FLORENCE SCHOOL OF REGULATION

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POLICY BRIEF

Recent energy price dynamics and market enhancements for the future energy transition

Highlights

- EU gas and electricity prices have increased rapidly over the last few months and reached unprecedented levels. While the recent energy price dynamics reflect current market conditions and have little to do with the future energy transition, they provide an opportunity to reflect on the most appropriate electricity market design to support this transition.
- As a reaction to the recent price surges, calls have been made by different stakeholders, including some national governments, to introduce changes in the electricity market design. Some of these proposals could be interpreted as calling for the 'pay-as-cleared' pricing approach in the wholesale day-ahead electricity market to be replaced by some version of the 'pay-as-bid' method.
- This is not the first time that 'pay-as-bid' has been proposed to replace 'pay-as-cleared' as the remuneration rule in the day-ahead electricity market and every time the conclusion is the same: 'pay-as-cleared' is a superior pricing method for the day-ahead electricity market. 'Pay-as-bid' pricing would not necessarily result in lower overall payments to resources selling electricity on the market, while possibly having a negative impact on the efficiency of the generation mix used to serve demand.
- This Policy Brief also assesses how consumers could be protected from the impact of wholesale price volatility on their energy bills and how best to protect vulnerable consumers from higher energy prices without depriving them of the opportunity to participate in electricity markets to offer their valuable flexibility, and which instruments can best ensure resource adequacy in the context of the future energy transition.

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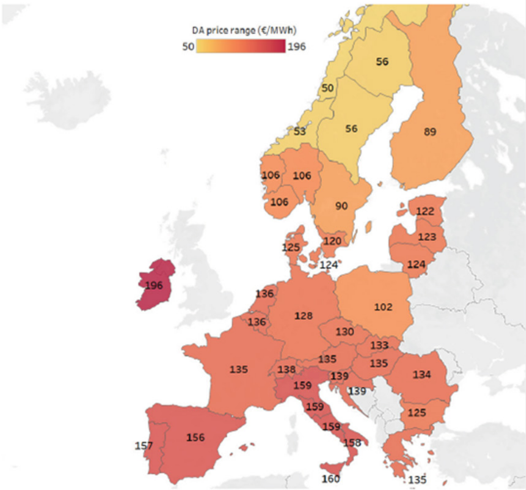
1. Introduction

"*EU gas and electricity prices have increased rapidly and reached unprecedented levels. Gas prices in early October* [2021] *were 400% more expensive than in April 2021, driven significantly by global supply and demand dynamics. Electricity prices have increased by 200% over the same period, driven mainly by the gas prices.*"[1] The extent of the increase in wholesale electricity prices has been quite different across different regions, as is illustrated in the following figure[2].

Figure 5: **Average electricity prices for bidding zones in Europe: September 2021 (EUR/MWh)**



Source: ACER based on ENTSO-E

There seem to be many causes of the sharp increase in world gas prices, but the main ones appear to be a fast economic recovery after the pandemic, boosting strong growth in demand in many regions, and a tight global LNG market[3].

While it is the largest buyer of internationally traded gas (accounting for almost half of the total volumes), Europe has little leverage on the global LNG market, where it is often a price-taker.

Instead, wholesale electricity prices[4] in Europe reflect demand and supply conditions on the Continent. These are clearly affected by international energy (mainly fossil fuel) prices, but also by other, more local factors, such as weather conditions and renewables-based electricity generation.

A number of EU Member States have taken or are considering taking national uncoordinated actions to mitigate the impact of higher energy prices on consumers[5]. To tackle rising energy prices, while preventing damage to the internal energy market from these uncoordinated national actions, in October 2021 the European Commission proposed a 'toolbox for action and support'[6], which outlined a set of measures which the Commission itself and Member States could adopt to deal with the current high-price situation. Many of these measures are aimed at mitigating the impact of higher energy prices on industry, businesses and households, especially vulnerable ones. However, and interestingly, the Commission also expressed its intention of "*task*[ing] *ACER to study the benefits and drawbacks of the existing electricity market design and propose recommendations for assessment by the Commission by April 2022*"[7].

While recent wholesale energy price dynamics reflect current market conditions and have little to do with the future energy transition[8], they

1 ACER, High Energy Prices, October 2021, page 3.
2 ACER, High Energy Prices, October 2021, page 6.
3 For an analysis of the causes of the sharp increases in gas prices in the recent period, see, *inter alia*, Enrico Tesio, Ilaria Conti and Guido Cervigni, *High gas prices in Europe: a matter for policy intervention?,* FSR Policy Brief, Issue 2022/06, January 2022.
4 Retail electricity prices are also affected by regulated transmission and distribution charges, and taxes and levies. However, these have not increased to the same extent over the past few months. In fact, in some cases taxes and levies have been reduced to dampen the impact of the increase in wholesale prices on consumers' bills. See also footnote 37.
5 For example, the French government introduced a temporary freeze on gas prices and a cap on electricity prices as of October 2021. The Italian government has also intervened temporarily to reduce levies and taxes on end-users' energy bills. In September 2021, the Spanish government announced new measures to claw back some of the extra profits that energy companies were making as a result of higher wholesale electricity prices. See footnote 38.
6 Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions, Tackling rising energy prices: a toolbox for action and support, Brussels 13.10.2021, COM(2021) 660 final.
7 *Ibid*, Section 3.2.1, page 15.
8 Indeed, the energy transition is likely to entail higher energy and carbon prices. However, the causality might be different. In the current situation, a tight gas market has resulted in higher gas prices and a switch away from gas and back to coal, leading to higher coal and EU carbon allowance prices. Instead, the energy transition, with its greenhouse emission reduction targets, will reduce the supply of EU carbon allowances, probably resulting in an increase in their prices and in the cost of coal-based generation. This could lead to a switching to gas and higher gas demand and prices.

provide an opportunity to reflect on the most appropriate electricity market design to support the transition.

In this regard, this Policy Brief does not aim to analyse the causes of the recent increases in electricity prices. Instead, it looks at the extent to which (some features of) the current electricity market design might need to be enhanced or complemented to support the future energy transition.

2. The current European Electricity Target Model

The current European Electricity Target Model (ETM), developed in the mid-2000s and enshrined in legislation in the Third Energy Package[9] and, more recently, in the Clean Energy Package[10], envisages a zonal geographical (bidding-zone) structure for the wholesale electricity market and comprises five main pillars:

- cross-zonal transmission capacity calculation;
- the forward market, including for financial transmission rights or similar instruments providing hedging of the risk emerging from the volatility of cross-zonal price differentials;
- the day-ahead market (DAM);
- the intraday market; and
- the balancing market,

and the coupling of the DAM and intra-day markets across different bidding zones. The zonal configuration of the market assumes that there is no or little congestion in the network within each zone[11], with congestion requiring the allocation of transmission capacity only between different bidding zones. In the case of congestion, different bidding zones might express different prices for the same hour[12]. Electricity is traded over different time horizons, on different markets according to different trading models (bilateral trading on organised markets, over the counter or auction-based trading). The DAM is the reference market, i.e. the market expressing the prices which are used as references in other markets and contracts.

The organisation of the DAM, as envisioned in the ETM, is based on an auction run the day before delivery time, in which, for each time unit (i.e. each hour), all accepted bids (to buy power) and offers (to sell power) in each price area (bidding zone) pay or are paid the same hourly 'equilibrium price'. This pricing mechanism is referred to as 'pay-as-cleared' (or 'marginal pricing'), as opposed to the 'pay-as-bid' approach in which each bid and offer pays or is paid the price indicated in it.

Looking to the future, one of the main challenges for the market design is the increasing penetration of variable renewable energy sources – such as wind and solar energy – that are characterised by zero or near-zero marginal/incremental costs. In systems with a high share of these sources, electricity prices might be zero or very low in many hours, and peak at very high levels in other hours, to allow these and other resources offering electricity into the system to recover their fixed costs. This is a trend already observed in Europe, where the frequency of price spikes increased by 1/3 between 2016-2017 and 2019-2020[13], with 2,369 price spike instances recorded in 2020. There is therefore a clear need to protect consumers from price spikes,

9 In particular, Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC, and Regulation (EC) No. 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No. 1228/2003.

10 In particular, Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU, recasting Directive 2009/72/EC, and Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, recasting Regulation (EC) No. 714/2009.

11 This assumption has proven to be unrealistic in many parts of Europe, leading to high levels of loop flows, i.e. flows which originate from intra-zonal transactions, but affect network elements in other (mainly neighbouring) zones.

12 Exchanges between different bidding zones might also be limited by network elements within one of the zones.

13 From 1,620 to 2,154, on an average annual basis. The number of peak hours in the European electricity market were atypically low in 2018 (240). ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020 - Electricity Wholesale Markets Volume, October 2021, Section 3.2.

and producers from negative prices[14,15], which are also becoming much more frequent: they increased by over 170% between 2016-2017 and 2019-2020[16], with more than 1,900 negative-price instances recorded in 2020.

This increased volatility in wholesale electricity prices will probably be superimposed, during the energy transition, on an upward long-term trend in energy prices, if nothing else because the measures which are being put in place to promote and steer the transition internalise some of the environmental externalities associated with the energy sector[17]. This long-term upward trend in energy prices will provide signals to reduce energy consumption (through energy efficiency) and/or to redirect energy consumption towards the vectors with the lowest carbon footprint.

This Policy Brief first considers whether the current market design of the DAM is fit for the future, a future characterised by a much greater share of renewables-based and demand-side response resources in the electricity system. It then assesses how consumers could be best protected from the impact of wholesale price volatility on their energy bills and how to protect vulnerable consumers from higher energy prices without depriving them of the opportunity to participate in electricity markets to offer their valuable flexibility. Finally, it assesses which instruments could more effectively ensure resource adequacy in a market context and in the face of the future energy transition.

However, before going into these issues, some recent calls for changes in the electricity market design deserve brief comments.

3 .Recent calls for changes in the current electricity market design

As a reaction to the recent price surges, calls have been made by different stakeholders, including some national governments, to introduce changes in the electricity market design. For example, on 5 October, the governments of Spain, France, the Czech Republic, Romania and Greece issued a common statement calling for a reform of the day-ahead electricity market, which would need to be improved "*to better establish a link between the price paid by the consumers, and the average production cost of electricity in national production mixes. This is all the more important as decarbonisation will increase the use of electricity in our economy*".

Following this call, a number of 'non-papers' were released in November proposing a variety of measures. For example:

- In a 'Non-paper on energy and electricity & gas markets'[18], it is argued that urgent action is needed to ensure that "*final consumers pay electricity prices that reflect the costs of the generation mix used to serve their consumption*" and that this could be achieved through "*mechanisms based on financial transfers between producers and consumers, [which] would have no effect on the functioning of the wholesale market, nor affect the merit order of the different generation plants mobilised in the energy market on an hourly basis*".
- In a 'Non-paper on electricity, gas and ETS markets', after indicating that "*a common European approach is our preference for the whole European energy internal market", it is suggested that "in exceptional situations, Member States have to be allowed to adapt the electricity price formation to their specific situations (mix, resources, level of interconnections)"* and therefore it is proposed that consideration be given to reforming the electricity market design so that *"the electricity price would be obtained as an average price with reference as well to the cost of 'inframarginal' clean technologies (particularly renewables)".*

These are just examples of the kind of (often contradictory) proposals that have been floating around in recent months. On the one hand, financial transfers are advocated which "*would have no effect on the functioning of the wholesale market, nor affect the merit order of*

14 In the past, negative prices were associated with the limited flexibility of thermal generating units, willing to pay a negative price for their production rather than shutting down and starting again within a few hours. More recently, an increasing number of negative price instances have been associated with badly-designed renewable support schemes, which pay the support also in the presence of negative market prices, signalling an excess of production. In these instances, supported renewable-based generators find it convenient to produce and inject power into the grid even at negative market prices, as long as these prices are, in absolute terms, lower than the support they receive.

15 Consumers and producers might not be worried by occasional price spikes or occasional negative prices, respectively, which can be averaged out over time. However, if such instances become more frequent, they may indeed raise concerns.

16 From 522 to 1,424, on an average annual basis.

17 A most notable example is the EU Emissions Trading Scheme, which gives a (negative) value to the emissions of greenhouse gases.

18 Non-paper by the Spanish, French, Italian, Romanian and Greek governments.

the different generation plants mobilised in the energy market on an hourly basis". On the other hand, it is proposed that Member States "*be allowed to adapt the electricity price formation to their specific situations"* so that *"the electricity price would be obtained as an average price with reference as well to the cost of 'inframarginal' clean technologies (particularly renewables)"*.

4. 'Pay-as-cleared' vs. 'pay-as-bid' pricing in the electricity day-ahead market in Europe

Some of the proposals floated in the debate in recent months, including one of those above, could be interpreted as calling for the 'pay-as-cleared' pricing approach in the DAM to be abandoned in favour of some version of the 'pay-as-bid' method[19].

These calls are prompted by a misconception that the latter method – by providing that each resource whose offer to sell electricity on the market is accepted is paid the price it has offered rather than the price offered by the highest-priced accepted offer – would reduce the overall payments for electricity sold on the market. The misconception stems from the unrealistic assumption that the bidding behaviour of parties offering electricity on the market would be the same under the two pricing methods. This clearly cannot be the case!

Under the 'pay-as-cleared' pricing method, it can be shown that, assuming a competitive market setting, it is optimal for resources offering electricity on the market to indicate a minimum acceptable price equal to their short-term marginal/incremental/opportunity costs[20]. In fact, the price offered only determines the likelihood of the resource's offer being accepted but, unless the resource's offer turns out to be the highest-priced accepted one, not the price it will be paid if accepted. Therefore, since each resource finds it profitable to produce an extra quantity of electricity if the price it can receive is at least as high as its marginal/incremental cost, it will adopt a bidding strategy aimed at that result by offering electricity at its short-term marginal/incremental/opportunity cost (the additional cost, or foregone opportunity, that it faces for producing the additional quantity of electricity once all fixed costs are paid). Such a strategy, if adopted by all resources, will also result in the most efficient market outcome (i.e. the outcome which ensures that demand is met at the least cost). Market coupling between the different bidding zones based on prices set using the 'pay-as-cleared' method would also maximise the social welfare from cross-border trading.

Under the 'pay-as-cleared' method, in most hours when an offer is accepted (i.e. in all the hours in which the offer is not the highest-priced accepted one), the resource will earn some extra money with respect to its short-term marginal/incremental costs. This profit, which is the target of those commentators calling for a change in the market pricing method, is necessary to recover fixed capital and operating costs, without which the plant will not be able to survive financially and which makes investment in the electricity sector economically and financially viable.

Under the 'pay-as-bid' method, where offers, if accepted, are paid the price offered, resources will have to offer a price higher than their marginal/incremental costs in order to earn, if their offers are accepted, the extra return needed to cover their fixed costs. However, in doing so, they will reduce the likelihood of their offers being accepted, even when this would be efficient and they could earn a margin above their marginal/incremental costs to pay their fixed costs. Therefore, under the 'pay-as-bid' pricing method, resources would have to guess the price of the highest-priced accepted bid in order to offer just below that price so as not to miss out on possible revenues above their marginal/incremental costs while not substantially reducing the chances of their offers being accepted. This is clearly a much more difficult and risky strategy than offering at the resource's marginal/incremental/opportunity cost. The efficiency properties[21] of the resulting market outcome are difficult to assess, as they depend on the actual bidding strategies of the different resources. Since the 'pay-as-bid' method does

19 It seems that this is the way in which ACER also interpreted at least some of the proposals voiced in the last few months. It addressed the 'pay-as-bid' vs. 'pay-as-cleared' debate in its Preliminary Assessment of Europe's high energy prices and the current wholesale electricity market design, Part 1, November 2021, Section 4.3.

20 For energy-constrained resources – such as reservoir hydroelectric plants – or where participating in more than one market is possible, the opportunity cost – the cost of the foregone opportunity to sell electricity at another time or on another market – also influences the optimal bidding strategy.

21 Efficiency of the market outcome is particularly important in the electricity sector. In fact, since electricity cannot be easily or economically stored on a large scale, the market outcome strongly influences the production pattern. Therefore, efficiency of the market outcome promotes efficiency of the generation/resource deployment pattern.

not express a single price in each bidding zone in each hour, the properties of any market coupling outcome would also be uncertain. Certainly, the risk in market participation will be increased and this might discourage market entry.

These considerations have been well-rehearsed for many years[22] since this is not the first time that 'pay-as-bid' is proposed to replace 'pay-as-cleared' as the pricing method in electricity markets. Every time the conclusion is the same: 'pay-as-cleared' is a superior pricing method for electricity markets and it is not true that 'pay-as-bid' pricing would necessarily result in lower overall payments to resources selling electricity on the market. Increasing prices is the exact signal that the market should convey when scarcity emerges in order to attract additional resources – e.g. demand-side response and additional generation investment – into the market. However, it seems that the debate regains its appeal every time prices in the electricity market increase.

ACER has also intervened in this debate and, in a note prompted by the recent increases in energy prices, noted that: "*any future market design needs to be able to (a) remunerate technologies above their marginal costs, sometimes quite significantly so, and (b) incentivise the alleviation or smoothing of volatility in the market. The 'pay-as-clear' model allows for both of these elements*"[23].

5. Enhancing the Electricity Target Model to make it future-proof

Beyond the pricing method in the DAM, more interesting questions are how the electricity market design could, in the future:

- protect consumers and resources offering electricity on the market from the volatility of market prices;
- protect vulnerable consumers from the impact of high energy prices on their energy bills; and
- ensure long-term resource adequacy;

without removing short-term price signals.

5.1 Hedging price volatility risk

With respect to the first question, it is worth noting that volatility in itself does not necessarily increase the average price consumers pay for the electricity they consume, unless some actors in the value chain need to incorporate a risk premium in the price of the electricity they sell. However, the very high prices that volatility is likely occasionally to produce might be socially disruptive, politically unacceptable and lead to the kind of impromptu interventions that we have seen proposed or adopted in recent months, in some cases risking disrupting the proper functioning of the electricity market.

To address volatility, hedging instruments – in the form of long-term forward and financial futures contracts – have been available and traded on organised markets for many years. However, their liquidity is very different in different markets[24]. Hedging instruments are used by energy-intensive industrial customers and other large consumers buying directly in the wholesale market to hedge their exposure to the volatility of market prices. These instruments may become a key feature of an enhanced future-proof electricity market design, and their hedging properties may be passed on to many more final consumers.

Currently, many final consumers in Europe are supplied through 'fixed-price contracts'. These contracts fix the price of the 'commodity' component in the final bill over a certain period of time (typically one or two years). The other components – transmission and distribution charges, taxes and levies – are not contractually fixed since they are regulated. Fixed-price contracts protect consumers from the volatility of wholesale prices, but also prevent them from being exposed to short-term price signals to which they could respond with implicit demand-side response[25]. Suppliers[26], on their part, do not always hedge their supply portfolio (especially of fixed-price contracts), with the result that some of them have recently gone out of business when wholesale prices started to trend upwards.

22 Cfr., among many, Susan Tierney, Todd Schatzki and Rana Mukerji, "*Pay-as-Bid vs. Uniform Pricing: Discriminatory Auctions Promote Strategic Bidding and Market Manipulation,*" Public Utility Fortnightly, March 2008.

23 ACER, High Energy Prices, October 2021, page 12.

24 Churn factors in European forward electricity markets range from over 8 in Germany to below 1 in the Iberian market, with illiquid forward markets in Hungary, Belgium, Bulgaria and the Czech Republic. See ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020 – Electricity Wholesale Markets Volume, October 2021, Section 5.1.

25 Implicit demand-side response is the consumer's reaction to price signals.

26 According to the definition of supply in article 2(12) of Directive (EU) 2019/944, suppliers are entities selling, including reselling, electricity to consumers. The situation referred to in the text is that of suppliers which are not also generating electricity.

Therefore, the current market design could be supplemented by:

- inducing[27] or requiring suppliers offering fixed-price contracts to hedge a large fraction of their fixed-price supply portfolio on the market, e.g. through financial forwards/ futures or contracts for differences[28,29];
- ensuring that fixed-price contracts do not remove the incentives for consumers to reduce their consumption in times of high prices. Smarter grids and meters could support fixed-price contracts for fixed quantities/profiles, with upward or downward deviations from these quantities being valued at the prevailing short-term price. These deviations, to the extent that they represent explicit demand response[30], could be managed by aggregators or similar entities and offered on the market.

A greater role for aggregators in facilitating the participation of demand response in the market would require a proper regulatory framework[31]. At present, the rules governing demand response through aggregation provide that the compensation paid by final consumers or aggregators offering demand response on the market to consumers' suppliers is to be strictly limited to covering the resulting costs incurred by the suppliers or the suppliers' balance responsible parties during the demand response activation, but also that such compensation "*may take account of the benefits brought about by the independent aggregators to other market participants*"[32]. As was also recommended by ACER and CEER already in 2017[33], suppliers should be fully compensated for energy procured on the market and then resold by aggregators as demand response[34].

5.2 Protecting vulnerable consumers

Vulnerable consumers require special attention. As it has already been indicated, the energy transition is likely to increase energy costs overall and therefore to extend and exacerbate the phenomenon of energy poverty, especially in countries with higher per-capita energy consumption and/or lower household incomes.

It is not the ambition of this Policy Brief to assess the schemes currently in place to protect vulnerable consumers or to formulate structured proposals on how to improve them. Instead, we only offer one consideration.

While vulnerable consumers should be protected from the impact of higher energy prices, this should be done in a way which does not distort the price signals they are exposed to and therefore their ability to consume energy efficiently and, possibly, to engage in implicit demand response or participate in explicit demand response schemes. In this respect, payments which are not linked to actual metered consumption, but

27 This could be done by requiring suppliers which are not hedged in relation to their fixed-price supply portfolio to post a bond to cover their exposure to price volatility. Such an approach could be criticised on the ground that it would discriminate against smaller suppliers, which are typically financially weaker. But these are exactly the suppliers which may be the first to go out of business if prices in the wholesale market turn against them. Moreover, smaller suppliers would be able to avoid the requirement to post the bond by hedging their fixed-price contract portfolio. Another interesting question is whether regulation should mandate some of the features of the hedging instruments to be used by suppliers.

28 Such an induction or requirement could also apply to large (industrial) consumers buying directly in the wholesale market, even though, as previously mentioned in the text, these consumers are typically already managing the price risk of their electricity purchases. Physical power purchase agreements (PPAs), stipulating a pre-defined price for the electricity supplied to the consumer, can also be used to shelter consumers from price volatility risk, but, compared to financial instruments, they (a) reduce the liquidity in the short-term market and, unless they are for fixed quantities, (b) do not expose the provider and the consumer to short-term price signals.

29 Similar considerations and a somewhat similar proposal are presented by Peter Cramton in a still unpublished paper entitled '*Fostering resiliency with good market design: Lessons from Texas*', October 2021, available at: cramton-lessons-from-the-2021-texas-electricity-crisis.pdf (umd.edu). However, according to Cramton, hedging by suppliers should be voluntary, primarily to speed up the establishment of a non-mandatory financial forward market. In this Policy Brief, the opportuneness of mandatory hedging is considered, as such an instrument would be introduced as part of an enhancement of the current market design.

30 Explicit demand response is committed dispatchable flexibility that can be traded (similar to generation flexibility) on the different energy markets (wholesale, balancing, system support and reserves markets). See SEDC-Position-paper-Explicit-and-Implicit-DR-September-2016.pdf (smarten.eu)

31 Article 4 of Directive (EU) 2019/944 gives consumers the right "*to have more than one electricity supply contract at the same time, provided that the required connection and metering points are established*", which opens the way for consumers to buy electricity from multiple suppliers, thus going beyond the current aggregator-supplier model.

32 Article 17(4) of Directive (EU) 2019/944.

33 ACER-CEER White Paper on Facilitating Flexibility, 22 May 2017, section 3.3.

34 By December 2020, only four Member States – France, Italy, Romania and Slovenia – had incorporated a method for calculating financial compensation to suppliers or balance responsible parties during demand response activation in their national legislation. ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020 – Electricity Wholesale Markets Volume, October 2021, Table 25.

instead are aimed at covering the cost, in excess of what the consumer could afford[35], of a pre-defined consumer-specific level of consumption, thus providing a minimum comfort level[36], are preferable to interventions aimed at reducing the energy prices paid by these consumers[37]. In this way, vulnerable consumers too will be exposed to the correct price signals, promoting efficient consumption (to the extent that these prices correctly reflect the cost of service) and possible participation in demand-response schemes.

5.3 Ensuring resource adequacy

Finally, a large debate has developed over recent years on how to ensure the adequacy of the electricity system in the face of more volatile short-term prices, with many hours of very low prices and uncertainty about the number of price spikes and their levels. Investors may also be worried that sudden increases in prices, reaching levels which are politically too high, might attract government attention, with the risk of interventions to introduce caps or take the higher profits earned in these hours away[38].

A hedging requirement for suppliers as outlined above might promote the development of financial hedging instruments, which could also provide a more stable stream of revenue for operators of resources selling electricity on the market and therefore reduce investment risk. However, this might not be sufficient to address adequacy concerns fully, as hedging instruments do not typically extend sufficiently into the future to cover a sizeable part of the economic life of new investments.

In this respect, EU legislation[39] allows Member States to introduce capacity remuneration mechanisms (CRMs), with a preference for strategic reserve, but only:

- as a last resort, to address residual resource adequacy concerns emerging from a European resource adequacy assessment and, if performed, a national resource adequacy assessment, and
- as a temporary remedy while any identified regulatory distortions or market failures are addressed.

Currently, 12 Member States have introduced CRMs, and only three of them – Finland, Germany and Sweden – have opted for strategic reserve[40].

Reliability options[41] could be considered as the CRM which best complies with the design principles stated in EU legislation[42]. In fact, while a reliability option creates a strong incentive[43] for capacity providers to sell electricity on the market at times of high prices, it does not in itself create a direct obligation for capacity providers which have sold the option to do anything particular in the electricity market. In this sense, the reliability option minimises market distortions.

35 What consumers can afford would clearly need to be defined. However, formal and informal definitions of energy poverty might help in this respect. For example, in the United Kingdom, according to the first official definition (1991), which is still unofficially used in other countries, "a household is said to be fuel poor if it needs to spend more than 10% of its income on fuel to maintain an adequate level of warmth" (see Energy poverty Energy (europa.eu)). Following this logic, what a consumer could afford in terms of their electricity bill could be defined as a percentage of their disposable income.

36 This is the approach adopted, for example, in Italy, where an electricity bonus is offered to low-income households defined by certain characteristics. See ARERA - Bonus elettrico.

37 Some of the short-term interventions adopted by certain European governments in the wake of the recent energy price surge have been of this nature, temporarily exempting consumers from some energy bill components. However, a better way of interpreting these interventions could be to remove some energy bill items which have little to do with the cost of providing the energy service (e.g. charges to cover subsidies for renewable generation) and therefore which should not have been in the bill in the first place.

38 A temporary tax on renewables-based generators was introduced in Spain in September 2021, and then extended to nuclear and hydroelectric power plants, but it was later partially withdrawn.

39 Article 21 of Regulation (EU) 2019/943.

40 ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020 – Electricity Wholesale Markets Volume, October 2021, Section 6.1 and Table 13.

41 A reliability option is described, *inter alia*, in the Commission Staff Working Document accompanying the document Final Report of the Sector Inquiry on Capacity Mechanisms by the European Commission, COM(2016) 752 final, Section 5.4.2.1, as a scheme in which "*the capacity provider will receive a regular payment* […]. *In return for this regular payment, the capacity provider that has sold a reliability option will be required to pay the difference between a market reference price and a strike price whenever the reference price goes above the strike price*".

42 Article 22 of Regulation (EU) 2019/943.

43 This is at least what reliability options are advocated for, including in the Commission Staff Working Document referred to in footnote 41. Note, however, that the differential payout for the capacity provider between selling and not selling electricity at times of high prices is the same in the presence of a reliability option as without it. For more detail on this point, see Alberto Pototschnig, *Capacity Remuneration advancing the speed of Renewables*, In my view, IEEE Power & Energy Magazine, January/February 2021.

Moreover, reliability options are credited with two additional benefitting features[44]:

- they promote the availability of capacity at times of scarcity, where these are not defined *ex-ante*, but on the basis of the occurrence of high prices;
- they provide consumers with a hedge against (very) high prices.

The first feature sets reliability options apart from most other CRMs which commit capacity providers to be available at pre-specified times. Strategic reserve also shares this feature, but when this reserve is activated, it effectively increases supply and, if it is sufficient to meet demand, it prevents the market price from increasing above the activation price level. Instead, reliability options by themselves do not introduce any limitation on the market price. That said, for capacity which is contracted through reliability options, these options protect buyers from the impact of very high prices above the strike price. This begs the question of the level at which the strike price should be set.

In some national implementations, the strike price has been set with reference to the marginal cost of the most expensive (peaking) generating unit in the market. This is a questionable approach, as already now, and more and more in the future, there are and there will be other resources – e.g. on the demand side – which could contribute to adequacy, but which require much higher prices for their activation. Therefore, it would be better to set the strike price at a level which represents the 'conceptual' discriminant between market functioning, including under tight demand-supply conditions, and a situation in which nothing could prevent prices from increasing up to the value of lost load (or whichever other price cap is imposed on the market). This was already recognised almost twenty years ago in the seminal work on the topic: the strike price of a reliability option could be considered "*as a frontier between the normal energy prices (p<s) and the near-rationing or emergency prices (p>s)*"[45].

Reliability options can also be implemented in a way to meet other design principles set in legislation: not limiting cross-zonal trade; not going beyond what is necessary to address identified adequacy concerns; selecting capacity providers by means of a transparent non-discriminatory competitive process; ensuring that the remuneration is determined through a competitive process; setting out technical conditions for the participation of capacity providers in advance of the selection process; being open to participation by all resources that are capable of providing the required technical performance, including energy storage and demand-side management, and resources located in other (neighbouring) jurisdictions; and applying appropriate penalties to capacity providers that are not available in times of system stress[46].

So far, the European Commission and the EU legislator have not dared to propose or impose a standard design for CRMs, as it happened with the energy markets, but have limited themselves to expressing a "preference" for strategic reserve and setting some general requirements for CRMs. This approach is predicated on the assumption that CRMs would be a temporary measure to address the effect of regulatory distortions on incentives for investments in the electricity sector until such distortions could be removed[47]. In reality, the jury is still out on whether a future electricity sector characterised by a much higher, and eventually predominant, share of variable renewable energy sources with zero or near-zero marginal costs would require a long-term complement to the short-term market beyond a greater role for hedging instruments.

This consideration raises two further questions:

- whether reliability options could be the CRM of 'preference' beyond the short-term role of strategic reserve; and
- what the interrelation should be between

44 For an assessment of reliability options vis-à-vis these features, see Pradyumna C. Bhagwata and Leonardo Meeus, *Reliability options: Can they deliver on their promises?,* The Electricity Journal, Volume 32, Issue 10, December 2019.

45 C. Vázquez, M. Rivier and I. J. Pérez-Arriaga, *A market approach to long-term security of supply*, IEEE Transactions on Power Systems, Vol. 17, No. 2, May 2002.

46 On this last point, see footnote 43. The reliability option in itself does not penalise capacity providers for not being available at a time of scarcity more than would be the case, through loss of revenues, in the absence of such an option. Therefore, an explicit penalty might be added to the design of the reliability option and imposed if the electricity is not produced by the capacity provider at the times when the option is 'called'. This, however, would introduce a physical capacity dimension to the option, which is not a problem in itself, but which its standard design does not include.

47 Delivering "*appropriate investment incentives for generation, in particular for long-term investments in a decarbonised and sustainable electricity system*" is one of the guiding principles for the design of the electricity market listed in article 3 of Regulation (EU) 2019/943.

reliability options and the hedging instruments the development of which should be promoted, as was advocated earlier in this Policy Brief.

On the first point, as indicated above, reliability options meet all the requirements for CRMs stated in EU legislation. Moreover, they could be claimed to be the CRM with the lowest impact on the electricity market, especially if the strike price is set well above the prices which the market expresses, even under tight market conditions.

On the second point, if the strike price of reliability options is set at suitably high levels, they would not provide adequate hedging for consumers. Moreover, reliability options and hedging instruments would be likely to have different durations. Reliability options are aimed at reducing risk for investors in resources contributing to adequacy. Therefore, while they do not necessarily need to extend to the full economic lives of these resources, they are most effective when they cover several years. Instead, hedging instruments should aim at shielding suppliers from risks associated with short-term wholesale price volatility with respect to their fixed-price contract portfolio. These contracts typically cover one or two years at most.

Therefore, the two instruments – hedging instruments and reliability options – can operate side by side, aiming to provide different benefits: reduce price volatility risk for suppliers, consumers and generators, and promote system adequacy, respectively. However, if reliability options and hedging instruments were to coexist, the latter would have to be designed in such a way that they do not provide cover for prices above the reliability option's strike price.

A final reflection: should reliability options be contracted centrally or should the responsibility be left to consumers/suppliers? And in this latter case, should entering into a reliability option be voluntary or mandatory?

Advances in digital technologies and smart meters could allow consumers to choose their preferred level of supply guarantee[48]. Some consumers might want their full consumption to be guaranteed by an adequacy mechanism and therefore a reliability option to cover their total power demand. Others might opt for a firm supply only for part of the power they need. Governments might want to guarantee a minimum level of supply for everyone so that the choice for consumers is limited to the additional guarantee that they might want to contract individually. This could be implemented by introducing a 'subscription model' in which retailers offer different levels of quality (i.e. supply security) at different prices[49]. This would require consumers to determine explicitly their willingness to pay for different levels of quality, and different consumers might end up contracting different levels of quality for their various applications and devices.

As Texas showed last year, when there is a shortage of electricity, the current electricity market model applies rationing, which is referred to as load shedding. Some regions are put in the dark while others can continue to use as much electricity as they want. Consumers located close to a hospital or another priority electricity user will continue to be supplied irrespective of the value that they assign to electricity, while others experience supply interruptions even if their willingness to pay is higher. A smarter solution could be to guarantee that everyone can continue to keep their lights and refrigerators on and heat their homes while additional consumption for less essential uses during a shortage period would only be available to those who have contracted higher supply quality at an extra cost.

48 In this context, the guarantee would refer to resource adequacy and would clearly not cover disruptions caused by transmission or distribution failures or other *force majeure* events.

49 Some academics have referred to this idea as the internet subscription model applied to electricity markets (e.g. Michael Pollitt in his chapter in Jean-Michel Glachant, Paul L. Joskow, Michael G. Pollitt (eds.), *Handbook on Electricity Markets*, Edward Elgar Publishing, November 2021). Others conceptualise it as priority service contracting or multi-level demand subscriptions (e.g. H. P. Chao and R. Wilson, *Priority Service: Pricing, Investment and Market Organization*, The American Economic Review, 1987, vol. 77, no. 5), or privatisation of reliability (e.g. Shmuel S. Oren, *Privatizing Electric Reliability through Smart Grid Technologies and Priority Service Contracts*, Proceedings of the IEEE PES Annual Meeting, Minneapolis, MN, July 25-29, 2010).

6. Conclusions and recommendations

It is not the aim of this Policy Brief to provide definitive recommendations on how to tackle the current surge in energy prices or to assess fully the current market design's ability to support the future energy transition. This would be a much larger exercise.

In this Policy Brief we have commented on some recent calls to replace the 'pay-as-clear' pricing method with the 'pay-as-bid' approach in the DAM.

We have also considered three specific areas where the current market design, which in our view represents a good basis for embarking on the forthcoming energy transition, could be complemented by additional measures:

- to protect consumers and resources offering electricity on the market from the likely higher volatility of market prices in the future. We recommend that suppliers offering fixed-price contracts to their customers are induced or required to hedge their exposure to wholesale electricity price volatility with respect to these contracts. Such a measure is aimed at reducing the risk of these suppliers going out of business when wholesale electricity prices turn against them and the costs for the system of protecting the consumers of failed suppliers;
- to protect vulnerable consumers from the impact of high energy prices on their energy bills. We stress that such protection should not remove or distort the price signals facing these consumers in order to promote efficient consumption (to the extent that these prices correctly reflect the cost of service) and promote participation in demand-response;
- to ensure long-term resource adequacy. To the extent that CRMs would be required to continue to attract investment in electricity sector resources, we suggest that consideration be given to making reliability options the preferred CRM in the Internal Electricity Market. We also offer some suggestions on the design of reliability options, in particular with respect to setting the strike price, and claim that, serving a different purpose, they could coexist with hedging instruments aimed at protecting consumers (and suppliers) from electricity price volatility.

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