EREF European Renewable Energies Federation

EREF response to the public consultation of the European Commission on the revision of the Electricity Market Design

February 2023

Introductory comment by EREF on the whole questionnaire

EREF is deeply concerned that the questions asked point to a very limited view of the European Commission on a reform of the Electricity Market Directive.

It seems that the consultation and its guidance missed the boat. We need urgently a reform which acknowledges that the roll-out of renewable energies is of the highest priority and of an overriding public interest as has been laid down under the so-called SOS Emergency Regulation of the Council and is at present a non-disputed part of the Trilogue negotiations concerning the REDIII and RED IV amendment process.

It is no longer adequate or correct to try to enable the decentralised renewable, storage and balancing energy system to adjust to the centralised electricity market rules form decades ago but rather to change the market structures to adhere to the new world of renewable energies as main source. Europe urgently needs a holistic transformation from the outdated conventional to the renewable energy system.

A true reform of the electricity market would need to review the supply side, the grid management under decentralised system services, trade, and generation as one system reform approach. The European Commission in its own analyses is aware that soon one third of energy supply will be generated, stored, and used locally. In this system, generation capacity, flexibility, complexity reduction and resilience of the power system will be provided by on-site supply. The incumbent paradigm of avoiding grid congestion only through expansion without first including flexibility and storage potential e.g. on the local level including correct and up to date smart systems is of clear importance and needs to gain priority attention.

Smart markets and energy-storage facilities must be encouraged to develop the trade of electricity as flexible and regionalised link between production and consumption. Unfortunately, the first energy market reforms and strict unbundling lead to the phenomenon that often e.g. TSOs are blocking storage capacity since this might endanger the - outdated- business models of many TSOs. TSOs are often private companies which manage a natural monopoly. Their cost structure is not often clear enough, especially when it comes to flexibility. Together with long-time disregarded electric mobility these can be seen as major stumble blocks for the market reform welcoming renewables as main source.

Hardly any of these major needs and aspects are included in this questionnaire. Rather, the questions would more suit to manage a still centralised system facing some renewables and more suited to oligopolistic and market dominant structures, as can be found in some Member States.

We do need to achieve a lot in only seven years until 2030 to reach the new renewable energy target, and to lower drastically thus the level of dependence from fossil sources, as coal, oil, gas, and uranium. A hesitant reform proposal by the European Commission would make the European Union loose an important momentum for acceleration and leave investors in renewable energies, storage and flexibility in an uncertain position.

EREF would also like to underline its support for the answers submitted by RESCOOP for this consultation: their main findings do match our view:

- Local communities, including citizens, local authorities, cooperatives and other small and medium enterprises (SMEs), are uniquely impacted by the ongoing energy crisis. And yet, they also have a large role to play in providing solutions as active participants in the energy transition. Nevertheless, their ability to take ownership and play a meaningful role in removing Europe's reliance on imported fossil energy and building up renewable energy production relies heavily on the design of the internal energy market.
- It is, therefore, unfortunate that the Electricity Market Design has been primarily framed around interventions in the wholesale market. Defining the scope of the problem and the potential solutions around centralised exchanges of energy ignores the role that alternative ways of exchanging electricity through local ownership of production and supply can play in hedging consumers against volatility during the crisis and as we move to a 100% renewables future.
- Even if the Electricity Market cannot create more decentralised, local energy markets overnight, the building blocks must be put in place now to make long-term changes easier in the future. The EU's ambition to move away from imported fossil fuels and to rid the energy market of gas will require a further unprecedented rollout of renewable energy production in the next few years. This installation of new projects and grid infrastructure will most certainly have significant impacts on local communities. If rolled out without participation and chance for local communities to take ownership, trust in the energy transition could falter, and public acceptance will become an even bigger problem than it already is today. On the other hand, if local ownership is prioritised, communities can spend the next few years mobilising capital and resources to prepare for, and influence, more decentralised energy markets of the future.

- At the very least, the Electricity Market Design reform should be anchored around the principle of prioritising local ownership of production and supply of renewable energy. Local communities themselves, including citizens, public authorities and SMEs, should be empowered to invest and take ownership in such resources' this consultation as they mirror our view on the urgency for reform in order to enable community energies , energy cooperatives and in genal citizens renewable energy.

EREEF will answer most of the following questions but appeals to the European Commission to be more courageous.

Making Electricity Bills Independent of Short-Term Markets

Power purchase agreements

The conclusion of PPAs between electricity generators and final customers (including large industrial customers, SMEs and suppliers), is a way of supporting long-term investment by providing both parties with certainty regarding the price level over a longer time horizon (typically, 5 to 20 years) compared to other alternatives. In particular, PPAs contribute to reduce the uncertainty of final customers concerning electricity prices and their exposure to price variations, allowing to make consumers' bills independent from the fluctuation of fossil fuels prices. However, as PPAs are contracts signed over a long period of time, they bear considerable risks and costs for smaller market participants. Hence, their accessibility is currently limited to a few large final customers (e.g. energy intensive undertakings), creating a risk that access to decarbonised generation is limited to a subset of consumers.

Whilst the uptake of renewable PPAs is growing year-on-year, the market share of projects marketed under renewable power purchase contracts covers still only 15-20% of the annual deployment. Furthermore, renewable PPAs are limited to certain Member States and large undertakings, such as energy intensive undertakings.

To address these barriers, Member States can consider ways of supporting the conclusion of PPAs in line with State Aid rules. The Commission has described in detail the additional measures that could help the development of renewable PPAs in the Commission Staff Working document accompanying the REPowerEU Communication[1]. This could be achieved, inter alia, by pooling demand in order to give access to

Commission Staff Working Document Guidance to Member States on good practices to speed up permit granting procedures for renewable energy projects and on facilitating Power Purchase Agreements *smaller final customers, by providing State guarantees in line with the State Aid Guarantee Notice[2] and by supporting the harmonization of contracts in order to aggregate a larger volume of demand and enable cross-border contracts.*

Questions for Stakeholders on Power purchase agreements

Q1. 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?

Power Purchase Agreements (PPAs) are in principle an important element of an energy market design aiming at rapidly increasing quantities of renewable energy in the power system.

We need to underline that PPAs are mostly applied in relation to energy intensive industry or similar off-taker in reality. Therefore, their application is already restricted in smaller countries. Also, in some Member states the dominance of larger, often state owned or state-dominated suppliers are in a stronger position on the regional and local markets and thus access to other independent market participants is restricted.

In addition, the electricity price on the spot market had historically been relatively low, which previously hindered interest for concluding PPAs.

Generally, there is always a risk of the counterparty defaulting over an agreed PPA timeframe, it hence limits long-term green PPAs to a few credit-worthy off takers. Thus, financiers will generally prefer a secure business model, e.g. state support with strong guarantees over a purely market driven one.

Q2. Please describe the barriers that currently prevent the conclusion of PPAs.

Most of the contracted green PPAs are short-term and remain inaccessible to smaller customers as only larger industrial actors can meet necessary collateral requirements.

Furthermore, a CfD-like framework like the new German electricity price ceiling mechanism prevents new PPAs, because it skims fictive revenues (e.g. on the spot market). Other marketing channels, particularly PPAs, which are based on a fixed price for a number of years, would be a significant risk for the power plant operator, because the

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Accompanying the document Commission Recommendation on speeding up permit-granting procedures for renewable energy projects and facilitating Power Purchase Agreements SWD/2022/0149 final https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52008XC0620%2802%29 income from a PPA might be lower than the fictive revenues from the spot market.

Especially the Bioenergy sector faces an unexpected sharp increase of feedstuff costs. Due to the risks of these market developments in crises times, CHP plants cannot offer competitive electricity prices under PPAs. Moreover, within PPAs, the default risk often remains with stakeholders, so that smaller market participants such as municipal power suppliers or cooperatives or community energy providers would not choose a PPA as sustainable business model.

Q3. 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,

Yes.

Bundling of demand is already done via the aggregators (energy supply companies). Longer-term PPAs could be modelled and strengthened in a way as to provide more investment security for project developers whereas PPA pools could support smaller consumers in signing up to a PPA. However, pooling smaller consumers with different credit capabilities increases the financial risk for the undertaking, which could hamper the financing decision and subsequently blocks the urgently needed rollout of renewables.

Pooling the demand, accompanied by specific insurance, public guarantee, and linked to State-support could provide long term (20 years) visibility to renewable energy investments and facilitate opening PPAs to smaller producers and consumers could be an adequate framework condition for supporting roll-out of needed massive renewable energies in the EU. Pooling could encourage further uptake of renewables regionally, independent of the presence of substantial energy demand (intensive industries) or future potential of pooling smaller consumers. Plus, the development of an international PPA market should be encouraged in accordance and in collaboration with grid and system operators.

In addition to the measures mentioned before, the electricity demand from public sector institutions should be pooled and procured via renewable energy PPAs.

It is also important to add that today's practice shows the viability of PPAs with relatively shorter timelines, with 3-5 years contracts possible now on regional level.

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

Yes.

Accessibility of PPAs for consumers of different size and capital basis should be improved, e.g. by guarantees or loans issued by regional or local banks or authorities. In order to ensure the diversity of actors, especially of smaller actors such as energy cooperatives small municipal power suppliers, community energy also in the PPA market, an optional insurance against risks in best-case scenario via a publicly funded guarantee system would make sense, among other mechanisms to assume the risk of default. The insurance would capture partially or fully the default of the counterparty under a PPA.

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

Green Power Purchase Agreements (PPA) can complement the state supported market segment and provide the opportunity for industrial consumers to reliable access green electricity and test new business models. These mechanisms, however, must not impose a price-cap as in a CfD or lose the green quality as in most certificate trading systems.

(d) supporting the standardization of contracts,

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

This would limit market flexibility and – could negatively impact the possibility of new PPAs with new customers.

(f) facilitating cross-border PPAs.

Due to limited interconnector capacities, cross-border PPAs would only have a very limited potential and therefore would be difficult to implement. Moreover, under security of supply constraints there is a risk that Member States might curtail cross border flow outside their country, at least temporarily. The effect of a situation where a Member State (France) failed to ensure sufficient output from its nuclear power plants and thus being unable to export electricity but becoming an importing country which then lead to very high electricity prices in Europe last year shows the delicate situation which in combination with the still limited interconnector capacities calls for caution to bank on cross-border PPAs as realistic and strong market addition in the medium term.

Q4. 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.

A combination with green PPAs could result in lower costs for final customers. The regional context of the PPAs with energy consumption would be relevant. Energy sharing would be an option.

The risk of a counterparty defaulting over a 15 to 20 years' timeframe, however, is significant and hence limits long-term green PPAs to a few credit-worthy off takers. Thus, financiers will always prefer a secure business model (state support) over a purely market driven one. To address counterparty risks, we suggest the introduction of PPA guarantees issued by a local or regional promotional bank (for example, by KfW or EIB). These would – under to be defined circumstances – protect generators against off takers default and guarantee a partial repayment.

Guarantees, however do not tackle profile and shaping risks, namely the necessity for industrial consumers to access reliable energy supply. Here, the concept of green pool PPAs represents a practical possibility. Correspondingly, one could realise reduced ancillary electricity costs for final customers. The regional context of the green PPA for electricity consumption could be decisive here. One possibility could be the topic of green "energy sharing". In addition, a reduction in taxes and levies in the context of green PPAs can trigger further investment. Moreover, non-subsidised green PPA installations could continue to be able to participate in the market on a regular basis without being subject to revenue levies or CfDs. In addition, Member States should be allowed to limit the issuance of Guarantees of Origin to non-subsidized plants (double marketing ban) to create additional incentive for non-subsidised plants. It also would be useful, to integrate flexibilities into PPAs and to reward them financially so that such flexibilities are also developed alongside the market, Albeit, in case of parallel introduction of a wrongly designed CfD framework, the latter would very much counteract to this flexibility advantage.

Q5. 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?

Yes.

State guarantees could support the market introduction phase for renewable installations in this area. Such guarantees could secure the off-taker's deficiency risk and thus reduce financing costs for the plant operators. Such programmes should be implemented on national level.

Disproportionally, green PPAs have suffered under the revenue cap as it has been implemented in Germany. This significantly hampered investments in new green PPA and thus slowed its growth for the near future. Thus, in our view, the best incentive for existing generators to enter PPAs is to put clear and definitive end date to the revenue cap.

Q6. 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?

Yes

Q7. Do you consider that increasing the uptake of PPAs would entail risks as regards:

a. Liquidity in short-term markets; NO
b. Level playing field between undertakings of different sizes; NO
c. Level playing field between undertakings located in different Member States; YES
d. Increased electricity generation based on fossil fuels NO
e. Increases costs for consumers NO

If yes, how can these risks be mitigated

Forward Markets

Organised forward markets are a useful tool for suppliers and large consumers such as energy intensive undertakings to protect themselves against the risk of future increases in electricity prices and to decouple their energy bills from fluctuations of fossil fuel prices in the medium to long-term. However, it has been argued that liquidity in many organised forward markets across the EU is insufficient and that the time horizon for such hedging seems too short (usually up to one year). One possibility to increase the liquidity in forward markets would be to establish virtual trading hubs for forward contracts, as already exist in certain regions.

Such hubs would need to be complemented with liquid and accessible transmission *rights to hedge the remaining risk between the hub and each zone.*

While hedging up to approximately three years could be improved with better organization of the market, additional measures might be needed to incentivise forward hedging beyond this timeframe (see for example the section above on PPAs).

Questions for Stakeholders on Forward Markets

Q1. 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?

YES

Q2. Do you consider that the liquidity in forward markets is currently sufficient to meet this objective?

YES, but there is no guarantee for stability of liquidity as we have seen last year in view of a chain of stress-events (war-related gas supply crisis, river transport failure for coal barges due to drought and likewise failure of more than half of the French nuclear power plants) which created a serious situation of temporary lack of liquidity.

Q3. In your view, what prevents participants from entering into forward contracts?

The obstacle for entering can mostly be linked to the above-mentioned extreme constellations resulting e.g. from the aggressive war of Russia against Ukraine, when forward markets had significantly higher prices than short term markets (spot markets). Many Member States have sufficiently liquid forward as well as OTC markets. Current electricity price cap laws in Member States (e.g. Germany) prevent many renewable energy players (fluctuating sources) from participating in forward markets.

Q4. In your view, would requiring electricity suppliers to hedge for a share of their supply be beneficial for consumers and for retail competition?

NO.

Utilities should derive their hedging strategy from their own framework conditions. Mandatory hedging would not be supportive and could result in higher prices on forward markets.

Q5. 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?

NO

Q6. In case you have experience with the existing virtual hubs in the Nordic countries, how do you rate this experience?

Q7. 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?

When possible, forward markets should be oriented to accommodate (more) variable feed-in of renewable energy.

Contracts for Difference

Two-way CfDs and similar arrangements have been used in some Member States to support publicly financed investments in new inframarginal generation (in particular, renewables) to cater for situations where the necessary investments are not made on a market basis. Similarly to PPAs, they ensure a greater certainty to investors and consumers, and they cater for situations where the necessary investments require public support.

Public support for new inframarginal generation granted in the form of two-way CfDs could ensure that the beneficiaries receive a certain minimum level of remuneration for the electricity produced, while preventing disproportionate revenues. Typically, the beneficiary receives a guaranteed payment equal to the difference between a fixed 'strike' price and a reference price and the revenues above the strike price need to be returned to the CfD counterpart (i.e. Member State).

At the same time, two-way CfDs require the generation supported by the CfDs to pay back the difference between the market reference price and a maximum strike price whenever the reference price exceeds the strike price. If these paybacks are then channelled back to the consumers, suppliers or taxpayers, two-way CfDs also provide them with some protection against excessive prices and volatility, if they are passed on proportionally and objectively.

As it may be difficult for regulators to estimate the actual investment costs, the possibility to determine the remuneration of supported generators through a competitive bidding process is an important instrument to avoid long-lasting excessive costs.

Questions for Stakeholders on CfD:

Q1. 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)?

NO.

It is far from clear that the introduction of CfDs will result in a decrease of electricity prices, as CfDs only impact support costs if at all. Even a decrease of support costs under a CfD is highly unlikely as this would only be the case if one assumes continuously high electricity prices, which is unlikely in a system where power plants with low marginal costs dominate.

CfDs could result in less PPAs being concluded and squeezing forward/futures market. With less liquid forward markets also retailers will have difficulties to fix prices and pass these on to consumers.

Renewables, such as wind and solar power come with a high investment cost up front. They require an investment signal with a guarantee of long-term profitability through e.g. long-term contracts. In this regard, CfDs (particularly with a floor and with a possible inclusion of a cap) could theoretically play a role in supporting further and faster renewable energy uptake and investments.

Contracts for Difference in their classical form are not suitable to increase market exposure and limit costs of electricity production, they might even result in higher costs. They channel the remuneration in a way that does not facilitate system supporting feed in and optimal cost reduction due to a lack of exposure to price spikes, which are part of the calculation in a sliding premium system and thus reduce overall costs. Exposure to market signals however is vital for the long-term strategic, development of European energy systems, with integrated energy storage and dynamic demand response. On the contrary, under a CfD generators will be incentivised to bid above their LCOE as any upside potential is taken away. Furthermore, CfDs based on virtual revenues, as in current proposals, may even destroy the economic viability of renewable energy projects.

Classical CfDs mean a relapse into "produce and forget". Faced with a fixed price, generators will no longer have an incentive to adjust their dispatch to a price and systematically valuable hour. Thus, renewable energy plants with low load hours but high system value, especially flexible bioenergy plants, are those systematically punished, and the potential of non-variable renewable energy technologies to stabilize and reduce costs for the energy system as a whole could not be used.

Imposing a CfD mechanism as a rule endangers the roll-out of renewables and cannot be acceptable. It would violate the established principle of priority for swift renewable roll-out as being of overriding public interest. This public interest was the reason for the Council to issue the Council Regulation on the acceleration of renewables and is established under the new REDIII/REDIV Directive. The introduction of an imposed CfD mechanism would also violate the *effet-utile* principle under European law. The Commission would be in danger to neglect its constitutional loyalty obligation.

The CfD mechanisms would also violate the necessity that the European internal energy market needs to adjust to the fact that renewable and particularly variable sources will be the rule, paired and combined with storage and flexibility. CfD is agnostic to this flexibility and integration partnership. Important storage capacities would lose their financial viability under a CfD regime.

The times that renewables alone have to compete against each other before being allowed to enter the market are an outdated concept in contradiction to the revised Renewable Energy Directive.

As a minimum, CfDs must certainly not be mandatory for supported electricity production from renewables. Even for voluntary CfD-schemes monthly or annual average values should be the basis instead of shorter periods.

Furthermore, if a system of CfDs has to be implemented at all, at least a de minimis limit is mandatory. For flexible bioenergy plants with low load hours the limit should not be defined in terms of a plant's installed capacity but in terms of the annually produced electricity (so called "work-relevant capacity"). Otherwise, bioenergy plants are incentivised to maximize their load hours instead of dispatching their electricity production to hours with the highest system value. Specifically, at least all biogas plants up to a limit of 1 Megawatt work-relevant capacity - which equals an annual electricity production of 8.760 Megawatt hours - shouldn´t be part of a CfD system.

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Q2. 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?

NO.
Classical CfDs are a relapse into "produce and forget". Faced with a fixed price, generators will no longer have an incentive to adjust their dispatch to a price and systematically valuable hour. Thus, renewable energy plants with low load hours but high system value, especially flexible bioenergy plants, will be systematically punished and the potential of non-variable renewable energy technologies to stabilize and reduce costs for the energy system as a whole could not be used. Also, maintenance, retrofit and repowering investments are distorted as generators will have an inherent incentive to hold on to their 'old' CfD payments.

Q3. What technologies should be subject to two-way contracts for differences or similar arrangements and why?

Two-way contracts will result in increased financing risks for renewable energy and therefore impede market-based PPAs, particularly in combination with fictive revenue-skimming. Furthermore, they limit market participation and lead to higher macro-economic costs (i.e. due to auctions resulting in higher prices, and illiquid future markets) and thus reduce public support for the energy transformation.

If the discussion moves further into the implementation of a CfD, we caution to incorporate essential design principles: At the minimum, CfDs should be voluntary and apply to new RE installations only. Any mandatory and/or retroactive intervention into existing contracts would constitute a breach of contract that would significantly shake confidence in the European Union as an investment location. Ultimately, this would translate into surcharged political risk premiums and higher financing costs.

Q4. What technologies should be excluded and why?

All renewable energy technologies should not be subject to mandatory CfDs. Two-way contracts would result in increased financing risks for renewable energy and therefore impede market-based PPAs, particularly in combination with fictive revenue-skimming. (see answer to Q 3). Furthermore, since CfDs cut off any incentive to adjust the dispatch to price signals, the advantage of non-variable RE technologies like bioenergy or hydro power to stabilize and reduce costs for the energy system as a whole could not be used.

Any mandatory and/or retroactive intervention into existing treaties would constitute a breach of contract that would significantly shake confidence in the European Union as an investment location and would increase the current danger of “exiling” of investment to the United States of America.

Q5. 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?

Please see answers to Q3 and Q4.

Q6. 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?

Skimming actual instead of fictive revenues would at least leave freed markets and thus prevent there bleeding out.

Q7. How can it be ensured that any costs or pay-out generated by two-way CfDs in highprice 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?

This should be implemented by governments/public authorities via respective direct payments. Obliging utilities would be difficult, because high price periods on spot markets often significantly differ from the way business source their electricity via long-term contracts.

Q8. What should be the duration of a two-way CfD for new generation and why? Should this differ depending on the technology type?

CfDs are not appropriate to facilitate renewable energy deployment, because they result in higher costs and higher financial risks and less flexibility and market responsiveness. Where they are applied, the CfD duration has to cover pay-back time of each technology thus it has to be adapted to it.

Q9. 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?

If CfDs are introduced despite all odds and disadvantages, they have to be strictly limited in duration with a fixed end-date for repayment obligations. After CfD expiration generation has to be free to earn full market revenue.

Q10. Without prejudice to Article 6 of Directive (EU)2018/2001[3], 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)?

NO.

Q11. Under what terms and conditions could regulated two-way CfDs on existing generation capacity be imposed?

Retroactive imposition of CfDs on existing projects would be a breach of contract and would undermine investors' confidence. It is unknown which financial considerations have been taken when placing the initial bid. Interfering with existing contracts (incl. Green PPAs) is not acceptable and detrimental to market developments. Ultimately, imposing CfDs on existing generation would translate into higher financing costs through surcharged political risk premiums. Higher financing costs particularly negatively impact RES due to their high CAPEX costs.

A revenue cap endangers RES expansion and hinders innovative business concepts.

Under full reserve against CfD models, it must at least be ensured, that after the expiration of CfDs, with enough lifetime before refurbishment, the generation has to be free to earn full market revenue or alternatively free to ask for a new CfD adapted to refurbishment. It is necessary to indicate the relative scarcity of RES regarding the climate targets, which means preserving existing renewable generation must be a priority.

Article 6 (1) Without prejudice to adaptations necessary to comply with Articles 107 and 108 TFEU, Member States shall ensure that the level of, and the conditions attached to, the support granted to renewable energy projects are not revised in a way that negatively affects the rights conferred thereunder and undermines the economic viability of projects that already benefit from support.
6(2) Member States may adjust the level of support in accordance with objective criteria, provided that such criteria are established in the original design of the support scheme.

Q12. 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; VERY HIGH

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

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

(d) impact on the efficient short-term dispatch. VERY HIGH

Q13. Would it be enough for existing generation to be subject only to a simple revenue ceiling instead of a revenue guarantee?

No imposition of cap and/or CfD on existing installations is acceptable - price caps are detrimental/"fatal" to market functioning

Revenue guarantee could be needed especially for refurbishment. Refurbishment must be taken into consideration by future market design to make investment profitable.

Q14. 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?

There are none for CfDs. PPAs and forward hedging could however be part of the solution. In general, it should be noted that the evolving market design needs a combination of all elements: a state supported segment, market-based solutions, and liquid forward/futures markets.

Within a PPA or in a forward contract, consumers and producers can voluntarily and market -based mitigate the risks of short-time variability at the spot market. In theory this could also be possible within CfDs, but with a risk of higher consumer prices.

Accelerating the deployment of renewables

The shortage in gas and electricity supply as well as the relatively inelastic energy demand have led to significant increases in prices and volatility of gas and electricity prices in the EU. As stated above, a faster deployment of renewables constitutes the most sustainable way of addressing the current energy crisis and of structurally reducing the demand for fossil fuels for electricity generation and for direct consumption through electrification and energy system integration. Thanks to their low operational costs, renewables can positively impact electricity prices across the EU and reduce direct consumption of fossil fuels.

Through the REPowerEU plan, the European Commission has put forward a range of initiatives to support the accelerated deployment of renewable energy and to advance energy system integration. These include the proposal to increase the renewable energy target by 2030 to 45% in the Renewable Energy Directive, legislative changes to accelerate and simplify permitting for renewable energy projects or the obligation to install solar energy in buildings.

These efforts should be accompanied by appropriate regulatory and administrative action at national level and by the implementation and enforcement of the current EU legislation.

Within the framework of the Electricity Market legislation, accelerating the deployment and facilitating the uptake of renewables is one of the guiding principles of the Clean Energy Package and of this consultation paper. For example, a transmission access guarantee could be envisaged to secure market access for offshore renewable energy assets interconnected via hybrid projects, where the relevant TSO(s) would compensate the renewable operator for any hours in which the actions of the TSO led to not enough transmission capacity being accessible to the offshore wind farm to offer their export capabilities to the electricity markets[4].

Also, removing the barriers for the uptake of renewable PPAs or generalising two-way CfDs, enhancing consumer empowerment and protection, and increasing demand response, flexibility and storage should contribute to the accelerated deployment of renewables.

See the recommendations of the Study "Support on the use of congestion revenues for Offshore Renewable Energy Projects connected to more than one market" https://energy.ec.europa.eu/system/files/2022- 09/Congestion%20offshore%20BZ.ENGIE%20Impact.FinalReport_topublish.pdf

Questions for Stakeholders on Accelerating the deployment of renewables

Q1. Do you consider that a transmission access guarantee could be appropriate to support offshore renewables? Please explain and outline possible alternatives.

YES

Q2. Do you see any other short-term measures to accelerate the deployment of renewables?

YES.

For a broad range of renewable installations sliding market premiums have become the preferred option to combine solid financing with increased market exposure and thus apply market mechanisms for a system friendly production and feed-in of renewable energy. For smaller and community- or citizen-owned installations fixed feed-in tariffs and self-consumption remain the preferred option.

Accelerate permitting: It requires that the entire permit-granting process for power plants should normally not exceed 18 months.

- The overriding public interest of renewable energy plants must be applied in all contexts. Planning constraints e.g. minimum distance to housing, height restrictions, limit the expansion of renewables.
- The build-out of renewables is often delayed by complicated bureaucratic processes and unclear rules and procedures. Administrations should be obliged to adhere to given deadlines.
- Permitting authorities at all levels often lack sufficient digital and/or human resources to process a growing number of permitting applications.

Accelerate grid connection: Operators of renewable energy plants must plan, build, and finance the connection lines to connect the renewable energy plant to the grid connection point themselves. This often leads to lengthy negotiations with landowners, which often demand high compensation payments. Since it is often the case that certain property owner refuse to allow the installation of connection lines on their ground, plant operators need to take enormous detours to the grid connection point. This increases economic costs. Also, projects are significantly delayed and sometimes even abandoned. Thus, an obligation to tolerate a connection pipe on one's property for the connection of renewable energy plants shall be introduced by law. The law should also define an appropriate compensation for landowners.

Designation of sufficient areas: Member States shall be obliged to provide sufficient land to renewable energy by 2025. What "sufficient" means, shall be clearly defined, so that it can develop its effects immediately.

If yes, please specify.

(a) at national regulatory or administrative level, YES

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

(c) via changes to the current electricity market design? YES

Q 3: 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?

Due to the necessities of climate policies, the need for rapid increase of renewable energy capacities as well as sector coupling and infrastructure investment is evident. Grid infrastructure needs to be developed to be resilient and available when a connection is needed. Grid fees should include time variable elements oriented along the availability of variable renewable energies. This will not only result in urgently needed consumer flexibilities in the market, but also to significantly improved use of power grids and thus to reducing the need for grid expansion. Therefore, time-variable tariffs increase the flexibility of grids.

Introduction of regional flexibility markets represents a no-regret option and a key element for the future energy system. An example of how this can be done is provided by the ENKO platform. Here, consumers can offer flexibility, which is then called upon by the grid operator before an impending grid bottleneck. This saves costs for congestion management and integrates the regional players into the energy transition. For the specific design of regional flexibility markets, the current cost-based redispatch system needs to be further developed into a market-based one ("Redispatch 3.0"). To fully exploit the available flexibility potential, all flexibility providers, including micro consumers and storage facilities, should be enabled to participate in those markets.

Limiting revenues of inframarginal generators

During the current energy crisis, temporary emergency measures have been put in place under Council Regulation 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices. One of these measures is the so-called inframarginal revenue cap which limits the realised revenues of inframarginal generators to a maximum of 180 Euros per MWh. The aim of introducing this inframarginal cap was to limit the impact of the natural gas prices on the revenues of all inframarginal generators (new and existing) and to generate revenues allowing Member States to mitigate the impact of high electricity prices on consumers.

The question to be addressed in the context of the reform of the electricity market rules is whether, in addition to relying on long-term pricing mechanisms such as forward markets, CfDs and PPAs, such revenue limitations for inframarginal generators should be maintained beyond its current expiry date.

Questions for Stakeholders on Limiting revenues of inframarginal generators

Q 1. Do you consider that some form of revenue limitation of inframarginal generators should be maintained?

NO.

Revenue limitation of inframarginal generators should be forbidden as it is denying market principle. It’s a cause of lack of trust for investment.

Q2. 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, NOT AT ALL PREFERABLE

(b) its impact on decarbonisation, NOT AT ALL PREFERABLE

(c) security of supply, NOT AT ALL PREFERABLE

(d) investment signals, NOT AT ALL PREFERABLE

(e) legitimate expectations/legal risks NOT AT ALL PREFERABLE

(f) fossil fuel consumption, NOT AT ALL PREFERABLE

(g) cross border trade intra and extra EU, NOT AT ALL PREFERABLE

(h) distortion of competition in the markets, NOT AT ALL PREFERABLE

(i) implementation challenges. NOT AT ALL PREFERABLE

No investment is possible under such a threat.

Q.3. 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?

The emergency interventions in the context of the energy price break to limit energy prices by temporary measures are basically a CfD and resulting in related problems (see above). In addition, due to the very short notion and due to inclusion of existing installations, they result in a loss of confidence and trust and therefore investor uncertainty- They should therefore be phased out immediately.

Q.4. Should the modalities of such revenue limitation be open to Member States or be introduced in a uniform manner across the EU?

Member States, but probably based on clear guidelines.

Q.5. 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?

This should be implemented by governments/public authorities via respective direct payments. Obliging utilities would be difficult, because high price periods on spot markets often significantly differ from the way business source their electricity via long-term contracts.

Alternatives to Gas to Keep the Electricity System in Balance

Short-term markets enable trading electricity close to the time of delivery, covering day-ahead, intraday and balancing timeframes. Well-functioning short-term electricity markets guarantee that the different assets are used in the most efficient manner - this is key to deliver the lowest possible electricity prices to consumers. Short-term markets should therefore deliver relevant price signals reflecting locational, time-re-

lated and scarcity aspects: this will ensure the adequate reaction of generation and demand. Even if an increasing share of generation were covered by long term contracts such as PPAs or CfDs (cf. section (i) and (ii)), the short-term markets would remain key to ensure efficient dispatch. The short-term markets also ensure efficient exchanges of electricity across borders.

Well-functioning short-term markets require healthy competition between market participants so that they are incentivised to bid at their true cost and regulators have the necessary tools to detect any kind of abusive or manipulative behaviour. Demand response, storage and other sources of flexibility must be put in a situation where they can compete effectively so that the role of natural gas in the short-term market to provide flexibility is progressively reduced, which will bring multiple benefits including lower electricity prices for consumers. To ensure this, targeted changes to the functioning of short-term markets could be envisaged, which could include:

Incentivising the development of flexibility assets

The Commission together with ACER has started the work on new rules to further support the development of demand response, including rules on aggregation, energy storage and demand curtailment, and address remaining regulatory barriers.

Adapt incentives in the System operators tariff design: The Electricity Regulation and Directive already give the possibility for system operators to procure flexibility services including demand response. However, in most Member States, the current regulatory framework treats capital expenditures (CAPEX) of system operators different from operational expenditures (OPEX), resulting in a bias in detriment of investments by system operators concerning the operation of their network. An alternative to this approach is a regulatory framework based on overall total expenditure (TOTEX), including capital expenditures and operational expenditures, which would allow the system operators to choose between operational expenditures and capital expenditures, or an efficient mix of both, to operate their system efficiently without bias for a certain type of expenditure. This would incentivise system operators to procure further flexibility services, and in particular demand response, which should be a key enabler for greater renewable integration.

Using sub-meter data for settlement and observability: The deployment of smart meters as envisaged in the Electricity Directive is delayed in several Member States. In addition, smart meters do not always provide the level of granularity required for demand response and energy storage. In these situations, it should thus be possible for system operators to use sub-meter data (incl. from private sub-meters) for settlement and ob-

servability processes of demand response and energy storage, to facilitate active participation in electricity markets (see also section "Adapting metering to facilitate demand response from flexible appliances" in the section on "Better consumer empowerment and protection"). The use of sub-meter data should be accompanied by requirements for the sub-meter data validation process to check and ensure the quality of the submeter data. Access to dynamic data of electricity consumed (and injected back to the grid) notably from renewable energy sources helps increasing awareness amongst the consumers and allows shifting demand towards renewable electricity.

Developing new products to foster demand reduction and shift energy at peak times

To foster demand reduction and energy shifting (through demand response, storage and other flexibility solutions) at peak times, a peak shaving product could be defined and considered as an ancillary service that could be bought by system operators. Such a product could be auctioned a few weeks/months ahead (with a capacity payment) and activated at peak load (with an energy payment), considering renewables generation, therefore contributing to phasing out gas plants from the merit order, and contributing to lowering the price. Demand reduced could also be shifted to another point in time, outside of peak times. This would incentivize flexibility when fossil fuel capacity is needed the most in the system. It would be important to ensure such a product is cost effective if implemented over the long term.

Coordinating demand response in periods of crisis: In periods of crisis, it would also be possible to combine the limitations of inframarginal revenues described in the section above with market- based coordinated demand response (reduction and/or shifting) in times of peak prices or peak load. The aim would be to reduce the market clearing price and fossil fuel consumption.

Improving the efficiency of intraday markets

Shifting the cross-border intraday gate closure time closer to real time: Intraday trade is a key tool to integrate renewable energy sources and balance their variability with flexibility sources up to real time. Wind and solar producers see their forecasts strongly improving close to delivery, and it should be possible to trade shortages and surpluses as close as possible to real time. Setting the cross-border intraday gate closure time closer to real time therefore appears as a meaningful improvement, in combination with maximising the cross-border trade capacity.

Mandating the sharing of the liquidity at all timeframes until the time of delivery: EU day-ahead and intraday electricity markets are geographically coupled, meaning that trades can take place anywhere across Europe if the grid cross-border capabilities are sufficient. This considerably increases the liquidity and therefore the efficiency of the mar-

kets. The Commission considers extending these benefits also to intra-border trade between different market operators. This would support competition development and facilitate market participants to balance their positions - a key aspect for integrating further variable renewables.

Questions for Stakeholders on alternatives to Gas to Keep the Electricity System in Balance

Q1. Do you consider the short-term markets are functioning well in terms of:

(a) accurately reflecting underlying supply/demand fundamentals, YES

(b) encompassing sufficiently liquidity, YES

(c) ensuring a level playing field, YES

(d) efficient dispatch of generation assets, YES

(e) minimising costs for consumers, YES

(f) efficiently allocating electricity cross-border? YES

Q2. 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?

NO

Q3. How can the EU emission trading system and carbon pricing incentivize the development of low carbon flexibility and storage?

Reducing the number of available certificates as well as progressively increasing CO2-prices will create opportunities for flexibilities and storage.

Q4. 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.

Q5. 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?

Q6. 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?

No improvement.

Q7. 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)?

The challenge would be harmonizing of local markets and resilience of implementation. In addition, time limits in trading are another challenge. Locally using free flexibilities in the context of local markets would be an asset. Mandatory participation in day ahead markets would exclude other forms of marketing. PPAs would become more difficult and regional green marketing concepts might not be possible. This again would prevent lower fees for consumers and at the same time limit public support the energy transition.

A question would be, which influence such additional information could have. Would they result in exclusion or prioritisation? Would the impede regular pricing mechanism? Most likely, the results will be rather unfavourable, because the present mechanism is functioning well for two decades now.

Q8. What further aspects of the market design could enhance the development of flexibility assets such as demand response and energy storage?

Additional direct and indirect support would have a positive impact. Limiting incidental costs, if the installations are operated in a flexible and market- and system-serving way would be another positive impact.

The short-term market must be designed to optimize the dynamic performance (fast start-up, fast ramping, etc.) necessary for frequency control and ultimately for the balance of the power system, for example through market blocks with short time steps.

The introduction of regional flexibility markets represents a no-regret option and a key element for the future energy system. An example of how this can be done is provided by the ENKO platform. Here, consumers can offer flexibility, which is then called upon by the grid operator before an impending grid bottleneck. This saves costs for congestion management and integrates the regional players into the energy transition.

Q9. 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?

YES.

Ancillary services must be designed to optimize dynamic performance (forecasting, dispatching, ramping, modulation) of different technologies in power mix. To do this, grid code, which by its nature levels out the technologies, must be reduced to minimum common requirements. Auxiliary services must be remunerated for all their services (reserve, including reserve at shutdown, congestion, voltage regulation, etc.), particularly for the guarantee of flexibility due to their very existence.

Q10. 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?

Q11. 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?

YES

Q12. Do you consider that some form of demand response requirements that would apply in periods of crisis should be introduced into the Electricity Regulation?

Q13. 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?

YES

Q 14: 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?

YES, adequate. It is important not only to address capacities but in particular flexibilities. Flexibility can be a result from supply and demand side as well as from storage. Therefore, support for flexibilities should be open to all of them. In addition, Member States should evaluate whether the flexibilities which are necessary for the timely and rapid deployment of more renewable energy capacities are available in time. Short term adaptations may become necessary.

Short-term markets and capacity mechanism have to be complemented by a flexibility mechanism to guarantee the balance of the power system at any time from year to microsecond. Energy, capacity, flexibility are the three pillars of any future power system.

Such a mechanism has to be confirmed to guarantee sufficient flexibilities at all times.

Q 15: Do you see a benefit in a long-term shift of the European electricity market to more granular locational pricing?

NO.

Better consumer empowerment and protection

Union legislation recognizes that adequate heating, cooling and lighting, and energy to power appliances are essential services. The European Pillar of Social Rights includes energy among the essential services which everyone is entitled to access.

Union legislation also aims to deliver competitive and fair retail markets, as well as possibilities to reduce energy costs by investing in energy efficiency or in renewable generation thereby putting consumers at the heart of the energy system. The energy crisis has shown the importance of delivering on this ambition but also weaknesses in the existing system. For that reason, there is scope to further reinforce the Electricity Directive to deliver the needed consumer empowerment and protection, and avoid that consumers are powerless in the face of short-term energy market movements.

Increasing possibilities for collective self-consumption and electricity sharing

Digitalisation - particularly when applied to metering and billing - facilitates energy sharing and collective self-consumption. Collective self-consumption means customers are able to invest in offsite generation and become "prosumers" reducing their bills just as if the renewable energy production installation were installed on their own roof. Consumers can then avoid buying gas produced electricity which leads to real decoupling.

The practical uses are potentially very significant - for example, families can share energy among the different members located in different parts of the country and farmers can install renewable generation on one part of their farm and use the energy in their main buildings even if located a distance away. Another clear use case is municipalities and housing associations can include off- site energy as part of social housing, directly addressing energy poverty.

Member States such as Belgium[5], Austria, Lithuania[6] Luxembourg, Portugal and others[7] have shown that it is possible to implement this model in practice quickly and at reasonable cost for consumers to develop energy sharing and collective self-consumption.

Customers should be in a position to deduct the production of offsite renewable generation facilities they own, rent, share or lease from their metered consumption and billed energy. Specific provisions could allow energy poor and vulnerable customers to be given access to this shared energy, for example produced within municipalities, or by investments of local governments.

Energy sharing should be treated in a non-discriminatory way compared to normal suppliers and producers. This means costs for other consumers are not unduly increased. Production and consumption has to happen at the same market time unit. Energy sharing be possible where there are no transmission constraints for wholesale trade - that is within price zones.

Adapting metering to facilitate demand response from flexible appliances

The roll out and uptake of demand response has been slower than desired. One of the reasons for this has been the very complex relationships between suppliers and aggregators. The greatest demand response possibilities often come from individual appliances - in particular behind-the- meter storage, heat pumps and electric vehicles. Enabling dedicated suppliers and aggregators to offer contracts covering just these appliances could help both speed the roll out of these appliances and increase the amount

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Lithuanian consumers to access solar parks under CLEAR-X project
Spain, Croatia, Italy ,France.

of demand response in the system. The Electricity Directive already provides that customers are entitled to more than one supplier, but this has been seen to require a separate connection point increasing costs for customers significantly.

Therefore, there is a case for adapting the current provisions of the Electricity Directive to clarify that customers who wish to have the right to have more than one meter (i.e. a sub-meter) installed in their premises and for such sub-metered consumption to be separately billed and deducted from the main metering and billing.

Better choice of contracts for consumers

In many Member States as the crisis unfolded, the availability and diversity of contracts became more limited, making it increasingly difficult for customers to obtain fixed price contracts in many Member States. This was also often insufficiently clear to customers who believed that they had entered into fixed price contracts, alongside a wider lack of understanding of consumer rights.

There are also few "hybrid" or "block" contracts available. Such contracts combine elements of fixed price and dynamic/variable prices giving consumers certainty for a minimum volume of consumption but allowing prices to vary above that amount.

Customers with variable price contracts can find budgeting more difficult, particularly consumers on low incomes or vulnerable consumers. The effect of such contracts is that the cost of managing the risk of wholesale price increases is faced exclusively by customers and not by suppliers. On the other hand, variable prices - at least for the energy where the customer is effectively able to control consumption - can incentivise a more efficient use of energy.

While suppliers above a certain size are obliged to offer dynamic price contracts, which were less in demand during the crisis, the legislation is silent on fixed price contracts. This should be rebalanced to allow consumers a choice between flexible or fixed price contracts. Fixed price contracts could still be based on time of use to maintain incentives to reduce demand at peak hours. Suppliers would remain free to determine the price themselves.

Suppliers often argue that it is difficult to offer attractive fixed price offers for two reasons - firstly if they do not have access to longer term markets which allow them to hedge their risks. These issues are addressed in the sections on forward markets above. Secondly, suppliers argue that it is difficult to offer fixed price fixed term contracts because consumers are allowed to switch supplier (i.e. leave the fixed price fixed term contract) - leaving the supplier with additional costs. Currently, termination fees for fixed price fixed term contracts are allowed - but only if they are proportionate and if they *reflect the direct economic loss to the supplier. Without abandoning these principles, it could be considered allowing regulators or another body to set indicative fees which would be presumed to comply with these obligations.*

Strengthening consumer protection

A) *Protecting customers from supplier failure*

Increased supplier failure during the crisis, generally because of a lack of hedging, has been observed in several Member States. This has often resulted in all consumers facing higher bills because of socialisation of some of the failed suppliers' costs.[8] *Customers of the failed suppliers are also faced with unexpected costs. Obliging suppliers to trade in a prudential way may involve some additional costs, but would reduce the risks that individual consumers face and also avoid socialisation of the costs of suppliers with poor business models. This is separate from, but complementary to, prudential rules applicable to energy companies on financial markets where the Commission has also taken action. At the same time, we recognise such obligations need to take account of the difficulties smaller suppliers face in hedging, particularly in smaller Member States (see also section on "Forward Markets" above).*

All Member States have implemented a system of supplier of last resort, either de jure or de facto. However, the effectiveness of these systems varies and EU framework is very vague without clarifying the roles and responsibilities of the appointed supplier and the rights of consumers transferred to the supplier of last resort[9]*.*

B) *Access to necessary electricity at an affordable price during crises*

The Electricity Directive includes specific provisions for energy poor and vulnerable customers, which are part of a broader policy framework to protect such consumers and help them overcome energy poverty.[10] *However, the crisis has shown that affordability of energy can be a major issue not only for these groups, but also for wider sections of population. Member States can apply price regulation for energy poor and vulnerable households. Council Regulation (EU) 2022/1854 on an emergency intervention*

For example, network charges owed to TSOs and DSOs and potentially imbalance costs.

In particular, we would consider confirming that customers transferred to Supplier of Last Resort retain the right to change supplier within normal switching times (i.e. customers cannot be required to stay with the supplier of last resort for a fixed period); clarifying that the supplier of last resort must be appointed based on an open and transparent procedure; right of consumers to remain with supplier of last resort for reasonable periods of time.

The Energy and Climate Governance Regulation together with the 2020 recommendation on Energy poverty provide a more structural framework to address and prevent energy poverty. The Fit for 55 legislative package further reinforces this framework through other sectoral legislation, through the revision of the Energy Efficiency Directive and the Energy Performance of Buildings Directive and through setting up of the Social Climate Fund to address the impact of the ETS extension to buildings and transport.

to address high energy prices allows for below cost regulated prices for all households and for SMEs on a temporary basis and subject to clear condition. In particular, such measures can only cover a limited amount of consumption and must retain an incentive for demand reduction. One of the lessons of the crisis is that the objective of reducing energy costs for consumer should not come at the expense of encouraging excess demand and fossil fuel lock-in, or fiscal sustainability. However, some form of safeguard to allow Member States to intervene in retail price setting might be needed for the future during a severe crisis, such as the current one. This could ensure that citizens have access to the energy they need, including ensuring that certain consumers have access to a minimum level of electricity at a reasonable price, regardless of the situation in the electricity markets, while avoiding subsidies for unnecessary consumption, such as heating of swimming pools[11]. This would also help ensure that when making large purchases, customers would take into account the full cost of energy. As the objective is to mitigate the impact of high prices during crisis periods, it would seem sensible to develop specific criteria to define a crisis in these terms. One alternative would be to link the Electricity Risk Preparedness Regulation, however this is focused on system adequacy, system security and fuel security, rather than mitigating the impacts of a crisis on users. Fossil fuel lock-in, however, needs to be avoided.

Questions for Stakeholders on better consumer empowerment and protection

Energy sharing and demand response

Q 1. Would you support a provision giving customers the right to deduct offsite generation from their metered consumption?

YES

Q 2. If such a right were introduced:

(a) Would it affect the location of new renewable generation facilities? YES

(b) Should it be restricted to local areas -

(c) Should it apply across the Member State/control/zone - NO

This is also in line with the Recommendation on the economic policy of the euro area which called for a two- tier energy pricing model, whereby consumers benefit from regulated prices up to a certain amount

Q 3. 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?

YES

Offers and contracts

Q 4. Would you support provisions requiring suppliers to offer fixed price fixed term contracts (i.e.. Which they cannot amend) for households?

Q 5. If such an obligation were implemented what should the minimum fixed term be?

(a) less than one year,

(b) one year, YES

(c) longer than one year

(d) Other

Q 6. 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?

YES

Q 7. Do you see scope for a clarification and possible stronger enforcement of consumer rights in relation to electricity?

YES

Prudential supplier obligations

Q 8. Would you support the establishment of prudential obligations on suppliers to ensure they are adequately hedged?

Q 9. Would such supplier obligations need to be differentiated for small suppliers and energy communities. If Yes/No, why (not)?

YES

Supplier of last resort

Q 10. 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?

Not as a rule, normally on Member states level system have proven to function also under the current crisis.

Q 11. 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:

YES.

Not as a rule, normally on Member states level system have proven to function also under the current crisis.

(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?

Enhance the integrity and transparency of the energy market

Never has there been as much of a need as today to enhance the public's trust in energy market functioning and to protect EU effectively against attempts of market manipulation.

Regulation (EU) 1227/2011 on wholesale market integrity and transparency (REMIT) was designed more than a decade ago to ensure that consumers and other market participants can have confidence in the integrity of electricity and gas markets, that *prices reflect a fair and competitive interplay between supply and demand, and that no profits can be drawn from market abuse.*

In times of extra volatility, external actors' interference, reduced supplies, and many new trading behaviours, there is a need to have a closer look as to whether our REMIT framework is robust enough. In addition, recent developments on the market and REMIT implementation over last decade have shown that REMIT and its implementing rules require an update to keep abreast. The wholesale energy market design has evolved over the past years: new commodities, new products, new actors, new configurations and not all data is effectively reported. The existing REMIT framework is not fully updated to tackle all new challenges, including enforcement and investigation in the new market realities.

Current experience, including a decade of REMIT framework implementation (REMIT Regulation from 2011 and REMIT Implementing Regulation from 2014) and functioning show that REMIT framework may require improvements to further increase transparency, monitoring capacities and ensure more effective investigation and enforcement of potential market abuse cases in the EU to support new electricity market design. The following areas could be considered in this context:

- *The alignment of the ACER powers under REMIT with relevant powers under the EU financial market legislation including relevant definitions, in particular the definitions of market abuse (insider trading and market manipulation);*
- *The adaptation of the scope of REMIT to current and evolving market circumstances (new products, commodities, market players);*
- *The harmonisation of the fines that are imposed under REMIT at national level and the strengthening of the enforcement regime of certain cases with cross-border elements under REMIT;*
- *Increasing the transparency of market surveillance actions by improved communication of the market-related data by ACER, regulators and market operators.*

Questions for Stakeholders on Enhance the integrity and transparency of the energy market

Q1. What improvements into the REMIT framework do you consider as most important to be addressed immediately?

Q2. 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?

Q3. 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?