Department for
Business, Energy
& Industrial Strategy

Review of Electricity Market Arrangements

Consultation Document

Closing date: 10 October 2022

July 2022

Any enquiries regarding this publication should be sent to us at: REMA@beis.gov.uk.

Ministerial foreword

This is a moment of both challenge and opportunity for the GB energy system. Energy prices are high, in large part due the war in Ukraine, and this is pushing up consumer bills and the cost of living. We have announced a huge package of support to protect consumers from the worst impacts of these price rises this winter and we are looking at measures to keep prices down over the coming years. But the only long-term, sustainable solution to high prices is to reduce our reliance on fossil fuel fired generation, and unlock the full potential of our abundant, cheap renewable resources – particularly wind and solar – here in GB. We have the opportunity to design an electricity system which passes the savings of renewable electricity generation onto consumer bills, keeps us on our world-leading decarbonisation trajectory, and ensures our supply of energy is secure and stable.

Our electricity markets will be the backbone of this future electricity system. So it is critical that they are designed right, with renewables (and the wider ecosystem they require) in mind. The last major programme of electricity market reform was 10 years ago, and left some key parts of our market structure unchanged from the time when fossil fuels were the dominant source of energy; it is time to look again at whether they are fit for purpose, or whether reform is needed to deliver a clean, secure and low cost energy system for consumers. That is why we are publishing this consultation today: the first step in the process towards a new set of electricity market arrangements, which will ensure we meet our commitment of fully decarbonising the power system by 2035, subject to security of supply. This will help keep energy bills down for consumers in the long-term, and make the promise of plentiful, affordable green electricity a reality.

The Rt Hon Kwasi Kwarteng MP
Secretary of State for Business, Energy & Industrial Strategy

Contents

General information

Why we are consulting

The government made a commitment in the British Energy Security Strategy to undertake a comprehensive review of electricity market design, to ensure that it is fit for the purpose of maintaining energy security and affordability for consumers as the electricity sector decarbonises. Effective markets will be key to delivering the most efficient energy mix through the transition to a decarbonised economy, and it is critical that those markets are properly set up to deliver affordable, secure, and clean energy. This will become even more important as we move to greater electrification of heat, transport and industry over the coming decade. This consultation explores options to deliver an enduring market framework that works for our businesses, industry, and households.

Consultation details

Issued: 18/07/2022

Respond by: 10/10/2022

Enquiries to:

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Consultation reference: Review of Electricity Market Arrangements

Audiences:

Energy industry, NGOs, consumer groups, academics, policy think tanks

Territorial extent:

REMA will have a direct effect on Scotland and Wales where energy policy within the scope of REMA is reserved to the UK government.

How to respond

Response should be provided online at https://beisgovuk.citizenspace.com/clean-electricity/review-electricity-market-arrangements where possible, or alternatively use the response template and email REMA@beis.gov.uk.

When responding, please state whether you are responding as an individual or representing the views of an organisation. Your response will be most useful if it is framed in direct response to the questions posed, though further comments and evidence are also welcome.

Confidentiality and data protection

Information you provide in response to this consultation, including personal information, may be disclosed in accordance with UK legislation (the Freedom of Information Act 2000, the Data Protection Act 2018 and the Environmental Information Regulations 2004).

If you want the information that you provide to be treated as confidential please tell us, but be aware that we cannot guarantee confidentiality in all circumstances. An automatic confidentiality disclaimer generated by your IT system will not be regarded by us as a confidentiality request.

We will process your personal data in accordance with all applicable data protection laws. See our privacy policy.

We will summarise all responses and publish this summary on GOV.UK. The summary will include a list of names or organisations that responded, but not people's personal names, addresses or other contact details.

Quality assurance

This consultation has been carried out in accordance with the government's consultation principles.

If you have any complaints about the way this consultation has been conducted, please email: beis.bru@beis.gov.uk.

Executive summary

The recent rise in energy prices has unavoidably led to an increase in the cost of living in the UK. In the short term, the government has announced a huge support package to shield consumers from the worst impacts of volatile international energy markets this winter. But the long-term solution to this rise is to reduce reliance on fossil fuel fired generation, and to unlock the benefits – to consumers, businesses, and the climate – of our cheap, abundant renewables in Great Britain. A key part of this will be ensuring that our power markets are fit for purpose over the period to 2035 and beyond, and that is why we have announced a Review of Electricity Market Arrangements (REMA).

Our electricity markets have driven significant decarbonisation since 2010: we have built 37GW[1] of renewables and moved away from coal generation, reducing emissions from our power sector by around 68%[2] whilst maintaining high levels of security of supply. As a result, we have decarbonised faster than any other G7 country. However, meeting our commitment to deliver a fully decarbonised power sector by 2035, subject to security of supply, will require an even faster scale-up of low carbon technologies. This will be an opportunity to drive innovation across the energy sector, create hundreds of thousands of well-paid, highly-skilled jobs, and to reduce our dependency on energy imports by growing our domestic energy supply, helping to lower consumer bills. But alongside these opportunities, the increasing volume of variable renewables, such as wind and solar power, will pose great challenges for managing the electricity system.

So our electricity markets need to be updated to manage these challenges. They will need to unlock unprecedented levels of investment across the full range of low carbon technologies, including low carbon generation, electricity storage, and flexible demand from consumers; maintain security of supply, in an increasingly uncertain geopolitical context; and ensure that we can operate the network safely and cost-effectively as variable renewables come to dominate the capacity mix. In short, this means ensuring that our market arrangements support consumers by facilitating a low cost, low carbon and secure electricity system.

This consultation is our first step in the REMA programme (our timeline is set out below). It sets out our objectives for electricity market design, our case for change, and an initial assessment of options for reform. At this stage we are keeping most options on the table, from the continued evolution of existing schemes to more fundamental change. A key priority for us will be ensuring that existing progress is not undermined, and that investors remain confident in our market arrangements throughout the transition. Whilst this programme runs, all existing schemes will continue, and there will be further consultation on any specific reforms arising from this Review.

[1] BEIS, March 2022, Energy Trends, Renewable electricity capacity and generation, https://www.gov.uk/government/statistics/energy-trends-section-6-renewables

[2] 68% reduction in greenhouse gas emissions in the power sector between 2010 and 2020. BEIS, 2022, Final UK greenhouse gas emissions national statistics: 1990 to 2020, https://www.gov.uk/government/statistics/final-uk-greenhouse-gas-emissions-national-statistics-1990-to-2020

Chapter one sets out the context for this work, our vision for our future electricity market arrangements and the outcomes they will deliver, and our policy objectives: security of supply, cost-effectiveness and decarbonisation.

This Review will focus on the enduring market arrangements needed to deliver a fully decarbonised and cost-effective electricity system by 2035, subject to security of supply. It focuses on options for reform for all (non-retail) electricity markets: the wholesale market, balancing mechanism and ancillary services; as well as policies that impact these - including the evolution of and alternatives to the Contracts for Difference scheme and the Capacity Market.

We will do this in a way that ensures continued investor confidence in our energy system and assets. Any changes to the core mechanisms that drive investment - the CfD and Capacity Market - will be considered carefully with this in mind and whilst this programme runs, all existing schemes will continue. Any reforms would be subject to further consultation.

All technologies are within scope to the extent that they currently do, or potentially could, participate in electricity markets. The Review will consider how best to support the deployment of mature technologies, including electricity demand reduction; it will not look at the support mechanisms needed by immature, ‘first of a kind’ technologies (e.g. power generation with Carbon Capture, Usage and Storage (power CCUS)), except where they can be supported through existing schemes such as Contracts for Difference (e.g. floating offshore wind). However, the Review will consider the role of these technologies in the electricity system and how, once mature enough, they might transition to compete on more of a cross-technology basis. Similarly, the Review will not consider the support mechanisms for investment in large-scale nuclear, but will consider how these plants participate in electricity markets.

The REMA programme will take place alongside a refresh of our energy retail strategy. Our retail market programme will be considering a set of issues that are separate to those covered by REMA, including consumer protection, retail market sustainability and financial resilience, as well as new business models and services that could support net zero. However, we recognise that there are clear interdependencies between the two programmes, and that the retail market should be a key enabler of the reforms that we will be exploring in REMA. Therefore, we are looking at wholesale markets (under REMA) and retail market reform in separate but parallel programmes that work side-by-side. Both programmes are essential for delivering the right outcomes for consumers. We will carefully consider the impact of REMA options on consumers and suppliers, whilst the retail strategy will consider how the retail market can support decarbonisation of the electricity system whilst continuing to protect consumers as we transition to a net zero system.

Likewise, we recognise that the electricity market is one part of a wider electricity (and energy) system, and that key aspects of this wider system are changing at the same time as we are looking to reform our market arrangements. Taking a whole-system approach means ensuring that our policies and activities are coherent across the board. So whilst the wider policies and enablers required to achieve a fully decarbonised electricity system, such as digitalisation, planning, network regulation and system governance – as well as other non-electricity markets, such as those for carbon, gas and hydrogen, are out of scope of this programme, they will be considered throughout the Review to ensure our electricity and energy systems work effectively together, with incentives aligned to deliver our overall objectives.

Chapter two sets out our analysis of the challenges the future electricity system will need to meet, and makes the following conclusions:

- it is unlikely that the significant investment needed to decarbonise the power sector will be delivered cost-effectively by our market arrangements in their current form. In particular, they are unlikely to bring forward low carbon flexibility at the pace required;
- ensuring a reliable supply of electricity to meet rising demand will require new and more innovative approaches, as variable renewables make up a larger proportion of the generation mix; and
- the most cost-effective route to a net zero power sector by 2035 will require changes to markets to optimise both investment and dispatch (where and when to produce and use electricity) as current market arrangements are based on the needs of fossil fuel generation rather than renewables.

This means that there is a case for changing our current electricity market arrangements, and that we should consider the full range of possible options for reform: from incremental modifications to existing schemes to more transformational changes to the structure of our markets.

Chapter three sets out our approach. Our work will proceed in three stages:

- Setting out a clear statement of the case for reform (this consultation)
- Developing and determining what reforms are needed through extensive engagement with energy sector (2022-23)
- Establishing a full delivery plan and overseeing implementation (from the mid-2020s) in time to meet our 2035 commitment

A broad range of options are being considered, from medium-term changes to existing arrangements that can be delivered from the mid-2020s, to longer-term transformational reforms, as well as low regret ‘quick wins’ which could be pursued on accelerated timelines and implemented regardless of the end package of reform.

Our discussion of options for reforms to electricity markets is organised around core outcomes that our future power system will need to deliver: a net zero wholesale market; mass low-carbon power; flexibility; capacity adequacy; and operability. We will assess options against the following five criteria: least cost, deliverability, investor confidence, whole-system flexibility, and adaptability, and packages of reform against our overall policy objectives, as well as wider considerations including statutory obligations, coherence and comprehensiveness.

A key part of the REMA programme will be considering how individual policy options relate to each other, to ensure that any overall package of reforms is coherent, consistent, and comprehensive. However, we are not proposing to group individual options into coherent policy packages in this consultation, because we want to engage with stakeholders before moving further along in the process, although we recognise that the choices we make in one area will impact what is feasible and desirable in others. We are also open to stakeholder suggestions of options we have not yet considered.

The remaining chapters set out our emerging conclusions from our initial assessment of policy options for reform to electricity markets. We are considering a wide range of options at this stage, with the view to narrowing the field through consultation with industry and determining what reform is needed in 2023.

Chapter four discusses some cross-cutting questions about our overall approach to market reform, including the role of the market, the extent of competition between technologies, the extent of centralisation, the role of marginal pricing, how to send more accurate price signals to consumers, the scale of change that is needed, possible approaches to introducing or enhancing locational signals, and approaches to supporting demand reduction.

Chapter five considers options for delivering a net zero wholesale market. We set out a wide range of approaches to wholesale market design, some of which are relatively theoretical, including splitting the market, introducing locational pricing, establishing distribution-level markets, and changing the parameters of the status quo.

Chapter six considers options for delivering mass low carbon power. The majority of our options involve long-term contracts with the government, as this seems likely to be the best way of delivering the volumes of investment we require at least cost. These include a revenue cap and floor and a range of variants on the CfD scheme (including retaining the status quo). It also considers the decentralised alternative of an obligation on suppliers to procure low carbon power. All options under consideration, except the existing CfD, would increase the role of the market, whether through greater exposure of those contracts to prices, or in the allocation of those contracts, in order to minimise costs which are passed to consumers.

Chapter seven considers options for delivering flexibility. Much of the incentive for flexibility should come through more accurate market signals, delivered through options set out in the wholesale market chapter. Such market signals could deliver much of the flexibility needed for our 2035 commitment, but challenges around investor certainty, for example, may mean a mechanism to de-risk investment on an enduring basis could also be required. Options under consideration include a (reformed) Capacity Market, a multi-technology revenue cap and floor, and a supplier obligation, including a 'Clean Peak Standard'.

Chapter eight considers options for delivering capacity adequacy. Our core options under consideration take a centralised approach to procuring capacity adequacy. These include reforming the Capacity Market to better support firm low carbon technologies, a centralised reliability option scheme, and a strategic reserve. We are not minded to pursue decentralised approaches to ensuring capacity adequacy, because it is a system outcome that the government will always value more highly than any individual market participant.

Chapter nine considers options for delivering operability. We consider whether small modifications to current practices would be sufficient; or if a more substantial change, like giving Distribution Network Operators and local markets a greater role, co-optimising frequency and reserve under a central dispatch model, or making changes to the design of the Contracts for Difference or Capacity Market, are necessary.

Finally, **chapter ten** considers two options which cover multiple market elements: “Equivalent Firm Power” and “auctions by cost of carbon abatement”.

We welcome the work already done by stakeholders – including Ofgem, the Electricity System Operator, academia, think tanks, Non-Governmental Organisations, and industry – to develop options and suggest frameworks for the next phase of our electricity market arrangements. This is an important and multifaceted area. Our reforms need to work for all consumers and businesses, and there are significant interlinkages and dependencies across all technologies, markets and regulations. Therefore, we will engage extensively and transparently across the sector (and beyond – to see how other sectors have implemented comparable reform programmes). We will publish a consultation response in the winter and continue to engage extensively with stakeholders throughout the REMA programme.

Chapter 1. Context, vision, and objectives for electricity market design

Context

A record rise in global energy prices has led to an unavoidable increase in the cost of living in the UK. As the government set out in our recent British Energy Security Strategy, the long-term solution is to address our underlying vulnerability to international oil and gas markets by reducing our dependence on imported fossil fuels. Electricity will be crucial to our success in this, and the UK has the pedigree to deliver: we have led the world in decarbonising power and will continue to see a significant ramp-up in low carbon electricity as we drive towards a decarbonised grid by 2035. As we do so, the government is committed to reducing energy bills and help temper the full impact of high global gas prices currently being experienced by consumers.

The government has announced a huge support package to shield consumers from the worst impacts of volatile international energy markets this winter; but these must be a bridge to a sustainable solution which sees consumers benefit from our abundant, cheap renewables. REMA will deliver this solution, establishing an enduring regime which overcomes the structural issues in our current and future markets, and ensures that households, businesses and industry – as well as the climate – reap the full rewards of the energy transition. While this fundamental reform work is taken forward at pace, the government will also urgently assess whether there are immediate changes could help limit the impact of high prices in the shorter term.

Decarbonising the power system will be essential for meeting ambitious GB carbon targets. We have made great progress to date, reducing greenhouse gas emissions by over 70% since 1990;[3] but this means that we still have almost a third left to decarbonise, and it is likely to be the trickiest so far, because we cannot achieve it cost-effectively through the deployment of renewables alone. We are also driving the electrification of heat and transport, for example through phasing out the sale of petrol and diesel cars and vans by 2030, and our ambition for the deployment of 600,000 heat pumps per year by 2028. This will enable us to use renewable electricity generated in Great Britain to power our buildings and vehicles, reducing dependence on expensive imported fossil fuels, and keeping consumer bills low. Meeting this new demand for power will be challenging: electricity demand may rise threefold by 2050.[4]

One of the most important aspects of power sector security and decarbonisation is electricity market design. Our success over the last ten years has been driven in large part by the changes introduced as part of Electricity Market Reform (EMR) in 2013. At the time, our central objective was to reduce the risk – and so the cost – of investing in renewables, delivering the

[3] BEIS, 2022, Final UK greenhouse gas emissions national statistics: 1990 to 2020, https://www.gov.uk/government/statistics/final-uk-greenhouse-gas-emissions-national-statistics-1990-to-2020
[4] Peak demand, 2020 to 2050, BEIS Higher Demand scenario.

investment we needed to replace fossil fuels, whilst ensuring that the fossil fuel generation which remained critical to security of supply would continue to be an investable proposition. On these metrics, EMR has been a success. The Contracts for Difference (CfD) scheme and its predecessors have delivered 27GW of new low carbon electricity capacity since 2014 (compared to a total UK installed generating capacity of around 75 GW),[5] and figures from the industry estimate that the current potential renewables pipeline could be up to 160GW.[6] The CfD scheme has contributed to the price per unit of offshore wind falling by around 70% between the first allocation round in 2015 and the fourth in 2022[7] The Capacity Market has supported investment in just under 15GW of new, flexible capacity to replace older, less efficient plants, ensuring security of electricity supply.

The other two planks of EMR – Carbon Price Support (CPS) and the Emissions Performance Standard (EPS) – alongside Emissions Trading, have also played a key role in decarbonising the electricity sector, particularly in driving coal off the system. A robust carbon price provides a market signal to decarbonise cost-effectively and in a technology-neutral way, by ensuring carbon emitting plants directly internalise the cost of carbon emissions.

But the challenges of this next phase of the transition, as well as the opportunities, will be different. The CfD and Capacity Market were introduced as additions to the set of wholesale market arrangements introduced by the New Electricity Trading Arrangements (NETA) (2001) and British Electricity Trading and Transmission Arrangements (BETTA) (2005) reforms. These underlying wholesale market arrangements had largely been designed for a fossil fuel-based electricity system. We now need a set of market arrangements – both the underlying structure and the policies which fit into that structure – which can deliver a cost-effective transition to the future larger, cleaner and more decentralised electricity system.[8] we will need, as well as ensuring a smooth transition away from our remaining fossil fuel generation capacity.

That is why we launched this Review in the British Energy Security Strategy. We need to look again at whether our market arrangements are well-positioned to help us unlock the full potential of low carbon technologies for consumers: to take us all the way to net zero, reduce our reliance on fossil fuels, and maintain security of supply in an uncertain geopolitical context. In doing so, the REMA programme will support delivery of the government's key policies and priorities for the power sector set out in the British Energy Security Strategy, which will support up to 150,000 jobs around the country by 2030. The programme will also help enable wider delivery of the total public and private investment of £280-400 billion needed in generation capacity and flexible assets to fully decarbonise the power system[9].

[5] Total UK installed capacity was around 75GW in 2020. BEIS, 2021, Digest of UK Energy Statistics: electricity, https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes
[6] Renewable UK, 22 March 2022 'Offshore wind pipeline surges to 86 gigawatts, boosting UK's energy independence'; Renewable UK, 22 October 2021, 'UK's total pipeline on onshore wind projects rises to 33 gigawatts'; Solar Energy UK, March 2022, 'Everything Under the Sun: The Facts About Solar Energy.'
[7] BEIS, 2022, AR4 Press Release, https://www.gov.uk/government/news/biggest-renewables-auction-accelerates-move-away-from-fossil-fuels
[8] New Electricity Trading Arrangements and British Electricity Trading and Transmission Arrangements.
[9] BEIS, Net Zero Strategy: Build Back Greener (p. 99), 2021, https://www.gov.uk/government/publications/net-zero-strategy

Vision for our future market arrangements

Our future market arrangements will:

- *Deliver a step change in the rate of deployment of low carbon technologies, and reduces our dependence on fossil fuelled generation*
- *Provide the right signals for flexibility across the system*
- *Facilitate consumers to take greater control of their electricity use by rewarding them through improved price signals, whilst ensuring fair outcomes*
- *Optimise assets operating at local, regional, and national levels*
- *Ensure that the security of the system can be maintained at all times*

Markets are a critical part of delivering our future electricity system. In this section we set out our vision for our future market arrangements, and the contribution they will make to delivering the overall outcomes we are aiming for.

Our future market arrangements will deliver a step change in the rate of deployment of low carbon technologies (both on the supply and demand side); continue decarbonising whilst meeting the rapidly growing demand for electricity; and reduce our reliance of fossil fuelled generation. The majority of this decarbonisation will come from the deployment of renewables. In the British Energy Security Strategy we set out our ambition for up to 50GW of offshore wind, including up to 5GW of floating offshore by 2030, and the expectation of a five-fold increase in the deployment of solar by 2035, as well as up to 24GW of nuclear by 2050. Our future market arrangements will enable this unprecedented level of investment, building on the excellent progress already made. Renewables are usually cheaper than fossil fuels: once the infrastructure is built, power from the sun and wind costs (almost) nothing. They are also domestic energy sources, helping us reduce energy imports and reliance on fossil fuel fired generation.

Our future market arrangements will provide the right signals for flexibility across the system, so that the system can cope with the variability of intermittent renewables, maximising their value. Flexibility technologies (for example electricity storage, flexible demand, hydrogen to power, hydrogen electrolysis, and power Carbon Capture, Usage, and Storage (CCUS), as well as technologies which are not yet established as market participants) will make up shortfalls when it is not windy/sunny, store excess electricity when renewable output is higher than demand, and provide services to the system to maintain operability. Flexibility will also reduce peaks in demand and generation, so that less network infrastructure and new generation is needed. Our market arrangements will need to ensure this flexibility is investable at all scales, built in the right place, and operated at the right time.

Our future market arrangements will also facilitate consumers to take greater control of their electricity use, by rewarding consumers whose behaviour benefits the electricity system. This will lead to lower bills for all consumers and reduced carbon emissions. As the smart meter rollout is completed, and more households and businesses have smart heat pumps, energy storage and electric vehicles, there will be a new generation of consumers – supported by innovative suppliers and third-party intermediaries – with the potential to take greater control of their energy use (increasingly via automation). Smart technologies will enable consumers to change consumption patterns to match supply. This will reduce system costs, by reducing the amount of network and generation needed to meet peak demand – benefiting all consumers. Our electricity markets will reward consumers who choose to reduce and shift their demand in this way. At the same time, our market arrangements will need to ensure fair outcomes for consumers. Consumers will not be unfairly exposed to price signals that they cannot respond to, will retain choice over how they engage with the energy system, and remain protected as the system evolves. Most importantly, they will have a reliable and affordable electricity supply so that they can go about their daily lives.

Assets operating at local, regional and national levels will be optimised. We are moving from a world with a small number of large generators, connected to the transmission network and providing most of our electricity needs, to one where millions of energy assets, often connected to the distribution network (e.g. solar PV, smart-charged electric vehicles, smart heating systems), make a major contribution to system balancing. This will bring substantial benefits, including cost savings; but it will also make our electricity system much more complex. Electricity markets will need to adapt to this complexity, utilising system-wide digitalisation to send the right price signals to co-ordinate investment and operational decisions for these assets across national and local electricity grids, whilst minimising network constraints, in the most effective way. More widely, we also need to see significant investment in new network capacity to transport all this low carbon electricity from generators to consumers: much of our renewable potential is far from our towns and cities.

Our market arrangements will provide consumers with a secure and reliable electricity supply by ensuring that the security of the system can be maintained at all times, as it becomes increasingly dominated by variable renewables and the demand for electricity changes and grows. The system will need to cope with both sudden changes in output, and sustained periods of low output, with markets bringing forward investment in the range of low carbon, flexible technologies that can provide both back-up power and wider system services on demand.

Electricity market arrangements cannot deliver this vision on their own. All elements of electricity and energy policy, including our refresh of our retail market strategy, will need to work together to achieve these outcomes. More broadly, we will need to make use of all the levers available to us across government, including fiscal policy, regulation and standards, public engagement, skills and training, in order to achieve net zero. Nevertheless, having well-designed electricity markets is a critical enabler of the decarbonisation of power, heat, transport and industry, particularly as a primary driver of the scale of investment we need, and will be crucial to achieving our 2035 and 2050 commitments.

This consultation is intended as the first step to ensuring that our electricity market design is fit for purpose, building the platform from which we can decarbonise the power sector and the energy system as a whole.

Question:

1. **Do you agree with the vision for the electricity system we have presented?**

REMA Objectives

Our future market arrangements will:

- *Deliver a step change in the rate of deployment of low carbon technologies, and reduces our dependence on fossil fuelled generation*
- *Provide the right signals for flexibility across the system*
- *Facilitate consumers to take greater control of their electricity use by rewarding them through improved price signals, whilst ensuring fair outcomes*
- *Optimise assets operating at local, regional, and national levels*
- *Ensure that the security of the system can be maintained at all times*

Our core objective for the REMA programme is to reform our electricity market arrangements so that they facilitate the full decarbonisation of the electricity system by 2035, subject to security of supply, and are cost effective for consumers. These objectives for electricity market reform can only be delivered jointly with Ofgem, the system operator and the energy sector.

Decarbonisation: The power sector meets its sector contribution for carbon budgets and net zero targets and facilitates economy-wide decarbonisation. This means full decarbonisation by 2035 with all our electricity coming from low carbon sources (subject to security of supply).

To achieve this in GB, in the context of significantly increased demand (due to the electrification of heat and transport), our market arrangements will need to deliver the required pace and scale of investment in the full range of low carbon technologies we need: generation and flexibility, on the supply and demand side, and at both the transmission and distribution level. They need to provide consumers with the right tools – particularly price signals – so that they can engage more effectively with the decarbonisation agenda. They will also need to facilitate zero carbon operation of the system. This will ensure that high carbon capacity is called upon only when essential to maintaining security of supply.

Decarbonising the power sector by 2035 is a critical step on the path to our 2050 economy-wide net zero target; and while our focus in this Review is on meeting our 2035 commitment, we will do so whilst ensuring our market arrangements put us on the right trajectory towards our net zero future.

Security of supply: Reliable supply and system resilience are maintained throughout the transition to a fully decarbonised power sector by 2035, by ensuring capacity adequacy and operability. The system adapts to evolving physical and digital challenges and effectively manages short-term and seasonal variations. This will ensure a secure and reliable electricity supply for consumers.

To achieve this in GB, our market arrangements will need to ensure that there are sufficient firm, flexible assets on the system to meet peak demand, particularly at times of low renewable output, and that low carbon generators, including renewables, are incentivised to set up so that they can provide operability services as well as energy output. We will also need to ensure that our market arrangements work to reduce our dependence on fossil fuelled generation and our exposure to volatile global gas markets, maximise our use of domestic energy sources, and promote diversity of supply and system resilience.

Cost-effectiveness: The pathway to a fully decarbonised power sector by 2035 must be cost-effective, providing value-for money for consumers and taxpayers by maximising benefits and minimising risks.

To achieve this in GB, our market arrangements will need to ensure that competition leads to investment in a least cost capacity mix that will get us to 2035. Due to the cost structure of renewables, capital costs will become an increasingly large proportion of total system costs, so our market arrangement will need to balance both financing costs and wider system costs. Our market arrangements will also need to ensure that the cost of operating the system is minimised (meaning the full value of all assets across the transmission and distribution networks is harnessed). A key part of this will be ensuring that our arrangements send appropriate temporal and locational signals, both in terms of where to invest and which assets to dispatch, and that prices are sufficiently granular to drive efficient and flexible behaviour. This should result in lower consumer bills, but it will also be important that consumers are not unfairly exposed to costs that they cannot control.

Question:

2. **Do you agree with our objectives for electricity market reform (decarbonisation, security of supply, and cost-effectiveness)?**

REMA Scope

This Review will consider all options for reform to all non-retail electricity markets, understood as the structures that facilitate the balancing of supply and demand of electricity, as well as policies that can provide signals for the investment in, and operation of, assets that generate or use electricity. The principles below define which markets, mechanisms, and technologies are in scope.

In Scope

All electricity-related (non-retail) markets are within scope of REMA

This includes the wholesale market, the balancing mechanism, and the provision of operability services (including developing markets); and policies that impact these, including the CfD scheme and the Capacity Market. This Review will consider changes from the mid-2020s onwards. Ongoing design changes being made to the CfD and Capacity Market schemes, considered in recent Calls for Evidence, are out of scope, though will be taken into account throughout this Review. Whilst this programme runs, all existing schemes will continue. Network charging will be explored as a means of creating locational price signals. Any proposals on locational signals will need to be assessed alongside ongoing and future network charging and access reforms, for which Ofgem is responsible, ensuring it is coherent with wholesale market design.

All technologies are within scope to the extent that they currently do, or potentially could, participate in electricity markets

These technologies are renewables, biomass (incl. power bioenergy with carbon capture and storage (BECCS), energy from waste, small modular reactors, large-scale nuclear, short- and long- duration electricity storage, flexible demand, Demand Side Response (DSR), electricity demand reduction, power CCUS, hydrogen-to-power, interconnectors, electrolysis, and unabated gas generation.

REMA will seek to establish the market arrangements needed for 2035, as a critical step towards net zero, rather than be an interim step with a further major programme of reform to follow.

This Review will focus on the enduring market arrangements needed to deliver a fully decarbonised electricity system by 2035 subject to security of supply, considering how best to support the deployment of mature technologies, or innovations that build on proven technologies and are eligible for existing support schemes, such as floating offshore wind. This Review will not look at the appropriate support mechanisms needed to support development of 'first of a kind' technologies (see below), however it will consider their role in the electricity system and how these technologies, once mature enough, might transition to compete on a cross-technology basis.

Out of scope

The scope of this Review does not include:

- Investment mechanisms for large-scale nuclear, due to the unique cost profile of these projects (but we will consider how these plants participate in electricity markets).
- Policy on Greenhouse Gas Removals. Therefore, given BECCS will play a dual role delivering both negative emissions and firm, zero carbon power, it is only within scope of REMA with respect to its participation within electricity markets.
- The delivery of projects, infrastructure, and bespoke support mechanisms to bring forward certain key 'first-of-a-kind' technologies, due to the need to consider the requirements of each technology or project individually. This includes the business model for low carbon hydrogen production, the Dispatchable Power Agreement for

power CCUS, multi-purpose interconnectors and potential support for large-scale, long-duration electricity storage, small modular reactors and power BECCS.

- The existing cap and floor for interconnectors. Ofgem recently concluded a review of their regulatory and policy approach to new electricity interconnectors and will implement its recommendations. Though – as for other technologies – the way that interconnectors participate in markets is within scope.
- The existing suite of policy levers for incentivising demand reduction, including subsidy schemes, building regulations, fiscal policy and product standards. Whilst electricity demand reduction is in scope, this is only to the extent that it is incentivised through electricity market arrangements.

There are a host of other existing and future markets (retail, carbon, gas, heat and hydrogen) that will exist alongside the electricity markets that are the focus of this Review. Policies in those markets will have an impact on electricity markets, and vice versa. These markets and policies are out of scope; however, the coherence of electricity market options with these related markets will be a central consideration in our assessment.

Our reforms to wholesale and retail markets are two parallel programmes that work side-by-side – see Box 1 on the relationship between this programme and our work to refresh our retail markets strategy.

BOX 1: The interactions between reforms to electricity and retail markets

There are strong linkages between the electricity markets that are the subject of REMA, and retail energy markets, most obviously in that energy suppliers need to purchase electricity in electricity markets to be able to provide it to end-consumers.

We will therefore need to consider the interactions and overlaps between the electricity and retail markets in detail. Electricity markets will need to incentivise the participation of consumers, for example rewarding them for shifting demand away from costlier and more carbon intensive peak periods, whilst not unfairly exposing consumers to costs they cannot respond to. Electricity markets have an impact on the way generators trade and therefore the products they sell to retailers. Some of the more radical options considered by this Review may also involve a greater role for retailers through, for example, obligations on suppliers to reduce the emissions of electricity sold to their consumers. Other options might change the risks faced by retailers – for example, more granular pricing in the wholesale markets might affect hedging requirements for retailers.

Similarly, the way consumers are protected and suppliers regulated in retail markets could significantly impact decisions on electricity market design. If a retail price cap is extended to overlap with implementation of REMA policy options, we will need to consider any interactions. Policies such as half-hourly settlement pave the way for more granular wholesale market prices and, consumers should be able to exercise choice in their level of engagement with the markets being developed in this Review.

We therefore plan to consider potential reforms to electricity markets, and our overall strategy for retail energy markets, in two separate but interlinked programmes that work side-by-side.

The focus of this Review is on the markets which send price signals for the investment in and operation of electricity assets. One of our key objectives is to bring down energy system costs for consumers and taxpayers. Our refresh of our retail markets strategy, working alongside this Review, will look at how these low costs are passed onto consumers, and on how new supplier business models can support cost-effective decarbonisation. As well as this it will be focusing on consumer protection, competition, and retail market sustainability and resilience.

Wider policy considerations

In addition, there are a wide range of policy areas which are beyond the scope of REMA, but which will be critical enablers of our reforms. We recognise that we will only achieve our 2035 and 2050 commitments if we adopt a genuinely whole-system approach across the electricity and wider energy system; that various aspects of these systems are changing simultaneously; and that a key consideration for stakeholders will be whether the overall policy landscape continues to function as a coherent whole. So we will ensure that we are adopting a coherent approach across the board, working closely with the relevant programmes and adapting our work as necessary.

First, we will need to design our reforms mindful of the way in which consumers contribute, through their energy bills, to policies which drive investment in the energy system. This investment funds infrastructure such as new generation technologies (for example through the CfD or Renewables Obligation schemes), alongside funding vital energy efficiency and fuel poverty schemes (for example the Energy Company Obligation), which benefit low income and vulnerable households.

The way that these costs are passed through to bills can incentivise or disincentivise consumer behaviour in a way that affects our energy security and net zero goals, including the electrification of industrial or domestic heating, and the provision of flexibility to the system. The government has committed to publishing proposals on “rebalancing” the costs placed on energy bills away from electricity in 2022, to incentivise electrification across the economy and accelerate consumers’ and industry’s shift away from volatile global commodity markets. In doing so, we will consider impacts on the electricity system and limiting the impact on bills, particularly for low-income consumers.

Likewise, emissions from power generation are currently captured under the UK Emissions Trading System (UK ETS), as well as the Carbon Price Support (CPS) which works alongside it. While carbon pricing affects investment and operational decisions across the market (by raising the operating cost of fossil fuel plants, making less competitive and sending a long-term market signal to decarbonise), we are not directly considering changes to carbon pricing policy as part of this Review. This is due to the UK ETS extending to a broad range of sectors beyond the power sector, all with varying degrees of abatement potential. Moreover, a consultation setting out proposals to set the UK ETS’s net zero 2050 consistent trajectory was published on 25 March 2022.[10] Within the power sector, additional policy levers alongside the UK ETS will be needed to help deliver the UK’s separate, accelerated 2035 commitment for decarbonisation, and provide the long-term revenue certainty that low carbon assets require to cover upfront costs (see case for change).

There are also wider policies, beyond our market arrangements, which will play a key role in meeting our 2035 commitment. Network regulation, system governance (e.g. role of system operators) and wider market enablers (i.e. metering, digitalisation, planning, licencing and product standards) are all key pieces of the 2035 puzzle, and ensuring they are all working in concert will be critical to our overall success.

Finally, we are not directly reviewing our international agreements. However, in considering options for reform of GB electricity market design, we will need to take into account our international agreements and obligations for energy trading and co-operation, and consider the role and interactions of interconnection, both now and in the future.

[10] BEIS, 2022, Developing the UK Emissions Trading Scheme, https://www.gov.uk/government/consultations/developing-the-uk-emissions-trading-scheme-uk-ets

Chapter 2. The case for change

Introduction

This chapter sets out our assessment of the case for change. We have assessed a wide range of evidence, including conducting an external literature review and quantitative system modelling. We have also drawn from responses to our recent calls for evidence on the CfD,[11] the Capacity Market[12] and large-scale long duration electricity storage,[13] to reflect the views of industry, academia, and civil society. From the external evidence we considered there was a broad consensus that there is a case for change, with which we agree; but there were a variety of views on the form and magnitude of change needed. This chapter provides our structured approach to identifying the challenges with the current market arrangement that reforms will need to address.

Current Electricity Market Arrangements

NETA came into force in March 2001, covering England and Wales. On 1 April 2005, changes to harmonise electricity trading across GB (i.e. England, Wales and Scotland) came into effect with the introduction of a single set of wholesale electricity trading and transmission arrangements known as BETTA. BETTA is based on bilateral trading between generators, suppliers, customers and traders, and participants self-dispatch rather than being dispatched centrally by the Electricity System Operator (ESO). There is a balancing mechanism to incentivise supply matching demand, with the ESO performing the role of residual balancer and manager of system stability. Northern Ireland is separate from these trading arrangements, it being part of the island of Ireland's Single Electricity Market (SEM).

As climate change has become more clearly understood and a central priority for the government, incentives and regulations that are designed to drive the delivery of renewables and decarbonisation have been added to the policy framework. EMR was introduced in 2013 and consisted of four parts:

Contracts for Difference (CfDs): A 15-year private law contract between low-carbon electricity generators and the Low Carbon Contracts Company, a government-owned company that is operationally independent and manages CfDs at arm's length from government. Contracts are awarded in a series of competitive auctions; the lowest price bids are successful, which drives efficiency and cost reduction and is a low-cost way to secure clean electricity.

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[11] BEIS, 2020, Enabling a high renewable, net zero electricity system: call for evidence https://www.gov.uk/government/consultations/enabling-a-high-renewable-net-zero-electricity-system-call-for-evidence

[12] BEIS, 2021, Capacity Market 2021: call for evidence on early action to align with net zero https://www.gov.uk/government/consultations/capacity-market-2021-call-for-evidence-on-early-action-to-align-with-net-zero

[13] BEIS, 2021, Facilitating the deployment of large-scale and long-duration electricity storage: call for evidence https://www.gov.uk/government/consultations/facilitating-the-deployment-of-large-scale-and-long-duration-electricity-storage-call-for-evidence

Generators receive revenue from selling their electricity into the wholesale market. However, when the market reference price is below the strike price, generators receive a top-up payment for the additional amount. Conversely, if the reference price is above the strike price, the generator must pay back the difference.

Capacity Market: A payment to any generator (or storage / DSR provider) who can respond when notified upon by the System Operator in times of system stress. Auctions for this capacity take place at both four years and one year ahead of delivery, and agreements generally last for one year for existing plant (fifteen and three-year agreements are available for new build and refurbishing units respectively). The procured capacity is the amount required to meet peak demand.

Carbon price support: Electricity generated from fossil fuels is taxed for carbon dioxide (CO_2) emissions. It was first designed to raise the EU emissions trading scheme carbon price to a Carbon Price Floor. Instead, the CPS is now set at £18/tCO_2. This price is currently set until Financial Year 2023-24. The UK ETS replaced the UK's participation in the EU ETS on 1 January 2021.

Emissions performance standard (EPS): Limits CO_2 emissions from any new power station to 450g/kWh. The EPS prevents new coal fired generation from being built without carbon capture and storage technology.

What the current market has delivered

Since EMR was introduced, our market arrangements have performed well. They have successfully delivered the first phase of power sector decarbonisation:

- Power sector emissions have fallen by around 68% between 2010 and 2020.[14]
- Since 2014, the CFD scheme and its predecessor investment contracts have awarded contracts totalling around 27GW of new low-carbon electricity capacity. The CfD scheme has helped to dramatically reduced costs by providing investors with stability. The clearing prices for offshore wind have fallen by around 70%[15] since the first allocation round, creating savings for consumers.
- The proportion of coal in the generation mix has fallen from 26% in 2010 to 7% in 2020.[16]
- The Capacity Market has helped to maintain security of supply during this period at least-cost to consumers. The Electricity System Operator's assessment shows winter margins have stayed well within the legislated reliability standard since the Capacity

[14] BEIS, 2022, Final UK greenhouse gas emissions national statistics: 1990 to 2020, https://www.gov.uk/government/statistics/final-uk-greenhouse-gas-emissions-national-statistics-1990-to-2020
[15] BEIS, 2021, AR4 Press Release, https://www.gov.uk/government/news/biggest-renewables-auction-accelerates-move-away-from-fossil-fuels
[16] Including Northern Ireland. BEIS, 2021, Plant capacity: United Kingdom (DUKES 5.7), https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes

Market's introduction. To date, Capacity Market auctions have secured over 10GW of new capacity from a range of technologies, at low clearing prices.[17]

However, the current wholesale market is based on marginal pricing, which means the most expensive generator that is needed to meet demand sets the price for all technologies. While marginal pricing provides a strong signal for the value of electricity at all times, it has limited our ability to reduce our reliance on fossil fuel fired generation.

Future Challenges

There is broad consensus on how to decarbonise the power sector, and it can be done with technologies that are known today. Low carbon electricity generation will need to increase to meet demand from electrified transport and heating. Renewables will make up the majority of generation, alongside nuclear, with low carbon flexibility providing resilience in periods of low renewable output. Not acting today will result in higher costs in the future, as the challenge of meeting net zero will become steeper.

Our market arrangements will continue to play an important role in delivering an affordable, secure, and reliable system. While existing markets have successfully delivered the first phase of the transition, the challenges of the next stage – rapid movement towards full decarbonisation – will be different. To assess whether our existing arrangements will remain fit-for-purpose, we first need to characterise the new challenges they will need to meet.

To help identify these challenges, we conducted scenario analysis that explored the characteristics of the future system. We conducted this analysis in collaboration with Ofgem and National Grid ESO, using both BEIS scenarios and National Grid ESO's Future Energy Scenarios. Further information on the analytical approach is available in the Annex. The scenarios used in this analysis are examples of many different possible pathways for the electricity system and should be treated as illustrative. The scenarios are indicative of what a future electricity system may look like, rather than being prescriptive forecasts: they are not preferred outcomes or expressions of government policy. Optimal pathways will continually be developed in light of developments in technology and wider market developments.

There is a high degree of uncertainty about the development of the electricity system, including the pace of innovation, demand levels, the technical feasibility of some technologies, and investment in supporting infrastructure. This is particularly true for modelling over such a long period: the further into the future we forecast, the greater the uncertainty. Given this uncertainty, the results of the analysis should be viewed as indicators for the scale and direction of the future challenges that the modelling identifies, rather than as precise projections.

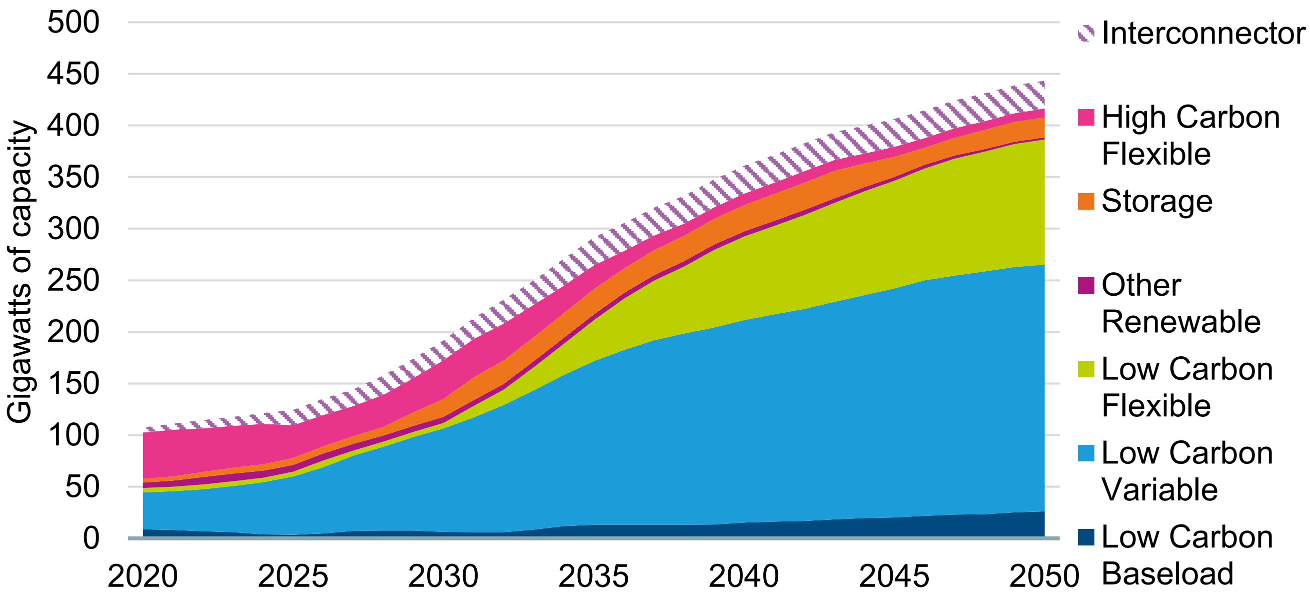
Our analysis identifies five key challenges that were consistent across the illustrative scenarios we assessed. These are:

[17] BEIS, 2019, Capacity Market: 5-year Review (2014 to 2019), https://www.gov.uk/government/publications/capacity-market-5-year-review-2014-to-2019

- **Increasing the pace and breadth of investment in generation capacity**. The system will require a significant amount of new low carbon electricity capacity in order to meet decarbonisation targets, while meeting the increased demand from heat and transport electrification. This will require us to deploy renewable capacity faster than ever before, and to expand the range of technologies that come forward, in particular low carbon flexibility assets.
- **Increasing system flexibility**. Flexibility is the ability to shift the consumption or generation of energy in time or location - it is critical for balancing supply and demand, enabling the integration of variable renewables and maintaining the stability of the system. A system dominated by cheaper, variable renewables will reduce costs for consumers, but will also present a new challenge for balancing supply and demand and managing new and growing constraints in the network. Periods of excess generation, where renewable output is greater than demand, will become more prolonged. The system will also need to manage periods when renewable output is low.
- **Providing efficient locational signals to minimise system cost**. Renewable assets are likely to locate where the requisite natural resources (e.g. wind) are most plentiful, and where they are able to obtain planning consents, which are often at the extremities of the network, far away from demand. This will require rapid expansion of the network, but will inevitably increase the periods when there are physical constraints on the ability of the network to transport electricity, and when renewables have to be turned down to resolve local imbalances in supply and demand. To maintain a low-cost system the market will need to send locational signals that incentivise generation and flexibility assets as well as sources of demand to build in suitable parts of the network and to operate in a way that lowers system costs. An increasing number of distribution-connected and behind-the-meter generation assets will need to be integrated into the system.
- **Retaining system operability**. The cost of operating the electricity system will rise as the system decarbonises. Currently gas-fired power stations provide a range of system services, such as inertia, as a by-product of their generation. An increase in variable, renewable generation and a decline in the volumes of conventional gas plant will result in less of the system's operability requirements being provided by thermal generation. Market arrangements will need to bring forward enough investment in alternatives to high carbon technologies that can deliver the full range of operability services.
- **Managing price volatility**. As the penetration of renewables increases, the wholesale market price will become more volatile, as prices fluctuate between periods of high and low renewable output. At the same time, the system will become less exposed to global gas markets, as increasingly gas no longer sets the price of electricity. However, in periods where power CCUS or hydrogen are generating, or when unabated gas is required to ensure security of supply, the electricity price could still be influenced by the gas price. Price volatility can reduce investor confidence and can be harmful to consumers, whilst sending beneficial signals to system assets. Our market arrangements will need to help mitigate this volatility, providing sufficient certainty to investors and ensuring fair outcomes for consumers.

Increasing the pace and breadth of investment

Figure 1: Illustrative Capacity Mix, 2020-2050, GW, BEIS Higher Demand Scenario



High Carbon Flexible: Peaking (incl. OCGT), CHP Gas, CCGT, Coal

Storage: Battery, Pumped Hydro, Other

Other Renewable: Hydro, Other RES

Low Carbon Flexible: Biomass, Gas CCUS, Hydrogen

Low Carbon Variable: Solar, Onshore Wind, Offshore Wind

Low Carbon Baseload: Nuclear, BECCS

The BEIS Higher Demand scenario indicates the need for around 2.5 times more additional generation capacity by 2035 and over four times more by 2050 from 2020 levels. Across all scenarios, currently first-of-a-kind or immature technologies represent 2-6GW of deployment per annum between 2025 and 2035. By 2035, peak demand increases by 20-85% and total demand by 20-60%. Our scenario also assumes significant amounts of demand side response (although this is not captured in Figure 1).

All modelled scenarios require a significant volume of new capacity to deliver a secure, low carbon system. Our scenarios indicate that around 300GW of capacity could be needed by 2035, up from around 100GW today. That means that over 10GW of new capacity is required on average each year until 2035, against an historical average of 5-6GW. To fully decarbonise the power sector at the pace we have set out, whilst meeting increasing demand, total public and private investment of £280-400 billion is needed in generation capacity and flexible assets.[18]

Investment in renewable assets

The cost structure of renewables is characterised by high upfront capital costs of construction, followed by very low operating costs once the assets have been built. This is the opposite to

[18] BEIS, 2021, Net Zero Strategy: Build Back Greener (p. 99), https://www.gov.uk/government/publications/net-zero-strategy

fossil fuelled plants, which are typically lower cost to build, with high operating costs of which a large proportion is their fuel costs. In a highly capital-intensive system the cost of financing will have a greater impact on total system costs. For low carbon assets, long-term price stability is important for covering upfront costs. This may increasingly become a problem for end-of-life plants seeking to ‘repower’, as there are significant capital costs to replacing old equipment in order to continue operating at the site.

In a high renewables future, there will be significant correlation between large parts of the generation fleet, as we will have to build the majority of assets where there is strong wind or solar potential. Despite some variation across the country, many assets will be subject to similar weather conditions, and therefore will have similar output patterns. The price in the wholesale market is set on the basis of short-run marginal cost: each generator bids in the price they are willing to accept to produce the next unit of electricity, and the price is set at the level which ensures all demand is met. This can lead to the phenomenon of ‘price cannibalisation’, which can pose a disincentive to investment in renewable energy assets. Price cannibalisation occurs because when it is windy and sunny, variable renewables tend to generate together. In some periods there is enough generation from only renewables to meet total demand, and this drives the wholesale market price down towards their short-run marginal cost (close to zero, as the sun and wind are free resources). But because renewables are expensive to build, these low wholesale market prices may not be enough to cover their capital costs.

Investment in flexible low carbon assets

The profile of renewable generation has significant implications for the rest of the assets on the system. Although renewables will make up the majority of our generating capacity, there will need to be a range of firm and flexible assets to generate when renewable output is low. As renewables have low operating costs, they will always be among the first assets to generate, and increasingly will have a generating potential that could meet the entirety of electricity demand. So flexible assets will only generate when renewable output falls, or to provide essential services to ensure the stability of the electricity system. As the capacity of renewables increases, we will need to call on flexible assets less and less. Figure 2 shows that the average annual load factor[19] of each additional GW of flexible capacity required. It shows that for the first GW of flexible capacity load factors could fall from around 90% in 2025, to around 50% in 2035. For the tenth GW of flexible capacity this could fall from around 70% in 2025 to 30% in 2035. This means that there will be fewer opportunities for these assets to earn revenue in the wholesale market. There will be fewer periods where the assets are operating, and these periods will become increasingly uncertain, driven by the intermittency of renewables. Our analysis indicates that under current market arrangements, in order to remain profitable flexible assets will need to earn an increasing larger proportion of their revenue outside the wholesale market. We will need to ensure our market arrangements and policy

[19] Load factor is a measurement of the utilisation of an asset. It is defined as a ratio of energy generated in a given time of period compared to the maximum possible generation in that time period.

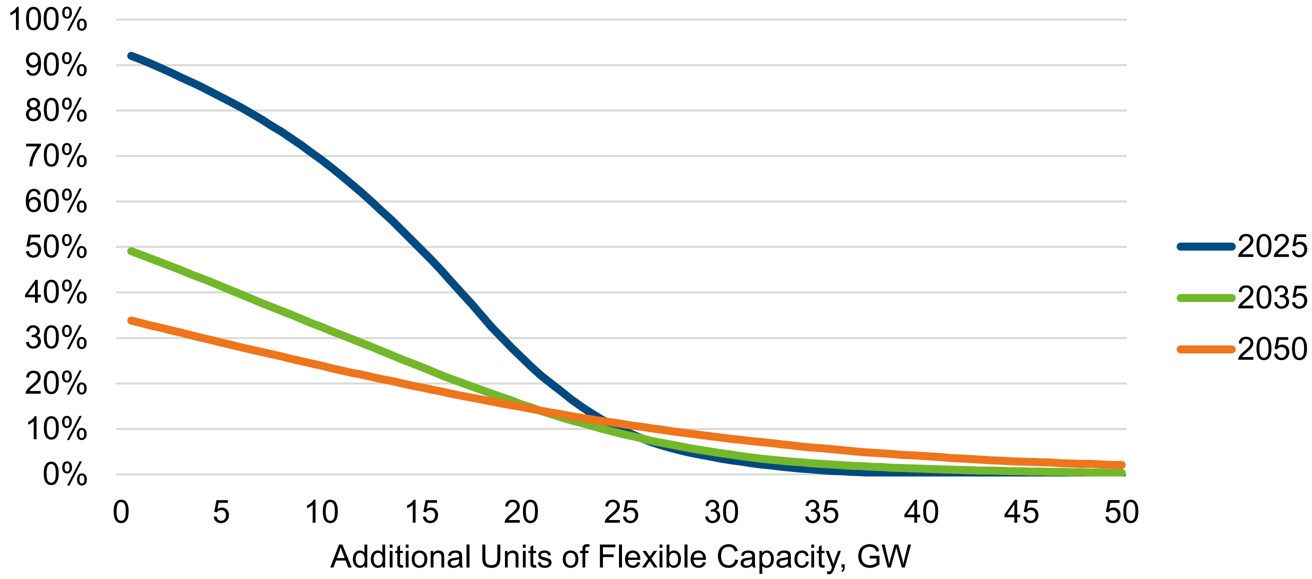
framework enable investment in critical low carbon flexible capacity as we undertake this transition.

Short-term investment in unabated assets

Although the system must rapidly decarbonise, in the short term the challenge of falling load factors also applies to unabated gas generation. The existing fleet, and new build gas generation, will be essential to maintain security of supply whilst low carbon alternatives deploy. In the short term, as older plants retire, the gap in capacity will need to be partly filled by unabated assets, before low carbon flexibility can be built at scale. For these assets the opportunity to earn revenue across their lifetime is likely to be significantly diminished. We anticipate that the carbon price will increase as the economy decarbonises. Therefore, unabated assets are likely to have the highest operating costs of all assets, and will be the last assets to generate, further reducing the periods in which they will be able to earn wholesale market revenues.

Decarbonising unabated assets where possible will be key to enabling us to hit our decarbonisation targets whilst retaining capacity on the system. This summer we will publish our consultation on proposals expanding Decarbonisation Readiness requirements so all new build and substantially refurbishing combustion power plants will have to demonstrate a viable plan for decarbonising by retrofitting either CCS or hydrogen generation technology.

Figure 2: Flexible Capacity Average Annual Load Factors for Each Additional Units of Flexible Capacity, %, BEIS Higher Demand Scenario



For flexible capacity, average annual load factors in the wholesale market are likely to continue to reduce, especially for the first GW of flexible capacity. This will mean that revenue from other sources, such as payments for availability, becomes an increasing important component as wholesale revenues fall.

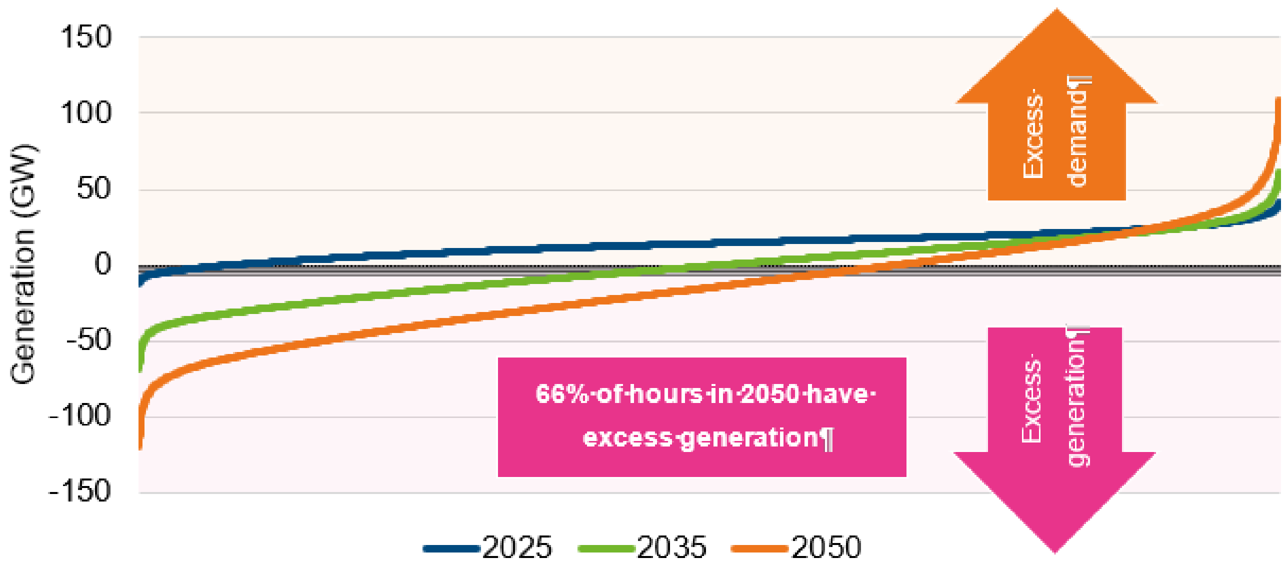
On the other hand, more flexible capacity will be needed in future to respond to larger capacity gaps. Modelling suggests that the 35th GW of flexible capacity has an average annual load factor of around 2% in 2025 increasing to over 5% in 2050.

Increasing system flexibility

The electricity system needs to match supply and demand on a second-by-second basis. Flexibility – the ability to shift the consumption or generation of energy in time or location – is critical for balancing supply and demand, enabling us to integrate renewables and maintaining the stability of the system. In the past, much of our flexibility has been provided by turning up or down coal or gas fired power stations. In order to retain security of supply in a fully decarbonised power system, where possible, we will need to replace most of these with low carbon flexible capacity. In a future system the demand side has the potential to be much more active. Responsive consumers, including domestic, industrial and commercial consumers, will be vital to reduce the scale of the flexibility challenge by changing the time when they consume energy, for example when they charge electric vehicles and run their heat pumps. Additional flexibility could also be secured through consumers flexibly charging and discharging domestic batteries and self-consuming and exporting electricity from rooftop solar PV panels.

Figure 3 shows the proportion of the year that demand could be met, and exceeded, by renewable and baseload low carbon generation alone, and the remaining proportion when there is not enough renewable generation, and so flexible technologies will be needed to meet demand. In 2025 there are relatively few (less than 10%) periods where there is excess supply. As the capacity of renewable generation increases, the proportion of the year with excess demand increases: by 2035 there could be excess supply for around 50% of the year.

Figure 3: Residual Demand Distribution, GW, BEIS Higher Demand Scenario



This chart shows the distribution of excess demand (and generation) for each snapshot year in hours. We need to move quickly to a smart, flexible energy system. By 2035, excess generation will represent around 50% hours, with this rising to above 60% by 2050.

The patterns of excess renewable generation and the need for flexibility are increasingly driven by weather conditions and periods of high and low wind, rather than daily demand. This leads to long-lasting periods of excess generation, rather than regular daily patterns. These excess supply periods will become more extreme and prolonged as the proportion of renewables increases. By 2035, there could be periods where there is over 50GW of excess supply, and periods of excess supply could last for multiple days. In periods of excess generation the wholesale price is likely to be set by renewables, and therefore will result in very low prices. This provides an opportunity for demand-side flexibility to utilise (and create value from) excess generation that would otherwise be curtailed; for this reason electricity prices in these periods will sometimes be negative. For example, excess electricity could be used to produce hydrogen through electrolysis, run a dishwasher that would otherwise have run later in the day or stored for future use.

At the other end of the scale, a highly weather-dependent system will have excess demand during periods of low renewable output. These periods will become less frequent as more renewable and low carbon baseload generation comes online, but the magnitude of individual periods will become greater as demand increases. The most challenging system security events will be driven by extended periods, potentially weeks, of low wind output. Low carbon flexibility with the ability to maintain output over long durations, on both the demand and supply -side, will be required to manage these periods of residual demand.

Not only will the system require a greater capacity of low carbon flexible assets, it will also require these assets to respond more quickly. This is because in a high renewables system, fluctuations in wind and solar output are greater than the changes in demand which drive ‘ramping’ (how quickly output needs to change) requirements today. This demonstrates that a significant proportion of the flexible fleet will need to have the ability to ramp up and down very quickly despite only being required infrequently.

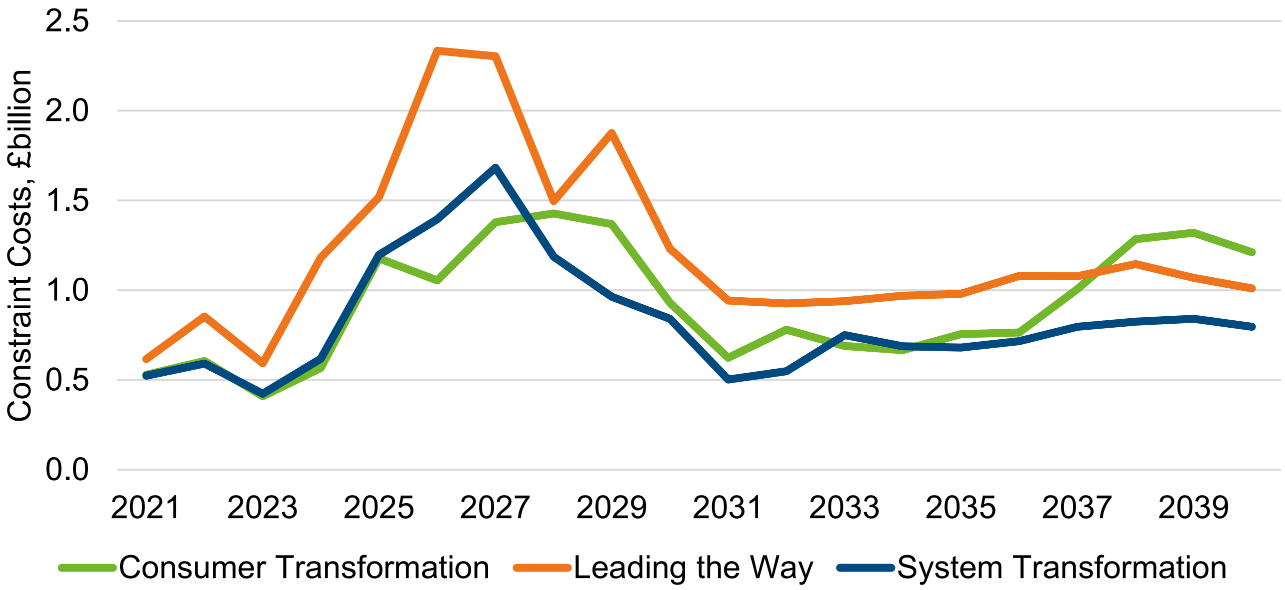
Providing efficient locational signals to minimise system cost

Decisions about where to build renewable assets are primarily driven by where it is windy and sunny, in order to maximise the generation they provide. These decisions are also influenced by the ease of securing appropriate planning permissions. For example, offshore wind sites are limited by: leased Crown Estate and Crown Estate Scotland zones; the ability to connect to the transmission network; and the planning process, which factor in environmental considerations and other marine activities. The main locational investment signal in our current market structure comes from network charges. These charges can be difficult for generators (and investors) to forecast, and do not reflect how constrained the network is in particular locations and conditions. Taken together, this means that in GB our renewable resources are often at the extremities of our network; new generation is increasingly being built far from our centres of demand; and this is putting increasing strain on the network.

When there are physical constraints on the network (i.e. the network does not have the capacity to physically transfer the power from one region to another), generators can be asked by the system operator, via the balancing mechanism, to reduce or ‘curtail’ their output, while assets in another part of the network are asked to increase generation to replace this output. Compensation to these generators is known as ‘constraint costs’. As renewable generation investment has outpaced network reinforcement, constraint costs have increased significantly in recent years, from around £360m in 2015 to £1.2bn in 2021.[20] As energy curtailed due to network constraints is fully reimbursed through the balancing mechanism, generators have limited incentive to locate away from constrained areas.

[20] Calculated using data from National Grid ESO, 2022, Monthly Balancing Services Summary (MBSS), https://www.nationalgrideso.com/industry-information/industry-data-and-reports/system-balancing-reports

Figure 3: Network Constraint Costs, £billion (real, 2020), ESO FES Scenarios



ESO's 2020/21 Network Options Assessment analysis suggests that even after optimal reinforcements have been made, constraint costs will rise in the near future across all FES scenarios. Even after optimal reinforcements, constraint costs are predicted to increase across the late 2020s to between £1bn and £2.5bn/year.

Network constraints have a cost impact, which is ultimately paid for by consumers, but they also have a carbon emissions impact. When renewable assets reduce their output because the network is constrained, rather than because demand is low, other assets must increase their output to ensure the system remains balanced. Historically, wind generation has been curtailed and the replacement generation has predominately come from unabated gas and coal power stations. If renewable generation continues to be curtailed and replaced by unabated assets, it reduces the effectiveness of deploying renewable capacity, making decarbonisation targets more challenging.

In addition to the curtailment on the transmission network, the decarbonisation transition will bring challenges for the distribution network. An increasing number of distribution-connected and 'behind-the-meter' (i.e. directly connected to buildings) generation assets will need to be integrated into the system. A large proportion of the increase in demand will come from the electrification of heat and transport, as many homes and businesses shift to electric vehicles and heat pumps. Most of these assets will be connected to the distribution network, and the transition will have a locational element as different cities, towns and streets decarbonise at different rates. This will increase the constraints on the distribution network, likely leading to more actions needed to resolve local imbalances. While distribution networks are already procuring flexibility services to alleviate local network constraints, the need for effective market facilitation and more active system operation at a local level will increase significantly over the coming decade.

Increased curtailment and associated constraint management are likely to be a characteristic of any low carbon GB system. A rapid increase in the scale and pace of network infrastructure build will be needed and is being implemented, as set out in our British Energy Security Strategy and the soon to be published Electricity Networks Strategic Framework. An efficient system will have to balance network reinforcement and generation curtailment. It would not be feasible or cost-effective to expand network capacity to prevent all curtailment, as some of the network capacity would have very low utilisation.

However, one of the key drivers for increased network constraint costs is a lack of locational signals in our existing market arrangements. Market arrangements should incentivise generators, flexible assets, and demand to locate and operate in a manner that minimises system costs. Stronger locational investment signals would ensure new assets consider their impact on the network when deciding where to build, and so would minimise spend on network reinforcements and generation capacity. More effective locational signals could also diversify the locations of renewable generation; this could lower the cost of delivering security of supply through less correlated renewable output (e.g. at times of low wind output in one location could be counteracted by greater output in another). However, since some assets will be restricted in where they can locate, either through the available of renewable resources (e.g. wind patterns), planning regimes, or through the location for supporting infrastructure (e.g. carbon capture transport and storage), locational signals are not a substitute for necessary network reinforcement.

Once an asset has been built, locational operational signals would incentivise the asset to generate or consume energy in a way the helps to mitigate network constraints. Sending efficient operational signals would allow the market to consider real-time network constraints in dispatch decision, rather than locational constraints being solved be the system operator through re-dispatching market trading. This would likely result in more efficient system operation and minimised operational constraints payments.

Maintaining system operability

Alongside balancing supply and demand nationally and locally, there are a range of other challenges in managing the electricity system. The system operator regularly needs to take action to ensure the safe and efficient movement of power across the network. The operability requirements are met through the provision of ancillary services which include:

- frequency response – it is necessary to ensure frequency is maintained on a second-by-second basis so that both demand and generation assets are able to operate within safe parameters. Response services help manage the system frequency when there is a sudden change in generation or load, which creates a mismatch between demand and supply.
- reserve – delivery within a specified timescale of increased generation and/or demand turndown to deal with an unforeseen increase or reduction in demand.
- stability – refers to a range of services, primarily provided by inertia, which is a measure of the system's inherent resistance to changes in frequency. Inertia is normally provided by the kinetic energy stored in the rotating masses of turbines in generators connected to the network, although it can be provided by other technologies. These rotating

masses are linked to the frequency of the network and respond automatically if the frequency changes, by instantaneously injecting or absorbing some power.

- reactive power – voltage levels of all parts of the electricity networks must be controlled and maintained for the safe and efficient transport of power. Reactive power services are required to ensure transmission efficiency is maximised.
- restoration – this is the procedure used to restore power if there is a total or partial shutdown of the system. This is performed by re-energising certain parts of the transmission network incrementally before bringing the whole system back online. System restoration requires generators on the system that can turn on quickly without an external supply of electricity.

The ancillary services which meet the above operability requirements are currently provided overwhelmingly by fossil fuelled thermal generators. As the system decarbonises, these services will need to be provided by low carbon assets. Low carbon technologies can potentially meet all our system operability needs, but a portfolio of technologies will be needed. Lithium-ion batteries, for example, are already providing frequency response; long duration storage, power CCUS, hydrogen fired generation and power BECCS will be capable of providing a range of ancillary services, and new nuclear will be an important provider of inertia.

In our illustrative scenario the majority of operability costs are determined by the cost of inertia – vital for maintaining system security. Stability requirements have traditionally been provided by synchronous generation, such as gas and coal assets. [21] Importantly, these generators naturally provide inertia as a by-product of their generation. However, most renewable assets are not synchronous and do not naturally provide services such as inertia.[22] The challenge of efficiently procuring services to maintain the stability of the system will grow, as synchronous plant makes up a smaller proportion of the generation fleet. Inertia costs are projected to be high in the late 2020s, with high renewable penetration plus the retirement of synchronous generation (such as nuclear). In our illustrative scenario, new nuclear, power CCUS and power BECCS deployment in the late 2020s and early 2030s temporarily reduces inertia costs, before costs rebound due to higher renewable build. Inertia costs then fall again as subsequent nuclear plants come online. System inertia could also be supported by incentivising renewables assets to include synthetic inertia in their designs.

The move towards more distribution-level generation is also presenting operational challenges. As more generation is located on the distribution network, the power flows and the assets that the system operator needs to manage will change. For example, active power from solar or wind generation feeding into the grid at times of low demand is already leading to more instances of voltage level rises which need to be remedied through voltage management.

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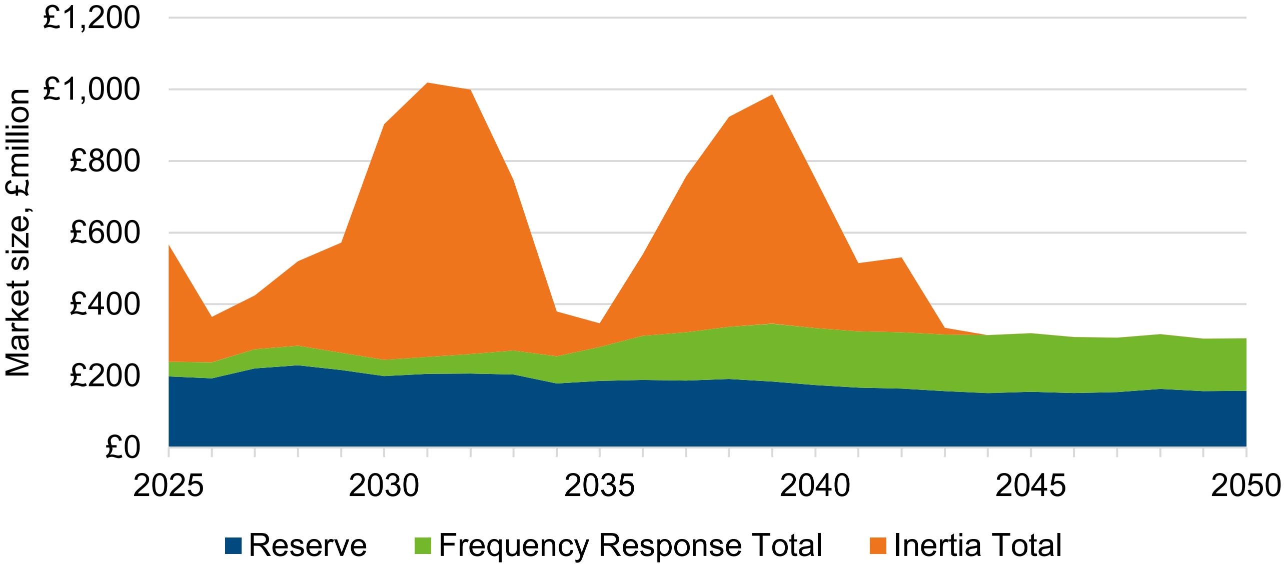
[21] Synchronous generators produce power that is synchronised with the frequency of the electricity network. They generate power through rotating alternators through an electromagnetic field, which are connected to turbines that are all linked to spin at the same speed. Synchronous generators include coal, gas, nuclear, hydro, and biomass.

[22] New converter designs and associated control algorithms are evolving and can replicate some of the stability characteristics.

Figure 4: Total Inertia, Frequency Response, and Reserve Ancillary Services Market Size, £million (real, 2020), BEIS Higher Demand Scenario



The chart shows the total revenue paid to inertia, frequency response, and reserve ancillary services providers. In our illustrative scenario the majority of operability cost is determined by the cost of inertia. Inertia costs are projected to be high in the late 2020s, with high renewable penetration plus the retirement of synchronous generation (such as nuclear). Inertia cost falls as new nuclear, gas CCUS and BECCS deploy. Inertia cost rise again in the late 2030s as renewable generation increases, before falling to zero as additional new nuclear come online.

Managing price volatility

As the penetration of renewables increases, there could be periods where their variability drives volatility in the wholesale market price. The market arrangements will need help mitigate this volatility and help provide certainty to investors and provide value for money for consumers.

The price duration curve in Figure 6 shows the distribution of wholesale market prices over given years. In 2025 there are few very low prices, but by 2035 very low (or negative) prices make up around half of all hours, rising to two-thirds by 2050.[23] The proportion of the year with very high prices also increases in future years as increasing commodity and carbon prices pushes up operating costs.

Our modelling predicts more frequent periods of zero prices set by renewables, but also more highly priced periods when renewable output is low. This volatility creates a challenge for the system. For assets which are dependent on the wholesale market price, their revenue may be less certain, thereby increasing the risk of their investment. Assets will be expected to make a

[23] Note that the price is typically floored at zero, rather than going negative, due to the change in CfD rules which mean that AR4+ plant are not incentivised to run if prices are below zero.

large proportion of their revenue in a small number of high-priced periods. These periods will be uncertain, driven by variable renewable output resulting from fluctuations in wind, solar and demand profiles, leading to plant revenues varying from year to year.

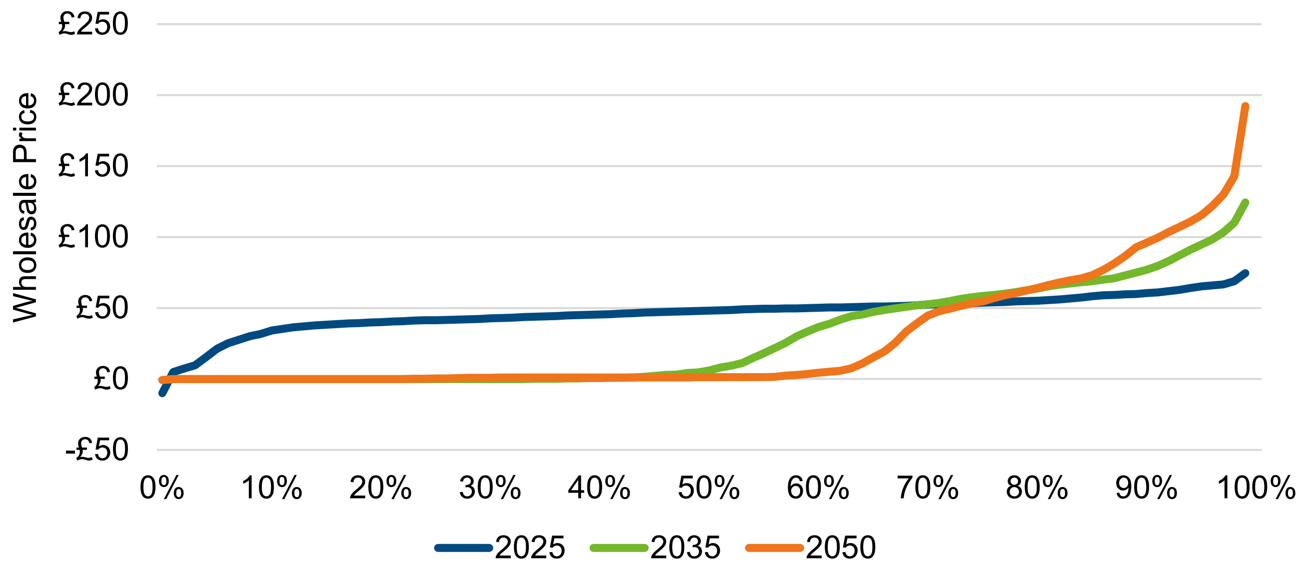
The electricity market has also historically been exposed to fluctuations in international commodity prices. Gas and coal have been the primary fuel used to generate electricity; therefore, the cost of electricity generation was determined by their price. As the existing wholesale market is based on short-run marginal cost pricing, it will be exposed to commodity prices to the extent that commodities are used in generation. Russia's recent invasion of Ukraine has caused global gas prices to rise, and this has led to a high gas price setting the price for electricity across GB – despite record levels of cheap renewables on the system.

As the system decarbonises, unabated gas will be replaced by low carbon generation. Gas will less frequently be the marginal plant and therefore the electricity price should increasingly be detached from the price of gas. However, in the shorter-term gas generation will still be needed to provide system flexibility and under current market arrangements will continue to set the price for electricity.

In the longer-term, some low carbon technologies will still be influenced by commodity prices. Power CCUS relies on gas as an input fuel and hydrogen generation could be influenced by gas prices to the extent that the hydrogen price is determined by the cost of blue hydrogen[24] production. This means that in periods where power CCUS or hydrogen are generating, or when unabated gas is required to ensure security of supply the electricity price could still be set by the gas price. However, these periods are likely to be much less frequent than today.

[24] Blue hydrogen is derived from natural gas through the process of methane reformation with CCUS.

Figure 5: Cumulative Distribution of Wholesale Price, £ (real, 2020)/MWh, BEIS Higher Demand Scenario



As the system moves closer to 2050, wholesale prices will become increasingly volatile – switching between periods of very low prices and very high prices, and less periods in between these two extremes.

This increase in volatility occurs across all scenarios but is most pronounced in the BEIS scenario, largely driven by the assumption of no electrolysis in that scenario leading to more zero price periods.

Assessment of future market arrangements

To meet the policy objectives set out in Chapter 1, the electricity market will need to meet the future challenges set out above. In this section, we discuss the main issues with the existing market arrangements that are likely to prevent the system from overcoming these challenges, and therefore failing to meet our objectives.

Decarbonisation

The CfD scheme has been successful in delivering a substantial volume of low-cost renewable capacity through competitive auctions. Since the first allocation round (2015), the CfD scheme has delivered 27GW of renewable capacity and seen the clearing price of certain technologies, like offshore wind, fall by around 70%. However, a wider range of technologies will be needed to deliver the next phase of decarbonisation. We identify the following issues with the current market arrangements:

- **Average wholesale prices are likely to fall as the proportion of renewable generation increases, which would lead to a greater dependence on existing support schemes**: The increasing volume of low marginal cost renewable generation is creating downward pressure on wholesale prices during periods of high renewable generation, which may reduce generators' ability to recover their construction costs in the wholesale market. This means that under current arrangements renewable support schemes, which provide revenue outside of the wholesale market, are necessary to drive investment.

- **The CfD scheme limits market exposure**: The fixed strike price in the CfD contract means that renewable assets are not exposed to price signals. A lack of real-time market exposure reduces incentives for plants to operate more flexibly where possible, increasing the investment needed in low carbon flexibility.
- **Lack of investment signals for low carbon flexibility**: The current wholesale market and Capacity Market are unlikely to bring forward these technologies at the pace required, and unlike renewables they are unable to participate in the CfD scheme. The Capacity Market has historically been dominated by high carbon technologies and under its current design is unlikely to favour low carbon flexible technologies, and therefore will continue to lock in unabated gas capacity beyond 2035. Current CfD design makes it unsuited to flexible technologies. The Dispatchable Power Agreement has been introduced to overcome this challenge for investment in power CCUS as we deliver against our commitment of at least one power CCUS plant by the mid-2020s, and there is a cap and floor mechanism place for interconnectors. But the issue remains for other sources of low carbon flexibility. Without further intervention, unabated gas may still undercut low carbon flexibility.
- **Bespoke support schemes that drive investment in low carbon flexibility may hinder competition**: Bespoke support schemes may be required to de-risk investment in first-of-a-kind technologies and deliver cost reduction through sustained deployment. They are also likely to be needed to support technologies that require large infrastructure beyond electricity and gas grid connections such as hydrogen and carbon dioxide transport and storage. However, bespoke schemes reduce the opportunity for competition between flexible technologies, and some technologies may be incentivised more than others. Market design will need to consider how we transition away from bespoke schemes once technologies are sufficiently developed.
- **Limited market signals for electricity demand reduction**: Electricity demand reduction (permanent reduction in electricity use achieved through energy efficiency measures) provides a wide range of system benefits but can usually only generate returns by avoiding wholesale market cost and certain network and policy costs. Without the ability to access and stack multiple revenue streams, electricity demand reduction will continue to face greater market barriers than other energy technologies.
- **Missing market for sustained response**: Fossil fuel generation such as gas can provide stable generation for long periods of time. With unabated fossil fuels being progressively replaced by variable generation, assets that can provide sustained output will become scarce and valuable, for example long duration storage. However, existing wholesale and balancing markets currently reward charging and discharging frequently. As such, they do not currently reward the system value of sustained response, and new markets may need to be introduced to fulfil this gap and bring forward long duration storage.

We therefore conclude that current arrangements will not deliver a fully decarbonised power system by 2035, as renewables alone will not be enough to meet 2035 targets, and the Capacity Market is unlikely to bring forward low carbon flexibility at the pace required.

Security of Supply

The Capacity Market has ensured that sufficient capacity is available to meet peak demand. It has been successful in ensuring the reliability of the electricity system since its introduction. A scheme that rewards the availability of capacity is likely to continue to be necessary, to support the flexible technologies with low load factors which are essential for meeting demand in periods of low renewable output. We identify the following issues with the current market arrangements:

- **Reduced running hours for flexible assets will require a greater proportion of revenue from other markets**: The cost of the current Capacity Market is likely to increase as the amount of capacity needing to be procured rises, and as flexible plant need a greater capacity price to cover their reduced wholesale market running hours. As support for capacity schemes becomes a greater proportion of system costs and the technology mix changes, it will be important to ensure the design of any such mechanism adapts to optimise its design to keep costs as low as possible.
- **Current Capacity Market is unlikely to drive sufficient investment in low carbon flexibility**: Capacity Market contracts have historically been awarded to firm, dispatchable gas generation, but also to older and less flexible plants, (e.g. nuclear) that are less able to respond to system conditions. The Capacity Market has also supported storage and demand side response assets, and these assets will become more competitive as the carbon prices increase. However, it is unlikely to bring forward these assets at the pace required to meet decarbonisation target.
- **Current market arrangements may not incentivise investment in low carbon capacity with the right characteristics to provide system services**: It is unclear whether the market is sending the right signals to bring forward the deployment of assets required to support operability challenges (e.g. inertia), particularly in the short-term. Assets are rewarded in the ancillary services markets, but these markets may not send sufficient investment signals to encourage new assets to build. Frequency response markets have helped to deploy new batteries, but the technologies needed to meet other operability requirements may be dependent on wider support schemes. For example, power CCUS and hydrogen will have the capability of providing low carbon reserve and inertia but may not be in place in sufficient quantity until the 2030s.

We therefore conclude that under current arrangements our approach to maintaining security of supply is likely to come at risk of missing our decarbonisation objectives, as the current Capacity Market continues to lock in high carbon assets.

Cost-effectiveness

Our current wholesale market arrangements are open to a range of participants and have traditionally delivered efficient dispatch signals. The CfD scheme has been hugely successful in lowering financing costs for renewable assets, which will be increasingly important in a system dominated by capital costs. The Capacity Market auctions have secured over 10GW of new capacity from a range of technologies, at low clearing prices. However, we identify the following issues with the current market arrangements:

- **Lack of locational investment and operational signals**: The current wholesale market has a single national price and currently the CfD or Capacity Market are not designed to send locational signals. Non-market factors like weather patterns and seabed leasing are the main driver for where renewables locate. The main locational investment signal in our current market structure comes from network charges. These charges can be difficult for generators (and investors) to forecast, and do not reflect how constrained the network is in particular locations and conditions. Network users may not be appropriately incentivised to locate in areas with spare network capacity and to use the network in ways that help overall system efficiency. Because of the lack of location operational signals, the system operator needs to manage locational constraints through re-dispatch in the balancing mechanism.
- **Limited temporal signals for flexibility**: Temporal flexibility (shifting when electricity is consumed or generated) is important for lowering system costs, it smooths demand peaks, which lowers the requirement for generation and network build. There are a number of factors in existing market arrangements the limit temporal signals. The current market arrangements only financially reward balance across 30min periods, although there is value is matching demand and supply continuously. On the demand-side the way that costs are passed through dampens the signals for flexibility, policy costs generally passed through flat volumetric charges, while Capacity Market and network costs are simplified and, therefore, not fully cost-reflective. Dampened signals undervalue flexible assets and limit the ability of suppliers to provide tariffs that incentivise flexible behaviour from consumers.
- **Wholesale market prices are broadly set by the most expensive plant**: The wholesale market is based on marginal pricing,[25] which means the cost of the most expensive generation asset sets the price for the entire market. The marginal price model had been adopted by the majority of liberalised electricity markets. As the market price reflects the value of an additional unit of electricity at all times, this model provides efficiency, transparency, and incentives to keep costs down. However, as gas and carbon-emitting technologies (amongst others) frequently set the wholesale price under current arrangements, the low cost of renewables is not being fully passed on to consumers, leading to excess profits for some generators. This is partially addressed through the CfD, which requires generators to pay back if prices are high but remains an issue for non-CfD plants. This issue will reduce over time as gas generation generates less frequently but will remain to some extent as power CCUS, hydrogen and potentially some unabated gas, is needed to maintain security of supply.
- **Low wholesale market liquidity**: Liquidity refers to the extent to which a market allows assets to be bought and sold at stable, transparent prices. A liquid market is needed in

[25] Energy in the wholesale market is traded in multiple ways including on exchanges and bilateral trades. Across all these platforms the expectation of the marginal plant will have a role in price formation.

forward markets to allow suppliers to hedge the impact of volatile wholesale prices for consumers, allowing them to offer products such as fixed tariffs, which help consumers avoid exposure to price volatility. A number of factors will affect GB wholesale price liquidity. Weather dependant renewables typically enter into either CfDs and Power Purchase Agreements (PPAs). CfDs incentives renewables to trade only in intraday markets whereas PPAs are a delivery contract with one specific supplier. The increasing penetration of renewables over the last few years means these types of contracts make up a large proportion of the market. While having a positive impact decarbonisation, this is likely hampering liquidity. The retail price cap pushes suppliers to hedge energy contracts a year in advance as year ahead prices are observed by Ofgem as the reasonable wholesale costs of an efficient supplier. Generators are not under the same obligation and free to trade in any time market, which creates a liquidity challenge if generators do not trade at similar timescales as suppliers. There may be other factors at play as well, for example intraday exchanges are currently split across two separate platforms. In addition, current high commodity prices may impact liquidity as this makes it harder for market players to meet credit requirements with counterparties.

- **Current market arrangements do not make efficient use of all assets on the system**: Lack of clear visibility of generation and demand at all levels of the system is a key barrier to effectively integrating these assets into the system. Greater co-ordination is needed between the distribution networks and the Electricity System Operator to improve asset visibility and the development and co-ordination of national and local markets. Local markets, whilst growing, are relatively nascent, and it is important that distribution networks take the necessary steps to utilise existing assets on the network and expand those markets, improving liquidity, and making it a viable opportunity for all providers in the long run. The new independent Future System Operator, will also play a vital role in meeting this challenge. The participation of actors in other sectors needs to be facilitated to realise the full potential of demand-side participation.

We therefore conclude that current arrangements are unlikely to place us on a least cost pathway to power sector decarbonisation.

Timing challenge

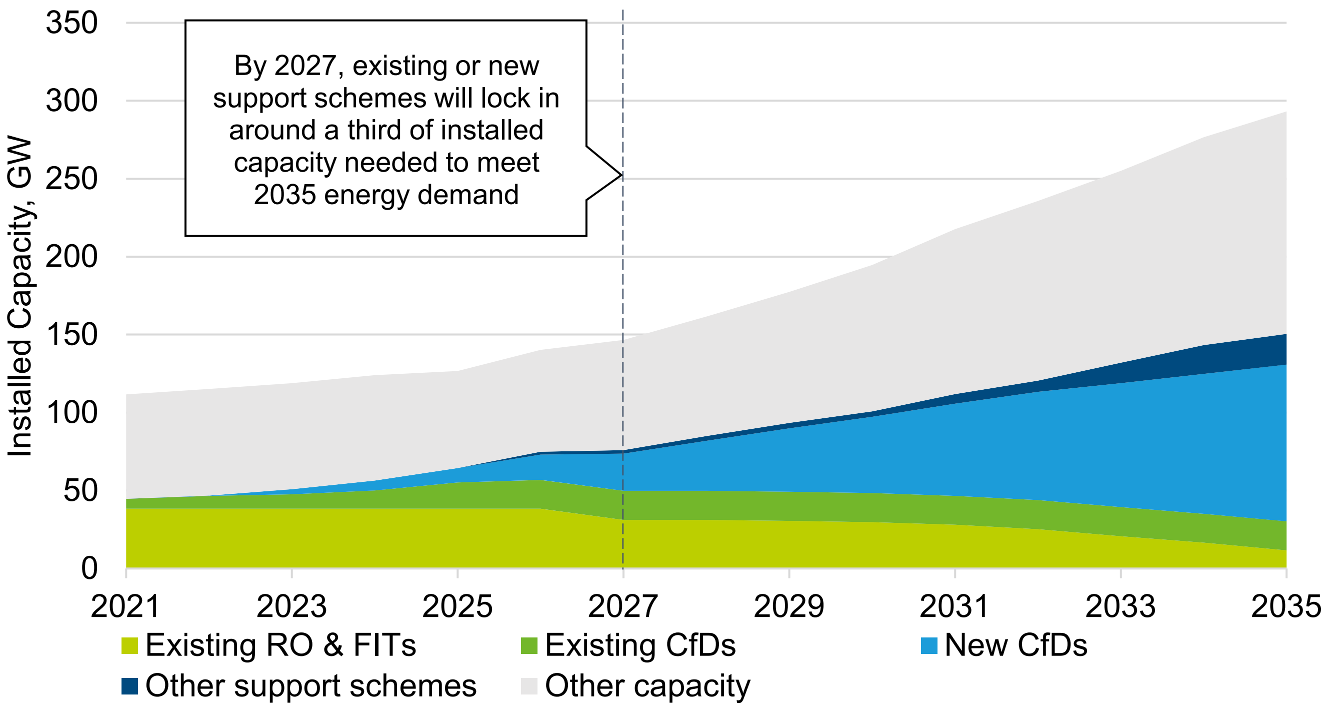
While 2035 may appear distant, market reform takes time, and energy infrastructure is planned years before it becomes operational. We estimate that by 2027 existing or new support schemes could already have locked-in around a third of the capacity needed in 2035 (see Figure 7[26]). There is therefore a need to think about potential long-term reform now so that reforms can be implemented in time to support our decarbonisation targets.

We need to maintain stability in the market to deliver our 2030 ambitions, for example those set out in the British Energy Security Strategy, while progressing reform that ensures we have

[26] All Contracts for Difference (CfD) rounds up to Auction Round 3 are included. Data is GB only. The “Existing CfDs” series in Figure 7 includes Investment Contracts, the precursor transition arrangement. Schemes for nuclear and CCUS are included in the “Other support schemes” series. In the modelling, it is assumed most low carbon capacity is supported in some way. This does not indicate that these schemes will remain BEIS’s preferred method to deploy these technologies but reflects the possibility that these technologies may continue to require some support to deploy in future.

markets that can effectively enable a low-carbon system in 2035. To meet these goals our existing mechanisms, such as the CfD and Capacity Market, will need to continue to deploy assets in the short-term. However, these schemes provide long-term contracts (up to fifteen years), therefore the longer existing arrangements are maintained, the less opportunity there will be for market reforms to have an impact on the 2035 electricity system. It is important that we find the right balance in making the necessary changes as soon as possible to achieve our objectives, while limiting disruption during the transition.

Figure 6: Installed Capacity by Low-Carbon Technology Support Type until 2035 in GB, GW, Net Zero High Scenario



Conclusion

This chapter has identified the future challenges that the electricity system will face and has assessed whether the existing market arrangements are likely to meet these future challenges. We conclude that while existing market arrangements have been effective in delivering the first phase of power sector decarbonisation, they may not meet the challenges of the next phase of decarbonisation in a way that secures supply and at least cost.

We do not consider that existing market arrangements are likely to deliver our ambition for a decarbonised and secure electricity system by 2035 at least possible cost to consumers, and put us on a pathway to a meet our 2050 net zero target. We therefore conclude that there is a strong case for change. The following chapters consider the potential options for market reform.

Questions:

3. **Do you agree with the future challenges of an electricity system that we have identified? Are there further challenges we should consider? Please provide evidence for additional challenges.**
4. **Do you agree with our assessment of current market arrangements/that current market arrangements are not fit for purpose for delivering our 2035 objectives?**

Chapter 3. Our Approach

The previous chapter demonstrated that there is a case for change. This chapter sets out how we intend to consider options for reform, with the following chapters setting out the emerging conclusions from our work so far. Specifically, this chapter sets out our programme objectives and approach to this Review, including stakeholder engagement and options assessment.

Purpose

The purpose of REMA is to identify, assess, and – where necessary – implement options for reforming our market arrangements in GB, to ensure that they are fit for the purpose of meeting our commitment to a fully decarbonised electricity system by 2035, subject to security of supply.

There are three main stages to achieving this purpose:

- Setting out a clear statement of the case for reform (this consultation)
- Developing options and determining what reforms are needed through extensive engagement with the energy sector (2022-23)
- Establishing a full delivery plan and overseeing implementation (from the mid-2020s) in time to contribute to our 2035 commitment.

This Review will focus on delivering the enduring market arrangements needed to deliver a fully decarbonised electricity system by 2035. A broad range of options are in scope of this Review, from medium-term changes to existing arrangements that can be delivered from the mid-2020s, to longer-term transformational reforms, as well as low regret ‘quick wins’ which could be pursued on accelerated timelines and implemented regardless of the end package of reform. We will do this in a way that ensures continued investor confidence in our energy system and assets. Any changes to the core mechanisms that drive investment - the CfD and Capacity Market - will be considered carefully with this in mind and whilst this programme runs, all existing schemes will continue. Any reforms would be subject to further consultation.

Stakeholder engagement

This document is an early consultation that sets out our thinking so far. The consultation will be open for written responses for 12 weeks and after this we will publish a consultation response in winter 2022.

Our reforms need to work for all consumers and a highly diverse range of businesses, and there are significant interlinkages and dependencies across all technologies, markets and regulations. So we will engage right across the sector and beyond – to see how other sectors have implemented comparable reform programmes. Our engagement plans will include:

- Regular communications to all interested stakeholders to update on progress and milestones
- Dedicated workshops (both large and small) to dive into specific policy areas
- Speaking at large events or fora organised by the sector to focus on specific perspectives.

We will consider all the evidence from our engagement with stakeholders as well as the responses to our consultation to inform a future consultation on policy proposals.

If you would like to be involved in our stakeholder engagement plans going forward, please email REMA@beis.gov.uk with the subject 'Request to participate in future REMA Engagement'.

Approach to options assessment – criteria

We will assess options against the following five criteria. These are intended as considerations which – all else being equal – lead to improved market design, and which together ensure that our objectives of decarbonisation, security of supply and cost-effectiveness are met. We developed these criteria by considering the characteristics of market design which will be needed to facilitate the delivery of our objectives. Our criteria should be comprehensive, covering all main attributes of good market design, without being duplicative. Our approach should allow options to be differentiated by their performance when assessed against criteria.

- **Least cost**. Market design should lead to solutions being delivered at least cost to consumers and sub-groups of consumers, with ongoing incentives to keep costs low and drive innovation (through competition where appropriate). Markets should be open to all relevant participants, including demand-side and innovative technologies.
- **Deliverability**. Changes to market design should be achievable within designated timeframes and seek to minimise disruption during the transition, taking account of the highly complex and integrated nature of the power system.
- **Investor confidence**. Market design must drive the significant investment in low carbon technologies needed to deliver our objectives. Risks will differ by technology type, but should be borne by those best able to manage it.
- **Whole-system flexibility**. Market design should incentivise market participants of all sizes (both supply and demand side) to act flexibly where it is efficient to do so. Market design should promote greater coordination across traditional energy system boundaries, including between electricity and other vectors like heat and hydrogen, to enable effective optimisation across the system as a whole.

- **Adaptability**. Market design should be adaptive and responsive to change. It should help ensure delivery of our objectives in a wide range of scenarios and should be robust to uncertainty, for instance regarding commodity prices and technology costs.

Question:

5. **Are least cost, deliverability, investor confidence, whole-system flexibility and adaptability the right criteria against which to assess options?**

Approach to options assessment – organising options

We have organised our assessment around the core outcomes that our future low carbon electricity system will need to deliver. These are: a net zero wholesale market; mass low-carbon power; flexibility; capacity adequacy; and operability. A full description of the scope of each of these areas is set out below. We recognise that electricity market reform is a whole-system problem, and so requires a whole-system solution; but given the diversity of views about the right way forward for each element of our arrangements, let alone our market as a whole, our first step must be to break the problem down into tractable parts whilst recognising the interdependencies throughout, before recombining at a later stage.

A net zero wholesale market: We will consider whether alternatives to the wholesale market and balancing mechanism would better suit our renewables-heavy future, particularly by ensuring that there are sufficient operational signals for low carbon flexibility. Our case for change outlines that the existing wholesale market arrangement alone were unlikely to bring forward the required investment in renewables or low carbon flexibility. Our current focus is on whether there is a case for fundamental wholesale market reform – for example, introducing locational marginal pricing, or splitting the market into separate ‘as available’ and ‘on demand’ markets. We will also consider how national and emerging local markets will interact, and the choice between self- and central dispatch. Also in scope are smaller improvements to the parameters of the current wholesale markets: e.g. settlement period, gate closure, and options for improving forward liquidity. We will also consider how options for future wholesale market design interact with future carbon and policy costs, and how these costs send behavioural signals to consumers.

Mass low carbon power: We will consider options for delivering investment in the production of the majority of the low carbon electricity which will be required to meet carbon budgets, i.e. any plant which is expected to operate at or close to its highest possible load factor. Our case for change identified that price cannibalisation, where renewables capture low wholesale market prices, will result in these technologies continuing to need support schemes to cover their costs. Renewables are our primary focus; but Energy from Waste (EfW), and – in the long run – potentially small modular nuclear reactors are also in scope.

Flexibility: Flexibility is the ability to shift the consumption or generation of energy in time or location. It is critical for balancing supply and demand, enabling the integration of low carbon power, heat and transport, and maintaining the stability of the system. Our case for change identified an increasing need for flexibility technologies to respond to the variation in renewable output. Low carbon flexible assets will therefore become increasingly valuable. We are taking a twin track approach to ensuring there is enough flexibility on the system. The options considered in the wholesale market and operability chapters will be fundamental in ensuring the right operational signals are there for flexibility. In the flexibility chapter we consider whether these operational signals will create strong enough investment signals for all types of flexibility needed by the system, or whether additional investment support is required. The full range of assets which can provide low carbon flexibility are in scope, including electricity storage, flexible demand, hydrogen-fired generation, power CCUS, electrolysis, and interconnection.

Capacity adequacy: We will consider all options for reliably delivering the overall capacity that will be required to ensure security of supply. We will consider how to do this in the most efficient way that best supports our decarbonisation goals. Our case for change identifies that system stress events are likely to be increasingly driven by weather patterns, and significant amounts of firm capacity will be needed to manage extended low wind/sun periods. A wide range of technologies are in scope, including all which currently participate in the Capacity Market, future technologies such as power CCUS and hydrogen-fired generation, and electricity demand reduction. Notable focuses are on power CCUS, hydrogen-to-power, long-duration electricity storage, batteries, demand side response, interconnectors, and electricity demand reduction.

Operability: We will consider options to promote investment in low carbon ancillary services that will meet the needs of a system increasingly dominated by variable renewable energy. Our case for change identifies that while operability costs are a relatively small proportion of total system costs, decarbonisation will increase the challenge of operating the system. As well as replacing fossil fuel based ancillary services with low carbon alternatives, it is important that barriers for participation in procurement are removed to ensure competition to help drive down prices.

This organisation of options is reflected in Figure 8, which is a schematic representation of the options under consideration. The diagram is not comprehensive: it does not cover, for example, the full range of smaller changes that could be made to the wholesale market or the question of how locational signals are best delivered. Rather, it is intended as a high-level summary of our approach to narrowing down options in this consultation.

To ensure we were considering a comprehensive list of options, we carried out an extensive literature review, reviewed stakeholder responses to recent calls for evidence (for example relating to the CfD and Capacity Market), and undertook internal policy development. We then carried out an initial assessment of the options, to focus our work on the proposals we thought could meet our objectives, which are presented in this document. We welcome views on whether there are any further options, not considered in this document, where there is evidence to suggest that they are worthy of detailed consideration.

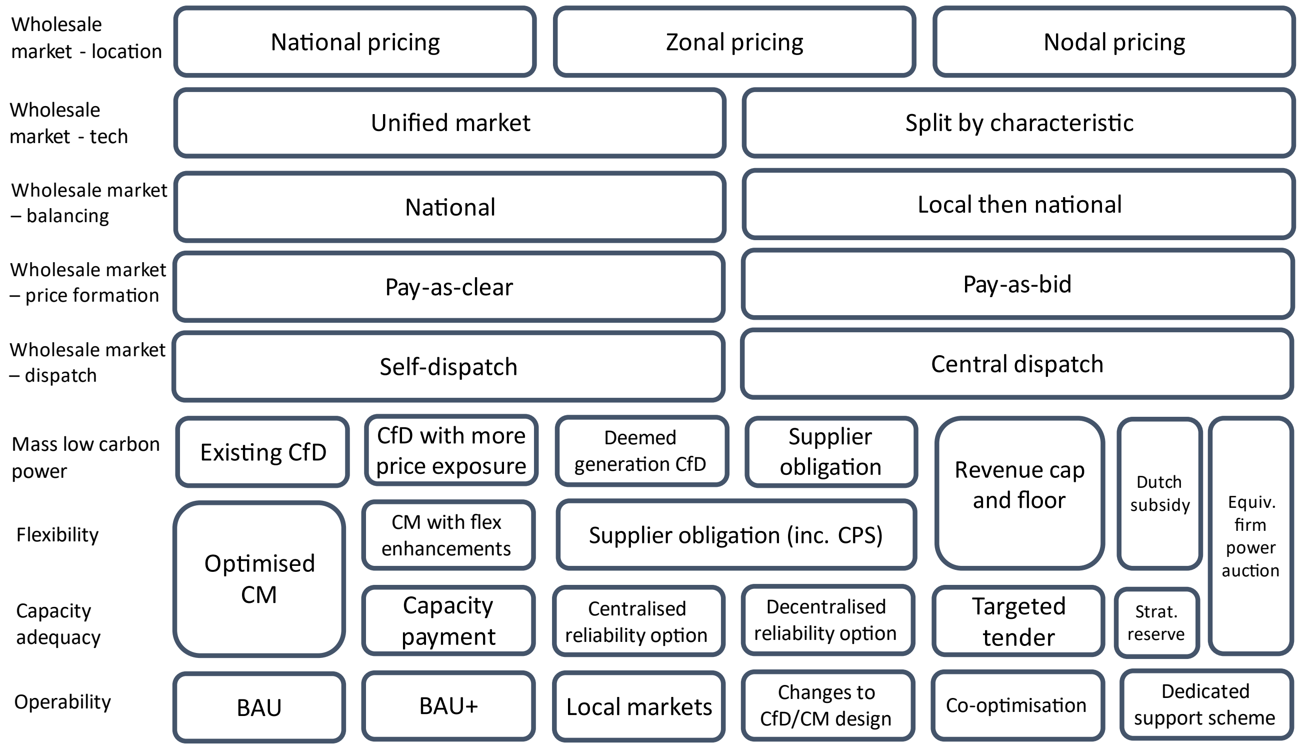


Figure 7 - options under consideration

Approach to options assessment – packaging

We have not constructed packages of reform at this stage: as Figure 8 shows, we are consulting on a large number of options, which need to be narrowed down further before we can consider possible combinations in a reasonably comprehensive, and sufficiently detailed, way. We are also open to new options being proposed as part of this consultation. Moreover, there is a high degree of compatibility between options, meaning choices in one area do not go very far in defining overall packages. For these reasons, we are seeking to further narrow down our options before we begin packaging.

In the remaining chapters, our focus is on narrowing down options which are unlikely to fit into any optimal packages.

Packages of options will include at least one option from each row in Figure 8; but could include more than one, for example if two (or more) options are needed to ensure all kinds of flexibility are incentivised appropriately. Some options in different areas will have similar impacts, and we will take this into account when constructing packages: for example, if the wholesale market sends sharp signals for flexible behaviour, there may be less need for support for investment in flexibility. There are also asymmetrical dependencies between elements of market design: for example, the optimal scheme for ensuring capacity adequacy depends on the nature of the capacity gap, which in turn depends on our wholesale market design and scheme for supporting low carbon investment. We will take all these considerations into account when constructing and assessing packages.

We will aim to construct policy packages which are distinct enough to be effectively compared, and which achieve a different balance in terms of how they address the challenges we have identified. We will assess packages against:

- Our objectives (chapter 2), including – for example – whether the package has sufficient locational signals, and whether it provides enough incentive for smaller-scale and demand-side technologies;
- Our criteria (this chapter);
- A range of other considerations, including coherence (how well options work together and with the rest of the electricity system, including whether they risk distortions or have potentially unintended consequences, and whether they avoid duplication), and comprehensiveness (whether packages achieve everything we want them to achieve);
- Statutory obligations; and
- The possible impact of reforms on the nature and location of electricity assets and the wider industrial, social and environmental impacts this could have.

Question

6. **Do you agree with our organisation of the options for reform?**
7. **What should we consider when constructing and assessing packages of options?**

Chapter 4. Cross-cutting questions

There are a number of cross-cutting questions and issues arising from our consideration of options for market reform, which will need to be addressed as part of this Review. In this chapter we set these out and discuss the trade-offs between different approaches to resolving them.

Questions:

8. **Have we identified the key cross-cutting questions and issues which would arise when considering options for electricity market reform?**
9. **Do you agree with our assessment of the trade-offs between the different approaches to resolving these cross-cutting questions and issues?**

The role of the market

Market forces are a central part of the electricity system. The complexity of organising the activity of all the various generators and consumers into an efficient whole means that the kind of spontaneous ordering that markets can provide will be necessary to ensure cost-effectiveness. However, there will always be a key role for central institutions. The government will set the overall vision for the system, and establish market structures that meet societal objectives. The government is ultimately responsible for guaranteeing that everyone has access to electricity so they can participate in society; for securing the public goods of decarbonisation and security of supply; and ensuring that our markets are fair so that they work for all of us. The regulator, Ofgem, needs to ensure that our markets are working effectively, including by enforcing regulations, and to encourage innovation on the part of market participants; and the system operator is needed to provide important functions from second-by-second balancing of electricity supply and demand, to developing markets for operability services.

If our market arrangements are designed optimally, and our markets are working well, decisions about what, where and how much to build (i.e. investment decisions), and what should be turned on and off at which times (i.e. operational decisions), would be primarily driven by the interactions of generators, suppliers and consumers responding to price signals in the market; and the government would only need to intervene if it became clear that we were likely to miss a key objective. Businesses would invest in low carbon capacity, including both renewables and flexibility, based on what they expect to earn in the wholesale market (and other markets). Consumers – including domestic consumers with smart-charging electric vehicles and heat pumps – would choose time-of-use tariffs, or certain other smart tariffs. and adjust how much electricity they demand (and supply) based on changing prices. This electricity market would be open, with consumers at its heart, and would deliver the kinds of innovation that will be critical to achieving net zero at least cost.

But our assessment is that market forces alone are currently unable to deliver our objectives. A range of market failures – set out in more detail in our case for change – mean it will not deliver the investment in the kinds of capacity we need on its own, either to meet our decarbonisation or security of supply targets. In addition, many of the risks and opportunities of the transition to net zero are policy-dependent, or have significant distributional impacts across society, and so are potentially unsuitable to be wholly managed by private interactions in the wholesale market. Government intervention of some form will likely still be necessary, to ensure that we transition to a fully decarbonised power sector quickly, fairly, and at least cost. We will pursue solutions which maximise the role of the market where possible; but there is a strong case for continued intervention – including through the establishment of other markets in which the government plays a more central role – to deliver objectives which cannot be independently met by the market.

Extent of competition between technologies

Effective competition between technologies is a key driver of delivering a least cost capacity mix. The government has set strong ambitions for the power sector, to encourage investment in technologies which we know we will need, but there is significant uncertainty as to what the most efficient system will look like. The wider the range of technologies competing, particularly on the demand-side, the more likely it is that the lowest cost solution will be found; and greater competitive pressure tends to spur innovation. In particular, as we move towards an electricity system which is dominated by renewables, the potential benefits of competing different technologies against each other will grow, because our system requirements will become more complex, and it will be more difficult to determine the most efficient solutions administratively. It is hard to predict how quickly technology costs will fall, and which ones will prove most cost efficient and effective. So our general approach is to seek out options which widen the degree of cross-technology competition, as this is key to achieving our objective of cost-effectiveness.

But there can be limits to the effectiveness of competition between different technology types. First, it may be difficult to design a single market that appropriately values all the attributes that the electricity system needs, and fairly takes into account the very different characteristics of participating technologies, like how much of their cost is upfront or ongoing, or the kinds of risk they need to manage. One technology may consistently win contracts because its characteristics mean that it delivers the output that the competition rewards, but without necessarily delivering the wider range of benefits that the system requires. The Capacity Market, for example, has a high degree of cross-technology competition, but has historically been dominated by unabated gas plant with low capital costs, and low carbon assets with higher capital costs have struggled to participate. This is in line with the design of the scheme, but shows that the difficulties of designing a market that reflects overall system value – the result is that wider competition does not always provide the greatest benefit to the system. Second, immature technologies may need protection from competition as they develop, and the necessary enabling infrastructure is put in place. Once these technologies are on a level playing field that protection can be removed, to allow competitive pressure to deliver low-cost outcomes.

Finally, we need to consider the wider benefits that some technologies provide. For instance, CCUS will play a key role in decarbonising industry as well as power, and shared infrastructure is required to achieve these economy-wide objectives. Steady offshore wind development has significant industrial benefits as the domestic supply chain grows. These economy-wide benefits will affect the outcomes that competition should seek to achieve, but they are not a justification for permanent support. We recognise that wider competition is not always better, or even possible; and that cross-technology competition needs careful design in order for it to be effective.

Extent of decentralisation: where decisions are made

There is a related question about who should be responsible for investment and operational decisions within our markets, to best deliver our ambitions for the sector.

Greater decentralisation puts decisions in the hands of a more dispersed set of market participants, including suppliers, generators, consumers, distribution networks, and local and combined authorities. These market participants will have better information about their own assets, business models and networks. This enables them to identify opportunities to coordinate and join up infrastructure investments to increase efficiency, and – through their connections to local communities – to better articulate the wider socio-economic benefits of the energy transition. For example, some local and combined authorities are developing cross-sectoral strategies to reach net zero and local plans which will have implications for local decarbonisation pathways and electricity demand, and which will require forward planning of investment in infrastructure.[27]

There is a rationale for harnessing the value of this information; and setting out the role of regional and local actors, and combined local authorities to help design the future energy system.

Furthermore, this approach incentivises market participants to continually improve their own information, in order to make better decisions, and to refine and innovate their business models. Accurate market signals, coupled with the digital transformation of the energy system, are an essential enabler for the efficient deployment of distributed resources. As market participants get access to more comprehensive data, they will become better informed and have the potential to make better decisions, and our market arrangements should facilitate this where possible. The continued uncertainty about the exact shape of the future electricity system means innovation and adaptability will be critically important, and these are most likely to be deliverable when decision-making is responsive and decentralised. Finally, decentralised approaches can more easily incorporate both supply and demand-side technologies, meaning they are more likely to support electricity demand reduction and flexible demand.

However, while market participants will have better information about their own and their customers' situations, they will be less well-informed about the wider system. For example,

[27] Government and Ofgem are working together to consider the role local and regional energy planning could play in delivering net zero and supporting efficient network planning, including considering the respective roles of national governments, local government, a Future System Operator, distribution network operation and other key stakeholders for energy planning.

they will not be fully aware of the impact their decisions have on other participants, or how their actions contribute to the overall functioning of the system. More widely, we recognise that various interconnected aspects of the electricity (and broader energy) system, beyond our market arrangements, are changing simultaneously. The required pace of the energy transition makes this necessary; but it also means that we need to actively ensure that our whole system works together as a coherent unit, and this continues to be the case all the way to 2035 and 2050. Our objectives are system-wide: decarbonisation, security of supply and cost-effectiveness require synergy across the whole system; and delivering them with confidence will mean a level of joined up, strategic decision-making. To ensure our objectives are met, then, there is also a case for a more centralised approach, putting decision-making in the hands of a narrower set of central bodies. These central bodies will have better information about the system as a whole and will be able to take a wider set of factors into account – including social benefits that the market does not value – when making decisions. Some investments will also benefit from economies of scale when decisions are made at a system level, and the supporting infrastructure needed for a low-carbon system would be difficult to deliver without a degree of coordination. And there are delivery risks associated with decentralised models: they require a wider set of organisations, each with differing capacity and capability, to collectively deliver an outcome.

We are cautious about how far decentralised models can go, whilst recognising their advantages. Where we are confident that market participants have better information, and that this means that their decisions will lead to more efficient outcomes, it is right to give them greater responsibility. But we also acknowledge that our objectives will only be achieved if all parts of the system are co-ordinated effectively, so some decisions may be better if made centrally. There may also be intermediate options which strike a balance between the benefits of local involvement in, and central oversight of the national energy system.

Role of marginal pricing

The wholesale market is based on marginal pricing,[28] which means the cost of the most expensive generation asset sets the price for the entire market. The marginal price reflects the value of consuming or generating an additional unit of electricity at any given time, providing an efficient signal for supply and demand decisions. Given the current role of gas generation within the GB electricity market, this also means that the current GB wholesale electricity price tends to closely track gas prices, which are largely set by global market developments.

The marginal price model has been adopted by the majority of liberalised electricity markets. As the market price reflects the value of an additional unit of electricity at all times, this model provides efficiency, transparency, and incentives to keep costs down. Furthermore, the electricity system must become increasingly flexible, so competitively-determined, real-time marginal price signals are essential for reflecting the true needs of the system.

The impact of gas fired power generation on the GB electricity price will naturally diminish over time, as it becomes a small proportion of the generation mix, and increasingly cheap-to-

[28] Energy in the wholesale market is traded in multiple ways, including on exchanges and bilateral trades. Across all these platforms the expectation of the marginal plant will have a role in price formation.

operate renewables, rather than gas assets, set the price for the market. However, some low carbon technologies will still be exposed to international commodity prices. For instance, power CCUS relies on gas as an input fuel, and hydrogen generation could be exposed to gas prices to the extent that the hydrogen price is determined by the cost of gas. Under a marginal pricing system, these technologies are likely to be price-setting when they are generating, and so their load factors (how often they generate) will partly determine how much the electricity price is driven by the gas price. The increasing interconnections between the GB and other electricity markets may also strengthen the relationship between domestic and international electricity prices.

Furthermore, the marginal pricing model may become less desirable as we transition towards a majority renewable system. The cost structure of renewables means that most of their system costs will be in construction rather than in operation. A model that incorporates this cost structure could better reflect the underlying characteristics of the system and provide benefits such as protecting assets from price cannibalisation. For example, one option of this kind involves splitting the wholesale market, so that some renewables receive an average price, independent of the marginal cost of production (discussed in more detail in chapter 5).

For these reasons, we are exploring reforms that move away from marginal pricing. These options are novel, and in some instances only theoretical. Given the scale of change these types of reform would entail more evidence is needed on their deliverability and impact.

Minimising financing cost and maximising operational signals

We also need to consider the role of market arrangements in driving down the cost of capital investment as well as maximising the operational efficiency of the system. For most technologies, exposure to market signals is essential to ensure assets operate in way that provides value to the system. For these technologies, such as low carbon flexibility, strong price signals will improve their investment case. However, variable renewable assets are limited in their ability to respond to price signals, so there is a greater trade-off between financing costs and operational signals. As mentioned above, the electricity system will become increasingly characterised by the cost profile of renewable assets: high upfront capital costs of construction, followed by very low operating costs once the assets have been built. This means that how expensive our renewable capacity is will be largely driven by the cost of financing, i.e. the interest and other costs incurred when borrowing funds to build these assets (as well as the efficiency of building cost-effective capacity in the right parts of the network). There is a strong case for a market design that minimises investor risk, to reduce financing costs and allow construction of renewable assets to be realised at least cost. This was a key priority for our reforms under EMR; the CfD scheme provides renewable investors with a fixed price for 15 years. Investors are protected from wholesale market price risk and are paid the strike price as long as the wholesale price is above zero.[29] These long-term, low-risk contracts have been successful in bringing down the cost of capital of these projects, and alongside

[29] Under the negative pricing rule, CfD payments are not made during periods of negative wholesale electricity prices (i.e. when the Intermittent Market Reference Price is negative)

competitive auction and global technology innovation, have driven down strike prices and provided value for money for consumers.

Nevertheless, insulating renewable assets from market conditions can create problems for the operation of the system. A renewable generator with a CfD gets paid the same amount regardless of the market price for electricity, so has no incentive to respond to this price. Market signals are a very effective way of allocating resources in the short run, but if assets do not respond to these signals they may not dispatch in the most optimal way for the system. Moreover, the lack of such exposure limits the incentive for renewable assets to act more flexibly, for example by co-locating with storage, or providing system services like synthetic inertia. So there is also a strong case for greater exposure to market signals. Investors would be incentivised to manage these market risks when investing in and operating their asset. This could include building an asset in a different part of the network, with less correlated renewable resource to capture higher wholesale prices, or to develop flexibility (for example electricity storage) as part of their portfolio, in order to better manage volatile prices.

Ultimately, our view will be determined by the evidence on the relative benefits of lower financing costs and more efficient system operation. This will build on work that has been ongoing throughout the development of the CfD scheme. Evidence will continue to be gathered as future CfD auction rounds are delivered to ensure the development of our support schemes aligns with the direction of the future market design. The right balance of exposure to market signals will also depend on the type of technology in question, and the wider risks that investors face. Flexible assets will need greater exposure to market signals, as their value to the system is dependent on responding when the system needs them.

More accurate price signals and the benefits for consumers

There is a further question about how price signals can be used to incentivise more flexible behaviour, and to capture the upside of this behaviour for consumers, whilst guarding against the risks. In a renewables-dominated power system, flexible behaviour from both demand and supply will be vital in ensuring energy can flow to where it is needed at the right time.

Several options have been identified that could drive the significant increase in flexibility required to efficiently operate a high-renewables electricity system. The net zero wholesale market chapter considers options that would enable that market to play a leading role in bringing forward flexible behaviour, by sending accurate price signals to demand and supply that indicate the value of producing or consuming more or less electricity at specific times and places. When market signals lead to more efficient demand and supply behaviour, the amount of generation and costly new network capacity that is needed to meet increasing electricity demand can be minimised.

This would come with considerable upsides for consumers. For instance, non-domestic consumers could take these price signals into account when deciding where to locate new investment; others (such as domestic consumers with electric vehicles and smart heat pumps) will be able to choose services that allow them to respond automatically to changing prices throughout the day. This will be beneficial to these groups themselves, as they can avoid consuming (and therefore paying) for electricity at times of peak prices when electricity is scarce, and consume greater volumes when electricity is plentiful and prices are low. It will also benefit those consumers who are unable or unwilling to flex their demand: for example, if enough demand is deferred from peak times, this will dampen wholesale price spikes, making electricity more affordable for all.

Prices that vary by time of day and location have the potential to significantly reduce costs for consumers. But we will also need to consider other impacts on consumers carefully, particularly those on low incomes, including as part of the parallel refresh of our energy retail market strategy. Specifically, there is a question about how to ensure they can manage the greater price volatility which comes with more accurate price signals, even if overall energy costs were reduced. There could be a trade-off between these overall cost reductions and the risk of exposing consumers to higher prices which they cannot respond to. Suppliers will have a key role to play in encouraging consumers who are less engaged, or live in areas with network constraints, to flex their demand. There are a range of options to mitigate against potential disparities between flexible and inflexible consumers. For example, exposure to varying price signals could be limited to the generators only, or through schemes which offset higher prices in particular locations. Exposure to price signals could be optional. But such options would reduce the incentive for consumers to shift their demand in time and place, thereby reducing the benefits to the overall electricity system.

The scale of change: delivering our objectives throughout the transition

Our reforms need to both deliver our 2035 objectives and set us on the path for meeting 2050 commitments. This means creating an effective market design for the 2030s, once the market is closer to a ‘steady state’, but also minimising disruption during the transition to that state. There is a strategic question about how transformational our reforms need to be.

There is a case for revolution: the energy system is already changing radically, with fossil fuelled plants being replaced by technologies with very different characteristics. Renewables have a different cost profile, provide a different kind of power (intermittent, rather than firm), and are more likely to be located in certain parts of the country. Our market arrangements will need to keep pace with this transformation in our underlying capacity mix, and this may only be possible through radical change.

There is also a case for evolution. We already have a set of market arrangements which work well at delivering key aspects of our objectives, including the successful deployment – and cost reduction – of renewables through our CfD scheme, and the maintenance of security of supply through the Capacity Market. Investors are comfortable with these schemes, and the transformational alternatives tend to be untested models which need careful consideration before they could be put in place. Given the unprecedented scale and pace of deployment required in order to meet our 2035 commitment, we need to maintain the confidence of investors to keep financing costs low, and so ensure that any reforms continue to bring forward the level of investment required in a cost-efficient way.

We want to keep both revolutionary and evolutionary approaches on the table; and we recognise that the best approach may be some combination of the two, potentially on different timescales. We recognise that there is a growing misalignment between our market arrangements and the core technologies which produce the power that is sold in our market, and that this is likely to necessitate fundamental reform at some stage in the transition. The most cost-effective solution may be to undertake this reform whilst the problems it is seeking to resolve are mostly important future concerns, rather than waiting until they are immediate issues. But it remains possible that we could resolve our most pressing concerns with minimal disruption through gradual change, and only undertake transformational reforms once we have arrived at a more 'steady state' market. We are exploring all possible options in this Review, with deliverability a key criterion in our assessment. If we conclude that radical change is needed, we will set out a clear pathway for the transition from existing arrangements, which ensures investment in low carbon capacity remains an attractive prospect throughout.

One example of the balance we need to strike is in our approach to ensuring security of supply in the transition to 2035. As older plants retire, and as demand increases through the rapid electrification of heat and transport, we have a capacity gap to fill. To do this our market will support investment in new capacity, including unabated gas before low carbon flexibility can be built at scale. However, we know decarbonising unabated assets where possible will be key to hitting our decarbonisation targets whilst retaining capacity on the system. This summer we will publish our consultation on proposals expanding Decarbonisation Readiness requirements, so that all new build and substantially refurbishing combustion power plants will have to demonstrate a viable plant for decarbonising by retrofitting either CCS or hydrogen generation technology.

Delivering more accurate locational signals

The case for change highlighted the need for more accurate locational signals, for generators, demand and storage, to locate and operate in a manner that minimises system and consumer costs. It also set out the potential benefits of such signals, including reduced spending on network reinforcement and generation capacity, lower system operation costs, and a reduction in carbon emissions through reduced re-dispatch of thermal assets.

Our current wholesale market arrangements send both investment and operational signals, but do not generally provide these signals for location (except to a limited extent through the balancing mechanism), and so are unlikely to be sufficient to address the locational challenge we face. Investment locational signals are sent through network usage and connection charges.[30] These can be paid upfront, based on peak capacity/demand, or on total generation/usage. Operational signals at transmission level are sent predominantly through the balancing mechanism, where the ESO redispatches generators to avoid network limits being breached. However, this signal is muted, as ESO instructions address a variety of system needs beyond thermal locational constraints. At the distribution level, network operators have started to introduce flexibility tenders and other mechanisms to help alleviate local network

[30] The methods for calculating the charges vary substantially depending on voltage levels they apply on.

constraints.[31] It is important to note that these locational challenges are strongly linked to the state of our network – as it is the physical manifestation of location in the system.

How might locational signals be introduced?

There are a number of options for delivering stronger locational signals under consideration. These options include:

- Moving to zonal or nodal wholesale pricing;
- Introducing locational signals into renewable support schemes and/or capacity adequacy mechanisms;
- Locational imbalance pricing; and
- Network access and/or charging reform (in conjunction with Ofgem).

We will expand on our thinking about the options for introducing locational signals in the next phase of REMA. Many of the options discussed in the following chapters could be modified to reflect locational costs.

There are a range of options for sending operational locational signals. However increasing locational signals would result in winners and losers and the overall balance of costs and benefits needs to be assessed. Many of the options require significant changes to existing arrangements and would need to be introduced carefully.

Alongside introducing locational pricing (zonal or nodal), or introducing locational imbalance charges (discussed in Chapter 5), low carbon support schemes could also be adapted to ensure they are compatible with more granular locational signals in the market. For example, CfDs could be adapted to work alongside locational wholesale pricing by internalising changes to zonal or nodal prices. This could be done by making adjustments to top-up payments on an hourly basis, accounting for price differentials across different zones or nodes. Another way of sending locational operational price signals is by defining access rights to the network, which could determine curtailment according to pre-defined rules, such as giving priority to existing generation over new entrants. Expanding local markets, operated by distribution network operators, could also be a way of providing stronger locational flexibility signals at lower voltage levels. Modifications could also be made to the Balancing Mechanism, or to network charging arrangements (e.g. varying charges throughout the day).

Investment locational signals could be sent more widely, going beyond use of network and connection charges. Those could be sent through locational wholesale prices, or through adequacy or low carbon support mechanisms which directly drive investment. For instance, mechanisms for ensuring capacity adequacy could reflect the relative capacity scarcity in some zones versus others in their clearing prices, or auctions could be split geographically. Alternatively, location could be introduced into support schemes for low carbon investment in the future, weighting bids to reflect expected network conditions and the impact on useful

[31] In the first half of 2021, the ENA reported 1.6 GW of flexibility was procured across the DNOs' five main products.

output or balancing costs. We will also consider wider changes proposed by the sector, such as David Newbery's yardstick CfD' model, which is based on providing generators with a strike price for a fixed number of full operating hours, separating revenue received from actual output, and uses a regional spot price to determine the "top-up" received (see discussion of 'deemed generation CfD in chapter 6).[32]

Any proposals on locational signals will need to be assessed alongside ongoing and future network charging and access reforms, for which Ofgem is responsible. Additionally, locational signals will need to work alongside proposed changes by the Offshore Transmission Network Review and the wider move to a more strategic, whole-system approach to planning the electricity network as we will set out in the joint Government/Ofgem Electricity Networks Strategic Framework, which is likely to be undertaken initially by the ESO and then by the Future System Operator once established.

Questions:

10. **What is the most effective way of delivering locational signals, to drive efficient investment and dispatch decisions of generators, demand users, and storage? Please provide evidence to support your response.**
11. **How responsive would market participants be to sharper locational signals? Please provide any evidence, including from other jurisdictions, in your response.**

Electricity demand reduction

The decarbonisation of our electricity supply, and the forecast rise in demand, will together require the building of costly new generation and network capacity. Reducing total electricity demand can therefore minimise system and decarbonisation costs, as less capacity will need to be built, whilst lowering GB dependence on gas-fired electricity generation. It also benefits consumers and local communities through reduced bills, warmer homes, job creation, and improved air quality.

Electricity demand reduction currently struggles to – or cannot – compete across electricity markets, while its system benefits are likely undervalued. Permanent demand reduction through energy efficiency is different in nature to dynamic and responsive technologies such as generation or flexibility. Although demand reduction creates benefits for the system over given time periods, it cannot be dispatched or respond to system events. For this reason, it is challenging to set market arrangements that allow energy efficiency to compete effectively with other technologies (see 'extent of competition between technologies', above).

At present, the only energy market signal which electricity demand reduction responds to is the wholesale price, as well certain avoided network and policy costs. In contrast, generators and flexible assets have access to multiple revenue streams, allowing them to build a more

[32] Newbery, D., 2021, 'Designing Efficient Renewable Electricity Support Schemes', Cambridge Working Papers in Economics. The proposal also includes providing non-firm connection access rights, and deferring revenues when curtailment is expected.

comprehensive investment case. For example, energy storage can access revenues from the wholesale, balancing, capacity, local flexibility, and ancillary services markets.

There have been some examples of distribution networks using energy efficiency as an alternative to network reinforcement. Under the RIIO-2 price controls,[33] distribution networks have an obligation to consider energy efficiency as a network intervention where it is cost effective. Distribution networks do now include electricity demand reduction as an option in their tenders for alternatives to network build. However, few (if any) energy efficiency projects have won contracts, due to other barriers such as demonstrating a causal link between implementation and peak electricity demand reduction and a lack of data on the energy savings potential.

One possibility is to develop a specific electricity demand reduction mechanism. To date, the only trial in the UK was the Electricity Demand Reduction pilot (2014-2017), which tested whether energy efficiency could be procured as a capacity resource through a capacity market-style auction. It concluded that energy efficiency projects were not yet ready to compete in the Capacity Market due to low clearing prices and inability to meet minimum capacity requirements. The pilot evaluation noted that significant changes would likely need to be made to the Capacity Market to accommodate energy efficiency.

There are multiple international examples of energy markets where electricity demand reduction competes alongside other energy resources. In some markets electricity demand reduction is treated as a capacity measure. In the United States in New England, and the multi-state programme run by the system operator PJM, electricity demand reduction is procured in 'forward capacity' auctions by the megawatt (like the UK Capacity Market). In other markets, for example California, Switzerland and Portugal, electricity demand reduction is procured by the megawatt-hour, often based on a methodology where the rate paid to projects is based on the avoided cost of delivering electricity in specific periods.

Possible approaches

The design of energy efficiency and low carbon heating schemes and regulations is outside the scope of REMA and is not being considered in this publication. REMA will consider whether and how electricity market design should further incentivise electricity demand reduction. We believe there are several ways this could be done:

- Primarily relying on existing energy efficiency policies, however in addition providing additional support through new standards, metrics or platforms to facilitate uptake of electricity demand reduction measures. For example, making it easier for distribution networks to contribute funding to energy efficiency schemes where it reduces network costs.
- Building appropriate incentives for electricity demand reduction to compete with other technologies across markets. For example, low carbon and capacity adequacy investment mechanisms, and strengthening distribution network operator incentives,

[33] Electricity Distribution Standard Licence Condition 31E

following the next price control (ED2) to invest in energy efficiency solutions (this is an area of Ofgem responsibility). This would be technically challenging due to the non-dispatchable nature of demand reduction.

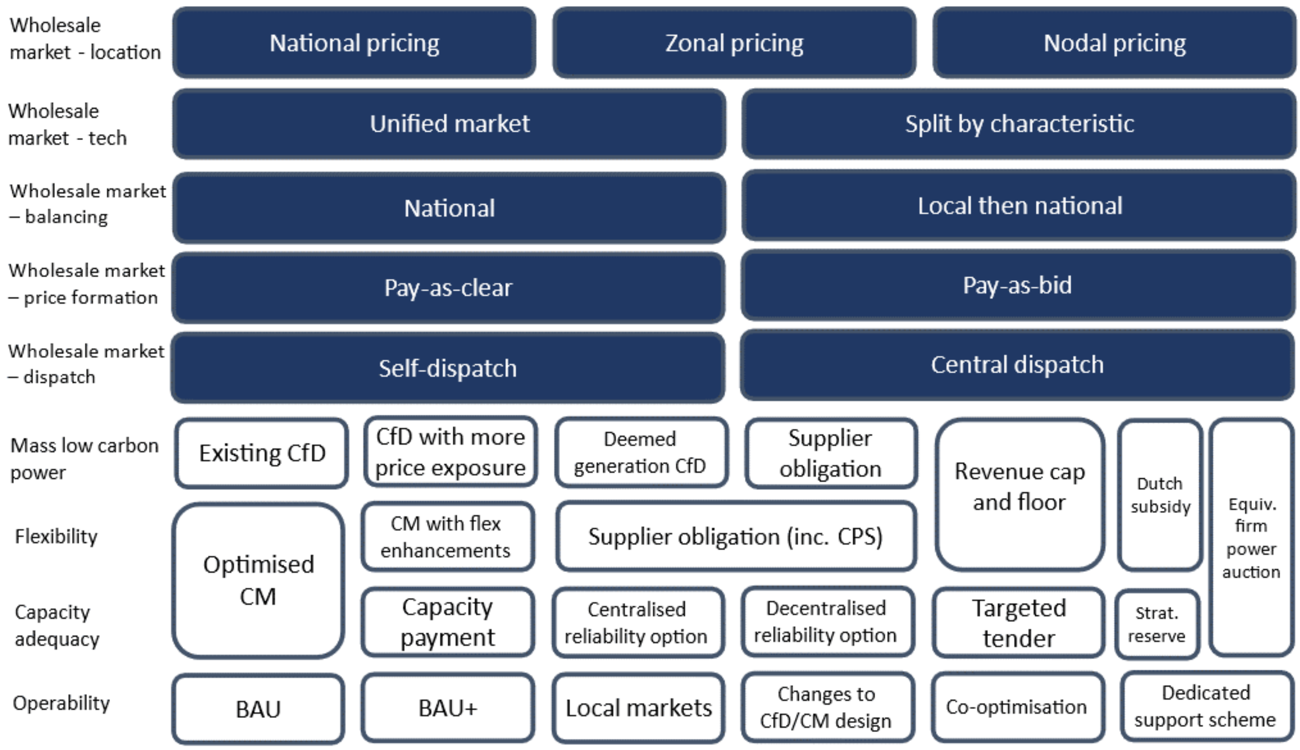
- Creating a bespoke mechanism for electricity demand reduction where electricity demand reduction alone, or electricity demand reduction and other demand-side technologies, would compete against one another.
- Choosing a REMA option (for example a supplier obligation) where electricity demand reduction may be naturally incentivised through market arrangements.

We will consider how any potential reform across the other workstreams will incentivise or hamper electricity demand reduction. For example, we will consider how certain options such as a supplier obligation (Chapter 6) or Clean Peak Standard (Chapter 7) could incentivise demand reduction, and whether demand reduction could compete in auction mechanisms discussed in the low carbon, flexibility and capacity adequacy workstreams (Chapters 6, 7 and 8). We will also consider how demand reduction could be treated in options that consider the role of distribution networks, including local balancing (Chapter 5) and local flexibility markets (Chapter 7).

Question:

12. **How do you think electricity demand reduction should be rewarded in existing or future electricity markets?**

Chapter 5. A net zero wholesale market



Challenges and opportunities of the status quo

As our electricity system decarbonises, the wholesale electricity market will need to provide sufficient investment and operational signals for low carbon generation. As set out in our case for change, existing wholesale market arrangements alone are unlikely to deliver this: so we are exploring whether there is a case for fundamental wholesale market reform, as well as whether smaller improvements to current arrangements can help meet our objectives.

Our existing wholesale market arrangements – understood as the system of trading established by the British Electricity Trading and Transmission Arrangements (BETTA) in 2005 – are based on the following core principles: national pricing (all generation and all demand receive the same wholesale price, irrespective of their physical location or system impact of their operation), with locational signals being provided through network charges; technology neutrality (all technologies can, by and large, compete in the same set of markets – though there are exceptions); and self-dispatch (generators self-schedule and commit their output, with National Grid ESO handling any necessary balancing action). There is a balancing mechanism to incentivise supply matching demand.

The growth of renewables is leading to a growing mismatch between our trading arrangements, which were designed for fossil fuelled plant, and the market's core technologies. This will result in a range of challenges that our wholesale market arrangements will need to overcome, as well as opportunities, if we can meet the challenges effectively.

These include: price cannibalisation (set out in our case for change), missing money (the fact that revenues for generators do not accurately reflect the value of investment in reliable energy supply), a lack of sufficiently granular temporal or locational price signals, a lack of investment signals for low carbon flexibility, the fact that prices are set by the most expensive plant (usually gas), and the limited visibility of generation and demand at the distribution level. These challenges, and the uncertainties around the possible extent of them, are explored in the 'assessment of current arrangements' section of the case for change; here we discuss the issues of liquidity and ensuring the right operational signals for flexibility.

Liquidity

Volatility in the wholesale and balancing markets is likely to increase, driven by both sudden changes in renewable generation and demand, e.g. when temperatures fall and electric heating demand increases. High power prices have caused difficulties for market participants over the last year when gas prices have been very high. Sufficient market liquidity is needed in order for all market participants to have suitable trading strategies in place to manage the risks associated with high energy prices and increased market volatility.

Liquidity is a key issue for wholesale market design, as – for example – the size of the trading zone, or whether trading in a central pool is mandatory, are likely to impact on liquidity across different timescales. We will therefore need to consider how any reforms to the wholesale market, as well as reforms to investment support mechanisms discussed in subsequent chapters, might impact on liquidity in general, particularly in forward markets.

Operational signals for flexibility

We are taking a 'twin track' approach to market reform for flexibility. In this chapter we focus on options for enhancing operational signals; in chapter 7 we consider options to strengthen investment signals for the deployment of flexibility.

It is imperative that we get the operational signals for flexibility right (i.e. accurately signalling to assets when and where to generate or consume energy in accordance with system needs), otherwise we risk not maximising the full value of our capacity mix, and potentially adding to problems such as network constraints. These signals will be strengthened – through increased price volatility – as more variable renewables deploy throughout the 2020s, creating significant opportunities for flexibility providers. We expect to see prices fluctuate in accordance with this variability across time and location, revealing the value of flexibility. But reform may be needed to ensure these signals are accurate and granular enough to support the full range of flexibility we require, on both the supply and demand side and at both the transmission and distribution level; this chapter considers options for achieving this.

These strong, granular operational signals may be sufficient to generate investment in flexible assets. However for some assets, particularly with high upfront capital costs, this may not be the case: so in chapter 7 we consider options for supporting investment in flexibility.

Options assessment

Summary

This section sets out the main approaches we are considering for addressing these challenges. These are:

- splitting the market into separate markets for variable and firm power;
- introducing locational pricing, either zonal or nodal;
- reorienting the market towards the distribution network ('local markets');
- moving to pay-as-bid rather than pay-as-clear pricing; and
- maintaining the fundamentals of the status quo, with incremental reforms of parameters such as gate closure.

These options remain at a high level, with detailed further evidence-gathering and analysis required on each; for this reason, we are proposing to take all of them forward for further consideration. They are not mutually exclusive and solve different issues: we consider them separately for ease, but it is possible to envisage workable (if complex) combinations between them.

Many of these options represent fundamental redesigns of wholesale electricity markets. The wholesale market is the foundation of the electricity system as a whole; as such, these options would have signification implications across the system, and would take time to design and implement. Business models for all market participants would be likely to change; existing support schemes would need to be updated, including those considered in this consultation (CfD and Capacity Market) but also, amongst others, the Dispatchable Power Agreement for power CCUS, the Regulated Asset Base model for large-scale nuclear, and the interconnector cap and floor; the System Operator would require new infrastructure and system changes; and there would need to be changes to retail market regulation to ensure that households and large electricity users continue to be appropriately protected. For these reasons, implementing any of these options (beyond some elements of 'evolving the status quo') would be likely to take a number of years.

We welcome views on our analysis of specific options, particularly where respondents have evidence about the impact that options would have, or on how risks we identify could be overcome.

Question:

13. **Are we considering all the credible options for reform in the wholesale market chapter?**

Splitting the market

One key choice is whether there should be separate markets for variable and firm power. The most detailed proposal of this kind is Malcolm Keay and David Robinson's 'two markets' model, which we take as representing the approach in general.[34] This model is at a very early stage of development: we are not aware of any existing market which follows this structure, and a wide range of crucial design questions remain to be answered.

Splitting the market is primarily proposed as a solution to price cannibalisation, and the resulting price volatility (i.e. fluctuations between lower price periods of high renewable output, and higher price periods of low renewable output). Prices in the variable, 'as available' market would be set on the basis of the long-run marginal cost of renewables (i.e. factoring in all the costs of producing that unit of energy, including building a new plant); prices in the firm, 'on demand' market would continue to be set by short-run marginal cost (i.e. only factoring in the cost of producing an extra unit of energy, mostly made up of fuel costs). If this were successful, prices in both markets would be more stable and predictable, as both would tend to reflect the average long-run cost of the generators participating in them (because fuel costs make up a high proportion of the total cost of non-renewable generators). The CfD scheme currently isolates renewables and remunerates them at their long-run marginal cost; a split market would embed this approach into the structure of the wholesale market itself, and extend it to the demand side as well: both the lower cost and the variability of renewable electricity would be passed onto consumers in the 'as available' market, whilst consumers in the 'on demand' market would pay a premium for the firmness of supply. Most consumers would participate in both markets but those who were able to flex their demand more could purchase a higher proportion of their electricity from the 'as available' market (though in practice, for domestic consumers, such decisions would likely be made by their supplier). For example, a consumer could choose a tariff under which they only charge their EV battery with 'as available' power, unless the battery is at less than 20%.

We see four main advantages to this approach:

- It would decouple the electricity price from the gas price in the 'as available' market, reducing reliance on fossil fuel fired generation and helping to resolve the issues of price cannibalisation and volatility, which impede investment in a range of key technologies.
- It enables the discovery of the value of flexibility. Consumer behaviour – how much people are willing to shift their demand in order to capture the lower prices of the 'as available' market – would reveal their preferences about variability, and would allow different consumers to reflect how much they value supply 'on demand' in their consumption decisions, rather than having this value set administratively and on behalf of all consumers (which is set by the 'value of lost load').
- It would provide strong incentives for demand-side flexibility: the price differential between the two markets would provide arbitrage opportunities for technologies able to shift demand in time.

[34] Keay and Robinson, 2017, The Decarbonised Electricity System of the Future: The 'Two Market' Approach, Energy Insight.

- It is one of the few options under consideration which represents a potential alternative to continued government support for investment in the long run. In the shorter term, investment support (as discussed in the 'mass low carbon power' chapter) would be a necessary complement, to ensure investor confidence; but in the future splitting the market could potentially enable all types of investors to recoup their costs through market revenues alone (though a mechanism to ensure security of supply is likely to continue to be needed indefinitely).

These are substantial benefits, if they can be realised, and so we believe this model merits further consideration. But this model remains an untested, conceptual approach, with a number of potential downsides. These include:

- The number of fundamental design questions still be answered: for example, how prices would be formed in the 'as available' market; how the two markets would interact (e.g. would all 'as available' power be consumed before any 'on demand' power?), how costs would be recovered, the system would be balanced across the two separate markets, and how responsibility for ensuring network operability would be managed.
- The extent to which a split market would deliver additional benefits. Many of the benefits of splitting the market come from sending more granular temporal signals to consumers, but some of these benefits will be delivered by the move to half-hourly settlement: what additional benefits splitting the market would deliver remains an open question.
- Reduced competition. Splitting the market in two could lower liquidity and, by extension, lead to lower competition in each market compared to the status quo. It is also unclear which technologies would compete in each market – for example, interconnectors or biomass could conceivably compete in either the “on-demand” or “as-available” market.
- The transition to a split market would require careful management, to avoid a hiatus in investment.
- Consumer protection risks: engaged consumers should be able to take advantage of the two markets to reduce their bills, and suppliers would have a key role in packaging access to the two markets into products that consumers would value. However, if this model results in greater complexity of consumer offers or more variability in price signals, then detailed wholesale and retail market design will need to ensure that ensure that consumers, particularly vulnerable consumers, do not suffer undue detriment if they do not engage with the market.
- The extent to which a split market would deliver additional benefits. Many of the benefits of splitting the market come from sending more granular temporal signals to consumers, but some of these benefits will be delivered by the move to half-hourly settlement: what additional benefits splitting the market would deliver remains an open question.
- Reduced competition. Splitting the market in two could lower liquidity and, by extension, lead to lower competition in each market compared to the status quo. It is also unclear which technologies would compete in each market – for example, interconnectors or biomass could conceivably compete in either the 'on-demand' or 'as-available' market.

Many of these issues arise from the degree of transformation required to split the market fully. An incremental variant on this option, such as the green power pool proposed by Michael Grubb and Paul Drummond, could avoid some of these drawbacks, and could be implemented sooner.[35] A green power pool is motivated by the same desire to isolate renewables from the rest of the market as the two markets model, but primarily in order to pass on the lower costs – and higher variability – of renewables to consumers, rather than as a solution to gas setting the price of electricity, price cannibalisation and volatility (though it would make some impact on these issues as well).

Under this option, the System Operator would manage a pool for renewable power, which would operate alongside the existing wholesale market: in effect, a centrally co-ordinated Power Purchase Agreement (PPA) market.[36] Participation in the pool would be on a voluntary basis. Renewable generators would contract with the System Operator to sell their power into the pool at their long-run marginal cost – from their perspective, contracting with the pool would resemble having a CfD. Consumers – on Grubb and Drummond's conception, mostly industrial and commercial consumers – would sign standard contracts to purchase electricity from the pool, which would be cheaper than the wholesale market but with greater variability. Consumers could choose how much variability they would be willing to accept in exchange for what degree of price reduction. The System Operator would be responsible for balancing the pool: any imbalances would be covered through purchases from the wholesale market, the cost of which would be spread over all consumers in the pool.

How far this approach could capture the benefits of a fully split market, whilst mitigating its downsides, remains an open question. The extent to which these benefits could be achieved through power purchase agreements under our existing market structure is also unclear.

Questions:

14. **Do you agree that we should continue to consider a split wholesale market?**
15. **How might the design issues raised above be overcome for: a) the split markets model, and b) the green power pool? Please consider the role flexible assets should play in a green power pool – which markets should they participate in? – and how system costs could be passed on to green power pool participants.**

Introducing locational signals: locational pricing

A second key choice is whether more granular locational signals should be sent by the wholesale market price. Our current GB wholesale market design has a single national electricity price, which applies to the entirety of the network. This means all generation and all demand receive the same wholesale price, irrespective of either their physical location or the

[35] Grubb and Drummond, 2018, UK Industrial Electricity Prices: Competitiveness In A Low Carbon World, https://www.ucl.ac.uk/bartlett/sustainable/sites/bartlett/files/uk_industrial_electricity_prices_-_competitiveness_in_a_low_carbon_world.pdf

[36] Power purchase agreements are long-term bilateral contracts to supply energy between power producers (typically generators) and consumers.

system costs/benefits associated with their operation. Long-term locational signals are provided by network charging.

National pricing means the wholesale price does not send signals to market participants that incentivise them to operate and locate in a way that is consistent with the physical needs of the system. As set out in the case for change chapter above, this has given rise to significant operational and balancing issues, such as increased network constraint costs, as the share of renewables generation has increased.

An alternative would be to introduce more granular locational signals into wholesale electricity prices, through locational energy pricing models.

These models include both nodal pricing designs (or locational marginal pricing, “LMP”) and zonal (regional) pricing, discussed in more detail below.

Locational wholesale pricing

Nodal pricing is an electricity market design where the price in each location in the transmission network (also known as a “node”) represents the locational value of energy. With nodal pricing, the physical constraints of the network – capacity and losses – are reflected in the market clearing process, with the associated costs fed through to the wholesale price.

Nodal pricing has been implemented in several electricity markets in the USA, in New Zealand and Singapore, and is currently being implemented in Ontario, Canada. Design and implementation vary across these jurisdictions. For example, some jurisdictions expose both demand and supply to locational prices, while others only expose generators, and allow consumers to ‘opt-in’ to locational prices (a number of markets settle the demand side on a zonal price to reduce the complexity for the retail market). A common feature of most nodal markets is some form of central dispatch market clearing, due to the complexity of balancing the network across the high number of nodes. It is unlikely to be practical to extend nodal pricing to the distribution network, so it would be important to ensure coherence between nodal pricing on the transmission network and actions taken locally, such as local flexibility markets.

The implementation of nodal pricing with central dispatch in GB would require complex design choices that would need careful consideration to ensure inflexible, vulnerable, and fuel poor consumers were not disproportionately impacted (see Chapter 1 for further discussion of this point).

An alternative to nodal pricing is zonal pricing, which is the established arrangement in the internal European energy market. Under zonal pricing, the network is split into clearly defined zones. The boundaries of the zones are drawn to reflect where major transmission network constraints occur. In Europe, this is typically between different countries, but can be within countries (e.g. Italy’s electricity market comprises seven zones).

In a zonal market, each individual zone has a single price which (like the current single national price) assumes no network constraints within the zone. Where zonal pricing applies on both the supply and demand side, a supplier will pay for energy at the same price it receives for selling energy within a single zone. Where the price for energy differs between two zones, a supplier will pay the difference between the price in the zone it was generated and the price in the zone where the energy is supplied, with the cost difference being the cost of network congestion between the two zones. System operators calculate and notify the values of capacity available between zones.

We see the following advantages of nodal and zonal pricing compared to our current arrangements:

- Locational pricing (both nodal and zonal, to differing extents) sends locational signals in operational timeframes. This means that energy system users in each location are encouraged to produce or consume in a way that benefits the system as a whole, given the physical limitations of the transmission network. For example, interconnectors and storage assets are more likely to flow in the 'right' direction, exporting energy when the network is constrained, and importing to relieve constraints.
- Under a fully nodal pricing system, the wholesale market itself would resolve network congestion. This could deliver significant consumer savings, as consumers would no longer pay generators compensation payments when they cannot operate because of limited transmission. In a zonal system, the market also internalises the costs of network congestion and losses to some degree, leading to more efficient locational and dispatch decisions (to the extent that network constraints are reflected in how zones are drawn).
- Locational wholesale prices would send strong locational investment signals for all generation, storage, and demand which is exposed to the wholesale price to site in locations that reduce system costs. This would enable more efficient network development, through increased transparency of where network constraints are, how frequently they occur, and their economic importance. It could also bring some first-of-a-kind low carbon technologies to new locations.
- Locational wholesale prices would also provide enhanced price signals to all market participants, rather than only those participants that are able to contract with the ESO in the balancing mechanism or through ancillary services. This could enable greater participation of demand-side response and distributed energy resources.

For these reasons, we believe locational wholesale pricing merits further consideration. But we have also identified several challenges that would need to be addressed before either a zonal or nodal model could be recommended. For instance, it is uncertain what proportion of the potential benefits of locational wholesale pricing could be realised, given our future capacity mix. In practice, sources of supply and demand are often limited in their ability to relocate in response to more granular locational price signals. In particular, renewables need to locate where it is windy or sunny, and – particularly for wind – that often means at the fringes of the network in GB. This could lead to increased investment costs for comparatively little benefit.

We also see the following challenges specific to a nodal pricing model:

- Full nodal pricing on both the supply and demand side would have differential impacts on consumers, with prices in some parts of the country likely to fall and in others likely to rise. This could have distributional (and other) impacts, which would need careful consideration. One possibility is to limit consumers’ exposure to nodal pricing, for example through either zonal or ‘opt-in’ nodal pricing on the demand side; this would mitigate the potential distributional impacts, but could also dampen the locational signals passed onto demand-side assets, limiting the potential efficiency gains.

- Dividing the current national market into hundreds of smaller markets raises concerns for liquidity within the bidding zones, though the precise impact on market liquidity is unclear.
- The large volume of individual nodes could lead to reduced predictability of short-term prices, meaning increased risk through uncertainty. This may require the implementation of new financial tools – such as Financial Transmission Rights – to allow market participants to hedge the risks associated with locational variability. Another option is the creation of defined marketplaces, which could help improve liquidity. These mitigations would come with additional implementation costs, and their effectiveness in international markets has been mixed.
- Operating a nodal pricing market requires the continuous calculation of prices at all nodes on the network. This would require the implementation of new IT systems by both the ESO and market participants, and may require changes to the roles (and therefore systems) of other industry parties.
- The transition to nodal pricing would require careful management, to minimise disruption for market participants and avoid a hiatus in investment. In comparison, the zonal market design is potentially compatible with current self-dispatch arrangements, and provides incentives to operate and invest in higher-priced zones without the complexity of hundreds of nodes. This could reduce the extent of reform required compared to nodal pricing.
- The compatibility of a nodal market design and the European zonal market design, so that interconnectors continue to be dispatched efficiently.
- Zonal pricing could bring some first-of-a-kind low carbon technologies to new locations, potentially easing network congestion as a result.

The main challenges we see specific to a zonal pricing model are:

- The potential for disproportionate market manipulation – for example, a generator located at an export-constrained node can sell power in the day-ahead market and then buy it back at a lower price at the redispatch stage (the “increase-decrease game”).
- Difficulties in defining the boundaries of each zone. Zones could potentially need to be frequently redrawn to reflect changes in the key transmission constraint boundaries – otherwise significant inefficiency could arise. This could create regulatory risk for market participants, with the process to update the definition of zones requiring the careful balancing of many different interests. As the deployment of renewables continues, zones may need to be redrawn frequently to ensure the accuracy of the price signals.
- Uncertainty about the extent to which zonal pricing delivers increased dispatch efficiency. As noted above, zonal pricing offers a simplified representation of network

congestion relative to locational marginal pricing, but at the expense of providing more granular locational signals. This means that efficiency gains in dispatch may be blunted as a result – a case in point is the Australian National Electricity Market, originally established as a zonal market but which now plans to move to nodal pricing, as the zonal model has not provided sufficient incentives to encourage generation to site at the most efficient locations.

Questions:

16. **Do you agree that we should continue to consider both nodal and zonal market designs?**
17. **How might the challenges and design issues we have identified with nodal and zonal market designs be overcome?**
18. **Could nodal pricing be implemented at a distribution level?**

Introducing locational signals: local markets

A third approach aims to re-orient the wholesale market around local, distribution-level markets, either through new local market structures or locational imbalance pricing. We are not aware of any markets that have applied these in practice.

One variant of this model of this kind has been proposed by Thomas Pownall.[37] He proposes a separate market (pool, balancing, and ancillary services) at each connection between the transmission and distribution networks, overseen by distribution network operators (DNOs). Participation would be voluntary. DNOs would be responsible for balancing the local market and ensuring its operability: they could procure from other markets to do so (either other local markets or the national wholesale market). The national wholesale market would continue to exist and would be reconfigured to co-ordinate with these new local markets. The System Operator would be responsible for overseeing the national markets and would have responsibility for residual national issues on the grid.

An alternative model has been proposed by Pol Olivella-Rosell.[38] In this model, Smart Energy Service Providers run local markets, in which the local distribution networks, consumers, storage owners and distributed generators participate. All trades go through the Service Provider, which supervises the operation of the local market and acts as an aggregator, able to participate in (national) wholesale markets. There are local day-ahead, intraday and balancing markets for consumers who are connected to the local grid and want to participate in the local market, but participation in these markets is entirely voluntary, and broader wholesale market mechanisms are retained.

Another approach that could provide locational signals at the distribution level would involve the introduction of 'locational imbalance pricing.' In this model, the network would be divided

[37] Pownall, Soutar and Mitchell, Energies, 2021, 'Re-Designing GB's Electricity Market Design: A Conceptual Framework Which Recognises the Value of Distributed Energy Resources'.
[38] Olivella-Rosell et al., Energies, 2018, 'Local Flexibility Market Design for Aggregators Providing Multiple Flexibility Services at Distribution Network Level',.

into local 'zones' at each grid supply point (or potentially at a more granular level), and suppliers would face charges if there were a both an imbalance and a constraint between the location of their consumers' demand and their generators' supply. These charges should incentivise suppliers to source power locally rather than nationally. This would aim to reduce network constraints, with imbalance prices initially being higher in areas that currently face elevated constraints.

Our view is that these distribution-led approaches warrant further investigation. They are the only approaches to wholesale market design we are aware of that put the distribution network – and so the growing volumes of distributed generation and demand, which will increasingly define the electricity system – at its heart, and could lead to a least cost system overall. Nevertheless, the specific models we have considered are very complex. This complexity suggests substantial deliverability challenges, particularly around the large number of new actors and market participants they involve; and also leads to potential risks for liquidity, market power, and gaming. Further work is needed to understand a) the costs and benefits relative to our current arrangements, b) how the GB market might implement a local market model or imbalance pricing in practice; and c) the potential role of sub-national institutions, including combined authorities, in supporting the delivery of a distribution-level approach.

Questions:

19. **Do you agree that we should continue to consider the local markets approach? Please consider the relative advantages and drawbacks, and local institutional requirements, of distribution led approaches.**
20. **Are there other approaches to developing local markets which we have not considered?**

Moving to pay-as-bid pricing

The GB wholesale electricity price is currently broadly determined by marginal pricing, meaning all generators receive the same price as the most expensive unit of generation procured. Electricity exchanges operate on a pay-as-clear basis, meaning all generators receive the price of the most expensive accepted bid, and bilateral trades tend to converge with the marginal price. This means prices represent the cost of procuring an additional unit of electricity, and so reflect the current balance of supply and demand in the market.

Gas plants are frequently the marginal plant in GB, meaning the price of gas generation often sets the wholesale electricity price. Wholesale electricity prices will be exposed to gas prices for as long as gas plants are the marginal plant, even as the proportion of gas generation decreases (as all the illustrative scenarios we have considered assume a role for power CCUS and hydrogen-fired generation in the electricity system.

An alternative approach is pay-as-bid, where participants receive the price of their bids/offers, rather than the bid of the highest priced supplier selected to provide supply. This could be a way to decouple prices from the gas price, and to reduce wholesale electricity prices, if generators lower down the merit order were to bid below the current marginal price. However, generators are likely to bid strategically, and have an incentive to bid at the price of the most expensive offer accepted. This means that the average bid could be close to the expected marginal price, meaning reductions in wholesale electricity prices may not materialise. This risk could be mitigated by introducing a limit on the price that individual technologies can bid into the market.[39] These would result in a 'cost-based' market design.[40] For example, participants could be required to report the technical characteristics of their assets, which would allow a central body to calculate their marginal costs. Bids which are greater than the estimated marginal cost would be rejected. This would require a monitoring and compliance regime to ensure participants provided complete information.

A move to pay-as-bid would require a fundamental change in the regulation of the wholesale market, including a move to central dispatch arrangements, and a mandatory power pool. It could substantially reduce the incentive for flexibility, as assets are paid based on their cost of production, rather than the value of an additional unit of electricity at a given time or location. It would also reduce the investment signal provided though wholesale market revenue, as lower cost generators would not profit when higher cost generators are setting the price. This would likely require changes to investment support schemes, to ensure that generators were about to recover their construction costs. Furthermore, demand uncertainty and the difficulty in establishing the marginal plant may result in inefficient dispatch. Strategic bidding may create distortions in the merit order, as plants with lower costs of generation may bid higher than those with a higher cost. More work would need to be done to determine whether pay-as-bid could provide a net reduction to wholesale electricity costs.

Question

21. **Do you agree that we should continue to consider reforms that move away from marginal pricing?**

Evolving the Status Quo

Alternatively, it may still be possible to address many of the challenges we face by amending some of the parameters of the existing market, without undertaking any of the more transformational reforms discussed so far. These choices include:

- changes to dispatch arrangements, from self-dispatch to central dispatch;
- changes to settlement periods and gate closure to increase temporal granularity in the market; and
- changes to the Balancing Mechanism (e.g. introducing improved locational signals).

[39] In the Mexican wholesale electricity market firms are required to provide technical information, and the system operator compares the price component of the offers against the calculated marginal cost and rejects offers that lie outside a 10-percent tolerance band. However, the Mexican market is pay-as-clear.
[40] A cost-based market design limits the price generators can offer to sell their electricity at to the generator's direct operating costs. A bid-based market design does not limit the generators offers.

The logic of this approach would be to minimise disruption by sticking as close as possible to our existing arrangements, and delivering more of the necessary reforms through changes to other elements of our market arrangements.

First, the current market in GB operates on the basis of self-dispatch: generators are responsible for dispatching their portfolio to meet their declared position, based on their availability and capacity for each settlement period. The day ahead and intraday markets exist to facilitate changes to these positions, and generators can change their position up until gate closure (one hour before real time). After gate closure, the balancing mechanism operated by the ESO provides a final opportunity for aligning generation with demand, but changes in balancing timescales can result in higher costs, due to limited availability of efficient options at late stages in the market when providers may have finalised their position.

The main alternative to this is central dispatch, which is prevalent in US electricity markets. Under central dispatch, participants notify the system operator of their availability ahead of time through day ahead and intra-day markets. This allows the operator to schedule generation and dispatch in cost order with all participants paid the market clearing price. A key advantage of central dispatch is that it moves the burden of optimisation from market participants to the System Operator, which is able to take a market-wide view and consider additional factors such as network constraints in its scheduling. Central dispatch could be more efficient as a result, with balancing, congestion management, and reserve procurement performed simultaneously. Optimal day-ahead clearing could be achieved so long as bids reflect all costs truthfully.

However, some central dispatch models leave less room for adaptation, when dispatch decisions are taken well ahead of delivery time (though some markets with central dispatch, for example in New Zealand, take dispatch decisions close to real-time). Under self-dispatch, intra-day trading can allow for adjustments to be made under competitive pressures much closer to real time.

Second, changes to the timescales of market settlement and gate closure may be effective ways of making the most of the opportunities for flexibility across the system. Although electricity is produced and consumed continuously, the market is divided into discrete windows known as ‘settlement periods’, to facilitate its functioning. In GB the settlement period is 30 minutes; there are 48 settlement periods per day. Shortening the settlement period would allow prices to be more reflective of actual market conditions, incentivising generation and demand to respond to the state of the system more frequently.

Gate closure is the cut off between market-driven changes in position and system operator actions (currently one hour ahead of real time in GB). Reducing the gate closure interval could help all generators make their final positions more accurate, and could reduce the need for balancing action.

Our current settlement period and gate closure time provide greater granularity than markets in some other jurisdictions, and less than others; we will continue to explore the possibility of shortening these periods, which could help drive flexibility, as well as making changes to other market parameters.

Third, changes to improve the Balancing Mechanism could help optimise the system and drive down costs passed onto consumers. The Balancing Mechanism is the primary tool the ESO uses to balance supply and demand in real time and ensure appropriate security margins are in place. The changing characteristics of the electricity system come with a new set of challenges for balancing in real time. A system with large volumes of renewables located in areas of higher wind or sun levels (and often further away from demand) will mean the ESO needs to take action more frequently to manage locational constraints, whilst an increase of assets located on the distribution network increases the need to make full use of local assets, in particular through use of flexibility technologies.

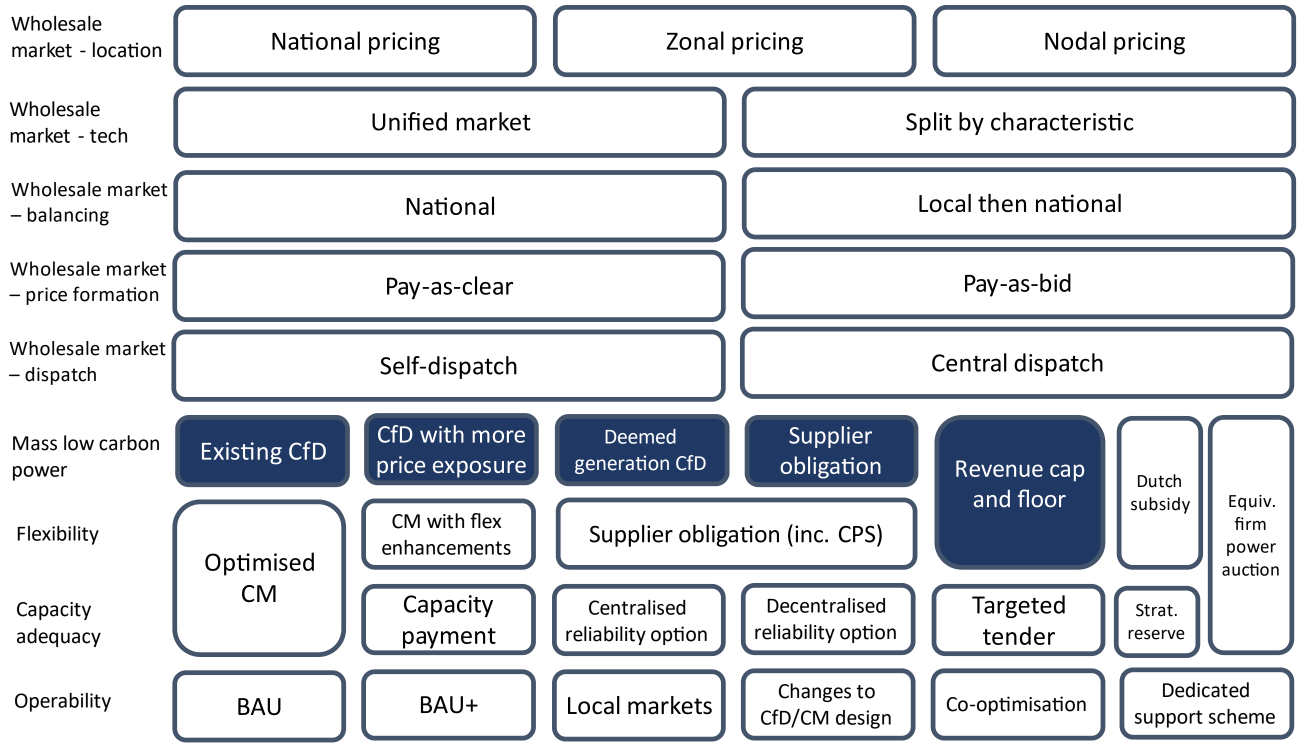
Recently, there have been significant increases in balancing costs. Last winter costs in the Balancing Mechanism rose to over £1.5bn from an average of £0.5bn over the previous four winters[41]. We note the ESO's ongoing review of the Balancing Mechanism in light of the high balancing costs last winter. There are a number of ways to reform the Balancing Mechanism to address this rise in costs, including introducing price caps or changing licence conditions to directly restrict excessive Balancing Mechanism offer prices, managing the extent to which generators can amend their schedule at short notice, strengthening locational signals within the Balancing Mechanism, or changing its bidding structure. We will explore these options, amongst others, in more detail as part of the next phase of REMA.

Questions:

22. **Do you agree that we should continue to consider amendments to the parameters of current wholesale market arrangements, including to dispatch, settlement and gate closure?**
23. **Are there any other changes to current wholesale market design and the Balancing Mechanism we should consider?**

[41] In the winter months November to February. Calculated using data from National Grid ESO, Monthly Balancing Services Summary (MBSS), 2022, https://www.nationalgrideso.com/industry-information/industry-data-and-reports/system-balancing-reports

Chapter 6. Mass low-carbon power



Challenges and opportunities of the status quo

Meeting our 2035 commitment to decarbonise the electricity sector means delivering significant investment in new low carbon electricity capacity. This chapter considers options for supporting this investment in the low carbon technologies which we expect to produce the majority of low carbon electricity. In general, these are technologies which will be generating whenever possible rather than flexibly. Renewables are at the heart of this: we have set a world-leading ambition of up to 50GW of offshore wind, including up to 5GW of floating offshore, by 2030, and the expectation of a five-fold increase in the deployment of solar by 2035, supporting sustainable and competitive domestic industries and tens of thousands of high-quality green jobs in the areas that need them most. Also in scope are energy from waste, and potentially small modular reactors in the long run.

As we set out in the case for change, support is needed because – due in large part to the phenomenon of price cannibalisation[42] – wholesale market revenues alone will not be sufficient to deliver the unprecedented volumes of investment we require. Any support scheme will also need to meet a range of challenges, including considering how and whether to tackle muted

[42] Where wholesale market revenues fall during periods of high renewable output, due to the low marginal cost of renewables and the fact that they tend to generate simultaneously. See chapter 2.

locational signals and limited market exposure for supported generators. These challenges are set out in more detail in the 'assessment of current market arrangements' section of Chapter 2.

Under current market arrangements, the CfD scheme provides certainty to investors in low carbon projects, by guaranteeing a pre-determined 'strike price' for every MWh generated. If the real-time market price is below this, they receive a top-up. If it is above, they must pay back into the scheme (over £39m was forecast to be paid back in Q4 of 2021).[43] In each round the strike price is set through a competitive auction and contracts are awarded for 15 years. Some renewables are supported through legacy schemes such as the Renewables Obligation and the Feed-in-Tariff, and a small number of assets sign Power Purchase Agreements (long-term bilateral contracts), often with industrial and commercial consumers. Under the terms of the Smart Export Guarantee, suppliers with more than 150,000 domestic customers are also required to offer an export tariff to customers with small-scale generation.

The existing CfD scheme has been hugely effective at driving down the cost of capital, which – given the cost profile of renewables, with high capital costs and near-zero running costs – will continue to be a considerable, perhaps dominant, proportion of total system costs. The long-term price certainty it provides is attractive to investors, who are comfortable with the scheme. Increasing global deployment has spurred innovation and reduced technology costs, while competitive auctions have driven down strike prices and provided better value for consumers. The current pot structure ensures that a range of technologies, with diverse generation profiles, are supported. The contract structure can also provide consumer protection against high electricity prices, as generators pay back revenues above their strike price.

Nevertheless, the design of the CfD and other aspects of the market come with some limitations. These are likely to become more prominent as CfD-supported assets become a greater proportion of the generation mix. Among the limitations are that the CfD limits exposure to market signals for a significant portion of asset life, incentivising assets to run whenever possible; does not incentive assets to locate optimally for system needs; and does not facilitate competition with low carbon flexible assets. Full insulation from price risk also removes the need for generators to hedge, reducing market liquidity.

Options assessment

Summary

This section sets out the main approaches we are considering to for addressing these challenges. These are:

- a supplier obligation;
- the current CfD scheme;
- CfD variants with increased price exposure
- a revenue cap and floor; and

[43] LCCC, 2022, Reconciliation of Q4 2021 payments sees CfD portfolio paying back to electricity suppliers, https://www.lowcarboncontracts.uk/news/announcement/reconciliation-of-q4-2021-payments-sees-cfd-portfolio-paying-back-to-electricity-suppliers

- a CfD based on deemed generation

The majority of the options under consideration retain competitively allocated, long-term, private law contracts between generators and a government-owned counterparty, as these seem likely to remain the most cost-effective way of delivering our investment requirements for Carbon Budget Six. The lower borrowing costs that come with a bankable long-term contract, combined with competition for those contracts, work to keep the cost of capital low, which benefits consumers as capital costs are expected to be one most significant costs in our future low carbon system.

The only option under consideration which does not rely on such contracts is the supplier obligation, under which investment would be underpinned by market contracts between generators, suppliers, and intermediaries (though some versions of the supplier obligation could still involve government underwriting of contracts, at least in the early stages). This could lead to a more efficient capacity mix overall, and possibly more business model innovation, but would likely entail additional financing and delivery risks, which would need clear mitigation before this option could be recommended.

However, all options under consideration – apart from the existing CfD – would increase the role of the market, whether through greater exposure of those contracts to prices, or in the allocation of those contracts, in order to minimise costs which are passed to consumers.

Two options which value something other than the delivery of power, the Equivalent Firm Power auction or auctions by the cost of abatement, are discussed in chapter 11.

We welcome views on our analysis of specific options, particularly where respondents have evidence about the impact that options would have, or on how risks we identify could be overcome.

We also welcome proposals from respondents on how market arrangements could better value the low carbon and wider system benefits of small scale, distributed renewables. Under the Smart Export Guarantee, large suppliers are required to offer small-scale, distributed renewables (<5MW) an export tariff but the rate of that tariff is discretionary, and current market arrangements and administrative costs means they may not reflect the low carbon and wider system benefits of these smaller assets. This is an area in which the options for reform are less clear; it is possible that the reforms proposed in the wholesale markets chapter (particularly relating to sharper temporal and locational price signals), the supplier obligation model described below, and existing work (particularly through the Smart Systems and Flexibility Plan) to remove barriers to entry for smaller scale assets, could help drive deployment.

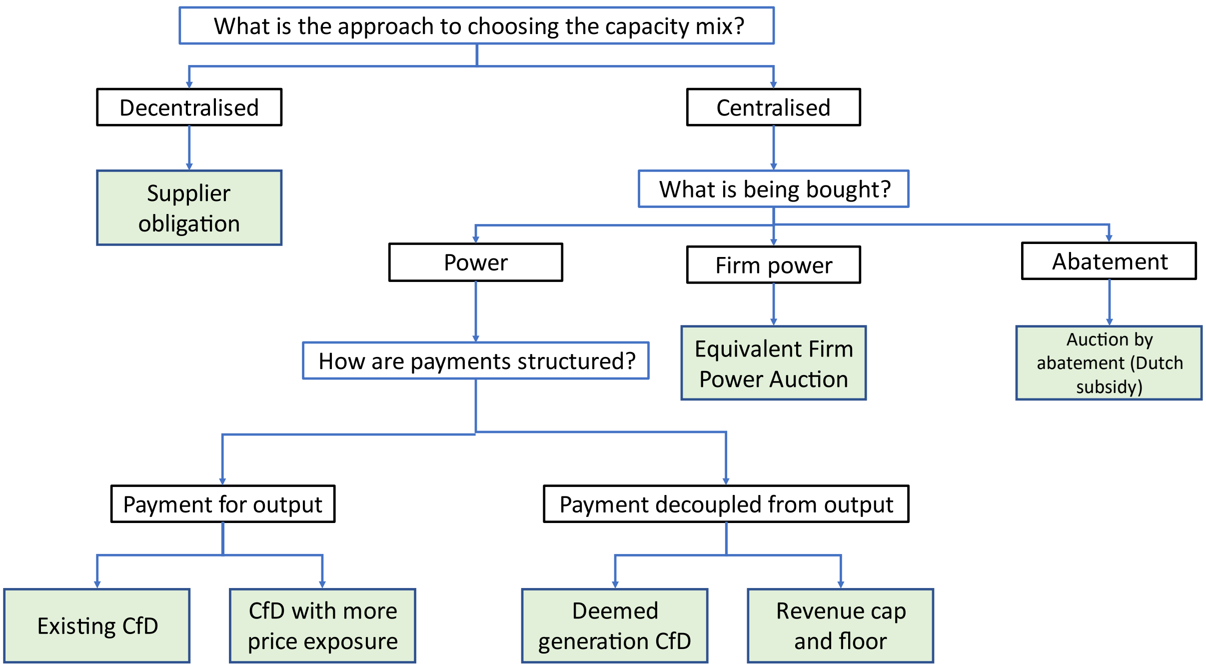
Questions:

24. **Are we considering all the credible options for reform in the mass low carbon power chapter?**

25. How could electricity markets better value the low carbon and wider system benefits of small-scale, distributed renewables?

Grouping options

Below is a decision tree which sets out, at a schematic level, the key choices which define the different options under consideration. It is intended to be illustrative, not exhaustive; we welcome feedback on whether there are other choices which should be included, or whether there are further possible variations which we have not considered.



Supplier obligation

The main decentralised approach under consideration is an obligation on electricity suppliers to procure green electricity directly on behalf of their consumers. The government would set a trajectory of maximum carbon intensity of electricity that electricity suppliers can sell to their customers, aligned with Carbon Budget Six and net zero, and suppliers would contract either directly with generators, or through an intermediary.

A decarbonisation obligation offers advantages which few other options under consideration can match. Most importantly, investment decisions are market-driven. This reduces the risk of the government making inefficient decisions about the future capacity mix, and maximises the potential for cross-technology competition. This differs from past measures, including the Renewables Obligation scheme, as suppliers have more freedom as to how they meet their obligation, rather than having to procure from Ofgem-accredited plants. They would therefore play a key part in decisions about the capacity mix, and would create more direct incentives for smaller-scale and demand-side flexibility, and electricity demand reduction. This would also create more incentives for innovation, both in terms of technologies and business models, which will be critical to least cost decarbonisation. An obligation could also send more effective locational signals, as generation assets could be rewarded for building in locations which best matched suppliers' demand profile.

The key risks with this option are financing and delivery. In the existing supplier landscape, the counterparty risk of contracting with suppliers would be high, and so any obligation would require intermediaries between generators and suppliers to pool and hedge this risk. These intermediaries could be financial institutions or large utilities; alternatively, there could be a role for the government or the System Operator to manage this risk, for example if there was a supplier obligation to procure electricity from a green power pool (see chapter 4 on the wholesale market). Any increase in counterparty risk would likely lead to higher financing costs for renewable projects. Although intermediaries could mitigate counterparty risk, a greater number of organisations involved in developing projects could lead to additional costs. There is also a question about whether suppliers are well-placed to manage the delivery of billions of pounds of investment needed to meet Carbon Budget Six and net zero. Our parallel work on retail market reform will seek to address the current challenges facing the retail market, but the full impact of this may not be realised for a number of years. There is also a risk that more established technologies with similar generation profiles would be preferred by suppliers, meaning less-mature technologies, with the potential to become more affordable over time, are not deployed.

Questions:

26. **Do you agree that we should continue to consider supplier obligations?**
27. **How would the supplier landscape need to change, if at all, to make a supplier obligation model effective at bringing forward low carbon investment?**
28. **How could the financing and delivery risks of a supplier obligation model be overcome?**

Central contacts with payment based on output

The current CfD scheme is a contract paid on output, and options in this section are all variations of the existing CfD. The CfD scheme is constantly evolving, and specific changes will continue to be considered before each allocation round. The main difference between options in this section is the level of market exposure for CfD-supported generators.

One option is to retain the current CfD scheme in the long term, under which generators receive their pre-agreed strike price, except for when wholesale prices are zero or negative (as this is a signal that the grid is oversupplied). The scheme has been hugely successful in delivering renewables to date, meaning this would retain investor confidence, and should help to keep financing costs down for developers, and therefore consumers. It is well-tested and familiar to industry, helping to ensure a steady flow of investment. The main drawbacks of this option, in addition to those set out above, are that market insulation reduces signals to innovate or behave more flexibly, and so reduces the incentive for generators to respond to the needs of the system or to adapt to future changes, and may increase the risk of oversupply in the market or continuation of challenges above.

There is also a risk that as price cannibalisation increases, and periods of zero or negative pricing become more common, additional uncertainty is created and the CfD becomes less effective at de-risking investment. From allocation round 4 (July 2022), generators are no longer paid in these periods, as insulating them from the market here creates perverse incentives for them to generate when the grid is already over-supplied. Schemes that pay on output can only de-risk investment by encouraging plants to generate, which limits options when we also want to prompt more flexible behaviour.

The other options in this category are CfD variants with increased price exposure, either during the length of the contract or shorter contracts to increase the amount of time (after their contract expires) that generators are fully exposed to market signals. This could include:

- **A CfD with a strike range**: instead of a single price, plants are guaranteed a maximum and minimum price per MWh output, with market exposure within that range.
- **Changes to the reference price methodology**: for example by setting CfD top-up payments for an entire week, with opportunities for profit or loss if plants do better in the market than the weekly average.

These may be desirable if evidence suggests that developers will innovate in ways that increase whole-system flexibility and reduce overall costs to the system, and in the British Energy Security Strategy we committed to consulting on these kinds of changes for CfD Auction Round Six. These potential benefits must also be weighed against increased financing costs, which are a significant proportion of overall system costs.

All of these options are subject to second order questions of auction design, such as pot structure or technology eligibility. These types of decisions can be made ahead of specific rounds, to reflect the benefits of competition and specific government ambitions for deployment.

Questions:

29. **Do you agree that we should continue to consider central contracts with payments based on output?**
30. **Are the benefits of increased market exposure under central contracts with payments based on output likely to outweigh the potential increase in financing cost?**
31. **Do you have any evidence on the relative balance between capital cost and likely balancing costs under different scenarios and support mechanisms?**

Central contracts with payment decoupled from output

One option of this kind is a revenue cap and floor. Under this option, which follows the precedent of the interconnector cap and floor, generators would be guaranteed a minimum revenue in each period. They would compete in the full range of markets (capacity, wholesale, balancing, ancillary services), and if they do not meet their minimum revenue, then they would be topped up at the end of the period. There would be no transfer if their revenue was between the floor and the cap. If their revenue was above the cap, a proportion of the excess would be paid back – we are interested in views on how the cap could be designed to avoid disincentivising valuable behaviour, whilst ensuring value for money. The floor would be set competitively, likely on a £/MW basis. This option could also enable cross-technology competition: a cap and floor scheme could support both renewable and flexible assets, and it is possible that, in the longer run, they could compete against one another for the floor (see further discussion of the cap and floor in the flexibility chapter).

This option would provide investors with confidence, as their minimum revenue would be guaranteed – this kind of guarantee has been sufficient to unlock 10.9GW of investment in interconnectors since 2013.[44] As long as the floor is set low enough, assets will still be incentivised to seek returns across all markets: if these markets are designed appropriately, this should reward flexible behaviour. It should also deliver value for money, as there would be no top up for any plant which surpasses their floor: there have been no top up payments under the interconnector cap and floor for this reason (though price cannibalisation might mean renewable assets would be more likely to require topping up than interconnectors). The potential for renewables and flexibility to compete in the same auction could lead to a more efficient capacity mix, though more work is required to ensure such competition would be effective (this option is also discussed in the next chapter, on flexibility).

An alternative option is a CfD based on deemed generation, in which plants are paid based on their potential to generate in a particular period, rather than their actual generation behaviour. This means generators would not have to export energy to receive their CfD top-up payment, as they do currently. Where there is more value in participating in ancillary service markets, or charging on-site battery storage for times when demand is higher, they will be incentivised to do so. While this should incentivise innovation and more efficient operation, by exposing plants to market signals for dispatch, this option comes with significant delivery challenges. The main challenge would be how to reliably deem potential to generate, which would either require using estimates or paying on non-metered measurements of wind or solar resource, and the risk of perverse incentives. It is difficult to make accurate estimates and this could mean under- or overpaying generators, while non-metered measurements are potentially less secure, and more open to gaming, than metered measurements. We welcome any evidence on how these barriers might be overcome.

Questions:

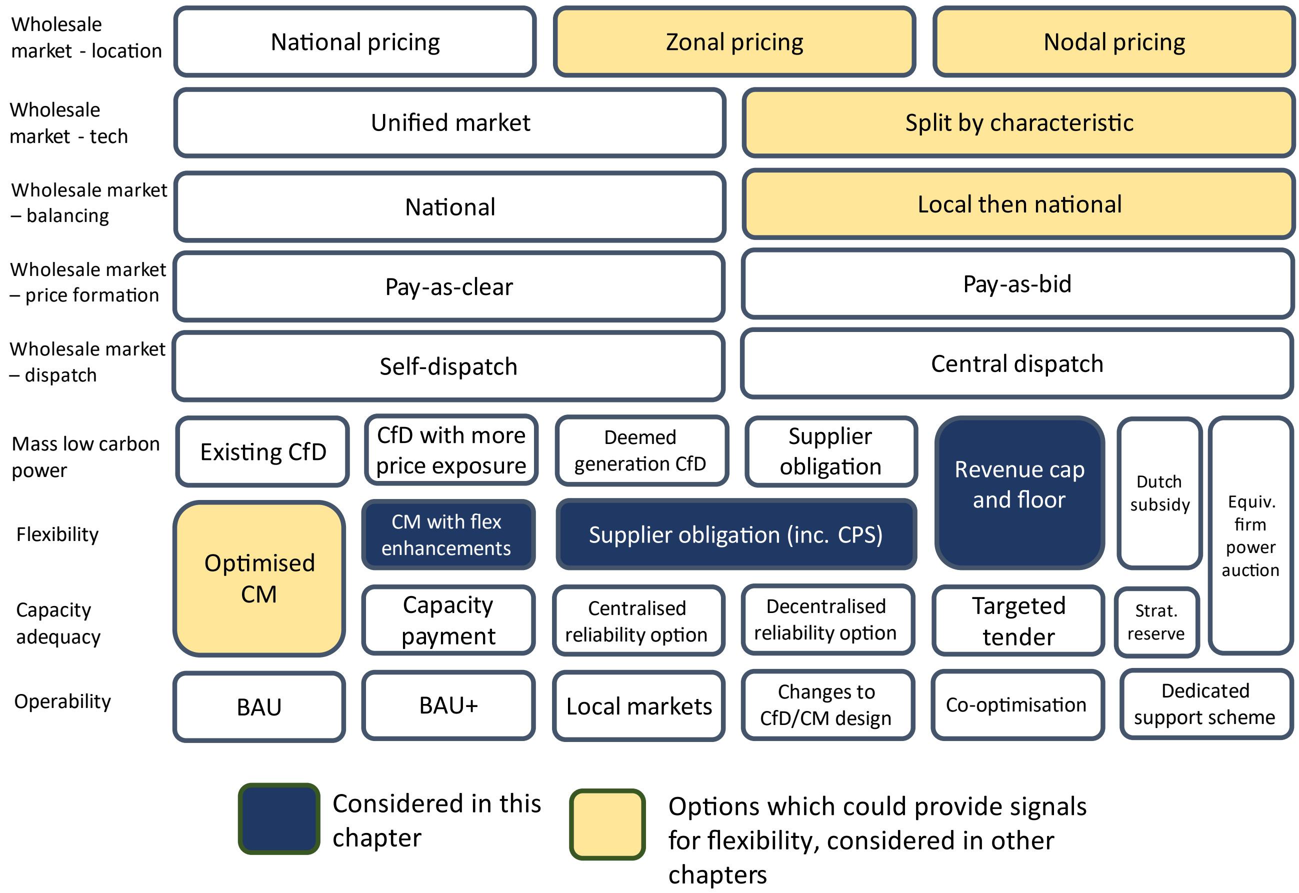
32. **Do you agree that we should continue to consider central contracts with payment decoupled from output?**

[44] Ofgem, 2021, Interconnector Policy Review – Decision, https://www.ofgem.gov.uk/publications/interconnector-policy-review-decision

33. How could a revenue cap be designed to ensure value for money whilst continuing to incentivise valuable behaviour?

34. How could deemed generation be calculated accurately, and opportunities for gaming be limited?

Chapter 7. Flexibility



Challenges and opportunities of the status quo

Flexibility – the ability to shift the consumption or generation in time or location – is critical for balancing supply and demand, enabling the integration of low carbon power, heat and transport, and maintaining the stability of the system. Our case for change identified a significant, increasing need for low carbon flexibility technologies (including low carbon flexible generation, storage, interconnection to other countries, and devices and technologies which shift or reduce demand) to respond to the variation in renewable output.

The current market framework does not maximise the potential for the full range of flexible technologies to deploy or operate flexibly, low carbon flexibility faces a range of challenges: a lack of sufficiently granular time- and location-based operational signals to incentivise flexible operation of assets, limited investment signals, a reliance on infrastructure that is not yet in place (i.e. a hydrogen network and CO_2 transportation and storage), and limited signals for flexible assets to hold back energy for periods of system stress, for example long-duration storage. These challenges are set out in more detail in the 'assessment of current arrangements' section of chapter two.

Bespoke support schemes are being implemented in the coming years to de-risk investment in some types of low carbon flexibility, including the Dispatchable Power Agreement for power CCUS. Investment in other flexibility technologies, such as short-duration electricity storage and flexible demand (also known as demand side response, or DSR), is primarily driven by revenue stacking across the wholesale, capacity, balancing and ancillary services markets. However, often the signals in these markets are not fully reflective of system needs, reducing incentives to act flexibly at different times or across locations, and in particular removing signals to enable local, distributed flexibility.

The Smart Systems and Flexibility Plan will deliver accelerated deployment of low carbon flexibility in the 2020s, by sharpening signals for flexibility and removing barriers to entry within the current market framework. However, given the significant investment in flexibility needed, and the conclusion from the case for change that the current market arrangements might fail to deliver this, we are looking at whether wider market reforms are required to facilitate power sector decarbonisation by 2035.

Approach to Flexibility

If our market arrangements are designed optimally, decisions about where and how much to build (investment decisions) and what should be turned on and off at which times (operational decisions) would be driven primarily by responding to prices in the wholesale and balancing markets.

As set out in chapter five, we are taking a 'twin track' approach to market reform for flexibility. Firstly, it is imperative that we get the operational signals right. These signals will be strengthened as more variable renewables deploy throughout the 2020s, creating significant opportunities for flexibility providers. We expect to see prices fluctuate in accordance with this variability across time and location, revealing the value of flexibility. Operational signals will primarily come from the wholesale market – we set out options for reforming the wholesale market, and the impact those might have on operational signals for flexibility, in chapter five. Signals are also provided at the distribution level through local flexibility markets. Changes in the way local grids operate, given the increasing prevalence of local generation, flexibility technologies and new sources of demand such as heat pumps and electric vehicles, will drive the need for significantly greater levels of active distribution system operation. It is crucial we ensure the appropriate institutional and governance arrangements are in place to support the delivery of key energy system functions and roles at a local level. Ofgem is currently undertaking a review to consider options for achieving this and the government will work with Ofgem to ensure appropriate arrangements are implemented.

Flexibility technologies can also provide many of the services required by system operators to manage the system. Options set out in chapter nine are looking to ensure signals for operability are adequate and incentivise low carbon technologies, for example enhancing local ancillary services markets and considering the balance between long- and short-term contracts for these services.

We also need to ensure flexibility can attract the investment it needs to deploy. Strong, granular operational signals from the wholesale and balancing markets may be sufficient to generate investment. However, where there are particularly high capital costs and/or risks relating to wider infrastructure, investment signals through a long-term forecastable contract may be needed to de-risk investment. Examples of such projects include hydrogen-to-power generation which are dependent on new transport and storage infrastructure, or pumped hydro storage.

Bespoke mechanisms are already being considered or implemented to de-risk “first-of-a-kind” technologies as they develop - especially given the need to deliver flexibility of all types at scale in the 2020s and 30s. But in the long-term having multiple technology-specific mechanisms could create a fragmented market and risk distorting competition between technologies. We will not prematurely expose developing technologies to cross-technology competition; however, we do need to consider how to incorporate them into our broader electricity market arrangements when the time is right.

Ensuring flexibility can attract the investment it needs to deploy is the focus of the options set out in this chapter. The options consider whether changes to investment signals would enable greater competition between flexible assets. These policy options could also complement the separate work to develop new bespoke mechanisms for investment in ‘first-of-a-kind’ flexible assets, by potentially setting out a pathway by which these technologies could transition away from bespoke support in the medium-term[45]. Enabling technologies to potentially transition from a bespoke scheme to market-wide arrangements in future will be a key design consideration.

Options Assessment

Summary

Several options for improving flexibility investment signals have been considered, and we have identified four primary options. These are:

- a revenue cap and floor;
- introducing flexible auctions within the Capacity Market
- introducing multipliers to the clearing price within the Capacity Market; and
- a supplier obligation.

We welcome stakeholders’ views on our assessment of these options, how well each works for different forms of low carbon flexibility, as well as how the challenges/risks of each option may be overcome.

Taken in isolation, these options are not intended to provide the level playing field we need to support all forms of flexibility. The range of supply and demand-based flexibility technologies needed in a net zero world have different requirements. As such, the options set out below will need to be packaged with other market reforms where required – for example sharpening

[45] This would not impact existing contracts already in place.

location and time-based operational signals as discussed in the wholesale markets chapter – to deliver optimal market arrangements for flexibility.

The options below focus on specific market interventions for supporting investment in low carbon flexibility. However, an additional market-wide mechanism for flexibility may not be needed. For example, sharpened wholesale market and operability signals, coupled with an optimised Capacity Market (see next chapter) and bespoke mechanisms for first-of-a-kind technologies, might together provide sufficient support for flexibility.

We welcome views from stakeholders on whether stronger operational signals alone could be enough to incentivise investment in flexibility, or whether for some technologies an investment mechanism is required. We are also interested in how we can create a relatively level playing field across technologies, and between demand side and supply side flexibility technologies.

Questions:

35. **Are we considering all the credible options for reform in the flexibility chapter?**
36. **Can strong operational signals through reformed markets, bring forward enough flexibility, or is additional support needed to de-risk investment to meet our 2035 commitment? Please consider if this differs between technology types.**

Revenue (Cap and) Floor

Under this option (also discussed in the previous chapter), flexibility assets – potentially including low carbon generation, storage, demand side response, and portfolios of decentralised assets (e.g. electric vehicles or heat pumps) – would compete for a guaranteed minimum revenue (floor) from the government for each period. Such a mechanism already exists in GB to support interconnectors, and could be extended to apply across the full range of flexible technologies. A guaranteed revenue would provide certainty to investors, lowering the cost of capital, while still exposing assets to operational signals across all the markets in which they would be expected to compete (capacity, wholesale, balancing and ancillary services). Such a scheme could provide value for money, as flexible assets would be incentivised to exceed their revenue floor and are only topped up where they didn't meet it, meaning in many instances a payment may not be required.

Additionally, a maximum revenue (cap) could be introduced, to protect consumers from excessive profits. Any such cap would need to be designed in a way that maximises competition, with additional incentives (often referred to as a soft cap) – such as a sustaining or availability payment – to ensure plants keep responding to operational signals even once the cap has been reached.

We are interested in stakeholder views on whether such a mechanism could be designed to enable direct competition between flexible technologies, across scales and supply and demand. For example, we note that such a mechanism has to date been applied to medium and large assets and therefore may not be appropriate (or indeed needed if operational signals are stronger) for aggregated portfolios of smaller scale assets.

Questions:

37. **Do you agree we should continue to consider a revenue cap and floor for flexible assets? How might your answer change under different wholesale market options considered in chapter 5 or other options considered in this chapter?**
38. **How could a revenue cap and floor be designed to ensure value for money, for example how could a cap be designed to ensure assets are incentivised to operate flexibly and remain available if they reach their cap?**
39. **Can a revenue (cap and) floor be designed to ensure effective competition between flexible technologies, including small scale flexible assets?**

Options for reforming the Capacity Market

Several options for reforming the Capacity Market are being considered in the capacity adequacy chapter. There are a range of ways that this could be undertaken, with potentially different outcomes for flexibility. Expanding an existing and well-functioning market could also reduce the risk of further market fragmentation and be less disruptive to market participants. Three specific options for flexibility have been considered as listed below:

- An optimised Capacity Market (as described in the capacity adequacy chapter)
- Running specific auctions for flexibility.
- Introducing multipliers to the clearing price for particular flexible attributes.

In this chapter we focus on options two and three as option one is covered under capacity adequacy. These options introduce 'flexibility enhancements' into the Capacity Market mechanism, which could value the contributions of low carbon flexible technologies, such as their response time and duration of capacity provision.

We also recognise there could be variations of these or entirely new designs. We are interested in stakeholder views on the full range of options for reforming the Capacity Market.

Option two: introduce 'flexible auctions'. A version of this option was explored through the Capacity Market 2021 call for evidence, and would procure specific flexible characteristics, for example response time and duration. These auctions would be open to all low carbon technologies which meet an agreed set of flexibility criteria. Separate auctions could enable innovative and smaller-scale technologies to participate, whilst retaining competitive downward pressure on the clearing price.

However, introducing additional auctions would increase the complexity of the Capacity Market, and there could be a risk of reduced liquidity as participants are spread across the auctions, potentially increasing clearing prices. A further challenge could lie in setting the auction parameters for the flexibility auctions to ensure adequate volumes are procured but without setting the target too high and under procuring, or setting it too low and risking innovative technologies from not being supported.

Option three: introduce multipliers to the clearing price. Only low carbon capacity which meets the flexibility criteria would be eligible, and multipliers would be applied to their clearing price valuing flexible characteristics, for example:

- Response Time – the speed at which assets can respond to signals.
- Duration – the ability to sustain capacity over a prolonged period of time.
- Location – the benefit to the system, depending e.g. on proximity to constraints.

The setting of multipliers could create a mechanism to reward specific flexibility needs and provide stronger investment signals in flexible technologies. For example, long-duration electricity storage has not to date been directly rewarded through the Capacity Market, as de-rating factors significantly weaken the investment case.

It may also be important to reward the location of flexibility assets. Storage may be most beneficial to the system when located near a network constraint as it can reduce the severity and frequency of constraints. However assets in these locations are then more likely to be regularly constrained, reducing revenues and undermining business cases.

The methodology and setting of multipliers would likely require resources akin to the initial development of Capacity Market de-rating factors. There are significant risks associated with miscalibration of such multipliers, which could inadvertently lead to outcomes misaligned with system needs. Whilst they could be reviewed periodically and be adjusted to provide stronger or weaker signals to certain technologies or locations, a degree of stability would be required to maintain investor confidence.

Questions:

40. **Do you agree we should continue to consider each of these options (an optimised Capacity Market, running flexibility-specific auctions, and introducing multipliers to the clearing price for particular flexible attributes) for reforming the Capacity Market?**
41. **What characteristics of flexibility could be valued within a reformed Capacity Market with flexibility enhancements? How could these enhancements be designed to maximise the value of flexibility while avoiding unintended consequences?**

Supplier obligation

A supplier obligation is a decentralised, market-led approach which places a legal requirement on suppliers to achieve a target set by the government. Supplier obligations are in place internationally, notably in the US where 31 states have implemented Renewable Portfolio Standards with varying parameters and degrees of success.

A flexibility-focused supplier obligation could provide stronger investment and operational signals for flexibility, particularly for demand side and small-scale flexibility. The option also allows for competition across technologies and ensures assets are exposed to price signals, incentivising efficient behaviour and helping to create a cost-effective overall flexible system mix. However, it could be challenging for this mechanism to provide sufficient revenue certainty for large scale flexibility assets. More broadly, as noted in the mass low carbon investment chapter, the supplier obligation model carries risks associated around financing and delivery. In particular, cost of capital is likely to increase if suppliers play a more significant role in determining the capacity mix, the counterparty risk of contracting with suppliers is high, and there is a wider question around the suitability of suppliers to lead in bringing forward investment in the longer term. For these reasons, we are not considering this as a standalone option which could drive all the required investment in flexibility, but rather as a supplementary mechanism to contribute to the investment case, particularly for small-scale flexibility with lower upfront costs, such as demand side response.

An example of a flexibility-focused obligation is a Clean Peak Standard, used in Massachusetts, which incentivises flexible technologies by requiring suppliers to use low carbon electricity, or reduce demand, during times of peak demand, and shift renewable generation from off peak to peak periods. It requires suppliers to spend a minimum percentage of their annual sales – set by the government and increasing yearly – on Clean Peak Energy Certificates (CPECs).[46] CPECs are credits generated by eligible flexibility technologies, including certain kinds of renewables, electricity storage and DSR, for each megawatt hour of energy or energy reserves provided during a seasonable peak period.[47] Multipliers are added to award more CPECs to resources that have a larger impact and help align generation with periods of highest value. In Massachusetts, the current mechanism includes multipliers designed to reflect location, season, actual monthly system peaks, resiliency and certain kinds of technology, such as energy storage systems paired with generation.[48] One potential flaw of this model is the difficult of determining in advance peak periods, as we expect these will become more variable as heat and electric vehicles are electrified and more consumers shift their demand patterns.

Questions:

42. **Do you agree that we should continue to consider a supplier obligation for flexibility?**
43. **Should suppliers have a responsibility to bring forward flexibility in the long term and how might the supplier landscape need to change, if at all?**

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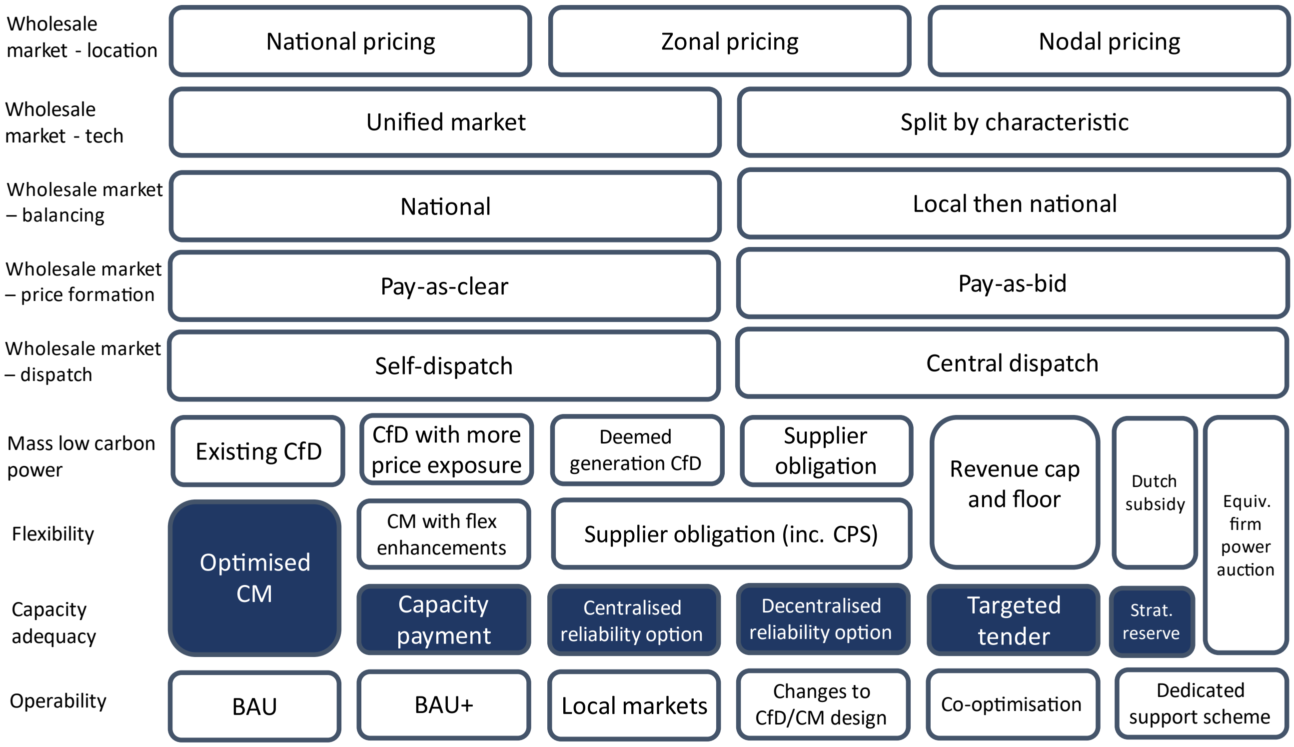
46 For example, in 2022 the Clean Peak Standard will be 4.5% of a supplier's annual sales, 16.5% by 2030, and 31.5% by 2040.

47 Seasonable peak periods are the time periods during the four seasons when net demand for electricity is typically highest.

48 For example, the peak demand in summer and winter is significantly higher than the rest of the year, so there is a x3 seasonal multiplier for CPECs earned during these periods. Another is the resilience multiplier of 1.5x, which rewards resources that can demonstrate the added ability to provide electricity during an external outage. Further information on the methodology outlining the current suite of multipliers in the Clean Peak Standard can be found on the Massachusetts government website: https://www.mass.gov/doc/clean-peak-energy-standard-final-regulation/download

44. For the Clean Peak Standard in particular, how could multipliers be set to value the whole-system benefits of flexible technologies? And how would peak periods be set?

Chapter 8. Capacity Adequacy



Challenges and opportunities of the status quo

Recent geopolitical events emphasise the importance of ensuring long term and sustainable planning when it comes to security of supply. Our market arrangements will need to secure investment in sufficient capacity to enable system balancing at all times, even in extreme cases (e.g. winter peak, or during long periods of low wind). Currently, meeting 'peak demand' is defined as maintaining an average 'loss of load expectation' of three hours per year (Reliability Standard).[49] This means that the installed capacity must be sufficient so that on average (under normal operation) there are no more than 3 hours a year when available generation is less than demand, i.e. there may be 3 hours per year when supply does not match demand, and exceptional measures may need to be taken (not that there would be 3 hours of blackouts per year).

Our case for change has shown that as the system becomes increasingly dominated by renewables, firm capacity will be pushed out of the wholesale market, limiting the opportunities for these assets to re-coup their costs ("missing money"). Modelling suggests that between

[49] NB Loss of load expectation (LoLE) is a probability-based approach and the 3 hours LoLE does not mean there will be a loss of supply for 3 hours per year – it instead provides an indication of the amount of time in which ESO will need to take additional actions outside of the market to ensure supply matches demand (e.g. call on system balancing tools). In most cases loss of load events would be managed without significant impact on end consumers. Our definition of the Reliability Standard may need to change – it has not been updated since the 2012 Electricity Market Reform.

now and 2035, over 20GW of unabated natural gas generation capacity is projected to retire,[50] while peak demand is expected to increase by over 50GW. Significant investment is therefore needed to provide replacement firm capacity.

Our current intervention is the Capacity Market, which provides a mechanism for providing capacity adequacy. The Capacity Market has worked well as intended, but – as we set out in the case for change – it does not provide incentives for the kind of low carbon, flexible, firm power needed to complement renewable generation.

Indeed, the outcome we want for capacity adequacy is to not only deliver the capacity required to meet demand at all times, including during peak times, but to do this in a way that supports and complements net zero (including by moving away from unabated gas) and at least cost to consumers. We need to ensure new build capacity is coming forward to meet our adequacy needs and this will increasingly need to be low carbon flexible capacity. In the medium term, we anticipate high carbon technologies will continue to deploy to ensure security of electricity supply whilst low carbon alternatives mature and the necessary infrastructure for hydrogen and power CCUS is built. This summer we intend to publish a consultation, building on our 2021 call for evidence,[51] outlining our proposed expansion to Decarbonisation Readiness which will require all new build and substantially refurbishing combustion power plants to demonstrate a viable plan for decarbonising by converting to either power CCUS or hydrogen generation technology. This should ensure any new or substantially refurbished high carbon combustion power plants are built such that they can take advantage of decarbonisation opportunities and convert as hydrogen and power CCUS infrastructure expands.

We want to incentivise new build capacity, as well as keeping existing capacity online – and do this in a way that allows us to meet decarbonisation objectives.

We expect that the options for reform will need to overcome a range of challenges with the status quo, including missing money and price volatility, and the fact that the Capacity Market was not designed to value low carbon technology, and locks in unabated assets. These challenges are set out in more detail in the 'assessment of current arrangements' section of chapter 2.

Options Assessment

Summary

We are considering a range of capacity mechanisms and other options including those that have been proposed by stakeholders (including in the recent Capacity Market Call for Evidence) and those that have been deployed internationally. This includes a wide range of

[50] Annex O, 2021, Energy and emissions projections: Net Zero Strategy baseline (partial interim update December 2021), https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021
[51] BEIS, 2021, Decarbonisation readiness: call for evidence on the expansion of the 2009 Carbon Capture Readiness requirements, https://www.gov.uk/government/consultations/decarbonisation-readiness-call-for-evidence-on-the-expansion-of-the-2009-carbon-capture-readiness-requirements

options: from incremental changes to the existing Capacity Market to more radical options which propose to replace it completely.

This section sets out the main approaches we are considering for addressing these challenges. They are:

- an optimised Capacity Market;
- a strategic reserve;
- centralised reliability options;
- decentralised reliability options;
- capacity payments; and
- targeted tender.

Out of the options we have considered, there are three we believe could have potential advantages over current arrangements, and which we propose taking forward for further exploration: an Optimised Capacity Market, a Strategic Reserve and a Centralised Reliability Options model. There are another three that we believe do not offer advantages over current arrangements, which we are minded not to pursue: a Decentralised Reliability Option or Obligation, a Capacity Payment and a Targeted Tender. We welcome views on these conclusions. As mentioned above, our findings indicate that some form of capacity adequacy intervention will likely still be required in the future, and we do not consider that an 'Energy Only' market (where there is no capacity mechanism) would address security of supply needs or bring forward the new investment needed.

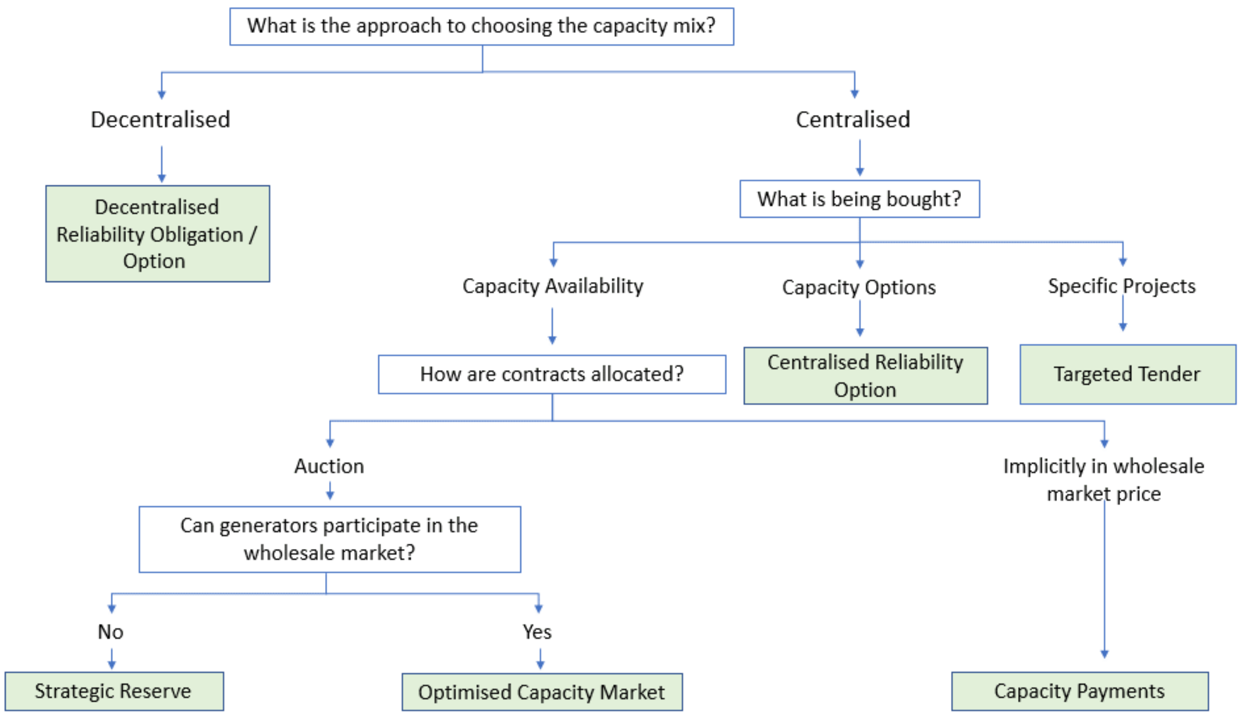
We welcome views on our analysis of specific options, particularly where respondents have evidence about the impact that options would have, or on how risks we identify could be overcome.

Question:

45. **Are we considering all the credible options for reform in the capacity adequacy chapter?**

Grouping options

Shown here is a decision tree which sets out, at a schematic level, the key choices which define the different options for reform under consideration. It is intended to be illustrative, not exhaustive; we welcome feedback on whether there are other choices which should be included, or whether there are further possible variations which we have not considered.



Optimised Capacity Market

This option involves making changes to optimise the existing Capacity Market for the participation of low carbon capacity, without jeopardising security of supply. We have previously consulted on similar changes in the Capacity Market Call for Evidence, which ran from July-November 2021, and so we are seeking additional views through this consultation to add to this. In addition, separate to this consultation and outside the scope of REMA, we will also be considering shorter term changes to the Capacity Market, also consulted on through the Call for Evidence.

Optimising the Capacity Market for low carbon shares similarities with the ‘Capacity Market with Flex’ option described in the flexibility chapter; the key difference is that an optimised Capacity Market directly targets generators with low carbon or new build characteristics.

There are two main variations on optimising the Capacity Market we are considering:

Separate auctions. Low carbon new build or refurbished assets would participate in separate auctions to the main capacity auction. The Electricity System Operator would set the total amount of target capacity and then, separately, how much of that to procure in each of the auctions. Target setting would therefore be more complex than with the existing Capacity Market.

As low carbon new build or refurbished assets would only be competing against each other for agreements, there is likely to be reduced liquidity. The clearing price for these projects is therefore likely to be higher than in a single capacity market auction. However, this is not certain – there could be significant competition in a low carbon auction, driving the clearing price down.

Multiple clearing prices. A single auction, as at present, but with different clearing prices depending on capacity type (for example, a different price for low carbon generation, new build generation, etc). This could involve imposing additional constraints, such as a maximum acceptable bid for low carbon new build or refurbished assets, to prevent prices rising too high.

This option would avoid the target-setting issues of separate auctions, and could lead to more reasonable compensation relative to costs, as it would limit how much existing capacity bids are raised by the clearing price if set by (more expensive) new build assets.

Overall, we feel an Optimised Capacity Market has advantages, in that it would offer ways for the low carbon capacity assets to participate while insulating them from competing directly with established high carbon capacity. In addition, as an evolution of the existing Capacity Market, implementation is likely to be less disruptive than some of the other options.

Possible drawbacks include increased price volatility from a smaller pool, and more complexity around volume and parameter setting, along with reduced predictability.

Questions:

46. **Do you agree that we should continue to consider optimising the Capacity Market?**
47. **Which route for change – Separate Auctions, Multiple Clearing Prices, or another route we have not identified – do you feel would best meet our objectives and why?**
48. **Do you consider that an optimised Capacity Market alone will be enough for ensuring capacity adequacy in the future, or will additional measures be needed?**
49. **Are there any other major reforms we should consider to ensure that the Capacity Market meets our objectives?**

Strategic Reserve

In a Strategic Reserve model, a central authority auctions a certain amount (and type) of reserve capacity on top of what the market is expected to provide. Successful providers receive payment at their bid price, which usually includes a payment for being available and a separate activation payment. Capacity in strategic reserves generally does not participate in the market, and is dispatched only in case the market does not clear, i.e. when there is a danger that demand will outweigh supply. This will be at a price above a reference level signalling scarcity – in theory at a price close to the Value of Lost Load – in order not to interfere with the market. Contracts contain provisions for notification time, duration of activation and costs are typically passed on to consumers through system charges.

Strategic reserves can be seen predominantly as transitional measures; both Belgium and Poland operated strategic reserves which have since been replaced by new capacity market mechanisms. Current international examples of strategic reserves being used include Germany, Sweden and Australia. Some models have sought to include demand side response, although further research would be needed to assess the extent to which this has been successful. A possible variation could be where reserve plant is under government ownership.

The advantages of this option are that it is only procuring additional capacity for peak times, and could therefore be cheaper than a Capacity Market. Even if established alongside a Capacity Market, it could potentially reduce costs in the long term, by taking out plants with very low load factors that might put upward pressure on the clearing price. Although likely to be made up of high carbon capacity, this capacity would only be dispatched rarely. Some form of strategic reserve payment may also be required in order to ensure long duration assets hold back storage capacity for when it is most valuable to the system.

A significant disadvantage is that a strategic reserve in itself is unlikely to drive low carbon investment. However, we feel there is value in exploring the option further, as it could operate as a backstop mechanism to ensure security of supply where flexibility and decarbonisation is promoted elsewhere within a wider package of measures.

Questions:

50. **Do you agree that we should continue to consider a strategic reserve?**

51. **What other options do you think would work best alongside a strategic reserve to meet flexibility and decarbonisation objectives?**

52. **Do you see any advantages of a strategic reserve under government ownership?**

Centralised Reliability Options

In a Centralised Reliability Option model, the incentive to provide power is signalled through the level of wholesale market pricing rather than by targeting a system stress event. The mechanism is based on the concept of a ‘call option contract’, which gives the buyer of the contract the right to buy a commodity at a predefined price. The Transmission System Operator determines the amount of capacity to be auctioned (sufficient to ensure peak demand can be met) and, in return for a reliability premium (usually determined through the auction process), secures the right to buy electricity from the assets on the wholesale market at a ‘strike price’ (usually determined by a formula). A physical capacity guarantee for all options sold is made part of the contractual obligation

A reliability option mechanism theoretically ensures the availability of supply during scarcity because the design of the mechanism inherently penalises contract holders that remain unavailable during a period when the real-time price is above the agreed strike price. Contracts obligate contract holders to pay the difference between the real-time price and the agreed strike price when there is system scarcity and the real-time price is higher than the agreed strike price. A contract holder that is unavailable not only loses the income from the spot market (at the strike price level) but also has to pay the difference between the spot price and the strike price. There can also be an additional penalty mechanism for capacity providers that do not meet the availability and/or pay back obligations.

Capacity providers who are able to provide capacity in times of scarcity can participate, and the option can be designed to include renewables and potentially demand side response, as is the case in Italy (which is technology neutral and storage, non-programmable renewable energy sources and demand side response are allowed to participate) and Ireland.

Capacity providers with options contracts continue to participate in the wholesale market, and the System Operator only exercises the reliability option in situations of scarcity, i.e. when the price on the spot market exceeds the strike price of the option. When the option is exercised, the generator pays the Transmission System Operator the difference between the spot price and the strike price regardless of whether it is generating. Reduction factors are applied on capacity that can be bid into the auction, as a percentage of maximum capacity, and these operate in a similar way to Capacity Market de-rating factors.

Generators who participate in capacity options effectively cap their wholesale revenues in times of peak system stress in exchange for the premium, which is their capacity rent. This cap prevents generators from being double-remunerated for their capacity rent on the wholesale market. Other generators, including flexible generators, that do not participate in options contracts are unaffected. As generators that participate in options contracts are still able to generate in the wholesale market during times of system stress, it is unclear if there would be any effects on the wholesale market.

Internationally, Colombia, Ireland and Italy have operated a variation of a reliability option scheme. Ireland's mechanism is the Capacity Renumeration Mechanism within the Integrated Single Electricity Market (I-SEM) which replaced the capacity payment mechanism in 2017. Some designs envisage an obligation for generators above a set MW to participate, while others have price caps as a safeguard to mitigate risks arising from abuse of market power.

This option could address the issue of rising Capacity Market clearing prices due to declining load factors meaning that firm, flexible capacity must rely more on non-wholesale market revenues. The option can also work in a variety of wholesale market arrangements, including nodal pricing and split markets. The option may also have benefits for security of supply as participants are incentivised to provide capacity due to the contracts and the penalty mechanism.

Questions:

53. **Do you agree that we should continue to consider centralised reliability options?**

54. **Are there any advantages centralised reliability options could offer over the existing GB Capacity Market? For example, cost effectiveness or security of supply benefits? Please evidence your answers as much as possible.**

55. **Which other options or market interventions do you consider would be needed alongside centralised reliability options, if any?**

Decentralised Reliability Options / Obligations

As well as the centralised approaches set out above, we have also considered options under which responsibility for security of supply is transferred to suppliers. These are Decentralised Reliability Options and Decentralised Reliability Obligations.

The reliability options in the Decentralised Reliability Options model work in a similar way to those in the centralised Reliability Option model above, but the role of the Transmission System Operator is stripped out, with suppliers being required to secure reliability options to meet their peak demand through direct contracts with capacity providers. If a supplier fails to procure sufficient capacity to ensure security of supply, or a generator overestimates its ability to perform during a certain period, then administered penalties are applied.

The Decentralised Reliability Obligation is a different but related model. As with the Decentralised Reliability Option, suppliers are obliged to secure the capacity needed to meet their customers' demand requirements through individual contracts between electricity supplier and capacity providers. However, the Obligation model secures capacity rather than the option to buy power at a pre-determined level. Another difference is that the Obligation model has a role for a centrally determined capacity requirement volume, whilst the Option devolves this to the supplier to decide how much their customers will need.

A Decentralised Reliability Obligation model was introduced in France in 2015. Australia also operates a version of this model alongside a form of strategic reserve.

We can see some potential advantages with these models, notably that empowering suppliers to choose from different options to meet consumers' needs could promote innovation and whole system flexibility, as consumers may have choice over tariffs that are more targeted to their individual consumption. However, there are significant concerns about deliverability within a timeframe compatible with decarbonisation goals. Changing the role of market participants in this way would likely require significant work and upheaval, both legislatively and in practical steps. But more importantly, we have concerns that these models come with considerable increased risk to security of supply compared to centralised options: despite potential steps that could be taken to mitigate this somewhat.[52] We are not convinced that the risk of penalties will be enough to ensure suppliers and generators will meet the conditions under their contracts to procure or generate sufficient electricity to ensure that security of supply will be met. We also have concerns about where the costs could fall and consumer fairness, for example if suppliers or generators end up passing costs of penalties (or anticipated risk of penalties) down to consumers, and consumers that can less afford to pay may be more exposed to price risk. We therefore do not propose to take this forward as a lead option, however, we remain open to the idea that moving to a more decentralised approach may be something we move to in the longer term, if we are in a position to transition to less intervention being needed to ensure security of supply and decarbonisation.

[52] E.g. The Supplier of Last Resort (SoLR) procedure was established in 2003 to ensure that when supplier failure occurs, affected domestic customers are guaranteed continuity of supply. Nonetheless, we are still concerned about suppliers or generators choosing to accept penalties and whether it is possible to put in place enough checks and balances to ensure security of supply is maintained.

Questions:

56. **Do you agree that we should not continue to consider decentralised reliability options / obligations? Please explain your reasoning, whether you agree or disagree.**

57. **Are there any benefits from decentralised reliability option models that we could isolate and integrate into one of our three preferred options (Optimised Capacity Market, Strategic Reserve, Centralised Reliability Option)? If so, how do you envisage we could do this?**

Capacity Payment

This model is a market-wide approach which sets an explicit price for capacity. All capacity is eligible for a capacity payment for every 'trading period' (half hour) in which they are available, including demand side response. The level of payment is set by a central body at a level calculated to achieve investment in the amount of capacity required. The capacity price varies by trading period; at times of lower margin the price will be higher and therefore the overall price achieved by a generator will depend on the timing of its availability.

We see few advantages for this option. While it could be a useful ‘top-up’ revenue stream, it is unlikely to be an efficient way to incentivise new-build capacity. Payment is on a rolling basis - capacity providers receive a capacity payment for every 'trading period' (half hour) in which they are available and this payment will vary by trading period; at times of lower margin the price will be higher and therefore the overall price achieved by a generator will depend on the timing of its availability. This may create uncertainty for new projects. Another disadvantage is that, because the price is set to attract sufficient capacity to come forward, there is a risk of over-remuneration if the price is set too high. International examples suggest that it is not the most cost-effective model and possibly may not incentivise capacity at the right times – a report reviewing the Irish Capacity Payment Mechanism conducted by Poyry for the Regulator in 2011 concluded that the level of payments was not always highest when capacity was scarce.[53] It is therefore not one of our lead options.

Question:

58. **Do you agree that we should not continue to consider a capacity payment option? Please explain your reasoning, whether you agree or disagree.**

Targeted Tender / Targeted Capacity Payment

A targeted tender is a centrally coordinated process to secure the construction of a specified quantity of new capacity which is determined to be needed to improve the balance of supply and demand. The volume of capacity required is identified by a central body. New capacity secures a long-term contract and tenders can be tailored to meet specific requirements such

[53] Poyry, 2011, Capacity Payment Mechanism Medium Term Review, https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-11-019a%20CPM%20Review%20Appendix%201%20-%20Poyry%20Report.pdf

as location, the type of technology and any additional system services to be provided. It differs from a Strategic Reserve in that it applies to a limited subset of new capacity in the market, and this capacity can still participate in the wholesale market.

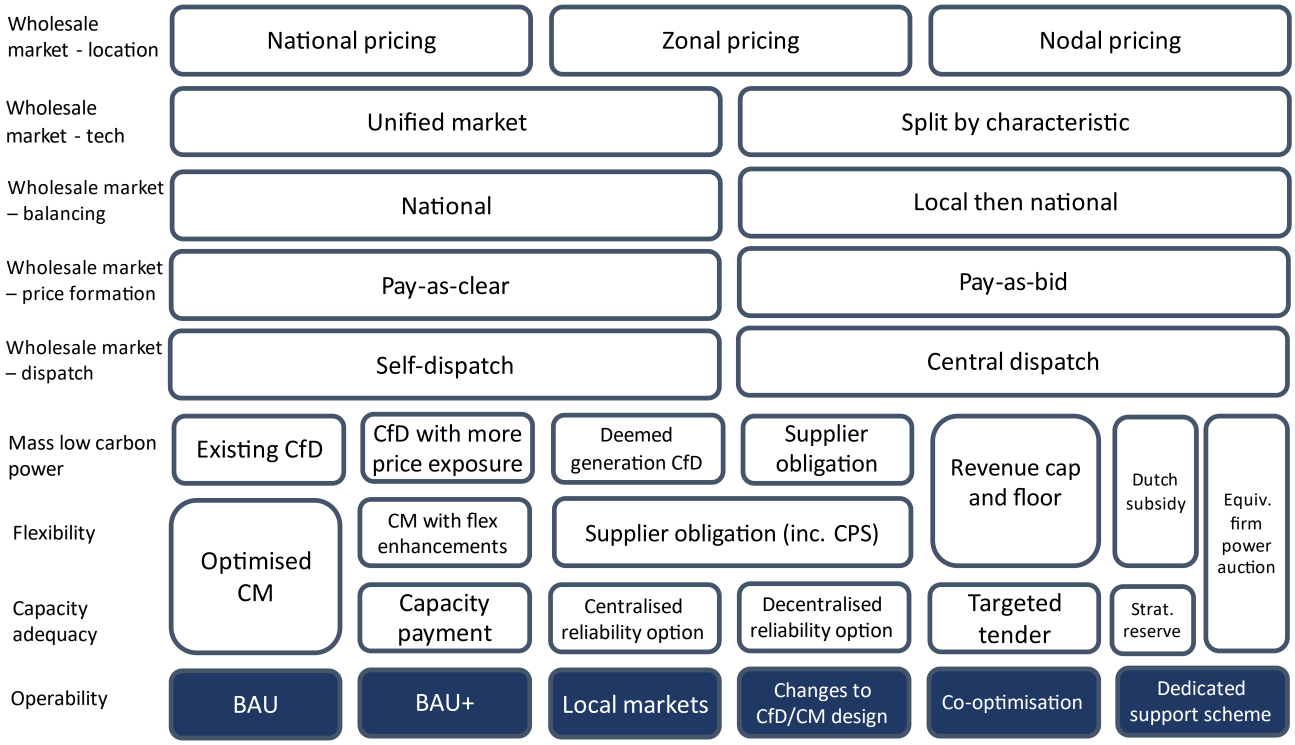
There are a number of possible advantages with this option, in particular the way in which it can be adapted to specific needs, such as supporting renewables and strengthening ancillary services as the tender can be targeted towards elements such as location and/or additional system services to be provided (and can be either tech specific or tech neutral). However, similar to our views on a Strategic Reserve, we consider that it would be more useful as an add-on or emergency measure for specific capacity issues. And, whilst we are minded to take forward Strategic Reserves for further exploration, we have more concerns about the cost effectiveness of a Targeted Tender approach. It is unclear whether it would be cost effective to target new build only as payments would need to cover all costs over the whole lifetime of these assets. Moreover, while the tender process could be competitive, the requirements would be restrictive as they would need to fit pre-determined criteria and local system needs. This may lead to overcompensation as there may be limited competition and it might be difficult for a central body to calculate the appropriate price level. For this reason, this model may be more likely than other mechanisms to lead to either over- or under-investment, depending on whether the price is set too low or too high. It is therefore not one of our lead options.

Questions:

59. **Do you agree that we should not continue to consider a targeted capacity payment / targeted tender option? Please explain your reasoning, whether you agree or disagree.**

60. **Do you agree with our assessment of the cost effectiveness of a targeted capacity payment / targeted tender option, and the likely risk of overcompensation? If not, why not?**

Chapter 9. Operability



Challenges and opportunities of the status quo

Ensuring operability through the provision of ancillary services, as explained in the case for change, is crucial for the efficient and safe functioning of the electricity system. In our current market arrangements, ancillary services are procured by the Electricity System Operator (ESO) outside of the wholesale electricity market, through the Balancing Mechanism or as a contracted service in advance of system need and in some cases in day-ahead markets, to ensure their availability when they are needed. As most ancillary services are currently provided by fossil fuelled thermal generators, meeting our 2035 commitment implies a large proportion of this being rapidly replaced with low carbon generation. We expect that the need for ancillary services is likely to grow in response to a greater proportion of variable renewables on the system, and to changing patterns of demand.

In this chapter we consider options to promote investment in low carbon ancillary services that will meet the needs of a system increasingly dominated by variable renewable energy. Options under consideration in this chapter will need to overcome a range of challenges, including the decarbonisation of ancillary services and more activity at the distribution level (more detail on these challenges is set out in the sub-section on ‘Maintaining system operability’ in chapter 2).

While it is technically possible to provide all ancillary services from low carbon sources, sufficient incentives and signals will be needed for market participants to make this transition. A challenge to efficient decarbonisation of operability is the ease with which variable renewables and flexible demand can participate due their unpredictability – procurement in close to real-time markets is difficult as suppliers and producers need to take account of the most up-to-date information (e.g. weather forecasts and demand). New products recently introduced by the ESO have helped address this problem for frequency response. Some ancillary services may be easier to decarbonise (such as frequency response) than others (such as reserve).

Other challenges include the extent to which existing energy support policies, namely Contracts for Difference and the Capacity Market, provide sufficient incentive to provide low carbon ancillary services (or indeed provide a disincentive to do so). The move towards more production and consumption of electricity at a distribution level from renewable and other low carbon generation raises questions about the role for Distribution Network Operators (DNOs) for system operation functionality. While the cost of ancillary service provision may represent a relatively small proportion of the overall costs of the system, the cost impacts of failure to provide adequate ancillary service provision could be substantial, and the revenues can still be significant to ancillary services providers.

Options Assessment

Summary

We are considering a wide range of options for ensuring operability, these are:

- continuing with the status quo;
- incremental modifications to existing arrangements;
- developing local ancillary services markets and giving a greater role to DNOs;[54]
- changes to the CfD and Capacity Market; and
- co-optimisation with the wholesale market.

The only option which we are not minded to pursue is the development of a dedicated support scheme for ancillary services, because assets which have the potential to provide these services can be supported by other schemes, and an additional bespoke scheme would pose deliverability and efficiency challenges.

We welcome views on our analysis of specific options, particularly where respondents have evidence about the impact that options would have, or on how risks we identify could be overcome.

Question:

61. **Are we considering all the credible options for reform in the operability chapter?**

[54] The term DNO as used in this chapter refers to DNOs currently undertaking DSO functions and roles

Continue with existing policy approach

Policies are already in place to help ensure that ancillary services meet the challenges posed by the transition to a decarbonised electricity system. The Smart Systems and Flexibility Plan,[55] published jointly by the government and Ofgem in 2021, includes actions on the ESO relating to ancillary services to help support the government's decarbonisation objectives, including implementing a single day-ahead market for response and reserve by 2023 which will make it easier for variable renewables and demand side response to participate. The ESO has set out commitments in its Market Roadmap[56] to facilitate greater participation of variable renewables and has already introduced a suite of day-ahead products for frequency response. Ofgem's GB energy system review[57] and the Energy Network Association's Open Networks project[58] are also considering how DNOs can play a more active role in delivering our net zero commitments.

We are interested in stakeholder views on whether these existing and planned policies will be sufficient to ensure operability in a net zero context.

Question:

62. **Do you think that existing policies, including those set out in the ESO's Markets Roadmap, are sufficient to ensure operability of the electricity system that meets our net zero commitments, as well as being cost effective and reliable?**

Enhanced existing policies

This option would build on existing policies for ensuring operability. They could make a potentially significant impact, though involve less structural change than the options considered further below. Possible measures include:

- Giving the ESO or Future System Operator (FSO) the ability (or an obligation) to prioritise zero/low carbon procurement. The government already intends to include a net zero objective for the FSO, alongside maintaining security of supply and ensuring an efficient, coordinated and economical system. The FSO will have a statutory duty to undertake its functions in a way that best promote these objectives and manage the trade-offs and synergies between them.[59] As an extension to this, we could consider giving the existing ESO or future FSO the ability to prioritise low carbon ancillary services, or give carbon reductions equal weighting to cost effectiveness, allowing it greater flexibility to aid decarbonisation. It is difficult however to assess how much this

[55] BEIS, 2021, Transitioning to a net zero energy system: smart systems and flexibility plan 2021: www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021
[56] National Grid ESO, March 2022, Markets Roadmap, www.nationalgrideso.com/research-publications/markets-roadmap
[57] Ofgem, 2021, Review of GB energy system operation: www.ofgem.gov.uk/publications/review-gb-energy-system-operation
[58] ENA Open Networks project: https://www.energynetworks.org/creating-tomorrows-networks/
[59] Future System Operator: government and Ofgem's response to consultation: www.gov.uk/government/consultations/proposals-for-a-future-system-operator-role

freedom would be used in practice. An obligation on the ESO could also be considered which would offer greater certainty, but could be challenging to design and to meet.

- Ensuring the ESO strikes the optimal balance between long and short-term contracts for ancillary services, recognising that some assets benefit from close to real time procurement, whereas investment for other assets depends on long-term contracts;
- Aligning Capacity Market and CfD tenders with those for ancillary services, for example coordinating their timings so that developers can more easily align and stack revenue streams from the different markets;
- Introducing a matrix approach to ancillary service provision in which providers can submit linked bids for ancillary services which can only be delivered together. This could drive down costs by allowing the ESO to select the optimal 'bundled' bids but might only be useful for close to real time markets.

Question:

63. **Do you support any of the measures outlined for enhancing existing policies? Please state your reasons.**

Developing local ancillary services markets

This option would involve an expanded role in the operability of networks at a local level, which could include procurement of ancillary services from local markets – we discuss this option, from a system balancing perspective, in the wholesale market chapter. It could include a greater role for DNOs in managing operability. The growth in electric vehicle charging and heat pump installation could lead to a greater need for ancillary service responses to the unpredictable use of these assets, and a greater role at the distribution level in management of local level operability could reduce the need for ESO interventions. DNOs already are involved in thermal constraint and – to a limited extent – voltage control, however, there are questions about the practicality of DNOs procuring ancillary services like frequency response and reserve. Ofgem's review of Distribution System Operation governance is assessing the key energy system functions at a local level and the effectiveness of institutional and governance arrangements in place to support their delivery, with a Call for Input published in April 2022.[60] Formalisation of the roles for maintaining network operability between DNOs and the ESO may be necessary, which could also be complex.

Questions:

64. **To what extent do you think that existing and planned coordination activity between ESOs and DNOs ensure optimal operability?**
65. **What is the scope, if any, for distribution level institutions to play a greater role in maintaining operability and facilitating markets than what is already planned, and how could this be taken forward?**

[60] Ofgem Call for Input: https://www.ofgem.gov.uk/publications/call-input-future-local-energy-institutions-and-governance

Changes to CfD design to support low carbon ancillary services

The existing CfD could be modified to remove disincentives for assets that are supported by the scheme to engage in ancillary services markets. ESO in its Market Roadmap[61] and other stakeholders in their responses to the BEIS's Call for Evidence,[62] including through the Capacity Market Call for Evidence, have told us that the substantial proportion of renewables providers that receive CfD support are disincentivised from offering ancillary services as they would need to bid high prices in Ancillary Service tenders to recover the loss of subsidy from diverting power from the wholesale market.[63]

The majority of options we consider in the mass low carbon power chapter could deliver this, as they expose generators to market signals, and so incentivise flexibility between providing power and ancillary services, depending on system need.

Question:

66. **Do you think that the CfD in its current form discourages provision of ancillary services from assets participating in the scheme? If so, how could this be best addressed?**

Changes to Capacity Market design to support low carbon ancillary services

The existing Capacity Market would be modified to include obligations or incentives to provide ancillary services. The Capacity Market works effectively to ensure adequacy of supply but is not designed to incentivise the provision of ancillary services (although it does not prevent participants from holding ancillary services contracts). A number of respondents to BEIS's Call for Evidence on aligning the Capacity Market to net zero[64] commented that the Capacity Market could be usefully reformed to provide services like stability. Gaining low carbon ancillary service capability through Capacity Market payments could potentially represent good value for money. Capacity Market payments could be expected to incentivise investors who would be attracted to long-term certainty of Capacity Market contracts. However, as with the options for Capacity Market with Flexibility Enhancements (Chapter 7), modifications to the Capacity Market to promote low carbon ancillary services could add an additional layer of complexity to the scheme.

Question:

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[61] ESO Markets Roadmap: www.nationalgrideso.com/research-publications/markets-roadmap..

[62] Enabling a High Renewable, Net Zero Electricity System: Call for Evidence (Dec 2020): www.gov.uk/government/consultations/enabling-a-high-renewable-net-zero-electricity-system-call-for-evidence

[63] Some stakeholders raised this in their response to: Enabling a High Renewable, Net Zero Electricity System: Call for Evidence (Dec 2020): https://www.gov.uk/government/consultations/enabling-a-high-renewable-net-zero-electricity-system-call-for-evidence.

[64] Question 30 sought evidence on, inter alia, whether the Capacity Market should (or alternative electricity security mechanism) also address wider system services such as flexibility and stability: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1005672/capacity-market-cfe.pdf

67. **Do you think it would be useful to modify the Capacity Market so that it requires or incentivises the provision of ancillary services? Is so, how could this be achieved?**

Co-optimisation of ancillary services

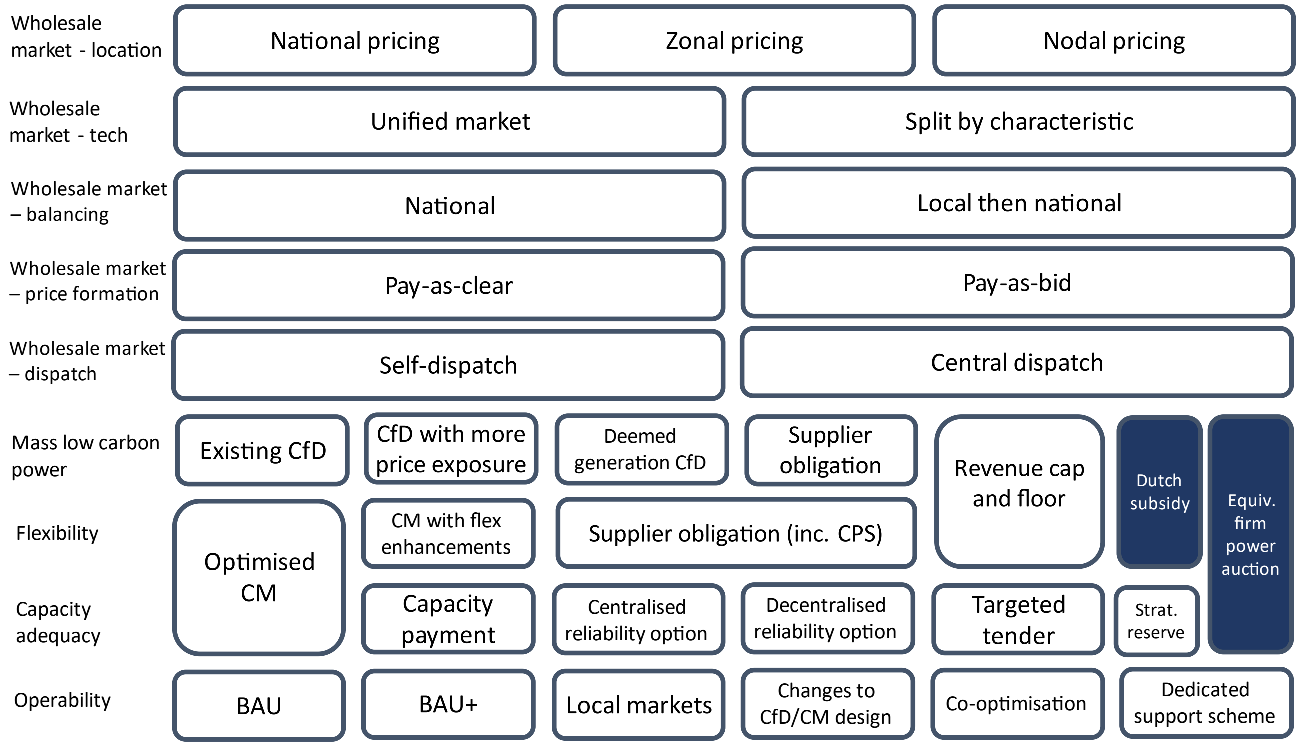
This option would be considered as part of broader wholesale market changes which involve central dispatch (dispatch controlled by the System Operator), such as nodal pricing. In a system with central dispatch, ancillary services can be co-optimised with wholesale dispatch. Assets provide both generation and ancillary services prices to the System Operator, and these are co-optimised when sending dispatch instructions. In theory, co-optimising between different markets could lead to a very efficient allocation of generation/demand between the wholesale market and ancillary services market. Short timeframes could help enhance flexibility, and the optimisation between the wholesale market and ancillary services brings this closer to a 'whole systems approach'. This system seems to be working in certain US markets;[65] however, it is unclear whether this type of market for ancillary services could incentivise provision of the ancillary services required for a market with a high proportion of variable renewable energy. Furthermore, in the US co-optimisation is only used for frequency and reserve, with other ancillary services still provided through long-term contracts.

Question:

68. **Do you think that co-optimisation would be effective in the UK under a central dispatch model?**

[65] Co-optimisation of ancillary services has been employed in the US by, inter alia, the California Independent System Operator (CAISO), the Midcontinent Independent System Operator (MISO) and the New York ISO (NYISO). There is evidence that market efficiency improved where it was applied. See for example e Michael G. Pollitt and Karim L. Anaya: www.iaee.org/en/publications/download-instant.aspx?id=3676

Chapter 10: Options across multiple market elements



In this chapter we consider two options which cover multiple elements of market design at once: an auction by abatement along the lines of the Dutch ‘SDE++’ scheme, and an Equivalent Firm Power Auction, as proposed by Dieter Helm in the 2017 Cost of Energy Review.[66]

Auction by cost of carbon abatement

In the Netherlands, the ‘SDE++’ scheme focuses on the large-scale rollout of technologies for renewable energy production and other technologies that reduce carbon emissions in the Netherlands. The scheme is open to numerous technologies across renewable electricity, renewable heat, renewable gas, low-carbon heat, and industrial decarbonisation. The Dutch system uses technology-specific ceiling prices.

Auctions are based on the cost effectiveness of different technologies at avoiding CO_2 emissions. There is a set budget for each auction, and bids are accepted until this budget is reached. The Dutch government contracts directly with assets and provides a subsidy to assets for up to 15 years (similar to CfDs). The level of support covers the difference between the base tariff awarded per tonne of CO2 equivalent avoided and an estimated market

[66] https://www.gov.uk/government/publications/cost-of-energy-independent-review

remuneration. This is broadly equivalent to the average CfD top-up payment (per MWh) divided by an assumed marginal CO2 saving (kgCO2/MWh).

The main advantage of the Dutch Subsidy is that it creates a common currency for comparing the relative value for money of decarbonisation projects. This allows a large range of technologies to compete for support, including generation, flexibility and demand reduction, which should lead to a lower cost capacity mix overall. The government underwriting revenues provides investors with confidence, and the top-up payment being recalculated every year provides current technologies with the incentive to innovate and encourages new technologies to enter the auction.

The key challenge in designing a version of the Dutch Subsidy for the power sector is maintaining the value of this common currency whilst providing different technology types with appropriate incentives. Paying generators per tonne of CO2 abated incentivises assets to maximise their output, in order to maximise their revenue. This would be inappropriate for flexible assets, which should only be incentivised to generate or reduce demand when there is a deficit of renewable (and nuclear) generation, and also require signals to increase demand when there is an excess of renewable generation. We are interested in exploring whether the mechanism could be adapted to mitigate this issue.

This option also relies on a range of assumptions to calculate abatement, such as a 7-year forecast of the marginal plant at different times to estimate carbon saved, which creates a risk of under- or over-rewarding technologies. There is also no payback mechanism, as there is under the CfD, when wholesale market revenue goes over the base price, meaning value for money may be less than under the status quo.

We are minded to take this a variation on this option forward for further exploration as a potential way of structuring support for investment in low carbon flexibility, as cost of abatement might function as an effective metric for comparing the value of flexible assets. But we are minded not to pursue this option for mass low carbon power, as there do not appear to be significant benefits over the existing CfD scheme. We welcome views on whether an auction for abatement could be designed so as to provide the right incentives for assets to behave flexibly, whilst having both renewables and flexibility compete in the same auction.

Questions:

69. **Do you agree that we should not continue to consider a payment on carbon avoided for mass low carbon power?**

70. **Do you agree that we should continue to consider a payment on carbon avoided subsidy for flexibility?**

71. **Could the Dutch Subsidy scheme be amended to send appropriate signals to both renewables and supply and demand side flexible assets?**

72. **Are there other advantages to the Dutch Subsidy scheme we have not identified?**

Equivalent Firm Power Auction

An Equivalent Firm Power (EFP) auction is a single unified auction for procuring system capacity. The auction would be an evolution of the Capacity Market, integrating CfDs within it, so that renewables – contracting alongside flexible assets – and firm capacity compete for capacity contracts based on their 'equivalent firm power'. This model was proposed by Dieter Helm in the 2017 Cost of Energy Review.

By unifying the Capacity Market and CfD, this model aims to consolidate support schemes and give a greater role to the market in determining the capacity mix. It is also intended to make renewables internalise the cost of their variability. The variability of renewables introduces several costs to the system:[67] the EFP auction, by valuing equivalent firmness, forces renewables to directly bear the system costs of their variability.

The equivalent firm power of a generator is based on its 'equivalent' firmness in security of supply relevant periods (when there is not enough capacity to meet demand). Within the auction, de-rating factors would be applied to variable generators based on the quantity of firm capacity required to offer the same level of security of supply during these periods. The auction would include enforceable capacity contracts with penalties for non-delivery, and so incentivise variable generators to seek contracts with flexible assets to back up their variability and improve their de-rating factor to provide a greater 'equivalent' firm power.

A central body would determine de-rating factors for individual technologies and packages, as well as the amount of capacity to procure, and hold auctions to find the least cost pathway to ensure security of supply. As originally proposed, the auction would not value decarbonisation, instead leaving this objective to an economy-wide carbon price; however a second stage process of applying a carbon constraint could be designed to ensure the auction results meet an emissions target.

The strengths of the EFP auction are that it creates a technology-neutral auction and a secondary market for flexibility as renewables seek to improve their de-rating factors. The current separation of the CfD scheme and the Capacity Market address the different market issues faced by renewables and firm power. However, low carbon flexible assets, which are able to deliver both decarbonisation and security of supply, have historically struggled to participate in either. Current schemes also place the cost of variability on the system rather than individual generators. Holding technology-neutral auctions would incentivise market participants to find the most efficient ways to deliver security of supply (and potentially decarbonisation, depending on design).

While the concept of an EFP auction has merit, we also think there are a number of potential drawbacks.

Firstly, the auction encourages variable renewables to contract with flexibility providers at an individual project level, but it may be more cost-effective to procure system security at a system level. Procurement at an individual level could lead to an over procurement of flexible

[67] These include balancing, transmission, distribution, and back up capacity costs.

assets, and risks forgoing economies of scale in procuring firmness at a system level. In addition, the auction only values flexible assets which are able to contribute towards the capacity margin, but not other flexibility services, such as response time. This means that it may not bring forward the most cost-effective suite of technologies to meet a range of system security needs.

Second, the EFP auction is likely to increase risks for renewable investors. Renewable assets would receive EFP capacity payments, but these could be a relatively small revenue stream due to high de-rating factors, or would have to be shared with a paired flexibility provider. The majority of renewables' revenue would come through the wholesale market, meaning they would be exposed to considerable price risk. Our illustrative analysis suggest that the average wholesale market capture prices are likely to fall as renewable penetration increases, further increasing the risk of this revenue stream. Generators could also face additional counterparty and co-ordination risks when submitting joint bids alongside flexible providers. The increase in risk is likely to increase the financing cost of these assets, relative to the CfD scheme status quo.

Third, while the auction is intended to be technology-neutral, the choice of capacity mix would likely be dependent on the various auction parameters, including de-rating factors (for both technologies and packages) and potentially shadow carbon prices. These would be set by the government, and could create greater opportunities for complexities in parameter-setting to translate into an inefficient capacity mix.

Questions:

73. **Do you agree that we should continue to consider an Equivalent Firm Power auction?**

74. **How could the challenges identified with the Equivalent Firm Power auction be overcome? Please provide supporting evidence.**

Consultation questions

Chapter 1

1. **Do you agree with the vision for the electricity system we have presented?**

2. **Do you agree with our objectives for electricity market reform (decarbonisation, security of supply, and cost effectiveness)?**

Chapter 2

3. **Do you agree with the future challenges for the electricity system we have identified? Are there further challenges we should consider? Please provide evidence for additional challenges.**

4. **Do you agree with our assessment of current market arrangements / that current market arrangements are not fit for purpose for delivering our 2035 objectives?**

Chapter 3

5. **Are least cost, deliverability, investor confidence, whole-system flexibility and adaptability the right criteria against which to assess options?**

6. **Do you agree with our organisation of the options for reform?**

7. **What should we consider when constructing and assessing packages of options?**

Chapter 4

8. **Have we identified the key cross-cutting questions and issues which would arise when considering options for electricity market reform?**

9. **Do you agree with our assessment of the trade-offs between the different approaches to resolving these cross-cutting questions and issues?**

10. **What is the most effective way of delivering locational signals, to drive efficient investment and dispatch decisions of generators, demand users, and storage? Please provide evidence to support your response.**

11. **How responsive would market participants be to sharper locational signals? Please provide any evidence, including from other jurisdictions, in your response.**

12. **How do you think electricity demand reduction should be rewarded in existing or future electricity markets?**

Chapter 5

13. **Are we considering all the credible options for reform in the wholesale market chapter?**

14. **Do you agree that we should continue to consider a split wholesale market?**

15. **How might the design issues raised above be overcome for: a) the split markets model, and b) the green power pool? Please consider the role flexible assets should play in a split market or green power pool – which markets should they participate in? - and how system costs could be passed on to green power pool participants.**

16. **Do you agree that we should continue to consider both nodal and zonal market designs?**

17. **How might the challenges and design issues we have identified with nodal and zonal market designs be overcome?**

18. **Could nodal pricing be implemented at a distribution level?**

19. **Do you agree that we should continue to consider the local markets approach? Please consider the relative advantages and drawbacks, and local institutional requirements, of distribution led approaches.**

20. **Are there other approaches to developing local markets which we have not considered?**

21. **Do you agree that we should continue to consider reforms that move away from marginal pricing? Please consider the relative advantages and drawbacks, and local institutional requirements, of distribution led approaches.**

22. **Do you agree that we should continue to consider amendments to the parameters of current market arrangements, including to dispatch, settlement and gate closure?**

23. **Are there any other changes to current wholesale market design and the Balancing Mechanism we should consider?**

Chapter 6

24. **Are we considering all the credible options for reform in the mass low carbon power chapter?**

25. **How could electricity markets better value the low carbon and wider system benefits of small-scale, distributed renewables?**

26. **Do you agree that we should continue to consider supplier obligations?**

27. **How would the supplier landscape need to change, if at all, to make a supplier obligation model effective at bringing forward low carbon investment?**

28. How could the financing and delivery risks of a supplier obligation model be overcome?

29. Do you agree that we should continue to consider central contracts with payments based on output?

30. Are the benefits of increased market exposure under central contracts with payment based on output likely to outweigh the potential increase in financing cost?

31. Do you have any evidence on the relative balance between capital cost and likely balancing costs under different scenarios and support mechanisms?

32. Do you agree that we should continue to consider central contracts with payment decoupled from output?

33. How could a revenue cap be designed to ensure value for money whilst continuing to incentivise valuable behaviour?

34. How could deemed generation be calculated accurately, and opportunities for gaming be limited?

Chapter 7

35. Are we considering all the credible options for reform in the flexibility chapter?

36. Can strong operational signals through reformed markets bring forward enough flexibility, or is additional support needed to de-risk investment to meet our 2035 commitment? Please consider if this differs between technology types.

37. Do you agree we should continue to consider a revenue cap and floor for flexible assets? How might your answer change under different wholesale market options considered in chapter 5 or other options considered in this chapter?

38. How could a revenue cap and floor be designed to ensure value for money? For example, how could a cap be designed to ensure assets are incentivised to operate flexibly and remain available if they reach their cap?

39. Can a revenue (cap and) floor be designed to ensure effective competition between flexible technologies, including small scale flexible assets?

40. Do you agree that we should continue to consider each of these options (an optimised Capacity Market, running flexibility-specific auctions, and introducing multipliers to the clearing price for particular flexible attributes) for reforming the Capacity Market?

41. **What characteristics of flexibility could be valued within a reformed Capacity Market with flexibility enhancements? How could these enhancements be designed to maximise the value of flexibility while avoiding unintended consequences?**

42. **Do you agree that we should continue to consider a supplier obligation for flexibility?**

43. **Should suppliers have a responsibility to bring forward flexibility in the long term and how might the supplier landscape need to change, if at all?**

44. **For the Clean Peak Standard in particular, how could multipliers be set to value the whole-system benefits of flexible technologies? And how would peak periods be set?**

Chapter 8

45. **Are we considering all the credible options for reform in the capacity adequacy chapter?**

46. **Do you agree that we should continue to consider optimising the Capacity Market?**

47. **Which route for change – Separate Auctions, Multiple Clearing Prices, or another route we have not identified – do you feel would best meet our objectives and why?**

48. **Do you consider that an optimised Capacity Market alone will be enough for ensuring capacity adequacy in the future, or will additional measures be needed?**

49. **Are there any other major reforms we should consider to ensure that the Capacity Market meets our objectives?**

50. **Do you agree that we should continue to consider a strategic reserve?**

51. **What other options do you think would work best alongside a strategic reserve to meet flexibility and decarbonisation objectives?**

52. **Do you see any advantages of a strategic reserve under government ownership?**

53. **Do you agree that we should continue to consider centralised reliability options?**

54. **Are there any advantages centralised reliability options could offer over the existing GB Capacity Market? For example, cost effectiveness or security of supply benefits? Please evidence your answers as much as possible.**

55. Which other options or market interventions do you consider would be needed alongside centralised reliability options, if any?

56. Do you agree that we should not continue to consider decentralised reliability options / obligations? Please explain your reasoning, whether you agree or disagree.

57. Are there any benefits from decentralised reliability option models that we could isolate and integrate into one of our three preferred options (Optimised Capacity Market, Strategic Reserve, Centralised Reliability Option)? If so, how do you envisage we could do this?

58. Do you agree that we should not continue to consider a capacity payment option? Please explain your reasoning, whether you agree or disagree.

59. Do you agree that we should not continue to consider a targeted capacity payment / targeted tender option? Please explain your reasoning, whether you agree or disagree.

60. Do you agree with our assessment of the cost effectiveness of a targeted capacity payment / targeted tender option, and the risk of overcompensation? If not, why not?

Chapter 9: Operability

61. Are we considering all the credible options for reform in the operability chapter?

62. Do you think that existing policies, including those set out in the ESO's Markets Roadmap, are sufficient to ensure operability of the electricity system that meets our net zero commitments, as well as being cost effective and reliable?

63. Do you support any of the measures outlined for enhancing existing policies? Please state your reasons.

64. To what extent do you think that existing and planned coordination activity between ESO and DNOs ensures optimal operability?

65. What is the scope, if any, for distribution level institutions to play a greater role in maintaining operability and facilitating markets than what is already planned, and how could this be taken forward?

66. Do you think that the CfD in its current form discourages provision of ancillary services from assets participating in the scheme? If so, how could this best be addressed?

67. Do you think it would be useful to modify the Capacity Market so that it requires or incentivises the provision of ancillary services? If so, how could this be achieved?

68. Do you think that co-optimisation would be effective in the UK under a central dispatch model?

Chapter 10: Options across multiple market elements

69. Do you agree that we should not continue to consider a payment on carbon avoided for mass low carbon power?

70. Do you agree that we should continue to consider a payment on carbon avoided subsidy for flexibility?

71. Could the Dutch Subsidy scheme be amended to send appropriate signals to both renewables and supply and demand side flexible assets?

72. Are there other advantages to the Dutch Subsidy scheme we have not identified?

73. Do you agree that we should continue to consider an Equivalent Firm Power auction?

74. How could the challenges identified with the Equivalent Firm Power Auction be overcome? Please provide supporting evidence.

Glossary

Balancing mechanism	One of the tools the Electricity System Operator uses to balance electricity supply and demand close to real time. Where the Electricity System Operator predicts that there will be a discrepancy between the amount of electricity produced and the level of demand during a certain half-hour period, they may accept a 'bid' or 'offer' to either increase or decrease generation (or consumption).
Baseload	The minimum level of electricity demand required over a period. Plants that are running continuously over extended periods of time, for example large-scale nuclear power plants, are said to be baseload generators. The power from these plants is used to meet the minimum demand of the system.
BECCS	Bioenergy (i.e. burning biomass to produce electricity) with carbon capture and storage
BETTA	British Electricity Trading and Transmission Arrangements, which came into effect on 1 April 2005 to harmonise electricity trading across GB. BETTA is based on bilateral trading between generators, suppliers, customers and traders, and participants self-dispatch rather than being dispatched centrally by the Electricity System Operator.
British Energy Security Strategy (BESS)	This strategy, published in April 2022, sets out how Great Britain will accelerate homegrown power for greater long-term energy independence.
Carbon price support	Electricity generated from fossil fuels is taxed to guarantee a minimum price for CO2 emissions.
Capacity Market	A payment to any generator (or storage / demand side response provider) who can respond when notified upon by the Electricity System Operator in times of system stress. Auctions for this capacity take place at both four years and one year ahead of delivery, and agreements generally last for one year. The procured capacity is the amount required to meet peak demand.
Capacity Mix	The mix of various energy sources and technologies for electricity generation.

CCGT	Combined-cycle gas turbine power plant, an electrical power plant in which a gas turbine and a steam turbine are used in combination to achieve greater efficiency than would be possible independently.
CCUS	Carbon capture, usage and storage: technology for capturing carbon dioxide that would otherwise be emitted and either using it (often in industrial processes) or permanently storing it.
CfD	Contracts for Difference, a 15-year private law contract between low-carbon electricity generators and the Low Carbon Contracts Company. Contracts are awarded in a series of competitive auctions. Generators receive revenue from selling their electricity into the wholesale market. When the market reference price is below the strike price, generators receive a top-up payment for the additional amount. If the reference price is above the strike price, the generator must pay back the difference.
Dispatchable generation	Dispatchable generation refers to sources of electricity that can be produced on demand, according to market needs.
DPA	Dispatchable power agreement, the proposed contractual framework to enable power CCUS to play a mid-merit role in meeting electricity demand. Under the terms of the DPA, power CCUS plants will receive an availability payment for being available to dispatch, and a variable payment to ensure that plants dispatch ahead of the most efficient unabated gas plant.
DNO / DSO	Distribution network operators are the companies that own and operates the power lines and infrastructure that connect the grid to properties. Distribution system operation refers to the active management of the distribution system at the local level, currently undertaken by DNOs, and involves the delivery of three core roles: network planning, system operation, and market facilitation.
DSR	Demand-side response, also known as flexible demand, i.e. when consumers respond to market conditions by changing how much and/or when they consume.
Domestic consumers	Households that consume electricity.

EfW	Energy from Waste, turning waste into a useable form of energy (e.g. electricity, heat and transport fuels), for example through incineration.
EMR	Electricity Market Reform, a set of reforms (including the CfD and Capacity Market) introduced by the government in 2013 to incentivise investment in secure, low-carbon electricity.
EPS	Emissions performance standard, which limits CO2 emissions from any new power station to 450 gm/kWh and prevents new coal fired generation from being built without carbon capture and storage technology.
ESO	The Electricity System Operator performs several important functions, from second-by-second balancing of electricity supply and demand, to developing markets and advising on network investments.
ETS	Emissions Trading Scheme. A UK ETS replaced the UK's participation in the EU ETS on 1 January 2021. Emissions trading schemes usually work on the 'cap and trade' principle, where a cap is set on the total amount of certain greenhouse gases that can be emitted by sectors covered by the scheme. This limits the total amount of carbon that can be emitted and, as it decreases over time, will make a significant contribution to how we meet our Net Zero 2050 target and other legally binding carbon reduction commitments.
Financial Transmission Rights	Financial Transmission Rights, also known as FTRs, allow market participants to offset potential losses (i.e. hedge) related to the price risk of delivering energy to the grid.. They are a method to bypass congestion charges associated with Locational Marginal Pricing. They give market participants the ability to attain a better price certainty when delivering energy across the grid.
Flexibility	The ability to shift the consumption or generation of energy in time or location. Flexibility is critical for balancing supply and demand, integrating renewables and maintaining the stability of the system. Flexibility technologies include electricity storage, flexible demand, CCUS, hydrogen power and interconnectors.
FOAK	First-of-a-kind technologies

Frequency response	National Grid have an obligation to control system frequency at 50Hz plus or minus 1%. There are several different types of frequency response that National Grid procure.
Future Energy Scenarios	These are produced by the Electricity System Operator and represent a range of different, credible ways to decarbonise our energy system as we transition towards net zero.
Hydrocarbon	A hydrocarbon is an organic compound consisting of hydrogen and carbon found in crude oil, natural gas, and coal, i.e. fossil fuels. Hydrocarbons are highly combustible and the main energy source of the world.
Inertia	Inertia is important to the stable operation of the electricity system. Many generators producing electricity for the grid have spinning parts – they rotate at the right frequency to help balance supply and demand and can spin faster or slower if needed. The kinetic energy 'stored' in these spinning parts is system inertia. If there's a sudden change in system frequency, these parts will carry on spinning – even if the generator itself has lost power – and slow down that change (called the rate of change of frequency, or ROCOF) while the Electricity System Operator's control room restores balance.
Interconnector	An electricity interconnector runs under the sea, underground or via overhead cabling, to connect the electricity systems of two countries. It allows the trading and sharing of surplus electricity.
Intermittent Market Reference Price	The reference price used for variable renewables with a CfD contract. When the reference price is below the Strike Price, payments are made by Low Carbon Contracts Company (LCCC) to the CfD Generator. when the Reference Price is above the Strike Price, the CfD Generator pays LCCC the difference. The IMRP is calculated using day-ahead market data, the IMRP is calculated for every hour of the day.
LCCC	Low Carbon Contracts Company, a government-owned company that is operationally independent and manages CfDs at arm's length from government.
Locational imbalance pricing	Introduces imbalance charges for suppliers if there is both an imbalance and a constraint between the location of their consumers' demand and their generators' supply.

Locational Marginal Pricing (LMP)	See nodal pricing.
LoLE	Loss of Load Expectation is the expected number of hours per year that electricity generation cannot meet electricity demand.
Long-run marginal cost	The marginal cost is the change in the total cost that arises when an additional unit is produced. The long-run marginal cost includes any fixed costs of production, for example the construction cost of a generator.
Marginal pricing	Means that the cost of the most expensive generation asset required to meet demand sets the price for the entire market. Currently, due to the current role of gas generation within the GB electricity market, the GB wholesale electricity price tends to closely track gas prices, which are largely set by global market developments.
Network constraint costs	The Electricity System Operator needs to balance the generation and demand across the network. Sources of generation and the points of demand are not always located in the same place. This can lead to bottlenecks on the system as there can be limited capacity to transmit the electricity across the different locations. Where the energy is restricted in its ability to flow between two points this is known as a constraint and the Electricity System Operator needs to take action to mitigate these constraints. Generators are asked to reduce their output to maintain system stability and manage flows on the network, and are compensated through a constraint payment.
Net Zero Strategy	This strategy, published in October 2021, sets out policies and proposals for decarbonising all sectors of the UK economy to meet our net zero target by 2050.
NETA	New Electricity Trading Arrangements. The trading arrangements introduced in 2001 in England and. In 2005 NETA was developed into the British Electricity Trading and Transmission Arrangements (BETTA).
Nodal pricing	Also known as Locational Marginal Pricing (LMP). An electricity market design where the price in each network location (also known as a “node”) represents the locational value of energy.

Non-domestic consumers	Business/industry consumers of gas and electricity.
Offshore Transmission Network Review	The review looks into the way that the offshore transmission network is designed and delivered, consistent with the ambition to deliver net zero emissions by 2050.
Power CCUS	Gas-fired power generation with CCUS technology
PPA	Power Purchase Agreement, a long-term bilateral contract between power producers (typically generators) and consumers, under which a business agrees to purchase electricity directly from a renewable generator, providing the revenue certainty needed to secure financing for construction.
Price cannibalisation	As renewable generation is correlated, wholesale electricity prices are reduced at times of high output from intermittent, weather-driven generation such as solar, onshore and offshore wind. This reduces the revenue that renewable generators can earn in the wholesale market.
REMA	Review of Electricity Market Arrangements
RIIO-2	Stands for 'Revenue = Incentives + Innovation + Outputs'. The framework used by Ofgem to ensure that individual network companies provide a safe and reliable service, value for money, maximise performance, operate efficiently, innovate, and ensure the resilience of their networks for current and future markets. RIIO-2 is the second set of price controls implemented under this framework.
I-SEM	Single Electricity Market on the island of Ireland
Short-run marginal cost	The marginal cost is the change in the total cost that arises when an additional unit is produced. The short-run marginal cost excludes fixed costs. For electricity generators, construction costs are fixed therefore only operating costs, such as fuel costs, are included in short-run marginal costs.
TCA	Trade and Cooperation Agreement between the UK and EU
Unabated assets	A fossil fuel plant that has not installed technology that reduces its carbon dioxide emissions.
Value of Lost Load	The value of lost load (VoLL) is a monetary value expressing the costs associated with an interruption of electricity supply.

Zonal pricing	Under zonal pricing, the network is split into clearly defined zones. The boundaries of the zones are drawn to reflect where major transmission network constraints occur. In a zonal market, each individual zone has a single price which assumes no network constraints within the zone.

Annex: Quantitative Analysis Methodology and Assumptions

This annex provides additional background and detail on the quantitative analysis included in the Chapter 2: The Case for Change, including the scope, methodology and assumptions of the modelling and scenarios.

Modelling Approach

For this analysis, we have primarily drawn on evidence from modelling undertaken on behalf of National Grid ESO, in collaboration with BEIS and Ofgem, by Lane Clark & Peacock LLP, specifically designed to support thinking on the case for market reform. This analysis was intended to develop our understanding of the near and longer-term challenges of a low-carbon electricity system under market current arrangements. The input data includes the National Grid ESO's Future Energy Scenarios 2021, the BEIS Net Zero and the Power Sector Scenarios[68], the BEIS Generation Costs Report 2020, and additional specific reports and databases.

Scenarios

The modelling used four Net Zero-consistent scenarios: three from the Future Energy Scenarios (FES) and the BEIS "Higher Demand" scenario.[69] These scenarios are intended to be illustrative of possible future states of the system in terms of demand levels and capacity/generation mix. They do not necessarily represent "optimal" demand levels or technology mixes. FES scenarios are not built based on cost-optimised modelling, but instead on available intelligence and stakeholder engagement). Additionally, the scenarios do not indicate a preferred outcome nor are they an expression of government policy.

The BEIS Higher Demand scenario is the main scenario that we present throughout the analysis. We have included the additional three FES scenarios as sensitivity analysis to reflect uncertainty in the assumptions and projections. All scenarios indicate the same trends and outcomes so we therefore have confidence that the modelling, and the BEIS Higher Demand scenario, provides evidence supporting the identified future system challenges.

Work packages

The analysis was split into two 'Work Packages'. The modelling outputs of Work Package 1 (WP1) were the flexible capacity and flexibility requirements;[70] firm capacity; operating profiles

[68] BEIS, 2022, Annex O: Net Zero and the Power Sector Scenarios, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/947439/energy-emissions-projections-2019-annex-o-net-zero-power-sector-scenarios.pdf
[69] Note that this scenario differs from the standard BEIS Higher Demand scenario as any unabated gas capacity past 2030 was replaced with hydrogen generation only for this analysis.
[70] Based on residual demand

of technologies including load factors, starts, and time up; flexible fleet flexibility including ramping and peak turn ups; and time horizons including intraday, intraweek, intramonth, and intraseason.

Work Package 2 (WP2) used outputs from WP1 to model the impacts on markets, namely the wholesale market, CfD support, the balancing market, the capacity market, and ancillary services market, and on gross margins for generators. WP2 modelling includes analysis of revenue breakdown and profitability of different technologies out to 2050, and considered both shorter-term volatility (e.g. windy vs calm years) and longer-term market uncertainty (e.g. different capacity/generation mixes across scenarios). Stochastic dispatch modelling approach was used to capture variations in weather (demand, wind, solar).

Key assumptions

- **Demand** – All four scenarios show higher peak demand and significant demand growth to 2050 due to electrification of transport & heat. The illustrative BEIS Higher Demand scenario assumes significantly higher demand growth than the 3 FES scenarios (over 50% higher than most extreme FES scenario). However, the BEIS High Demand assumes much higher electrification of heating than FES, which assumes a large hydrogen-based economy.
- **Capacity** – The capacity assumptions are based on the underlying scenarios from the FES and the illustrative BEIS Higher Demand scenario, including the flexible fleet. The underlying FES scenarios were modified to add additional gas peaking capacity to ensure security of supply/achieve Loss of Load Expectation (LOLE) of 3 hours (unabated in early years and hydrogen from 2030 onwards). In the illustrative BEIS HD scenario, we have assumed that any non-CCS gas capacity added post 2030 will be hydrogen-fuelled.
- **Existing market arrangements** – The modelling assumed that there would be no change to existing market arrangements. The Contracts for Difference (CfD) strike prices and Capacity Market (Capacity Market) prices are calculated to ensure plants breakeven. Additionally, the balancing market and key operability services are simulated based on fundamentals analysis.
- **Low-carbon support** – In the modelling, it is assumed most low carbon capacity is supported in some way; renewables are deployed through the Contract for Difference (CfD) mechanism, Nuclear is deployed through a Regulated Asset Base (RAB) and Gas CCUS through a Dispatchable Power Agreement (DPA) type mechanism. This does not indicate that these schemes will remain BEIS's preferred method to deploy these technologies but that this is a way to reflect the possibility that these technologies may continue to require some support to deploy in future.
- **Carbon prices and commodities** – Gas and carbon prices are based on the FES and BEIS assumptions for their respective scenarios. All FES scenarios assume the same gas price trajectory, i.e. a steady increase until 2035 followed by a very slow decline to 2050. The illustrative BEIS HD scenario gas prices assumptions also increase until 2035, when they level off. Two of the included FES scenarios assume a lower rate of

increase in carbon costs in comparison to the Leading the Way and the BEIS HD scenarios which assume a much higher trajectory.

Uncertainty

There are numerous paths to net zero and the scenarios are indicative of what a future electricity system may look like rather than prescriptive forecasts, nor do they indicate a preferred outcome or an expression of government policy. Whilst they are not forecasts, these scenarios do illustrate the mix of properties required for a NDC, CB6 and net zero consistent power system.

There remains much uncertainty, including for example about the pace of innovation in the market, demand levels, the technical feasibility of some technologies, and the investment decisions of electricity generators.

Given this uncertainty, the results of the analysis should be viewed as indicators for the scale and direction of the future challenges that the modelling identified rather than as precise projections. This is particularly true as the time horizon extends as uncertainty compounds over time.

For detail on the underlying assumptions and technical approach to the BEIS Higher Demand scenario, please refer to Annex O: Net Zero and the power sector scenarios, March 2020.[71] For the National Grid Future Energy Scenarios, please refer to the National Grid ESO FES 2021.[72]

Future modelling always comes with uncertainty, and not all possible outcomes can be predicted. That uncertainty becomes more profound the further into the future the modelling goes. We have made certain assumptions to focus on certain possible futures, namely one in which the power sector has achieved Net Zero in the most cost-effective path.

How we have considered uncertainty

We have considered uncertainty by including several scenarios which all have slightly different but distinct approaches and assumptions to achieving Net Zero. By including the three Net Zero compliant NG ESO FES scenarios, in addition to our own illustrative BEIS Higher Demand scenario, we have presented a ‘range’ of outcomes to reflect uncertainty in the future. The BEIS Higher Demand scenario was included to illustrate a particularly challenging possible outcome for GB demand; it is indicative and does not define or bound what is possible.

[71] BEIS, 2022, Annex O: Net Zero and the Power Sector Scenarios, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/947439/energy-emissions-projections-2019-annex-o-net-zero-power-sector-scenarios.pdf
[72] National Grid ESO, 2021, ESO Future Energy Scenarios, https://www.nationalgrideso.com/future-energy/future-energy-scenarios

Key uncertainties

- **Demand** for power including peaks, totals, and minimums in each scenario is based on historical demand profiles. The BEIS Higher Demand scenario also assumes high levels of electrification in road transport, with higher traffic, in addition to higher electrification of heating in homes and business. Demand profiles, including the relationship between peak, average, and minimum and the demand across the hours of the day could change in future. Actual road transport and heating demands, in addition to other interactions that sectors have with the power sector in future may be different to the scenario assumptions.
- **Technology costs** includes the costs to build, maintain, finance, and operate (excluding fuels). Some technologies have future technology cost projections,[73] but this is uncertain and impacted by global trends.
- **New technologies** and innovations in the power sector may become available and commercially viable in the next 30 years but only existing and highly developed new technologies that are commercially viable are included in the model. The transition to net zero will involve considerable technological innovation and investment; how the market responds to these changes and challenges will play a considerable part in determining future capacity mixes.
- **Consumer behaviour** is modelled in the form of electricity demand reduction and shifting. The prevalence and effectiveness of demand turndown and reduction/shifting is uncertain.
- **Commodity costs** such as fuel/gas prices are determined by markets and exogenous shocks and are therefore inherently uncertain—especially for distant time horizons. Additionally, the carbon price is determined by market outcomes, and influenced by wider decarbonisation policy, and so is also uncertain.
- **Market design and regulation** is dependent upon many of the above uncertainties, including future policy decisions and technologies. We have assumed in the modelling that the current market arrangements are in place throughout.

[73] BEIS, 2020, BEIS Electricity Generation Costs (2020), https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020

This consultation is available from: www.gov.uk/government/consultations/review-of-electricity-market-arrangements

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