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To whom it may concern,

Consultation Response: Review of Electricity Market Arrangements Second Consultation

About Scottish Renewables

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 360 organisations that deliver investment, jobs, social benefits and reduce the carbon emissions which cause climate change.

Our members work across all renewable energy technologies, 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 can help sustainably heat and power Scotland's homes and businesses.

The REMA challenge in the context of reaching net-zero

Risk and its allocation across electricity market actors has emerged as a central theme in the latest phase of the UK Government's Review of Electricity Market Arrangements (REMA). It is the basis of much of the discussion in the REMA second consultation document, and achieving the optimal degree of market risk exposure is posed as the objective of many of the reforms being considered. Markets are indeed powerful, and the incentives they create are major determinants of real-world actions. Well-designed markets are therefore a crucial tool in achieving policy objectives as the UK progresses towards net-zero.

However, it is important to recognise that well-designed markets are not an end in and of themselves, and what qualifies as 'well-designed' will ultimately depend on more fundamental objectives. The fundamental objective in the case of REMA is reaching net-zero whilst maintaining energy security and delivering best value to consumers. This is reflected in the stated REMA objectives: decarbonisation, security of supply and cost-effectiveness. Whilst the question of optimal risk allocation is undoubtedly important, these primary REMA objectives must remain paramount when considering options for electricity market reform.

The second consultation document sets out what will be required to meet these fundamental objectives: 140-174GW of renewable capacity, 55GW of short-duration flexible capacity and 30-50GW of long-duration flexible capacity all by 2035. This is an order of magnitude greater than what exists on the GB electricity system today and 2035 is barely more than a decade away. The challenge posed by the REMA objectives (and of reaching net-zero more broadly) is therefore first and foremost one of deployment.

To achieve deployment of this scale at the pace required at a cost which represents best value to consumers requires a stable and predictable policy environment. Market signals will have an important role in driving and guiding this deployment. However, given the quantity of investment required, the top priority at this stage of the UK's transition to net-zero must be minimising the cost of the required investment.

To implement radical market reform now would unavoidably lead to increases in the cost of capital. This would have an outsized impact on the cost to consumers of achieving the deployment required over the next decade and ultimately the cost of reaching net-zero. There is therefore a strong industry consensus across all regions of GB that implementing radical market reform, such as a move to zonal pricing, should not be considered at this stage of the REMA process. Stable, reliable investment signals need to be prioritised as the system gets built, whereas operational signals will become relatively more important once the system is established.

The role of market signals

The government has committed to producing a Strategic Spatial Energy Plan (SSEP) and overall adopting a more strategic approach to energy system development. This move towards strategic planning promises to offer strong signals to developers and planning authorities regarding the siting of new energy assets. The SSEP will be able to take a whole-system, forward-looking view of how the GB energy system should be developed and therefore represents a welcome paradigm shift in the UK's approach to delivering on its decarbonisation targets.

Taking this wider policy landscape into account, 'improving' market signals does not necessarily mean making them stronger or more granular. If price signals conflict with non-market signals delivered through the SSEP, for example, making these price signals stronger will be counterproductive. To be effective, the signals to which market actors are exposed need to be clear, consistent and aligned with decision-making timeframes. In other words, they need to be *useful*.

However, this context is largely absent from the consultation document and none of the consultation questions address how REMA reforms will interact with the emerging strategic planning processes. It is therefore not clear how DESNZ views the role of market signals within this wider approach to energy system development. We believe this is a significant omission. Without clear coordination between market and strategic planning frameworks, there is the significant risk of subjecting electricity market actors to an uncoordinated and conflicting set of signals. If this were the case, instead of being useful, these signals would jeopardise the timely and efficient deployment of low carbon technologies. It is therefore crucial that the coordination between REMA reforms and strategic energy system planning is a primary focus of the next phase of REMA.

A Reformed National Market

We accept and support the case for change set out in the first REMA consultation. However, we believe the fundamentals of our current market remain strong. There are also many benefits that can be realised in a relatively short period of time by incremental reform of existing market arrangements compared to implementing more radical reform. An evolutionary package of reform is also the only viable option for meeting the deployment challenge set out above.

We, therefore, believe that REMA should pursue a 'Reformed National Market' based on the foundation of retaining the current national, bilaterally traded wholesale market with firm access rights and self-dispatch, the key pillars of which include:

- An evolved CfD framework. Both deemed and capacity-based CfD models alongside AR7 consultation proposals provide potentially viable options to mitigate distortions related to the current CfD. This should involve measures which allow co-location for all assets, including offshore wind.
- An improved network charging regime which offers a stable, predictable investment signal that aligns with locational investment signals delivered via strategic planning and connections reform.
- The development of a new, robust, forward-looking constraints market that is implemented alongside the recommendations of the Transmission Acceleration Action Plan and the delivery of the Holistic Network Design and Centralised Strategic Network Plan.
- Co-ordinated, long-term investment signals to unlock efficient investment in flexibility for dispatchability, stability and congestion management services. Bespoke 'First of a Kind' business model support arrangements being developed outside the scope of REMA should continue to be progressed at pace.
- A reformed Balancing Mechanism with improved transparency and shorter settlement periods.
- A focus on developing improved planning and operational arrangements for cross-border interconnectors, standardising trading processes, aligning with European market arrangements, and utilising frameworks for closer operational cooperation between neighbouring system operators across interconnectors.

Legacy arrangements

The topic of Legacy Arrangements represents a red-line issue for Scottish Renewables members. The principles of grandfathering are essential for maintaining investor confidence and ensuring that developers can attract low-cost finance for their projects. If investors do not view the UK as an attractive market, they will invest elsewhere, and the UK will miss out on the benefits to energy security and the economic benefits of low-carbon investment.

On this basis, we believe DESNZ must make the following commitments. Firstly, that all assets and agreements in place up until the point that clarity is provided over the REMA reform package will be within the scope of Legacy Arrangements. Secondly, that for all assets, whether covered by a support scheme or not, the approach to Legacy Arrangements will ensure that investors' legitimate expectations at the time investment decisions were made continue to be met. If government fails on either commitment, there will be a high risk of a hugely detrimental investment hiatus occurring whilst uncertainty over REMA reforms continues, resulting in lasting damage to investor confidence. Consideration must also be given to avoid undermining the commercial viability of operational assets to ensure they are not stranded.

We also urge DESNZ to take account of investors' perception of wider regulatory and policy risk associated with the GB market. The impact of these risks is real and can be seen in the UK slipping from 4th in October 2021 to 7th in November 2023 in the [EY Renewable Energy Country Attractiveness Index (RECAI)](). Government must not make the mistake of ignoring this as we are increasingly competing globally with investors comparing the UK with other jurisdictions.

Government should also not underestimate the scale of the challenge of protecting Legacy Assets if implementing radical market reform. Contractual agreements will have to be changed to insulate existing assets from the impact of new wholesale market arrangements and avoid both windfall gains and windfall losses. This would be a very complex process and government must be clear about how it will be managed to avoid a slowdown in the required deployment during any transition from one set of arrangements to another.

Further analysis will also have to be carried out to understand the operational impact of having legacy assets and assets subject to REMA reforms coexisting in the electricity system.

Next steps and the need for a further consultation

The consultation presents many options at a conceptual level with limited detail on the design choices. Options, such as a deemed CfD, which may provide effective mechanisms with certain design choices, could easily become counterproductive if different design choices are made. A significant amount of further detail and analysis is required to fully define and assess the REMA proposals.

A range of reforms remain on the table with the potential to be combined into a large number of potential packages, each with it is own balance of costs, benefits and risks. The government must commit to issuing a further consultation on any minded to position. This minded to consultation must include quantitative impact analyses of the proposed policy reforms to allow informed, evidence-based decision making.

Additionally, with this REMA consultation being held in an election year, it would be inappropriate for DENSZ to take major policy decisions prior to the election. DENSZ should commit to ensuring the next government can take decisions on the full range of REMA policy options.

Overview of Scottish Renewables' consultation response

In the attached annex, we provide our responses to the consultation questions accompanied by summaries corresponding to each chapter of the consultation document. We provide an overview of the key points of our response across the four REMA challenges below.

Passing through the value of a renewables-based system to consumers (Challenge 1): We support the approach of maintaining a unified wholesale market for all technologies and we agree that CPPAs should continue to play an important role in providing a route to market for renewable energy projects. However, we believe that the CfD will continue to be the primary driver of large-scale renewables deployment. We agree that demand reduction is a cross-cutting issue which cannot be addressed by policies in one single area. We would also note the complexity of contracting arrangements in our current wholesale market, which we believe DENSZ should ensure it has a strong understanding of as a basis for considering REMA reforms.

Investing to create a renewables-based system at pace (Challenge 2): The CfD will be essential to ensuring we can achieve the required renewables deployment at best value to the consumer. To ensure that the implications of reform options are fully understood, we recommend that a standard assessment template is developed and applied to quantify the expected impacts of proposed CfD reforms. Scottish Renewables has a provisional preference for the deemed CfD model. However, we believe both the deemed and capacity-based CfD models should be taken forward for further development and analysis.

Transitioning away from an unabated gas-based system to a flexible, resilient, decarbonised electricity system (Challenge 3): Flexibility is central to REMA, and we welcome that the REMA proposals intend to deliver long- and short-term price signals for flexibility. However, it is still unclear how this will be achieved. The proposed Capacity Market (CM) reforms lack detail and are focused on delivering megawatt (MW) flexibility. However, dispatchable ancillary service characteristics will also be required. We suggest that the potential for coordinated long-term price signals to trigger efficient investment in combined flexibility for dispatchability, stability and congestion services be considered further. Outside of REMA, we urge DENSZ to ensure bespoke support schemes, such as the Long Duration Electricity Storage cap and floor regime, are delivered at pace.

Operating and optimising a renewables-based system, cost-effectively (Challenge 4): Scottish Renewables remains of the position that zonal pricing should be ruled out, as a credible case for implementing zonal pricing has still not been made. Instead, progressive reform to the current national bilaterally traded wholesale market will ensure renewables deployment can scale up to the level required, will deliver much of the supposed benefits of locational pricing and give the Government, the NESO and Ofgem significantly more control over the signals that the market framework delivers overall.

Scottish Renewables looks forward to engaging with the next phase of REMA and would be happy to discuss our response in more detail.

Yours sincerely,

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Annex: Responses to consultation questions

Challenge 1: Passing through the value of a renewables-based system to consumers

Summary of response to Challenge 1

- We support the decision to rule out green power pools and split market options.
- We agree with the focus on a unified wholesale market without distinction by technology.
- We think that marginal pricing naturally plays an important role in such a market. However, it is important to recognise the implications of marginal cost pricing in a future electricity system dominated by renewables. Wind and solar generation have near-zero short-run marginal costs so a market based on marginal pricing will potentially lead to difficulties in recovering long-run investment costs. We believe this needs to be acknowledged and considered when assessing REMA reforms.
- We also note that the reality of our current market involves a complex ecosystem of contracting arrangements with a range of prices struck over different timescales. Energy is often sold several times between generation and consumption meaning, depending on the structure of contracts, the split of costs and benefits between parties can be complicated. It is important that DESNZ engage with the complexities of the market to understand this properly.
- We believe that a healthy CPPA market should play an important role in providing a route to market for renewable energy projects. However, we believe its role will remain limited with the CfD being the primary driver of large-scale renewables deployment.
- We also feel it is important to note that the discussion of infra-marginal rent in the consultation document does not adequately acknowledge the critical role that infra-marginal rent plays in allowing capital-intensive technologies to recover their initial investment.

Responses to Challenge 1 questions

Corporate PPA Market

The consultation highlights that the UK's CPPA market is small but growing, with around 3.5GW of renewable capacity contracted in this way.

DESNZ would like to see the CPPA market grow as it provides a route to develop renewables without centralised support mechanisms. However, they acknowledge the limitations of the approach, including offtaker risk for renewable investors, high transaction costs, a mismatch in the length of contract desired between generator and consumer, and CPPA complexity.

DESNZ is interested in how a growing CCPA market will affect the overall distribution of risk and benefits between consumers, generators and other market participants.

Whilst DESNZ considered if there is a role for government, they do not, at this stage, propose to intervene. However, they are keen to understand the potential of the CPPA market.

1. What growth potential do you consider the CPPA market to have? Please consider: how this market is impacted by the barriers we have outlined (or other barriers), how it might evolve as the grid decarbonises, and how it could be impacted by other REMA options for reforming the CfD and wholesale markets.

We support the development of CPPAs and agree they have an important part to play in the electricity market.[1] However, we expect their role to remain relatively limited.

The primary barrier to the growth of the CPPA market is the lack of viable offtakers. The electrification of final energy demand and the deployment of green hydrogen production at scale will therefore be key to the future growth of the CPPA market.

We do not expect CPPAs to provide the majority route to market for renewables for several reasons, most of which are laid out in the consultation:

- They will largely be suitable for large offtakers with very good credit ratings who are able to sign long contracts of up to 15 years. Renewable developers will only be able to invest where they have high confidence in the credit rating and stability of their offtaker.
- We expect CPPAs will continue to form part of a hybrid model for financing large projects, with the output of these projects split up across multiple financing routes.
- We do not see them providing a material role for smaller scale renewables due to the complexity of contracting arrangements. In addition, offtakers with sufficient credit ratings are likely to be large corporations with large energy needs.

The consultation does not suggest that CPPAs should be developed as an alternative to CfDs. We agree with this and want to reinforce the point that there is a potentially complementary role between a growing CPPA market and a reformed CfD mechanism. However, whilst a 'partial CfD' may be the preferred route to market for some projects, for many projects this option would be unsuitable. We therefore believe that projects should have the option to apply for a CfD for a proportion of their capacity but it should not be mandatory to do so.

CPPA contracts may not only follow simple 'fixed price' formulas but could include elements of index-linking, temporary price fixing opportunities, etc. In such a way, these private contracts may develop significantly more nuanced approaches to risk sharing between large consumers and investors.

[1] SR are aware of several renewable projects that have already signed CPPAs for part of their output. For example, Moray West has contracted to sell the output from half of its capacity to Amazon.

We believe it is important that DESNZ realises that REMA itself is already having a negative impact on the PPA market. Since the REMA process started it has introduced significant uncertainty which is making it more challenging for CPPAs to gain traction. There is reduced liquidity for contracts in the late-2020s because the sector does not know what the market will be like and there is a risk that radical changes could be implemented.

Zonal pricing and central dispatch would have particular impacts on the CPPA market, with uncertainty over any transition period undermining the PPA market as market participants wait for clarity on the form of a future zonal market. Zonal pricing would also undermine the option of a CPPA as a viable route to market in typically export constrained zones as generators will not be able to make a return on investment due to higher volume risk and lower prevailing prices in these zones. Generators would likely instead have to rely on a CfD to provide a route to market.

2. How might a larger CPPA market spread the risks and benefits of variable renewable energy across consumers?

A large CPPA market will affect the distribution of risk and benefits differently across two types of consumer: those who sign CPPAs and those who don't. The Energy Intensive Industries (EIIs) exemption means that these industries do not contribute to certain market costs or face certain risks, nor do they benefit from the hedge, of the CfD scheme, but these industries can benefit from additional renewables once built, through the overall decarbonisation of the system. Therefore, EII's in both categories should be considered separately.

For those who sign a CPPA: by signing a CPPA these organisations actively decide their own risk / reward exposure. It may be appropriate to exempt all power supplied under a CPPA from the CfD levies (whether these organisations are EIIs or not).

For those who don't sign a CPPA (the vast majority of consumers): the effect should be broadly neutral as (1) CPPAs that are signed are likely to reduce the capacity of renewables that require a CfD; but (2) the benefits and risk sharing of those CPPAs will be limited to the renewable project and the consumer involved in the contract.

Demand reduction

The consultation discusses permanent demand reduction and makes the following suggestions:

i. It identifies that cross-cutting benefits for demand reduction are not sufficiently valued and commits to reviewing government methodologies for valuing demand reduction.
ii. Sharpen price signals, both locationally and temporarily.
iii. Strengthening government spending commitment on energy efficiency.
iv. Delivering the steps identified in the UK government's response to the Call for Evidence on 'towards a more innovative energy market'.
v. Discount changes to electricity wholesale markets specifically designed to incentivise demand reduction.

3. Do you agree with our decision to focus on a cross-cutting approach (including sharper price signals and improving assessment methodologies for valuing power sector benefits) for incentivising electricity demand reduction? Please provide supporting reasoning, including any potential alternative approaches to overcoming the issues we have outlined.

SR agrees that energy demand reduction is a cross-cutting issue that cannot be solved with policies in any one particular place.

We agree that the electricity wholesale market should not be seen as a core option for delivering demand reduction signals.

We agree that delivering a coordinated policy, regulatory and funding landscape across government is the best way to deliver permanent demand reduction.

We also note that whilst permanent demand reduction is important, within the scope of REMA there is an interplay with demand-flexibility. Historically, incentivising reduced consumption at peak demand has been an important part of ensuring capacity adequacy. Today and in the future, there is a growing need to incentivise consumption reduction during periods of low renewable availability. This is not permanent demand reduction, but a form of flexibility.

Challenge 2: Investing to create a renewables-based system at pace

Summary of response to Challenge 2:

- Since 2013 the CfD mechanism has delivered significant capacity of renewable generation by providing price-confidence over a 15-year period. This underpinned significant renewable investment and ensured that the cost of capital has remained low.
- However, over the next decade there will be growing risk associated with periods when available renewable output and inflexible generation (such as nuclear) exceeds the ability of demand and flexibility to use it. Under current arrangements, this will lead to prices turning negative and CfD contract holders losing CfD uplift payments.
- There are also a growing range of associated challenges for the system operator, such as a lack of incentives for CfD generators to respond to market signals around ancillary services and flexibility.
- We support the focus on updating the CfD mechanism. However, the consultation does not identify or quantify the degree to which the existing CfD contributed to these challenges. Neither does it quantify the impact of proposed reforms which in principle attempt to address these challenges.
- **We therefore recommend that a standard assessment template is developed and applied to ensure there is a consistent analysis of the impact of each of the proposed reforms and that the consequences of changes in risk allocation associated with each option are fully defined and quantified.**
- **We think that whatever mechanism is chosen it must deliver a similar level of risk allocation between generators and consumers as the current system to avoid undermining investor confidence.**
- We believe that the deemed CfD model, if well designed, represents the most promising option. Scottish Renewables therefore has a provisional preference for the deemed CfD model, contingent on certain design requirements. However, the capacity-based CfD also represents a viable option. We believe both should be carried forward for further development and analysis with close engagement with industry.
- DESNZ should commit to developing a broader ‘Repowering Strategy’ by 2026. This would ensure cost-effective decisions are made for life extensions, refurbishments, and repowering as wind assets come off the Renewables Obligation in the late 2020s and CfDs from the early 2030s. This would have the important benefit of enabling the scale-up of renewables investment and continuing to pass on the value of renewables to consumers.

Responses to Challenge 2 questions

Challenges for the future of the CfD

The consultation identifies the following challenges to reforming the CfD framework:

i. Scale up renewable energy investment to increase operating capacity by 150%-200% of current levels by 2030.
ii. As a result of this increase in deployment, manage the growing risk to investors associated with an increase in the number of periods when electricity supply is likely to exceed demand.
iii. A growing need to increase CfD asset's responsiveness to market needs.
iv. Dealing with operational timescale distortions, including an incentive on all CfD generators to act in exactly the same way relative to the day ahead power exchange prices (referred to as 'herding behaviour').
v. Dealing with investment timescale distortions including pressure that maximises output rather than maximises system benefits and a lack of incentive to locate in places beneficial to the system.

4. Have we correctly identified the challenges for the future of the CfD? Please consider whether any challenges are particularly crucial to address.

We agree with many of the points made. In particular, **we agree that the current CfD methodology is likely to need reform** in order to support renewables in a net-zero electricity system.

The characterisation of investor risk is correct: in particular, without change, investors will face increasing risk associated with periods when renewable resources exceed the ability of the system to use them. However, any change to the CfD mechanism which changes revenue risk will have an impact on the cost of capital and the ultimate cost to the consumer. All the CfD options considered in Challenge 2 could change the revenue risk generators are exposed to. To ensure that the assessment of the costs and benefits of each option to amend the CfD mechanism is comprehensive and complete, it is essential that the change in revenue risk is fully defined and quantified.

Each of the CfD options presented in the consultation addresses a potential distortion, but their application will create new risks for different parties. **When assessing options, there is a need to identify the additional risks and understand their costs and compare that to the cost of the root issue driving the option.**

Changes in risk are cumulative and combine by multiplication, rather than by addition. A combination of several changes can very quickly change the risk profile of the CfD instrument to a point where it ceases to be effective in delivering meaningful revenue risk reduction. We are concerned that, for many of the CfD options presented in the consultation document, the associated change in the allocation of risk has not been clearly defined or quantified. **We strongly recommend that a standard assessment template is developed and applied to ensure there is a consistent analysis of the consequences of changes in risk allocation.**

The consultation identifies several distortions created by the incentives associated with the current CfD. We agree that the current framework rewards output over other actions which, at times, could be more valuable to the system. This may include the provision of ancillary services and behind the meter storage or consumption. However, without a quantitative analysis of the impact of the distortions and the degree to which they are attributable to the CfD, it is not possible to reliably assess their materiality as justification for proposed reforms to the existing CfD mechanism.

Under the price risk section, we do not agree with the consultation which characterises generator cost-certainty as 'ultimately being borne by consumers' (page 50-51)**. It shouldn't be forgotten that the CfD acts as a two-way hedge in which consumers benefit** from confidence that prices won't exceed the strike price, in return for providing confidence to generators that prices won't fall below the strike price. Both sides benefit from the certainty the CfD provides. The protection the CfD offers to consumers was starkly demonstrated during the recent energy security crisis. Had more generation been backed by CfDs, the impact of rising wholesale prices on consumer bills would have been significantly mitigated.

If zonal wholesale pricing were introduced, or other mechanisms which reduce expected revenue and increase downside-risk for generators, it will be even more important that a support mechanism provides (a) sufficient revenue and (b) sufficient revenue certainty, particularly for generators in Scotland: in these situations we believe it is likely that only a firm, deemed CfD would be capable of providing the level of confidence needed to support investment. However, we would reiterate our recommendation that a systematic analysis which quantifies the consequences of changes in risk allocation is required to fully understand the impacts of CfD reform in different wholesale market reform scenarios.

Additionally, the volatility and unpredictability of TNUoS charges continue to be a major challenge. This is particularly impactful on projects located in Northern England and Scotland where TNUoS charges make these projects more expensive thus impacting their competitiveness in CfD allocation rounds. This challenge has been recently acknowledged by DESNZ when setting Administrative Strike Prices (ASPs) for AR6, by adding a 2% and a 1% risk premium to offshore wind and onshore wind respectively to reflect the "uncertainty of longer term TNUoS charges". The impact of volatile and high TNUoS charges leads to higher costs for the consumers via more expensive CfDs, compounded through the CfD 'pay-as-clear' auction process as projects with higher TNUoS charges are most likely to be the marginal or clearing project, setting the price for all projects.

Whilst DESNZ's intention is to support repowering for onshore wind projects from as early as AR7, DESNZ should commit to developing a broader 'Repowering Strategy' by 2026. This would ensure cost-effective decisions are made for life extensions, refurbishments, and repowering as wind assets come off the Renewables Obligation in the late 2020s and CfDs from the early 2030s. This would have the important benefit of enabling the scale up of renewables investment and continuing to pass on the value of renewables to consumers.

Distortions caused by the current CfD

The consultation highlights the following behaviour that DESNZ believe the CfD encourages:

i. Maximise generation whenever the reference price is zero or greater.

ii. Require turn down payments in the BM.
iii. Display herding behaviour around periods where the reference price is close to zero.
iv. Avoid providing ancillary services where this requires sacrificing output unless the AS prices are higher than the difference payments.
v. Trade output exclusively in the day ahead market.
vi. Face minimal incentive to locate away from constrained areas.
vii. Fail to invest in equipment to deliver services other than maximising export.

5. Assuming the CfD distortions we have identified are removed, and renewable assets are exposed to the full range of market signals/risks (similar to fully merchant assets), how far would assets alter their behaviour in practice?

We think generators are well placed to develop business models which involve reacting to the market environment in innovative ways. Doing so requires an environment which provides confidence that investment will be recovered. We would expect significant changes in project design and operational behaviour over time if an appropriate support mechanism can be put in place that reflects the capital-intensive nature of renewables and does not place over-reliance on prices based on short-run marginal cost.

In particular, **if the right incentives are in place, we expect Scottish renewable developers to bring forward a range of innovative approaches to better manage constraints such as co-development of hydrogen, heat-demand, or long-duration energy storage and operate these assets flexibly against their own generation**. However, whilst we agree that the right incentives must be in place to incentivise this, such business models will be highly innovative and therefore could involve significant risk, developers will still need to be supported to take these risks without unduly negative impacts on cost-of-capital or overall investability that would ultimately lead to poor outcomes for consumers.

However, for many of the concerns set out in the consultation, it is not clear that, in practice, there is a significant distortion in asset behaviour caused by the CfD. For many of the categories of system need identified in the consultation, there is evidence that the CfD is not a significant barrier to responsiveness, or is just one of several barriers. We discuss each category of system need in turn:

- **Ancillary services**: The experience of SR members indicates that the CfD is not the main disincentive for participation of assets in the provision of ancillary service, so this needs closer examination and quantification. It may be the case that the revenue from ancillary services is not sufficient to cover costs. That is not the same as the CfD being a disincentive, for example, to invest in the additional equipment needed to provide services. It is essential that more evidence is obtained on the balance of incentives and costs for providing ancillary services. If the barrier is not the CfD, but the fact that the provision of services is simply not commercially viable for generators, then amending the CfD will not solve the concern.

- **Intraday dispatch distortions:** We agree that intraday dispatch distortions exist in principle, but we're not aware of any data (e.g. from the ESO) which shows the degree to which this happens or the value at stake/costs to consumers arising from higher balancing costs. If there is clear evidence that there is a risk of significant distortion because CfD generators are prepared to run even when intra-day prices are negative after day ahead prices were positive, and that this issue is financially material, we agree that this would be a driver for considering reforms.

- **Balancing mechanism distortions:** As with the point above we agree that this concern is probably justified but we have seen no analysis which quantifies the scale of the issue or its contribution to rising balancing costs being incurred by the ESO, relative to other factors which are impacting on balancing costs.

- **Herding behaviour and negative price rule:** We are aware of one example of "herding behaviour" provided by the ESO relating to the negative pricing rule as it applies to AR2 projects – as set out in their recent Net Zero Market Reform pack. However, as with other issues, the materiality of this issue relative to other balancing costs faced by the system operator has not been rigorously quantified. We also note herding behaviour will always be a potential problem when there are many similar assets responding to the same market conditions, particularly for low marginal cost renewables when market prices are approaching zero. Analyses of this issue should therefore consider the costs which could still arise in a credible counterfactual scenario, without the CfD or with an alternative support mechanism in place.

- **Disincentive for forward trading:** We agree that a day ahead reference price is a disincentive for CfD generators to engage in forward trading. However, this is not the only disincentive at play. Whether in a CfD or operating on a merchant basis, there is a natural tendency for wind and solar generators to trade close to delivery when they have more certainty about their output, in order to minimise their exposure to volume risk. Changing the CfD reference price to include forward market indices will not alter this inherent generator preference for short term markets.

  Without a CfD, a generator might choose to sell some output in forward markets, but this can be a risky strategy. (For example, if a windfarm sells forward at high prices but then can't generate because of low wind, they may have to buy back at even higher prices.) As a result, changing the reference price to include forward prices may not have the expected effect in increasing a renewable generator's motivation and incentives to forward trade. Instead, it would introduce basis risk into the contract which generators would struggle to hedge in the forward market without taking volumetric risk. This would flow through to impact investor appetite and lead to increases in the cost of capital.

- **Incentive to locate in areas of highest natural resource:** This is true for any renewable asset. Developers will prioritise locating in areas where they can achieve the highest load factors because that is where they will make the most money (subject to other factors), not because they have a CfD. However, we recognise there is a wider issue around the optimal location of assets taking account of network access, transmission losses and the costs of network up-grades. We discuss locational signals in greater detail in our response to Challenge 4.

Taking the above points into consideration, we believe it is essential that more evidence is obtained to provide a complete understanding of the actual scale of any distortions and their materiality. This evidence, combined with a systematic analysis of the impact of CfD reform options on risk allocation, will provide a robust basis for implementing any chosen reforms. This evidence base will be invaluable for ensuring broad stakeholder support and protecting investor confidence during the reform process.

Ongoing reform to the CfD

The consultation notes the existing reform of CfDs through the recent AR7 consultation. It specifically mentioned the proposed expansion of the scope of CfDs to support repowering, and the introduction of new hybrid metering arrangements for CfD assets, aiming to improve renewable site flexibility and grid operability.

6. How far will proposed 'ongoing' CfD reforms go to resolving the three challenges we have outlined (scaling up investment, maximising responsiveness, and distributing risk)?

Ongoing reforms represent an important evolution of the current CfD regime. They are important for keeping the current CfD scheme up to date, for example, by considering the changing inflationary context for projects, for ensuring that repowered projects can be supported and for removing barriers to building the business case for co-location and flexibility of operation.

However, whilst significant, we agree that ongoing changes may not solve the larger, structural challenges that will come with the levels of investment needed for a decarbonised electricity system.

We think this applies to all three challenges identified:

- The growing risk that projects will face under the current CfD scheme associated with periods of negative pricing could begin to drive up strike prices and that a new approach may be needed to overcome that and **distribute risk appropriately**.
- The current CfD structure may limit the ability of renewable projects to maximise responsiveness. Decoupling support payments from output could remove this barrier. However, it is also important to recognise the changes that the proposals in the recent AR7 consultation concerning hybrid metering will deliver in terms of improved flexibility and operability which will likely be far more significant than those realised by decoupling payments from output, provided further consideration is given to offshore wind and the barriers to colocation currently posed by having the BMU boundary metering at the offshore substation.[2] A hybrid metered, co-located AR7-AR9 project should therefore be considered as a counterfactual when assessing REMA CfD reform options.
- Whilst the current CfD mechanism could **support continued and growing investment**, the previous two points mean that in order that new capacity is (a) responsive and (b) delivered at the lowest cost to consumers (by ensuring an appropriate level of risk for renewable developer) we agree that a new approach should be considered.

However, as above, the impact of ongoing reforms must be identified and quantified to provide a robust and reliable evidence base to justify further reforms.

[2] For further detail, see Scottish Renewables' response to Question 17 of the January 2024 DESNZ consultation on proposed amendments for Allocation Round 7 and future rounds of the CfD.

Deemed generation and capacity-based CfD models

The consultation suggests four methodologies for calculating the ‘deemed’ available outputs of generators:

i. Site specific weather and asset data assessed by a third party using a standard methodology.
ii. Site specific weather and asset data assessed by the asset owner using a standard methodology.
iii. A single profile (theoretical or real) is used across a geographical area.
iv. Only deem when assets are providing ancillary services and use ESO data at that time.

The consultation also proposes a new ‘CfD’ model based on capacity payments. Developers would bid into an auction for a capacity payment (£/MW) rather than an output-based payment (£/MWh). To mitigate the risk that consumers would pay generators the capacity payment even when wholesale prices are high, a ‘gainshare’ mechanism (or similar) would be used to limit overall generator revenues.

7. What specific gaming risks, if any, do you see in the deemed generation model, and do any of the deeming methodologies/variations alter those gaming risks? Please provide supporting reasoning.

We believe a well-constructed deemed CfD would have lower price and volume risk compared to the current CfD. However, deeming output will introduce a new basis risk if the deeming methodology does not accurately reflect the potential real time achievable output of individual projects.

The deeming methodology is most likely to deliver the right outcomes if site-specific data is used. **Our preferred option of deeming methodology is Option 2 as set out in the consultation document.**

We set out below our views on each the options for deeming methodologies proposed in the consultation document:

- **Option 1:** We believe this is a viable option, however it may come with significant administration costs.
- **Option 2:** Our preferred option as it is close to the current approach. An arrangement for auditing will need to be developed, but, in principle, this could be subject to audit by LCCC.
- **Option 3:** This option is too complex and should be ruled out.
- **Option 4:** This option is too complex and only addressed one issue of ancillary service provision. We believe this option should also be ruled out.

We would expect that any gaming risks associated with Option 1 and Option 2 could be suitably mitigated through a monitoring and enforcement regime. Generators are already required to provide a “generation available” signal to the system operator and we believe that this can be developed to provide the appropriate data stream for the deeming methodology.

As well as gaming risks, several other factors should be considered when designing a deemed CfD model. Below, we offer our view on the factors set out in the consultation:

- **Remove negative pricing rule**: this is an essential change. We agree that removing the negative pricing rule for deemed CfD assets would protect them from volume risk.
- **Deem only when prices are negative**: we do not support this option. It is unlikely to have much positive impact and it would give the wrong incentives when day ahead prices are low and then prices go negative within day.
- **Deem below strike price**: we support this option. It would introduce an extra step for LCCC to administer, but it is essential to implement this to mitigate the very high generator risk of being liable to large repayments during periods of high prices when the generator has been unable to operate.
- **Turn off deeming when unavailable**: we support the intent of this option. However, it would be difficult to monitor. More information is needed on the availability signal that generators would provide.
- **Removal of firm access rights**: deeming could reduce the impact of removing firm access rights, mitigating the increased risk from such a change.
- **Remove payments during periods of constraint**: we do not support this option. It is too complex and creates an uncertain risk that will be difficult for investors to quantify, undermining the benefits of moving to a deemed CfD in the first place. It will increase the risk to generators, push up the required CfD strike price and increase cost to the consumer, undoing the benefit of moving to a deemed CfD. The Transmission Constraint License Condition already prevents renewable generators from making excessive profits from constraint payments.
- **Deemed CfD with a switch to zonal pricing**: An important principle for any mechanism is that there is a clear signal available to a developer/investor at the time at which they prepare an investment case and submit a bid for a CfD. Wholesale prices in a zonal market will be more volatile and therefore total revenues will be more uncertain. This will make it very difficult to assess the level of revenue risk and price a CfD bid. CfD strike prices will increase as a result.

8. Under a capacity-based CfD, what factors do you think will influence auction bidding behaviour? In particular, please consider the extent to which developers will be able to reflect anticipated revenues from other markets in their capacity-based CfD bid.

We support the continued consideration of a capacity-based CfD and we believe it should be included in the quantitative assessment of the impact of CfD reform options which we recommend in our responses to Q4-5.

However, we do have some initial concerns about the capacity-based CfD model which we would like to set out at this stage. We believe these concerns could be reason enough to rule out a capacity-based CfD, but a quantitative impact assessment is required to support this conclusion.

A CfD aimed at underpinning investment mitigates the main market risk, in return for a limit on upside opportunities. The capacity-based CfD does not do this.

Under this model or others, there is a fundamental and significant level of market risk and uncertainty associated with the forecasting of revenue streams from any market over the circa 15+ years between the initiation of the project and the end of investment support and the subsequent operational period.

The capacity-based CfD option is not, despite the name, a form of CfD and is better described as a capacity payment awarded by competitive auctions. However, it is unclear how much the capacity payment would be and how a capacity-based CfD auction would function. A significant level of volume risk will continue to sit with the generator.

The risk of windfall gains to generators is mitigated by the proposed gainshare mechanism, although designing this will involve setting arbitrary limits on the price at which such a mechanism would operate and the fraction of gainshare. It is unclear how and at what level the payback threshold would be set and whether this would be a hard or soft cap. On the other hand, the risk of windfall losses to generators does not appear to be mitigated as there is no mechanism to provide the reverse of the consumer protection through the gainshare mechanism.

The option of using an availability factor in the auction design will be complex to apply and, due to inevitably imperfect information available to the auction designer, will disadvantage some technologies compared to others. We believe a capacity-based CfD would instead have to be allocated on a technology-specific basis because the level of generation and corresponding revenues vary substantially per unit of capacity between technologies.

The capacity-based CfD will be more uncertain and more difficult to analyse than a deemed CfD, as the scale and price of merchant revenues are more uncertain. Developers will be more reliant on forward price curves when preparing bids for a CfD compared to the deemed CfD. That in turn is likely to result in a wider range of bids for similar scale projects than the deemed CfD. This type of CfD would favour those with the most optimistic view of future markets, and not necessarily the best value projects. This means there will be a higher risk of non-delivery and stranded assets. Capacity-based CfD bids are also likely to be more volatile from auction to auction.

Additionally, a capacity-based CfD could create the perverse incentive for a developer to engage in poor procurement practices and sub-optimal siting/design principles. If the capacity payment was based on installed capacity in £/MW, there would be little incentive to procure the best components such as turbines that maximise the efficiency and output of a site.

9. Does either the deemed CfD or capacity-based CfD match the risk distribution you detailed in your response to Q25 on which actors are best placed to manage the different risks?

We think that the deemed CfD approach most closely follows the distribution of risks that we discuss later in our response.

This is because it transfers market risk faced by investors in high CapEx, low OpEx projects (including renewable projects) to consumers in a manner similar to today’s CfD whilst leaving investors with the resource, site, construction, and operation risks. It therefore has the potential to deliver similar investability and cost-of-capital.

We acknowledge that individual consumers are not themselves able to manage risks associated with a deemed CfD, but we would expect DESNZ, NESO and Ofgem to manage those risks in a sophisticated way on consumers' behalf as they are ultimately responsible for the decisions that lead to the risks that deeming is aiming to tackle. We think it will be important to consider how DESNZ, NESO and Ofgem are themselves incentivised and supported to carry out this function effectively.

An important principle for any mechanism is that there is a clear signal available to a developer and investors at the time at which they prepare an investment case and submit a bid for a CfD. If the signal is inherently uncertain and/or highly volatile then it will have a high level of risk. That risk will be priced into the project financing and increase the cost of capital. In terms of locational risk specifically, a major challenge for the deemed generation variations for different wholesale market designs set out on p60-61 of the consultation document (as well as locational pricing mechanisms more widely) is that future locational market prices will be even more uncertain that national market prices. Given that the benefits of the CfD arise from the stabilisation of revenues that it provides, reintroducing exposure to a more uncertain revenue risk will directly undermine the benefit of introducing the CfD in the first place. This trade-off has to be fully quantified and the overall cost-benefit balance understood in order to judge whether any of these location pricing mechanisms offer a net benefit to the system and the consumer.

10. Do you have a preference for either the deemed CfD or the capacity-based CfD model? Please consider any particular merits or risks of both models.

We think that, in principle, both the capacity-based CfD and deemed CfD could be designed to enable low-cost investment by developers. However, both models have features which could allocate high risks to developers which would end up being passed on to consumers in an inefficient manner. Scottish Renewables has a provisional preference for the deemed CfD model. However, there is insufficient information and evidence about both models to offer a firm preference at this stage. Both models should be taken forward for further development and analysis.

Scottish Renewables has a provisional preference for the deemed CfD model because, if well designed, we envision it being best able to address the distortions identified in the consultation as well as the key challenges for the future of the CfD. However, we would welcome further thinking and targeted industry engagement on its detailed design. We would support the deemed model on the condition it meets some essential design considerations outlined below.

The deemed model has the advantage of continuing to protect CfD assets from price risk while playing an important role in reducing constraint costs and operational distortions. By decoupling CfD payment from output, it could resolve some of the operational distortions associated with the current CfD by allowing assets to participate in whichever markets would generate the greatest returns. It could also allow CfD assets to remove subsidy payments from bids in the balancing mechanism, removing some distortions in the merit order stack.

However, it is imperative a deemed CfD design clearly addresses the risks outlined below.

Removing the negative pricing rule. This is an essential change in the design of a deemed CfD and is key to protecting assets from volume risk. It is key to maintaining investor confidence and allowing assets to be responsive to operational signals.

It is also essential that there is a mechanism to protect generators during period of high prices when an asset is not operational. For example, in winter periods of high demand, high wind, and cold conditions – a site may not be able to operate due to technical faults caused by the cold conditions. However, in this period, the generator could be liable to significant difference payments to the LCCC if market prices are significantly above the deemed CfD strike price. The site did not avail of any revenue to honour the difference payments in this period due to technical problems. To balance costs to the consumer, the above risks could be mitigated by removing deeming when an asset is not operational.

The price risk from high price, no operation periods must be protected against in the design of any deemed CfD variation to ensure it is investable.

We would also like to highlight the likely increases in administration costs required for the LCCC to manage this scheme. Regarding deeming methodologies, Option 1 would incur additional costs through determining deemed output by combining site-specific weather and asset data in a standard process set by government. Option 2 and any mechanism to monitor sites during periods with no operation require auditing that will incur additional administrative costs.

Partial payment CfD

The consultation proposed an option where assets can only bid for a certain fraction of their capacity to be covered by a CfD.

11. Do you see any particular merits or risks with a partial payment CfD?

We do not agree that partial CfDs should be mandatory. A mandatory partial payment CfD would hamper investment, particularly for smaller projects which would struggle to manage their risk on the remaining part of their project.

Optional partial CfDs would simply represent a continuation of current practice; they have already been used by some large-scale offshore wind projects. We support the ability of a project to opt for a partial CfD.

Reference price reform

The consultation lays out two options for reference price reform either within the current structure (payment based on output) or other options, such as deemed CfDs. Two proposals are put forward: a 'hybrid reference price'; and an 'extended reference price'. It is not clear what the difference is, although it appears that both involve creating a basket of prices for contracts over different timescales for a particular settlement period. For example, including forward contracts struck a month or more in advance.

12. Do you see any particular merits or risks with the reforms to the CfD reference price we have outlined? Please consider how far the two reforms we have outlined might affect both liquidity in forward markets and basis risk for developers.

There could be merit in reforming the reference price and agree that it should be explored further. However, whilst we acknowledge that there could be benefits in reforming the reference price, these benefits could be outweighed by increased strike prices.

It is important to realise that introducing a higher forward pricing component will introduce more volumetric risk into the market due to the intermittency of renewables which will ultimately flow through to consumer costs. **We, therefore, think that the guiding principle to consider is what changing the reference price does for the risk profile of renewable investments rather than other actors in the electricity supply chain. If changing the reference price increases the market price risk faced by renewable investors, this will result in increased strike prices.**

It is likely that these costs will outweigh any expected supplier risk management benefits given the very limited potential CfD generators have to adjust their output. The reality is that as generators become exposed to greater market risks, they will look to contract with parties who can manage these risks – this simply increases the number of parties in the supply chain and is likely to add rather than reduce cost.

We agree that the current reference price tends to focus trading in the day ahead market, which forms the reference price. However, whether operating under a CfD or operating on a merchant basis, there is a natural tendency for wind and solar generators to trade close to delivery when they have more certainty about their output in order to minimise their exposure to volume risk. This is not to say that renewable generators exclusively trade close to delivery. Nevertheless, removing the incentive to trade in the day-ahead market in the CfD will not alter this inherent generator preference for short-term markets.

Aligning the reference price based to day-ahead index is an efficient trading solution and avoids excessive forecast error risk, which in turn avoids excessive market risks for generators in trading against this error.

Some operators with their own trading capability will trade their own output. But many sign PPA contracts with offtakers that are index-linked to the day-ahead market price. This ensures that generators are hedged with the PPA delivering the reference price (or a fraction of it) and the CfD providing the difference payment. In this scenario, the offtaker manages risk at a cost included within the contract.

We think that reforming the reference price would likely lead to ‘follow the basket’ trading with the best risk-hedge provided if power was sold in line with the basket. For example, if a reformed reference price was based on a basket of 50% month-ahead forward contracts and 50% day-ahead power exchange prices, then traders would likely look to trade in those two markets. This would result in renewable generators increasing their risk profile. It will also be important to consider what form of PPA this would drive between independent generators and offtakers.

As such, the design of any basket would need to be carefully considered because it would likely drive the direction of trading into the specific products which are being used to define the basket. When assessing reference price reform from the point of view of cost-effectiveness, the balance between consumer benefit from liquid forward markets (which can provide price certainty) and the increased risk associated with hybrid reference prices will have to be considered.

Small-scale renewable deployment

The consultation includes a brief discussion on small-scale renewables. It notes that opening CfDs up to sub-5MW generators is unlikely to be beneficial, as smaller projects see the CfD process as too onerous and costly to participate in. It also discusses the Smart Export Guarantee and the potential role of PPAs.

13. What role do you think CPPA and PPA markets, and REMA reforms more broadly, will play in helping drive small-scale renewable deployment in the near-, mid- and far-term?

Where small-scale generators are unable to access CfDs, a fixed price PPA (or similar) over a sufficiently long period is critical to being able to access finance. Therefore, an appropriate market framework that encourages PPAs will be necessary for bringing forward small-scale renewables. PPAs could also offer further support to generators beyond the end of the 15-year CfD contract.

The consultation refers to 'small-scale renewables'. Although it does not define small-scale, the discussion of relevant factors suggests 'less than 5 MW'.

There are several distinct differences between large- and small-scale renewables. Small-scale renewables are usually distribution connected, often developed by smaller developers for whom fixed costs such as IT systems and metering can represent a significantly larger fraction of their total costs. DevEx costs per MW will also be higher for smaller developers.

We would urge DENSZ to consider lowering the 5MW threshold to enable smaller projects to bid for a CfD. The application process should be reviewed to identify how it could be streamlined and simplified to make it less onerous for all projects and a separate pot could potentially be introduced for smaller projects.

Small-scale renewables could play an important role in balancing the grid at a local level. We would therefore also recommend that DESNZ set out a clear vision of the role of small-scale renewables in our future energy system. Re-introducing a mechanism similar to the FIT regime could be required for GB to fully utilise sub-5MW renewables projects as, for developers to take the cost risk of these smaller sites, they need to know they have a quick and easy route to market for the project once they have gained planning approval.

In general, we expect that REMA reforms will have a similar effect on small-scale renewables as larger renewable generators, as all will face similar challenges in understanding the changes in risks and markets. However, the challenges are likely to be greater for small-scale renewables as they will have less in-house capacity to review such complex changes and, in response, investors and corporate offtakers will tend to focus on larger projects.

Challenge 3: Transitioning away from an unabated gas-based system to a flexible, resilient, decarbonised electricity system.

Summary of response to Challenge 3

We welcome that the flexibility challenge continues to be a key focus of REMA. Economic, reliable, low-carbon flexibility resources will be critical for:

- Enabling renewable electricity generation: providing flexible demand to 'soak up' excess renewable electricity, reducing the need for renewable curtailment.
- Dispatchability: providing dispatchable low-carbon electricity when renewables are unavailable, displacing flexible fossil-fuel generators.
- Maintaining system stability: providing system ancillary services, such as inertia, voltage flexibility and restoration, which renewables may not provide.
- Lower network costs: providing flexible demand or generation in constrained grid areas to reduce the need for investment in transmission networks.

Our members are developing large-scale flexibility resources such as pumped storage hydro projects, which can deliver all these capabilities. However, they need long-term price signals that reflect all these benefits to trigger the large capital investment required.

It will be important that REMA market design delivers effective and coordinated long-term price signals for each of these capabilities to achieve the optimum solution. An uncoordinated market design could deter efficient investment and lead to higher costs.

The REMA Second Consultation proposals reflect many of the comments about flexibility in our response to the first REMA consultation. In it, we suggested that:

- Long term price signals should be provided for low carbon flexibility, including for system stability, temporal and locational characteristics.
- A single optimised capacity market should be examined further as a way of providing investment signals for flexibility resources.
- Investment and operational signals should be provided for low carbon operability resources, including system stability resources, and distributed energy.

We note that the REMA second consultation proposes that:

- The CM should provide long-term price signals for flexible capacity through a single auction with multiple clearing prices.
- Due to complexity, cost and liquidity concerns, DESNZ has decided to discount introducing a locational element to the CM as a standalone option.
- DESNZ proposes that greater temporal signals for flexibility be provided through shorter settlement periods e.g. to 5 or 15 mins.

- Alignment of ‘longer term’ ancillary service contracts with CfD/CM auctions being considered.
- Prioritisation of Low Carbon flexibility – the NESO should deliver this through its general duty to enable net-zero delivery. No specific obligation is proposed.

We welcome that the REMA proposals intend to deliver long- and short-term price signals for flexibility to both enable investment and optimise operation in electricity markets. The choice of the Capacity Market (CM) to deliver the long-term price signals has the advantage of being a proven mechanism. We suggest that a CM auction for ‘flexible’ capacity should take account of the following:

MW capacity - Dispatchable generation, storage, or demand reduction, with appropriate capabilities including realistic de-rating factors. This will need to reflect:

- Flexibility envelope – reflecting individual CMU flexibility characteristics.
- Endurance – reflecting individual CMU characteristics e.g., storage durations.

However, there are other flexibility characteristics that will be needed to ensure a secure electricity system. A future CM design, as part of a wider package of reforms to deliver low-carbon flexibility, will also need to address:

Ancillary service capacity - Dispatchable ancillary service characteristics e.g. response, reserve, voltage support, inertia, black start. This will again need to reflect individual CMU characteristics.

We note that the consultation proposes to align ‘longer term’ ancillary service contracts associated with CM/CfD contracts. We would welcome this approach - coordination of these price signals would better enable investment in assets such as pumped storage hydro which could deliver both flexible MW and ancillary service capacity.

We note that the REMA Consultation does not consider that the CM should provide a locational signal for flexibility. We recognise the challenge of doing so. However, flexibility could provide lower-cost solutions than network investment.

Network investment requirements and price signals could be coordinated with the CM to trigger this investment. These requirements could potentially be identified by the NESO Strategic Spatial Energy Plan (SSEP) of generation locations which will feed into their Centralised Strategic Network Plan (CSNP).

Outside of CM design, we suggest that the potential for coordinated long-term price signals to trigger efficient investment in combined flexibility for dispatchability, stability and congestion services be considered further.

We note the proposals to allow an extension to the incentivisation of unabated gas for flexibility and security of supply purposes. We do not consider that this is appropriate as it will deter or delay investment in low carbon flexibility and may lead to higher than necessary costs to customers. It appears unnecessary to take this decision until the delivery pathway for preferred low-carbon flexibility is better understood.

We welcome the proposals to continue the integration of flexible distributed energy resources into the CM and other electricity markets. This is an area of significant potential but there is much coordination and market design work (such as how to treat transmission and distribution assets fairly) to be done before the benefits can be realised.

Finally, another important flexibility initiative - Long-Duration Electricity Storage (LDES) - is being pursued on a separate timeline from the REMA process. Our members are actively pursuing pumped storage hydro projects that already have land rights, planning consent, a grid connection, strong developer backing and are ready to build. Early award of cap and floor contracts will be needed if these projects can complete their major construction programmes by the early 2030s.

We urge DESNZ to open the first application window for LDES projects following LDES policy decisions later this year or by Q1 2025 at the latest. While this will be a challenging timescale, early decisions on the above policy points should enable all parties to undertake the necessary preparation to achieve this deadline. Plans for further application windows should be outlined to give confidence to future project development.

Once the application window opens, it will be important to have an accelerated approach to LDES eligibility assessment, cost assessments and cap and floor awards for advanced projects, running these activities concurrently where possible. This should target cap and floor awards during 2025 such that final investment decisions can be taken for the most advanced LDES projects.

Responses to Challenge 3 questions

Challenge 3 proposes a package of reforms to ensure that there is sufficient investment in all forms of low carbon flexibility at the pace and scale required, whilst maintaining security of supply through the transition to a fully decarbonised electricity system. To address this challenge, the electricity market design should be designed in a way that sends:

- Sharper operational signals demonstrating when and where valuable flexibility is needed, and to which these technologies can respond; and
- sufficient investment signals to bring forward technologies and services of all sizes and types.

Since the first REMA consultation, the following decisions have been taken:

- An Optimised Capacity Market will be used as the capacity adequacy mechanism.
- The auction design will be a single auction with multiple clearing prices with a focus on introducing a minimum procurement target for desirable characteristics (i.e. minima).
- There will be no locational element in the market design.

The consultation highlights that further work is underway to:

- Develop how minima should be defined and set (i.e. to procure low carbon capacity and/or key flexibility capabilities).

- The interactions between minima, wider auction set-up, auction parameters and short-term CM policy changes.

The aim is to devise an enduring package of changes that will ensure the Optimised CM can continue to deliver a secure, decarbonised and cost-effective electricity system.

The DESNZ consultation conclusions and proposals for Challenge 3 are summarised below:

- The GB electricity system could require up to 55GW of short-duration flexibility and between 30 and 50GW of long-duration flexibility by 2035 to ensure security of supply. The aim is for as much of this long-duration capacity as possible to be low carbon.
- New investment in long-duration flexible capacity will be needed in the coming years to replace expiring plants and ensure security of electricity supply. But a limited amount of new gas capacity will be required in the immediate term whilst low carbon long duration alternatives, such as Power CCUS, H2P and LDES scale up.
- Bespoke policy will support the deployment of low carbon long-duration flexibility in the short term, including through the consultations on H2P and LDES published in December 2023 and January 2024 respectively.
- This extensive build-out of low carbon flexible capacity such as hydrogen and CCUS and supporting infrastructure to secure electricity supply through to 2035 and beyond will need public policy frameworks to leverage private finance.
- The CM will be retained as the capacity adequacy mechanism, but auctions will be optimised to further support low carbon flexibility by introducing minima, recognising the interactions with other markets will need to be considered.
- In the longer term, the GB Reliability Standard will be reviewed to ensure the metric effectively addresses future risks to security of supply.
- Work with Ofgem, the ESO and industry will continue to accelerate reforms within the current market framework to bring forward distributed low carbon flexibility. The need for further intervention will be determined once the final REMA package is known.

The overall Challenge 3 questions posed by the consultation are:

- *How do we maintain security of supply in a future electricity system dominated by intermittent renewable generation?*
- *How do we manage a transition away from unabated gas to low carbon technologies?*

Introducing minima to the Capacity Market

14. Are there any unintended consequences that we should consider regarding the optimal use of minima in the Capacity Market (CM) and/or the desirable characteristics it should be set to procure?

We note that the consultation proposes that an Optimised Capacity Market will be used as the capacity adequacy mechanism for flexibility using minimum procurement targets for desirable characteristics.

In the October 2022 Scottish Renewables REMA response, we proposed the following:

Flexibility – This should be defined to include dispatchable generation or demand, plus dispatchable ancillary services, plus network congestion flexibility. It should prioritise low-carbon flexibility. Long-term price signals for flexibility should be provided as they are not available from existing wholesale or balancing markets.

Capacity market – We supported the development of the capacity market to provide signals for flexibility investment. We suggested that a reformed capacity market was needed to prioritise low carbon flexibility also reflecting locational and temporal requirements.

Capacity adequacy – We agreed an Optimised Capacity Market should be explored further. We suggested the CM auction should set targets for flexibility to reflect system need.

Operability - We agreed that appropriate market signals are needed to ensure sufficient operability resources are available in future decarbonised markets. We proposed that:

- Net-zero flexibility resources should be prioritised.
- To utilise distributed flexibility there should be greater TSO/DSO coordination.
- Energy system planning should consider the needs of the whole energy system.
- The redesign of the CM should consider incentivisation of ancillary services.

We welcome that the consultation appears to reflect many of our comments. We agree with the proposal for a single auction for the desired characteristics, whilst ensuring capacity adequacy is delivered.

However, we are concerned that the proposed REMA design appears to have excluded the economic benefits of combining several flexibility characteristics. Our members are developing large-scale flexibility resources such as pumped storage hydro projects, which can deliver all of the following capabilities.

- Enabling renewable electricity generation: providing flexible demand to ‘soak up’ excess renewable electricity, reducing the need for renewable curtailment.
- Dispatchability: providing dispatchable low-carbon electricity when renewables are unavailable, displacing flexible fossil-fuel generators.
- Maintaining system stability: providing system ancillary services, such as inertia, voltage flexibility and restoration, which renewables may not provide.
- Lower network costs: providing flexible demand or generation in constrained grid areas to reduce the need for investment in transmission networks.

However, they need long-term price signals that reflect all these benefits to trigger the large capital investment required. It will be important that REMA market design delivers effective and coordinated long-term price signals for each of these capabilities to achieve the optimum solution. An uncoordinated market design could deter investment and lead to higher costs.

We suggest that a CM auction for 'flexible' MW capacity should incentivise dispatchable generation, storage, or demand reduction, with appropriate capabilities including realistic de-rating factors. This should address:

- Flexibility envelope – reflecting individual CMU flexibility characteristics.
- Endurance – reflecting individual CMU characteristics e.g., storage durations.

A future CM design will also need to address dispatchable ancillary service characteristics e.g. response, reserve, voltage support, inertia, black start. This will again need to reflect individual CMU characteristics.

We note that the consultation proposes to align 'longer term' ancillary service contracts associated with CM/CfD contracts. We welcome this approach – coordination of these price signals would better enable investment in assets such as pumped storage hydro which could deliver both flexible MW and ancillary service capacity.

We note that the REMA Consultation does not consider that the CM should provide a locational signal for flexibility. We recognise the challenge of doing so. However, flexibility remains a useful tool to optimise the available network capacity in parallel with the necessary future network investment. Coordinated long-term requirements and price signals could send stronger signals for this investment. These could potentially be identified by the NESO Strategic Spatial Energy Plan (SSEP) of generation locations which will feed into their Centralised Strategic Network Plan (CSNP).

Outside of CM design, we suggest that the potential for coordinated long-term price signals to trigger efficient investment in combined flexibility for dispatchability, stability and congestion services be considered further.

In terms of the CM, as the optimal use of minima has yet to be defined, it is not possible to identify all possible unintended consequences at this stage. However, DESNZ should consider how the defined minima/characteristics will impact the degree to which different low carbon flexible technologies are incentivised and the proportion that Government is seeking to achieve between different technologies.

The design of this package is likely to be complex and will need detailed consideration and timelines for the introduction of changes to provide clear investment signals. It is essential that this design be subject to industry consultation, expert review and be fully transparent.

Furthermore, the introduction of a CM market design to deliver low carbon flexible resources will need to exist alongside legacy assets where such services are provided by fossil fuel plants with potentially low ongoing costs for such services. As such, the market design may simply serve to deliver additional revenues to fossil fuel plants. We suggest that low carbon flexibility resources should be given priority access to CM contracts in any future CM design.

15. What aspects of the wider Capacity Market (CM) framework, auction design and parameters should we consider reviewing to ensure there are no barriers to success for introducing minima into the CM?

DESNZ has yet to set out in detail the technical design of the proposed reforms to the CM. This limits our ability to respond to this question.

In responding we would refer to our response to the prior question, and would offer some further high-level comments below:

CM Access barriers for long construction projects

In responding to the previous DESNZ CM consultations, we highlighted the need to allow long build-time projects such as pumped storage hydro to participate in the CM with suitable eligibility and operational conditions in place to minimise the risks and uncertainties of non-delivery.

We are supportive of proposals to allow long build-time projects to compete in T-4 auctions. We therefore welcome that government has considered measures to this effect. However, we would stress that:

- Given the size and complexity of new build pumped storage hydro projects, strong consideration needs to be given to a minimum 36-month extension or a delay to delivery to allow such projects to participate in T-4 auctions.
- Due to the 6-7-year construction build time for pumped storage hydro projects, particularly those requiring underground caverns and tunnels, a 24-month Declared Long Stop Date as recently proposed would not be sufficient. Maintaining the full 15-year contract length is critical for project financing.

CM/Related Markets – Co-ordination and Design Challenges

Investors are seeking clarity on how price signals will be revealed in the CM and related markets.

To achieve this, there are several barriers that we think should be considered in the future CM design:

- **Coordination of CM auctions with NESO tenders for long-term stability service contracts** (assuming these continue). There is a risk that separate NESO tenders do not attract the most efficient investment in assets that provide both firm power and stability services. Investors may receive conflicting investment signals and revenues from more efficient resources may be cannibalised by more expensive short-term solutions.
- **Market access –** integration of flexible distributed energy resources into the CM and other electricity markets. This is an area of significant potential but there is much coordination and market design work to be done before the benefits can be realised.
- **Grid access –** there is a major challenge for new flexible technologies in gaining grid access and being able to participate in auctions. It may be appropriate to consider ways in which grid access may best be prioritised.

- **Access to constraint management markets –** there will be many cases where there will be a choice as to whether investment is needed in transmission or in non-network solutions. Flexible technologies can provide an alternative solution. It will be important that this is coordinated with transmission network planning and investment decisions.
- **Hydrogen development** – Congestion will mean there are very few areas where hydrogen to power will be an option until hydrogen transport and storage infrastructure is built. Green ammonia and methanol should be allowed to compete in and Optimised CM as a bridge to this future.

Capacity market emission limits

The January 2023 capacity market consultation proposed that new and refurbishing CMUs with multi-year agreements awarded in relevant auctions following implementation, (which run beyond 2034) would, from 1 October 2034, have to meet an emissions intensity limit of 100gCO2/kWh or a yearly emissions limit of 350kgCO2/kW.

The emissions limit would limit operations to approximately 750 hours per year for a typical gas peaking plant. These limits would help ensure that the CM is aligned with the broader ambition for a fully decarbonised electricity system by 2035, subject to security of supply.

In June 2023, the government proposed to introduce the lower emissions limit for new build and refurbishing plant from 2024 at the earliest, subject to further analysis and development. This consultation proposes not to implement the limits until the 2026 CM auctions at the earliest.

16. Do you agree with the proposal that new lower emission limits for new build and refurbishing CMUs on long-term contracts should be implemented from the 2026 auctions at the earliest?

We do not support the extension to the introduction of the lower emissions limit in the capacity market for unabated gas generation. As well as risking the delivery of net-zero decarbonisation targets, extended incentives for the development of unabated gas will cannibalise the capacity market, wholesale, and other market revenues from low carbon flexibility assets.

This policy proposal is likely to deter or delay investment in low-carbon flexibility assets, including those being developed under the LDES scheme.

This would appear to conflict with the REMA assessment criteria for investor confidence which states that '*Market design must drive the significant investment in the full range of low carbon technologies needed to deliver our objectives, from different types of generation to investment on the demand side'*.

We suggest that the proposal to introduce the lower emissions limit from 2024 should remain to help achieve the aim of a fully decarbonised electricity system by 2035. If future security of supply concerns become evident due to the lack of low carbon flexibility resources, the government, possibly via ESO contracts, will always have the option of introducing policies to incentivise the delivery of new unabated gas plants.

If this proposal does go ahead, the government should ensure that action is taken immediately to ensure that rule changes can be implemented in time for prequalification in 2025 to avoid any further delay.

In any case, it is important that any new build unabated gas is decarbonisation ready. DESNZ should therefore consider strategically planning the locations of these sites and ensuring a joined-up approach with CCUS and hydrogen support mechanisms to ensure that government policy is consistent and delivers whole-system outcomes.

17. If you are considering investment in flexible capacity, to what extent would emissions limits for new build and refurbishing capacity impact your investment decisions?

Our members are developing flexibility resources, including batteries, conventional hydro, pumped storage hydro and hydrogen assets. These investments rely on forecast market price signals to trigger investment and economic operation. In this context, changes to, and uncertainty about, the expected future operating profile of unabated gas will impact business cases for these investments, as will uncertainty about the availability of sufficient hydrogen for power as a feedstock.

We would specifically draw attention to the impact on LDES technologies which are subject to the development of a separate cap and floor regime. Our members are developing several GW of pumped storage hydro projects which should make a significant contribution to the delivery of low carbon flexibility capacity.

The proposed cap and floor regime does not change project revenues – it simply enables the large-scale capital investment needed in these projects by introducing a minimum revenue to sustain debt finance. The continued operation of unabated gas increases the risk that this low carbon flexibility investment is deterred or delayed due to expected reductions in key revenue streams (wholesale prices, capacity market prices, ancillary services revenues).

We consider that the delay in implementing emissions limits could increase risk and potentially chill investment in these technologies. Competition from unabated gas plant with capacity market contracts, even for limited running hours, could reduce the forecast returns for flexibility assets and deter investment.

We would reiterate the importance of maintaining investor confidence and would highlight the related REMA assessment criterion which states that, ‘Market design must drive the significant investment in the full range of low carbon technologies needed to deliver our objectives, from different types of generation to investment on the demand side’. We are concerned that a delay in emission limits would undermine progress towards this and hinder the delivery of much needed low-carbon flexibility.

Increasing the deployment of long-duration flexibility

Providing the flexibility required to manage a predominantly renewables-based system in the 2030s and beyond will require a mix of solutions to effectively balance supply and demand over both short-duration and long-duration timeframes. Long-duration flexibility will be essential for ensuring the stability and security of electricity supply during longer periods where renewable generation is not able to meet demand.

The consultation states that the GB electricity system could require between 30 and 50GW of long-duration flexibility by 2035. The government's aim is for as much of this long-duration capacity as possible to be low carbon. The relevant policies which are already in place or in development, include:

- Financial support for low carbon conversion: e.g., the DPA scheme for Power CCUS.
- Capacity Market "managed exits": For example, options for enabling unabated generators to exit an existing multi-year CM agreement.
- Enabling H2P and Power CCUS participation in the CM.
- Establishing a 9-year CapEx threshold for new and refurbishing projects.
- Decarbonisation Readiness to ensure new build and substantially refurbishing combustion electricity generators are built so they can easily decarbonise in the future by converting to 100% hydrogen-firing or retrofitting CCUS.
- Carbon pricing: carbon pricing through the Emissions Trading Scheme (ETS) and Carbon Price Support (CPS) can incentivise alternatives to unabated gas.

In addition, a separate policy stream is underway to encourage the development of LDES through a cap and floor mechanism.

The consultation expects that a limited amount of new build gas capacity will be required in the immediate term to ensure a secure and reliable system, to replace existing generation capacity as it expires. It is the only mature technology capable of providing sustained flexible capacity whilst low carbon long-duration alternatives, such as Power CCUS, H2P, and LDES scale up as we move into the 2030s.

18. Considering the policies listed above, which are already in place or in development, what do you foresee as the main remaining challenges in converting existing unabated gas plants to low carbon alternatives?

We welcome the government's assessment of the 30-50GW scale of flexibility resources needed to realise decarbonisation of the electricity system. We also recognise the importance that the government must take steps to ensure security of supply in a decarbonised energy system.

For hydrogen to power, there is significant uncertainty regarding the availability of hydrogen and whether government will be able to meet its ambition of having 10GW of low carbon hydrogen production capacity by 2030.

Government should ensure through the cluster sequencing process and future Hydrogen Allocation Rounds (HAR) that sufficient quantities of hydrogen in the right geographical locations are produced to meet the future H2P demand. It is similarly critical that DESNZ, through its hydrogen transmission and storage business models, puts in place the requisite infrastructure to enable hydrogen to power assets.

However, we would question the logic of incentivising additional investment in unabated gas when a known pipeline of low carbon flexible technologies including some 9GW and 190GWh[3] of pumped storage hydro (a proven technology) being developed by our members can be built by the early 2030's.

We would repeat our above comments that the introduction of policies to encourage new build unabated gas will have the perverse effect of chilling investment in the very low carbon flexible technologies that the government is seeking to encourage.

Given the short lead time to build new gas power stations, a capacity market design that triggers such investments earlier than necessary is likely to lead to stranded assets. This would fail another REMA assessment criteria of delivering value for money for consumers.

Finally, we emphasise that time is of the essence for clarity on the design of the LDES support scheme. The nature of projects of the scale of pumped storage hydro means that weeks lost now in policy design can cause delays of months and potentially years in project construction and can have wider implications for maximising domestic supply chain opportunities. Scottish Renewables therefore urges the government to progress at pace and publish its LDES consultation response early this summer confirming the design principles of the cap and floor support scheme.

19. Do you think there is currently a viable investment landscape for unabated gas generation to later convert to low carbon alternatives? If not, please set out what further measures would be needed.

The current CCUS and H2P pathways and associated support mechanisms being developed by DESNZ appear to offer the prospect that new and/or existing unabated gas generation can contribute to future flexibility needs.

From the perspective of LDES developers, as for market distortions arising from changes to emissions limits, incentives given to unabated gas plants to convert to low carbon alternatives could also cause uncertainty and deter LDES investment.

We recognise that this is a complex landscape with alternative flexibility technologies (CCUS, H2P, LDES) all receiving different types of development support. Ultimately, in order to deliver value for customers, they should all be able to compete equally to provide the required flexibility services in future markets.

[3] We provide details of these projects in our response to the 2024 DESNZ LDES consultation.

Until experience has been gained from early CCUS/Hydrogen projects and the technology and economic results become evident, it seems premature to commit to a landscape requiring conversion of unabated gas generation.

Supporting deployment and utilisation of distributed low carbon flexibility

The consultation states that responses to the first REMA consultation have confirmed that sharper operational signals are required to strengthen the investment case for distributed flexibility. The key barriers to sharper operational signals are:

- inefficient market operations;
- barriers to market access;
- temporal signals that do not fully reflect system needs; and
- locational signals that do not fully reflect system needs.

The consultation highlights that there is a significant amount of work already underway to address these barriers. This includes actions from the 2017 and 2021 Smart Systems and Flexibility Plans, the 'Delivering a Smart and Secure Electricity System' initiative, the retail market reform programme and the Energy Digitalisation strategy.

In addition, the NESO will publish a Flexibility Strategy in the first half of 2024. This will set out the vision, key milestones and a transformation roadmap for enabling participation from all low carbon flexibility in markets. Ofgem have also published a decision on the future of local energy institutions and governance, including an intention to assign a market facilitation function to a single entity to deliver more joined-up flexibility markets.

20. Do you agree that an Optimised CM and the work set out in Appendix 3 will sufficiently incentivise the deployment and utilisation of distributed low carbon flexibility? If not, please set out what further measures would be needed.

No, while we welcome the above initiatives to grow the scale of distributed low carbon flexibility, we consider that much more needs to be done if significant benefits are to be realised from distributed flexibility whilst also ensuring a level playing field between transmission and distribution connected flexibility.

This is potentially a vast resource, comprising a wide range of distributed energy resources, including behind the meter storage, generation, and flexible demand, able to contribute significantly to wider system flexibility. But short- and long-term price signals are needed, with coordination across NESO and DSO boundaries to ensure services are complimentary.

For example, Scotland has a significant number of distribution-connected conventional hydro plants which will provide a valuable flexibility resource. Scotland's hydropower fleet offers a renewable and domestic solution to help fill both the short- and long-duration flexibility gap by providing rapidly dispatchable and highly controllable power to the system, as well as storing large amounts of energy for days and even seasons. Hydropower can be tailored to meet a wide range of flexibility needs both in response time and sustained response. However, clear signals through the Optimised CM would be required to ensure investment in these assets could meet the needs of the mechanism, for example when refurbishing. An appropriately designed CM minima, in conjunction with an ancillary services market which sufficiently values hydro flexibility, could bring forward new investment in innovative flexibility upgrades that unlocks the full potential of our existing hydro assets. This will become even more critical in a variable renewable-based energy system.

An optimised CM should certainly help the growth of distributed low carbon flexibility, however, without full details of how and when minima will be introduced and what characteristics this will look to support it is difficult to comment on how this could impact on the growth of low carbon flexibility. An optimised CM must be accompanied by the associated policy to allow easy but fair market access and clear short- and long-term price signals.

Transitioning away from bespoke support

The consultation proposes to introduce minima in the CM (i.e. Optimised CM). It is proposed that, once a certain level of technology readiness and infrastructure availability has been met, there should be a way to transition low carbon long-duration flexible technologies away from any administratively awarded bespoke mechanisms.

The consultation proposes to keep the progress of any low carbon flexible technologies in receipt of bespoke support under review until we have confidence that they can compete in an Optimised CM, noting that this may occur at different times for different technologies or different types of projects.

It is acknowledged there may be a need to continue to offer bespoke support into the 2030s for certain low carbon flexible technologies, for example, to mitigate ongoing cross-chain or other risks. The recently published CCUS Vision and H2P consultation proposed to consider price-based competition into any bespoke mechanisms as a stepping stone towards technology-neutral allocations.

21. Do you agree that our combined proposed package of reforms (bespoke mechanisms for certain low carbon flexible technologies, sharper operational signals, and an Optimised Capacity Market) is sufficient to incentivise flexibility in the long-term? Please set out any other necessary measures.

Firstly, we agree with the decision that Long-Duration Energy Storage (LDES) be pursued on a separate timeline to the REMA process. Early award of cap and floor contracts will be needed if these projects can complete their major construction programmes by the early 2030s. We urge DESNZ to open the first application window for LDES projects following LDES policy decisions later this year or by Q1 2025 at the latest, and to ensure that this mechanism is covered under legacy arrangements from the perspective of REMA reforms.

Turning to the REMA consultation package of proposals, it necessarily reflects how markets work around a wide range of central policy interventions including the CfD, Capacity Market, CCUS and hydrogen to power business models, Nuclear, LDES investment mechanism, and the EU Emissions Trading System/Carbon Border Adjustment Mechanism.

The REMA CM proposals do not include specific obligations to prioritise low carbon flexibility, relying on the NESO general duty to deliver this. However, it is unclear how this may be delivered by the NESO unless a form of carbon pricing or other market restriction is introduced. The benefits of stronger power sector carbon pricing are under-recognised in the REMA document and could form a key element of government strategy for achieving a net-zero power sector. Higher and gradually increasing power sector carbon prices can send the right signals for low carbon flexibility in a technology-neutral way and should reduce the amount of other bespoke market interventions required by government.

As a starting point, DESNZ should make sure to take a holistic approach and ensure that measures set out in the REMA consultation align with existing policy and policy being developed outside of this consultation, including potential reforms to the UK Emissions Trading Scheme which were recently consulted on.

The REMA design seeks to optimise the delivery of sufficient MWs of the desired technology to meet decarbonisation and security of supply targets. However, the focus on flexibility in this package is on the provision of MW flexibility. It does not address the other flexibility resources needed for a stable electricity system e.g., voltage support, inertia, response, fault levels. These are also important flexibility resources which require investment signals. These are the type of system services that may be provided by pumped storage hydro plant for example.

Currently, these ‘flexible system stability’ resources are usually provided by fossil fuel plant under their grid code requirements, without any additional payment. There are currently no long-term price signals driving investment in these services other than specific ancillary service tenders run by the ESO for long-term service provision.

Continuation or expansion of the current arrangements is likely to result in a non-optimum solution where a capacity market incentivises the delivery of MW adequacy while ignoring the provision of ‘flexible system stability’ resources.

We suggest that, alongside the provision of MW capacity adequacy, the package of reforms should also take into account how price signals may be provided for ‘dispatchable stability capacity' to be optimally provided in future electricity markets, and especially how the long-term price signals may best be provided to trigger investment.

We would also suggest that the package of reforms also takes into account how this may introduce ‘non-network solutions’ instead of transmission investment. There are potentially major savings to be realised by procuring flexible resources such as LDES instead of transmission network investments. There would be a need to coordinate the procurement of LDES assets to assess their value as an alternative to transmission network investments and associated congestion costs.

Any transition away from bespoke support should be carefully considered and DESNZ should not set a deadline for doing so and instead should apply a criteria approach

for considering transitioning away from bespoke support to ensure the Optimised CM is suitable, and that the technology can compete and be delivered.

Finally, we suggest that the potential for coordinated long-term price signals to trigger efficient investment in combined flexibility for a) dispatchability, b) stability and c) congestion services be considered further.

Challenge 4: Operating and optimising a renewables-based system, cost-effectively

Summary of response to Challenge 4

- Whilst we would caution against overestimating their magnitude, we agree that the consultation has correctly characterised many of the challenges that we face around locational and temporal outcomes and the need to improve key processes and frameworks, including the balancing mechanism.
- That is why we agree both that there is a need for significant reform and that the current market framework is not suitable to deliver net-zero. However, this reform needs to be appropriate to the challenges which exist and should not overlook the fundamental strengths of our existing market arrangements. Reforms must also be viewed within the context of the massive increase in renewables deployment which must be achieved over the next decade, with assets' locations being guided by strategic planning of the energy system.
- **SR welcomes the ruling out of nodal pricing. However, we are concerned that a credible case for implementing zonal pricing has still not been made.** The existing modelling of the benefits of a move to zonal pricing is flawed and DENSZ has not provided clarity regarding the model of zonal pricing which would be adopted and how this model would interact with other market arrangements. We also believe that zonal wholesale pricing would send conflicting investment signals to those delivered through the forthcoming Strategic Spatial Energy Plan. DESNZ has not provided evidence to the contrary, and the consultation document does not provide a substantive discussion of how the increased role of strategic planning should impact market reform. These are issues which DESNZ must address as a priority in the next phase of REMA.
- **Whilst the benefits case has not been made, it is clear that the majority of the risks identified for nodal pricing also exist for zonal.** Given that the major transmission constraints lie between regions, for example between Scotland and northern England, that would likely become zonal boundaries. **We therefore remain of the position that zonal wholesale pricing should also be discounted as an option.**
- **SR supports the idea of progressive reform of the current national bilaterally traded wholesale market – the process that the consultation calls 'alternatives to locational pricing'.** We think that there is an important role for locational price signals where appropriate, but that these should not be delivered through the wholesale price. As discussed below, we believe there are opportunities to improve operational signalling through the BM and to develop constraint management products and markets to run alongside the wholesale market.
- Whilst locational pricing, whether delivered through a zonal wholesale market or an alternative approach could have an important role to play, we would suggest that **locational price signals should only be used where it is clear that they are useful and do not undermine investment by placing inappropriate risk on assets.**
- The growing emphasis on strategic planning, which will play a role in directly influencing the siting of electricity system resources, means that locational investment-timescale price signals is less important than it would have been under a fully market-driven approach. **Therefore, we believe that the focus of locational signals should be on operational timescales rather than investment timescales**.

- And, whilst we agree that operational-timescale locational signals may be important, they must align well with the wider issue, articulated well under Challenge 2: 'how to de-risk investment in renewables while increasing operational risk exposure to deliver lowest overall system cost'. Introducing additional operational price signals has the potential not just to increase risk on operational timescales but also on investment timescales (given that business cases are made up of the sum of risk-adjusted operational timescale revenues that are expected over investment timescales).
- **We are concerned that the consultation and the wider REMA debate when discussing locational approaches focus too much on 'push factors' rather than 'pull factors'.** By this we mean that many of the proposed options focus on decreasing revenue, increasing cost or increasing revenue risk on renewable generators locating behind a constraint – these options risk 'pushing' those projects out. We think a much better approach is to focus on providing strong 'pull' signals for flexibility of production behind and in front of constraints and for additional and more flexible demand behind those constraints. This would better reflect that fact that a wide range of non-price signals make the location of renewable generation relatively fixed (e.g. by renewable resource, leasing, and strategic planning). Removing access rights for renewable generators behind a constraint is an example of a 'push' factor (Alternative Option B); a voluntary constraint management market represents an example of a 'pull' factor (Alternative Option C). Incentivising co-location would complement these pull factors.

Responses to Challenge 4 questions

Zonal pricing

The consultation highlights the following design choices that would need to be made to create a concrete zonal pricing model. These are:

- Number of zones/approaches to zonal definition.
- Approach to reviewing zonal boundaries.
- Dispatch (self, central or hybrid).
- Demand-side exposure.
- Support scheme design (low or high exposure assets in receipt of support to locational price and volume risk).
- Market power and gaming mitigations (Status quo including REMIT etc. or additional measures).
- Access rights and hedging products.
- Approach to inter-zonal capacity allocation.

22. Do you agree with the key design choices we have identified in the consultation and in Appendix 4 for zonal pricing? Please detail any missing design considerations.

The concept of zonal pricing is extremely broad, with a wide range of models for implementation. Some of these models already exist elsewhere in the world, whilst others do not. An important point is that **significantly more information is needed to understand how DESNZ expects the different models would work.**

We think that UK government is considering at least the following:

- ‘A mini-EU target model’ in which multiple GB zones operate as largely independent, potentially self-dispatched / bilaterally traded markets with power transfer between those zonal markets allocated through either explicit or implicit auction of inter-zonal network capacity. Generators could have firm financial access rights within the zone but, as each zone is in effect operating as a separate market, would need to compete to gain transmission rights (either physical or financial) to other zones. This would likely be incredibly complex for anything but a very small number of zones – potentially no more than two.
- A ‘centrally dispatched LMP-lite’ model in which, as with nodal pricing, all parties bid and offer into a centralised mandatory GB-wide auction which is then cleared via a central algorithm in a way that respects inter-zonal transmission limits and sets zonal prices. Market participants would not have firm access rights in this auction and would only gain access to the system if they won a contract in the auction. Further arrangements would still be needed to solve *intra* zonal constraints (within the zone).
- These two might be the two ends of a spectrum and it is possible to construct hybrid versions of each.

DESNZ needs to provide greater clarity on the options under consideration and how they might work in practice. This includes a full, systematic analysis of how different zonal pricing models would interact with other market arrangements such as the CfD, the impact of grandfathering and how the cost of capital would be impacted. We are concerned that DESNZ’s current understanding of these interactions appears underdeveloped, so we believe this analysis should be carried out as a priority.

We would note that the UK market already operates on a de facto zonal pricing basis through the creation of zonal transmission losses introduced by BSC modification P350. There has however been no evidence that P350 has yielded any benefits for the market since its introduction and in particular any of the benefits that are targeted by REMA. Zonal pricing would exacerbate the impact of P350, further disincentivising generation in Scotland without a demonstrable benefit case.

We welcome the LCP Delta/Grant Thornton study on the impact of a move to locational wholesale pricing. Whilst we note that system benefits are found to arise when it is assumed no increase in the cost of capital occurs, we believe that it is the findings set out in Chapter 6 of the report which are particularly instructive. **The study finds that the modelling results are highly sensitive to changes in the cost of capital, with an increase of just 0.3-0.9 percentage points enough mean that a move to locational pricing becomes a net cost to the system.**

This finding makes intuitive sense; given the massive scale of investment required to reach net-zero, even small changes in the cost of this investment can lead to large increases in the absolute cost of achieving the required deployment to reach 2035 and 2050 targets. These costs therefore quickly outweigh any potential system benefits of a move to locational pricing. Credible estimates place the impact of a move to locational pricing on the cost of capital in the region of a two-percentage point increase.[4]

In LCP Delta/Grant Thornton's core modelled scenario, a two-percentage point increase in the weighted average cost of capital leads to a move to locational pricing resulting in over £30 billion in system costs. There are several reasons why this study could in fact underestimate of the net system costs of a move to locational pricing:

- LCP Delta/Grant Thornton acknowledge that improved management of constraints and operation of interconnectors (which accounts for the majority of the benefit case for locational pricing) could be achieved through reform to existing market arrangements.
- Total capacity is assumed to be fixed. This means renewable capacity is assumed to be built whether it is economical to do so or not, thus erroneously transferring significant benefits to consumers. The modelled benefits of zonal pricing appear to largely arise from unrealistic assumptions about large movement of offshore wind from northern GB to the south coast of England. Additionally, assumptions made about interconnector capacity growth in southern England do not align with latest views that take congestion into account. It is also not clear that the study accounts for the additional CapEx costs associated with deploying renewable generation capacity in areas of lower renewable resource – in areas of lower wind resource more turbines will be required to produce the same amount of power.
- There is no effort to quantify the disbenefits associated with either Financial Transmission Rights (i.e., the cost of hedging) or the loss of liquidity in smaller zonal markets.
- The modelling does not account for grandfathering costs, which are likely to be substantial.
- Dispatch costs under the BM are significantly higher in the counterfactual scenario (representing current market arrangements) than under a zonal market despite the outturn dispatch being broadly the same.
- The percentage of time that network boundaries are congested in the modelling does not align with industry expectations.

In direct response to the question, we identify the following additional design choices:

- **Options for forward trading (longer than day ahead):** the process for forward trading will differ between self and central dispatch designs. If self-dispatch, then forward trading could evolve in a similar way to today. If central dispatch it would likely need to take the form of private CfD or financial PPA arrangements.
- **Auction timescales and trading design:** day-ahead and intraday (or 'real time') auctions are likely to be an important part of a zonal system. In the case of central dispatch, these would likely be centralised mandatory auctions, in the case of self-dispatch they could develop in a similar way to today's national power-exchanges. DESNZ should explicitly consider the temporal design of trading within a zonal market.

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[4] A 2022 study by Frontier Economics estimated that a move to locational marginal pricing could lead to a 2-3 percentage point increase in the cost of capital. Further studies, including those by Afry (2023) and Aurora Energy Research (2023), which give consideration to the investment impact also emphasise the likelihood that a move to locational pricing will result in net system costs.

- **Access rights:** Although mentioned in the list above, the focus appears to be on inter-zonal access rights. DESNZ should confirm explicitly whether intra-zonal (within zone) access rights will be on a firm financial basis.
- **The mechanisms for managing inter-zonal constraints:** the consultation proposes that 'interzonal capacity' would need to be allocated explicitly or implicitly. This is a critical part of zonal markets. However, the consultation does not provide any thinking on how this might happen. For example, the transmission capacity is owned by the TOs and will be operated by the NESO. With the number of zones and the process for reviewing zonal boundaries still undecided, it is unclear both how cross border trading will be managed and the what the impact will be on markets in neighbouring countries.
- **Managing intra-zonal constraints:** the consultation does not lay out the different options that DESNZ are considering for resolving constraints within a zone. Two examples for how they could be managed: a balancing mechanism, similar to today; or integrated into the centralised auction algorithm with dispatch respecting intra-zonal as well as inter-zonal constraint but prices remaining set at a zonal level. This question interacts with the point above on the need for more information on access rights within a zone.

Alternatives to locational pricing

The consultation lays out four main alternatives to locational pricing:

- **Using Ofgem's pre-existing network charging reform programme (option A).** *This involves reforming network charging to deliver more effective locational signals. Although TNUoS is largely outside the scope of REMA, DESNZ have agreed with Ofgem that the two processes – TNUoS reform and REMA – should be taken forward in parallel.*
- **Reviewing Ofgem's transmission network access arrangements (option B):** *changing network access arrangements. This is based on four detailed options:*
    - *Administrative allocation of firm access for new users.*
    - *Auctions for firm access rights for new users.*
    - *Local firm access rights only for all users (with 'local' to be defined).*
    - *Removal of financial access rights to the entire network for all users.*
- **Expanding measures for constraint management (option C):** *this involves augmenting the BM with pre-gate closure options for managing constraints. It includes options such as day-ahead constraint management markets, improved constraint forecasting, solutions involving storage and longer term contracting / price signalling.*
- **Optimising the use of cross-border interconnectors (option D):** *including improving the efficiency of the SO-SO trading, new options to exchange balancing services with the EU and the introduction of an EU-GB cross-border balancing platform.*

And in addition two further options that are largely ruled out:

- **Introducing a locational element to the CM (option E)** which is fully ruled out.
- **Introducing a locational element to the CfD (option F)** which is ruled out as a primary option.

23. How far would our retained alternatives to locational pricing options go towards resolving the challenges we have identified, compared with locational pricing? Please provide supporting evidence and consider how these alternative options could work together, and/or alongside other options for improving temporal signals and balancing and ancillary services.

A Reformed National Market, as set out in the covering letter to our response, will deliver the vast majority of the benefits that zonal pricing is claimed to deliver more quickly and with significantly less disruption and lower impact on investment.

We also think that a combination of progressive reforms developed to deliver an overall strategic objective provides UK Government, the NESO and Ofgem with significantly more control over the signals that the market framework delivers overall.

However, there are some elements of the ‘alternative’ options that we think need greater consideration, and we do not agree that all of these options should be carried forward.

The reason we don’t believe certain alternative options should be carried forward is because they will significantly increase the risk, investability and cost-of-capital associated with renewable projects in much the same way as zonal pricing. Similarly to zonal pricing, these options would impact not only the cost of capital but the availability of capital. The recent period of very low interest rates has made infrastructure investments attractive for institutional investors. However, with rising interest rates, infrastructure capital allocations are declining. This means there is no guarantee the quantum of capital needed for decarbonisation can be secured as investors may not find the risk profile acceptable. We comment on each option below.

We also think there are several core components of the ‘alternative approach’ that are missing from the list of options. Some of these are not related to the wholesale electricity market framework itself and there is a risk that they are considered outside the scope of REMA. Whatever the scope, it will be important to ensure these are captured. In particular the following components are missing:

- **Strategic planning:** over the past year that has been a welcome acknowledgement that strategic planning will play an important role in the development of the energy system. A strategic plan delivers strong long-term locational signals (albeit not as price signals) and gives vital clarity to investors and planning authorities regarding long term transmission upgrades and new capacity to be built in a given area. This in turn will provide an attractive market for investors with lower risks, lower cost of capital and therefore lower cost to consumers. On the other hand, if market actors are reliant solely on REMA reforms to deliver those signals, there remains huge uncertainty for investors and NGESO/NESO.

  As NGESO transition to NESO, we can see that strategic spatial plans will have a major influence on the locational signals given to developers and to planning authorities, and many of the market signals that are being considered as part of REMA will be fundamentally influenced by the network topology that is developed through these spatial plans. It is therefore critical that locational price signals do not interfere with the delivery of a strategic plan designed to ensure that we reach net-zero following a ‘best value’ approach. REMA reforms should aim to deliver locational signals that work in harmony with locational signals delivered by strategic energy planning. This should include targeted locational signals for assets and demand that is harder to centrally plan in a meaningful way – particularly flexibility and strategic demand, such as data centres and electrolysers.

The worst regret outcome would be a combination of strategic energy plans that guide investment to locations coupled to a system of locational signals that is set up to penalise/reward assets for making particular locational choices without reference to the strategic plan. An example of this would be penalising plant that has connected under “Connect and Manage” which then receives a retrospective locational signal through a zonal pricing arrangement which methodologically fails to recognise that the zonal price outcome is largely down to a failure to build the grid that was at the heart of the Connect and Manage policy, rather than the locational choice of the producer.

- **Coordination of the development of the electricity system and strategic planning with seabed leasing, land availability, planning and consenting, and wind resource:** these are critical factors in the development of renewable projects and are highly location dependent. We expect these factors to be considered through the strategic planning process when developing the SSEP and the CSNP. We also expect both future leasing rounds and the evolution of the planning and consenting frameworks to work with the market reforms being taken forward through REMA. **Whilst these processes may not be directly within the scope of REMA, taking account of this context needs to be considered under any REMA options**. For example, how support mechanisms and market designs incorporate these factors will play an important part in delivering a joined-up approach to energy policy making.

We provide our view on each of the alternatives to zonal pricing below.

Option A - Using Ofgem's pre-existing network charging reform programme

We agree that network charges can play an important role in providing locational signals within the market framework, working in harmony with the access arrangements of connections reform and network capacity signals which will flow from strategic energy planning. We also agree that the generation TNUoS charges are presently volatile, hard to predict, and challenging for market participants to respond to. We would go further and say that TNUoS acts as a barrier to development rather than a positive incentive to locate appropriately. Since the last consultation, the growing importance of strategic planning in the government’s plan for development of the electricity sector suggests that locational TNUoS is likely to be in tension to the objectives of strategic planning. We also note that, in its September 2023 Open Letter, Ofgem acknowledges that ‘transmission charging reform effort would likely be characterised by the need to make material trade-offs between the charging principles’ (pg 9) and that ‘In principle, the more prescriptive that planning processes are on siting decisions, the less useful a TNUoS locational price signal may be as the ability of new assets to respond to such signals would reduce’ (pg 25).

We are also concerned that strong locational TNUoS signals will interact with CfDs to deliver poor value for consumers. At present, there is evidence that locational TNUoS leads to CfD auctions clearing at higher prices than would be necessary. This happens because projects subject to higher TNUoS charges must factor this additional cost into their strike price bid. When these projects clear an auction, other projects which had lower prices bids receive an uplift in their strike price beyond what would be required to deliver their project. This ultimately leads to higher costs to consumers.

Therefore, in the context of an increasingly centrally planned energy system, we do not think that stronger locational TNUoS is the most appropriate way to deliver useful signals.

Option B - Reviewing Ofgem's transmission network access arrangements

Firm financial access rights are the bedrock of investor confidence. We are concerned that DESNZ is considering options to remove firm financial access under some circumstances. As a minimum, we would expect grandfathering for generators who have connected under the Connect and Manage policy arrangements.

The consultation states that "This form of financially firm access rights has contributed to rapidly escalating constraint management costs". We disagree. We think that the growth of constraint management costs beyond what is economically efficient is due to a lack of timely transmission investment made during the 2010s. The policy of Connect and Manage during the last decade was meant to allow projects to get built in advance of reinforcement, not instead of reinforcement. A certain level of constraints is desirable as it means that the system is operating without excess capacity.

However, the levels we have experienced in recent years should have been the signal to build additional network capacity. Only the ESO and Ofgem have the visibility and ability to trigger those reinforcements. It would therefore be inappropriate for the failure to deliver network investment to sit with developers.

It is important to characterise constraint cost (or at least the curtailment payment part of them) correctly: these are payments to make good the revenue stream and revenue certainty required to draw in the initial investment at an affordable cost-of-capital. Given fixed costs account for 94%, 86% and nearly 100% of the LCoE of offshore wind, onshore wind and solar respectively (compared with 11% or less for CCGT gas)[5] **without curtailment payments wind farms would (a) require significant additional revenue from other sources and (b) if the extent of future curtailment is uncertain (as it inevitably is given the lack of willing long term buyers and long term FTRs) there would be a considerable increase in the cost of capital required to draw in investment, potentially to the point that business cases become unviable.**

At a distribution level we are really starting to see this impact projects. The risk that is placed on generators with Active Network Management connections with potentially high levels of curtailment, technical limits and constraints from operational outages and a lack of clarity of the operational criteria from DNOs is leading to a very difficult situation for developers and investors. If this was introduced at the transmission level for offshore wind projects, for example, it would make it very difficult to maintain current pricing levels.

The four access right reform options under consideration range from administrative allocation of firm access rights to new generators with an option for new generators to accept non-firm access rights in return for quicker / cheaper connections through to full non-firm access to the entire network for all generators.

Options 1 and 2 are likely to be worthy of exploration, and we can see the potential role the voluntary non-firm access could play for storage, or for time-limited early access to the network. However, we believe they must remain 'optional' whilst the ambition of providing firm access rights to all generators at the earliest opportunity should remain the overall ambition.

We do not think that Options 3 and 4 should be taken forward. We agree with the statement 'There is a risk, however, that without further reforms alongside these changes, reforming access rights could have a negative impact on levels of investment needed to reach our net zero targets.'

[5] Analysis of [DESNZ levelised cost estimates for electricity generation technologies](#).

Option C: Expanding measures for constraint management (option C)

We think that a significant expansion of constraint management options represents the best way to provide appropriate locational price signals and optionality to support efficient and best-value dispatch of the electricity system.

Our recent report on improving constraint management, '[Exploring options for constraint management in the GB electricity system: the potential for constraint management markets]', suggests that constraints should be managed via a portfolio approach with a range of tools running at operational and investment stage. Operational tools such as day-ahead constraint management markets, which could mimic the new Balancing Reserve services on a locational basis, can provide the price signals and incentives needed to drive operation, and can be contracted and dispatched in a way that reduces the pressure on the BM and returns it to its role as a residual balancer. Investment-timescale constraint contracting could act as a 'pull factor', drawing in energy storage and new forms of demand into constraint areas, locking in prices, and hedging consumer risk.

Option D: Optimising the use of cross-border interconnectors

We agree that there is a need to better manage the dispatch of interconnectors in line with internal GB constraints. We support the approach laid out in the consultation to work with the interconnector sector. We think there is a range of options which can be used to ensure that interconnectors are dispatched in a way that supports efficient GB system operation, including improved planning and operational arrangements for cross-border interconnectors, standardising trading processes, aligning with European market arrangements, and utilising frameworks for closer operational cooperation between neighbouring system operators. It is important to realise that, in isolation, reforms in GB will be unlikely to maximise the potential system benefits provided by interconnectors. Improving the operation of interconnectors will require working with system operators of connected markets.

We note there has been a lack of interaction between the interconnector sector and the wider debate on REMA. In our aforementioned constraint management report, we recommended that an expert group be set up and we reiterate that recommendation here.

Scottish Renewables will be publishing a report with more detailed recommendations for how the use of cross-border interconnectors can be improved. We will share this report with the DENSZ REMA team upon publication.

Options E and F: Introducing a locational element to the CM and CfD

We agree with the decision to rule out a locational element to the CM. We believe that the appropriate way to ensure regional security of supply is through the development of appropriate network capacity, and through the evolution of the Security and Quality of Supply Standard (SQSS) which defines the required network capacity between regions of the GB system and the limits on the way in which the system can be operated.

We also agree with the decision not to use CfDs to send locational signals.

Summary: Taking forward a package of progressive reform represents the most appropriate way forward for REMA. This approach will deliver many of the benefits claimed for zonal pricing but without leading to increases in investment risk and cost of capital. We think a major focus on developing a well-designed and thought through constraint management portfolio should be at the heart of this, along with an urgent focus on developing new tools to support efficient interconnection dispatch. We think that this, combined with the non-price locational signals that will come from a growing focus on strategic planning, including the signals from seabed leasing, land availability, planning and consenting, is most likely to lead to a successful outcome.

Ensuring system operability

The consultation lays out a variety of proposals for system operability these include:

i. Shorter settlement periods.
ii. Tighter gate closure (ruled out).
iii. BM reform including increasing competition and transparency.
iv. Central dispatch (either with zonal pricing, or as a stand alone reform).
v. Additional measure including: an electricity system operability strategy, improved forecasting of medium to long term operability needs, improved GHG emissions reporting, exploring perceived barriers to provision of ancillary services from collocated assets and alignment of longer term ancillary service requirements with CM and CfD auctions.

24. Do you agree with our proposed steps for ensuring continued system operability as the electricity system decarbonises? Please detail any alternative measures we should consider and any evidence on likely impacts.

We agree that operability of the future decarbonised electricity system needs to be given careful consideration. Before progressing with any changes, a substantially higher evidence base needs to be prepared and fully transparently discussed with operable assets industry and wider stakeholders.

We agree that shorter settlement periods should continue to be considered and we can see the value that they can potentially deliver.

We agree that the BM should continue to be improved, and we welcome the recent moves that have increased transparency in the BM. It is critical that we have a modern and responsive system to balance the electricity system between gate closure and final delivery. However, it will be important to acknowledge the limits of what BM reform can achieve. It will need to be augmented, for example with constraint management markets ahead of gate closure, and further evolution of the ancillary service market.

We do not agree that central dispatch should be considered. We think the rich ecosystem of bilateral trading that has developed around the GB wholesale market is a strength of the current approach. Whilst we acknowledge the need to reform and adapt that approach to reflect the context of a decarbonised system, we think much would be lost by moving to central dispatch.

It is also important to realise the role that co-located projects, in particular those which could come forward as a result of the introduction of hybrid metering to the CfD, could have in terms of improving the operability of the electricity system. (Further consideration needs to be given to incentivising co-location for offshore wind projects, as noted in our response to Question 6.)

We believe greater focus does need to be placed on operability and we welcome the additional ideas presented, particularly the requirement for an electricity system operability framework which could form the coordinating hub of the actions that need to be taken.

As set out in our response to Challenge 3, REMA should ensure that sufficient investment is triggered in flexible energy resources to satisfy future operability requirements recognising that flexibility has public good characteristics. Economic, reliable, low-carbon operability resources will be critical for:

- Dispatchability: providing dispatchable low-carbon electricity when renewables are unavailable, displacing flexible fossil-fuel generators.
- Maintaining system stability: providing ancillary services, such as inertia, voltage flexibility and restoration, which renewables may not provide.

It will be important that REMA market design delivers effective and coordinated long-term price signals for each of these capabilities to achieve the optimum solution. An uncoordinated market design could deter efficient investment and lead to higher costs.

Options compatibility and Legacy Arrangements

Risk allocation across market actors

The consultation discusses risk extensively throughout. It also identifies and characterises risks in different ways. Whilst the consultation identifies a relatively large number of risk types, it does not present an overarching typology of risk types. This feels like an omission as it would be useful to have a consistent framework for the sector to use for discussing risk.

DESNZ continues to advocate for the principle that allocating risk to the parties best suited to manage it should lead to system-wide benefits and a more efficient system overall.

We answer this question in terms of the specific sources of risks.

25. Which market actors (e.g. generators, suppliers, consumers, government) are best placed to bear / manage different types of risk?

We think there are the following important risk categories:

- **Technical project considerations** such as asset failures: should be held by asset owners.
- **Renewable resource variability:** should be held by asset owners.
- **Future demand for electricity:** Where government is committing to delivering policies which will increase demand, as is the case from now until at least 2050, government should primarily be responsible (either through taxpayers or consumers) for holding and managing this risk.
- **Competition from other generators and other technologies:** in principle should be held by asset owners. However, given the level of control that government has over the plant mix via planning policy and the introduction of multiple support schemes, in practice government has a role in holding and managing this risk.
- **Geopolitical events:** risks should be shared between asset owners, consumers and government. However, government and Ofgem should take responsibility for lowering the potential impact of geopolitical events through the acceleration of renewables.
- **Delivery of network infrastructure:** successfully delivering appropriate scale and location of network infrastructure is the responsibility of the government, Ofgem, the NESO, and the TOs. Given that these organisations do not have the capacity to hold this risk it is a simple fact that this risk should largely fall on consumers or taxpayers. TOs can face some of the risk associated with developing, building and operating network infrastructure but not the risk of scale and location of network as these decisions are ultimately taken by Ofgem and government with ESO advice.
- **Delivery of flexibility assets / operation:** this is highly dependent on government policy and Ofgem's regulation. Whilst individual projects may co-develop generation and flexibility or partner with it, the overall delivery of sufficient flexibility of the right type in the right location is out with the control of individual asset developers. The risks associated with the operation of flexibility assets, on the other hand, are best held by asset owners.

Options compatibility

The consultation lays out considerations of some interactions between options. Some of the key interactions that it does discuss are:

i. Shortening settlement periods would provide greater temporal granularity would interact with flexibility and could interact with the responsiveness of CfD generators in conjunction with changes to CfD risk allocation.
ii. Introduction of central dispatch would interact with CfDs, particularly when payments are linked to outputs.
iii. Locational wholesale pricing would interact with renewable support schemes (e.g. requiring change of definition of the reference price for CfDs).
iv. Locational wholesale pricing and other investment support schemes.

26. Do you agree with our initial assessment of the compatibility between our remaining options? Please set out any key interactions we have missed.

We agree that the points that the consultation has raised represent important interactions.

However, the analysis provided in the consultation is unstructured and incomplete, and therefore we cannot agree that it has identified all material interactions.

We believe that DESNZ should carry out a systematic analysis of interactions between options, for example looking at all material interactions and identifying each combination as ‘complementary’, ‘feasible’, ‘in tension with each other’, ‘unfeasible’, etc. This analysis should then be published for consultation.

Legacy arrangements

The consultation specifically considers how REMA reforms could interact with existing government support schemes. Any such scheme introduced before a decision on REMA is referred to as a legacy arrangement, with the relevant assets referred to as legacy assets.

DESNZ intends to consider two categories of effect on legacy arrangements and assets:

i. Functional effects
ii. Financial effects

DESNZ intends to take a scheme-by-scheme basis for reviewing effects, noting that the interaction between each individual REMA option and each individual legacy arrangement is specific.

DESNZ intends to consider the following legacy arrangements:

i. CfD
ii. CM
iii. ROC
iv. FIT
v. Net Zero Hydrogen Fund
vi. Interconnector C&F
vii. Nuclear CfD and RAB

viii. Additional ‘new’ legacy arrangements still in flight (e.g the Dispatchable Power Agreement)

27. Do you agree with our approach to assessing the impact of REMA reforms on Legacy Arrangements?

It is vital that DESNZ considers the impact on Legacy Arrangements and on Legacy Assets and where the impact is significant that DESNZ considers how to mitigate or exempt Legacy Assets from those changes.

We agree that there is the potential for tension between the need to abide by commitments already made and the challenge of dealing with an increasing capacity of assets that are ‘locked in’ to Legacy Arrangements. However, this challenge would not be a justification to make retrospective changes to policy frameworks which underpin investments made in good faith. For the consultation document only to provide assurance to CfD projects up to AR6 would be insulated from locational price risk is not acceptable. Similarly, it is very concerning that bespoke support schemes which are currently under development and will be implemented prior to REMA reforms, such as the LDES investment mechanism, are not stated to be considered within the scope of Legacy Arrangements.

Many of the REMA proposals being considered will take several years to implement and will have significant consequences for existing operational assets and assets which will be built in the near term under current market arrangements. This is particularly true of a move to zonal pricing.

On this basis, we believe DESNZ must make the following commitments. Firstly, that all assets and agreements in place up until the point that clarity is provided over the REMA reform package will be within the scope of Legacy Arrangements. Secondly, that for all assets, whether covered by a support scheme or not, the approach to Legacy Arrangements will ensure that investors’ legitimate expectations at the time investment decisions were made continue to be met. If government fails on either commitment, there will be a high risk of a hugely detrimental investment hiatus occurring whilst uncertainty over REMA reforms continues, resulting in lasting damage to investor confidence. Consideration must also be given to avoid undermining the commercial viability of operational assets to ensure they are not stranded.

This will be a very complex task, and government must clearly demonstrate how protection of Legacy Assets will be achieved in order to maintain investor confidence. We consider that more radical reform is likely to bring greater challenge in terms of developing and implementing appropriate arrangements for protecting Legacy Assets. It is important that these challenges are further explored and assessed as part of DESNZ’s assessment of REMA reform options and packaging.

Failing to address negative revenue/profitability impacts on existing assets would create a negative precedent undermining revenue certainty, which high CapEx project investment depends on. We would also note that future investment relies on equity (alongside debt) financing. Therefore, negative impacts to revenue and profitability would also more directly reduce investment capabilities (and increase the cost of investment) for existing UK generators.

We agree that considering functional and financial impacts on projects is a useful way to analyse the issue.

We would also suggest that DESNZ **consider the impact on sunk-investment and payback periods** within financial impacts. Investment decisions have already been made and are underway based on a specific assumption of future market arrangements; the introduction of zonal pricing risks undermining these investments at a time when significant investment is critical.

We also **agree that it is important to consider this on a scheme-by-scheme basis** including long life merchant assets and periods when long life assets reach the end of their support period (e.g. the 15-year CfD term) and begin operating on a merchant basis**.**

A particular concern is that the discussion in this section of the consultation document makes no mention of the categories of:-

- RO supported generation,
- unsupported or “merchant” generation,
- storage assets.

We are concerned by the potential implication that government considers that these categories of asset would not require or merit any form of legacy protection in the event of significant market reforms introduced by REMA. We would highlight that owners and developers of merchant assets have invested on the basis of a range of reasonable assumptions and understandings about the nature of the electricity market in which they will operate and that changes being considered as part of the REMA process could significantly impact on those assumptions.

28. What risks do we need to consider with regard to Legacy Arrangements, and how can they best be mitigated?

It will be important to consider a very wide range of risks. **It will also be important to consider the context for each type of asset separately.**

For example, at FID, many renewable projects sink the majority of their project costs and recover these over expected project lifetimes which in many cases are 25 to 30 years (significantly longer than the 15-year agreements of the CfD). This means there is the potential for huge risk to investors.

The political risks associated with allocation of grandfathering costs should be an important consideration e.g. per zone or across GB and the subsequent impacts of these approaches.

Additionally, the benefits of Legacy Arrangements should be accounted for when considering legacy risks – e.g. the consumer benefits associated with renewable generation growth and interconnector deployment should feature in any assessment of legacy.

It is necessary for DESNZ to **take proper account of investors’ perception of regulatory and policy risk** associated with the GB market. The impact of these risks is real and government must not make the mistake of ignoring it. We are increasingly competing globally with investors comparing GB with other jurisdictions, and securing the quantum of investment required to achieve 2035 and 2050 targets cannot be guaranteed should the UK lose its attractiveness as a destination for low carbon investment.

[END]