CONSULTATION RESPONSE

EFET
European Federation of Energy Traders

European Commission consultation on electricity market design reform

Brussels, 13 February 2023 – The European Federation of Energy Traders welcomes the opportunity to provide views on the options laid out by the European Commission to reform the design of the internal electricity market.

The energy system has been under stress since mid-2021, a situation exacerbated by the supply crisis following the invasion of Ukraine. At EFET, we believe that the pillars which have made that framework so effective – cost-efficiency, European integration, competition – should remain and be reinforced. The European Commission consultation on electricity market design gives us a good opportunity to reflect on the lessons of 20 years of European integration of energy markets and systems, and on our expectations for the future.

Key messages

1. **Cost-effectiveness to deliver decarbonised, secure energy** – Our main challenge over the decades to come is, and will remain, the fight against climate change. This necessitates a huge contribution of the electricity sector. Massive investments will be needed for the further uptake of renewables as well as the development of the flexible assets and services needed for the transition. Strong, efficient and transparent markets with longer maturities and empowered demand will help secure electricity supply at the lowest cost for consumers.
2. **Integration at European level** – European cooperation and integration of electricity markets has brought significant benefits over the past 20 years, including strong signals towards decarbonisation. Carefully designed, interconnected European markets optimise resources and demand at a greater scale, and they should be strengthened to do this even better. National interventions that often run counter to agreed European objectives, on the other hand, should be avoided.
3. **Coherence of market design** – The various options discussed in the consultation need to be looked at holistically. Commercial instruments like PPAs forward contracts on the one hand, and regulated mechanisms such as mandatory CfDs or revenue capping mechanisms on the other hand, have counteractive effects on each other. There will be only one electricity market design, so it is important to ensure coherence between the different policy instruments enacted as part of the reform. Lessons from the 2022 energy crisis should be learnt, so that we address questions – including that of tackling energy poverty – at the right level and with the right tools.

Detailed comments

A. Power purchase agreements (PPAs)

A1. Do you consider the use of PPAs as an efficient way to mitigate the impact of short-term markets on the price of electricity paid by the consumer, including industrial consumers?

Commercial PPAs are important market-based hedging instruments for electricity producers and consumers. They are **particularly useful in hedging risks related to price and volumes fluctuations on both sides, especially beyond the trading horizon of forward markets** (earlier than three years before delivery). PPAs also price in other risks (locational, balancing risks, etc.) which are taken on by market participants themselves.

Commercial PPAs help getting projects off the ground and hence contribute to security of supply. PPAs allow these projects – often RES-E installation – to be built in the most economically and environmentally efficient locations, taking into account production and demand. This in turns contributes to providing affordable and decarbonised supply of electricity to consumers.

Interest for commercial PPAs has increased in the last years. The contracted PPA capacity increases year on year. However, they remain a niche market with about 15 GW of production capacity contracted in 2022. As a matter of comparison, traditional forward markets represent above 400% of annual electricity consumption (2019 data). Hence, the contribution of PPAs to price and volume risk reduction should be assessed hand in hand with that of forward markets.

Commercial PPAs provide price stability for the buyer and the seller over extended periods of time, which helps reduce the impact of short-term market volatility for consumers, including industrial consumers. Acting as a long-term revenue stabilisation mechanism, they make it possible for developers – especially RES-E – to obtain financing for their projects from banks and investors, and help them reduce the cost of capital. PPAs can thus complement and reduce the need for public financial support for renewable energy or fill the gap where such support is being phased out.

In general, the questions related to commercial instruments like commercial PPAs and forward contracts on the one hand, and those related to regulated mechanisms such as mandatory CfDs and CRMs on the other hand, should be discussed in a holistic manner. Forward trading and PPAs are the key instruments allowing market participants to hedge risks in the market. Regulated mechanisms, such as mandatory CfDs, but also other support schemes, CRMs and market revenue caps, when imposed through regulatory measures, diminish the incentive to hedge through forward markets or PPAs for producers and/or suppliers/consumers. This, in turn, makes producers more dependent on public support. Hence the scope and specific design of regulatory interventions is a key element to consider when seeking to avoid counterproductive effects on commercial instruments such as PPAs.

A2. Please describe the barriers that currently prevent the conclusion of PPAs.

We welcomed the European Commission Recommendations to Members States on PPAs published in May 2022 and encourage Member States to implement them as a matter of priority. We list below the main hurdles we see for the conclusion of commercial PPAs:

- **For the conclusion of PPAs in general:**
    - ***Legal and regulatory uncertainty***: this is a major barrier. The inconsistent application of emergency interventions across EU Member States has undermined PPA market liquidity in some of the areas. Ongoing regulatory interventions, when considered necessary, need to be communicated as clearly as possible. Uncertainty around measures leads to uncertainty in PPA deal-making. It adds complexity to bids, transactions and valuation, which in turn leads to higher transaction costs and longer negotiation time.
    - ***Regulatory barriers***: in some cases, administrative and/or regulatory barriers prevent the conclusion of supply contracts with consumers (especially domestic consumers and SMEs) beyond one year (e.g. in Spain) or two years (e.g. Germany). This means suppliers have no rationale concluding PPAs to cover an exposure for these customers beyond this short time horizon. This effectively excludes a whole segment from the PPA market, and limits demand.
    - ***Profile risk management***: the price and volume risks resulting from the intermittency of renewables mean that renewable PPAs can only be entered into for a carefully profiled percentage of the production volume. Otherwise, generators risk not meeting the obligations, or consumers not receiving the amounts of electricity they expect. Depending on the type of PPA concluded ("pay as produced" or base load), the producer or the consumer can be exposed to having to match undelivered matching those "missing" volumes at high cost.
    - ***Treatment of financial PPAs under EMIR***: PPAs are products classified as OTC derivatives. This means that unless the buyer can justify that the PPA is a hedge for their own consumption, the transaction will count towards EMIR commodity clearing threshold. Breaching the clearing threshold involve significant obligations, including mandatory margining and operational requirements. There is a real risk that market participants will not provide this type of product to renewable producers, therefore shrinking the market of available hedging for renewable projects.
    - ***Credit risk profile***: Currently, most SMEs cannot access the PPA market as buyers due to stringent credit requirements (investment grade credit rating).

Offering a fixed-price PPA allows an asset owner to swap market risk with credit risk, hence prudent PPA sellers will only consider credit-worthy counterparties or a range of them.

- ***Treatment of guarantees of origin (GoOs)***: GoOs are an indispensable element of renewable PPAs, as they allow the buyer to claim the renewable attributes of the consumed electricity. Rules preventing their issuance to producers receiving public financial support obstruct the growth of PPAs. It also excludes the possibility for producers to find alternative routes of financing that could gradually diminish the need for and public expenditure linked to financial support schemes.
- ***Accounting standards***: In Europe, financial PPAs are, according to IFRS (international financial reporting standards), to be treated as financial instruments and lead to Profit and Loss and/or balance sheet fair value swings, which lead to more complexity accounting-wise.

- **For the conclusion of cross-border PPAs in particular:**
  - **Inconsistent national regulatory frameworks** hinder the conclusion of cross-border PPAs.
  - **Lack of long-term cross-border hedging instruments beyond the year ahead of delivery** (and limited cross-zonal capacity) also hampers the conclusion of cross-border PPAs

A3. Do you consider that the following measures would be effective in strengthening the roll-out of PPAs:

(a) pooling demand in order to give access to smaller final customers,
(b) providing insurance against risk(s) either market driven or through publicly supported guarantees schemes (please identify such risks),
(c) promoting State-supported schemes that can be combined with PPAs
(d) supporting the standardization of contracts,
(e) requiring suppliers to procure a predefined share of their consumers' energy through PPAs
(f) facilitating cross-border PPAs.

From the highest to lowest priority:

(d) supporting the standardization of contracts,

This is a very important area to reduce negotiation time and transaction costs, and facilitate the secondary markets in PPAs. Still, flexibility in standard contracts is needed for such long-duration agreements.

EFET, in cooperation with the RE-Source Platform, has developed a standard long-term renewable PPA agreement (freely available at https://efet.org/home/documents?id=26, in multiple languages). We are confidents it contributes to reducing costs and complexity, thereby facilitating the growth of PPAs and renewable energy. Any standardisation should remain voluntary and left to the market to define.

(c) promoting State-supported schemes that can be combined with PPAs

Existing public financial support schemes must be compatible with renewable PPAs to facilitate their uptake. Public financial support schemes should be designed in a way that leaves enough room and incentives for commercial PPAs to be concluded independently of them. Public financial support schemes can be designed in a way that would allow for such support to be combined with commercial PPAs. In this way, a project could partially be supported through public support schemes and partially through a commercial contract, thereby reducing the amount of public expenditures needed for renewables.

A particular point of attention is to ensure that public financial support still allows producers to claim GoOs even if projects are subsidised. Indeed, GoOs are essential attributes to prove and value the renewable character of the electricity generated. Jurisdictions that prevent this, such as France or Germany, have seen virtually no PPAs concluded locally.

(f) facilitating cross-border PPAs

The lack of long-term cross-border hedging instruments beyond the year ahead of delivery (and limited cross-zonal capacity) hampers cross-border PPAs. A PPA with a counterparty located in another market would facilitate the financing of projects across borders. It would ensure that projects get built and that the off-takers can reduce the cross-border transmission risk.

In the case of renewable PPAs, ensuring they can be concluded across borders would also contribute to ensuring renewable projects are built in the most suitable locations.

(b) providing insurance against risk(s) either market driven or through publicly supported guarantees schemes (please identify such risks)

Credit risk reduction instruments backed by public authorities could be helpful in mitigating counterparty risk. This should ideally be developed as EU-wide instruments to ensure a level-playing field across Member States with varying financial standing. This would particularly help small off-takers, which otherwise wouldn't have sufficient resources or credit rating.

A European institution (ECB, EBRD?) could provide credit guarantees for long-term markets in general (commercial PPAs and forward contracts). This could create a virtuous circle by which increasing the buyer pool in the PPA market could attract financial companies, insurances and other risk-takers who would offer standardized risk hedging or credit risk management products. This would open more options for asset owners to finance their projects.

Not identified as a priority:

(a) pooling demand in order to give access to smaller final customers,

Demand pooling for small consumers is currently being performed by suppliers or intermediaries, which can negotiate on par with producers.

Further, voluntary demand pooling seems difficult to imagine, especially if it concerns domestic and small commercial consumers, irrespective of their supplier. Instead, ensuring that demand aggregation services are available to consumers in all Member States is key. As a principle, demand pooling should be market-based rather than centralised/state-backed mechanisms which are likely to concentrate the risk to consumers.

(e) requiring suppliers to procure a predefined share of their consumers' energy through PPAs

Mentioning a specific instrument like PPAs as a mandatory tool for suppliers to procure electricity on behalf of consumers seems unreasonable. The long-term character of PPAs (up to 15 years) does not match the maturity of suppliers' customer base, especially in an environment with increasing supplier switching.

Although we oppose this idea, if an onus is placed on suppliers in terms on hedging risks on behalf of consumers, it should be coherent with consumer demand/the type of contracts they offer.

National approaches to such an obligation would also distort the level-playing field. Therefore, if the European legal framework is reformed to tackle this topic, we advise to be comprehensive and consistent on the terms and conditions mandating suppliers.

To ensure suppliers are hedged appropriately to meet their contractual commitments towards consumers, legislation could mandate suppliers to inform consumers more clearly about their degree of coverage. It should also consider that part of demand is willingly taking risk (not hedged) as this provides them opportunity in short-term markets such as hydrogen electrolysers, demand response, etc.

A4. In addition to the options proposed in question 3, do you see other ways in which the use of PPA for new private investments can be strengthened via a revision of the current electricity market framework? If yes, please explain which rules should be revised and the reasons.

Most important in the current market reform is to ensure consistency between the policy instruments, and avoid damaging the PPA market. Mandatory CfDs (in particular if the design is not carefully assessed) and/or the prolongation of emergency measures (inframarginal rent cap) could be detrimental to the growth of commercial PPAs.

Additional suggestions:

- ***Avoiding political intervention into the market and stop-and-go policies*** as this reduces confidence in the political and regulatory environment. This increases the risk premium and thus the cost of renewables for consumers.
- ***Ensuring that portfolios can be traded in the market*** through different market instruments, including commercial PPAs. This allows a better optimisation of production and demand from years ahead until moments before delivery.
- ***Creating the framework for credit guarantee issuance*** as foreseen in RED III, but for all technologies. Credit support schemes for smaller end-consumers would contribute to the greater uptake of PPAs.
- ***Improving the financial regulatory framework*** for PPAs in order to tailor it to the complexity and long maturity of these instruments.
- ***Abolishing physical trading limitations*** to allow free competition while negotiating PPAs with costumers with sites dispersed across Europe, as well as aggregation of multiple physical assets with multiple owners. E.g. in Spain physical route-to-market for non-controlled assets (<50% share) is not allowed for biggest companies (physical sleeving).
- ***Simplifying financial PPA accounting*** by recognising the link between virtual off-take of green power and the underlying power consumption of a corporate to simplify their financial statement and enable more SMEs to access PPAs.

A5. Do you see a possibility to provide stronger incentives to existing generators to enter into PPAs for a share of their capacity? If yes, under which conditions? What would be the benefits and challenges?

The electricity market long before delivery is traditionally a buyers' market, i.e. there is ample offer years before delivery, while demand concentrates one to three years before delivery. Incentives for producers to offer PPAs seem unnecessary, as they have a natural incentive to enter into PPAs or other long-term off-take agreements to hedge their long position as asset owners.

The growth of the PPA market shows that demand – especially from RES-E generation – is starting to develop for longer term horizons than one to three years. However, the offer often concentrates on electricity produced by new RES-E installations, due to the many limitations posed on existing assets, especially when supported by public support schemes. PPAs will become more attractive as public financial support ends, or diminishes and can be combined with commercial PPAs. Challenges would be linked to transitioning from existing arrangements (support schemes) to PPAs.

In addition, existing uncertainties regarding potential interventions hinder forward and PPA market liquidity and diminish incentives to hedge. This is particularly the case for the inframarginal rent caps adopted over the past year, and which should be phase out.

A6. Do you consider that stronger obligations on suppliers and/or large final customers, including the industrial ones, to hedge their portfolio using long term contracts can contribute to a better uptake of PPAs?

Mentioning a specific instrument like PPAs as a mandatory tool for suppliers to procure electricity on behalf of consumers seems unreasonable. The long-term character of PPAs (up to 15 years) does not match the maturity of suppliers' customer base, especially in an environment with increasing supplier switching.

Although we oppose this idea it, if an onus is placed on suppliers in terms on hedging risks on behalf of consumers, it should be coherent with consumer demand/the type of contracts they offer.

National approaches to such an obligation would also distort the level-playing field. Therefore, if the European legal framework is reformed to tackle this topic, we advise to be comprehensive and consistent on the terms and conditions mandating suppliers.

To ensure suppliers are hedged appropriately to meet their contractual commitments towards consumers, legislation could mandate suppliers to inform consumers more clearly about their degree of coverage. It should also consider that part of demand is willingly taking risk (not hedged) as this provides them opportunity in short-term markets such as hydrogen electrolysers, demand response, etc.

A7. Do you consider that increasing the uptake of PPAs would entail risks as regards:

- *(a) Liquidity in short-term markets;*
- *(b) Level playing field between undertakings of different sizes;*
- *(c) Level playing field between undertakings located in different Member States;*
- *(d) Increased electricity generation based on fossil fuels*
- *(e) Increased costs for consumers*

If yes, how can these risks be mitigated?

Moderate level of risk:

(b) Level playing field between undertakings of different sizes

As in all businesses, larger producers and suppliers/consumers will have economic advantages in negotiating better deals. Allowing aggregation of assets and/or clients is essential to ensure a level-playing field.

In general, PPAs are less transparent compared to a liquid and efficient forward market. Thus, more PPAs being concluded might result in more asymmetric information between large and small players. A way to mitigate this could be to facilitate access to credit-schemes for smaller market participants.

(a) Liquidity in short-term markets

We expect limited impact of the widespread use of PPAs on short-term markets, as the need for optimisation close to delivery will remain. We observe similar dynamics between forward markets and spot markets currently.
A small portion of volumes contracted under PPAs may however not be redirected towards forward or spot markets depending on market conditions.

(e) Increased costs for consumers

The main value added of PPAs is revenue stabilisation over long periods of time. The cost for consumers (up or down) will depend on the overall market conditions, but PPAs will ensure they that prices are buffered over time.

Low level of risk

(c) Level playing field between undertakings located in different Member States

If European legislation ensures that barriers to the conclusion of commercial PPAs are lifted in all Member States consistently, we do not expect an unlevel playing field, geographically speaking. However, if specific PPA-related obligations are placed on suppliers/consumers at national level, these will have a strong impact on the playing field.

It is important for the European Commission Recommendations outlined above to be applied consistently across the EU to ensure a level playing-field in terms of regulation.

Another threat to the playing field would be the introduction of mandatory, state-backed PPAs (either through a centralised entity, or through financial guarantees) with the condition that producers are required to sign PPAs with consumers in that specific country. This could create significant distortions between generators and/or consumers, depending on the Member State's financial capacity.

(d) Increased electricity generation based on fossil fuels

Commercial PPAs as such are agnostic to generation technology, hence they would not have an impact on the generation mix. However, recent data shows that commercial PPAs contracted by large consumers tend to specify RES-E as a mode of production, and hence promote the growth of RES-E.

B. Forward markets

B1. Do you consider forward hedging as an efficient way to mitigate exposure to short-term volatility for consumers and to support investment in new capacity?

Mitigating exposure to short-term volatility:

Forward trading is currently the main instrument for hedging risks – including short-term price volatility – in the electricity market.

However, in order for this to be efficient, liquidity is crucial. Liquidity beyond one year in forward markets is currently largely limited to the German bidding zones (up to about three years). As a result, most market participants in Europe perform proxy hedging on the German market, wherever their actual exposure lies. With numerous and sometimes poorly liquid bidding zones in Europe, the availability of cross-zonal capacity on a forward basis is key to decrease cross-border transmission risk and facilitate proxy hedging.

A big challenge for suppliers in terms of risk hedging on behalf of consumers is related to customer turnover, in particular for B2C customers. This adds volume risk to price risk.

We remind that the variation of customer consumption, modelled as "profiles" by suppliers, may only be hedged in short-term markets (forward markets allow to hedge baseload and, in some markets, peak load as well). Therefore, forward markets are an efficient tool to hedge price exposure well in advance, but the optimisation and the profiling risk (risk that consumers vary their consumption close to real time, for instance due to temperature sensitivity) is addressed through active participation in short-term markets. In this sense, short term markets are a platform to hedge profiling risk against imbalance exposure.

Supporting investment:

Market maturity is also important, especially to support investment. The limited maturity of forward electricity markets (about three years ahead of delivery in the most liquid hub) and cross-border hedging instruments (one year ahead of delivery) means that forward markets are not the only tool to support investments in new capacity over time spans of 10 to 40 years. However liquid forward markets can provide near-end predictability, while the far end comes with significant political and regulatory risk.

Commercial PPAs can complement forward markets as market instruments to support investment beyond the maturity of forward trading (see part A for more details).

B2. Do you consider that the liquidity in forward markets is currently sufficient to meet this objective?

Forward electricity market liquidity is limited: the most liquid hub for forward electricity trading (Germany) has churn rate of about 8, while all other European bidding zones present a churn rate of 2 or less.

The current circumstances of prolonged high prices have a severe impact on collateral requirements for market participants. The guarantees or cash needed to secure contracts over long periods have become far more important. This has reduced the capacity or appetite for forward trading, hence the liquidity on forward markets.

The inconsistent national implementation of the inframarginal rent cap has also reduced appetite for forward hedging. Indeed, the different inframarginal rent caps put in place according to the loose legislative framework of Regulation 2022/1854 either do not take gains/losses from forward transactions into account or, where they do, impose significant reporting requirements on generators that disincentivise forward trading. The Romanian case is a good example of this: most liquidity disappeared from the Romanian forward market only a few days after the entry into force of the measures imposed by the Government. The harsh consequence is that the Romanian market does not provide signal of potential scarcity or surplus in the forward timeframe anymore, leaving producers and consumers much more exposed to short-term signals.

B3. In your view, what prevents participants from entering into forward contracts?

Traditional market fundamentals:

As mentioned in relation to PPAs, long-term markets are primarily a buyers' market. Electricity producers, in particular, have a natural incentive to enter into forward contracts or other long-term off-take agreements to hedge their long position as asset owners.

In comparison, demand for forward contracts from consumers – directly or through suppliers – was so far limited due to stable and relatively low prices. Demand was also limited to one to three years ahead of delivery, given the limited willingness of consumers to enter into commitments with suppliers for a longer period than that (especially for fixed-tariff contracts).

Like for cross-border PPAs, the lack of long-term cross-border hedging instruments beyond the year ahead of delivery (and limited cross-zonal capacity) hampers cross-border and proxy hedging.

Finally, public financial support schemes for certain kinds of technologies – especially RES-E – reduce the incentive for some generators to participate in the forward market.

Current market fundamentals:

The current circumstances of prolonged high prices may create consumer demand for longer contracts, and hence boost forward liquidity.

However, the current circumstances also have a severe impact on collateral requirements for market participants. The guarantees or cash needed to secure contracts over long periods have become far more important. This has reduced the capacity or appetite for forward trading, hence the liquidity on forward markets.

Unpredictable political, legal and regulatory measures, such as inframarginal rent caps, pose certain risks for liquidity to develop on forward market. The wave of uncoordinated and unexpected measures adopted in many Member States over the past year and a half has had an unprecedented chilling effect on forward markets, both on the supply and demand sides (cf. Romanian example, mentioned in our response to Q2).

B4. In your view, would requiring electricity suppliers to hedge for a share of their supply be beneficial for consumers and for retail competition?

In principle we are against solutions where market participants are forced to enter into specific contracts, as this should be subject to commercial strategy and decision.

In current times, and if price signals are not muffled by further regulatory interventions, consumers may themselves create demand for longer contracts. In turn, suppliers will necessarily have to hedge contracts they enter into with their customers in order to limit their exposure.

Although we oppose the idea of mandating the conclusion of forward contracts, if an onus is placed on suppliers in terms on hedging risks on behalf of consumers, it should be coherent with consumer demand/the type of contracts they offer. This balance would be particularly difficult to achieve. If miscalculated, it would expose suppliers to significant volume and price risk without the certainty of having customers to supply.

National approaches to such an obligation would also distort the playing field. Therefore, if the European legal framework is reformed to tackle this topic, we advise to be comprehensive and consistent on the terms and conditions mandating suppliers.

The impact of such an obligation on the collateral requirements borne by suppliers should not be underestimated either. Should such an obligation be pushed forward, credit risk reduction instruments back by public authorities would be necessary to mitigate counterparty risk. This should ideally be developed as EU-wide instruments (by the ECB, EBRD?) to ensure a level playing-field across Member States with varying financial standing.

To ensure suppliers are hedged appropriately to meet their contractual commitments towards consumers, legislation could instead mandate suppliers to inform consumers more clearly about their degree of coverage. It should also consider that part of demand is willingly taking risk (not hedged) as this provides opportunity in short-term markets such as, hydrogen electrolysers, demand response, etc.

B5. Do you consider that the creation of virtual hubs for forward contracts complemented with liquid transmission rights would improve liquidity in forward markets? If yes, do you consider that such virtual hub(s) should be developed at national, regional or EU level?

From a general perspective, liquidity of forward markets in Europe will improve if the primary fundamentals of demand and supply change. Trying to move liquidity from existing bidding zones (especially the liquid German forward market) to virtual hubs can only affect the liquidity of forward markets at the margin – positively just as well as negatively.

Virtual hubs are presented as a solution to reduce cross-border transmission risk in cross-border and proxy hedging. However, without significantly higher volumes of cross-border risk hedging instruments made available by TSOs (and earlier than Y-1), this design is highly unlikely to boost forward liquidity. Providing more long-term cross-border capacity does not seem to be the direction of travel of TSOs (see recent ENTSO-E report at https://www.entsoe.eu/news/2022/12/23/eu-s-electricity-forward-markets-policy-paper/).

Virtual hubs have no fundamentals of supply and demand of their own, hence their need to build on the liquidity of physical bidding zones. Without very significant volumes of cross-border risk hedging instruments linking the virtual hubs to the bidding zones, the level of residual risk would be too important for market participants. This will not make the hubs attractive, which would be essential to create a virtuous circle for the take-up of liquidity.

Virtual hubs also bear a risk of isolating certain regions if the legislator or regulators predefine these hubs on a regional basis, and if the volume of hub-to-hub cross-border risk hedging instruments made available by TSOs is not significant.

Instead of virtual hubs, cross-border and proxy hedging can be improved thanks to 3 levers:

- ***TSOs increase the volume of cross-zonal capacity offered to the market in competitive auctions of long-term transmission rights*** (LTTRs). With greater volumes of offered capacity, the frequency of the auctions could also be increased.
- ***TSOs offer LTTRs with longer maturity*** (three to five years ahead)
- ***TSOs ensure that optional products are offered***: should there be a willingness to offer FTR obligations in addition to FTR options, then TSOs should allocate both obligation and option products to maximize allocation surplus.

Should the virtual hub design be pursued, we advise policy makers and regulators against predefining such hubs. As for all other forward/derivative markets, economic actors should decide which reference hubs are the most useful to them, via a trade-off between the usefulness that the hubs can provide for hedging (i.e. how much risk can be hedged and what is the level of the residual risk) and the liquidity that they will attract (i.e. how many economic actors see interest to trade at the hub).

B6. In case you have experience with the existing virtual hubs in the Nordic countries, how do you rate this experience?

The experience of the virtual Nordic hub is not positive as far as its forward market is concerned.

Liquidity in the Nordic forward energy market has severely degraded from 2009 to 2019, in absolute terms (from about 2.5 TWh to 1 TWh) and churn rate of (from 4 to 2). Historically, the introduction of the system price in the Nordics seemed a reasonable tool to counterbalance the high number of small bidding zones and the limited liquidity within them.

However, with grid constraints increasing, the model rapidly collapsed and did not offer a good hedge for market participants anymore.

Cross-border risk hedging instruments traded in the Nordic area – Electricity Price Area Differentials (EPADs) – are proposed by market participants themselves, not the TSOs. From the early until the mid 2010s, when data on actual traded volumes of EPADs was still publicly available, a constant decline was observable. In the meantime, the metric developed by Nordic regulators (so-called “open interest in EPADs”) rather shows a stable level in the EPADs market. However, a number of market participants, including large market makers, have ceased proposing EPADs to the market, citing liquidity and volatility issues. The main organised trading venue for EPADs, Nasdaq, has also announced only a few weeks ago a reduction of the number of available EPAD products.

The low liquidity in both forward energy and risk hedging products has resulted in forward market liquidity migrating from the Nordic area to central Europe by way of proxy hedging.

The Nordic example cannot serve as a positive example of virtual hub for the forward market. Alongside many reasons, its lack of success can be attributable to the absence of significant volumes of cross-border risk hedging instruments made available to the market by the TSOs.

B7. In your view, what would be the possible ways of supporting the development of forward markets that could be implemented through changes of the electricity market framework?

What to do:

- ***Developing incentives for voluntary market making*** on forward market (in particular for yearly contracts traded on Y-3 and onwards) are an interesting instrument to attract liquidity.
- ***Mandating TSOs to issue transmission rights earlier than the year ahead of delivery*** (up to Y-5, Y-10), and to develop a continuous secondary market for transmission rights.
- ***Preserving the full financial firmness of transmission rights by TSOs***, against some of the recent suggestions made many European TSOs.
- ***Reforming collateral/margining requirements*** to reduce the cost of trading forward and counterparty risk, e.g. through a joint guarantee facility for forward products.
- ***Gradually phasing out public financial support schemes*** – especially for RES-E – that do not expose electricity volumes to the market.
- ***Restoring credibility in regulatory stability*** to ensure confidence that entering into a long-term contract to address risks makes sense.
- ***Reducing barriers to entry for non-asset owners and financial institutions*** (licencing, heavy bureaucratic requirements) so that energy markets can attract new participants that can offer a variety of hedging services.

- ***Tailoring electricity market supervision to the electricity industry*** to avoid complexities created with generic obligations developed for financial institutions (EMIR, MIFiD).

What to avoid:

- **Losing market participants' trust in the legislative and regulatory environment needs to be restored**. The market reform and instruments promoted by the reform should not negatively impact forward market liquidity. For instance, the notion of mandatory hedging requirements (either for forward contracts or PPAs) risks obstructing the natural balance between sellers and buyers. Equally, mandatory CfD schemes for all new investments would drain the forward market. It is important to ensure coherence between the different policy instruments enacted as part of the electricity market design reform.
- ***Conducting bidding zone reviews with neglect for the impact of zonal re-delineations on forward market liquidity***: the bidding zone review methodology should be reformed with a view to ensure that merging bidding zones is analysed just as well as splitting bidding zones. Bidding zones with a larger number of market participants would improve liquidity and hence incentivise forward trading.

C. Contracts for differences (CfDs)

C1. Do you consider the use of two-way contracts for difference or similar arrangements as an efficient way to mitigate the impact of short-term markets on the price of electricity and to support investments in new capacity (where investments are not forthcoming on a market basis)?

In general, the questions related to commercial instruments like commercial PPAs and forward contracts on the one hand, and those related to regulated mechanisms such as mandatory CfDs and CRMs on the other hand, should be discussed in a holistic manner. It is important to ensure coherence between the different policy instruments enacted as part of the electricity market design reform.

The primary tools to mitigate the impact of short-term volatility should remain hedging in the market, via forward trading and commercial PPAs. Regulated mechanisms, such as mandatory CfDs, but also other support schemes, CRMs and market revenue caps, when imposed through regulatory measures, diminish the incentive to hedge through forward markets or PPAs for producers and/or suppliers/consumers. This, in turn, makes producers more dependent on public support. Hence, the scope and specific design of regulatory interventions is a key element to consider when seeking to avoid counterproductive effects on market-based instruments such as forward contracts.

Where no public support is involved, CfDs should remain a voluntary risk mitigating instrument in the market. It should be up to market participants involved to design their characteristics.

Especially if two-way CfDs are made mandatory, here are important elements to consider:

- ***The tenor of CfDs***: Circumstances in the market will change. Therefore, it is important that the CfDs term is set between properly balancing the desire for visibility (on producers and consumers sides) vs. the negative effects of CfDs on the forward and PPAs markets. The longer the tenor the more distorted the short-term and long-term market prices, making electricity supply less efficient.
- ***The counterparty to CfDs***: Mandatory two-way CfDs will mean that public authorities will need to commit resources and collateral to secure the contracts, and therefore assume the associated market risks.
- ***The level of the cap and floor price (collar or strike price)***: uncoordinated levels of the cap and floor prices of the CfDs between Member States would lead to distorting investment signals (unlevel playing field) and impacting short-term dispatch. An EU framework would be needed to avoid inconsistencies and inefficiencies that undermine cross-border trade.
- ***The scope of CfDs (new or existing capacity, RES-E only or beyond)***: a scheme designed only for new renewable capacity (and innovative technologies) could be beneficial as a support scheme, while a scheme targeting a wider range of existing inframarginal generation capacities would significantly undermine the appetite of consumers and producers to hedge risks via forward contracts and PPAs.
- ***The nature of CfDs***: purely financial CfDs would be less likely to affect electricity markets – be it commercial PPAs, forward or spot markets – as market participants would be incentivised to still use markets to hedge volume risks.
- ***The allocation of CfDs***: mandatory two-way CfDs should be awarded via competitive tenders, and include a phase-out mechanism.

C2. Should new publicly financed investments in inframarginal electricity generation be supported by way of two-way contracts for differences or similar arrangements, as a means to mitigate electricity price spikes of consumers while ensuring a minimum revenue?

Mandatory CfDs cannot be seen as a substitute to a well-functioning market delivering real value to consumers through autonomous decisions, innovation, etc.

Public support should follow State Aid rules, focus only on technologies that are not competitive enough. The existing legal framework foresees how public support may be awarded when an adequacy assessment shows potential security of supply shortfalls. Under such conditions, CfDs (like other forms of subsidies, including CRMs) may be considered. In this case, other investment support instruments – including those with fewer or no effect on electricity markets – should also be considered alongside of CfD.

Especially if investment is under public support, here are important elements to consider with regards to mandatory two-way CfDs:

- ***The tenor of CfDs***: Circumstances in the market will change. Therefore, it is important that the CfDs term is set between properly balancing the desire for visibility (on producers and consumers sides) vs. the negative effects of CfDs on the forward and PPAs markets. The longer the tenor the more distorted the short-term and long-term market prices, making electricity supply less efficient.
- ***The counterparty to CfDs***: Mandatory two-way CfDs will mean that public authorities will need to commit resources and collateral to secure the contracts, and therefore assume the associated market risks.
- ***The level of the cap and floor price (collar or strike price)***: uncoordinated levels of the cap and floor prices of the CfDs between Member States would lead to distorting investment signals (unlevel playing field) and impacting short-term dispatch. An EU framework would be needed to avoid inconsistencies and inefficiencies that undermine cross-border trade.
- ***The scope of CfDs (new or existing capacity, RES-E only or beyond)***: a scheme designed only for new renewable capacity (and innovative technologies) could be a beneficial as a support scheme, while a scheme targeting a wider range of existing inframarginal generation capacities would significantly undermine the appetite of consumers and producers to hedge risks via forward contracts and PPAs.
- ***The nature of CfDs***: purely financial CfDs would be less likely to affect electricity markets – be it commercial PPAs, forward or spot markets – as market participants would be incentivised to still use markets to hedge volume risks.
- ***The tendering of CfDs***: mandatory two-way CfDs should be awarded via competitive tenders, and include a phase-out mechanism.

C3. What technologies should be subject to two-way contracts for differences or similar arrangements and why?

New capacity that is considered important to ensure security of supply and meet climate goals while not competitive enough for the market to deliver could be supported by way of voluntary CfDs. This should be regulated based on an appropriate capacity adequacy assessment, and according to the State Aid Guidelines.

Offering the conclusion of CfDs can only work for new technologies which the market cannot deliver. This could be in the form of a support scheme for renewables and innovative technologies.

C4. What technologies should be excluded and why?

All producers, whichever generation technology they use, have an interest to hedge on a forward basis through available market instruments (forward contracts and commercial PPAs). Promoting liquidity in these markets should be the priority of policy makers.

As a result, would government-backed two-way CfD be made mandatory, such schemes should exclude existing capacity. The more capacity is subjected to a mandatory CfD scheme, the more forward liquidity will suffer and short-term dispatch be de-optimised. Inefficient optimisation would overrun the potential benefits for end-consumers.

C5. What are the main risks of requiring new publicly supported inframarginal capacity to be procured on the basis of two-way contracts for difference or similar arrangements, for example as regards of the impact in the short-term markets, competition between different technologies, or the development of market based PPAs?

The risks related to mandatory two-way CfDs largely depends on their design. In any case, they would entail a material change in existing market mechanisms and will significantly distort all market segments, from the forward market all the way to balancing mechanisms. This would impact the capacity of producers and consumers to appropriately price in risks in the market – and hedge these risks on their own – as well as de-optimise short-term dispatch.

Main risks on the "subsidy" side of mandatory two-way CfDs:

- Disincentives to hedging in forward markets and through commercial PPAs, as price and volume risk is reduced
- Public financial support could distort competition between different technologies, depending on the level of the price floor
- Unlevel playing field between Member States if price floors are decided at national level and are not coordinated

Main risks on the "revenue cap" side of mandatory two-way CfDs:

- Renewable investments would be displaced in more lucrative markets outside of Europe (as we already see today with inframarginal rent caps, see https://windeurope.org/newsroom/press-releases/investments-in-wind-energy-are-down-europe-must-get-market-design-and-green-industrial-policy-right/), putting at risk the necessary massive investments to achieve the decarbonisation targets and long-term affordability of energy in Europe.
- The revenue cap could distort competition between different technologies, depending on the level of the price cap
- Unlevel playing field between Member States if price caps are decided at national level and are not coordinated

The impact on spot markets is likely to be more limited, as the volumes contracted under such contracts will be marketed in the spot market. However, the hedge applied through the price corridor (or the applied strike price) of the two-way CfDs risks being mirrored in spot markets through orders that do not efficiently reflect scarcity and/or surplus signals, especially if the CfDs include physical delivery. This would be dangerous for system security and adequacy. In this respect even the most sophisticated two-way CfDs will have an impact on the price formation in the spot market.

Distortions to spot markets would include:

- continued production when the price is already zero or negative
- limited incentives to trade in different market segments (day-ahead, intraday, balancing).

C6. What design principles could help mitigate the risks identified in question 4, in particular, in terms of procurement principles and pay out design? Should these principles depend on the technology procured?

Main design elements to keep in mind to reduce risks:

- ***Stable regulatory and legal framework***: as for any policy decision of this magnitude, a stable framework is essential. This also entails ensuring that legislation does not result in a piecemeal application of the framework or creates national dents in the internal energy market, two things that can already be observed following the approval of Regulation 2022/1854.
- ***Transparent and competitive procurement***: if CfDs are intended to mitigate the impact of short-term power price fluctuations, technology-neutral levels for cap and floor prices should be set. Market-based mechanisms should be set-up to discover the price level. Procurement design and payout should provide as great an exposure to the market as possible, e.g. by allowing bids for only partial capacity, payouts not for the full market price, contracts to be financial rather than physical.
- ***Room for the market***: should it be implemented, mandatory two-way CfD schemes should establish EU-wide levels for cap and floor prices to avoid an unlevel playing field. These should be defined wide enough to avoid locking in certain level of capacity at excessively high or low prices, which would be inefficiently dispatched in future. The appetite for private future investments in technologies that will drive decarbonisation should be preserved.
- ***Financial product***: ensuring that mandatory two-way CfDs are designed as purely financial instruments would limit negative effects on spot markets by avoiding that electricity volumes be withdrawn from day-ahead and intraday.
- ***Mitigation of effects on dispatch***: Incentives to deliver electricity when it is needed, not when it is available, need to remain. For this reason, we need to ensure that the market provides time-shift products that allow to consume RES electricity when it is

needed, by way of an exposure to short-term market signals. Payouts to generators under the CfDs should be suspended during periods of negative day-ahead prices to cease generation when it is not required and ensure more efficient dispatch.

C7. How can it be ensured that any costs or pay-out generated by two-way CfDs in high-price periods are channelled back to electricity consumers? Should a default approach apply, for example, should these revenues or costs be allocated to consumers proportionally to their electricity consumption?

As a general rule, revenues from mandatory two-way CfDs should remain in the power system and should be used where they are needed, e.g. for grid development, energy efficiency, decarbonisation or flexibility measures, and compensation of vulnerable customers.

If intended to link back, entirely or partially, to consumers who choose to limit their exposure to the market, costs or pay-outs generated by mandatory two-way CfDs should effectively come from/go back to consumers.

The question of which consumers would benefit from mandatory two-way CfDs is particularly complex:

- A lesson from the current crisis is that benefits should go to vulnerable consumers in priority (equity principle).
- Pay-outs to consumers should not deter responsiveness to price signals, e.g. shifting or reducing demand. This is less likely to be the case with vulnerable consumers, who have limited leeway in their consumption already
- However, a first hurdle is that we still miss a common definition of vulnerable consumers at EU level.
- But the main hurdle is the question of what happens when consumers do not get benefits (high prices in the market) but have to compensate generators (low prices in the market). Can we realistically expect vulnerable consumers to be the ones compensating generators in priority?

This example show that the question of the political acceptance of two-way CfDs should be carefully considered before legislating, especially if they are made mandatory. And that social policy instruments (social benefits, tax breaks, etc.) would be better suited to tackle affordability problems for certain parts of the population than seeking to amend the electricity market design.

Whichever the chosen approach, effective reporting by the public counterparty to the CfDs and the NRAs would be needed to ensure transparency, as well as public reporting to ACER/EC.

If not implemented on voluntary basis, a consistent European legal framework must adequately regulate the following:

- A methodology for setting the cap/floor prices, including a reserve price, should be harmonised at EU level and supervised by ACER.
- The holder of the energy (i.e. the public counterparty to the CfD) shall be obliged to sell the energy on the same market segment as the index used for the CfD. Supply to vulnerable consumers can be directly fulfilled by this long position, as an exception of the general tendering process.
- Avoid gaming in retailing activity when market prices are lower than CfDs sold at secondary auctions.

C8. What should be the duration of a two-way CfD for new generation and why? Should this differ depending on the technology type?

The tenor of mandatory two-way CfDs should properly balance the desire for visibility (on producers and consumers sides) vs. the negative effects of CfDs on the forward and PPAs markets. The longer the tenor, the more likely the impact on forward and PPA markets, as well as on short term dispatch.

C9. Should generation be free to earn full market revenues after the CfD expires, or should new generation be subject to a lifetime pay-out obligation?

There should be no lifetime regulated or mandatory CfDs.

As a general principle, we are not in favour of limiting the amount an operator can earn from the asset as it disincentivises innovations (e.g. extending asset operating lifetimes). Besides, at bidding and investment decision stage, the level of the CfD price corridor or strike price already incorporates the expected back-end market revenues. Consequently, if such market revenues are capped, the level of the CfD would probably be higher, resulting in the same cost for society overall.

Market revenues, including from forward markets and PPAs, after the CfD term are an important incentive for the investors. Ensuring that assets are exposed to market signals after the expiration of a mandatory CfD is crucial for liquidity in the forward and PPA markets.

C10. Without prejudice to Article 6 of Directive (EU)2018/20016, should it be possible for Member States to impose two-way CfDs by regulatory means on existing generation capacity? If such possible use of regulated CfDs for existing generation is deemed appropriate, should the obligation apply to all types of existing inframarginal generation or be limited to certain types of generation (and if so, which types)?

Existing capacity should not be subject to mandatory CfD, here is why:

- Imposing regulated two-way CfDs to existing capacity is a significant change to existing market mechanisms in the EU, which would also raise compliance concerns with existing contracts.
- Existing assets have been built and operate under certain contractual and regulatory frameworks which shall be improved to attract liquidity and hedging. The more capacity is subjected to a mandatory CfD scheme, the more forward liquidity will suffer – and short-term dispatch be de-optimised. Inefficient optimisation would overrun the potential benefits for end-consumers.
- Some inframarginal capacity is fully commercial and switching them under a regulated CfD scheme would mean subsidising them when there was no need to do so.
- By allowing Member States to apply such measures unilaterally, we undermine the capacity of the integrated EU market to provide competitive solutions in matching supply and demand. While only national consumers might access potentially cheap energy in the short term, the retail market and its credibility is hindered. On the "revenue cap" side, emergency measures currently in place have a similar objective, however these are measures to address an emergency in the market and as such should be phased out.
- The subsequent change in investment conditions for existing generation plants will cause lasting damage to investor confidence. In such a case, it will put the attainment of the 'Fit for 55' targets at risk.

C11. Under what terms and conditions could regulated two-way CfDs on existing generation capacity be imposed?

See the answer above. If mandatory two-way CfDs are made mandatory, they should not be imposed on existing assets. Existing assets should only have the option to conclude such agreements.

C12. How would you rate and address the following potential risks as regards the imposition of regulated CfDs on existing generation capacity?
- *(a) legitimate expectations/legal risks;*
- *(b) ability of national regulators/governments to accurately define the level of the price levels envisaged in these contracts;*
- *(c) locking in existing capacity at excessively high price levels determined by the current crisis situation;*
- *(d) impact on the efficient short-term dispatch.*

Very high risk level with mandatory two-way CfDs for new capacity:

(a) legitimate expectations/legal risks

High legal and regulatory risk exist in relation to the switch from existing commercial contracts, support schemes and/or CRMs. Litigation cannot be excluded.

(b) ability of national regulators/governments to accurately define the level of the price levels envisaged in these contracts

Competitive tendering could help define the right levels, but it will be difficult to assess bids when bidding concerns both a cap and a floor price.

National approaches to setting these prices would lead to an unlevel playing field between Member States, undermining the integrated EU market and the optimisation of production and consumption at a pan-European level.

High risk level with mandatory CfDs for new capacity:

(c) locking in existing capacity at excessively high price levels determined by the current crisis situation

A reasonable tenor would limit lock-in effects. It is important that the CfDs term is set between properly balancing the desire for visibility (on producers and consumers sides) vs. the negative effects of CfDs on the forward and PPAs markets.

(d) impact on the efficient short-term dispatch

The impact on spot markets is likely to be more limited, as the volumes contracted under such contracts will be marketed in the spot market. However, the price corridor of the CfDs risks being mirrored in spot markets, and would silence scarcity and/or surplus signals – dangerous for system security and adequacy. In this respect even the most sophisticated CfD will have an impact on the price formation on the spot market.

Additional risks not identified in the question:

- Illiquid and obsolete forward/PPAs market due to lower incentive to hedge on forward basis, which would be a massive step back for the internal electricity market
- Lack of market-based investments in technologies targeted by the regulated CfD scheme (especially RES-E), displacement of investments outside the EU leading to slower progress on decarbonisation (see red flag raised by WindEurope already following market interventions in 2022: https://windeurope.org/newsroom/press-releases/investments-in-wind-energy-are-down-europe-must-get-market-design-and-green-industrial-policy-right/).
- Lack of signals for active participation of consumers in the market and exposure to the non-competitive wholesale price.

C13. Would it be enough for existing generation to be subject only to a simple revenue ceiling instead of a revenue guarantee?

Revenue caps (like inframarginal rent cap) are an emergency tool, meant to be phased out.

A revenue ceiling for existing capacity would create massive distortions, disincentive producers and consumers to hedge themselves on the forward market and de-optimise short-term dispatch.

C14. What are the relative merits of PPAs, CfDs and forward hedging to mitigate exposure to short-term volatility for consumers, to support investment in new capacity and to allow customers to access electricity from renewable energy at a price reflecting long run cost?

The primary tool to mitigate the impact of short-term volatility should remain hedging, through more liquid forward markets and commercial PPAs.

Each tool is designed to address a specific need. Electricity market design reform should aim at eliminating all barriers to effective market participation and foster/promote all tools for market participant to support an affordable, decarbonised and secure supply of electricity.

Rightly designed, voluntary instruments can deliver reduction of consumer exposure to short-term market volatility and effective investment signals, while still leaving incentives to respond to price signals e.g. by shifting or reducing demand.

All three instrument should be available to market participants in the future and the choice for one or the other should remain with the market participants. Likewise, governments should remain free to decide if they want to provide public support measures in line with their needs and in compliance with the EU competition rules.

Interactions between the market mechanism and interventions should be assessed with due care.

D. Accelerating the deployment of renewables

D1. Do you consider that a transmission access guarantee could be appropriate to support offshore renewables? Please explain and outline possible alternatives.

We appreciate the reasons behind the discussion on the possibility or not to grant a dispatch guarantee for offshore renewables connected to cross-border interconnectors. Solving this question will be key to facilitate the growth of offshore hybrid projects, which will be important to help reaching Europe's net zero target.

However, granting a dispatch guarantee already assumes that offshore renewable assets connected to a cross-border interconnector would be attached to stand-alone offshore bidding zones (OBZs). We do not think that the OBZ model should necessarily be implemented as a general rule for all offshore renewable assets connected to cross-border interconnectors. The need to establish an OBZ should be assessed on a case-by-case basis by the concerned jurisdictions. For each offshore project and each interconnector, this decision should be taken in full transparency and considering the network specificities in order to guarantee efficient price signals and coherent outcomes.

In cases where the OBZ model is assessed to be the more efficient design, introducing a dispatch guarantee could mitigate the specific volume risk faced by asset owners directly connected to a cross-border interconnector. However, dispatch guarantees constitute a specific network privilege, the legality of which should be assessed against article 12 of Regulation 2019/943.

D2. Do you see any other short-term measures to accelerate the deployment of renewables? If yes, please specify.
(a) at national regulatory or administrative level,
(b) in the implementation of the current EU legislation, including by developing network codes and guidelines,
(c) via changes to the current electricity market design?

(a) at national regulatory or administrative level

- ***Transparent and efficient permitting and grid connection procedures***: currently permitting procedures can last between three and seven years for wind, and one to two years for solar; connection processes can last even longer.
- ***Coherent grid development***: ramping up procedures for permitting new capacity must be accompanied by a coordination of grid development and consumption scenarios.

(b) in the implementation of the current EU legislation, including by developing network codes and guidelines

- ***Electricity market integration***: integrating RES-E generation and consumption across the Union is key to reach our decarbonisation targets. In this sense, ensuring that a maximum amount of cross-border interconnection capacity is made available to the market will ensure better integration (minimum 70% requirement and 20% minimum RAM in day-ahead flow-based). Well integrated markets would facilitate the growth of renewables, as they would reduce the need for RES curtailment.
- ***Long-term hedging (forward and commercial PPAs)***: liquid forward markets and forward transmission rights available in greater volumes and longer-term horizons to enable cross-border PPAs is also essential to allow private investors to hedge risks directly in the market. This reduces the need for public financing.
- ***Trading close to delivery***: liquid continuous intraday markets are also essential, as they allow for optimisation of portfolio close to delivery. As the share of intermittent renewable generation will grow, intraday markets will become crucial to ensure system security and reduce balancing costs for society.
- ***Flexibility in the market***: facilitating the growth of demand response and flexible assets and services will ensure a smooth integration of RES-E in the system. This entails ensuring they have non-discriminatory access to wholesale energy markets as well as balancing and ancillary services.
- ***No need for new network codes***: we do not see a need for the development of new network codes and guidelines specifically for renewable electricity. Instead, existing legislation and network codes/guidelines must be implemented properly.

(c) via changes to the current electricity market design

- ***Reducing regulatory uncertainty stemming from national interventions***: There is a risk that measures adopted or contemplated in the context of the current crisis – such as inframarginal revenue caps and price control mechanisms – have a lasting negative impact on RES investment. This may lead to RES investment shifting to other jurisdictions, which puts at risk the necessary massive investments to achieve the decarbonisation targets and long-term affordability of energy in Europe (see: https://windeurope.org/newsroom/press-releases/investments-in-wind-energy-are-down-europe-must-get-market-design-and-green-industrial-policy-right/).

D3: How should the necessary investments in network infrastructure be ensured? Are changes to the current network tariffs or other regulatory instruments necessary to further ensure that the grid expansion required will take place?

Network tariffs should evolve to better reflect the costs induced by different infrastructure and therefore enable better assessment. Current network remuneration models are mostly based on historical costs and should be updated to reflect the increasing cost of grid expansion and thus support efficient investments by system operators.

At cross-border level, it is crucial to ensure that the existing capacity is efficiently utilised. There are two aspects here:

- the minimum 70% requirement on all CNECs everywhere and the 20% minimum RAM in flow-based regions
- the use of congestion revenues collected by the TSOs to ensure firmness and improve the grid infrastructure

Speeding up permitting process for both RES and needed grid connection/reinforcement is also important, with a specific attention to coherence between the two.

Full transparency from TSOs and DSOs on bottlenecks is needed to ensure that market participants can use the network as efficiently as possible.

E. Limiting revenues of inframarginal generators

E1. Do you consider that some form of revenue limitation of inframarginal generators should be maintained?

We do not support revenue limitation of inframarginal generators as a main rule.

The emergency measures approved over the past year and a half must phase out, as planned by Regulation 2022/1854. This is essential to allow private investment and forward hedging.

Regulation 2022/1854 created a patchwork of national interventions particularly detrimental to the internal energy market. In particular, inframarginal rent caps limiting virtually all revenues above costs, such as the one introduced in Romania, should be reformed immediately.

As emergency measures they should not be a structural component of the market. Phasing out such measures would guarantee that incentives for energy saving and energy efficiency are restored and preserved on the consumers' side.

E2. How do you rate a possible prolongation of the inframarginal revenue cap according to the following criteria:

- *(a) the effectiveness of the measure in terms of mitigating electricity price impacts for consumers,*
- *(b) its impact on decarbonisation,*
- *(c) security of supply,*
- *(d) investment signals,*
- *(e) legitimate expectations/legal risks*
- *(f) fossil fuel consumption,*
- *(g) cross border trade intra and extra EU,*
- *(h) distortion of competition in the markets,*
- *(i) implementation challenges.*

Strong negative effect:

(a) effectiveness of the measure in terms of mitigating electricity price impacts for consumers

- Inframarginal rent caps may have had a temporary relieving but limited effect on consumer prices, though it is difficult to tell at the moment, and extremely hard to attribute it to these specific measures. We see it unlikely they could have a strong effect in the long term.
- In the case of Spanish and Italian examples, far less revenues have been collected from the inframarginal rent cap than expected.
- In the Romanian case, the inframarginal rent cap had extremely negative effects on the liquidity of the forward market. As a consequence, market participants have not only downsized activity, they have also withdrawn from the Romanian market altogether, in large numbers.
- No assessment so far was provided by Member States, even where inframarginal rent caps had been in place before the entry into force of Regulation 2022/1854.

(h) distortion of competition in the markets

- Inconsistent application across MS has created gaps between some of the markets and it had direct impact on liquidity.
- In the Romanian case, the inframarginal rent cap had extremely negative effects on the liquidity of the forward market. As a consequence, market participants have not only downsized activity, they have also withdrawn from the Romanian market altogether, in large numbers.
- No assessment so far from Member States.

(d) impact on investment signals
- Negative impact on investment in RES and associated PPAs already noticeable (see: https://windeurope.org/newsroom/press-releases/investments-in-wind-energy-are-down-europe-must-get-market-design-and-green-industrial-policy-right/)
- No assessment so far from Member States

(i) implementation challenges
- The implementation of Regulation 2022/1854 has effectively resulted in more than 24 different inframarginal rent caps (three Member State decided not to apply the Regulation). Some are still adopting primary legislation two months after the official entry into force.
- Each Member State opted for a different design, with different caps, technologies included, reporting responsibilities and timelines. In most Member States, the practical details are still to be developed in secondary legislation or by regulators.
- Many Member States are already in breach of the Regulation, with timelines for application that overstep the initial 7 months foreseen in the Regulation. European authorities do not seem to have issued reminders towards Member States that the application of inframarginal revenue caps after 30 June 2023 is not automatic. National legislation or regulation foreseeing the application of inframarginal revenue caps until the end of 2023 (or beyond in some cases) are not in line with one of the few firm elements of Regulation 2022/1854.
- Implementation, especially for market participants active in multiple Member States, promises to be an ordeal. It is also a serious dent in the integrity of the internal energy market.

(e) legitimate expectations/legal risks
- Potential contractual and development projects put on hold due to high uncertainty around legal and regulatory risks.
- Litigation risk from private investors.

Limited effect (either positive or negative):

(g) impact on cross border trade intra and extra EU
- Impact on cross-border trade is less important than in the case of price control measures (cf. Iberia) but still possible, especially when uncoordinated caps.
- No assessment so far from Member States

(b) impact on decarbonisation
- Limited displacing of consumption towards marginal technologies (gas, coal), but less noticeable than in the case of the Iberian price control measure, for instance

- Negative impact on investment in RES already noticeable (see: https://windeurope.org/newsroom/press-releases/investments-in-wind-energy-are-down-europe-must-get-market-design-and-green-industrial-policy-right/)
- No assessment so far from Member States

(f) fossil fuel consumption,
- Limited displacing of consumption towards marginal technologies (gas, coal), but less noticeable than in the case of the Iberian price control measure, for instance
- No assessment so far from Member States.

(c) impact on security of supply,
- Negative impact on RES investments, but also investments in technologies that provide flexibility.
- Probably only noticeable in the medium term.
- No assessment so far from Member States.

E3. In case you consider maintaining such a revenue limitation warranted, in what situations should it apply? How should the level of the cap be defined?

We do not consider that inframarginal revenue caps should be maintained after the expiration of Regulation 2022/1854.

We note that many Member States are already in breach of the Regulation, with timelines for application that overstep the initial 7 months foreseen in the Regulation. European authorities do not seem to have issued reminders towards Member States that the application of inframarginal revenue caps after 30 June 2023 is not automatic. National legislation or regulation foreseeing the application of inframarginal revenue caps until the end of 2023 (or beyond in some cases) are not in line with one of the few firm elements of Regulation 2022/1854.

E4. Should the modalities of such revenue limitation be open to Member States or be introduced in a uniform manner across the EU?

Consistency in principle is important, though in this specific case the revenue limitation should be treated as a bespoke emergency measure and not a structured component of the market design.

The measure has significant drawbacks, including the inconsistent application across Member States. Hence, if prolonged, it will further distort the playing field between market participants located in different Member States.

E5. How can it be ensured that any revenues from such limitations on inframarginal revenues are channelled back to electricity consumers? Should a default approach apply, for example, should these revenues be allocated to consumers proportionally to their electricity consumption?

Revenues from any revenue cap, if pursued, should remain in the power system and should be used where they are needed, e.g. for grid development, energy efficiency or flexibility measures, and compensation of vulnerable customers.

A lesson from the current crisis is that benefits should go to vulnerable consumers in priority (equity principle).
Pay-outs to consumers should not deter responsiveness to price signals, e.g. shifting or reducing demand. This is less likely to be the case with vulnerable consumers, who have limited leeway in their consumption already. However, a first hurdle is that we still miss a common definition of vulnerable consumers at EU level.

Whichever the chosen approach, effective reporting by the public counterparty to the NRAs would be needed to ensure transparency, as well as public reporting to ACER/EC.

We remain convinced that social policy instruments (social benefits, tax breaks, etc.) would be better suited to tackle affordability problems for certain parts of the population than seeking to amend the electricity market design.

Inframarginal rent caps limiting virtually all revenues above costs, such as the one introduced in Romania, should be reformed immediately. Their sole effect so far has been to destroy market activity, with negative impacts on the short and long run for consumers.

F. Spot markets and flexibility

F1. Do you consider the short-term markets are functioning well in terms of:

(a) accurately reflecting underlying supply/demand fundamentals,
(b) encompassing sufficiently liquidity,
(c) ensuring a level playing field,
(d) efficient dispatch of generation assets,
(e) minimising costs for consumers,
(f) efficiently allocating electricity cross-border?

(a) accurately reflecting underlying supply/demand fundamentals

- Absolutely. The level of sophistication and accuracy of spot markets is really high.

- The day-ahead market would benefit from better transparency in data publication from TSOs, especially when applying flow-based capacity calculation and market coupling
- The continuous intraday market can continue to improve, notably with recalculation of cross-border capacity at market opening, cross-border trading closer to real time and shared order books until local market gate closure.
- The current REMIT framework helps to preserve the integrity and the correct price formation (see section H).

(b) encompassing sufficiently liquidity

- Most volumes already go through spot markets, as market participants have a natural incentive to trade in day-ahead and re-optimise portfolios in intraday until close to delivery.
- As a general principle, liquidity in spot improves with clear and simple common rules to trade all across Europe. Specific national/regional features are now a major factor that limits spot trading (e.g. specific local products).

(c) ensuring a level playing field

- Market coupling in day-ahead and intraday ensures European optimisation of spot markets. The playing field can be further improved by ensuring that the maximum available cross-border capacity is made available to the market (minimum 70% requirement; minimum 20% RAM in flow-based day-ahead coupling).
- Electricity market reform as currently consulted should ensure that the playing field is kept level and avoid dents in the European integration of markets (cf. Regulation 2022/1854).

(d) efficient dispatch of generation assets

- The more liquid a market is, the more efficient dispatch of production and demand will be. Spot markets serve the efficient dispatch of physical assets depending on their variable costs and the natural need for adjustments after forward markets.
- For a variety of market participants (generators, storage, both implicit and explicit demand response via suppliers/aggregators/direct participation), the day-ahead market is the first opportunity to disclose flexibility in terms of supply/demand fundamentals. The continuous intraday market serves to refine this until close to delivery, as fundamentals continue to move.

(e) minimising costs for consumers

- Spot markets optimise costs for consumers to the maximum (meaning they won't necessary be low, but the lowest they can be according to market fundamentals).
- The market has not only provided efficient pricing for consumers in the last two decades, it has done so in a fundamentally changing business and regulatory environment driven by the fight against climate change.

(f) efficiently allocating electricity cross-border

- Market coupling in day-ahead and intraday ensures European optimisation of spot prices.
- Cross-border trading can be further improved by ensuring that the maximum available cross-border capacity is made available to the market (minimum 70% requirement; minimum 20% RAM in flow-based day-ahead coupling).
- Transparency from TSOs in cross-border capacity calculation and allocation is key to ensure that it is efficiently used by market participants. This is particularly true when flow-based methodologies are applied.
- In a wider context, current unbundling rules and the clear separation of roles in the system (market participants, TSOs, DSOs, market operators) must be preserved to avoid potential conflicts of interests, especially in the case of system operators. This guarantees that price signals across Europe are not affected by vested interests.

F2. Do you see alternatives to marginal pricing as regards the functioning of short-term markets in terms of ensuring efficient dispatch and as regards the determination of cross border flows?

We see no alternative to marginal pricing in the day-ahead auction:

- Marginal pricing in the day-ahead auctions is crucial to ensure efficient dispatch, including across borders.
- Marginal pricing optimises cross-border transmission infrastructure use. It provides important price signals to ensure economically efficient and secure supply of electricity across borders.
- Marginal pricing is also key to incentivise demand response, which is crucial to achieve demand reduction and optimisation objectives and support the decarbonisation of the economy. This was also proven in the last 18 months.
- Marginal pricing is also important to optimise the use of balancing resources and associated incentives.
- Regulatory or technical measures distorting marginal pricing (e.g. Iberian price control mechanism) hinder this essential feature of the EU internal electricity market and create distortions which will need to be fixed with more regulatory interventions.

F3. How can the EU emission trading system and carbon pricing incentivize the development of low carbon flexibility and storage?

Carbon pricing via the EU ETS is and must remain the corner stone of EU decarbonisation.

It already strongly incentivises the deployment of low carbon flexibility and storage as the carbon price signal pushes producers emitting carbon emissions to seek and switch to low-carbon and carbon free alternatives.

The carbon price helps maintaining the cost of fossil fuel generation at levels that make low carbon flexibility and storage more competitive. Eventually, with technology development, falling technology costs and economies of scale, the carbon price will help push fossil fuel generation out of the merit order and displace it entirely by low carbon flexibility and storage.

As ESMA concludes in their report on the EU carbon market, the carbon market functions well, and we trust that it can deliver the right signals for a switch to low carbon and carbon free technologies.

F4. Do you consider that the cross-border intraday gate closure time should be moved closer to real time (e.g. 15 minutes before real time)?

Yes, it is an important feature. It will however require all Member States to reduce their imbalance settlement periods and intraday market time unit to 15 minutes. This collective move to shorter ISP and intraday MTU was delayed by a number of Member States until 2025.

In any case, European rules on ISP and intraday MTU must be compulsorily and homogeneously applied across Europe.

A number of measures to improve intraday markets can be implemented rapidly in the meantime. These include:

- recalculation of cross-border capacity at intraday market opening
- cross-border trading closer to real time
- shared order books until local market gate closure

F5. Do you consider that market operators should share their liquidity also for local markets that close after the cross-border intraday market? What would be the advantages and drawbacks?

Yes, order books should be shared until local intraday GCT. Liquidity sharing will ensure efficiency, transparency and integrity of the continuous intraday market.

Sharing order books until local intraday GCT would allow pooling liquidity from different NEMOs within single bidding zones, even if cross-border capacity is not usable anymore.

This would be beneficial for the overall welfare and it must prevail over the commercial interest of individual NEMOs.

We consider that NEMO competition should not lead to liquidity fragmentation. The processes and tools already exist to allow such pooling: the continuous intraday trading platform (XBID) can accommodate such pooling of liquidity in local markets. It does not necessitate new processes and tools and is hence a low hanging fruit to improve the efficiency of intraday markets.

F6. Would a mandatory participation in the day-ahead market (notably for generation under CfDs and/or PPA's) be an improvement compared to the current situation? What would be the advantages and drawbacks of such approach?

We do not see any added value in compulsory trading for non-regulated physical assets. Mandatory trading imposes an unnecessary burden on market participants, which increases the cost of trading (and of the electricity delivered to consumers down the line).

There is a natural incentive to efficiently trade in day-ahead for non-regulated physical assets. This is also true when PPAs, bilateral or multilateral forward contracts have been concluded beforehand for the production of these assets: parties to such contracts effectively use spot markets to honour commitments of physical delivery in the most efficient way while guaranteeing that the variable costs of physical assets are recovered. Furthermore, this behaviour allows flexibility disclosure of all kinds of assets.

Mandatory trading requirements, where they exist, have not proved to make these markets attractive – no development of forward liquidity as a consequence, no effect on prices, no effect on competition.

Regulatory oversight of capacity withholding practices is performed efficiently by national regulators in countries without mandatory participation rules.

F7. What would be the advantages and drawbacks of having further locational and technology-based information in the bidding in the market (for example through information on the composition of portfolio, technology-portfolio bidding or unit-based bidding)?

Regarding unit bidding:

- The electricity price should remain the driver of short-term dispatch. It is formed based on the bids placed by production and demand. Market participants should be free to structure their bids in the way that makes most sense to reach on overall economic optimum.

- In general, portfolios are composed and are hedged as such through the market. Market participants can and should solely submit in their bids the information that is necessary for market clearing and price formation. This does not include information on the composition of portfolios that would justify mandatory unit-by-unit bidding.
- We strongly oppose measures mandating unit bidding, as it prevents market participants to optimise their production across technologies. This creates misaligned incentives and distorts market prices.
- From a purely operational perspective, mandatory unit bidding also results in a more costly and inefficient bidding process for market participants, without significant added value in terms of monitoring by the NRAs. All these inefficiencies have a cost, which is ultimately borne by consumers.
- As an example, in Spain, self-dispatch in spot markets (day-ahead, intraday) is in practice significantly hindered because of unit bidding. This translates into serious hurdles for optimal dispatch and affects physical forward contracts (e.g. physical optimisation of a fleet of CCGT). This creates welfare losses for both generators and consumers.
- Given the key role that long-term contracts should play in the new market design, inefficiencies created by unit bidding should be removed in all self-dispatch systems across the EU, by way of an explicit legal provision at the EU level.

Regarding locational and technology specifications:

- Today, we can reflect technological constraints in block orders, exclusive groups and linked block orders. Those products are essential in our bidding strategy for pump-storage hydro, battery, thermal generators, etc. While we currently do not feel restricted by the NEMOs' product offering, we anticipate that the availability of those products (i.e. smart and linked products) should further increase to reflect the flexibility required by renewables integration or to sustain finer time granularity (such as the 15-minute MTU in day-ahead and intraday).
- To further detail technologies and flexibility, it could be timely to promote more specialised products, in order to allow flexible assets to value their flexibility in the short-term market. We trust that NEMOs will develop these products as demand for them grows. In this context, European legislation and regulation should only ensure that innovation is not hampered.
- Instead of regulating the locational or technology "granularity" of products, we support a reform of detailed physical nomination rules of schedules by the TSOs. This is important in particular for within-zone operation of TSOs, where the locational information is vital to the TSOs for system operation, i.e. balancing and redispatching.

F8. What further aspects of the market design could enhance the development of flexibility assets such as demand response and energy storage?

Marginal pricing remains essential to provide incentives on hourly volatility and spreads, as well as in the balancing timeframe. It is also important that all market participants, including consumers, have some exposure to hourly prices.

There is no need for a technology-specific “market for flexible assets” besides the electricity market. However, there is a need to promote the market-based use of flexible assets and services by system operators for purposes of congestion management, redispatch and more broadly system operations, in line with the Electricity Directive and Regulation.

In practice, system operators should provide more visibility (transparency) on their current and future needs so that market players could invest, offer (and monetize) products based on their capabilities (and those of their clients).

The Electricity Directive and Regulation were set out to address barriers to the non-discriminatory participation of flexible assets and services in wholesale markets, as well as balancing and capacity mechanisms. As of today, many Member States haven't fully implemented relevant provisions regarding balancing reserves, market-based procurement of flexibility, aggregation and storage. These include:

- Adopting harmonised & efficient requirements with regards to eligibility, pre-qualification, backup, procurement, baselining, monitoring, settlement and penalty rules.
- Reducing the minimum bid size to 500kW, as is already the case in Italy and France
- Removing supplier consent i.e., the possibility for suppliers to discriminate against consumers under contract with an aggregator. This has recently been addressed in France, Belgium, Italy, etc. Rules should be enacted to ensure that suppliers are not unduly exposed to risk they cannot control as a result of their customers contracting with an aggregator.
- Enabling submetering and review relevant metering standards.

Aggregated participation of explicit DSR is already being developed following the European framework. More oversight could be needed from the EC and ACER to guarantee full and consistent/coherent implementations at national level.

Making the maximum cross-border capacity available to the market is also key. This can be further improved by ensuring that the minimum 70% requirement and minimum 20% RAM in flow-based day-ahead coupling are effectively applied. Transparency from TSOs in cross-border capacity calculation and allocation is also key to ensure that capacity is efficiently used by market participants. This is particularly true when flow-based methodologies are applied.

In the future, we expect participants in the forward market to develop new products that are more adapted to power mixes with a high share of intermittent renewable generation and flexibility technology.

F9. In particular, do you think that a stronger role of OPEX in the system operator's remuneration will incentivize the use of demand response, energy storage and other flexibility assets?

First and foremost, TSOs/DSOs must focus on providing more transparency on their current and future needs so that market participants can invest, offer and monetise products based on their capabilities.

A stronger role of OPEX in the SOs' remuneration would be welcome to incentivise the use of all kinds of flexible assets and services, be it demand or supply response, energy storage or others, instead of the usual CAPEX-related SO investment in lines/cables or flexibility network devices.

In any case, conflicts of interests on the SOs' should be avoided to preserve the integrity of markets, the European target model and trust in price signals. For this, unbundling principles must be respected in all regulatory aspects:

- At the level of investment, the separation between network and non-network assets should always be the rule. Flexibility must be primarily provided by competitively owned and operated generation, demand and storage, and all of them should compete on a level playing-field.
- At the level of operations, OPEX is also important to incentivise flexibility responses from system operators instead of pure operational network responses.

F10. Do you consider that enabling the use of sub-meter data, including private sub-meter data, for settlement/billing and observability of demand response and energy storage can support the development of demand response and energy storage?

Smart metering in general, including in relation to sub-metering data, provides infrastructure for more efficient demand response and energy response. In addition, it will also facilitate the role of the aggregators. We recommend reinforcing a mandatory roll-out of smart meters by DSOs in European Regulation.

We do not consider sub-metering a solution to replace smart meters. They are different. Sub-meters can be used to monitor and operate demand response and energy storage, and to provide access to dynamic data. The settlement must be checked by a proper meter to avoid fraud and achieve a level playing-field.

Balanced observability requirements at EU and national levels must be guaranteed to avoid unjustified burden for all flexible assets and services in the market.

F11. Do you consider appropriate to enable a product to foster demand reduction and shift energy at peak times as an ancillary service, aiming at lowering fuel consumption and reducing the prices?

The primary revenue stream for demand response comes from the electricity market. Wholesale electricity prices should be the basis to trigger demand reduction and shift energy consumption, provided that consumers are exposed – directly or indirectly via their retail contracts – to these prices. The focus of policy makers should not only be on ancillary services.

As far as balancing mechanisms and ancillary services are concerned, our preference goes for products that are accessible to all assets and services. This means that SOs need to check that all balancing and ancillary services products are open to effective demand participation (and other providers of flexibility). SO products should stem from a need, rather than from a specific type of asset or service that can deliver.

F12. Do you consider that some form of demand response requirements that would apply in periods of crisis should be introduced into the Electricity Regulation?

We need a plan to adjust demand in case of supply shocks. To create a safeguard, the demand reduction measures from the emergency regulation could be put into EU legislation and accompanied with a trigger level for when to activate them. The need for such safeguard could decrease with increasing consumer responsiveness to prices.

Other than this, the focus should be on making sure that Member states properly implement Directive 2019/943, rather than setting new rules. Priority should be given to market-based demand reduction and optimisation. This provides a real signal also for investment in flexible assets and services.

F13. Do you see any further measure that could be implemented in the shorter term to incentivize the use of demand response, energy storage and other flexibility assets? If so, what would that be?

The incentivisation of demand response needs to be carefully assessed against what consumers actually want (maybe some prefer long-term fixed contracts) and what consumers can actually do (smart meters and appliances are necessary).

Active participation of consumers would help bringing more flexibility to the demand curve. Possible avenues for that include new tariffs structures, smart/interval meters, and smart appliances. These elements are key to propose varying tariffs depending on capacity availability.

F14: Do you consider the current setup for capacity mechanisms adequate to respond to the investment needs as regards firm capacity, in particular to better support the uptake of storage and demand side response? If not, what changes would you consider necessary in the market design to ensure the necessary investments to complement rising shares of renewables and to better align with the decarbonisation targets?

In general, we believe that the Clean Energy package and the State Aid rules provide a comprehensive framework at EU level. Implementation of this framework at national level, however, is not always in line with the EU rules.

Demand response and storage should have equal access to CRMs, alongside generation. This also includes cross-border participation in CRMs.

Derating factors of flexible assets and services, including intermittent renewables, should be properly designed to adequately reflect their contribution to security of supply.

F15: Do you see a benefit in a long-term shift of the European electricity market to more granular locational pricing?

The internal electricity market is designed as a zonal market and there is a detailed framework on how zones are delineated and reviewed. The existing framework foresees an assessment of zonal design efficiency based on technical (network) and economic efficiency (market) elements.

We support any measure aiming at increasing the efficiency and the transparency around congestion management. As stated in question 9, the target should be to aim at the most cost-effective solution between grid investment, zonal re-delineation and procuring services from the market.

With regard to locational price signals, if further developed, maintaining the link to the zonal price will be essential as BRPs are settled against the zonal imbalance price.
We view nodal pricing/more locational pricing as leading to significant risk increases for investors. Indeed, clients/off-takers are typically not situated where generating assets are located, and geographical price spread will need to be managed. Increases in this basis risk could seriously jeopardise investments in RES development in Europe.

A move to more granular pricing would also pose challenges to existing contractual arrangements (e.g. commercial PPAs, industrial contracts, etc.) or to the value of existing assets and contracts for a number of market participants.

More granular locational pricing may allow to manage more efficiently grid congestions that are currently resolved by TSOs redispatch systems. However only a (pan-European) market-based approach would lead to efficiency gains, notably as it will be open to all technologies and will facilitate demand response participation. This should notably foster battery developments by allowing them to properly integrate congestion management in their value proposition.

G. Better consumer empowerment and protection

G1. Would you support a provision giving customers the right to deduct offsite generation from their metered consumption?

A deduction of offsite generation from metered consumption would mean that the concerned consumers not only save on the price of electricity, but also on network fees, including corresponding taxes. The concerned consumers would however continue to make use of the network as before. This would distort the playing field in the energy market, providing an unfair advantage to these consumers. This could lead to a less efficient use of the system as behind-the-meter solutions would be prioritised to the detriment of more efficient solutions that are metered.

Grid costs should be borne proportionally to the use of the grid, which consumers with offsite (or onsite) generation continue to use, whether or not their installations are producing electricity.

Additionally, it can be questioned whether the actual value of the electricity produced is equal to the one deducted from the meter. Such a deduction would force suppliers to socialise the costs linked to the deduction of offsite production from a set of individual customers onto their entire portfolio (i.e. all their customers). This means that those without access to offsite (or onsite) production would contribute to subsidising those who do have access.

Net metering schemes, where they have been adopted, have proved inefficient and difficult to manage. Offsite generation could instead be promoted through virtual schemes, such as the one introduced in Italy, with an ex-post remuneration through a financial agreement. They are easy to implement and do not impact retail operations. Such schemes should have locational criteria to limit the distance between generation plant and consumption point, to minimise the impact on the grid.

G2. If such a right were introduced:

(a) Would it affect the location of new renewable generation facilities?
(b) Should it be restricted to local areas – why?
(c) Should it apply across the Member State/control/zone – why and what should
(d) happen if bidding zones are changed?

Applying such measure across bidding zones would have an influence on capacity made available to the market and potentially discriminate between market participants.
The deduction mechanism would distort the locational element in the price, because no grid tariffs have to be paid. Thus, there is no incentive to build in the most suitable location.

G3. Would you support establishing a right for customers to a second meter/sub-meter on their premises to distinguish the electricity consumed or produced by different devices? If yes, what particular issues should be taken into account?

This is an option, though we rather support network tariffs being reviewed to avoid discrimination and cross-subsidisation between consumers.

G4. Would you support provisions requiring suppliers to offer fixed price fixed term contracts (ie. Which they cannot amend) for households?

Yes, this is an option. However, the mandate to offer fixed-price contracts should be guided by consumer demand. Figuring out whether the demand for such contracts is there could be carried out via a mandatory survey of clients, overseen by regulators, highlighting the benefits and drawbacks (incl. costs) of providing fixed-term contracts.

G5. If such an obligation were implemented what should the minimum fixed term be?

(e) less than one year,
(f) one year,
(g) longer than one year
(h) Other

Consumers should be offered a right to choose the term of their contracts. The commercial incentive to do longer-term deals should be the guiding instrument for consumers to choose contract duration. Clients should be properly informed of the benefits and drawbacks of both flexible and fixed-term contracts – and the conditions attached to their length.

G6. Cost reflective early termination fees are currently allowed for fixed price, fixed term contracts. Should these provisions be clarified? If these provisions are clarified, should national regulatory authorities establish ex ante approved termination fees?

Cost-reflective early termination fees are essential to ensure some minimum financial coverage for retail suppliers who have already hedged their portfolio on behalf of consumers, on the basis of the contracts they have signed. Thus, it avoids that suppliers are penalised for hedging appropriately.

A balanced risk distribution shall be sought so that not all the risk is transferred to the consumer either. The objective should be to ensure predictability on the termination period and on the level of the termination fee that will apply to consumer.

Regulatory oversight is always welcome to ensure transparency and avoid any abuse (but also unwarranted blame).

Alternatives to termination fees also exist and could be further explored: in Sweden, a market-to-market compensation exists instead of a termination fee; in the Netherland a standard contribution is paid by consumers ex-ante. Whichever the mechanism, the termination coverage for suppliers should refer to the wholesale electricity market price (at which they procure the electricity for consumers).

G7. Do you see scope for a clarification and possible stronger enforcement of consumer rights in relation to electricity?

Full consumer consent to the contractual terms they agree to is essential. Hence, information about the benefits and drawbacks of various contract types could be improved; possible extra conditions could be introduced to further protect consumers (e.g. flagging risks of dynamic contracts in the absence of smart meters, smart appliances, electric heating or cooling…).

Consumer empowerment would mean that they are offered infrastructure that enables their participation in the market - smart metering rollout should be prioritised, the importance of smart appliances should be highlighted.

Consumers protection through clear energy poverty criteria for support is also needed to square the circle and ensure equity. A clear EU definition of vulnerable consumers is still missing.

G8. Would you support the establishment of prudential obligations on suppliers to ensure they are adequately hedged?

Although we oppose the idea, if an onus is placed on suppliers in terms on hedging on behalf of consumers, it should be coherent with consumer demand/the type of contracts they offer. This balance would be particularly difficult to achieve. If miscalculated, it would expose suppliers to significant volume and price risk without the certainty of having customers to supply.

Such obligation might have to be linked with retail contracts with consumers, with associated costs for switching (see question 6).

G9. Would such supplier obligations need to be differentiated for small suppliers and energy communities. If Yes/No, why (not)?

We do not support such an obligation. Should it however be implemented, we do not see the rationale for a difference of treatment for small suppliers and energy communities.

G10. Should the responsibilities of a supplier of last resort be specified at EU level including to ensure that there are clear rules for consumers returning back to the market?

There should be consistent application of the Supplier of Last Resort obligation across the EU.

G11. Would you support including an emergency framework for below cost regulated prices along the lines of the Council Regulation (EU) 2022/1854 on an emergency intervention to address high energy prices, i.e. for households and SMEs:

(a) If such a provision were established, price regulation should be limited in time and to essential energy needs only?
(b) Would such provisions substitute on long term basis for direct access to renewable energy or for energy efficiency? Can this be mitigated?
(c) Would such contracts reduce incentives to reduce consumption at peak times, can this be mitigated?

Regulated prices (below or above costs) should be limited to vulnerable consumers – as per the exemption provided in Directive 2019/944. A structured energy poverty standard should be established together with the measures on how such consumers will be protected.

Regulated prices (especially below costs) disincentivise consumption reduction and optimisation (demand response). Such measure would also not be consistent with other measures discussed in this consultation, especially with regard to the promotion of forward markets and commercial PPAs.

H. Transparency and REMIT

H1. What improvements into the REMIT framework do you consider as most important to be addressed immediately?

The REMIT framework has contributed towards an improvement in the integrity and transparency of wholesale energy markets. To support this function, EFET proposes to simplify the rules to make REMIT more efficient, and to develop the REMIT framework to strengthen it. It is important that REMIT implements a tailor-made approach to give due consideration to the specifics of energy markets and their participants, incl. in relation to renewable energy and new flexible services.

We propose numerous changes to the REMIT framework in Q2 and Q3 which are all equally important. We would like to highlight the following:

- **ACER and the European Commission to define binding technical implementation and updates:**
    - ACER together with the EU Commission should create a harmonized and binding REMIT implementation across the EU. In addition, ACER and the European Commission should be able to regularly update REMIT rules to react on market developments. This would help create legal clarity and security, to establish a level playing field and an effective REMIT regime across the EU.
    - This could take the form of a mandate for ACER to propose binding regulatory implementation measures on technical matters, for review and adoption by the European Commission. Areas for such measures could be reporting and transparency requirements but also the market abuse provisions under the REMIT/REMIT Implementing Regulation. This would be a chance to consolidate the existing ACER documents (FAQ, TRUM, REMIT Guidance) into such measures.
    - Alternatively, ACER could be empowered to issue binding REMIT guidance to market participants and NRAs. This empowerment could equally cover all aspects of the REMIT and guidance is a proven instrument under MAR (see example of BAFin Issuer Guidelines).
    - However, any such ACER implementation measures and guidance must be subject to a strong governance. In particular, they need to be consulted with market participants before adoption and they need to be subject to scrutiny and

adoption by the European Commission, in particular when these concerns the interpretation of the Level 1 text of REMIT.

- **Setting of fixed disclosure thresholds for inside information for power and gas**
  - Such thresholds would create legal clarity and certainty and facilitate market participant compliance with the REMIT inside information disclosure regime. Also, it would avoid publishing not price-relevant information and hence make the disclosure regime, and in particular the IIPs, more effective.
  - EFET has commissioned a study for the German power markets, which confirms that a 100 MW threshold would be appropriate. This threshold was also confirmed through a report for the Nordic and the Baltic markets published by the Nord Pool Group. Also, the French regulator CRE produced a similar report.
  - Such confirmed power and gas thresholds should be applicable in all situations except for extraordinary market situations such as national authorities' declaration of supply emergency, risk of black outs or rationing announced by TSOs.

- **Delegated and Single-Sided Reporting** (both incl. transactions, orders, lifecycle events) will improve the data quality of reporting, facilitate market participants' compliance and make reporting more efficient:
  - Allow for single-sided reporting for OTC wholesale energy markets. Like under EMIR Article 9 (1f), market participants that are subject to the REMIT reporting obligation shall be empowered to delegate that reporting obligation to another counterparty.
  - Direct reporting obligation (single-side reporting) of Organised Market Places (OMPs) for wholesale energy transactions and orders entered via their venue.
  - In both cases the reporting party should bear full responsibility and liability on the reporting of the trade (other than the accuracy of (counterparty) data provided by the counterparty).

H2. With regards to the harmonization and strengthening of the enforcement regime under REMIT: what shortcomings do you see in the existing REMIT framework and what elements could be improved and how?

Extension of REMIT scope and improvement of cooperation between ACER / NRAs and ESMA / FCAs

We wish REMIT to become a comprehensive and tailor-made sector-specific framework for market transparency and integrity in physical and financial energy markets to create a harmonized interpretation, application and supervision. The application of REMIT and MAR causes duplicative compliance efforts and bears the risk that competent authorities' supervisory practices are substantially different, in particular with regard to the market abuse regime.

The following approaches are possible to avoid this:

- The European Commission could extend the REMIT scope and competence of ACER/ Energy NRAs to cover physical and derivatives energy wholesale markets. ACER/NRAs could be the competent authorities regarding transparency/reporting obligations and market abuse prohibitions for the entire energy markets.
- In particular, if the REMIT market integrity scope is not extended to cover energy derivatives, it will be key to introduce a mandatory cooperation between the different authorities to apply a consistent approach of the different competent authorities under REMIT and financial regulation towards breaches of insider dealing and market manipulations prohibitions. Hence, they should come to a joint understanding on the interpretation and enforcement on these prohibitions, with full consideration of the specifics of the energy markets. In this context, it would be helpful to also introduce a prohibition of double penalties (ne bis in idem) to avoid that firms and/or persons would be punished twice for the same conduct by different authorities.
- In any case, NRAs and other authorities (national financial regulators, ESMA) should be obliged to cooperate to ensure efficient data exchange. This should create a sufficient level of transparency towards authorities of market participants' activities based on existing reporting and disclosure regimes, and avoids imposition of new transparency/reporting obligations. ACER/NRAs (and ESMA) should establish mechanisms to share that information amongst themselves and with other EU and national authorities.

Updating of REMIT definitions and framework

There should be a general alignment of REMIT definitions of market manipulation with MAR definitions (Art. 6), unless a differentiation is required to take account of specifics of energy (gas and power) markets.

Include implications of energy transition

The definition of wholesale energy products should be updated to include and address implications of new market developments, for example to include new wholesale energy products such as hydrogen and others into the REMIT scope, subject to the same conditions as defined in Art. 2 (4). This would ensure that those markets adhere to the same integrity and transparency standards.

Improved supervisory regime

In its supervision of Registered Reporting Mechanisms (RRMs) and Inside Information Platforms (IIPs), ACER should define and monitor standards for technical and organizational requirements and responsibilities. This is crucial as IIPs and RRMs are essential service providers for market participants to fulfil their REMIT obligations and hence the supervisory powers should be the same as for market participants. The aim would be to improve the RRMs/IIPs service and data quality, including the portability between RRMs (e.g. by standard interfaces).

The definition of a set of harmonized administrative and penal sanctions at national level for REMIT breaches is not a priority for our membership. In case such a REMIT Directive is established, we request that sanctions, in particular for market manipulations, can only be imposed when committed intentionally. This is necessary to avoid that operational errors are sanctioned as a criminal offence under national sanction regimes. This condition is embedded into the Market Abuse Directive as well (e.g. in Art. 5)

ACER and EU Commission to define binding technical implementation and updates: See our response under Q1

H3. With regards to better REMIT data quality, reporting, transparency and monitoring, what shortcomings do you see in the existing REMIT framework and what elements could be improved and how?

More efficient reporting:

- ***Delegated and Single-Sided Reporting (both incl. transactions, orders, lifecycle events)***: See our response under Q1
- ***Avoid double reporting obligations for firms at EU and national level for data which is already reported under REMIT (and EMIR)***: It could be provided that data subject to REMIT data reporting or disclosure shall not be subject to national reporting requirements and that NRAs shall make use of the existing ACER data bases or other existing data sources.
- ***Consider increasing the de-minimis threshold to exclude SMEs*** under a defined level of power and gas production from reporting.
- ***Exclude bilateral OTC contracts for physical energy delivery to final customers from reporting***: These contracts do not contribute to the wholesale price formation processes on wholesale trading markets and are not a suitable instrument to manipulate wholesale energy markets. This could be replaced by an ad-hoc reporting based on a reasoned ACER request. However, industrial end-consumer should remain in the scope of REMIT if they are active on the energy wholesale markets, e.g, to disclose their inside information
- ***Reduce complexity of reporting formats*** such as:
    - update through CEREMP for company mergers
    - simplification on Table 2 non-standards contract reporting
- ***Access to ACER database*** is necessary for reporting parties in order to verify data quality and completeness.

- ***Integrate the scope and content of EU LNG data reporting under Council Regulation 2022/2576 into REMIT***: Contracts and transactions that are not needed for the daily LNG price assessment under the benchmark methodology, should be subject to the existing REMIT reporting rules (T+1/T+30).

Improve the transparency regime:

- ***Setting of fixed disclosure thresholds for inside information for power and gas:*** See response under Q1
- ***Creating a central ACER platform for market transparency*****:** Currently there exist a multitude of regulated platforms on national and EU level. These are in particular the IIPs under REMIT and websites for the publication of transparency information under the Transparency Regulation. ACER could set up a single aggregation web portal to collect all relevant information for REMIT and Transparency Regulation to enable market participants to have a single access to all relevant information.
- ***Setting up aggregated, anonymized post-trade transparency for market participants based on existing reporting***: This would address the lessons learnt from the energy crisis as it would allow market participants to better assess the market liquidity and prices and impact of fundamentals, in particular on the (non-standardised) OTC markets, and hence better manage and mitigate their commercial risks. ACER can perform this task based on existing data reporting so that no extension of data reporting is necessary.
- ***Clarifying the framework of IIP publication of reported inside information*****:** If a market participant can demonstrate that it sent the inside information to the IIP, it should be regarded to be in compliance with the disclosure requirement and able to act upon it, even if the IIP defaults in publishing it.
- ***Including Distributions System Operators (DSOs), LNG System Operators (LSOs) and Storage System Operators (SSOs) into the definition of market participants*****:** These entities possess information that could constitute inside information and fundamental data which is disclosable / reportable. Therefore, we propose the collection of fundamental data directly from DSOs, LSOs and SSOs and the disclosure of inside information by these entities as far they are the primary owner of information. This would also avoid the risk for market participants to be qualified as secondary insider

Transparent monitoring:

- Firms need information about the main elements of cases regarding sanctioned REMIT breaches from NRAs in English. NRAs should inform ACER and ACER shall issue a public notice with defined details (e.g. main legal elements and sanctions imposed).