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Public Consultation: Revision of the EU’s electricity market design

Fields marked with * are mandatory.

Electricity Market Design

The consultation document with the questions can also be downloaded here:

EMD_Consultation_document.pdf

Introduction

Background

Over the last year, electricity prices have been significantly higher than before. Prices started rising rapidly in summer of 2021 when Russia reduced its gas supplies to Europe while global demand picked up as COVID-19 restrictions were eased. Subsequently, Russia’s invasion of Ukraine and its weaponisation of energy sources have led to substantially lower levels of gas delivery to the EU and increased disruptions of gas supply, further driving up the price. This has had a severe impact on EU households and the economy. High gas prices influence the price of electricity from gas fired power plants, often needed to satisfy electricity demand.

In the immediate reaction to global dynamics, the EU provided an energy prices toolbox with measures to address high prices (including income support, tax breaks, gas saving and storage measures). The subsequent weaponisation of gas supply and Russia’s manipulation of the markets through intentional disruptions of gas flows have led not only to skyrocketing energy prices, but also to endangering security of supply. To address it, the EU had to act to diversify gas supplies and to accelerate energy efficiency and the deployment of renewable energy.

Following the Russian invasion of Ukraine in February 2022, the EU responded with REPowerEU - a plan for the Union to rapidly end its dependence on Russian energy supplies by strengthening the European resilience and security, reducing energy consumption, accelerating the roll-out of renewables and energy efficiency, and securing alternative energy supplies. The EU also established a temporary State Aid regime to allow certain subsidies to soften the impact of high prices. Further, to address the price crisis and security concerns, the EU has agreed and implemented a strong gas storage regime, effective demand reduction measures for gas and electricity, and price limiting regimes to avoid windfall profits in both gas and electricity markets.

The EU Electricity Market Design

The current electricity market design has delivered a well-integrated market, allowing Europe to reap the economic benefits of a single energy market in the normal market circumstances, ensuring security of supply and sustaining the decarbonisation process. Cross-border interconnectivity also ensures safer, more reliable and efficient operation of the power system.

Market design has also helped the emergence of new and innovative products and measures on retail electricity markets – supporting energy efficiency and renewable uptake and helping consumers reduce their energy bills also through emerging services for providing demand response. Building on and seizing the potential of the digitalisation of the energy system, such as active participation by consumers, will be a key element of our future electricity markets and systems.

In the context of the energy crisis, the current electricity market design has however also demonstrated a number of shortcomings. The reforms the Commission will undertake will address those shortcomings and ensure stable and well-integrated energy markets, which continue to attract private investments at a sufficient scale as an essential enabler of the European Green Deal objectives and the transition to a climate neutral economy by 2050.

In addition to these shortcomings, the European electricity sector is facing a number of more long-term challenges triggered by the rising shares of variable renewable energy and the progressive drive towards full decarbonisation by 2050. This includes ensuring investments, not just as regards renewables but also as regards weather independent low-carbon technologies until large scale storage and other flexibility tools become available. Stronger locational price signals in the system may be needed to ensure that the investments take place where they are needed, reflecting the physical reality of the electricity grid whilst at the same time ensuring incentives for cross-border long-term contracting. Some of these challenges will require ongoing policy reflections going beyond the scope of the current reform.

Making Electricity Bills More Independent from the Short-Term Cost of Fossil Fuels

The strong focus of the current market design on short-term markets, still very often determined by volatile fossil fuel prices, has exposed households and companies to significant price spikes with effects on their electricity bills. Many consumers found they had no option but to pay higher electricity prices driven by wholesale gas prices – either because they had no access to electricity cheaper electricity from renewable sources or could not install solar panels themselves.

The current regulatory framework regarding long-term instruments has proven insufficient to protect large industrial consumers, SMEs and households from excessive volatility and higher energy bills.

The gas price increase together with the strong role that short-term markets play in today's electricity market design have also boosted the revenues and profits well beyond the expectations of many generators with lower marginal costs such as renewables and nuclear ("inframarginal generators"), while receiving – in some cases - public support as well.

Short-term markets remain essential for the integration of renewable energy sources in the electricity system, to ensure that the cheapest form of electricity is used at all times, and to ensure that electricity flows smoothly between Member States. Whilst short-term price spikes can in general incentivize consumers to reduce or shift their demand, sustained high prices over a longer period translate into unaffordable bills for many consumers and companies.

This is why there is a need to complement the regulatory framework governing these short-term markets with additional instruments and tools that incentivise the use of long-term contracts to ensure that the energy bills of European consumers and companies - and the revenues of inframarginal generators - become more independent from the fluctuation of prices in short-term markets (often driven by fossil fuel costs) and thus more stable over longer periods of time. The reforms should create a buffer between consumers and short-term markets, ensuring that they will be better protected from extreme prices and that electricity bills better reflect the overall electricity mix and the lower cost of generating electricity from renewables. Electricity bills across Europe should depend less on the short-term markets, with an increasing share of consumers shifting into more stable and affordable longer-term pricing arrangements.

There are two main types of long-terms contracts which allow to pass on the benefits of renewables to all consumers. One is power purchase agreements (PPAs) between private parties which ensure that electricity is sold on a long-term basis at an agreed price, therefore not determined by short-term markets. Power purchase agreements bring multiple benefits. For consumers, they provide cost competitive electricity and hedge against electricity price volatility. For renewable projects developers, they provide a source of stable long-term income. For governments, they provide an alternative avenue to the deployment of renewables without the need for public funding. Although power purchase agreements are becoming more widespread in the EU and the Renewable Energy Directive obliges the Member States to remove unjustified barriers to their development, the overall market share of power purchase agreements remains limited. The growth of power purchase agreements is concentrated in some Member States only and confined to large companies.

The Commission will suggest ways in which the share of PPAs in the overall electricity market can be increased and their roll-out incentivised through the market design. The uptake of power purchase agreements, in particular by small and medium companies, can, for example, be more widely promoted by public tendering for renewable energy in which a share of a project could be contracted through power purchase agreements. Credit guarantees to power purchase agreements backed by public actors could be considered as a form of support that could efficiently drive the emergence of a power purchase agreement market. Potentially, measures could be considered to ensure that industrial consumers use the full potential of power purchase agreements to lower their exposure to short-term markets and that energy suppliers more actively enter into the power purchase agreement market.

The other type of long-term contracts applies where public support is needed to trigger investments, so-called two-way contracts for difference ("two-way CfDs"). These contracts ensure that the income of the generators in question (and the corresponding cost for consumers) provides an adequate incentive to invest and is less dependent on short-term markets. These contracts for difference are typically established by a competitive tender process, allowing support to be channelled to the projects with the lowest expected production costs. In situations of very high prices two-way CfDs would provide Member States with additional funds for reducing the impact of high electricity prices on consumers.

The upcoming reform offers an opportunity to present ways in which two-way CfDs can be integrated into the electricity market design. A number of issues need to be considered in this context, notably as to the extent to which the use of CfDs becomes mandatory for investments involving public support and whether the use of such contracts should only cover new generation assets entering the market or also certain types of existing generation assets.

In any case, given the multiple benefits of the power purchase agreements, the actions of the reform concerning the CfDs should not affect the development of the power purchase agreement market across the EU. Both instruments are necessary complements to achieve the necessary deployment of renewables.

- The simplest way to introduce two-way CfDs would be to complement the existing principles for support schemes with the specific ones to govern such contracts in the regulatory framework, with Member States deciding whether or not to use these instruments to drive new investments in inframarginal generation.
- A more binding way to anchor these contracts in the regulatory framework would be to require that all investments involving the use of public support rely on such contract structures. This would need to be carefully calibrated to ensure that CfDs provide the necessary incentives at the least cost for consumers.
- Another option would be to not only envisage the use of CfDs for new generation but also to allow Member States to offer contracts on certain types of existing inframarginal generators (e.g., for specific types of technologies). These contracts could be awarded to existing generation, where possible, on the basis of competitive bidding.
- A more far-reaching approach would be to not only envisage the use of CfDs for new generation but also to allow Member States to impose these contracts on certain types of existing inframarginal generators (e.g., for specific types of technologies). Contrary to the situation for new generation, the contracts for these types of existing generators would typically not result from market-based tendering but would result from ex-post price regulation. Whilst this would accelerate the uptake of contracts for difference, it would also create significant uncertainty for investors in renewables. This could risk the necessary investments in this type of generation, increase the costs of those investments and as a result be counterproductive.

Driving Renewable Investments – Europe’s Way Out of the Crisis

Increasing renewable energy deployment as well as electrification in general, is critical for Europe’s security of supply, the affordability of energy and achieving climate neutrality by 2050. The accelerated deployment of renewables and energy efficiency measures will structurally reduce demand for fossil fuels in the power, heating and cooling, industry and transport sectors. Thanks to their low operational costs, renewables can lower energy prices across the EU. Furthermore, faster deployment of renewable energy will contribute to EU’s security of energy supply.

Any regulatory intervention in the electricity market design therefore needs to preserve and enhance the incentives for investments and provide investors with certainty and predictability, while addressing the economic and social concerns related to high energy prices.

Alternatives to Gas to Keep the Electricity System in Balance

The consultation also covers ways to improve the conditions under which flexibility solutions such as demand response, energy storage and other weather independent renewable and low carbon sources, compete in the markets. These include measures aimed at incentivising the development of such flexibility solutions in the market (such as adapting the tariff design of system operators to ensure that they fully consider all flexibility solutions and use the existing network as efficiently as possible, allowing for access to more detailed data from electricity consumers through the installation of submeters or developing products to reduce demand or shift energy consumption in periods of high demand or prices) and targeted measures to improve the efficiency of the short-term markets, with particular focus on the intraday market (such as allowing trading across Member States closer to the delivery of electricity and further increasing the liquidity in this market). In addition, the consultation seeks input on how to safeguard security of supply and adequacy also in situations of unforeseen crisis to ensure timely investments in capacity.

Combined with renewable generation and enhanced investments in grid capacity and inter-connectivity, this should contribute to reducing the role that natural gas-fired generation plays as a flexible source of generation and will, over time, replace, and thereby, phase out natural gas-fired power generation in line with the EU's decarbonisation targets.

Lessons Learned from Short Term Market Interventions

During the crisis, a number of emergency and temporary market interventions have been introduced to mitigate the impact of high energy prices on consumers and companies. In the electricity market, the measure introduced at EU level is the so-called inframarginal cap, which softened the impact of high prices whilst requiring mandatory demand reduction.

The consultation seeks stakeholders' views on whether certain aspects of these emergency interventions could be turned into more structural features of the electricity market design, for example activated in future crisis situations, and if so, under what conditions.

Any such potential element of the reform would depend on the success of these measures in terms of limiting the impact of high electricity prices and on whether they can be introduced without harming the investment incentives required to achieve the decarbonisation of the power sector.

Better Consumer Empowerment and Protection

The energy crisis has exposed consumers across the internal market to higher energy costs – resulting in a real lowering of their standard of living. In some cases, customers face a choice between paying for their energy and buying other essential goods[1][2]. The crisis has also hit industry and service sectors increasing energy costs, particularly for energy intensive industry. This has given rise to cuts in production capacity, temporarily or permanent closures and lay-offs.

The Electricity Directive has not yet been fully implemented. Better implementation, and enforcement of consumer rights, would have helped mitigate the impact of the crisis for consumers. However, targeted improvements are also needed. This consultation covers different options for creating a buffer between consumers and short-term energy markets.

By giving consumers who want to actively participate in energy markets more opportunities do so, including by sharing energy to control their costs[3]. We can also better use digitalisation tools to make it easier for consumers with renewable heating or electromobility to manage their costs through avoiding the most expensive times of the day to use grid electricity. Even without being active on the market consumers need to be able to access longer term contracts for electricity, notably based on renewable power purchase agreements between suppliers and renewable producers. This will allow them to manage their costs and support new investments in renewable energy.

The crisis has also shown that often consumers pick up the costs when suppliers fail. This could be mitigated by requiring suppliers to be adequately hedged, combined with an effective Supplier of Last Resort Regime to ensure continuity of supply.

Finally, in cases of crisis it may be worthwhile enabling Member States to guarantee households and SMEs access to a minimum necessary amount of electricity at an affordable price, as was done in the Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices.

Stronger Protection against Market Manipulation

Regulation 1227/2011 on wholesale market integrity and transparency (REMIT) ensures that consumers and other market participants can have confidence in the integrity of electricity and natural 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 very high price volatility, external actors' interference, reduced supplies, and new trading behaviours, there is a risk that entities engage in illegal wholesale trading practices. There is therefore a need to ensure that the REMIT framework is up to date and robust. Further improvements would increase transparency, monitoring capacities and ensure more effective investigation and enforcement of cross-border cases in the EU to support new electricity market design.

Next Steps

The aim of the present public consultation is to give the opportunity to all stakeholders and other interested parties to provide feedback on a series of policy objectives to be pursued by the reform proposal and possible concrete legislative and non-legislative measures resulting from them.

The Commission intends to present a proposal for amendments to the electricity market design in March 2023. The replies to the present consultation should be provided by 13 February 2023 at the latest.

[1] See European Pillar of Social Rights, principle 20, and also the upcoming first EU Report on Access to Essential Services.

[2] See notably the Eurobarometer on "Fairness perceptions of the green transition", 10 October 2022

[3] Examples include allowing families to share energy among the different members located in different parts of the country; farmers installing renewable generation on one part of their farm and using the energy in their main buildings even if located a distance away; municipalities and housing associations including off-site energy as part of social housing, directly addressing energy poverty. Electricity production and consumption would need to take place at the same time which can be ensured by the use of smart metering.

About you

* Language of my contribution

- Bulgarian
- Croatian
- Czech
- Danish

- Dutch
- (selected) English
- Estonian
- Finnish
- French
- German
- Greek
- Hungarian
- Irish
- Italian
- Latvian
- Lithuanian
- Maltese
- Polish
- Portuguese
- Romanian
- Slovak
- Slovenian
- Spanish
- Swedish

* I am giving my contribution as

- Academic/research institution
- Business association
- (selected) Company/business
- Consumer organisation
- EU citizen
- Environmental organisation
- Non-EU citizen
- Non-governmental organisation (NGO)
- Public authority
- Trade union
- Other

* First name

Jan

* Surname

Eustachi

* Email (this won't be published)

jan.eustachi@eex.com

* Organisation name

255 character(s) maximum

European Energy Exchange AG

* Organisation size

- Micro (1 to 9 employees)
- Small (10 to 49 employees)
- Medium (50 to 249 employees)
- (selected) Large (250 or more)

Transparency register number

255 character(s) maximum

Check if your organisation is on the [transparency register](). It's a voluntary database for organisations seeking to influence EU decision-making.

09579576238-53

* Country of origin

Please add your country of origin, or that of your organisation.

This list does not represent the official position of the European institutions with regard to the legal status or policy of the entities mentioned. It is a harmonisation of often divergent lists and practices.

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Algeria	Ecuador	Luxembourg	Samoa
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Belize	Ghana	Montserrat	Sri Lanka
Benin	Gibraltar	Morocco	Sudan
Bermuda	Greece	Mozambique	Suriname
Bhutan	Greenland	Myanmar/Burma	Svalbard and Jan Mayen
Bolivia	Grenada	Namibia	Sweden
Bonaire Saint Eustatius and Saba	Guadeloupe	Nauru	Switzerland
Bosnia and Herzegovina	Guam	Nepal	Syria
Botswana	Guatemala	Netherlands	Taiwan
Bouvet Island	Guernsey	New Caledonia	Tajikistan

Brazil	Guinea	New Zealand	Tanzania
British Indian Ocean Territory	Guinea-Bissau	Nicaragua	Thailand
British Virgin Islands	Guyana	Niger	The Gambia
Brunei	Haiti	Nigeria	Timor-Leste
Bulgaria	Heard Island and McDonald Islands	Niue	Togo
Burkina Faso	Honduras	Norfolk Island	Tokelau
Burundi	Hong Kong	Northern Mariana Islands	Tonga
Cambodia	Hungary	North Korea	Trinidad and Tobago
Cameroon	Iceland	North Macedonia	Tunisia
Canada	India	Norway	Türkiye
Cape Verde	Indonesia	Oman	Turkmenistan
Cayman Islands	Iran	Pakistan	Turks and Caicos Islands
Central African Republic	Iraq	Palau	Tuvalu
Chad	Ireland	Palestine	Uganda
Chile	Isle of Man	Panama	Ukraine
China	Israel	Papua New Guinea	United Arab Emirates
Christmas Island	Italy	Paraguay	United Kingdom
Clipperton	Jamaica	Peru	United States
Cocos (Keeling) Islands	Japan	Philippines	United States Minor Outlying Islands
Colombia	Jersey	Pitcairn Islands	Uruguay
Comoros	Jordan	Poland	US Virgin Islands
Congo	Kazakhstan	Portugal	Uzbekistan
Cook Islands	Kenya	Puerto Rico	Vanuatu
Costa Rica	Kiribati	Qatar	Vatican City
Côte d’Ivoire	Kosovo	Réunion	Venezuela

Croatia	Kuwait	Romania	Vietnam
Cuba	Kyrgyzstan	Russia	Wallis and Futuna
Curaçao	Laos	Rwanda	Western Sahara
Cyprus	Latvia	Saint Barthélemy	Yemen
Czechia	Lebanon	Saint Helena Ascension and Tristan da Cunha	Zambia
Democratic Republic of the Congo	Lesotho	Saint Kitts and Nevis	Zimbabwe
Denmark	Liberia	Saint Lucia	

To which category of stakeholder do you belong?

- [ ] a) National or local administration
- [ ] b) National regulator
- [ ] c) Transmission System Operator
- [ ] d) Distribution System Operator
- [ ] e) Market operator
- [ ] f) Energy company with generation assets
- [ ] g) Independent energy supplier with no generation assets
- [x] h) Company conducting business in the energy sector no included in f) or g)
- [ ] i) Industrial consumer and associations
- [ ] j) Energy community
- [ ] k) Academia or think tank
- [ ] l) Citizen or association of citizens
- [ ] m) Non-governmental organisations
- [ ] n) Other

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Please provide feedback only on the questions that are relevant for you. Questions can be left blank.

Making Electricity Bills Independent of Short-Term Markets

Subtopic: Power Purchase Agreements (PPAs)

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 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.

[1] 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 Accompanying the document Commission Recommendation on speeding up permit-granting procedures for renewable energy projects and facilitating Power Purchase Agreements SWD/2022/0149 final
[2] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52008XC0620%2802%29

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?

- (x) Yes
- ( ) No

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

2000 character(s) maximum

1. Regulatory risk: The current crisis has led to structural market interventions (e.g., inframarginal revenue claw-back) resulting in significant market uncertainty, thereby reducing the volume of contracted PPAs. With stabilizing market conditions, the PPA uptake is increasing again, as demonstrated by the latest conclusion of two long-term hedges executed in EEX's Spanish Power Futures (from CAL-27 to CAL-31), totaling 1.1 TWh shows.
2. Permitting: regulatory complexity, uncertainty, & lengthy procedures, discourage investors, delay projects, & increase costs.
3. National subsidy schemes for competitive renewable energy sources such as two-way state backed CfDs limit the PPA market to become more mature.
4.Lack of knowledge with developers & investors on the possibilities of existing market instruments to hedge their risks, e.g., price risk, volume risk, counterparty risks can be hedged via existing trading products & clearing on energy exchanges & central counterparties.
5.Need to strengthen & facilitate market-based platforms already in existence providing small- & medium sized actors with access to PPAs (e.g., increasing standardization & transparency).
6.Need for liquidity support for risk management of PPAs: Initial margin requirements for long-term PPA hedges were stable at 3-7% in terms of notional value before the current supply crisis.
7.Adverse effects from IFRS accounting: depending on design, PPAs are classified as financial instruments consequently leading to further requirements under financial regulation (MiFID II) and financial accounting standards (IFRS). This can lead to additional reporting obligations up to adverse financial ratings as a PPA is rated as a long-term obligation in the profit & loss statement of a company.
8.Regulatory barriers affecting the transfer of GOs to off-takers, e.g., it would be beneficial to harmonize rules for the use of GOs across countries and support the development of reliable GO-systems in third countries.

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

at most 6 choice(s)

- [x] a) Pooling demand in order to give access to smaller final customers
- [x] 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
- [x] d) Supporting the standardisation of contracts
- [ ] e) Requiring suppliers to procure a predefined share of their consumers' energy through PPAs
- [x] f) Facilitating cross-border PPAs

Do you have additional comments?

2000 character(s) maximum

Under normal market circumstances with lower regulatory uncertainty, PPAs have proven themselves as an important hedging tool. Already today, PPAs are a crucial building block for utilities to adequately hedge their risk exposure in combination with other market-based instruments. It is therefore of outmost importance to ensure regulatory stability and evaluate different market-based hedging options in detail with market participants to identify further potential improvements.
a) Promote the availability of experienced intermediaries that already today provide pooling and risk-management services to small- and medium sized market participants. In addition, small- and medium-sized market participants should be further educated on already existing options for market-based risk management.
b) Market participants should make use of existing market-based instruments to protect them against potential price risks. One of the biggest risks in such long-term contracts is counterparty risk which can effectively be hedged with long-term cleared products.
c) State-support schemes should not interfere with market-based PPAs as they will result in significant market distortions.
d) An increased standardization of short-term PPAs would positively result in the product being more tradeable and in a more efficient conclusion of PPAs. The more standardized the product becomes, the better it can be traded among market participants.
e) Suppliers should not be required to procure a pre-defined share of their consumers' energy through PPAs. Market participants with an adequate hedging culture should make use of market-based hedging instruments to optimally hedge their individual risk profile.
f) Cross-border PPAs should be further facilitated by investing in sufficient cross-border transmission capacities as well as further harmonization of the regulatory framework.

In addition to the measures proposed in the question above, 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?

- (•) Yes
- ( ) No

If yes, please explain which rules should be revised and the reasons.

2000 character(s) maximum

1. As stated in our answer to question number 2, reducing uncertainty regarding regulatory risk for market participants should be the clear priority to foster PPA growth. The need for regulatory certainty for investments to take up is currently largely underestimated in the political debate.
2. Already today, EEX lists power futures for 20 European markets. In addition, EEX extended yearly futures to CAL+10 in markets with high potential of PPA activity (DE, ES & IT), to facilitate long-term hedging and provide additional market-based instruments to strengthen PPA development.
3. Member states should refrain from unnecessary structural market interventions and especially avoid that already implemented claw-back mechanisms, such as the inframarginal revenue caps, are prolonged. Uncoordinated structural market interventions lead to significant uncertainty and further distort investors' confidence. As a result, and within the overall high-level of uncertainty due to the ongoing energy supply crisis, such mechanisms further limit the willingness of investors to engage in long-term contracts such as PPAs.

Do you see a possibility to provide stronger incentives to existing generators to enter into PPAs for a share of their capacity?

- (•) Yes
- ( ) No

If yes, under which conditions? What would be the benefits and challenges?

2000 character(s) maximum

In general, the underlying principle should be freedom of choice. It is of utmost importance that market participants can identify and make use of the most adequate hedging solution in accordance with their respective risk profile. Already today, most generators and consumers follow an adequate hedging strategy by hedging large parts of their revenues and costs well in advance. In addition, and as the market evolves, the level of sophistication of RES investors will further increase making them more accustomed to the usage of market-based risk management instruments such as PPAs and financial derivatives.

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
- (•) No

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

	Yes	No
(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	○	◉

Please explain

2000 character(s) maximum

a) It depends on the specificities of the individual PPA. Virtual and financial PPAs are based on a strike price agreed upon in the spot market and therefore still allow the flow of volumes into the latter. A purely physical PPA with direct delivery indeed entails the risk of cannibalizing the short-term market.
b) Small- and medium sized actors can currently gain sufficient access to PPAs via intermediaries. We see these conditions further improving with an additional up-take of PPAs. Standardization will further increase allowing small- and medium size actors to better understand and conclude PPAs. Increasing liquidity within the PPA market eases the process of market participants to find their adequate counterparts and reduces overall transaction costs.
c) No but, the regulatory framework for PPAs needs to be harmonized on a European level. The more regulatory complexity and uncertainty there is, the harder it will be for PPAs to evolve.
d) PPAs are an important market-based cornerstone to promote the roll-out of renewables.
e) PPAs contribute to risk management and stability of revenues and costs.

Subtopic: 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).

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
- ○ No

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

- ◉ Yes

No

Do you have additional comments?

2000 character(s) maximum

Under the current framework conditions, forward hedging is a highly efficient way to mitigate exposure to short-term volatility. At the European level, the liquidity between bidding zones might vary, but this does not lead to an inability for market participants to properly hedge themselves in the forward market. Already today, location spread products offered by exchanges can be traded continuously complementing the continuous nature of electricity trading. Therefore, LTTRs are not needed since spread products provide the same hedging opportunities. This is also true if LTTRs should be turned into FTR obligations (see ACER Policy Paper on the Further Development of the EU Electricity Forward Market) reflecting the functioning of spread futures. Consequently, forward hedging represents a highly efficient way to mitigate exposure to short-term volatility and should remain the primary hedging instrument. Against this background, we call for a detailed impact assessment to precede any further changes to the current design of forward markets.

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

2000 character(s) maximum

In many cases, liquidity issues prevent their entering into forward contracts. Causes of liquidity issues can differ between different bidding zones. A generalization of liquidity problems in the forward market across bidding zones does not adequately reflect this complexity. But we can identify throughout the different bidding zones, that in the light of the recent energy supply crisis market participants have overall reduced demand for long-term hedging due the increased level of uncertainty about future regulatory market framework. Structural national interventions hindering the building up of liquidity in certain bidding zones, such as subsidies on fossil, renewable and nuclear investments or regulated tariffs should be tackled with priority. Location spread products offered by exchanges can be traded in a continuous manner complementing the continuous nature of electricity trading. In case of deviating levels of liquidity for forward products in different bidding zones market participants can chose to either hedge themselves directly in the less liquid product or to use a locational spread product with the more liquid product to manage basis risk.

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

- ○ Yes
- ● No

Do you have additional comments?

2000 character(s) maximum

In general, market participants should be able to freely decide on the appropriate management of their risks, but incentives to follow an adequate hedging culture should be provided. While increased hedging would indeed have a positive impact on reducing price volatility, obliging electricity suppliers to hedge a certain share of their supply could lead to higher electricity prices for consumers as suppliers will incur additional costs they may have otherwise chosen to avoid. After the experiences made during the energy supply crisis, market participants should have a natural incentive to be hedged in the future to avoid being exposed to highly volatile spot prices.

Do you consider that the creation of virtual hubs for forward contracts complemented with liquid transmission rights would improve liquidity in forward markets?

- ○ Yes
- ◉ No

Do you have additional comments?

2000 character(s) maximum

To provide adequate solutions to the functioning of the forward market, it is crucial to analyze in detail the specificities hampering liquidity in the respective bidding zones. While in theory the virtual hub option may seem like a potential solution, it is disconnected from the physical realities of the underlying spot markets and an improper hedging instrument to manage basis risk. A hub with liquid transmission rights does not solve the problem as:

1. The transmission rights between the hub and a smaller zone within the hub will remain illiquid, since the same market participants that are interested/not interested in trading the smaller zone will be interested/not interested in trading the transmission rights. Any program to make these transmission rights more liquid can also be applied to the small zone in the first place. Thus, creating a hub with transmission rights only transforms the problem without solving it, at the expense of turning market structures upside-down.
2. There is no spot market that corresponds to the hub. However, it is the strong connection of physical spot markets and derivative trading that creates a perfect hedge to these spot markets that drives liquidity in these derivatives. This means that the hub market might turn out to be relatively illiquid.
3. There is no reason why market participants should prefer a hub over a liquid neighboring market. If we take the example of the German bidding zone: market participants based in Germany will have little incentives to trade a hub containing Germany. A hub containing Germany will therefore lack a large amount of liquidity and will likely be less liquid than the German bidding zone. Neighboring markets must therefore have a strong preference for the hub price compared to the German price to trade the hub instead of the German market. Such strong preference can only arise if the hub price is sufficiently different from the German price on a yearly average. As of today, this seems unlikely.

Do you have experience with the existing virtual hubs in the Nordic countries?

- ◉ Yes
- ○ No

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

2

Do you have additional comments related to the existing virtual hubs in the Nordic countries?

2000 character(s) maximum

While in theory this option may seem like a potential solution, it is disconnected from the physical realities of the market. This can be seen if we look at the Nordic market. In the past, in times where there was limited congestion, the model did not show any deficiencies. But after splitting the Nordic market into different bidding zones, this hub no longer allows for a proper hedge. Consequently, the trading volumes in the Nordics have experienced a continuous downtrend over the last years, resulting in a current overall market volume which is less than half the size compared to 5 years ago. Furthermore, the solution is not neutral to bidding zone reconfigurations. The liquidity of the reconfigured bidding zone would be affected just as much as without the hub configuration. Finally, the Zone-to-Hub option leads to liquidity issues being shifted to the Hub-to-Zone risk. Market participants will therefore continue to have exposures in individual bidding zones.

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?

3000 character(s) maximum

We do not see ways of supporting the development of forward markets through changes of the electricity market framework, priority should be given to the implementation concerning the forward capacity allocation (FCA), the improvement of the permitting process for renewable technologies, the removal of barriers for the conclusion of PPAs as well as focusing on the following principles:
1. Enhance predictability of market design to allow market participants to enter long-term hedging positions and make use of already existing products (e.g., EEX Cal+10).
2. Refrain from structural market intervening policies (e.g., Iberian exception) increasing uncertainty and consequently decreasing forward market liquidity.
3. Avoid subsidies (e.g., state-backed contracts for difference (CfDs)) for competitive technologies reducing competitive pressure thereby minimizing demand for market-based hedging.
4. Use already existing instruments such as locational spread products offered by exchanges to increase forward market liquidity.
5. Weigh bidding zone configuration against market harm such as a loss in liquidity.

In addition to improvements in the electricity market framework further aspects in clearing and settlement of forward markets could foster the development of forward markets:
• Broaden the pool of eligible collateral under the European Market Infrastructure Regulation (Regulation (EU) 648/2012) for improved flexibility in meeting margin requirements.
• Support access to financing of margin requirements in exceptional market situations to allow continued hedging when it is needed most.

Subtopic: Contracts for Difference (CfDs)

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.

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)?

- ○ Yes
- ● No

Do you have additional comments?

2000 character(s) maximum

The mechanism behind contracts for difference covering fluctuations against an underlying asset is anything but new in energy trading – it is widespread practice. Derivatives market contracts are used to hedge a price. Deviations in the underlying physical spot market are settled between the counterparties. This is guaranteed by the exchange and its clearing house. However, the decisive difference compared with the present discussion on the introduction of CfDs is that trading participants assume the risks involved in their contracts. But, at present, advocates of this instrument for funding of renewables via a two-way state backed CfDs are asking for the full socialization of the risk of investments, with the state assuming this risk. Instead of commercial hedging contracts and clearing via Clearing House, the state would become the counterparty of all transactions. The introduction of state-backed 2-sided CfDs for the expansion of renewables would constitute a break with the approach of gradual market integration of all types of generation in a joint market, which has been developed and implemented over many years. It would also move away from the principle of a market-based energy transition in which trading participants align their activities to the market price signal. A fundamental change to the funding system would reduce hedging incentives significantly, thus reducing the liquidity in forward markets, and weakening the forward market price signal. The prices determined on the wholesale market are important indicators for scarcity in the power system both in the short and long-term perspective. Wholesale market prices are the impulses for investment in generation, consumption, hedging, flexibility, and act as a driver for innovation. These incentives coordinate the power market and are indispensable for the energy transition.

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?

- [ ] Yes
- [x] No

Do you have additional comments?

2000 character(s) maximum

To speed up the roll-out of renewables and ensure the minimization of costs on the end-consumers, market ready renewable technologies need to be fully integrated into the market to contribute and to be exposed to an efficient price signal. Fully market integrated renewables are both necessary and feasible. It is in the interest of the end-consumer that subsidies for mature technologies are avoided.
Investment grants for immature technologies, situated outside of the market, are the sole form of aid that should be used. This form of subsidy ensures that the financial resources are effectively directed where they are needed and does not distort competition or the integrity of the internal market. As investment aid lowers the risk of market distortions compared to operating aid and is easier to phase out, support schemes should be designed as a form of direct payment or tax relief. In addition, and as stated in the EEAG support study published by the Directorate-General for Competition in 2021, grants had the highest effect on investment levels and investment aid did not score lower than operating aid regarding the effective securitization of investment. Finally, operating aid can have considerable distortive effects on liquidity of energy markets and the weakening of the price signal can even work against the overall objective of a carbon neutral economy by 2050.

What power generation technologies should be subject to two-way contracts for difference or similar arrangements?

2000 character(s) maximum

As stated in our answers to questions 1 and 2, we are extremely critical of two-way state backed contracts for difference due to their distortive effects on electricity markets. Consequently, no power generation technologies should be subject to two-way state backed contracts for difference. Financial assistance for capital intensive non-mature technologies should always be provided via an investment aid and not a market distorting operating aid.

Why should those technologies be subject to two-way contracts for differences or similar arrangements?

2000 character(s) maximum

Two-way state backed CfDs should not be used, because they prevent full market integration of renewable technologies. As stated in our answers to questions 1 and 2, the State should not assume the financial risk for renewable volatility. Improved demand side flexibility is a more efficient and non-distortive way to fulfil this task. Additionally, the significant initial cost of renewable installations is only one piece of the puzzle. Equal attention should be paid to extending and upgrading electricity grids and investing in storage and other complementary technologies to ensure the energy system can accommodate larger volumes of intermittent generation of renewables.

What technologies should be excluded and why?

2000 character(s) maximum

In reference to our answer provided under question 2, all technologies should be excluded from a two-way state backed CfD. It is of utmost importance to fully integrate market-ready technologies for them to contribute and to be exposed to an efficient price signal. Market integration will not only result in the speed-up of renewables deployment and their system-supportive dispatch but to the minimization of costs for the end-consumer. For immature technologies investment aid should always be the preferred subsidy option to avoid market distortions.

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?

2000 character(s) maximum

• Uncertainty as to how the state guaranteed CfD system can be integrated into an overall concept for investment in inframarginal technologies and their system integration.
• Danger of a slippery slope away from market principles.
• State backed two-way contracts for difference have a detrimental effect on market liquidity, market liquidity, lower hedging possibilities for uncovered technologies and reduce the need for system integration.
• New, extensive funding programs worsen the market perspective for plants after the end of their funding period and call into question sector integration. Innovation towards the full market integration of competitive renewable technologies is prevented as CfDs prevent a proper incentive to do so.

To avoid the risks outlined above, existing market-based instruments such as futures should be used more extensively by market participants to hedge their respective risks. For immature technologies investment grants should support initial investment.

What design principles could help mitigate the risks identified in your reply to the question above, in particular, in terms of procurement principles and pay out design? Should these principles depend on the technology procured?

2000 character(s) maximum

As stated in our response to question 1, we urge the Commission to take into consideration the potential detrimental effects of CfDs on the forward market and therefore clearly refrain from the promotion of this subsidy scheme.

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?

2000 character(s) maximum

Please refer to the answers provided above.

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

2000 character(s) maximum

Please refer to the answers provided above.

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?

2000 character(s) maximum

We are extremely critical of CfDs, due to the reasons outlined in the answers above. If nonetheless CfDs - or any other operational aid subsidy scheme like feed-in tariffs - are applied for a certain period, the generation assets should be integrated into the market after the clearly pre-defined expiry date of the scheme. This market integration is essential to continuously improve the marketing of power generated from renewable energy sources. This has the objective of ensuring that producers and consumers of power from renewable systems respond fully to the market price signal. In this context, the requirement is that income from marketing on the power markets is maximized while government funding/aid is minimized. The use of market mechanisms avoids misallocations, which would otherwise be caused because of the assumption of risks by the state.

Without prejudice to Article 6 of Directive (EU)2018/2001[1], should it be possible for Member States to impose two-way CfDs by regulatory means on existing generation capacity?

[1]

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.

Article 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.

- ○ Yes
- ● No

Do you have additional comments?

2000 character(s) maximum

We do not support the retroactive application of CfDs. As stated before, regulatory uncertainty is one of the main barriers to investment in the EU.

How would you rate the following potential risks as regards the imposition of regulated CfDs on existing generation capacity?

	Negligible risks	Low risks	Medium risks	High risks	Very high risks
Legitimate expectations/legal risks	○	○	○	○	●

Ability of national regulators/governments to accurately define the level of the price levels envisaged in these contracts	○	○	○	○	●
Locking in existing capacity at excessively high price levels determined by the current crisis situation	○	○	○	○	●
Impact on the efficient short-term dispatch	○	○	○	○	●

How would you address those potential risks as regards the imposition of contracts for difference on existing generation capacity?

2000 character(s) maximum

a) Any attempt to force CfDs on existing generation capacity will face extreme legal risks, heavily harming property rights. It would increase regulatory uncertainty for the coming years.
b) The definition of the strike price by the respective regulators/governments faces the risk of not reflecting a reasonable price level. An inefficient administrative setting of a CfD strike price will on the one side lead to significant economic losses for market participants investing in the energy transition. If set too low, it might tighten the availability of financial resources for the transition. If the strike price is too high, the state budgets will be put under pressure. Furthermore, it would introduce an unnecessary complexity when it comes to allocation, as strike prices do not only differ between technologies but also between projects.
c) There is a risk of choosing a too high strike price for a long-term CfDs. However, the definition of a too high strike price is difficult to determine when entering a CfD. The huge advantage of an exchange-registered long-term contract compared to a CfD is that each party can leave the contract (close the position at the current market price) in case its expectations change. This is not possible with a CfD.
d) The negative impacts of forcing CfDs on existing generation assets for short-term dispatch are the same as the negative impacts of any (voluntary) CfD. CfDs result in a "produce and forget" attitude, which potentially impedes activity on short-term markets or at least impedes reasonable behavior on short-term markets. If we want asset operators to be responsible for their short-term dispatch (and if we want them to take on balancing responsibility), short-term markets are the only reasonable way to organize short-term dispatch. If more volume is disregarding the signals sent by the short-term markets, grid operators will have to get more active in redispatch & system services, which results in higher costs for end consumers.

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

- ○ Yes
- ● No

Do you have additional comments?

2000 character(s) maximum

As already expressed in our answers above, we oppose imposing any measure on the existing generation. Consequently, the existing generation should neither be subject to a simple revenue ceiling, nor to a revenue guarantee.

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?

2000 character(s) maximum

CfDs, PPAs and forward hedging all have one thing in common: they are tools to agree on a price already now to be paid in the future. In this sense, they can all mitigate price volatility and - if set at an appropriate level - support investment in new capacity. If the price is determined in a competitive process, it can be expected that it is set at or close to the expected long-run cost in all the three contract forms.
However, there are significant differences between the three contracts. One counterparty in a CfD is the state and it must be questioned if the state is best placed to take part in price definition. Especially in the case of forced CfDs, free and competitive price formation is not given.
This is different from PPAs. PPAs - because they usually are negotiated for an individual generator and a consumer - offer a lot of room for detailed, individually agreed rules, be it regarding start of production, minimum or maximum takeoff etc. In addition, PPAs can lead to a "produce and forget" attitude on the generators' side - but here this attitude is balanced with the guaranteed take-off of a concrete consumer. Thus, PPAs do not lead to inefficient dispatch behavior, as opposed to two-way state backed CfDs.
Forward hedging, as opposed to PPAs and CfDs does offer much more tradability due to the standard contracts' specifics. So, while all three contract types can bring about a reduction of price volatility, revenue certainty for investments and potentially prices reflecting (expected! not necessarily real!) long-term costs, they come with different weaknesses, which are especially pronounced in the case of two-way state backed CfDs (refer to our CfD-related answers above).

Subtopic: 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[1].

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.

[1] 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

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Do you consider that a transmission access guarantee could be appropriate to support offshore renewables?

- ( ) Yes
- ( ) No

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

	Yes	No
At national regulatory or administrative level	(•)	( )
In the implementation of the current EU legislation, including by developing network codes and guidelines	(•)	( )
Via changes to the current electricity market design	( )	(•)
Other	( )	( )

If yes, please specify

2000 character(s) maximum

a, b) The energy system must be fit for the expected increase in renewable production – decentralized and volatile. Congestion might increasingly become an issue for the EU energy network. Therefore, the development of local flexibility markets for market-based congestion management is a mandatory complement to the necessary but costly grid expansion. Such markets represent a ‘’soft’’ and cost-efficient solution to complement grid development for tackling congestion through making best use of system flexibility increasing demand-side flexibility (see also question 3 below).
At EU level, to increase the deployment of flexibility solutions, the Network Code on Demand Response should be swiftly finalized.

At national level, Member States should fully implement the EU Clean Energy Package, which sets the pace for a renewed approach to congestion management, favoring market-based solutions as well as market-based flexibility procurement and prompting system operators to better coordinate their operations, all for the sake of a cost-efficient energy transition. As provided by the CEP, Member States should apply the Regulation (EU) 2019/943 Art. 13, providing congestion management has to be market-based, and transpose into national legislation the Directive (EU) 2019/944 Art. 32, providing DSOs need to consider alternative options to grid investments such as market-based flexibility procurement.

Boost renewables through markets: the successful path towards full market integration of renewables shall be continued. Support schemes should be progressively phased out where not needed anymore, and replaced by all possible market remunerations, i.e., power exchange, GOs, PPAs, etc. This leads to more efficient market price formation and saves taxpayers'/ electricity consumers' money. The EU Guarantees of Origin (GOs) market can potentially become the main EU-wide support mechanism.

Do you have additional comments?

2000 character(s) maximum

(c) The existing electricity market design based on a marginal pricing, zonal model and portfolio-bidding is the best possible market design for incentivizing the deployment of renewables, as it ensures the cheapest generation capacities are always activated first. Within an energy future characterized by a high share of decentralized renewable energy, it would make no sense to centralize the EU power markets, developing a nodal market design with central dispatch. As data on renewable generation indicated, the existing electricity market design is fit-for-purpose for staying on track with EU Green Deal trajectory. Indeed, in 2022, wind and solar production scored a record of 22% in Europe electricity generation mix, passing gas generation for the first time (https://ember-climate.org/app/uploads/2023/01/Report-European-Electricity-Review-2023.pdf). Yet, more can be achieved: before making up new legislations to change the overall design of energy markets, it would be important to complete the EU power market integration, implementing what has already been agreed upon, i.e., the Clean Energy Package, through the following: achievement of 70% cross-border capacity made available and market-based TSO-DSO procurement of flexibility to optimize grid investments (see point a) and b)). Furthermore, EU spot power markets can be further integrated by (i) implementing the Nordic Flow Based Market Coupling, (ii) adding one Pan-European Intraday Auction only when recalculation of capacity is guaranteed, (iii) harmonizing and shortening the time interval for which the market price is established and (iv) coupling the borders with the neighboring countries of the EU. Finally, when it comes to the foundations of the Internal Energy Market, we strongly advocate against a fundamental change of both, the market design and the governance of market coupling.

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?

4000 character(s) maximum

The introduction of further renewables in the system risks creating local congestion at the Transmission and Distribution grid levels. We believe that the introduction of local flexibility markets will allow to lower the requirements to reinforce the network infrastructure or postpone it, with

1. a better allocation of flexibility resources,
2. the creation of price signals to foster the investment in flexibility resources, and
3. a better coordination between TSOs and DSOs for the use of local flexibilities

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Subtopic: 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.

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

- ( ) Yes
- (x) No

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

0

(b) its impact on decarbonisation

0

(c) security of supply

0

(d) investment signals

0

(e) legitimate expectations/legal risks

0

(f) fossil fuel consumption

0

(g) cross border trade intra and extra EU

0

(h) distortion of competition in the markets

0

(i) implementation challenges

0

Do you have additional comments?

3000 character(s) maximum

We strongly believe the inframarginal revenue cap should not be prolonged after 30 June 2023, as agreed in the Council Regulation 2022/1854. We regret to see several Member States have implemented it, extending way beyond that deadline. Revenue caps on inframarginal technologies should not become a structural feature of the EU market design. If not well-devised, revenue caps can virtually become price caps, distorting the merit order, disrupting the price signal and endangering security of supply. It is fundamental that price signals are left intact, to strengthen investment incentives. In addition, the effectiveness of such instruments can be questioned, namely the revenue target expected by politicians might not be met. For example, the ‘' windfall profit'' tax implemented in Spain in September 2021, has only raised €366 million until mid-2022, instead than the expected €9 billion (from: Eurelectric letter addressed to Commissioner Simson).

Finally, the unfolding of the revenue cap today in place across Europe has highlighted several drawbacks. During the last few months, each Member State has introduced complex cap mechanisms, which often differ from each other, fragmenting the Internal Energy Market into a complex patchwork of national schemes.

More in detail,
a) Its effectiveness depends on governments' ability to collect revenues and redistribute them to consumers. The mechanism itself does not mitigate the impact of price volatility for consumers.
b) Such government interventions significantly reduce investors' certainty, endangering the EU decarbonization trajectory
c) If not well-designed, namely if the cap is set at a threshold that does not let certain generators to cover their short- and long-term costs, we risk those to withdraw capacity, endangering security of supply
d) See point b); moreover, the revenue cap might not fit with the reality of PPAs. For example, in Germany, it remains unclear whether existing or potentially new PPAs should be treated equally or differently. Overall, such uncertainty can decrease liquidity on long-term markets.
e) The existing revenue cap has been legally challenged by several actors
f) Such government interventions endanger the EU Green Deal trajectory
g) The patchwork of national cap schemes across Europe can affect cross-border trade significantly, also with non-EU countries, which do not apply the same cap mechanism
h) As in point g), diverging caps distort the EU level playing field
i) Several months were necessary to implement the existing revenue cap by all Member States and many elements have been hardly sorted out (e.g., bodies responsible for necessary data collection and provision).

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

- ( ) Member States
- (•) EU

Do you have additional comments?

2000 character(s) maximum

Despite the drawbacks, if the EU decided to introduce such measure, it should be introduced in a uniform manner across the EU. Yet, a better alternative exists: a ‘‘solidarity contribution’’ tax for the whole electricity sector, such as the one agreed upon in the Council Regulation 2022/1854. This would resolve some of the drawbacks identified above: it would apply completely ex-post after market settlement, avoid complex implementation and destructive effects on electricity markets, refer to actual realized profits, and it could cover also realised gains on the retail level, besides the wholesale.

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?

3000 character(s) maximum

First, any form of government subsidy should only be targeted to vulnerable end-consumers, SMEs and industries. For non-vulnerable end-consumers, changes in price level should be seen as an efficient instrument for incentivize demand response.
Nevertheless, any subsidy scheme should still foresee demand reduction incentives, for example during peak hours. The goal of governments is to provide vulnerable end-consumers with direct monetary support, while encouraging demand reduction initiatives and preserving the correct functioning of electricity markets.
A mechanism that allocates revenues proportionally to previous year electricity consumption would leave out any incentives for demand reduction.

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-related 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. the sections above), 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 observability 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 sub-meter 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 markets. 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.

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

	Yes	No
(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	◉	○

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?

- ○ Yes
- ◉ No

Do you have additional comments?

2000 character(s) maximum

The wholesale electricity markets' price formation mechanism is based on marginal pricing, ensuring the cheapest generation capacities are always activated first, and so, demand is always met at the lowest possible cost. This mechanism gives investment signals in new clean technologies and allows power generators to cover their costs, eventually ensuring security of supply. Marginal pricing guarantees the best resources' allocation mechanism, in terms of their cost and efficiency: it activates the most economic and environmental efficient resources and delivers electricity where and when most needed, even across borders. Such mechanism creates dispatch signals that allow the deployment of most cost-efficient resources, such as renewables and flexibility assets. Further, marginal pricing has strengthened the solidarity principle among Member States, flowing energy where it is most needed. So far, alternative pricing models, which can provide a resources allocation, which is as much cost-efficient as marginal pricing, do not exist.

In addition, another proposal about market design configurations consists of substituting the European Day-Ahead auction following a pay-as-clear model based on marginal pricing with an alternative market set up – pay-as-bid, as implemented on the Intraday continuous market. If the pay-as-bid mechanism were applied in the day-ahead market, market participants would try to anticipate the market clearing price and bid above their marginal costs in order to maximize their profits. Hence, the power generation units' activation priority would be based on the traders' ability to best forecast the market price, instead of on their economic and environmental efficiency. Therefore, a shift from marginal pricing would generate negative consequences but not lower energy prices.

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

3000 character(s) maximum

By internalizing the cost of carbon emissions, it will become more expensive for companies to emit greenhouse gases, making low-carbon flexibility and storage solutions more attractive. Encouraging demand response will also be aided by carbon pricing as the EU ETS provides a clear incentive for consumers to shift their demand to times when low-carbon generation is abundant and prices are lower, increasing the offer of flexibility and the demand for additional storage solutions.

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)?

- (x) Yes
- ( ) No

Do you have additional comments?

2000 character(s) maximum

The market participants should be allowed to trade as close to real time as possible to balance their needs.

However, the importance of trading close to real time for the integration of renewables must be nuanced. Indeed, with the improvement of weather forecasting in recent years, an accurate prediction of renewable outputs is usually available well in advance of the last hour. Many of the corrections in day-ahead forecast error for renewables generators are now carried out before the last hour and the forecast error accuracy gains are only incremental in the last hour. What is key for the facilitation of renewable integration is therefore innovation and the introduction of new products, rather than trading close to real time.

The importance of the last hour mainly depends on market design, market structure, country size, power generation mix, and even more so on the features of the European balancing markets. In addition, balancing requirements influence greatly the volumes of trade in the intraday market.

Most importantly, the possibility to trade closer to real time is subject to the ability of TSOs to manage a closer to real time allocation of cross-border capacity. Indeed, if no cross-border capacity is available, there is no justification for shifting the cross-border intraday gate closure time and pooling the liquidity closer to real time.

Do you consider that market operators should share their liquidity also for local markets that close after the cross-border intraday market?

- Yes
- (x) No

What would be the advantages and drawbacks of sharing liquidity in local markets after the closure of the cross-border intraday market?

2000 character(s) maximum

On every market, effective and fair competition is the key principle. It is only in very exceptional cases that a regulatory framework may provide for the mandatory sharing of a facility or property. The sharing of liquidity between the cross-zonal intraday gate opening and gate closure times, as a clear interference in the market, was taken at the expense of competition between power exchanges, to facilitate cross-border trade.
However, preserving healthy competition between power exchanges & between other players contributes to accurate price on the spot market, innovation on exchange platforms & investment signals for new sources of energy, which are central for the cost-effective integration of renewable technologies in the electricity mix.
Besides, trading is also possible with other marketplaces or OTC offering facilitation services. The further socialization of liquidity between NEMOs will create an unlevel playing field between NEMOs and other providers of trading options. Moreover, there is no rationale for market operators to share their liquidity also for local markets in the absence of the provision of cross border capacity by the TSOs. When the liquidity is pooled in one order book, competition is limited to only a few of the parameters of competition and there is little room left for competition between power exchanges, whereas it is innovation and the introduction of new products that will be key to facilitate renewables integration. The German government also acknowledged in 2022 (https://dserver.bundestag.de/btd/20/031/2003163.pdf), that it cannot be assumed that mandating the socialization of liquidity also for local markets would support competition development between power exchanges and that the negative impacts on product innovations and investments would not outweigh any alleged benefit.
Finally, it is unclear how the proposed measure relates to the declared goal of “addressing the economic and social concerns related to high energy prices".

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?

- Yes
- (x) No

What would be the advantages and drawbacks of such an approach?

2000 character(s) maximum

Mandatory participation in the day-ahead market could have negative effects for the spot market efficiency without having a downward effect on prices. In fact, prices are driven by underlying supply and demand fundamentals. In addition, mandatory participation does not belong to the EU Energy Market, based on fair competition among market participants and voluntary participation in the market.

For generation under PPAs, a mandatory participation in the day-ahead would need to be questioned as PPAs themselves are instruments made to minimize the short-term price variation. At the same time, generation under CfDs functions in a "produce and forget" manner, disregarding the actual situation in the grid. Thus, impacting prices and impeding the reasonable behavior of short-term markets.

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)?

2000 character(s) maximum

We are not in favor of having further information in the bidding in the market that could decrease market efficiency and disrupt the price signal.

Locational: locational tags within the wholesale market would disrupt the price signal, reduce transparency and hamper the well-functioning of the wholesale market. Different markets should not be mixed up. Different markets are intraday, balancing and local flexibility with different products, uses, risks and so prices. In addition, locationally tagged bids would be technically not easy to implement.

Technology: portfolio-based bidding is the prerequisite for improving efficiency and liquidity of the spot market. Unit-based bidding is a less efficient model, for which market participants cannot deviate from schedules linked to individual transactions or are obliged to trade on the market every schedule variation. Instead, portfolio-based bidding allows the reallocation of production or demand within the same portfolio. In addition, we believe unit-based bidding would not contribute to achieving one objective of this chapter, e. g., ‘‘improving the efficiency of intraday markets’’. Unit-based bidding is poorly flexible, highly complex and cumbersome, namely, unapt for the dynamic trading environment of intraday markets.

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

2000 character(s) maximum

In terms of wholesale markets, demand response and storage can be further facilitated through more open access in terms of the overall market rules and arrangements. The Electricity Directive and the Electricity Regulation already set useful rules and frameworks for flexibility to develop. However, in some countries, the transposition processes and overall implementation are lagging.

In addition, to facilitate the progress of these flexible resources, the development of local flexibility markets can be a way to improve their profitability and their development, as well as help Transmission and Distribution System Operators handling congestions and improving their grid investment and grid operation costs.

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?

- (selected) Yes
- No

Do you have additional comments?

2000 character(s) maximum

From our experience, regulatory barriers in the system operator’s incentive regulation act as barrier for the use of local flexibility, demand response, energy storage and other flexibility assets by system operators in their operations.

Traditionally, system operator’s remuneration has been very dependent on CAPEX through accounting mechanisms based on their regulatory asset base, creating a situation in which there is a natural incentive for system operators to invest in the grid (CAPEX) to manage grid constraints, rather than to use other means such as flexibility (OPEX), which are not incentivized.

For this reason, we believe that existing incentive regulations based on CAPEX are fit to tackle neither the energy transition in an affordable way nor the development of flexible resources. A renewed incentive regulation approach based on TOTEX (where CAPEX and OPEX are on an equal footing) would be a very good way to improve the incentives around the grid-oriented use of flexibility resources when it makes senses and decrease the overall costs of grid investments and operations at EU level.

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?

- (selected) Yes
- No

Do you have additional comments?

2000 character(s) maximum

We consider that the use of sub-meter data can be beneficial. It could be considered in cases where sub-metering can help overcome identified barriers vis à vis main metering. As the share of intermittent and decentralized renewable power production grows, it is crucial – for operational security, ecological and economic reasons – that demand is made more flexible, especially at low voltage levels. In the Consumer-Centric Market Design (CCMD), active demand participation and flexibility foster innovative business models “behind the meter” to make the most of rapid electrification and digitalization.

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

No

Do you have additional comments?

2000 character(s) maximum

First, it is crucial to keep separate two different concepts, demand response (DR) and demand reduction. On the one hand, demand response mitigates the occurrence of price spikes by delivering additional required capacity to electricity markets during peak times, and therefore, shifts demand in time to deal with short-term capacity constraints. Demand response does not necessarily reduce the overall demand, and hence, consumption. On the other hand, demand reduction consists of consumers reacting to already-manifested prices to reduce their energy consumption – e.g., by lowering heating in their houses or investing in energy efficiency measures, which can save energy over the long-term.

Particularly during periods of crisis demand reduction is needed. At the same time, DR will be mostly needed if the supply/demand balance is tight at particular times – e.g., because of high peak demand for capacity during days of cold weather. If supply capacity is used at maximum, then price spikes are observed on the spot and balancing markets to signal the need for DR to shift the peak of capacity demand and relieve the constraint.

Finally, we convey that a new product as an ancillary service, or DR products, will not result in demand reduction, as the two concepts consist of two unrelated mechanisms, as above explained. In addition, before enabling such new products, we should focus on swiftly developing DR solutions.

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

Yes

No

Do you have additional comments?

2000 character(s) maximum

We strongly believe the deployment of demand response (DR) should not be considered only during periods of crisis, but rather being a key, regular feature of energy markets. To foster demand response solutions, it could be beneficial to facilitate the integration of DR in the commercial short-term markets. In addition, default rules should be in place to sort all financial and physical settlements involved among the aggregator, the supplier, and at retail level between the concerned consumer and its supplier. In fact, a key issue with demand response remains the interaction between the demand response provider (i.e., aggregator) and the concerned consumer's supplier/Balance Responsible party. Such rules should consider (1) the compensation of suppliers by DR aggregators and (2) the correction of the Balance Response perimeters, in the case the supplier and the aggregators are not managing to agree.

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?

Yes

No

If so, what would that be?

2000 character(s) maximum

We remark once again Member States need to fully implement what has been already agreed upon, the Clean Energy Package, rather than completely overhauling the EU electricity market. The CEP already sets the pace for a renewed approach to congestion management, favoring market-based solutions as well as market-based flexibility procurement. Yet, its complete application is lagging across several Member States. Indeed, the transposition of Directive (EU) 2019/944 Art. 32 into national legislations has been insufficient in recent years in several Member States. As the article mandates DSOs to consider alternative options to grid investments, such as market-based flexibility procurement, a push to further implement this directive would foster the development of local flexibility markets and will create the necessary price signals to incentivize the grid-oriented use of demand response, energy storage and other flexibility assets. This will help mitigate the overall cost of the energy transition for European end-consumers.

Do you have additional comments?

2000 character(s) maximum

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?

- ○ Yes
- ● No

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?

4000 character(s) maximum

We consider that in some EU countries, capacity mechanisms have the potential to become an important feature. To achieve this potential, these capacity mechanisms need to be well-designed to minimize the impact on market functioning and at the same complementing the energy-only market. Moreover, they should possibly be harmonized at EU level where needed. As such, capacity mechanisms can ensure timely investments in back-up and dispatchable generation and enhance security of supply to facilitate the integration of vast amounts of renewables in the next years. Also, such complement to the energy-only market could decrease the need for price spikes (to finance new investments) and the likelihood of price spikes occurring in the future. Yet, the current crisis would not have been alleviated by additional capacity markets, as its origin is rather due to shortage of energy supply (e.g., gas), not to lack of capacity.

Against the background of this potential increase in relevance, however, we believe that the basis for the current setup, Regulation (EU) 2019/943, needs to be further exploited. Finally, the current regulation needs to be adapted for allowing for a faster and easier approval of capacity mechanisms.

Do you have additional comments?

4000 character(s) maximum

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

- ○ Yes
- ● No

Do you have additional comments?

3000 character(s) maximum

There is a benefit in introducing locational elements in the current market design, but not to a long-term shift of European electricity markets to nodal markets with central dispatch.

Nodal is sound theoretically, but its implementation is based on the model developed in the 1980s and implemented in the 1990s and 2000s in some US states/markets. In terms of RES integration, US states have lagged significantly behind the EU. Europe’s market model has proven its ability to generate large capacities of wind and solar. Moreover, the nodal design requires moving to central dispatch, which again has several major drawbacks to accompany the energy transition. For example, it remains technically impossible today to integrate and optimize, in one single algorithm, the entire European power system, the way market coupling is operating today. This becomes even more true with the integration of storage and all other decentralized assets. This already been a limitation in the horizontal expansion of RTOs in the US (large ISOs expanding across states) and the vertical expansion of markets at lower voltage levels (i.e., with DSOs).

Instead, developing local flexibility markets on the distribution level, incorporating coordination with the TSOs to manage the impact on the transmission network, can create an opportunity to promote DSR, prosumers and distributed connected generation without resorting to a full market redesign.

Local flexibility markets at the distribution level can complement grid development through tackling the challenge of grid congestions by making best use of system flexibilities. Flexibility markets centralize local flexibility offerings. They allow network operators to resolve physical congestions and flexibility providers benefit from an additional revenue opportunity without having to move towards a central dispatch system which is rigid, administrative/bureaucratic/monopolistic and characterized by inertia. Squeezing the entire system complexity that is driven by the decentralization into one single algorithm that handles the grid, asset and market complexity will not be fit for the Net zero future.

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[1], Austria, Lithuania[2] Luxembourg, Portugal and others[3] 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 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.[4] 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[5].

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.[6] 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 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[7]. 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.

[1] Energiedelen en persoon-aan-persoonverkoop | VREG

[2] Lithuanian consumers to access solar parks under CLEAR-X project

[3] Spain, Croatia, Italy ,France.

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

[5] 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.

[6] 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.

[7] 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

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Energy sharing and demand response

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

- Yes
- No

If such a right were introduced:

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

- Yes
- No

(b) Should it be restricted to local areas?

- Yes
- No

(c) Should it apply across the Member State/control/zone?

- Yes
- No

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?

- Yes
- No

Offers and contracts

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

- Yes
- No

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

at most 1 choice(s)

- (a) less than one year
-

(b) one year
- (c) longer than one year
- (d) other

Cost reflective early termination fees are currently allowed for fixed price, fixed term contracts:

	Yes	No
(a) Should these provisions be clarified?		
(b) If these provisions are clarified should national regulatory authorities establish ex ante approved termination fees?		

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

- Yes
- No

Prudential supplier obligations

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

- Yes
- No

Would such supplier obligations need to be differentiated for small suppliers and energy communities?

- Yes
- No

Supplier of last resort

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?

- Yes
- No

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
- No

Do you have additional comments?

2000 character(s) maximum

Enhancing 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.

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

4000 character(s) maximum

We support the following input submitted by Europex:
We believe the REMIT framework is a key tool to prevent and detect market abuse in European wholesale energy markets & adds significant value to the functioning of the Internal Energy Market overall. REMIT works well & has evolved significantly since its formal adoption in 2011. An extensive body of guidance has been developed & a complex & robust data collection and market surveillance system has been put in place which is overall fit for purpose. Against this background, Europex would like to insist that future improvements build constructively on this legacy & provide regulatory stability without further increasing the level of complexity. This should be ensured by a close dialogue between all involved stakeholders.

Monitoring of transmission capacities
One aspect that we believe needs urgent regulatory attention is reaching more clarity on the consistent and systematic monitoring of cross-zonal transmission capacity. Transmission capacities are paramount for price formation and even a minor capacity reduction in one Market Time Unit can lead to a major price impact on the market. Withholding transmission capacity is explicitly mentioned in Recital (13) of REMIT & in subsequent ACER Guidance as a form of market manipulation. In practice, however, there is no clarity on which entity is responsible for monitoring if the transmission capacity provided in every MTU corresponds to the actual available capacity & is not unduly limited. This means that there likely exist breaches of REMIT in the provision of transmission capacities, e.g., through illegitimate capacity withholding, left undetected and with a significant impact on price formation. Providing actual available transmission capacity should be explicitly covered in REMIT & the monitoring of it should be clarified. We find that the 70% minimum target for transmission capacity made available for cross-zonal trade is not an appropriate indicator & proactive monitoring is urgently required. Our experience from conducting day-to-day market surveillance shows this is a real problem which has a large market impact & requires urgent legislative and regulatory attention. To this end, a clear definition which explicitly includes the responsible entity for transmission capacity monitoring should be included in the REMIT review, not only limited to a recital but in the main body of the legal text. Further technical details could be clarified in the REMIT Implementing Regulation & additional ACER Guidance. In the short term, further harmonization among NRAs could partly improve this issue within the existing legal framework. However, ultimately ACER is best positioned to monitor available cross-zonal transmission capacity at European level.

Extension to additional products
In principle, we support the current scope of REMIT “wholesale energy products”, defined as “electricity and natural gas”, as they represent the key grid-bound commodity markets in Europe. As for a possible inclusion of other gases, like hydrogen, at this moment we believe that the market is not sufficiently mature yet to require such an inclusion. Nevertheless, for market actors to prepare for a possible future inclusion into REMIT, a reliable outlook & timeline would be welcome. Finally, we do not support an extension to other non-grid bound commodities, such as emission allowances. Given that the latter are financial instruments under the Markets in Financial Instruments Directive (MiFID), they are already comprehensively covered by financial regulation, including the Market Abuse Regulation (MAR), among others, and their inclusion into

REMIT would create an overlapping framework requiring a total revision of the system to accommodate duplicate obligations. In addition, the interdependence between gas and electricity on the one hand and EUAs on the other hand is limited and will be even more so with the schedule expansion of the EU ETS to new sectors.

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?

4000 character(s) maximum

We support the following input submitted by Europex:
Improved data and best practice sharing between energy, financial and competition regulators would be beneficial for the efficiency of REMIT and European energy market surveillance more generally. In this regard, we were pleased to see the creation of a Joint ACER-ESMA Task Force in October 2022 as this cooperation can improve data and intelligence sharing without creating duplicative reporting obligations for market participants and other stakeholders.

In addition, the relationship between ACER and the Energy Community should be clarified and upgraded and REMIT should become fully applicable to all Contracting Parties. We explicitly support central transaction, fundamental and inside information data collection and data monitoring by ACER as well as the coordination of cross-border investigations between EU Member States and Contracting Parties and directly between Contracting Parties. This is especially relevant as the Energy Community is moving ever closer to full market integration with the Internal Energy Market and the same market integrity and transparency standards should apply across the common market.
Fair competition between Inside Information Platforms (IIPs) should be ensured. Currently, ENTSO-E, ENTSOG as well as individual TSOs operate IIPs which are not in line with the principle of a competitive level playing field as they can socialise their cost of offering such as for inside information disclosure services. Hence, if those services are offered to market participants, including TSOs in the case of the ENTSO, explicit cost- reflecting fees including public price lists should be required. This would help to prevent further endanger the level playing field with the well-established inside information platforms set up by private companies.

Additionally, we believe that more transparency regarding REMIT enforcement decisions is needed. Publishing detailed case descriptions (also) in English will improve monitoring by Persons Professionally Arranging Transactions (PPATs) and compliance by market participants.

As also stated in our response to Q1, we find that clearly defining who is responsible for monitoring cross-zonal transmission constraints will improve enforcement. Transmission capacities are paramount for price formation and even a minor capacity reduction in one Market Time Unit (MTU) can lead to a major price impact on the market. Even though withholding transmission capacity is explicitly mentioned in Recital (13) of REMIT and in subsequent ACER Guidance as a form of market manipulation, in practice we have seen that there is no clarity on which entity is responsible for monitoring if the transmission capacity provided in every MTU corresponds to the actual available capacity and is not unduly limited. This means that there likely exist breaches of REMIT in the provision of cross-zonal transmission capacities, e.g., through illegitimate capacity withholding, left undetected and with a significant impact on price formation. In the short term, further harmonisation and cooperation among NRAs could improve this issue within the existing legal framework. However, ultimately ACER is best positioned to monitor cross-zonal transmission capacity at European level.

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?

4000 character(s) maximum

We support the input submitted by Europex in a separate PDF-document under "additional information".

Here you can upload additional information, if you wish to do so

Only files of the type pdf,txt,doc,docx,odt,rtf are allowed

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