

EU Climate Policy and Electricity Market Design

Electricity Market Design, Decarbonization, and Industries' competitiveness



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About this report

This report discusses, through the prism of decarbonisation, some of the main elements of the EU electricity market design (EMD) proposal put forward by the European Commission in 2023.

After an introduction and background to the EMD reform (chapter 1), chapter 2 discusses the interaction of the current market design with climate policy, as well as some of the emergency measures taken by EU countries in 2022. Reflecting the EMD proposal, chapter 3 focuses on Power Purchase Agreements (PPAs), Contracts for Difference (CfDs) and Capacity Remuneration Mechanisms (CRMs) and their link to decarbonisation. Chapter 4 then provides considerations and open questions with respect to both short- and long-term instruments from the perspective of industry competitiveness, as well as an overview and initial assessment of various proposals for more profound modifications of the current market design to reduce price volatility and/or investor risks, put forward over the last years. Finally, chapter 5 provides concluding remarks and takeaways.

1. Introduction

1.1. Background to the electricity market design reform

The EU power system and market has gone through a gradual transformation over the past 20 years, in which calls for reconsidering the electricity market design. This situation has therefore preexisted the 2022 energy crisis, the latter however has made the need for reform more urgent.

The wholesale market in the EU is based on the marginal pricing mechanism and the merit order. This mechanism, when paired with an ETS, can create effective economic incentives for reducing emissions in the short-term by dispatching cleaner energy sources, thus supporting decarbonization.

However, since early 2000's there has been some recognition that the short-term wholesale market, together with the EU ETS has not provided sufficient and appropriate long-term signals to foster the necessary investments in renewables and low carbon energy to achieve the 2050 decarbonization targets. Recognizing this limitation, the UK government introduced already in 2014 complementary measures (e.g., auctioned CfDs) to incentivize and support the transition to a low-carbon energy system.

Historically, i.e. prior to deregulation, the EU power system has been characterised by excess capacity. This allowed for the stability of the system: excess capacity generally ensured the stability of the electricity grid because there was a significant reserve of generation capacity available to meet demand even during peak periods or unexpected events. Due to the surplus capacity, electricity prices tended to be relatively low. There was also less immediate pressure to invest in new power generation infrastructure because existing capacity could initially still cater for growing demand.

However, with the gradual liberalisation of electricity markets, a transition from a historically comfortable position of surplus capacity to one of capacity shortages and market fragility started to emerge since the mid-2000s. Several factors may have contributed to this shift. Economic growth can drive an increase in electricity demand, potentially outpacing the growth of new generation capacity; Shifts in energy policies, such as a greater emphasis on renewable energy sources or the closure of aging coal-fired power plants, can impact the balance of capacity; the transition to cleaner and more sustainable energy sources can introduce challenges related to the intermittency of renewables and the need for new infrastructure; Delays in building new power plants or upgrading existing infrastructure can leave regions vulnerable to capacity shortages. This shift has been the reflection of changing energy dynamics in the EU. It made the market more vulnerable to disruptions and fluctuations and exacerbated the need for measures to address growing electricity demand and ensure the stability of the energy market.

More recently, the significant reduction in the supply of natural gas from Russia to the EU has triggered the EU energy crisis. The reduced availability of Russian gas caused natural gas prices in the EU to reach record-high levels, leading to persisting high electricity prices. This recent energy crisis has exposed some of the weaknesses in the design of the European electricity market in that respect: a lack of resilience to handle unexpected shocks to the energy supply; a high exposure to extreme price volatility due to the interdependence of gas and electricity markets, which can affect the reliability and affordability of energy; the inability to provide adequate incentives for long-term planning and investments in energy infrastructure, which could help mitigate supply disruptions and price spikes.

1.2. Structural and Emerging issues

The changing EU energy landscape and the recent energy crisis have prompted the need for reforming the electricity market design to address various structural and emerging issues.

The CO₂ and electricity markets need to complement each other, or at least not compromise each other's functioning. Their close interactions also imply that measures taken on one can impact the functioning of the other.

These two markets have been working in the same direction and have provided the right short-term decarbonization signals. As such, they have played a key role in the process of the phasing out fossil-fuel based generation. However, there is an ongoing shift, from an energy matrix that has traditionally been fossil-dominated and centralised to one with a growing share of renewables that are intermittent and more decentralised, and the market design needs to recognize this.

Some of the short-term emergency measures put in place in 2022 to address the high energy prices did not function synergistically with the EU ETS. It is therefore important to take stock of the lessons learnt.

Moreover, the lack of long-term visibility in both markets hampers their ability to provide the right long-term signals for decarbonization.

To reach the 2050 decarbonization targets and meet the increasing electricity demand, there is a need to significantly increase RE capacity. This requires a massive amount of investment.

There is a need for longer-term visibility in the electricity market to achieve two critical goals: protecting consumers from price volatility and attracting the substantial investments required for the transition to a net-zero carbon emissions future.

The recent spike in energy prices has had a considerable impact on European industry, specifically energy intensive industries. Making the European industries more competitive requires them to have access to a renewable, non-fossil and affordable power supply. By transitioning to cleaner and more affordable energy sources, not only can European industries improve their competitiveness but also contribute to a more sustainable future.

Longer-term visibility helps create a stable and predictable environment that benefits both consumers and investors, ultimately supporting the sustainable and low-carbon energy transformation necessary to achieve climate objectives.

2. Short-term pricing mechanisms, short-term market interventions and their link to decarbonization

2.1. Marginal Pricing in wholesale electricity market

Marginal Pricing mechanisms, merit order and ETS

One of the main characteristics of electricity is that it cannot be stored, or at least in an economically viable manner. Electricity production is therefore meant to be constantly adjusting to consumption, i.e electricity demand. The liberalized wholesale market in the EU is a system of marginal pricing, also known as pay-as-clear market. Marginal pricing refers to electricity prices being set by the variable cost of the marginal plant (last unit i.e., the most expensive plant that is required to serve demand). The variable cost includes fuel, maintenance, and operational costs and is, by definition, independent to the fixed costs (which usually include depreciation, rent, salary costs...). Variable renewable energies do not use fuel, so their marginal production costs include mainly the operational costs. For the other technologies, their marginal production costs are mainly determined by the fuel costs (uranium, coal, lignite, oil, gas), increased by their respective CO₂ emissions costs. Different power sources have therefore varying levels of marginal cost. The availability of a variety of different sources enables the grid to bring generators with the lowest marginal cost online first, in order to meet demand in the most cost-effective way. Generators with higher marginal cost are only used if cheaper sources are not meeting demand or are unavailable, and the absence of fuel costs makes renewable energy a very competitive option.

The main implication of this system is therefore that the electricity price is determined based on the last, and therefore most expensive offer required to meet the market demand at a certain point in time: this offer, which has the highest marginal costs sets the market clearing price. Once the demand is met, all electricity generators get the same price for the power they are selling in a given settlement period.

The fossil fuel-based power plants have higher marginal productions costs, also partly due to the CO₂ price component. The more electricity producers emit CO₂, the more they must compensate for their carbon footprint by buying CO₂ certificates. The unit price of CO₂ certificate represents an element directly accounted for in the production costs for electricity producers. The CO₂ price component therefore contributes to increase the marginal production costs of carbon emitting generation sources, shifting fossils fuel-based plants at the end of the merit order, and reducing their chances of being needed to meet electricity demand. In case fossil-fuel based plants remain in the merit order curve and set the electricity market clearing price, the carbon costs they incurred contribute to increase revenues of all other electricity technologies. Moreover, the implementation of a CO₂ price signal increases the variable production costs in order to reduce the competitiveness of the most CO₂ intensive plants in favor of the less CO₂ intensive plants, thus also potentially changing the dispatch order of the fossil-fuel based plants between themselves.

EU ETS and the marginal pricing system complement each other in providing a short-term operational signal for decarbonization. Through marginal pricing, electricity producers are incentivized to bid at their true electricity production costs to stay in the merit order and get dispatched. It delivers a cost-effective signal to use decarbonized energy sources as a priority. To reduce their overall marginal production costs, and to become more competitive in the merit order, electricity producers are incentivized to reduce the share of these variable costs attributed to carbon emissions. Marginal pricing mechanism also allows RE

generators to recover part of their capital costs of investments (which would otherwise have to come fully from subsidies or capacity mechanisms) and sends signal promotes innovation with a clear economic signal for investment in new technologies (peak generation plants, electricity storage or conversion) ¹.

Through the marginal pricing system, energy consumers are provided with signals about scarcity, giving them the ability (when and if possible) to adapt their consumption in line with changing conditions. The affordability for consumers will depend on the balance between supply and demand for electricity and the marginal costs of the technology setting the marginal price. If such technology is a fossil-fuel plant, consumers will be exposed to high marginal costs (including carbon costs), regardless of the production costs of all other technologies.

Cannibalization risk / Profile risk

With the marginal pricing mechanisms, renewables lower the costs of electricity, when RE injects to the grid, the spot price tends to go down due to priority dispatch. The term “capture price” relates to the actual electricity price achieved by a generator in the market, and it’s compared against the wholesale price. Actual capture prices achieved by RE sources are lower than the average wholesale market prices (baseload price)². At times when RE sources are generating large amounts of electricity at low marginal cost, the merit order effect is upheld, and the grid’s demand is met with a welcome supply of cheap electricity. Certain markets, such as the UK, Germany or Denmark, allow for negative pricing in their systems, this means that there is no “floor”: during specific periods when wind and solar energy may overproduce, if there’s low demand at this time, prices can get below zero.

In the long run, this poses a serious threat to the viability of renewables operating on the free market³. When a lot of renewable energy is injected at the same time, which is particularly material for solar energy because there’s a stable generation profile shape, the realized price they will get will fall. At the beginning of the energy transition, renewable energy was a fraction of the electricity mix. Nowadays, renewables increasingly participate in the electricity markets on a merchant basis. The amount of renewables in the grid is set to tremendously increase, posing a significant risk for their long-term remuneration. Moreover, as subsidy mechanisms typically reward production, the incentive is to continue to oversupply in order to overcome the opportunity cost of not generating. These factors depress the wholesale market price, resulting in an effect known as “price cannibalization”. This effect is set to increase in prominence as the growth of renewables continues. The phenomenon is called ‘cannibalization’ because renewables are cannibalizing their own profits.

In the long term however, marginal pricing mechanism and EU ETS does not provide long-term signals for decarbonization: if the expensive and fossil-fuel based generators are pushed out of the merit order, the market clearing price then set by cheaper RE/low carbon generators, will very likely not be high enough for renewables and nuclear generators to be able to recover on their fixed costs. This may disincentivize investments for decarbonization in the power sector.

¹ EFET insight into Marginal Pricing in Wholesale Markets, available at:

[https://efet.org/files/documents/20220222%20EFET Insight 02 marginal pricing.pdf](https://efet.org/files/documents/20220222%20EFET%20Insight%2002%20marginal%20pricing.pdf)

² <https://www.bdo.global/en-gb/blogs/valuations-blog/june-en/power-price-cannibalisation-%E2%80%93-how-is-it-affecting-your-renewables-projects>

³ The effect of cannibalisation : behind the renewables’ silent risk, Pexapark, 2023; Available at:

<https://pexapark.com/blog/cannibalization-effect-renewables/>

From a pure economics perspective, a market design with even a complete penetration of zero-variable cost technologies would function exactly like the system of today encompassing a merit order with different technologies⁴, however scarcity pricing would be critical to providing efficient incentives. In an ideal world the economics hold but in the real world the intuition of practitioners is linked to risks and uncertainties, and scarcity events are the only moments when an investor earns anything. In a zero variable cost world, those scarcity events might not materialize very often, which essentially means that investments would have to be paid off in very few instances, and practitioners might face on top the risk that regulators cap the earning earned during these events. This makes for an uncomfortable setting for investors.

2.2. Short-term market interventions

Marginal pricing encourages the production of lower cost energy from renewable and low-carbon sources, which are remunerated for their electricity production at price levels set by costlier fossil fuels. In the long run, marginal pricing encourages Member States to work towards phasing out the costliest fossil fuels and to address problems of peak demand. However, in the current energy crisis, marginal pricing means that wholesale electricity prices are largely set by the price of gas (although in some countries the marginal fuel source is coal), and are expected to continue to do so in 2030⁵. Gas prices have reached record levels in Europe in 2022. As a result, power sources whose costs are not affected by changes in gas prices such as wind, solar and nuclear – so-called inframarginal plants – have all seen their revenues rise significantly due to the higher prices. This electricity market model has exacerbated the energy crisis for consumers, paying far more for their electricity than is justified by the cost of production (especially in Member States where most electricity is generated by nuclear energy and/or renewable energy sources). This situation has been framed as electricity producers extracting unreasonable profits, and consumers seeing their electricity bills skyrocketing.

In response to skyrocketing prices, every EU Member State introduced emergency measures. There have been different approaches taken: some countries introduced (natural gas) subsidies to thermal units (gas, coal and CHP) as a means to reducing wholesale electricity prices (e.g. Spain/Portugal). Others taxed windfall profits made by energy firms (e.g. Italy), and provided temporary tax reductions and tax credits to help low-income households or energy-intensive companies pay their energy bills (Italy). Finally, France nearly removed the domestic tax on final electricity consumption and mandated low regulated electricity tariffs to shield consumers in retail markets. In practice, Member States implemented a number of emergency measures simultaneously, leading to further market distortions e.g. in Spain there was the Iberian exception, a clawback on the revenues from inframarginal technologies, and taxes on windfall profits.

⁴ Hogan, 2016. ELECTRICITY MARKET DESIGN AND THE GREEN AGENDA. Presentation provided at MIT Symposium Session on Wholesale Markets: Strengths and Weaknesses for a Decarbonizing Future. 2 May 2016 https://scholar.harvard.edu/whogan/files/hogan_mit_050316.pdf

⁵ Gas-run power plants set the price 55% of the time in 2022 while generating 19% of total EU electricity. In 2030, the price-setting share is still close to 56%, even with generation decreasing to 11% of electricity. Source: Gasparella A., Koolen D. and Zucker A., The Merit Order and Price-Setting Dynamics in European Electricity Markets, European Commission, Petten, 2023, JRC134300. <https://publications.jrc.ec.europa.eu/repository/handle/JRC134300>

A total of 439 measures of 28 distinct types were implemented between July 2021 and February 2023, according to an inventory by ACER⁶⁷. About two thirds of measures were aimed at tackling affordability for end-consumers and one third were aimed at broader security of supply objectives. About half of the measures were in the form of direct support to final consumers, with the other half aimed at increasing energy efficiency and renewable generation uptake, thereby also contributing to decarbonisation objectives. With few exceptions, most countries intervened in the wholesale and/or the retail market, through measures like price or bid limits, revenue caps, windfall profit taxes or regulation of retail tariffs⁸.

Below, two of these measures are discussed in greater detail: the Iberian exemption, and the inframarginal revenue cap.

Iberian exemption

Spain and Portugal established an exceptional and temporary mechanism to adjust electricity production costs which impacts on the generation of the electricity market price for the wholesale reference market of the Iberian Electricity Market (MIBEL)⁹. The exception has been implemented in Iberian power markets from June 2022. It was originally scheduled to end in May 2023, but it will run until at least the end of 2023. This intervention targets the marginal plants by means of a subsidy to thermal units (gas, coal and CHP), tagging the price for power offered by these generators to a below-market price for gas. This temporary measure aims at ensuring gas generators submit lower bids into the power market, thus depressing prices. This measure is partially decoupling gas and electricity prices: gas remains in the merit order and usually, sets the final electricity price, however, at lower levels than the full gas price.

On one hand, this model suited Iberian consumers on short-term contracts and thus highly exposed to market volatility (10 million consumers under regulated tariff PVPC, which are directly exposed to the spot prices). A downside of this idea is that it distorts the price signal for consumers and, in the absence of other measures, leads to increased gas consumption.

The measure was effective in lowering electricity prices. Between its passage and the end of 2022, Spanish wholesale electricity prices effectively distanced themselves from other European markets (such as France, Italy, and Germany), where prices remained very high. Between June 2022 and February 2023, Spanish power prices averaged €127.9/MWh, compared with €273.2/ MWh in France, €240.5/MWh in Germany, and €306.2/MWh in Italy.¹⁰ Moreover, the Spanish government estimated that the savings for all final electricity consumers between June 15, 2022, and January 31, 2023, amounted to €5 billion.¹¹ Although the Spanish government did not publish the methodology used to account for these savings,

⁶ ACER's interactive dashboard of emergency measures implemented by Europe Member States and Norway in 2022 in response to the energy crisis, The European Union Agency for the Cooperation of Energy Regulators, March 2023 <https://app.powerbi.com/view?r=eyJrIjoibWJiZDlkYjMtNTMyNi00ZDU5LTkYzgtNTYzNWU5ODY5NGMyIiwidCI6ImU2MjZkOTBjLTcwYWUtNGRmYy05NmJhLTAyZjE4Y2MwMDA3ZSIsImMiOiI9>

⁷ ACER, 2023. Wholesale Electricity Market Monitoring 2022 High-level Analysis of Energy Emergency Measures, Report in PowerPoint format, The European Union Agency for the Cooperation of Energy Regulators, 20 March 2023 https://www.acer.europa.eu/Publications/Electricity_MMR_2022-Emergency_Measures.pdf

⁸ Idem

⁹ Iberian mechanism, Decree-Law no. 33/2022 of 14th May 2022 ; [https://www.dgeg.gov.pt/en/statistics/energy-statistics/iberian-mechanism/#:~:text=Decree%2DLaw%20no.,Iberian%20Electricity%20Market%20\(MIBEL\).](https://www.dgeg.gov.pt/en/statistics/energy-statistics/iberian-mechanism/#:~:text=Decree%2DLaw%20no.,Iberian%20Electricity%20Market%20(MIBEL).)

¹⁰ Boletín Oficial del Estado, "Real Decreto-ley 3/2023," March 29, 2023, <https://www.boe.es/boe/dias/2023/03/29/pdfs/BOE-A-2023-7937.pdf>

¹¹ Ibid.

some have argued that these estimates do not take into account the elasticity of demand, and thus savings might have been overestimated.

However, the measure has also had unintended consequences, which (had it been extended to the EU or in duration) would have affected decarbonization paths¹²:

- Power exports to France have increased: the reduced Iberian power prices triggered an increase in spread prices with France and subsequently contributed to an increase in power exports to France to the point of saturating the interconnection capacity in the export direction and creating congestion revenues. Meanwhile, exports from France nearly stopped just after the measure entered into force on June 15, a situation that was likely exacerbated by French nuclear issues. In practice, this has meant that Spanish consumers have been subsidizing power for French consumers. While an EU-wide price cap would stop this specific effect, it could persist with neighboring non-EU markets such as the United Kingdom, Norway, or Switzerland, which have power exchanges with EU markets of roughly the same magnitude as that between France and Spain.
- Gas demand in the Spanish power sector has surged: Although this surge preexisted the royal decree and was also driven by the heat waves and the very extreme dry conditions for hydropower, it became steeper from May 2022¹³. Indeed, the measure has effectively contributed to change the merit order in the Spanish electricity market. The Iberian exception has therefore contributed to Spain's gas use for power, which surged by 52.7 percent in 2022— in contrast to a 3.7 percent drop in total Spanish gas demand.¹⁴ Extrapolating from the Spanish case, a broad application of the measure at the EU level could potentially lead to increased gas demand for power and counter Brussels' efforts to reduce gas consumption.
- The measure has led to no incentive to reduce power consumption. In contrast to measures taken in other European countries, including one in Germany that attempted to shield consumers while incentivizing a power and gas demand reduction¹⁵, this measure is solely aimed at protecting consumers. Instead of addressing the core problems (tight gas and power supply) by reducing demand, it exacerbates them by treating only the symptoms (high prices). Separate measures were passed to target energy savings, but they may be counterbalanced by lower power prices.¹⁶

¹² Section below (bullet points) taken from "The Iberian Exception and its impact", Anne-Sophie Corbeau and al, May 2023. Available at: <https://www.energypolicy.columbia.edu/publications/the-iberian-exception-and-its-impact/>

¹³ [Iberian-Exception Commentary CGEP 051723-2.pdf \(columbia.edu\)](https://www.energypolicy.columbia.edu/wp-content/uploads/2023/02/Commentary_Iberian-Exception_Commentary_CGEP_051723-2.pdf)

¹⁴ Enagas, "Statistical Bulletin—December 2022," January 10, 2023, <https://www.enagas.es/content/dam/enagas/en/files/gestion-tecnica-del-sistema/energy-data/publicaciones/boletin-estadistico-del-gas/Monthly-Bulletin-Gas-December-2022.pdf>. Enagas splits gas demand in two categories: power and conventional (industry and residential/commercial users).

¹⁵ Anne-Sophie Corbeau and Ann-Kathrin Merz, "Understanding Germany's Gas Price Brake: Balancing Fast Relief and Complex Politics," Center on Global Energy Policy, February 6, 2023, https://www.energypolicy.columbia.edu/wp-content/uploads/2023/02/Commentary_Understanding-Germanys-Gas-Price-Brake.pdf

¹⁶ "Spain's Parliament Approves Energy Saving Plan," Euractiv, August 26, 2022, <https://www.euractiv.com/section/energy/news/spains-parliament-approves-energy-saving-plan/>

- The measure (together with the clawback of inframarginal rents implemented in September 2021 and still in force) contributed to a decrease in liquidity. EEX reported a 50 percent drop in year-on-year volumes traded on EEX Spanish power futures. This regulatory uncertainty led to a splitting of participants' interests, a fractured market, and hesitancy among market participants to trade beyond the front month.¹⁷

Inframarginal Revenue Cap

At the European level, the Council agreed an urgent regulation¹⁸, setting different temporary mechanisms to address high energy prices in the EU in 2022. Amongst these measures, attention is given to the so-called inframarginal cap and its potential impact on decarbonization objectives. The Council regulation introduced a temporary revenue cap on 'inframarginal' electricity producers. This emergency measure was in place from October 2022 to June 2023¹⁹.

The idea behind this mechanism was for excess revenue to then be collected by Member State governments and used to help energy consumers reduce their bills.

The regulation, however, did not provide a common and harmonized European approach for implementing the inframarginal revenue cap. While this has allowed Member States (MS) to design the implementation of the cap in a way that best fits their national priorities, the non-harmonization of implementation across Europe has had impacts on the level playing field.

The significant degree of freedom left to each MS has resulted in a very heterogeneous implementation of the inframarginal revenue cap across the EU, in terms of: technologies covered, relevant market, and period of application. The report²⁰ of the European Commission on the review of emergency interventions to address high energy prices also states that "diverse implementation was observed not only with respect to the level at which the revenue cap was set (...) but also regarding the temporal scope of the measures".

Moreover, the level of the cap and the duration of this intervention could have had a strong impact on the decarbonization objectives: caps on market revenues risks undermining the necessary RE investments. Inframarginal revenues play a critical role in providing efficient investment signals.

The 'merit order' principle minimizes the short run power system costs (the generators being dispatched based on increasing variable costs) but also ensures an efficient remuneration for all plants. It allows for the larger inframarginal revenues of generators with lower variable costs is necessary to compensate for their higher investment costs.

¹⁷ EEX, "Investing Ourselves Out of the Energy Crisis with Market-Oriented Solutions, Recommendations for a Sound Long-Term EU Electricity Market Design Reform," December 21, 2022,

https://www.eex.com/de/newsroom/news/detail?tx_news_pi1%5Baction%5D=detail&tx_news_pi1%5Bcontroller%5D=News&tx_news_pi1%5Bnews%5D=6633&cHash=f0182a9a8f38bcc6cc4a0ffbcbce67b7

¹⁸ Emergency intervention to address high energy prices in the EU;

[https://www.europarl.europa.eu/RegData/etudes/BRIE/2022/733687/EPRS_BRI\(2022\)733687_EN.pdf](https://www.europarl.europa.eu/RegData/etudes/BRIE/2022/733687/EPRS_BRI(2022)733687_EN.pdf)

¹⁹ Some countries prolonged the measure on a national basis further than the end of June 2023 (e.g. RO, PL, CZ, ES, etc)

²⁰ REPORT FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT AND THE COUNCIL on the review of emergency interventions to address high energy prices in accordance with Council Regulation (EU) 2022/1854.

Available at : https://energy.ec.europa.eu/system/files/2023-06/COM_2023_302_1_EN_ACT_part1_v2.pdf

Capping inframarginal rents mostly affect renewables and low carbon technologies, but depending on the level of cap and the type of technologies they would apply to, risks are that these caps may also affect flexible and peaking capacity and distort the most efficient combination of technologies in the generation mix in the short term.

In the long-term and based on the marginal pricing mechanism and merit order principle, these inframarginal revenues are also a key element for incentivizing investments in the new RE capacity. The implementation of such caps therefore harms the investment incentives required to achieve the decarbonization of the power sector.

The implementation of emergency measures, such as the inframarginal revenue caps, also creates a highly uncertain political environment. In 2022, the policy uncertainty associated with the lifting of these market revenue caps put on hold several projects across Europe. The extension of these caps could lead to a standstill of investments which would jeopardize Europe's decarbonization targets. As an example, according to WindEurope²¹, in 2022 Europe invested only €17 billion in new wind projects compared to €41 billion in 2021, the lowest since 2009. Moreover, the report²² of the European Commission on the review of emergency interventions also recognizes the negative impact on renewable Power Purchase Agreements – the market contracted by -21% in 2022 due to the regulatory uncertainty.

These mechanisms have been implemented to address the shortcomings of the marginal pricing system in a situation of crisis. These shortcomings have resulted in some inframarginal producers extracting unreasonable profits, and consumers seeing their electricity bills skyrocketing. In this context and given that these mechanisms remain as short-term emergency intervention, they should have been addressing the issues they have been designed for, allowing for the EU industry to maintain their competitive advantage, and ensuring electricity affordability for all consumers. However, the magnitude and extent of their impact on affordability and competitive advantage depends on how those revenues are redistributed to energy consumers: general principles of such redistribution are set in state aid rules and depends on national decisions.

However, these interventions have, by nature, a distortive effect on the marginal pricing system, which consequently does no longer provide short-term signals for decarbonization. Some renewable generators have fixed long-term off-take contracts in place but some of them remain exposed to wholesale price swings. Emergency interventions create policy uncertainty, not only on energy policies, but also on climate policies, given their close interactions. In general terms, situations in which policy uncertainty is high may result in investments being postponed until a clear and stable market environment has been reached, thus impacting the decarbonization targets negatively.

²¹ <https://windeurope.org/newsroom/press-releases/europe-invested-e17bn-in-new-wind-in-2022-the-lowest-since-2009/#:~:text=Europe%20invested%20just%20%E2%82%AC17bn,and%20ensure%20affordable%20electricity%20prices.>

²² REPORT FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT AND THE COUNCIL on the review of emergency interventions to address high energy prices in accordance with Council Regulation (EU) 2022/1854. Available at : https://energy.ec.europa.eu/system/files/2023-06/COM_2023_302_1_EN_ACT_part1_v2.pdf

Emergency measures effects

Overall, the emergency measures taken by countries in 2022 generally met their short-term objective in terms of mitigating the increase in retail electricity prices despite the peak of wholesale prices²³.

However, they entailed significant spending, while the required urgency in decision making did not allow Member States to fully consider neither their short-term effects and longer-term implications nor their (unintended) impacts beyond national borders – including on emissions - and their interaction with measures taken in neighboring countries.

National interventions did not only sometimes slow down decarbonisation but actually led to increased emissions (e.g. through an increase in gas consumption in electricity generation in Iberia).

What is more, such measures have impaired confidence in the stability of the regulatory and fiscal framework, and jeopardised investor confidence and trust in the EU integrated electricity market, further slowing down the energy transition. The Commission itself recognized all the drawbacks brought by the revenue cap and recommends avoiding its prolongation²⁴. There has been a signal that “there will be a limit to how much money renewable, and clean energy in general, will be able to make at certain times” and this is not the signal investors want to hear.

From an international trade point of view, some of these measures – e.g. governments capping generator profits or subsidizing electricity prices for industry – might be defended as temporary, and exceptional, but may run counter to the underlying principles of world trade and may thus risk countervailing duties, especially if extended.

As such, emergency measures should ideally be temporary, targeted, and tailored to avoid distortionary effects.

A main aspect of the crisis mode was the change from the ordinary legislative procedure to Article 122 of the TFEU²⁵ (Treaty on the Functioning of the European Union). Once moved to crisis legislation, Member

²³ p.4, ACER, 2023. Assessment of emergency measures in electricity markets 2023. Market Monitoring Report. The European Union Agency for the Cooperation of Energy Regulators, 14 July 2023.
https://acer.europa.eu/Publications/2023_MMR_EmergencyMeasures.pdf

²⁴ “the Commission considers that the benefits of the current inframarginal revenue cap would not outweigh the impact on investor certainty and the risks to the market functioning and the transition. The challenges in the implementation process also discourage a prolongation of the inframarginal revenue cap set out in the Council Regulation. The Commission’s conclusion is in line with the feedback received from most respondents to the public consultation, who opposed a prolongation of the measure due to the investor uncertainty concerns”, REPORT FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT AND THE COUNCIL on the review of emergency interventions to address high energy prices in accordance with Council Regulation (EU) 2022/1854. Available at :
https://energy.ec.europa.eu/system/files/2023-06/COM_2023_302_1_EN_ACT_part1_v2.pdf

²⁵ Article 122 (ex Article 100 TEC) :

1. Without prejudice to any other procedures provided for in the Treaties, the Council, on a proposal from the Commission, may decide, in a spirit of solidarity between Member States, upon the measures appropriate to the economic situation, in particular if severe difficulties arise in the supply of certain products, notably in the area of energy.

States had a “free hand” to implement mechanisms that were sometimes badly designed and certainly had negative impact on the market functioning in Europe, especially the Iberian exemption. Many of the national schemes included electricity exports restrictions, in Romania for instance.

Against this background, the EMD proposal introduces criteria for declaring an electricity price crisis (Article 66a of the EMD proposal). One option is that well-defined and quantitatively robust triggering criteria be established, in which case the question is whether the fulfillment of these criteria is a sufficient condition resulting in an “automatic” trigger of a declared energy crisis, or whether human judgement would also need to come into play. Moreover, there is a fine balance to be achieved with respect to defining criteria that on the one hand provide clarity and predictability, but that cannot be gamed by market participants on the other.

2. Where a Member State is in difficulties or is seriously threatened with severe difficulties caused by natural disasters or exceptional occurrences beyond its control, the Council, on a proposal from the Commission, may grant, under certain conditions, Union financial assistance to the Member State concerned. The President of the Council shall inform the European Parliament of the decision taken.

3. Medium to long-term instruments, and their link to decarbonization

In March 2023, EU policymakers reached a political agreement on raising the EU's binding renewable target for 2030 to a minimum of 42.5% of energy consumption. Decarbonization of the EU power system, as well as decarbonization of the EU economy, require significant investments in renewables and other low carbon power generating technologies.

High penetration of both renewable and low carbon energy sources not only reduce the emissions produced in power sector but also unlock the decarbonization potential of energy dependent sectors through electrification such as electric vehicles and heat pumps, or various industrial processes benefitting from emission-free electricity production.

Analysis by the IEA²⁶ highlights the contribution of renewables with respect to shielding consumers from high costs, estimating that EU electricity consumers were expected to save EUR 100 billion during 2021-2023 thanks to additional electricity generation from newly installed solar PV and wind capacity. This is thanks to low-cost new wind and solar PV installations having displaced an estimated 230 TWh of expensive fossil fuel generation since Russia's invasion of Ukraine, leading to a reduction in wholesale electricity prices on all European markets. Without these capacity additions, the average wholesale price of electricity in the European Union in 2022 would have been 8% higher. However, a decline in renewable energy investments at the EU level was observed, particularly in 2022 at the peak of the energy crisis. In the EU, 10 GW of new wind projects were financed which is under the required rate of 31 GW per year to meet decarbonization targets. One of the most important reasons for the drop in wind investment is the inability of TSOs to connect more wind farms to the grid, reflecting the fact that the lead time of the necessary network reinforcements are substantially longer than wind project lead times. Moreover, according to Wind Europe, investments in wind energy in Europe fell in 2022 due to inflation, with costs rising at a higher rate than prospective revenues²⁷. Furthermore, the uncertainties surrounding the regulatory framework, as well as the temporary caps applied on inframarginal power plants during the energy crisis, have made investments decisions more challenging.

Investment decisions are generally based on investors' perception of risks and opportunities. And banking institutions are more likely to give financing to stable businesses. Investors aiming to build up new capital expenditures (CAPEX) intensive low carbon power generating capacity, require certainty on revenues over a longer time period such as 10-15 years.

Spot prices have been expected to send price signals for immediate and operational needs while also serving as a means to offer foresight into future pricing trends through their anticipated levels. However, the short-term market carries long-term price risks resulting from both commodity price risks and cannibalization from more renewables as explained in Chapter 2. The relatively low day-ahead market (DAM) prices or price volatility compromised the long-term financial sustainability of certain types of power plants with high CAPEX. Besides the energy crisis increased the uncertainty regarding the expected long-term price levels, alternative solutions are needed to ensure further long-term investments.

In Europe, several sorts of public support programs have been used by MSs, i.e., feed-in premiums, feed-in tariffs, CfDs, to encourage the development and spread of renewable energy, up to now. In order to

²⁶ IEA (2023), Renewable Energy Market Update - June 2023, IEA, Paris <https://www.iea.org/reports/renewable-energy-market-update-june-2023>, License: CC BY 4.0

²⁷ Wind Europe, Financing and Investment Trends – the European wind industry in 2022

address the energy crisis and align with ambitious climate targets there is a need to transition towards a market framework that enhances price signals for renewable energy projects. This will enable them to recover their initial investments and ongoing operational expenses more effectively. Achieving this necessitates a combination of improved integration of public support and the exploration of advanced market-based hedging opportunities.

The EMD reform aims to strengthen the EU electricity market with better functioning long-term pricing mechanisms such as low carbon Power Purchase Agreements (PPAs), two-way Contracts for Difference and more liquid forward markets. The long-term contracts secured by the electricity market reform have the potential to limit exposure to volatile electricity prices by providing stable long-term price signals to most renewable and low carbon generation investors in Europe.

3.1. Power Purchase Agreements (PPAs)

Power purchase agreements (PPAs) are private long-term delivery contracts between a power plant operator and a consumer. The agreement fixes the delivery price and amount/profile for the duration of the agreement and long term PPAs gives the parties the opportunity to spread their electricity costs to a longer period to achieve an averaging effect instead of procuring power for the near-term future. Thus, PPAs create a win-win situation for the parties of the contract:

- Fostering renewables and low-carbon investment through long-term price visibility/stability for electricity generators, and,
- Providing clarity and long-term hedging opportunity to reduce risk of price volatility for consumers or suppliers.

However, the PPA market is not functioning well across Europe. In 2022, an estimated 8.4 GW of PPA volumes were contracted in Europe with a 21% decrease with respect to 10.7GW in 2021²⁸. On the other hand, while some member states are utilizing this mechanism to a high extent to activate renewable energy investments, it is noteworthy that the mechanism is not working in some Member States. For instance, while Spain leads the PPA market in Europe with more than forty percent of the total PPA trade in the EU with approximately 3.2 GW of PPA contracts in 2022, in some Member States this market is still immature i.e., in Eastern European countries.

Despite the high level of volatility in the European energy markets in recent years, the low number and volume of trade in the EU PPA market give signals that there is an urgent need to speed up the development of the PPA market. One of the objectives of the Electricity market design reform is to facilitate the widespread use of PPAs to provide long term signals for decarbonization. One important pre-condition for achieving this goal is to have sufficient liquidity in the PPAs market.

. This process involves an examination of the obstacles that dissuade parties from engaging in these contracts. It is essential to ensure that Member States take the requisite actions to eliminate these barriers, thus enabling the effective utilization of PPAs in stimulating investments in renewables and low carbon technologies. The disparity between the EU member states in the utilization of the PPA market can also be turned into an advantage by transferring the experience of the developed PPA markets across the EU.

²⁸ Pexapark, European PPA market outlook 2023

Based on the analysis of Baringa²⁹, the main barriers in the EU PPA market include price risk and competition, credit worthiness and contract complexity/length. According to this study, so far, large credit-worthy companies like tech majors and telecommunications have faced less problems in the EU PPA market, while SMEs as well as heavy industry i.e., metals have limited accessibility. Lack of flexibility in terms of size and duration, adaptation to specific consumer needs, absence of standardization, high transaction costs and complexity have also blocked the development of EU PPA market³⁰.

The EMD reform aims at the removal of barriers thereby strengthening and extending the PPA market on smaller players.

The EMD reform also introduces some measures to avoid distortions of one short/long term market mechanism to another. For instance, developers of renewable and low-carbon energy projects that participate in a public support tender should be permitted to allocate a portion of their generation for sale through a PPA. The development of PPA markets within Member States should be carried out voluntarily to prevent any adverse impacts on liquidity in the forward markets³¹. This will enable investors to have a degree of freedom to make their own trade choices and provides positive signals for decarbonization both for the short and long term.

Interaction with climate policy and objectives

PPAs provide positive long-term signals for decarbonization by reducing uncertainty on future revenue streams, thus enabling developers to secure financing at competitive rates, attracting investors and facilitating the implementation of renewable and low carbon energy projects.

A well-functioning PPA market for electricity interacts positively with the EU ETS market in providing long-term signals for decarbonization. The predictability of the allowance price is a key element of the effectiveness of the EU ETS in driving decarbonization. Effectively functioning ETS, producing stable and/or predictable carbon price will shift the investment decisions on low carbon energy solutions.

CO₂ emissions targets in the industry and the energy sectors are predefined at EU level. This cap defines the total amount of GHG emissions that EU ETS sub-installations are allowed to emit. The cap is continuously reducing over time according to the fixed number of certificates auctioned (volume of EUAs) annually. In case that a compliant entity (a steel plant for example), is entering into a green PPA with a renewable or low carbon power generator (a wind plant for example), this entity guarantees that it consumes decarbonized electricity and reduces its emissions related to electricity consumption. If ETS installations emit less than what they need according to the cap, they will need to buy fewer EUAs.

Additionally, entering into a low-carbon electricity PPA provides the relevant parties with certainty in terms of emission reductions as well as the number of allowances. This certainty will increase the long-term trading ability in carbon market for those entities. Therefore, the commercially active PPA market in Europe may have a potential to stabilize EU ETS prices with a domino effect, as it may increase the stability of the

²⁹ European Investment Advisory Hub & Baringa, 'Commercial Power Purchase Agreements', March 2022

³⁰ European Investment Advisory Hub & Baringa, 'Commercial Power Purchase Agreements', March 2022

³¹ Article 19.a.4, Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL amending Regulations (EU) 2019/943 and (EU) 2019/942 as well as Directives (EU) 2018/2001 and (EU) 2019/944 to improve the Union's electricity market design.

EU carbon market thanks to improved certainty and hedging opportunities in long term carbon trading. As a result, the signal that the EU ETS provides to producers in the covered sectors to invest in low-carbon technologies like CCUS, storage, and hydrogen for will be improved. On the other hand, EU ETS contributes to the development of PPA market by incentivizing the EU ETS subsectors to invest in electrification and enter to low carbon PPAs to reduce their overall carbon emissions.

Potential obstacles for the development of well-Functioning PPA markets-from the perspective of low carbon project developers

Based on recent work by the European Commission Joint Research Centre (JRC),³² power prices in Europe are expected to remain largely dependent to gas and coal prices over the next decade. In case that the electricity price-setting in 2030 is still dominated by fossil fuel-based power plants, spot prices will still be more attractive for renewable project developers with relatively lower CAPEX requirements i.e., solar power investments may still compete with wholesale power prices in 2030. This situation may result in limited corporate PPA market activity in the medium term and reduce the access of EU industry to cheapest solutions for low carbon electricity in the PPA market (in case that the low CAPEX intensive renewable energy investors-cheaper solutions will stay in the wholesale energy market). This may impact negatively the liquidity of the PPA market as well as its capability to provide the EU industry affordable electricity prices in the medium term.

On the other hand, offshore renewable energy sources, such as offshore wind, ocean energy and floating photovoltaic, will play an instrumental role in building a power system largely based on renewables and in ensuring climate neutrality by 2050. There are, however, substantial obstacles to their wider and efficient deployment i.e., high CAPEX requirements of those technologies reduce their accessibility to PPA market and/or public auctions i.e., CfDs. Removal of the barriers preventing the massive scale up of those technologies can be ensured with additional support measures i.e., government guarantees specific to those technologies in PPA market and/or CfD auctions specific to those technologies.

3.2. Contracts for Differences for Electricity (CfDs)

Public support schemes play a fundamental role in the rollout of renewables. In cases where a market-based approach falls short of achieving the targeted renewable energy developments, Member States may consider implementing a renewable support scheme. As we progress towards a decarbonized economy, it remains crucial to ensure stable remuneration for renewable energy producers during periods of low prices, thereby providing them with sufficient incentives for renewable investments. Simultaneously, it is essential to prevent government overcompensation and excessive returns for producers during periods of high prices. The Electricity Market Reform, through the introduction of two-way Contracts for Difference (CfDs), serves as a pivotal step in shaping a unified public support mechanism for non-fossil electricity generation, effectively eliminating government overcompensation.

CfDs are a type of financial incentive that guarantees a certain price for low-carbon electricity generators. Essentially, they provide a stable, long-term revenue stream for renewable energy projects, making it more attractive for investors to fund these projects.

³² European Commission Joint Research Centre, The Merit Order and Price-Setting Dynamics in European Electricity Markets, September 2023

Two-way Contracts for differences aim at preventing producers of electricity receive excessive returns and, governments are supposed to be paid back the difference between the strike price and the market price. When designed sensibly, this type of CfDs help de-risking RES investments and reaching a predefined capacity level of targeted technologies at relatively low cost. Ideally, the main criteria for the reference price of a two-way CFD shall be amortization and cost of production (therefore the levelized cost of energy LCOE), ensuring the limitation of profits by electricity producers.

Two-Way CfDs bring to renewable energy investors the advantage of risk mitigation by guaranteeing a stable revenue stream and enhancing the bankability of renewable energy projects. The long-term revenue certainly enables developers to secure financing at rates close to that of government bonds, fostering the realization of ambitious renewable energy targets. These are public-based instruments complementary to market-based PPAs. Although each serving for different purposes, PPAs and CFDs can work together to provide long term signals for decarbonization and to create secure and stable investment conditions for renewable energy developers. While PPAs provide revenue certainty and direct buyer relationships, two-way CfDs focus on price stabilization and risk mitigation. In contrast to PPAs, two-way CfDs exclusively benefit electricity generators, but they still have a positive impact on consumers by helping to stabilize electricity prices. Moreover, developers will have the possibility to combine the use of PPAs and CfDs. The EMD reform provides the renewable energy investor a degree of freedom ensuring that bidders to two-way CfDs are allowed to reserve part of their project's generation for a market-based revenue stream and access to the PPA market. On the other hand, capability of both schemes in supporting research and development of new technologies in low carbon electricity generation remains questionable. RED III, lately voted in mid of September 2023 by the EU Parliament, ensures that member states should set an indicative target for innovative renewable energy technology of at least 5% of newly installed renewable energy capacity³³. Meeting this obligation, the two-way CFDs also could be designed in a way that gives room for the development of high CAPEX intensive and more innovative solutions for RES development i.e., offshore wind.

In this respect, well designed CfDs play a crucial role in providing the right signals for decarbonization, giving the chance to development of diversified of non-fossil generation technologies. EU ETS funds can also contribute to two-way CfDs to finance the more expensive but highly innovative solutions on generation of low-carbon electricity i.e., the Innovation Fund (IF) provides an opportunity for innovative clean tech i.e., wave energy and to finance the demonstration of first-of-a-kind projects i.e., highly innovative offshore wind projects.³⁴

On the other hand, in Europe, energy production, supply and demand are structured very differently from region to region. Considering this diversification and the national security of supply concerns, design principles of two-way CfDs are to a large extent left to the Member States under the EU EMD reform

³³ Position of the European Parliament adopted at first reading on 12 September 2023 with a view to the adoption of Directive (EU) 2023/... of the European Parliament and of the Council amending Directive (EU) 2018/2001, Regulation (EU) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652

³⁴ Innovation Fund Project Portfolio Dashboard available at <https://webgate.ec.europa.eu/dashboard/sense/app/e32ef3f5-0e0e-4be3-8f14-8e2fb5a20aa7/sheet/bac47ac8-b5c7-4cd1-87ad-9f8d6d238eae/state/analysis>

package. Removal of uncertainty in design parameters and providing clarity to investors are pre-conditions for these public support schemes to be effective on achieving the EU climate goals.

To ensure diversification of low carbon electricity technologies and secure the energy independency and competitiveness of EU on renewable energy technologies, Member States will take the risk of investments to unlock the potential of EU in CAPEX intensive renewables such as offshore wind. For instance, in 2023, any offshore wind developers did not bid in the latest renewable energy auctions in UK and awards for all renewables remain limited at 3.7 GW compared to 11 GW in 2022 auction³⁵.

Although the technology neutrality in two-way CfDs auctions may result in the best value for money in the short run, technology specific circumstances can also be taken into consideration to provide healthier long-term signals for decarbonization, to ensure the level playing field of EU in each renewable energy development technologies and to benefit from the potential of diversified technology solutions securing the electricity supply. Besides, ensuring that the two-way CfDs auctions are fit for purpose and provide signals for final investment decisions on all renewable technologies, indexation of the prices in line with the price increases in the electricity market, commodity price increases and inflation is crucial.

In terms of types of investments covered, the EMD reform proposal foresees that two-way CfDs should be the preferential support scheme by MSs for new investments for the generation of electricity from RES or nuclear power, including investments in new power-generating facilities, but also investments aimed at repowering, extending, or prolonging the lifetime of existing power-generating facilities. EU Member States are at odds with respect to utilizing public funds to prolong the lifetime of existing nuclear power facilities. While France emphasizes the implications for energy security and climate goals if reactor lifetimes cannot be extended, Germany, Austria, Spain, and Luxembourg are concerned that using two-way Contracts for Difference (CfDs) for the purpose will distort the EU's internal market and give France an unfair advantage. Aside from the debate between Member States on the necessity of nuclear power plants in generation fleet from a fair competition perspective, the facilitating role of nuclear energy in the achievement of decarbonization goals should not be disregarded. Nuclear energy has the potential to support EU-ETS in phasing out carbon intensive electricity production by providing the necessary base load energy supply.

3.3. Complementary mechanisms enabling RES integration

In the presence of market imperfections (the missing money and the missing market problems), the availability of capacity to enable security of supply can be ensured through instruments additional to the market (i.e., reliability options). At the same time, the need for flexibility adequacy, i.e. the ability of a power system to respond to unforeseen generation and/or consumption changes in real-time operation, has been increasing with the increased integration of variable and non-controllable renewable sources.

Forward looking, all countries can be envisaged to have some kind of remuneration mechanism for flexibility. In countries with Capacity Remuneration Mechanisms (CRM), this could be done by integrating flexibility in the participation criteria. Countries that do not have CRMs in place would need to develop dedicated mechanisms for flexibility (Flexibility Remuneration Mechanism - FRM).

³⁵ [Record number of renewables projects awarded government funding - GOV.UK \(www.gov.uk\)](https://www.gov.uk/government/news/record-number-of-renewables-projects-awarded-government-funding)

CRMs, create direct investment signals that by-pass the short-term market (bypassing therefore also altogether the missing money and the missing market problems), and could come close to the result of the “complete” market³⁶.

For years, however, there has been a focus in Brussels on energy-only wholesale markets, and at the same time a reluctance for CRMs. As such, there is no “blueprint” or common framework for implementing capacity remuneration mechanisms and their features of the schemes across the EU: while some Member States are implementing quantity-based schemes³⁷ i.e., capacity obligations or capacity auctions, others are applying price-based schemes³⁸ like strategic reserves or capacity payments.

Interaction with climate policy and objectives

CRMs were initially implemented by EU countries, for fossil-based plants i.e., CCGT or coal power plants to either avoid plant closures in periods of low profitability or to attract additional investments that did not materialize without this predictable income. The marginal pricing system in the spot market, together with EU ETS and renewable support policies, have significantly reduced the hours of fossil fuel plants operation thanks to the low marginal cost of low carbon generation sources.

To further provide medium to long term signals for decarbonization, CRMs can be geared towards providing additional revenues to new flexibility resources needed to integrate more renewable energy into the grid. In this area, the EMD proposal explicitly recognizes the role of demand side management (DSM) and storage, however by doing so it is implicitly vague about the role of other flexibility sources that could potentially prove cheaper, such as hydrogen or biomethane gas turbine plants or other technologies that might emerge in the near future, and this could be a missed opportunity.

Competitive market-based approaches for CRMs are likely to better provide long term investment signals for decarbonization. CRMs in Europe generally distinguish between 2–3-year time horizons. Longer time frames might contribute to the development of business cases for flexibility sources and enable those to enter and compete in the market.

CRMs have the principal objective of ensuring the necessary level of resource adequacy by remunerating resources for their availability in a technology neutral way. They work in tandem with policies that are aimed at decarbonisation, i.e. the EU ETS. Avoiding lock-ins of high emitting technologies can be a legitimate justification for introducing environmental criteria (i.e. emission limits) for new power plants in new CRMs; keeping in mind however that giving up on technology neutrality comes with substantial economic costs. Avoiding lock-ins can also be ensured by demonstrating that CRM participating plants can be decarbonized (e.g. through CCS).

³⁶ Economists refer to the market as “complete” when the (perfect) physical market is accompanied by a (perfect) financial market where all risk can be traded.

³⁷ The required volume of generation or flexibility to be supported is determined by a central agency i.e., TSO.

³⁸ The price (the amount of support) is determined by a central agency i.e., the regulator or the TSO.

4. Electricity Market Design Reform and industries' competitiveness

Soaring electricity prices pose challenges for both decarbonisation and industrial competitiveness.

Electro-intensive industries are particularly exposed to high and unpredictable electricity prices. Other energy-intensive industries whose decarbonisation pathway involves electrification (e.g. steel) are likely discouraged from investing in electrification.

European energy-intensive industries compete with industry overseas, where electricity prices might be regulated or where industry might have access to average cost-based power pricing.

At the same time, there is a sentiment among European Industry that they do not benefit from the falling cost of renewables as this is not reflected in their bills. Added to this, are rising indirect carbon costs (reflecting rising prices of allowances) for electricity that are decoupled from indirect emissions, and while measures are in place to partly correct this situation, this is another factor contributing to an unlevel playing field with international competitors.

The industry in Europe already experienced difficulties to compete, and the energy crisis has exacerbated the situation. The IEA has reported that due to the steep increases in natural gas and coal prices in 2021-2022, consumers in the EU wholesale market such as large companies without strong hedging positions had to purchase electricity at rates of up to 15-20 times the averages of 2015-2020³⁹. The order of magnitude with respect to electricity price increases at the peak of the energy price crisis (second half of 2022) has been several times larger in Europe compared to the United States⁴⁰. Even passed this peak, prices in Europe in the first half of 2023 remained at about double the 2019 levels while in the United States they nearly returned to 2019 levels amid lower prices for energy commodities⁴¹.

Besides being an end-user, the European energy intensive industry is a supplier of inputs to the technologies needed for the energy transition (e.g. use of steel in wind turbines). High energy prices are reflected in these inputs, further increasing the cost of low-carbon generation technologies (e.g. 38%

³⁹ IEA (2023), Renewable Energy Market Update - June 2023, IEA, Paris <https://www.iea.org/reports/renewable-energy-market-update-june-2023>, License: CC BY 4.0

⁴⁰ According to the 'IEA Electricity Market Report 2023', wholesale prices for Germany, France, Spain and the UK in the second half of 2022 was almost four times as high as the 2019-2021 second-half average, while in the same period the average wholesale price in the United States stood at about USD 91/MWh, more than twice the 2019-2021 second-half average. Average wholesale electricity prices on Europe's Nord Pool power exchange remained at unprecedented high levels in the second half of 2022, exceeding EUR 150/MWh. In a large number of European countries, wholesale electricity prices in the second half of 2022 exceeded the second-half average prices between 2019 and 2021, e.g. fourfold increase in France. In the second half of 2022, the average wholesale price reached almost EUR 330/MWh in Germany and surpassed EUR 320/MWh in France, exacerbated by the unavailability of nuclear plants. By contrast, in Spain, average prices were much lower for the same period at about EUR 130/MWh due to the Iberian price cap. Link to source: <https://iea.blob.core.windows.net/assets/255e9cba-da84-4681-8c1f-458ca1a3d9ca/ElectricityMarketReport2023.pdf>

⁴¹ According to the 'IEA Electricity Market Report – Update 2023', European prices in the first half of 2023 stood at around 100 EUR/MWh, i.e. more than double of the 2019 levels (about 40 EUR/MWh), while electricity futures showed an increase towards the end of 2023, reaching a peak in the first quarter of 2024. At the same time, the average price in the United States in the first half of 2023 was only 10% higher than the 2019 average, while forward prices for 2023 and 2024 indicated a relatively stable price level. Link to source: https://iea.blob.core.windows.net/assets/15172a8d-a515-42d7-88a4-edc27c3696d3/ElectricityMarketReport_Update2023.pdf

increase in wind turbine costs in two years, with the price of steel accounting for a significant share of the increase), which is then reflected in higher electricity prices.

Allowing an industrial exodus out of Europe is economically and politically unwise, and would potentially increase global emissions (risk of carbon leakage). There is thus the need for policies that enhance access to predictable, low-cost and low-carbon electricity.

This chapter discusses some of the short-term measures targeted to industry taken or under consideration in EU Member States (section 4.1), proposed measures in the EMD reform that could provide longer-term signals (section 4.2), as well as other proposals related to modifying the marginal pricing mechanism and could provide end-using industries with cost-reflective prices (section 4.3).

4.1. Short term interventions

As discussed in section 2.2 there was a variety of interventions by EU Member States in 2022 aimed at shielding consumers from high energy prices. Most EU countries intervened in the wholesale and/or the retail market, through measures like price or bid limits, revenue caps, windfall profit taxes or regulation of retail tariffs.⁴²

Overall, there have been ad hoc interventions to the market design to try to ensure consumer affordability. Going forward perhaps the question is whether some of these measures, or specific elements and learnings from their implementation can be ex-ante integrated in the market design to provide a more predictable and uniform solution across the EU (see section 4.3 for a discussion on proposed modifications to the current market design or alternatives). For example, the ITRE Committee draft report on the EMD proposal contemplated integrating in the market design a temporary EU-wide revenue cap on inframarginal generators at times of declared crisis⁴³. Although this idea was not further carried forward in the final position of the European Parliament, because of the shortcomings of revenue caps in general, the rationale behind it was that it would provide regulatory stability via a more predictable and uniform across Europe response to crisis situations that would not lead to severe distortions of the internal market.

Apart from electricity market interventions, many of the measures were in the form of direct support to final consumers. Among these, there have been (and still are) measures targeted to energy-intensive industry. A quick search of the 'IEA Policies database' for measures supporting specifically the electro-intensive industry has given no less than 30 initiatives in Europe since 2022⁴⁴. While these are all primarily state aid measures, there is divergence in terms of the eligibility criteria and conditions, with some incorporating conditionalities that translate into providing support temporarily, i.e. as long as exceptional circumstances prevail (e.g. see measure in Sweden in the text box below).

⁴² ACER, 2023. Wholesale Electricity Market Monitoring 2022 High-level Analysis of Energy Emergency Measures, Report in PowerPoint format, The European Union Agency for the Cooperation of Energy Regulators, 20 March 2023 https://www.acer.europa.eu/Publications/Electricity_MMR_2022-Emergency_Measures.pdf

⁴³ See for example Amendment 15 in the Draft report of the European Parliament Committee on Industry, Research and Energy on the proposal for a regulation of the European Parliament and of the Council amending Regulations (EU) 2019/943 and (EU) 2019/942 as well as Directives (EU) 2018/2001 and (EU) 2019/944 to improve the Union's electricity market design (COM(2023)0148 - C9-0049/2023 - 2023/0077(COD)), ITRE_PR(2023)747032 https://www.europarl.europa.eu/doceo/document/ITRE-PR-747032_EN.html

⁴⁴ The database was searched for the keyword "intensive" and filtered for policies in Europe (including the UK and Norway). This is not an exhaustive list and the number of initiatives is likely a lower bound. <https://www.iea.org/policies?q=intensive®ion%5B0%5D=Europe&page=1>

Poland: PLN 5 billion allocated in state aid for energy intensive industrial companies to help cover the increases in natural gas and electricity costs incurred in 2022 (in the maximum amount of EUR 4 million per undertaking);
Sweden: SEK 2.4 billion allocated in support for electricity-intensive companies to overcome the energy crisis and improve their competitiveness by compensating costs of purchased electricity. Eligible companies receive support for electricity costs that exceed one and a half times their average price in 2021 based on 70 percent of their consumption in 2021 and receive compensation for 50% the eligible costs, up to a ceiling of 2 million euros.
Germany: A targeted package of measures for energy-intensive companies (the Energy Intensive Industry Grant Scheme - EKDP) adopted in April 2022. It encompassed an Energy Cost Mitigation Programme worth EUR 5 billion for energy- and trade- intensive companies as well as federal guarantees for loan programmes and other guarantees. The government subsidized a proportion of the additional natural gas and electricity costs from February to December 2022, provided that the price had more than doubled compared to the 2021 average.

Source: ERCST, based on 'IEA Policies database'

The emergency measures taken by countries generally met their objective in terms of shielding consumers from high prices in the short term, however they entailed significant spending, might have had unintended consequences with respect to increasing overall power system costs and emissions (e.g. through the instability of the regulatory and fiscal framework impairing investor confidence). From an international trade point of view, measures involving governments subsidizing electricity prices for industry, might be defended as temporary, and exceptional, but may run counter to the underlying principles of world trade and may thus risk countervailing duties, especially if extended.

The peak of the energy crisis has passed in the sense that energy prices have decreased, however they remain and are expected to continue to remain at high levels relative to pre-pandemic levels. There still remains a role for public intervention to enhance industry's access to more predictable, low-cost and low-carbon electricity.

Going forward, measures that are geared towards supporting decarbonisation investments by industry like Carbon Contracts for Difference (CCfDs) might be more defensible compared to directly subsidizing electricity prices. They are also aligned with the Temporary Crisis and Transition Framework⁴⁵ adopted in March 2023 by the European Commission, and which prolongs the possibility for Member States to provide state aid measures to support the transition towards a net-zero industry until 31 December 2025 through schemes for accelerating the rollout of renewable energy and energy storage, and schemes for the decarbonisation of industrial production processes.

Germany, for instance launched In June 2023 preparations for a novel subsidy programme in the form of Carbon Contracts for Difference (CCfDs), which compensate energy-intensive companies for the extra costs of climate-friendly production. The contracts serve not only to protect the climate, but also to ensure the country's industrial future in response to the U.S. green industry subsidy programme IRA. A separate proposal according to which energy-intensive firms would be guaranteed electricity for 6 cents per kilowatt hour, for 80 percent of their consumption until 2030 has been welcomed by the industry but remains controversial amongst economists who warn that an industrial electricity price would keep uncompetitive firms in business and slow the transformation to climate neutrality, thereby undermining the country's long-term competitiveness⁴⁶.

⁴⁵ See https://ec.europa.eu/commission/presscorner/detail/en/ip_23_1563

⁴⁶ See <https://www.cleanenergywire.org/factsheets/qa-germany-weighs-electricity-subsidies-shield-industry>

4.2. Long term instruments (PPAs, CfDs)

Capacity markets aside, long-term contracts like PPAs and CfDs are discussed as main ways to enhance visibility for renewable and nuclear investors and rationalizing costs for end-users. The role of policy would be to tackle the barriers that have so far hampered their emergence on the market (PPAs) as well as the role of governments as counterparties to such contracts (CfDs)⁴⁷.

While chapter 3 discussed long-term contracts from the prism of decarbonisation, below we discuss some considerations with respect to PPAs and CfDs from the end-user perspective.

PPAs

PPAs tend to be a more obvious choice between large entities of certain characteristics both on the supply and the demand side: between large offtakers with a large energy footprint (and typically with public CSR commitments), with large margins and long business cycles on the one hand, and large power suppliers with a large enough and diverse portfolio (combining different low carbon generation sources and storage assets) that can satisfy customer requirements with respect to demand and reliability of supply (e.g. a large data centre needs x amount of flat demand, 24/7).

In contrast, an individual wind farm owner would be unlikely to satisfy such customer requirements and could only offer and pay-as-produced PPA contract. On the demand side, customers in sectors with tighter margins and stiffer competition such as heavy industry have shown limited price risk appetite as they see a risk of price decline, which in general prevents them from contracting (a large share of) their demand via long term PPAs⁴⁸. Similarly, when retail companies are the offtakers, they cannot contract large volumes of PPAs, as if it turns out that spot market prices are lower than PPA prices, their consumers will switch to other retailers that offer these lower prices (assuming retail competition)⁴⁹.

Credit worthiness is another major barrier to PPAs identified across most sectors, and particularly in heavy industry and manufacturing, and in less developed European economies, where many organisations have appropriate energy footprint for PPAs but are not rated by major credit rating agencies⁵⁰. Credit worthiness of PPA counterparties is a prerequisite for finance providers of green energy projects linked to PPAs.

There is therefore a role for policy to help tackle the barriers that have so far hampered a higher uptake of PPAs and the EMD reform proposal in that respect goes into tackling the topic of public intervention to ensuring the availability of guarantees.

An increased role for PPAs can be envisaged in the future. Notwithstanding, other types of contracts would likely be needed in addition that might be better suited for smaller power producers, and offtakers with

⁴⁷ We make the simplification that when we refer to PPAs we mean commercial PPAs where the counterparty to the generator is a non-governmental entity that has a commercial interest in procuring the power output (although in theory governments could also be the offtaker), and when we refer to CfDs we mean a non-tradeable contract with the government as the counterparty to the power supplier (although in theory the offtaker could also be a private entity). This simplification seems appropriate in the context of EU discussions on electricity market design.

⁴⁸ Baringa, 2022. Commercial Power Purchase Agreements - A Market Study including an assessment of potential financial instruments to support renewable energy Commercial Power Purchase Agreements. Final report prepared by Baringa for the EIB and the EC. <https://advisory.eib.org/publications/attachments/commercial-power-purchase-agreements.pdf>

⁴⁹ Green, R. J., 2004. *Retail Competition and Electricity Contracts*. <https://doi.org/10.17863/CAM.5049>.

⁵⁰ Baringa, 2022. Commercial Power Purchase Agreements - A Market Study including an assessment of potential financial instruments to support renewable energy Commercial Power Purchase Agreements. Final report prepared by Baringa for the EIB and the EC. <https://advisory.eib.org/publications/attachments/commercial-power-purchase-agreements.pdf>

smaller margins and/or shorter business cycles (including from industry). Other forms of government support will continue to play an important role in delivering the scale of investment at a pace needed for achieving the EU climate and energy goals.

Some considerations and open questions with respect to PPAs from the end user point of view include:

- When energy retailers are the counterparties, what can be done to make sure that conditions/potential savings are passed on to final end users? This challenge arises because retailers will offer electricity at the equilibrium price that prevails in the retail market, regardless of the price at which they procured it⁵¹.
- How can the difference in appetite with respect to contract duration between power producers and offtakers be bridged? Low carbon generation developers might want PPAs ideally covering the entire lifetime of assets, while industry offtakers are reluctant to sign very long contracts. Is there a role for a government intermediary (i.e. the regulator) that signs 15-20 years with developers and 2-3 year contracts with offtakers?
- Is there a role for standardization with respect to PPAs? Currently, PPAs are individually negotiated with each customer and there is probably not two PPAs that are alike (their terms remain confidential between counterparties); If governments are to provide guarantees for PPAs some form of standardization seems to be inevitable to avoid the risk of moral hazard. Moreover, standardization of terms and conditions could reduce complexity and improve accessibility for smaller players.
- Some governments in the EU might have better capacity and experience in offering guarantees, and this is likely to have an impact on the development of national PPA markets. Is there a role for the EU and financial institutions like the EIB in leveling the playing field, through getting involved in instruments enabling guarantees or driving the work on standardisation?

CfDs

Government support will continue to play an important role in delivering the scale of investment in low-carbon generation at a pace needed for achieving the EU climate and energy goals since there is no guarantee that sufficient PPAs will be emerging. Two-way CfDs have emerged as a key instrument to channeling such support.

CfDs are straightforward contracts where energy is taken as produced. CfDs are not per se a market design tool but rather a tool for decarbonisation. Some claim that it is state aid, however this might hold less true for the case of two-sided CfDs that generate revenues or tradeable CfDs that might emerge in the future.

Some considerations and open questions with respect to CfDs from the end user point of view include:

- We are moving towards a world where a significant share of decarbonized electricity is likely to be built on the basis of CfDs (two sided CfDs, which avoid windfall profits). Then the question arises: how will potential revenues be allocated? Will there and should there be preferential treatment of certain users (e.g. energy intensive industry)? The decision of how to allocate could become a tool for competitiveness.
- CfDs might reduce the incentive of producers to enter forward contracts. What are the implications for retail competition and consumers?

⁵¹ Ambec, S, A Banal-Estanol, E Cantillon, C Crampes, A Creti, F Decarolis, N Fabra, R Gerlagh, K Neuhoﬀ, C Landais, M Liski, G Llobet, D Newbery, M Polo, M Reguant, S Schwenen and I Vehviläinen (2023), Policy Insight 120: Electricity market design: Views from European economists, CEPR Policy Insight No 120, CEPR Press, Paris & London. <https://cepr.org/publications/policy-insight-120-electricity-market-design-views-european-economists>

- CfDs derisks the producer side but not the consumer. That said, is there a need for a ‘reverse’ CfD for consumer?
- What considerations in the design of CfD schemes could help minimize costs for consumers (strike price, reference price etc)? E.g. do you give the same/uniform strike price (of the highest bidder that was needed to clear demand) to all participating generators or do you give to each one of them the price they asked in their bids? Is the reference price the day ahead price or another prices e.g. we see an increasing number of CfD implementations in Europe where a longer-term average price rather than the hourly day-ahead price is used as the reference price. While the design of CfDs would be up to the individual Member States, there is probably some role for capacity building and guidance in terms of best practices at the EU level.
- It seems to that the proposed reform tries to improve the market conditions for investments by the private sector to happen. And also at the same time recognizes that this will not sufficient, and therefore puts an emphasis on elements such as CfDs (and capacity mechanisms), which imply a stronger role for governments in the development of their national energy systems. Wouldn’t this emphasis on national incentives and planning require coordination at EU level of investment decisions given that we are interconnected and that we want to have an efficient and resilient power system at European level (and avoid fragmentation). What role / level of coordination in the EU would we envisage? Extreme example would be having CfDs auctions at EU level? A formal European-level system planning and forecasting would be needed to, at least, assist national decision-makers in understanding how their choices fit into a European system⁵².

Paradoxically, while the EMD proposed reform includes some provisions aimed at containing fragmentation of approaches and responses by Member States in response to energy crisis situations (e.g. defining criteria for declaring energy crisis), it also implies a greater role for MS governments in the planning of national energy systems through an emphasis on CfDs, capacity remuneration mechanisms and government guarantees for PPAs. Without coordination at EU level, an unlevel playing field reflecting national administrative and financial capabilities across Member States is likely to emerge.

4.3. Market design proposals for risk reduction

The reform of energy markets design and a potential departure from marginal pricing has been a recurring topic, since several years in academic circles (especially in the UK), and in EU political circles since the end of 2021 amidst soaring energy prices that have put the focus on affordability.

A central consideration here has been the observation that although the EU generates twice as much electricity from renewables as it does from gas, the current power market design does not allow for the falling cost of renewables to be reflected in bills. As the most expensive generator in the merit order needed to meet the last bit of demand, gas plays an outsized role in setting the price in wholesale markets, and it is expected to continue to do so in 2030⁵³.

⁵² P. 20, Zachmann, G. and C. Heussaff (2023) ‘Phased European Union electricity market reform’, Policy Brief 06/2023, Bruegel, https://www.bruegel.org/sites/default/files/2023-03/PB%2006%202023_4.pdf

⁵³ Gas-run power plants set the price 55% of the time in 2022 while generating 19% of total EU electricity. In 2030, the price-setting share is still close to 56%, even with generation decreasing to 11% of electricity. Source: Gasparella A., Koolen D. and Zucker A., The Merit Order and Price-Setting Dynamics in European Electricity Markets, European Commission, Petten, 2023, JRC134300. <https://publications.jrc.ec.europa.eu/repository/handle/JRC134300>

EU Member States have been somewhat divided on the topic, with positions sometimes shifting over time. Some governments especially from the South of Europe (e.g. Spain, France, Greece) have in the course of the past two years gone to Brussels with the message that the current market design does not work and that there is a need for an overhaul. Other countries have advocated against far-reaching reforms of the market design⁵⁴, with some of them subsequently softening their stance⁵⁵ and even launching national initiatives on how to reform power market design to accommodate the energy transition⁵⁶.

The European Commission President Ursula von der Leyen provided in June 2022 the political direction for the ongoing reform, with her initial statements alluding to a review and a potential overhaul of the marginal pricing mechanism and the decoupling of gas and power⁵⁷. This constituted a departure from the previous position of the European Commission who resisted calls for a deep reform, pointing to the results of a review of the wholesale electricity markets by the EU Agency for the Cooperation of Energy Regulators (ACER) that found that markets worked as intended⁵⁸.

Von der Leyen's statements were well received by the EU energy-intensive industry, especially those producing globally traded products, and who had been bearing the impacts of sustained high prices on their competitiveness. There have been voices from the industry calling for more cost reflective power prices in the EU, as there is a sentiment that the falling cost of renewables is not reflected in their bills, while their international competitors often benefit from average cost-based or low regulated tariffs. Another factor contributing to an unlevel playing field with international competitors, are rising indirect carbon costs under the EU ETS that are decoupled from indirect emissions, with measures in place only

⁵⁴ For instance, nine EU MSs including Germany, Austria, Denmark, Estonia, Finland, Ireland, Luxembourg, Latvia and the Netherlands, issued a joint statement ahead of an emergency meeting of energy ministers in October 2021, saying that they would not support a reform of the EU electricity market, and rejecting an October 2021 (i.e. prior to Ukraine/Russia war, but already amidst soaring prices) French-led bid to reform Europe's wholesale energy markets. See for more info: <https://www.euractiv.com/section/electricity/news/nine-eu-countries-reject-franco-spanish-push-for-electricity-reforms/>; and <https://www.reuters.com/business/energy/nine-eu-countries-oppose-electricity-market-reforms-fix-energy-price-spike-2021-10-25/#:~:text=As%20the%20price%20spikes%20have,linked%20to%20fossil%20fuels%20markets.%22> ;

⁵⁵ E.g. Germany and Austria. Germany, that was initially very skeptical with respect to market reform, acknowledged in August 2022 the need to fundamentally reform the electricity market to decouple the development of end customer electricity prices from rising gas prices, with the Federal Economics Ministry issuing relevant statements. <https://www.handelsblatt.com/politik/strommarkt-habeck-will-strompreis-vom-gaspreis-entkoppeln/28630846.html> ; and <https://www.bloomberg.com/news/articles/2022-08-29/germany-wants-power-market-overhaul-to-dampen-soaring-prices>

⁵⁶ The German *Platform for a climate-neutral electricity system* (PKNS) was launched in February 2023 with the task to come up with a power market design that can accommodate a largely climate neutral power system. <https://www.bmwk.de/Redaktion/EN/Dossier/the-climate-neutral-electricity-system-platform.html#:~:text=In%20the%20coalition%20agreement%20of,design%20in%20a%20largely%20climate%20>

⁵⁷ Statements made by Ursula von der Leyen at the European Parliament in June 2022 acknowledged that the EU's electricity market system "does not work anymore. We have to reform it. We have to adapt it to the new realities of dominant renewables" <https://www.euractiv.com/section/electricity/news/eu-chief-announces-electricity-market-overhaul-amid-skyrocketing-prices/>

⁵⁸ ACER's review found that the electricity market design was not to blame for the energy crisis and that it had rather helped mitigate energy prices to some extent and avoided electricity curtailment or even blackouts. See ACER, 2022. ACER webinar: Presentation and walk- through of the ACER Final Assessment of the EU Electricity Market Design, 5 May 2022. <https://www.acer.europa.eu/sites/default/files/events/documents/2022-05/20220505%20Webinar%20-%20Walk-through%20presentation%20of%20ACER%20April%20assessment%20on%20market%20design.pdf>

partly correcting this situation. There was therefore an initial expectation by stakeholders of a possible review of the marginal pricing model, however it quickly became evident that this would not be the case.

The marginal pricing model has been generally accepted by economists as best suited for liberalised electricity markets, as it (theoretically) provides efficiency, transparency and incentives to keep costs as low as possible. The current electricity market design is inspired by the pioneering work of Boiteux⁵⁹, former executive at EDF, who proved that peak load (marginal cost) pricing is efficient⁶⁰. *“However, this conclusion rests on an assumption that does not apply in practice: the free entry (and exit) condition. Under this assumption, firms make zero profits as, otherwise, entry or exit would take place until the zero profits condition holds. However, in real-world markets, various entry and exit barriers (including legal obstacles or constraints on the availability of resources or locations, among others) prevent profit adjustments, or at least not at the necessary speed⁶¹”.*

The breakdown of this assumption results in a situation where the price of electricity might on average deviate from the average cost of generating it. As such, revisiting the current marginal pricing model, in the sense of assessing it and comparing it to alternative setups, does not have to be a taboo topic.

Different proposals for a more profound reform have been floating, ranging from adjusting the marginal pricing mechanism to partly or completely doing away with it.

For example, at the end of July 2022, the Greek government presented a detailed proposal⁶² to split electricity markets, putting: 1) renewables, nuclear and flow hydro into one market where prices would reflect total levelized cost, and 2) fossil fuel generation and stored hydro into another basket/market, where prices would reflect scarcity and marginal costs. The Greek proposal is a variation of previous proposals⁶³ put forward by academics (primarily in the UK) to split the single wholesale electricity market into two and have one market for renewables generation based on average cost pricing, and a separate market for traditional fossil fuel-based generation based on marginal cost pricing.

Other proposals integrating a temporary ‘relief valve’ mechanism in the market design triggered only under exceptionally high prices, creating Green Power Pools as a way to decouple gas from power markets, or having a government agency as the sole offtaker of power and thereby essentially eliminating the market.

There have also been suggestions to replace the “pay-as-cleared” remuneration mechanism with the “pay-as-bid” approach in the day-ahead market. However, the latter approach would be detrimental for investment in ‘high CAPEX, low OPEX’ generation technologies like renewables, which can only recover high investment costs if the market clearing price is significantly above their marginal costs for a significant number of hours during a year⁶⁴. Moreover, the pay-as-bid pricing would likely see a radical change in

⁵⁹ Boiteux M. (1956). Sur la Gestion des Monopoles Publics Astreints à l’Equilibre Budgetaire, *Econometrica*, Vol. 24, No. 1 (Jan., 1956), pp. 22-40. <https://doi.org/10.2307/1905256>

⁶⁰ I.e. that it is the best social outcome under constraints.

⁶¹ Fabra, N. Electricity Markets in Transition: A proposal for reforming European electricity markets. EEL Working paper 115. https://drive.google.com/file/d/11YJVeSCqfcAYk8KJ_Br20bLrTJ3h3Axx/view

⁶² Link to the Greek proposal: <https://data.consilium.europa.eu/doc/document/ST-11398-2022-INIT/en/pdf>

⁶³ See for example: Keay, M. and Robinson, D. (2017). ‘Market design for a decarbonized electricity market: the “two market” approach’, in Rossetto, N. (ed.), Design the Electricity Market(s) of the Future, proceedings from the Eurelectric- Florence School of Regulation Conference.

https://cadmus.eui.eu/bitstream/handle/1814/50004/Rossetto_Ebook_2017.pdf?sequence=2&isAllowed=y]

⁶⁴ ACER, Note on High energy prices, October 2021, available at: [Energy Prices_Final.pdf](#)

bidding behaviour by market participants that would introduce new inefficiencies, weaken competition in new generation, and hamper capacity expansion⁶⁵.

The table in Annex 1 provides an overview of some of these proposals⁶⁶, as well as some reflections on their potential implications.

Policy makers might be able to discard some of these proposals right from the outset, without studying their implications further. For instance, the proposal for 100% pay-as bid would render investments in low carbon technologies unattractive and only increase the need for subsidies for low-carbon generation technologies. Other proposals might be more a matter of socio-economic choices, e.g. the EESC proposal would entail returning to central planning and doing away with efficiency gains of markets altogether.

Some of these proposals have to some extent been studied, in particular with respect to price impacts in the short run. However, they would still need to be assessed fully and better understood in terms of their impact on investment signals, what they might entail in terms of backup and balancing costs and the extent to which they allow for a least cost and resilient power system.

What these proposals have in common is that they reduce risk, either solely the risk of price volatility for consumers or also investor risks. These proposals (along with other proposals not discussed here, e.g. nodal pricing, or ways of introducing scarcity pricing⁶⁷) would need to be compared to the current market design to understand whether the latter - in combination with complementary measures - is likely to deliver the same benefits (e.g. through a widespread and expanded application of long-run fixed-price private PPAs for low-carbon power, coupled with a short-run variable price market).

This would not have been possible within the short timeframe available for the current EMD reform, which consequently focused on tackling some of the gaps of the current design but did not go into exploring more far-reaching modifications or alternatives.

⁶⁵ Alfred E. Kahn, Peter C. Cramton, Robert H. Porter, Richard D. Tabors, 2001. Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond. The Electricity Journal, Volume 14, Issue 6, July 2001, Pages 70-79.

[https://doi.org/10.1016/S1040-6190\(01\)00216-0](https://doi.org/10.1016/S1040-6190(01)00216-0)

⁶⁶ The table is non-exhaustive, and takes a narrow approach in the sense that it covers some of the proposals that reduce the risk of price volatility for consumers and investment risks for producers, but does not cover other proposals that would increase operational efficiency of the power system such as scarcity pricing, nodal pricing or increasing the number of bidding zones.

⁶⁷ For instance, for a proposal on how the implementation of a real-time market for reserve capacity can be aligned with European legislation, and a description of how scarcity pricing based on operating reserve demand curves can be integrated in such a design, see: Papavasiliou, A., Scarcity pricing and the missing European market for real-time reserve capacity, The Electricity Journal 33 (2020) 106863.

https://dial.uclouvain.be/pr/boreal/object/boreal%3A259554/datastream/PDF_01/view

5. Takeaways

- The issues discussed in this report can be divided into short-to-medium term and long-term. The former can be seen as a matter of “survival”, while the latter as providing the signal for investment in decarbonized electricity, the only reasonable approach to ensure the survival of EU industry in the context of carbon prices and increasingly ambitious climate policy.
- While solutions for long-term investment signal are presented, the challenge for solutions for the short term lies in ensuring that they do not conflict with climate objectives.
- The balance between the short-term and long-term signal is what is highlighted below. Having more of a sense of how much of the market would be navigating on long-term contracts and how much on marginal pricing, would allow carbon markets to better integrate long-term price signals into the carbon price.
- Given the interconnectivity of the EU power system, some degree of coordination of investment planning at EU level is needed, if we are not to lose sight of the aspiration of having an efficient and resilient power system at the European level.
- There are doubts whether the current marginal pricing system, which remains in place, applies itself well to a new decentralized and RE focused energy matrix resulting from the increasingly ambitious decarbonization policies.

Short-term markets have over the years received considerable attention in the restructuring of the power industry, while long-term markets have been largely left unaddressed. Given the deregulation of the electricity industry, creating a short-term liquid market was seen as a priority.

Even in the absence of imperfections in the energy-only market (or with restorative measures in place), short term markets alone have been shown to not be able to deliver a least cost and reliable power generation system. The liquidity of long-term contracts has largely been absent for maturities exceeding five years and has hence been insufficient for investors (the “missing market”⁶⁸ problem). It has however provided, together with the carbon market part of the incentive to decarbonize, especially fuel switching.

The emergence of long-term contracts has largely been hampered by high transaction costs and complexity. Prior to deregulation, their absence did not pose a serious issue for investment as market participants could sell with minimal risk in geographically segmented systems. After restructuring, however, their absence started to be felt in that investments largely came to a stall (except for subsidized ones). The historic overcapacity gradually disappeared in the first years following deregulation, giving way

⁶⁸ A missing market is a situation where a competitive market allowing the exchange of a commodity would be Pareto-efficient, but no such market exists, because of some obstruction such as poor information, high transaction costs or the inability to price all social costs/benefits e.g. externalities. See for example:

1) Newbery, D.M.G. and Stiglitz, J.E. (1984) Pareto Inferior trade. *Review of Economic Studies*, 51, 1-12.
<http://dx.doi.org/10.2307/2297701>, where the authors show that a market satisfying all assumptions of perfect competition in a deterministic world may become grossly inefficient in a risky environment if the proper instruments for trading risk do not exist;

2) For a recent quantified analysis of the missing market problem see: Abada Ibrahim, Gauthier De Maere D'Aertrycke, Andreas Ehrenmann, Yves Smeers, What Models Tell us about Long-term Contracts in Times of the Energy Transition, *Economics of Energy & Environmental Policy*, Vol. 8, No. 1, 163-181, March 2019, published by the by the International Association for Energy Economics.

https://dial.uclouvain.be/pr/boreal/object/boreal%3A217354/datastream/PDF_01/view

to an ever-tighter system as the energy market largely failed to attract new investments to cater for the growing demand.

Partly due to this prolonged period of underinvestment, energy prices are likely to continue to remain a challenge for the EU, both in terms of affordability /competitiveness and for decarbonisation.

In the long-term, the solution that is clearly emerging is that of electrification and decarbonization of the power industry through renewables, as well as other sources such as nuclear which is absolutely necessary. Electro-intensive industries are particularly exposed to high and unpredictable electricity prices, while other energy-intensive industries whose decarbonisation pathway involves their electrification are discouraged from making the relevant investments.

Decarbonisation requires a significant amount of investment, and as such the signal from the electricity market, the carbon market, and the interaction between these two needs to ensure a good framework that will incentivize these investments.

CfDs, cCfDs, long-term PPAs, are some of the means that have been mentioned and addressed by the latest (2023) market design proposal. Facilitating access to long-term contracts is welcome, but there also needs to be customer demand for such contracts. For example, end-users in sectors with tighter margins and stiffer competition such as heavy industry tend to see a risk of price decline, which might prevent them from contracting a large share of their demand via long term PPAs. Other instruments like CfDs seem destined to fill the gap and meet climate targets.

The proposed reform preserves the current market design based on short-term marginal pricing and complements it with initiatives to improve access to long-term contracts. This is in recognition of the fact that the current market design in conjunction with EU ETS prices have for more than 20 years proved to provide the appropriate signal for dispatching the less carbon intensive plants. At the same time, long-term contracts, along with capacity and flexibility remuneration mechanisms are emerging as the solution for providing sufficient long-term investment signals and addressing the missing markets and the missing money problems. Access to both the short-, and long-term markets improves risk hedging opportunities for market participants.

The relative contribution of short-term vs long-term pricing in terms of financing the assets and providing long-term price signals is however missing from the debate. Having more of a sense of how much of the market would be navigating on long-term contracts and how much on marginal pricing, would allow carbon markets to better integrate long-term price signals into the carbon price.

An indication of the desired balance is also an important first step towards determining the balance between the long-term instruments. The relative contribution and prioritization of different long-term instruments e.g. PPAs vs CfDs is also missing from the debate. For instance, one could render PPAs as the “primary” (primary in the sense of timing) instrument for delivering a given amount of additional low-carbon capacity in line with climate targets; and subsequently through a regular (e.g. every six months) stock-take exercise determine the ‘distance to target’ for which CfDs (the “secondary” instrument) would be auctioned.

As already mentioned, however, although there is room for increasing the importance of PPAs compared to today, their contribution is likely to remain restricted by the lack of substantial demand and difficulties with respect to containing the risk of moral hazard if there is government backing for them. Government

support instruments in the form of CfDs but also CCfDs are likely to emerge as the leading instruments in terms of their relative contribution.

There remain the issues of short-medium-term up to 2030, which is seen by many in industry as a “survival” period. Prices will be high, and in this period structural reforms of the electricity markets are unlikely to provide the “survival” measures that are so necessary to ensure that, before the long-term, there continues to be an industrial EU.

One necessary condition is that the measures put in place in the short-term cannot be conflicting with the EU climate change objectives - which was the case with some of the measures that were put in place to address the energy price crisis over the last years (e.g. inframarginal caps, the Iberian exemption, etc.)

The power sector was set on the road to decarbonization through incentives and subsidies, with a significant amount of contribution from the carbon price signal. With energy prices expected to remain at high levels relative to pre-pandemic levels, there still remains a role for public intervention to enhance access to more predictable, low-cost and low-carbon electricity. Ad hoc emergency measures with potential negative impacts on emissions or non-defendable from an international trade perspective, are increasingly giving way to other state aid schemes with potentially less distortions, such as CfDs for power producers and CCfDs for industry. Going forward, there is also the question of whether some of these ad hoc interventions addressing consumer affordability can be ex-ante integrated in the market design to provide a more predictable and uniform solution across the EU.

Paradoxically, while the proposed electricity market design reform includes some provisions aimed at containing the proliferation of divergent emergency measures by Member States in response to situations of energy crisis (by spelling out criteria for declaring an energy crisis), it also implies a greater role for national governments in the planning of national energy systems through an emphasis on CfDs, capacity remuneration mechanisms and government guarantees for PPAs. Given the interconnectivity of the EU power system, some degree of coordination of investment planning at EU level is needed, if we are not to lose sight of the aspiration of having an efficient and resilient power system at the European level. The role of the EU in avoiding a race for subsidies and the emergence of an unlevel playing field reflecting national administrative and financial capabilities across Member States needs to be further deliberated.

There will need to be significant financial outlays and the question that needs to be squarely faced is “who pays the bill”. In some countries with a larger industrial base (e.g. Germany) it has been largely the consumer, with industry being in many cases shielded. Policy makers would need for instance to consider whether and how the fee/revenue structure for schemes like CfDs could become a tool for competitiveness, and whether there is a need for a downstream mechanism to derisk also the consumer side. More broadly, governments would need to consider a portfolio of different policy instruments and its macroeconomic impacts: an emphasis on subsidies for low-carbon generation investments reduces the need for carbon price surges and results in lower inflation, while production subsidies boost investment and GDP with little impact on inflation⁶⁹. Put more simply, the mere choice of relying more on CfDs implicitly means more of the cost borne by households rather than industrial consumers who might see a reduction in carbon prices.

⁶⁹ IMF, 2022. Chapter 3 Near-Term Macroeconomic Impact of Decarbonization Policies, World Economic Outlook, October 2022, International Monetary Fund.

<https://www.elibrary.imf.org/display/book/9798400218439/CH003.xml>

In the US the cost has been (ironically) socialized through the IRA. The EU has introduced the NZIA and possibly other measures, but a number of countries are proposing to introduce state aid measures at the national level (e.g. in Germany).

While some measures may be addressing the transition cost in the short-term, such as NZIA, the issue of carbon prices and high electricity prices remains and needs to be addressed. The industry in Europe already experienced difficulties to compete, and the energy crisis has exacerbated the situation. Allowing an industrial exodus out of Europe is economically and politically unwise, and bears the risk of carbon leakage. Besides being an end-user, the European energy intensive industry is a supplier of inputs to the technologies needed for the energy transition (e.g. use of steel in wind turbines). Breaking the negative spiral of high energy prices being reflected in these inputs, further increasing the cost of low-carbon generation technologies, which is then reflected in higher electricity prices, is a challenge.

The EU, and many other jurisdictions, are faced with an increasingly changed energy matrix. At the same time, there is a sentiment among consumers that they do not benefit from the falling cost of renewables as this is not reflected in their bills. There are doubts whether this market design applies itself well to a new decentralized and RE focused energy matrix.

The marginal pricing model has been generally accepted by economists as best suited for liberalized electricity markets, however, this rests among other things on the assumption of free entry (and exit) that might not apply in practice. Moreover, a market design with a complete penetration of zero-variable cost technologies would theoretically function like the current system provided that scarcity pricing is supported. In practice, however, a zero variable cost world makes for an uncomfortable setting for investors who would have to recover investments in very few scarcity events.

Various proposals for revisiting the marginal pricing model to reduce risk for both consumers and producers have been put forward over the years, ranging from adjusting the marginal pricing mechanism to partly or completely doing away with it. In the context of the next market design review, some of these merit further assessment, in terms of their costs and benefits compared to the existing set up.

Annex 1 Detailed overview of market design proposals for risk reduction

Table 1 Market design proposals for risk reduction⁷⁰ (non-exhaustive)

Proposal	Description	Possible implications / comments
Split markets (Greek proposal, 2021 ⁷¹)	Split the electricity market into two: 1) renewables, nuclear and flow hydro into one market with prices reflecting total levelized cost, and 2) fossil fuel generation and stored hydro into another market, with prices reflecting scarcity and marginal costs.	Straightforward concept but major departure from current design. It may be seen more as a potential final outcome for zero-carbon systems rather than an option for near-term implementation ⁷² .
Dual market through a Green Power Pool (Grubb et al 2018; and 2022 ⁷³)	The central proposition involves aggregating the output of groups of low carbon generators on fixed-price contracts through a 'green power pool'. This would offer the electricity directly to offtakers rather than through the wholesale market and its marginal pricing structures. This 'green power pool' approach would interact with the wholesale market.	Less radical than the split markets approach, and therefore more suitable/practical for near-term implementation.

⁷⁰ The table is non-exhaustive, and takes a narrow approach in the sense that it covers some of the proposals that reduce the risk of price volatility for consumers and investment risks for producers, but does not cover other proposals that would increase operational efficiency of the power system such as scarcity pricing, nodal pricing or increasing the number of bidding zones.

⁷¹ Link to the Greek proposal: <https://data.consilium.europa.eu/doc/document/ST-11398-2022-INIT/en/pdf>

⁷² P11, Michael Grubb, Paul Drummond and Serguey Maximov, 2022. Separating electricity from gas prices through Green Power Pools: Design options and evolution, Working Paper No. 193 November 9th, 2022, Institute for New Economic Thinking, The Bartlett Institute for Sustainable Resources.

<https://www.ineteconomics.org/research/research-papers/separating-electricity-from-gas-prices-through-green-power-pools-design-options-and-evolution>

⁷³ 1) Michael Grubb and Paul Drummond, 2018. UK Industrial Electricity Prices: Competitiveness in a Low Carbon World, Report Commissioned by the Aldersgate Group, February 2018. <https://www.aldersgategroup.org.uk/content/uploads/2022/03/1802-UK-industrial-electricity-prices—FINAL.pdf> ; 2) Michael Grubb, Paul Drummond and Serguey Maximov, 2022. Separating electricity from gas prices through Green Power Pools: Design options and evolution, Working Paper No. 193 November 9th, 2022, Institute for New Economic Thinking, The Bartlett Institute for Sustainable Resources.

<https://www.ineteconomics.org/research/research-papers/separating-electricity-from-gas-prices-through-green-power-pools-design-options-and-evolution>

Proposal	Description	Possible implications / comments
Renewable energy pool for Contracts for Difference (Neuhoff et al 2023 ⁷⁴)	Creation of a “Renewable Energy Pool”, which connects renewable producers covered by contracts-for-difference to consumers. The Pool comprises three elements. For producers of renewable energy, it provides long-term CfD contracts to remunerate new wind and solar power projects, tendered by a government agency. The agency then combines all individual CfD-contracts to a standardized “Renewable Pool” that is allocated to final electricity consumers (industry, private households) on quasi-fixed volume basis (i.e., for a standard weather year).	For consumers, the Renewable Pool provides a hedge against fluctuating power prices for the generation volume according to the generation profile of RE-pool, without diluting energy price signals on short term markets. For governments the pool is budget-neutral, except in situations of contract defaults. Builds on Green Power Pool proposal (see row above) but differs from it in that the hedging payments are structured as a financial hedge rather than as physical delivery.
Government E-Facility (proposal by the European Economic and Social Committee – EESC, 2023) ⁷⁵	The heart of this model is a government-established "E-facility" which buys the electricity from the producers and sells it to the suppliers of household customers, SMEs, Citizen Energy Communities and large consumers, and to other countries. This facility would conclude long-term contracts with electricity producers on the basis of tenders. Contracts would be of various types, i.e. PPAs, CfDs, and cost+ contracts.	The government as the sole offtaker would need to decide how to allocate the government-backed energy to different users; Convergence to removal of the market/central planning, and highly demanding in terms of administration. Challenging to ensure an efficient (least cost) power system with no over- or under-investment.
Pay-as-bid	Replacement of the “pay-as-cleared” remuneration mechanism with the “pay-as-bid” approach in the day-ahead market. Electricity producers would no longer be paid a uniform price for their electricity (equal to the price bid of the last producer in the merit order necessary to meet demand), but the price in their individual bids.	Detrimental for investment in ‘high CAPEX, low OPEX’ generation technologies (RE), which can only recover investment costs if the market clearing price is significantly above their marginal costs for a significant number of hours during a year ⁷⁶ . Likely radical change in bidding behaviour that would introduce new inefficiencies, weaken competition in new generation, and hamper capacity expansion ⁷⁷ .

⁷⁴ Karsten Neuhoff, Fernanda Ballesteros, Mats Kröger, Jörn C. Richstein, 2023. Contracting matters: Hedging producers and consumers with a renewable energy pool, Discussion paper 2035, 26 S, DIW Berlin - German Institute for Economic Research, https://www.diw.de/documents/publikationen/73/diw_01.c.868545.de/dp2035.pdf

⁷⁵ OPINION by the European Economic and Social Committee, Electricity Market Reform, Proposal for a Regulation of the European Parliament and of the Council amending Regulations (EU) 2019/943 and (EU) 2019/942 as well as Directives (EU) 2018/2001 and (EU) 2019/944 to improve the Union's electricity market design [COM(2023) 148 final – 2023/0077 (COD)] TEN/793. <https://www.eesc.europa.eu/en/our-work/opinions-information-reports/opinions/electricity-market-reform>

⁷⁶ ACER, Note on High energy prices, October 2021, available at: [Energy Prices_Final.pdf](#)

⁷⁷ Alfred E. Kahn, Peter C. Cramton, Robert H. Porter, Richard D. Tabors, 2001. Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond. The Electricity Journal, Volume 14, Issue 6, July 2001, Pages 70-79. [https://doi.org/10.1016/S1040-6190\(01\)00216-0](https://doi.org/10.1016/S1040-6190(01)00216-0)

Proposal	Description	Possible implications / comments
ELFI/TIF combined pay-as-clear and pay-as-bid market clearing / 'Price shock absorber' mechanism ⁷⁸	Combination of pay-as-clear and pay-as-bid clearing methods: – Least cost 90% of volume (or other share) cleared with pay-as-clear – Highest cost 10% of volume (remaining share) cleared with pay-as-bid. This proposal splits wholesale pricing into three categories, two applicable for supply participants, and one for demand: - P1: Price for all production in the least cost 90% of the successful bids (based on pay as clear) - P2: Volume-weighted average price (based on bids) for all production in the most expensive 10% of the successful bids - P3: Uniform price for all demand (volume weighted average of P1 and P2)	The proposed market design essentially introduces a “dynamic” price cap on the market, that is determined by market participation (equivalent to the average costs of the 10% most costly sales orders necessary to meet demand) rather than fixed ad-hoc by regulators at a certain level. Would need to be compared to a price cap in terms of benefits and costs. It shares - albeit to a lesser extent - the disadvantages of a design based entirely on pay as bid clearance (see row above), in particular with respect to negatively impacting investment in high CAPEX/low OPEX or flexible capacity, and changing the bidding behaviour of market participants that would introduce inefficiencies.
Temporary EU-wide revenue cap on inframarginal generators at times of declared crisis ⁷⁹	Proposal to integrate in the market design a temporary EU-wide revenue cap on inframarginal generators that would be activated solely at times of declared crisis (when certain conditions are met according to predefined criteria with respect for example to energy prices).	The rationale for the proposal is that it would provide a uniform response across EU Member States to crisis situations that would avoid severe distortions of the internal market. Caps diminish investor confidence, reduce incentives to invest in new capacity, induce the wrong mix of generating capacity and could increase the total costs of the EU power system. If the rules/conditions under which the mechanism is activated are clearly spelled out and adhered to, it could provide better predictability than ad hoc interventions.

⁷⁸ This market design has been proposed by the Association of Energy Users in Finland (ELFI) and Technology Industries Finland (TIF), thus it is referred to as the ELFI/TIF proposal; It has also been backed by the EU association of non-ferrous metals producers and recyclers (Eurometaux) under the name “price shock absorber mechanism”. For more information see: 1) ELFI/TIF proposed market design: analysis of impact on wholesale power prices: Draft Report, 25 November 2022 https://teknologiateollisuus.fi/sites/default/files/inline-files/AFRY_TIF_modelling_of_proposed_market_design_report_100.pdf ; 2) Eurometaux, Electricity market reform recommendations: Targeted EU action for industry competitiveness, January 2023. <https://eurometaux.eu/media/1yulgwkd/eurometaux-electricity-market-reform-recommendations.pdf>

⁷⁹ This was a proposal included in the European Parliament’s ITRE Committee draft report on the EMD proposal, but was abandoned in its final report. See proposed amendments (for example proposed Amendment 15) in the Draft report of the European Parliament Committee on Industry, Research and Energy on the proposal for a regulation of the European Parliament and of the Council amending Regulations (EU) 2019/943 and (EU) 2019/942 as well as Directives (EU) 2018/2001 and (EU) 2019/944 to improve the Union’s electricity market design (COM(2023)0148 - C9-0049/2023 - 2023/0077(COD)), ITRE_PR(2023)747032 https://www.europarl.europa.eu/doceo/document/ITRE-PR-747032_EN.html

Proposal	Description	Possible implications / comments
Temporary Relief Valve Mechanism ⁸⁰	This proposal involves the ex-ante establishment of a temporary price ceiling mechanism, triggered under clearly specified conditions (e.g. unusually high electricity price rises in a short period of time) for a specified period of time. Markets with these so called 'relief valve' mechanisms (e.g. ERCOT's 'Peaker Net Margin' in Texas, or 'Cumulative Pricing Threshold' in Australia) foresee a regular market clearing with regular price signals (incl. price spikes), up to the point where sustained high prices have exceeded a pre-defined threshold. The measure would need to ensure that sufficient revenue is earned by generators and would require a compensation mechanism for those generators who are able to prove sourcing costs above the ceiling.	Such a mechanism could prove a significant intervention in price formation, and as such it carries risks (similar to the EU-wide inframarginal revenue cap; see row above). However, as long as the measure is implemented well ahead of the triggering events and its design features are clear and transparent, the risk is partly mitigated by providing regulatory stability. In the EU context, such a measure would benefit from being coordinated at the EU level.

Source: ERCST, based on sources included as footnotes to the table

⁸⁰ See p. 48-49 of ACER, 2022. ACER's Final Assessment of the EU Wholesale Electricity Market Design, April 2022.
https://www.acer.europa.eu/Publications/Final_Assessment_EU_Wholesale_Electricity_Market_Design.pdf