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Capacity Market: Improving delivery assurance and early action to align with net zero
Call for Evidence
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Uniper

Uniper is an international energy company with around 12,000 employees in more than 40 countries. The company plans to make its power generation CO_2-neutral in Europe by 2035. With about 35 GW of installed generation capacity, Uniper is among the largest global power generators. Its main activities include power generation in Europe and Russia as well as global energy trading, including a diversified gas portfolio that makes Uniper one of Europe's leading gas companies. In 2020, Uniper had a gas turnover of more than 220 bcm. Uniper is also a reliable partner for municipalities, public utilities, and industrial companies for developing and implementing innovative, CO_2-reducing solutions on their way to decarbonising their activities. As a pioneer in the field of hydrogen, Uniper has set itself the target of operating worldwide along the entire value chain in the future and implementing projects that will make hydrogen the mainstay of the future energy supply.

The company is headquartered in Düsseldorf and currently the third-largest listed German utility. Together with its main shareholder Fortum, Uniper is also the third-largest producer of CO_2-free energy in Europe.

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.

Call for Evidence

We agree with the need for policies to align to the net zero target and consistently incentivise the move to a decarbonised economy. The interaction between policy instruments and the combined impact of these needs to be considered when assessing potential changes to the CM design. 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.

As the Call for Evidence sets out, the challenges of continued security of supply can currently only be met by unabated gas, and given the expected increases in demand and retirement of older capacity, some unabated new build may need to be supported.

This, in the context of a growing proportion of wind on the system, leading to lower load factors for flexible gas plant which will need continued investment to maintain its reliability and flexibility, whilst having less income from running in the energy market.

As the key policy instrument to maintain security of supply, in the short to mid-term the Capacity Market design must focus on its core purpose and maintaining investor confidence. Major Redesign, such as the outlined potential Alternative Auction designs, introduces uncertainty and will inevitably introduce risks from an investor perspective.

There are a number of essential and obvious changes that need to be made, which, by increasing transparency or giving more opportunities to manage risk serve to increase investor confidence:

- Improving transparency by bringing the estimated 8GW of distributed capacity into the market in a way in which it is visible to National Grid and the market, for example by adopting the proposal to make all CMUs register as BMUs;
- Requiring all relevant CMUs to be subject to carbon pricing. For example, there is no clear rationale in a net zero context to continue to exempt plant below 20MW capacity from participating in the UK Emissions Trading System; and
- Increasing non-delivery penalties and at the same time better enabling secondary trading by allowing the registration of secondary trading ahead of the respective T-1 auction.

Low carbon alternatives that can provide the reliable flexible generation needed to support the integration of renewables are not yet available. We agree that it is necessary for the Capacity Market to eventually support gas plant abated through Carbon Capture and Storage (CCS), and generation using alternative fuels such as hydrogen or biogas, via retrofit as well as potential new build.

However, initially to bring these technologies to market requires financial support and new business models, which go beyond the reach of the Capacity Market. Those mechanisms are in development with proposals for a Contract for Differences (CfD) model for hydrogen production and a Dispatchable Power Agreement (DPA) for CCS. There is, however, currently no business model under development that we are aware of that envisages support for conversion or new build plant to run on hydrogen outside of a pre-combustion CCS approach.

The first power CCS plant is anticipated to be operational by 2027, and hold a 15 year DPA, precluding participation in the CM until deliver year 2042. A steep ramp up is necessary.

Two factors will ultimately work in tandem to avoid fossil lock-in:

- Prioritisation of finalising development and implementation of policies and business models to bring forward those low carbon technologies (e.g. CCS, hydrogen fuelled, biogas), and thus attract investment in the low carbon alternatives to unabated gas; and
- The clear direction, meaning that investment in unabated plant is likely to be unattractive due to uncertainty, anticipated regulatory risk (e.g. implementation

of a phase out policy), forecast low load factors, the Environment, Social and Governance, and Sustainable Finance Taxonomy.

Further, as a net zero rather than zero target, the government needs to consider whether some unabated gas on the system that runs for limited hours is part of the future system, or whether government policy will be to exclude these assets completely, as it did for coal. Emissions limits in the CM should follow a transparent policy decision.

Question 1

Could ‘low carbon capacity’ in the context of the Capacity Market be defined in terms of an emissions limit? If so, what should form the basis of this limit – for example, would it be better to base a limit on carbon intensity or overall annual emissions, and what types of capacity should be captured by this emissions limit?

An emission limit could be used to define low carbon capacity for the purposes of the CM. However, implementing an emissions limit to restrict access to the capacity market should not be done in isolation as it would introduce a phase out trajectory without ensuring adequate low carbon plant can come forward to fill the gap. The EU Regulation introduced an emissions threshold to prevent coal fired power stations from participating in the capacity market after a coal phase out policy had been introduced and in the context of a clear alternative to coal i.e. gas. It is essential that low carbon forms of reliable flexible generation are brought to market first through other mechanisms, such as the CCS DPA and a hydrogen business model.

An overall annual emissions limit could then be used and adjusted to ensure a level of unabated gas used only infrequently is supported as part of the transition.

Question 2

Are there alternative approaches to defining low carbon capacity in the context of the Capacity Market? Please provide justifications

If it is envisaged that no unabated gas is on the system and at a time when CCS abated, hydrogen or biomass fuelled plant becomes commonplace, then low carbon capacity could ultimately exclude those technologies covered by the ETS. However, the current ETS exemption for generators with a capacity 20MW or below skews the market in favour of small scale unabated fossil plant.

Question 3

What are your views on the benefits or challenges of linking future long-term Capacity Market agreements to a new carbon emissions limit? Do you have any suggestions regarding an appropriate approach to setting such an emissions limit, and how could we best account for ‘lower’ rather than ‘low’ carbon technologies in determining eligibility for multi-year agreements?

In the long term we’d envisage only capacity that is defined as low carbon being eligible for 15 year agreements. The definition of low carbon must include CCS abated gas plant, and hydrogen or biogas fuelled generation. It should also enable retrofit or refurbishment of existing gas plant to be CCS abated or run on alternative fuels.

In terms of length of agreement, it may be that 5 year agreements are suited to support investment needed for hydrogen blending capability, which would reduce emissions.

In the short to mid-term, an annual emission limit could be implemented for new build capacity to be eligible for 15-year agreements. This would take account of the need for capacity running at lower load factors to support the integration of the growth in renewables before other technologies are available. 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 minimum income from the energy market.

Question 4

Is it necessary and appropriate for carbon intensive generation to continue to access shorter multi-year agreements, until such a time as low carbon dispatchable generation is more widely available?

Yes. Certainly, shorter multi-year agreements could be suitable to support investment needed for hydrogen blending capability. Also, access to capital to invest in maintaining fossil plant will become more challenging and a multi-year agreement reduces the uncertainty of annual one year agreements. However, an assessment could be made of expected load factors as increasing renewables come on line, and an annual emissions limit set alongside auction parameters for capacity seeking 3 to 5 year agreements.

Question 5

Would you expect these suggested changes to agreement lengths to affect your decision to participate in the Capacity Market, your bidding behaviour, or the costs of and access to finance? If so, how? Can you suggest any alternative approaches to ensuring agreement lengths offered in the Capacity Market are consistent with the delivery of net zero targets?

We would expect the cost and access to finance to become more challenging for unabated generation as investors take account of Environmental, Social and Governance (SDG) factors and Sustainable Finance Taxonomy developments. These considerations may, in time, outweigh the impacts from changes in accessing different CM agreement lengths.

It is helpful that this Call for Evidence sets out the need for unabated gas in meeting the increasing challenges in securing electricity supplies. Whilst we agree with the proposal to avoid unnecessarily locking in future fossil, the short to mid-term focus for the CM is ensuring adequate reliable flexible generation is available.

There is a risk that preventing access to multi-year agreements for unabated gas plant before alternatives are widely available increases costs overall as the finance cost and uncertainty risk is factored into bidding prices.

Assessing expected future load factors and allowing new-build projects access to long-term agreements with an appropriate annual emission limit could mitigate that risk. As unabated gas plant will be needed but will run less frequently, lower market running will already be factored in to bid prices and access to multi-year agreements will lead to a lower bid price as companies can also factor in stable payments over the agreement period.

Question 6

Is it still appropriate to maintain the link between capital expenditure thresholds and multi-year agreements? If not, what other criteria could we consider using to assess eligibility for multi-year agreements (other than the new lower emissions limit discussed in section 2.3.2.1)?

Yes.

Question 7

Should we revise the applicable capital expenditure thresholds? If so, what data could we base them on, and do we still need to have two different thresholds? Should low carbon DSR be able to access shorter multi-year agreements on the basis of emissions limits rather than capital expenditure thresholds?

The threshold for 15 year and shorter agreements for lower-carbon technologies should be reviewed to reflect latest cost information. Once first projects or FEED studies are complete, the cost of retrofitting CCUS to an existing plant could be considered in setting the threshold. Thresholds for shorter agreements for lower carbon capacity could be benchmarked against the cost of converting an existing plant to burn a blend of hydrogen and natural gas.

Question 8

Should we review the 77 month window for new builds?

We do not see any need to review the 77 month window in the short to mid-term. It may be necessary to review to check whether the 77 month window is still appropriate in the longer term, once technologies such as CCS abated are widespread and participate in the Capacity Market.

Question 9

What are the benefits of maintaining the Extended Years criteria?

The Extended Years Criteria (EYC) provides some important tests to ensure that new build agreements are backed by capacity that is genuinely new to the market, capable of delivering for the duration of the agreement and compliant with relevant environmental standards. If the EYC is removed then alternative provisions should be made to provide these safeguards. Whilst SPDs can be used to confirm ongoing performance they do not provide the evidence at the start of the delivery year that the EYC provides (EYC must be provided within 3 months whereas SPD is not required until 7 months).

Question 10

What are your views on the introduction of a declared later delivery year as a way of addressing the challenges experienced by projects with long build times seeking to enter the Capacity Market? Would this affect your decision to participate in the Capacity Market, and if so, how? Are there other approaches we could take to removing barriers to participation for technologies and projects with long build times?

Where support is needed for technologies with long build times then it should be provided outside of the CM. The proposals for a declared delivery year are complicated, introduce further uncertainty, and risk impacting liquidity and price as the auction is buying for different delivery years.

Question 11

Do you agree with our suggested approach to determining and verifying eligibility for a declared later delivery year? Are there other approaches we could consider?

We do not agree with the proposal to introduce a declared delivery year.

Question 12

How can we best mitigate any security of supply risks arising from this approach? Can you identify any additional risks and/or disbenefits related to the introduction of a declared later delivery year?

We do not agree with the proposal to introduce a declared delivery year. Risks could be better managed by providing support for technologies with long build times outside of the CM.

Question 13

What are your views on the benefits and challenges of introducing an auction design splitting auctions between new build and refurbishing low carbon capacity and existing capacity? Would this affect your decision to participate in the Capacity Market or your bidding behaviour, and if so, how?

As the key policy instrument to ensure security of supply, maintaining investor confidence is essential. Any significant redesign such as splitting auctions, introduces uncertainty and will inevitably introduce risks from an investor perspective.

A split auction would undermine the aim for cost-effectiveness, as the overall volume required would need to be allocated between each category. The government would be planning the mix and would choose whether or not to bring forward new build rather than having all available capacity and potential development projects compete. In contrast, a single auction maximises liquidity and outcomes to date are a result of highly competitive auctions.

Question 14

What are your views on the potential split auction designs considered in sections 2.5.2 and 2.5.3? Are there alternative designs we should consider? And what approach could we take to setting targets for a separate low carbon auction?

In addition to our comments under question 13, the designs considered in in sections 2.5.2 and 2.5.3 introduce both uncertainty and difficult to resolve challenges, without bringing any clear benefits.

Question 15

What are your views on expanding the scope of the Price Taker Threshold to potentially make it a price cap for Price Taker Capacity? Would this impact bidding behaviour? What changes to the Price Maker Memorandum might be necessary to ensure any changes to the Price Taker Threshold would be effective?

Having a single auction which maximise competition between existing and new projects is the best way to ensure an efficient outcome. Increasing wind generation on the system and bringing forward low carbon generation through the CCS DPA and a hydrogen business model will result in existing plant running at lower load factors. Low load factors combined with the potential for higher carbon prices may result in some existing plant requiring CM prices above the Price Taker Threshold to continue operations.

Our own analysis shows that if government ambitions are achieved or even exceeded, then in a 2035 scenario[1] with analysis against nine recent weather years, unabated gas plant have very low load factors, and peakers seldom run, over the period of a year.

Question 16

What are your views on the potential benefits or challenges of amending the Net Welfare Algorithm to calculate to next lowest bid, rather than by the round floor price? Would this have an impact on bidding behaviour?

This change would likely have an impact on bidding behaviour as CMUs will no longer have the protection of the round floor price. This will force CMUs to enter an exit price earlier during the auction to avoid a situation where the price drops unexpectedly. However, it is unclear if this change in bidding behaviour could undermine any potential cost saving.

Question 17

How might the changes to auction design considered in section 2.5 interact with other design possibilities explored in Chapter Two concerning agreement lengths (2.3) and projects with long build times (2.4)?

It is most efficient to maintain the current single auction, pay-as-clear design.

Question 18

What are your views on changing the figure used in calculating the penalty rate (for example, from 1/24 to 1/8 or 1/4)? Should the penalty rate be linked to the Value of Lost Load rather than the auction clearing price? Please provide supporting reasons/evidence.

As the key instrument for ensuring security of supply, CM delivery needs to be robust and the penalty regime should make the auction unattractive for speculative bids, and ensure participants have a clear view of the risk of non-delivery. We agree that penalties should be increased and consistently applied. As in private contract law, the penalty should not be penal and exceed the value of the agreement i.e. it should not be higher than the annual CM payment.

There is merit in considering a link to the Value of Lost Load as a measure of damages.

A number of other measures in addition to increasing penalties would support robustness of the CM, such as improving transparency by bringing the estimated 8GW of distributed capacity into the market in a way in which it is visible to National Grid, for example by adopting the proposal to make all CMUs register as BMUs; and by better

[1] We'd be happy to share with officials details of our analysis if required.

enabling secondary trading. We have made proposals on how to better enable secondary trading in answer to question 27.

Question 19

What are you views on the changes we consider in relation to the annual and monthly penalty caps?

The annual penalty cap should remain at 100% of a CMU's capacity payments in the relevant delivery year.

Question 20

What are you views on the options we consider for improving the coordination of capacity during a stress event?

Introducing the requirement for all CMUs to be registered as BMUs will increase transparency and improve coordination of capacity before, during and after a stress event.

Question 21

Do you agree with the idea of introducing an additional Satisfactory Performance Day for CMUs that fail to deliver in a stress event?

This proposal blurs failure to deliver under a stress event, which results in a penalty, and overall capability of delivery which is already tested under the current requirement to meet three Satisfactory Performance Days (SPDs). Further, SPDs are typically done in winter when de-rated capacity can be achieved, if a stress event were to occur in summer most CMUs would be unable to do another SPD in the remaining CM delivery year as ambient conditions would make this unachievable.

Question 22

What are your views on the options we set out regarding the recovery of unpaid penalties?

In the event of non-payment of penalties, recovery should be from future Capacity Market payments, as is currently the case.

Question 23

Would you expect any of these changes to the penalty regime to affect your decision to participate in the Capacity Market, your bidding behaviour, or the costs of and access to finance, and, if so, how?

No. Although participants will take account of any increase in penalty in their risk assessment, the main driver of that risk is the availability and reliability of the asset. Higher penalties incentivise capacity providers to manage their assets towards ensuring delivery. For capacity anticipating a higher likelihood of non-delivery, the risk of incurring higher penalties will flow through to bid prices. For those more confident of delivery, there will be less impact on bid prices. This could potentially lead to more reliable capacity successfully securing agreements.

Question 24

What are you views on the benefits and challenges of the alternative model for a penalty regime set out in section 3.1.5? Are there other models we should consider?

Implementing the alternative model, capacity payment loss, could have negative consequences if future monthly CM payments are critical to funding remedial maintenance following the failure to deliver, to be ready for the next system event.

In addition, the incentive should be for a CMU to generate as much as possible during a system stress event even if its constraints prevent its output reaching its de-rated capacity. The alternative model fails to provide that incentive, as the penalty is the same for output below de-rated capacity as for producing zero output. Finally, a suspension rolling into the following delivery year may be difficult to apply in practice as CMUs may change their configuration from year to year.

Question 25

What are your views on appropriate testing arrangements for wind and solar CMUs, distribution connected CMUs, and co-located CMUs?

CMUs of all technology types should be subject to a connection capacity test, whether connected to the transmission or distribution system. The current Rule 3.5.3 sensibly allows an average of three separate settlement periods in the previous 24 months to be used as evidence of connection capacity. This occurs during normal commercial operation of the plant and gives a strong indication of plant capability.

During a system stress event CMU delivery is assessed on its derated capacity, not its connection capacity. Therefore, running a plant to reach a maximum output on three occasions is not necessary. If a plant were required to deliver maximum output during a stress event it would do so. However, it could be that running to maximum output more frequently potentially puts stress on the plant that would require additional maintenance or repair. The ability to deliver to meet the commitment under the agreement is demonstrated by the SPDs.

Question 26

Which is your preferred option of those proposed in section 3.2.5 relating to the timing of the connection capacity test? Are there alternative approaches we could consider?

Our position is that the proposed connection capacity test is inappropriate and that the existing method to demonstrate connection capacity, as described in Rule 3.5.3, should be retained.

Question 27

Would it be beneficial for us to enable a third party (such as the Delivery Body) to re-auction capacity obligations in respect of CMUs that have been terminated during the delivery year, or between a capacity auction and the start of the relevant delivery year? If so, what are your views on the principles for such an arrangement (set out in section 3.3.2), and do you have any commercial considerations and/or concerns about the use of a third-party facilitator?

The Target Capacity for the T-1 auction can already take into account agreements that have been terminated or are likely to be terminated, effectively re-auctioning this capacity within the auction cycles.

Increasing non-delivery penalties and at the same time better enabling secondary trading would improve delivery assurance and could avoid the need for re-auctioning in some cases. Making it easier to secondary trade gives a participant the opportunity to manage transfer of the agreement from a failing CMU to uncontracted capacity that can deliver.

Allowing the registration of Secondary Trading ahead of the respective T-1 auction would allow capacity providers which cannot deliver their obligation to search for a replacement in the market well ahead of delivery.

This would allow capacity providers to manage risks for older plant, allowing maximum participation of available capacity with a route to transfer agreements should technical issues arise. The transferee will also benefit as they would have a longer lead time to prepare a plant for example, where the plant is mothballed or to undertake any required maintenance.

This flexibility could also allow the trading of more than one year's worth of agreements. In which case, the transferee would have more visibility of future revenues to underpin their business case.

Early secondary trading would increase transparency as deals would be notified in a more timely fashion to the market. It would also reduce the cost of T-1 auctions by removing the need to procure additional capacity at short notice.

Some limitations should be kept for CMUs with long-term agreements to avoid speculative bids and to prevent otherwise ineligible CMUs from securing a long term agreements. For example, Capacity Providers should be required to satisfy Rule 8.3.6 (Evidence of Total Project Spend) before being allowed to register trades.

Question 28

In your view, do the current de-rating methodologies remain appropriate and reflect a CMU's risk of non-delivery? If not, what alternative methodology could be applied and why? Please submit any evidence in support of your view.

It is possible that an approach where capacity providers decide on their own de-rating factors could produce a better outcome than applying a generic technology type de-rating factor calculated by NG ESO. The capacity provider would have knowledge of that particular CMU and its environment and could provide a plant specific de-rating factor. Combined with robust penalties, a capacity provider is incentivised to offer the capacity it can deliver and therefore use a de-rating factor that accurately reflects the specifics of the plant.

Modifying de-rating factors on some 'end-of-life' assumption would be misleading. Plant age is not necessarily related to risk of failure. For example, Uniper's Enfield plant was commissioned in 2002 but has recently been refurbished. The plant received the OEM's "HE upgrade", resulting in improved efficiency and increased output. De-rating on the basis of initial commissioning date would be erroneous.

Question 29

Do you have initial views based on your experience on the Capacity Market's performance since its implementation that we should consider?

The Capacity Market is considered a successful instrument as assessed in the five year review.

There has been a need to remove or reduce market distortions as they have become apparent and to address unintended consequences, such as the growth of diesel reciprocating engines.

It is clear that redesign would introduce uncertainty and will inevitably introduce risks from an investor perspective. It is important to learn from the impact of those initial market distortions and assess where there are still inconsistencies in treatment, such as the exemption from carbon pricing for small scale generators.

The ten year review should look at the interaction between policy instruments and the combined impact of these in terms of bringing forward low carbon capacity.

As the key policy instrument to maintain security of supply, in the short to mid-term the assessment of the success or otherwise of the Capacity Market must focus on its core purpose.

Question 30

What are your initial views on the Capacity Market as a continuing mechanism to address system adequacy? Is there a need for continued market intervention by the government to address electricity security? And could the Capacity Market (or an alternative electricity security mechanism) address wider system services such as flexibility and stability?

The Capacity Market continues to be required as a mechanism to ensure security of supply. The mechanism itself does not address flexibility and stability services, however, the reliable flexible assets that are needed to provide flexibility and stability services will run at lower load factors in the future system and continue to need capacity payments. The capacity market continues to be an essential part of the market alongside the energy and ancillary services markets. It should be noted that interconnectors are network not generation and as such cannot directly provide supply security, flexibility and stability, but facilitate transport of generation on the other side of the link.

Question 31

Are there alternatives to the Capacity Market that may meet our current or future electricity security needs better, that we should consider? Please provide evidence to support your views.

No. There is no clear change in market features that would negate the considerations and decision taken at the time of Electricity Market Reform when the Capacity Market was introduced.

Question 32

Should we continue to enable cross-border participation in the Capacity Market? If not, why not? In the absence of cross-border participation, how should target capacity calculations be altered to reflect the contribution of cross-border flows to security of supply?

As the Call for Evidence sets out, there has been a significant change which removes the requirement for participation of cross-border capacity. Moreover, putting in place arrangements for direct participation of cross border capacity would now be even more challenging. As network, interconnector should not be allowed to participate in the Capacity Market, and were only included as an interim arrangement to comply with State Aid rules with the view to enabling direct cross border participation. Interconnectors are not subject to Transmission Use of System charges (TNUoS), Balancing Services Use of System charges (BSUoS), or Carbon Price Support, representing major market distortions, which can now be addressed.

The benefit of interconnectedness could nonetheless be taken into account in setting the Target Capacity for CM auctions by NG ESO assessing the expected contribution from flows across interconnectors.

Question 33

If the CM continues to enable cross-border participation, what should be the preferred approach to cross-border flows – enabling direct participation of foreign generation, or continue with the existing indirect cross-border participation model (via interconnectors)? Please provide evidence to support your views.

If the CM continues to seek cross-border participation then this would be best pursued by the direct participation of foreign generators, and on the basis that GB generators can participate in the capacity market on the other side of the border.