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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
- (•) English
- Estonian
- Finnish
- French
- German
- Greek
- Hungarian
- Irish
- Italian
- Latvian
- Lithuanian
- Maltese
- Polish
- Portuguese
- Romanian
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- Swedish

* I am giving my contribution as

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

* First name

mark

* Surname

needham

* Email (this won't be published)

mark.needham@eirgrid.com

* Organisation name

255 character(s) maximum

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* Organisation size

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

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

* 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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- Ecuador
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- Libya
- Liechtenstein
- Lithuania
- Luxembourg
- Macau
- Saint Martin
- Saint Pierre and Miquelon
- Saint Vincent and the Grenadines
- Samoa
- San Marino

- Andorra
- Angola
- Anguilla
- Antarctica
- Antigua and Barbuda
- Argentina
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- Aruba
- Australia
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- Bolivia
- Bonaire Saint Eustatius and Saba
- Bosnia and Herzegovina
- Botswana
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- Gabon
- Georgia
- Germany
- Ghana
- Gibraltar
- Greece
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- Guatemala
- Guernsey
- Madagascar
- Malawi
- Malaysia
- Maldives
- Mali
- Malta
- Marshall Islands
- Martinique
- Mauritania
- Mauritius
- Mayotte
- Mexico
- Micronesia
- Moldova
- Monaco
- Mongolia
- Montenegro
- Montserrat
- Morocco
- Mozambique
- Myanmar/Burma
- Namibia
- Nauru
- Nepal
- Netherlands
- New Caledonia
- São Tomé and Príncipe
- Saudi Arabia
- Senegal
- Serbia
- Seychelles
- Sierra Leone
- Singapore
- Sint Maarten
- Slovakia
- Slovenia
- Solomon Islands
- Somalia
- South Africa
- South Georgia and the South Sandwich Islands
- South Korea
- South Sudan
- Spain
- Sri Lanka
- Sudan
- Suriname
- Svalbard and Jan Mayen
- Sweden
- Switzerland
- Syria
- Taiwan
- Tajikistan

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

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

To which category of stakeholder do you belong?

- [ ] a) National or local administration
- [ ] b) National regulator
- [x] 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
- [ ] 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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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?

- (●) Yes
- ( ) No

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

2000 character(s) maximum

The PPA market today is dominated by large players. This is largely due to long contract durations for new assets and high collaterals required to enter into a PPA agreement. Countries such as Spain, France and Norway introduced credit risk schemes to this end. In addition, PPA agreements are non-standard and require a lot of consideration to enter into. Repackaging by the supplier is possible, but smaller-scale consumers are in many cases excluded from the PPA market. Opening up the demand side for PPAs could accelerate their growth. It is furthermore hard for some consumer types to assess their electricity needs in the long run.

The lack of interconnection infrastructure between different EU countries can limit the volumes and make it more difficult for companies to enter into PPAs. Even for purely financial contracts, which are in essence equivalent to physical PPAs, the lack of transport capacity can lead to an increased risk of price spread between zones. This includes upgrading existing interconnection infrastructure and building new interconnection lines.

In the current crisis, there is little incentive to sign PPAs, as consumers do not wat to lock themselves in high prices and generators are able to profit from revenues from the spot market. Additionally, there is a high uncertainty regarding evolution of future prices, bidding zone reconfigurations, and potential political interventions. Overall, these factors present a risk for fixed prices and arrangements under the PPAs. It should be kept in mind that PPAs can mitigate short-term price volatility, but also lock-in a price for the long-term, creating a risk of missing out on a better price later on. Solid revenue security on the long-term might reawaken an interest in PPAs. Exposing PPAs to the risk of windfall tax, for example, hampers such agreements.

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

at most 6 choice(s)

- [ ] 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)
- [x] c) Promoting State-supported schemes that can be combined with PPAs
- [ ] d) Supporting the standardisation of contracts
- [ ] e) Requiring suppliers to procure a predefined share of their consumers' energy through PPAs
- [ ] f) Facilitating cross-border PPAs

Do you have additional comments?

2000 character(s) maximum

It should be recognized that PPAs are perceived as purely commercial contracts however, considering interventions such as the ones described above risks creating a type of "hidden" subsidy for such agreements. This would lead to society bearing a cost/risk to support/de-risk a contract which favours selected parties. It could also negatively affect competition with other, more cost-efficient products.

Regarding promotion of standardisation of the PPA contracts (d), while it would reduce administrative burden on PPAs it could also potentially lead to locking-in of the negative effect for the off-taker and duplication of possible design errors in the contract design. PPAs are bilateral agreements and parties should have freedom over contents of these agreements.

Cross-border PPAs are already possible with virtual PPAs. The main risk is price spread, which can only be mitigated through a state-backed schemes, in which case, you might opt for proposal under point (c). The "carve-out" mechanism in Contract for Difference question 14 could be considered to meet point (c). In addition, the suggestion to offer CfD volumes to consumers in Contract for Difference question 7 could offer PPA-like hedging vehicles to all consumers, incl. those with no access to that market today. Standardized contracts (d) would also be of aid to facilitate this, though the higher-mentioned risks of standardization should be considered.

As mentioned in Q2, a proper infrastructure would strengthen the roll out of PPAs. In this regard, the achievement of increased electricity interconnection for 2030, set in the Governance Regulation, provided that system benefits outweigh costs, is key to enable PPA, to fulfil the goals of the Energy Union and the Green Deal and facilitates the cost effective integration of the growing share of RES.

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

The current emergency measures and other revenue cap mechanisms, aiming at protecting consumers in period of crisis against sustained high market prices, pose a threat of lowering appetite for new investments in case they don't guarantee correct accounting for PPAs, If they are to be kept, they should at least properly account for PPAs and other long-term commitments to ensure they are not hampered.
Moreover, it must be ensured that the design of CfDs and/or PPAs supports or does not hinder the provision of flexibility by market parties, including via balancing and ancillary services which are essential for system security. In this context, procurement timeframes of ancillary services may also need to be revised in the future to ensure liquidity and cost-effectiveness

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

- ○ Yes
- ◉ No

Please explain

2000 character(s) maximum

The preferred approach would be to foster and expand PPA markets in accordance with the suggestions made above, in order to make appropriate use of PPAs. This will maximize the true value of this hedging /investment vehicle. By comparison, ill-considered incentive schemes risk over-subsidizing PPAs, which inflates costs overall. Mandatory shares of PPAs may distort market demands by locking in demand for fixed contracts and hampering the development of flexibility (particularly DSR). The alternative, to foster liquid forward markets and ensure accessibility of hedging opportunities to market parties (and in the end: the consumers), seems a more efficient way to achieve the intended goals.

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	○	◉

If yes, how can these risks be mitigated?

2000 character(s) maximum

Please explain

2000 character(s) maximum

While EIRGRID indicates the risk for liquidity in short-term markets as “no”, it should be noted that this is under the assumption that the increase in PPA uptake occurs in an optimal way, i.e., by improving on the markets and not by imposing PPA contracts. Otherwise, the risk could become quite severe, particularly in taking flexible resources out of the short-term markets and hampering the development of flexibility in the long run, thus reducing liquidity in ancillary/balancing markets.

In addition, some degree of harmonization between member states is likely desirable to retain a competitive European market. In particular, if there were forms of support schemes making PPAs particularly attractive, this may influence the cost of electricity in that area and in turn incentivise the development of energy-intensive consumers and demand side flexibility. Local arrangements need to be flexible and transparent while respecting the need for strong cross border regulation.

Finally, it should be noted that both PPAs and CfDs have a merit in managing the cost for the end consumer (point e). PPAs are a versatile, commercial instruments that allow parties to define optimal arrangements for them. For CfDs, competition in dedicated, open tenders on the generation side could lead to pricing close to LCOE and with reduced capital costs. However, the risks and preferred design features for CfDs presented in the dedicated section of this questionnaire should be thoroughly considered.

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

In principle, forward markets can provide important long-term signals to incentivise investment in new capacity. However, they are not sufficient to support investments in low-carbon generation nor to ensure resource adequacy in a rapidly evolving market and policy environment, also considering the absence of liquidity on longer durations products (> 10y) which is likely to persist. To manage a rapid energy transition in a secure manner we thus see CM necessary in most markets (see Alt to Gas question 14) to ensure sufficient dispatchable resources in the system. These should complement CfDs and PPAs for investment signals in low-carbon generation resources.Current forward markets in Europe have very different levels of liquidity. Although there are a few highly liquid ones, most of the bidding zones (BZ) are illiquid e.g. in the SEM. The relative tightness in the short term market negates the need for forwards hedging by existing generators, thus exposing suppliers and their consumers to short-term price shocks more quickly than would be expected. However, a distinction between hedging within a BZ and across borders must be made, as TSOs are only involved in providing hedging possibilities across borders via long-term transmission rights. With sufficiently liquid forward markets in all BZs, market participants could obtain effective and efficient hedges against the volatility of the spot prices in any BZ simply by entering a transaction for the corresponding forward market. However, due to several factors such as their limited sizes, most national markets are not sufficiently liquid. For such illiquid markets, either access to other liquid markets or measures to increase local liquidity should be considered. Access to other liquid markets should not hamper the development of local liquidity by draining it into neighbouring markets. measures to increase local liquidity must aim primarily at a cost-efficiency and be in the ultimate interest of end consumers.

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

2000 character(s) maximum

Forwards markets in SEM are typically less liquid as markets are tight there is no need for exsiting generators to look beyond the spot markets. There is relatively low likelihood of getting a counterparty for certain forwards product outside of the Directed Contracts which is offered by ESB. This has been the only real liquid forward instrument across the market. See KPMG report 2022? In some countries many participants (generators) seem to not feel a need to enter into organised forward markets because they prefer supplying directly to the end consumers (vertically integrated companies, PPAs, reliable partners, etc.). Therefore, they may offer only part (if any) of their production at the organised market. However, one basic prerequisite to enable functioning organised forward markets and foster liquidity is an environment free from hidden and/or indirect barriers that hamper the development of such markets. Potential barriers from the point of view of EIRGRID include: the collateral systems of commodity and, financial regulation provisions as well as regulatory interventions like regulated/fixed prices. In our view, improving simplicity and transparency for market participants seems to be another key prerequisite for the markets to develop

and increase the level of liquidity. Having a mismatch between supply and demand in a bidding zone can be seen as another relevant factor. Policy makers should carefully analyse all potential barriers of entry, especially in illiquid bidding zones

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

Making it more attractive rather than making it mandatory will ensure that there are both buying and selling parties for the forwards products.

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 experience with the existing virtual hubs in the Nordic countries?

- ○ Yes
- ◉ No

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

2000 character(s) maximum

EIRGRID does not have experience with virtual hubs, however, the Nordic TSOs have had the following experience:
The Nordic market has been known for providing a generally well-functioning hedging setup managed by fully commercial markets linked to the "system price", the theoretical price without transmission constraints in the Nordic area. Nordic TSOs are generally not offering LTTRs or other financial products to market participants. However, the financial market in the Nordic area has, since 2008, been suffering from decreasing liquidity and trading interest like many forward electricity markets in EU have. To a large degree, the decreasing liquidity in the Nordic market stems from increasing costs for collateral and reporting caused by the introduction of MIFID II and EMIR (bank guarantees defined as invalid in financial regulation in 2018) and the following transition to bilateral trading/hedging by a significant number of market participants, in particular RE-generators with a electricity generation profile deviating from forward products, base- and peak load.

This development teaches Nordic TSOs the important lesson that it is not in itself sufficient to introduce new

or even improved instruments by itself, i.e., the demand needs to be sufficient for the new products. They also need to be offered in a trading environment that makes it cost efficient for market participants to use them. One additional issue besides the changes in collateral requirements to be mentioned is the declining correlation between bidding zone prices and the system price during the recent energy crises. This however will likely improve as the situation returns to stability.

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

EIRGRID would like to point out that the forward market is a commodity market first. In this context TSOs come only into play by providing long-term transmission rights (LTTRs) in auctions, which is a comparably small market.
EIRGRID considers that the changes in market fundamentals require a reconsideration of the current design of forward markets to make them fit-for-purpose and to ensure the better protection of market participants, retail suppliers and consumers. EIRGRID is happy to support initiatives to address the perceived current challenges of the forward markets such as apparent low liquidity and undervaluation of LTTRs.
In the Policy Paper on “EU’s electricity forward markets”, ENTSO-E is exploring the current state of these markets, particularly considering four main aspects: 1. Meeting the demand of increased hedging due to greater RES penetration; 2. Increasing the liquidity in illiquid forward markets; 3. The interests of end consumers; and 4. The risks of capacity calculation in the long-term timeframe. In this context, it provides an initial analysis on possible policy options with three approaches. The evaluation of the three main approaches shows that all of them will solve some of the observed challenges. However, at the same time, all approaches have drawbacks and come with a shift of risks between TSOs, market participants and end-consumers.

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

First and foremost, it is imperative for the continued well-functioning of the electricity market as well as the effectiveness of such mechanisms that 2-sided CfDs do not distort the market . In Ireland, CfDs have been included in RESS auctions which are seen as efficient ways of protecting against double/over compensation in markets with very high levels of renewables. It also is a way of ensuring that sizeable inframarginal rent is clawed back in the interest of end consumers. To facilitate development of new generation assets in line with system requirements and transmission constraints, locational signals or constraints could be introduced in auctions for CfDs, but require further consideration. In any case, CfDs should be designed so they do not hamper participation in Ancillary (System) Services market in order to maintain liquidity in those markets.

A two-way CfD allows long-term price stability for both inframarginal generators and governments.. Moreover, liquidity in the forward market and price signals incentivizing demand side flexibility could be hampered in such a case. A transparent, market-based, cost-effective and structural mechanism should resolve these concerns and provide certainty and efficient allocation to end consumers in the long run. Suggestions to this effect can be found in in Contract for Difference question 7 .

Conversely, the compensation for generators offers them a hedge for the price risk. Hence, generators have security for their investments and consumers have hedging opportunities available to shield them from high prices. CfDs would therefore constitute an efficient tool to achieve different sets of policy objectives. CfDs offer generators a hedge for the price risk leading to potentially lowered cost of capital for these investment projects.

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
- ( ) No

Do you have additional comments?

2000 character(s) maximum

EIRGRID would like to stress, as underlined in Contract for Difference question 1.1, how imperative it is for the well-functioning of the market that if such mechanisms are to be implemented they should not distort short-term prices: CfD designs that decouple the CfD from the dispatch decision of the asset are therefore key to ensure this principle (see also Contract for Difference question 6).

It should be noted that CfD-backed RES can develop alongside commercial PPA-backed RES. It requires a smart allocation and clear separation of capacity between both (e.g. through a “carve-out” mechanism where a share of the capacity is under PPA and a share under CfD). However, hidden subsidies should be avoided to ensure risks are allocated to the appropriate parties and in order to retain market incentives in the interest of the system.

Further, CfDs with inframarginal generators alone don’t mitigate price spikes for consumers. There should be a well-considered allocation mechanism, such as the suggestions in in Contract for Difference question 7.

Other options for supporting inframarginal electricity generation could also stimulate investment such as capacity based support schemes for a maximum number of full load hours guaranteeing a minimum revenue, but also here they should be non-distortive with regards to dispatch and market prices. In particular, the support scheme should not be tied to injection.

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

2000 character(s) maximum

Two-way CfDs could be awarded to low-carbon weather dependent generation technologies. On the other hand, flexible resources should remain exposed to price variations.

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

2000 character(s) maximum

Ambitious policy objectives have been set to reach certain decarbonisation goals. They can be considered as market intervention from the perspective of an energy only market. It is unsure whether the market alone (e.g. through commercial PPAs) can be sufficient to reach those policy objectives. Hence, it makes sense to develop instruments supporting these targets. They can be seen as specific instrument complementing the energy market. A well-designed, non-distortive CfD has key benefits in this regard (see Contract for Difference question 1.1.) Such mechanisms, when correctly designed, are by far preferable to market interventions (see Limiting Revenue of Inframarginal Generators question 3.1) which can undermine the correct functioning of short term markets.

What technologies should be excluded and why?

2000 character(s) maximum

Carbon intensive technologies should be excluded. Such support schemes should be used to accelerate the energy transition and allow Member States to reach the Fit for 55 and net zero targets. In light of these

uncertainties, flexible generators which are necessary for ensuring system security and security of supply should be incentivised by other means, e.g. Capacity Remuneration Mechanisms and System (Ancillary) Service markets.

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

In all cases, support schemes if badly designed may compromise the efficient dispatch of resources through short-term markets. Furthermore, the lack of exposure to market signals also leads to suboptimal investment decisions, hamper liquidity in forward and PPA markets and, depending on the redistribution mechanism, limit incentives for DSR.

These problems could be avoided with well-designed CfDs. To that extent, a variety of non-distortive two-sided CfD designs, decoupling the CfD from the dispatch decision of the asset, are to be considered (such as capability-based CfDs, cf. Contract for Difference question 6). Moreover, the redistribution considerations under Contract for Difference question 7 should be considered to retain appropriate DSR incentives. Coexistence of PPAs with CfDs could retain liquidity in the PPA market. The experience of RESS has been that CfD may actually clear at a higher price as a result of increased uncertainty.

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

There is a need for those markets that have well established arrangements to have flexibility to allow for local circumstances. To ensure incentives for optimal dispatch, volumes paid out under CfDs should be decoupled from the actual injection e.g.Capability-based CfDs: Power plant owners compete in an auction for a fixed strike price. The payment is based on the volumes that “could” be produced, based on technical characteristics and local weather conditions. Such a signal is already used by some TSOs in balancing products.Financial CfDs: The government provides a fixed hourly lump-sum. The generator pays the hourly spot market revenues – but not the actual revenues, but benchmark revenues based on a reference profile. The design of these measures can vary. The preferred design is a matter of further discussion, but it seems highly feasible to come up with an efficient solution. Each option has the advantage that it eliminates distortive dispatch incentives in short-term markets of injection-based CfDs. With capability-based CfDs, the revenue of the producer is not affected by welfare-enhancing measures e.g. (new bidding zones, new interconnectors…). In addition, the granularity of the volume definition is specific to the plant, which should lower risk for the generator owner and suppress costs of the mechanism.Financial CfDs directly incentivize to optimize market revenues. This means that operators will plan maintenance during expected low-price periods. In addition, there is a stimulus for the diversification within the technology classes to reduce cannibal effects (e.g., PV systems with an east/west orientation or low wind turbines). An advantage from the perspective of the operators is that they also have a hedge for the generation volume. In a low-wind month, spot revenues are low, but so is the payback to the state. The risks regarding forward markets and DSR development should be tackled by the redistribution design (cf. in CfDs question 7) & coexist PPAs.

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

As stated previously, transparent, market-based, cost-effective and structural mechanism is strongly preferable to also provide certainty and efficient allocation to end consumers in the long run, as opposed to ad-hoc policy measures.
An economically sound way of doing so would be to trade the volumes resulting from CfDs as hedging options for electricity consumers which would provide more stability both to the government and to the consumers. This concept works as a “back-to-back tender”, where generation is tendered on one side, and this volume is passed to consumers on the other. Governments can hold competitive auctions for financial products where they bid strike prices for the volume of generator CfDs. The central counterparty in such a mechanism can opt to decouple the contract lengths from those on supply side, creating the opportunity for shorter and periodically re-auctioned contracts for consumers. As an alternative, CfD volumes could be resold as new standardized products in future markets. Careful design of the allocation mechanism is required to avoid any risks/inefficiencies.
Further regulation to limit the cost for the end consumer through such a mechanism is possible but is a policy choice and potential distortive effects should be considered. Particular risks are the discriminatory treatment of some consumer types and hampering the efficient development of demand side response, although this could be addressed, (cf. Alternatives to gas question question 8 and Better Consumer Empowerment and Protection question 4). Other examples of more policy-driven allocation are integration through a regulated retail price when there is one, obligation for suppliers to transfer the costs or pay-out to their consumers, etc.

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

Yes, it should differ depending on the technology type. It could potentially be awarded based on a regulatory audit. A priori, it makes sense to relate it to the economic lifetime of the investment, as is often done in support schemes today (typically starting at 15 years for new investments). Another option would be to a apply CfDs for a maximum number of full load hours instead

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

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

Imposing CfDs to existing assets leads to difficult negotiations with the owners of such assets. In the current context it risks creating a power dynamic that a priori favours the generator owners; in that sense, it risks inflating the bill for the end consumer in the long run.
We should not forget that the current situation is unprecedented, and that the future most probably will seelong periods of low prices caused by renewable development. Fixed, regulated prices with existinggeneration will then most probably result in consumers paying much more than the market price. Conversely, such measures also undermine overall market optimism and could further discourage needed investments.
However, ENTSO-E considers that, instead of such a compulsory approach, it still should be a possibility for Member States to sign such contracts with voluntary generators. The framework of such contracts should focus on:
-direct or indirect impacts on market and system integration aspects avoiding distorting market signals
- Incentives for RES units to provide system services, including balancing, non-frequency ancillary services & correctly forecast their production, eliminating risk of excessive support
- proper calculation of reference prices
- high competition between generation sources resulting in appropriate price signals
- proper definition of contract timeframes to reflect decreasing technology prices
-limiting contracts to technologies with long-term revenue risks
- balancing the need for sufficient investment stability while avoiding overcompensation
Different types of CfDs/PPAs will play an increasing role in the market by facilitating some installations to bebuilt and operated; however, they cannot be treated as a silver bullet for all problems the European energy25system is facing today. These go much deeper than that: the currently high electricity prices are derivative ofunderlying market fundamentals, i.e. where the revenues and costs originate.

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

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

A revenue cap limits the appeal to invest in the energy market, whereas we rely on substantial investments to achieve the energy transition. A simple revenue cap compromises timely achievement of the energy transition. Furthermore, if CfD support schemes are well-designed and competitive, i.e. generators would bid competitively for a limited volume of such contracts, they should lead to a least-cost revenue guarantee in the long run anyway through the resulting level of the strike price.

The experience of the implementation of the revenue cap from the emergency measure regulation hints that a revenue cap is complex to implement, legally uncertain, and leads to much less pay back than expected, mostly due to the consideration of hedged volume. Additionally,, a one-way mechanism like this bears additional legal risks, stemming from the fact that the economic risk is not shared. This would most probably affect the legal assessment with regard to legitimate expectations and could raise the standard on the required legal basis.

On a side note, EIRGRID would like to stress that the introduction, irrespective of the technology perimeter they encompass, of CfD mechanisms is fully compatible with the introduction of capacity mechanisms (or the presence of existing ones) and the first should not lead to questioning the relevance of the latter. Both types of mechanisms aim at addressing different purposes and, provided a given capacity does not get compensated twice, their coexistence should be allowed by the market design framework, as it is already the cases in some Member States for RES under CfD-like support schemes.

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

To achieve a carbon-neutral power system, we need to strengthen long term signals for investment in both low-carbon generation assets and flexibility resources to support both the wholesale electricity and ancillary /balancing services market. For the former, a combination of 2-ways CfDs and PPAs has the potential to support investments in new capacity while also mitigating exposure of end-user bills to price shocks. However, it is essential to design CfDs and PPAs so to ensure that the resources covered by these instruments are efficiently dispatched and to avoid any distortion or liquidity decrease in spot and balancing markets which are key for efficient use of infrastructure and system stability.

All products have merit and appeal to different stakeholders. Forward hedging entails a very generic electricity commodity, tailoring to large consumers, energy suppliers, owners of large dispatchable assets and/or large pools of assets. PPAs, on the other hand, are particularly appealing to support investments in specific assets, such as RES. In addition, they offer clean power at a stable price to consumers. However, both consumer and RES asset owner in this case are typically a large entity. CfDs and the associated method to return their benefits to all end consumers (cf. Q 21) can appeal to smaller developers and consumers as well. Because of this, the coexistence of these products can provide an inclusive and sustainable hedging climate.

The coexistence of notably CfDs and commercial PPAs could already be ensured as of the tendering phase for the CfDs, for example by a “carve-out” mechanism. Therein, a generator participating in the tender could exempt a share of its capacity from the CfD and develop it under a commercial PPA instead. If the tender is competitive, this could lead to reduced costs for the CfD through a potential margin on the PPA contract. It should further reduce the dependence on subsidy.

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

Please explain and outline possible alternatives.

2000 character(s) maximum

It may be a normal market outcome that offshore renewable assets are not selected in the market. To avoid discrimination, this should not lead to compensation other than a possible support scheme (see Regulation (EU) 2019/943).

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

From a TSO perspective, it’s essential to coordinate the acceleration of RES development with the necessary development of transmission grids and system flexibility to ensure resource adequacy, system stability and resilience at all times.

The existing barriers for the development of RES should be removed, ensuring a stable regulatory and investment framework, while preserving environmental protection. More precisely, EIRGRID welcomes an improved regulatory framework and stakeholder engagement to speed up permitting processes and acceptability. Concrete targeted measures should be in place to guarantee adherence to the planned

timeline. The regulatory framework should not only support the development of RES, but should also support the further development of the infrastructure needed to connect those assets to the rest of the grid. In this regard, EU institutions must ensure that the measures adopted at EU level are effectively implemented by Member States within a short period of time.

We recommend incorporating the respective rules and provisions for the acceleration of planning and permitting procedures, which are also relevant for electricity grids, of Council Regulation EU 2022/2577 to the revision of the RES Directive (REDIII/IV). Thereby, these provisions would apply for an indefinite period of time instead of being limited for period of 18 months.

Moreover, ensuring a full implementation of the current EU legislation and a stable and strengthened investment framework will be key enablers for the development of RES. Rapid development of renewables should be supported by the right market mechanisms, ensuring the most efficient dispatch and the right investment support tools, such that RES is exposed to the right market signals. Hence, changes to the electricity market design should focus on keeping the right dispatching signals (through capability based CfDs for example).

Do you have additional comments?

2000 character(s) maximum

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

A fully decarbonised, secure and integrated electricity system in 2050 will require an unprecedented scale of investments in new transmission capacity, including interconnections. Even if the uptake of complementary grid enhancing solutions can somewhat mitigate the need for capital and the need for smarter, OPEX-friendly regulation is obvious (see answer Alternatives to Gas question 9), TSOs' activities are and will continue to be capital intensive and must be able to attract equity and debt. Tariff increases should be kept as low as possible. At the same time, regulatory frameworks should be sustainable with mechanisms that support sufficient remuneration to cover necessary costs including a reasonable return on capital invested.

The remuneration of costs of capital is not sufficiently taking into account the recent economic developments which will slow down the necessary investments for a swift grid expansion. EIRGRID recommends that the new market circumstances with rising interest rates over the last months should lead to a revaluation of the regulated rate of return components (primarily risk-free rate, market-premium, and the cost of debt) to be carried out across national regulatory frameworks.
Furthermore, it would be advisable that national frameworks include remuneration for projects under construction. Given that permitting and other administrative processes result in a long lead-time between the initial investment decision and the asset being in operation, non-remuneration of assets under construction would require higher revenue stream over the lifetime of the asset to compensate for cost of capital in the construction period. In addition, additional costs may be necessary to address social acceptance and avoid project delays.
Besides, innovation in transmission assets should be considered in the remuneration frameworks covering the costs associated to digitalisation of new infrastructures. Future investments in transmission infrastructure

are inevitably linked to an increase in operational expenditures (e.g. future offshore grid). Sufficient means should be ensured to remunerate the operation and maintenance of transmission infrastructure to maintain high quality of service.

A re-evaluation of the cap on the G-component in grid tariffs (i.e. charge for generators) should be considered, as all grid users should pay a fair share of grid costs. Dimensioning of the grid is becoming more related to (peak) generation and generation is more dispersed over all voltage levels of the network. A well-coordinated grid tariff for generation across the EU would establish a level playing field between production and demand response and would incentivise generators to efficiently use scarce transmission capacity. Connection charges should also reflect at least the customer specific costs.
Without prejudice to national prerogatives, tariff structures should incentivise efficient behaviour of generation and load to minimise the total costs of the electricity system, while keeping cost-reflectivity and fairness as guiding principles. Tariff structures should also be reviewed with the objective of making use of the available flexibility in the system. Stronger capacity components (kW), locational elements, and more dynamic time elements (e.g. a kW-peak component could be zero or discounted during non-congested periods to stimulate flexibility) will result in better cost-reflectiveness.
Finally, for cross-border RES connected through offshore hybrid projects, greater alignment of tariff practices should be assessed in order to provide a level playing field across countries and a clearer investment outlook for both transmission and generation.

EIRGRID nonetheless believes that introducing any EU-wide rules on tariffs should be considered only after an in-depth impact assessment.

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
- ◉ 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

(b) its impact on decarbonisation

(c) security of supply

(d) investment signals

(e) legitimate expectations/legal risks

(f) fossil fuel consumption

(g) cross border trade intra and extra EU

(h) distortion of competition in the markets

(i) implementation challenges

Do you have additional comments?

3000 character(s) maximum

With regards to the criteria listed above to rate a possible prolongation of the current inframarginal revenue cap, we have chosen not to provide a scoring (as the numbering would also depend on other alternative policy options considered) instead offering some substantiated remarks:

- The current revenue cap doesn't per se impact consumer prices. Depending on its specific implementation (included generators, cap level and duration, exemptions, etc) it allows Member States to collect a variable amount of revenues that can then be redistributed to (some) consumers in different forms. By not directly affecting wholesale price formation it should not distort incentives for flexibility, demand response or energy savings. However, incentives for demand to react to prices can also be affected

depending on how revenues are redistributed to consumers.

- In the long-run, negative effects on investment signals and investors' confidence have to be considered. Taking a long-term perspective, to decarbonise the power system it is essential to strengthen investments signals for transmission/generation infrastructure and incentivising flexibility. Furthermore, additional mechanisms which compensate for reduced investment incentives imposed by revenue caps may be needed to compensate for the deteriorated investment framework.
- In terms of distortions, the revenue cap does not seem to impact the merit order and hence fossil fuel consumption. As per cross-border trade and competition, some distortions may be introduced by different implementation at national level (e.g. via technology-specific caps, accounting of hedging), especially in the long run if leading to investments being more advantageous in some countries vs. others.
- The implementation complexity also depends on specific national designs and specificities. However, the administrative burden and necessary data exchanges to manage or comply with such mechanism must not be underestimated.
- The legal framework supporting this mechanism could also be legally challenged, which would generate further uncertainty in the electricity market.
- A revenue cap is a relatively blunt instrument applied ex post via regulation. Therefore, more targeted market design measures in relation to long term contracts like the CfDs discussed elsewhere are preferred

Lastly, from a security of supply perspective, EIRGRID considers fundamental to ensure that the implementation of the revenue cap does not lead to distortions or decrease of liquidity in balancing markets which are essential to guarantee the stability of the system at the lowest cost for consumers.

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

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

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

There is a constant need to match demand and supply to keep the system stable. However, as in other commodity markets, marginal pricing will secure the most efficient solution, dispatching the cheapest resources and incentivising flexibility. Changing price rules will not solve structural market errors. As documented in academic literature and other experiences, alternative models to marginal pricing will at best lead to the same results, or more likely to inefficient market outcomes. Alternative pricing mechanism would not ensure efficient use of cross border capacity. With marginal pricing, the prices in two bidding zones (BZ) reflect the costs of the most expensive resources in each BZ. Power flowing from one BZ to the other will then substitute the most expensive resource in the importing BZ, which truly reduces this BZ cost. Because the price in the exporting BZ reflects the cost of the most expensive unit there, it is ensured that the cost increase in the exporting BZ is less than the cost reduction in the importing BZ, increasing social welfare. With marginal pricing, this result is automatically obtained via the market clearing.As per Alter. to Gas question 1(d/e), we agree that price signals are essential to optimising the integrated energy system. However, short-term markets alone cannot minimise costs for consumers and need to be complemented by efficient investment signals, retail pricing and effective policies. To ensure dispatch efficiency it is vital to reflect grid constraints: the current application of virtual capacity leading to redispatch has to be reconsidered. In the longer term, future network expansion and transition cost will need to be considered. Sandboxes should be allowed to integrate efficiently the use of remedial actions while avoiding undue discrimination between internal and cross-zonal exchanges. In the future, with higher rates of renewable penetration there will be pressing need to more accurately reflecting operational reality.

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

3000 character(s) maximum

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

- ○ Yes
- ◉ No

Do you have additional comments?

2000 character(s) maximum

Experience with the European SIDC shows great opportunities and flexibility for market participants to adapt their schedules in accordance with their best forecasts. At the same time, the accelerating development of RES results in an increased demand for participation in the upcoming European Balancing Platforms or where this is not possible for shorter intraday gate closure time (ID GCT). In the future, shorter intraday gate closure times could be introduced where needed – subject to compatibly with operational constraints which also depend on different balancing approaches by TSOs. In any case, it important to avoid including requirement on timings in a primary regulation, as these are better dealt via methodologies of CACM GL and EB GL. As such, we do not see a need for the market design reform to amend provisions on ID GCT in the current Electricity Regulation.Reduction of the TSO's operational window to 15 min would make it necessary to ensure the availability of sufficient generation able to correct system imbalances in less than 15 min. This can only be achieved through the use of costly fast acting generation or by establishing contracts with BSPs outside of the balancing market. Either approach is sub-optimal. Apart from being costly, this change may

have a negative impact on emissions as the units able to provide such a service often have high emissions. Moreover, it should be noted that the current ID GCT for cross border trade is 60 minutes due to several technical reasons: Need of sufficient time to nominate and match cross border nominations, determine target values for load-frequency control, to manage any virtual capacity due to the 70% requirement, build-up grid models, analyse load flows and coordinate remedial actions. For countries that participate in TERRE, this balancing platform requires GCT of 60 min. For other European balancing platforms, the GCT for BSPs to submit bids is at t-25 min.

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

- Yes
- 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

The European power system can rely on an efficient and integrated cross border intraday market where liquidity has increased significantly since 2018. This is to the benefit of NEMOs, TSOs and market participants. In this market the order books from the NEMOs are shared and all orders are matched via the Shared Order Book (SOB).

In some bidding zones intraday trade is still possible within the bidding zone after the cross-border gate closure 60 min before operational hour. Currently order books are not shared between the NEMOs in the local markets the last 60 minutes. The arguments to share the liquidity also in local market is the same as in the pan European market. Increased liquidity leads increased efficiency. On the other hand, some could argue that sharing liquidity could reduce the incentives for NEMOs to work on innovation.

In other bidding zones, where balancing markets already start after intraday cross-zonal gate closure time no split of liquidity takes place as remaining liquidity after European intraday is gathered and directly available in balancing markets and, when fully in place, will be made available to the European Balancing Platforms. The opening of balancing markets right after European Intraday market is very related to systems with high renewable energy penetration and pertaining to areas weakly interconnected with the rest of European Electricity system which require one hour lead-time for ensuring system security through balancing markets.

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
- No

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

2000 character(s) maximum

High liquidity in the single European Day ahead market is important to get reliable prices. Prices which are also necessary for a well-functioning financial market. Currently the liquidity in the day ahead market is sufficiently high. Therefore, no specific requirements for traders or other measures are necessary.

If 2-sides CfDs become widespread, there should be strong incentives to parties with such CfDs to be in the spot market to hedge their positions, and then there should not be a problem to keep high liquidity. However, if by some reason we observe a drop in liquidity that raises concern about market functioning, further measures that give incentives to trade in the organised markets may be required, ultimately mandatory participation. When considering possible obligations to participate in day-ahead markets, it is important to ensure that liquidity in balancing market is also preserved as it's essential for ensuring system stability at the lowest cost for consumers.

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

From a TSO point of view, detailed time and geographical granularity of information provided by market parties is critical to accurate forecasting and modelling of flexibility needs. This eventually makes planning and operational processes are leaner and more efficient thereby increasing security of supply and reducing related cost.
Market design should be able to better reflect the physical reality of the grid, e.g. through bidding zone reconfiguration, location dependent investment incentives for system services, dispatch hubs, or nodal market design (where appropriate).

With regards to day-ahead and intraday markets, locational information – which is essential for efficient congestion management. –
When it comes to the balancing markets, for other jurisdictions in the EU, there could be benefits of more locational information as applied in the SEM, to facilitate the TSOs in balancing the system within its technical constraints. This is even more important close to real time, as there is little time left to correct activations that are in conflict the system needs and requirements. If you apply unit-based bidding as in the SEM, there is also an advantage that balancing bids can be used for congestion management where relevant. A challenge here is that the TSOs need a lot of data and advanced planning process to be able to adhere to all local constraints on the activated units.
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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 the longer run, stronger locational & temporal signals would give better opportunities for both demand response (DR) and storage to value their flexibility. The right responses in the right locations and time would also be beneficial for system operation. Locational & temporal signals have the potential to unlock the wide range of sources of flexibility by providing stronger incentives for dispatching and for siting of e.g. electrolysers, storage, DR, ensuring that they react in line with system needs. The most efficient solution will differ depending on future scenarios and on regional/national specificities. As a result, different levels of spatial granularity may be applied across the EU while ensuring the preservation of the IEM.
- Where the current market framework is insufficient to timely develop storage capabilities, alternative market mechanisms providing LT investment signals could be explored.

• Remove technical and regulatory barriers for DR to participate in energy, system services, congestion management and capacity markets. Regulation should foster consumer participation and allow competition behind the meter with the use of sub-meters, providing a generic model for allocation of energy among market parties, and enabling consumers to provide flexibility for all services, via all technologies, at all voltage levels.
• Capacity subscriptions could facilitate smart load modulation during system scarcity, remunerating flexible consumers, reducing overall system costs to ensure adequacy, and establishing a price for capacity based on individual consumers' preferences.
• Fixed price contracts with fixed volumes (Better Consumer Empowerment and Protection question 4) - where the difference between the profiled contract volume and the actual consumption is settled at the spot price - give a high degree of consumer protection while retaining incentives for flexible consumption.

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

- (●) Yes
- ( ) No

Do you have additional comments?

2000 character(s) maximum

First, it should be noted that different regulatory regimes coexist in Europe regarding the treatment of balancing and congestion management costs, which are treated in some countries as OPEX for TSOs, and elsewhere as electricity system costs. In both cases EIRGRID supports setting appropriate incentives to achieve cost efficiency and value for end-consumers.
The use of efficient and innovative solutions that lead to smarter use of the grid should be better incentivised, to complement the vast investments in the physical grid that are necessary to reach the EU's climate neutrality goals.
EIRGRID observes there is widespread and structural under-remuneration of these. In many cases, TSOs do not even get full recovery of these, in particular for cross-border projects delivering substantial value to society (e.g. operating costs of European Platforms) and maintenance costs arising from the construction of network assets for system security (e.g. load flow-controlling equipment).
EIRGRID has identified several recommendations to move remuneration models towards greater technological neutrality and more efficient use of the infrastructure:
a. Remuneration for end-of-life maintenance: when technically feasible, TSOs should be encouraged to prolong the economic lifetime of assets which can lead to significant cost savings and resources for society , as current frameworks often incentivize re-investments or out-of-pocket maintenance.
b. Market facilitation incentive: TSOs should be fully reimbursed for improving market services and preferably be financially incentivized by allowing to share in the benefits.
Finally, regulatory frameworks should give much stronger incentives to TSO spending in innovation and digitalisation and should encourage (econ.) risk-taking. EIRGRID's paper on innovation uptake (June 2022) outlines several key recommendations. Regulatory frameworks should notably include more output-based innovation incentives (e.g based on smart KPIs).

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?

- (●) Yes
- ( ) No

Do you have additional comments?

2000 character(s) maximum

Sub-metering is beneficial not only for settlement/billing and observability of demand response but for all different types of services an active consumer might wish to contract. Sub-metering with correct allocation rules and proper data access rules would allow active consumers to sell their flexibility to the markets, participate to energy communities, proceed to energy sharing or P2P transactions, contract different suppliers for different appliances behind the main meter, or to offer services to system operators.

For explicit demand response and certain flexibility services, the use of metering data from sub-meters for settlement purposes should be allowed, to allow competition behind the meter. DSOs should exchange with TSOs all the operational data of assets connected to their grid (also for units that are below the de-minimis levels of the SEM).
At the same time, full smart meter roll-out and billing based on market time units will be a key prerequisite for reflecting more accurately the dynamic value of electricity, thus facilitating large-scale implicit demand response.

However, “main” meters are not always sufficiently accurate or “granular” to measure the service that is provided by units behind the meter. The capabilities of flexibility resources behind the main meters are increasingly used by TSOs. To support these developments, clearer rules should be determined to favour participation of flexible resources behind the main meter, without compromising the overall safety of the power system. In particular, new rules (preferably at national level) will need to define roles and responsibilities (meter operator, metering point administrator/data responsible/data administrator) in relation to sub-meters, while ensuring interoperability as well as and non-discriminatory and transparent procedures for access to metering and consumption data.

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

As a target, demand response (DR) needs to participate through aggregation or directly in the existing DA, ID and balancing markets, as well as congestion management, to support liquidity in existing markets. In case a dedicated product is developed, then it should be complementary to existing standard balancing products and not interfere with other balancing products.

A guiding principle should be to keep the energy market (day-ahead, intraday) as the cornerstone for dispatch signals to all kinds of assets (DR, supply or storage). In this context, DR should be progressively fostered through price signals such as time-varying tariffs or exposure to dynamic prices (or fixed price fixed volume contracts, cf. (Better Consumer Empowerment and Protection question 4) thereby triggering an

efficient usage of flexible technologies already in the energy market, limiting the volumes that would be adjusted in a dedicated ancillary service and thus respecting the proportionality principle.

Technologically, the rollout of smart meters and the usage of sub-meters are enablers for a faster adoption of DR in both energy markets and ancillary services markets. From a regulatory perspective, the upcoming DR Network Code could be used to specify rules of sub-meter usage.

Finally, we note that dedicated market mechanisms for energy storage and dispatchable capacity could be complementary to ancillary services by DR. The former instrument incentivizes the realization of CAPEX-intensive assets, while the latter service enables a better usage of flexible assets whose primary purpose is to serve a final use (e.g. EVs).

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 do not need DR in periods of crisis but at all times. To ensure the availability of DR also during crises, the main task ahead is therefore to ensure a rapid development of DR in all relevant markets. This will make DR available also during crises, avoiding the necessity of specific requirements. At the same time, coherence with the Risk Preparedness regime must be ensured. Moreover, it is not necessary to put a formal requirement for DR in the Electricity Regulation, as long as MSs have the possibility to introduce such requirements in periods of crisis. The current energy crisis has shown that consumers are prepared to adapt their consumption behaviour but are often lacking clear or timely signals. Smart meters are a key enabler and the rollout of smart meters shall be accelerated where it is lagging behind. But even consumers without smart meters can be engaged through broad-based communication for specific events of limited duration. Communication campaigns could become ordinary instruments that governments or system operators can trigger in moments of exceptionally low renewable generation and/or peak load, incentivising domestic consumers and small businesses to contribute to system security. To ensure the availability of DR, we see a number of possible measures:Member States shall provide an updated roadmap for the deployment of smart meters as well as clarify the framework for the use of certified sub-meters.A dedicated body (power exchange, TSO, NRA or other) shall publish or enable the publication of prices on the electricity forward and spot markets (at least day-ahead) free of charge. In the SEM, SEMOpx currently provide day-ahead and intraday auction prices shortly after market clearing while SEMO publish the Imbalance Settlement Price within 30 minutes of the Imbalance Settlement Period. Member states should be encouraged to implement measures for broad-based communication towards electricity consumers ahead of specific critical events.

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

• A long-term assessment of the system needs for flexibility will provide a basis for market parties to accelerate investments and R&D in relevant technologies fitting such needs.
• Accelerate smart meter rollout so to deploy them everywhere, to enable efficient demand response and local storage facilities.
• Allow the use of submetering and competition behind the meter, so to isolate the inflexible and/or essential consumption (which can be subject to fixed price contracts) from the flexible appliances (e.g. EVs), which can be exposed to dynamic price signals.
• Expose as many consumers as feasible to dynamic prices, while also offering hedging tools to limit their exposure (cf. fixed price fixed volume contracts in Alternative to Gas question 8 This should also be accompanied by better information to consumers about benefits & risks of dynamic prices and by raising awareness on energy saving measures.
• Where the current market framework is insufficient to timely develop storage capabilities, alternative market mechanisms providing LT investment signals could be explored.
• Modify Measuring Instruments Directive to include improvement of smart meters technology and remove barrier for embedded measuring equipment (See Alternatives to Gas question 8)
• Explicitly exempting ancillary services markets from the EU Directive on Public Procurement. As the integration of balancing markets progresses, and as flexibility services are procured in an increasingly dynamic manner, (e.g. via auction platforms) such procurement constraints are not fit for purpose - as they result in lengthy and burdensome process - and redundant considering regular monitoring TSOs are subject to by NRAs.

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

Capacity mechanisms are likely to be necessary in most EU countries as a standard feature of well-functioning wholesale markets to ensure system adequacy. At the same time, CRM design should be consistent with need to accelerate decarbonization of the power system and to avoid lock-in effects of fossil fuel technologies beyond their necessary contribution to adequacy.
Today, CRMs are considered by EU regulation as a last resort measure and are subject to strict pre-requisites and cumbersome and lengthy approval processes. The upcoming market design reform is an

opportunity to introduce targeted improvements to the regulatory framework to:
1) Recognise the structural need of long-term investment signals in national market designs to ensure overall system and resource adequacy while achieving EU long-term policy objectives;
2) Facilitate Member States' introduction or amendment of capacity mechanisms through faster, clearer and more fit-for-purpose approval processes;
3) Improve consistency and regional/EU coordination of capacity mechanisms and related applications of EU reliability standards by promoting best-practices and high-level design principles.
Concretely, considering CRMs as a possible structural element of national markets implies that the control of such a measure by the European Commission (assessment of compatibility under the state aid regime), based on the CEEAG and verifying the requirements of Regulation 2019/943 are met, should be significantly limited since it would by default be considered compliant with the EU target market design. The European Commission's assessment could then be primarily focused on ensuring that the design of CRMs avoids market or cross-border distortions Since timing is also key to solve adequacy issues, CRM approval should be framed into a reasonable and reduced delay to avoid a too long delay between the decision of the MS and its actual implementation. The approval process should primarily focus on a proper design, rather than the elaborate justification for introducing the mechanism or a Member State's discretionary and strategic choice for a capacity mechanism as an enabler for the energy transition, increased energy independence or other policy objectives.
Regulation should allow national adequacy assessments to further complement the ERAA in assessing system adequacy more holistically, with a higher granularity and dedicated sensitivities beyond generation adequacy, for instance addressing locational adequacy issues. The phase-out of conventional generation also requires considering local capacity compensation needs and ancillary services availability both in system adequacy assessment and in CRM design. Most importantly, today's governance process for ERAA approval needs a fundamental review with an approval process that looks beyond only CRMs and is more inclusive to Member State views.
While CRMs should be designed taking into account the energy transition objectives, we believe that a full integration of policy objectives in the CRM should not be required. In fact, other market mechanisms may be more suitable to support specific objectives or technologies such as storage (see for instance dedicated auctions for storage assets being considered in Italy).
It is important the CRMs assign value to the contribution of different technologies to their respective contribution to adequacy. While existing CRMs already allow participation of demand response and storage, future designs should enable them to participate to the full extent possible.
Considering the need to quickly adapt the design of electricity markets to make them fit with the long-term policy goals, the cumulative conditions that do make capacity mechanisms instruments of last resort, once all other options have been exhausted, should be carefully reconsidered.

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

The topic of market granularity and locational pricing at a European level deserves an in-depth assessment, appropriate cost benefit analysis and discussion which we would welcome, but that we do not see it as being feasible in the desired timeline of the market design reform of 2023-2024. Also, EirGrid would not consider this an appropriate approach for a small bidding zone such as the SEM without further detailed studies. In this assessment, the outcome of the ongoing bidding zone should also be taken into account.
Stronger locational signals will improve quality of price incentives provided to the market participants making them more aligned with real-time system state and/or longer term investment needs in ancillary services and back-up generation capacity. This will better bridge the gap between market and physics. This will allow for reduction of the tariff-payers' costs related to resolving system constrains, which are expected to increase as an effect of going towards net-zero generation and more volatile and dynamic system. Due to significantly increased volatility of generation, load and flows patterns as well as rapid investment in new resources, the constraints problems cannot be efficiently solved only by grid reinforcements but needs to be complemented with electricity generation, demand and ancillary services at the right locations.
On the other hand, shifting to more granular locational pricing leads to challenges concerning liquidity, regulatory stability, and transition costs. These are to be taken into account, when performing a holistic assessment.
There are several options of increasing locational price signals: improved bidding zone configuration, integrating so-called "dispatch hubs" in the market coupling, nodal market design (where appropriate), and location dependent investment incentives also considering ancillary services. The most efficient solution will differ depending on future scenarios (e.g., pace of grid infrastructure development) and on regional/national specificities such as grid structure and congestions. As a result, different levels of spatial granularity may be applied across the EU while ensuring the preservation of market integration.
Whichever market design option is chosen, it should not only have benefits that exceed implementation costs but ensure that the integrated European electricity markets seamlessly work together.

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

Do you have additional comments?

2000 character(s) maximum

We don’t believe an obligation on suppliers to offer fixed price contract would be of a great benefit. Forcing them to offer fixed price contracts would impact the business process and costs of such suppliers, with negative impact on competition in the retail market which may ultimately increase costs for consumers.
As end-consumer flexibility will be key in a system with increased volatility, fixed price contracts should be combined with tools and offers to complement risk hedging with effective incentives for valuing flexibility, especially from consumers and assets that have such flexibility potential.
Allowing competition behind the meter via sub-metering (as developed in question 56), allows flexible assets being exposed to short term signals. It is positive for the consumers as it will allow benefiting from low prices at times of high RES generation, and it is positive for the system as the flexible part of the load will tend to follow RES generation variation.
Alternatively, and where submetering would not yet be available, a particular type of fixed price contract would be worth promoting: contracts with fixed prices for a pre-defined volume. In these contracts, surplus /deficit consumption compared to the contractual volume - distributed across the year according to a predetermined
profile - is settled at the spot price. This option is in nowadays a common contract for industrial and

commercial customers, but not (yet) for households. With appropriate support and awareness, it could be suitable also for households, especially the most flexible ones. Such contracts offer an attractive balance between consumer protection on the one hand and exposure to dynamic pricing on the other hand. As such, it could prove an important tool to ensure social acceptance of demand flexibility.

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

Member States should implement policies and tools to partially shield less flexible, energy intensive, or more vulnerable consumers from unlimited exposures to possible extreme or sudden retail prices increases. These should primarily include direct support of consumers while not removing incentives for demand response, storage, or energy efficiency nor distorting wholesale market functioning.

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

• The regulation could benefit from clear and updated definitions of wholesale energy market and wholesale energy product (e.g., should capacity market be considered as a wholesale market?)
• The regulation could benefit from a clear definition on what is considered inside information
• Comprehensive market surveillance requires access to complete market data; therefore, it should be performed by ACER and NRA that have an overview over all markets and only supplemented by surveillance efforts performed by Persons Professionally Arranging Transactions(PPATs). Surveillance performed by PPATs should not be used as a main tool of detection of market abuses. Monitoring capacities to be better utilized by ACER while investigation and enforcement must remain at national level.
• Ensure that there are no regulatory gaps in the market monitoring between the physical and financial markets (derivative-markets).
• Improving efficiency in market monitoring by enhancing consistency between the Transparency Regulation and REMIT. Firstly, it should be clear that publishing given information on the Transparency Platform (TP) in accordance with the Transparency regulation implies it does not have to be published again on an Inside Information Platform (IIP) in order to comply with REMIT. Secondly, the scope of TP publications should be updated to reflect current system dynamics (e.g. smaller thresholds for generators' publications).
• Current requirements in ACER guidance regarding Inside information publications are not optimal; as the Market Participants are responsible for publications but required to do it via Inside Information Platforms (IIP). The way the liability is shared between IIP and Market participants (MPs) are unclear and require clarification for better efficiency.

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

- Clarify the notions of market manipulation and insider trading. Be prescriptive vis-à-vis known malfeasance to put under surveillance.
- Comprehensive monitoring of the entire market with overview of markets and market players activities. Fragmentation, and possible gaps in roles and responsibilities to be avoided between markets, parties, and jurisdictions. Improvements on the accessibility of information cross border and 'cross products' for efficient market monitoring. Provide clear guidance on cross-border monitoring coordination processes between PPATs.
- Enforcement power should remain on national level with the responsible National Regulatory Authority.

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 recommend that all relevant data related to prices and volumes traded from all parties should be published and available. A good example is EIRGRID Transparency platform which publishes free of charge relevant data in interoperable formats, and across all wholesale markets and products.
- Implementing regulation 1348/2014 does not refer to the IIPs, but to the website of a market participant. To address these shortcomings, we recommend a single point for publication and communication of data and information. The concept of IIPs should be revisited with a solid regulatory impact assessment, including whether it has a sufficient legal basis in the light of the associated costs.
- Regarding the XML schema mapping of reporting table should be extended to TSOs. Currently, the parameters to be specified are too much tailored to producers. (e.g., The existing requirements to report unavailable capacity as inside information on an Inside information platform is not aligned with the requirements on publication of unavailable transmission capacity set out in the transparency regulation (EU Reg. 543/2013) which is considered fundamental data reporting under REMIT.)
- The publication of insider information should be possible as time series.
- For reporting insider information, the date and time of the first submission and revisions of the information should be made accessible.

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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