Review of Electricity Market Arrangements

Consultation Response from Regen

10/10/2022

About Regen

Regen is an independent centre of energy expertise with a mission to accelerate the transition to a zero carbon energy system. We have 20 years' experience in transforming the energy system for net zero and delivering expert advice and market insight on the systemic challenges of decarbonising power, heat and transport.

Regen is also a membership organisation and manages the Electricity Storage Network (ESN) – the voice of the UK storage industry. We have over 150 members who share our mission, including clean energy developers, businesses, local authorities, community energy groups, academic institutions, and research organisations across the energy sector.

This response is based on extensive practical experience and input from our members.

Introduction and Regen Response Summary

Introduction

The challenges facing our electricity system are escalating. The importance of solving them is hard to overstate, and the pace of change needed for success is growing.

The current energy price crisis has exposed how failing to prepare for the uncertainty that is inherent in our energy system has led to devastation for many who face being unable to afford their bills this winter. At the same time, the scale of investment needed in all aspects of our electricity system to deliver on net zero power in just 13 years highlights the importance of focusing on delivery, and of de-risking the transition.

Delivering an electricity system that can provide secure, affordable and zero carbon energy is critical to our future as a country. We need to do so in a way that is equitable and fair, supports a strong economy and makes use of regional strengths.

Get this right and we can deliver a system that makes use of renewable technologies for the bulk of our energy production, technologies that we know today are far cheaper than fossil fuels, and reduce our dependency on volatile international energy markets. It will also be one that brings together a raft of zero carbon technologies from battery storage, hydrogen and greater interconnection to ensure a secure supply.

Get this wrong and we risk failing on net zero, blackouts, and a situation where many cannot afford basic necessities such as a warm home.

Our wholesale market and the structures that go around it will play an important part in delivering the system we need. It will help incentivise investment in the right technologies, in the right places at the right time. It can help dispatch the resources we have available in an effective and efficient way. It can help make sure that prices reflect costs, ensuring that consumers pay bills that are predictable and affordable. It should provide clear and consistent signals that give investors confidence that, if they invest to support the UK's overall goals for our electricity system, then they can have confidence of making a fair return.

Our current wholesale market arrangements, based on a trading market introduced in 2002 and extended to Scotland in 2006, are far more complex, dynamic and advanced than is sometimes understood. It certainly needs reform and enhancement, but combined with the Balancing Mechanism, Capacity Market, the Contracts for Difference (CfD) scheme and an evolving carbon trading scheme it gives us a wide range of options that could be expanded and adapted to support the net zero journey.

While our wholesale market and the structures that go around it will play an important part in delivering the future electricity system we need, it is important that they aren't given undue priority. Market reform needs to be considered in conjunction with other key areas of reform:

- A significantly greater role for strategic planning to create a net zero and energy security delivery plan including an overarching system architecture and a holistic infrastructure investment plan.
- Reform of network development and investment processes in order to deliver the transmission capacity increases urgently required.
- Consideration of wider social and economic policies, such as judicious use of government spending, and the speeding up of planning and consenting.
- A clear vision for how carbon pricing and trading will influence the electricity market. These are not separate markets and carbon policy can play a big role in delivering our net zero ambitions both within electricity and across the wider energy sector.

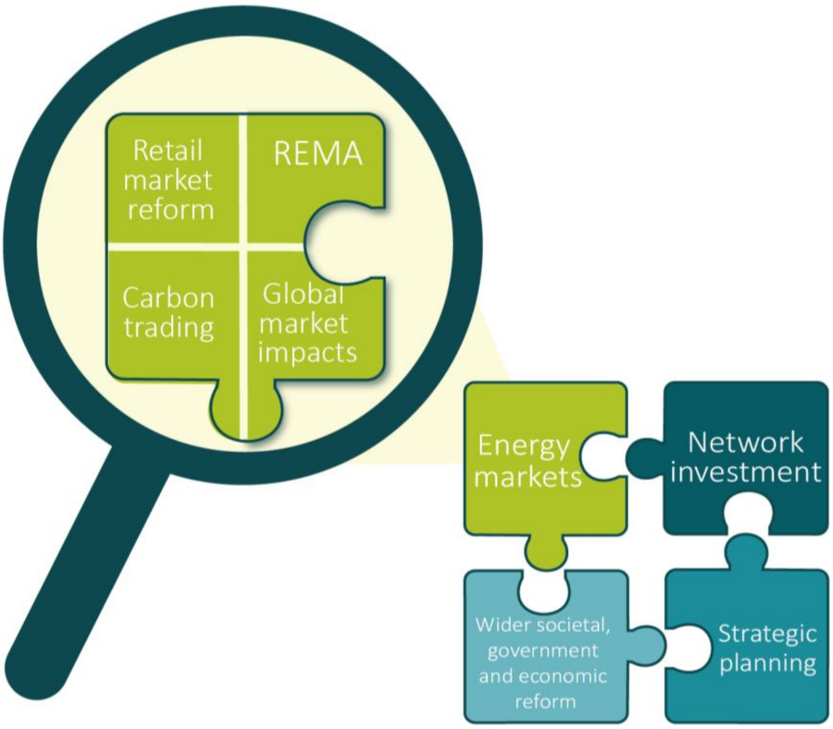


Figure 1: Any energy market reform must be considered within the context of the wider energy system

Scale and pace of investment needed

The biggest market challenge right now is to bring forward massive investment in low carbon technologies, flexibility assets and network infrastructure. Investment that will provide economic growth, energy security, lower energy costs and achieve net zero.

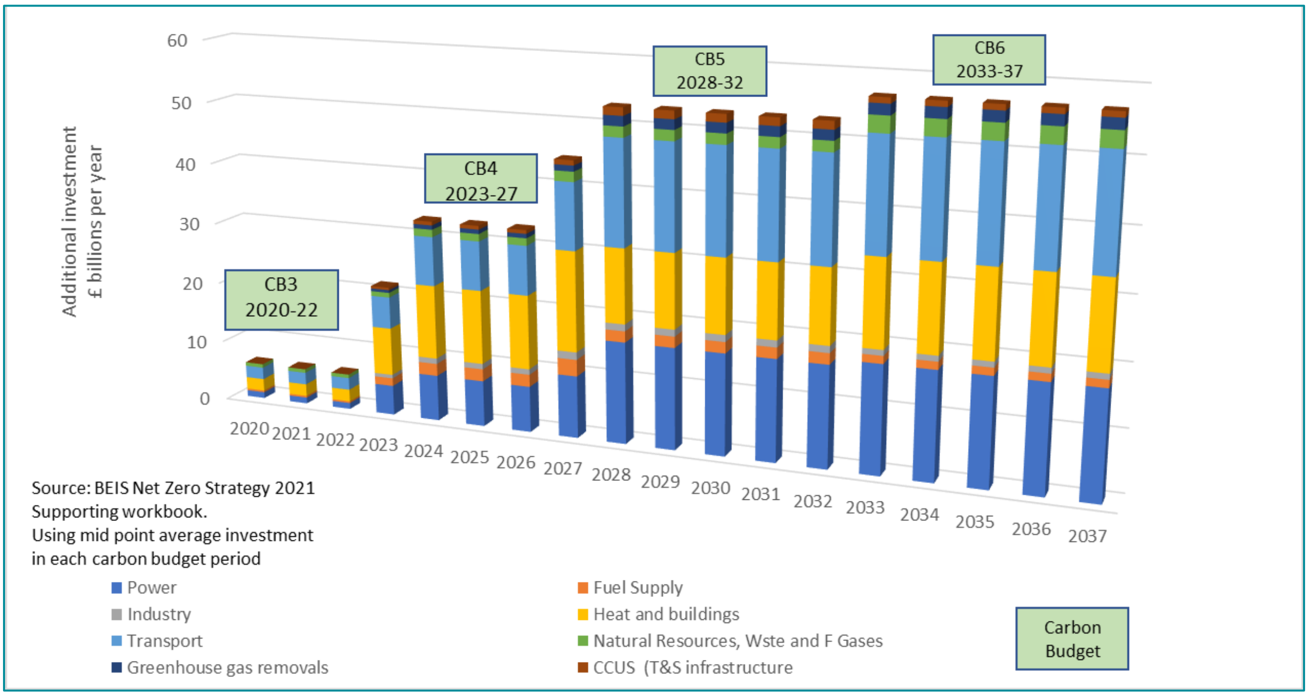
Events over the past year have raised the urgency of progress towards our net zero goals. Even before the current energy price crisis, the Government had acknowledged the need to reform our electricity system quickly. The 2021 Net Zero Strategy committed us to net zero electricity by 2035, reflecting the growing realisation that decarbonising our electricity supply with be a key driver in achieving our wider net zero aims: while today electricity accounts for 20% of our end use energy demand, by 2050 we expect it to be between 50 and 80%[1].

According to the most recent Future Energy Scenarios published by the National Grid[2], by 2035 we need to be delivering around 80% of our electricity from wind and solar in order to achieve net zero. That means an increase in renewable capacity of between 100 and 150 GW in 13 years, with build-rates of between three and four times greater than those we have achieved over the past five years[3].

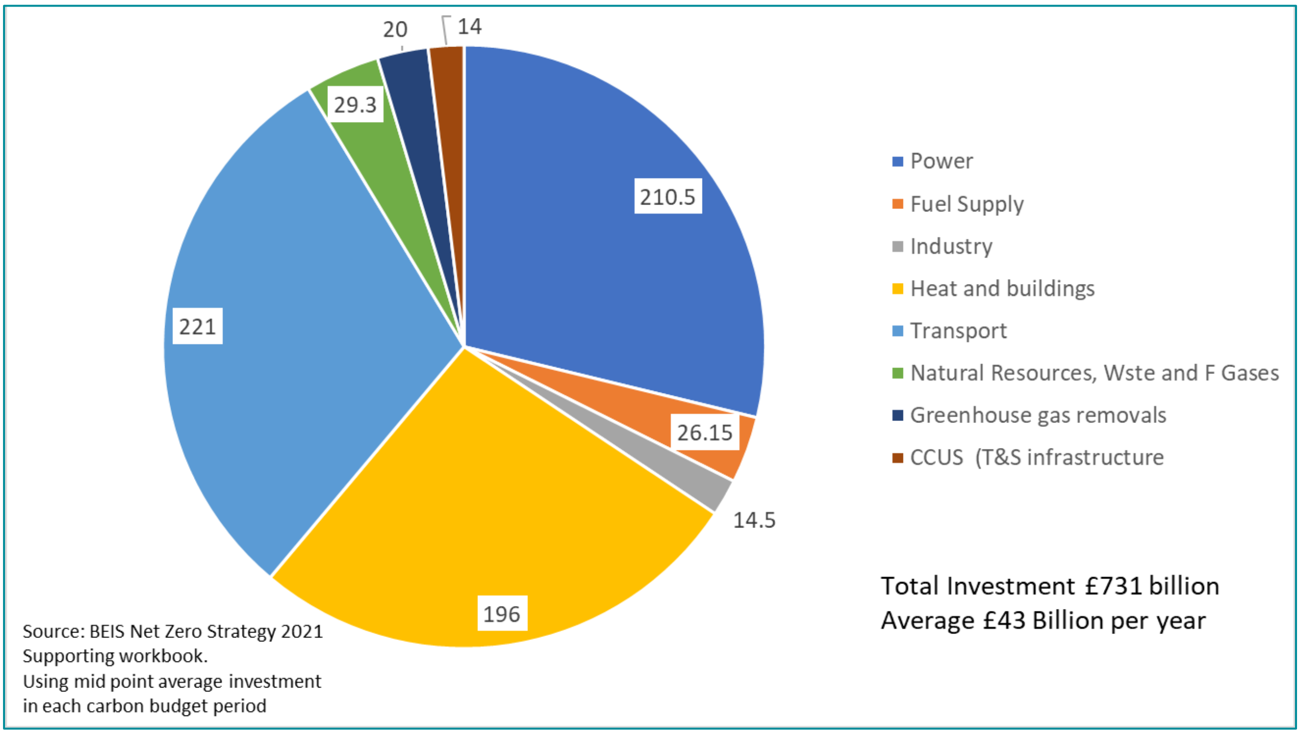
[1] Percentages calculated from the *FES 2022* energy flow diagrams, NGESO, https://www.nationalgrideso.com/future-energy/future-energy-scenarios

[2] National Grid, 2022 https://www.nationalgrideso.com/future-energy/future-energy-scenarios

[3] Regen analysis. Figures based on REPD (historical) and FES LtW, CT and ST.



Figures 2 and 3: Additional annual investment required to reach net zero, 2020-2037 (£bn, undiscounted 2020)



Treasury analysis for the Net Zero Strategy has identified the need for **£730 billion** of investment to decarbonise the UK economy by 2037, of which **£210 billion** would be in the power sector. In addition to this, around **£80-100 billion** will be required to upgrade critical electricity network infrastructure.

This investment significantly ramps up during the next decade and is a step-change on the current levels of investment[4].

More recent analysis from the CCC has highlighted that low carbon investment needs to reach £50 billion per year by 2030. Achieving these levels of investment must be a key goal for REMA.

Furthermore, the urgency posed by rises in energy bills makes the argument for accelerating the move towards net zero power more compelling. Renewables are substantially cheaper today than fossil fuel generators, with the most recent Government estimates of the levelised cost of energy putting wind and solar at less than half that of fossil fuels for projects commissioned in the middle of this decade[5].

Our current CfD system, initially envisaged as a competitive support mechanism for technologies which were not yet fully mature, is now starting to deliver significant savings to consumers, allowing renewable developers to pass their lower costs through to consumer bills in return for the long term price confidence needed to investment. If we had been more ambitious with CfD auction capacity over the past few years, both consumers and the public purse would have seen even greater savings today.

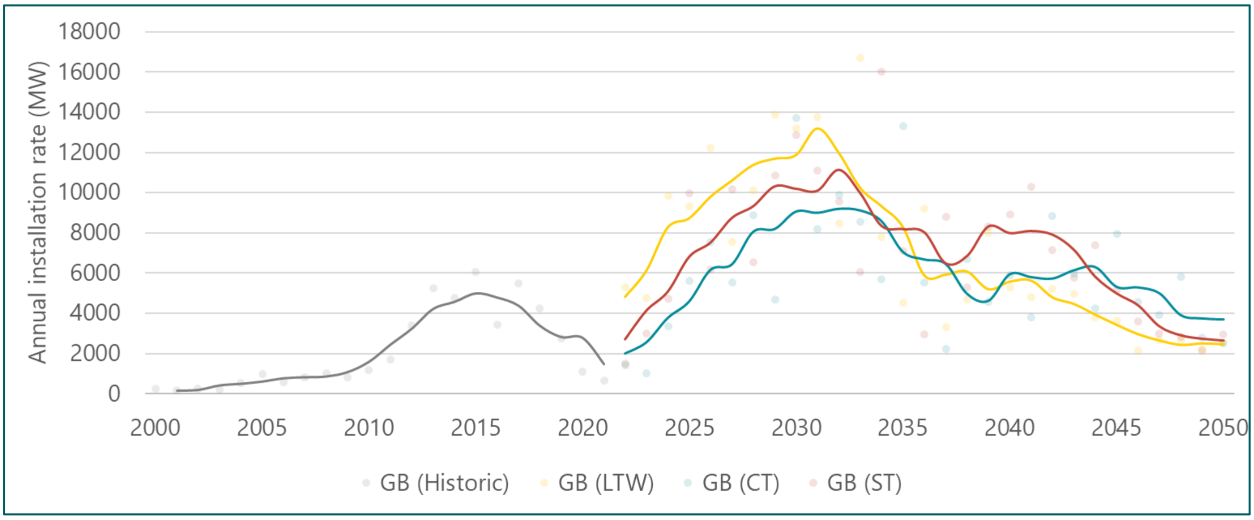


Figure 4: Historic installation rates for renewable technologies together with installation rates implied by the 2022 FES scenarios

[4] Treasury Analysis BEIS Net Zero Strategy 2021 supporting workbook, and CCC 6th Carbon Budget

[5] BIES, 2020 https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020

However, renewables alone won't give us the operability, flexibility and security that we need. Delivering flexible technologies at pace represents an even greater step-change. For example, while the battery storage sector has grown over the past few years and is now providing substantial support to the system through ancillary services, we need to move from a system which is installing a few hundred MW of battery storage per year to one that consistently delivers GWs of new capacity.

We will also need significant investment in new forms of low carbon dispatchable generation, including thermal generation with Carbon Capture and Storage and hydrogen-powered generation. The business case for these projects remains uncertain. The characteristics of a net zero power system will mean that their value will be in supporting periods of system security at times when the wind isn't blowing and the sun isn't shining.

Market reform must deliver a clear business case for low carbon dispatchable generation that supports its role in operating with low capacity factors, but high availability. It is likely this will be based on Capacity Market and ancillary service revenues, providing an investable business case based on operating flexibly and responsively to back up renewable generation, flexibility and interconnection, rather than on an ongoing basis as baseload.

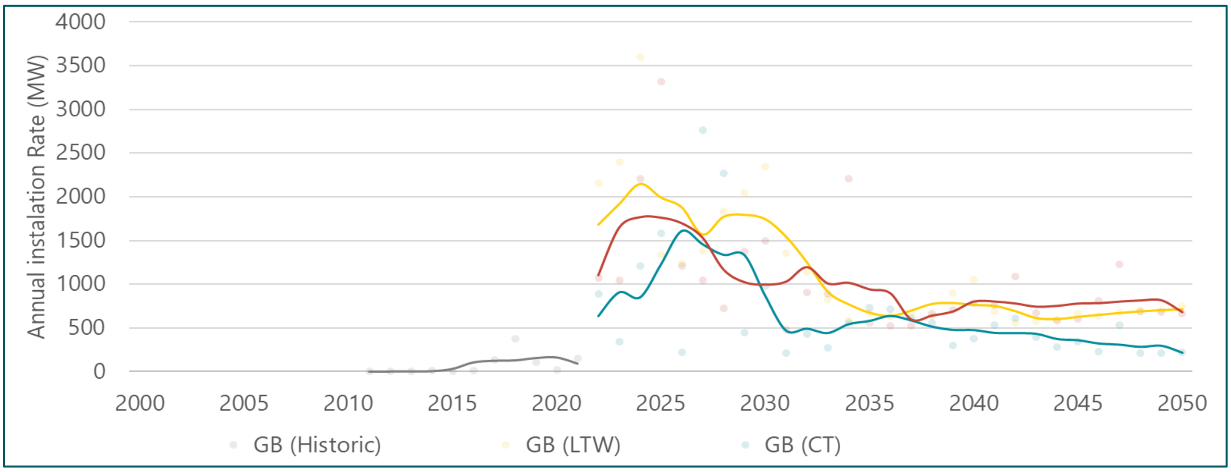


Figure 5: Historic installation rates for battery storage together with installation rates implied by the 2022 FES scenarios

Principles for market reform

Market reform needs to support a step-change in investment in all zero carbon technologies and it needs to pass the cost-savings that come from a net zero power system through to consumers. This can be achieved if reform follows the following principles:

- Remain laser focused on the objectives of **net zero, affordability, security of supply and sustainable economic growth.** Do not put these at risk by taking uncertain gambles on new theoretical frameworks that we are not confident can deliver. For any reform consider carefully the impact on the **pace and scale** of delivering each of the objectives.
- Be very clear and explicit about the **case for change.** At present the case for change, in some areas at least, has not been well articulated and critically examined. There are certainly areas of reform that are needed, but the common perception that the "market is simply broken" has not been proven and in some cases is based on a misunderstanding of how the current market works.
- Always put **electricity *market* reform** in the wider context of **electricity *system* reform** and take due consideration of the other key areas of development: strategic planning; network development; and wider government policy. At each point ask whether market reform is the best approach, or whether one of these other tools would be more effective. Where market reform is the best option, think carefully about how that reform will interact with each of the other areas of system reform.
- As well **as structural reform**, REMA must consider the efficiency of the **operation of the market** and whether this can be improved. A recent study by LCP has identified that 51% of recent wholesale price increases could not be explained by the underlying supply/demand balance and bid fundamentals[6]. This implies that there is a significant amount of speculation, market sentiment and/or inefficiency in market which is driving up prices and costing the consumer billions. REMA should consider the operation of the market and what is driving pricing behaviour: forecasting, transparency, speculative behaviour, interaction with the BM, liquidity, trading platforms, price triggers and the occurrence of bullwhip effects.
- In terms of prices and consumer bills: **long term stable affordability** should be prioritised over the promise of a 'least cost' pathway that entails significant risk of failing to deliver any of the elements of the trilemma.
- In electricity, **networks are a prerequisite for markets**. You cannot have an electricity market without an electricity network, and the design of the network has a major impact on how efficient the markets that use them can be.
- **Maintain confidence in investment**, economic growth and the UK's commitment to accelerate the transition to clean and secure energy.
- **Local energy systems and national energy systems are both important** and should complement each other, each delivering on its own strengths whilst supporting the other with theirs. Wholesale energy markets and the bulk delivery of low carbon power

[6] LCP, 2022; "*51% of price uplift is NOT explained by scarcity presented and bidding fundamentals*" https://www.linkedin.com/posts/lcp-energy_power-gas-electricity-activity-6977959550620467201-SHop?utm_source=share&utm_medium=member_desktop

are likely to work best at a national level, whilst reform of the demand side may be better achieved at a local level.

Summary recommendations for future REMA development

In acknowledging the challenge posed by REMA we know that substantial change is required. REMA has provided a welcome framework in which to discuss some of that change. The consultation asks important questions about the locational signals, price formation and the interaction between wholesale energy and other important aspects of electricity markets – ancillary services, capacity, and continuing support for low carbon generation.

Our proposal for market reform is one in which we radically develop the existing electricity wholesale market at pace, but at the same time make equally radical changes to strategic planning, network development and wider societal, government and economic reform. A full list of the recommendations provided throughout the document can be found in the Appendix.

Strategic planning and investment

- REMA must be aligned with the development of an overarching **Net Zero and Energy Security Delivery plan**. This plan should include an analysis of the key elements of the future electricity system; generation and demand growth, network infrastructure, flexibility, system balancing, capacity adequacy, curtailment and constraints, and projected energy and system cost.
- This Net Zero Energy Security Delivery Plan should include an **Overarching System Architecture** which indicates the capacity of key technology types (generation, flexibility, interconnection and demand) with an indicative breakdown at a regional level.
- Support this with wider reform of the planning system aimed at ensuring that networks, along with generation and flexibility infrastructure, can gain consent and planning approval in appropriate timescales.
- Market reform must be backed up by the accelerated build-out of transmission and distribution network capacity. This could be based on a holistic network design approach to determine what network capacity is needed in ten to twenty years' time and ensuring that Ofgem, NGESO (expected in the near future to become the Future System Operator, or FSO) and the transmission owners are resourced to deliver and held to account for failure. Support infrastructure decision making with a whole system cost benefit analysis (CBA).

Wholesale Market

- Maintain a national wholesale energy market that supports a varied and dynamic trading ecosystem that includes bilateral trading, a vibrant PPA market, organised power exchanges, forward contract markets and short term markets.

- Increase the proportion of energy that is supplied on the basis of long term contracts including PPAs and those backed by CfDs (whilst maintaining appropriate marginal cost price signals to ensure optimal energy usage and flexibility).
- Explore the idea of a green power pool with a specific focus on how it would work in practice, the mechanisms required and worked examples of who it helps and why. Ensure a clear industry-wide understanding of the issue before further consultation.
- Ensure that dispatchable low carbon assets (e.g. BECCS, CCUS, SMRs and Hydrogen) are responsive to the market price and do not become baseload generators that crowd out lower cost and lower carbon renewables energy.
- Critically examine the operation and efficiency of the wholesale market and the occurrence of price speculation, uneconomic volatility, loss of liquidity, scarcity rent taking and bullwhip effects. Consider measures to bear down on these, focusing on transparency, forecasting, flexibility and liquidity.
- Forward market liquidity should be addressed, for example by increasing the availability of longer term PPAs and potentially creating a secondary hedging market for CfD price differentials.

Locational Signals

- **Do not** pursue Locational Marginal Pricing either in nodal or zonal forms, since this will not provide effective locational signals and would significantly increase investment risk.
- Reform TNUoS charging to provide long term stability and forecast ability, with long term cost reflective prices and appropriate locational signals to influence decisions.
- Consider the range of locational signals that currently effect investment decisions and whether these are consistent with an overall net zero system architecture and the delivery of the **Net Zero and Energy Security Delivery plan**.

Low carbon investment

- The CfD scheme could be enhanced, but overall it has been successful in bringing forward investment. It is also now transferring significant value from generators to consumers in the form of negative payments. Its use should be expanded, including increasing the frequency and amount of new capacity included in each allocation round and extending its remit to offer CfD-type contracts to existing variable generators. Auction rounds should be completed annually as planned, following the announcement by BEIS in February.
- BEIS should undertake a full review of the CfD mechanism to better align it with future system challenges. This would include how it responds at times of excess renewable generation, the value of geographical signals and the creation of secondary CfD categories for targeted deployment.
- Alongside CfDs, REMA should consider ways to encourage forward markets, for example by increasing the availability and use of long term PPAs and increasing

forward market liquidity. PPA reform should look at the cost/complexity of the PPA market, the challenge of credit and their availability for small-scale and local generators. This will help to reduce energy costs, reduce market volatility and also encourage investment in low carbon renewables.

- More long term clarity on the future role of energy suppliers in the future energy system is needed ahead of any new supplier obligations on low carbon deployment, or flexibility.

Capacity adequacy, operability and flexibility

- Develop a long term plan for Capacity Adequacy and System Operability as part of an integrated **Net Zero and Energy Security Delivery plan** and the future system architecture. We have called this a **Capacity Adequacy Plus** approach.
- Review the definition and requirements for future stress events, recognising that they are already becoming far more frequent, diverse and dynamic and will therefore require a range of responsive assets, flexibility and other market solutions. Doing so will allow projects and technologies to design towards delivering for typical 2035 stress events rather than 2022 stress events.
- Keep options within the REMA scope including
    - An optimised Capacity Market to support low carbon and flexibility assets
    - Strategic Reserve for legacy high-carbon generation, including the option of public ownership
    - Potentially consider targeted tender as an additional option
- Begin the process of removing fossil fuels from the Capacity Market, moving those that are still required for capacity adequacy into a Strategic Reserve.
- Ensure that the Energy Security Bill is not delayed further in its progress through Parliament and confirm the definition of energy storage in legislation.
- Give the ability to prioritise low carbon ancillary services to the ESO and future FSO as soon as practically possible. This includes the creation of clear carbon reporting and setting emissions limits where feasible/appropriate.
- Action needs to be taken speed up network connection processes for storage providers, as well as network investment. This might include reforming queue management processes, changing the way storage assets are modelled by network planners and looking at a range of alternative connection offers that could be made to storage providers.

Taken together, this **radical evolution** of the electricity system and markets would represent the most far reaching process of reform since privatisation. The scale and pace of change is unprecedented. Delivering such unprecedented change carries risk – therefore, reform must look both to drive change and to manage risk. Rather than a single ‘big-bang’ change that would be high-risk, cause an investment hiatus and may be impossible to deliver, these reforms should be delivered as part of a controlled but major programme of change that could be rolled out within a 3-5 year period.

Delivering radical evolution requires strong, well-informed and strategic leadership at the centre of the electricity system. The complexity of the electricity system, the systemic uncertainty inherent in decision making, and the multiple objectives that we are trying to reach all mean that it critical that a full 'system approach' is needed.

In the past Regen has recommended the creation of an Office of Net Zero, or another integrated body, to be tasked with net zero delivery[7]. It may not be possible to create such an entity at present but there is a need for more integrated leadership across the FSO, BEIS and Ofgem, with the capability and authority to deliver the strategic planning and system architecture elements of system reform. Parallel policy initiatives should be clearly linked up and coordinated, or avoided.

In the modern energy system, which is far more decentralised and democratised, stakeholders from devolved governments, regions and localities must be fully engaged and their objectives recognised. The industry itself is also highly diverse. Therefore, REMA must continue to be transparent and multi-party; open to all and welcoming of challenge. This will not only help to ensure that the REMA design is fit for the future, but also that it can then be implemented.

BEIS engagement

We would like to offer our help and insight as the REMA process continues following this consultation. As a centre of expertise and a collection of leading companies and organisations, both in the electricity storage sector and the wider energy sector, we are well positioned to help design the solutions and additional work that will follow on from this initial consultation.

As part of our engagement activities Regen and ESN hosted a members session on REMA on 20 September in Bristol. This included a presentation from Polly Roberts, Senior Policy Adviser REMA, BEIS.

We are also developing a specific Regen and ESN REMA task and finish group that will cover this extended policy area as it progresses and develops. Again, we would welcome interaction with policy makers in this group moving forward.

[7] Regen, 2021 https://www.regen.co.uk/download/energy-networks-for-the-future/

Part 2

Consultation response to specific chapter questions

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

We are pleased to see that the objectives for REMA are based on the trilemma; placing net zero, security of supply and cost-effectiveness at the heart of the process. However, we believe that a wider view of REMA objectives is required to ensure that market reform is successful. This should include supporting economic growth and investment, and should also consider the role that energy systems can play in supporting regional growth and the Government's levelling-up goals. This applies both to the scope of reform needed and of the role of the electricity system in our economy and society.

1.1 Vision

The vision for REMA does not make clear what role REMA itself will play in delivering elements of the vision, and what role other aspects of system reform will play.

1. **Link between vision and objectives:** The vision should be based on how REMA supports delivery of the overall objectives. In the current wording there are some mis-alignments:
    - The vision talks of reducing our dependence on fossil fuel generation, whereas the objective is achieving a net zero power system, and therefore a *removal* of our dependence on (unabated) fossil fuel generation. The vision could be to "reduce our dependence on fossil fuels and ensure the complete removal of unabated fossil fuel generation"
    - The vision fails to mention costs, while the objectives discuss cost-effectiveness. Embedding the concept of affordability for all has to be a central part of REMA.
2. **A vision for REMA or a vision for wider electricity system change?** The vision includes elements which require change well beyond the scope of REMA. For example, the proposal that REMA should deliver a step change in the rate of deployment of low carbon technologies is something that requires significant improvements in the planning and operating of the electricity networks. This element of the vision is not solely (or even mainly) within the gift of the options laid out in REMA. The vision should, therefore, explicitly discuss the interactions across the wider system.

1.2 Objectives

We agree that the trilemma should be central to our objectives for change. However, we have a number of suggestions:

1. **Cost-effectiveness should change to affordability:** An overall objective for the electricity system should be that it is affordable for all consumers, both domestic and businesses. Cost-effective investment is not itself the end goal. It will be a critical part of ensuring that a net zero electricity system is affordable, but it is unlikely to be sufficient on its own. It may need to be paired by progressive pricing regimes, government support, and appropriate regulation. REMA should take the broader societal outcome of affordability as its objective.
2. **Objectives should go beyond the trilemma:** In addition to decarbonisation, security of supply and affordability, we would add that growth needs to be addressed by **'supporting a strong economy'** and **'supporting economic growth and investment'.**
3. **Objectives should also recognise the levelling-up agenda: 'Supporting regional economic growth and job creation, 'ensuring fair and equitable access to energy'** and **'supporting regional strengths'** should be added to the list of objectives. Access to electricity is a central part of a modern economy, and one that is going to become more important as we decarbonise.
4. **Objectives need to recognise the wider system reform that REMA is part of:** wholesale market reform is only a part of the wider set of reforms needed. In both the vision and the objectives for REMA we would like to see a clear articulation of the other aspects of reform required and the links to REMA. An important principle of a systems approach to change is the mapping out of interactions across a system, as well as the consistent consideration of those linkages. A systems approach doesn't prelude drawing a clear scope of work focused on one element of the system, but it does require explicit acknowledgement and reference to other elements of the system at each stage of the process.
5. **The role of objectives in assessing options should be clarified:** it is clear from the text that the objectives are considered throughout the document. However, the ability of an option to deliver each of the objectives is not listed as an assessment criteria. This can lead to a mismatch between what REMA is trying to achieve and what is delivered. We have further comments on this in response to Chapter 3.

1.3 Response questions

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

☐ Yes X No ☐ Don't know ☐ No opinion

Please expand on your response here: See comments above

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

☐ Yes X No ☐ Don't know ☐ No opinion

Please expand on your response here: See comments above

Chapter 2: The case for change

Our view is that the case for change has not yet been fully articulated and critically examined as part of the REMA process. This may lead to REMA focusing on the wrong areas for reform and the wrong policy solutions. We would suggest that, after this consultation, there will be a need to re-evaluate the case for change in order to pinpoint the exact changes that are needed.

There has been a tendency for some commentators and industry influencers to make general statements that the current market is broken or not fit for purpose. Whilst agreeing that the current market arrangements require reform, and in some areas significant change, we do not see evidence the current arrangements are so far broken as to require a complete market restructure.

In part, we feel that the tendency to propose complex theoretical market concepts, such as a shift to LMP, stems from a lack of understanding of how the current GB market operates and a failure to identify the underlying cost drivers or causes of market inefficiency. There has been a tendency to skew the benefit case for change by taking a worst-case counterfactual – ignoring the potential for improvements within the existing arrangement (many of which are already in progress) and taking a rose tinted view of a future theoretical arrangement.

For example, it has been argued that the cause of rising constraint management costs is the mis-location of renewable energy projects due to the lack of a locational price signal, hence the case to shift to a nodal or zonal pricing system. Our contention, however, is that the rise of constraint costs has been the result of delays in network investment and the reliance of large and inflexible gas fired power stations (and sometimes biomass) to provide balancing services. There is potential to address these issues through reform of TNUoS locational signals, looking at how infrastructure investment is planned and delivered and considering how the ESO can reduce constraint management costs by improving control room functions and making greater use of flexibility assets and services. We discuss these in our recent paper: 7 Solutions to Reduce Constraint Management Costs.

Another perceived market failure has been whether variable renewables ought to be forced, or encouraged, by the market to provide firm power. In fact, this isn't really a case of market failure: assets that are providing very low cost but variable energy, and assets that are providing flexibility, are providing different market services. It may be valuable in some cases for those assets to co-develop, either at the same location (behind the same meter) or under joint ownership as part of a wider portfolio of generation and flexibility. Market signals should make clear what is needed across both sets of services and avoid forcing them together into an uneconomic single market service.

While the focus of the REMA consultation workshops has been on areas like locational pricing, market splitting and the question of renewable variance, we would suggest that there are more urgent priorities to address, which would provide a better basis for the case for change.

The case for change could be better centred around:

1. The need to massively accelerate the rate of investment in renewables and other low carbon technologies and whether the market is giving the right investment signals to achieve this. REMA could look at the current queue of projects with connection agreements on both the distribution and transmission networks which are currently stalled, to find out why these projects are not coming forward.
2. The delays in network investment, and whether the regulatory framework is sending the right signals to investment decision makers to make an accurate cost benefit analysis of investment delivery and timing.
3. How the market can ensure the transfer of value from very low cost renewable energy from the generator to the consumer, without compromising the investment case for low carbon generation.
4. An investigation of why the GB wholesale market is subject to such high price volatility and what appears to be the taking of super profits by generators and speculation by traders[8]. This area of study could consider factors such as the underlying market efficiency, forecast accuracy, transparency, price discovery, drivers of market sentiment, operation of trading markets, liquidity and the occurrence of bullwhip effects.
5. An examination of how the market will respond and perform during periods when there may be excess generation and very low or negative wholesale prices. It is not clear, for example, whether negative prices would be a problem for the market (and for CfD holders), or whether they would in fact provide the stimulus needed for investment in new technologies like flexibility and hydrogen production.
6. How the market can ensure the provision not just of capacity adequacy but also the range of responsive and flexible asset (and non-asset) solutions needed to provide future energy resilience.

In the next phase of development we would urge the REMA team to really get under the skin of how the current market operates and take a critical and evidenced based approach to define the case for change. As part of this examination, consideration should be given to whether the

[8] LCP, 2022; "*51% of price uplift is NOT explained by scarcity presented and bidding fundamentals*" https://www.linkedin.com/posts/lcp-energy_power-gas-electricity-activity-6977959550620467201-SHop?utm_source=share&utm_medium=member_desktop

case for change outweighs the cost of transition and the potential impact/risk this would have to achieve the core energy system objectives.

Recommendation: Critically examine the operation and efficiency of the wholesale market and the occurrence of price speculation, uneconomic volatility, loss of liquidity, scarcity rent taking and bullwhip effects. Consider measures to bear down on these, focusing on transparency, forecasting, flexibility and liquidity.

2.1 Response questions

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.

☐ Yes X No ☐ Don't know ☐ No opinion

Please expand on your response here: See comments above

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?

☐ Yes X No ☐ Don't know ☐ No opinion

Please expand on your response here: See comments above

Chapter 3: Our approach

The REMA consultation has successfully laid out a very broad set of options for reform in a way that has allowed the sector to engage and discuss a very complex area. In moving to the next stage of the process, we think the approach needs to be more focused.

1. **Assessment options need to connect more to the objectives:** the consultation does not specifically describe how the assessment of options will refer back to the objectives of REMA. Whilst the assessment criteria are related to the objectives, they are different in several important respects. In particular:
    - The assessment criteria of 'least cost' does not align with the objective proposed of 'cost-effectiveness'. And both differ from the objective we propose of affordability. The difference between least cost and cost-effectiveness is important with the two potentially leading to different outcomes. For example, lowest cost would not necessarily consider the level of risk inherent in different pathways. And both may fail to consider the overall impact on bills and affordability of electricity to end users. **Therefore, we suggest you change the 'least cost' assessment criteria to 'affordability'.**
    - The REMA assessment criteria on deliverability refers to deliverability of the reform process itself. However, the bigger challenge is deliverability of a net zero power system by 2035. Therefore, we propose that you **split this assessment criteria into (a) impact on deliverability of net zero; and (b) deliverability of reform.** The first of these points could be covered by a more direct reference to the objectives in your assessment criteria which clarified the role they will take in decision making.
    - An aspect of deliverability that needs to be highlighted is the deliverability of reform in the context of the **current market arrangements** including, for example, the current investments, contracts, commercial agreements and commitments that are already in play and may be subject to significant cost expenditure, natural justice and/or legal challenge to unpick. Deliverability should also consider whether there is a viable transition pathway.
    - **We agree that investor confidence and whole system flexibility are appropriate assessment criteria.**
    - **We agree that adaptability is an appropriate assessment criteria.** This could be expanded to specifically state that options will be **tested against different scenarios and pathways to net zero.** To ensure that adaptability extends to security of supply, they could be **'stress tested' against possible shocks to the**

system such as how it may respond to a whole system blackout, or a decade-long continuation of very high gas prices.

2. **Greater focus on how REMA options relate to other areas of reform:** the consultation acknowledges the importance of other aspects of system change, in particular the need to consider network development, retail market reform, support for first of a kind projects, and carbon trading. However, we are concerned that REMA does not lay out concrete proposals for how decisions under REMA will take account of options in each of these other areas. Therefore, we would propose **a system-level review of decisions** under which options would be explicitly assessed against potential developments beyond the scope of REMA. We feel this would balance the need for a well-defined scope with the risk of making decisions on wholesale market reform in isolation.

Recommendation: REMA must be supported by wider reform of the planning system aimed at ensuring that networks, along with generation and flexibility infrastructure, can gain consent and planning approval in appropriate timescales.

3. **Review of REMA scope:** as well as a review of the case for change, the REMA team may wish to look again at the scope of the REMA programme and whether REMA is the best vehicle to deliver the required changes. **System operability,** for example, is incredibly important (see Chapter 9 response) but there is already a well advanced programme of initiatives which are being led by the ESO, working with the DSO and networks. Their timetable of delivery is also well advanced, with the ambition to have a net zero-ready system that is operable by 2025. We would question, therefore, whether this should be considered a core part of REMA, or a closely allied programme of work.

Recommendation: Based on consultation feedback, the REMA team should quickly review progress towards system operability and whether this area of market and technology development would be better pursued as a parallel but aligned activity, led by the ESO and networks.

4. **Carbon markets, carbon trading reporting and tracking**: the REMA scope currently excludes carbon trading (GB ETS), carbon reporting (e.g. fuel mix disclosure) and the market for REGOs and other Guarantee of Origin (GOO) products. While it is understandable that this complex area may be considered separately, it is very important that the operation of these markets is aligned with any future market arrangements. It is expected that the operation of carbon markets will become increasingly important as the UK approaches net zero. For example, the use of REGOs

is now an important feature of the GB wholesale and PPA markets, and a key point of interface between the retail and wholesale markets[9].

Recommendation: REMA should, at least, consider the integration and interaction between carbon markets (carbon trading scheme, carbon tracking and the use of REGOs) as it will strongly impact and underpin the transition to net zero in the wholesale market.

3.1 Response questions

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

X Yes - but there are other criteria ☐ Don't know ☐ No opinion

Please expand on your response here: See comments above

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

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here: See comments above

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

Please provide your response here:

The main things to consider are:

a) Whether a package of options is the right solution
b) Whether the proposed package will work together in a coherent and integrated way
c) Whether the package need the overall objectives
d) Whether the package is implementable (including the transitional stages)
e) The degree of transitional risk including risk of investment delay
f) Delivery of net zero and decarbonisation

[9] See our response to BEIS 2021 consultation *Designing a Framework for transparency of the carbon content in energy products.* Regen would be happy to send this response to the BEIS team directly, if that would be helpful.

Chapter 4: Cross-cutting questions

There are many questions which cut across all aspects of REMA. It is important that the evaluation of REMA finds a suitable way to consider each of the issues appropriately without sacrificing the clear scope. As we note in our response to Chapter 3, it is important that REMA embeds and is embedded in a whole system approach to planning energy system change.

An important part of that is to identify, as the REMA consultation does, that wholesale market reform is only one element of wider system change. We have articulated that in Figure , which shows the scope of REMA in relation to other aspects of energy system reform.

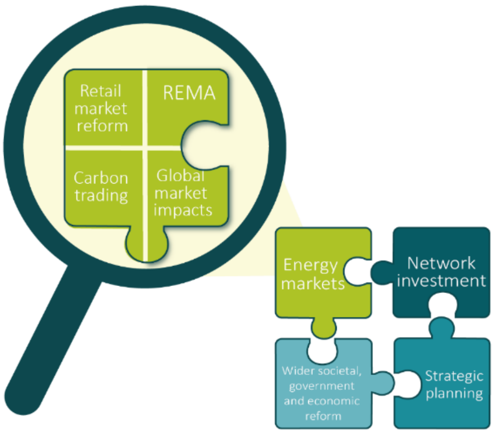


Figure 6: Any energy market reform must be considered within the context of the wider energy system

4.1 Response questions

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

☐ Yes X No ☐ Don't know ☐ No opinion

Please expand on your response here:

On the specific 'cross-cutting issues' identified in the consultation we make the following comments:

- **The role of the market**: we agree with your statement that market structures alone won't solve the challenges. It is important that reform considers the potential impact of other factors of influence, and in particular the role of government. We would like to see REMA options considered in light of how they would work with non-market reform, such as an increased role for strategic centralised planning via a future system architect. In particular, we aren't convinced that a 'leave it to the market approach' will deliver the optimal geographical spread of generation, flexibility and network capacity.

Therefore, there is a need for an overarching **Net Zero and Energy Security Delivery plan**, which should include within it a detailed plan of how the electricity system will decarbonise by 2035 and how energy security will be maintained. We also recommend that the Net Zero and Energy Security Delivery Plan presents, at a high level at least, an overarching **energy system architecture**.

This system architecture should include the energy system attributes and capabilities that are needed: levels of generation, flexibility, responsiveness, dispatchability, storage and interconnection, alongside a central projection of the key technologies that must be built. It should also include the infrastructure that is needed to deliver them.

Having a clear view of this architecture, even if there are still areas of uncertainty, sensitivities and options to consider, will help the industry, policy makers, supply chain and investors to focus on delivery. It will help to move thinking forward, and away from the current tendency to think in terms of alternative, and often hypothetical, scenarios.

Where appropriate, the overall architecture could be broken down on a regional basis which will greatly aid the development of regional and local area energy plans, including the development of regional supply chains and industrial strategies. For example, the Government has set overall ambitions for technology capacities (e.g. 50 GW of offshore wind by 2030). There is value in expanding this to include indications of likely optimal capacities in each region across Britain. These could be flexible ambitions rather than government-mandated targets, but would help provide confidence to developers and give the long term, multi-decade foresight required for transmission network development.

An example is the Australian Integrated System Plan (ISP)[10] which estimates 'optimal' future generation mixes across the Australian National Electricity Market, including locations, as part of its planning for development of the transmission network. They have also explored the potential to develop wider regulatory and government policies based around renewable 'energy zones' to support development of generation in optimal locations identified in the ISP[11]. This provides an example of how greater levels of strategic planning could interact with market mechanisms.

[10] AEMO, 2018 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf

[11] Australian Energy Security Board, 2021 https://www.datocms-assets.com/32572/1637195631-access-reform-project-initiation-document-nov-2021-final.pdf

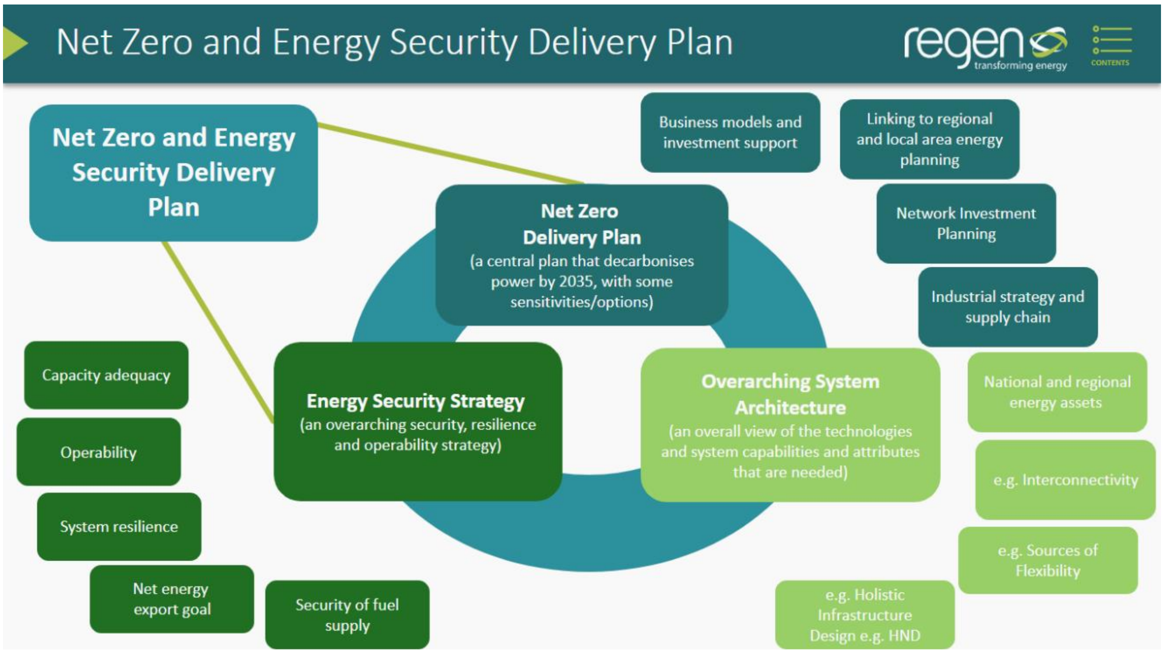


Figure 7: Net Zero and Energy Security Delivery Plan, map of key elements

Recommendation: REMA must be aligned with the development of an overarching Net Zero and Energy Security delivery plan. This plan needs to include an analysis of generation and demand growth, network infrastructure, flexibility, system balancing, capacity adequacy, curtailment and constraints, and projected energy and system cost. The plan should include an overarching whole system architecture which indicates the system capabilities that are required and capacity of key technology types (generation, flexibility, interconnection and demand) that should be expected within each region of Britain.

- **Extent of competition between technologies**: we agree that competition alone is unlikely to deliver sufficient diversity in the technology mix connected to our networks. Diversity is a critical component of security of supply, and helps ensure the system is robust against both known and unknown risks. We would recommend that BEIS investigate the value of different elements of diversity including:
  - Diversity of technology type and its role in mitigating risks associated with low levels of high prices of any one particular resource.
  - Diversity in location to ensure resilience against extreme weather events and reliance on particular elements of infrastructure.
  - Diversity in manufacturer to ensure resilience against common mode failures, for example in controller software.

  With a greater understanding of the value of different elements of diversity, a better appraisal can be made of the role of market and non-market options in delivering that diversity.

- **Role of marginal pricing:** see comment below against Q21.

- **Minimising financing costs**: this is a significant factor in the overall system cost, and one that we believe is poorly understood outside the energy financing sector. We would recommend that significant effort is made to understand the structure of financing costs and to provide evidence on how specific REMA options may affect these costs across each technology type.
- **More accurate price signals and the benefit for consumers:** see comments below against Q10.

- The scale of change: it is critical that any decision on REMA fully reflects the scale of change that needs to be delivered. National Grid's FES 2022 work, along with work by the Committee on Climate Change (CCC), and BEIS' own modelling referenced in the consultation, all provide an indication of the scale of investment needed both in financial and capacity terms. Decisions under REMA should consider how credible it will be to deliver the scale and pace required to meet net zero power in 2035. If net zero power in 2035 involves developing all credible projects in the existing pipeline including, for example all 28 GW of capacity leased under Scotwind and projects identified in the Celtic Sea, then REMA options should be assessed on how they support those existing projects. If credible alternatives exist that could be delivered by 2035 that may open up alternative options.

- **Delivering more accurate locational signals:** see comments below against Q10.

- **How might locational signals be introduced:** see comments below against Q10.

In addition to the cross-cutting issues already identified, we believe the following should also be considered:

- **Interaction with network development and connections:** as noted in the introduction to this response, we believe that the emphasis placed on development of our electricity networks needs to be increased. In the context of REMA it is important to consider how any wholesale market reform will interact with the network that is available at that point in time. For example, electricity markets work most efficiently with the 'optimal' balance between network capacity and generation / demand / flexibility mix. However, in reality, there is never an optimal mix and the expectation is that over the coming decade there will likely be a lack of transmission network relative to generation (even accounting for flexibility). Therefore, we need to consider market reforms which (a) work with a non-optimal network and (b) are compatible with a system that places stronger incentives on network companies and the ESO to plan, deliver and operate transmission network.

The ability to connect to the network, including the cost and timing of connection, is a separate, and equally important, network issue. Discussion with members of the Energy Storage Network (ESN) has identified that getting a connection is one of the biggest barriers to developing a project. Therefore, market reform without substantial improvement to the process of getting connected to the network is unlikely to lead to the step change in flexibility capacity that we need. Again, REMA must consider how market reform interacts with connection processes both in an ideal future world and in today's real world.

- **Interaction between wholesale markets and carbon market:** although the consultation document notes that carbon markets are out scope for REMA, it is hard to see how an appropriate set of market structures focused on delivering net zero power can be designed without direct consideration of carbon pricing. A key part of the process of decarbonising electricity is to continually reduce incentives for unabated fossil fuel plants to run when lower carbon alternatives are available, and in the longer term to make sure that the business case for carbon intensive generation is infeasible. Carbon pricing can play a central part in that process - its level of effectiveness may determine the degree to which other measures are required.

Recommendation: The interaction between REMA and carbon pricing reform should be explicitly reviewed and considered as decisions are made on which REMA options to take forward.

- **Market performance and efficiency:** alongside structural reform, REMA should consider the performance of market arrangements including, for example, the efficiency of the wholesale market in terms of forecasting, transparency, price speculation, gaming, occurrence of bullwhip effects, risk and market sentiment. Asking why, for example, do current market price increases not seem to align with the underlying supply/demand balance and bid fundamentals?

Recommendation: Market reform must be backed up by the accelerated build-out of transmission and distribution network capacity. This could be based on a holistic network design approach to determine what network capacity is needed in ten to twenty years' time and ensuring that Ofgem, NGESO (FSO) and the Transmission Owners are resourced to deliver and held to account for failure. Support infrastructure decision making with a whole system cost benefit analysis (CBA).

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

☐ Yes X No ☐ Don't know ☐ No opinion

Please expand on your response here: While the consultation identifies many trades-offs, we believe some important ones have been missed or misrepresented. Please see the response to Q8 above for further details.

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.

Please provide your response here:

As the consultation identifies, locational signals have the potential to align the geographical spread of generation, demand and flexibility with the development of the networks which connect them. There are four competing principles:

- An assumption that locational signals can drive economically efficient decisions.
- Access to affordable, secure and increasing low carbon energy underpins life in our economy and society, no matter where in the country you live or do business.
- Short-run marginal prices on a locational basis which could potentially drive efficient dispatch.
- Long-run average prices on a locational basis can potentially drive efficient investment.

Therefore, the use of locational signals needs to find a balance between efficient costs and social justice, and between the tensions inherent in highly volatile and potentially unpredictable short-run marginal costs aimed to dispatch and the need for long term stability for investment.

Our view (outlined in more detail against Q11 and Q16) is that basing locational price signals on short-run marginal costs, as would be achieved through nodal or zonal pricing, represents a significant risk to investment which could lead to a reduction in investment and new capacity overall. There is also a risk that it is better at reducing investment in areas of low prices than it is at increasing investment in areas of high prices.

TNUoS is an existing mechanism that provides locational signals based on the long term costs of transmission investment. At present, its signals are volatile and unpredictable, but this is due to the specific design of the current TNUoS methodology. We would like to see reform of TNUoS explored as an option for providing the right level of stable, investable, locational price signals. For example, reform could aim to provide fixed network charges on a ten-year annual basis. We discuss the potential to address these issues through reform of TNUoS locational signals in our recent paper 7 Solutions to Reduce Constraint Management Costs. In addition, the REMA team should consider whether locational signals for investment should be introduced through the CfD mechanism. In Chapter 6 we suggest that there is value in exploring the concept of geographical CfD pots which would support geographical diversity and reflect the different levels of system benefit that new capacity in different parts of the country would bring.

There are also many other locational signals that need to be considered. In our discussions with developers it is clear that they are most heavily influenced by factors such as:

- Government energy and industrial strategy e.g. creation of industrial clusters
- Planning rules and planning risk
- Designation of areas for development e.g. the Welsh Tan 7 and Tan 8 areas for onshore wind
- Grid connection availability, time delays and connection costs (especially on Distribution Network but also on Transmission)
- Land and energy resource availability
- Regional and local policy and strategic initiatives e.g. provision of test facilities and development areas
- Marine spatial planning and the award of offshore leasing or onshore development rights by Government agencies
- The existing location of generation and demand customers
- A myriad of other (non-energy) factors depending on the nature of demand and generation technologies, such as location of customers, industrial centres, skilled workforce, telecommunications links, port infrastructure, supply chain

Recommendation: Explore the potential for a reformed TNUoS system to provide an appropriate long term price signal, which is properly cost reflective and has appropriate locational signals to influence decisions.

Recommendation: Consider the influence of all locational factors as part of the development of the Net Zero Energy Security Delivery Plan.

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

Please provide your response here:

In terms of investment: We are concerned that the introduction of locational pricing risks a greater negative response from market participants in areas of low locational prices than the positive response from market participants in areas of high marginal prices. The result of this would be an overall reduction in investment.

As we discuss in our answer to Q16 below, we know that other (non-price) locational signals such as resource availability, seabed leasing and planning regimes provide strong 'yes / no' signals to generation investment. Today developers and investors have identified appropriate sites that fit with these existing locational signals and allow for a business case in the current market frameworks. The introduction of locational pricing is likely to make some of these existing pipeline site less viable. However, the reverse is not always true: in areas where price signals may be higher under a locational model, the stronger non-price signals may limit the ability to bring forward projects at all.

While it may be expected that flexibility could respond well to locational and more time-granular price signals, discussion with our members suggest that there is not enough evidence to form a strong view on this. Many members have suggested that the main driver for investment in flexibility is the continued growth in renewable capacity, the key driver for those members, therefore, is a system that supports the acceleration of renewable rollout.

Our analysis of the use of LMP in the US, and in particular in Texas, suggests that LMP marginal price signals offer very weak locational signals for future investment, and that other factors, such as the construction of grid capacity in advance of deployment and a regional support package was far more pertinent[12].

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

Please provide your response here:

Demand response is an important part of net zero. We would like to see it given greater prominence in all aspects of electricity system reform. It is important to consider electricity demand in the context of wider energy system change. Electricity demand reduction is likely to be dwarfed by increases in electricity demand as heat, transport and industrial demand electrify. Therefore the appropriate objective is **efficient use of energy and electricity** overall. Energy efficiency across all forms of energy demand, not just electricity, needs to be supported.

Recommendation: Policies and programmes to deliver efficient use of energy and electricity will need to sit alongside wholesale electricity market reform rather than being a key goal of REMA itself.

[12] See Wild Texas Wind: Regen, 2022 https://www.regen.co.uk/wp-content/uploads/Regen-Insight-Paper-Locational-Marginal-Pricing.pdf

Chapter 5: A net zero wholesale market

The wholesale electricity market represents the way in which electrical energy is brought and sold in bulk across Great Britain and how traders will buy and sell electricity between GB and our neighbouring countries.

The current system brings together a diversity of trading options which emerge from the decentralised system that was put in place through NETA and BETA.

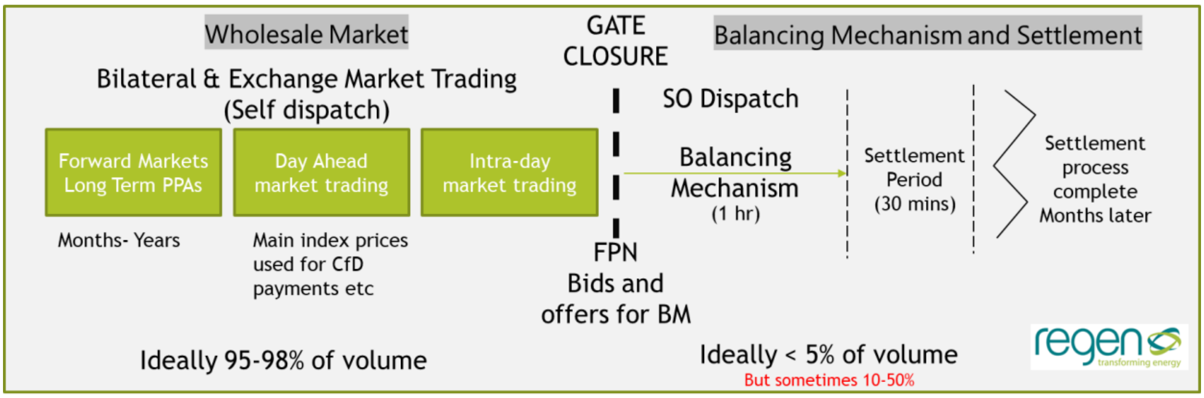


Figure 8: Summary of the organisation of today's wholesale market

The way the current system is characterised in the public debate is often a misrepresentation, one that risks leading to incorrect conclusions. As such, it is worth clarifying how the current system works in practice:

- For 'over the counter' bilateral trades, which account for a significant fraction of trading, **the price is neither pay-as-bid nor pay-as-clear buy 'pay-as-contracted'.** Each participant is well informed about other activity in the market, but strikes a deal based on their own needs and expectations.
- In addition, there are a number of private exchanges that run day ahead and intra-day auctions that are characterised as 'pay as clear'.
- Finally, the Balancing Mechanism, which operates during the last hour to delivery, represents a pay-as-bid element of the wholesale market.
- Because of the range of methods through which market participants choose to trade **there is no such thing as 'a' single wholesale price.**
- This means that while it is correct to say that, today, gas prices have an unduly strong influence on the electricity price, **it is not true that the current market works on marginal pricing**. Rather, the current market is a mix of pure marginal pricing (e.g. through day-ahead power exchanges), quazi-marginal (where bilateral trading for short

term contracts tend to approximate the marginal price) and long-run pricing (for example through long term Power Purchase Agreements).

- Dispatch in the current market is largely decentralised – self-dispatch with a Final Position Notification to the ESO at Gate Closure. From that point the ESO (control room) takes final control of the market and dispatch processes through the operation of the Balancing Mechanism.

In summary, we believe the most appropriate way to proceed with the wholesale market is to maintain a national wholesale market and balancing system, but to evolve that system, at pace, into one that can support us in delivering the radical system reform that we need to deliver net zero.

A shift (back) to a centralised dispatch market arrangement could be considered. However, this would have a significant impact on the current market trading ecosystem, including the development of flexibility services and operability markets. It is far more likely that an appropriate market design will be to keep the existing trading market as a basis, but enable and allow the ESO to take more 'centralised' dispatch actions – such as the forward procurement of flexibility services and forward trading ahead of gate closure – in order to better manage balancing, constraints and operability. Furthermore, any development of market design must also consider those (hundreds of thousands of) assets that are connected to the distribution networks.

5.1 Response questions

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

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here:

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

☐ Yes X No ☐ Don't know ☐ No opinion

Please expand on your response here:

It is very unclear what is meant by a 'split market' in the context of the existing market arrangements.

If we consider a 'split market' to mean the formal splitting of the market by generation type in order to maintain a market transaction and price separation, then formally splitting the market will introduce unnecessary bureaucracy, require arbitrary rules around which technologies are in which market, and fail to reflect the nature of electricity as a single generic commodity.

A formal split of the market in this way also risks increasing the level of profit and scarcity rent taken by non-renewable generators. Furthermore, splitting the market, if it were possible, would introduce significant distortion and complexity in the operation of energy storage and interconnectors. One can imagine exporting our cheap renewable energy while reimporting more expensive continental energy, while the electrons, in fact, go nowhere.

However, there is an issue that does need to be addressed – how to ensure that the value of lower cost renewable generation is transferred to consumers and is not taken as super-profits by renewable energy generators. The appropriate approach is to use other tools to encourage the market towards longer term contracts which more closely reflect the long term average costs, rather than short term marginal ones. Many of the tools are already in place: Power Purchase Agreements (PPAs) and CfDs are two tools which allow generators, particularly those with high upfront capital costs and close-to-zero marginal costs, to contract in a way that supports investment and trades off exposure to future price volatility for revenues which are slightly below expectations but highly certain.

As we discuss in Chapter 6, if the Government had been more aggressive in awarding competitive CfDs over the past few years, electricity customers would be benefiting from greater levels of renewable capacity, whose output would be pegged, through strike prices, at levels well below the wholesale prices seen this year.

Recommendation: Maintain a national wholesale energy market that supports a varied and dynamic trading ecosystem that includes bilateral trading, a vibrant PPA market, organised power exchanges, forward contract markets and short term markets.

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.

Please provide your response here:

We are interested in the idea of how a green power pool might support the market in moving towards long term contracts and prices which more closely reflect long term averages rather than short-run marginal costs. The Government, or its agencies such as the ESO, could have a role to procure energy in the market under a long term PPA contract.

The green power pool concept has the potential to help bring together variable renewables with dispatchable low carbon generators and flexibility in a way that provides firm power.

However, we also point to comments elsewhere in the response about the risks of attempting to package together separate products - very low cost but variable energy together with firm and flexible power. (See response to Q73). We also note that the concept is poorly defined at present without clear papers describing how it would work in practice and how responsibilities would be split between market participants.

It is also not clear for how power pool-sourced energy would be used and allocated between different consumer groups e.g. within a social tariff, for selected industries or some other purpose.

Therefore, we recommend that BEIS takes forward consideration of green power pools with the aim of better understanding their potential.

Recommendation: Explore the idea of a green power pool with a specific focus on how it would work in practice, the mechanisms required and worked examples of who is helps and why. Ensure a clear industry-wide understanding of the issue before further consultation.

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

☐ Yes X No ☐ Don't know ☐ No opinion

Please expand on your response here: See comment above for Q14

We do not believe that locational pricing, either nodal or zonal, is a useful way forward. We think there is value in ruling it out as early as possible in the process to allow BEIS, and the energy sector, to focus on exploring options more likely to deliver useful change.

Recommendation: Do not pursue Locational Marginal Pricing either in nodal or zonal forms, since this will not provide effective locational signals and would significantly increase investment risk.

Our rationale for this decision is based on:

- **Risk of investment hiatus:** delivering a net zero power system by 2035 will mean building renewable capacity as quickly as possible. This is likely to include at least 80 GW of new wind and 25 GW of new solar over a timeframe of 13 years[13], requiring a build-out rate of three to four times faster than we have achieved over the past five years. A locational market will lead to a significant hiatus in investment, something that would put both net zero and long term affordability at risk.

- **Other locational factors will drive investment decisions:** evidence from speaking to developers shows that whilst price is important to getting investment off the ground,

[13] Numbers derived from the three net zero compliant FES 2022 scenarios.

the key locational factors affecting projects are: (a) ability to find a site on which to develop; (b) resource availability, for example how windy or sunny a site is; (c) ability to get planning permission or consent; (d) the ability to get a grid connection. These four non-price locational signals determine whether a project is viable and represent significantly stronger locational signals to investment than would be provided by price. Because existing locational signals have been in place for a long time and have driven much of the investment we have today, new LMP price signals are likely to be weak in comparison for many technology types. The result of this is that low locational price signals in areas with good opportunities for developing renewable capacity would put projects that are currently viable at risk. However, we do not think that high locational prices in other areas would bring forward enough additional capacity: the fact that projects have not developed in areas where LMP prices signals would be high, shows that other factors limit development here.

The outcome is likely to be that locational pricing will have a stronger effect in driving down investment in low-price areas than it will in driving up investment in high-price areas. The result is likely to be overall lower levels of renewable capacity

- **LMP provides a price signal based on today's system:** however, future prices – the signal against which investment is made – will depend heavily on a range of action by others. This includes decisions by market participants (generators, consumers, flexibility) and those responsible for the development of new transmission network. These are factors that a renewable investor cannot influence and is not well placed to predict. Investment depends on being able to forecast both future *expected* prices and an ability to estimate the *uncertainty* in future prices. The latter is how investors quantify the risk of any investment. If the level of uncertainty itself is hard to predict, it makes the initial investment case more challenging to make. The introduction of LMP will significantly increase the *level of uncertainty* in future prices, but also decrease the *confidence in predicting the level of future uncertainty*. Both first and second order effects will be important.

- **It is unclear how and whether LMP would support the development of flexibility solutions** (when compared to other options such as the procurement of flex services by ESO and DSOs). For example, feedback from our ESN members suggest that it is very unlikely that battery storage providers would have a viable business case to locate on the constraint side of a network boundary in order to access low cost energy. This is partly because of the underlying energy profile modelling, the existence of the constraint itself and the very difficult commercial arrangements. It is also unclear how a shift back to centralised dispatch would impact flexibility business models and asset optimisation. We have found no evidence in US markets of LMP supporting the deployment of flexibility. There is an argument that the greater risk and requirement to build capacity, in advance of renewable deployment, may reduce flexibility opportunities[14].

- **Visibility of congestion and allocation of costs and risks of congestion:** some argue that moving to an LMP market (a) makes the risks and costs of network congestions visible and (b) places them on market participants able to respond. We do not believe LMP is required for the former point and we disagree with the latter:
    - **Making congestion visible:** whilst network congestion may be more visible in existing LMP than in the current GB system, there are better ways to increase the visibility of network congestions without moving to LMP. We believe that NGESO should be required to publish network congestion maps on a regular basis, and possibly in real time. This would include information about the current 'secure transfer capacity' of each of the major system boundaries, current transfer levels, and a live list of network outages. This would provide transparency around the design and operation of the transmission system.
    - **Who takes the risk:** market participants are not well placed to manage the risks associated with network congestions. Congestion depends on many factors, the majority of which are outside the control of a particular participant. Key risks include whether or not a new transmission link is built on time or is delayed, whether or not there are major outages on particular elements of transmission infrastructure and business decisions of other major network users in the locality, including whether new generation connects, how it operates, and whether or not large-scale industrial consumers cease to operate.

Recommendation: Explore ways to make transmission network congestion and the operation of the transmission network more transparent under a national wholesale market. This could include publication and mapping of congestion in real-time, network outage lists, and operational boundary transfer capacities.

- **Locational markets are not fair and equitable to consumers:** any attempt to apply nodal or zonal pricing to electricity is at odds with the concept of access to electricity as a

[14] See Wild Texas Wind: Regen, 2022 https://www.regen.co.uk/wp-content/uploads/Regen-Insight-Paper-Locational-Marginal-Pricing.pdf

social good, and a right of citizens and businesses in an advanced economy. There is a risk of significant price differentials between different parts of the country.

In the domestic sector, this is particularly problematic for those in fuel poverty and other vulnerable groups. For example, under locational pricing, prices are likely to be highest in London, an area where high rents and other cost-of-living factors mean that many of those on minimum wage already struggle to make ends meet.

Even if only applied to non-domestic customers, locational pricing for demand risks stymieing economic development in places which need it most. It isn't just domestic energy for which a fairness argument can be made: access to affordable electricity drives strong local and regional economies and the associated jobs and economic welfare which citizens rely on.

- **The practicalities of business cases for developers are unclear:** it is clear that managing complex risk will be difficult in an LMP market and there is little real-world evidence of how this would work in a highly constrained, high zero-marginal price market. There are a number of specific issues which we do not believe are well understood:
  - With a large fleet of generators, each with essentially the same short-run marginal cost (close to zero) and with a combined capacity in excess of the export capacity from that region of the network, it will be very difficult for generators to forecast which of the fleet will be dispatched on and which will be dispatched off under an LMP central dispatch algorithm. It may depend on very small differences in variable O&M costs or on relatively small differences in the marginal system losses associated with different generators. As these factors are so small, they will be very difficult to forecast and model with accuracy, hence making investment against them highly risky.
  - There can be significantly different revenue outcomes for generators dispatched on and those dispatched off, even if the price is zero. This will depend on bilateral trading arrangements that sit around the day ahead and real time LMP spot markets and may hedge or share the locational price differences (often referred to as 'basis risk').
  - Removing firm access rights will change the relationship between the network and network users, particularly generators and flexibility providers. This could be legally difficult. Even if proved to be legal, if pushed through it would require significant grandfathering of rights to avoid damaging investor confidence.

- **It is highly unlikely that LMP will be delivered in the current period of transition.** The challenges facing a radical market redesign, including the existence of current connection agreements, PPA contracts, investment commitments etc, as well as the likely industry and regional opposition, could make LMP a theoretical distraction at a time when the imperative must be to accelerate investment. Perhaps in the future, when the energy system is in a period of stability, it may be worth considering. We note that the Climate Change Committee expert group has also suggested caution against radical market changes and favours a more evolutionary approach.[15]

- In addition to the points above, Regen has conducted research into the development of a key comparison system: the LMP market in Texas. The following paper provides additional evidence: Wild Texas Wind.

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

Please provide your response here: We do not believe that either nodal or zonal pricing should be progressed further at this time.

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

☐ Yes X No ☐ Don't know ☐ No opinion

Please expand on your response here: We do not believe it should be implemented at any 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.

☐ Yes X No ☐ Don't know ☐ No opinion

Please expand on your response here:

Local energy approaches are important to successfully decarbonising our economy. Where local communities wish to generate and use electricity locally, and make use of the local distribution network to connect sources, this should be encouraged.

[15] Climate Change Committee, 2022 https://www.theccc.org.uk/publication/net-zero-electricity-market-design-expert-group/

However, it is also true that local and national energy systems need to work well together, with each delivering on its own strengths whilst supporting the other.

Wholesale electricity markets should be designed to shape the bulk trading of power and ensure that consumers across GB benefit from economies of scale and the very low levelised cost of energy that comes from large-scale infrastructure developed and delivered nationally, which, as we have discussed above, is best done at a national level.

We do agree that future Distribution System Operators (DSOs) will be well placed to continue developing local flexibility markets. These markets will continue to play three critical roles: firstly, to manage the risk of delay to network infrastructure and allow new capacity to connect ahead of network upgrades; secondly, at the margin it will always be most efficient to leave network capacity slightly short of that which would be required for the absolute peak of local generation output, and local flexibility markets play an important role in making efficient use of a well-sized distribution network; and thirdly, to support those who wish to trade electricity locally.

We believe the principle for wholesale electricity and national balancing actions should be **a national market supported by sufficient and timely investment in electricity networks.** These should be supported by local flexibility markets which can help the development of local energy systems.

We also think it is important to encourage innovation in cross-vector approaches to energy at a very local level. This could be enabled by reforming the system of energy license exemptions, as set out in our response[16] to the exemptions from the requirement for an electricity licence: call for evidence[17]. An exemption from the complex administrative responsibilities that licenses entail can allow many projects to deploy using innovative arrangements and has been particularly important in allowing many renewable projects to deploy, from large-scale projects at airports and seaports, to local and community projects, to many on-site projects with demand such as housing, hotels, and industrial estates.

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

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here: See comments above against Q19

[16] Regen would be happy to send this response to the BEIS team directly, if that would be helpful.

[17] BEIS, 2020 https://www.gov.uk/government/consultations/exemptions-from-the-requirement-for-an-electricity-licence-call-for-evidence

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

X Yes ☐ No ☐ Don’t know ☐ No opinion

Please expand on your response here:

As discussed in our introductory comments to this chapter, it is not true to say that our current system is based on the premise of marginal pricing. Where marginal pricing has come to predominate, this is due to an over-reliance on short term contracting.

Recommendation: Reforms should aim to encourage market participants into long term contracts that more closely reflect the long term average cost of generation rather than short term marginal costs. As we discuss in our response to Chapter 6, we believe that there are routes to encourage greater use of long term PPAs and adjustments to existing CfD mechanisms that can help deliver a market outcome less focused on short-run costs.

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?

X Yes ☐ No ☐ Don’t know ☐ No opinion

Please expand on your response here:

Amending current trading arrangements will help to ensure that national wholesale and balancing markets operate more effectively and efficiently. In particular, we recommend that National Grid ESO should explore the value of shortening settlement periods from thirty minutes to 15, or even 5 minutes. This could provide sharper dispatch signals, particularly for flexibility, within broadly the same market framework. It is important the potential impact of such a move on different market participants is considered.

We also think that amendments to existing arrangements can significantly reduce the cost of constraints within a national wholesale market. Our recent insight paper Seven solutions to the rising cost of transmission network constraint management describes some of the available options in detail. The key to managing constraints efficiently is to make use of all available resources, and particularly low carbon compatible resources like energy storage, and do so in a way that is transparent. This is best achieved by moving the bulk of balancing activity out of the ‘last hour’ before delivery. This can be achieved by significantly greater use of forward contracts for flexibility where constraints are predicted, with relatively high levels of certainty, hours, or even days, ahead of operation.

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

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here:

The balancing mechanism (BM) is used as a tool to support delivery of three separate but related outcomes in the electricity system:

- Ensuring a balance between supply and demand at a GB level
- Managing transmission constraints
- Dispatching some ancillary services to maintain system operability

The BM is an important way in which each of these outcomes is delivered, but the BM itself is supported in each by other mechanisms.

As we reform the wholesale energy market, ancillary services provisions, and develop new ways to manage constraints (such encouraging NGESO to contract further ahead of time), it will be important to review the role that the BM should play in delivering each outcome in future. We agree that the BM is not the best place to deal with all these issues, particularly due to the 'last-hour' timescale within which it operates.

Within a national wholesale market it is important that other approaches to managing network congestion are considered.

Recommendation: Our recommendations for reform of the Balancing Mechanism are:

- Removing a large fraction of transmission constraint management from 'the last hour' through a revamp of the BM, including adjusting timescales and introducing new mechanisms.
- Enabling and incentivising the ESO to take balancing actions outside the 1hr BM gate closure period by, for example, negotiating long term contracts for flexibility services and placing forward market trades for balancing and constraint management.
- Adapt existing mechanisms and add new ones, to encourage demand side and behind the market technologies to participate delivery in the BM. Make sure that ESO is appropriately incentivised to use them where they are cost-effective against other technologies.
- Focus on significant cost reduction in the 'turn up' element of constraint costs: introduce mechanisms that encourage the ESO to use flexibility assets when available (rather than relying on CCGT plants) and by investing in digitalisation and control room capability.
- Review rules for participation in the BM, the behaviour of assets operating in the BM and adherence to regulatory standards.

- Continue with the development of new markets for operability services and flex, and for each consider the appropriate role of the BM and other mechanisms for delivering them.
- Continue to develop and widen access to the BM following BSC p375 implementation. Further work is needed to reduce the barriers to entry for smaller assets, particularly at the domestic scale (e.g. cost of hardware and lack of installer base).

Chapter 6: Mass low carbon power

Renewables now account for almost 40% of the UK's electricity generation[18], a significant increase from only a decade ago when renewables represented less than 10%. The uptake of low carbon power has been supported by a number of market support measures including the ROC and FiT schemes which have now been closed.

With regards to deployment of large-scale generation, recent wholesale prices have reinforced the success of the Contracts for Difference (CfD) scheme, with the Low Carbon Contracts Company highlighting that in the last quarter of 2021 generators paid back over £133 million to the CfD scheme, helping to reduce levy costs for bill payers[19]. If the Government had been more ambitious with previous allocation rounds, this sum could have been even greater.

Regen has long supported the extension of the CfD scheme for variable renewable generation such as wind, solar and potentially tidal energy, calling for a much clearer long term strategy for renewable energy deployment and supporting the move to annual allocation rounds. This would send a positive signal to investors, allow developers to build their project portfolios, utilities to invest in grid infrastructure and supply chain companies to build the jobs, skills and capabilities needed to efficiently deliver net zero. We continue to strongly support the scheme, and the opportunities it represents, as evidenced by the latest allocation round securing renewable energy capacity that will generate electricity nine times more cheaply than current gas prices.[20]

In early 2022 we wrote to Kwasi Kwarteng[21] calling for more regular CfD auction rounds to provide a much clearer long term strategy for renewable energy deployment, and welcomed the announcement in February that the 2023 allocation round will the first in a series of annual auctions. We continue to advocate for the expansion of the CfD scheme and believe that

[18] BEIS, 2022 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1107502/Energy_Trends_September_2022.pdf

[19] Low Carbon Contracts Company, 2022 www.lowcarboncontracts.uk/news/announcement/reconciliation-of-q4-2021-payments-sees-cfd-portfolio-paying-back-to-electricity-suppliers

[20] Carbon Brief, 2022 https://www.carbonbrief.org/analysis-record-low-price-for-uk-offshore-wind-is-four-times-cheaper-than-gas/

[21] Regen, 2021 https://www.regen.co.uk/call-for-beis-to-double-the-capacity-of-renewables-in-2021-contracts-for-difference-auctions/

allocation rounds should be held annually, and should be extended to offer contracts to existing variable generators.

Recommendation: The CfD scheme should be expanded in its ambition, including increasing the amount of new capacity included in each allocation round. Auction rounds should be completed annually as planned, following the announcement by BEIS in February.

However, we recognise that the CfD scheme in its current form is not perfect. The current CfD mechanism does not, for example, account for energy system benefits when allocating financial support and values each generated unit of energy equally, irrespective of where and when the electricity was generated. This means that geographically diverse assets such as offshore wind sites, which make use of variable wind patterns, are not rewarded for diversifying and increasing energy security. We discuss this as part of our upcoming report, Go West!, which explores the energy system benefits of an offshore wind fleet balanced across the east and west coasts of Great Britain. We recommend that the Government should consider a means of providing a geographic locational signal within the CfD scheme to encourage greater geographic diversity of supply and harness these system benefits. This could be achieved in several ways, such as:

1. Running a specific Allocation Round for floating wind projects to support their deployment on the west coast.
2. Running bespoke regional CfD rounds, or rounds with regional minima.
3. Focusing support for floating wind, tidal and other technologies that offer more geographic diversity.

Recommendation: Develop a mechanism to provide a geographic locational signal to encourage greater diversity of supply within the CfD scheme.

Another significant issue, as recognised in the REMA consultation, is the impact of the CfD scheme on liquidity in the forward markets. Contract holders are incentivised to sell into the day ahead market, as this is the market their strike price is tied to, meaning there is less available energy in the forward markets for those suppliers and consumers who need to buy ahead. This increases supplier risk because it means that they are obliged to buy more energy in the short term market and are more exposed to short term price volatility. Recent analysis from LCP Energy suggested that 51% of the current price lift cannot be explained by the scarcity presented and bidding fundamentals, suggesting that a significant amount of uplift is due to market sentiment, pessimism and speculation[22]. Therefore, while the CfD scheme represents

[22] LCP, 2022; "*51% of price uplift is NOT explained by scarcity presented and bidding fundamentals*" https://www.linkedin.com/posts/lcp-energy_power-gas-electricity-activity-6977959550620467201-SHop?utm_source=share&utm_medium=member_desktop

an excellent national hedge against rising power prices, there is room for adjustments to address these, and other, issues.

The REMA consultation proposes three main options for reform to the CfD scheme:

- Retain the current CfD scheme in the long term.
- 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.

Currently, we are neither for or against the proposed reforms to the CfD scheme at this stage, as more analysis needs to be done to understand the impacts of each option before any decision can be made. As the market becomes more reliant on variable renewable generation, the types of events it is required to deal with will change. For example, how will the market respond to more frequent price cannibalisation events? How much should generators be exposed to curtailment and negative price risk during periods of excess generation? What is the impact of each of the suggested reforms on these kinds of pricing events? Before any reform is implemented, modelling needs to be undertaken to see how each of the options respond to, and influence, a number of market events, and the implications of each option need to be thoroughly understood. Only at that point can a decision be made. This also relates to the recent change implemented for allocation round 4 (July 2022), where generators are no longer paid in periods of zero or negative pricing.

Recommendation: Undertake a full review of the CfD mechanism as it stands, to better understand the future system challenges faced – such as times when generation exceeds demand – and whether there is a case for reform. If there is a strong case for reform, each of the proposed options should then be modelled in depth to fully gauge the impact of any such change, ahead of implementation.

However, we do not believe that the CfD scheme should be extended to cover dispatchable renewable generation, such as biomass, CCUS and hydrogen generation, as this would incentivise such technologies to maximise generation and become baseload energy generators, displacing lower cost and lower carbon renewables energy. We also note that dispatchable plants may have the perverse incentive not to generate during times of very high electricity prices, in order to avoid making negative CfD payments. Investment in these low carbon solutions should be supported via other means, including capital investment, innovation funding, a regulated asset base and also through an enhanced Capacity Market

Recommendation: Do not incentivise dispatchable low carbon assets – such as by offering them CfDs – to become baseload energy generators and displace lower cost and lower carbon renewable energy. Do ensure that investment in low carbon dispatchable generation is supported via other schemes.

6.1 Response questions

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

☐ Yes X No ☐ Don't know ☐ No opinion

Please expand on your response here:

The REMA consultation focuses on the use of CfDs which are appropriate for variable renewable generation such as wind and solar. However, CfDs are not appropriate for all generation types and should not be misused, for example to support biomass generation.

There are other support mechanisms that could be explored to support other types of low carbon generation including, for example, Regulated Asset Base models for nuclear and for dispatchable low carbon generation. cap and floor models for long duration storage and direct investment and capital support.

There is also a need to support small-scale, local and community based generation by, for example: (a) encouraging the development of the PPA market, (b) a targeted supplier obligation, (c) a community-focused version of the CfD, and (d) the availability of third party CfDs.

In addition to the options explored in this chapter, there are a number of other ways the Government could support the development of variable renewable generation, and encourage the move from short term marginal pricing to long term contracts approaching levelised cost.

1. Expand the use of a CfD-type contract to existing variable renewable generation, in exchange for a lower long term energy strike price

This option of a 'Pot Zero' CfD has been discussed in the media and in various forums and is based on a paper published by UKERC[23], although the option of switching RO and FIT generators into a CfD contract was considered when the CfD scheme was introduced under the EMR.

Like many in the industry, Regen supports this proposal and believes it could be a very effective way to ensure that the value of low cost renewables is transferred to the consumer, whilst

[23] UK Energy Research Centre, 2022 https://ukerc.ac.uk/publications/can-renewables-help-keep-bills-down/

providing generators with longer term revenue security. There are, however, a number of factors to be considered:

- A CfD extension to existing generators should not be awarded to dispatchable generation such as biomass
- The strike price agreement needs to be fair and competitive and ensure that future consumers are not penalised in order to reduce costs today
- The terms of the contract need careful consideration
- Whether the term is intended to support re-powering of generation assets is an important consideration
- Negative CfD payments must be clearly and transparently passed back to UK consumers and not taken as additional profits by energy supply companies

Recommendation: Expand the use of a CfD-type contract to existing variable renewable generation, in exchange for a lower long term energy strike price.

2. Expand and support the private PPA market – including sleeved PPAs

Power Purchase Agreements (PPAs) are a well-established tool allowing generators to sell power to an off-taker, whether that be a supplier or, via a sleeved PPA, a third-party. While sleeved PPAs have been in operation for some time, the cost and complexity of such agreements – compounded by the need to partner with a licensed supplier who would administer the scheme – has limited their take-up at scale. The recent spate of supplier collapses has further reinforced the challenge, as credit risk presents a significant cost and generators can be unwilling to broker a contract via an off-taker that might collapse.

However, the current energy crisis could provide the opportunity for the Government to support and grow the private PPA market. The Government could oversee the creation and adoption of a number of standard, industry-wide non-negotiable PPAs, such as a sleeved PPA or a virtual PPA. This could have a number of advantages for the Government, generators and other organisations:

- Sleeved PPAs have characteristics of popular CfDs without the same long term risk to the Government, as the customer is the counterparty.

- Encouraging widescale adoption of sleeved PPAs would avoid exhausting any of the CfD 'pot' available for projects, or conflicting with the CfD regime which could be operated or be expanded entirely independently.

- They represent a relatively quick fix contribution towards delinking electricity and gas, and would be easier and quicker to implement than some of the more radical market reforms being discussed in this consultation.

- This could also open up the market to a greater number of generators and consumers, providing greater long term price certainty and encouraging further renewables deployment.

Such a scheme could be coupled with supplier licensing reform, imposing a mandatory obligation on a supplier to enter into the standard sleeved PPA with a customer if requested to do so. There are other adjustments that could also be made to encourage a successful rollout of this scheme, such as the removal or reduction of some non-commodity charges on the sleeved PPA.

While we support the concept of the Government participating in the market more directly, as a way of supporting renewables, we do not agree that this should be in the form of splitting the market, as described in Chapter 5. However, long term PPA contracts for renewables could provide a way for the Government to leverage renewable generation in the market. The Government could buy power directly via long term PPAs, and the resulting generation could be targeted at certain industry sectors, used to support a social tariff, or used to dampen down price volatility.

Recommendation: Oversee the creation and adoption of a number of standard, industry-wide non-negotiable PPAs, such as a sleeved PPA or a virtual PPA, to encourage widespread adoption of such mechanisms in the wholesale market.

These options are not mutually exclusive. In fact, variation in support could strengthen the energy market; the CfD isn't an appropriate mechanism for all renewable deployment and should not be viewed as such. Furthermore, all of the mechanisms proposed above move us towards some of the ambitions of a split market, without requiring radical upheaval and the introduction of a new administrative framework, which takes time to implement and could reduce investor confidence. While we agree with some of the ambitions of a split market, we do not agree with the requirement of a single market design that is entirely split or unsplit – the mechanisms proposed above are levers that can be used to move us towards the long term, levelised cost of renewables in a simpler way.

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

Please provide your response here:

Community energy organisations are a vital component of a decarbonised energy system, for a number of reasons. In addition to installing renewable generation assets, community energy organisations can help establish public consent for the energy transition, facilitate a just transition by providing local jobs and ensuring the hard-to-reach are not left behind, as well as alleviating fuel poverty and supporting the green recovery by reinvesting the economic returns of community-owned generation into the local area. Other smaller scale renewable deployment can be similarly impactful, such as local businesses looking to reduce their energy costs and local authorities seeking to decarbonise their operations.

Regen supports the expansion of support schemes targeted at smaller scale renewables, including those owned by community energy groups. The CfD scheme has been successful in supporting the deployment of large-scale renewables but, while the current energy crisis has reduced the payback time on investment for smaller scale renewables, since the closure of the FiT the market does not sufficiently value the generation from these smaller sites.

The Smart Export Guarantee (SEG) rate is less generous than the FiT, and does not provide sufficient incentive to invest in renewable deployment. Furthermore, for sites that seek out a more commercial proposition, such as a PPA, they are increasingly struggling to procure an off-taker for energy generated, as suppliers perceive the risk as too great. This is even more of a challenge for those generators with onsite usage. The South West Net Zero Hub, which supports public sector and not-for-profit organisations to complete green energy projects, reported to us that almost 65% of the projects they support have business models that rely on trading power, either via a PPA or a private wire. However, if they are not able to procure an off-taker for these deals, there is a risk that such investment in future renewables projects may stall.

Another member of Regen, who supports sites in procuring PPAs, gave us the following testimonial:

"*With the market being so volatile these last couple of months, we've noticed a change in behaviour in off-takers. Some suppliers may be less inclined to bid if the site:*

- *Is small scale*
- *Is multi-tech*
- *Has a lot of onsite usage*
- *Has a lower load factor than expected.*

It's certainly not impossible to get prices for sites with the above criteria, there is just a limited number of suppliers currently willing to offer fixed prices. This has changed over time – a year ago we could expect 3-5 bids for smaller sites, whereas now it's more like 1-2 bids. We've also noticed an increase in registrations to our platform from smaller-scale installations. This is due to them struggling to contract with their existing supplier. As some currently aren't even renewing current contracts.

We've also noticed that small-scale generators seem to be less familiar with the types of PPAs available (fixed, floating and flexible). Not knowing about floating or variable PPAs means they haven't known to ask for that with their existing supplier."

Regen proposes a number of solutions to address this:

Renewable energy support in Ireland (RESS)

The Irish Renewable Energy Support Scheme (RESS) is based on a Contract for Differences (CfD) structure and completed its first auction round in 2020. It was announced in 2021 that the second auction round would include a separate 'community preference category', with a minimum offer quantity of 0.5MW and a maximum offer quantity of 5MW. The aim of this category was to stimulate the growth of community energy in Ireland, with community groups applying for the funding needing to demonstrate that 100% of the development was owned by the community, and that all profits, dividends and surpluses derived from it would be returned to the relevant community. Projects bidding into this pot received a separate strike price to the primary category:

Weighted Average Strike Price of Provisionally Successful Offers in the 2022 auction[24]

	Community projects	All projects
Average Price	€116.41/MWh	€97.87/MWh

10 community projects were successful in this initial auction round, representing almost 20 MW of capacity.

The creation of a community preference category within the GB CfD scheme would be an easy change to implement, with potentially significant impacts for growing the sector. However, encouraging development of new sites does not address the challenges being faced in sourcing an off-taker for generation, as described above.

Another option for CfD reform to target distributed generation could be the creation of regional CfD pools, managed or overseen by local authorities, DNOs or regional authorities.

Recommendation: Consider the creation of a secondary CfD category to encourage to deployment of locally owned, distributed assets.

Expand and support the private PPA market

[24] Eirgrid, 2022 https://www.eirgridgroup.com/site-files/library/EirGrid/RESS-2-Provisional-Auction-Results-(R2PAR).pdf

See answer to Q24 – expansion of the private PPA market could also benefit smaller scale generation. This could also include providing support for the creation of sleeving pools, as we explored with Bristol City Council.[25]

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

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here:

We believe that there needs to be more certainty regarding the future role of electricity suppliers in the energy system, and that a detailed response on the future of energy suppliers in the current regulatory environment is needed before additional obligations can be assessed. We appreciate that this has been delayed in light of the unprecedented energy price crisis but a response from government following the call for evidence in early 2022[26] is needed before any new licence obligations can be properly analysed. As with other elements of REMA, it is impossible to design appropriate wholesale market reform, or reform of support for mass low carbon power, without a clear idea about retail market reform and the nature of the participants who will form the interface between the wholesale and retail market.

A supplier obligation would be challenging to implement in current market conditions. Indeed, as recognised in the consultation document, the existing supplier obligation to provide a SEG offering has not led to the provision of competitive offerings or a fair price for the generation produced.

It might be beneficial to implement a supplier obligation alongside the standardising of PPA products, to encourage the purchasing of renewable generation directly. Prior to the energy price crisis this was becoming an increasingly popular option for suppliers looking to 'green' their supply, in light of increasing public suspicion of 'greenwashing'. However, the implication of any such obligation must be carefully considered, particularly within the context of any potential reform of the retail supply market.

As mentioned above, one quick win could be to impose a mandatory obligation on a supplier to enter into the standard sleeved PPA with a customer if requested to do so, which would

[25] Regen, 2021 https://www.regen.co.uk/publications/feasibility-analysis-of-bristol-city-councils-electricity-sleeving-pool/

[26] BEIS, 2022 https://www.gov.uk/government/consultations/future-of-the-energy-retail-market-call-for-evidence

encourage uptake of PPAs without placing additional burdens on suppliers to procure generation from PPAs directly.

Recommendation: More long term clarity on the future role of energy suppliers in the future energy system is needed ahead of any new supplier obligation for the purchasing of low carbon generation being designed and implemented.

Recommendation: Develop a clear vision for how wholesale and retail markets will work together including a clear specification of the role that future supply companies will be asked to undertake.

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?

Please provide your response here:

As highlighted in the answer to Q26, any reforms implemented as part of the REMA consultation must also work within the context of the future energy retail market. If the terms of reference under which suppliers must operate are reformed, such as to prioritise decarbonisation or to move away from a competitive, free-market operational style, then there may be greater appetite to support small-scale generators. However, the current risk associated with procuring energy via PPAs with small-scale generators, in the current challenging market conditions, mean that such a strategy is unlikely to be a priority.

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

Please provide your response here: See answer to Q27

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

☐ Yes ☐ No ☐Don't know X No opinion

Please expand on your response here:

As described above, we currently are neither for or against the proposed reforms to the CfD scheme at this stage, as more analysis needs to be done to understand the impacts of each option before any decision can be made.

The case for change in this area has not been articulated and critically examined. There is a commonly held belief that, under a scenario where zero marginal cost generation exceeds total demand (i.e. there is the potential for excess generation and curtailment):

- instances of negative pricing must mean that there is a market failure.

and/or

- that generators would be incentivised to generate even if they do not have an off-taker/customer thereby creating a system imbalance, **and** that this would cause a significant market problem. (Note: generators do sometimes today put themselves in a long or short balance position if they judge that the market will be imbalanced. A practice known as NIV Chasing.

Before any reform is implemented, modelling and analysis needs to be undertaken to see how the market would actually respond in the case of excess generation and whether market price signals would be 'correct', including sending a strong signal to invest in areas like storage, DSR and H2 electrolysis, or market distorting.

Recommendation: Undertake a full review of the CfD mechanism as it stands, to better understand the future system challenges faced – such as times when generation exceeds demand – and whether there is a case for reform. If there is a strong case for reform, each of the proposed options should then be modelled in depth to fully gauge the impact of any such change, ahead of implementation.

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?

Please provide your response here:

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

Please provide your response here:

Please provide any additional evidence in .pdf or Microsoft Word format.

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

☐Yes ☐ No **X Don't know** ☐ No opinion

Please expand on your response here: The case for change need to be fully examined. See answer to Q29.

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

Please provide your response here:

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

Please provide your response here: Before considering this option, the specific case for change needs to be defined. See answer to Q29.

Chapter 7: Flexibility

This consultation rightly highlights that energy storage, alongside other technologies, is an essential source of low carbon flexibility, helping to integrate high volumes of variable renewable generation into the system by balancing supply and demand, maintaining system frequency and exerting a calming effect on volatile energy markets.

The UK currently has 3.7 GW of electricity storage, mainly in the form of pumped hydro plants. However, in recent years 1.7 GW/1.9 GWh[27] of new battery storage has been added, despite storage not receiving any form of revenue subsidy. This investment has mainly been driven by the development of new markets from ancillary/operability services such as frequency response. The successful deployment instigated by the FFR initiative and, more lately, by the Dynamic Containment programme shows the importance of creating markets for flexibility assets. Future markets that need to be developed for flexibility include the balancing mechanism, constraint management services, capacity market and, in the medium term, price arbitrage within the wholesale markets.

Regen has written a number of papers on the subject of energy storage, including Energy Storage: The Next Wave and Energy Storage: Pathways to a Net Zero Future.

In the near term - by 2025 - storage capacity needs to increase to at least 8.4 GW, and by 2035 most credible net zero scenarios envisage at least 18-20 GW of electricity storage in the form of both short duration/high response assets and large-scale/long duration energy storage (LLES)[28]. We discuss how LLES should be defined in our response to the Long Duration Energy Storage call for evidence[29].

There is a very large pipeline of energy storage projects in development, many of which have planning permission. However, sector growth has been hampered by two main factors: **getting a timely and affordable grid connection,** and **having access to a revenue model that is robust enough to secure financial investment**.

The Electricity Storage Network (ESN)[30] managed by Regen is the main industry body dedicated to the electricity storage sector in the UK, representing over 50 leading organisations. The ESN

[27] Figures taken from TEC register.

[28] Figures taken from FES 2022 five year forecast for 2025

[29] Regen and ESN, 2021 https://www.regen.co.uk/wp-content/uploads/Facilitating-the-deployment-of-LLES-Regen-ESN-response.pdf

[30] ESN, 2022 https://www.regen.co.uk/the-electricity-storage-network/

has been at the forefront of the storage sector, helping to shape and influence government policy and to advocate the potential of storage technologies and solutions since 2008. For example, Ofgem and BEIS have adopted the ESN definition of electricity storage in to the generation licence.

BEIS engagement

We would like to offer our help and insight as the REMA process continues following this consultation. As a collection of leading companies and organisations in the electricity storage sector that could help design the solutions and additional work that follow on from this initial consultation.

In terms of additional help that could have a more immediate impact on low carbon flexibility deployment than those outlined in Chapter 7, we would highlight:

- **Definition of energy storage in legislation:** energy storage, especially long-duration storage, will be critical to make best use of low cost energy, balance demand and supply, and to operate the net zero system. The Energy Security Bill is an opportunity to cement that role by finally putting into legislation the accepted definition of electricity storage drafted by the Electricity Storage Network[31], ending the current ad-hoc treatment of storage and helping to unlock its role in aiding power sector decarbonisation. We are concerned that the progress of this Bill has been delayed and would like to take this opportunity to reinforce the importance of the Bill being passed.

Recommendation: Ensure that the Energy Security Bill is not delayed further in its progress through Parliament and confirm the definition of energy storage in legislation.

- **Carbon emissions in operational signals:** Regen and ESN have been raising this issue for a number of years (e.g. our position paper published in 2020[32]) and it has been a policy area we have focused on as part of our ongoing discussions with National Grid ESO in the Electricity Storage Network Markets and Revenues working group. Broadly, we are asking for better valuation of carbon in electricity markets, including clear carbon reporting on all markets and services, and setting emissions limits where feasible/appropriate (e.g. in a new Capacity Market auction), and we are looking for any policy changes in REMA to deliver on these areas. We welcome the data being provided by the ESO from the Balancing Mechanism and new methodology for carbon

[31] Regen and the Electricity Storage Network, 2019 https://www.regen.co.uk/ofgem-adopts-esns-definition-of-storage-in-the-electricity-generation-licence/

[32] Regen, 2020 https://www.regen.co.uk/building-flexibility-markets-for-a-net-zero-electricity-system/

reporting of DSO services. However, we would like further ESO services to monitor the carbon intensity of the services and markets they deliver, and we have been working with the ESO on how the new Future System Operator role could work more effectively at driving net zero delivery. We therefore would support the suggestion in Chapter 9 for enhanced existing policies to give "*the existing ESO or future FSO the ability to prioritise low carbon ancillary services*", as a crucial step in supporting additional low carbon flexibility provision.

Recommendation: Give the ability to prioritise low carbon ancillary services to the ESO and future FSO as soon as practically possible. This includes the creation of clear carbon reporting and setting emissions limits where feasible/appropriate.

- **Locational signals for flexibility assets signals:** more work is needed to understand the locational factors that affect where investment in flexibility is targeted. Based on feedback from our members, we are doubtful that flexibility assets would move into areas of network generation constraint in order to take advantage of low cost renewables under an LMP model. This is because the energy profile of storage combined with constrained wind (and solar) would lead to asset under-utilisation, while the presence of a constraint would also impact storage assets preventing them from accessing other important revenue streams. Except in cases where there is a continuity of supply requirement, storage providers are more likely to locate on the demand side of boundary constraints; as we are seeing at present.

  At present, the strongest locational signals are the availability and cost of network connections, potential flexibility contracts for constraint management services, land space and planning.

Recommendation: Engage with the industry to fully understand the locational and commercial factors that affect the investment decisions of flexibility assets.

- **Accelerating investment in flexibility assets:** there is currently a huge queue of flexibility projects in the development pipeline. Many of these have both planning permission and the promise of a grid connection, but in many cases they have a connection date in the future and/or uncertain connection charges. It seems perverse that storage providers are prevented from connecting to the network in areas where they then could provide a range of network services.

Recommendation: Action needs to be taken speed up network connection processes for storage providers, as well as network investment. This might include reforming queue management processes, changing the way storage assets are modelled by network planners

and looking at a range of alternative connection offers that could be made to storage providers.

Revenue support for flexibility

- Revenue (Cap and floor)

  Recommendation: Cap and floor funding model is not suitable for the support of low carbon flexibility in general but should be developed as an option for large-scale and long-duration electricity storage (LLES).

- Capacity Market

  Recommendation: We support the CM flex enhancements option as a funding model for low carbon flexibility, including a separate auction and specific multipliers. But care must be taken in the design of these changes and we could be happy to help BEIS and others look at more detailed options in the future.

- Supplier Obligation

  Recommendation: More long term clarity on the future role of energy suppliers in the future energy system is needed and that lessons should learnt from the delivery of the new Demand Flexibility Service from the ESO ahead of any new supplier obligation for flexibility being designed and implemented.

  Recommendation: Develop a clear vision for how wholesale and retail markets will work together including a clear specification of the role that future supply companies will be asked to undertake.

7.1 Response questions

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

☐ Yes X No ☐ Don't know ☐ No opinion

Please expand on your response here:

Demand side response (DSR) may need further support and this could be supported by a specific CM auction with some flex enhancement and a Supplier Obligation. We discuss some of the challenges of these options in the next set of questions. In the domestic setting DSR will be incentivised by dynamic tariffs, half-hourly settlement, and smart metering. We are also keen to see how the market responds to the new Demand Flexibility Service from National Grid

ESO[33]. And, as we mention in our response to Q23, there needs to be continued reform to the BM to allow for wider access of smaller assets and demand side actors.

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.

Please provide your response here:

We would restate the question as – "can strong operational signals through reformed markets bring forward enough *low carbon* flexibility, or is additional support needed to de-risk investment to meet our 2035 commitment?" At the moment we have functioning flexibility markets, but they are often dominated by high-carbon assets. This needs to change rapidly in order to deliver the 2035 commitment. Therefore, we would re-emphasise the need for better valuation of carbon in electricity markets, including clear carbon reporting on all markets and services, and setting emissions limits where feasible/appropriate (e.g. in a new Capacity Market auction), and we are looking for any policy changes in REMA to deliver on these areas.

Recommendation: Consideration of flexibility should focus specifically on how markets support and encourage investment in low carbon flexibility and not, for example, fossil fuel peaking plants.

There is a significant pipeline of new projects that are in development (over 304 GW of contracted connections at transmission network level and around 35 GW at the distribution level). This includes considerable amount of battery storage. Getting these projects connected is the key challenge and grid capacity is the major barrier to further growth in deployment.

Key messages from our members forum on the REMA consultation held in Bristol on the 20th of September (Polly Roberts, Senior Policy Adviser REMA, BEIS presented and attended) included:

- It is vital that any reforms also work for renewable energy technologies and do not impact the current deployment of renewable energy projects.
- Getting sufficient investment in short to medium duration battery storage projects is not a barrier in the current market structure.
- An incremental approach to change in the markets is needed to maintain investor confidence and keep the cost of capital low.

[33] National Grid ESO, 2022 https://www.nationalgrideso.com/industry-information/balancing-services/demand-flexibility

However, as you have highlighted, LLES should be treated differently within this discussion and a cap and floor or RAB-type revenue support will be needed to incentivise the deployment of LLES projects.

Demand side response (DSR) may need further support and this could be supported by a specific CM auction with some flex enhancement and a Supplier Obligation. We discuss some of the challenges of these options in the next set of questions. In the domestic setting DSR will be incentivised by dynamic tariffs, half-hourly settlement, and smart metering. We are also keen to see how the market responds to the new Demand Flexibility Service from National Grid ESO[34]. And, as we mention in our response to Q23, there needs to be continued reform to the BM to allow for wider access of smaller assets and demand side actors.

37. Do you agree that 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?

X Yes but for LLES only **X No for general flex** ☐ Don't know ☐No opinion

Please expand on your response here:

We do not think the cap and floor funding model provides the right funding model for low carbon flexibility. However, as we confirmed in our response to the Long Duration Energy Storage call for evidence[35], we believe that cap and floor could be a potential funding model for LLES (as RAB could be). But there are many other areas that need to be clarified before we can get to that point, such as the ESO identifying the service need, and therefore market value, of LLES.

Recommendation: Cap and floor funding model is not suitable for the support of low carbon flexibility in general but should be developed as an option for LLES.

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?

Please provide your response here: See answer to Q37

[34] National Grid ESO, 2022 https://www.nationalgrideso.com/industry-information/balancing-services/demand-flexibility

[35] Regen and ESN, 2021 https://www.regen.co.uk/wp-content/uploads/Facilitating-the-deployment-of-LLES-Regen-ESN-response.pdf

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

Please provide your response here: See answer to Q37

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?

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here:

We do see value in using the CM to incentivise further low carbon flexible capacity. We suggest this should be done by delivering separate auctions for low carbon flexibility (including electricity storage technologies and DSR) and specific multipliers (options two and three). This auction could include a carbon limit as in France, or some other specific requirement, such as a list of eligible technologies.

We recognise the risk of less liquidity in any separate auctions, but feel that this would change as more capacity enters the market over the next few years and could be mitigated by designing the specifications of any auction with industry. And that the risk of price premium for low carbon flexible capacity needs to weighed against the wider benefits of increasing the pace of decarbonisation, as the current market supports the continued operation of high-carbon assets.

It is clear that assets that are low carbon, provide sustained response, two-way response and have fast ramp rates are under-rewarded by the CM for the value they provide at present and that this needs to change.

In terms of multipliers, we agree that some form of multiplier would be beneficial for any new CM contracts and auctions, and that response time and duration are useful starting points for discussion. Duration in particular is clearly crucial, as new battery storage projects are being designed with 2-2.5 hr duration (rather than 1-1.5 hr). And any changes in terms of an additional duration multiplier would help incentivise longer duration assets that could help increase system security (e.g. 4 hr Capacity contract requirement in CAISO market).

Location as a multiplier could be challenging to implement as the transient nature of constraints may be difficult to represent and reward. The granularity (e.g. GSP) of how this constraint is assessed and valued in any multiplier would also be a key factor. In our recent paper on managing constraint costs[36], we recommended expanding the use of more long term forward contracts for flexibility services. This could include CM contracts with a multiplier for certain locations with constraints. However, further analysis on the exact methodology options would be needed before we can recommend any specific solution.

In general, the design of the multipliers would need to be very carefully implemented to avoid any unforeseen consequences.

Any changes to the CM need to align with the new set of reserve services being implemented by the ESO. These services require faster acting assets (full activation within 15 mins of instruction) and procurement at day-ahead or intraday, and there may be some lessons to be learnt from these services.

We would also recommend reducing the amount of fossil fuel assets active in the Capacity Market auctions, by limiting the terms of new contracts to, for example, 5 years. Bringing some of these assets in to public ownership could also be an option to investigate further – see our response to Chapter 8.

Recommendation: We support the CM flex enhancements option as a funding model for low carbon flexibility, including a separate auction and specific multipliers. However, care must be taken in the design of these changes and we could be happy to help BEIS and others look at more detailed options in the future.

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?

Please provide your response here: See answer to Q40

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

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here:

We believe that there needs to be more certainty regarding the future role of electricity suppliers in the energy system. And that a detailed response on the future of energy suppliers in the current regulatory environment is needed before additional obligations can be assessed. We appreciate that this has been delayed in light of the unprecedented energy price crisis but

[36] Regen, 2022 https://www.regen.co.uk/transmission-network-constraints/

a response from government following the call for evidence in early 2022[37] is needed before any new licence obligations can be properly analysed. As with other elements of REMA, it is impossible to design appropriate wholesale market reform, or reform of support for flexibility, without a clear idea about retail market reform and the nature of the participants who will form the interface between the wholesale and retail market.

The supplier obligation would be challenging to implement in current market conditions. In our view of the energy retail market there are some exemplary examples of flexibility innovation from energy suppliers, but that is not the case across the board. With many suppliers likely to be laggards in delivery of any new licence obligation for low carbon flexibility, as we have seen in the delivery of the Smart Export Guarantee.

If any Supplier Obligation is used we would see this as a supplementary funding model aimed at small and medium scale low carbon flexibility projects, as this is a key market that is not necessarily supported at the moment.

The new Demand Flexibility Service launched by the ESO for delivery this winter will provide further useful data and information on the potential for suppliers and aggregators to provide flexibility (turn down) from smaller assets. The good level of guaranteed price and testing will help increase uptake. Findings from delivery of the service of the next few months should be used to inform any future Supplier Obligation for flexibility.

Recommendation: More long term clarity on the future role of energy suppliers in the future energy system is needed and that lessons should learnt from the delivery of the new Demand Flexibility Service from the ESO ahead of any new supplier obligation for flexibility being designed and implemented.

Recommendation: Develop a clear vision for how wholesale and retail markets will work together including a clear specification of the role that future supply companies will be asked to undertake.

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?

Please provide your response here: See answer to Q42

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?

[37] BEIS, 2022 https://www.gov.uk/government/consultations/future-of-the-energy-retail-market-call-for-evidence

Please provide your response here: See answer to Q42

Chapter 8: Capacity Adequacy

In broad terms we are supportive of the options being considered under the Capacity Adequacy theme.

However, we would highlight that, in a net zero future, the scope and objectives of Capacity Adequacy needs to be much broader and better aligned with overall system resilience and net zero objectives, and not just the current focus on ensuring a capacity margin.

In particular, the REMA approach for Capacity Adequacy must:

- Ensure that a long term plan for Capacity Adequacy and System Operability is developed as part of an **Integrated Net Zero Delivery and System Architecture.**
- Refine the definition of what constitutes a stress event to encompass the **more varied and dynamic events** that are expected in the future.
- Move from a capacity neutral position (all MW are the same) to better align the Capacity Market with the delivery of an overall **net zero system architecture** and a set of system attributes and capabilities required for resilience and operability – such as duration, responsiveness, reliability, flexibility, power quality, stability, recovery, diversity of supply and low carbon. For Further discussion see Day in the Life of the Energy System 2035.

We might call this new approach **Capacity Adequacy Plus** (plus flexibility plus dynamic resilience plus system capability plus low carbon).

Recommendation: Extend and adapt the objectives of Capacity Adequacy to consider full energy system resilience and capability, aligned with an overall system architecture and Net Zero and Energy Security delivery plan.

The **Capacity Market** has been successful and should be retained and enhanced as the main market mechanism to deliver **Capacity Adequacy Plus**. We support the idea of an enhanced Capacity Market that ensures the development of flexibility assets, low carbon dispatchable generation[38] and investment in other system attributes. This means a more sophisticated Capacity Market arrangement that places value on responsiveness, dispatchability, flexibility, diversity of supply[39] and duration as well as absolute power capacity.

[38] Analysis suggests that the net zero energy system could require at least 20 GW of low carbon dispatchable generation – at the moment this is expected to be thermal plant with CCUS and hydrogen generation

[39] Diversity: meaning by technology and also by geography and infrastructure – for example, the system and resilience value of a more diversified offshore wind fleet is further discussed in our report Go West!

We expect that this will require REMA to consider different auction parameters, including potentially different auction pots, minima and/or differential pricing based on attributes. These could be set by technology type but they could also be set by system attribute.

Capacity Market payments for attributes would entail obligations to provide additional system and operability services which, for example, could be specified as requirements to participate and adhere to bidding rules and behaviour within the balancing mechanism. This would help to address a current 'value for money' issue of CM payments recipients declining to be available to offer system services.

Recommendation: Keep, but reform, the capacity market to bring forward investment in a wider range of system capabilities and attributes such as flexibility and responsiveness.

The **Capacity Market** should now be used exclusively to support new investment in low carbon technologies that are consistent with the UK's target to deliver a decarbonised power sector by 2035. As well as flexibility assets, the most important area for investment will be a new suite of low carbon dispatchable generation assets including CCUS and Hydrogen generation.

Assets using unabated fossil fuels should not be given long term CM contracts, or should only be given contracts on the basis that they will convert to a low carbon solution by a specified date.

Legacy fossil fuel assets, such as older CCGT plants, that are still required for system backup and security of supply, should, over the next decade, be moved out of the Capacity Market and into a **Strategic Reserve** as part of their 'end-of-operating-life' management plan. Similar to the current arrangements that the ESO has undertaken with some coal-fired power stations, these Strategic Reserve assets would no longer participate in the wholesale, balancing or ancillary service markets and would only operate under instruction from the ESO under prescribed conditions.

At some point, the Government may need to consider bringing Strategic Reserve assets into public ownership, either because of cost, security of supply or commercial reasons. Given the status of these generators as assets critical to security of supply, but ones that we would only retain as an insurance policy rather than for operation within the market, the option to nationalise should be proactively explored. This works should consider the conditions under which public ownership, rather than subsidy to private owners, would be the best option for delivering our overall system objectives

Moving unabated fossil fuel assets into a Strategic Reserve, alongside a low carbon Capacity Market, offers a number of advantages:

- Creating a clear market demarcation between active low carbon assets and legacy assets that are on stand-by for energy security.
- Avoiding the risk that Capacity Market clearing prices are set by end-of-life assets that are able to exploit security rents

- Providing a better basis to negotiate a bespoke end-of-life management plan for assets (including the option to bring into public ownership)

Recommendation: Cease offering long term Capacity Market contracts to unabated fossil fuel assets and begin the process to move unabated fossil fuel assets out of the Capacity Market and into a Strategic Reserve, including the option to bring into public ownership. Focus the Capacity Market to support a new fleet of low carbon dispatchable generators including CCUS and Hydrogen.

8.1 Response questions

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

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here:

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

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here: (See also comments above)

The Capacity Market has proven itself to be a useful lever to ensure capacity adequacy. It could now be improved, in particular to:

- Recognise the value of more responsive and flexible assets to overall energy system resilience (CM plus Flex options).
- Support the net zero transition – by ending CM payments for new build fossil fuels and transition existing fossil fuels into a Strategic Reserve and/or direct tender options.
- Ensure that the CM is designed to meet future stress events which may be far more diverse and dynamic.
- Aligning Capacity Market outcomes within the context of an overall energy system delivery plan and architecture – i.e. support the technologies and capacities that we need to deliver net zero and energy security.

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?

X Separate Auctions X Multiple Clearing Prices X Another Route

☐ Don't know ☐ No opinion

Please expand on your response here:

We should continue to explore all CM options at this stage. We expect that this will require REMA to consider different auction parameters including potentially different auction pots, minima and/or differential pricing based on attributes. These could be set by technology type but they could also be set by system attribute.

Capacity Market payments for attributes would entail obligations to provide additional system and operability services which, for example, could be specified as requirements to participate and adhere to bidding rules and behaviour within the balancing mechanism. This would help to address a current 'value for money' issue of CM payments recipients declining to be available to offer system services.

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?

Please provide your response here:

A Strategic Reserve and Targeted Tender may also be required. Additional measures are likely to be needed especially to support the development of low carbon dispatchable generation such as CCUS and Hydrogen generation – technology development support, capital investment and return on investment measures such as cap and floor and RAB models. The CM provides an additional layer of support.

We note that the ESO has this year separately contracted winter capacity availability from 5 legacy coal fired power stations – this could arguably be considered an existing form of Strategic Reserve.

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

Please provide your response here:

We have suggested moving fossil fuels out of the Capacity Market and into a Strategic Reserve, both to send an important decarbonisation signal and to ensure that CM auction clearing prices are not set by marginal standby (fossil) capacity. Key recommendations:

- Stop awarding long term CM contracts to fossil fuel generators or make these contracts dependent on a decarbonisation date.
- Reduce the award of T1 and T4 contracts to fossil fuels and instead negotiate Strategic Reserve contracts either via auction, or more likely bilaterally based on a remaining life RAB.
- Be prepared to take end-of-life fossil assets into public ownership if that is the most cost-effective option.
- Set an end date for participation of fossil fuels in the CM.

The rationale to move fossil fuel generators out of the CM:

- Ensuring that the CM price is not set by the final marginal capacity of fossil generators.
- Allowing the CM to be focused on support for low carbon generation including CCUS and hydrogen generation.
- Sending a strong decarbonisation signal and a clear demarcation between net zero enabling technology and capacity that may be held in standby.

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

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here:

A Strategic Reserve option may be the most cost efficient option to ensure adequate reserve capacity, especially of legacy fossil fuel plants.

We note that the ESO has recently secured a capacity adequacy services from 5 coal fired power stations for winter 2022/23, as a form of Strategic Reserve:[40]

"the units contracted will ***not be available to the open market and will only be dispatched at the request of ESO****. These contracts are only intended to be used when* ***all commercial options have been exhausted*** *within the Balancing Mechanism."*

We note also that the ESO has previously established a 'Supplementary Balancing Reserve' service which had many of the characteristics of a 'Strategic Reserve' from 2014/15 to 2017/18, albeit on a temporary and time-boxed basis. The service was available for NGET between 6am and 8pm on non-holiday weekdays in the months of November to February. SBR providers were not able to participate in the market for the duration of their contracts. See paragraph 1.3 here.

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

Please provide your response here:

Strategic Reserve could work alongside a enhanced CM Flex option.

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

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[40] National Grid, 2022 https://www.nationalgrideso.com/news/national-grid-eso-confirms-early-detail-winter-coal-contracts

X Yes ☐ No ☐ Don’t know ☐ No opinion

Please expand on your response here:

Government ownership should always be kept as an option to avoid the risk that standby plant owners will extract scarcity rent in either the CM or Strategic Reserve negotiations. It is quite likely that it will be necessary to bring some end-of-life plants into public ownership at some stage either for cost, commercial (e.g. liquidation) or security of supply reasons. This outcome should therefore be prepared for within the REMA arrangements.

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

☐ Yes ☐ No ☐ Don’t know X No opinion

Please expand on your response here:

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.

Please provide your response here:

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

Please provide your response here:

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

☐ Yes ☐ No ☐ Don’t know X No opinion

Please expand on your response here:

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?

Please provide your response here:

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

☐ Yes ☐ No ☐ Don’t know X No opinion

Please expand on your response here:

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.

X Yes ☐ No ☐ Don’t know ☐ No opinion

Please expand on your response here:

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?

☐ Yes ☐ No ☐ Don’t know X No opinion

Please expand on your response here:

Chapter 9: Operability

Whole system energy balancing is critical, ensuring that electricity demand is matched by electricity supply on a minute-by-minute basis. It is also essential that the electricity system functions effectively within its operational tolerances, meaning that the system can provide electricity at the correct frequency, voltage and power quality to ensure reliability and customer service. The National Grid defines system operability as the five key areas of Frequency, Stability, Voltage, Thermal and Restoration and in our recent Day in the Life of the Energy System 2035 report, we set out how critical these are in achieving net zero power in 2035. In the future, managing the quality and continuity of power supply will become more challenging, but good progress is already being made in this area with exciting new technical and market solutions coming forward. The Day in the Life points to a wide range of industry initiatives and innovation projects that are addressing this issue.

System operability is critical to security of supply. Many aspects of operability involve highly technical engineering challenges, and it is important that markets are used appropriately alongside technical regulations such as requirements set out in the grid code, detailed strategic planning which will influence the way operationality challenges develop, and strong focused technical innovation.

Each individual element of operability is a bespoke engineering challenge. For example, the provision of inertia to support frequency stability is technically very different from the provision of voltage support.

However, we note that many of the operability challenges that have been identified are already the subject of market and/or technical innovation initiatives that are being led by the ESO, DSOs and networks. This initiatives including Power Responsive, Dynamic Containment, Stability Pathfinder, Control Room of the Future, Digitalisation, and a host of other solutions. Many of these are discussed in the Day in the Life of the Energy System 2035 reports and also in the Bridging the Gap project

We note also that the ESO has set itself a target to have the technical capability to be able to operate a net zero energy system by 2025[41].

Since these solutions are already well advanced, there is a risk that their inclusion as a core part of REMA may in fact slow down their development and deployment. In light of this, we

[41] National Grid ESO, 2021 https://www.nationalgrideso.com/electricity-transmission/document/189361/download

would suggest that the REMA team considers whether system operability should remain within the core scope of the REMA or should continue to be progressed as a separate (but integrated and coordinated) work programme by the ESO, DSOs and networks.

We also feel that some of the broader questions in the consultation, such as the extent to which ESO and DSO/DNO actions are coordinated and optimised (important though they are) overlap with several other consultations and policy development areas and should be taken outside the scope of REMA.

Recommendation: The REMA team should quickly review the case for change to meet system operability challenges and whether these challenges and solutions (including the development of ancillary markets) should be progressed outside the scope of REMA by the ESO working with the DSOs and Networks.

9.1 Response questions

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

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here:

We know that renewable and low carbon technologies can deliver the operability services that the system needs. Innovation, demonstration and pathfinder projects are showing the way forward. However, we would question whether REMA is the appropriate avenue for exploring these reforms or whether operability (including the development of ancillary service markets) would be better progressed (and fast-tracked) by the ESO working with DSOs and networks.

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?

☐ Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here:

We recognise that a huge amount of work is currently underway to improve the operability of the system and prepare the way for net zero. Many of these initiatives are already well advanced, including through technological innovation and the development of new ancillary markets.

There is always more that can be done, and there is a strong case for accelerating existing initiatives. We would advocate for continued development of new markets that support ancillary services and a smart system, and there is further room to encourage innovative solutions to the operability challenges faced in a future energy system.

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

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here:

- **Giving the ESO or Future System Operator (FSO) the ability (or an obligation) to prioritise zero/low carbon procurement**. As we discussed in Chapter 7, we are asking for better valuation of carbon in electricity markets, including clear carbon reporting on all markets and services, and setting emissions limits where feasible/appropriate (e.g. in a new Capacity Market auction), and we are looking for any policy changes in REMA to deliver on these areas. We welcome the data being provided by the ESO from the Balancing Mechanism and new methodology for carbon reporting of DSO services. However we would like further ESO services to monitor the carbon intensity of the services and markets they deliver. And we have been working with the ESO on how the new Future System Operator role could work more effectively at driving net zero delivery. We therefore would support this suggestion as a crucial step in supporting additional low carbon flexibility provision.

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

Please provide your response here:

There are lots of other projects already underway that need delivering.

The primacy product (product 5 Workstream 1A) in Open Networks project[42] is good example of a key output that is working through the operability conflicts that are likely to occur between DSOs and the ESO. We would emphasise that this work should try and include future services that are in the process of being implemented rather than existing services (not STOR). This will become particularly important as more connections and constraints connect to the energy system.

[42] Energy Networks Association, 2021 https://www.energynetworks.org/assets/images/Resource%20library/ON21-WS1A%20Flexibility%20Consultation%202021%20overview%20(30%20July%202021).pdf

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?

Please provide your response here:

For certain aspects of operability, the DNOs are far better placed to access assets and flex those assets, such as the frequency services already being managed by the DNOs. In those cases, giving DNOs a stronger role in operability makes a lot of sense.

However, other aspects of operability are better placed to remain within the remit of the ESO, such as black start transmission level fault currents, voltage levels, and overall system stability, including highly technical elements such as angle stability. The key is to encourage the DNOs and ESO to work together. We discuss this in more detail in the Day in the Life of the Energy System 2035 reports.

Furthermore, this is already being addressed in Ofgem's ongoing call for evidence on the future of local energy governance[43]. The fact that this is already being addressed further reinforces our point that it is not appropriate for operability to be within the scope of REMA. There are two key principles: (a) who is best placed to identify and manage the demand for a services and (b) who is best placed to access providers of the service and ensure that the service can be delivered to the appropriate level of the system.

For example, frequency response is a system-wide effect for which NGESO is best placed to identify the requirements and to check that sufficient supply is provided. However, as we phase out large scale fossil fuel plants, a greater fraction of providers will be connected to the distribution network. Therefore, DSOs may be better able to work such providers and ensure that the frequency response services that they deliver work within any active management of the distribution network, to ensure that it reaches the 'whole electricity system' level required.

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?

☐ Yes ☐ No X Don't know ☐ No opinion

Please expand on your response here:

We are in favour of exploring the option to remove the disincentive for assets that are supported by CfD scheme to engage in ancillary services markets. However, as we discuss in

[43] Ofgem, 2022 https://www.ofgem.gov.uk/publications/call-input-future-local-energy-institutions-and-governance

our response to Chapter 6, BEIS should undertake a full review of the CfD mechanism as it stands, to better understand the future system challenges faced and the implications of any such changes, before any decisions are made. We suggest this as changing the terms of the CfD scheme to encourage the provision of additional services may change the risk profile for such projects, and could have unintended consequences.

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?

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here:

As we discuss in our response to Chapter 8, ensuring that a long term plan for Capacity Adequacy and System Operability is developed as part of an Integrated Net Zero Delivery and System Architecture is critical. As part of this, the Capacity Market should become more closely aligned with aspects of system operability.

The **Capacity Market** has been successful and should be retained and enhanced as the main market mechanism to deliver **Capacity Adequacy Plus**. We do not believe the Capacity Market should be used to procure ancillary services, but we do support the idea of an enhanced Capacity Market that ensures the development of flexibility assets, low carbon dispatchable generation[44] and investment in other system attributes. This means a more sophisticated Capacity Market arrangement that places value on responsiveness, dispatchability, flexibility, operability, diversity of supply[45] and duration as well as absolute power capacity.

We expect that this will require REMA to consider different auction parameters, including potentially different auction pots, minima and/or differential pricing based on attributes. These could be set by technology type, but they could also be set by system attribute.

Capacity Market payments for attributes could entail obligations to provide additional system and operability services which, for example, could be specified as requirements to participate and adhere to bidding rules and behaviour within the balancing mechanism and ancillary service markets. This would help to address a current 'value for money' issue of CM payments recipients declining to be available to offer system services.

[44] Analysis suggests that the net zero energy system could require at least 20 GW of low carbon dispatchable generation – at the moment this is expected to be thermal plant with CCUS and hydrogen generation

[45] Diversity: meaning by technology and also by geography and infrastructure – for example, the system and resilience value of a more diversified offshore wind fleet is further discussed in our report Go West!

However, procuring ancillary services, at the transactional level, as part of the Capacity Market would not be appropriate.

Furthermore, at present it is possible to 'stack' the Capacity Market with other frequency services, meaning multiple income streams can be accessible to market participants. We would be keen to for this to remain the case. Furthermore, it is important that the 'stackability' of services is a default characteristic of ancillary services and CM contracts without compromising energy security and capacity adequacy, as this allows optionality for market participants.

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

☐ Yes X No ☐ Don't know ☐ No opinion

Please expand on your response here:

In a traditional energy system dominated by large thermal generators, a centralised dispatch model may lead to a co-optimisation of balancing and ancillary operability services.

In our future smart net zero energy system, with many more options for flexibility and operability solutions, a centralised dispatch model may in fact lead to sub-optimal outcomes. It could, for example, inhibit the ability of service providers to stack different revenue streams and to optimise their own asset use. It could dissuade investment in new form of flexibility and innovation.

However, we do agree that the ESO should be able to procure and, if necessary, dispatch ancillary services outside of the current balancing mechanism gate closure window (as is already happening in a number of trial projects). For example, the ESO could procure long term contracts for flexibility services, which would then be available to manage network constraints.

Chapter 10: Options across multiple market elements

10.1 Response questions

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

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here:

As we discuss in Chapter 6, there are a number of simpler mechanisms for encouraging the delivery of low carbon power.

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

X Yes ☐ No ☐ Don't know ☐ No opinion

Please expand on your response here:

Firstly, as we mention in our response to Chapter 7, Regen and ESN have been raising the issue of carbon emissions in operational signals for a number of years and it has been a policy area we have focused on as part of our ongoing discussions with National Grid ESO in the Electricity Storage Network Markets and Revenues working group. Broadly, we are asking for better valuation of carbon in electricity markets, including clear carbon reporting on all markets and services, and setting emissions limits where feasible/appropriate (e.g. in a new Capacity Market auction), and we are looking for any policy changes in REMA to deliver on these areas. These mechanisms we have been calling for may be simpler to implement than creating an entirely new scheme based around the idea of carbon abatement.

Furthermore, when considering the carbon intensity of flexible assets, a number of small gas peaking plants are currently not exposed to a carbon price, being below emissions threshold to participate in the UK ETS. They compete alongside BESS and other low carbon flexible assets in the Balancing Mechanism and ancillary services. Another, more simple solution, might be to extend the carbon price to apply to all fossil-fuel flexibility. This could be through extension of the UK ETS.

However, there could be room to explore the implementation of a type of Dutch Subsidy to encourage uptake of small-scale, distributed flexible assets and co-location. Having such sites operating under a single support mechanism may be more attractive than the complexity of generation and storage operating under two mechanisms; simplicity is important in encouraging widespread uptake. As we discussed in our response to Chapter 6, there are currently a number of barriers facing smaller-scale generators and the market does not correctly value the generation they produce. Such a support could be a form of additional revenue, to be stacked on top of other payments such as the SEG, or sleeved PPAs.

A Dutch Subsidy could fill this gap. The simplicity of operating under a single support mechanism would be attractive for sites with co-location, and may encourage innovative solutions to abate carbon, such as as-yet unexplored solutions involving power and heat to maximise abatement. In addition to ensuring the scheme targets only smaller sites, such as through as capacity limit, investors would need to be a degree of certainly in long term support, and clarity as to how the carbon intensity of the grid has been calculated - to ensure transparency and fairness in the payments being made.

Recommendation: We support the exploration of a form of Dutch Subsidy as a potential way of structuring support for investment in low carbon flexibility, but only to encourage the installation of smaller-scale, distributed assets and co-location.

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

Please provide your response here:

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

☐ Yes ☐ No ☐ Don’t know ☐ No opinion

Please expand on your response here:

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

☐ Yes X No ☐ Don’t know ☐ No opinion

Please expand on your response here:

As we discussed in our response to Chapter 2, the discussion around whether variable renewables ought to be forced, or encouraged, by the market to provide firm power, is a perceived market failure that we would suggest that is not actually a market failure. Assets that are providing very low cost but variable energy, and assets that are providing flexibility, are providing different market services. It may be valuable in some cases for those assets to co-develop, either at the same location (behind the same meter) or under joint ownership as part of a wider portfolio of generation and flexibility. Market signals should make clear what is needed across both sets of services and avoid forcing them together into a single market service.

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

Please provide your response here:

Please provide any supporting evidence in .pdf or Microsoft Word format.

Do you have any other comments that might aid the consultation process as a whole?

Please use this space for any general comments that you may have, comments on the layout of this consultation would also be welcomed.

Additional consultation information

Thank you for your views on this consultation. However, as part of the BEIS wider customer survey plans, we would appreciate your views on x, y and z below.

Thank you for taking the time to let us have your views. We do not intend to acknowledge receipt of individual responses unless you tick the box below.

Please acknowledge this reply X

At BEIS we carry out our research on many different topics and consultations. As your views are valuable to us, would it be okay if we were to contact you again from time to time either for research or to send through consultation documents?

X Yes ☐No

Appendix: Full list of recommendations

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

Chapter 2: The case for change

- Critically examine the operation and efficiency of the wholesale market and the occurrence of price speculation, uneconomic volatility, loss of liquidity, scarcity rent taking and bullwhip effects. Consider measures to bear down on these, focusing on transparency, forecasting, flexibility and liquidity.

Chapter 3: Our approach

- REMA must be supported by wider reform of the planning system aimed at ensuring that networks, along with generation and flexibility infrastructure, can gain consent and planning approval in appropriate timescales.
- Based on consultation feedback, the REMA team should quickly review progress towards system operability and whether this area of market and technology development would be better pursued as a parallel but aligned activity, led by the ESO and networks.
- REMA should, at least, consider the integration and interaction between carbon markets (carbon trading scheme, carbon tracking and the use of REGOs) as it will strongly impact and underpin the transition to net zero in the wholesale market.

Chapter 4: Cross-cutting questions

- REMA must be aligned with the development of an overarching Net Zero and Energy Security delivery plan. This plan needs to include an analysis of generation and demand growth, network infrastructure, flexibility, system balancing, capacity adequacy, curtailment and constraints, and projected energy and system cost. The plan should include an overarching whole system architecture which indicates the system capabilities that are required and capacity of key technology types (generation, flexibility, interconnection and demand) that should be expected within each region of Britain.

- The interaction between REMA and reform of carbon pricing should be explicitly reviewed and considered as decisions are made on which REMA options to take forward.
- Market reform must be backed up by the accelerated build-out of transmission and distribution network capacity. This could be based on a holistic network design approach to determine what network capacity is needed in ten to twenty years' time and ensuring that Ofgem, NGESO (FSO) and the Transmission Owners are resourced to deliver and held to account for failure. Support infrastructure decision making with a whole system cost benefit analysis (CBA).
- Explore the potential for a reformed TNUoS system to provide an appropriate long term price signal, which is properly cost reflective and has appropriate locational signals to influence decisions.
- Consider the influence of all locational factors as part of the development of the Net Zero Energy Security Delivery Plan and overarching architecture.
- Policies and programmes to deliver efficient use of energy and electricity will need to sit alongside wholesale electricity market reform rather than being a key goal of REMA itself.

Chapter 5: A net zero wholesale market

- Maintain a national wholesale energy market that supports a varied and dynamic trading ecosystem that includes bilateral trading, a vibrant PPA market, organised power exchanges, forward contract markets and short term markets.
- Explore the idea of a green power pool with a specific focus on how it would work in practice, the mechanisms required and worked examples of who it helps and why. Ensure a clear industry-wide understanding of the issue before further consultation.
- Do not pursue Locational Marginal Pricing either in nodal or zonal forms, since this will not provide effective locational signals and would significantly increase investment risk.
- Explore ways to make transmission network congestion and the operation of the transmission network more transparent under a national wholesale market. This could include publication and mapping of congestion in real-time, network outage lists, and operational boundary transfer capacities.
- Reforms should aim to encourage market participants into long term contracts that more closely reflect the long term average cost of generation rather than short term marginal costs. As we discuss in Chapter 6, we believe that there are routes to encourage greater use of long term PPAs and adjustments to existing CfD mechanisms that can help deliver a market outcome less focused on short-run costs.
- Our recommendations for reform of the Balancing Mechanism are:

- Removing a large fraction of transmission constraint management from 'the last hour' through a revamp of the BM, including adjusting timescales and introducing new mechanisms.
- Enabling and incentivising the ESO to take balancing actions outside the 1hr BM gate closure period by, for example, negotiating long term contracts for flexibility services and placing forward market trades for balancing and constraint management.
- Adapt existing mechanisms and add new ones, to encourage demand side and behind the market technologies to participate delivery in the BM. Make sure that ESO is appropriately incentivised to use them where they are cost-effective against other technologies.
- Focus on significant cost reduction in the 'turn up' element of constraint costs: introduce mechanisms that encourage the ESO to use flexibility assets when available (rather than relying on CCGT plants) and by investing in digitalisation and control room capability.
- Review rules for participation in the BM, the behaviour of assets operating in the BM and adherence to regulatory standards.
- Continue with the development of new markets for operability services and flex, and for each consider the appropriate role of the BM and other mechanisms for delivering them.
- Continue to develop and widen access to the BM following BSC p375 implementation. Further work is needed to reduce the barriers to entry for smaller assets, particularly at the domestic scale (e.g. cost of hardware and lack of installer base).

Chapter 6: Mass low carbon power

- The CfD scheme should be expanded in its ambition, including increasing the amount of new capacity included in each allocation round. Auction rounds should be completed annually as planned, following the announcement by BEIS in February.
- Develop a mechanism to provide a geographic locational signal to encourage greater diversity of supply within the CfD scheme.
- Undertake a full review of the CfD mechanism as it stands, to better understand the future system challenges faced – such as times when generation exceeds demand – and whether there is a case for reform. If there is a strong case for reform, each of the proposed options should then be modelled in depth to fully gauge the impact of any such change, ahead of implementation.
- Do not incentivise dispatchable low carbon assets – such as by offering them CfDs – to become baseload energy generators and crowd out lower cost and lower carbon renewables energy. Do ensure that investment in low carbon dispatchable generation is supported via other schemes.

- Expand the use of a CfD-type contract to existing variable renewable generation, in exchange for a lower long term energy strike price.
- Oversee the creation and adoption of a number of standard, industry-wide non-negotiable PPAs, such as a sleeved PPA or a virtual PPA, to encourage widespread adoption of such mechanisms in the wholesale market.
- Consider the creation of a secondary CfD category to encourage to deployment of locally owned, distributed assets.
- More long term clarity on the future role of energy suppliers in the future energy system is needed ahead of any new supplier obligation for the purchasing of low carbon generation being designed and implemented.
- Develop a clear vision for how wholesale and retail markets will work together including a clear specification of the role that future supply companies will be asked to undertake.

Chapter 7: Flexibility

- Ensure that the Energy Security Bill is not delayed further in its progress through Parliament and confirm the definition of energy storage in legislation.
- Give the ability to prioritise low carbon ancillary services to the ESO and future FSO as soon as practically possible. This includes the creation of clear carbon reporting and setting emissions limits where feasible/appropriate.
- Engage with the industry to fully understand the locational and commercial factors that affect the investment decisions of flexibility assets.
- Action needs to be taken speed up network connection processes for storage providers, as well as network investment. This might include reforming queue management processes, changing the way storage assets are modelled by network planners and looking at a range of alternative connection offers that could be made to storage providers.
- Cap and floor funding model is not suitable for the support of low carbon flexibility in general but should be developed as an option for large-scale and long-duration electricity storage (LLES).
- We support the CM flex enhancements option as a funding model for low carbon flexibility, including a separate auction and specific multipliers. But care must be taken in the design of these changes and we could be happy to help BEIS and others look at more detailed options in the future.
- More long term clarity on the future role of energy suppliers in the future energy system is needed and that lessons should learnt from the delivery of the new Demand Flexibility Service from the ESO ahead of any new supplier obligation for flexibility being designed and implemented.

- Develop a clear vision for how wholesale and retail markets will work together including a clear specification of the role that future supply companies will be asked to undertake.
- Consideration of flexibility should focus specifically on how markets support and encourage investment in low carbon flexibility and not, for example, fossil fuel peaking plants.

Chapter 8: Capacity adequacy

- Extend and adapt the objectives of Capacity Adequacy to consider full energy system resilience and capability, aligned with an overall system architecture and requirements plan.
- Keep, but reform, the capacity market to bring forward investment in a wider range of system capabilities and attributes such as flexibility and responsiveness.
- Cease offering long term Capacity Market contracts to unabated fossil fuel assets and begin the process to move unabated fossil fuel assets out of the Capacity Market and into a Strategic Reserve, including the option to bring into public ownership. Focus the Capacity Market to support a new fleet of low carbon dispatchable generators including CCUS and Hydrogen.

Chapter 9: Operability

- The REMA team should quickly review the case for change to meet system operability challenges and whether these challenges and solutions (including the development of ancillary markets) should be progressed outside the scope of REMA by the ESO working with the DSOs and Networks.

Chapter 10: Options across multiple market elements

- We support the exploration of a form of Dutch Subsidy as a potential way of structuring support for investment in low carbon flexibility, but only to encourage the installation of smaller-scale, distributed assets and co-location.

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October 22