Energy UK

The voice of the energy industry

Energy UK response to Review of Electricity Market Arrangements: second consultation

7 May 2024

About Energy UK

Energy UK is the trade association for the energy industry with over 100 members - from established FTSE 100 companies right through to new, growing suppliers, generators, and service providers across energy, transport, heat, and technology. Our members deliver nearly 80% of the UK's power generation and over 95% of the energy supply for 28 million UK homes as well as businesses.

The sector invests £13bn annually and delivers nearly £30bn in gross value - on top of the nearly £100bn in economic activity through its supply chain and interaction with other sectors. The energy industry is key to delivering growth and plans to invest £100bn over the course of this decade in new energy sources. The energy sector supports 700,000 jobs in every corner of the country.

Energy UK plays a key role in ensuring we attract and retain a diverse workforce. In addition to our Young Energy Professionals Forum, which has over 2,000 members representing over 350 organisations, we are a founding member of TIDE, an industry-wide taskforce to tackle Inclusion and Diversity across energy.

Executive Summary

Energy UK welcomes the opportunity to respond to the Government's second consultation on the Review of Electricity Market Arrangements. Our members are committed to delivering a Net Zero energy system and support the Government's REMA programme to ensure that the UK's electricity markets can support a more efficient system while attracting the scale of investment required.

Challenge 1: Energy UK emphasises the crucial role of the CfD scheme alongside Corporate Power Purchase Agreements (CPPAs) in facilitating the transition to Net Zero. CPPAs are vital for linking renewable energy generators with commercial customers, offering both stability in revenue and energy costs. However, due to complexities and risk factors, CPPAs will have a limited lifetime for several reasons including policy uncertainty. Energy UK suggests removing obstacles to the CPPA market and monitoring potential impacts on market liquidity and price distortions. Additionally, Energy UK recommends examining international CPPA market reforms, particularly in the EU, to inform decision-making for advancing CPPAs in GB's industrial decarbonisation efforts.

Challenge 2: Energy UK does not support the view that the design of the Contracts for Difference (CfD) scheme is solely responsible for all of the challenges and distortions identified in the consultation. However, we agree that we should explore alternative arrangements to address the responsiveness of CfD assets to system needs. Our members recognise that either the Deemed CfD or the Capacity-based CfD could potentially work. However, based on the information available the majority of members have a preference for the Deemed CfD model as it offers comparable risk distribution with the existing CfD, and aligns with the principle of shielding both generators and consumers from unmanageable risks. However, further analysis is required to assess respective risk implications before Energy UK can fully endorse any of the CfD proposals. Finally, we would emphasise the need to prioritise risks related to future auction design and the CfD supplier obligation levy.

Challenge 3: Energy UK supports retaining the Capacity Market to ensure capacity adequacy and security of supply, and we support the need for reforms to enable full participation of low-carbon technologies in the transition to a net-zero energy system. There is, however, a lack of specifics on several aspects of the proposals including low carbon characteristics and flexibility criteria. Clarity on desirable characteristics is vital for developers and investors to understand market alignment with policy frameworks, and industry engagement will be critical to explore options to manage efficiency and risk. Understanding decarbonisation pathways for CM-contracted plants, including CCS and hydrogen retrofit options, requires a coordinated system-wide approach to infrastructure development and network connections. Clarification is needed on how plants with bespoke support will transition into the CM, and the timelines for low-carbon flexible plant participation remain unclear.

Challenge 4: Members appreciate the consolidation of options but underscore the importance of comprehensive strawman proposals. Overall, members lean towards an evolutionary approach that enhances national pricing and reduces investment risks. Members emphasise the need for greater clarity on the costs and benefits of zonal pricing and advocate for a comprehensive analysis of retained alternatives to allow a robust comparison. While a minority support zonal pricing, the majority prefer further exploration of alternatives that could offer a more efficient system with reduced investment risks compared with the current arrangements. Some of our members recognise zonal pricing's potential to reduce constraints and balancing costs, but concerns persist about the potential benefits and the possible higher capital costs. Our members stress the need to maintain investment momentum and call for an objective and comprehensive assessment of both proposed pathways (zonal market and national market) to address identified challenges. Finally, selected reforms must include measures that safeguard consumer interests, ensuring transparency and fairness.

Options Compatibility and Legacy Arrangements: Energy UK members believe that full grandfathering is essential for all existing assets where investment decisions were made on the basis of national pricing and lacked certainty regarding the final REMA reform package. This includes CfDs, CM agreements, and CPPAs. The Government must promptly clarify the process of grandfathering to uphold investor confidence. This will provide a crucial signal to future project investors and is necessary for non-CfD generation in potential zonal pricing arrangements through effective financial transmission rights (FTRs). We would stress various risks and their impact on investor perception, confidence, and liquidity. This underscores the need for detailed consultation and analysis to inform decision-making and mitigate adverse effects on future investments and REMA reform benefits.

In addition to the above, Energy UK would highlight that carbon pricing (while outside the scope of REMA) remains vital in the context of electricity market reform as it aligns economic incentives with our decarbonisation goals. The continual low prices in the UK Emissions Trading Scheme alongside the Carbon Price Support (CPS) has resulted in a modest carbon price within the power sector. A stronger UK ETS price would incentivise investment in low-carbon generation and reduce the need for support from the CM and/or other bespoke mechanisms. Alongside the REMA programme, the UK Government needs to strengthen the UK's carbon price through ongoing policy developments and advancing progress to link the UK ETS with the EU ETS.

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

Question 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.

A larger CPPA market will play an important role in the transition to Net Zero. Energy UK notes that this is the first time that CPPAs have been discussed as part of the REMA process and, given the lack of detail in this consultation on how any reform to the CPPA market would be carried out, it is difficult to comment on the exact potential for growth in this market.

CPPAs have a role in linking renewable generation and industrial and commercial customers together, providing a stable, long-term revenue stream for the renewable generator and providing customers with certainty on energy costs, as well as the ability to meet corporate sustainability goals. CPPA models are likely to continue to exist as a secondary investment mechanism to the government-supported CfD scheme, as the number of credit-worthy parties will always be marginal given the relative higher risk of any PPA agreement unless the risk is relocated. At present, most UK businesses are unable to sign longer-term PPA agreements that may be able to underwrite new renewables projects, and multi-party CPPAs are more complex to design. Energy UK therefore believes that the CPPA market will remain important but niche.

Energy UK agrees with DESNZ on the need to remove barriers to the CPPA market. Energy UK broadly agrees with the DESNZ analysis of current market barriers for CPPAs. Many of the barriers that apply to CPPAs apply to other areas of the electricity market. For example, members note that policy uncertainty plays a fundamental role in preventing the development of a CPPA market, as it is hard to price in, for example, network charging reform when considering a fair price for both parties. It is important for DESNZ to consider the consequences of a potential move to a zonal pricing model on the CPPA market, including the additional cost of understanding CPPAs relative to the alternative, and the potential for lower overall market liquidity a move to a zonal pricing model would entail. The introduction of FTRs may also alter the balance of risk compared to a reformed national market, given that the FTRs typically available would have no positive impact on protecting CPPA parties from zonal risk.

DESNZ should also monitor the possible risk of negative impacts an increase in CPPAs might have on wholesale market liquidity and potential for price distortions. As CPPAs, like PPAs, might be referenced to day-ahead or intraday markets without offering these volumes in these markets, there is the potential for an increasing amount of renewable generation to be locked in at these prices without having as much liquidity or price discovery. This effect could be further exacerbated should more PPAs and CPPAs be pegged to day-ahead or intraday market prices.

Members suggest that DESNZ consider how the CPPA market is being reformed in other markets, for example within the EU. The EU's reforms to its electricity market design aim to incentivise the use of CPPAs and should be considered in any DESNZ decision-making on next steps. Given the potential importance of CPPAs for industrial decarbonisation in GB, DESNZ should additionally explore the interaction of the CPPA market with the non-domestic retail market. Energy UK and Public First are looking at potential areas for policy development in the non-domestic retail market, which will also consider the potential for growth in the CPPA market. Energy UK is happy to share this analysis with the DESNZ REMA team once completed.

Finally, Energy UK welcomes the fact that options for more radical reform of the market, for example Green Power Pools, have been ruled out in this consultation.

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

Energy UK members note the need for the considerable benefits of a decarbonised energy system for customers, and are pleased that DESNZ have ruled out some of the more radical options for reform in this space, including the Green Power Pool. Some considerations for market reform to enable these benefits to be felt more easily are laid out below.

- **CPPAs**

CPPAs play an important role in ensuring that the benefits of variable renewables are spread across different customers, and will help to decarbonise industry in the UK. However, as noted in our response to Q.1 we have concerns about the extent to which ongoing policy uncertainty, including that generated by REMA, will impact the growth of the CPPA market that can then pass on the benefits of an increasingly renewables-led energy system to consumers.

- **Reform to the REGO system**

While not currently playing a significant role in driving renewable investment decisions we support the enhanced investment in renewables through the reform of the REGO system and their clearer interaction with green supply. REGOs were intended to ensure the accounting of generation of renewable energy was accurate, however, this has become increasingly less transparent for consumers over time and disconnected from the generation of renewables. REGOs have the potential to play a key role in increasing low-carbon power in the UK, speeding up investment in renewables and therefore generation. Better alignment between the REGO system, green energy services and Net Zero would support the market for commitments to green power commitments. We would also urge DESNZ to make use of the responses to the 2021 Call for Evidence on Designing a framework for transparency of carbon content in energy products[1] to aid a potential reformation.

Question 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.

Energy UK welcomes the intent to ensure the energy system better creates incentives to address clear barriers associated with efficient demand reduction. We broadly agree with the decision to focus on a cross-cutting approach to demand reduction. Members agree that direct upstream market interventions are inappropriate for addressing demand reduction and energy efficiency improvements. A distinction should be made between demand-destruction (where demand is permanently reduced due to measures such as energy efficiency), and demand-shifting behaviours (where demand is shifted to a different time). Wholesale market arrangements should support demand shifting and demand reduction.

Energy UK fully supports the decision to focus on incentivising downstream interventions to support the link from suppliers to the actual customer behaviours that will reduce system costs. Where Government support is required to facilitate hard-to-activate reductions, this needs to be well-focused at those that need it.

There are two types of demand reduction. One provides value to system and saves consumers money though the non-use of energy at a particular time. The second is where demand reduction pressure does not provide overall value and wellbeing to consumers where they cut energy in an unhealthy or dangerous way. Demand reduction can be a dangerous message for those struggling to heat or eat. This means that it is vital that energy demand reduction strategies are focused downstream on holistic consumer outcomes and that they are

[1] Energy UK (2021) Energy UK response to consultation on designing a low carbon hydrogen standard.

facilitated through an affordability strategy that includes targeted support to reduce problematic demand reduction. It is also important that any demand reduction measures provide real system benefits and do not simply represent market transfers.

Retail market design and more substantial cost-reflective price signals are important elements of a strategy to encourage demand reduction. We encourage the Government to take a customer-centric approach to energy reduction in the domestic space that focuses on ensuring the retail sector and other innovators are well-positioned to effectively support customers to deliver enduring interventions.

This requires Government and Ofgem in coordination to more explicitly support the development of effective demand reduction services alongside energy provision. This requires a holistic, incentive-based approach to drive specific demand reduction behaviours where required to support the stated market design intent. This could include:

- A commitment to use more policy interventions as opportunities to get smart meters installed.
- Better data sharing from Government to suppliers to support identification of vulnerable and low-income customers.
- Reforms to price regulation to support equitable access to demand reduction opportunities.
- Modernising housing standards and planning rules.
- Support scheme obligations.
- Greater direction from Government on the role of price signals. Members suggest that Government has a clear strategy for using price signals to shape demand reduction.

Within a cross-cutting approach to incentivising electricity demand reduction, the following should be considered:

- The need for policy to focus on incentivising demand turnup to occur at times of high renewable generation.
- The use of cross-cutting solutions, for example the rebalancing of policy costs to facilitate the uptake of heat pumps.
- Greater data sharing between parties, including Government and ESO. Many of the challenges that a move to central dispatch would address could be mitigated by better data sharing, visibility and forecasting. This would also help to incentivise electricity demand reduction.

Energy UK further welcomes the commitment to review the methodology and process for valuing electricity demand reduction during 2024. Energy UK looks forward to engaging with the Government on these initiatives.

Energy UK agrees that Market-Wide-Half-Hourly settlement (MHHS) settlement will sharpen temporal signals for electricity demand reduction. However, MHHS settlement or any other settlement period that is enacted in the electricity market must be reflected in the design of energy efficiency schemes such as the Energy Company Obligation (ECO) and building regulations such as the Future Homes Standard (FHS) to be effective. To enable this, we encourage DESNZ, DLUHC & Ofgem teams to engage with one another and with industry to ensure that building regulations, electricity market arrangements and government schemes continue to be aligned after the REMA programme is concluded.

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

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

- This chapter has outlined several challenges facing the CfD scheme, however, there is still a notable **absence of evidence** supporting arguments for reform. Any proposed reforms aiming to address either the barriers that might prevent the participation of CfD assets in electricity markets or aim to help mitigate operational risks must undergo thorough modelling and follow an evidence-based approach to comprehensively understand the potential benefits and impacts.
- There is an inherent contradiction in Challenge 2 aiming to 'de-risk investment in renewables while increasing operational risk exposure'. Each option presented has the potential to alter the risk profile for generators and raise the cost of capital. While proposals might address operational risks, they cannot simultaneously maintain low capital costs.
- If zonal wholesale pricing is introduced, **fairness and stability in grandfathering** for investors will be crucial to mitigate potential adverse effects on existing investments during a transition to a potential new scheme, thereby safeguarding investor confidence.
- Each of the proposals put forward to reform the CfD scheme will alter the expected revenue for generators and this will have an **impact on the cost of capital** and ultimately on the **cost to the consumer**. This needs to be considered carefully as the current design of the CfD has been hugely successful in shielding consumers from volatile prices, while reducing the cost of deployment for large volumes of renewables.
- One challenge that was not identified in the consultation was the need to establish a long-term, sustainable approach for **setting targets and auction parameters** in a way that consistently and predictably delivers the required capacity. The significance of this challenge is underscored by recent allocation rounds, which highlight the need for ambitious and reliable auctions.
- The **volatility and unpredictability of TNUoS charges** continue to be a major challenge for developers, particularly for projects located in Northern England and Scotland. This has a major impact on the competitiveness of projects in allocation rounds resulting in higher strike prices and ultimately higher costs for the consumer. More broadly, this impact undermines the case for certain regions in GB with high potential to unlock the major supply chain opportunities.

It is clear that quantifying the potentially distortive effects of the CfD is crucial to understanding the specific issues and prioritising solutions effectively. At present, we are still discussing theoretical scenarios rather than concrete, quantified risks and impacts, which emphasises the need for empirical data to guide our decision-making. Energy UK believes that the challenges identified in this Chapter should be grouped into two distinct categories: (1) challenges that are directly related to the design of the CfD mechanism itself and (2) challenges that are linked indirectly to the CfD or to renewable generator characteristics with or without a CfD.

(1) Challenges related directly to the CfD mechanism

Energy UK agrees that one of the challenges of operating a renewables-based energy system is the increase in the number of periods where electricity is in oversupply as a result of either (1) insufficient demand and/or (2), insufficient infrastructure (transmission or storage) to support the electricity. We believe this to be the fundamental challenge associated with the current CfD framework which does not effectively manage inherent periods of excess generation that is part of a renewables-based system and the associated costs. Proposed modifications to the CfD design should therefore be tailored to address this specific challenge, aiming to better incentivise generators to respond to market conditions, while also recognising the potential for inefficient herding behaviour.

(2) Challenges that are linked indirectly

The vast majority of Energy UK members remain unconvinced that the majority of issues highlighted in the consultation are solely attributable to the current design of the CfD or will therefore be adequately addressed through reforms to the CfD scheme. However, some members view that the design of the CfD can have distortive impacts on dispatch and clearing prices in wholesale and ancillary service markets. This categorisation is explained below.

CfD's distortive impacts identified in the consultation	(1) Challenges that are linked to the design of the CfD mechanism	(2) Challenges that are linked indirectly to the CfD mechanism
Operational risks. The current CfD design incentivises maximum generation output (when DA reference prices are above zero) which creates various dispatch inefficiencies and higher costs. Operational risks identified include: • Dispatch • Storage and flexibility • Alternative use • Trading	Energy UK agrees that the current design of the CfD does not incentivise generators to respond appropriately to system needs, and this can have a distortive impact on dispatch signals.	Energy UK disagrees that the following distortive impacts are being driven solely by the design of the CfD mechanism. • Storage and flexibility • Alternative use • Trading
Investment risks. The current CfD design incentivises developers to invest in technologies that can maximise output, often in locations with better weather conditions, rather than supporting wider system benefits such as ancillary services. Investment risks identified include: • Location • Project characteristics		Energy UK disagrees that the current CfD is disincentivising assets to locate in areas with less renewable deployment. In the case of offshore wind, locating CfD assets are often down to government choices on seabed leasing. Energy UK also disagrees with the assertion that the absence of asset participation in ancillary services is inherently linked to the current design of the CfD. The consultation also does not provide any evidence to quantify this risk.
Challenges that are not included in the consultation		
Auction design risks. The current approach to designing CfD auction and associated parameters is failing to attract the volume of capacity that is required to deliver our energy security targets.	Energy UK believes the CfD has a clear role to play in attracting investment to 2030 and beyond, which is critical to delivering 50GW of offshore wind by 2030 (estimated to be in the region of £175bn) and deploying sufficient renewable generation capacity to decarbonise the power sector by	

	2035. The current design of CfD auctions does not sufficiently maximise or facilitate the volume of capacity that's required to meet targets or the capacity that industry believes is in the pipeline. Deployment of the renewable energy capacity needed to meet future decarbonisation and demand targets has, in part, been delayed by uncertainty over how much capacity will be procured on an annual basis. There is need to reform this process with CfD budgets linked to 2030 and 2035 targets that will give much needed certainty to the sector but still allow Government to refine auction parameters ahead of each auction. Currently, budgets are not transparent, with no certainty on how much renewable capacity will be procured.	
CfD Supplier Obligation risk. Alongside the challenges for the future of the CfD related to how it supports generation investment, and how supported generators interact with the wholesale market, there are also challenges for electricity suppliers in managing the impacts of the scheme.	These challenges are not discussed in the REMA consultation but they are significant and will grow as the volume of generation covered by the CfD scheme and its successor variants increases. We believe that DESNZ should review the operation of the CfD Supplier Obligation to consider how to reduce risks for suppliers, which will help to reduce costs for consumers. Ofgem should also review the operation of the Default Tariff Cap so that it passes through the actual costs of the CfD Supplier Obligation, rather than an estimate.	

Question 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?

As outlined in the table in Q5 above, Energy UK does not believe that the design of the CfD is the primary cause of all of the challenges and distortions that have been identified within the operational and investment risks in this consultation. However, our members agree that it is worth considering whether alternative mechanisms could help to solve the issue of CfD assets' responsiveness to system needs. In order to assess how renewable assets would behave if the distortions were eliminated, there are key considerations that need further investigation, starting with greater scrutiny of the perceived distortions. Thorough analysis is essential to completely understand their impact on asset behaviour, and this process should involve evaluating how assets adapt their operations, production levels, and investment decisions in response to changing market conditions. This includes fluctuations in wholesale electricity prices, shifts in demand and grid constraints.

Energy UK's assessment of the distortions identified in the consultation caused by the CfD

- **Disincentive for forward trading**

We agree that the day-ahead reference price is a disincentive for CfD generators to engage in forward trading. However, some assets operating on a merchant basis also tend to favour the day-ahead market and this preference stems from the tendency for wind and solar generators to trade closer to delivery when they have greater certainty regarding their output. Redesigning the CfD contract to broaden exposure to market signals with a reformed hybrid reference price or extended reference price could change generator behaviour. However, it could also introduce price exposure risks for variable resource renewable generators as they may be required to buy back power that was sold on forward markets if they are faced with lower than expected wind output. This will increase the cost of capital for investment, which undermines the reductions in capital costs that the CfD was originally designed for and which remains its primary purpose.

- **Herding behaviour and negative pricing**

We agree that when renewable energy generation exceeds demand, generators with a CfD may continue to generate electricity even when prices in the wholesale market are low. This is because current CfD revenue support is based on actual output, which exacerbates negative pricing events. Removing the link between actual output and revenue support would reduce the likelihood of herding behaviour as it would allow CfD assets to bid closer to their true avoidable costs. However, we do not believe this has been sufficiently quantified and it isn't clear whether a generator that is exposed to the full range of market signals/risks would behave differently. This requires further analysis.

- **Lack of participation in ancillary services**

An important aspect of the participation of CfD assets in ancillary services is the opportunity cost associated with the provision of ancillary services. It is clear that linking revenue support to actual output makes it difficult for CfD assets to compete in the provision of ancillary services. This is turn makes it more difficult for CfD assets to build investment cases that include designing in the capability to provide ancillary services. The prevailing issue with the lack of CfD assets participating in electricity markets including ancillary services is often because the price is too low and it is not therefore a commercially viable option. The second reason is that ancillary services and balancing markets are designed by the Electricity System Operator (ESO) to address specific system requirements. These markets are often designed to target the participation of specific technologies, such as batteries, and it is not clear which ancillary services will be required long-term and how intermittent renewables could effectively participate. As there are likely to be other factors at play, we cannot attribute the lack of renewable participation in these markets solely to the CfD without further examination.

- **Distortions in the Balancing Mechanism**

The reliance on actual output for payment influences how CfD generators participate in the balancing market in a similar way to what has been outlined above. Our members believe that one aspect relates to issues with the rules around the submission of dynamic parameters that restrict the ability of CfD plant to offer its flexibility in ways that would be of most benefit to effective system management. This is problematic for other non-CfD based assets who rely on accurate wholesale market prices and balancing mechanism dispatch to support investment.

However, our members agree there has been no quantified analysis of the scale of the issue or its contribution to rising balancing costs being incurred by the ESO, relative to other factors that are impacting on balancing costs. There is also a lack of information available to generators about live constraints which makes compliance with the Transmission Constraint Licence Conditions difficult. It clear that the distortions are the direct result of the design of the CfD and some of the issues related to the distortions in the balancing market could be addressed through reforms such as BSC Code Modification P462. Overall, greater transparency as recommended by the Energy Data Task Force would allow for parties to better understand the challenges here and to encourage market participants to see and appropriately respond to signals.

- **Disincentive to locate away from constrained areas**

Finding optimal locations for energy generation projects involves various challenges. The CfD mechanism can provide a signal to locate away from constrained areas by reflecting the cost implications of connecting to the grid in different locations via TNUoS. The TNUoS signal is however somewhat misaligned with existing constraints. Energy UK thinks that one effective way to direct a CfD plant to locate in areas that are less likely to be constrained is through the central planning aspects of connections policy and strategic spatial energy planning (SSEP). Alongside strategic planning, the centralised strategic network plan will also be key to expanding network infrastructure to address the challenge of locating generation efficiently. This would directly facilitate the integration of renewables and support the development of renewable energy generation in the most optimal locations. The ESO has also recognised that "paying constraint costs is critical to the development of renewable generation capacity in the short-term and is more than offset by optimising transmission investment and the long-term power price savings they enable." [2]

It is important to note that in the absence of locational incentives, renewable developers are likely to locate in areas of high renewable resource, regardless of whether they have a CfD or not.

Question 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)?

Energy UK's view of the current 'ongoing' reforms including expanding the scope of the CfD to support repowering, introducing hybrid metering arrangements and considering wider reforms that consider CfD auction dynamics and macroeconomic challenges. Energy UK believes these will all have a positive but potentially limited effect on scaling up investment, maximising responsiveness and distributing risks. This is explained in more detail below.

- **Scaling up investment**

One of the most important ways of addressing the scaling-up challenge is to reduce the risk faced by investors by maintaining the low market risk aspects of the CfD. Energy UK supports the introduction of hybrid metering to facilitate co-located generation and storage and this is particularly important as asset co-location increases. By streamlining metering processes for co-located assets, such as offshore wind farms with battery storage or hydrogen production facilities, hybrid metering has the potential to reduce operational complexities and project development costs, thereby attracting greater levels of investment in renewable energy projects.

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[2] ESO (2020) Modelled Constraint Costs NOA 2020/21, [download (nationalgrideso.com)]

To make this proposal feasible for offshore wind, Energy UK suggested in its response to the AR7 consultation to either relocate BMU boundary metering to an onshore substation which would enable the DESNZ proposals in the AR7 consultation for sub-metering to work for offshore wind. Alternatively, virtual metering could be utilised to enable assets located at the onshore substation to be treated by ESO/BSC as being behind the BMU boundary meter offshore. This would require more complex metering and communication protocols than option 1, but is well within Elexon's technical ability given it carriers out similar tasks to enable virtual lead parties actions to be adjust supplier positions.

- **Maximising responsiveness**

As has been established, the key issue that limits the responsiveness of CfD assets is the fact that revenue is linked to output. However, the introduction of hybrid metering also has the potential to increase responsiveness from CfD assets. By allowing for more accurate monitoring of energy generation and consumption at co-located sites, hybrid metering has the potential to allow better management capabilities. This increased visibility and control over an asset's output, particularly for those equipped with storage or hybrid technologies, could allow them to respond more effectively to fluctuations in market conditions, demand patterns and grid requirements. As a result, CfD assets could optimise their operations and provide more ancillary services to maximise their responsiveness to system requirements.

- **Distributing risk**

It is important to recognise that the CfD's success is due predominantly to the fact there is a compelling case to reduce the market risk for developers, and bringing forward investment with a low cost of capital. It is also important to recognise that the CfD is also a hedge for consumers and not just a subsidy, which reforms should seek to maintain. Investing under the CfD still exposes generators to significant risk including site selection, planning, designing, building, and operating long-life, high capital cost assets. Energy UK believes these risks are best held by generators as they can predict and manage them. However, market size, price, and volume risks are increasingly determined by central institutions (e.g. GB portfolio mix and transmission system availability risk).

Energy UK members believe that distributing these to CfD investors is likely to result in significant increases to the cost of scaling up renewable capacity. This should be borne in mind when considering proposals. It is difficult to properly assess the distribution of risk without more detailed and comparative analysis.

Question 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.

Energy UK's assessment of the deeming options:

Option 1: Our members believe this might work if generators and investors have advanced sight of the approach and involvement in how it would work.

Option 2: Our members believe this could also work as it is closest to the current approach.

Options 3: Our members believe this option could increase basis risk i.e. variability in earnings.

Option 4: Our members believe that option 4 is too complicated and would be too difficult and expensive to implement. Both options 3 and 4 should be ruled out.

Energy UK supports an asset-led deemed approach as we believe that generators and asset owners are better placed to do this than third-party providers, who will not be actively managing, trading or maintaining an asset. However, further assessment is needed on the costs and benefits of each approach before Energy UK is able to confirm a specific preferred option. If the deeming methodology is appropriately designed then we do not see a significant risk of gaming under the deemed CfD model, as the price and volume risks are likely to be similar to that of the current CfD. We would expect that anticipated gaming risks could be mitigated through a suitable monitoring and enforcement regime being set out by DESNZ and the LCCC, with support from the NESO as required, and potentially with oversight by an independent expert body. This would include establishing what a reasonable enduring forecast accuracy expectation is.

As identified in the consultation, generators are already required to provide a 'power available' signal to the electricity system operator and although this may not currently be accurate enough for the purposes of deeming, we believe that this could be developed to provide the appropriate data for the deeming methodology. Paying on a measure such as 'power available' allows the signal to be monitored and tracked against metered output with intervention, if necessary. This could include enforcement action to improve accuracy, reconciliation, or fines.

There is a hybrid option that could combine option 1 and 2. In this scenario, the asset owners would report their deemed generation, but an accredited third party could conduct a regular audit. This could also minimise gaming while lowering administrative costs. This is a similar approach taken in RO projects.

Two further important issues to consider in respect of the deeming methodology are:

- There is a risk that a generator is unable to operate during a period of high prices, but still incurs an obligation to make a large payment to the CfD counterparty, under the CfD terms and conditions. This risk could potentially make the CfD uninvestable. One possible solution would be that deeming would not apply when market prices are above the strike price.
- There is no need to apply the negative pricing rule with a deemed generation CfD. Generators have no incentive to generate when prices are negative. Moreover, continuation of the negative price rule with a deemed generation CfD creates extra revenue uncertainty for generators, leading to higher strike prices and higher prices for consumers.

Question 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.

There are several uncertainties around how a capacity-based CfD would function and its potential implications for market dynamics, investment viability and risk allocation. Some of our members have drawn parallels between the capacity-based CfD to a Capacity Market, and have expressed concerns that it could end up incentivising and prioritising the lowest cost bids, leading to a detrimental 'race to the bottom' in terms of quality, overall value for money and risk of preferential treatment.

Some of our members suggested a technology-specific allocation of the capacity-based CfD due to substantial variations in generation levels and revenues. We would also note that there is still a significant level of volume risk for the generators under this model.

One of our members has indicated their support for the capacity-based mechanism and believes it is more compatible with zonal wholesale pricing, and could encourage more diversity in trading behaviours and more innovation in business case development than the current CfD does.

However, overall, we have apprehensions that it could become a 'cap and floor' model and would require careful consideration of the gain share mechanism. It could also introduce dispatch distortions and several of the complex design issues that were sufficient to discount the 'cap and floor' model as part of the options assessment. The capacity-based CfD could also introduce more volatility compared to the current CfD with ongoing reforms, or the deemed CfD, potentially exacerbating market distortions and various forms of bidding behaviour.

The uncertainty and difficulty in analysing the capacity-based CfD model compared to the deemed CfD model stems from the uncertainty around the price of merchant revenues, which could potentially result in wider bid ranges and increased volatility across auctions.

Question 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? [To be reviewed with Q25]

As mentioned in the previous answer, it is difficult to make an informed assessment about the risk distribution of these two models, as we don't currently have enough quantified modelling of how they will work.

However, on balance, our members believe the deemed CfD has similar risk distribution as the existing CfD and therefore better alignment with the general view that renewable plants should not be exposed to certain risks that cannot be adequately managed. An appropriately designed deemed CfD could satisfy both de-risking investment and increasing an asset's exposure to operational price signals to maximise operational responsiveness, resulting in well-managed risk allocation that could deliver a similar level of cost of capital to today's CfD mechanism.

Regarding risk distribution, there is potentially more basis risk if the deeming methodology is inaccurate or does not turn off during outages. If the negative pricing rule is removed then it could slightly reduce volume risk.

The risk distribution of the capacity-based CfD model depends on the capacity payment, the gainshare mechanism, and the availability factor. Beyond the capacity payment, developers are fully exposed to price and volume risk and we have concerns about the potential risk this could expose generators to. As with the deemed CfD, much more detail is required to assess the benefits case and risks of this approach against the other CfD proposals.

Question 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

While our members believe in theory that both of these models could work to facilitate investment by developers, a much more detailed analysis needs to be done on the design of both models, as they each have features that could significantly (and disproportionately) add increased risks to generators. This analysis would need to be done before Energy UK can fully support or reject either of these proposals. The lack of detail on the specific design of each model also means that we are unable to assess the impacts and implications of either option on the wider market and market participants outside the CfD framework. Wider market implications, including any impacts on the BM, ancillary services, liquidity and wider policy objectives should be considered in any assessment.

On balance, the majority of our members have stated a preference for the deemed CfD, however, at this stage of development, based on the available information, we would ask that DESNZ carry out further analysis and risk assessment.

As we have mentioned throughout our response, ensuring investor confidence remains paramount. Therefore, there needs to be transparency and clarity in the design and implementation of either model to ensure confidence among investors. Maintaining a stable investment environment is crucial for attracting the capital necessary to drive the transition and this should be considered throughout the development and policy-making process. Energy UK would welcome DESNZ developing a package of reforms with some comparative analysis that our members can properly engage with in order to assess the merits or risks of both models.

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

The vast majority of Energy UK members do not see any merit in supporting a mandatory partial payment CfD, and have emphasised that partial CfD's should remain optional as they are currently.

Question 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.

As mentioned in our answer to Q5 on distortive impacts, the majority of our members believe there is a natural tendency for wind and solar generators to trade on the day-ahead market when they have more certainty about their output. This minimises their exposure to volume risk – whether it's operating with a CfD or on a merchant basis. The proposed use of longer reference price periods could expose generators to increased basis risk and could also result in higher capital costs and/or higher strike prices. It isn't clear, therefore, whether reforming the reference price to incentivise generators to increase their trade on forward markets would help solve some of the perceived distortions in the market. However, some members have suggested that generators would look to follow any reference price as long as it's hedgable and reduces basis risks.

Energy UK does not believe that changes to the design of the CfD done in isolation will solve issues related to poor liquidity. Alongside any potential CfD reforms, liquidity also needs to be considered in the context of retail market reform, in collaboration with Ofgem. Some of our members have highlighted that there are also challenges with longer-term trades for thermal power assets in the UK market which indicates the liquidity challenge may not be unique to renewables. It could be useful to examine what happens with RO-supported wind in assessing forward sales behaviour of renewable assets which do not need to sell against a CfD reference price to understand the strength of this preference. This preference will limit the degree to which either of the two reforms proposed can improve liquidity in forward markets.

We would also highlight that our members across generation and supply agree that liquidity has decreased in recent years and the de-coupling of GB's Power Exchanges (EPEX Spot and Nordpool) which now operate independent day-ahead markets, has led to high volatility and lower levels of liquidity. We would strongly encourage efforts to re-couple both Power Exchanges with Europe, noting the already significant challenges with multi-region lose volume coupling (MRLVC).

Energy UK members support the Government's proposed action to bring about the re-coupling of the GB Power Exchanges in the day-ahead market. We recommend re-coupling and re-merging the order books with prioritisation of the single day-ahead auction as outlined under the Trade and Cooperation Agreement (TCA). Following this, the Government should explore how to re-couple order books in intraday timeframes. This would reduce risks and costs, and enhance liquidity in the market. We agree it is important to consider how potential reforms to the CfD could help address issues with liquidity, alongside other actions to address liquidity issues.

Question 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?

As with large-scale projects, there are a number of non-market barriers restricting the development and deployment of small-scale renewables. Progress must be made in removing barriers linked to grid connection delays, network buildout speed, and planning and consenting timeframes. While there is a role for CPPA and PPA markets to play in supporting small-scale renewables (see answer to Question 1), the Government's focus should remain on the CfD to incentivise investment in renewables.

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

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

The vast majority of Energy UK members welcome the decision to retain the Capacity Market as the mechanism to ensure capacity adequacy and deliver security of supply. We agree that it requires reform to enable low-carbon technologies to fully participate in ensuring security of supply and supporting the transition to a net-zero electricity system. However, one member believes that the current Capacity Market does not represent good value for money for consumers and feels that wider reforms should be considered.

The document seeks to take forward the single auction with multiple clearing prices option, whilst not specifically discounting the split auction approach. However, it provides little detail on how the minima will be designed or on the low-carbon characteristics or flexibility criteria such as response time and or duration. At a high level, these seem to be the right characteristics, but without further consideration of these parameters, it is difficult to comment in anything other than general terms.

Below are some of the overarching concerns and questions that members have raised:

- Detailed definitions of desirable characteristics will be needed, as well as identifying which technologies meet the criteria, and how they are supported by other mechanisms.
- Timing of introduction, is this as existing first-of-a-kind (FOAK) support expires, or will it operate alongside such support? Is there a trigger for the introduction of minima? Will it only be applied in T-4 auctions? Will there be sufficient notice of introduction to ensure a pipeline of suitable projects?
- How many minima will there be in one auction? The more minima in any given auction will add significant complexity and could increase the timescales for implementation. How will potentially interacting minima be handled in the auction? E.g. low carbon and sustained response
- Could one characteristic be taken forward for minima at first (e.g. low carbon minima) to reduce the complexity of the options and ensure faster implementation, with further characteristics considered at a later stage if DESNZ believes this to be necessary?
- Is there a risk that existing assets offering multiple attributes (e.g. hydro) could be disadvantaged? If so this should be avoided.
- How would co-located projects with different characteristics participate?
- Is there an interaction with the ability to provide ancillary services?
- Could minima be used to support unabated gas?
- Could minima be set on a sub-national basis, e.g. near a cluster? Is there any interaction with the Strategic Spatial Energy Plan (SSEP)?
- Consideration needs to be given to how behind-the-meter assets capable of providing flexibility can participate in the capacity market. With greater co-location, this will be a growing issue
- How would secondary trading work in relation to minima? Could trading only be with assets in the same category? What if an asset provides multiple attributes? Secondary trading could be severely impacted – leaving limited options to manage unanticipated outages. This could be detrimental to the scheme as a whole.
- Will the desirable characteristics persist over time to provide confidence to project developers and investors, what notice will be provided for changing the characteristics?
- How will this work alongside the de-rating factors that already introduce duration signals for storage?

The issues highlighted above must be well understood to ensure project developers and investors understand how the capacity market arrangements fit in the wider policy and regulatory framework. Clarity on these issues will also instil more investor confidence to bring forward a pipeline of suitable projects for competitive allocation to deliver efficient outcomes.

There would be benefits in developing strawmen of options as part of a package and engaging with industry to understand likely responses, considering reform in isolation from each other is very risky.

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

The capacity mechanism already has several operational challenges, including slow progress in implementing rule changes due to much of the framework being in regulations rather than rules. Also the complexity of the rules with dependencies on CMAG, Ofgem, and the Delivery Body, with a lack of clarity on governance between the delivery partners. There needs to be greater clarity on roles and responsibilities within the CM, among the advisory group and delivery partners, These issues need to be addressed before changing the rules and adding further complexity, which the minima will undoubtedly bring. Delays to the delivery of the reforms once agreed upon could have a negative impact on investment and could compromise security of supply. Members are also concerned about the portal's ability to deal with these changes.

In general, there needs to be a full understanding of the whole framework including the package of reforms and timing of implementation to ensure that policy levers for low-carbon assets work alongside each other rather than at odds with each other or over-incentivise any technologies.

Secondary trading provides an important mechanism for contract holders to manage risk and exposure to penalties in the event of issues with assets. Reforms have been considered for many years, but Ofgem has failed to move this work forward. Energy UK believes this has added to non-delivery and therefore to customer costs. This must be resolved as a matter of urgency. If the CM with minima restricts trading to assets with the same characteristics, liquidity could be limited even further, with contract holders facing increased risk of penalties.

The interaction of de-rating factors with the EPT rules for storage assets effectively reduces connection capacity below capability and will need further exploration in the context of duration minima to ensure such assets are not unduly penalised. The cutover from existing bespoke support schemes and their transition to new arrangements needs careful consideration to ensure assets remain viable.

Consideration should be given to how an optimised CM would work with central dispatch and locational pricing, unless and until these options are ruled out. Policies can be set in isolation, but market participants respond to the full set of market arrangements on both a daily basis and in investment timescales.

Question 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?

Energy UK agrees with the objective to align the CM with Net Zero and that an emissions limit could form part of these measures. However we have concerns over cliff edge effects and impacts on investor confidence, the latter being a particular issue if the implementation date keeps moving back, a clear rationale for this is needed. It is essential that there is a sufficient pipeline of low-carbon flexible technology projects to ensure security of supply is maintained. There is also a risk of building a lot of new plants that runs for only a few hours a year when it might be more cost-effective to allow them to run longer.

An alternative approach could focus the CM on procuring capacity and flexibility in a technology-neutral way designed to deliver the required short and long-term characteristics, whilst other policy levers such as carbon prices could ensure that all CM participants bear the full costs of their carbon emissions. In this way, carbon emitters should in time be out-competed by lower carbon forms of flexibility.

There also needs to be a better understanding of decarbonisation pathways for any new build or refurbishing plant that holds a CM contract, whether that be the addition of CCS to capture emissions or retrofit to use hydrogen instead of natural gas where this might be possible. This needs to consider CM obligations during a major outage and potentially exploration of the timing of outages across the plant. Both CCS and H2P retrofit require other infrastructure to be in place, pipelines and storage for CO_2 and hydrogen, and adequate production capacity for hydrogen. So there needs to be a joined-up system-wide approach for plans to deliver this, otherwise the plant will be unable to convert in the timescales required which could then impact security of supply if they can no longer operate and there is insufficient other flexible plant available. Clearly there is also an interface with being able to secure a connection to the electricity network which needs to be resolved.

It is also relevant here to consider whether a plant with bespoke support for power CCS or hydrogen to power (H2P) can participate in the CM subject to minima being introduced or whether the expectation is that such a plant will transition from bespoke support to CM at the end of bespoke contracts which is quite some time in the future. The process and timelines are not clear for when and how low-carbon flexible plants will be able to participate in the CM.

Question 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?

Energy UK notes there is a very limited pipeline of new build unabated gas and refurbishing plant as detailed in the DESNZ research paper[3] 2023/51, and is concerned whether these projects will be sufficiently incentivised to proceed to ensure security of supply whilst low carbon flexibility alternatives are deployed. The comments under question 16 are relevant here, particularly the lack of clarity over the arrangements for outages for refit.

With respect to hydrogen-ready CCGT investments, emissions limits create significant uncertainty if the threshold is to be applied from 2034. It is uncertain whether sufficient hydrogen would be available to fuel the plant by that time and is largely outside of the control of the power plant owner/operator as it will be determined by government policy on hydrogen production, transport and storage. Given this, it may be more appropriate to focus on decarbonisation readiness than an inflexible emissions limit.

Also whilst OEMs are working on 100% hydrogen-fired turbines these are not yet commercially available so availability and costs cannot be assured at this time.

Question 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?

In no particular order, Energy UK members see the following as key challenges:

- Clarity on decarbonisation pathways and expectations for plant types for capacity adequacy to support investment in flexibility on existing plant prior to decarbonisation and appropriate technologies with an enduring role to avoid stranded asset risk, particularly as there is competition for investment.
- Further understanding the detail of the policies under development and their implementation timelines, even before bespoke mechanisms for power CCS and H2p have been introduced
- Design and introduction of minima into the CM

[3] Review of Electricity Market Arrangements (REMA): technical research supporting consultation - GOV.UK (www.gov.uk)

- Management of outages within a CM contract to schedule outage for decarbonisation
- Understanding interactions of the new and existing policies
- For hydrogen fuelled plant; management of cross chain risks. Including availability of hydrogen and transport and storage infrastructure to ensure reliable supply, potentially for very low load factor unpredictable use, but also possibly large volumes at short notice. H2P support does not seem to consider this.
- Availability of CO_2 infrastructure for power CCS projects and methane reforming hydrogen production
- The location of hydrogen and CO_2 infrastructure will define where conversion of natural gas plant or new build of H2P or power CCS is possible. This is not considered but cannot be left to the market to resolve.
- Clarity on role expected of H2P plant, peaking only or also for decarbonisation of sector (e.g. CCS plant expected to be mid-merit)
- The role of CHP plant is unclear
- Availability and price of technology
- Availability of resources for retrofit including personnel
- Availability of space on site could be an issue
- The way the demand curve is set
- The price cap not having changed since 2014
- Rule 4.4.4 - needs amending to enable plant to be reconfigured
- Auction targets and ESO modelling done only four years ahead – the government's proposal to work with the ESO to extend the number of future years modelled would be a welcome improvement to this issue and would provide better insight into future capacity needs.

There may be a risk that existing plants reach the end of their economic lifetime before there are sufficient alternative low-carbon options available. There needs to be clear signals to allow for these assets to plan their life extension or closure.

Question 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 points here are similar to those for Q18, Energy UK recognises the need to address the security of supply issue and HMG has proposed that the UK will need a limited amount of unabated gas into the 2030s and possibly beyond, which will need supporting market frameworks. However, the proposals are complex, and may not sufficiently incentivise the plants that are needed to ensure security of supply. The investment landscape for new build gas generation is very challenging. Uncertainty in the policy space, lack of detail and a lack of a clear decarbonisation pathway or implementation plan will inhibit investment, whether that is for an existing plant, to convert a plant, or for a new build. Connections will be a particular issue for new builds, especially if the connection queue alters if a plant is not successful in a CM auction round such that its capacity is removed so it cannot participate the following year.

We note that the pipeline of unabated gas plants or for major refurbishment is very limited. For any potential new CCGT plant that does not already have a DCO the timeline would be several years before they are able to participate in the CM. With competition between projects for investment it would be a challenge to make a case to start developing a new project for an unabated plant at this time.

In the longer term there may also be concerns about natural gas infrastructure and supply availability and reliability to point of conversion to low-carbon options if other natural gas use has declined substantially, location of the remaining unabated assets could be an important consideration.

Question 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

It is not possible to answer this, more detail is needed on the design of the optimised CM and minima to understand how it would work in practice and alongside the work summarised in Appendix 3. A coherent plan for implementation is needed.

Energy UK is aware that there is a lot of work going on in this area but notes that flexibility requirements need to be considered across distribution and transmission systems as a whole rather than in isolation from each other. It is not clear where distribution connected gas engines or CCGTs fit into this section nor their potential conversion to low-carbon alternatives. Clear signals are also needed for other existing assets such as hydro to ensure ongoing investment is tailored to response incentivised by the CM. In time there should be fair competition between all asset types large and small and transmission and distribution connected.

It is disappointing that there is not more focus on improving the current regime, including; progressing trading, improving prequalification and deleting rule 4.4.4.

In addition, a key missing element in the REMA document and Appendix 3 with respect to incentivising the deployment and utilisation of low carbon flexibility is any reference to the power sector carbon price. Currently low UK ETS prices plus CPS are delivering only a modest total power sector carbon price. A stronger price would incentivise more low carbon options and reduce the need for support from the CM or other bespoke mechanisms. DESNZ, HMT and HMRC should bring forward reforms to the UK ETS to deliver a stronger carbon price and progress linkage discussions with EU ETS.

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.

Energy UK welcomes DESNZ thinking on this topic, noting there is a good pipeline of projects capable of providing low carbon flexibility. It is important to consider how the whole package of measures work together to drive the necessary investment and desired operational responses, since market participants respond to the arrangements as a whole rather than individual policy measures.

We note that FOAK and NOAK technologies have bespoke support that will need to transition to more market-based arrangements where they compete with other technologies in time. We agree that technologies are likely to transition to competitive processes at different times for some technologies which are yet to receive FOAK support this will be some considerable time away. The transition will need to be carefully managed to avoid unintended consequences and ensure fair competition between different asset types.

The combined package of reforms could work but DESNZ will need to: A) consult on and then deliver the Optimised CM B) sharpen operational signals with stronger carbon pricing amongst other elements c) deliver the bespoke mechanisms and develop the strategy for bringing them into Optimised CM over time. There are also issues that are important but seem beyond the scope of REMA and this consultation:

- The reliance on CO_2 and hydrogen infrastructure for a reliable fuel supply for H2P, and for emissions abatement for power CCS.
- Ofgem's work on caps on bids and offers in TCLC
- Role of deemed CfD in pricing
- The need for higher clearing prices in the CM

- The need for CM arrangements to be amended to provide 15 years support when late delivery is due to late network connections

On paper it seems possible that the reforms will deliver the desired outcomes but at this stage there is a lot of detail to be developed so we cannot be certain. However, we are aware that DESNZ is working up some strawmen, and we would encourage working with the industry on these. The ESO's flexibility strategy should align with this work.

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

Question 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.

Energy UK members agree that these design choices are broadly correct in terms of a theoretical list of options, however, more analysis from DESNZ is necessary to comment in further depth. Our members would value more clarity on the various design choices and their feasibility in the GB context, and how each design choice might interact with other REMA proposals and wider industry change, such as the strategic spatial energy plan. For example, generators with a CfD with the same project costs in different zones would have different impacts on budget takes.

Energy UK believes the following design considerations are missing:

- Interaction with EU markets: For example, the interaction with offshore bidding zones, offshore hybrid assets (OHAs) and multi-region loose volume coupling (MRLVC).
- Calculation of interzonal transfer capacity: Appendix/annex 4 includes capacity allocation but not capacity calculation. Design options here are for either net transfer capacity or the EU approach of a flow-based capacity calculation (implicit or explicit).
- Intra-zonal constraint costs:
- Timeframes: When there is the right level of network investment and when suitable liquid financial transmission rights and financial futures have been designed.
- Grandfathering: Whilst included in the following chapter, Energy UK members believe the approach to grandfathering is an integral design choice. For example, the completeness of coverage, the inclusion of the merchant tail of CfD, and the timeframes for projects in the pipeline.
- Interaction with other GB markets (CM, CfD, forward PPA markets, impact on distribution-connected plants, and interactions with energy intensive industries and exemptions for network charging.
- Liquidity: As identified in the consultation, reforms need to carefully consider the impact on trading and liquidity in forward markets.
- Exposure of interconnectors to locational price signals such as cost of balancing, transmission access
- The extent to which consumers are exposed to imbalance
- Methods for charging for networks, policy support

More generally, whilst this is not a design parameter, Energy UK would note the critical importance of increasing network capacity – and Ofgem's role in getting network capacity (TO and DNO) delivered faster and in ensuring that future network investment keeps up with market requirements. Similarly, we highlight the need for policy stability as an important parameter, as there needs to be a level of stability maintained throughout system changes. There needs to be a balance between structural system challenges identified, and the short-term tools available to address these issues and the long-term system requirements.

Energy's assessment of zonal pricing

Energy UK members have emphasised the need for the REMA assessment to objectively and comprehensively determine the extent to which moving to zonal pricing would benefit consumers overall. However, the majority also remain concerned about the potential impact and resulting higher costs for building the necessary low-carbon generation and storage infrastructure needed for the transition, The majority of our members agree that zonal pricing could reduce constraint and balancing costs, as well as encourage more local matching of demand and supply, but that this has not been adequately demonstrated in the context of the GB electricity system.

As set out in Energy UK's response to REMA 1 (October 2022), the majority of our members continue to support an evolutionary approach to change and maintain national rather than locational pricing. The view here is that the energy transition is primarily about replacing polluting infrastructure with clean, efficient alternatives with lower running costs and as such is an investment challenge. The cost of capital is a major determinant of the total price for low-carbon projects, which is ultimately borne by consumers. Given the scale of new infrastructure required by 2035/2050, the availability and cost of investment will be critical and this is becoming more acute as other countries pursue decarbonise and competition for global capital increases. The consultation Impact Assessment for example, estimates that installed renewable capacity will need to increase by 150% to 200% by 2035 (from 56 GW in 2023 to 140-174 GW in 2035).

The potential benefit of the REMA reforms will also depend on how investors will react and whether a perceived increase in risk leads them to either divert their investment elsewhere or increase the cost of borrowing to mitigate the additional risk. Energy UK members are very clear that there needs to be greater clarity around the costs and benefits of zonal pricing and evidence of greater whole-system benefits overall vs the potential issues. The LCP modelling found that an increase in the cost of capital beyond 0.9% could result in 'a move to locational pricing becoming a net cost to the system'. For many, this has reinforced the view that the scale of potential net benefit remains unclear. In this context, many members would highlight that whilst the alternative options may have a lower potential to deliver purported benefits that zonal pricing could, if they can deliver a more efficient system whilst minimising investment risk, then this would be the better trade-off for consumers (at least within the short-medium term timeframe envisaged). Members support further work to identify further alternatives.

Our members have highlighted that zonal pricing and the implementation timelines should be viewed in the context of both the 2030 and 2035 delivery and decarbonisation targets, where substantial volumes of renewables and low carbon flex are required to be deployed. Some of our members have suggested that DESNZ should prioritise what is still collectively a substantial package of reform under the scope of the enhanced national market and a reformed CfD and assess the extent to which these low regret interventions address the case for change that REMA has identified with a further review of whether to move to zonal pricing should be explored for the post-2035 timeframe.

However, not all of our members agree with this view of zonal pricing. A minority of members have expressed support for zonal and the benefits that have been presented by the studies to date.

Question 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.

Energy UK members largely agree that the options retained can send both investment and operational signals that could address the challenges identified in this consultation, instead of a move to zonal pricing. In August 2023, Energy UK published a briefing on Locational Marginal Pricing[4], which outlined alternative options to address system challenges that would be significantly easier and quicker to introduce and would be less likely to harm investment, and capital costs through market uncertainty. This included reforms to TNUoS and the Balancing Mechanism, building on the design of ESO's Local Constraint Market, CfD reform and improvements to GB's investment landscape. We are very pleased that DESNZ will continue to consider how a reformed national market can enable investors to continue working within recognised and respected frameworks while improving the cost-reflective locational signals, without risks to securing the substantive investment that is required.

[4] Energy UK (2023) Energy UK high-level views on Locational Marginal Pricing

As outlined in our paper, many of the retained alternatives including constraint management could be implemented sooner to deliver system benefits, while others could have similar implementation timeframes to zonal pricing. Members would support a more concerted focus on changes that could be delivered within the existing market to ensure storage and interconnectors are used effectively and to increase competition in the BM, as the modelling suggested this had the greatest potential for cost savings.

Whilst acknowledging the potential shortcomings of the alternative measures in sending sharp enough operational signals, the view of the vast majority of our members is that the deemed CfD, together with the development of constraint management measures and work to optimise interconnectors should be explored further as a reasonable alternative to zonal pricing. This combination of measures could send improved location and operational signal and help to ensure that intermittent renewables were maximising their responsiveness to the system requirements. These retained alternatives would also reduces the basis risks, investment risks and market uncertainty.

More substantial evidence is required to support that alternative options can resolve operational and investment signals compared with zonal pricing, The next stage of the REMA process must incorporate an objective, comprehensive, and transparent assessment of the extent to which the two pathways can address the challenges identified. We understand that Ofgem is currently leading the workstream within REMA which will develop options for a reformed national market. Transparency and stakeholder engagement will be crucial for this workstream, particularly because of its exclusion from this consultation and the misalignment of timeframes.

We would therefore welcome more work into establishing a robust counterfactual. This will better inform an understanding of the residual problem and the extent to which more fundamental reform (which comes with a risk to investment) may be warranted. Alongside this, members would welcome further design work by the Department on what a zoning pricing model for GB could look like, the number of zones and where they might be drawn, how it might interact with existing support mechanisms and the level of exposure of consumers. For example, the design of the CfD will need to consider how assets in low-priced zones can complete with assets in high-priced zones. As the LCP modelling acknowledges, zonal pricing does not represent a singular well-defined market reform. Instead, there are numerous forms of zonal pricing, with the exact implementation of zonal pricing having the potential to greatly change both the costs and benefits of such a market reform.

- **Network charging**

While there are differences in approaches, the vast majority of Energy UK members support reforms to TNUoS, and believe it could deliver more predictability and more efficient locational investment signals. Energy UK responded to Ofgem's open letter[5] supporting the need to review the methodology and urging that timescales be accelerated and pragmatic (not to 'let the perfect be the enemy of the good'.

Members agree that network charging and network access would mainly drive investment signals rather than operational signals but recognise that whilst they could impact operation the bulk of the operational benefits would be delivered by other reforms. Members are optimistic about the extent to which they can deliver. Many of our members believe that the operational benefits that are outlined as being delivered through zonal prices could equally be delivered through incremental reform. The two main operational benefits that appear to drive zonal price modelling results can be addressed through alternative measures. Increased efficiency in dispatch of generators, storage and demand can be delivered through revised balancing, Increased efficiency of interconnectors can be delivered through revised balancing and greater SO to SO cooperation and improved locational choices regarding future interconnectors.

[5] https://www.energy-uk.org.uk/publications/energy-uk-response-to-ofgems-open-letter-on-strategic-transmission-charging-reform/

There are several ongoing initiatives that merit consideration here including the TNUoS Task Force, various proposed modifications to the Connection and Use of System Code (CUSC) (including CMP433, ScottishPower's OpTIC [Optimised Transmission Investment Cost]). Energy UK would also note that the REMA scope does not include the DNOs despite the scale of assets connected at this level and the demand signals they can send.

Members also highlighted Regen's paper Insight Paper: Improving Locational Signals in the GB electricity market. This recommends that Ofgem should use the TNUoS network charging reform to provide a long-term investment signal for generation that is cost-reflective, transparent, stable and consistent (and in tandem to review the signals directed at demand).

- **Network access**

Our members have stated that firm access rights for existing generation assets should be preserved or protected in all reform scenarios. Firm access rights are a fundamental element of the existing market arrangements and there would be a significant loss of investor confidence if these were removed without compensation or countervailing protections. Our members recognise there may be some arguments for different rules for new projects in some scenarios but this deserves careful consideration as access right are crucial for investment. Our members agree that network charging and network access would mainly drive investment signals but are more optimistic about the potential for constraint management, storage and interconnectors.

- **Expanded constraint management**

Energy UK members are very supportive of action here and highlighted a paper by Simon Gill for Scottish Renewables Exploring options for constraint management in the GB electricity system: the potential for constraint management markets which looks at options for improving constraints and interconnector utilisation and recommends developing a portfolio approach to tackling constraints.

On constraint markets, members noted that whilst the Local Constraint Market (LCM) has been fairly limited to date, it is hampered by its design, and as such, may not represent a proper test for what such markets could deliver. Issues noted were (i) price and the requirement to undercut the national BM to solve a specific locational constraint which was not viewed as realistic for a smaller less liquid market, (ii) issues with revenue stacking and ESO's exclusivity requirement for more lucrative products such as the Demand Flexibility Service which reduced interest from demand flexibility providers, and (iii) challenges for National Grid being able to take informed action at the day-ahead stage.

However, some members have noted that LCM has highlighted challenges of day-ahead procurement of constraint actions, as ESO may not have sufficient information about market participant positions, network constraints, or wind forecasts. Unless these information barriers can be tackled, the overall effectiveness of this option may be limited. Energy UK members support further analysis on the potential for LCMs.

- **Interconnectors**

Our members agree that this work needs to be undertaken regardless of the decision on national or locational pricing. Revisions to interconnector flows to optimise imports and exports closer to real-time are an integral part of the system and an example of flexibility creating additional efficiency. The ESO has tools to manage this (ITLs/ID NTC) and additional commercial services could and should be developed to manage the assets in a way that delivers common benefits. Some members here felt that there was more than could be done here including to participate in cross-border trading programmes such as Terre. The energy chapter of the UK-EU

TCA is up for renegotiation in 2026 - this presents an opportunity to re-join implicit coupling and cross-border balancing platforms, which GB played a leading role in designing, and which included the ability to re-dispatch interconnectors to solve system issues such as network congestion. Some of the members have also expressed the need for a revised approach to the approval of additional interconnectors when considering future locational challenges.

- **Supporting evidence on the potential impact on retained alternatives**

Energy UK considers that this is a key part of the next stage of REMA. Similar resources to what has been spent on nodal and zonal must now be deployed to consider the counterfactual that consists of the combination of alternative options.

In modelling studies such as the LCP Delta analysis for DESNZ a significant element of the benefits of zonal pricing comes from locational investment decisions (even if the larger bulk is from locational dispatch). Also a material portion of the locational dispatch benefit will be related to interconnectors. Therefore it is reasonable to assume that changes to a national market which delivered better locational investment signals and better interconnector dispatch arrangements would deliver at least a meaningful portion of the modelled benefits of zonal pricing but without the same level of market disruption and investment risks

- **How the alternatives work together to improve temporal signals and balancing and ancillary services**

As the bulk of the options are in effect evolutionary improvements to existing arrangements, they will likely be able to work alongside other options including shorter settlement periods and revisions to the BM and ancillary services.

For enhanced national market, this includes:

- Strategic Spatial Energy Planning and an enhanced national market based on the following components could address the majority of issues we are looking to solve through zonal pricing:
- CfD reform that removes the current distortions
- Enhanced TNUoS that improves long-term predictability and reduced volatility can make transmission costs an investable locational signal
- Constraint management markets introduced as temporary measures whilst grid investment is underway can help lower congestion costs
- Better SO-SO alignment to improve interconnector dispatch particularly through re-joining implicit coupling and cross-border balancing platforms, which GB played a leading role in designing, which included the ability to re-dispatch interconnectors to solve system issues such as network congestion.
- Removing barriers to co-location particularly with offshore wind

Energy UK members have suggested that DESNZ explore better alignment with CCUS and H2 policy and explore location-specific Hydrogen Allocation Rounds in areas such as the Humber. This would combine the need to decarbonise industry with areas with higher resources.

Energy UK's assessment of modelling to date

In the LCP modelling, the majority of the modelled (system and consumer) benefit (£10bn out of £15bn from 2030-2050) comes from operational efficiency rather than locational efficiency. This is because whilst there is some ability of plant to shift location in response to investment signals, it is relatively limited given the dominance of offshore wind in the future GB system and geographical constraints.

We note that there are striking differences between the results of LCP's analysis for DESNZ and FTI's analysis for Ofgem here. For example, LCP predicts that batteries will relocate *away from* Scotland whereas FTI suggests that they will relocate *into* Scotland; and LCP predicts that solar farms will relocate *away from* the southernmost zone of England following the introduction of zonal wholesale pricing whereas FTI suggest they will relocate *into it*. This demonstrates the difficulty of confidently predicting the impacts, the sensitivity of the findings to assumptions and the uncertainty that such reforms would create for potential investors.

Some members have noted important omissions from LCP's assessment of the impacts of zonal pricing. For example, it does not properly consider the interactions with the retail market (it is not clear that it is compatible with the continuation of the price cap) or quantify the upward pressure on consumer prices of the reduction in forwards market liquidity that would result from the introduction of zonal pricing (most energy for retail is bought ahead of time, a shift to zonal would potentially shift trading to day-ahead which could have implications for liquidity and price volatility)

Energy UK's view on the Impact Assessment

Energy UK members broadly support the Impact Assessment, which notes that the market is only one tool for delivering location signals. Planning, consenting and connections are also important tools. Unlocking these in particular areas may provide a stronger signal on where assets with the potential to shift location (e.g. BESS) get built, without the risk to investment. One example of this is the inability to access project finance for projects with long connection agreements. The LCP modelling suggests that between 2030 to 2040, the benefits of zonal pricing would be 26% higher with a 3-year network delay. This highlights both the interdependencies between the market and non-market measures and network build-out as a critical lynchpin of the transition. It also highlights the potential risk transfer that is central to zonal pricing. Under zonal pricing the consequence of failure to deliver transmission capacity effectively lands on generators in constrained areas and consumers in non-constrained areas. Both parties have no real ability to manage that risk, especially in operational timescales.

As a major reform that could impact the investment needed for the transition, it is important for participants to have a clear sight of the cumulative impact of initiatives already in train, including both non-market changes (strategic spatial planning and connections reform) and market (REMA proposal and BAU) change (such as balancing and ancillary reform and MHHS). This would provide a more accurate counterfactual to measure the impact of change against.

As the LCP analysis highlights, whilst zoning pricing is a way to drive these operational efficiencies, it may not be the only way ('it may not be unique to locational pricing'). It therefore recommends that the Government *'consider if some of these benefits can also be achieved through modifications to the current national pricing model'*. This includes alternative ways to provide more efficient signals to interconnection and storage.

Question 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 impact.

Energy UK agrees that the introduction of shorter settlement periods is an option that warrants further exploration, we believe that the near-term focus should remain on delivering market-wide half-hourly settlement, with even shorter settlement considered as a longer-term option. Setting out a clear plan and timescale for the change would provide direction to all parties and help minimise costs.

An updated cost benefit analysis is needed here along with a clearer view of the implementation route. Setting out a clear plan and timescale for the change would provide direction to all parties and help to minimise costs. The CBA should include impacts on all market players, suppliers, generators, and ESO. A change could increase the volume of balancing actions so would require the ESO having the technical capacity to optimise and dispatch relevant actions. The CBA should also include impacts on supplier forecasting and interaction with a zonal approach (and the potential need for a zonal cash out prices) .

Whilst meter change could be challenging, it was noted that in the Australian NEM market change to 5-minute SP, domestic meters were not changed and instead, the profile was adapted for domestic customers. In the GB context, there was a view that SMET-1 smart meters would need to be profiled (divide by 2 for a 15-min settlement period or 6 for 5 minute) but that SMETS-2 could be adapted. There was also more pragmatism about how a transition could be managed (versus the Arup recommendation), for example, with domestic customers with a SMETS-1 meter remaining on a 30-minute settlement period until the meter is upgraded.

Energy UK does not agree that shortening gate closure should have been ruled out for the (assumed 5 year) period of the REMA changes. Whilst a short-term change could have risks, a transition to a 30-minute period (over for example, a five-year period) as recommended by Arup should (some members felt), have been supported as it complements other measures. It was noted that the concern about balancing volumes would not apply with a move to zonal as locational pricing would be more closely aligning supply and demand before gate closure.

Energy UK suggests the following measures are included

- **Policy levies and the decreasing influence of the wholesale price in customer bills**

This was included in REMA 1 and continues to be relevant. Whilst wholesale costs currently account for half of the typical domestic bill (January to March 2024 price cap from here), pre-gas crisis, this was only a third (see here using Ofgem data from 2020) with network and policy costs each accounting for around 20 percent. As more generation is supported by CfDs or alternatives (RAB, Cap and Floor), wholesale market costs will make up a declining proportion of consumers' bills over time. This trend dampens temporal signals, limiting the ability of suppliers to provide tariffs that incentivise flexible behaviour from consumers. This will make it harder to use demand-side approaches for balancing and could increase costs.

Members note an inconsistency in the consultation on whether these price signals are intended to reach the end consumer. More consideration is needed on how REMA proposals interact with retail reform and how Government envisages the demand side responding (including roles for intrinsic and extrinsic DSR) as these will affect proposals. The points here are relevant to the proposals on settlement periods and the granularity of data that will be required/ beneficial.

- **More dynamic DUoS** This would help with the issue identified above (although this would be fairly limited as DUoS accounts for a fairly small proportion of the bill). We note that at the recent Charging Future Forum (March 2024), Ofgem committed to near-term work to '*establish a framework for assessing long-term reform of DUoS charging*'. The timeframe for this work was set out a minded-to position towards the end of 2024 in order for implementation in 2026/7.
- **More real-time local flex markets** (e.g. the new UKPN day-ahead flexibility product with Epex Spot)
- **Improved visibility** (at both transmission and distribution levels)
- **Improving balancing and ancillary services**

The consultation highlights rising balancing costs and volumes as a challenge. It notes the ESO's work on Balancing Mechanism reform which uses 2 key principles of increasing both competition and transparency. Appendix 3 outlines work underway in this area

Members agree that further work is necessary across all markets to address baselining methods for DSR, standardisation and simplification where possible to improve revenue stacking, lowering participation thresholds and introducing closer to real time procurement.

Members note and welcome the BAU incremental measures that are in train. It was noted though that whilst the Balancing Mechanism is referred to several times, there is no comprehensive list of plans here (it is presumed to refer to the ESO work here which the Arup Technical Paper 9 lists in the appendix, although members note this is not delivering quickly and may overrun into 2027/28).

In general, it was felt a more coordinated approach was needed to bring together the incremental change happening across the sector through ESO initiatives, trials, code modifications, DESNZ and Ofgem initiatives. This would help to identify what further additions might be needed to align it with the 2035 target. Without this comprehensive view (which may come in the ESO's forthcoming Flexibility Strategy), it is hard to see if the resulting change is likely to be sufficient to manage future balancing challenges (and to what extent more significant reform might be warranted).

- **Additional measures to maintain operability**

Members support the work that Ofgem is doing here (but continue to urge Ofgem to push for faster action with the ENA-led work on the 'enablers' through the Open Networks programme. Relevant Energy UK responses here are listed below:

- Response to Ofgem's consultation on the Market Facilitator Delivery Body (2024)
- Response to Ofgem's Call for Input on Distributed Flexibility (2023)
- Response to Ofgem's consultation on the future of local energy institutions and governance (2023)

Energy UK's position on central dispatch

- Design – Internationally, there are many different models for how unit commitment, scheduling and dispatch processes can work; the choice is not a binary one between "self-dispatch" and "central dispatch" but would be a question of the right design for the GB market. It will be necessary to look at more detailed proposals to form a clear view on the merits of a change.
- Managing variability - Electricity demand will become harder to predict and more variable. Members were unclear whether central dispatch would help or hamper this.
- Alternatives for mitigating issues with self-dispatch It was felt that the ESO work (via the Afry Net Zero Market Reform work) had not sufficiently quantified the cost of the problems of self-dispatch (e.g. NIV chasing, rapidly changing PNs) or options for managing this. Members also felt that the ESO workshop here had highlighted the urgency of acting here and the need to do this faster than a move to central dispatch could be implemented.
- Co-optimisation - Members acknowledge challenges with the competing costs/revenues of delivering energy as well as ancillary services (reserve, reactive power etc) but feel that this can be met by delivering efficient markets in these services which providers can then consider via a stacking approach. Whilst this might have been difficult historically, it could be achievable with the use clearer information, as well as process efficiency improvements including a more algorithmic approach.
- Visibility - increasing the visibility of both smaller assets (non-BMU) and network flows has been a consistent Energy UK ask to help manage system issues. Alternatives approaches here could be i) requiring Capacity Market Units to become Balancing Mechanism Units, or ii) via GC0117 (reducing the threshold over which physical information is required to be submitted to NG ESO).
- Governance - central dispatch is one of the REMA proposals with the greatest potential to disrupt the market (not incremental). Members have expressed concern about the misalignment of timelines of this workstream and the REMA consultation. There are also concerns that DESNZ has not been transparent enough about the

process, and the governance which will underpin the ESO's analysis. There are also concerns about the opportunities for industry engagement (and to shape and challenge the underlying assumptions on the ongoing work). Members generally agreed that these are complex questions and require more time, consideration and better transparency. Members have highlighted that the role of the ESO as residual balancer is changing as the energy system changes and the response to this should be to find ways to reduce the ESO's role in dispatch rather than to increase it as this proposal would do. Asset owners rather than the SO are better positioned to dispatch their own plant optimally.

- Energy imbalance – some of our members felt the case for central dispatch seemed more appropriate in relation to energy imbalance and intertemporal issues (lack of real-time market signals), although here too members felt that there were other less disruptive approaches that could be tried first such as a future move to 15-min ISP and BAU ESO work on battery state of charge). However, many of our members remain very cautious about the case for central dispatch and the level of evidence provided.
- Interaction with zonal pricing – most of our members elt that if the market is to move to a zonal model, it would be better to introduce this change and analyse the impact – rather than simultaneously move to central dispatch at the same time. As zonal pricing would incentivise plant to dispatch in a way that is consistent with any boundary constraints, it should significantly reduce the amount of balancing actions required and therefore the key reason members can see for introducing central dispatch. This is especially true if the visibility problem the ESO have reported is a significant part of the dispatching problem.
- Extent of central dispatch – Given the increasing role of distributed energy resources, it will be necessary to consider the extent to which centralised dispatch would be extended to distribution-connected assets.
- Complexity – There is an increasingly wide variety of assets on the system with different technical characteristics; can the system operator understand these and capture the necessary technical details to enable them to use these assets more efficiently than the asset operators themselves?
- Wider market impacts – a move to central dispatch would involve significant changes to market processes in the day ahead, intra-day and balancing timeframes. It may also raise the question of whether forward markets could continue to operate on the basis of physical trading or would need to move to a financial basis – and the implications for this must be fully considered.

Liquidity in the wholesale market

The GB wholesale market has a long-standing issue with poor liquidity (see for example, Ofgem's Dec 2023 Power Market Liquidity consultation). In this context, any reforms will need to be measured against their scope to increase or decrease potential liquidity. Energy UK agrees that all of the proposals need to be looked at with a liquidity lens. We note that all markets are different and what increases liquidity in one market, could impact differently on another. It is also worth noting that as GB progresses in the Net Zero transition and deploys greater amounts of renewable generation, there is likely to be increasing demand to trade electricity closer to real-time. Short-term markets are likely to play an increasingly significant role in GB's energy system and it is crucial that these markets are competitive and well-positioned to utilise this generation.

The needs of both suppliers and generators must be properly considered in the context of the uncertainties that are being managed how they arise and how they are resolved in practice. This should in turn highlight what metrics should be used for considering liquidity today and going forward. This evaluation should be an essential step before consideration of possible actions is undertaken.

Options Compatibility and Legacy Arrangements

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

REMA's primary objective should be to align the necessary investment with electricity market reforms to deliver a decarbonised power system by 2035. This requires market arrangements and an implementation process that bolsters investor confidence in the GB power market at a time of increased global competition for capital. Increased risk for developers could precipitate an increase in capital costs, causing an investment hiatus or stalling the development of ongoing projects. It is also important to ensure that assets are operated as efficiently as possible in accordance with existing network capacity.

Delivering a decarbonised power sector by 2035 will require significant private sector investment in low-carbon generation, flexible assets, network infrastructure, and the smart technology to manage the operation of these assets. The cost of capital is therefore crucial to this objective succeeding and ensuring an appropriate balance of risk within the reforms proposed by REMA is essential.

In principle, Energy UK members believe that risk should be borne by the party that is in the best place to manage that risk. It is essential that if a party is asked to bear a risk, then the market design should allow for that party to actively manage that risk. Furthermore, where it is difficult to decide which party should bear a risk, we should avoid the consumer becoming the default option. If it is determined that exposing parties to new risks supports the most system-efficient approach, then this should be managed with mechanisms that allow parties to mitigate this risk.

Consideration must also be given to risk dependencies that make it difficult or impossible to manage a risk. For example, it is not appropriate for the risk of an inadequate buildout of network infrastructure to sit with generators, as they do not have the ability to manage that risk within market frameworks. DESNZ must explore how some of this risk can be borne by institutions that make decisions that, for example, National Grid ESO. In the absence of that, if the final market design does not enable the efficient management of risk, there will be increased costs that will ultimately fall on consumers.

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

Energy UK notes the need to consider holistically the impact of any proposed reforms. Given the amount of time required to plan and deliver the significant quantity of infrastructure required to deliver a Net Zero power system, our members are already making investment decisions on new projects, with other projects already in development. How these reforms interact with existing assets is also a key consideration, given the need to bear in mind that policy uncertainty is creating issues for an energy market that is live and dynamic.

The vast majority of Energy UK members strongly believe that, where possible, an incremental approach to market reform should be explored and exhausted first. A further advantage of an incremental approach is that it allows for a much easier assessment of options compatibility compared to more radical reforms. This will also allow for a more thorough assessment of impacts on areas not directly in scope of proposed reforms, but that nonetheless would be impacted by any reform, for example secondary markets.

Members also note that this section of the consultation document does not refer to existing policy objectives, for example on the rollout of 50GW of offshore wind by 2030. The delivery of Government objectives is key for the Net Zero transition, so DESNZ must ensure these are taken into account when considering compatibility of the remaining options. This could also include policy changes which will already provide strong locational signals, including the SSEP, CSNP, as well as hydrogen, transport and storage. It is important that these policy proposals are in alignment and do not create contradictory investment signals.

Finally, Energy UK notes the need for clarity on whether there will be an opportunity for consultation on future phases of REMA, once a minded-to package of reforms has been finalized. It is vital that stakeholders, including industry, have an opportunity to provide feedback on any final decisions as part of a transparent and public consultation process.

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

It is essential that DESNZ provide clarity as soon as possible to industry regarding which projects will have legacy arrangements, and what these will look like. Industry needs further information from DESNZ about how arrangements would impact revenues for both legacy and pipeline assets, before being able to give a clear view on any risks.

Energy UK believes that full grandfathering must be applied to all existing assets and generation procured in CfD allocation rounds that do not have certainty on the final REMA reform package. The Government must clearly state how any grandfathering would occur as soon as feasible to ensure that investor confidence can be maintained. Whilst grandfathering would reduce some of the stated benefits of a move to a zonal pricing model, existing support scheme commitments must be honoured to ensure that investors are kept whole against their expectations at the time of investment. The principle of grandfathering has, in past (for example with RO), sent a vital signal to investors in future projects. Grandfathering would also be needed for non-CfD generation should there be a move to zonal pricing arrangements through FTRs.

For a zonal market there are a series of design choices that must be made by DESNZ. Only once these choices are made, will industry be able to fully assess any impacts on the market. Some of these choices include the number of zones, the CfD reference price, the CfD pot size and budget methodology, the length of FTRs, self-dispatch, shorter settlement periods and closer gate closure.

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

The consultation paper proposes that CfD-supported generators would be protected by using the zonal price as the CfD reference price in the event of moving to a zonal market. This is welcome, but is not enough, even to protect CfD-supported generation. Energy UK believes that full grandfathering must be applied to all generation supported by existing support schemes that do not have certainty on the final REMA outcomes. This includes merchant generation and RO-supported generation or the "merchant tail" of CfD-supported generation and consideration of how any changes would affect both generator and offtaker in PPA contracts.

Specific risks to consider include:-

- Exposure to lower wholesale prices in some zones of a zonal market; generators will also be exposed to the risk that wholesale prices will remain lower over the longer term if there are delays in transmission build;
- Greater incidence of zero or negative prices in some zones, affecting CfD revenue for generators that have CFDs with negative price rules;
- Reduced liquidity in a zonal market, making it more difficult to trade and increasing basis risk in achieving CfD reference prices, particularly for baseload CfD generators;
- Potential loss of revenue arising from changes to access rights and/or a move to centralised dispatch (which might occur in a zonal market or some potential choices for an enhanced national market) if the

consequence is that generation can be curtailed by the NESO with no compensation or inadequate compensation

- Demand for CPPAs is being impacted by the prospect of zonal pricing as CCPA participants look to put in clauses in agreements to protect themselves from the possibility of zonal pricing being introduced. This has and will continue to stifle uptake of CCPAs until there is greater clarity about the potential for zonal pricing. If zonal pricing is taken forward, CPPAs with a 5 – 15 year lives signed before the prospect of zonal pricing being introduced, will be undermined. Zonal pricing could lead to a large disruption of low carbon revenue flows as parties seek to renegotiate their CPPA conditions. This could happen if CCPA participants are in a zone in which their local price is more favourable than the fixed CPPA price.

Any move to a zonal market is also likely to be accompanied by changes to TNUoS, which may impose an extra cost on some generators and may deliver a saving to others. There may be a case for considering whether TNUoS savings could be used to fund some form of Long Term Transmission Rights that could protect generators from risks of low wholesale prices.

More broadly, the following risks should also to be considered:

- Many renewable projects will invest the majority of their costs at FID and recover these over 1- year contract period and beyond. This creates a risk to investors and was a key reason behind the introduction of the CfD. Whilst the costs associated with renewables have fallen since the introduction of the CfD, this underlying risk remains.
- Investor perception of regulatory and policy risk associated with the GB market. Whilst this risk is difficult to quantify, it is nonetheless important to consider in any decision-making given the ongoing competition between jurisdictions for investment in clean technology.
- The impact of any proposed reform on investor confidence and certainty. If not properly managed this would lead to higher risk premiums for future investments and undermine any benefits case of REMA reforms. DESNZ should seek to gain more evidence of the impact of market changes on cost of capital, hurdle rates, and wider investor appetite through detailed consultation and discussion with the wider energy investor community. This should also include analysis of the impact on investor confidence across a range of grandfathering options.
- Further analysis is required on the impact on liquidity through the implementation of zonal pricing, coupled with a CfD hybrid reference price. Parallel reforms to the status quo should be further considered.