ELEXON

10 October 2022

By e-mail to: rema@beis.gov.uk

Dear REMA Team,

Re: Review of Electricity Market Arrangements (REMA) Consultation

Thank you for the opportunity to respond to your consultation on the Review of Electricity Market Arrangements (REMA).

Elexon is the Code Manager for the Balancing and Settlement Code (BSC), which facilitates the effective operation of the electricity market. We are responsible for managing and delivering the end-to-end services set out in the BSC and accompanying systems that support the BSC. This includes responsibility for the delivery of balancing and imbalance settlement and the provision of assurance services to the BSC Panel and BSC Parties (energy Suppliers, generators, flexibility service providers and network companies). We manage not just the assessment, but also the development, implementation and operation of changes to central systems and processes. In addition, our expertise is available to support the industry, government and Ofgem in considering future changes and innovation against the existing industry rules, for the benefit of the consumer. Elexon is a not-for-profit company, set up as an arm's-length subsidiary of National Grid ESO (Electricity System Operator).

In addition, through our subsidiary, EMR Settlement Ltd, we calculate, collect and distribute payments to Contract for Difference (CfD) generators and Capacity Market (CM) providers, on behalf of the Low Carbon Contracts Company (LCCC). These services are provided to LCCC through a contract and on a not-for-profit basis. EMR Settlement Ltd is also the proposed Nuclear Regulated Asset Base Model Revenue Collection agent for LCCC.

We have been instrumental in ensuring the BSC and accompanying systems evolve to deliver Net Zero solutions and facilitate innovation in the energy market. We recognise the significance and importance of the REMA consultation and welcome the opportunity to share our comments, observations and suggestions. We do this from the perspective of having more than 20-years' experience of working alongside Ofgem, BEIS (and predecessors) and the energy industry and encompass a vast wealth of knowledge and experience through our team.

In our response to the consultation questions, we have focused on those questions where we believe we can add value and outline practical considerations and suggestions based on our role at the centre of the electricity market.

Below we provide a summary of the key points for our response and follow those up in detail in our answers to your questions:

- **Split Markets/Green Power Pool:** We believe a split market or green power pool will have negative distributional impacts on consumers, is untested and will not bring forward as much flexible supply and demand. The Market-wide Half-Hourly Settlement (MHHS) programme and Smart Meter rollout will bring forward flexibility, and extending the CfD scheme to other renewables is a better approach.
- **Locational Pricing (Zonal and Nodal):** In a nodal or zonal model, our assessment is that there is a risk of reduced investment in renewables and disproportionate outcomes for inflexible consumers. However, we have also set out potential mitigations of those risks so that, if this route were chosen, a transition could be managed properly.

- **Electricity Demand Reduction (EDR):** Elexon could facilitate a potential market for EDR, subject to MHHS and Smart Meter roll-out success. We are already progressing modifications such as P375 which are facilitating EDR in the Balancing Mechanism (BM).
- **Distribution-led Local Markets:** We highlight the need for standardisation and convergence in settlement and balancing methodologies for Distribution System Operators (DSOs) when developing local balancing markets. We also recommend that local markets should be developed incrementally and we note that P441 assists this aim. Finally, it would also be beneficial to consider reform of Distribution Use of System (DUoS) tariffs when considering the development of local markets.
- **Shorter Settlement Period and other parameters:** Smaller changes to existing arrangements are preferred and can have more of a direct impact. We explain how shorter settlement has both advantages and disadvantages. Elexon has agile systems to adapt to such a change if it were considered as a preferred design option in the future.
- **Deemed Generation:** Calculating deemed generation is difficult and complicated, a better method of reform could be by adjusting ancillary service volumes, and making sure the metered data used in CfD Settlement includes power generated and used to charge a battery.
- **Capacity Market:** It would be beneficial to consider reforms to the CM such as increasing incentives for flexibility and new technologies, more robust performance assurance of parties holding capacity obligations obtained via secondary trading and making the penalty regime less complex.
- **Strategic Reserve:** We support this, as diverse market and non-market methods of procurement could be available should a Stress Event occur, acting as a back-stop if the capacity cannot be procured in the CM. It is also a sensible mechanism to enable the FSO to plan investment and prepare for different load scenarios.
- **Supplier Obligation for Flexibility:** This would increase costs for suppliers and they are not best placed to deliver flexibility, given current market circumstances. Flexible generation and demand should be encouraged through a range of alternative mechanisms, including the CM, Demand Side Response (DSR) and co-location of renewable energy generation with storage.
- **Centralised Reliability Options:** This is an interesting idea in principle as the ESO buys volumes at a strike price – we would however refine this approach by adding a "strike price adjustment". This removes the need for complex penalty processes and calculations in the CM, and may reduce the risk of arbitrage opportunities by those who set out to procure a balancing service contract as well as an Obligation at the same time.
- **Contracts for Difference (CfD):** The CfD could be reformed by implementing a maximum and minimum strike price, which could lead to optimisation. In this way, current CfDs could be amended by increasing market exposure, and protect future investment - by setting a minimum it may effectively reduce price cannibalisation.

If you would like to discuss any areas of our response, please contact Mahamid Ahmed, Strategy & External Affairs Manager (Mahamid.Ahmed@elexon.co.uk).

Yours sincerely,

Angela Love
Director of Future Markets and Engagement

Elexon's consultation response

Q1. Do you agree with the vision for the electricity system we have presented?

Elexon agrees with the vision presented in the consultation that the future market arrangements need to:

- "Deliver a step change in the rate of deployment of low carbon technologies, and reduce our dependence on fossil fuelled generation"
- "Provide the right signals for flexibility across the system"
- "Facilitate consumers to take greater control of their electricity use by rewarding them through improved price signals, whilst ensuring fair outcomes"
- "Optimise assets operating at local, regional, and national levels"
- "Ensure that the security of the system can be maintained at all times" in order to fully decarbonise the electricity system by 2035.

Furthermore, we fully agree with your statement that collectively we need to "make use of all the levers available across government, including fiscal policy, regulation and standards, public engagement, skills and training, in order to achieve net zero".

Q2. Do you agree with our objectives for electricity market reform (decarbonisation, security of supply, and cost effectiveness)?

Elexon fully supports the objectives of electricity market reform:

- Decarbonisation
- Security of supply
- Cost effectiveness

We also agree with your assessment that the objectives can only be delivered jointly, by BEIS, Ofgem, the FSO (Future System Operator) and the energy sector working together.

Q3. Do you agree with the future challenges for the electricity system we have identified? Are there further challenges we should consider? Please provide evidence for additional challenges.

Elexon broadly agrees with the challenges identified:

- Increasing the pace and breadth of investment in generation capacity
- Increasing system flexibility
- Providing efficient locational signals to minimise system cost
- Retaining system operability
- Managing price volatility

As REMA seeks to address these challenges, the systems, processes and data flows that underpin the electricity market will need to adapt to the new market design and framework. However, we believe this adaptation and change should be delivered in the most efficient, practical and cost-effective way, where projected costs and benefits are carefully weighed against each other.

Whichever market design model BEIS determines as the most appropriate solution at the end of the consultation process, Elexon is committed to working together with the industry, BEIS and Ofgem to implement any changes to our processes and systems in the most efficient, practical and cost-effective way to minimise the burden of change on industry and, ultimately, the consumer.

Q5. Are least cost, deliverability, investor confidence, whole-system flexibility and adaptability the right criteria against which to assess options?

Elexon believes these are the right criteria. We believe the 'least cost' category should also include consideration of the cost of change management to the industry.

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We have been discussing the proposed options for market reform with Ofgem and BEIS and are willing and able to assist with designing these changes (as well as implementing them). However, we would caution that it is important not to underestimate the amount of design work that will be required to introduce any, and especially entirely new, market arrangements and mechanisms.

Whilst some of the proposed changes have been implemented elsewhere in the world (such as locational pricing) the arrangements cannot simply be picked up and replicated in the GB market, as they will need to be adapted to the specifics of our market (e.g. the competitive supply market, which is not always well developed in other markets).

We would further add that, given the amount of change that is currently ongoing in the market, it would be beneficial to agree a roadmap for change, so that we can ensure those changes which bring the most benefit and/or are easier to implement are bought forward first.

Q6. Do you agree with our organisation of the options for reform?

We agree and find the schematic whereby the options are depicted alongside each other very helpful. However, we would like to note that *how* these reforms relate to each other should also be considered in future iterations of the REMA process, e.g. how would a pay-as-bid system complement/or work alongside a variable and firm power separation of the wholesale market and whether this is a key consideration or not. As mentioned in Q5, prioritisation of the more beneficial and easier to implement changes should enable a smooth evolution of the future market design.

Q7. What should we consider when constructing and assessing packages of options?

We believe the government focus should firmly be on establishing the new market frameworks to support the electricity market Net Zero target of 2035. Any proposed changes should be firmly set on actionable, practical steps rooted in evidence and cost-benefit analysis. Where verifiable best practices exist (in the GB arrangements), these need to be taken in account and built upon to aid the transition and maintain stability of the market arrangements during this unprecedented time of change for the industry and society as a whole. Broadly, we believe there should be an assessment of:

- The cost to the consumer of change programmes (including) consideration of the cost of change management to the industry, against the value realised;
- The timing of the change and how long it would take the industry to change its systems and processes, with resilience built in through mechanisms such as an interim solution or a fall-back option;
- What post-delivery assessment processes are in place, to ensure that the preferred option has fulfilled its objectives and that its delivery has been a success (i.e. by having consistent feedback loops);
- How to keep the arrangements under a regular review process to ensure that we do not face any real-life scenarios/issues that were not contemplated when the arrangements were initially set; and
- Understanding of how each proposal relates to each other and its impacts on the industry.

While considering elements of a new market design, we believe the REMA team should also consider the implementation timelines and interrelationship of the following ongoing initiatives and change programmes:

- Energy code reform: governance framework
- Future System Operator (FSO) transfer into public ownership
- Market-wide Half Hourly Settlement (MHHS) Programme
- DNO to DSO transition and local balancing markets development
- Review of DCC licence arrangements
- Reforming the Framework for Better Regulation
- Energy Digitalisation Taskforce recommendations
- Energy retail market strategy

- BEIS Committee Call for Evidence into the Cost of Energy Review
- BEIS Net Zero Review
- BEIS Review into Energy Regulation
- Results of recent independent reviews (e.g. Energy UK), as they pave the way to a Net Zero energy system and rely on the same organisations to develop and implement the solutions

Q11. How responsive would market participants be to sharper locational signals? Please provide any evidence, including from other jurisdictions, in your response.

We have not attempted to review the literature on other markets, but we note that many commentators are doubtful about the extent to which both demand and renewable generation can respond to locational price signals. For example, onshore wind projects will locate where the weather conditions and topography are optimal, and manufacturing locates where there are the right skills and availability of labour. In addition, for heavy industries the cost of transporting raw materials and parts, and the cost of shipping final products have to be taken into consideration. Lower energy costs may well be offset by an increase in transportation costs. Physical location can also be critically important for data centres too due to data latency, i.e. the time it takes data packets to travel from one place to another. Where real-time operations are of importance, businesses are likely to use data centres that are closely connected to their own operations. We, therefore believe it is important that any decision to move to locational pricing is based on actual evidence about the extent to which market participants can respond to it, rather than assuming on theoretical grounds that they will respond.

Q12. How do you think electricity demand reduction should be rewarded in existing or future electricity markets?

We note the potential for the REMA process to propose an option similar to California, Switzerland or Portugal where the System Operator procures electricity demand reduction by the MWh by paying an "avoided cost rate" to projects for the avoided cost of delivering electricity in specific periods.

In the GB market, there is an ongoing modification to the BSC – P376[1] 'Utilising a Baselining Methodology to set Physical Notifications' that will allow balancing service providers to be fully recompensed for their actual change from normal usage and the benefit that this change in consumption has on the system. Ofgem has approved P376 with an Implementation Date of 23 February 2023.

Further BSC Modifications such as P344[2], and P375[3] are intended to allow varied types of flexible parties, such as demand reduction aggregators, to access the Balancing Mechanism (BM). As these solutions are introduced, we should increasingly see demand reduction access the BM.

Further, Market-wide Half Hourly Settlement (MHHS) processes, once implemented, will enable greater participation in the BM from the small commercial and residential sectors, where accurate half hourly settlement is currently less prevalent and is elective rather than mandatory in the industrial and commercial sectors. The widespread rollout of smart meters to the residential and small commercial sectors, if completed by the target date of 2025, alongside MHHS, will make half-hourly settlement the norm.

However, we would highlight that a half-hourly Electricity Demand Reduction (EDR) system is dependent upon widespread smart meter coverage, without which the signals for consumer/residential EDR (via aggregators/suppliers) might not produce the cost savings, which would justify a new market design. For example, California had a programme where almost all households had a smart meter installed via a street-by-street instalment programme led by their Distribution Network Operators (DNOs), which allowed for the half-hourly system to provide

[1] P376 'Utilising a Baselining Methodology to set Physical Notifications' - Elexon BSC
[2] P344 'Wider Access and Project TERRE'
[3] P375 'Settlement of Secondary BM Units using metering behind the site Boundary Point'

value-creation opportunities for EDR. By comparison in the UK the approach to smart meter installation has been Supplier led and at present there is only 53% penetration of smart meters, whereas California has a 95% penetration rate.

Elexon is already enabling EDR participation in the BM by progressing the enabling modifications mentioned above. The Smart Meter Rollout alongside MHHS Programme implementation will allow Elexon further to adapt its systems and processes and enable this innovative market framework that incentivises energy efficiency and its ability to stack up different revenue streams to a larger scale than current frameworks allow.

Q14. Do you agree that we should continue to consider a split wholesale market?

Whilst we appreciate the benefit of a split market in creating revenue certainty for renewable generators in the long-run as it is based on the long-run marginal cost, a split market has not been tested anywhere in the world - making it hard to predict and model the impact on electricity market systems and processes of such a design.

We note that consumers who are able to flex their demand could purchase a higher proportion of their electricity from the as 'available market', mainly through their suppliers. The REMA process going forward could conduct an assessment of the impact on those consumers who cannot flex their demand (i.e. those that do not have an EV or smart appliances) and we believe that there should be protection for those consumers against any negative price externality as a result of those using the market to adjust demand profiles.

An alternative mechanism to encourage renewable generation and lower prices/spread prices across a long timeframe would be to move the legacy Renewables Obligation (RO) generators across to CfDs, thereby eliminating the extra subsidy the RO generators collect (noting however, that such a change would be dependent on the strike price and longevity of the contracts). That option could be furthered by either encouraging or enforcing new renewables and low carbon flexible generation projects to be built and operated on the basis of long-term CfD contracts.

The current market arrangements allow CfD holding generators to have revenue certainty and enable a pay-back to consumers when the wholesale price is high. Reforming CfDs (for both new and existing generators) by setting a minimum and maximum strike price so that the CfD is more reflective of market conditions and offers greater protection against price cannibalisation could provide a better alternative solution to splitting the market – the CfD scheme is itself a de-facto way of splitting the market. Further, co-location of renewable projects with storage (which can now bid in CfD auctions) should reduce the need for curtailing generation on the system.

Q15. How might the design issues raised above be overcome for: a) the split markets model, and b) the green power pool? Please consider the role flexible assets should play in a split market or green power pool – which markets should they participate in? - and how system costs could be passed on to green power pool participants.

We believe that a downside of a split market or a green power pool is that the perceived additional benefits are too low or negligible as compared to the existing temporal signals provided by half-hourly settlement and recent modifications to the BSC to bring forward incentives for flexible supply and demand.

As noted in our answer to Q12, Elexon is progressing several modifications, and has already implemented a few modifications such as P415[4], P376 and P375, which incentivise demand-side flexibility in the form of aggregated DSR and Vehicle-to-Grid (V2G) and also supply-side flexibility in the form of long-duration storage. More specifically:

- P375 and P376 will enable smaller assets, such as electric vehicle (EV) batteries via V2G, smart grids, storage and community energy to provide balancing services to the grid.

[4] P415 'Facilitating access to wholesale markets for flexibility dispatched by Virtual Lead Parties'

- P415 will allow greater provision of demand-side response (DSR) services which help to lower demand during peak times. This will be through enabling the participation of "Virtual Lead Parties (VLPs)" in the GB wholesale market, offering services such as aggregated flexibility.

Further, we believe that a varied marketplace where renewable generators can use the CfD scheme to attain revenue certainty and also participate in the wholesale market, paying back to consumers when the price is high and not having a significant impact when prices are low, as CfDs only represent a small percentage of the consumer bill, already demonstrates a de-facto split without distorting market signals. As mentioned in our answer to Q14, moving all renewable generators to the CfD model would further equilibrate the market to ensure the market is fair for final consumers and system costs are as low as possible.

CfD holders have options to either sell their power via Power Purchase Agreements (PPAs), forward curve prices or current wholesale prices – we believe this optionality should continue as a diversity of market mechanisms for CfD holders will smooth out any price impacts for consumers and provide a range of revenue-making opportunities for generators at the same time. Co-location of storage with renewable projects should also be accelerated through existing market mechanisms and contracts (i.e. PPAs) to ensure that large amounts of energy are not curtailed, increasing system costs.

In our view, MHHS, alongside the smart meter rollout, when completed, should be sufficient to address demand side flexibility participation in the market and is likely to reduce system costs in the future. For example, the settlement arrangements that arise from MHHS will create incentives for suppliers and aggregators to incentivise customer behaviour such as demand reduction/charging at specific times that contribute to a lower cost electricity system, by balancing the intermittency of renewable generators on a much bigger scale and reducing the need for network reinforcement and building.

We therefore disagree a split market or a green power pool model would provide sufficient benefits as compared to half-hourly settlement in enabling flexible participation in the market.

Q16. Do you agree that we should continue to consider both nodal and zonal market designs?

We acknowledge the potential of providing sharper locational signals might reduce balancing and transmission constraint costs, but would note that careful consideration is needed to ensure that it delivers an overall benefit to consumers.

We believe the local flexibility and/or balancing markets that are being created through the DNO to DSO transition de-facto represent zonal markets.

Q17. How might the challenges and design issues we have identified with nodal and zonal market designs be overcome?

As we comment above, we note that many commentators are doubtful about the extent to which both demand and renewable generation can respond to locational price signals. For example, onshore wind projects will locate where the weather conditions and topography are optimal, and manufacturing locates where there are the right skills and availability of labour. We believe it is important that any decision to move to locational pricing is based on actual evidence about the extent to which market participants can respond to it, rather than assuming on theoretical grounds that they will respond.

The key challenges to implementing locational pricing are around ensuring that the design is robust and its implications for all types of parties are fully understood. In general we have many concerns with locational pricing as its implementation would cause an investment hiatus and we are not convinced it will drive investment into renewables or even enable demand-side response. We, however list several options to manage risks to consumers, suppliers and generators in our response to Ofgem's call for input on locational pricing. Broadly, we think the challenges and design issues can be overcome by:

- Mitigating the potential for penalising businesses and consumers for decisions they

cannot change by:
  - Choosing less sharp signals and not exposing vulnerable consumers to locational prices, or;
  - Having a choice for customers (either directly or through suppliers) to “opt-in” to be exposed to full locational prices, so that flexible customers can be rewarded for shifting consumption and inflexible customers are not exposed (as they have not opted in) to the negative externality.
- Introducing a new process for mapping metering systems to nodes or zones (at least for those customers who choose to provide flexibility services).

However, we also recognise that there is a risk that locational pricing could dis-incentivise large-scale investment in renewables, due to a combination of:

- Lower wholesale prices in those areas of the country which are geographically remote from population centres and other forms of demand (many of which are areas where building wind farms is currently most economically attractive); and
- Increased risk from more complex Contracts for Difference, and having to rely on Financial Transmission Rights (FTRs) that are not necessarily available long-term.

To mitigate some of these dis-incentives the Transmission Network Use of System (TNUoS) and DUoS charges could have sharpened locational signals within them as an interim measure/alternative, to see if this re-balances the economic attractiveness of renewable assets to encourage them to locate closer to demand.

If locational pricing is considered for implementation, we believe it should take place gradually using transitional arrangements (by grandfathering current arrangements, for example), as there would also be a risk to suppliers through:

- Sudden step changes in the wholesale prices to which they (and their customers) are exposed; and
- Potential teething problems with the complex new systems and processes that they need in order to operate in the new market arrangements.

Q19. Do you agree that we should continue to consider the local markets approach? Please consider the relative advantages and drawbacks, and local institutional requirements, of distribution led approaches

Yes, we believe that DSOs will play a critical role in the local institutional arrangements.

We believe several of the processes, as well as corresponding governance mechanisms and central systems that Elexon runs for the **national** balancing market, can be adapted to serve **local** balancing markets.

In our response to Ofgem’s recent call for input on the Future of local energy institutions and governance, we proposed an idea that settlement processes could be converged across the industry to deliver efficiencies and consistency for all stakeholders, including DNOs and flexibility service providers.

We also note that, through our recent engagement with various DNOs, we have observed that some DNOs are further ahead than others in their transition to the DSO model. We believe that having standardised, commonly agreed and universally understood processes for clearing balancing transactions across local markets will facilitate faster development of the DSO services.

Q20. Are there other approaches to developing local markets which we have not considered?

The approaches discussed in the consultation document such as DNO-led local markets, Smart Energy Service Providers-running local markets and local imbalance pricing are complex and untested in any jurisdiction, which means attempting to implement them on a large scale in GB could be a high-risk strategy. We suggest consideration should be given to whether more modest incremental change could facilitate development of local markets *alongside* wholesale market reform, rather than as an alternative to it.

For example, BSC Modification P441[5] 'Creation of Complex Site Classes' represents a small initial step in this direction. The modification proposes to recognise in the BSC arrangements settlement of local energy markets that currently fall into a 'grey area' of being neither formally recognised nor explicitly prohibited. A potential further step could be the introduction of appropriate DUoS tariffs for local energy markets that will recognise that local balancing of demand and generation reduces the load on distribution networks and frees up distribution capacity for other customers. There could be incentives to coordinate and connect both demand and generation to distribution networks through the RIIO-ED framework.

Q22. Do you agree that we should continue to consider amendments to the parameters of current market arrangements, including to dispatch, settlement and gate closure?

Yes, we fully agree with this proposal. These types of change are much more straightforward to implement and have a much lower risk of unintended consequences than major reforms of the trading arrangements. These amendments could also be implemented faster and in parallel with the development of more fundamental changes, if those are considered necessary. We would therefore support further work to assess the potential large-scale, longer-term benefits of these changes.

With regard to a shortening of the Settlement Period, we note that previous analysis has suggested a net dis-benefit of moving to a 15 minute Settlement Period, as explained in Ofgem's 2020 decision to exempt GB from the requirement to move to a 15-minute Settlement Period. However, we observe that:

- Recent high balancing costs are likely to increase the benefits; and
- High costs of re-configuring/installing smart meters so that they can record a shorter settlement period (currently they are only obliged to record half-hourly data) could potentially be addressed by a 'profiling' approach allowing those customers not active in wholesale markets to retain their non-Half Hourly metering.

A potential shift to a shorter settlement period and resulting benefits will have to be also assessed in the context of the on-going major industry changes.

If – based on the updated analysis of benefits arising from the 15-minute settlement – the decision were taken to progress with this change, a careful consideration would be required as to the implementation of it. For example, whether a parallel or staggered implementation approach would deliver the most benefit to the industry.

Should a shorter settlement period be considered in the future, Elexon's systems and processes could be adapted to deliver this change. Our re-architected IT systems have the ability to support the shortening of the settlement period - for example, one of the key Design Principles of MHHS is that all the newly built systems should be able to accommodate a change to the duration of the settlement period. However, careful consideration needs to take place of the impacts of such a change on other IT system changes taking place in the near-term.

Q23. Are there any other changes to current wholesale market design and the Balancing Mechanism we should consider?

Another change to consider is improved data provision from both transmission-system connected and distribution- system connected generation assets. This will require putting in place new industry arrangements to give NGESO access to data and timely and accurate information on the scheduled activity of all market participants, including for embedded generation and large customers.

5 P441 'Creation of Complex Site Classes'

Elexon notes the significant increase in balancing costs in recent years and welcomes the chance to feed into more detailed analysis of potential reforms to the BM that have been listed in the consultation as to be explored in the next phase of REMA, namely:

- Having price caps or changing Licence conditions to directly restrict excessive BM offer prices;
- Managing the extent to which Generators can amend their schedule at short notice;
- Strengthening locational signals within the BM; and
- Changing the BM's bidding structure.

Elexon is ready to work with BEIS, Ofgem and the industry to develop these ideas further and if/when required, to develop estimates of the implementation timelines and costs.

Q25. How could electricity markets better value the low carbon and wider system benefits of small-scale, distributed renewables?

We believe low carbon, small-scale distributed renewable projects, in addition to the wide-spread use of PPAs, should have access to local/national balancing and flexibility markets. As detailed in Q54, this will require a change in asset visibility and also a change to how networks are managed. The change from DNO to DSO model, proposed and funded through the RIIO-ED2 period (2023-2028), should lay a solid foundation for the wider proliferation of the local flexibility markets.

Q26. Do you agree that we should continue to consider supplier obligations?

No, we do not believe this should be the case as it would increase costs for Suppliers, who are already financially constrained in current market circumstances, and likely to remain so going forward. Please refer to our answer under Q42 for further details on alternative approaches. We, however suggest some design changes that could facilitate a Supplier Obligation in Q27, should it be considered further.

Q27. How would the supplier landscape need to change, **if at all, to make a supplier obligation model effective at bringing forward low carbon investment?**

We believe that introducing a premium to carbon heavy electricity generation technology should be relatively easy to apply, currently only at BM level. It would be possible to adapt the Final Consumption Levies (FCL) to flip to a positive multiplier on carbon heavy generation - blanket applied, rather than self-reporting as Green Energy Exemptions (GEE).

An alternative to this is to blanket apply GEE - like incentives, based on accurate technology description rather than self-reporting.

Q29. Do you agree that we should continue to consider central contracts with payments based on output?

Yes, we believe central contracts with payments based on outputs should continue to be considered. New generation is being built slowly and not necessarily in locations with the highest demand. The current central contracts tend to be inflexible, with the price based on 15-year contract duration, with very limited market exposure. This decreases the risk for Generators but, arguably, can help push up market prices to cover the margin.

By implementing a maximum and minimum strike price, optimisation of the CfD market could occur. It would increase exposure to the market whilst still providing investment resilience. In this way, current CfDs could be amended by increasing market exposure, and protect future investment - by setting a minimum it may effectively reduce price cannibalisation.

Q30. Are the benefits of increased market exposure under central contracts with payment based on output likely to outweigh the potential increase in financing cost?

Yes - when coupled with further reform.

The deemed model negates the need for generators to export, and should therefore not be considered for anything other than investment and build purposes. If this is carried forward, it incentivises availability though, perhaps not flexibility, and limits market exposure.

When considering a move to a locational pricing model, actual output is a stronger signal than deemed output. For example, in a nodal pricing model, there are sharper signals to consider physical constraints of the system and potentially drive up investment in the physical network, but this may mean that generation is only provided where there is an incentive to connect to the network (i.e. demand centre).

Zonal pricing would be relatively straightforward to implement; however, locational market signals and increased participation from DNOs and IDNOs would be required - it is not clear yet, what role these agents would need to play in this situation. Clear development of the DSO model should ease any uncertainties regarding DNO participation. For both zonal and nodal pricing, unintended consequences need to be properly understood and mitigations conceived and put in place, should this be the market design of choice – we have set out further what these would look like in response to Q17.

Q32. Do you agree that we should continue to consider central contracts with payment decoupled from output?

No, we do not agree that central contract with payments decoupled from outputs should be considered, as this is the current design feature in Capacity Market contracts – an availability and/or an output payment on top of capacity incentivises market participants to provide generation to the system and not take in payments for sitting idle.

Q34. How could deemed generation be calculated accurately, and opportunities for gaming be limited?

Calculating deemed generation is intrinsically difficult. Having an independent party calculate all the deemed volumes in an agreed manner would remove the gaming risk; but such a process would necessarily be complex and need to take into account a wide variety of factors that affect the potential to generate electricity. The alternative is to have generators provide their own estimates, but that is definitely open to gaming.

Such an approach also gives the impression that the potential reform is too large and complicated to solve a problem that is relatively small – for example, CfD generators having to export energy to get their top-up payment is a relatively small problem. Letting them receive payments for deemed or potential generation requires using estimates or non-metered data of wind/solar, which could lead to significant under or overpayment to solve a small problem. If the intention is to allow the CfD Generator to receive payments while providing ancillary services or charging an on-site battery, that could be achieved much more easily. For example, by explicitly adjusting volumes for ancillary services, and making sure the metered data used in CfD Settlement includes power generated and used to charge a battery.

Q41. What characteristics of flexibility could be valued within a reformed Capacity Market with flexibility enhancements? How could these enhancements be designed to maximise the value of flexibility while avoiding unintended consequences?

We believe the following characteristics could be valued within a reformed Capacity Market: technology type, resource requirement (both locational and fuel type) and dispatch time.

Q42. Do you agree that we should continue to consider a supplier obligation for flexibility?

No, we do not believe a Supplier obligation for flexibility should be continued to be considered, as this is likely to increase costs for Suppliers. Flexible generation and demand should be encouraged through a range of alternative mechanisms, including the CM, DSR (enabled by active DSOs) and co-location of renewable energy generation with storage (through introducing a requirement for flexible procurement in the CfD and PPA contractual terms, for example).

Q43. Should suppliers have a responsibility to bring forward flexibility in the long term

and how might the supplier landscape need to change, if at all?

We do not believe that Suppliers should have a responsibility for bringing forward flexibility, the unintended consequence could be an increase in costs for Suppliers. Instead, we believe that through robust incentives for DSR services, a range of market participants, such as Suppliers (if they choose to), aggregators and other parties should be encouraged to derive value from DSR and storage by delivering balancing services to the system operator(s).

In recent years, as highlighted in our answers to other questions, the industry, Ofgem, NGESO and Elexon have developed a number of modifications to the BM and BSC rules to facilitate wider participation in the BM. These modifications include: P375, P415, P441, P376 and P344.

Q46. Do you agree that we should continue to consider optimising the Capacity Market?

Yes, we agree that Capacity Market optimisation should be considered as it would make it easier for low carbon assets to participate in the CM, however this would not work in isolation, but with tandem other measures such as a Strategic Reserve – see response to Q47.

Q47. Which route for change – Separate Auctions, Multiple Clearing Prices, or another route we have not identified – do you feel would best meet our objectives and why?

We believe that separation of the market, auctions, and multiple clearing prices will not work in isolation.

Separation of auctions targeting specific technology types and, perhaps, location allows for greater control of that capacity thus facilitating adequacy in areas where it is required.

Further investment would be procured by implementing a Strategic Reserve - allowing CPs (Capacity Providers) to continue to be paid for availability, removing the complexities of inadequate penalty processes, and paying out upon delivery. Where it is proposed that the activation price be passed back to consumers, it may further incentivise demand reduction upon Periods of High Demand (POHD) – particularly, if the activation price is exposed to market forces over a capacity cleared price.

Only a single Capacity Market Unit (CMU) is currently known to provide ancillary services to the BM. Introduction of a revenue cap and floor (as proposed for CfDs) would incentivise investment and availability across multiple markets - it would also support the ESO / FSO in setting the capacity required (Strategic Reserve) - and buying this at a set wholesale market strike price.

Q48. Do you consider that an optimised Capacity Market alone will be enough for ensuring capacity adequacy in the future, or will additional measures be needed?

No, we do not believe that an optimised Capacity Market alone will be enough for ensuring capacity adequacy in the future. Encouraging storage, DSR and energy efficiency will also help reach an optimal level of capacity adequacy.

The current regime incentivises provision of capacity during a Stress Event, via the use of penalties. Whilst this scheme acts as a fall back for a low probability stress event scenario, it does not go far enough to help ensure that scenario does not occur. We support a greater focus on incentivisation via specific options for flexibility and technology type linked to the cleared auction price.

Stronger regulation to encourage visibility of capacity on the grid is also strongly supported.

Q49. Are there any other major reforms we should consider to ensure that the Capacity Market meets our objectives?

We believe that simplification of the Capacity Market Penalty Regime should form part of the REMA. However, Elexon notes that these reforms are being investigated distinctly from the REMA, and Elexon supports this.

In addition to those reforms mentioned here, we believe that there should be a greater emphasis on reform of Secondary Trading. Such greater emphasis is needed to apply actual performance assurance of these non-BSC parties to ensure that, should it be required, they are able to provide the flexibility and capacity they are obligated to.

Currently Capacity Providers are able to trade obligations in and out, but there is little to no incentive to provide visibility that the capacity is actually available.

Q50. Do you agree that we should continue to consider a strategic reserve?

Yes, we believe a strategic reserve is now even more important given the concerns about security of supply. Multiple mechanisms ensure a diverse pool of procurement options are available should a Stress Event occur, a strategic reserve acts as a back-stop in case the capacity cannot be procured in the CM. It is also a sensible mechanism to enable the FSO to plan investment and prepare for different load scenarios.

Q51. What other options do you think would work best alongside a strategic reserve to meet flexibility and decarbonisation objectives?

Please see our response to Q47

Q52. Do you see any advantages of a strategic reserve under government ownership?

Yes, we believe there is an advantage of a strategic reserve under government ownership - for details please see our responses to Q47 and Q54

Q54. Are there any advantages centralised reliability options could offer over the existing GB Capacity Market? For example, cost effectiveness or security of supply benefits? Please evidence your answers as much as possible.

To allow the NGESO (FSO in the future) to buy electricity at a specified strike price in the event of capacity inadequacy may allow for locational pricing. However, greater visibility of the assets available would be required - a mechanism such as the CfD SPA (Strike Price Adjustment) would be required, and would need to be iteratively revised to ensure it remains current. This removes the need for overly complex penalty processes and calculations that, for example, exist under the CM, and may reduce the risk of arbitrage opportunities by those who set out to procure a balancing service contract as well as an Obligation at the same time.