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Introduction

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8 How could European Day-Ahead and Intraday markets be improved to further facilitate market access of RES and Distributed Energy Resources in 2030?

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Due to the volatility and the dynamics of wind and solar, liquid continuous intraday market with gate-closure as close to delivery as possible is a fundamental need because the best available generation or consumption forecasts can be utilised for trading purposes. Consequently, the resulting schedules submitted to the TSOs ensure an accurate and balanced portfolio. This results in reduced portfolio imbalances of the BRPs.
More specifically Day-Ahead and Intraday markets could be improved by:
• Increasing time granularity with a maximum of 15 minutes: we consider that this is a balanced period trade-off between the need of having markets closer to real-time and the significant start-stop costs of power plants;
• Defining gate closure time as closer to real time as possible to maximise self-balancing
• Continuous trading option between auctions to account for unforeseen events e.g., trips.
• Increasing the number of ID auctions does not make sense if there is not sufficient market liquidity. Combining DA and ID auctions (so that DA fixes the baseline and ID adjusts on top of it) is meaningful. For instance, the Iberian MIBEL market is now a combination of DA, ID auctions and hourly trans-border continuous market (XBID) while the 15 minutes market has been already announced for deployment. Such set-up can be efficient to manage imbalances due to wind farm schedules.
• Increasing the geographical scope of the markets to benefit from different demand and generation profiles, with increased market liquidity;
• Improving access to continuous cross-border intraday trading and to demand-side;
• Lowering barriers for market entry of flexible demand and generation;
• Investigating how risk of non-delivery can be reduced e.g., by modelling a small amount of “reserve storage” to prepare for storage buffers going forward;

9 Are there any best practices which could be used as an example for RES and DER participation in DA and ID markets?

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10 What do you consider to be the main barriers for the participation of RES into balancing markets?

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We have identified the following barriers that concern the design of the balancing market as well as prequalification processes and other technical requirements:
Design:
• The need in some European markets to tender for capacity one month or week ahead is a major barrier. Due to the variability of wind and solar, day ahead bidding (or as close to real time as possible) is crucial to ensure accuracy and reduce risk of non-delivery and therefore penalties - both aspects inadequately designed today in most EU countries for making RES participation viable. Overall, timing of reserve procurement should be much closer to time of delivery.
• Without secondary markets that would allow RES providers to transfer their balancing services commitments to other market participants, it is almost impossible for RES to guarantee a significant balancing capacity commitment one week or month ahead.
• The requirement for redundancy (e.g., in the German market) instead of taking a probability of non-delivery approach increases the barriers for RES to enter the market and leads to an inefficient market design. This results in higher costs to consumers. TSOs should investigate probability methods for reserve dimensioning and procurement.
• Some countries do not even allow RES to participate in balancing markets (e.g., Poland only allows thermal plants for FCR and aFRR). In other countries even though RES participation may be allowed imbalance cost for renewables is de facto an entry barrier and it is also strongly penalizing operational assets. This is the case of Romania where balancing costs account for a cost equivalent to above 20% of market revenues (even with the latest migration to a pseudo-single imbalance price). Those cases should be carefully studied to identify potential market malfunctioning.
• The product structure needs to be asymmetrical to allow RES to provide down and up regulation separately. For instance, for wind generation to provide up-regulation, it needs to provide headroom by reducing its position in the DA market, thereby foregoing some DA revenue. This is not the case for downward regulation. An asymmetrical design allows RES to participate by providing only downward capacity when not financially feasible to provide upward regulation.
• Some balancing products are mutually exclusive and/or constrain RES operators' ability to participate in regulatory power markets. Where technically feasible and meaningful, stacking of revenues from different services should be made possible to decrease revenue uncertainty and increase procurement efficiency.
• Minimum bid sizes sometimes are not small enough (ex: 5 MW in Germany for aFRR and mFRR, 25MW in UK for aFRR, 20 MW in PT for aFRR) especially when one considers the participation of pure wind portfolios.
• At the same time there are often barriers to aggregated participation (e.g., TSO requiring individual contracts between 3 parties TSO/aggregators/plant operators, instead of requiring one with the aggregator). In some countries the TSO requires control by each power plant (individual set points), instead of allowing BRPs to optimize portfolio management (ex: Portugal).
• Generally, a too demanding and/or frequent administrative process constitutes a big hurdle (pre-/requalification requirements), drives costs (e.g., investments in hardware) and makes it less attractive to become an active provider of balancing capacity. Some of these aspects will be addressed with the implantation of the target model and introducing MARI and PICASSO. In general, harmonizing the design of products and prequalification processes across countries is crucial for making RES participation in balancing markets viable.
Prequalification and other requirements
• In most EU countries prequalification is designed for thermal power plants, hydro or other incumbent technologies.
• Another big barrier (especially for smaller units) is the communication requirements (ICCP links, redundant systems, etc.) established by System Operators. Technical aggregation (for sending measurements), together with appropriate commercial aggregation (for compensating imbalances among units) can be a good solution for it.
• Some older RES assets do not have integrated balancing services capabilities as per construction, thereby requiring CAPEX investments to participate in those markets. To justify CAPEX investments, it requires business case certainty and clear signals of the respective future market size and design (volume procurement targets, tender length, technical requirements, payment structure etc.).

11 Which kind of support scheme has the least distortive effect on the participation of RES in balancing markets?

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All support schemes incentivise RES to produce at maximum output to obtain the financial support. As the development and operation cost of RES will be decreasing and support schemes may be providing less value, RE assets may be more incentivized to offer into balancing markets more competitively. If not, the addition of provisions to incentivize participation in balancing markets whilst still earning the full value of the support scheme will be necessary.
A potential solution for improving production-based support mechanisms (€/MWh) could be to pay premiums based on deemed MWh produced, including MWh that are not produced due to downward activations in the balancing market, so that RES producers would not need to account for loss-of-revenue when sending their balancing offers.
Spain could be considered as a good example; there are two different support schemes both incentivising participation of RES in balancing markets:
- Wind farms between 2004- 2017 (coming from the former regulatory framework or as results from 2016-2017 auctions) have a fix remuneration based on €/MW (for almost 3.000 MW of these auctions the investment income is active only when the spot hourly price is below 30 €/MWh) and therefore these are incentivized to participate in the balancing market to obtain additional incomes.
- The new auction of 2020 is based on a CfD below 28€/MWh and winners can participate in the balancing markets. Anyway, this strike price is guaranteed for the energy metered not the scheduled one therefore wind farms must optimise their operation to fulfil that guaranteed energy value in the 12 years period of the plant operation (please note that there are some restrictions to participate in the downwards services if this implies a reduction of generation).
However, in the context of the increased energy demand expected in the long-term due to electrification of several industrial sectors, downward regulation might not be the right technical solution to the balancing issue. In a bidding zone where negative prices occur, this renewable electricity could be needed in another bidding zone or stored for later use. (Large-scale) storage seems to be an efficient way to deal with the mismatch between demand and supply in the energy market; however, it can currently not recover its investment costs as much of the value it creates is not captured by any market price/signal in most EU countries. Support mechanisms for integrating renewables with storage are another important element that needs to be defined soon. A €/MW/year remuneration (as we have seen in many markets such as Ireland, UK) for at least 5 years period complemented by participation in the balancing market and remuneration of service provision could be adequate.
Remuneration mechanisms based on capacity could also incentivize the participation of RES in balancing markets and could be explored. On another hand they are more complex and do not necessarily incentivize higher efficiency. A solution for now could be an energy-only market supplemented with a capacity market - where required – but fully incentivizing the participation of RES and not only of thermal and hydro power plants as is the situation in currently deployed EU cases.
Finally, compared to fixed FiTs, CfD support schemes provide more appropriate price signals, through decreasing (or even negative) difference payments, as DA prices become very high. These periods also tend to coincide with system stress and the need for balancing services. Therefore, considering the options

discussed by ENTSO-E, we support the payment of CfD premiums based on deemed generation and believe that this approach could appropriately balance retaining risk reduction and efficient dispatch. We believe that this approach would encourage renewable developers to consider how their developments can offer grid or balancing services and benefit developer who can accurately price these e.g., into their CfD bids.

12 What do you consider as best practice to the ensure effective provision of voltage control and other non-frequency Ancillary Services by RES?

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To ensure an effective provision and procurement of ancillary services, it is essential that the market is open to all market players. A market-based approach would ensure competition to drive down procurement costs and ensure the right investment signals to future ancillary services providers. Any mandatory approach must be avoided and phased out where it has been already adopted in favour of market procedures aimed at delivering the lowest cost solution for the system.
Voltage control and other non-frequency ancillary services need to be properly valued to incentivise participation if extra resources are required to participate. RES can provide most ancillary services such as voltage control, inertia and black start if properly incentivised to invest in and develop the capabilities. Some of these capabilities are not an integrated part of wind turbines – exactly as in the case of thermal powerplants. Adequate price signals and market continuity are crucial to generate such investments: non-frequency ancillary services should not be contracted out on a bilateral basis, but a market should be established to allow for greater price transparency. Contracts for non-frequency ancillary services should be of longer duration to allow for a return on the investment required to provide the service.
The effective provision of the voltage control in each grid level (transmission or distribution) should be done by the plants connected directly to each grid. It is fully inefficient controlling voltage problems in the transmission grid by RES connected to the distribution grid. This can increase power losses and accelerate the degradation of electrical equipment (transformers).
Another element that needs to be considered is the increasingly important role of capabilities of combined renewables power plants (wind/PV/storage). TSOs would be inefficiently rejecting important useful resources to meet their needs if requirements for these assets are set separately for each of the integrated technologies instead of for the whole unit.
Finally, DSOs should also implement a market or remuneration practices for non-frequency ancillary services by distribution-connected RES assets.

13 How could market design mitigate the side effects of the interaction of negative prices and RES supported technologies?

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Negative prices are a clear reflex of the lack of flexibility in a power system. Instead of using exposure to negative prices as the main instrument to enforce flexibility provision, planners should be focusing their efforts to foster new investments in flexible technologies (ex: interconnection, storage, demand response) by other future-proof means aligned with decarbonisation goals i.e., adapting markets to more flexibility requirements or procuring flexibility services adapted for RES.
One solution could be introducing ramping products as additional ancillary services or as an additional product simultaneously or linked to the DA auction. Moreover, a market design that efficiently supports the co-location of storage or demand while keeping the green value of electricity could mitigate the risks resulting from negative prices.
The payment of premiums during hours with negative prices is highly distortive of the market. Therefore, WindEurope's current position is that support for production in times of negative prices should be phased out hand in hand with regulatory requirements that increase system flexibility on supply and on demand side.
If RES are remunerated based on deemed MWh (which includes MWh actually produced and MWh curtailed in the balancing market), they will be incentivised to curtail their production in response to negative prices contributing positively to restoring the balance. Market products must exist for the RES to respond to the 'price signal' of losing their support otherwise the loss of support is merely a punishment rather than an incentive. In the Belgian system for example, certain installations lose their support in case of 6 consecutive hours of negative day-ahead prices. However, there is no product on the DA market whereby RES can curtail their production, conditional on the DA price being negative for 6 consecutive hours. Therefore, the regulation does not serve as an incentive, on which market actors can react accordingly as they do not have the tools to do so. In addition to such tools, other solutions can be considered like the framework implemented in Italy: this one considers that no top up payment would be received during periods of more than 6 hours of negative prices but the tenure of the contract for the concerned RE asset is extended accordingly.
Overall an EU wide regulatory framework which mitigates the risks for RES related to negative energy prices should be developed as approaches related to capping negative hour risks vary across the EU. A level playing field should apply also about negative prices.

14 What do you consider to be the key market design barriers limiting the uptake of demand response?

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15 What do you consider to be the best practices for the facilitation of demand response?

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16 Do you see benefits in increasing the number of intraday auctions?

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17 If so, what would be an adequate number of intraday auctions per day?

.. :

18 Would you still see a role for cross-zonal intraday continuous trading in case an adequate number of intraday auctions would be implemented?

.. :

19 What potential benefits or drawbacks do you foresee in combining day-ahead and intraday auctions?

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20 Would you recommend any alternative solution to combining day-ahead and intraday auctions which could achieve similar objectives?

.. :

21 How could markets for forward transmission capacity be improved to support the energy transition?

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22 Do you see value in developing new durations of long-term transmission capacity products mirroring products for forward electricity trading?

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23 Do you see other means to improve the forward markets and hedging possibilities besides long-term transmission rights?

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24 Which potential benefits or drawbacks do you foresee with the co-optimisation of energy and balancing capacity?

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25 Would you recommend any other solution which could achieve similar objectives?

.. :

26 Do you think that the implementation of co-optimisation or other market features could increase market complexity to a level which may be detrimental for the entrance of new players?

.. :

27 How can TSO procurement of balancing services evolve to be a better fit for the new power system of 2030?

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The market for balancing services should be open to all participants and enable the potential of RES and demand-side to deliver balancing services. The balancing product requirements shall not be designed to accommodate only certain technologies. They should be designed to solve the balancing challenges of the future considering dynamics and volatility of the system. Any technology-specific product requirements will add unnecessary market complexity and fragmentation. Consequently, this will not contribute to more transparency on the costs of balancing the system and the resulting imbalance price.
Some specific recommendations:
• TSOs could arrange a second auction closer to real-time where part of the reserve capacity is procured, but also including the option to “buy back” any capacity committed in a prior reserve auction i.e., an auction that both serve as a procurement mechanism for the TSO to ensure part of the capacity close to real time and an organized secondary market for market players that have committed capacity in the first auction. A mini version of this is in the Swedish-Danish FCR auctions, but design and communication of the secondary market option needs to be more explicit;
• TSOs need to increase cooperation with DSOs to ensure a normative optimal balancing procurement combining bottom up and top-down approaches;
• For sure, separate up and down procurement would be an incentive for RES (and almost all types of flexibility providers) to participate in balancing markets. Separate procurement for capacity and energy may also be a good idea; under certain conditions, it may be economically advantageous for the system (with regard to RES curtailment) to procure reserves and wind can potentially improve overall system dispatch by allowing turning off of more costly (on an operating basis) generators that are online primarily to provide reserves;
• The firm frequency response service should be recognized and remunerated in all countries for the participating technologies – currently it is not paid for Portugal and Spain;
• Need to improve revenue visibility and stability to promote investments in “dispatchability” capabilities from RES e.g., short-term and seasonal storage. For example, in the UK, firm frequency response is procured through a monthly tender and STOR is procured through 3 tenders a year.
• The very much discussed need to implement the EU Electricity Balancing Guideline based on a persistent harmonisation effort all across EU and also ACER’s Decision 18/2020, of 15 July, which establishes that each player should have a single net imbalance position (netting between generation and demand in the BRP);

28 Do you have concrete examples of best practices in theprocurement of balancing services?

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29 For system with limited congestions and reactive balancing approaches, would you foresee any benefits to implementing real-time markets managed by the relevant TSO?

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Generally, it should be considered that market parties need time to adapt their production to the contracted delivery. Therefore, different markets should not be executed simultaneously or closely to each other.
The suggested gate-closure times of 15 to 5 min before delivery for real-time markets would clash with the evolution of continuous intraday markets with a gate closure around the same gate closure. Further, we foresee challenges to implement real-time markets where BRPs are required to self-balance, no matter if the TSOs are pro- or reactive.
Moreover, market players in certain markets are already acting real-time to e.g., imbalance price signals. Therefore, the justification of a dedicated real-time marketplace can be questioned. The future market design should focus on simple and transparent solutions and not add additional complexity.

30 Are there any other Balancing Markets enhancement which you would recommend?

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31 Would you support the simplification of products traded in the DA and ID auctions to speed up the implementation of ongoing and future market evolutions?

.. :

32 If yes, which DA and ID market evolution would you consider to be a priority and which specific products could be discarded?

.. :

33 Which potential benefits or drawbacks do you see with the alternative pricing methodologies described in section 2.4.2?

.. :

34 Would you recommend any other solution to improve the performance of DA and ID coupling algorithms?

.. :

35 Which potential benefits or drawbacks do you foresee by allowing more time for the algorithm optimisation?

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36 Would you be in favour of keeping an hourly auction in day-ahead followed by 15 min intraday auctions?

.. :

We are in favour of keeping a DA auction (both 15 minutes and hourly granularity can work). If it is possible to link bids in time, keeping hourly auctions in DA might not be necessary and we could move towards 15-minute auctions. However, the liquidity of the DA market should not be diminished by 15-minute auctions that follow shortly after. The DA market will remain very important for clearing most of the baseload and delivering a strong and reliable price reference. It is not given that more auctions lead to more liquidity.
We regard an opening ID-auction as a productive development however we strongly support the continuation of the continuous ID market and no (or as few as possible) ID-auctions as they could interfere with the continuous market from GOT to GCT. Thus, there should be good reasons to add more ID auctions.
NordPool recently made a survey among their 10-15 largest customers where the feedback was clear and uniform: all these stakeholders preferred continuous market versus ID-auctions.
We would prefer a Pan-European Opening ID-auction for example at 15:00 D+1 (or 16, 17, 18 at the latest) and then remaining Europe at 22:00. The timing currently proposed 10:00 auction (D+0) brings limited additional value and significant drawbacks.
The main benefit with continuous market is the time to market (= 0) which allows market participants to have full control of their balance position, and act immediately when the need arises. To meet this goal with auctions we would probably need to have auctions every 15 minutes (or even more often). However, market liquidity could possibly become an issue for most auctions. Especially in regions with several minor bidding zones and bidding zone borders, such as the Nordics, this market could probably not work well.

37 Would you recommend any other solution to adapt market coupling procedures?

.. :

38 Do you think the zonal market model including the planned evolutions of the Clean Energy Package is suitable for the 2030 power system?

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39 What is the most important feature of the current zonal market design that must be adapted to make it future proof?

.. :

40 Which potential benefits or drawbacks do you foresee with introduction of the PST and cross-border/internal HVDC in the allocation phase of transmission capacities alongside the market coupling?

.. :

41 Which potential benefits or drawbacks do you foresee with the introduction of several Flow-Based domains in the allocation phase of transmission capacities?

.. :

42 Do you see the Dispatch hubs model as a promising option to be further analysed in the future? If so, which variant: Redispatch potential bids or market bids appears the most promising?

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Dispatch hubs are a solution that requires further analysis, and their impact should be assessed both in a short- and a long-term perspective. We acknowledge that some countries/bidding zones have significant intra-zonal congestion and that market remedies such as a dispatch hub can improve the societal benefit within the hour. However, such approaches should be supplementary to strong incentives to build and reinforce internal grids.
For this and the following questions on congestion management it is important to start assessing the impact of the location of new electrified demand over the coming years. This includes both direct electrification (heat pumps) and indirect electrification (electrolysers). Especially the location of electrolysers is interesting as their location is more geographically flexible than most other assets. Correct price signals are very important over the coming years to optimise future grid build-out in favour of societal needs.
Many large-scale investments in sector coupling projects are quite mature and some of them will reach investment decision within the next 5 years. This accelerates the need for TSOs to put in place a framework that investors can work into their business cases especially for flexibility and location. For electrolysers, the ability to provide flexibility should be set in stone already at the CAPEX phase of the project. Therefore, a “best guess” of future needs for this kind of flexibility is needed already today. This would optimise the installed assets’ ability for cost-effective system support.

43 Do you foresee any challenge in the implementation/operation of the dispatch hubs model?

.. :

44 Do you consider more locational information in the balancing timeframe to be a solution worth requiring further analysis?

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We are open to analysis/pilot projects showing the benefits of such approach, but implications need to be considered carefully.

45 Would you recommend any alternative solution to solve intra-zonal congestion in the balancing timeframe?

.. :

46 Do you think experience with nodal models can be useful in Europe, and how?

.. :

We do not see the need to introduce nodal wholesale markets in the European markets where we participate. Nodal market models could be useful in a situation where there are many more structural bottlenecks than currently observed in Europe. However, creating bidding zones around systemic structural bottlenecks is not a slope towards nodal market, but a consequence of the current zonal market model which still needs to be fully implemented. Local corrections due to congestion situations could be addressed with other mechanisms, such as location-based balancing (in properly justified situations) and local flexibility markets for congestion management.

47 What other advantages or disadvantages do you foresee with nodal models in a European context than those mentioned here?

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48 How could the increasing participation of distributed energy resources to the balancing market be handled in nodal pricing models?

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49 Under which conditions do you think a nodal market could be a relevant solution for some countries?

.. :

50 Do you foresee other challenges or solutions than those mentioned in section 3.6 with respect to the interaction between zonal and nodal solutions?

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51 How can distortions and inc/dec gaming in market-based redispatch be addressed/mitigated?

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52 What type of alternatives (e.g. capacity-based payments) exist to efficiently make use of distributed flexibility sources?

.. :

The contracting options are:
• Bids for activation (may be like a day-ahead market or closer to real time): procures flexibility services in the day before delivery and the payment is based on utilization (MWh).
• Tender platform: operates like a capacity mechanism, months or years before the delivery date. Usually includes an availability payment as well as a utilization payment.
• A combination of both, with obligation to bid for activation if under availability contracts, but allowing for other providers to bid for activation
We consider that the tender model provides more visibility both to network operator and to flexibility providers but the option should be explored further. Capacity-based payments are being reviewed as wind farms can now provide capacity availability services, combined or not with storage systems. However, it should not prevent providers from participating in other markets but allowing for revenue stacking through the provision of different services.

53 What recommendations do you have for the development of local flexibility markets based on existing initiatives?

.. :

We support the development of local flexibility markets as a temporary or in some cases permanent solution to congestion management. Local flexibility products at both TSO and DSO level should be procured through a market-based approach to foster competition and price signals rather than through a regulated, cost-based approach. However, the evolvement of separate market platforms for local flexibility products may reduce the liquidity of existing balancing markets. This may be best addressed by harmonising products across TSO and DSO level and integrating local flexibility bids as much as possible into existing markets. Therefore, we encourage harmonised legislation for lowering the barrier of entry, offering transparency, requiring competitive auctions with low bid size, offering incentives for investments through long-term auctions, ensuring variety of actors.
Moreover, it is important to:
• Promote grid digitalisation for more market liquidity;
• DSO investments to foster flexibility should be assessed with a TOTEX approach (OPEX and CAPEX) for optimised decisions regarding grid upgrades and flexibility market setups and operation. Such DSO assessments should use probabilistic methodologies and address value factors such as capital cost deferral, value of lost loads, network losses, O&M, etc. The risk associated with each option should be also monetized and considered in a CBA;
• It is also important to set up some market access principles to value stacking at EU level while allowing enough freedom to adjust to locational conditions at a Member State level.
• Flexibility markets do not require, at least at a first stage, to be integrated with all wholesale markets, but it is critical to ensure a proper coordination between DSO-TSO and avoid any mutual harmful interference when invoking balancing and/or congestion management actions on a system level. However, it would be beneficial to have a co-optimized congestion management, which would result in less costs for the system.
We consider that, at least in a first phase of development, these challenges might be addressed at national level but based on a persistent effort for harmonisation and standardisation across countries and System Operators. Local flexibility market rules should be as consistent as possible with existing market rules for ancillary services and congestion management at the TSO level. This should be taken into consideration in a NC for distributed flexibility resources, abiding by the applicable rules from the SO GL, CACM, EB GL and all applicable NCs, with the necessary adjustments.

54 Should EU legislation attempt to define some fundamental common principles (e.g. degree of integration with existing wholesale markets, products standardisation, etc.)?

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55 Do you agree that all three models described above (enhanced energy only markets, strategic reserves, capacity mechanisms) could be suitable for European countries in 2030

.. :

We prefer a well-functioning energy-only market with undistorted price signals as it works well as an economic dispatch model including congestion management. However, experience shows that the enhanced energy-only market model might not be suitable to provide sufficiently effective investment signals to ensure adequacy of the power system. Most EU countries have either already implemented a capacity mechanism - including strategic reserves- or are in process, with different characteristics to cope with the specific challenges of each market. Most markets that were energy-only have introduced some type of capacity markets or resource adequacy mechanism to ensure security of supply. Indeed, as the penetration of renewables increases, the spot price reduces and volatility in the market increases both leading to higher risk for investors. Therefore, we need to explore ways to complement the energy-only market model for fostering long term investments to fulfil decarbonisation targets and to ensure system resilience.
The improvements in energy-only markets suggested by ENTSO-E are important but might not be enough to ensure power reliability and the necessary investment to reach the decarbonization targets. Market changes aimed at providing “financial incentives” to limit intermittency (such as scarcity pricing, artificially raising the imbalance price) are not a good solution as they ignore the technical reality that variable sources cannot always react to a price signal due to absence of the resource. Even though such price incentives could indirectly incentivise investments in dispatchable sources (e.g., DSM, storage, etc.), they will not do so significantly nor sufficiently as investment decisions are not made on rare price-events.
We see both strategic reserves and capacity mechanisms as potentially useful solutions to ensure the stability and delivery of the future power system as part of a matrix combining the best of the models in tandem. However, both need further exploration and new design to reflect a fully renewable system and not just a slightly higher RES penetration than today. Unfortunately, capacity mechanisms are designed today as subsidies for fossil fuel-based systems and do not support in any way RES development and decarbonisation targets. Moreover, it remains to be clarified how the three models can inter-operate. The question of how capacity markets affect the energy-only market is comparable to the question of how support schemes for renewables affect the response to price signals in the energy-only market. There is a large potential for combined RES-storage assets to participate but only if the regulatory framework supports it. Any uncertainty about this will deter investments in reserve capacity.

56 Is there any additional market model which would be suitable for European countries in 2030 to ensure resource adequacy?

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57 Do you see capacity mechanisms with flexibility requirements as a promising option for further analysis?

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58 What are in your view the main potential advantages and drawbacks of capacity mechanisms with flexibility requirements?

.. :

59 Do you consider the capacity subscriptions model as a promising option for further analysis?

.. :

60 In your view, what are the main potential advantages and drawbacks of the capacity subscriptions model?

.. :

61 Which potential benefits or drawbacks do you foresee with the implementation of scarcity pricing in your market?

.. :

62 Do you have any specific suggestions on how scarcity pricing could be implemented?

.. :

63 What type of RES supports is more fit for purpose for the 2030 power system?

.. :

Delivering on EU decarbonisation targets requires a massive scale-up of renewable energy capacity. Energy-only markets work well for ensuring economic dispatch. However, these alone might not be able to incentivise a massive build-out of low-marginal cost renewables (see our reply to question 55).
Consequently, support systems that provide revenue predictability will be needed until a suitable market redesign has been found and implemented that allows to attract investments at scale. For wind generation both onshore and offshore the 2-sided Contract for Difference (CfD) awarded in technology-specific competitive auctions and based on payment per generated electricity is today the best mechanism in terms of revenue stability and societal cost (cheapest finance option).
As conventional power plants phase out, the role of wholesale markets should be on dispatching the most cost-effective plants and to liquidate the differences between real and contracted generation. In this context, most revenues of power plants should come from contracts, with a long-term price set by ex-ante competition. However, electricity prices are mostly set today in function of run marginal costs of conventional power plants. As the latter will be phasing out towards 2030 and beyond, it is unclear how the electricity prices will be set in their absence. We will need to explore ways to diversify potential revenue streams for RES, ensure market continuity for these, and foster investments in new assets and capabilities (see replies in questions about participation in balancing markets, strategic reserves and capacity mechanisms as well as frequency and non-frequency related ancillary services)

64 What other market design elements can facilitate investments in RES to achieve EU climate objectives?

.. :

Europe needs to move towards a fully decarbonised economy and must therefore answer the crucial question “which market design is required to manage a fully renewable system” rather than “how can we increase renewable penetration in our current market design”. In this context, no aspect of the current market design should be off-limits for discussion or treated as non-negotiable.
This change of mindset regarding underlying assumptions and approaches can have a far-reaching impact:
o The system should not aim to minimise variability at the asset level but rather take the variability as a given and deal with it from a system perspective.
o Adequacy should not be seen as something that can only be provided by non-variable sources.
o Market design and financial incentives should consider the new technical reality of assets that are not fully controllable.
As our economy accelerates towards net zero there will be new opportunities to pair sectors and technologies. These opportunities may help to expand the growth of low-carbon generation, but it will take time for technologies and business models to mature.
We do see opportunities arising from industrial decarbonisation, hydrogen or system and grid services. However, these revenue streams are currently too uncertain to drive Final Investment Decisions on a significant volume of large-scale low carbon developments and are generally taken forward on small scale projects or as innovation pathfinders.
We recommend that industry and government continue to explore these opportunities and promotes cross sectoral innovation, as new business models can help to abate hard to decarbonise sectors and help to accelerate low-carbon growth.
We believe that more focus is necessary on demand side electrification, flexibility, and electricity time of use. These elements at scale could help provide more confidence in the long-term wholesale electricity price.

65 What are the best practices for the design of RES tenders?

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Auctions shall be technology specific. Fully technology-neutral capacity tenders based on one single indicator (EUR/MWh) ignore correlation between assets at system level, and other technology-specific risks (e.g., even if offshore wind energy is cheaper than rooftop PV solar in a certain country, having a mix of both creates additional value for the system thus diversification that is not captured by single project developers and therefore not reflected in the EUR/MWh bid price).
For bid prices to be comparable, the risk profile and the injection profile should be similar. Making tenders technology-specific ensures this is the case; however, it might be a bit too restrictive when thinking about combined assets (e.g., offshore wind + H2; offshore wind + storage; etc.) so such setups should be further analysed.
Other issues related with technology-neutral capacity tenders in a capacity market structured as a supplement to the energy-only market are discussed in our reply to question 66.

To ease system integration, countries should improve resource assessments and make auction volumes reflect the resource complementarity of e.g., wind and solar. Auctions could consider some locational prioritization mechanism to better exploit the regional grid capabilities and, in last instance, decrease the connection time of new RES.
Impacts of auction design, bidding behaviour of legacy installations on negative power prices as well as on investment certainty need to be carefully balanced and auction designs need to be flexible enough to address national circumstances. Cross-country auctions will become increasingly important for offshore.
Member States should provide as part of their National Energy and Climate Plans a schedule of at least 5 years for revenue stabilisation mechanisms to renewable energy with well-defined in-advance dates and volumes to be tendered. Non-awarded volumes should be added to next auctions. Auction rounds should be frequent (instead of "stop-and-go" implementation) as this increases long-term planning certainty for market players.
The participation of wind farms operators in other markets, such as the balancing market, should be allowed without resulting in a loss of the financial support. RES generators should be able to combine revenue from corporate renewable PPAs with policy-drive revenue stabilisation mechanisms.

66 How should capacity mechanisms consider the participation of RES?

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The proposed capacity mechanism (CM) with ramping and peaking capacity requirements seems to address issues that are currently handled in a transparent and market-based manner though existing reserve markets. The interaction between a CM with flexibility requirements and these markets should be carefully assessed. The aim of the capacity market/strategic reserve, as established in the Clean Energy Package, is to ensure firmness and adequacy needs, and flexible capability needs must be addressed through ancillary services.
Overall capacity mechanisms, flexible or not, should not result in locking in carbon-intensive capacity or incentivize building new fossil fuel-based power plants. Instead, they could be redesigned to enable the participation of RES with a de-rating factor that reflects RES contribution to cover peak demand, with a secondary market closer to delivery time and considering how RES participation can be handled and co-exist in case of RES with support schemes. Overall, the design of such mechanisms should consider a fully renewable-based system rather than just a higher penetration of RES than today. With their current national scope CMs act as a subsidy for fossil fuel-based power plants. In terms of investment the resulting prices in some countries (for instance the UK) are not really a market signal to build new plants. CM auctions could for example incentivize the participation of existing RES – still under support scheme or not – integrated with storage or different additional renewable generation technology ("hybridisation").
The capacity subscription model instead will not be suitable for all Member States; it is based on short-term price signals and it might not provide sufficiently effective investment signals for new capacity. Such a model may be investigated in a very long-term horizon, well after 2030.

67 Do you see potential for the development of new frequency ancillary services?

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Grid operators should specify technical needs and technology providers will support addressing these needs. Certain frequency ancillary services are already implemented in some countries but not in others, e.g., Fast Frequency Reserve (FFR) already in place in the UK, Ireland, and Finland but not available in Portugal or Spain. Are these considered as "new" in the question? Ramping products is an option to mitigate some of the challenges caused by large shifts on the interconnectors or on the energy market in general.
It is essential that all dispatching services (both those already planned and those that will gradually emerge) are remunerated and procured in the market. Approaches based on mandatory supply (e.g., retrofit, etc.) that are not remunerated or with administered remuneration must be overcome and avoided. At the same time, the extension of the participation in the dispatching services market to all resources, including innovative ones, must be guaranteed, removing the current barriers.
In this regard, another important element that needs to be considered is the increasingly important role of the capabilities of combined renewables power plants (wind/PV/storage). Requirements for such assets should not be set separately for each of their different technologies but for the whole unit instead (which means that these assets should be established and defined in national legislation and requirements for their permitting and operation should be clarified).
Electrolysers have the potential to provide a wide variety of ancillary services but visibility into future demand for ancillary services is key because components to ensure that these services can be delivered from a technical perspective must be ordered in advance (in CAPEX phase).

68 Which non-frequency ancillary services are more suited for market-based procurement?

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All ancillary services need to be procured in a market-based and technology neutral way. Product resolution should follow resolution in the market, with short procurement period. Allowing for subsequent 'recharge' will give higher potential for wind energy to participate. Such services should also be enabled at DSO level – when possible – potentially with smaller bids.
For non-frequency ancillary services, the products and some respective examples are:
• Black start: the UK introduced in 2017 a framework for determining the allowed revenue derived from black start; in Ontario, IESO has certified 4 plants for black start (as of 2020), remunerated by monthly fixed payments; Belgium, Denmark, Netherlands, and Switzerland procure Black Start services through tenders; Austria, Finland, Germany, and Ireland procure through bilateral contracts.
• Voltage control:
o In Ontario, all market participating generators are eligible to contract with the IESO to receive payment for providing Reactive Support and Voltage Control service, with prices based on the cost of service;
o The Irish TSOs procure 3 products for voltage control: a Steady-State Reactive Power product, a Fast Post-Fault Active Power Recovery product (response within 0.25 sec of at least 90% of a Providing Unit's pre■Fault Disturbance MW Output), and a Dynamic Reactive Response product (supply of a reactive current with an activation time of 40 ms). All products are remunerated for availability.
o In UK alongside the Obligatory Reactive Power Service (ORPS) an Enhanced Reactive Power Service (ERPS) has been developed. ERPS are procured through tenders. Usually, the service must ensure a target MegaVar (MVAR) level within two minutes. These services are remunerated for availability and utilisation.
o Belgium and the Netherlands hold yearly tenders for voltage control services providers with the delivery period of 1 year of MVAR absorption/production. In Belgium, some units are obliged to participate in the service although the remuneration is still set through open public tenders.
- Inertia (addressed in next question)

69 Do you have suggestions on how to best ensure that market participants provide the necessary system inertia to the system?

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As previously commented, excessive mandatory grid connection requirements, with no remuneration in turn, will hamper the economic viability of assets and TSOs would end having risks to manage the power system. The visibility of revenues for ancillary services and capacity mechanisms will efficiently ensure that TSOs will have appropriate service providers to manage the power system. TSOs should conduct market-based procurement of all services necessary to operate the system, including inertia from rotating generators or synthetic inertia from other technologies.
Integrating grid-forming capabilities in wind turbines (to contribute to system inertia) entails high investment and development costs and impact on turbine and plant design and will only be needed at neuralgic points in the system. A tender might be the most appropriate model for procuring inertia services, as it promotes ex-ante competition and provides visibility of revenues in the medium/long term that can enable investments in such capabilities. In January 2020, the UK did a tender for inertia awarding 6-year contracts. In Ireland, there is also the “synchronized inertial response” product, which compensates synchronous generators based on the available stored kinetic energy to help manage system events within each half hour period.
Securing some RES capacity dedicated to inertia services could entail considerable cost savings in the balancing market and foster the decrease of greenhouse gas emissions by replacing the use of thermal generation for providing inertia services. Wind farms could indeed partly contribute to the provision of synthetic inertia with the integration or storage or through curtailment. However, the implications regarding societal cost and wasted renewable energy should be carefully assessed before the wide deployment of such capabilities in wind farms.

70 Would you recommend any other solution for ancillary services in 2030?

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71 Is there any other key market design area not addressed in this paper which deserves particular attention to enable the achievement of European energy and climate goals for 2030?

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