Review of Electricity Market Arrangements (REMA) – Second Consultation
Department of Energy Security and Net Zero

Consultation response from the Sussex Energy Group, University of Sussex

About the authors:
This submission has been prepared by the following members of the Sussex Energy Group (SEG) at the University of Sussex:
Dr Malte Jansen, Lecturer in Energy and Sustainability
Prof Steve Sorrell, Professor of Energy Policy
Siobhán Stack-Maddox, Senior Research Engagement Officer

The Sussex Energy Group is a globally-networked, interdisciplinary group of energy policy researchers, studying transitions to net zero energy systems that are fair to everyone. We produce world-leading research addressing contemporary policy challenges.

Responses to selected consultation questions:

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

1. What growth potential do you consider the Corporate Power Purchase Agreement (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 Review of Electricity Market Arrangements (REMA) options for reforming the Contract for Difference (CfD) and wholesale markets.

cPPAs are naturally limited in uptake. Whilst there may be a lot of renewable generators willing to negotiate a cPPA outside the CfD scheme, the volumes on the offtaker side are constrained. Many renewables projects are non-recourse financed (i.e., project financed), meaning that they require high levels of income certainty to service their debts. This in turn creates requirements for the offtakers: (1) A sufficiently large electricity consumption to offtake hundreds of MW, (2) a predictable electricity consumption for at least a decade, (3) a known consumption profile and (4) a high credit rating. These aspects have been mentioned in the call for evidence.

However, these limitations act as a natural cap for the possible volumes for cPPAs. This was not explored in sufficient depth in the consultation document. The limitations above typically reduce the options for the counterparty to large technology and industrial companies, many of which have self-declared netzero goals under the RE100 group (https://www.there100.org/). This global selection of companies have an electricity demand exceeding 500 TWh as of 2023. However, this does not mean that this electricity demand will be solely served by cPPAs. The RE100 suggests that in 2023, the equivalent of 17.5% of installed renewable capacity was signed as cPPA contracts (https://www.there100.org/sites/re100/files/2023-

11/Financing%20the%20Energy%20Transition%20How%20Governments%20Can%20Maximise%20Corporate%20Investment.pdf?utm_id=G20+report+2023). Whilst the actual share of cPPAs leading to investment decisions in renewables projects may differ significantly, it may serve as an indicative number of the share of renewables that could potentially be realised through cPPAs.

Any reform to the CfDs shall mean that the volumes from the CfDs, which are derisked using consumers' money, end up in consumers' portfolios, not in corporate electricity consumption. A situation where CfDs are supporting *investment decisions* of renewable energy projects, but benefits are not fully transferred to the risk takers, is suboptimal. Thus, we would caution against allowing secondary cPPAs, which are typically closed after confirming a CfD agreement.

In either case, CfDs and PPAs are a necessary market addition (not substitution) to support the build-out of renewables. They can co-exist alongside each other and 'fully merchant' markets, serving similar purposes for the generators, but risk allocation on the consumer side differs. Variable renewable energies (VREs) have a significantly different cost structure (https://www.nature.com/articles/s41560-023-01401-w). Therefore, strong VREs buildout goals will require policy action to fix the "missing market" problem. CfDs and PPAs are suitable tools for this purpose, by providing certainty for investments in VREs.

References:

1. Beiter, Philipp, Jérôme Guillet, Malte Jansen, Elizabeth Wilson, and Lena Kitzing. 'The Enduring Role of Contracts for Difference in Risk Management and Market Creation for Renewables'. *Nature Energy* 9, no. 1 (January 2024): 20–26. https://doi.org/10.1038/s41560-023-01401-w.
2. Newberry, David. 'Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors'. *Energy Policy* 94 (1 July 2016): 401–10. https://doi.org/10.1016/j.enpol.2015.10.028.

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

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

Yes

Overall, the challenges for the future of Contracts for Difference have been identified correctly. However, it is worth noting that these challenges might change, as the energy market design evolves. Although REMA is a comprehensive undertaking with a holistic approach, it is likely that unanticipated challenges may occur. It might therefore be useful to establish a formal and continuous evaluation process of CfD arrangements.

References:

1. Beiter, Philipp, Jérôme Guillet, Malte Jansen, Elizabeth Wilson, and Lena Kitzing. 'The Enduring Role of Contracts for Difference in Risk Management and Market Creation for Renewables'. *Nature Energy* 9, no. 1 (January 2024): 20–26. https://doi.org/10.1038/s41560-023-01401-w.

5. Assuming the Contract for Difference (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?

Removing distortions in Contract for Difference (CfD) arrangements would likely prompt renewable asset owners to respond more directly to market signals and risks. However, due to the intermittency of wind and solar, their reactions would be somewhat constrained in how they can adjust output based on price signals. Whilst these price signals may incentivise renewable generators to partake in the ancillary services markets, it must be considered that those markets tend to be shallow (i.e., overall market value is comparatively low). The importance and market volumes of ancillary services markets, however, is likely to increase as more intermittent generation is added to the system.

A well-designed CfD can encourage the development of wind and solar projects that are optimised for higher capacity factors, albeit potentially at higher costs. This can be achieved by a higher blade length to generator capacity ratio. This could enhance projects' ability to respond effectively to market conditions, as they can deliver electricity at rated capacity for more hours of their life, and during more hours when it is needed. So far, the CfD design in its current iteration, or the above changes, would not incentivise such behaviour. Moving away from the 'cheapest kWh produced' paradigm may help, but could jeopardise the 'least value for money' objective.

In addition, it is necessary to consider other influencing factors beyond CfD design. For instance, the Crown Estate seabed lease auctions can significantly impact wind farm design choices, potentially introducing additional complexities or incentives that need careful evaluation to ensure alignment with broader market goals.

In practice, the extent to which renewable assets would alter their behaviour in response to these changes would depend on a combination of market dynamics, technological advancements, and policy frameworks. We expect the changes to be minimal, and potentially at higher costs, than procuring flexibility through the capacity market scheme.

References:

1. Beiter, Philipp, Jérôme Guillet, Malte Jansen, Elizabeth Wilson, and Lena Kitzing. 'The Enduring Role of Contracts for Difference in Risk Management and Market Creation for Renewables'. *Nature Energy* 9, no. 1 (January 2024): 20–26. https://doi.org/10.1038/s41560-023-01401-w.

2. Jansen, Malte, Iain Staffell, Lena Kitzing, Sylvain Quoilin, Edwin Wiggelinkhuizen, Bernard Bulder, Iegor Riepin, and Felix Müsgens. 'Offshore Wind Competitiveness in Mature Markets without Subsidy'. *Nature Energy* 5, no. 8 (August 2020): 614–22. https://doi.org/10.1038/s41560-020-0661-2.

3. Laido, Ahti Simo, and Lena Kitzing. 'Impacts of Competitive Seabed Allocation'. *Journal of Physics: Conference Series* 2362, no. 1 (November 2022): 012022. https://doi.org/10.1088/1742-6596/2362/1/012022.

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

The reforms on repowering are a welcome addition, especially if existing grid connections can be used for repowered sites. However, we have some thoughts on the effectiveness of the measure:

1. We do not expect this to significantly increase the capacity available to the GB power system. This is mainly due to timelines of the expected plant retirements way into the 2030s and 2040s.
2. It stands to question whether these repowered sites are actually competitive against newly developed generation. This is mostly down to the size of the wind/solar farm, with newly developed sites being much larger in size and thus more competitive.

On the proposed idea of 'hybrid metering' arrangements, some flexibility may be desirable. An exemption from the balancing and settlement code would be a good idea, but we advise close monitoring of the concessions for long-term viability and overall impact on the system. Should these changes prove beneficial overall, an adjustment of the balancing and settlement code would be advisable to formalise the arrangements.

References:

1. Beiter, Philipp, Jérôme Guillet, Malte Jansen, Elizabeth Wilson, and Lena Kitzing. 'The Enduring Role of Contracts for Difference in Risk Management and Market Creation for Renewables'. *Nature Energy* 9, no. 1 (January 2024): 20–26. https://doi.org/10.1038/s41560-023-01401-w.
2. Jansen, Malte, Iain Staffell, Lena Kitzing, Sylvain Quoilin, Edwin Wiggelinkhuizen, Bernard Bulder, Iegor Riepin, and Felix Müsgens. 'Offshore Wind Competitiveness in Mature Markets without Subsidy'. *Nature Energy* 5, no. 8 (August 2020): 614–22. https://doi.org/10.1038/s41560-020-0661-2.

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.

When considering the specific gaming risks associated with the deemed generation model and how different methodologies or variations may influence these risks, the following points would be relevant:

One potential gaming risk is the practice of wake steering, where turbines are oriented to influence wind patterns to increase generation. This could lead to issues such as turbines "stealing" wind from each other, thereby impacting the accuracy of modelled versus actual generation outcomes.

There is a risk that developers are placing turbines in less advantageous locations with the knowledge that the modelling of the deemed output would have higher output than the real wind farm. An equivalent for solar would be partially shaded solar panels, which may distort expected generation estimates, leading to inaccurate deemed generation assessments. To counteract the gaming potentials, site-specific assessments for each wind and solar farm would be required.

Implementing deemed generation methodologies may introduce significant compliance issues, particularly regarding accurate data collection and monitoring, if required from the asset owners. For instance, using turbine nacelle anemometers can introduce uncertainties in reported generation figures, thus costly lidar measurements might be mandated.

Among the variations of deemed generation methodologies, Option 1 may appear robust but can also introduce complexities such as increased administrative workload. This can potentially lead to challenges in billing accuracy, administrative red tape, and bottlenecks in the verification process.

A volume-based approach for the lifetime of the plant may alleviate a larger number of current CfD issues. This lifetime production volume approach has been successfully deployed in Denmark. The approach does offer more flexibility in plant design and operation, allowing plants to be shut down during low price hours and provide ancillary services instead. In combination with a monthly or quarterly strike price this would enable the sustaining of investor confidence by exposing wind and solar to short term market price fluctuations, without the exposure to long-term trends.

References:

1. Göçmen, Tuhfe, Albert Meseguer Urbán, Jaime Liew, and Alan Wai Hou Lio. 'Model-Free Estimation of Available Power Using Deep Learning'. *Wind Energy Science* 6, no. 1 (18 January 2021): 111–29. https://doi.org/10.5194/wes-6-111-2021.
2. Hulsman, Paul, Søren Juhl Andersen, and Tuhfe Göçmen. 'Optimizing Wind Farm Control through Wake Steering Using Surrogate Models Based on High-Fidelity Simulations'. *Wind Energy Science* 5, no. 1 (5 March 2020): 309–29. https://doi.org/10.5194/wes-5-309-2020.

8. Under a capacity-based Contract for Difference (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.

Developers' bids in a capacity-based CfD auction are unlikely to be significantly influenced by anticipated revenues from other markets. This is because such bids primarily hinge on the capacity price established in the auction, rather than anticipated revenues from energy sales in other markets. The capacity price is the most certain revenue stream, and thus will drive investment decisions and CfD strike prices. Uncertainty in revenue streams, particularly from markets outside the CfD, can pose challenges in securing project financing. The perceived uncertainty can affect the ability to load debt onto projects, as debt service cover ratios are linked to revenue predictability over time. In projects with high leverage (e.g., 80% debt and 20% equity), the debt service cover ratio becomes paramount. This ratio directly influences lenders' perceptions of revenue certainty and therefore impacts developers' bidding strategies in capacity-based CfD auctions.

A capacity-based CfD represents an extreme form of decoupling payment from actual kWh production, shifting the focus solely to capacity (kW). In this form, the CfD is akin to a capacity market product. While the capacity-based CfD simplifies the payment structure to the generator, a mixed approach could offer more nuanced bidding strategies but might introduce additional complexity.

Overall, developers' bidding behaviour in capacity-based CfD auctions is primarily influenced by the established capacity price and the feasibility of meeting debt obligations based on projected revenues, rather than considerations of revenue diversification across different market streams. The key financial metric driving decisions remains the debt service cover ratio, underscoring the importance of revenue predictability and project viability in securing financing for renewable energy projects.

References:

1. Schlecht, Ingmar, Christoph Maurer, and Lion Hirth. 'Financial Contracts for Differences: The Problems with Conventional CfDs in Electricity Markets and How Forward Contracts Can Help Solve Them'. *Energy Policy* 186 (1 March 2024): 113981. https://doi.org/10.1016/j.enpol.2024.113981.

9. Does either the deemed Contract for Difference (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?

No opinion

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

Deemed CfD

11. Do you see any particular merits or risks with a partial payment Contract for Difference (CfD)?

A partial payment CfD provides flexibility by allowing developers to participate in merchant markets alongside larger projects. This enables a diversified portfolio approach, optimising project development strategies based on market conditions.

Developers can strategically plan projects by defaulting to a 100% CfD arrangement for initial project progression, while retaining the option to transition to a cPPA for a share of the project when economic opportunities arise. This approach enhances project viability and adaptability to evolving market dynamics and may ease project development risks. However, as we have outlined earlier, this should not lead to a 'secondary cPPA' market, where the project risks are borne by the public but the benefits are allocated to private corporations.

Implementing a partial payment CfD can mitigate the risk of rapid deployment of projects in prime locations using cPPAs only. This ensures that premium sites are not exhausted prematurely by big corporate consumers. This helps in balancing renewable energy development across various site qualities and potentially mitigates consumer costs associated with site scarcity.

There is a risk that the availability of partial payment CfDs may disincentivise developers from opting for cPPAs to develop the entire project, particularly if fully funded CfDs are financially more attractive. This could impact market dynamics and the diversity of financing mechanisms available for renewable energy projects.

Overall, a partial payment CfD offers notable merits in promoting market flexibility, optimising project development, and addressing site selection biases. However, careful consideration is needed to ensure that this model does not inadvertently discourage the adoption of complementary financing structures with cPPAs.

12. Do you see any particular merits or risks with the reforms to the Contract for Difference (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.

The suggested reforms, particularly the hybrid option for reference pricing, are likely to enhance the performance of the CfD scheme. A hybrid approach combining both quarterly and monthly reference prices can provide more accurate and up-to-date pricing signals, aligning better with evolving market conditions.

Implementing monthly or quarterly reference prices can contribute positively to market liquidity in forward markets. This approach allows for more frequent and responsive price signals, supporting efficient risk management and hedging strategies for developers.

There are potential impacts on market liquidity. Forward market liquidity is currently driven predominantly by fossil fuel generation. Phasing out these generators in favour of renewables could lead to decreased liquidity in forward markets, particularly if renewable assets do not yet dominate forward trading (or may never do so).

Changes to reference pricing mechanisms can introduce basis risk, where the actual revenue earned differs from what was anticipated based on the strike price. This risk can impact project economics and financial viability, necessitating robust risk management strategies.

13. What role do you think Corporate Power Purchase Agreement (CPPA) and Power Purchase Agreement (PPA) markets, and Review of Electricity Market Arrangements (REMA) reforms more broadly, will play in helping drive small-scale renewable deployment in the near-, mid- and far-term?

In the near-term, cPPAs and traditional PPAs are likely to play a minimal role in driving smallscale renewables deployment. These agreements are typically more suited for larger projects with established corporate offtakers, due to credit risk considerations and financing complexities.

Over the mid-term, there may be opportunities for expanded use of cPPAs specifically tailored for smaller renewable projects. As market conditions evolve and financing mechanisms adapt, cPPAs could become more accessible and attractive for smaller-scale developments, but there is a large level of uncertainty about whether the 'right' market conditions will evolve. The success of small-scale renewable deployment will hinge on broader electricity market reforms (i.e., REMA).

The feasibility of cPPAs (and PPAs) depends on the creditworthiness of offtakers. Lower credit ratings can result in higher project finance costs, potentially limiting deployment opportunities. It is our opinion that CfDs will be required to roll out large capacities of low-carbon generation. The CfD will not act as a subsidy, but as a risk management tool for market creation.

References:

1. Beiter, Philipp, Jérôme Guillet, Malte Jansen, Elizabeth Wilson, and Lena Kitzing. 'The Enduring Role of Contracts for Difference in Risk Management and Market Creation for Renewables'. *Nature Energy* 9, no. 1 (January 2024): 20–26. https://doi.org/10.1038/s41560-023-01401-w.

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

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

REMA is the most complex consultation process that we have encountered in our professional careers. The second round of this consultation has significantly reduced the range of policy options and has prioritised incremental improvements over radical change – a choice that we support. Nevertheless, enormous complexity remains. The impact of individual policy options is therefore difficult to assess, uncertain and sensitive to design choices. Moreover, there are complex interactions between different policies within REMA (e.g. the capacity market and zonal pricing) and outside REMA (e.g. balancing market, retail market reform, hydrogen-to-power consultation, long duration storage consultation) that are very difficult to model.

In this context, the notion of 'optimal' policy choices is misleading. We expect the design of the capacity market and other elements of REMA to constantly evolve and adjust in the light of improving technology, changing markets, and better information. Experience suggests that capacity markets need continuous modification and must achieve a difficult balance between providing certainty to investors and accommodating changing circumstances. This complexity also increases information asymmetry and can make policy design more vulnerable to lobbying by partisan interests. Since REMA embeds a significantly more complex capacity market within a broader set of far-reaching policy changes, we expect these tensions to increase.

Capacity markets must trade off certainty over the delivery of capacity with certainty over prices and costs. The consultation appears to prioritise the former over the latter, which may be appropriate given the overriding importance of ensuring security of supply. However, experience suggests that this can easily lead to excessive costs.

Based in part upon the supporting analysis by Baringa, the government proposes the 'single auction with minima' design for the capacity market. We understand that this choice may no longer be reversible, but it differs from our preferred choice of a 'single auction with multipliers' design. We would like to highlight some concerns:

Evaluation:
First, the consultation proposes a sensible, multi-criteria framework for evaluating different policy options (KOKO). However, it appears to rule out some of these options because of their assessed performance against one of these criteria, rather than their aggregate performance against them all. The consultation lacks summary goals/options matrices that evaluate each of the options against each of the goals. Presenting the results in this way would make the trade-offs more transparent.

Auction design:
Second, we agree that the split auction design is administratively demanding, since it involves running several separate auctions and specifying the relevant parameters for each auction. We expect those parameters to include a price cap, a capacity target, and a capacity range – which together determine the demand curve. However, it is not clear why the 'single auction with minima' scores better than the 'split auction' in this regard. While the former involves only a single auction, it requires a demand curve to be specified for each of the categories within the auction. This may be relatively straightforward if the auction is confined to only two categories (e.g. low-carbon versus high-carbon) but becomes more demanding if multiple categories are proposed (e.g. low-carbon, long duration, ramping). In our view, it may be easier to specify multipliers to value these desirable characteristics rather than individual demand curves.

Uncertainties:
Third, we agree that the appropriate choice of multiplier(s) is uncertain, and that a large multiplier may be required to ensure delivery of a particular quantity of low-carbon capacity. In other words, fixing a price (the multipliers) leads to uncertainty in quantity (capacity). However, this merely reflects the inherent uncertainty of the auction process. It is equally true that the appropriate choice of capacity target is uncertain, and that a particular choice may lead to a high clearing price. In other words, fixing a quantity (capacity) leads to uncertainty in prices. The 'split auction with minima' establishes a target capacity for each category and an associated capacity range. It is possible that the resulting clearing price will be high and will impose significant costs on consumers – and if that price exceeds the cap, the target capacity will not be delivered at all. Hence, uncertainty in quantity (capacity) and/or cost (price) is unavoidable. Different auction designs and parameter choices reduce some uncertainties while increasing others. The rationale for why some uncertainties should be reduced and others accepted needs to be more explicit.

Flexibility:
Fourth, we are concerned that the consultation gives insufficient attention to other dimensions of flexibility, such as ramp rates, provision of ancillary services and sustained response. Many low-carbon flexibility technologies do not perform as well as unabated gas on these dimensions, creating

the risk of under-provision. As the consultation notes, "… some care may need to be taken that the design of the capacity market does not have the unintended consequence of crowding out desirable sources of flexibility that would otherwise participate." One way to reduce this risk would be to include additional minima for capacity that provides these characteristics. However, multiple minima would complicate the design of the auction and could potentially reduce liquidity and encourage strategic bidding. In contrast, the 'single auction with multiplier' design could include different multipliers for different characteristics from the beginning, with the multipliers being adjusted and expanded in subsequent auction rounds in the light of experience and evolving needs. We consider this a more straightforward way of encouraging capacity with the full range of valued flexibility characteristics.

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

The supporting report by Baringa informs the choice of auction design, but the analysis has some limitations (https://assets.publishing.service.gov.uk/media/65e3a3193f69450263035fc1/4-alternative-capacity-market-auction-design.pdf). Specifically:

- it focuses upon a binary classification of participating technologies (low-carbon versus high-carbon), rather than multiple categories;
- it focuses upon technologies such as Power CCS that will in practice be excluded from the capacity market for many years because they qualify for 'bespoke' support (see below); and
- it focuses more upon incentivising low-carbon flexibility than on other dimensions of flexibility, such as responsiveness and ramping time.

As a result, the appropriate auction design for incentivising *qualifying* low-carbon technologies and/or *multiple dimensions* of flexibility may differ from the design that is currently proposed.

The success of the auction will depend upon the appropriate choice of price cap, capacity target and capacity range for each category, together with the specification of other variables, such as the forward period (lead time before service must commence) and commitment period (the period over which winning bidders receive the cleared market payment for the service). The choice for the latter could have a strong influence on the success of the auction, and may need to vary between different categories of flexibility. For example, long-duration storage technologies such as pumped hydro and CAES have longer lead times than other flexibility options.

References:

1. Baringa Partners, 'Review of Electricity Market Arrangements Alternative Capacity Market Auction Designs: A report to the Department for Energy Security and Net Zero', DESNZ research paper number: 2023/027, Department for Energy Security and Net Zero, July 2023 https://assets.publishing.service.gov.uk/media/65e3a3193f69450263035fc1/4-alternative-capacity-market-auction-design.pdf

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

Yes

Please elaborate on your response here.

The proposed emission limits are welcome and necessary but raise some issues.

First, the proposed intensity limit (100 gCO_2kWh) and annual limit (350 kg CO_2/kW) are based upon the anticipated emissions from a Power CCS with 50% thermal efficiency and a minimum capture rate of 73%. Higher capture rates should be achievable by the mid-2030s, and there is a case for incentivising more efficient capture through the capacity market rules. This suggests that the proposed emission limits should be tightened.

Second, the proposed limits are equivalent to ~750 hours annual operation of an Open Cycle Gas Turbine (OCGT), which exceeds the typical operating hours of such plants (<400) (https://www.regen.co.uk/publications/rema-insight-paper-capacity-market-reform/). A tighter emission limit would appear more consistent with UK decarbonisation objectives and could increase the incentive for deploying low-carbon alternatives such as hydrogen to power.

Third, there may be benefits from phasing in emission limits in the period up to 2034 to accelerate the removal of high carbon generating plants.

Finally, the effectiveness of these emission limits will depend upon the associated penalties for non-compliance, which are not specified.

While tighter emission limits may incentivise and accelerate decarbonisation, they may also increase the risk to supply security by discouraging investment in new or life-extended unabated gas. The balance is difficult to judge, owing to uncertainties over the rate of deployment of low-carbon flexibility, and hence the future need for unabated gas. The consultation highlights the need for 'some' newbuild unabated gas but does not indicate the anticipated total capacity, the technology split (CCGT versus OCGT versus engine) or the anticipated load factor. While FES and NIC estimate a need for ~24 GW of unabated gas in 2035, the CCC estimates a need for only half that amount (~12GW) (https://www.theccc.org.uk/wp-content/uploads/2023/03/Delivering-a-reliable-decarbonised-power-system.pdf). Interestingly, the CCC estimate is approximately equal to Baringa's estimate (in their baseline scenario) of the capacity of *existing* unabated gas plant that is expected to remain on the system in 2035 (https://assets.publishing.service.gov.uk/media/65e3a3a32f2b3bbc587cd767/8-assessing-deployment-potential-flexible-capacity-gb-interim-report.pdf). This suggests that it may be possible to ensure supply security in the period to 2035 without *any* investment in new, unabated gas. While much of the unabated gas capacity may retire after 2035, the consequent risk to supply security should be mitigated by increased deployment of low-carbon flexibility.

The CCC estimates that 12 GW of unabated gas capacity would supply around 2% of total generation in 2035 (10 TWh), implying a load factor of ~10%. If this plant were CCGT (emissions intensity: ~0.35 $kgCO_2/kWh$), the annual emissions (~300 $kgCO_2/kWh$) would be less than the proposed annual limit (350 $kgCO_2/kWh$). However, if this plant were OCGT or reciprocating engines (emissions intensity:

~0.46 $kgCO_2$/kWh), the annual emissions (~380 $kgCO_2$/kWh) would exceed the annual limit. Hence, depending upon the mix of the plant, the emission limits appear broadly consistent with the CCC's expectations of the role of unabated gas in 2035 and should constrain load factors to <10%. However, in conditions of supply shortage, we would expect supply security to take precedence over emission limits.

References:

1. Gowdy, Johnny and Ellie Brundrett, 'REMA Regen Insight Paper: Capacity Market Reform', March 2023 https://www.regen.co.uk/publications/rema-insight-paper-capacity-market-reform/
2. The Climate Change Committee, 'Delivering a reliable decarbonised power system', March 2023 https://www.theccc.org.uk/wp-content/uploads/2023/03/Delivering-a-reliable-decarbonised-power-system.pdf
3. Baringa Partners and AtkinsRéalis UK Ltd, 'Assessing the deployment potential of flexible capacity in Great Britain – an interim report', DESNZ research paper number: 2023/051, Department for Energy Security and Net Zero, February 2024 https://assets.publishing.service.gov.uk/media/65e3a3a32f2b3bbc587cd767/8-assessing-deployment-potential-flexible-capacity-gb-interim-report.pdf

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?

The recent analysis from the CCC suggests a greater contribution from hydrogen-fired capacity than gas CCS in the period to 2035, since the former aligns better with the anticipated low to medium load factors required to balance residual demand (https://www.theccc.org.uk/wp-content/uploads/2023/03/Delivering-a-reliable-decarbonised-power-system.pdf). Load factors may decrease further beyond 2035 as deployment of wind and solar accelerates. Hence, we consider it essential to facilitate conversion of existing plants to hydrogen and invest in enabling infrastructure. Conversion will be easier for plants located near industrial clusters. Much of the policy incentives to facilitate conversion lie beyond REMA, and include the consultations on bespoke support for Hydrogen to Power (H2P) and on business models for hydrogen, transport and storage.

References:

1. The Climate Change Committee, 'Delivering a reliable decarbonised power system', March 2023 https://www.theccc.org.uk/wp-content/uploads/2023/03/Delivering-a-reliable-decarbonised-power-system.pdf

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.

Don't know

20. Do you agree that an Optimised Capacity Market (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.

Don't know

We do not have enough information to judge whether current and proposed policies will provide sufficient incentives for distributed, low carbon flexibility. The policy and institutional landscape in this area is especially complex, with multiple initiatives (e.g. Smart and Secure Electricity System programmes, Retail Market Reform, Energy Digitalisation Strategy, NESO Flexibility Strategy, Flex Markets Unlocked innovation competition) involving multiple institutions (e.g., DESNZ, Ofgem, NESO, DSOs). Ensuring the coherence of these policies appears to us a considerable challenge.

We expect distributed, low-carbon flexibility sources (notably batteries and demand side response) to be the dominant participants in the Capacity Market in the period to 2030. We further expect the Balancing Market to provide an increasing share of total revenue for these sources. Nevertheless, long-term capacity contracts will remain essential for reducing investor risk.

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.

Don't know

Again, the complexity of the policy package makes it difficult for us to assess its likely success. However, we make some observations.

Overall reform package:
First, the supporting report from Baringa assesses the economics of investment in unabated gas, the barriers to that investment, and the options for reducing those barriers (https://assets.publishing.service.gov.uk/media/65e3a3a32f2b3bbc587cd767/8-assessing-deployment-potential-flexible-capacity-gb-interim-report.pdf). Baringa is engaged in a comparable appraisal of other flexible technologies, including batteries, pumped storage, biomass, and hydrogen-to-power. Having the full report from Baringa would make it easier to evaluate the overall package of reforms, since this would allow the full range of flexibility options to be assessed and compared. In the absence of that report, there is a risk the consultation places excessive emphasis upon encouraging unabated gas to ensure supply security and insufficient emphasis on accelerating the deployment of low-carbon alternatives. The messaging that accompanied the launch of the consultation suggests that this may be the case.

Bespoke support:
Second, the government has proposed a bespoke support mechanism for Power CCS and is consulting on comparable support mechanisms for Hydrogen to Power (H2P) and Long Duration Energy Storage (LDES). The rationale for these policy proposals is that bespoke support mechanisms are necessary to reduce investor risk, and that reforms to the capacity market are unlikely to be sufficient to ensure investment in the short to medium term. However, Baringa's supporting report

on auction design contradicts this argument since it models these technologies being delivered through the capacity market alone (https://assets.publishing.service.gov.uk/media/65e3a3193f69450263035fc1/4-alternative-capacity-market-auction-design.pdf). Either Baringa's analysis is based upon overly optimistic assumptions about technology cost, performance and investment risk, or the arguments for bespoke support mechanisms do not stand up. We find the first of these explanations to be more persuasive, which raises questions about the credibility of the analysis of auction design.

"Glide path":
Third, both the H2P and LDES consultations envisage a "glide path" from bespoke support mechanism to multi-technology competition through the reformed electricity market. However, neither these consultations, nor REMA itself, elaborate on the nature and length of this glide path. To avoid redundancy, complexity, and excessive costs, we assume that the technologies covered by the bespoke mechanisms will be excluded from the capacity market until those mechanisms are withdrawn (although it would be helpful if the consultation made this explicit). That suggests the low-carbon capacity market will be confined to a limited number of short-duration technologies, such as batteries and demand-side response, until at least the 2030s, with long-duration flexibility being largely delivered through the bespoke mechanisms. Hence, the successful delivery of long-duration flexibility will depend more upon the success of the bespoke mechanisms than on the immediate changes to the capacity market. Lessons from these mechanisms can inform the subsequent design of the capacity market, but we would expect this to be preceded by further modifications to the bespoke mechanisms themselves – notably a transition from negotiations with individual developers to price competition. We expect the transition from bespoke mechanisms to full reliance on the capacity market may take up to a decade.

Broader energy policy:
Fourth, the combination of capacity market, sharper operational signals and bespoke support mechanisms will clearly not suffice in isolation to deliver the required capacity of flexible plant. Broader reforms are also required, including large-scale investment in electricity network upgrades, measures to reduce delays with grid connections, accelerated planning consent, rollout of hydrogen production, transport and storage infrastructure, and upgrades to the system operators' digital systems. The success of REMA therefore depends upon the success of ongoing policy initiatives in these and other areas. Within this, we would like to highlight the importance of hydrogen storage technologies – which can be used in combination with H2P to provide supply security during an extended 'wind drought'. Hydrogen storage is excluded from the LDES consultation but appears the most promising option for large-scale storage on both economic and environmental grounds. Recent work by the Royal Society, based upon an evaluation of weather patterns over a 37-year period, has suggested a need for 60-100 TWh of hydrogen storage by 2050 (https://royalsociety.org/-/media/policy/projects/large-scale-electricity-storage/large-scale-electricity-storage-report.pdf). While the government may not agree with this remarkably large estimate, there seems little doubt that long-duration storage presents a major technical challenge, and that hydrogen will play a leading role in meeting that challenge. The CCC has suggested a target of 5 TWh of hydrogen storage by the mid-2030s, which is itself ambitious. We believe, therefore, that the REMA reforms must be combined with a credible strategy to deliver substantial investment in hydrogen storage and associated infrastructure within the next decade.

Finally, we would like to see more consideration of how REMA in general and the capacity market reforms in particular could influence the volumes, benefits, and impacts of cross-border electricity trade. Differences in capacity support mechanisms between countries can introduce a variety of distortions and problems, and the UK's exit from the European Union has not eliminated those problems.

References:

1. Baringa Partners and AtkinsRéalis UK Ltd, 'Assessing the deployment potential of flexible capacity in Great Britain – an interim report', DESNZ research paper number: 2023/051, Department for Energy Security and Net Zero, February 2024 https://assets.publishing.service.gov.uk/media/65e3a3a32f2b3bbc587cd767/8-assessing-deployment-potential-flexible-capacity-gb-interim-report.pdf
2. Baringa Partners, 'Review of Electricity Market Arrangements Alternative Capacity Market Auction Designs: A report to the Department for Energy Security and Net Zero', DESNZ research paper number: 2023/027, Department for Energy Security and Net Zero, July 2023 https://assets.publishing.service.gov.uk/media/65e3a3193f69450263035fc1/4-alternative-capacity-market-auction-design.pdf
3. The Royal Society, 'Large-scale electricity storage', September 2023, https://royalsociety.org/-/media/policy/projects/large-scale-electricity-storage/large-scale-electricity-storage-report.pdf

May 2024