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Response to: Review of Electricity Market Arrangements

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Uniper is a leading international energy company, has around 11,500 employees, and operates in more than 40 countries. The company plans for its power generation business in Europe to be carbon-neutral by 2035. Uniper's roughly 33GW of installed generation capacity make it one of the world's largest electricity producers. The company's core activities include power generation in Europe and Russia as well as global energy trading and a broad gas portfolio, which makes Uniper one of Europe's leading gas companies. In addition, Uniper is a reliable partner for communities, municipal utilities, and industrial enterprises for planning and implementing innovative, lower-carbon solutions on their decarbonization journey. Uniper is a hydrogen pioneer, is active worldwide along the entire hydrogen value chain, and is conducting projects to make hydrogen a mainstay of the energy supply.

The company is based in Düsseldorf and is one of Germany's largest energy supply companies. Uniper is also Europe's third-largest producer of zero-carbon energy.

In the UK, Uniper operates a flexible generation portfolio of seven power stations capable of powering around six million homes, and a fast-cycle gas storage facility.

Consultation Response

We have set out below our answers to the questions in the consultation that are relevant to us. Our views in summary:

- Continued system stability and deliverable changes are critical, which needs an evolutionary rather than a revolutionary approach.
- Support for the investment and infrastructure to bring forward power CCUS, hydrogen power generation, and innovative electricity storage systems is key to decarbonising the UK electricity system.
- The proposals to move away from marginal pricing, split the wholesale market, or split the capacity market would all lead to a decrease market liquidity, introduce market-distortions, and lead to inefficient outcomes.
- Wholesale market pricing models should not be a substitute for adequate investment in reinforcing the electricity network.

Consultation questions:

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

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

Yes. Decarbonising the electricity system will be essential for meeting the net zero by 2050 goal. Huge progress has been made on decarbonising power, and decarbonising the remainder will be challenging. In order for this to happen efficiently and at the lowest cost it will be critical to maintain stable, functioning markets that are attractive for investors.

The deployment of renewables discussed in Chapter 1 must include onshore wind, which along with solar, is the cheapest source of energy. Scottish Government targets seek an additional 8 – 12GW of onshore wind capacity by 2030.

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

Yes.

Chapter 2: The case for change

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

We agree with the challenges set out. In addition, the UK market faces challenges of market stability and political intervention. We are currently in an energy crisis, with tight margins in winter and very high gas prices impacting margining costs and power market liquidity. In such a volatile market, it is even more critical that market changes are well signalled and delivered as promised to maintain investor confidence. Well thought through changes are preferable to rushed through changes.

When considering changes to the electricity market it is important to remember that electricity demand, as a necessity, is highly inelastic, and there will be significant impacts on demand patterns and seasonal usage as key areas of demand – transport, heating – are electrified. In addition, the majority of electricity users are not exposed to fluctuations in wholesale electricity prices – and even if they were, most do not behave in economically rational ways so it cannot be assumed that price signals in the wholesale market will translate to behaviour change. As electricity prices fall, with increasing renewable and other zero marginal cost generation on the system, convenience is likely to take precedence over cost saving in dictating customer electricity use.

It will also be important to be realistic about technology capability. For example, gas with CCS is capable of running both flexibly and at high load factors and at higher load factors there will be more efficient carbon capture. However, the scenario shown in figure 1 classes gas CCUS as flexible capacity and sees it running at a maximum 35% load factor in 2050 (figure 2)

4. Do you agree with our assessment of current market arrangements / that current market arrangements are not fit for purpose for delivering our 2035 objectives?

We do not agree that current market arrangements are not fit for purpose. The current market framework (including the wholesale market, Contract for Differences (CfDs) and the Capacity Market (CM)) may require improvements to deliver the government's 2035 ambition, but have been effective and efficient policy tools, delivering investment in flexible capacity and low-carbon generation and maintaining reliable supply.

We agree that the framework needs to adapt to better incentivise low carbon generation, ensure adequate firm dispatchable generation, and deliver the full range of balancing and auxiliary services. In transition, this is likely to require support for some technologies that are not currently at market maturity – in particular low carbon hydrogen generation, hydrogen transport and storage, CCUS, hydrogen power, and innovative electricity storage systems.

Chapter 3: Our approach

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

Yes. Of these criteria, investor confidence and deliverability (which are tightly linked) should be prioritised in order to deliver the efficient, working markets we'll need to get us to net zero at least cost.

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

Yes.

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

As well as the criteria you have identified, changes to the electricity market need to take account of the likely characteristics of the future generation sector. This is expected to be more fragmented than the current sector, with a greater number of smaller generators and more distributed generation. Increasing complexity is likely to increase administrative costs and create barriers to entry, so simplicity and deliverability should be key considerations when constructing and assessing packages of options.

Chapter 4: Cross cutting questions

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

Yes, though you should not pursue any further thinking about moving away from marginal pricing. Moving away from marginal pricing would most likely mean moving to a 'pay as bid' system. In marginal priced markets, participants are incentivised to bid reflecting their avoidable costs in order to compete, as they will automatically receive the marginal price even if they are not the marginal generator. 'Pay as bid' markets incentivise participants to bid at a level just below that at which they think the marginal accepted price will be. In order to avoid this we would need to move from a free market to a semi-regulated market, where market participants are required to only bid in their avoidable costs, with a huge monitoring burden needed to ensure that they have indeed done so – essentially a price control review. The regulator would need to look into every market participant's costs, which would be impractical in a market with a larger number of smaller and distributed generators, add a significant cost burden, and may create a barrier to entry for smaller generators.

We must be clear that the current, very high, costs of energy in the UK are not due to marginal pricing but to the lack of power supply resulting from the sharp reduction of Russian gas supply to Europe and very low nuclear availability in France. The recent review by ACER[1] found that interventions to cap energy market prices or divide markets by technology with quotas and potentially set prices would have significantly market-distorting effects and expressed "serious doubts as to whether such a model … could secure supply, short of a quasi-nationalisation of the energy industry in question".

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

Yes, though there are a couple of additional trade-offs you should add into your considerations:

a. The requirement to balance, second by second, supply and demand. This is an absolutely critical characteristic of electricity, which requires the system to work in a particular way. Any decentralisation of market mechanisms and responsibilities needs appropriate arrangements for coordination to ensure that flexibility is delivered in an efficient and reliable manner, at both a local and national level.

b. The trade-off between global markets and self-sufficiency. As recent events have demonstrated, over-reliance on global markets can cause problems when those markets break down. On the other hand, global markets are extremely efficient and can drive down prices: domestic production might offer lower exposure to geopolitical risks and shifts in global market demand but could be more costly.

In our view, maintaining network stability is a critical priority in transitioning to a net zero electricity system, which will favour an evolutionary rather than a revolutionary approach. This view is shared by the CCC's independent Expert Group[2], who recommend evolutionary reform of CfDs, consideration of locational signals for the wholesale market, and associated changes to the CM to deliver the changes we need to see in the 2020s.

In addition, a balanced focus is needed to bring forward both increased domestic production and efficient global trading and deliver the most cost effective system outcomes.

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

More work needs to be done to determine which is the most effective way of delivering locational signals. We support further consideration of locational signals in support schemes / adequacy schemes, network access or charging reform and, potentially, zonal pricing – it may be that a mix of approaches will be most effective in providing clear locational signals without unintended consequences. We note that zonal pricing can have undesirable outcomes, reducing liquidity and creating barriers to investment, and that limiting the number of zones would be important to minimise these impacts.

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1 ACER's Final Assessment of the EU Wholesale Electricity Market Design.pdf (europa.eu)

2 Net Zero Electricity Market Design (Expert Group) - Climate Change Committee (theccc.org.uk)

We don’t believe you should consider nodal pricing further, as it is inefficient and costly to administer. It is also a significant deterrent to investment as it doesn’t provide strong long term signals, which makes it very difficult to assess the lifetime value of assets.

We don’t understand the proposal regarding locational imbalance pricing and would need to know more about how it would be envisaged to work before we can comment.

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

A variety of market participants might be responsive to sharper locational signals, particularly new market entrants. With sharper locational signals we’d expect to see some movement in the supply side of the wholesale market, with some generation projects being geographically situated to take advantage of locational signals, and also on the demand side of the market, with large loads such as hydrogen electrolysers and Amazon warehouses locating in areas with significant amounts of surplus renewable generation.

However, locational signals will compete with other costs and will often not be the determining factor in decisions about where to locate infrastructure. For example: blue hydrogen production will need to be close to CCS infrastructure; a new hydrogen fuelled power station might need to be located closer to the hydrogen production facility than the electricity grid infrastructure; and onshore wind projects will continue to be driven geographically by concerns such as land value and planning permission.

We agree that in a market environment, locational signals are important to ensure that all costs associated with a generator’s choice to build in a particular area are internalised within its investment decision so that the most efficient outcomes are arrived at for the benefit of customers. This is why we support locational prices in network access charges. However, signals have to be useful so that generation and/or demand is able to respond. Mechanisms such as locational marginal pricing are likely to result in short term, volatile prices, which will be extremely difficult for parties to respond to – particularly less flexible plant. Such prices will also be significantly affected by network operators’ ability to build, reinforce and operate their assets; factors that are not in the control of market participants.

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

Although we believe that demand side response has an important role to play in a net zero market, permanent demand reduction is not part of the operation of the electricity system.

There are some drivers for electricity demand reduction or shifting demand in time in the electricity system: marginal pricing can drive demand reduction when the marginal cost of generation is high. Price signals could be used more widely to drive demand reduction – if everyone had a price-sensitive day ahead hourly curve it could help to reduce demand at peak times – though they are by no means a silver bullet: we have to be realistic about the potential, products, and appetite for responding to price signals, given the relatively inelastic nature of electricity demand.

We could potentially support a supplier obligation that works alongside the existing CM and CfD to drive demand reduction through promoting energy efficiency measures.

Chapter 5: A net zero wholesale market

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

Yes.

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

No. In practice, the market is already split between those technologies in the capacity market and those supported by other mechanisms. Splitting the wholesale market further will reduce market liquidity, which has long been an issue in the UK market, and damage investor confidence, and is unlikely to drive lower prices.

Moving from market signals to a regulated or semi-regulated market raises the questions of who sets the electricity price and how. There is a risk that regulating market prices could be more expensive for consumers in the long term. The ACER[1] study notes that it is not aware of any jurisdiction in which a split market has been implemented, and that it has serious doubts about whether such a model could secure supply (p55). The Energy Systems Catapult[3] notes that the wholesale market plays a valuable role as long as it provides enough certainty to participants to underpin long term contracts; from this perspective the need is to build more information into the wholesale market, not fragment it.

It is worth noting that in the UK at present the marginal cost of electricity is often not being set by gas but by our interconnectors: very low availability of nuclear power in France has pushed the power price to extreme levels due to capacity shortfall and system tightness.

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

The design issues raised cannot be overcome, and further splitting the wholesale market should not be pursued. The proposed interventions would increase the risk of and decrease the appetite for investing and would significantly reduce liquidity in the market. Splitting the wholesale market makes it harder to trade forwards and harder to manage imbalance if forecast volumes are wrong.

If government is to continue considering splitting the wholesale market it will need to answer the questions of who sets the electricity price, where, and how – and will this drive best value for consumers in the longer term?

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

No. Nodal pricing is incredibly complex. It is a deterrent to investment as it doesn't provide strong long term signals, which makes it very difficult to assess the lifetime value of assets. It would also be administratively very challenging to deliver.

There might be some value at looking more closely at a zonal market design, although further fragmentation of the UK market would not be our preferred approach. Questions about liquidity and how the system price will be created will need to be answered. Because the UK market is relatively small, it would be important not to divide it into too

[3] Don't give up on wholesale markets – thoughts for the Review of Electricity Market Arrangements - Energy Systems Catapult

many zones – maybe 3-5 maximum. Even 3 zones would impact overall market liquidity and investment decisions.

In a zonal market there will be a need for zonal demand signals as well as generation signals: locating demand closer to clustered generation is another way to reduce network investment and redispatch costs.

Before committing to moving the UK to zonal pricing, government should consider how much of the issue could be solved by adequately investing in reinforcing the electricity network. Neither the transmission nor the distribution networks are currently fit for a future with considerably increased electricity demand (especially if heating is largely electrified) and a larger number of smaller scale, disbursed, and intermittent generators. Neither nodal nor zonal market designs can erase the need for network development.

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

Some of the challenges you have identified in zonal market design can be overcome outside of that market design. We don't agree that boundaries would need to be frequently redesigned: network constraints can be tackled in other ways, e.g., through investing in reinforcing the network, and the work the ESO does in developing zonal products. In terms of the signals for generation capacity to site at the 'most efficient locations', we agree that in a market environment locational signals are important to ensure that all costs associated with a generator's choice to build in a particular area are internalised within its investment decision so that the most efficient outcomes are arrived at. However, mechanisms such as locational marginal pricing are likely to deliver short term, volatile prices that are difficult for parties to respond to, particularly for less flexible plant.

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

No. This would make the market even more volatile due to the higher constraints on the distribution network, and would preclude a forward market for electricity (financial forward trading may still occur). At present, it would also be inconsistent with the markets we are linked to; consistency is critical, particularly for technologies that span these markets, i.e. interconnectors.

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

As we transition to a system dominated by renewables and as generation becomes more distributed and smaller in scale, DNOs will face greater challenges in operating and balancing their networks. The DNOs are running some small locational markets to address some of this problem, which is an understandable approach. However, actions taken at the local level can have implications at the national level and on other connected local areas. It is therefore important that all markets are coordinated so that the most efficient outcomes overall are achieved.

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

No.

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

No. Moving away from marginal pricing could promote inefficient bidding behaviours. 'Pay as bid' markets incentivise participants to bid at a level just below that at which they think the marginal action will be. In marginal priced markets, participants are incentivised to bid reflecting their avoidable costs in order to compete, as they will automatically receive the marginal price even if they are not the marginal generator. In order to avoid this we would need to move from a free market to a semi-regulated market, where market participants are required to only bid in their avoidable costs, with a huge monitoring burden needed to ensure that they have indeed done so. The regulator would need to look into every market participant's costs – essentially a price control review, which would be impractical in a market with a larger number of smaller and distributed generators and may create a barrier to entry for smaller generators.

The marginal price removes incentives to inflate wholesale prices. The current high gas prices we are seeing are not as a result of inflation in the wholesale market.

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

Any potential changes to current wholesale market arrangements should be considered in the context of the markets we are linked to: consistency reduces the costs of trading between markets.

You should not continue to consider moving to central dispatch, as it would be less efficient than our current system.

Further consideration of moves to reduce the settlement period and gate closure intervals might be worthwhile, although we note there are practical issues that would be difficult to overcome. Demand is only metered on a half-hourly basis, so reducing the settlement period would have a limited impact on matching prices to market conditions. When this was last considered, in a cost benefit analysis carried out by Frontier Economics on behalf of ENTSO-E in 2016, the conclusion reached was that the benefits wouldn't outweigh the costs of implementation. The main drive of this was the costs associated with metering and notification systems in respect of distribution connected customers (estimated at £1295m).

Reducing the gate closure period would be challenging for National Grid: in Grid's recent review of high balancing costs in winter 2021 (letter "To all wholesale market participants and other interested parties" dated 15 July), one of the options it proposes for managing balancing costs in winter 2022 is to "Limit[ing] generators' ability to amend their schedules with little notice. For example, generators could be required to submit and keep to their day ahead schedules, with amendments only allowed on the basis of open, transparent intraday trading".

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

No.

Chapter 6: Mass low-carbon power

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

No. One further option is a CfD scheme with a floor price and no cap (a one-way CfD). This is likely to see market participants push the floor below where it would be in a capped scheme and might, therefore, be cheaper overall: participants would push the floor as low as they could to cover their debt, trusting the market to deliver incomes sufficient to cover other costs. A scheme with a potential upside could attract more investors. We currently operate in Germany under a scheme that pays a floor price without any accompanying price cap for renewable generation.

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

Any benefits could be better valued by bringing the estimated 8GW of distributed capacity into the market in a way that is visible to National Grid, for example by making all CMUs register as BMUs. Where appropriate, other mechanisms such as network charging and environmental requirements should be consistent to ensure fair competition between all categories of market participant,

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

Not as a replacement for the CfD. Suppliers aren’t likely to offer commitments on the kind of timescales developers need to be confident that they can recoup their capital costs: many suppliers are working to 1-2 year timescales, where developers are looking for 15 year certainty. Alongside the CfD, however, we think supplier obligations could deliver value, particularly in driving ongoing demand for the output of older assets that are beyond their CfD agreements. This would improve the overall efficiency of the renewable generation sector, increasing signals to keep assets working until end of life.

We are concerned at the apparent consideration, on page 80 of the consultation, of decoupling a supplier obligation and the need for Ofgem accreditation. Whilst Ofgem accreditation is a difficult process and might disincentivise some smaller plant, it is also critical in preventing fraud and ensuring that claimed emissions reductions are really delivered. Government should not consider moving away from existing fraud prevention measures without carefully considering what can be put in their place to ensure the integrity of the market.

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

We don’t have a view on this.

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

If a supplier obligation is additional to, rather than a replacement for, the CfD, the financing and delivery risks do not materialise: suppliers would buy energy at marginal cost from plants that have already covered their investment costs, and the CfD would continue to support new capacity to the market.

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

Yes. The CfD has been effective in bringing down the cost of investment and bringing new capacity to market. Increasing price exposure for market participants could bring down the costs of the CfD: where generators have the opportunity to benefit from market upsides they will be willing to compete for a lower level of support from the government, trusting the market to deliver adequate return to cover their investment costs.

A key consideration in central contracts with output-based payments is the settlement period for the floor price. An annual floor price will smooth out seasonal dispatch variation, but is likely to be higher overall than a shorter floor price settlement period, which helps protect generators against extreme renewable events. We currently operate in the German market, with a monthly settlement period.

Changes to the reference price methodology, such as CfD top-up payments, could also support a lower floor price, though are unlikely to have as big an impact as giving generators access to full market upsides.

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

Yes.

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

No. The balance of costs depends on a number of variables, including the market framework and the auction clearing price. It would need considerable modelling to work through all the possible scenarios: our modelling only covers existing market variables.

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

We are not convinced that central decoupled contracts are the most efficient way to incentivise renewable generators to balance the system. In Germany, the renewable floor price is not paid to generators if the market is negative, after an initial four-hour period. We understand the most recent UK CfD contracts work the same way. This seems a more cost effective way to incentivise generators not to generate when the power is not needed.

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

Any form of revenue cap will inhibit valuable behaviour to some extent. In a CfD with a floor price, any form of cap is likely to increase that floor price, as generators will need to be able to recover more of their costs from the floor price.

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

There several ways to calculate the curtailment losses for generators, depending on what you consider an acceptable degree of accuracy. Typical calculation methods are historical comparison of events and analytical grid models. The risks of gaming can be reduced by taking a multi-year and industry average approach. Nonetheless, a system based on deemed generation runs the risk of over-or under-paying generators, and thus either being poor value for consumers or a barrier to investment.

Chapter 7: Flexibility

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

Government should also consider revenue stacking options for all participants, which would enable broader participation in balancing services as well as the wholesale electricity market. Enabling stacking and moving away from bespoke offerings avoids market fragmentation and promotes liquidity.

36. Can strong operational signals through reformed markets bring forward enough flexibility, or is additional support needed to de-risk investment to meet our 2035 commitment? Please consider if this differs between technology types.

Yes, if markets are well designed strong operational signals would be enough. There is currently a gap in the market in terms of long term electricity storage, which we note that government is seeking to address (i.e. the recent call for evidence on large-scale and long-duration electricity storage). There are also gaps around hydrogen-fired generation and hydrogen transport and storage; we look forward to seeing further consideration of the role of hydrogen in the future energy system as hydrogen market policy develops.

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

No, a revenue cap and floor is appropriate for a system with a small number of large players but is administratively unwieldy and burdensome for any system with a large number of small and decentralised players.

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

As above, we believe any form of revenue cap is likely to inhibit valuable behaviour.

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

No.

40. Do you agree that we should continue to consider each of these options for reforming the Capacity Market?

Additional measures are not required to address duration or response time: de-rating in the CM already addresses duration, and the current rules already require a 4 hour response time from all participants in case of a stress event. Splitting the CM by types of product offered is likely to increase its complexity, decrease its liquidity, and put off new participants.

Having said that, if we move toward a zonal wholesale market it would make sense for the CM to reflect that. And if it doesn’t, zonal de-rating, instead of national, could provide locational signalling. We note the ESO is already looking at zonal products for ancillary services.

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

Geographic location. Other characteristics are already valued, either through the CM or other markets, such as balancing and ancillary services.

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

Not instead of stable and long term market arrangements: suppliers are not able to offer the long term contracts needed to support new-build investment decisions. A supplier obligation might work in addition to longer term signals for new capacity, helping to retain capacity that has already recouped its capital investment.

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

This would be inefficient. In addition, suppliers would need to have the stability and drivers to offer long term contracts.

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

We can’t answer this.

Chapter 8: Capacity adequacy

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

Yes.

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

Yes, although as the key policy instrument to maintain security of supply, in the short to mid-term the CM design must focus on its core purpose and maintaining investor confidence. Major redesign, such as splitting the market or introducing separate clearing prices, introduces uncertainty and will inevitably introduce risks from an investor perspective.

In terms of optimising the CM, we support extending it to include non-dispatchable generation without a CfD or after a CfD has expired, though this would need appropriate derating to consider the contribution of these technologies during future stress events. We also believe allowing renewable plant to bid back into the CfD once its original contract reaches its term should be considered as an option.

We would also like to see the penalty regime of the CM strengthened, to ensure that undesirable behaviours are unattractive to participants, and also measures to facilitate secondary trading, which would increase liquidity and reduce risk.

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

As high carbon generators operate less and low-carbon alternatives become more competitive, the most expensive plant will be priced out of the CM, delivering government's objectives without excessively interfering in a functioning market. Policies outside of the CM to bring forward low carbon alternatives to unabated gas will be key to avoiding fossil lock-in, e.g. the CCS Dispatchable Power Agreement (DPA); combined with the government's target for growth in wind, the Decarbonisation Readiness requirement, carbon pricing, and the ability to invest in existing assets that can retrofit CCS or convert to use hydrogen for example.

In the short to mid-term, an annual emission limit could be implemented for new build capacity to be eligible for 15-year agreements. If some unabated gas running very infrequently is foreseen as part of a net zero system, then in the longer term it could be that 5 year agreements would be appropriate to provide investor confidence in maintaining the reliability and availability of plant with little income from the energy market.

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

Yes. Additional measures will only be needed for unproven technology, or emerging markets – such as CCUS, hydrogen, and innovative energy storage systems.

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

Nothing beyond our proposals in Q46

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

A strategic reserve is inferior to the CM, and should only be considered as a last resort option in the case of serious market failure. There may be a limited role for a strategic reserve in the future, when there is a very small amount of very infrequent fossil plant on the system – post 2035.

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

The existing market framework is more efficient and effective than a strategic reserve.

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

No. Within a market-based strategic reserve we'd expect market forces to ensure that government is procuring backup capacity at the lowest possible price. In a government owned strategic reserve it is not clear that there would be the same drivers.

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

Yes. This could be a good option that would sharpen penalties, preventing operators taking agreements and not delivering.

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

The existing CM is a stable, well understood and functional market. To maintain market confidence and avoid investment hiatus, government should look to optimise the existing system, rather than develop a new one. There are a number of advantages that centralised reliability options could offer, many of which could be delivered through optimising the existing CM:

- Improving the incentive for generators to participate in the wholesale market after they have taken an agreement; at present this does not always happen.
- Simplifying the testing and penalties systems. All of the availability testing and accompanying penalty regime could be scrapped in favour of simple metering to evidence dispatch – this would not only reduce admin burden and costs for existing players and the delivery body but it will make the market more attractive to new entrants and would very much lend itself to a future market with a larger number of smaller and more widely dispersed generators.
- Simplifying secondary trading. We could have a continuous market where reliability options are traded between generators in parallel to forward electricity markets.
- Facilitating the direct participation of foreign capacity, as in the case of the Italian CM.

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

None.

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

Yes. Decentralised reliability options are complex and don't lend themselves to a market with a large number of smaller, dispersed players.

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

No.

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

Yes. This seems very inefficient and does not send the right signals about providing capacity when it is needed. There is no long term incentive for flexible operation.

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

Yes, there are more efficient ways of delivering targeted interventions, such as the ESO contracts for zonal/local projects or the Dispatchable Power Agreement.

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

Yes.

Chapter 9: Operability

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

Yes.

62. Do you think that existing policies, including those set out in the ESO's Markets Roadmap, are sufficient to ensure operability of the electricity system that meets our net zero commitments, as well as being cost effective and reliable?

As we have set out in responses to other questions, we favour an evolution of the existing arrangements wherever possible, rather than radical reform. Some of the wide range of proposals that have been set out in documents such as the Smart Systems and Flexibility Plan, the ESO's Market Roadmap, Ofgem's GB energy system review and the Energy Network Association's Open Networks project should achieve the above objectives, while others will be less effective. The key task to focus on now is to take forward these plans and proposals so they can be assessed and, where appropriate, implemented in order to deliver the benefits they are designed to achieve.

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

We support the ESO working towards delivering net zero, but we do not support the proposal to enable/require the ESO to prioritise low carbon procurement beyond the responsibilities it already has to do so. The role of the ESO is to enable net zero by ensuring the system works as efficiently and effectively as possible and does not put barriers in the way of low carbon technologies. The ESO's role is to be technology neutral, allowing policy, support mechanisms (such as CfDs), regulation and costs (including carbon pricing) to bring forward all the technologies needed for a reliable net zero system.

We support revenue stacking, though we note it will be important to ensure that market participants are not paid to deliver two services in the same time period that they cannot deliver at once. Moves to align auctions would be helpful, although a lot of services are procured monthly, so this may not be critical. It will be critical that where multiple services are being procured from market participants, those services are distinct and are individually valued so that market players can understand the value given to different services and make commercial decisions accordingly. Any moves to procure services in bundles would decrease transparency and would be likely to lead to market distortions.

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

We are not best placed to advise on this. There could be advantages in DNOs taking on more responsibility for system operability if they were the aggregator for their own zone – they could then bid in additional frequency or voltage to the national grid on behalf of local operators. However, DNOs are not currently structured to deliver these sorts of services.

We have experienced coordination issues where the DNO does not understand transmission rules.

Depending on how it is structured, the FSO could take on the role of coordinating between DNOs and the national transmission system.

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

We don't have a view on this.

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

The CfD in its current form does not incentivise the provision of ancillary services, though it does not prevent it. There are CfD plant that provide ancillary services at present. Increasing CfD plant exposure to market prices might encourage more provision of ancillary services from this sector, by increasing the potential benefit from revenue stacking.

67. Do you think it would be useful to modify the Capacity Market so that it requires or incentivises the provision of ancillary services? If so, how could this be achieved?

It may be useful to modify the CM to incentivise the provision of ancillary services, but this would increase complexity. It would be important to keep services distinct to ensure transparency and reduce the chances of market distortions.

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

No.

Chapter 10: Options across multiple market elements

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

Yes.

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

From the high level description provided, we do not understand how a payment on carbon avoided could be efficiently directed to supporting flexible generation. It would appear to create perverse incentives to maximise output, rather than signalling flexibility. The current system, which brings mass low carbon power onto the system ahead of flexible power, appears to work better.

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

We are not sure it can. In addition to the issues around supporting flexible technologies, in practice the SDE++ is better at supporting mature technologies and needs ringfencing and targeting to enable newer and/or more expensive technologies to come forward – which may be necessary in order to balance renewable generation and flexible assets. It may not, therefore, bring forward the diversity of technologies we will need in a flexible low-carbon system.

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

No, we agree with your assessment of the SDE++ scheme.

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

No. In practice, an Equivalent Firm Power auction will be complex and inefficient: even if every market participant perfectly balances their portfolio, the system overall will not be balanced as various assets will cancel each other out. It is also likely that flexibility will be over-procured, so that the total market size will be bigger than required. It is much more efficient to balance the system at system level.

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

There are no straight-forward solutions that we are aware of.