Navigating the Transition to Renewables in Eastern Europe

An Exploration of Electricity Market Reform and Price Signals

– EPG Fellowship Paper –

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1. Introduction

On 14 March 2023, the European Commission (EC) published a proposal to reform and improve the European Union (EU) electricity market design. The proposal encompasses mainly three areas of action:

1. **Protecting and empowering consumers from energy price volatility** through fixed and dynamic price contracts, multiple contracts option, improved transparency and information, the opportunity to share renewable energy without the need of energy communities' establishment, stabilization of energy supply by encouraging suppliers to hedge their exposure against high prices by using forward contracts with generators that can lock future prices;
2. **Strengthening the stability and predictability of the energy industry** through the optimization of short-term electricity markets, market access to more stable long-term contracts such as PPAs and CfDs, but also through liquidity enhancement in forward markets by introducing regional virtual hubs[2];
3. **Stimulating investments in renewable energy sources and flexibility solutions** by providing stable prices to consumers and reliable revenues to RES producers through PPAs and CfDs, designing capacity markets to provide low-carbon flexibility, implementing new support schemes and products for non-fossil flexibility such as demand response and storage, making connection capacity availability more transparent, and bringing trading deadlines closer to real time.

The primary goals of the EC legislative proposals are to optimize the electricity market design for a decarbonized energy system and to enhance affordability for consumers. This will require coordinated actions amongst Member States both at national and regional levels.

This paper assesses the current situation of the renewable energy market in Central and Eastern Europe (CEE) along with the inherent technical and economic challenges posed by the rapid deployment of renewable capacities. The marginal pricing (merit-order) mechanism remains a well-established and transparent way of determining prices in the short-term electricity markets in CEE, encouraging competition and innovation in the energy sector. The decline in wholesale electricity prices coupled with periodic price volatility signify that

[2] According to EC, 'virtual hub' means a non-physical region covering more than one bidding zone for which an index price is set in application of a methodology. The regional virtual hubs, by providing a reference price index, should enable the pooling of liquidity and provide better hedging opportunities to market participants.

generation lacks flexibility, the demand side is inexistent or is not adequately responsive to pricing, or there is insufficient energy storage for arbitrage. Recent negative price signals highlight the need to invest in solutions and technologies to enhance system flexibility in the region.

Obviously, an increasing renewable-based power system requires customers to play a more active role in electricity markets through various mechanisms like dynamic tariffs, aggregators and demand shifting. In order to accelerate the integration of renewable energy sources, customers can engage in demand response actions and benefit from grid stability and electricity cost reduction at the same time. The CEE region definitely lacks a comprehensive regulatory framework that incorporates demand-side management, through which electricity markets can better protect customers from price volatility, ensure fair pricing, and foster an environment where consumers can make informed decisions about their energy consumption.

Nonetheless, energy market revenues alone are insufficient to attract the level of renewable energy investment required in CEE, due to the electricity price and investment recovery uncertainty, jeopardizing all the energy sources, not just the renewable ones. Therefore, long-term arrangements backed both by governments and private stakeholders are still necessary to de-risk the investment in low-carbon power generation in the region, providing long-term visibility for investors and keep financing costs low. However, it is important that support mechanisms do not significantly disrupt the operation of wholesale markets, but rather enable renewable energy sources to respond to price signals and encourage their involvement in the wholesale markets, particularly in the balancing markets.

2. Overview of Electricity Market

2.1 Electricity Markets and Products

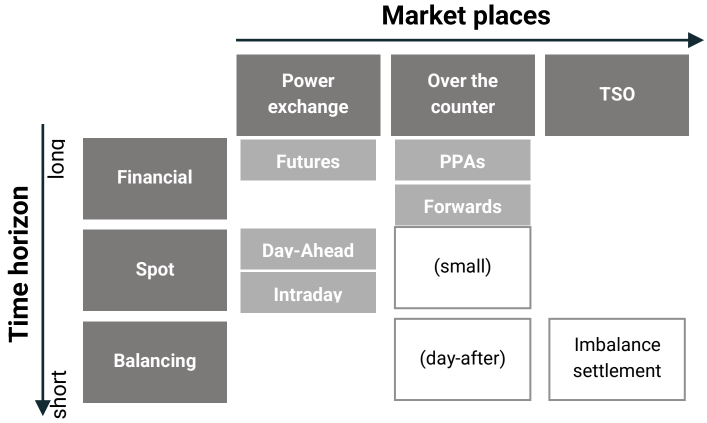
Electricity has always been considered a peculiar commodity that has specific characteristics which differentiate it from other tangible commodities like crude oil or natural gas. The electricity is an un-storable[3] good that must be produced and consumed simultaneously. This implies that the electricity price is formed instantaneously at the equilibrium of supply and demand. Electricity spot prices tend to be more volatile, primarily because they are shaped by the continuous change of hourly[4] supply and demand dynamics. Electricity is a perfectly homogenous commodity that offers the same output power independent of the energy source used (1 MWh of electricity generated by wind turbines should be a perfect substitute for 1 MWh generated by natural gas or coal). However, according to Hirth L. et al. (2016), electricity is a paradoxical good that is homogenous and heterogenous at the same time, suggesting that the electricity produced by different technologies has, on average, a different economic value when produced at different moments in time [27]. They argue that electricity is not only heterogenous over time, but also over space and lead-time between contract and delivery.

Electricity markets consist of all the commercial transactions involving the buying and selling of energy and electricity-related products by a wide range of market participants for different purposes. The power system is the core vehicle through which electricity is generated and supplied to final consumers. Power system structures in Europe have been liberalized and deregulated to a large extent, the processes being still ongoing [23]. Liberalized models of power system structures include two core markets: the wholesale and retail market. Other complementary energy-related products may comprise ancillary services, imbalance settlements and reliability products (part of capacity mechanisms) that are essential in providing an adequate and secure delivery of electricity [38].

[3] Electricity cannot be economically stored in large volumes due to high implementation costs (investment technology costs). Electricity can be converted to other forms of energy on a small scale which can be stored and later reconverted to electricity when needed, but this implies losses.
[4] Time granularity of electricity prices varies, ranging from 5 minutes to 60 minutes.

The central market channel through which electricity is procured is the wholesale market which is primarily organized based on two dimensions: marketplace and time horizon (Fig 1). Actors can trade electricity either on power exchanges or over the counter ('OTC') in various forms and time frames: from real time (spot market) to long-term (financial market), either through physical or financial contracts. The spot market is usually split into the Day-Ahead market ('DAM') and Intraday market ('IM'), whereas financial markets deliver electricity weeks, months or years into the future and are classified as futures, forwards and power purchase agreements ('PPAs') depending on the marketplace. On the very short-term, actors can trade imbalances OTC the day-after through the balancing market or the transmission system operator ('TSO') provides balancing services to keep the transmission system balanced ensuring that supply always meets demand. For instance, it determines the imbalance settlement price when differences between the market schedule and actual system demand exist.

Fig 1. Structure of wholesale electricity market



Source: Prof. Dr. Lion Hirth, Professor of Energy Policy at the Hertie School

Wholesale markets have been consistently expanded and more tightly integrated as part of the ongoing efforts to create a single European internal electricity market.[5] For instance, market coupling in the Eastern European region has continued to advance and, since late 2014, the joint wholesale market area of the Slovakia, Czechia, Hungary and Romania (4M Market Coupling project) increased wholesale price convergence over time [29]. Furthermore, the Bulgaria-Romania day-ahead market coupling has been successfully completed in October 2021, the project being integrated under the European single day-ahead market coupling ('SDAC') as foreseen by the European Union's regulation.[6]

Two pricing methods are commonly considered in electricity markets: pay-as-clear vs. pay-as-bid. Under pay-as-clear pricing, the last accepted bid sets the price for all transactions (marginal pricing) whereas under pay-as-bid format all bidders receive their own bid and the

[5] The Directive on common rules for the internal market for electricity
[6] Bulgaria-Romania Market Project, October 2021

prices are assessed in continuous trading. The procurement of balancing products is generally bilateral with pay-as-bid pricing. Given their heterogenous nature in terms of quality, location and time, the pay-as-bid clearing rules are more suitable for intraday and ancillary services markets than for electricity procurement in the day-ahead.

Pay-as-clear pricing has usually been applied in the day-ahead through the marginal pricing mechanism, giving the correct signals reflecting the teal-time value of electricity and the right incentives to generators. Past research papers reached similar conclusions, the pay-as-clear approach is more efficient in day-ahead markets than pay-as-bid [67]. Bert W. and Yueting Y. [73] conclude that that pay-as bid pricing is inefficient from both short-run and long-run perspectives, because the consumers' willingness to pay exceeds the marginal cost of production in the short term whilst in the long term, the revenue of baseload generation is depressed during high demand periods compared to intermittent or flexible generation, distorting thus the generation mix. Similarly, ACER paper (2022) [1] indicates that in Europe the pay-as-clear model maximizes the social welfare benefits from cross-border electricity trading, and it will soon apply also to pan-European intraday markets.

2.2 Marginal Pricing in Electricity Markets

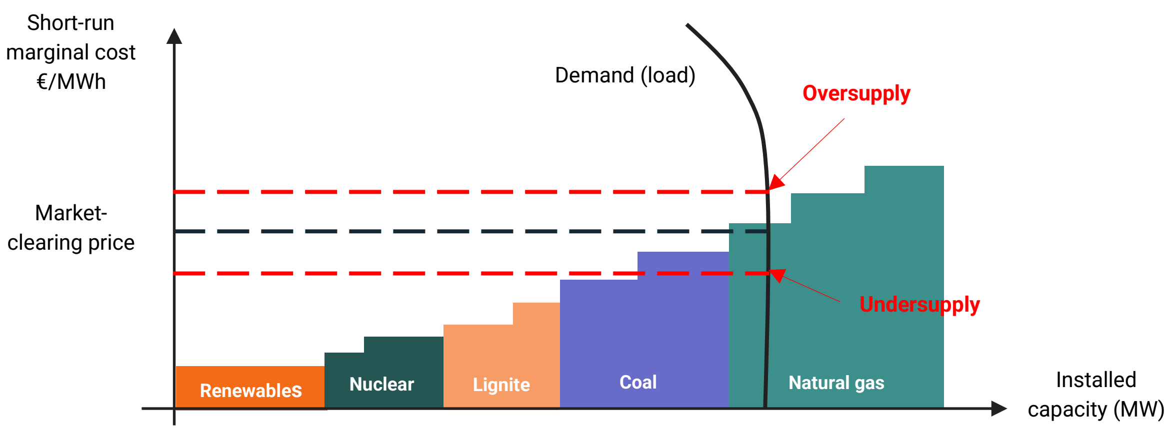
The current pricing mechanism of electricity in the EU short-term wholesale markets is based on the merit-order model[7] where the clearing price (marginal price 'MP') is set by the last bid needed to cover the whole demand, which in turn is determined by the short-run variable cost of the last unit produced (Fig 2). Thus, prices emerge at the production cost of the marginal plant, namely the most expensive power plant (usually gas plants) that is required to serve demand and all participants are rewarded the clearing price.

It is important to mention that the marginal cost ('MC') theoretically includes the operation and maintenance costs ('O&M') and the opportunity cost ('OC').[8] Most of the time, the MC comprises primarily the O&M costs, being the key driver for electricity price formation in the short-term. In the long-term, power plants operate at the levelized cost of energy ('LCOE') which also contain the capital expenditures of the plant ('CAPEX') apart from O&M. To operate successfully, power generators should recover LCOE, including profits, over the plant's useful

[7] The merit order ranks available sources of electricity based on ascending order of price and implies that the most economical generation dispatch should be performed with generating units out of merit order, starting with lowest marginal cost plants until the most expensive ones, if needed.
[8] OC refers to foregone revenues by not selling the electricity at another points in time or markets, according to IRENA 2022 [45].

life through the differential between MP and MC, otherwise the investment is unprofitable or unsustainable.

Fig 2. Merit-Order model: Electricity price formation in short-term wholesale markets



Source: Author's own compilation based on IRENA market reports

2.3 Challenges for current Electricity Markets

The decarbonization of the energy system is expected to be mainly accomplished through the deployment of variable renewable energy ('VRE') technologies, in particular wind and solar, thanks to rapid cost reduction and ease of installation. Other potential options would be dispatchable RE technologies (CSP[9], geothermal, hydropower with reservoirs or sustainable energy), however, they represent a relatively share of planned capacity deployment. VREs display idiosyncratic characteristics compared to other electricity-generating units that impact the functioning of the power system. The most important ones are the *variability* and *uncertainty*[10] nature inflicted by climatological patterns of each system, but also *complementarity between wind and solar production* due to inverse correlation (solar PV production is usually higher during summer whilst wind production is higher during winter) [38]. The variability feature of production hampers the system's ability to match demand and generation at any given time and it urges the need to enhance system flexibility. Mertens S. (2022) mentions *the mismatch in both location and time for wind and solar generation* creating seasonal unbalance between supply and demand [58]. Solar parks tend to be located in highly irradiated areas compared to wind parks which are usually located in scarcely populated areas where the grid is weaker. This could be solved through the implementation of distributed

[9] 'Concentrated Solar Power'
[10] Variability: *'The fluctuating nature of solar and wind resources, which translates into potentially rapid changes in electricity output.'* [39]
Uncertainty: *'The inability to predict perfectly the future output of solar and wind power sources.'* [39]

energy resources. Nevertheless, solar energy is delivered during the daytime, but it is predominantly needed in the evening, causing extreme positive or negative wholesale market prices. He found that a hybrid[11] mix delivers a more reliable and constant match with power demand in the short-term than with each source producing individually.

The market implications of an increasing renewable-based power system are also noticeable. The marginal pricing market was designed in the first place for the fossil fuel era incorporating the characteristics of traditional fossil fuel plants (high operating costs, dispatchability and predictable production) [46]. VRE technologies display distinct characteristics in the wholesale market compared to fossil fuel plants: a low marginal cost (MC) due to low operating costs (OPEX), cost structure dominated by large initial investments (CAPEX) and limited constant generation based on natural resources availability and variability [45]. As the energy transition advances in Eastern Europe and the VRE generation increases due to growing RE capacity deployment, lower bids are expected to clear the market, reducing thus the marginal price, situation known as the 'merit-order effect' [26]. Furthermore, taking into account that both wind and solar output is weather-dependent, all plants of each type produce simultaneously, creating thus a price-depressing effect caused by electricity overproduction, phenomenon known as 'auto-correlation' or 'cannibalization effect' [49]. Both the merit-order and cannibalization effects translate into a reduced captured electricity price and the capital expenditures recovery[12] tends to become difficult for RE generators, let alone earning profits, creating the so-called 'missing money problem' [21] [22] [47] [48]. Currently, the marginal pricing structure enables RE producers to recover their cost as the marginal price is cleared by the more expensive technologies (gas and coal power plants) allowing producers to capture the differential between MC and MP.

The decline in wholesale electricity prices and increase in price volatility caused by higher uptake of VRE has been covered extensively in the literature, particularly in Europe. For instance, Browne et al. (2015) [7] show that increasing wind penetration reduces spot market electricity prices due to the merit order effect in the short term, Clò et al. (2015) [11] conclude that solar deployment in Italy over the period 2005–2013 reduced wholesale electricity prices and amplified their volatility, De Vos (2015) [14] states that negative electricity prices result from a market distortion caused by renewable support mechanisms, Paraschiv et al. (2014) [65] find that renewables deployment lead to extreme changes in electricity prices in the case

[11] Hybridization refers to a hybrid power plant that integrates solar and wind energy systems to provide increased system efficiency and greater balance in energy supply via complementary of solar and wind resources.
[12] The goal of a power generator is at minimum to recover life-cycle costs.

of Germany, Dillig et al. (2016) [15] affirm that electricity prices in Germany, and also in Europe, dropped due to an excess of renewable energy and Azofra et al. (2015) [2] and Ballester et al. (2015) [3] find that the renewable generation tends to decrease the price and increase its volatility in the Spanish electricity market. Blazquez et al. (2018) [74] even mentions the paradox that successful penetration of renewables in liberalized power markets might lead to their own failure due to the interplay of low marginal cost, intermittency and volatility. The reduced clearing price reflects withal a lower volume sold at a lower electricity price by conventional power generators given the RE producers' tendency to gradually displace conventional thermal producers in the long-term [46]. Taking into account that wholesale electricity market is the core vehicle of revenue generation for dispatchable plants, price and volume depression is likely to require additional payments ('capacity payments') to traditional technologies (gas- and coal-fired plants) with the purpose of ensuring system reliability during the transition [37].

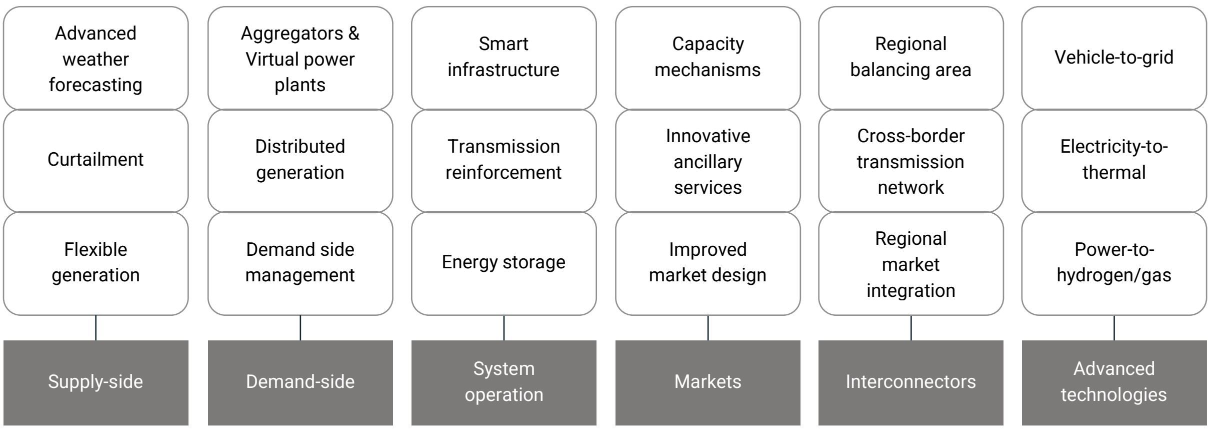
A successful energy transition requires integrating high shares of VRE into power systems at the lowest possible cost and through the integration of flexibility solutions. This will likely require an appropriate updated design of power markets that can address the system level impacts (associated with variability, uncertainty and complementarity) and market level impacts (decreasing wholesale market prices and high price volatility) of renewable electricity. A revised market structure coupled with changes in the regulatory framework aimed at encouraging flexibility and electricity value services through appropriate remuneration mechanisms and price signals are of significant importance in a renewable-based energy system.

2.4 Flexibility Resources: A New Market?

In a power system the balance between electricity supply and demand is necessary at all times (Kirby, 2007) in order to maintain system reliability and frequency. Power system flexibility is defined as the ability to cope with system variability and uncertainty at different timescales from the very short to the long-term [41]. The need to rethink the electricity system in the context of growing deployment of variable and distributed renewables involves a continuous search for the right balance between economic and engineering efficiency [38]. IEA (2016) [37] mention two kinds of flexibility solutions to accommodate weather-dependent outputs: *technical flexibility* (all system elements combined including demand, network, storage, conventional and variable generation) and *commercial flexibility* (referring to cost structures and incentives provided to all market participants). This paper will analyze both with a special focus on commercial flexibility in a future market design for a low-carbon power system. Figure 3 shows a qualitative representation of different sources of flexibility that could be accessed in Eastern European countries.

Energy systems need flexibility not just when variable renewable electricity is produced in large amounts, but also in traditional systems with conventional generation. The difference lies mainly in the kinds of flexibility measures needed to balance the supply-demand mismatches [55]. In conventional power systems (with low VRE shares) flexibility was generally provided by supply-side assets, such as thermal generators (open-cycle gas turbines), flexible renewables (hydropower) and traditional storage (pumped hydro storage) [42]. However, the advent of variable generation requires a larger number of dispatchable resources capable of dealing with changing situations, whose operation is to be based on faster and more accurate markets. IRENA research studies implied that increasing penetration of RES technologies caused a larger capacity started among peaking[13] units (gas turbines), fewer hours that a plant is online each time it is started and an increase in the number of ramps required (not only from peakers, but also from baseload[14] units), all of which draw the attention for the need of flexibility.

Fig 3. Flexibility sources for a low-carbon power system



Source: Author's own compilation from market reports

Even though RES do undermine the profitability of baseload electricity, numerous studies concluded that an energy system with a high share of intermittent generation is feasible and able to serve electricity demand and balance supply with adequate grid interconnections, storage, flexible generation and demand-side response measures [55] [57] [72].

[13] Peaking generators are designed for flexible operation with rapid start-up, fast ramping capabilities and low minimum operational level (gas turbines and internal combustion generators).

[14] Baseload generators have opposite techno-economic characteristic than peakers. They have limited cycling capabilities but are able to generate large amounts of energy at relatively low operational costs (coal, biomass, nuclear, CHP).

2.4.1. Supply-side flexibility

Flexible generation technologies are traditional power plants whose unit output can be modified to attain the power balance in the grid with the fastest start and ramping response and at relatively low cycling costs (thermal assets such as OCGTs and CCGTs[15], reciprocating engines and hydro units). Baseload power plants (coal, nuclear) ramping or shutdown is avoided due to economic and sometimes technical reasons. Gas-fired power plants serve as cost-efficient backup technologies due to low investments costs. Nonetheless, relying heavily on conventional thermal sources of flexibility results in high production costs (given high fuel and carbon costs) which may decrease the attractiveness of CCGTs as a balancing power [59]. Interestingly, coal power plants can be made more flexible by retrofitting certain physical components to achieve shorter start-up times, reduced minimum loads[16] and higher ramp rates. However, such assets are penalized more by the EU ETS, given their higher CO2 emissions intensity per unit of electricity produced. Curtailment[17] of VRE supply could be another practical technical solution in situations of limited transmission capacity, oversupply of VRE power or a large share of inflexible baseload generation. Nonetheless, it is a less desirable action as it implies a loss[18] of potential useful clean electricity and can affect the revenue of wind and solar energy projects.

It is important to mention that conventional dispatchable capacity remains needed for system adequacy, but its average load factor is expected to decline both for existing and new capacity installed, pushing gas plants out of the market during the transition and not making them operational for their entire lifetime. In this regard, gas-fired plants are expected to be rather needed as peaking capacities as long as RES deployment increases [9]. It is also worth mentioning that natural gas-fired capacity is also covered by the EU ETS scheme impacting thus its economic viability and becoming uncompetitive against renewables. Overinvestment in natural gas power plants increases the risk of stranded assets and may become the price to be paid for the push for greener electricity.

2.4.2. Demand-side flexibility

On the demand side there is a broad set of means to adjust consumption to follow generation, ultimately changing the role of end consumers and consumption patterns. One solution is demand-side management (DSM) which can be divided into: peak shaving, load growth or load

[15] OCGTs = Open-cycle gas turbines, CCGTs = Combined-cycle gas turbines
[16] In Germany, for example, minimum load levels of 12% have been achieved through retrofitting measures (Agora Energiewende, 2017).
[17] Curtailment is temporarily decreasing the load of renewable generation assets for economic or grid capacity constraints.
[18] Given that the VRE's capacity factor is much less than 1, the loss of electricity produced is not proportional to the power curtailed*: an average curtailment of PV power by 40% leads on a yearly level to 10% loss in PV electricity produced,* according to Lund et al. (2015) [55].

shifting[19]. Load shifting also requires an intermediate storage device and is considered the most beneficial as it provides flexibility without compromising the continuity of final electricity services offered [55]. DSM mechanics provide various benefits to electrical energy systems: balance of demand and supply in different time scales (Mathieu J. et al., 2013), reduction of price spikes and average spot prices (Kirschen D., 2003), market power shift from generators to consumers, reduction of transmission and distribution losses (Nourai A. et al., 2008), replace infrastructure expansion (Kazerroni A.K. et al., 2011) and prevent investments in additional thermal capacity [55] [59]. The potential for DSM schemes was analyzed for some European countries [19] and revealed that the potential for peak shaving is higher than load shifting in Romania and Bulgaria and the opposite is true for Czechia, Hungary, Poland and Slovakia. The investment cost is expected to be lower for peak shaving. Studies show on average roughly 20% cost reduction and 10% to 20% increase in VRE consumption due to DSM, in some cases combined with energy storage [55].

Besides DSM, the emergence of distributed energy resources (DERs) involving mainly small customers and the participation of the residential sector, such as rooftop solar PV, small energy storage systems, micro gas-fired turbines, mini-grids and plug-in electric vehicles enhances system flexibility on the demand side. Prosumers[20] are changing the traditional role of consumers, which are now switching from the traditional role of passive consumers to active participants in the energy transition. Distributed generation requires a new form of service for adding together demand response opportunities and aggregating or centralizing them into products that could be delivered on the wholesale market. This explains the rise of demand response aggregators[21] being a key driver for flexibility in energy systems, helping to optimize real-time electricity demand with generation available [37]. In South Australia 20% of daily power demand and 30% savings on energy bills can be achieved by aggregators (Government of Australia, 2018). Aggregators operate virtual power plants (VPPs) which function on software systems that control remotely and automatically the dispatch and optimize the DERs. VPPs have standard attributes that provide fast-ramping ancillary services considered to replace fossil fuel-based reserves [39]. Digitalization and emerging innovations are at the core of distributed energy development enabling aggregators to manage large amounts of data through artificial intelligence and big data techniques and consumers to constantly monitor and control consumption by adopting smart devices, behind-the-meter batteries and thermostats for heating and cooling [39]. The implementation of digital systems

[19] Peak shaving enables the reduction of peak consumption during tight system conditions, load growth refers to increasing energy demand and load shifting ('valley filling') reallocates part of the demand from one time to another.
[20] Prosumers are individuals who both consume and produce electricity for own consumption purposes and sells the excess back to the grid.
[21] An aggregator groups agents from the power system (consumers, producers, prosumers) to act as a single entity when participating in energy markets (MIT, 2016).

and data analytics by large industrial consumers was reported to increase RE generation by 8%, reduce curtailment by 25% and operation and maintenance costs by 10% (Neuhoff et al., 2011).

2.4.3. Energy storage flexibility

Storage is a valuable system tool that addresses the technical and economic challenges of renewables integration. Storing electricity has been part of the power system for a long time primarily through pumped water which has historically been the core technology for storing large volumes of electricity.

In energy terms, pumped hydro still remains by far the largest and the most cost-effective source of electricity storage [44]. Other options for electricity storage apart from pumped hydro are batteries, hydrogen, compressed air, flywheels, supercapacitors and superconducting magnets. The storage process involves the conversion of electricity to other forms of energy when stored (mechanical or chemical) and is usually accompanied by conversion losses when converted back to electrical energy. However, energy arbitrage[22] can help smooth the conversion losses by taking advantage of electricity price differences. For instance, the economics of hydro storage relies on arbitrage principles: electricity is pumped by water into higher gravitational reservoirs when it is cheap and re-generated when it is dear. The arbitrage is successful usually between night-time and day-time generation [70].

Electricity storage shifts power delivery through time and releases it on demand when it is most needed. It is worth mentioning that electricity storage could bring huge benefits to the power system compared to alternative flexibility options in the form of reduced cost for producing electricity and reduced capital investment [44]. This can relate to replacing costly thermal generation during peak hours (peaker plants with high marginal cost), supporting VRE penetration at the expense of fossil fuel generation, replacing fast response thermal capacity for load provision and ancillary services, reduced congestion which translates into lower grid operational expenditures, VRE curtailment savings and reduced cycling costs of thermal capacity. The literature has also showed that storage can provide advanced ancillary services offering grid services such as provision of primary and secondary reserves, fast frequency response, voltage support, black start as well as firm capacity [55]. Based on varying costs and techno-economical characteristics, storage could provide specific system services at different timescales to renewable power integration. For instance, batteries demonstrated to

[22] Energy arbitrage describes the situation of capitalizing on the difference between a higher selling electricity price and a lower charging electricity price. A storage device can participate in either day-ahead or intraday markets. (IRENA, 2020)

have an extremely fast response, quick deployment time and high-power ramping rate, being suitable for frequency regulation. This can pave the way for new valuable system services as one unit of fast frequency response can replace multiple units of primary reserve [44]. Moreover, batteries could improve network stability when there is a high share of renewables, as fluctuations require action within seconds to minutes and a high cycling capacity [55]. As the cost of emerging technologies declines further and performance improves, storage will become increasingly competitive and the range of economical services it can provide is expected to grow.

2.4.4. Interconnectors

Demand-response and storage reallocate demand only across time whereas interconnectors reallocate demand both across countries and time, exploiting locational and temporal synergies between neighboring electricity systems. Interconnectivity plays a major role, if not the most important one in the provision of flexibility, thus allowing electricity to flow dynamically across borders and countries to share balancing reserves among them. Regional market establishment commenced long before the accelerated deployment of VRE, in tandem with liberalization of electricity markets as a means to enhance security of supply, reduce costs and spur competition [39]. Interestingly, a well-integrated regional market brings additional benefits to VREs integration in power markets. Abundant RES production can be exported to neighboring locations that need electricity to avoid potential curtailment and expensive conventional thermal generation.

Consequently, power systems can reduce planned investments in peaking capacity in a strongly interconnected regional power system. A Metis study [59] found that existing and new interconnectors in Europe have a positive impact on all types of flexibility needs, providing roughly 26% and 22% of daily and weekly flexibility needs, respectively. Moreover, balancing services exchange across Europe, including Austria, Germany, Latvia and the Netherlands, helped to avoid 83%, 60%, 55% and 51%, respectively, of the system's balancing energy needs (Commission Regulation, 2017). For a deeply integrated regional market, harmonized rules across different markets (wholesale, ancillary and capacity markets) and trading time frames should be implemented. The implied advantages are many: increasing the balancing area and reducing balancing costs by trading ancillary services across countries, benefiting from complementarities between diverse renewable energy sources, reducing VREs curtailment, using energy assets more efficiently and lowering the risk of electricity shortages [39] [40].

3. Signals and Incentives in Electricity Markets

Electricity market rules should bring reliability[23] and adequacy[24] in the power industry and ensure visibility for either operations or investment. High reliability and adequacy standards have always been in place for meeting the load in a reliable manner given its relatively inelastic nature, variability in time and uncertainty in quantity [16]. However, power sector transformation is occurring at a very fast pace, changing the nature of both electricity production and consumption, and increasing the system risk from both sides. This made the argument for an electricity market reform more compelling amongst scholars and energy professionals who consider that the electricity market design should be adapted to capture the maximum benefits of renewable resources. This requirement has indubitably financial implications that should be addressed by market regulators. Market prices provide valuable feedback on the value of different assets to the power system and are thus vital for guiding effort in the right direction. The current design does not fully remunerate all energy assets for the value they could provide, preventing the flexible functioning of the system and calling for appropriate price signals [75]. This section emphasizes the importance of market signals and remuneration incentives for generators, consumers and for flexibility resources in a high share VRE system, meant to stimulate action when it is most needed, especially during high contingency events.

3.1 Operation signals

Electricity markets should provide efficient incentives to power producers during the operational stage.

Accuracy of price signals for short to medium-term decisions such as daily planning of generation and consumption, real-time scheduling and dispatch decisions, acquisition of operating reserves or seasonal maintenance is essential in power markets. Flexibility already exists within the electricity market framework, but it just needs to be accessed through the right design and operation signals.

[23] 'Reliability is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.' (NERC, 2014)

[24] Resource adequacy refers to the ability of the electric system to provide sufficient available capacity to satisfy demand at all times in order to avoid a potential load curtailment. (NERC, 2014)

3.1.1. Sending short-term signals to producers

Market price signals stimulate plant owners to utilize their assets efficiently, to always produce when the price is above short-term variable costs, to make efficient decisions about the choice of selling electricity between different markets (day-ahead, intraday, balancing) and to schedule plant maintenance during appropriate times, meaning during lower-price periods, in order to meet the power system needs [28]. The goal should always be to produce high value electricity (during peak or winter times for example) when it is most needed, rather than just maximizing overall RES production. For instance, west-facing solar panels have lower yields compared to south-facing panels, but they produce during peak-evening hours, when both the price and demand increase (scarcity times).

Generators must follow market prices, and they need to be dispatched according to demand and supply balance. Market price signals preserve optimal utilization of power plants and stimulate producers to make optimal operational choices. Organized wholesale markets create transparent spot prices that deliver important price signals even at depressed prices, as they incorporate all the available information and guide short-term operation decisions [20]. The revised design of short-term markets should address the operational challenges that come with the rapid deployment of VRE capacities, such as variability and uncertainty, while retaining the key short-term signals and introduce additional financial incentives if necessary. The literature points to the revision of certain short-term design elements that are key for an efficient wholesale market such as time frame, bidding formats, clearing and pricing rules, balancing responsibility and integration of reserve markets [38].

In Europe, electricity markets have lower resolution compared to the United States, with a focus on cross-border trade. However, some Eastern European countries are moving towards higher time granularity with the introduction of 15-minute contracts for continuous trading in intraday markets (Romania, Hungary, Slovakia, Bulgaria). Although gate closures[25] are still distant from real-time delivery in Eastern Europe, with the vast majority of gate closures occurring in 1h time before delivery, setting them closer to real time could
benefit power producers and TSOs by adjusting their positions as the accuracy of production forecast improves, minimizing imbalances and reducing the need for regulation reserves [62]. Similarly, increasing spatial granularity on price formation is expected to send the necessary price signals that reduce costly re-dispatch, incentivize demand response and encourage

[25] Gate closure is the moment up to which market participants can either submit or modify their own bid or ask orders on the intraday market, in order to balance their positions and correct their deviations without any type of intervention from the system operator. After that point in time, the final binding production schedule is determined for all participants, and only the system operator can adjust any deviation.

capacity investment in the right location of the network. Spatial resolution is more prevalent in United States where nodal pricing mechanisms[26] are practiced by internalizing network constraints through location-differentiated bidding of energy [66]. At the European level, some countries practice 'zonal pricing'[27] whilst others utilize 'single pricing'[28]. Nodal pricing in electricity markets can help provide better market signals to the TSO and generators, stimulating investments in high-priced zones. However, zonal pricing might be more efficient when specific transmission network lines are congested. Larger bidding zones are thought to increase liquidity and competition, and zonal prices represent a more stable signal for investors and tend to be less discriminatory for consumers [43].

The role of intraday markets is becoming more compelling, being the dividing line between day ahead market and gate closure (Weber, 2010) providing price signals for decentralized balancing transactions. In Europe, intraday markets perform two essential tasks: allow generators to make adjustments to day-ahead energy schedules and recover the balance between demand and supply if the system conditions change. Therefore, intraday markets are fundamental to cover renewables forecast errors, reduce the risk of imbalances and to inform all market actors about the incremental cost of serving electricity in real time. Intraday markets function using continuous trading in which bids can be submitted and matched at any time before the gate closure. Even though the continuous trading mechanism offers more flexibility as trading is unfolding anytime, it might result in insufficient liquidity [38]. The literature recommends that intraday, balancing and ancillary services markets to be improved to provide enough liquidity by enabling large consumers and new distributed technologies (i.e., PV rooftops and storage units) to participate in these markets via aggregators or smart equipment infrastructure. Donna and Rahmatallah [66] expect that most transactions will move from day ahead to intraday markets, as more RES generation is integrated in the power sector, and the information that is required to schedule the power dispatch (weather pattern updates and demand consumption forecasts) become available later than one day in advance of real time, as it was determined for traditional vertically integrated utilities in the past.

Intensive debates focus on innovative balancing products that unlock flexibility to integrate renewable and distributed energy into the power system [64]. These products address fast-ramping needs, like batteries with quick response but limited retention. RES generators can sell surplus energy as balancing energy but not as balancing capacity due to inaccurate

[26] In the United States, system operators use nodal prices to derive the locational marginal price (LMP)
[27] Separating countries' territory into several bidding zones, based on commonly grid congestion patterns
[28] Ignoring transmission congestion when clearing the day-ahead market

production forecasts. Belgium and Dutch markets already use variable RES units as frequency restoration reserves (FRRs) or secondary reserves. Balancing responsibilities for RES generators were traditionally exempted [38], but as RES volumes grow, imposing balancing responsibilities improves forecast accuracy. Ancillary services prices are expected to rise due to the increased need for short-term balancing and larger ramps from intermittent generation[29]. Harmonized rules in wholesale electricity markets at the regional level in terms of closure times or scheduling intervals of day-ahead and intraday allows market actors to act in a coordinated way and to benefit from complementarities offered by different demand patterns in the region. In this way, VRE capacities are better integrated in the market while inefficiency and curtailments are being reduced.

3.1.2. Sending short-term signals to consumers

Electricity prices should send the right price signals at the meter also, reflecting actual power system conditions and conveying real-time price information to final consumers. Retail prices represent an important factor that has a strong direct impact on consumers' consumption patterns. Given that distributed generation is expected to dominate new RES investments, the role of retail pricing will increase markedly. In particular, rooftop solar PV and micro-generators to be installed behind the meter, and not connected to the public distribution grid directly are expected to be much more disruptive for the electricity sector than the mere variable nature of renewable energy. The development of behind-the-meter generation will depend on retail prices, not wholesale electricity prices like generators connected to the transmission or distribution grid. This makes the design of retail prices much more compelling, which should include a wide range of design features meant to stir consumers participation in the market. The design features are mostly related to the possibility to net electricity generated and consumed (net metering), the tariff structure (fixed, capacity charge, variable charge), the surcharges to cover energy policy costs and the taxation of electricity [37].

An essential element is that price signals between retail and wholesale markets need to be efficiently coordinated in order to balance the contribution of centralized and decentralized resources in the market. This becomes much more important when introducing demand response mechanisms with the scope of providing enhanced flexibility to the system. Demand response mechanisms can be achieved based on consumers' reaction to price signals, time-

[29] LBL (2018a), Tracking the Sun, Lawrence Berkeley National Laboratory

of-use (ToU) pricing structure introduced at the retail level and advanced metering infrastructure. ToU tariffs are time-based tariffs which enable customers to adjust their electricity consumption voluntarily (manually or through automation) to reduce energy costs. They convey time-varying price signals to consumers, depending on the system balance and short-term wholesale market price signals. ToU tariffs can be designed in different ways, either static (determined in advance) or dynamic (determined in real time reflecting actual conditions of the power system). Dynamic tariffs based on real-time pricing represent a much more useful tool to integrate and factor in the value of renewable electricity in the market. For instance, Brown and O'Sullivan [6] show that dynamic pricing reflecting wholesale price levels stimulate rooftop PV installers to orient the PV panels from East to West during the day to produce more electricity later in the day when prices start to increase, and electricity is most needed. In this way, variable retail pricing reflects the higher social value of energy produced late in the day when the sun usually fades and demand increases. With a flat retail tariff per kWh, rooftop PV facilities will be positioned only to maximize production rather than social value, since the benefit is not driven by variable retail prices signaling increasing need of electricity.

The large increase in behind-the-meter generation sources (solar photovoltaics for rooftop, micro gas-fired turbines, distributed storage) will raise the general question of design of retail tariffs and their link to wholesale markets. A full integration of retail pricing with wholesale market pricing is desirable in this era of high-intermittency and volatility as a way to activate demand side flexibility. With flat KWh retail rates and net metering schemes, consumers have no incentive to take price-responsive actions following intermittent generation effects on wholesale prices [48]. Glachant (2016) considers also that access to demand-side flexibility through dynamic retail pricing is a key element in re-designing electricity markets. Dynamic electricity price contracts reflect the changing nature of day-ahead or intraday prices that would allow consumers to respond to price signals and actively manage their consumption. Therefore, consumers would be able to freely choose and change suppliers or aggregators, while also being entitled to a dynamic price contract.

In Eastern Europe, most retailers offer fixed tariffs with rates that are locked in for a certain period (12 to 24 months) thus reducing price volatility for consumers. In short, most residential and commercial customers are disconnected from price variations in the spot market. Although fixed prices could provide stability, this certainty may come at the expense of higher overall costs for the customer as compared to paying under variable pricing.

Nevertheless, the literature reveals that welfare gains from dynamic pricing increase significantly in systems heavily dependent on intermittent renewable generation (ranging between 8.5% to 24.3%) whereas in fossil-fuel dominated power systems dynamic pricing yields modest gains (2.4% to 4.6%) [36]. Joskow (2019) [49] finds this quite intuitive, because the average gap between the flat retail price and short-run marginal cost of production is way higher in systems with time-varying marginal costs (renewables systems). Moreover, Imelda et al. (2018) [36] find that demand-side mechanisms induced by real-time pricing mirroring intermittency and fluctuations in spot prices and short-run marginal costs of renewables significantly reduces the associated cost of reaching national renewables target, depending on consumers' demand elasticities and their responsiveness to variable pricing.

The development of innovative retail pricing offers should be encouraged with increasing renewable capacities deployed and gradual exit from coal. In particular, dynamic pricing could better reflect the presence of scarcity pricing, the increased volatility of wholesale prices and the periods of depressed electricity prices during hours of overgeneration [37]. These specific changes are expected to send efficient signals to consumers, who are increasingly able to react to prices in real time, as well as invest in rooftop solar PV and storage devices. Investment signals for behind-the-meter generation depend to a large extent on retail electricity tariffs, both in terms of level and structure. For instance, utilities can introduce time-of-use tariffs that charge higher prices during peak periods and lower prices during off-peak periods or can offer dynamic pricing that changes in real-time based on the supply and demand of electricity. This would provide customers with more accurate and immediate price signals that reflect the real-time cost of electricity production, while incentivizing them to shift their energy consumption to off-peak periods and reduce overall demand during peak periods.

3.2 Investment signals

3.2.1. Sending long-term signals to producers

Electricity prices should inform generators and customers in a precise manner about the value that electricity provides at each moment in time. The marginal pricing mechanism has been successfully doing that for a long period of time and continues to provide an efficient and reliable price signal. The recent electricity price shocks caused by the Covid-19 pandemic in 2021 and Russia's unprovoked invasion of Ukraine in 2022 coupled with a growing international energy demand changed the whole paradigm. The general consensus was that the recent events created temporary windfall[30] profits for VRE generators triggered by the natural gas price spike. Policy regulators assumed that the differential between marginal price and marginal cost was already sufficient to recover total costs (CAPEX and OPEX) plus additional profits, so they considered that the higher revenues are unjustified. In this regard, legislation aimed at minimizing these 'extraordinary' profits was quickly introduced, ignoring the potential insufficiency of cost recovery and the marginal pricing signal to deploy additional capacity needed to address the transition [45]. High electricity prices could reflect a rather normal event in the market, signaling a capacity deficit. In this case, high profits are not necessarily considered extraordinary, but being the result of producers' strategic choices to capitalize on market opportunities [24]. On the other hand, the research literature emphasizes the potential distortion that price signals could convey from joint effects of capacity shortage, transmission line congestion and market power. A correct signal for future generation capacity investment applies only in the first case when a surge in electricity prices signals a capacity deficit, whereas a high-RES profitability hides inefficient rents in the last two cases [5].

In Europe the Covid-19 pandemic could have been considered a scarcity event[31] which was exacerbated by the war unfolding in Ukraine. Peak-load pricing (scarcity pricing), a fundamental theory of long-run electricity markets, plays a key role in providing reliability, signaling action when it is most needed, especially during high contingency events. Demand side management and scarcity pricing could work in tandem, as high prices are useful for reducing demand. On the supply side, these temporary high prices, reflecting higher OPEX of fossil fuel plants, stimulate power plants to be available in the market when most needed and remunerate fixed investment costs of peak capacity, such as gas plants [37]. Considering that renewables are capital intensive with no or minimal marginal costs, energy-only markets become the main vehicle through which RE generators could recover fully their investments in solar and wind power plants, apart from government support mechanisms.

Similarly, peak generators that generate infrequently and are needed the most in high contingency events to balance supply and demand must recover their fixed costs through marginal price mark-ups usually created during scarcity events. The value of electricity rises exponentially during these times, and the system should let power generators to be remunerated accordingly by the market. Caps on electricity prices set by regulators in

[30] A windfall profit refers to a sudden and/or unexpected gain usually caused by one-time events that do not reflect a normal business environment.
[31] A scarcity event occurs when demand exceeds available regular generation triggered either by an increase in demand or reduction in generation, requiring more expensive forms of generation to be called in, setting a higher marginal price [45].

wholesale markets during scarcity events tend to lead to the missing money problem mentioned above. Apart from depressed price levels, the absence of a sufficient liquid forward market in Eastern Europe in which generators could hedge the risk of price volatility tends to be a concern for investors and their financiers, creating the phenomenon of 'missing market' [63]. Additional renewable capacities and their market integration could exacerbate both the issue of missing money and missing market even further [66]. Genoese and Egenhofer (2015) highlight the reduction and growing uncertainty of energy market revenues inflicted by low marginal cost and intermittent production of RES. One important stakeholders' recommendation was to refine the energy-only market by improving scarcity pricing across day-ahead, intraday and balancing markets.

The transition raises the risk of a reduced long-term resource adequacy due to phasing-out and decommissioning of coal and aging plants as well as potential mothballing[32] of newer gas capacities incurring losses caused by fewer running hours and depressed prices. This issue is thought to be solved by the intention of national governments to introduce capacity remuneration mechanisms, guaranteeing the fixed cost recovery. Yet, the practice of capacity remuneration is rather controversial as it incentivizes ineffective over-procurement and increases the cost of decarbonization [50]. Generators in Eastern European countries rely mostly on energy-only markets for generating their revenues as capacity markets are technically inexistent, except in Poland where a capacity mechanism was introduced in 2018 to address resource adequacy concerns. The capacity market in Poland provides payments outside the energy market, based on guaranteed availability of capacity. Projects are selected through competitive auctions designed to set the needed capacity to cover peak demand. Interestingly, roughly 80% of selected capacity in 2018 went to coal-fired generation[33] and since 2021[34] auction participants must not exceed emissions of 550g CO2/kWh requiring coal plants to have enough biomass co-firing or use carbon capture.

The capacity market is quite prevalent in Western Europe, the main argument for its implementation being that energy-only markets are not able to stimulate sufficient investment in generation and to ensure resource adequacy and reliability standards. In theory, an energy-only market design with sufficient demand response, scarcity pricing and storage can suffice. Scarcity prices should be regulated ex ante in order to make price spikes politically acceptable. This has been usually done by applying some cap on wholesale market prices to

[32] The practice of deactivation or preservation of power production facilities or equipment for future potential use or sale.
[33] Forum Energii, 2019
[34] In 2021, over 1 GW of co-firing coal and biomass units won the capacity support with delivery in 2026.

keep market power abuse in check. Setting a price cap that accurately reflects the reliability value to the consumer is a difficult process. According to market standards, the scarcity price cap is usually set at the value of lost load (VoLL[35]) or using an operating reserve demand curve which analyses situations of capacity shortage [37]. It is clear that in the absence of scarcity pricing, or where scarcity prices are capped too low a level, some kind of capacity mechanism will be necessary to ensure that RES generating resources are able to recover their fixed costs.

Another way of stimulating low-carbon generation investments proposed by policy makers was by introducing a strong carbon price in organized wholesale electricity markets. The theoretical vision of the CO2 pricing approach was conceived either in the form of a carbon tax or a cap-and-trade emissions market, similar to the one introduced in Europe in 2003. According to Matt B. et al. (2020) [8], the main benefits of introducing carbon pricing in electricity markets are the internalization of climate externality, triggering of correct investment signals for entry and exit and non-discrimination amongst technologies, being considered a technology-neutral approach. They claim that internalizing the CO2 externality changes the economic merit order and provides price signals that reflect the marginal external cost of CO2 emissions. CO2 pricing will theoretically prioritize the dispatch of generators with the lowest marginal social cost of production (zero or low CO2 emissions) even if they happen to have high fuel costs. The rationale is that strengthening and expanding the reach of carbon price signals could be sufficient to direct investors towards technologies that are less carbon-intensive in order to achieve 2050 objectives, speeding up at the same time the exit of fossil fuel resources by reducing their profitability during the transition. However, some critics claim that this could lead to very high and volatile wholesale electricity prices, whilst carbon prices have proven politically challenging in many countries.

3.2.2 RES support scheme signals

Optimal RES support mechanisms should not distort operation and investment decisions of producers. The interface between investment de-risking through RES support mechanisms and market exposure is tackled extensively in the literature. Newbery (2016b) admits the importance of RES exposure to short-term energy market for investment recovery and more efficient investment signals, however, he highlights the inherent risks implied by 100% exposure (considerable increase in cost of capital and cost of decarbonization due to high risk premia) and argues for long-term capacity auctions in

[35] 'VoLL represents the price that an average customer would be willing to pay to avoid an involuntary interruption of electricity supply.', IEA 2016

addition to short-term signals, position shared also by Fabra et al. (2015, 2022). Nonetheless, he acknowledges the arduous process over the determination of renewable capacity to be produced via auctions (Newbery, 2016a). The table below (Fig. 4) summarizes the main support schemes implemented in Europe and the general interaction between these instruments and the market.

Fig 4. RES support schemes and market incentives

Support scheme	Remuneration	Advantages	Market incentives
Fixed Feed-in Tariff (FiT)	RES generators receive a fixed payment for each unit of electricity generated independent of the electricity market price.	The fixed feed-in system turned out to be highly effective in practice, providing transparency, predictability and security in the market. It acts as a hedge against volatility because the fixed payment contributes to lowering investment risks and financing costs, decreasing the risk premium and enhancing market access for investors.	FiTs do not provide any incentive to respond to market prices. RES operators that benefit from FiTs are not stimulated to contribute or to react to the market price signal, possibly leading to temporary downward pressure on electricity price. Moreover, FiTs do not encourage direct price competition between project developers.
Fixed Feed-in Premium (FiP)	RES generators are remunerated at the spot market price and receive an additional constant (non-variable) payment on top.	Even though FIP schemes come with additional costs for electricity trading and procurement of balancing services, additional technology bonuses can pe paid on top of the FiP. Moreover, to reduce the chances of overcompensation/undercompensation, maximum (cap) / minimum (floor) levels for fixed FIP or for the total remuneration (FIP + market price) could be introduced.	Fixed FiPs offer exposure to market price formation and leave operators more exposed to market risks, encouraging an efficient reaction when needed. For instance, constant FiPs create an incentive to generate electricity in times of increased demand, when market prices are high, or when production from other energy sources is low. Moreover, FiPs stimulate operators to install new capacities in areas with higher average market prices, benefiting from locational pricing structures (if any). FIPs are considered to contribute to an increased integration of RES into the electricity market
Sliding Feed-in Premium (FiP)	Instead of a fixed payment on top of the spot market price, generators receive a floating or sliding (variable) payment with the purpose of limiting risks and windfall profits.	The sliding premium addresses some of the challenges imposed by the constant premium model, addressing better the overcompensation/undercompensation issues during periods of high/low electricity prices. The sliding premium is adjusted based on the market situation: if the market price increases, the premium can be designed to decline (and vice versa). Caps and floors could also be introduced for the premium to slide between an upper (cap) and a lower (floor) range in response to changes in the spot market price. This provides a guaranteed minimum range for FiT payments and reduces potential divergences between FiT payment levels and actual generation costs.	Sliding FiPs still respond to market prices, keeping the market exposure through the premium-price design and stimulating operators to produce when demand is high. This remove the artificial separation in the market between RES and conventional electricity. However, the incentive to react to the market tends to be lower than in the case of fixed FiPs. This support schemes allows for a more effective RES market integration than fixed FiPs, being the most compatible with the principles of liberalized markets.
Quota (Tradable green certificates - TGCs)	Operators receive certificates for each MWh produced of green electricity, which they sell further to market	Selling of GCs provides an additional revenue stream on top of the spot market price, attracting thus interest from investors. This scheme encourages RES market development	Quotas with GCs provide greater levels of market interaction than FiPs. Both the electricity produced and no. of GCs realized are based on market mechanisms, even though the GCs price is fixed.

	actors obliged to fulfill the annual quota acquisition.	by stimulating additional deployment of RES capacities involving technologies at different stages of maturity, including emerging technologies.	
Contract for differences (CfD)	Settlement of the difference between the 'strike price' (an electricity price that reflects the investment cost of a particular low carbon technology) and the 'reference price' (a measure of the average spot market price).	These instruments benefit investors, developers and electricity generators by providing greater certainty and stability of revenues, reduced exposure to volatile wholesale prices, easier access to long-term financing solutions and more attractive investment environment for RES projects.	If the parameters are equal, the incentives for the efficient commercialization of renewables on the spot market are similar under both CfDs and FiP schemes. However, the degrCEE of market interaction varies depending on specific design elements, such as the settlement period. Certain CfD designs have the potential to insulate generators from market price signals and negatively impact the forward market.

The relatively higher need for fixed costs recovery of RE generators can be addressed through government-procured long-term contracts, especially during periods of low market prices. However, fixed support payments are thought to distort wholesale and retail electricity prices in the long-term [13] and production-based subsidies (FiTs, CfDs)[36] distort operation and investment decisions as they rely on the 'produce-and-forget incentive' [28]. Both FiTs and CfDs influence dispatch decisions, as power generators are indifferent about high prices created during seasons of high demand, reduce abundant output during low or negative prices, schedule maintenance at times of low demand or invest in new capacity when needed that could capture above-average market prices.

The fixed payment provided to RES generators provides no incentive to increase output during scarcity times (high prices), reduce abundant output during low or negative prices, schedule maintenance at times of low demand or to invest in new capacity when needed that could capture above-average market prices. RES generators' incentive to bid negative prices in the wholesale market in order to remain in operation is highly probable, decreasing therefore the capacity factor for conventional generation and putting at risk the whole electricity system. During negative prices, operators are not dispatched for the system's sake, being a significant revenue risk beyond operators' control. L. Hirth et al. (2022) [28] mention in their paper that conventional CfDs distort retrofit and repowering choices, as these instruments mute the core price signal from the market. There is little incentive in repowering, as older generating units coupled with old CfD's payments might not be replaced by newer, more productive units. Similarly, CfD schemes impact maintenance scheduling decisions, as intermittent power plants are stimulated to schedule maintenance during periods of high prices in order to avoid high imbalance costs, given that imbalance settlement costs are correlated with spot prices.

[36] FiTs provide an incentive to maximize RES electricity production because they are output-based. The same applies for CfDs, as revenues across all hours of production equal the strike price.

They introduce the solution of the financial wind CfD, which is a financial rather than an asset-dependent instrument, payments being independent from the asset's own production, but rather set in relation to a reference wind farm that should provide a benchmark for production and revenues. As all payments are asset-independent, asset dispatch, investment and repowering decisions follow freely market price signals.

The constant premium model (FiPs) could help integrate better RES in the market where electricity prices influence total remuneration, stimulating generators to control production based on price and demand dynamics. However, the design and premium level could change the bidding behavior of RES producers, influencing thus short-term market prices. For example, several markets have experienced negative prices caused by generators bidding below their actual marginal cost in order to secure the premium payment, a situation intensified by the inflexibility of conventional generators. Nonetheless, detailed EU analyses mention that fixed feed-in premium system might be less cost efficient than basic FiT due to higher overall costs for society, resulting in higher average payments per MWh. For instance, Czechia offered a choice between fixed and premium policy options, resulting in higher incremental profits for generators that opted for the premium option, justified by greater investor risk, increased costs related to balancing procurement and electricity trading and greater market uncertainty, making thus FiPs a costlier policy design choice.

Whilst fixed FiPs set a constant payment on top of the market price, sliding premiums could better integrate RES in the market and address some of the fixed FiPs challenges, balancing out the differences between reference prices and average market prices [52]. Sliding or modulated premium is an intermediate category of instrument between fixed-price instruments that entirely shield low-carbon generators from all market risks (FiTs) and market plus subsidy instruments that fully expose them to long-term price uncertainties (fixed FiPs). Sliding FiPs aim to find a balance between providing certainty for capital intensive investment while maintaining market feedback. According to IEA analysis (2016) [37], the premium can also be modulated depending on the realized carbon price, rather than as a function of electricity market price. For instance, a high carbon price would translate into a lower premium offered on top of spot market price. In this case, investors would require a lower risk premium to compensate for the CO2 price risk, keeping the cost of financing low.

Some research studies favor the promotion of RES market integration via the sliding market [53], however, others are critical exposing the trade-offs between RES exposure to market price signals in order to increase decision efficiency for production and investment on the one hand and the creation of a secure planning basis for RES investors on the other [69]. Moreover, if RES producers carry a considerable share of electricity market risk, this would lead to increased costs of implementing RES objectives, as higher risks translate into higher risk premia which require larger remuneration.[37] Newbery (2016) claims that the CfD scheme can offer better results than premium feed-in tariffs. Given that CfDs maximizes the volume produced by a specific type of RES, the output increases in a local area, depressing wholesale prices in those hours. This fall in prices should stimulate developers to choose better locations, meaning higher local prices with less sun or wind. A contract price independent of the spot price represses active signals, potentially raising deployment costs.

4. Electricity market design in Eastern Europe

4.1 Energy sector overview in the region

The focus region of this report is the Eastern European area[38] including 7 out of 10 countries officially part of the region according to the United Nations definition: Bulgaria, Czechia, Hungary, Poland, Republic of Moldova, Romania and Slovakia. The countries of Eastern Europe share a similar history, as they were governed under communist regimes for an extended period of time until the 1990s. All these countries transformed their economies afterwards to a market economy and capitalist systems, through the introduction of economic reforms, privatization, open trade, economic integration with the West and a considerable increase in foreign direct investments [10].

Many similarities can be seen within the structure and development of the power system present in Central and Eastern ('CEE') countries. The traditional power sector paradigm was that of centralized decision-making by vertically integrated and regulated utilities ('VIUs') owning both the generation and network assets (transmission, distribution and system operations) creating thus a monopoly system. Alongside economic development, CEE countries introduced ambitious structural reforms aimed at both unbundling[39] the power sector and liberalizing the energy markets, in an effort to transpose and implement EU

[37] Pahle M. et al. (2014), Reeg M. et al. (2014)
[38] Belarus, Russia, and Ukraine will not be included in the analysis.
[39] 'Unbundling' is a structural reform referring to the organizational separation of the core power system operations: generation, transmission, distribution and retail (Organising Power Systems, IRENA 2022)

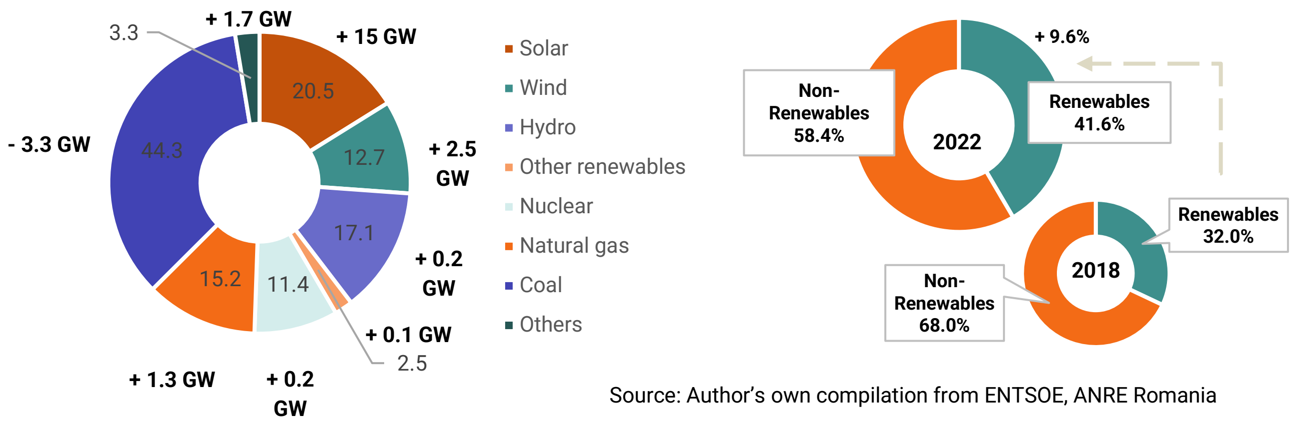
legislation. The horizontal unbundling has been enacted mainly to increase the competition in generation and retail, further spurring efficiency and reducing the overall costs to final users [4].

The installed power capacity in Eastern Europe tends to be largely dominated by fossil fuel (coal and natural gas), solar and hydropower (Fig 5). Nonetheless, over the course of the last five years, CEE countries strived to tap into their renewable resources (solar, wind, hydro and others), increasing the installed renewable capacity by roughly 16.0% (almost 18 GW), out of which 15 GW being solar capacity only. The exponential growth in solar capacity occurred mainly from Poland (+12 GW) and Hungary (+2.2 GW). On the other hand, the coal capacity has decreased by roughly 3.3 GW owing to coal capacity decrease in
Poland (-2 GW), Czech and Slovakia (-1.3 GW, -0.3 GW, respectively) given their focus on lowering carbon intensity by decommissioning coal-fired power plants.

The share of individual energy sources per country is slightly different due to distinct economic, climate, hydrological and geological conditions but also due to energy imports. It is important to mention that for some of the CEE countries the Russian political influence continues to be strongly felt in the energy sector, especially for the Republic of Moldova whose electricity and natural gas supply is highly dependent on imports from Transnistria region, Ukraine and Russia [32].

The electricity generation in Eastern Europe relied heavily on fossil fuels and nuclear power (76%) during January 2022 - 2023 (Fig 5.1), while the most significant renewable resources was wind (7.3%) coming mainly from Poland, followed by hydropower (7.0%), coming primarily from Romania. According to IEA statistics, the combined share of wind and solar power generation reached 12% of electricity generated during the period, excluding Moldova for which no monthly electricity statistics were available. The coal share was roughly 45% in the electricity production coming primarily from Poland which is historically dependent on cheap domestic coal for power [71].

Fig 5. Total installed power capacity (GW) by technology in Eastern Europe, 2022

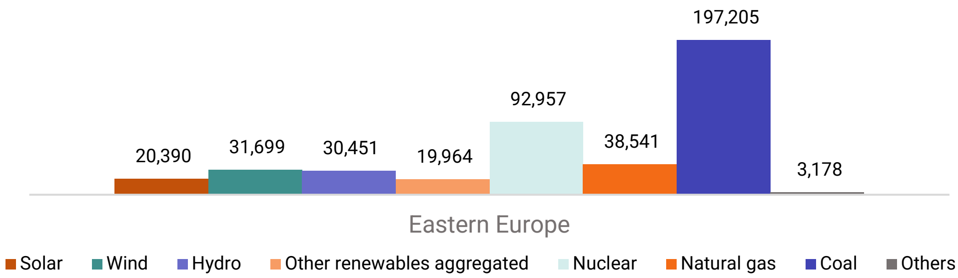


Source: Author's own compilation from ENTSOE, ANRE Romania

Electricity produced by nuclear power was also significant, standing at approximately 21.4%, the largest share being the Czechia (over 32,000 GWh). In Slovakia, nuclear energy accounted for more than half of electricity generation during the 2022 - 2023 (Fig 5.2), whilst in Hungary, it accounted for roughly 44.5%. A big part of the regional existing nuclear fleet dates back from 1970s and 1980s and is currently due to retire in the coming period. Large investments are planned for the lifetime extension, maintenance and modernization of existing nuclear

Fig 5.1 Electricity production by source (GWh) in Eastern Europe, Jan 2022 - Jan 2023

*The chart excludes Republic of Moldova

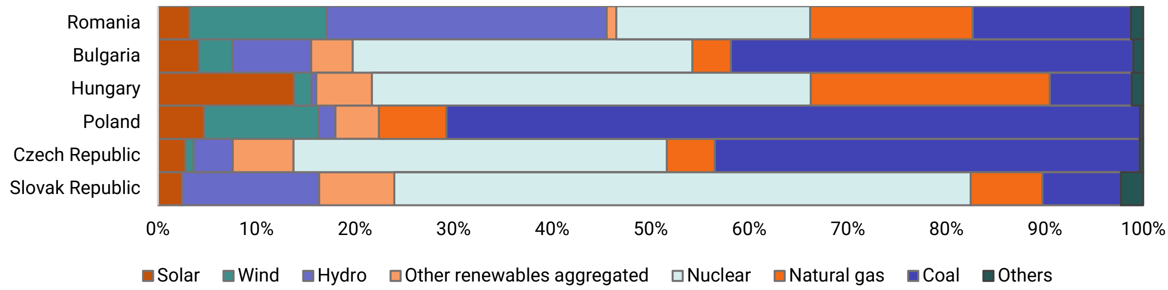


Source: International Energy Agency ('IEA'), Monthly electricity

reactors in the following period, especially in Slovakia, Hungary, Romania, Bulgaria and the Czechia [71], but also for construction of new nuclear capacity (the building of the first nuclear reactor is planned in Poland by 2033 and of six reactors by 2043 [33]). Therefore, it is expected for nuclear to play an important role in the regional energy transition towards low-carbon energy sources.

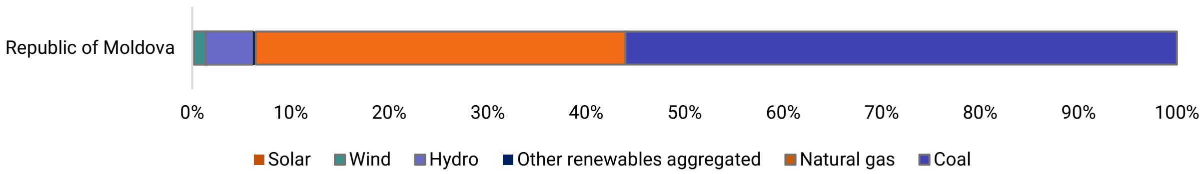
Romania, Bulgaria and Czechia have already met their 2020 RES targets for the final energy consumption (24%, 16% and 13%, respectively) [56] since 2014, whereas the other countries reached theirs later (Hungary – 13% in 2019, Poland – 15% in 2020, Slovakia – 14% in 2019, Moldova – 17% in 2020). This shows that all the CEE countries registered a positive trajectory regarding their commitments under the Europe 2020 Strategy. Owing to the large hydropower installed capacity, Romania has recorded the largest share of electricity production from renewables in 2021 (Fig. 6), reaching 44.1% (above the EU average of 37.2%). It was followed by Slovakia with 22.4% and Bulgaria with 20.6%.

Fig 5.2 Electricity production by source (GWh) in Eastern Europe, Jan 2022 - Jan 2023



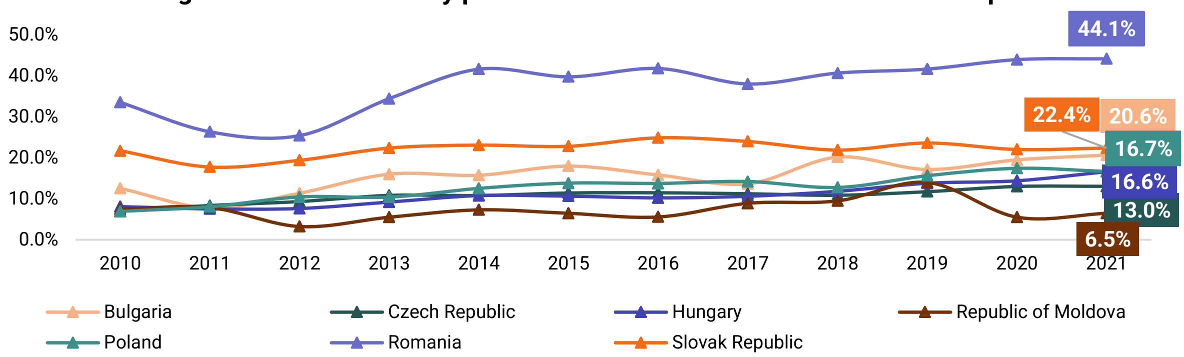
Source: International Energy Agency ('IEA'), Monthly electricity statistics

Fig 5.3 Electricity production by source (GWh) in Republic of Moldova, 2021



Source: Our World in Data, Moldova - Energy Country Profile

Fig 6. Share of electricity production from renewables in Eastern Europe

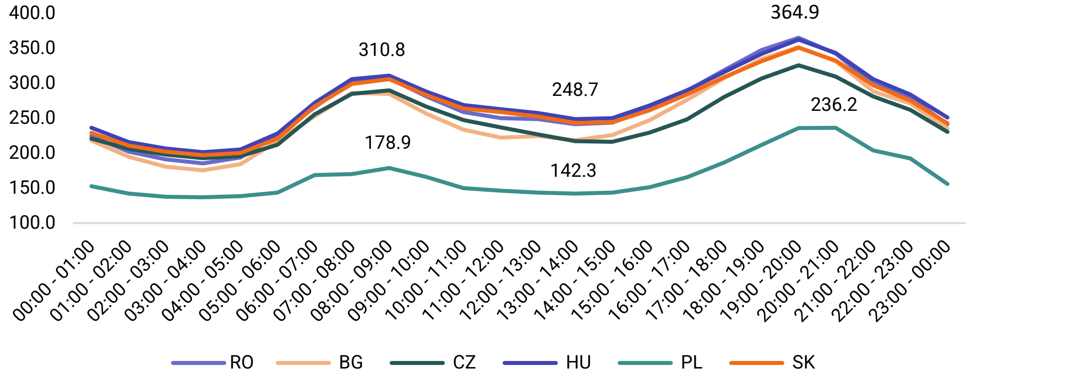


Source: Our World in Data, Moldova - Energy Country Profile

Investments in renewables are expected to increase due to ambitious RE targets for the post-2020 period, competitive auctions for utility-scale projects and continuous reduction of development and construction costs for RE projects [34]. The region is expected to benefit from the transition towards a zero-carbon economy, even though it lags behind Western Europe. The late adaptation advantage [71] provides manifold opportunities for the renewable energy sector expansion by virtue of downward trend of capacity costs deployment and innovative cost-effective technologies. Compared to conventional generation, the learning curve of renewable technology (especially solar and storage) keeps improving, thus costs keep decreasing. Geographic and climate conditions in Romania, Bulgaria and Hungary offer a great investment opportunity in solar energy due to high solar irradiation, whereas in Poland and Czechia is a high potential for wind power investments. Similarly, mountainous areas in Romania and Bulgaria also provide significant wind potential which is currently unexploited. In terms of geothermal energy potential, Hungary is considered an excellent location for investment. The first geothermal heat and power plant was connected to the grid at the end of 2017.

The average DAM price (Fig 7) registered a similar hourly trend in all countries with strong fluctuations during 2022, reflecting a peak in the early morning at around 9:00 a.m. and another peak later in the evening at around 20:00 p.m. The highest morning average peak was recorded in Hungary at 310.8 EUR/MWh, followed by Romania and Slovakia with 307.1 and 305.6 EUR/MWh, whereas the highest evening peak was recorded in Romania at 364.9 EUR/MWh. Poland experienced the lowest electricity price in 2022, as electricity generation in Poland is based primarily on coal-fired power plants so the price was less affected by the sharp rise in gas prices. Even though coal prices increased in 2022, the increase in prices was substantially lower than in other European countries. Fig 8 from Annexes exhibits the demand (load) curve for each country for one year (8,760h) in a descending order, reflecting the largest and smallest hourly demand in GW per country.

Fig 7. Average hourly DAM price (EUR/MWh) in Eastern Europe during 2022, excluding Moldova



Source: Author's own compilation from ENTSOE

Fig 8. Wholesale and Retail Markets in Eastern Europe

Country	Wholesale market	Retail market	Power market operator	Energy regulator
Bulgaria	○ Part of Bulgaria's energy market is still un-liberalized [35]. ○ In 2018 some of the most important regulations were implemented, such as the abolition of the 'single buyer' role (the Bulgarian National Electricity Company) and the inclusion of producers of 4 MW and over on the free market.[40] ○ In 2019, the free market was opened to small power producers (between 1 and 4 MW) replacing their electricity sale under Feed-in Tariff prices with Feed-in Premium Agreements (FPA). ○ The final steps for the full liberalization of the wholesale market should have begun in 2022, according to NRR[41] specified goals.	○ As of July 2021, all non-household electricity consumers were obliged to switch to the free market. The business consumers are now supplied by traders at freely negotiated prices. ○ According to NRRP, it is planned that the whole retail sector will transition to the free market in two successive stages in 2023 and 2025, covering a significant share of the household market.	**Independent Bulgarian Energy Exchange IBEX**	**Energy and Waste Regulatory Commission**
Czechia	○ The market is fully liberalized. The short-term (spot) market is organized by the market operator while long-term positions are traded on the European Energy Exchange. Bilateral over-the-counter agreements play an important role [30].	○ Since January 2006, the market is liberalized allowing end-consumers to freely choose their electricity provider based on current market conditions.	**Electricity and Gas Market Operator (OTE)**	**Energy Regulatory Office (ERU)**
Hungary	○ The wholesale market is divided between sales to the universal service providers and sales to other traders, who resell it on the wholesale market or supply it directly to the clients. ○ The Hungarian market is liberalized, however, the wholesale sector is still considered to be a 'concentrated market' due to the state-owned MVM which is a dominant player in electricity generation, wholesale supply and in the retail market. The Hungarian Power Exchange operates the HUPX DAM (day-ahead market) as well as the HUPX IDM (intra-day market) markets. The HUDEX (Hungarian Derivative Energy Exchange) was founded in 2017 by HUPX and operates the derivatives exchange for electricity [31].	○ Hungary maintains regulated retail prices under the so-called Universal Service Scheme for households and small businesses. Through the Universal Service Scheme, qualifying customers are provided electricity prices regulated by the government. ○ Residential consumers and consumers with a connection capacity of no more than 3 x 63 A for their low-voltage consumption sites are entitled to purchase electricity as a universal service. Any consumer can choose anytime to leave the Universal Service Scheme and enter into a market-based contract. ○ The majority of non-household consumers purchase electricity on the open market at unregulated prices.	**Hungarian Power Exchange (HUPX)**	**Hungarian Energy and Public Utility Regulatory Authority (MEKH)**
Poland	○ Polish electricity market is mostly liberalized. There is legal separation between commercial activities and network operations.	○ Consumers are free to choose their supplier, or to purchase electricity from a default	**Electricity Market Operator (TGE)**	**Energy Regulatory Office (ERO)**

[40] Bulgaria: International Trade Administration, Energy sector 2022
[41] Bulgaria's National Recovery and Resilience Plan: Annex 2022

	○ The wholesale market manages day-ahead and intraday electricity trading between interconnected European bidding zones, Poland being a single bidding zone [33].	supplier with prices regulated by the ERO. ○ Most household consumers purchase electricity through contracts with regulated prices. Prices for commercial consumers are not regulated.		
Republic of Moldova	○ The market is mostly based on bilateral contracts between transport and distribution companies and between generators and power suppliers. Currently, there is lack of wholesale competition, and most electricity is procured from MGRES[42] power station situated in Transnistria or imported from Ukraine [32]. ○ Market rules entered into force in June 2022 providing the basis for an electricity spot market. After the supply termination from Ukraine and Transnistria region, Energocom[43] started procuring electricity on the Romanian DAM. The REMIT regulation on wholesale energy market has not been issued yet. ○ The development of spot markets is intended to allow market coupling with the Romanian and Ukrainian Day-Ahead and Intra-Day market.	○ Since January 2015, final consumers became eligible to purchase electricity from any producer, or supplier, including from abroad. They still have access to regulated service supply until 2026. ○ Moldova has been progressively opening the retail market until the third quarter of 2021 [17].	Transelectrica, the Romanian TSO, plans the expansion of OPCOM in the Republic of Moldova, thus agreeing the next steps for OPCOM to become the electricity market operator in Moldova.[44]	**National Agency for Energy Regulation (ANRE)**
Romania	○ The market is fully liberalized, and prices are the result of free competition. Electricity is traded between generators and suppliers on the wholesale markets operated by OPCOM, and in a centralized, public, transparent, and non-discriminatory manner. The most used platforms on OPCOM are the Day Ahead Market and the Intra Day Market.	○ The electricity market has been fully liberalized starting January 2021, giving people the opportunity to choose their supplier based on the competitiveness of their offer. ○ Electricity price deregulation was finalized for industrial consumers in January 2014, while for household consumers the process was finalized in January 2018, however, the electricity price for households was further capped until 31 December 2020.	**Romanian Electricity and Gas Market Operator (OPCOM)**	**Romanian Energy Regulatory Authority (ANRE)**
Slovakia	○ Wholesale electricity markets are open for competition. ○ Electricity is mostly traded under bilateral contracts linked to the Prague Power Exchange and the European Energy Exchange, which are regarded as the sources for the most transparent price signals in the region. A small share of annual generation is traded on the Slovak day-ahead market.	○ Wholesale electricity markets are open for competition. However, retail prices are regulated for all households and small enterprises.	**Electricity Market Operator (OKTE a.s.)**	**Regulatory Office for Network Industries (URSO)**

[42] Moldavskaya GRES is the only participant from the Transnistrian region that has applied for and obtained a licence for electricity production from ANRE (Moldelectrica 2021a)
[43] JSC Energocom was designated as a Central Electricity Supplier during the validity period of its licence for the supply of electricity.
[44] Energynomics, January 2023

The main obstacles to the development of renewable energy in the region are of a political, financial, technical and social nature. One of the major characteristics of energy systems in the countries of the region is the inherited centralization established from the communist era [61]. Therefore, a few established energy suppliers and utilities still tend to dominate the market, due to their close ties to the government, strong entry barriers and lack of competition. Decentralized renewable energy could change the paradigm and diminish the centralization of fossil fuel and nuclear energy resources. Other obstacles are related to legislative matters, namely changing public policies and regulations along with complex procedures for the implementation of RE projects. On the financial side, RE technologies have a different cost structure compared to fossil fuels and nuclear energy, being capital intensive, but having near-zero marginal costs. The limited funding opportunities and low capacity of local banks to facilitate the financing of RE projects, especially in the case of small-scale projects, impede development. These barriers translate into high investment risks and a high cost of capital, which, together with limited access to finance, minimize investment attractiveness. The technical barriers refer to key elements of the region’s energy infrastructure which are outdated and need to be replaced in the next decade. The urgent need for replacing the aging infrastructure along with the high import dependency is expected to trigger the investment in RE generation [41].

Furthermore, a crucial obstacle will involve incorporating a progressively larger portion of RES in the future. This challenge goes beyond merely addressing infrastructure concerns; it also requires considering market design. Ensuring successful integration involves not only fully transposing and implementing the existing EU legislation on the internal electricity market but also adapting market mechanisms to accommodate a system where near-zero marginal cost generation capacities dominate. This is where the above-mentioned flexibility solutions come into play. By incorporating flexibility solutions into the electricity market design, the CEE region can efficiently integrate renewable energy sources, enhance grid stability, reduce carbon emissions, and ensure a more sustainable energy future. It also creates opportunities for innovative technologies and market participants to contribute to the region's energy transition while ensuring reliable electricity supply for consumers.

4.2 Flexibility sources under way

During the transition, most Eastern European countries plan to rely on nuclear power generation rather than on gas-fired generation to meet the major electricity demand. For instance, the Bulgarian electricity market is currently in transition, but nuclear power is expected to remain dominant. The government is slowly decreasing its coal power capacity to gradually replace it with renewable power capacity or to convert coal plants to run on natural gas or hydrogen. In Czechia no additional gas-fired plants are planned as the Czech government has placed a priority on nuclear power. Gas-fired generation will continue to be only of limited significance; however, the Coal Commission considers natural gas generation as the principal replacement for coal (IEA, 2022). Similarly, in Hungary gas-fired generation is not expected to be a key enabling source for the integration of VREs and the national plan does not include any objective to increase gas generation beyond 2030, focusing more on nuclear development. Matra[45] lignite-fired plant is scheduled to be converted to a 500 MW gas-fired plant including renewable installation by 2025. Additionally, the Hungarian government mentioned that any new gas-fired plant needs to be hydrogen-ready or capture-ready. On the other hand, Poland expects a notable expansion of gas-fired generation to back up the increase of VREs in the next decade. Poland has plans to build roughly up to 6 GW of new gas-fired capacity by 2030 to compensate for the reduction in coal-fired generation and switch some coal power plants to gas fuel too [33]. Romania also plans to replace coal capacities with fossil gas and highly efficient cogeneration gas power plants as a transition solution. The economic decline of coal plants in Romania likely played a significant role in establishing the 2030 phase-out objective. The carbon price within the EU ETS system[46] has imposed a substantial financial burden on CE Oltenia, the primary lignite power producer in Romania. In 2020, the company faced challenges in covering the costs of its emissions allowances, leading to the provision of a rescue loan by the Romanian government. As a condition for this loan, the EU mandated that CE Oltenia develop a plan to transition away from lignite generation. In Moldova most domestic electricity is already generated in natural gas-fired power plants and the government plans an additional small capacity installation of 55 MW in CCGTs.

[45] The only remaining coal power plant in Hungary, according to IEA 2022 [31].
[46] EU Emissions Trading System (EU ETS) is a cap-and-trade scheme set up by European Union in 2005, with the aim of reducing greenhouse gas (GHG) emissions, that lays the foundation of the world's first major carbon market. A cap is basically set on the total amount of GHGs emitted and the cap is reduced over time so that emissions fall. The limit imposed on total available allowances ensures that the (carbon) price increases over time. Within the cap, operators trade allowances on the market and their price signal stimulates emissions decline and investment in innovative, low-carbon technologies.

The need for a capacity mechanism in Eastern Europe could potentially arise due to several factors, including the retirement of conventional capacity (coal power plants), increasing system load, insufficient new investments, the rapid penetration of RES generation, as well as issues with the operation of short-term markets such as high price volatility and a missing money problem for conventional units. Poland is the sole Eastern European country that established a capacity market back in February 2018. The Polish authorities have highlighted that the Polish electricity market is likely to face significant temporary retirements and gradual withdrawal of existing inefficient generating units until 2020, rendering the electricity market incapable of meeting peak system load. In 2015, Poland already experienced electricity shortages that resulted in restricted electricity supply to numerous industrial end-consumers. However, it was unlikely that the market would resolve these concerns on its own as it suffered from the missing money problem. The European Commission (EC) acknowledged the Polish concerns and approved the capacity market as a form of public aid that is compatible with the single market.

It is likely that the evolution of flexibility resources and requirements will vary significantly throughout Eastern Europe, considering factors such as geography, local characteristics, and policies. Notably, as mentioned above, some Eastern European nations envisage nuclear power generation as a non-renewable yet carbon-free energy source and plan to rely on nuclear energy during the energy transition, which will partially diminish the need for long duration flexibility. Nuclear power is becoming more and more flexible and adaptable to the changing demand for electricity. Traditionally, nuclear power plants have operated at a constant rate, providing a steady supply of electricity to the grid. However, with the integration of more renewable energy sources, whose output can vary due to weather conditions, nuclear power plants modify their operating procedures, using advanced control systems, and implement new technologies such as small modular reactors (SMRs) that can ramp up or down quickly in response to fluctuating demand. The deployment of SMRs is already occurring in Romania and Poland. These advancements can help nuclear energy play a more significant role in balancing the grid and providing reliable power during times of peak demand, gradually reducing the need for capacity payments to fossil flexible plants such as CCGTs and OCGTs and limiting the risk of stranded assets at the same time.

Eastern European countries have already started to envisage demand side solutions for RE integration. Poland and Romania intend to significantly increase the market participation of prosumers and integrate more distributed renewable generation. Romania adopted substantial legislative reforms to simplify the procedure for setting up solar PV panels for self-consumption, allowing the electricity output to be consumed in other locations than PV panels point of installation. As of 2022 40,000 financing applications were approved denoting the large interest from the Romanian citizens. The 2023 budget provided for prosumers will increase to roughly EUR 600m expected to finance up to 150,000 projects.[47] Additionally, Enel X is expected to receive the first aggregator license in order to implement the demand-response system on the Romanian market.[48] In Poland the increase of solar PV capacity came mainly from prosumers (5.9 GW in 2021), being supported by the popular My Electricity program and favorable net metering conditions. The Polish government is also planning to include in the program funding for distributed storage and it is currently developing a digital system that facilitates efficient and transparent exchange of digital information (data from smart meters) expected to be operational in 2024 [33]. Poland plans to have 1 million prosumers (mainly PV) by 2030 and set a target for 80% of consumers to have a smart meter by 2028 (compared to 15% in 2020).

In Hungary 26 aggregators (total capacity of 820 MW) were registered in 2021 and demand response fundamentals along with market procurement rules for flexibility services have been enabled since January 2021. The Hungarian government aims at adding 100 MW of DER capacity and installing 1 million smart meters by 2030 with half of them being installed by the distribution system operators (DSOs). Surprisingly, the market for distributed solar PV in Bulgaria has been starting to grow despite the lack of a clear policy and regulatory framework. Most distributed solar PV projects built in Bulgaria were being configured for self-consumption, being used strictly to reduce the customer's electricity bill [12]. Early 2023 the government announced a simplified procedure for PV installations, however, there are no smart meters and aggregators on the market but proper regulation for their implementation is currently discussed [60]. Moldova has net metering rules in place stimulating households to cover their own electricity consumption from RES generation units having up to 200 kW. In 2019 Moldova registered roughly 127 end consumers who benefited from the scheme and approx. 40 MW of distributed generation in 2020 [32]. The Czechia currently lacks a legal framework for demand response mechanisms which is expected to hamper the accommodation of increased shares of VRE. In 2019, the government announced that deployment of smart meters would start mid-2024 until 2028, however, remuneration charges for development of small solar PVs is unattractive and no net-metering system is

[47] Minister of Environment, Energynomics
[48] economica.net, 2023

implemented [30]. Similarly, Slovakia has not yet developed demand response measures due to stalled growth in solar power since 2014 when the government eliminated the feed-in tariff (FiT) support for renewables [29]. Numerous changes are expected to be adopted at the region level to increase the market participation of prosumers and to integrate better DERs, such as transitioning from net metering[49] to net billing, introducing smart meters and smart grid services and establishing the legal framework for dynamic pricing and aggregators. Improvements in DSM and an effective load response to price signals can unlock demand-side flexibility, as will be discussed further.

Eastern European countries are expected to focus also on storage solutions for flexibility. Poland has already a small storage capacity that consists mainly of pumped hydro (approx. 1.8 GW in 2022) used by the transmission system operator (TSO) for system balancing. The deployment of batteries is limited (15 MW in 2021), but Poland intends to develop local industrial capacity for battery manufacturing (Northvolt announced substantial investments to build a large battery module factory[50]). The government set a target for 1.0 GW of storage (excluding pumped storage) by 2040 to allow balancing local power system [33], out of which 0.8 MW will be built by PGE[51] by 2030 (Tsanova, 2020). Pilot projects testing hydrogen storage are also planned in salt caverns. Hungary also proposed to increase energy storage capacity to at least 1 GW by 2026, however, the existing legislative framework is inadequate. Given that Hungary increased considerably its solar capacity and it is expected to do so in the future, it is important that scale of investments in solar power generation to be matched by an equal scale of investments in storage to avoid the potential large curtailment and to smooth the 'duck curve'[52] of solar production. In 2021 a 21 MW battery storage capacity was operated by four large-scale plants, with the first two being used by the TSO for primary and secondary reserves [31]. An important hydrogen production and storage project, the Aquamarine project, aims at constructing a 2.5 MW electrolyzing capacity to produce hydrogen with excess electricity produced from VRE. Hydrogen is envisaged to be stored and used to produce electricity for the network when needed. In Romania, the first technical regulation for power storage was enacted in January 2023 expected to encourage investors to develop large-scale storage projects as the legal conditions are there. The policy makers in the region have noticed that electricity storage is a highly relevant element of an electricity market with an increasing

[49] Under net metering, consumers are charged for the net electricity consumption from the grid after deducting the electricity injected. In this case prosumers are basically compensated at the retail price for the injected electricity. Net billing is a more mature scheme that compensated the excess RE injected at the wholesale electricity market price at the real time of injected.
[50] Northvolt.com: https://northvolt.com/articles/systems-poland/
[51] PGE is a state-controlled energy company that owns the largest share of generation assets. The company owns also the largest share of Poland's coal capacity and has expressed interest to convert closed coal plants into thermal energy storage facilities, rather than gas-fired capacity.
[52] The duck curve is a power production graph that presents the time mismatch between solar PV generation and peak demand over the course of a day (especially around midday and in the evening/night).

share of intermittent generation. However, the evidence suggests that relying solely on storage without interconnectivity is more costly than benefiting only from cross-border electricity opportunities and regional market dispatch for balancing supply and demand.

Electricity transfer opportunities in Eastern Europe will certainly depend on the countries' demand profile and structure of generation mix, but also on the transmission network infrastructure. The synergistic potential is enormous in terms of complementarity between countries: for instance, if the wind does not blow in Moldova, the sun might be shining in Romania. The possibility of importing electricity from the sunniest countries in this case reduces the need of local flexibility or balancing reserves required in the importing countries. As of March 2022, Moldova was able to connect to ENTSO-E[53] in emergency synchronous mode through Ukraine and full synchronization is under development. Furthermore, Moldova is currently strengthening network interconnections with Romania through a back-to-back converter and a 400 kV line [32]. Romania's transmission system is already well-connected with Bulgaria, Hungary and future additional network investments are planned to accommodate higher RES integration and cross-border electricity trade, reduce network losses and meet expected significant growth in peak load. Correspondingly, Bulgaria plans to increase the capacity for electricity interconnectivity primarily with Romania and Greece. Hungary has invested significantly in regional interconnections (55% interconnectivity in 2021) as three new 400 kW lines were commissioned with Slovakia in 2021 and further reinforcement connections are planned with Slovenia and Romania [31]. The transmission grid of Czechia is also well interconnected with 17 cross-border electric interconnections, directly connected with Slovakia, Germany, Poland and Austria [30]. Slovakia's cross-border capacity is developed as well, also reflecting the country's location significance as an energy transit hub in the Central Eastern European region for power that flows from the south of Czechia and Poland directly to Hungary and Ukraine [29]. The market coupling has been successfully completed in the region creating a joint wholesale market area for Czechia, Hungary, Romania and Slovakia [46]. Given that many EU member states did not reach the 2020 EU interconnectivity target of 10%, especially Poland which achieved only 4%, updated EU regulations as of January 2020 require all TSOs to make available to market participants a minimum of 70% of cross-border capacity for cross-zonal trading by the end of 2025.[54]

[53] European Network of Transmission System Operators for Electricity
[54] art.16 of Internal Market for Electricity Regulation

4.3 Reform of the electricity market design

The literature presents a series of electricity market designs for a renewables-based power system in Europe. The underlying proposals are not directed towards Eastern Europe but are rather generalist approaches suited for different technologies.

Fig 9. Overview of market design existing proposals

Paper	Proposal name	Description
RE-organising power systems for the transition, IRENA, 2022 [46]	**Dual Procurement** Mechanism	The dual procurement proposal addresses the different characteristics of renewable electricity generators and flexible resources by splitting the procurement of renewable electricity and flexibility into two complementary procurement mechanisms: ○ **Long-term renewable energy (LT-RE) ->** aims to provide a stable framework based on periodic, long-term, product-based allocation mechanisms such as **support mechanisms (FiT, FiP, PPA) and direct public investment.** ○ **Short-term flexibility (ST-Flex) ->** aims to **match supply and demand** in the short and very short-term dimension of wholesale and retail markets and of centralized dispatch.
The Decarbonised Electricity System of the Future: The Two Market' Approach, The Oxford Institute for Energy Studies, 2017 [78]	**Two Market** Approach: As Available and On Demand	The authors advocate for a two-market solution by creating separate markets for different sorts of power ('on demand' and 'as available') at both producer and consumer ends: ○ **On demand** -> For producers, dispatchable plants would operate in the 'on demand' or flexible market, be dispatched according to merit order when needed and paid on broadly the same basis as at present. ○ **As Available** ->Intermittent plants would participate in the 'as available' market; in principle, they would operate as available and, at least initially, be paid a price reflecting the levelized cost of electricity from the particular source in question (with the price normally set via auctions at the investment stage). The differing costs and operation of 'as available' and 'on demand' sources would also be reflected in the retail market. Consumers would have the option to choose either 'on demand' or 'as available' electricity, which may normally require separate meter readings, or a combination of both sources.
Electricity Markets in Transition. A proposal for reforming European electricity markets, Natalia Fabra, 2022 [22]	**Diversity of Contracts** Approach for diverse asset technologies	Natalia envisages the combination of short-run energy markets (preserving the short-run signals) with long-term contracts (providing a fair rate of return in the long term). ○ **Short-term market** -> Spot pay-as-clear for All plants ○ **Auctions for long-term contracts** > **CfDs** for Intermittent Renewables > **Reliability contracts** for CCGTs and Peakers > **Capacity payments** for Demand Response and Storage

		○ **Regulated long-term contracts** -> **Flexibility contracts**[55] for Dispatchable RES (hydropower plants, biomass and solar thermal) and nuclear power.
Re-powering Markets: Market design and regulation during the transition to low-carbon power systems, IEA, 2016 [37]	Introduction of **Carbon Pricing** in energy-only markets	Under long-term IEA assumptions, introducing a robust carbon price is crucial to attract investments in low-carbon power generation and effectively address climate externalities. In theory, adding a carbon price on top of market prices in a scenario with a high carbon price and a diversified generation mix consisting of renewables, nuclear, carbon capture and storage, gas power plants, as well as demand response and storage, revenues generated from electricity markets can contribute significantly to covering the fixed costs associated with low-carbon power sources. Under other scenarios, it is not feasible to rely solely on energy-only markets with a carbon price to facilitate the transition towards decarbonized power systems. However, even under the assumption of complete certainty regarding the carbon price level (which is unlikely in a cap-and-trade system unless accompanied by a price cap and floor), the carbon price would need to be sufficiently high to offset the uncertainties associated with electricity prices influenced by fossil fuel commodity prices. Thus, it is important for governments to acknowledge that this process may require a significant amount of time and can amplify perceived market risks for potential investors. In certain scenarios, by 2050, an energy market driven by energy prices, coupled with a carbon price, could serve as a catalyst for transitioning towards a low-carbon power system. This could be achievable if there is continued progress in demand response and a decline in storage costs, or if carbon and gas prices exert enough influence on wholesale prices to enable the recovery of investment costs for low-carbon technologies, while also providing adequate returns.

The proposal formulated by Natalia Fabra (2022) underlying a diverse array of contracts for different technologies and time horizons could be implemented in the region, relying on both short-term market functioning and long-term contracts between the regulator and the generators. It is clear that energy market revenues alone are insufficient to attract the level of low-carbon investment required, especially given the electricity price and investment recovery uncertainty, jeopardizing all the energy sources in the end, not just the renewable ones. Therefore, long-term arrangements backed by governments are still necessary to attract sufficient investment in low-carbon power generation in Eastern Europe. Given that low-carbon investments are capital-intensive and have a cost structure that is not well-suited to short-term marginal cost pricing, long-term visibility and support is needed to mitigate risks for investors and keep financing costs low. Nevertheless, it is important that support mechanisms do not significantly disrupt the operation of wholesale markets, but rather enable RES to respond to price signals and encourage their involvement in the wholesale markets, particularly in the balancing markets. In a separate paper, ENTSO-E has examined various

[55] The author refers to flexibility contracts as CfDs with a sliding premium: in addition to paying output at a fixed price, generators receive/charge a bonus/penalty for producing when prices are above/below the annual market average. These contracts are suitable for assets that have the flexibility to choose when to dispatch (hydro, biomass, thermal solar) or when to go under maintenance (nuclear). The author states that the short-run prices provide a valuable signal to stimulate optimal operations decisions for these technologies, where the de-risking objective is partially sacrificed for market price exposure.

types of support schemes and concluded that feed-in premiums, quota systems, and investment subsidies are more effective at interacting with wholesale markets than feed-in tariffs. In particular, auctions that determine a feed-in premium for a fixed amount of energy (which is essentially support for capacity) are deemed highly effective. Auctions can also introduce competitive forces to determine the level of support needed, in addition to market revenues. Carbon pricing can be a game changer, but it is definitely far away from being implemented within the wholesale market structures of Eastern European countries, due to considerable time needed, it may encounter resistance or remain a subject of political debate. These factors pose potential risks for prospective investors.

To achieve an efficient market design, a consistent market framework is required, including a balanced approach of market price exposure and support for low-carbon investments. The market incentives created by government support-based instruments differ based on the scheme implemented and on precise design elements, such as degree of market dependence, variable and non-variable payments, price corridors applied or settlement period. Both the type of remuneration and market incentives provided by support schemes have a significant contribution to the level of VRE market integration and market efficiency overall. In Eastern Europe, governments implemented a mix of support mechanisms to promote renewable energy sources and attract investments, summarized in Fig. 11 from Annexes. Given that Eastern Europe has a less mature renewable energy market, government intervention is necessary during the transition, to promote long-term arrangements that provide visibility and mitigate risks for investors, keeping financing costs low. A careful analysis of the market context in each specific country will be needed to determine the appropriate set of instruments to optimize low-carbon deployment. Some of the implementation challenges include the determination of fixed/premium support payment levels and deployment quantities, technology-neutral vs. technology-specific instruments and the determination of the modulation formula (if the case) that allocates risks. However, the general principles of exposing investors to some but not all market risk, of harmonizing support at the regional level and of setting subsidies through competitive mechanisms such as auctions, should prove applicable across Eastern Europe. In this way, distortion of energy wholesale markets is kept to a minimum.

This paper proposes the following policy measures that can be implemented by national governments to improve the electricity market design in the region:

- Introduce products with finer time granularity (e.g., 15 minutes Imbalance Settlement Periods and Market Time Unit) to stimulate new resource access to the market (e.g., storage) by better capturing the value of their flexibility. However, this process requires time and incurs costs, particularly for cross-border exchanges. Future evolutions towards even finer time granularity products (e.g., 5 minutes) must be carefully assessed in terms of cost-benefit in the region.
- Introduce smaller minimum bid size products (e.g., max 500 KW) in coupled day-ahead (DAM) and intraday (ID) markets to facilitate market access also for smaller and distributed energy resources (DER). For balancing markets, the minimum bid size for standard balancing products (e.g., automatic and manual frequency restoration reserves) is already set at 1 MW.)
- Establish more frequent intraday auctions to incentivize liquidity and market participation, to set a reference price for derivative products to hedge basic risk and also to enhance competitive and easier bidding strategies. As the proportion of RES in the electricity system grows, the significance of intraday and balancing markets will become more prominent. This is because day-ahead markets will be relatively less effective in capturing sudden changes in market conditions and outcomes that occur close real-time.
- Develop and enforce minimum technical requirements for grid-connected storage systems to enable their participation in the balancing markets, including ancillary services. As the proportion of renewable energy sources (RES) in the energy mix increases, it becomes more crucial for them to also provide system balancing services. However, a significant challenge is the integration of RES into balancing markets. While the participation of RES in balancing markets has been allowed in many countries, as stipulated by the Electricity Balancing Guideline and Electricity Regulation, their effective participation has yet to reach its full potential. To facilitate the access of emerging technologies and players like RES to balancing markets, these markets should be as "open" as technically feasible to all participants. Thus, explicit technical barriers to the participation of RES in short-term markets, such as specific pre-qualification criteria or disproportionate IT requirements, should be eliminated.
- Establish a regulatory framework that enables DERs to participate in the balancing market, either individually or aggregated. The rising integration of DERs presents balancing challenges for electricity systems. However, DERs also offer cost-effective solutions for system balancing. Removing market- and product design-related barriers for DERs and aggregators to enter balancing markets (e.g., product design, minimum

bid size, symmetrical products, auction lead time etc.) will further support this process. ACER and CEER[56] (2021) found that certain product specifications and features in balancing markets were initially designed for centralized production systems, thereby restricting the involvement of demand-side response, decentralized production, and energy storage solutions. They concluded that barriers are found to be more severe (or moderate) in Bulgaria, Croatia, Italy, Portugal, Romania and Sweden, including extended delivery periods, substantial minimum capacities in the prequalification process, lengthy validity periods for balancing energy bids, and large minimum bid sizes. Additionally, restrictions on aggregator participation and the obligation to offer symmetric balancing capacity were considered. Moreover, factors such as long procurement lead times and regulated or pay-as-bid pricing may further impede the participation of new entrants and smaller players.

Eastern European countries have been slow to adopt demand response programs, despite their potential benefits. The slow adoption can be attributed to a variety of factors, including lack of regulatory frameworks, limited advanced infrastructure, low customer awareness, lack of market competition and limited coordination among stakeholders, including utilities, regulators and customers. Demand side management could have an enormous positive impact in Eastern Europe as a short-duration flexibility solution.

This paper proposes the following policy measures that can be implemented by national governments to encourage the deployment of demand response mechanisms in the region:

- Develop clear regulatory frameworks that incentivize the deployment of demand response programs, such as offering subsidies or tax credits to utilities that implement demand response programs or creating a regulatory environment that rewards utilities for reducing peak demand. On the other hand, governments could add different market design elements, such as capacity mechanisms for demand response, where utilities are paid for ensuring a certain level of available capacity during peak periods. This would stimulate the deployment of demand response measures that help reduce peak demand and avoid capacity shortages. Demand response contracts can be structured as Interruptible Load Agreements, where customers agree to reduce their electricity consumption during periods of high demand in exchange for a payment.
- Set targets for the deployment of demand response programs, such as a percentage of peak demand that must be met through demand response. These targets can help

[56] Council of European Energy Regulators

create a sense of urgency and encourage utilities to invest in demand response technologies and programs.

- Support the deployment of advanced metering infrastructure (AMI), which enables real-time communication between utilities and customers. AMI allows for more accurate and timely measurement of energy consumption, making it easier to implement demand response programs.
- Encourage the integration of demand response programs with renewable energy sources, such as wind and solar. This can help utilities manage the variability of renewable energy sources and reduce the need for fossil fuel-based peaker plants. It can also provide an additional revenue stream for renewable energy producers by allowing them to participate in demand response programs.
- Launch public awareness campaigns to educate customers about the benefits of demand response programs. These campaigns could include information on how demand response programs work, their potential cost savings, and the positive impact on the environment.

In terms of flexibility needs, markets should provide a market-based mechanism for the provision of flexible capacity, including energy storage, demand response, and distributed generation. The design of flexibility markets could encourage investment in both short (demand response and storage) and long flexible resources (dispatchable hydro electrical power) that can support the integration of renewable energy sources into the electricity grid. Eastern Europe should focus preponderantly on short flexible resources, while preserving current flexible generation such as gas, hydro and biomass as long flexible resources. Further large-scale development of hydro units will be limited in most of Europe due to manifold techno-environmental barriers (lack of infrastructure, geological and water issues, biodiversity loss) and socio-economic ones (lack of skilled human resources and technology, institutional challenges, public opposition, high capital costs) [76].

Apart from demand response, this paper proposes the following policy measures that can be implemented by national governments to encourage the deployment of storage systems in the region:

- Develop clear and supportive regulatory frameworks that encourage the deployment of energy storage systems and provide a level playing field for all market participants. This could include the possibility of storage market operators benefiting from a wide range of revenue streams such as provision of firm capacity, arbitrage trading, congestion management, voltage control, stability/inertia, or reliability/restoration.

- Ensure market stability and create clear signals for investment in energy storage systems through long-term contracts and remuneration mechanisms. This can be achieved by setting up capacity markets to ensure adequate investment in storage infrastructure and ensure a reliable and secure energy supply. Before that, it is crucial to adequately estimate the firm capacity a storage unit can provide. A suggestion for policymakers and regulators is to revise or create Capacity Remuneration Mechanisms (CRMs) accordingly to allow for storage participation in an adequate manner, because the competitiveness of storage technologies is significantly affected by the regulations established for their participation in relation to conventional power plants. For instance, in Ireland and the United Kingdom, governments determined derating factors for storage technologies based on adequacy metrics, such as the storage volume that each unit can provide[57]. By applying derating factors, the goal is to base the compensation on the capacity credit of storage units, which means that they are paid only for the amount of firm capacity they can provide rather than their nominal capacity. This approach, as suggested by Usera et al. (2017) [77], could aid electricity storage in competing in CRMs rather than being treated on par with conventional resources. Special considerations should be attributed to procuring flexible resources through capacity contracts signed years ahead of delivery as it can lead to the risk of either over or under procuring the required capacity, which may result in increased costs for consumers.
- Currently, capacity mechanisms predominantly benefit fossil fuels. However, electricity storage technologies, such as home batteries or consumer demand response, have the potential to replace them as flexible backup solutions. In order to gradually transition away from fossil fuels, it is crucial to facilitate consumers' access to capacity mechanisms that promote flexible consumption. These mechanisms could impose a minimum allocation of 50% of the contracted capacity from energy storage and/or demand response options.
- Instead of CRMs, governments could provide financial incentives, such as subsidies, grants or tax credits, to support the installation and operation of energy storage systems.

[57] National Grid (2017); Single Electricity Market Committee, (2016, 2018)

- Explore innovative financing models such as public-private partnerships, green bonds, and crowdfunding to reduce upfront costs and make energy storage systems more accessible.
- Introduce net metering and net billing policies to encourage the deployment of small-scale energy storage solutions for households and businesses.
- Implement time-of-use tariffs, which go hand in hand with demand response policy measures, reflecting the real-time cost of electricity and stimulate the use of storage systems to shift consumption to off-peak periods.
- Promote the use of hybrid renewable energy systems, such as wind and solar with storage, to ensure a stable and reliable electricity supply.
- Coordinated approach between TSOs and DSOs for the successful implementation of short-term flexibility products. DSOs often have more knowledge of the local grid and its constraints than TSOs, whereas flexibility products storage require a fast response time, which is important for the effective implementation of demand response and storage solutions.
- Encourage research and development in energy storage technologies to reduce costs and improve performance and provide funding for innovation and commercialization.

5. Conclusion

The market and system implications of a renewable-based power system are increasingly noticeable in Central and Eastern Europe. Nevertheless, the region still encounters major challenges of different facets including political, financial, technical, and social barriers that hinder the development of renewable energy at a large scale. CEE Member States should firstly address the bottlenecks present at national levels and afterwards revise the electricity market design under a coordinated approach in order to be in line with the EU legislative proposal.

A wide range of flexible solutions are emerging in CEE, intended to solve the intermittency and volatility issue both at market and power system level. To bolster the overall system flexibility, updated regulatory frameworks are essential to incentivize demand-side flexibility and storage implementation. Apart from flexibility, discussions regarding the market structure for a low-carbon electricity system often offer two opposing strategies: a heavy dependence on wholesale electricity markets with a significant carbon price (energy-only markets), or technology-specific policies and regulations (capacity or support schemes markets). However, shortcomings have been observed in both approaches. It is now evident that a simple binary categorization is no longer adequate for outlining the market's structure.

Some alternative pricing mechanisms, such as capacity markets or government support schemes, may offer greater stability and predictability for renewable energy producers, while others, such as carbon pricing, may provide a more comprehensive approach to addressing the environmental and social costs of electricity production. Maintaining the current framework focused on day-ahead and intraday markets while introducing some design changes will continue attract investments and provide crucial feedback and valuable information to low-carbon generators about the value of different low-carbon technologies.

Nonetheless, retail markets should be reformed to enable efficient price signals to consumers. This could include time-of-use pricing, dynamic pricing, and other mechanisms that incentivize consumers to shift their energy use to times of day when electricity is cheaper and more abundant. Additionally, consumers can segregate their share of flexible consumption from their less flexible consumption by installing specialized digital metering devices. This allows them to potentially combine fixed-price contracts for their non-flexible consumption with dynamic price contracts for their flexible appliances, thereby mitigating their exposure to high prices while profiting from demand response incentives. This is in line with the recent EC proposal for the EU electricity market reform, aiming at better protecting consumers from future price spikes and potential market manipulation.

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7. Appendix

Fig 10. Overview of RES support schemes in Eastern Europe

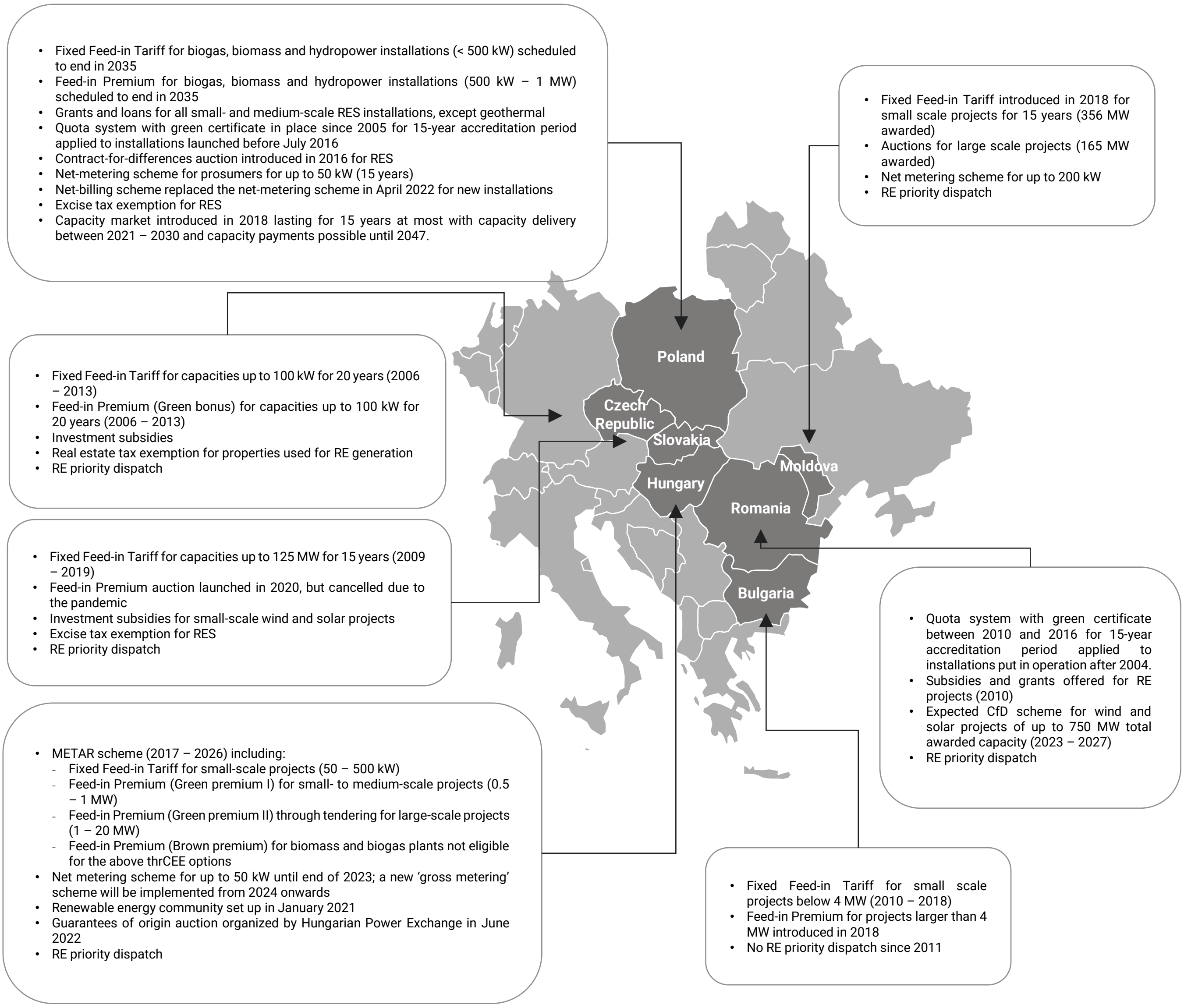
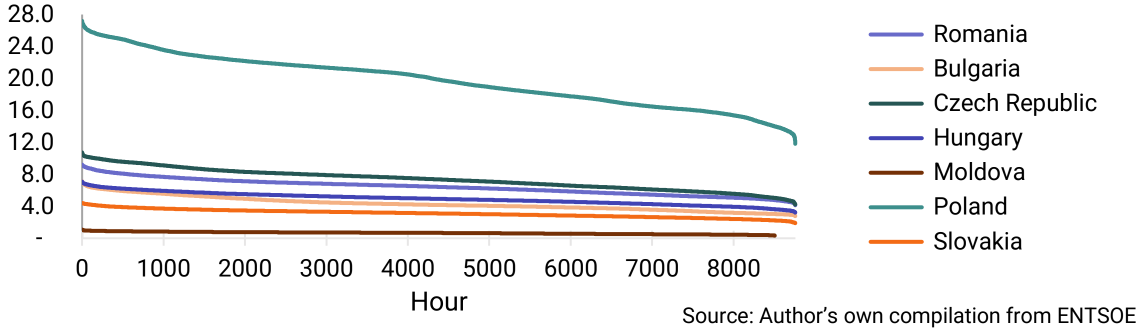


Fig 11. Load duration curve in Eastern Europe in 2022 (GW)



Source: Author's own compilation from ENTSOE