By email: remamailbox@energysecurity.gov.uk

**Uniper UK Limited**
Compton House
2300 The Crescent
Birmingham Business Park
Birmingham B37 7YE
www.uniper.energy

**Uniper**

Registered in
England and Wales
Company No 2796628

Registered Office:
Compton House
2300 The Crescent
Birmingham Business Park
Birmingham B37 7YE

**Response to: Review of Electricity Market Arrangements: Second Consultation**

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Düsseldorf-based Uniper is an international energy company with activities in more than 40 countries. The company and its roughly 7,000 employees make an important contribution to supply security in Europe, particularly in its core markets of Germany, the United Kingdom, Sweden, and the Netherlands.

Uniper's operations encompass power generation in Europe, global energy trading, and a broad gas portfolio. Uniper procures gas—including liquefied natural gas (LNG)—and other energy sources on global markets. The company owns and operates gas storage facilities with a total capacity of more than 7 billion cubic meters.

Uniper intends to be completely carbon-neutral by 2040. Uniper aims for its installed power generating capacity to be more than 80% zero-carbon by 2030. To achieve this, the company is transforming its power plants and facilities and investing in flexible, dispatchable power generating units. Uniper is already one of Europe's largest operators of hydropower plants and is helping further expand solar and wind power, which are essential for a more sustainable and secure future. The company is progressively expanding its gas portfolio to include green gases like hydrogen and biomethane and aims to convert to these gases over the long term.

Uniper is a reliable partner for communities, municipal utilities, and industrial enterprises for planning and implementing innovative, lower-carbon solutions on their decarbonization journey. It 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.

In the UK, Uniper owns and operates a flexible generation portfolio of seven power stations and a fast-cycle gas storage facility.

**Consultation Response**

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

- We are glad to see that options such as the green power pool and the split wholesale market have been discounted, and agree that bespoke mechanisms for certain low carbon flexible technologies, sharper operational signals, and an Optimised Capacity Market will incentivise dispatchable low carbon generation once there is CCS and hydrogen infrastructure to support it.

- We continue to have reservations about the introduction of locational energy pricing in GB, due to potential effects on liquidity and investment.

- We do not think a minima for low carbon technology in the Capacity Market is the right solution to bring forward flexible low carbon generation.

***Our views in full:***

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

The CPPA market has considerable growth potential, as corporations seek to reduce their scope 2 emissions and the market for green hydrogen grows, but it is not a given: the availability of government-backed, inflation-indexed CfDs could reduce the appetite of developers to enter into CPPAs. In addition, if customers only seek short term contracts, it will not offer the necessary investment certainty to support the development of new generation.

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

A larger CPPA market would see corporations directly supporting more renewable development, reducing the need for financial support from Government. We note that locational pricing will make it more difficult to match corporate demand with supply and might reduce this benefit.

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

Yes.

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

We agree with the challenges you have identified but think there is a fourth challenge, which is achieving a cost-effective technology mix. At present the CfD budget is very heavily weighted toward offshore wind; without rebalancing there is a risk of underinvestment in cost effective onshore technologies.

All of these challenges are equally crucial to address to ensure that renewables can play a major role in the future power market.

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

Changing the signals around negative pricing will change dispatch behaviour. On the whole, what you are proposing will definitely go at least some way towards improving assets' responsiveness to market signals.

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

The 'ongoing' reforms will slightly improve how the market operates but will not substantially affect renewable assets' market responsiveness or increase investment.

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

We cannot offer a view on specific gaming risks but think the deemed generation model will be very complex to administer and is likely to result in multiple challenges by developers and operators who disagree with the forecasts of deemed output for their assets.

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

As for the existing Capacity Market, the factor most likely to influence auction bidding behaviour is the operator's level of optimism about their future load factor and expected market returns – i.e. their attitude toward risk. Another significant factor will be operators' confidence in the CfD mechanism not being subject to further Government interventions.

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

The capacity-based CfD best matches the risk distribution we have outlined, as it avoids imposing further risks on renewable generators that are outside their control.

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

Of the two we prefer the capacity-based model, as the deemed approach would be complex to administer and the forecasts upon which deemed output would be based would be likely to be subject to challenge. We note that the capacity-based approach might not offer the best locational signals, as in theory it would be possible to secure a capacity payment for a wind plant in a place there is no wind. Renewable operators need to be incentivised to maximise assets' yield; it is possible that a capacity-based model with competitive auction would do this – if the auction price was relatively low, then operators would need to maximise the returns from their assets.

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

No. The concept of a partial payment CfD is not new and is happening now. The obvious risk of a partial CfD is that the operator is unable to sell their PPA capacity, which would result in under delivery of expected renewable capacity. The risk of not being able to deliver the second part of the expected capacity is likely to be priced into CfD auction bids, pushing up the cost of the CfD.

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

Both of the options you have described make the reference price a lot more complex to work out, which forces operators to take more risk and makes hedging difficult.

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

CPPAs will definitely drive small scale deployment – to meet corporate scope 2 emissions. Corporates are often now happy to hedge for 10 years, which would be enough to enable investment in small-scale developments.

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

Depending on how the scheme is designed, introducing a minima could have the effect of, in practice, splitting the market. This could be avoided by ensuring there is a single clearing price for capacity procured under the minima and all other capacity, but without a single clearing price a minima will reduce market liquidity. This is also true of secondary trading; if capacity procured under the minima can only be secondarily traded to capacity with the same characteristics it will significantly impact liquidity in the secondary trading market.

The introduction of a minima is also likely to increase cost for consumers, by increasing the price paid for certain capacity. For this reason, it should be carefully considered what characteristics (if any) are worth protecting.

It will be important that the role of the CM and of the Balancing Mechanism and Ancillary Services market are not unduly conflated. Flexibility needs should be provided via the BM and ancillary services, not via a minima in the CM.

The only characteristic we think is worth procuring through a minima is long duration low carbon generation. This could include, for example, HVO-fired and hydrogen-fired turbines with secured fuel supply, and/or power CCUS. The minima should not include alternatives such as Demand Side Response and battery storage, which the CM has already been able to secure in large volumes.

However, the real issue for low carbon technology is not that it cannot secure adequate support from the CM but that there is not adequate infrastructure to enable it to operate reliably. When access to CCS and hydrogen T&S is more readily available, and there is enough low carbon hydrogen to reliably fuel plant, the carbon price is likely to enable low carbon flexible technologies to participate in the CM without additional support. Government should focus now on supporting the build out of CCS and hydrogen infrastructure, and leave further review of the CM for low carbon technologies until it is needed.

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

You should consider increasing the price cap to attract more supply to future auctions. We note that the last two T-4 auctions procured less capacity than the target as the supply entering both auctions was very close to demand.

A similar recommendation was made in Baringa's interim report[1], as the CM price required to meet return requirements for new build capacity could be in excess of the current price cap and some stakeholders see the price cap of £75/kW as a barrier for new investment in capacity.

We note that the Single Electricity Market Committee (the decision making authority for the Single Electricity Market on the island of Ireland) has just increased the price cap for the T-4 capacity market auction for 2028-2029 from €163,757/de-rated MW/yr to €230,000/de-rated MW/yr. Developers will prioritise the markets that offer the most attractive returns for their projects.

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

Uniper's focus on decarbonising our operations has meant that we have backed the Government in your plans for CCS new build and retrofit. In Germany, we view the idea of new H2 ready plant as a highly viable business case, as long as there is a clear indication of when such plant should run on cleaner gases. At Uniper, our strategic aim is for 80% of our European generation capacity to be carbon neutral by 2030 and we're looking at a range of ways to meet this target, including new build, flexible low carbon power stations with CCS technology. We would not build unabated now without a clear route to future decarbonisation.

We would urge the government to be steadfast in its policy direction and ambition to enable confidence in government decisions and unlock long-term investment.

[1] Assessing the deployment potential of flexible capacity in Great Britain – an interim report (https://assets.publishing.service.gov.uk/media/65e3a3a32f2b3bbc587cd767/8-assessing-deployment-potential-flexible-capacity-gb-interim-report.pdf)

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

Reducing the ambition of previously announced limits weakens investment signals, undermining investor confidence. In addition, significant unforeseen market investment in cheap unabated gas without clear and meaningful routes to decarbonisation will undercut the business case for low carbon flexible generation projects in the UK.

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

As above, the main challenges in converting existing plant to low carbon alternatives are access to the necessary infrastructure and fuel, and technology readiness (commercial scale hydrogen turbines).

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

There may currently be a viable investment landscape for smaller scale low carbon OCGT, but there is not for larger plant or plant with higher load factors. Once the policies in development deliver adequate low carbon infrastructure and fuel availability, we would expect this to change.

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

Yes, this is a comprehensive package of work.

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

In policy terms what you set out is sufficient, but it relies on adequate availability of infrastructure and fuel security. This means the work to support hydrogen production, including work on blending and hydrogen certification, and on hydrogen and CCUS transport and storage infrastructure must progress at pace to enable market growth.

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

We agree with the design choices under consideration and don't think there is anything missing. We suggest government start with what the EU and others have in place when considering options. We continue to have reservations about the introduction of zonal energy pricing into the GB market as it can have undesirable outcomes, reducing liquidity and creating barriers to investment, and we believe that limiting the number of zones would be important to minimise these impacts.

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

Locational network charging will help to locate network-connected assets in the right place, although, as with locational marginal pricing, locational price signals will not be the only driver of investment decisions. We agree that it is not clear that network charging will address dispatch challenges or locate demand. However, there is currently work happening on demand network signals. Operational signals could be improved by more Balancing Mechanism services being procured by the demand side.

We are concerned that the Strategic Spatial Energy Plan may contradict a zonal pricing approach, and urge government to ensure that all policy and regulatory measures taken forward, including those being developed by regulatory bodies, are coherent.

A zonal energy pricing approach risks weakening drivers for network reinforcement. It is clear that, regardless of the pricing methodology employed, today's network is not adequate to support future demand, so network reinforcement must remain a priority. With this in mind, we would be interested to know government's intention regarding the use of any revenue that would be raised from zonal pricing.

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

We broadly agree with your proposed steps and agree there is value in continuing to consider a wide range of incremental changes to maintain and improve system operability.

Having said this, you should discount reducing the settlement period: as demand is only metered on a half-hourly basis, 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).

You should also discount centralised despatch, which would be less efficient than our current system.

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

Government is best placed to manage market stability risks, as you have the policy levers to stage large-scale interventions to help mitigate risks.

Suppliers should be mitigating risks for consumers by using bespoke financial contracting and/or demand-response strategies when markets are volatile.

Renewable generators are best placed to manage project and technology risks, and we think it appropriate that they should also bear some risks outside of their control, such as weather variability. Where risks are outside the control of renewable generators but within the control of other market players, such as Government or networks, those risks should be managed by those able to do so.

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

Yes.

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

Yes.

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

Risks include high carbon capacity lock in, and undermining the business cases for low carbon solutions. This is best assessed on a case by case basis as we transition to a net zero system: it is likely that transitional arrangements will be a patchwork, with unintended consequences needing to be managed as and where they arise.