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To whom it may concern,

Consultation Response: Review of Electricity Market Arrangements – July 2022 consultation

Scottish Renewables is the voice of Scotland's renewable energy industry. Our vision is for Scotland leading the world in renewable energy. We work to grow Scotland's renewable energy sector and sustain its position at the forefront of the global clean energy industry. We represent over 300 organisations that deliver investment, jobs, social benefits and reduce the carbon emissions which cause climate change.

Our members work across all renewable energy technologies, including energy storage, in Scotland, the UK, Europe and around the world. In representing them, we aim to lead and inform the debate on how the growth of renewable energy generation and storage can help sustainably heat and power Scotland's homes and businesses.

The future electricity system will be at the heart of the energy transition, with transport and heating demand increasingly switching to electricity, and significantly increasing the volumes and value of electricity markets. At the same time, if Net Zero is to be achieved, then by 2035 electricity production must be achieved without fossil-fuel generation and vast amounts of new low-carbon flexibility resources will have to replace flexible fossil fuel generation.

Scotland benefits from plentiful natural renewable resources and our renewable industry has already demonstrated it can deliver quickly and at scale to reach decarbonisation targets. For flexibility resources, Scotland has the unique topography and locations to develop new pumped storage hydro, as well as other new flexible resources based on hydrogen. The industry has a strong pipeline of potential projects and stands ready to scale up to deliver both low carbon technologies and flexible resources needed for the future.

We are writing our response to this consultation primarily from the perspective of investors in renewable and flexibility assets. The future electricity market design will need to attract vast amounts of new capital for both renewable and flexibility resources. To attract this capital, any reform of market arrangements must maintain investor confidence for existing market participants as well as for future investment.

In this cover letter, we have summarised the key issues from our response. Our detailed responses to individual questions in each of the consultation chapters is included in an annex to this letter.

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Summary of our response

Overall, we welcome the Review of Electricity Market Arrangements (REMA) and its goal to accelerate progress towards Net Zero. We strongly agree that future electricity markets must deliver the two critical REMA objectives to:

- Scale up low carbon technologies to meet Net Zero targets
- Scale up flexible resources to support renewables

Future electricity markets must mobilise unprecedented levels of investment across the full range of low carbon technologies while maintaining security of supply at best value to consumers.

Investor confidence is needed to mobilise capital

We welcome that an aim of market reform is to maintain investor confidence. To realise the scale up of low carbon and flexibility assets, it will be critical that future markets provide the long-term price signals that major infrastructure projects need to raise capital. Many billions of pounds of new capital will be needed. Furthermore, to maintain overall investor confidence, it will be important that existing long-term price signals are not undermined.

Long term price signals to lower cost of capital

Electricity markets that provide long-term revenue certainty to investors will not only allow this capital to be raised but should attract a lower cost of capital. We welcome the aim to introduce effective markets signals for both low carbon generation and flexibility assets. Long-term price signals for low carbon generation assets have been hugely successful and should also be introduced to support investment in low-carbon flexibility assets.

REMA scope should include market access barriers

REMA proposes to undertake a wide-ranging review of existing market mechanisms. However, we consider a key element is missing which, without attention, is likely to undermine all other reform proposals and benefits. We suggest that market access barriers resulting from transmission and distribution network congestion are included in the REMA scope. These access barriers are currently causing significant delays and investor uncertainty. For example, the ESO TEC register currently lists some 200GW of new transmission connections in GB with connection dates running through to the mid-2030's.[1]

Locational pricing

We are strongly opposed to proposals to introduce new zonal or nodal locational price signals for low carbon generation or demand assets. We believe that the most effective way of delivering locational signals is through network access and charging reform. The TNUoS Task Force is currently working to deliver a more cost-reflective and predictable locational signal for generators. We believe this is the most cost-efficient way to deliver the right signals for generators and demand users rather than the introduction of locational marginal pricing in wholesale markets.

In theory, the electricity system could be better optimised through stronger locational signals. But, in practice, the implementation of zonal or nodal locational price signals will simply penalise existing low carbon generation in areas with strong resource but where supply exceeds demand, and discourage future investment in those areas, which is wholly inconsistent with the overarching objectives of the consultation. The corollary of that is that higher prices in areas where demand

[1] Source: National Grid ESO Transmission Entry Capacity Register

exceeds supply will simply act as a tax on demand, given the limited potential for demand to re-locate simply on the basis of its energy costs, and given the many factors which drive this. Indeed, the current dispersion of renewables around the periphery of GB reflects resource availability, other physical factors (e.g., seabed conditions) and planning constraints despite the increasing and significant locational signal already delivered by TNUoS.

Additionally, it is unclear how these designs would support emerging technologies without market intervention. It is wrong to assume that technologies such as wave, tidal and floating wind would follow the same price trajectory as fixed bottom offshore wind and reach a point of similar price parity as established renewable technologies over the next several years. A shift to LMP by 2035, would effectively lock these technologies out as they don't have the ability to locate close to demand centres without support.

Whilst locational price signals are not appropriate for generation and demand assets, we recognise that separately targeted, locational signals could be useful in encouraging the siting of flexibility or operability assets to enable greater utilisation of nearby low carbon generation. We suggest these signals could be delivered through reforms to TNUoS and a more locationally focused Balancing Mechanism and Ancillary Services market to encourage storage assets to locate near to constraints. Long term ancillary service contracts offered by the ESO and DNOs to assets which locate in optimal locations should also be considered.

Wholesale market reform

The aim of wholesale market reform is to deliver long and short-term investment signals both renewable and flexibility resources, while ensuring competition can deliver best value for consumers. The REMA consultation is considering the use of separate markets for firm and variable (low carbon) power. We agree that options for split markets should be further investigated, with the costs and benefits being assessed.

We suggest that future market designs for mass low carbon power should seek to retain the benefits from existing arrangements including from self-dispatch and long-term confidence about revenues and system costs. We suggest it may be useful to consider the benefits of a dedicated market for flexibility resources, where low-carbon flexibility could be prioritised.

To mobilise investment, it will be important that each market delivers long-term price signals for both low carbon and flexibility resources to ensure the required capacity of each resource is available.

Mass low carbon power

The current CfD scheme with government-backed contracts has been extremely effective at providing certainty to investors in low-carbon projects. The long-term revenue certainty it provides is attractive to investors, both in terms of raising the vast amounts of required capital and enabling the cost of capital to be reduced. The certainty of a future deployment pipeline has spurred innovation and reduced technology costs. Competitive auctions have driven down strike prices and provided better value for consumers, and the CfD structure means that customers are protected against high prices.

We consider that any reform of the CfD should build on these successes. It is important that the CfD principle of long-term revenue stabilisation is maintained as this will both attract low-cost investment and offer value for money to consumers. It is also important to ensure that the CfD continues to provide dedicated support for floating offshore wind as this revenue security will be critical for driving further innovation and securing the massive projected increase in deployment.

Flexibility market reform

Flexibility is at the heart of REMA, and to enable investment in flexibility resources, we suggest that REMA needs to address the following issues:

- flexibility is not well defined – we suggest it should include dispatchable generation or demand, plus dispatchable ancillary services, plus network congestion flexibility. It should prioritise low-carbon flexibility.
- flexibility resources are not clearly valued – long-term price signals for flexibility are not being provided by existing wholesale or balancing markets. Short-term flexibility market prices are incentivising short duration storage which in turn is cannibalising revenues from lower long-run cost flexibility solutions.

We believe that market signals for flexibility would best be delivered through changes to the markets flexibility assets already operate in (the Balancing Mechanism and Ancillary Services). We also see a role for long term ancillary service contracts and for the locational value of flexibility to be better reflected through TNUoS charging. This is in addition to the support mechanism currently being developed for long duration storage. Whilst the reforms introduced as a result of REMA should support the development of long duration storage in the future, we welcome that the development of this mechanism is continuing on an accelerated timeline out with the scope of REMA.

There is potential for flexibility markets to enable greater renewable utilisation and there may be a case for a dedicated market for flexibility. This dedicated market should not undermine the market price signals for renewables, and we would reiterate that it would be highly detrimental to generators, consumers and investor confidence if locational price signals were applied to renewable generation. Whilst we think that a hybrid market such as this may warrant further investigation, given the complexity involved and the potential to undermine investor confidence in making radical changes to current market arrangements, it would not be our preferred mechanism to deliver market signals for flexibility.

Urgent action – pumped storage hydro

Our members have a pipeline of large-scale, pumped storage projects in Scotland and Wales that are either ready to build or in advanced stages of development. These projects have low lifetime costs compared to other technologies and could add valuable long duration storage capabilities to help meet future flexibility needs. This is the type of asset REMA reforms should be incentivising in the future, but early decisions need to be taken to enable these assets to be constructed and operational by 2035. While BEIS has recently announced an intent to incentivise the development of long-duration storage assets such as these, we would stress the urgency required.

Innovative technologies are critical for the future system

It is imperative that REMA recognises the value of early-stage investment in emerging technologies that will play a critical role in a Net Zero energy system. Early investment drives innovation and supply chain development and will be necessary if cost reduction pathways similar to those already experienced by solar, onshore wind and fixed bottom offshore wind are to be achieved.

Other market reforms

We have responded in the attached annex to the questions raised in relation to capacity adequacy and operability questions. These questions have largely focused on potential reforms to existing arrangements, and we generally agree with the proposals for further investigation.

Taking a pragmatic approach

Finally, we welcome the REMA objectives for future electricity market arrangements including proposals to provide price signals for renewables and flexibility, and for customers to take greater control of their electricity use. We recognise that the aim is to introduce technology-neutral market signals to optimise assets at local, regional and national levels using system-wide digitalisation to send the right signals to co-ordinate operational and investment decisions.

However, design of the perfect market, if such a thing exists, is likely to be highly complex and will take considerable time to implement. Given the challenges from market access barriers, the scale of investment, the scale of customer behavioural change, the potential complexity, and the consequent time to deliver, we suggest that the REMA plan for new market arrangements must take a pragmatic approach that ensures early investment in the new renewable and flexibility resources needed for 2035. To this end, we would welcome early communication of market design options that are ruled out as this will serve to provide more certainty to the market.

Scottish Renewables would be keen to engage further with you on this agenda and would be happy to discuss our response in more detail.

Yours sincerely,

Andrew MacNish Porter

Policy Manager – Economics and Markets

Scottish Renewables

Annex: Responses to individual questions by chapter

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

Overall, we welcome the Review of Electricity Market Arrangements REMA) and its goal of accelerating progress towards Net Zero. We strongly agree future electricity markets must deliver the two critical REMA objectives:

- Scale up low carbon technologies to meet Net Zero targets
- Scale up flexible resources to support renewables

REMA aims to create future electricity markets that will mobilise unprecedented levels of investment across the full range of low carbon technologies, including low carbon generation, electricity storage, and flexible demand from consumers. At the same time, these future markets must maintain security of supply at least cost to consumers.

We welcome that the stated aim in undertaking market reform is to maintain investor confidence. This will be critical to ensure that the scale-up of low-carbon technologies and flexibility resources can be realised. However, it is important that such certainty is provided as soon as possible. To realise such large expenditure commitments, investors and the supply chain will need to commit to development expenditure many years in advance. Uncertainty about the future market regime may cause development expenditure to be delayed, and consequently delay subsequent construction investment. Urgency is needed to give confidence to project developers.

Responses to consultation questions

Vision and objectives for future market arrangements

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

The REMA vision for future electricity market arrangements includes proposals to provide price signals for renewables and flexibility, and for customers to take greater control of their electricity use. The objective is also to introduce market signals to optimise assets at local, regional and national levels using system-wide digitalisation to send the right signals to co-ordinate operational and investment decisions. The vision is that all technologies should be able to participate in future electricity markets.

This vision appears to paint a picture of a perfect wholesale market design model where all renewable and flexibility resources (including distributed energy resources) receive price signals from open, highly liquid electricity markets receive a technology-neutral price signal. These resources are then optimised by operational, locational, and temporal factors to achieve least cost delivery of production to meet the customer demand.

While this is an admirable aspiration for future market design, there are many challenges to its achievement. For example, markets may be designed to enable future technologies such as hydrogen or CCUS or distributed energy before these resources are proven at scale and able to participate. The introduction of locational price signals or other major changes to existing market arrangements would undermine investor confidence. Grid congestion appears likely to restrict transmission and distribution market access for some years to come.

Design of the perfect market is likely to be highly complex and will take considerable time to implement. Given the scale of investment or behavioural change required, and the time to deliver, we suggest that the REMA plan for new market arrangements must take a pragmatic approach that ensures early investment in the new renewable and flexibility resources needed for 2035.

REMA Objectives

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

The objectives set out by REMA are that by 2035 future market arrangements should:

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

The potential benefits are significant and justify a need to reconsider whether the current arrangements are fit for purpose. However, we suggest these ambitions should take into account two additional factors:

- The time, cost and complexity associated with changing the supporting market processes, including service definition, trading, settlement, etc, and building the associated capabilities and governance to perform new activities.
- The impact upon investor confidence – a prolonged period of market reform will give rise to future market uncertainty and will weaken investor confidence, especially in high capital cost assets. As discussed elsewhere in our response, even the consideration of proposals for locational pricing is likely to have a negative effect on investor confidence.

REMA scope

The REMA scope proposes to exclude a number of market mechanisms and technologies including large scale nuclear, BECCS, hydrogen production, long-duration storage and interconnectors. But future market arrangements must include these technologies and their market impact. The bespoke support mechanisms should be considered in terms of their interaction with overall market design.

The REMA scope includes all technologies that currently (or could) participate in electricity markets, but the scope excludes new nuclear, first of a kind projects, and other markets e.g., natural gas, hydrogen, and policies for demand reduction, for example. While these exclusions may cause distortions to electricity market designs, it seems pragmatic and sensible to exclude these more tangential policies and focus on the main requirements for reform. However, while interconnectors are excluded, the future assumptions about interconnector operation assumptions have a significant impact on UK electricity markets. It is unclear how these factors will be addressed by the reform agenda.

We would highlight that BEIS has recently stated that it will be proposing measures to incentivise the development of long duration storage such as the pumped storage hydro opportunities in our region. These have not yet been published and we would ask that when they are, it is made clear how they will be treated separately from the REMA reforms or be integrated with them. This lack of clarity creates uncertainty for investors.

A key issue that we suggest should be included in the scope of REMA is market access barriers. A key barrier is transmission and distribution network congestion, which is causing significant delays and investor uncertainty. The connect and manage approach has not addressed these access barriers.

For example, the ESO TEC register currently lists some 200GW of new transmission connections in GB with connection dates running through to the mid-2030's as networks are reinforced. But much of this capacity may not be required and unless some form of prioritisation is established, then the aims of REMA will not be achieved. Similarly, market access for distributed energy may be restricted due to metering or data limitations.

We suggest that mechanisms to enable open market access should be included within REMA scope.

Chapter 2: The case for change

We agree with the case for change – the current market arrangements have been successful in delivering renewable investment and decarbonisation. But they will not deliver the investment signals for the optimum combination of low carbon, flexibility or operability resources needed to achieve Net Zero.

The REMA consultation considers that there is a case for changing the current electricity market arrangements and that the full range of possible options for reform should be considered, from incremental modification to more transformational changes to market structure.

We agree that a full review of the market design options should be considered, but this should take account of the need to maintain the confidence of investors in the current investment flightpath, and to ensure that urgent new investment is not delayed.

Responses to consultation questions

Future challenges

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.

The key challenges identified by BEIS are:

- Increasing the pace and breadth of investment in renewable generation
- Increasing system flexibility resources to balance supply and demand
- Providing efficient locational signals to minimise system cost
- Ensuring system operability using low carbon operability resources
- Managing price volatility as the penetration of renewables increases

We agree with four of the five key challenges that are outlined. We agree with the need to increase low carbon generation and flexibility capacity, to maintain system operability, and to mitigate the volatility of the gas price. However, we do not agree with the ambition to apply locational signals in wholesale markets to minimise system costs arising from the location of renewables or other low-carbon capacity.

Renewable projects have their location restricted by the availability of natural resources, planning consents, and grid connection. The introduction of locational pricing for renewable generators that have limited choice about siting will essentially be an ex-post tax levied on existing investors, thereby impacting project viability and investor confidence. Locational signals are already provided via TNUoS charges and improvements to the TNUoS charging regime are already being considered through the TNUoS Task Force.

The REMA consultation notes that it would not be feasible or cost-effective to expand network capacity to prevent all curtailment – as such, an efficient electricity system will always have some degree of constraints. This does not necessarily indicate a lack of a locational signal – simply that a level of transmission constraint cost should always be more economic than the alternative of network investment to alleviate constraints.

However, for flexibility resources, we recognise that locational pricing could potentially be valuable in determining where flexibility resources locate and operate both at a national and local level.

These locational signals for flexibility should enable the optimisation of non-firm low carbon generation and potentially reduce the need for transmission network investment. However, it would be critical to ensure that any such signals for flexibility do not undermine the market signals for renewable generation.

We suggest that the REMA case for change should recognise that the current operational and development pipeline of renewable energy projects has been developed on the basis of the existing regime i.e., that they are best located where sites and renewable resources are available, mainly driven by offshore wind leasing rounds.

Other challenges

Grid access and utilisation

The case for change as outlined in this section is the foundation upon which market reform options in the rest of the REMA consultation are built upon. Therefore, we believe it imperative that the scale of issues within current market design, such as current constraint management and the pass-through impact on the Balancing Mechanism, are completely understood.

We welcome the analysis of the carbon impact of the current constraint management and redispatch process, as mentioned on *page 33*. The scale of the carbon impact from managing transmission capacity constraints through market mechanisms such as the Balancing Mechanism is extensive and is counterproductive to legally binding Net Zero goals. The majority of generation capacity "constrained off" is renewable wind from Scotland, that is then lost and replaced with carbon intensive generation such as CCGT that tends to be in the south of England and close to demand centres.[2]

However, we feel that it is essential that an accurate review of the current market conditions is carried out to enable the whole system thinking and optimal decisions that are required to deliver our Net Zero goals.

The figures presented in Chapter 2 do not fully capture the scale of expected constraint costs within the GB system over the next few years. Constraint costs resulting from a lack of transmission capacity are quoted within the consultation as totalling £1.2bn in 2021. This figure is likely to be much larger in the future than is shown throughout the case for change. National Grid ESO's latest forecast from October 2022 predicts that constraint costs for the year 2023 are anticipated to reach nearly £3bn.[3] It should also be noted that managing the cost of constraints in the Balancing Mechanism is currently levied through Balancing Service Use of System (BSUoS) charges that are paid by generation and demand. However, as of 1st April 2023 this will change and the cost will be levied solely on demand, ultimately meaning consumer bills, as decided by Ofgem via code modification CMP 308.[4]

Figure 4: Network Constraint Cost page 33, within the document is an out-of-date publication from National Grid ESO published in July 2021[5] and relies on Network Options Assessment (NOA) that is now several years old. The NOA 2020/21 on which this modelling is conducted has since been surpassed by not one but two NOA assessments with the most recent being the NOA 2021/22 refresh.[6] The model presented in the case for change is based on out-of-date transmission plans, and

[2] Drax / LCP: Renewable curtailment and the role of long duration storage - May 2022
[3] National Grid ESO: Monthly BSUoS Forecast Summary - October 2022
[4] Ofgem: CMP308 Decision and final impact assessment - April 2022
[5] National Grid ESO: Modelled Constraint Costs NOA 2020/21 - June 2021
[6] National Grid ESO: Networks Options Assessment 2021/22 Refresh - July 2022

the costs for constraints within the model are already expected to be higher next year than what the model presents several years in the future.

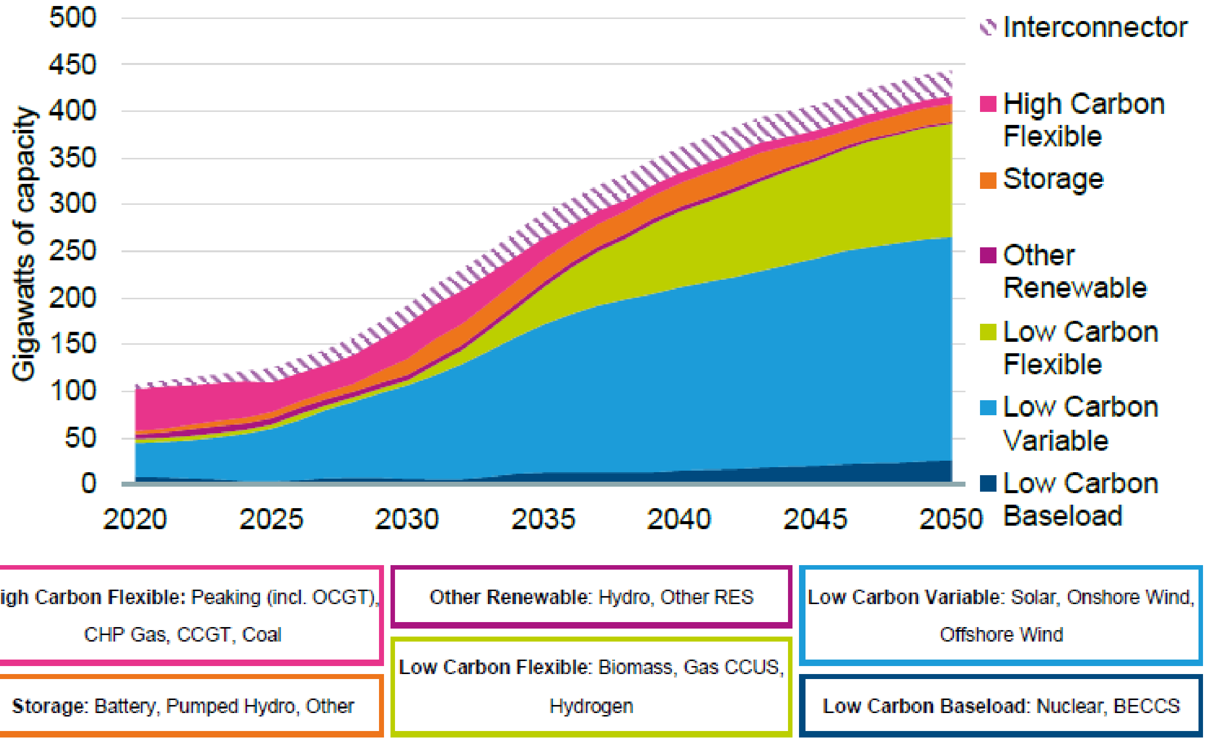
Given the reasoning for locational pricing is primarily driven by the need to reduce network reinforcement costs, we suggest that it may be appropriate for REMA to first consider how network congestion could be addressed. For example, greater grid utilisation may be realised by reducing the security standards for grid planning e.g., by reassessing the likely risk of failure, or planning to use (or restrict) flexibility resources where appropriate. In this case, the ESO TEC register currently indicates that some 50GW of energy storage is seeking connection – this could potentially be deployed to enable the connection and operation of more renewable capacity.

Notwithstanding the need to enhance grid utilisation, the issue of connection delays also presents a major challenge in gaining access to markets at both transmission and distribution network levels.

Incentivising alternative technologies

As shown in the following chart from the REMA report, rapid change in capacity is expected over the next decade, and some critical assumptions are being made in the technology development pathways that lie behind the proposed market design. For example, flexible low-carbon generation may not emerge at the pace expected and storage may be unsuitable for longer running periods. Having a technology-neutral market is likely to be difficult and create distortions.

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



It will be important that the assumptions used for different technologies are as accurate as possible. For example, we understand the REMA modelling assumes that pumped hydro plant can operate for just a few hours. This may not be accurate – a pumped storage hydro plant can be designed to operate for a few hours or a few weeks depending on the system needs.

We suggest that the ongoing incentives (or not) and assumptions for alternative technologies need to be carefully considered in market design for flexibility resources if optimisation is to be realised by these market mechanisms.

Assessment of current market arrangements

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?

We agree in principle with the BEIS analysis that:

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

In addition, the assessment does not account for the impact of the Connect and Manage policy. In particular, a failure to recognise the ramifications of the implementation of this policy – and the failure to establish a regulatory framework that facilitates the build-out and reinforcement of transmission network capacity at a rate that could keep pace with the rapid deployment of renewables.

This has led to the high level of constraint costs that we see today and the forecasts of higher costs until 2026 (when the beneficial impact of network reinforcement starts to have an effect). Having not identified this as a root cause, BEIS and Ofgem risk pursuing complex market reform to address a network capacity issue. Generation has not located in the wrong places under Connect and Manage, the fundamental issue is that TOs have not been permitted to increase network capacity at a sufficient rate to avoid constraint costs rising to unsustainable levels.

Overall, we agree with the BEIS conclusion that current arrangements risk not attaining Net Zero and ensuring security of supply.

We suggest they demonstrate the need for urgent action, including a greater focus on delivering the necessary transmission reinforcement together with long duration storage at scale (whether through smaller distributed assets, or a smaller number of larger assets).

Chapter 3: Our approach

We welcome that REMA plans to establish strong engagement with stakeholders and appreciate the BEIS commitment to this engagement via webinars and face to face events. We are pleased to offer our contribution to the process.

We agree that any overall package of reforms should be coherent, consistent, and comprehensive. We note that, following consultation with stakeholders, BEIS will be establishing a full delivery plan and overseeing implementation (from the mid-2020s) in time to meet the 2035 commitment.

Responses to consultation questions

Assessment criteria

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

In principle, the option assessment criteria of least-cost, deliverability, investor confidence, whole system flexibility, and adaptability appear appropriate to assess market design. However, we suggest that 'least cost' should be replaced with 'best value' which combines low cost with maximising value. Deliverability is important and the potential for investment hiatuses and stop-start development should be addressed explicitly so as to provide a stable platform from which GB's energy transition can be built.

We welcome that investor confidence will be a key assessment factor. Excessively high investment risks will deter or raise the cost of investment. To achieve efficient costs of capital, investment risks may best be borne by those investors who can manage them, otherwise large risk premia could inflate the already high cost of the transition.

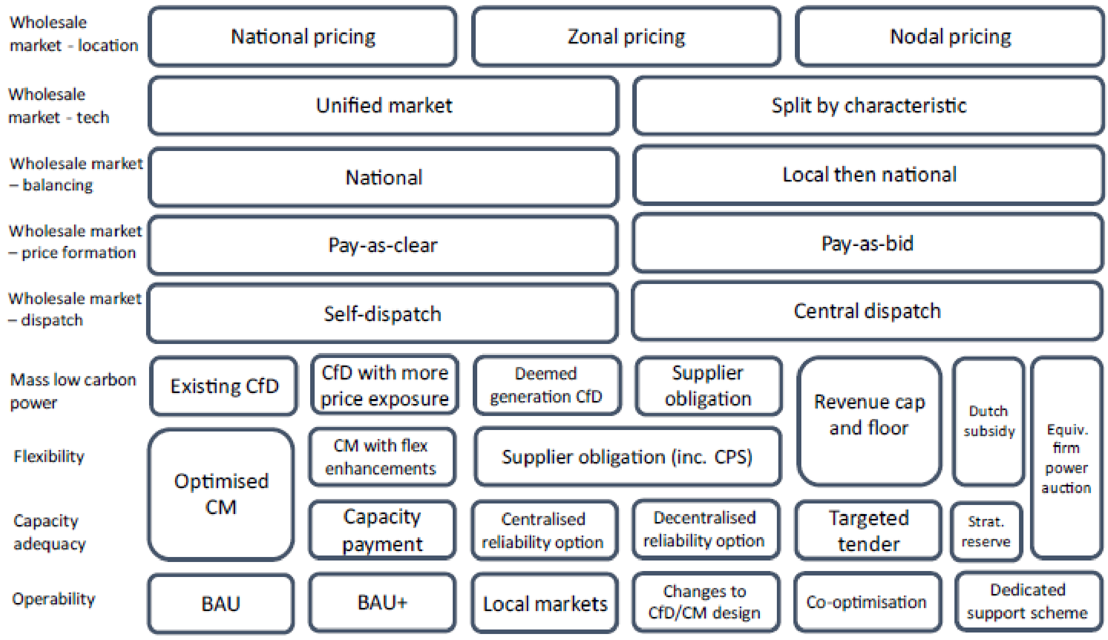
Meeting Net Zero should be another key criterion to assess options. It is important that the review also takes into account the need for continued growth in the supply of low carbon power and flexibility beyond 2035 in order to meet Net Zero. Options must be appraised against that longer term growth trajectory as well as the commitment to largely decarbonise the power sector by the middle of the next decade.

Organising options

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

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

In terms of organising options for assessment, we agree the following 'jigsaw' diagram provides a useful way of considering the options for each of these components. As stated previously, we are concerned that it becomes a search for the perfect market design – the top priorities for REMA must be the delivery of renewable and flexibility resources and attracting the investment needed. Unduly complex market design will add uncertainty and may deter or increase investment cost of capital.



We agree the broad range of options that are being considered, from medium-term changes to existing arrangements that can be delivered from the mid-2020s, to longer-term transformational reforms. However, we strongly support the need to focus on low regret 'quick wins' which could be pursued on accelerated timelines and implemented regardless of the end package of reform. Given the very long lead times for large electricity infrastructure investments to move from concept to operation, early decisions will be critical.

When considering options for assessment and 'quick wins', we suggest they are prioritised around the core outcomes that a future power system will need to deliver. We consider these to be:

- decarbonisation - delivery of mass low-carbon power and flexibility resources, including distributed energy
- security of supply - measures to ensure capacity adequacy and operability
- best value - net zero power markets that optimise these assets, providing both long and short-term price signals

Chapter 4: Cross-cutting questions

Responses to consultation questions

Questions and trade-offs

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

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

BEIS raise some cross-cutting questions about the overall approach to market reform, including:

- the role of the market,
- the extent of competition between technologies,
- the extent of centralisation,
- the role of marginal pricing,
- how to send more accurate price signals to consumers,
- the scale of change that is needed,
- possible approaches to introducing or enhancing locational signals, and
- approaches to supporting demand reduction.

We generally agree that these are the key issues. However, we would suggest that an additional key cross-cutting issue is the need to attract investment to enable rapid growth in renewable and flexible technologies. It is critical that investors have confidence in the overall market design and that the right trade-offs are being made to ensure an attractive environment for investment.

We have added some additional comments below on each of the identified cross-cutting issues.

Role of the market

We agree that greater leadership from government and central institutions is required to deliver the vision for the power system. Existing markets and the self-governance change framework will not be able to deliver such change alone. Proactive intervention from government will be needed to ensure that future markets can deliver the objectives. But competitive markets can bring significant benefits in driving innovation and optimising costs and should be retained wherever possible.

Competition between technologies

We agree that there are limits to the competitiveness of different technologies, and that market designs should recognise. Pragmatic trade-offs are needed that balance the benefits of enabling new technologies, while at the same time ensuring the electricity system is optimised with a low carbon prioritisation.

Decentralisation

The power system is becoming more decentralised with the growth of decentralised energy resources and investment decisions being increasingly taken at a local or individual customer level. This is expected to grow rapidly over the next decade with increasing penetration of electric vehicles head pumps and distributed storage and renewables.

We note that the REMA consultation considers the benefits of a having national decision-making approach which can take account of the system as a whole, including social and environmental benefits, and coordinate and optimise accordingly. The consultation expresses caution about decentralisation of decision making as this may reduce coordination and sacrifice economies of scale.

Given we are at a time of significant change and when decentralised markets are at an early stage of development, we agree with this approach. But it will be important for national markets to coordinate and engage with the development of local renewable/flexibility assets to ensure all benefits are realised.

Role of marginal pricing

We agree that short-run marginal pricing may be less relevant in the future and that options for moving away from such marginal pricing should be explored. But it will be important that there is a transparent approach to setting prices for competing renewable and flexible assets.

Minimising financing and operational cost

The consultation highlights the importance of market signals in driving down the cost of capital as well as maximising operational efficiency. We strongly agree with this concept from an investor perspective. This is particularly relevant for high capital value assets such as renewables and pumped storage hydro, where long term revenue certainty will reduce the cost of capital. Without such certainty, the capital may not be available or, because of the risk, only available at a significantly higher cost.

Enabling investment in flexibility resources such as pumped storage hydro will enable greater competition in short-term flexibility markets and maximise operational efficiency.

More accurate price signals and the benefits for customers

The REMA consultation considers how sharper price signals may incentivise more flexible behaviour, especially from customers. This could lead to them making different temporal or locational decisions about their energy use.

We suggest the behaviour change expected from such price signals is treated with caution. Customer and business choices about their energy use are likely to be secondary to other decisions about where to live and work and how to carry out their daily lives. In any case, they may not be exposed to these price signals in some circumstances as the recent energy price cap illustrates. In such circumstances, the supply of electricity may be considered as the supply of a public service to meet a social requirement rather than a traded commodity.

The scale of change – delivering objectives through the transition

The consultation poses the question of whether the future market design is addressing a revolution or evolution. The case for evolution is supported by the need to retain investor confidence and keep financing costs low. The case for revolution is driven by the misalignment between current flexible fossil-fuel technologies and the need to replace these with decarbonised technologies. We suggest this is a matter of semantics – there is a clear need to both retain investor confidence and replace fossil-fuel generation capabilities.

We agree that it is critical to retain investor confidence – this can be done by providing long-term price signals that give investors confidence about future revenues. This has been successfully achieved for low carbon electricity – the same needs to be applied for flexibility.

Locational price signals

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

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

In theory, the electricity system could be better optimised through stronger locational signals. But, in practice, the implementation of zonal or nodal locational price signals will effectively provide a tax on renewable generators that must locate in areas of renewable resources, or businesses that must locate close to their customers. These organisations have little choice about where to locate.

We strongly suggest that it is important to consider locational price signals in a pragmatic manner and in a way that appropriately allocates risk to parties who are making significant investments. We believe that it is not reasonable to deliver a locational price signal which puts significant financial risk on a party who can do little to respond to that signal after making an investment.

The location of renewable generation is decided early in the development process based on many factors. For renewable developers, factors such as wind conditions, seabed leasing, planning permission, access to grid, cooling, government support schemes, planned network according to NOA and HND and connect and manage arrangements all impact decisions on where to locate. There is therefore little renewable developers would be able to do to respond to sharper locational signals such as those that would be delivered by a move to LMP.

Similarly, locational investment decisions for demand are also driven by other factors including proximity to workforce, suppliers, customers and transport links for non-domestic and personal needs for domestic. Such locational charges may simply inhibit the ability of these generation/demand assets to participate in renewable generation or flexibility markets.

However, we recognise that locational price signals could have a role in optimising the siting of flexibility and operability assets which are not subject to the same locational constraints as generation assets. For example, the incentivisation of flexibility and operability resources in Scotland e.g., pumped storage hydro, electrolyser demand, and hydrogen storage may be able to free up system capacity to enable more renewable output and reduce the need for network reinforcement.

Please see our response to questions 16-20 we set out our position on locational price signals in more detail.

Demand reduction

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

The REMA consultation notes that demand reduction may struggle to compete across other markets and the benefits may be undervalued. We suggest this should be treated as a flexibility resource similar to storage, and that long-term price signals/contracts should become the norm.

Chapter 5: A Net Zero wholesale market

The REMA consultation notes that existing wholesale market arrangements - the system of trading established by the British Electricity Trading and Transmission Arrangements (BETTA) in 2005 – are based on the following core principles:

- national pricing (all generation and all demand receive the same wholesale price, irrespective of their physical location or system impact of their operation), with locational signals being provided through network charges;
- technology neutrality (all technologies can, by and large, compete in the same set of markets – though there are exceptions); and
- self-dispatch (generators self-schedule and commit their output, with National Grid ESO handling any necessary balancing action). There is a balancing mechanism to incentivise supply matching demand.

The consultation highlights that the growth of renewables is leading to a growing mismatch between trading arrangements which were designed for fossil fuelled plant, and low carbon technologies. The consultation proposes that existing wholesale market arrangements alone are unlikely to deliver sufficient investment and operational signals for low carbon generation and considers if there is a case for fundamental wholesale market reform, or smaller improvements to current arrangements.

Overall, we consider that there is a strong case for reform of the wholesale market so that effective investment and operational signals can be provided for both low carbon and flexible energy resources.

Responses to consultation questions

Option assessment

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

The main approaches BEIS are considering are:

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

We agree that these appear to be the appropriate options to consider. As we highlight above, to address the market reform objectives, each of these market design options would need to introduce clear long- and short-term price signals to attract complementary investment in both renewable and flexibility resources.

In this context, we would suggest that the priority should be first to determine how the long-term price signals may be effectively provided before considering how best to optimise in the short-term operational markets.

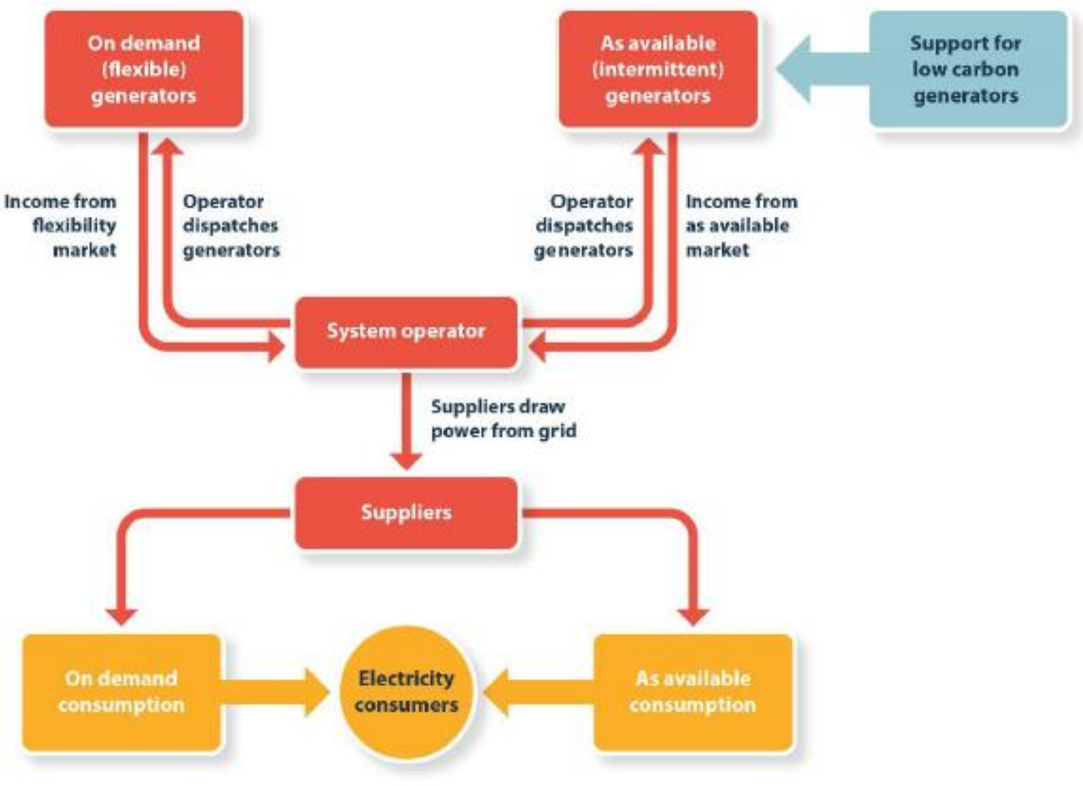
Splitting the market

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

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

The key aim of market reform is to deliver long and short-term investment signals for both renewable and flexibility resources, while ensuring competition can drive lowest cost for consumers. The REMA consultation is considering the use of separate markets for firm and variable power. This is illustrated by the model proposed by Keay and Robinson, as shown in the diagram below which suggests two centrally dispatched markets, one for 'variable' power or (as available) renewables, and one for 'firm' power for (on demand) flexible resources.

Chart 1: Schematic of two-market design



The market design suggests that prices in the variable 'as available' market for renewables would be set by the long-run marginal cost of renewables, whereas prices in the firm 'on demand' market would be set by the short-run marginal cost. The advantages of this approach are envisaged to be:

- decoupling the gas marginal price in the firm market from the variable market
- enabling the discovery of the price of flexibility
- provide strong incentives for demand-side flexibility
- it could reduce the need for government investment support in the long run

While acknowledging these are important benefits, the consultation recognises that there are many design questions still to be addressed, including how prices would be formed in the ‘as available’ market, how the two markets would interact, how the system would be balanced, and how operability would be maintained across the two markets. We agree the ability to reveal the price of flexibility will be important, but short-run cost signals are unlikely to provide the necessary long-term revenue certainty needed to invest in these assets.

An alternative model for a voluntary green power pool has been proposed by Grubb and Drummond which would operate alongside the existing wholesale market, with the system operator dispatching renewables based on long-run marginal cost. This assumes that firm power and flexibility resources will continue to be traded in the wholesale and balancing markets. While this proposal may have the benefit of some decoupling from gas marginal prices, it is unlikely to provide a clear price signal for flexibility.

We do not see merit in pursuing this option as proposed. Firstly, it is unclear that customers or suppliers will wish to contract for green power on a real time basis to the extent required. Secondly, it is not unclear how a green power pool would support investment in low carbon power.

Overall, we see a strong case for exploring how a split market can provide a clearer pass through of the benefit of low carbon energy with low short run marginal cost. This should address the fundamental problem expected in the future about price formation for low carbon energy.

As such, we consider that options for split markets should be further investigated, with the costs and benefits being assessed. We suggest that future market designs for mass low carbon power should seek to retain the benefits from existing arrangements including from self-dispatch and long-term confidence about revenues and system costs. We suggest it may be useful to consider the benefits of a dedicated market for flexibility resources, where low-carbon flexibility could be prioritised – this may be better suited to a central dispatch regime targeted to meet locational and operability requirements. This should have the benefit of providing a clear price signal for flexibility.

In order to mobilise investment, it will be important that each market delivers long-term price signals for both renewables and flexibility resources, to ensure the required capacity of each resource is available.

Locational pricing

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

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

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

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

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

Scottish Renewables does not agree zonal and nodal market designs should be considered.

LMP only works in theory in the simplified economic conditions of “perfect competition”, in a centralised energy system where planning decisions are taken by one entity in a coordinated way, none of which applies in practice.

Low carbon generators that must locate in areas of renewable resources and demand customers that must locate close to their customers have little choice about where to locate; the current dispersion of renewables around the periphery of GB is entirely rational, and reflects resource availability, other physical factors (e.g., seabed conditions) and planning constraints. Nodal and zonal market designs will thus simply inhibit the ability of these generation/demand assets to participate in renewable generation or flexibility markets.

We strongly believe that introducing more granular locational signals through a wholesale market reform (i.e., nodal or zonal pricing) will add complexity and volatility to the current system, which will hinder investments in low carbon generation when needed most. Moreover, since the location of renewable generation is decided early in the development process, it is questionable whether a system that offers a volatile locational dispatch signal would provide a useful signal at the point of choosing a location. The perceived benefits of the move to this type of market would be further offset by the additional cost to billpayers of making generators ‘whole again’ through CfD payments or long-term PPAs in a green power pool model.

The current TNUoS charging regime already includes a locational signal and work is currently ongoing through the TNUoS Task Force to ensure it provides a more cost-reflective and predictable charge. We believe that this is not the right time for dismissing the effort that the industry is making to improve the current charging regime, particularly in relation to locational signals. Quick changes are needed now, and more granular locational signals will not deliver benefits for consumers if a more complex and volatile system results in an increased cost of capital for projects.

Our further comments on the disadvantages of locational marginal pricing (LMP) follow below:

- more granular locational pricing, relying on wholesale market signals alone would favour operational decisions and smaller capital investment, over large capital projects. Zonal or nodal pricing would not provide the long-term revenue certainty necessary to attract investment in large scale capital projects. This would not necessarily lead to cost optimal outcomes for GB consumers.
- the implementation of a LMP system would tend to disadvantage northern generators and southern consumers. This means that the need and value of a diverse mix for security – both by technology and geography – is not reflected in the locational pricing model, which is a potential shortfall in the assessment of LMP and needs to be addressed as a priority.
- the implementation of LMP will mean that generation in Scotland will face increased risk compared to generation located in the rest of the UK, unless price signals move demand from southern to northern areas effectively, which we believe is unlikely. Developing renewable potential in Scotland is essential for achieving net-zero at least cost and is reliant on GB policy/regulatory frameworks, thus new market arrangements that could potentially harm government ambitions should be assessed carefully.

We believe that before implementing any market reform, a key measure of benefit should be focused on economic total system welfare, consistent with achieving net-zero targets and ensuring security of supply. Focusing only on consumers’ bills is not the right solution. This is because the redistribution of money that will come forward from nodal markets will mean an increased cost of capital for projects – due to a more volatile and complex system and due to the elimination of constraint payments. This means that generators will pass these costs to consumers, just in a different way. Therefore, it is important that the whole system cost analysis is considered before implementing any reform.

As highlighted elsewhere in our response, rather than insufficient locational signals, the main current barriers to the efficient delivery of low carbon generation and flexibility are related to the lack of anticipatory investments in networks and long-term investment signals for flexibility.

Overall, we do not consider that zonal or nodal market designs should be considered for wholesale markets. This is a critical issue for investors in existing and future low carbon technologies, where the risk of higher costs from LMP would jeopardise or increase the cost of the rapid investment needed to achieve decarbonisation targets.

Nevertheless, we recognise there may be value in having locational price signals for flexibility assets which can enable greater utilisation of nearby low carbon generation as these assets are typically not as locationally constrained as generation assets. For example, the incentivisation of flexibility and operability resources in Scotland e.g., pumped storage hydro, electrolyser demand, and hydrogen storage may be able to free up system capacity to enable more renewable output and reduce the need for network reinforcement. It would be critical to ensure these signals are separate from the wholesale market and price/cost signals for low-carbon generation. This would necessitate a split market design with a dedicated market for flexibility to ensure the benefits of national pricing and self-dispatch in the wholesale market are not undermined. Whilst we believe this hybrid model presents an interesting idea that is worth exploring, considerably more development will be necessary to allow an analysis of how such an arrangement would work in practice. Given the complexities involved, until we see the results of such an analysis, we would feel unable to make an informed decision on whether to support the implementation of a reform of this kind. For this reason, the options supported in our response to Chapters 7 and 9 remain our preferred approach to delivering flexibility and operability.

Finally, turning to local energy markets, we consider that the alternative ideas in the REMA consultation for locally-led wholesale markets are potentially interesting and worthy of future investigation. We believe that the deployment of flexibility at distribution level can be supported by a reform of the local energy institutions and governance, as SR highlighted in the response to the call for input on the future of local energy institutions and governance.[7] But the options are at a more conceptual stage, and many raise many questions about how they will be implemented and co-ordinate effectively with national markets. There is a risk that they add additional complexity and cost and potentially delay other priority reforms. We suggest that national energy market reform including national flexibility and operability resources, should be prioritised. Local market development could be encouraged in a complimentary way and co-ordinated way to address local flexibility and operability needs.

Moving to pay as bid pricing

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

The consultation considers that there are benefits to moving away from current arrangements where electricity exchanges operate on a pay as clear basis. Moving to a pay as bid arrangement could reduce the link to the gas price setting the marginal price for electricity. However, we suggest that generators would be incentivised to bid strategically, targeting what they thought was the most

[7] https://www.scottishrenewables.com/publications/1083-final-response-call-for-input-on-the-future-of-local-energy-institutions-and-governance

expensive offer so marginal prices may be higher as a result. This could eliminate the potential benefits of this approach.

Pay as bid would require significant changes to the market structure including a move to central dispatch and a power pool based more on cost of production. A central dispatch approach could reduce the benefits from competition realised through the current self-dispatch arrangements. Also, if generators lose control over their dispatch decisions this could have significant impacts on their future revenue certainty and increase cost of capital as a result.

Overall, we consider that pay as clear is the most appropriate approach to set marginal prices. However, this is not an issue that can be considered in isolation from other market changes and will need to be evaluated for alternative wholesale energy and flexibility market designs.

Evolving the status quo

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

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

The REMA consultation proposes that it may be possible to address many of the reform challenges by amending some of the parameters of the existing market, without undertaking any of the more transformational reforms proposed. The choices suggested include:

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

We agree these options should continue to be developed. We have suggested that flexibility markets should have different characteristics to wholesale markets. We believe the balancing and other existing markets could be reformed to provide the separate short- and long-term price signals needed for flexibility investment and optimisation. However, it will be important if introducing stronger locational signals through Balancing Mechanism that renewable generation located behind a constraint is not inadvertently penalised by being pushed further down the merit order as a result of higher balancing costs.

Evolving the status quo appears to have the advantage that ongoing improvements may be made while market reform design and implementation is still underway. Such developments could also enable a comparison of costs and benefits with the available improvements from more transformational market reforms.

However, we are concerned that a move from self dispatch to central dispatch is considered as an evolution of the status quo given the potentially far-ranging implications. We do not believe central dispatch should be applied to the wholesale market but could see it potentially having a role a dedicated market for flexibility. We have set out our position on central dispatch for wholesale and flexibility markets in more detail elsewhere in this response.

Chapter 6: Mass low-carbon power

We agree that the existing CfD scheme has been very effective at providing certainty to investors in low-carbon projects. The long-term revenue certainty it provides is attractive to investors, both in terms of raising the vast amounts of required capital and enabling the cost of capital to be reduced. The certainty of a future deployment pipeline has spurred innovation and reduced technology costs. Competitive auctions have driven down strike prices and provided better value for consumers, and the CfD structure means that customers are protected against high prices.

We consider that any reform of the CfD should build on these successes. It is important that the CfD principle of long-term revenue stabilisation is maintained as this will both attract low-cost investment and offer value for money to consumers. A key benefit of the CfD approach is the support given to different technologies under the separate allocation 'pots'. Of particular importance will be to maintain dedicated support for floating offshore wind (FOW) to deliver on the substantial pipeline of FOW projects[8] through maintaining Pot 2 or an equivalent as FOW is still only at a very early stage of deployment.

The REMA consultation highlights that the design of the CfD comes with some limitations that are likely to become more prominent as CfD-supported assets become a greater proportion of the generation mix. The suggested limitations are:

- the CfD limits exposure to market signals for a significant portion of asset life, incentivising assets to run whenever possible;
- it does not incentivise assets to locate optimally for system needs;
- it does not facilitate competition with low carbon flexible assets.
- Full insulation from price risk also removes the need for generators to hedge, reducing market liquidity.

In order to address these limitations, BEIS are considering alternative options that would increase the role of the market, whether through greater exposure of those contracts to prices, or in the allocation of those contracts, in order to minimise costs which are passed to consumers.

We would suggest that these limitations may be overstated, and the introduction of added market complexity may be premature. The current main challenge to meeting Net Zero and 2035 targets will be in ensuring that sufficient low-carbon generation capacity can be built to displace fossil-fuel generation. The current CfD arrangements provide for competition in the procurement of additional low-carbon capacity, already targeting the most attractive locations for this capacity. As described elsewhere in our response, introduction of additional market signals, with added complexity and uncertainty, may deter investment.

Responses to consultation questions

Options assessment

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

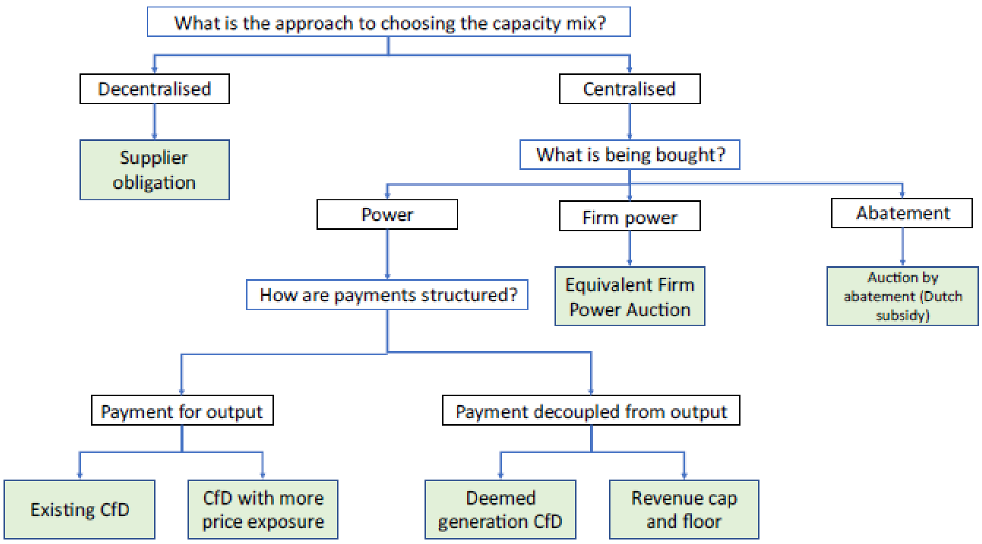
BEIS are consulting on the following options for delivering mass low carbon power:

[8] Through ScotWind alone there is over 17GW of projects in development.

- a supplier obligation which is underpinned by decentralised market contracts between generators, suppliers, and intermediaries.
- the following options using competitively allocated long-term private law contracts between generators and a government-owned counterparty.
    - The current CfD scheme
    - CfD variants with increased price exposure,
    - a revenue cap and floor; and
    - a CfD based on deemed generation

Overall, we consider that the current CfD principle around revenue stabilisation should be maintained. Long-term contracts with the government are the best way of delivering the required volumes of investment at least cost.

We agree the above options appear to be the main ones and have set out our views on each below. The decision tree provided in the consultation (shown below) appears an appropriate approach for grouping the options.



We suggest that options for reform of the mass low-carbon market should consider how they be extended market-wide, ensuring that technologies such as non-flexible hydro or tidal are addressed.

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

We consider it important that small-scale, distributed renewables are also able to benefit from market signals that enable their growth, and contribution to wider system benefits. Current reforms to local electricity markets with the creation of DSOs to manage network congestion, together with aggregator and supplier-led tariffs are already increasingly mobilising the benefits from distributed renewables in local and national energy markets. The main barrier to the growth in distributed renewables, does not appear to be market signals or viability, but rather difficulties in obtaining planning consents and grid connections.

However, it is important that mass low-carbon investment is not chilled by market reforms (and added complexity) to deliver common market signals to the millions of small renewable generators and large renewable generators. As such, we consider that mass power market investment should continue to be prioritised while also continuing to incentivise the growth of distributed renewables.

Supplier obligation

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

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

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

For mass low carbon power investors, a requirement to negotiate market contracts with suppliers would add additional counterparty and financing risks. It would increase investment uncertainty, leading to a reduction in available development capital and an expected increase cost of capital due to both contract uncertainty and a higher counterparty risk. A supplier obligation would be expected to result in the following additional risks for low carbon generators:

- Substantially increased credit requirements (and costs) from contracting with private sector counterparties
- An increased requirement for long-term contracting with customers
- Reduced flexibility for customers to switch supplier
- Significant reduction of supplier of last resort coverage to expose customers to jeopardy of not committing to long term contract.

We recognise the BEIS proposal that intermediaries between buyers and sellers may be able to hedge these risks, or that Government may be able to provide this guarantee. This would add additional complexity to deliver similar guarantees to those currently provided.

Furthermore, we agree with BEIS that suppliers are not well placed to forecast long term requirements for renewable capacity, or for conducting consistent procurement processes. Including this option risks undermining the benefits achieved from of centrally led procurement of low carbon generation.

We suggest this option be discounted at an early stage due to the higher risk and potential negative impact on investor confidence and likely increase in cost of capital.

Central contracts with payment based on output

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

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

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

This existing approach of contracts paid on output is well tested and has been successful – retaining it in the short-medium term will sustain investor confidence. BEIS highlight the future risks that low-carbon generation under this regime is insulated from market signals that could drive additional flexibility, including from negative prices due to oversupply.

The consultation considers options to give increased price exposure to CfD generators though a minimum and maximum CfD price range, or a flexible CfD reference price. These are suggested as ways of incentivising whole system flexibility and reducing overall system costs.

Overall, we consider that central CfD contracts with a single strike-price payment based on output remain the most appropriate. This will give greatest certainty to investors as they will drive the optimum project construction and financing cost.

The introduction of contracts with variable payments based on output adds uncertainty which would be priced into the strike price bid. Many renewable technologies e.g., wind, are not well placed to provide significant flexibility and the benefits of these price signals may be less valuable compared to other technologies.

The proposal to combine flexibility and renewable resources in a single market instrument may not give the clear investment signal for either.

However, we recognise that flexibility markets will be increasingly necessary in the future and that the potential option for a split market design with separate markets for low-carbon capacity and flexibility should be explored.

Central contracts with payment decoupled from output

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

We agree that this approach should be investigated further as we believe the option of a central contract decoupled from output could be necessary in the long term to address the growing problem of price cannibalisation. It could be possible to realise this with either a fixed payment, a floor, or a payment based on deemed output. However, as above, we suggest that combining price signals for flexibility and renewable capacity may not give clear investment signals for either resource.

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

This could be designed to be similar to the revenue cap and floor regime used for interconnectors. This would essentially provide a regulated minimum return on assets (the floor) and allow participants to operate in the relevant markets up to the cap.

This model would allow investors to be confident of a minimum level of return, with the incentive to participate in alternative markets for additional returns. We suggest a profit-sharing mechanism could be established above a cap to ensure that there is a continuing incentive to operate in the relevant markets.

This approach would seem to operate in a similar way as CfD's with centrally procured cap and floor contracts. Low carbon technologies should be able to participate fully in flexibility or other markets, otherwise it would be unlikely to drive market behaviour towards an optimum economic solution, and uncertainty about a more complex regulatory regime may increase financing costs.

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

An alternative option is to provide a CfD based on deemed generation, which rewards the potential to generate rather than actual generation. This would effectively become a form of capacity payment which could then encourage operation in flexibility markets where there is value in doing so.

The consultation highlights a number of challenges to this approach, including how generation would be reliably deemed and measured, and the risk of gaming. In addition, we would highlight the potential complexities of undertaking settlement activities for such an approach. We consider this could be a feasible option to introduce, perhaps building on the current balancing mechanism methodology.

While a capacity payment would remove output variation risk for a generator, setting these levels will require investors to make a number of assumptions about revenues from participating in other markets. We suggest that these challenges could add to investor uncertainty and risk, and consequently increase financing costs.

Chapter 7: Flexibility

We agree that the ability to flex consumption or generation is critical for balancing supply and demand and maintaining system stability. But the current market framework does not provide sufficient incentives or long-term price signals to enable investment, particularly in large scale, low-cost flexibility assets.

Flexibility is at the heart of REMA, and to enable investment in flexibility resources, we suggest that REMA needs to address the following issues:

- flexibility is not well defined – we suggest it should include dispatchable generation or demand, plus dispatchable ancillary services, plus local network congestion flexibility. It should prioritise low-carbon flexibility.
- flexibility resources are not clearly valued – long term price signals for flexibility are not being provided by existing wholesale or balancing markets. Short-term flexibility market prices are incentivising short duration storage which in turn is cannibalising revenues from lower cost flexibility solutions.
- future renewable capacity is essentially procured by a single buyer on long term contracts but the corresponding need for flexibility capacity is not.
- there are many different barriers to entry for flexibility assets to existing markets e.g., market access costs, complexity, and grid access constraints.

We note that the BEIS definition for flexibility is 'the ability to shift consumption or generation in time or location'. We suggest that more precise definition of the individual flexibility resources is needed such that a market design can be created to procure, monitor and remunerate these resources.

Responses to consultation questions

Option assessment

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

The key requirement from these options is to provide investors with a sufficiently strong long-term price signal that they would be able to finance these flexibility investments at a reasonable financing cost i.e., by attracting debt finance. BEIS have proposed the following options:

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

We consider these are appropriate options for further consideration and have provided further views below. Other options that could be considered include:

- an availability payment made to providers of dispatchable flexibility assets. This could operate in a similar way to a deemed generation CfD but could suffer from similar operational and settlement challenges
- a RAB model for large scale flexibility or operability assets. But this appears more suited to large one-off investments such as nuclear.

We suggest these options are not considered further because of these disadvantages.

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.

We do not consider that existing markets provide the investment signals for the high volume of low carbon flexibility investment that is needed. Indeed, current ambitions for effective flexibility capacity procurement and deployment have significant risks. For example:

- Interconnector flexibility may not be available when common low carbon shortfalls are experienced across interconnectors.
- New flexible low carbon technologies e.g., CCUS, BECCs, Hydrogen are not yet proven at scale. The potential for low carbon distributed energy resources is significant but scaling up to any significant level is likely to take time.
- ESO pathfinder tenders for specific system requirements may not identify the optimum flexibility solutions.
- Short term market prices are driving the development of higher cost flexibility solutions such as short-duration batteries, thereby cannibalising revenues for lower cost or more flexible solutions.
- Grid connection constraints and delays may limit market access for flexibility assets.

We suggest that the current market design is unlikely to deliver the investment signals needed to develop the flexibility assets needed to enable 2035 commitments. Current plans for flexibility delivery have significant risks and costs.

While decarbonisation targets may be met by a mixture of time and location shifting of generation, excess reliance on interconnection to move generation between markets is likely to lead to security of supply issues. Paradoxically, procuring sufficient flexibility to provide a greater degree of energy independence is likely to erode the market signal for additional flexibility, as margins for flexibility are competed away, increasing the need for additional targeted support.

This need is particularly relevant in the case of long duration storage, which is expected to play a critical role in time-shifting generation from periods of high wind and solar output to meet demand in multi-day periods of low wind. The long lead times and higher capex requirements for long duration storage mean that this type of asset is more likely to require a de-risking mechanism to ensure adequate investment comes forward to reduce GB's reliance on thermal generation to provide system security.

Revenue cap and floor

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

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

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

This should continue to be considered as it would provide the necessary long term revenue certainty which would support investment decisions in large scale, long-duration storage assets such as pumped storage hydro.

Similar to the regime used for interconnectors, revenue certainty from a cap and floor should enable investment funding in long duration storage at a lower cost of capital and a lower cost to customers. A cap and floor regime similar to interconnectors would determine the revenue needed to provide a regulated return on assets on a bespoke basis. This would add complexity and may be best suited to large scale assets such as pumped storage.

The cap and floor regime could potentially be applied to large volumes of smaller flexibility assets though an auction approach, allowing the administration to be simpler. However, the resulting process is likely to still be relatively complex so we therefore suggest that it would be sensible to restrict eligible technologies to those which cannot easily deploy through other mechanisms (as is currently the case with LLES under the CM).

The revenue floor could be set at a prescribed level e.g., equivalent to the cost of debt. Flexibility would be dispatched through short-term flexibility/operability markets. The revenue cap should allow sharing of benefits above the cap to give incentives to these assets to dispatch efficiently and so reduce overall system costs, to the benefit of customers.

Details of the design of the cap and floor should cover issues such as: the form of the profit-sharing arrangements; the period of any revenue assessment; the frequency with which these assessments are conducted; and the duration of the cap and floor mechanism.

Small scale flexible assets are likely to be simpler projects with shorter lead times and lower capex requirements. We suggest that such assets may be better supported via the CM (in whatever form it takes). One of the key design features of a revenue cap and floor should be that the support mechanism does not distort the dispatch price signals so operators of these assets have an incentive to respond to market needs. Where different types of flexible asset can respond to the same market issue, then competition will naturally exist between different asset classes.

However, this competition also presents a risk; the future system will need a mixture of longer and shorter duration storage assets to accommodate increased volumes of low carbon generation. If too much of the latter is developed relative to the former then it will result in short-term storage assets reducing the revenue earning potential of long duration storage, with the effect that the overall cost of support mechanisms for flexibility may increase. Conversely, if insufficient short duration storage exists on the system then it may result in sub-optimal utilisation of long duration storage, potentially increasing the cost of meeting demand at times of low renewables output.

Effective competition therefore depends more on the mix of storage duration available alongside flexible generation than it does on the design of the revenue cap and floor. It will be important that long-term price signals are provided such that the storage assets with the most efficient long-run costs are incentivised.

Commercial tenders or auctions for such long-term capacity may be introduced, potentially based on bids for revenue caps and capacity. These could potentially be similar to ESO pathfinder and DNO flexibility tenders. These tender processes could enable flexibility resources to be targeted where and when needed. The tenders could allow alternative solutions from demand, networks, and alternative generation technologies to be considered.

Capacity market

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

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

We suggest that capacity market reforms should be considered, including making them fit for Net Zero and flexibility. However, existing capacity markets were designed for the purpose of ensuring peak security of supply conditions could be met. CM adaptation for a significantly different purpose has major risks and may not deliver either objective.

We agree with BEIS' observation that introducing additional auctions for flexibility may reduce liquidity and competition in the auctions. But this potential cost would need to be offset against the value of higher likelihood of successfully procuring the desired mix of flexible capacity.

The alternative model of applying multipliers to the clearing price of capacity auctions to provide an uplift for meeting specific flexibility needs further investigation. However, the challenge of designing and operating a single process with the intention of optimising for both capacity and flexibility would be considerable. No matter how carefully target parameters are set for these auctions, there would be no guarantee that an optimal mix of capacity and flexibility is procured. The wide range of clearing prices from previous CM auctions highlights the inherent difficulty of identifying appropriate multipliers.

We agree that response time and duration of response are critical characteristics in valuing flexibility and also that different types of flexible assets have more or less value depending on where they connect to the system. However, the process to identify the right mix of flexibility at different locations on the network is complex and needs to be considered in parallel with the network planning process.

Overall, we consider that capacity markets would need to be significantly reformed to provide sufficient revenues for flexibility resource investment certainty. They would need to prioritise low-carbon sources of flexibility, which may conflict with security of supply requirements. There are likely to be significant locational and timing differences in flexibility resource needs, and the capacity market would not reflect this, unless it was redesigned accordingly.

Finally, for developers and investors, the capacity market currently operates as a top-up to other revenues obtained from stacking across different markets with different procurement timescales and different contract lengths. Short- and long-term price signals from capacity and balancing markets would still be subject to the volatility of market dynamics, with associated revenue uncertainty.

There appears to be a high risk that capacity market reform alone would not deliver the price signals to incentivise the development of flexibility resources needed in the future.

Supplier obligation

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

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

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

We suggest this option should not be considered further – supplier contracts for flexibility resources would add counterparty risk and complexity and could deter flexibility resource investment and may result in higher costs to consumers.

Such an obligation could distort the market signals for renewable generation. The impact of this intervention on other markets would be unclear, adding to market and revenue uncertainty – the risk of additional unexpected costs could undermine confidence in renewable generation investments.

This may not be an efficient approach. A market-wide obligation could lead to an excess or deficit of flexibility resources being procured with an associated cost penalty being passed to consumers. It may not signal the location or type of flexibility resources that are needed.

We suggest that government backed central contracts would be a better means of bringing forward flexibility in the long term. This centralised model is more resilient as it can be implemented independently of any changes or risks to the supplier landscape.

Chapter 8: Capacity Adequacy

We agree that recent geopolitical events emphasise the importance of long-term security of supply, and that market arrangements need to ensure investment in sufficient firm capacity. We agree that the current Capacity Market does not provide incentives for the kind of low carbon, flexible, firm power needed to complement renewable generation.

We agree that a capacity adequacy mechanism should be a necessary element of future markets and that it is critical that such a mechanism should be able to provide effective long-term investment signals consistent with Net Zero.

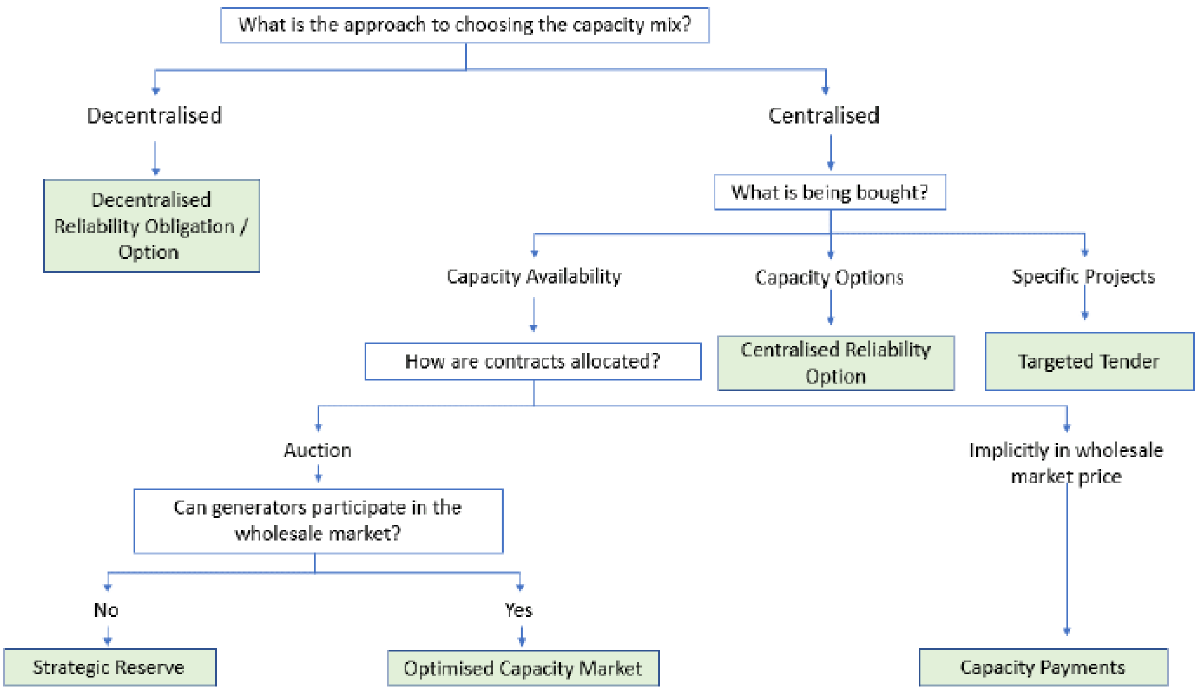
However, the design of the future capacity adequacy mechanisms will be dependent on the design of other market arrangements and the long-term price signals that they provide. It will be important to have complementary long-term price signals, that are not duplicated or inconsistent.

Responses to consultation questions

Option assessment

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

The main approaches BEIS are considering for addressing these challenges are set out below.



BEIS propose to further investigate: an optimised Capacity Market, a strategic reserve, and centralised reliability options. The decentralised reliability options, capacity payments; and targeted tender are not proposed for further investigation.

We agree that these appear to be the appropriate options to consider further. We note that the three options under consideration take a centralised approach to procuring capacity adequacy – this will be an important factor as it should ensure that government is leading these decisions, taking account of societal interests to meet Net Zero targets in a secure and least cost way. We highlight below that the targeted tender may be an option that the government may wish to keep in reserve.

Optimised capacity market

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

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

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

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

Yes, we agree this should be considered further. We note that this option would change the capacity market to enable the participation of low carbon capacity without jeopardising security of supply. The changes could potentially involve either separate auctions to the main auction for new/refurbished low carbon assets, or a single auction with multiple clearing prices based on capacity type.

We agree that these market design options should be considered as a way of incentivising low carbon capacity to participate in capacity auctions while insulated from competition from high carbon assets.

The CM has the advantage of being well established and familiar to market participants so evolutionary improvement could have the benefit of maintaining investor confidence. In assessing the options for reform, it will be important to consider if the existing CM could deliver better outcomes.

For example, each CM auction could set the target MW capacity and flexibility capacity at a level that better reflects system need. But in this case overall, derating factors should better reflect the realistic prospect of different assets providing capacity at times of system stress. There is strong evidence to suggest a negative de-rating factor for interconnectors given the scope for these to exacerbate tight generation margins in GB by exporting to higher-priced neighbouring markets.

Strategic reserve

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

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

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

Yes, we think this should be considered further, but it should be clarified whether this is a peak capacity reserve or a flexibility reserve, or a combination of both. Ultimately, it should provide a clear market signal for long-term investment in peak or flexibility capacity. But it would need to be designed in a way so that it does not harm investment in low carbon flexible capacity, or else it could undermine progress on power sector decarbonisation.

However, it is likely to be difficult to ensure a strategic reserve is compatible with Net Zero. It may be undesirable to allocate low carbon generation to a strategic reserve instead of gaining the cost and decarbonisation benefits from normal operation. It may be more appropriate for energy storage to be developed as a strategic reserve.

While a strategic reserve could be retained under government ownership, it is unclear what the benefits would be compared to private sector ownership that could be directed by government to deliver agreed obligations when required.

Centralised reliability options

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

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

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

Yes, we consider this should be considered further in order to provide more detail, but we would note that centralised reliability options were considered and rejected as part of the EMR development process in 2011-12 due to excessive complexity and risk of unintended consequences. The proposal for centralised reliability options would be to provide a 'call option contract' that the ESO could buy at a predetermined price in conditions of scarcity. However, there are risks that this option may undermine other market mechanisms such as the CM and the interaction would need to be considered carefully.

Decentralised reliability options

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

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

We agree that this decentralised approach to capacity adequacy should not be considered further. A reliance upon suppliers to procure capacity adequacy would result in inconsistent approaches and introduce higher risk for investors and customers.

Given its societal and policy responsibilities, we consider government should always take a leadership role in ensuring capacity adequacy.

Capacity payment

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

This approach proposes a centrally derived capacity top-up payment for all capacity that is available in each trading period. But it suffers from the disadvantage that it is not directly related to scarcity and may not give accurate price signals and result in limited incentives when needed. We agree this approach should not be considered further.

Targeted tender

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

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

This approach is based on centrally led targeted tenders for additional capacity. While BEIS suggest that this approach should not be considered further, we suggest that it may be a viable option for addressing emergency situations where specific capacity is needed for specific circumstances. However, we agree that under this option there is a risk of overcompensation from potentially limited competition. This could be mitigated with price caps but that would then introduce the risk of underinvestment. There is also a question over whether capacity could be tendered and built in short enough timeframes.

Chapter 9: Operability

The successful transfer of operability resources (provided via ancillary service) away from fossil-fuel generation will be critical for the future safe and secure operation of a decarbonised power system. But some of these will be harder to decarbonise - many low carbon resources will find it technically difficult or not economically viable to provide these services in addition to their normal operation.

We agree that this will be a critical area of focus and appropriate market signals will be required to ensure sufficient operability resources are available in future decarbonised markets.

Responses to consultation questions

Reform options

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

We note that BEIS are considering the following options for ensuring operability:

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

We note that the dedicated support scheme is not proposed to be considered further. This is because assets that provide these services can be supported by other schemes, and an additional bespoke scheme would pose deliverability and efficiency challenges. We consider this an appropriate approach.

Overall, we consider that insufficient focus is being placed on the long-term price signals needed to attract investment in low carbon operability assets. Similar to the comments made in our response to Chapter 7, Flexibility, the key requirement from these options is to provide investors with a sufficiently strong long-term price signal and revenue certainty. This would enable efficient financing of these flexibility investments, including the option to secure debt finance, and reduce costs to customers.

Continue with existing policy

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?

No, we do not consider these sufficient. The current market signals are not adequate to address the scale of the future challenge. These signals for future plans for operability and flexibility needs are not attracting sufficient investment to displace fossil plant operability resources. The current market roadmaps do not provide adequate signals for investment in flexibility resources. Short term market signals are encouraging higher cost flexibility investment with short deployment times e.g., short duration battery storage.

Progress by ESO and DNO-led initiatives is slower than needed. The ESO markets roadmap appears to be based upon the development of highly liquid short-term markets for operability services, assuming that these real-time price signals provide suitable investment signals for high value investments. They do not provide the necessary long-term revenue certainty that investors are seeking – and will likely lead to cannibalisation of revenues by alternative higher cost providers of these services.

Enhanced existing policies

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

The proposal for the ESO to prioritise low carbon procurement for ancillary services and flexibility would be a significant improvement to current arrangements. A common Net Zero flexibility obligation for ESO, Ofgem and BEIS would be needed for consistency. The Net Zero flexibility obligation would still need to provide consistent long and short-term pricing signals to trigger investment.

This approach relies on the ESO performing its role as a central dispatcher and planner of these services. But the ESO may seek to choose low risk options e.g., asset build instead of alternative solutions for flexibility or operability services. Additionally, it is unclear how using existing market arrangements would provide price signals for investment in flexibility and operability services.

While this approach has merit and should be investigated further, it risks overlaying new market arrangements on an already deficient market framework.

Developing local ancillary service markets

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

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

In our response to the recent Ofgem consultation on governance of local electricity flexibility markets, we suggested that there should be greater local involvement in planning and operating these local markets, coordinating electricity system development with plans for future local transport and energy use.[9]

We note that there is a risk of conflict of interest between DNO network build and flexibility procurement, and DSOs have limited interaction with energy markets.

In the immediate future, prior to any institutional reform, DSOs are expected to perform a greater role in maintaining operability and facilitating local markets. But DSOs are only just being created and there are significant differences in flexibility market development and the market system maturity. DSO flexibility markets are mainly related to congestion management.

[9] https://www.scottishrenewables.com/publications/1083-final-response-call-for-input-on-the-future-of-local-energy-institutions-and-governance

We suggest that co-optimisation between ESO and DSOs is essential to optimise the system flexibility resources in both planning and operational timescales. But the ESO should be responsible for the procurement of national ancillary services e.g., frequency response, reserve, inertia, voltage, and transmission congestion. DNOs should be responsible for the procurement of local services e.g., for local distribution network congestion and local voltage.

It is our view that there are three energy system functions that we should be focusing on to address the energy system change at a distribution level: Energy system planning, market facilitation of flexible resources, and real time operation of local energy networks.

Energy system planning

We think that energy system planning should look ahead at the needs of the energy system and decide what needs to be put in place to meet those needs. Energy system planning should be coordinated across the energy system both at a local level and nationally to inform the decisions on the most efficient long-term investments. This planning function should address the needs of the whole energy system, across power, transport and heat, and also extend behind the meter into customer premises.

Electricity distribution network planning should be informed by wider energy planning activities (such as transport, gas, heat, hydrogen and CCUS), and network planning should be coordinated between transmission and distribution.

We consider that sub-national and local energy system planning is critical for the design and delivery of the future energy system. Future plans must address the whole energy system, ranging across electricity, heat and transport and include the full consumption and production value chain including behind the meter.

The local energy planning landscape must consider many factors. These include local economic and social policy, and interaction with national policies, including those relating to energy, finance, planning, social and environmental policy. Energy and many other related policies are determined nationally, and such changes can have significant interactions with local plans.

Market facilitation of flexible resources

The development of flexibility markets at a distribution level is important and will allow distributed energy resources to access and compete in DSO-led flexibility markets, and also in national markets including wholesale and balancing. However, for these markets to be effective, Distributed Energy Resources (DER) will need simple, low-cost access to deliver the desired benefits from these competing resources. We would suggest that there needs to be a high degree of market design standardisation nationally to deliver these markets. In order to attract DER resources into these markets, it will be important for DNOs to provide price signals that attract investment in this capability.

We recognise that DNO/DSOs have begun to facilitate local markets for flexibility, but the ESO also enables national flexibility and balancing markets. We agree that development of these markets should be coordinated at national and local levels and seek to avoid the different design and pace of DSO implementation.

Real time operation of local energy networks

We recognise that the ESO, DNOs and GDNs each undertake real-time energy system operational activities. Operational coordination in real time may become more significant in future as Distributed Energy Resources (DER) increase and participate more fully in energy markets.

Each of these functions are closely related and could potentially be brought into one organisation to realise planning operational synergies. But there is a risk that change will take significant time and have a significant transition cost.

We think that local operation can help maintain functionality of the system and ensure sufficient capacity is available on the electricity distribution network. Effective delivery means the system should benefit from reliable, transparent operation with efficient decision making. We suggest that its appropriate to prioritise the governance of real-time operation of electricity networks as this is likely to be the primary enabler of the energy transition.

Changes to CfD design

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

We agree that the CfD in its current form discourages the provision of ancillary services.

- At present, the CfD regime has limited incentives for flexibility provision.
- Changes could be made to add incentives or require mandatory services e.g., voltage control.
- It is questionable whether ancillary service market signals could be strong enough to change the behaviour of renewable 'must run' generation to participate in these markets.
- The adaptation of the CfD scheme may add additional complexity as it would have to address flexibility assets that may have very different requirements. For example, storage would be both buying and selling power for use in ancillary service markets and this may be difficult to incentivise on a long-term basis.

While we agree this option should be considered further, we suggest that the primary purpose of the CfD is to deliver growth in renewables. While renewables could deliver ancillary services, we suggest it may be more appropriate for a separate price signal to drive the inclusion of these services, so renewables can determine whether they can provide these services competitively.

Changes to CM design

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?

We agree this should be explored further. However, similar to CfD arrangements, implementation is likely to be complex. At present, the CM is oversupplied and is essentially a 'top-up' revenue stream for generation and flexibility assets. In theory, changes could be made to add operability services e.g., voltage control, and these could be auctioned against locational or temporal criteria. It would need to prioritise low-carbon flexibility resources.

Overall, the adaptation of the CM scheme will add additional complexity as it would have to address a wide range of changing flexibility requirements and may then fail to deliver its original purpose.

Co-optimisation of ancillary services

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

We consider that it is an option that should be explored further. If there was a separate market for dispatchable flexibility services, then this could potentially be operated by the ESO, which would be in the best position to decide on the optimum future and operational requirements for locations, volumes, and timing of flexibility resource needs.

Under this arrangement, the ESO could decide in both planning and operational timescales what flexibility resources would be efficiently kept available and dispatched. Flexibility providers could receive availability and utilisation payments. This should optimise the dispatch of resources while maintaining security of supply. It would remove bilateral trading and competition between suppliers.

This would only work if there were also appropriate long term capacity price signals given for flexibility assets through a capacity procurement arrangement. This would present a major market redesign and have associated implementation risks. But we note that this proposal for a central dispatch approach may be able to use experience from the pre-NETA/BETTA market arrangements for central dispatch performed by the ESO.

Chapter 10: Options across multiple market elements

We note this chapter considers two market reform options which cover multiple market elements. “Equivalent Firm Power” and “auctions by cost of carbon abatement”.

Responses to consultation questions

Auctions by cost of carbon abatement

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

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

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

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

We note that the BEIS consultation describes the Netherlands’ ‘SDE++’ scheme which focuses on the large-scale rollout of technologies for renewable energy production and other technologies that reduce carbon emissions in the Netherlands. The scheme is open to numerous technologies and uses technology-specific ceiling prices.

We note that auctions are based on the cost effectiveness of different technologies at avoiding CO_2 emissions. There is a set budget for each auction, and bids are accepted until this budget is reached. The Dutch government contracts directly with assets and provides a subsidy to assets for up to 15 years (similar to CfDs). The level of support covers the difference between the base tariff awarded per tonne of CO_2 equivalent avoided and an estimated market remuneration. This is broadly equivalent to the average CfD top-up payment (per MWh) divided by an assumed marginal CO_2 saving ($kgCO_2$/MWh).

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

The key challenge highlighted in designing a version of the Dutch Subsidy for the power sector is maintaining the value of this common currency whilst providing different technology types with appropriate incentives. Paying generators per tonne of CO_2 abated incentivises assets to maximise their output, in order to maximise their revenue.

We agree with the BEIS conclusion that this would be inappropriate for flexible assets, which should only be incentivised to generate or reduce demand when there is a deficit or excess of low carbon generation. BEIS propose to explore if a variation on this mechanism could be used to incentive investment in low carbon flexibility. We don’t think this approach should be considered further.

The proposed Dutch approach is for renewables and flexibility to compete in the same auction for low carbon flexibility. While this may be possible, there is a risk that:

- renewables do not prioritise the provision of flexibility if this adds additional cost to renewable investments.
- it does not attract investment from flexibility resources such as storage and demand response.
- it does not provide the long-term investment signals for operability or flexibility resources
- the mechanism may be complex and the setting of abatement allowances for assets well into the future may be challenging to accurately predict.

As a result, this may result in a market with conflicting objectives and inefficient outcomes. We suggest this would not provide price signals for either flexibility or renewable resources that would be better than directly targeted long and short-term price signals for each of these.

Equivalent Firm Power Auction

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

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

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

We suggest that this runs a similar risk to the Dutch market model, of trying to value flexibility and renewables at the same time, adding to market complexity and uncertainty. It may reduce the ability of storage and demand side response to participate in such auctions.

It is suggested that this is not evaluated further given the fundamental challenges and risks associated with the application.