associated with their projects. If the Government is able to secure firm low-carbon resources through the CM and the CfD, then this would provide a benchmark for its bilateral negotiations with developers of BECCS and Power CCUS projects.

Recommendation 13: The Government should amend the Capacity Market to introduce regional (zonal) capacity pricing. This should be modelled on markets like New York State.

Today, the GB Capacity Market pays all resources the same price, mirroring the national pricing in the wholesale market. This approach ignores network constraints and local system balancing requirements.

For example, the Peterhead gas-fired power station in Aberdeenshire is one of very few resources that provides firm capacity and system balancing services in Scotland. Peterhead is a relatively old and inefficient power station that has high networks charges because it is based in Scotland. This puts Peterhead at risk of closing. If Peterhead were to close, then the ESO may not have been able to operate the electricity system, which is one reason why, in 2017, the ESO had to sign additional contracts with Peterhead to keep it open.[131] If the Government introduces locational pricing in the Capacity Market, then the capacity price might rise in Scotland, encouraging developers to build more firm resources there. This could reduce the ESO's reliance on power station like Peterhead and could reduce total system costs.[132]

New York State operates a regional capacity market with four price zones. These zones reflect major transmission constraints. Prices in New York City are over 10 times higher than in Upstate New York. This reflects higher underlying costs including land value, fuel costs, and more restrictions on air pollution in New York City. At a minimum, the UK Capacity Market should be reformed to include regional pricing.

Experience in New York State shows that there can be significant variations in capacity value within pricing zones. Therefore, the Government should consider reforming the GB Capacity Market to include local (nodal) capacity pricing; however, this should be balanced against the risk of market power in smaller bidding zones. Unlike local pricing in wholesale electricity markets, there is less international experience of mitigating market power in capacity markets with local pricing.

Recommendation 14: The Government should introduce a stricter testing regime and higher penalties for non-delivery in the GB Capacity Market.

131. SSE (undated). *SSE's Peterhead power station awarded National Grid contract.* Link
132. Of course, the ESO has other options to manage local network issues including contracting with small-scale "Distributed Energy Resources" and building new transmissions lines or other network assets like STATCOMs and shunt reactors.

The GB Capacity Market has never penalised a generator for not delivering during a system stress event. The penalties for non-delivery only kick in when some customers are forcibly disconnected from the network due to a lack of generation, known as a 'brownout'. Brownouts are extremely rare in Great Britain. Customers are usually only disconnected from the network due to a network outage or due to a sudden fault at one or more large power stations, rather than an overall lack of generation. For example, the partial power cut in August 2019 was caused by the sudden loss of two large generators following a lightning strike, not an overall lack of generation.[133]

As more customers switch to electric vehicles and electric heating, customers will rely on electricity for more of their basic needs, so the electricity system must be even more resilient. One way to improve resilience is to ensure the resources in the GB Capacity Market have strong incentives to deliver at times of system stress.

BEIS and Ofgem have already strengthened incentives through higher termination penalties,[134] and through reforms to the balancing market that will increase prices when the system is tight.[135] However, many in industry still see the Capacity Market as a one-way bet for generators. As highlighted in BEIS' 5-year review of the CM, the Government is now considering strengthening CM penalties further.[136]

The CM could include a Reliability Option (RO), modelled on Ireland and Northern Ireland. Alternatively, the CM could require all capacity providers to be available in the real-time Balancing Mechanism at times of system stress. Both of these approaches would lead to higher financial penalties on providers who are called on but do not deliver.

As well as higher penalties for non-delivery, the Government must ensure that there is a strict testing regime in place for projects that hold Capacity Market contracts. Even with higher termination fees, it is extremely rare for a penalty to be imposed and the testing regime is relatively light touch. In 2019, the Government committed to strengthening the penalty regime but has not yet published its proposals.

Recommendation 15: The first CM auction including a 'Low Carbon Quota' should be the T4 auction for 2027/28, held in Q4 2023.

These proposed changes are an evolution of the current Capacity Market, so they can be implemented relatively quickly. Therefore, **the first CM auction including a 'Low Carbon Quota' should be the T-4 auction for 2027/28, held in Q4 2023.**

The Government should not procure system balancing services

133. BEIS (January 2020). *GB power system disruption on 9 August 2019. E3C: Final Report.* Link
134. Ibid (Government response to 2016 CM consultation).
135. Ibid (Ofgem: EBSCR).
136. BEIS (July 2019). *Capacity Market: Five-year Review (2014-2019).* Page 43.

through the Capacity Market.

As described earlier in this report, increasing offshore wind in the UK means that the ESO will need more system balancing services. There is an argument that the Capacity Market is good at procuring firm capacity, but that it encourages relatively inflexible resources that cannot provide system balancing services.

This issue could be addressed by procuring system balancing services or a range of capabilities through the Capacity Market alongside firm capacity. However, to date there is little evidence that the CM is procuring the 'wrong' capacity mix from the perspective of system balancing services.

The new generators that have won CM contracts are mostly small-scale gas engines and battery storage. Both of these technologies are specifically designed to earn money by providing system balancing services:

1. Battery storage provides frequency response (FFR) and potentially voltage control.
2. Small-scale gas reciprocating engines have fast start-up times that are designed to provide Short-term operating reserve (STOR) and frequency response (static FFR) to the ESO.[137,138]

The ESO procures these system balancing markets through monthly and daily auctions. These short-term auctions signal developers to build flexible resources through the Capacity Market, even though the CM is an annual auction for contracts up to 15 years' long.

In addition to STOR and FFR, the ESO now needs new services like inertia and voltage control. The ESO is currently testing whether battery storage and solar farms are able to provide voltage control through the Power Potential trial in the southeast of England.[139] If this trial is successful, then the ESO will create new market for voltage control. This will encourage project developers to build even more battery storage resources to provide voltage control and other services.

New-build resources in the CM are generally not capable of providing inertia. However, this is largely because the ESO hasn't yet developed a liquid market for inertia. When the ESO creates markets for inertia, project developers are likely to bring forward resources that provide it.

It is tempting to try to design one 'super auction' to procure all firm capacity and system balancing services; Ireland and Northern Ireland actually considered this option before rejecting it as too complex.[140] As yet, there is limited evidence the CM will not procure resources that provide system balancing services. However, it is clear is that the ESO urgently needs to develop markets for more system balancing services like inertia.

137. NG ESO (undated). *Short-term operating reserve (STOR).* Link

138. NG ESO (undated). *Firm frequency response (FFR).* Link

139. NG ESO (undated). *Power Potential.* Link

140. SEM Committee (March 2016). *SEM-16-010 Capacity Remuneration Mechanism Consultation 3.* Link. Page 11:

"Such coordination of long run investment could be achieved by having a single joint auction for the procurement of capacity and DS3 System Services [system balancing services]. However, the SEM Committee also recognises that there is significant project risk associated with introducing a single auction at this stage and that the costs and benefits of joint procurement would need to be fully assessed before implementing a combinatorial auctions of capacity and DS3 [system balancing] products."

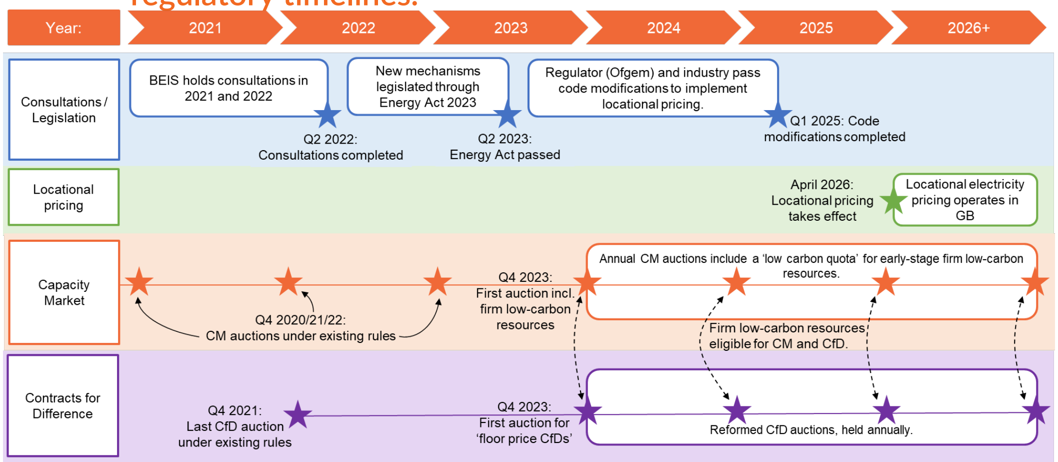
7. Policy timeline

Some of the recommendations in this report are incremental, whereas others are more substantial. We recommend that the Government legislates for these changes in 2023 through a new 'Energy Act' (Figure 20: Recommended policy timeline, including legislative and regulatory timelines.).

Our proposed changes to Capacity Market and Contracts for Difference schemes can be implemented for the auctions held in Q4 2023, whereas locational pricing will take longer. As well as legislative changes, locational pricing will require changes to regulations and industry codes. Ofgem and industry will need about two years to consider, consult and implement these changes. If all goes smoothly, locational pricing could take effect in 2026.

In the short-term, it is crucial that there is no gap in UK energy policy, as this would put security of supply at risk and could delay investment in the clean energy projects that are needed to deliver Net Zero. Our policy recommendations are specifically designed to ensure that existing mechanisms can be improved with as little disruption as possible.

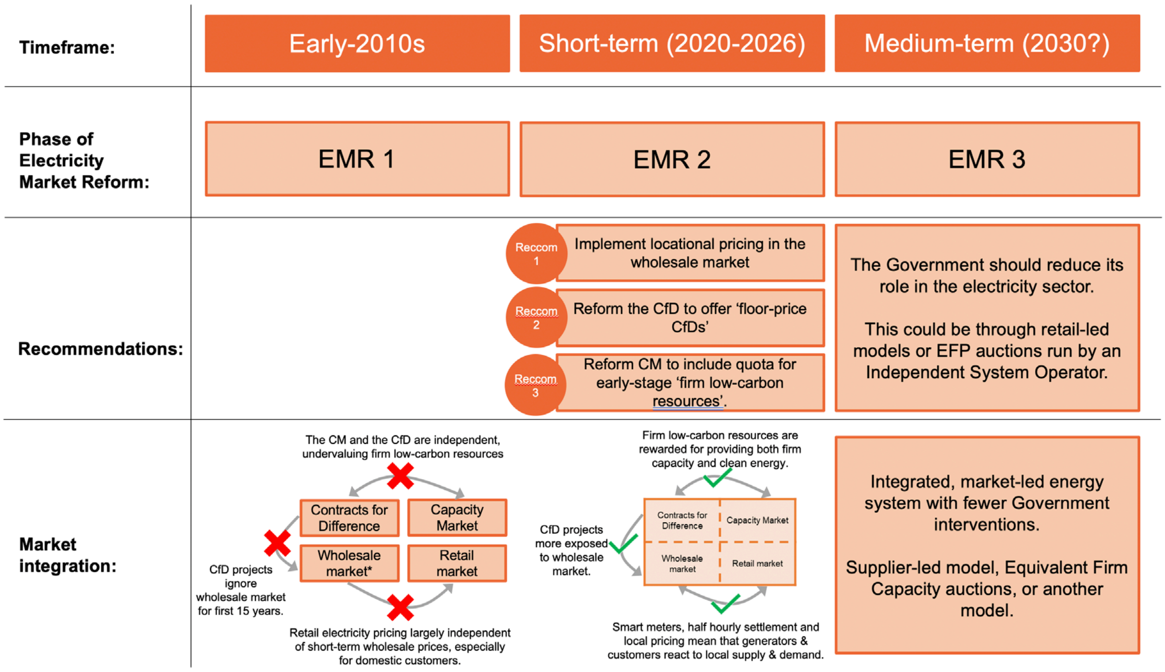
Figure 20: Recommended policy timeline, including legislative and regulatory timelines.



The Government should see this report's recommendations as the second phase of Electricity Market Reform (EMR 2), building on successful reforms in the early-2010s (EMR 1). Once these reforms are implemented, then the Government can start to consider a third, more radical, phase of Electricity Market Reform (EMR 3). These more radical changes could include Equivalent Firm Power auctions or giving energy retailers and customers more responsibility for decarbonisation and security of supply (Figure 21: Conceptual model of the three phases of Electricity Market Reform (EMR 1, EMR 2, EMR 3).).

By 2026, the GB electricity market should include locational pricing, which is a prerequisite for a smart and competitive electricity market. Suppliers will have installed smart meters in most UK homes and Ofgem will have implemented half-hourly settlement, giving customers more incentives to react to real-time supply and demand in their area. These developments will lay the foundations for the Government to reduce its role in the electricity sector over time.

Figure 21: Conceptual model of the three phases of Electricity Market Reform (EMR 1, EMR 2, EMR 3).



8. Conclusion

The UK's programme of Electricity Market Reform is a resounding success when compared to its objectives to create a secure, affordable, low-carbon energy system. However, this report has set out why further reforms are now needed.

If the Government doesn't reform the GB electricity market, then projects developers will build projects in the wrong places and customers won't be encouraged to vary their demand to match local supply and demand for electricity. System balancing costs will continue to rise and customers will pay the price in higher bills. Without further changes, customers won't benefit from the falling cost of wind and solar.

Local electricity pricing will cut customer bills.

Modelling from Aurora Energy Research shows that local electricity pricing can deliver major savings of **£2.1bn** per year. This would reduce customer bills by **£37 per year** compared to current policy.[141]

US electricity markets including Texas and California have used local pricing for more than a decade. By showing customers and energy suppliers the true cost of electricity, the Government will give customers and suppliers the motive and the means to react, lowering costs for everyone.

The UK's coastal industrial hubs will also benefit from local prices. These industrial hubs are close to the UK's abundant offshore wind resources, which means that local pricing will reduce their electricity costs. Local pricing could drive a new phase of industrial development including electrolysers for low-carbon hydrogen, data centres, and electric arc furnaces to produce green steel.

The Government also needs to make evolutionary changes to the Contracts for Difference (CfD) scheme and to the Capacity Market (CM). For the CfD, the Government should amend the scheme to offer 'floor-price CfDs', run auctions annually, and radically simplify the scheme. For the CM, the Government should introduce a 'low-carbon quota' for early-stage firm low-carbon resources like gas with CCS, BECCS, low-carbon hydrogen, geothermal and ultra-long duration energy storage.

The Government must balance evolution and revolution.

These proposals are a major change to the GB electricity market, particularly for the wholesale market. We have deliberately calibrated these changes to ensure that they will not disrupt crucial investment in offshore wind farms and in the power stations that provide firm capacity. There are good arguments for more radical reform that would reduce the role of the Government in the electricity sector. However, we think that these reforms should follow later, once local pricing is in place.

If the Government implements the reforms in this report, then it can significantly reduce the cost of reaching Net Zero, whilst laying the foundations to reduce its role in the electricity sector over time.

141. See Appendix 1 for details.

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