Powering the Future

Why the Review of Electricity Market Arrangements is so important

RESEARCH NOTE

By Ed Birkett

Foreword by John Penrose MP

Foreword

Energy bills are shooting up, hurting everybody but hitting the least well-off hardest of all. And a bad situation will get even worse when the Energy Price Cap rises again in October, delivering another hammer-blow to household bills.

The Chancellor recently announced a huge cash injection to soften the blow. But there's no magic money tree, and this latest £15bn package came only four months after his last £9bn handout.

More fundamentally, all he can do is to offer short-term help: an aspirin to soothe the pain today, not a long-term cure that will stop it coming back tomorrow. But without that long-term cure, we could be back here in a few months' time. And again next year. And the year after that too.

So, whilst the Government's short-term fix is welcome, it's not enough on its own. We need sustainable solutions.

What would that involve?

To start with, we should modernise the energy price cap, rather than just rolling it over when it returns to Parliament later this year. It was originally introduced to kill off the 'loyalty penalty', where loyal customers were ripped off by being charged far more than people who switched to cheaper fixed-price tariffs.

It has done this but only by forcing energy companies to sell energy to customers below cost, which has contributed to some going bust. The cost of failing energy companies is covered by bills, pushing them up even more.

Clearly, the price cap needs to change. Fortunately, there's a ready-made answer that's working well in the insurance industry. They've simply made it illegal to charge loyal customers a different price than someone who switches.

In energy, the solution is a "relative price cap", meaning that customers pay a similar price regardless of whether they have switched or which tariff they are on.

But updating the price cap alone won't be enough. The real problem is the skyrocketing international wholesale price of gas. Our gas and electricity bills follow the gas price, even though it has absolutely no impact on the costs of all the energy we generate from renewables. The cost of these has fallen massively, but it isn't showing up on bills.

Any long-term, sustainable solution has to upend our wholesale energy supply, redesigning the market so it delivers energy that keeps our net-zero promises, but more cheaply and reliably than today, and no matter what's happening in the international gas market.

What would that look like?

We would need to be more self-sufficient, using domestic production to uncouple us from the international wholesale gas price, which can be affected by Russia and other producers' actions. And we will need to have a mix of technologies and fuels, based on the cheapest long-term contracts so our bills are less likely to spike like they are now.

The Government also needs to stop picking winning projects and technologies.

Over the last 15 years successive governments have introduced a Byzantine array of schemes to support different technologies. But as Onward's new report sets out, with almost all new projects getting some taxpayer-funded support, it's not hard to see why it's created a boom for lobbyists, with all the costs ultimately being passed on to customers.

We should let energy firms find answers for our newly-modernised wholesale electricity market so they can buy the best of whatever they've got, rather than politicians trying to pick winners.

Last but not least, we must modernise the electricity grid so it can cope with more electric cars and small renewable electricity generators, and can discount electricity for local consumers if there's a surplus from Cornish solar farms in the middle of the day, or spare power from Scottish wind farms overnight. This could cut billions off our energy bills every year.

If we're looking for a sustainable long-term answer to give us hope alongside Rishi's short-term help, this is where we should start.

John Penrose MP,
Member of Parliament for Weston-super-Mare

30 second summary

The current energy price crisis raises major questions over the UK's energy policy. The Government's response is to boost domestic electricity production using new nuclear power stations and new offshore wind farms. Coupled with more electric cars and more electric heat pumps, this strategy will put Great Britain's electricity market at the heart of the energy system.

However, there are already warning signs that Britain's electricity market won't be able to accommodate these new technologies at scale, risking higher bills. In response, the Government has announced the Review of Electricity Market Arrangements (REMA).

Through REMA, the Government should harness markets to signal investors to build a coherent mix of technologies that will cut bills, maintain energy security and achieve net zero. Without reform, the Government is likely to miss its target to decarbonise the electricity sector by 2035, and customers will be more dependent on international gas prices for longer.

This report explores the key issues facing the UK's electricity market, and recommends that reforms are structured as three overlapping programmes of reform:

1. Reform wholesale and balancing markets;
2. Reform investment-support schemes; and
3. Reform regulation of energy suppliers.

Introduction

The UK's electricity system will be the backbone of a net zero economy. Between 2020 and 2050, demand for electricity is expected to more than double, whereas demand for oil and gas is forecast to fall by 85% and 70% respectively.[1]

Rising electricity demand will be met by more offshore wind, nuclear, solar and other sources. Because the output from wind and solar farms is variable ("intermittent"), they pose new challenges for the electricity system.

When wind output is low, alternative sources of electricity are needed. Today, this backup is provided by gas-fired power stations. However, net zero means that gas usage must fall, so new technologies will be needed to fill gaps in wind output.

Recent increases in wholesale gas prices have led corresponding increases in wholesale electricity prices; this is because the price of electricity is set by the most expensive generator that is generating at any point in time (known as the "marginal generator"). Today, the marginal generator is typically a gas-fired power station.

As the electricity system decarbonises, the UK's electricity system will rely less on gas and more on renewables. However, because prices are tied to the marginal generator, gas-fired power stations will continue to set the electricity price much of the time. Therefore, without reforms to the electricity market, customers' bills are likely to continue to be heavily influenced by the price of gas, which current market conditions demonstrate can be high and volatile.

The electricity sector also faces big challenges when it's windy, particularly getting electricity from where it's generated to where it's used. The UK's wind farms are concentrated in Scotland and off the east coast of England. This is far from where the bulk of electricity demand comes from, which is in the South of England.[2]

Because the capacity of power lines is limited, transmission lines between Scotland and England are often full ("constrained") when it's windy, which means that some Scottish wind farms must be paid to switch off. This, in turn, raises energy bills.[3] Constraints can be reduced by building new power lines, but bills can also be reduced by encouraging customers to use or store more electricity when it is abundant in their region. This would also ensure that existing power lines are used more efficiently, again reducing bills.

To address these and other issues, the Government launched a "Review of Electricity Market Arrangements" (REMA) as part of the British Energy Security Strategy (BESS).[4] REMA will consider structural reforms to Great Britain's electricity market and will be joined up with the Government's ongoing review of the retail energy sector.[5]

Without reform, the Government's 2035 target for "100% low-carbon electricity" is at risk.

There are already warning signs that the current market isn't designed to handle more renewables, as described in detail below.

In March this year, National Grid ESO issued a stark warning that:

> "...the status quo will not deliver net zero cost effectively, as current market design creates inefficient behaviours, particularly in dispatch, resulting in dramatic and rising costs for consumers..." [6]

In this context, the Government's plans to build more offshore wind farms could inadvertently drive up bills rather than reduce them. Without reform, there is therefore a risk that the Government will have to delay its headline target of decarbonising the electricity sector by 2035, with gas-fired power stations having to run for longer and the Government missing its targets for new offshore wind farms and new nuclear power stations.

One reason why market reform struggles to make it to the top of BEIS' agenda is that it has to compete against other priorities, especially a focus on delivering individual projects. In addition, the Government recently committed to reform key institutions, including by making the Electricity System Operator fully independent of the National Grid group and by reforming governance of energy codes.[7,8]

Against this backdrop, some market participants are understandably concerned about embarking on a complex process of market reform that, if handled incorrectly, could create uncertainty that would disrupt delivery and raise financing costs.[9]

However, with 2035 only thirteen years away and the existing market already creaking, our view is that the Government can't avoid the need to reform Great Britain's electricity market any longer. The challenge for the Government is to simultaneously reform the market whilst rapidly deploying new low-carbon energy projects. Experience from the UK suggests that this will be possible.

In the early-2010s, the UK's Electricity Market Reform programme introduced major changes to the electricity market, including creating the Capacity Market and Contracts for Difference (CfD) - two "investment-support schemes". These changes could have caused an investment hiatus, for example as the support for renewables transitioned from the Renewables Obligation to the CfD scheme.

To mitigate this risk, the Government took great care to maintain investor confidence during the transition. As a result, the UK's offshore wind sector has gone from strength to strength, with prices falling and deployment rising.[10] Similar care needs to be taken when implementing any changes resulting from REMA. The worst outcome would be to reform the system but lose investment appetite in the process.

Proposed aim for REMA:

Successive Governments have tried to develop an electricity system that is simultaneously secure, affordable and low carbon. These criteria are collectively known as the "energy trilemma".

To meet these criteria, the Government must harness markets to signal investors to build the right mix of technologies. In addition, the Government must also ensure that projects are financed cost-effectively and operated efficiently.

The optimal technology mix is likely to include a combination of:

- **“Firm”** technologies that are available to produce electricity whenever they are called upon. Firm technologies include nuclear power stations and gas-fired power stations;
- **“Low carbon”** technologies that produce electricity with low or zero carbon emissions. Low-carbon technologies include nuclear, wind, and solar. Unlike nuclear, wind and solar are “intermittent” technologies whose output depends on the weather;
- **“Flexible”** technologies such as battery storage and gas-reciprocating engines that can quickly increase or decrease their output;
- **Energy storage** technologies such as gas storage, battery storage, and hydrogen storage;
- **Energy networks** including power lines and pipelines, including cross-border electricity interconnectors; and
- **Grid support technologies** that help to keep the electricity grid stable. These technologies include reactors, capacitors, and synchronous condensers.

We believe that the aim of REMA should be as follows:

> The Government should harness markets to signal investors to build a coherent mix of technologies. Markets should be designed to ensure that these technologies are financed cost-effectively and operated efficiently.

When developing REMA, the Government should try to move closer to Nigel Lawson’s original vision for the UK’s electricity market post-privatisation, with markets rather than the Government determining the future of the electricity system.[11] Variations on Lawson’s philosophy have been reaffirmed by successive Energy Secretaries including Amber Rudd and Greg Clark in 2015 and 2018 respectively. As argued throughout this report, this approach is crucial to delivering net zero at least cost.

Proposed scope for REMA:

In this research note, we set out five questions that REMA needs to answer, based on the current and future challenges that the UK’s electricity system is expected to face:

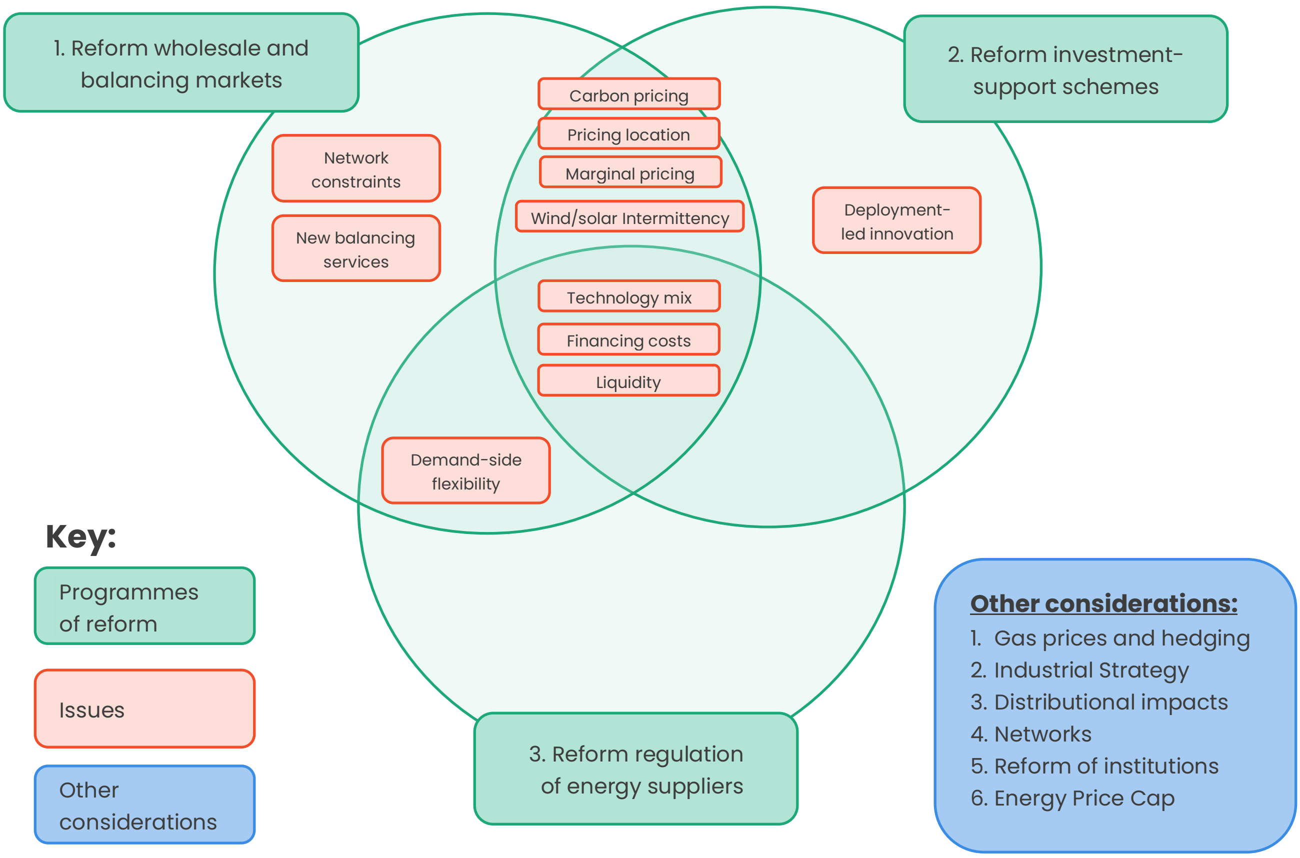
1. How can the UK’s electricity system be operated affordably and securely with lots of renewables?
2. How should markets fairly reflect the costs and benefits (“system value”) of different generators and customers?
3. How can the link between gas prices and electricity bills be broken?
4. What is the role for markets versus Government-run investment-support schemes?
5. What is the role of customers in a net zero electricity system?

There are potential solutions to all of these questions. However, the current market rules risk making it more expensive to deliver a net zero electricity system.

By exploring the questions, we have identified 11 key issues that REMA needs to address; these are listed in Figure 1 below and explored in later sections. We believe that these issues should be addressed through three major programmes of reform targeting wholesale and balancing markets, investment-support schemes, and supplier regulation.

We have also identified six additional considerations for REMA. However, these other considerations, whilst important, are largely independent of the optimal design of Great Britain's electricity market.

Figure 1: Mapping key issues to three programmes of reform
Source: Onward analysis



The three proposed areas of reform are explained in more detail below.

Reform programme 1: Reform wholesale and balancing markets.

REMA must consider major changes to Great Britain's wholesale electricity market to deal with rising network constraints, and to answer questions about the future of marginal pricing and how the location of customers and generators should be taken into account. Reforms are also needed to integrate the new balancing services that will help keep the electricity grid secure with more renewables.

Reform programme 2: Reform investment-support schemes.

The current suite of investment-support schemes risks bringing forward the wrong mix of technologies, raising bills. These reforms should consider how to bring forward the optimal technology mix at an affordable cost, whilst encouraging companies to operate their assets efficiently.

Reform programme 3: Reform regulation of energy suppliers.

In discussions of market design, the role of energy suppliers is often kept in a "downstream" bucket, with wholesale markets and investment-support schemes considered in a separate "upstream" bucket. New technologies like smart meters have blurred this distinction, and the growing importance of EVs and heat pumps means that there's huge potential for customers to participate in the "upstream" market.

Next steps

This research note does not attempt to provide a blueprint for the future of Great Britain's electricity market. Instead, it aims to highlight the key questions that BEIS will need to answer through REMA.

In future work, Onward plans to publish a full suite of recommendations for REMA. These recommendations will be published in a second report, expected in Q4 2022 or Q1 2023. As we develop these recommendations, Onward is keen to engage with as many stakeholders as possible. Please do get in touch if you would like to discuss.

Section 1: Five questions that REMA must answer

As outlined in the recent Energy Security Strategy, the Government is focused on delivering low-carbon electricity projects, particularly new offshore wind farms and new nuclear power stations.[12] Given the scale of investment needed for net zero, this focus on delivery is understandable. Government targets can be useful to catalyse supply chains and to coordinate investment in electricity networks.[13]

However, the Government has so far done relatively little to explain how its policies will ensure that the energy system as a whole will reach net zero at an affordable cost. To achieve this, it is critical that the right mix of technologies is deployed in the right places, rather than just headline targets for individual technologies. This is where markets come in.

Markets, if well-designed, can help to identify the lowest-cost mix of technologies, for example the right balance of offshore wind farms, nuclear power stations, solar farms and battery storage projects. But this is not how the market currently works, with incentives undermining the optimal mix of technologies as economists such as Dieter Helm have pointed out.[14]

The challenge for the Government is to ensure that Britain's electricity market rewards projects for the value that they create and penalises them for the costs that they impose on the system (known as "system value"). BEIS' Review of Electricity Market Arrangements (REMA) is a golden opportunity to design an electricity market that meets these aims, and therefore delivers net zero as affordably as possible.

In this section we have set out five questions that the Government needs to answer through REMA. These questions are based on the current and future challenges that the UK's electricity system is expected to face. For each question, we identify key issues that need to be addressed.

Question 1: How can the UK's electricity system be operated affordably and securely with lots of renewables?

The central challenge of energy policy is defined by the energy trilemma. How can governments design energy systems that are simultaneously secure, low carbon and affordable? Given the Government's ambition to decarbonise the UK's electricity system by 2035, ministers need to show that this transformation can be achieved both securely and cost effectively.

There are already warning signs that Great Britain's electricity market is ill-suited to handle a growing market share of wind and solar.

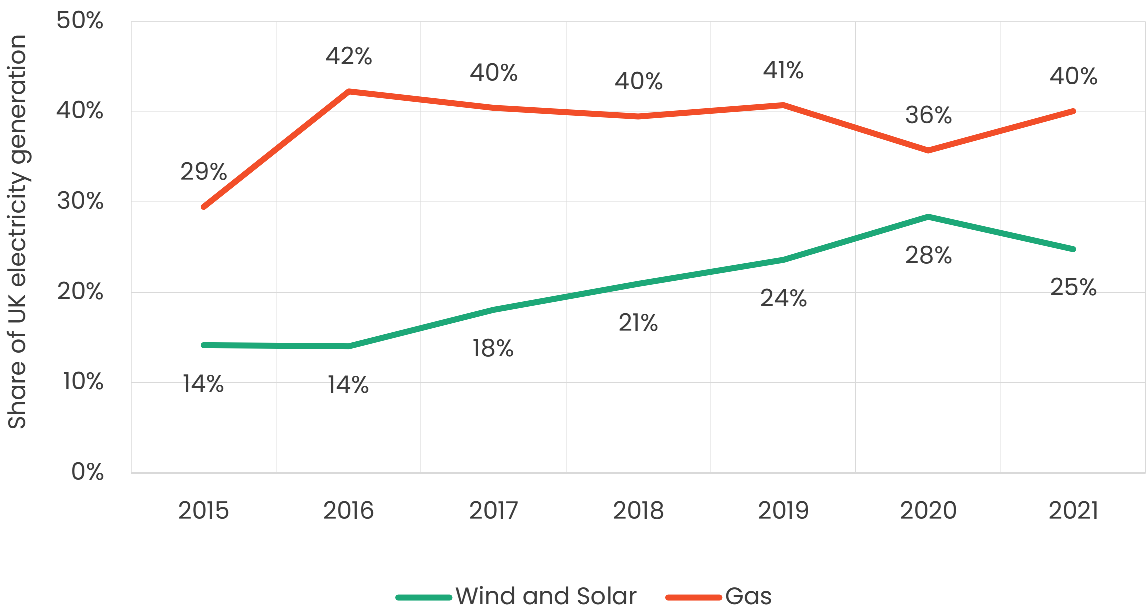
During the first coronavirus lockdown in Spring 2021, restrictions on economic and social activity caused electricity demand to fall by 15%.[15] Because wind and solar farms continued to operate, the market share of renewables was higher than normal. This meant that the grid operator, *National Grid* ESO, had to work harder to balance the electricity grid.

The ESO keeps the grid balanced by paying some generators to turn off or turn down and by paying others to turn on or turn up. For example, if the power lines between Scotland and England are full, the ESO could pay a wind farm in Scotland to turn down and could pay a gas-fired power station in England to turn up. This resolves the "constraint" between Scotland and England whilst ensuring that supply and demand remain balanced overall.[16]

During the four months of summer 2020, the ESO's increased interventions caused "system balancing costs" (including constraints) to rise by £220m, two-thirds higher than the previous year.[17]

In many ways, the conditions during the first coronavirus lockdown were a preview of the future, when renewables are expected to produce the vast majority of the UK's electricity. In 2020, wind and solar produced 28% of the UK's electricity (Figure 2). By 2030, the market share of wind and solar could reach 60%,[18] or even higher if the Government meets its new target for 50GW of offshore wind by the end of this decade.[19]

Figure 2: Share of UK electricity generation by resource type
Source: BEIS data, Onward analysis



Unless further steps are taken to integrate wind and solar, system balancing costs are likely to rise further, meaning that customers won't fully benefit from the falling cost of wind and solar. According to National Grid ESO, "constraint costs may continue to rise at an extreme rate, despite network reinforcement, through the 2030s".[20] The future electricity market must therefore be able to integrate more wind and solar without a big increase in system balancing cost.

Issue 1: Managing network constraints in a grid with more renewables.

The intermittency of wind and solar creates problems for electricity grids.

One of the main drawbacks of wind and solar farms is that their output depends on the weather and is therefore "intermittent". This doesn't mean that wind and solar are not valuable, but it does mean that they need to be complemented by other technologies.

Alongside wind and solar, nuclear power stations are expected to be the backbone of a net zero electricity system. Unfortunately, nuclear power stations are relatively inflexible, i.e. they cannot turn up or turn down quickly; this means that other "flexible" assets will be needed to balance changes in demand and variable supply from wind and solar farms.

Analysis from LCP suggests that, by 2030, the UK could need 50 GW of flexible technologies to complement output from nuclear power stations and wind and solar farms.[21] Much of this flexibility could be provided by gas-fired power stations; however, the net zero target means that these power stations will either have to be phased out or retrofitted with carbon capture and storage (CCS) technology.

Issue 2: Managing the intermittency of wind and solar.

Beyond intermittency, renewables also create other challenges.

Traditionally, the electricity grid has been kept stable by power stations running on gas, coal, and nuclear energy. These power stations all contain large, rotating masses that provide "inertia" to help to stabilise the electricity grid. Conventional power stations also provide other system balancing services such as voltage regulation.

When it's windy, fewer traditional power stations are turned on, reducing inertia and forcing the System Operator to procure services from other providers. Other options include batteries, which already provide some "frequency regulation" services previously provided by traditional power stations.[22] In addition, the ESO's "pathfinder" projects have brought forward novel solutions such as synchronous condensers to provide inertia and voltage control services.[23][24]

The challenge for the Government is to design a market where generators, energy storage and customers can compete fairly to provide the various services.

Issue 3: Creating markets for new system balancing services such as inertia.

The ESO is already rolling out a more competitive approach to procuring balancing services; however, there is more that could be done. For example, services could be procured as part of the main electricity market, as already happens in Australia.[25] This joined-up approach would help to lower bills by ensuring that balancing services are procured efficiently and therefore at the lowest cost.

Question 2: How should markets fairly reflect the costs and benefits ("system value") of different generators and customers?

Different technologies provide different benefits to the electricity system and impose different costs. The sum of these benefits, less any costs, is known as "system value".

For example, wind farms generate low-carbon electricity and reduce the need for natural gas imports (both benefits). However, their output depends on the weather, so backup is required (a cost). Similarly, nuclear power stations are low-carbon and reduce gas imports, but they can operate regardless of the weather (a further benefit). However, the headline cost of nuclear is high and nuclear plants can't be switched on and off quickly (both costs).

The current market rewards technologies in isolation rather than the optimal mix of technologies.

The challenge for market designers is to reward each of these technologies for the system value that they create. With system value priced correctly, investors will be more likely to invest in a coherent mix of technologies that can deliver a secure, low-carbon and affordable electricity system. This is very different to the current way of looking at technology costs, which often considers the "levelised cost" of individual technologies in isolation to the impact on the wider system (known as "whole system costs" or "system value").

It's not clear that today's market properly rewards system value, with concerns that intermittent technologies like wind farms are getting a free ride over intermittency, and concerns that small-scale and flexible technologies are not properly rewarded for the value that they create. These concerns are explored in more detail in the *ReCosting Energy* project.[26]

> **Issue 4:** Using markets to incentivise the optimal mix of technologies.

Carbon pricing is inconsistently applied across different parts of the system.

Carbon emissions are an important part of assessing and signalling system value. Pricing carbon is not just about explicit prices, although the UK does have explicit prices through the UK Emissions Trading Scheme (UK ETS) and the Carbon Price Support (CPS) tax.[27,28]

In addition, Britain's electricity market implicitly prices carbon through the Contracts for Difference regime, which offers low-carbon generators financial support that is not available to higher-carbon generators. However, other investment-support schemes mostly ignore carbon emissions, particularly the Capacity Market.[29] In the future market, carbon should be priced as consistently as possible. This could include a combination of implicit and explicit carbon prices.

> **Issue 5:** Carbon pricing (both explicit and implicit).

The current electricity market largely ignores the impact of geography on the network…

A further key determinant of system value is location. However, today's electricity market largely ignores the impact of location. As explained above, network constraints are a growing problem in Britain's electricity market. As more wind farms are built, typically far away from customers, constraint costs are forecast to keep growing.[30] To mitigate this, network companies are planning to build lots of new power lines and subsea electricity cables, typically between Scotland and England.[31]

New power lines and subsea cables will help to reduce constraint costs, but they are expensive. National Grid ESO forecasts that £16 billion will need to be spent on new networks by the mid-2030s,[32] to be paid for by generators and customers through annual fees known as "transmission charges". Transmission charges are likely to rise further due to pressure from communities to put power lines underground, rather than using cheaper overhead power lines.

Generators pay different transmission charges depending on where they are located, with the highest fees paid by those in areas that require the most expensive new networks to transmit their output to customers. Today, transmission charges are highest in Scotland because this is where most upgrades are needed (Figure 3).

Scottish politicians and renewable energy companies are increasingly concerned about the higher transmission charges levied on Scottish wind farms, fearing that these charges will deter investment.[33] Just because charges are highest in Scotland does not necessarily mean they are set incorrectly. However, the debate over transmission charges raises fundamental questions about how the location of projects is considered and priced in the electricity market.

...despite the fact location will be increasingly important in a net zero electricity system.

The importance of location will only grow as new technologies such as hydrogen electrolysers are added to the electricity system. Key questions include:

1. Where should companies build hydrogen electrolysers?
2. In what hours should those electrolysers operate?

The current market arguably answers the first question through transmission charges; for demand customers, charges are higher in areas with high demand (such as London) and lower in areas with low demand and high supply (such as Scotland). This encourages investors to build electrolysers in Scotland rather than in London.

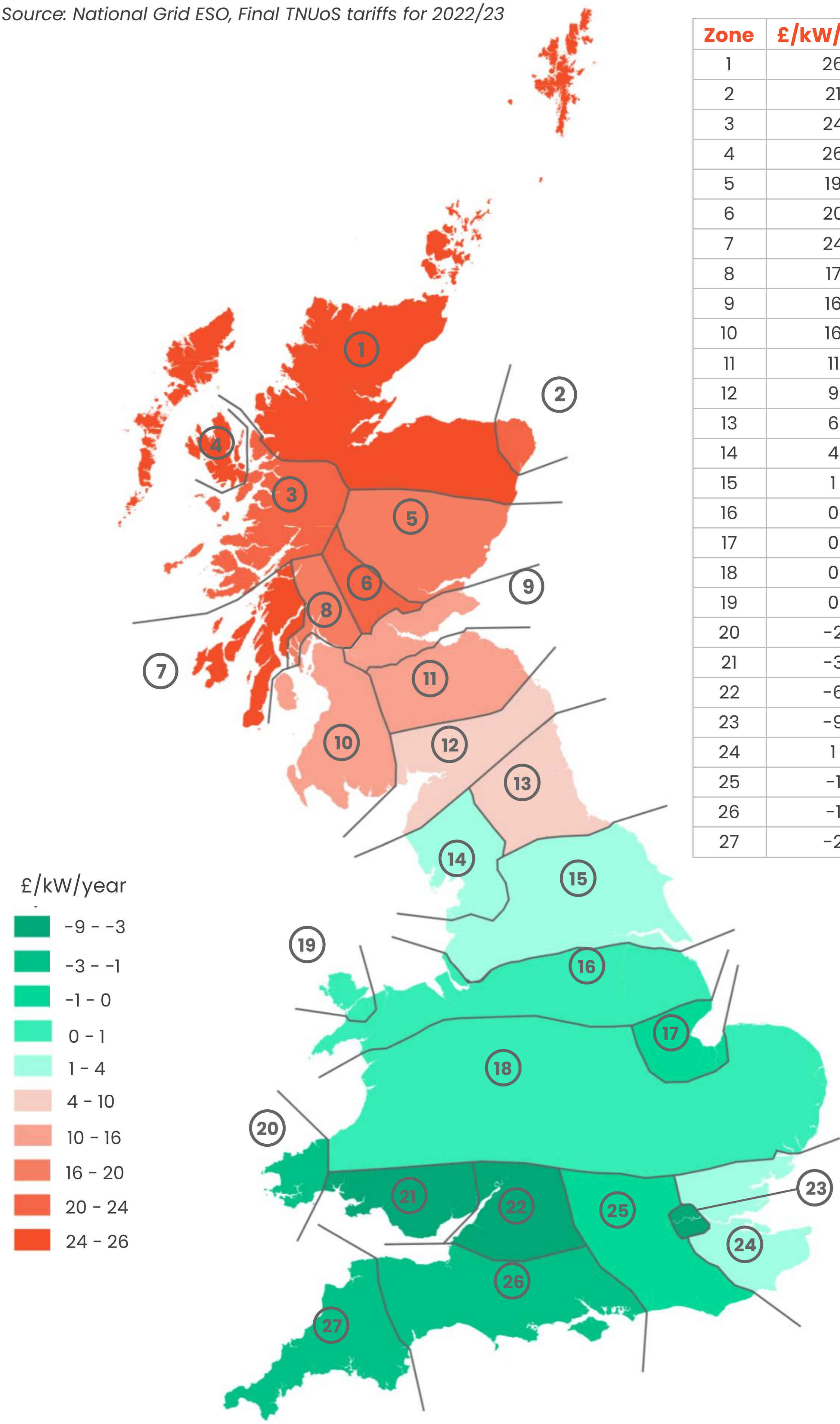
However, because transmission charges are currently structured as fixed charges, they can't signal an electrolyser when to operate. Transmission charges could only signal an electrolyser when to operate if they varied from hour-to-hour depending on local supply and demand.

Today, a hydrogen electrolyser in Cornwall would be encouraged to run in the same hours as an electrolyser in Scotland. This is clearly economically inefficient as supply and demand is very different in those two locations.

Figure 3: Current transmission charges (TNUoS) for a typical wind farm (40% load factor)

Source: National Grid ESO, Final TNUoS tariffs for 2022/23

Zone	£/kW/year
1	26
2	21
3	24
4	26
5	19
6	20
7	24
8	17
9	16
10	16
11	11
12	9
13	6
14	4
15	1
16	0
17	0
18	0
19	0
20	-2
21	-3
22	-6
23	-9
24	1
25	-1
26	-1
27	-2



Instead, electrolysers in Cornwall should be encouraged to run when there is high output from local solar farms, whereas those in Scotland should be encouraged to run when there is high output from local wind farms. This behaviour would reduce constraint costs and reduce wasted renewable energy, lowering electricity bills.

Similar arguments apply to owners of electric vehicles, who could be offered lower prices to charge their vehicles when there is excess supply in their area.

> **Issue 6:** Pricing location, including possible reforms to network charges.

Possible reforms in this area include "local electricity pricing" (also known as "nodal pricing") in the wholesale market. This would see prices vary across the UK at hundreds or even thousands of pricing "nodes". Local pricing has operated for years in markets including Singapore, New Zealand and much of the United States.[34] The main advantage of local pricing is that prices would automatically reflect local supply and demand, significantly reducing constraint costs. Local pricing could also allow transmission charges to be significantly simplified or even removed.[35]

The main downside of local pricing is that it would subject generators to more volatile local prices. This would increase uncertainty for investors in wind and solar farms, potentially increasing financing costs and offsetting some of the benefits of the local pricing. These new risks for investors can be mitigated, for example through CfDs or other long-term hedging arrangements.

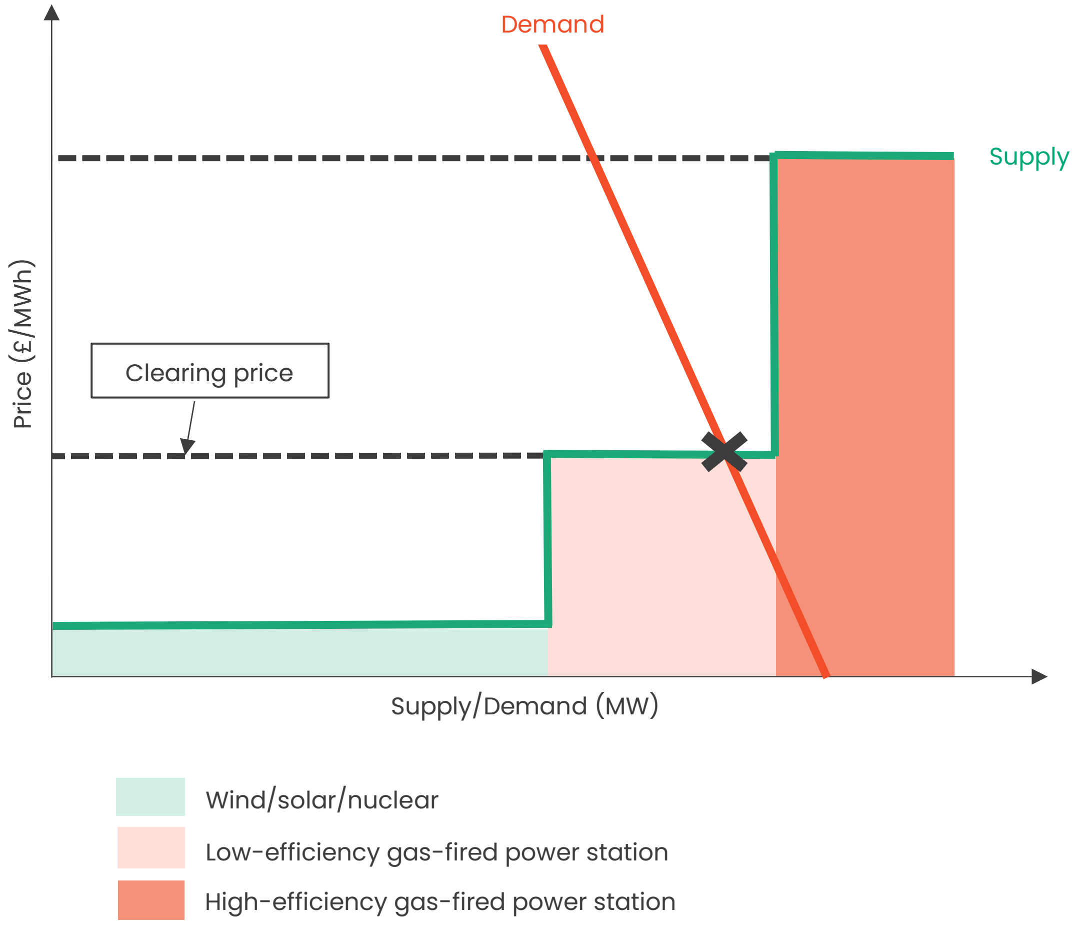
Local pricing is under active consideration in Great Britain. In March this year, National Grid ESO recommended moving to local pricing, which it said could be done within five years.[36] The regulator Ofgem is currently evaluating local pricing, having recently tendered for a consultant to assess design options.[37]

Question 3: How can the link between gas prices and electricity bills be broken?

Following Russia's invasion of Ukraine, UK gas prices have surged to extreme levels.

Under current electricity market rules, the wholesale price of electricity is highly influenced by the wholesale price of gas. This is because the wholesale price of electricity is set by the marginal electricity generator, which is typically a gas-fired power station (Figure 4).

Figure 4: Explanation of marginal electricity pricing
Source: Onward analysis



Marginal pricing makes it harder for renewables to cut customer bills.

Because of marginal pricing, rising gas prices have driven up electricity bills, even though the cost of renewables and nuclear has not changed. Analysis from *Carbon Brief* shows that nearly 90% of the increase in UK energy bills over the last year is due to the rising price of gas.[38]

As the UK builds more wind farms and solar farms, there will be fewer hours when the price of electricity is set by the price of gas; however, gas prices will still set electricity prices in many hours. Politicians and others are now starting to question the role of marginal pricing, including Ursula von der Leyen, President of the European Commission,[39] and Professor Sir Dieter Helm, author of the UK's Government's 2017 Cost of Energy Review.[40]

Issue 7: Marginal pricing in a Net Zero electricity system.

Several alternatives to marginal pricing have been proposed.

Alternative market designs tend to separate renewables from other generators. There are two main reasons to do this:

1. Renewables are intermittent, and therefore have very different characteristics to other generators that can be turned on or off as desired.

2. Renewables have low operating costs but high capital costs, unlike gas-fired power stations, which have significant operating costs, especially when gas prices are high.

One alternative is the **"two markets" model**, proposed by the Oxford Institute for Energy Studies.[41] This proposal separates the wholesale electricity market into two, creating one market for intermittent generators (the "as available" market), and one market for flexible generators (the "on demand" market). This proposal emphasises the difference between supply and demand that is controllable ("on demand") or uncontrollable ("as available"). This would fundamentally change the way that Britain's wholesale electricity market operates.

One potential downside of the two markets proposal is that it could make Britain's electricity market less compatible with those in neighbouring countries and therefore harm cross-border trading. This could become a growing issue as more interconnectors are built and more electricity is traded across borders to balance regional variations in renewables output.

Alternatively, the Government could implement a **"Green Power Pool"** for renewables, as proposed by Professor Michael Grubb of UCL.[42] Under this proposal, industrial customers would sign long-term, fixed-price contracts with renewables in the Green Power Pool, and would only access the rest of the market when the supply of renewables was too low to meet their demand. This concept could be extended to domestic customers, with energy suppliers signing contracts with the Green Power Pool. This proposal emphasises the differing cost structure of renewables compared to other generators.[43]

One advantage of a Green Power Pool is that it weakens the link between gas prices and electricity bills whilst leaving the underlying wholesale electricity market unchanged. This makes it much easier to implement and would not risk reducing the efficiency of cross-border electricity trading.

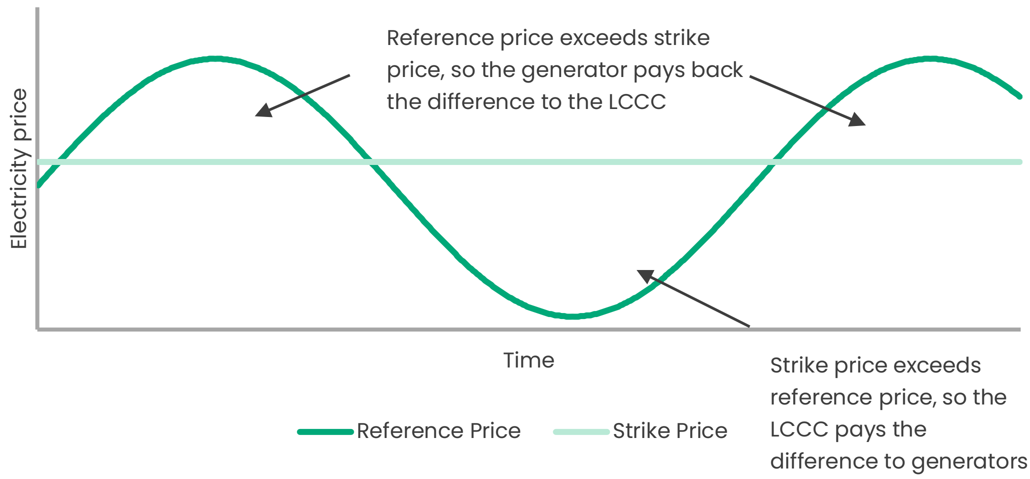
Arguably a Green Power Pool could be implemented by giving industrial customers and energy suppliers the ability to participate in the existing CfD auctions, where the Government is currently the only buyer. This would be a big change to the role of energy suppliers and would also introduce new contractual risks for generators. Today, generators sign contracts with the UK Government, so contractual risk is perceived to be low, reducing financing costs.

Recent reports in The Times suggest that the Government is considering introducing a Green Power Pool as part of the forthcoming Energy Security Bill.[44]

The Contracts for Difference (CfD) scheme is already weakening the link between gas prices and electricity bills.

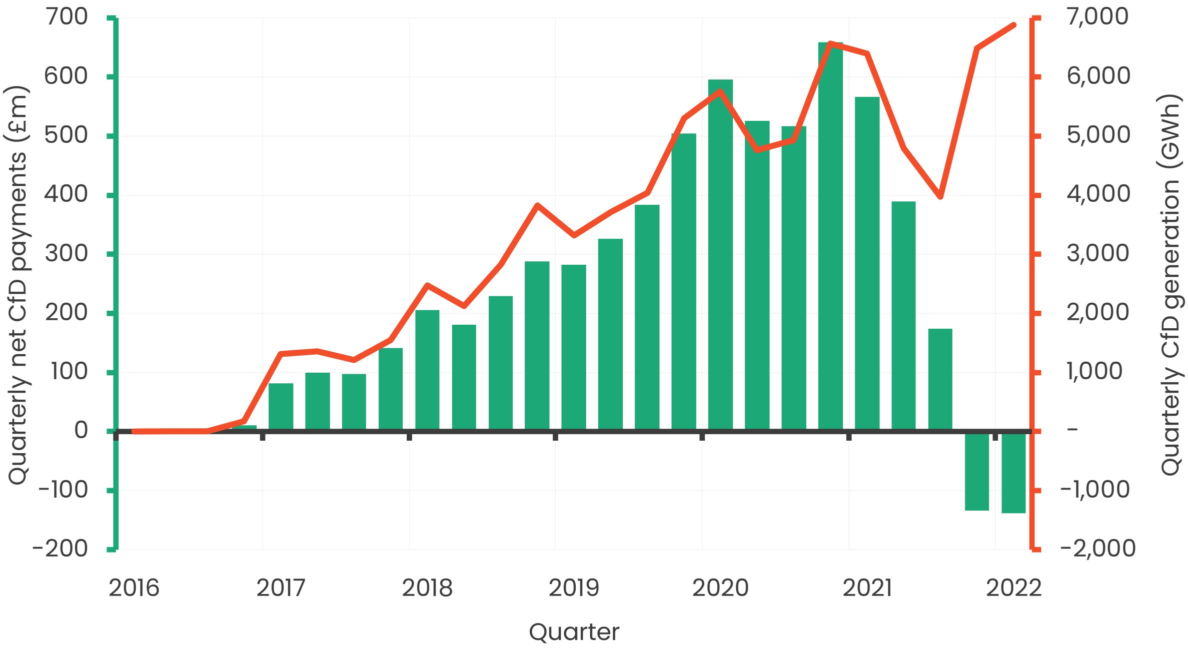
Under the UK's Contracts for Difference scheme, renewable energy generators are awarded 15-year, fixed price contracts for the electricity they generate. When wholesale prices are low, generators receive a top up, whereas when prices are high, generators pay back (Figure 5).

Figure 5: Explanation of the Contracts for Difference (CfD) scheme
Source: Low Carbon Contracts Company (LCCC)



The costs of the CfD scheme are recovered from customers, with customers paying a levy when wholesale prices are low and receiving a rebate when prices are high. Onward's recent research note, *Renewed Importance*, explored how high wholesale prices during the current crisis mean that projects with CfDs have paid money back to customers.[45] The most recent CfD data (as seen in Figure 6) shows how payments to CfD generators fell during 2021 and went negative in Q4 2021 and Q1 2022, reducing energy bills.

Figure 6: Quarterly net CfD payments to generators and CfD generation
Source: LCCC data on actual CfD generation and avoided GHG emissions, Onward analysis



CfDs weaken the link between gas prices and electricity bills because CfD payments to generators go down when wholesale prices go up, and vice versa when prices go down.

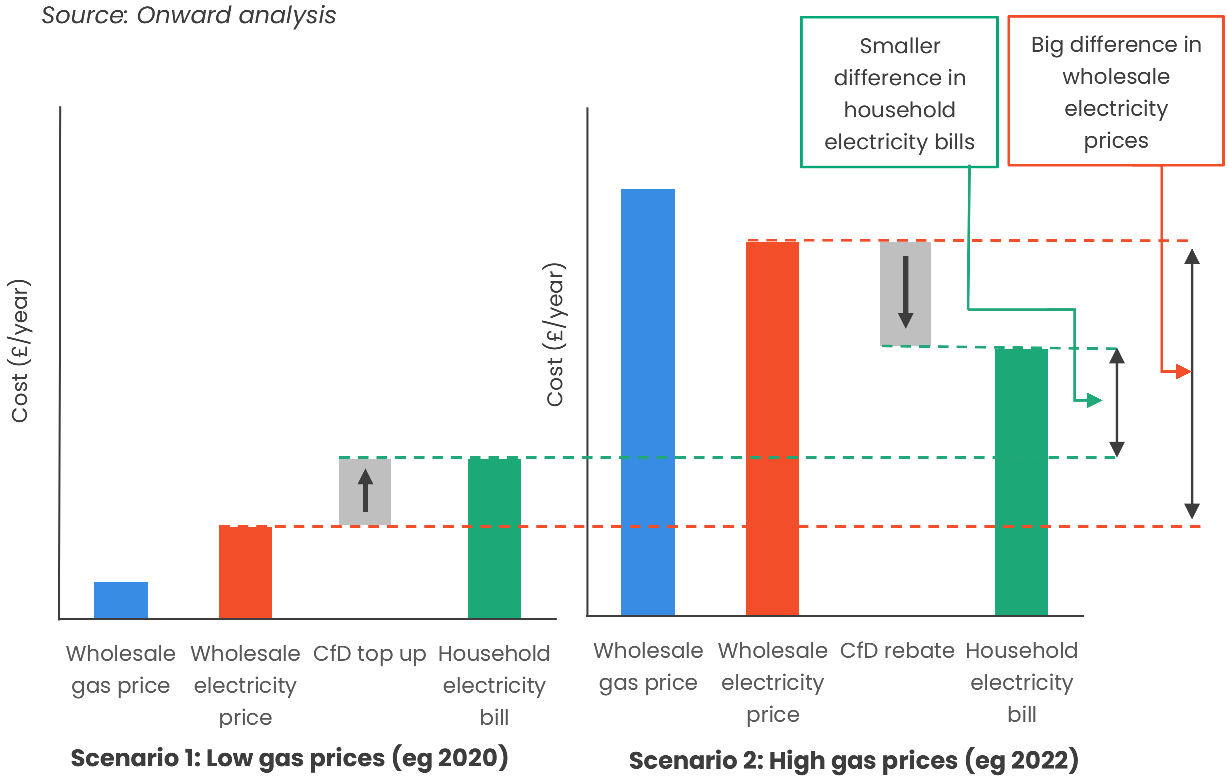
Today, the impact of CfDs is relatively small because the CfD scheme currently only accounts for 7% of UK electricity demand.[46] However, by 2030, CfD-supported generators could account for over half of UK electricity demand, significantly weakening the link between gas prices and electricity bills (shown schematically in Figure 7). This suggests that it may be possible to break the link between gas prices and electricity bills without pursuing radical solutions such as the proposed "two markets" model.

One possible risk to this approach is that it relies on CfD-supported generators honouring their contracts when prices rise, and therefore paying back to customers. Recently, new offshore wind farms have exploited a loophole in their contracts that allows them to delay the start date of their CfD contracts, allowing them to capture very high prices without paying back to customers.[47,48]

The solution to this problem is tighter drafting of contracts and strict penalties for companies that do not honour them. Given the high levels of public subsidy offered by taxpayers to de-risk renewables investment over the last decade, there is no justification whatsoever for price-gouging today.

Figure 7: How the CfD scheme can weaken the link between wholesale gas prices and household electricity bills[49]

Source: Onward analysis



Question 4: What is the role for markets versus Government-run investment-support schemes?

In addition to the wholesale electricity market, the Government operates “investment-support schemes” that are designed to achieve policy aims like decarbonisation and security of supply. These schemes include:

- **Contracts for Difference** (CfD) auctions for renewables such as wind and solar; and
- **The Capacity Market** (CM) for “firm” generators such as gas-fired power stations.

The main rationale for these schemes is a concern that, in their absence, energy companies might underinvest in certain types of technologies. For example, without the Capacity Market, there’s a risk that energy companies would build too few power stations, leading to blackouts during periods of high demand.

Similarly, without the CfD scheme, the Government worries that companies would invest in renewables too slowly to meet net zero by 2050 or at too high a cost.[50] Because the CfD scheme offers projects a fixed electricity price for 15 years, it reduces risks for investors, thus reducing financing costs. Given the amount of investment required for net zero, financing costs have a significant impact on the overall cost of the transition.

> **Issue 8:** Reducing financing costs.

The Government also uses the CfD scheme to encourage the deployment of technologies that are currently not cost competitive but could be in future. The best example of this is offshore wind, where “deployment-led innovation” helped to reduce the cost of new offshore wind farms by two-thirds in five years.[51,52]

> **Issue 9:** Using deployment-led innovation to drive down the cost of new technologies.

Some markets operate without investment-support schemes; these are known as “energy-only” markets because generators can only make money from the wholesale market.[53] Energy-only markets include the ERCOT market in Texas, which has faced blackouts in recent years arguably due to underinvestment in generating capacity.[54] Energy-only markets are the exception, and the UK is unlikely to return to one any time soon.

Current investment-support schemes risk supporting the wrong projects, raising bills.

One downside of current schemes is that there is only limited competition between technologies, so the market doesn’t have a chance to reveal an optimal technology mix. For example, in the CfD scheme there are separate auction pots for different technologies.

In the next CfD auction, the pots will be as follows:

- Pot 1: Established technologies including onshore wind and solar
- Pot 2: Less-established technologies including floating offshore wind, tidal stream, and wave power; and
- Pot 3: Conventional offshore wind (fixed foundations) [55]

These separate pots made some sense when offshore wind was not cost competitive with onshore wind and solar, given that the Government had a strategic aim to bring down the cost of offshore wind. The cost of offshore wind has since fallen to the point where it is competitive with onshore wind and solar. Given this, there are few reasons to protect offshore wind projects from competition, but the Government is resisting giving up control to the market.[56]

A further downside of current schemes is that they under reward technologies that can provide multiple services. For example, the Government supports low-carbon technologies through the CfD scheme and back-up ("firm") capacity through the Capacity Market. However, because projects can only enter one of these schemes, the Government undervalues technologies that are both firm and low carbon (for example bioenergy with CCS, low-carbon hydrogen, and long-duration storage).

By creating more investment-support schemes, the Government risks making the problem worse.

As explained above, some new technologies don't fit neatly into the existing schemes, including gas-fired power stations with CCS and low-carbon hydrogen. For these technologies, the Government is creating bespoke support schemes, including:

- **Dispatchable Power Agreements** for gas-fired power stations with CCS;
- **Hydrogen CfDs** for low-carbon hydrogen production; and
- A **Regulated Asset Base** for new nuclear power stations.

In the short term, this addresses some of the problems with the existing schemes; however, in the long term, this approach risks making the market even more disjointed. With limited competition between technologies in the CfD scheme, and no link between the CM and CfDs, the Government risks procuring a suboptimal or even incoherent mix of technologies, which would raise energy bills.

In addition, by creating more support schemes, the Government has made itself more vulnerable to lobbying by technology providers. Rather than letting the market determine which technologies are cost competitive and which provide the most value to the energy system, the Government is now pressured to "create a business model" for all new technologies.

Through REMA, the Government should look to consolidate as many of these support schemes as possible into a single mechanism. Not only will this reduce bills through fair competition, but it will also reduce the potential for lobbying.

Ideally, nuclear power stations would compete alongside other technologies in this consolidated market. Unfortunately, experience in the UK and globally shows that the risk of delays and expensive cost increases means that almost all new nuclear projects require governments to take on much of the financing cost and risk of cost overruns. Nuclear power is therefore likely to remain financed through a bespoke investment-support scheme.

However, even if nuclear remains in a bespoke scheme, Government decisions on nuclear would still be better informed by consolidating other schemes into a single mechanism. By consolidating existing schemes, the Government will have a clearer view of the value that technologies provide to the electricity system. This could then be compared to the estimated costs and benefits of new nuclear power stations.

Investment-support schemes risk harming market liquidity.

As currently designed, there's an increasing risk that the UK's investment-support schemes will harm liquidity in the forward market for electricity.[57] For example, under the current CfD scheme, the reference price for the contract is the "day-ahead" electricity price. This means that wind farms are expected to sell all of their output at the day-ahead stage, through the UK's two power exchanges.[58]

While this promotes liquidity in the day-ahead market, it reduces the incentive for wind farms to sell their power ahead of time in the forward market. This creates problems for energy suppliers, which are then less able to hedge by buying season-ahead or year-ahead contracts. There are a number of potential solutions to this issue, including encouraging financial players such as banks to play a greater role in the forward market. years.[59,60]

> **Issue 10:** Promoting liquidity in both forward and short-term electricity markets.

Alternative investment-support schemes include the Netherlands' "SDE++" scheme.

The Netherlands operates a multi-technology subsidy scheme known as the SDE++.[61] Unlike the UK's CfD regime, the SDE++ includes emissions reductions from outside the electricity sector, for example renewable gas (biogas).[62]

Under the SDE++, projects are ranked based on the cost of the CO2 emissions that they displace, measured in Euros per tonne (€/t). This makes it possible for very different technologies to compete against each other, for example for solar farms to compete against low-carbon heating for greenhouses.[63]

The main advantage of the SDE++ scheme is that it assesses projects using a single, comparable metric. In theory, this allows the Government to identify the cheapest emissions reductions, regardless of which sector they come from.

One downside of the SDE++ is that it is fiendishly complicated, not only because a carbon-reduction metric needs to be calculated for each technology, but also because there are different cost caps for different technologies depending on their stage of maturity. In addition, the SDE++ does not address security of supply in the electricity sector.

Question 5: What is the role of customers in a net zero electricity system?

Traditionally, governments and energy companies have seen customers as passive participants in the electricity market, unable to increase or decrease their demand in response to changing market conditions.

However, in the last decade, new technologies have created opportunities for customers to participate in electricity markets. These technologies include smart meters and electric vehicles (which can be charged during off-peak periods). Various trials have shown that, with the right incentives, customers can dramatically shift their electricity demand to lower-priced periods.[64]

As explained above, the need for flexibility is growing rapidly as more wind and solar farms are connected to the grid. Much of this flexibility will come from generators and energy storage projects, but there's also a growing role for customers, who may be able to shift some of their demand relatively easily and cheaply. This contribution from customers is known as "demand-side flexibility".

Demand-side flexibility will only be harnessed if energy suppliers are encouraged to offer new types of tariffs that reward customers for participating in the electricity market. This means that the potential for demand-side flexibility depends on changes to the regulation of energy suppliers.

The Government should do more to encourage demand-side flexibility as a route to reduce electricity bills.

The Government's Retail Energy Strategy, published in 2021, foresaw a retail market with lots of energy suppliers and with switching as the primary means to reduce energy bills.[65] However, since then, 29 energy suppliers serving four million households have failed, making the Government's vision untenable.[66]

In response to the failure of so many suppliers, the Government has reopened its Retail Energy Strategy. The Government is now expected to focus on measures to promote demand-side flexibility. This could include smart electricity tariffs, which offer customers lower prices for using more of their electricity during off-peak periods.[67]

Today, there are multiple barriers to suppliers and customers monetising demand-side flexibility. These include prescriptive regulation by Ofgem that discourages suppliers from offering innovative tariffs, as well as barriers to entry for households wanting to participate in local flexibility markets. In addition, some suppliers argue that the current wholesale market and network charging arrangements undervalue demand-side flexibility from domestic customers.[68]

Policy choices in REMA could have a substantial impact on the potential for customers to participate in the electricity market. For example, reforms to wholesale and/or balancing markets could make it easier for households to get paid for resolving local network constraints.[69] The Government should therefore consider energy suppliers and demand-side flexibility as a central issue in REMA.

> **Issue 11:** Encouraging domestic customers to flex their electricity demand ("demand-side flexibility").

Smart tariffs are one option to cut electricity bills for customers who can provide demand-side response.

Customers with traditional electricity meters typically pay the same price for electricity regardless of when they use it.[70] This keeps things simple for customers but fails to reflect variations in the underlying price of electricity. For example, wholesale prices are typically much lower overnight.

The situation is different for the growing number of customers with smart meters, who can either stay on a traditional electricity tariff or opt for a "smart electricity tariff". Smart tariffs offer cheaper electricity during off-peak periods, reflecting lower wholesale prices and lower network charges during these hours.

Different suppliers offer different smart tariffs. These tariffs can follow a fixed pattern, known as "static time-of-use tariffs",[71] or can vary based on the real-time market price, known as "dynamic time-of-use tariffs".[72] Other smart tariffs offer customers cheaper electricity for certain devices, for example to charge their electric car, but only if they let their supplier have some control over when it charges.[73] This allows the supplier to charge the car during times with lower market prices.

The Government also needs to tackle broader questions about the role of energy suppliers.

Suppliers are currently relatively passive participants in the wholesale electricity market. They are encouraged to buy electricity and gas in advance ("hedging") but are not encouraged to influence what types of new power stations or renewables are built.

In some alternative market designs, suppliers would remain relatively passive market participants, for example as envisioned by Dieter Helm's proposals for "Equivalent Firm Power" (EFP) auctions.[74] However, other market designs see suppliers contracting directly with generators and energy storage projects, for example as envisioned by the Energy Systems Catapult's *Rethinking Electricity Markets* programme.[75]

This choice clearly has significant implications for the future of investment-support schemes (Question 4). In particular, the Government needs to decide whether investment-support schemes like the CM and the CfD remain centralised (run by the Government), or whether they should be structured as decentralised obligations on energy suppliers that require them to contract with a mix of firm and low-carbon generators.

Other considerations

As well as answering the five questions above, REMA will need to consider other policy objectives and ongoing reforms. However, whilst these are important for broader energy policy, they should not drive the outcomes of REMA. Instead, REMA should deliver an effective market design, and then other policies should be layered on top to address the following six considerations.

Consideration 1: Gas prices and gas hedging.

The primary cause of the current energy price crisis is soaring wholesale gas prices. To avert future crises, the Government needs to reconsider its gas security strategy. Possible solutions include mandating suppliers to buy more gas in advance (hedging), building more gas storage, or even the Government contracting directly with major gas exporters. These decisions should be closely linked to the Government's strategic decisions on the future role of hydrogen, which will have big implications for natural gas and hydrogen storage requirements.

However, whilst gas prices and gas hedging are crucial for energy bills, they are not central to the design of the UK's electricity market. Regardless of the future structure of the UK's electricity market, the Government will be able to impose stricter and longer-term gas hedging obligations on relevant parties, should it wish to do so.

The design of gas hedging obligations will have a big impact on the future of the Energy Price Cap (Consideration 6), which is currently the main mechanism that the Government and Ofgem use to encourage hedging by energy suppliers.

Consideration 2: Distributional impacts.

The current energy price crisis has highlighted the plight of the many households that struggle to afford their energy bills even in normal times. You could therefore argue that a key aim of REMA should be to ensure that low-income households can afford their energy bills. However, the Government is likely to make energy bills lower overall if it separates questions about distributional impacts from broader questions about market design.

The aim of REMA should be to design an electricity market that drives down overall costs whilst meeting the other main policy goals of energy security and decarbonisation. The Government should then take the output of REMA, and overlay any policies needed to manage distributional impacts. This could include providing low-income households with discounted "social energy tariffs" or by expanding bill subsidy schemes such as the Warm Home Discount.

One distributional impact that REMA could have to manage is from local electricity pricing. Without mitigation, this could lead to significant variations in electricity bills in different parts of the country. Local price variations are desirable for generators, storage providers and industrial energy users, as local pricing is intended to change the way these market participants act.

However, it is unlikely to be desirable or politically viable to charge domestic customers different electricity prices depending on where they live. To overcome this, many electricity markets only implement local pricing for generators, with national pricing retained for customers.[76] If REMA takes a similar approach, then this would have to be considered as part of the Cost-Benefit Analysis for local pricing, as it would reduce the potential benefits.

Consideration 3: Design of institutions.

The Government is planning changes to key energy institutions including Ofgem and the Electricity System Operator, National Grid ESO. Much of this work is already underway, with BEIS overdue to publish a Strategy and Policy Statement for Ofgem,[77] and work on the "Future System Operator" well progressed.[78]

In addition, Ofgem is consulting on changes to the structure of the regional electricity network companies (Distribution Network Companies or DNOs).[79] These changes could lead to system operation and planning functions being moved into new legal entities, mirroring the separation of National Grid ESO from the National Grid group.

However, whilst REMA should be aware of these institutional changes, they should not drive the outcome of the review. Unlike the future role of energy suppliers, the role and structure of Ofgem, the ESO and the DNOs is unlikely to significantly impact the optimal design of Great Britain's electricity market.

Consideration 4: Industrial strategy.

The Government has a clear desire to secure green jobs in the UK, for example jobs manufacturing turbines for offshore wind farms. There are clear benefits to this ambition, including helping with the Levelling Up agenda and helping to secure public support for net zero

However, industrial strategy should not determine the design of Britain's electricity market. If the Government wants to secure green jobs in the UK, then it should continue to do so explicitly, for example through continued investment in enabling infrastructure such as ports.[80] The Government could also go further, for example by introducing a carbon border tax on imports of energy-intensive products.

Consideration 5: Investment in the electricity network.

As the energy system decarbonises, the electricity network will need to be significantly expanded. This will help to accommodate rising demand and to bring electricity from wind farms in remote areas to customers far away. Investment in networks will also need to be coordinated better, with new generators able to share power lines and substations to reduce costs.

Recognising this, the Government established the Offshore Transmission Network Review (OTNR), which aims to improve coordination between offshore wind farms and new power lines including subsea power cables.[81] The review could also lead to more “anticipatory investment”, with bigger investments made earlier to accommodate future projects. The OTNR must resolve debates over how this investment should be deployed, what criteria should be used to evaluate projects, and so on. Whilst this work is important, it is largely independent of the challenge of designing the optimal electricity market.

One interaction that the Government does need to consider is between network planning and investment-support schemes such as the CfD. When planning networks, the ESO must take into account the size and likely outcome of future procurement rounds (e.g. CfD auctions) to determine the optimal network configuration.

Consideration 6: The Energy Price Cap.

The Energy Price Cap has a significant impact on how suppliers operate and exacerbated the financial problems they faced when wholesale energy costs rose in 2021.

The current Energy Price Cap encourages suppliers to hedge in line with a rigid formula, rather than developing their own strategies to buy energy at the cheapest possible price. Other formulations of the energy price cap are available, including a “relative price cap”, which would limit the difference between the cheapest and most expensive tariffs offered by an energy supplier.[82] A relative price cap would continue to ensure that customers won’t get ripped off for not switching, but it would significantly reduce the Government and Ofgem’s role in directly setting prices.

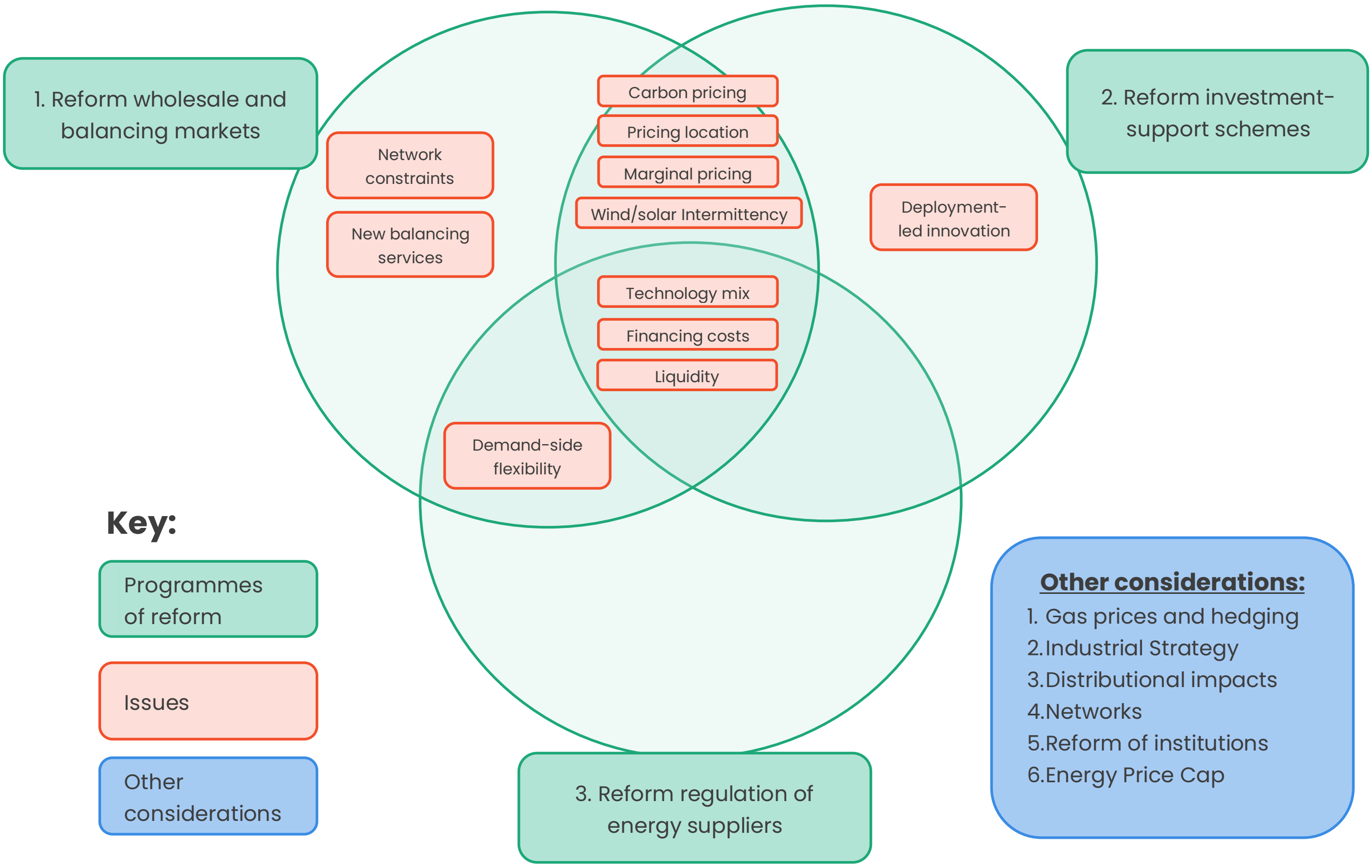
The Price Cap could be important for REMA as it could impact market liquidity and the type of tariffs that suppliers offer, which impacts the amount of demand-side flexibility that will participate in the market.

Section 2: Recommended scope and approach

Through the five questions above, we have identified eleven issues that REMA needs to resolve. These issues can be grouped into three overlapping programmes of reform (Figure 8). We have also identified six additional considerations for REMA.

Figure 8: Mapping key issues to three programmes of reform

Source: Onward analysis



The three proposed programmes of reform are explained in more detail below.

Reform programme 1: Reform wholesale and balancing markets.

REMA must consider major changes to Great Britain's wholesale electricity market to deal with rising network constraints and answer questions about the future of marginal pricing and how the location of customers and generators should be taken into account. Reforms are also needed to integrate the new balancing services that will help keep the electricity grid secure with more renewables.

This reform programme needs to be co-developed with reform of investment-support schemes and regulation of energy suppliers. A coherent package of reforms should signal the optimal technology mix, reduce financing costs and promote liquidity.

Reform programme 2: Reform investment-support schemes.

The current suite of investment-support schemes risks bringing forward the wrong mix of technologies, raising bills. These reforms should consider how to bring forward the optimal technology mix at an affordable cost, whilst encouraging companies to operate their assets efficiently.

These reforms must also retain the ability to reduce the cost of technologies through "deployment-led innovation". This is one of the best features of the current CfD regime, which has played a significant role in reducing the cost of offshore wind projects globally.

Reform programme 3: Reform regulation of energy suppliers.

In discussions of market design, the role of energy suppliers is often kept in a "downstream" bucket, with wholesale markets and investment-support schemes considered in a separate "upstream" bucket. New technologies like smart meters have blurred this distinction, and the growing importance of EVs and heat pumps means that there's huge potential for customers to participate in the "upstream" market.

This reform programme should consider demand-side response from households as an integral part of the market, as well as considering suppliers as a potentially important actor in deploying and financing new energy projects.

Proposed approach to REMA

Since privatisation in the 1990s, successive UK Governments have pursued a hybrid approach to the electricity sector, intervening in some areas and not in others. During the early 2010s, the Electricity Market Reform (EMR) programme increased the Government's role in the electricity sector by introducing the Capacity Market and Contracts for Difference scheme, both of which are run by the Government. These schemes have broadly achieved their aims; however, as described above, the negative side effects of these policies are becoming clear.

As early as 2015, Ministers were starting to get nervous about the Government's growing role in the sector. In November 2015, then-Energy Secretary Amber Rudd delivered a speech calling for what was dubbed an energy policy "reset",[83] and a return towards Nigel Lawson's original vision for the electricity sector post privatisation.[84]

In the speech, Rudd called for the Government to get tougher on subsidies, promote greater competition and innovation, and concentrate on technologies that could deliver at scale, particularly offshore wind and nuclear power.

Rudd argued that the Government "should enable, not dictate" and that "the market should lead our choices". To achieve this, Rudd wanted the Government to get "out of the way as much as possible, by 2025." Given the current direction of energy policy, the Government is almost certain to miss this timeline.

In 2018, one of Rudd's successors, Greg Clark, gave a speech arguing that the falling cost of renewable energy meant that the energy trilemma was "well and truly over", with renewables likely to cut bills rather than raise them.[85]

These two speeches set out a similar vision for the UK's electricity sector. They both foresee markets taking the lead and the Government getting out the way as much as possible.

In line with these two speeches, we recommend the following aim for REMA:

The Government should harness markets to signal investors to build a coherent mix of technologies. Markets should be designed to ensure that these technologies are financed cost-effectively and operated efficiently.

This is the best route to achieving the Government's objectives for an electricity system that is secure, affordable and achieves net zero.

Section 3: Next steps

This report does not attempt to provide a blueprint for the future of Great Britain's electricity market. Instead, this report aims to highlight key questions that BEIS will need to answer through REMA.

In future work, Onward plans to publish a full suite of recommendations for REMA. These recommendations will be published in a second report, expected in Q4 2022 or Q1 2023. As we develop these recommendations, Onward is keen to engage with as many stakeholders as possible. Please do get in touch if you would like to discuss.

Annex: Full list of questions, issues, and proposed programmes of reform

Recommended aim of REMA: The Government should harness markets to signal investors to build a coherent mix of technologies. Markets should be designed to ensure that these technologies are financed cost-effectively and operated efficiently.

Five questions for REMA to answer:

1. How can the UK's electricity system be operated affordably and securely with lots of renewables?
2. How should markets fairly reflect the costs and benefits ("system value") of different generators and customers?
3. How can the link between gas prices and electricity bills be broken?
4. What is the role for markets versus Government-run investment-support schemes?
5. What is the role of customers in a net zero electricity system?

These five questions lead to eleven issues:

1. Managing network constraints in a grid with more renewables;
2. Managing the intermittency of wind and solar;
3. Creating markets for new balancing services such as inertia;
4. Using markets to incentivise the optimal mix of technologies;
5. Carbon pricing (both explicit and implicit);
6. Pricing location, including possible reforms to network charges;
7. Marginal pricing in a net zero electricity system;
8. Reducing financing costs;
9. Using deployment-led Innovation to drive down the cost of new technologies;
10. Promoting liquidity in both forward and short-term markets; and
11. Encouraging domestic customers to flex their electricity demand ("demand-side flexibility").

These eleven issues can be grouped into three overlapping programmes of reform:

1. Reform wholesale and balancing markets;
2. Reform investment-support schemes; and
3. Reform regulation of energy suppliers.

There are six other issues that REMA needs to take into account:

1. Gas prices and gas hedging
2. Distributional impacts
3. Design of institutions
4. Industrial strategy
5. Investment in the electricity network
6. The Energy Price Cap

Endnotes

[1] CCC (December 2020), *The Sixth Carbon Budget - The UK's path to Net Zero*. See p.135-138 for electricity demand, and p.285 for oil and gas demand.

[2] For locations of operational and planned offshore wind farms, see BEIS (November 2021); *Offshore Transmission Network Review generation map*.

[3] National Grid ESO (March 2022), *Net Zero Market Reform - Phase 3 Conclusions. Detailed slides*.

[4] BEIS, Prime Minister's Office (April 2022), *British Energy Security Strategy*. See section on "Networks, Storage and Flexibility".

[5] UK Parliament (December 2021), *BEIS Update: Statement by Kwasi Kwarteng, Secretary of State for Business, Energy and Industrial Strategy*.

[6] National Grid ESO (March 2022), *Net Zero Market Reform: Phase 3 Conclusions*, p.24

[7] BEIS, Ofgem (April 2022), *Joint Statement on the Future System Operator*.

[8] BEIS, Ofgem (April 2022), *Energy code reform*.

[9] Financing costs are closely linked to investors' "cost of capital" (effectively the interest rate they pay on their financing arrangements).

[10] In addition, the better design of the CfD contracts means that, during the current crisis, customers are currently being paid back by CfD-supported generators. See the LCCC's historical CfD dashboard.

[11] In 1982, Lawson argued: "'I do not see the government's task as being to try to plan the future shape of energy production and consumption… …Our task is rather to set a framework which will ensure that the market operates in the energy sector with a minimum of distortion and energy is produced and consumed efficiently."

[12] BEIS, Prime Minister's Office (April 2022), *British Energy Security Strategy*

[13] The supply chain argument applies to both nuclear and offshore wind. The electricity networks argument mainly applies to offshore wind.

[14] Dieter Helm (March 2022), *Energy Policy*.

[15] Data from BEIS energy trends.

[16] If supply and demand are not balanced, then the frequency of the grid will rise or fall. If the frequency rises or falls too far, then it could become unstable, causing blackouts.

[17] Data from National Grid ESO monthly BSUoS updates.

[18] CCC (December 2020), *The Sixth Carbon Budget - The UK's path to Net Zero*. Page 134.

[19] In the *British Energy Security Strategy* (April 2022), the Government announced a new 50GW target for offshore wind by 2030, up from 40 GW previously.

[20] National Grid ESO (March 2022), *Net Zero Market Reform: Phase 3 Conclusions*, p.6

[21] Rajiv Gogna, Ed Smith, LCP (April 2022), *British Energy Security Strategy: Homegrown clean power, but at what cost*?

[22] Alex Done, Energy Storage News (September 2020). *What is Dynamic Containment and what does it mean for battery energy storage in the UK?*

[23] Alice Grundy, Current News (January 2020). *National Grid ESO claims world first approach to inertia, awarding £328m in contracts*

[24] National Grid ESO (undated). *NOA Stability Pathfinder - Phase 1 updates*

[25] AEMO (November 2021), *Guide to Ancillary Services in the National Electricity Market*.

[26] Laura Sandys CBE, Thomas Pownall (January 2021), *ReCosting Energy*.

[27] BEIS (Updated February 2022), *Participating in the UK ETS*.

[28] House of Commons Library (January 2018), *Carbon Price Floor (CPF) and the price support mechanism*

[29] The Capacity Market does include an "emissions limit" to determine project eligibility. However, this is a relatively blunt form of implicit carbon pricing. See BEIS (updated July 2021), *Carbon emissions limits in the Capacity Market*.

[30] National Grid ESO (March 2022), *Net Zero Market Reform: Phase 3 Conclusions*, p.6

[31] See National Grid ESO (January 2022), *Network Options Assessment 2021/22*

[32] National Grid ESO (January 2021), *Network Options Assessment 2020/21*, p.7. Cost information is not available in the most recent NOA (2021/22).

[33] See, for example, this tweet from Alan Brown MP, Member of Parliament for Kilmarnock and Loudoun.

[34] Energy Systems Catapult (October 2021), *Introducing nodal pricing to the GB power market...* (p.14)

[35] Ibid, p.15

[36] National Grid ESO (March 2022), *Net Zero Market Reform: Phase 3 conclusions*.

[37] Bidstats (December 2021), Ofgem tender: *Design options for nodal pricing in GB*.

[38] Simon Evans, Carbon Brief (January 2022), *Analysis: Cutting the 'green crap' has added £2.5bn to UK energy bills.*

[39] Ursula Von Der Leyen on Twitter (March 2022), "....to drive prices down and enhance our energy security in the longer-term, we have to look at the root cause of the price spike. Namely high and volatile gas prices and their impact on electricity prices."

[40] Professor Dieter Helm CBE (March 2022), *Energy policy*.

[41] Malcolm Keay, David Robinson, Oxford Institute for Energy Studies (June 2017), *The Decarbonised Electricity System of the Future: The "Two Market" Approach*.

[42] Professor Michael Grubb and Paul Drummond, UCL / Aldersgate Group (February 2018), *UK Industrial Electricity Prices: Competitiveness in a low-carbon world*.

[43] I.e. renewables have high capital costs and low operating costs, whereas conventional power stations have significant operating costs.

[44] Wright, O, The Times (June 2022), *Energy market reform will cut fuel bills*.

[45] Alex Luke, Onward (March 2022), *Renewed Importance: How investing in renewables cuts energy bills*.

[46] Assuming 50 GW offshore wind is installed by 2030, at least 40 GW of this would be supported by the CfD scheme. These offshore wind farms would generate approximately 160 TWh/year (assuming 45% load factor). This is approximately half of current demand (330 TWh/year). In addition, Hinkley Point C (3.2 GW, ~25 TWh/year) is expected to be operating by 2030. Taken together, these would produce approximately 50% of the CCC's forecast for 2030 electricity demand (360 TWh/year).

[47] Liam Deacon, GB News (May 2022), *Wind farms earn hundreds of millions more from energy crisis after delaying Government subsidy contract*.

[48] Emily Gosden, The Times (May 2022), *Wind farms cash in on contract loophole*.

[49] Note: other components of household electricity bills are not shown, including network charges, operating costs, and VAT.

[50] This risk is compounded by policy and political constraints on how high carbon prices can be allowed to go.

[51] KPMG (September 2019), *Blown Away: CfD Round 3 delivers record low price for offshore wind*

[52] "Deployment-led innovation" is also referred to as "learning curves" or "experience curves". These terms describe the phenomenon that many manufactured goods, including renewable energy

[53] In an energy-only market, generators can also make money from both various balancing markets.

[54] Ed Hirs, Yale Insights (March 2021), *Why the Texas power market failed*.

[55] BEIS (November 2021), *CfD Allocation Round 4: Statutory Notices*.

[56] The Government cites concerns about the potential negative impact on the UK's offshore wind supply chains if sufficient offshore wind farms failed to win contracts in subsequent CfD auctions. However, this risk has been substantially reduced by the move to annual CfD auctions, which give more opportunities for projects to secure contracts.

[57] The "forward market" includes contracts such as Month-Ahead, Season-Ahead or Year-Ahead contracts.

[58] N2EX and EPEX

[59] KPMG (September 2019), *Blown Away: CfD Round 3 delivers record low price for offshore wind*

[60] "Deployment-led innovation" is also referred to as "learning curves" or "experience curves". These terms describe the phenomenon that many manufactured goods, including renewable energy

[61] Business.gov.nl (undated), *Sustainable energy transition subsidy scheme (SDE++)*

[62] Eligible technology types: Renewable electricity, renewable heat and CHP, renewable gas, and other CO2 reducing technologies: electric boiler, large-scale heat pump, industrial waste heat, hydrogen through electrolysis and carbon capture and storage (CCS).

[63] Netherlands Enterprise Agency (undated), *Features of the SDE++*

[64] UKPN (September 2021), *Project Shift: Final Report*

[65] BEIS (July 2021), *Energy retail market strategy for the 2020s*.

[66] Ofgem (undated), *What happens if your energy supplier goes bust*.

[67] BEIS (December 2021). Call for Evidence: *Future of the energy retail market*

[68] *See, for example, this evidence submitted by Octopus Energy to the BEIS Select Committee (p.7).*

[69] This could include local pricing in the wholesale market, or expanding the role of local "flexibility markets".

[70] The exception to this is customers who have "Economy 7" meters, which offer customers a cheaper electricity tariff at certain times of day, typically overnight. See EDF (undated), *7 facts about Economy 7 meters, tariff and times*.

[71] For example, see EDF (accessed 16/05/2022), *GoElectric EV tariffs*, and Octopus Energy (accessed 16/05/2022), Octopus Go.

[72] For example, see Octopus Energy (accessed 16/05/2022), *Introducing Agile Octopus*.

[73] For example, see OVO Energy (accessed 16/05/2022), *OVO Drive EV Tariff*, and Octopus Energy (accessed 16/05/2022), *Tesla Energy Plan: FAQ*.

[74] Professor Sir Dieter Helm, BEIS (October 2017), *Cost of energy review*. See Chapter 7.

[75] Sarah Keay-Bright, George Day, Energy Systems Catapult (March 2021), *Rethinking Electricity Markets: EMR 2.0*.

[76] As explained on Slide 21 of National Grid ESO (March 2022), Net Zero Market Reform: Phase 3 conclusions.

[77] BEIS (December 2020), *Energy White Paper: Powering our Net Zero future*. On page 86, the Government committed to consulting on a Strategy and Policy Statement for Ofgem during 2021.

[78] BEIS and Ofgem (April 2022), *Proposals for a Future System Operator role*.

[79] Ofgem (April 2022), *Call for input: Future of local energy institutions and governance*.

[80] BEIS (October 2021), *Scotland and Wales could be home to new floating offshore wind ports…*

[81] BEIS (undated), *Offshore transmission network review*

[82] John Penrose MP (undated), *Energy Price Cap update - Relative or absolute?*

[83] Rt Hon Amber Rudd, DECC (November 2015). *Amber Rudd's speech on a new direction for UK energy policy*.

[84] In 1982, Lawson argued: "'I do not see the government's task as being to try to plan the future shape of energy production and consumption… …Our task is rather to set a framework which will ensure that the market operates in the energy sector with a minimum of distortion and energy is produced and consumed efficiently."

[85] Rt Hon Greg Clark MP, BEIS (November 2018). *After the trilemma - 4 principles for the power sector*.