Achievements and Challenges in European Energy Markets

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***Abstract*—The European electricity and gas markets have been deregulated more than two decades before. From rather diverse starting points, they have continuously evolved over the years to accommodate with new challenges and to improve integration. Since 2005, these markets have been complemented by the market for emission certificates established by the European Union (EU) emission trading system. Three partly competing paradigms have thereby shaped the markets and continue to drive their on-going transformation: effective competition, subsidiarity and sustainability.**

***Index Terms*—Electricity marker, Europe, carbon pricing, market design, deregulation, decarbonization, sustainable energy system.**

I. Introduction

FOR most of their history, electricity systems in Europe have been run as integrated systems which were not subject to the general market rules. Yet following the development of new concepts in the economic theory of competition, notably the theory of contestable markets [1], deregulation and the introduction of competition took place in the European electricity and gas markets in the 1990's. This movement was pioneered by the United Kingdom (or more precisely England and Wales) and Norway from 1990 onwards and generalized through the first European Union (EU) electricity market directive in 1996 [2], followed by a similar directive for the gas markets two years later [3]. The underlying principles are discussed in more detail in [4], whereas a detailed discussion of the subsequent evolutions in different countries may be found in [5], [6].

In parallel, international efforts to limit global warming started to shape the European energy and environmental policy. Early milestones were the Earth Summit in Rio de Janeiro in 1992 [7], [8] and the first international climate agreement, the Kyoto Protocol in 1997 [9]. These have led to the introduction of the EU emission trading system (ETS) [10] as well as to multiple initiatives at national and European level to foster the use of renewable and other low-carbon energy sources. With the Paris Agreement of 2015 [11] and the subsequent pledges for climate neutrality [12], the sustainability of the electricity system has come even more to the forefront while the recent energy crisis has highlighted the necessity to also consider security-of-supply issues when designing energy markets.

In the remainder of this paper, the focus is on the electricity markets. First, the key elements of deregulated electricity markets in Europe are highlighted in Section II. Then the implications of decarbonization and other strategies for a more sustainable energy system are discussed in Section III. Section IV points at current challenges in the European electricity markets - analyzing them as coordination issues at various levels. Finally, Section V concludes this paper.

II. Striving for Efficient Markets

In order to understand current European electricity markets, it is essential to look at both the key ingredients of the original process of deregulation and the different market segments. Moreover, the organization of international markets is also a distinctive feature of the European approach to competition in electricity markets and deserves closer attention.

A. Deregulation

The deregulation of the British electricity industry has been part of a larger movement to reduce the role of the government in the economy. It included the privatization of the formerly state-owned electricity sector and the introduction of competition among generation companies [5]. The Norwegian (and soon more generally Scandinavian) deregulation approach did not focus on privatizations, yet as in the British and the later European approaches, a key ingredient was unbundling.

The essence of unbundling is the strict separation between those parts of the electricity (or gas) system, where competition is feasible, from those parts where so-called natural monopolies constitute unsurmountable barriers to competition. This is notably the case for the grid infrastructure. Such monopolistic bottlenecks are characterized by the combination of two factors: sub-additive costs and irreversible investments [4].

Sub-additive costs arise in the grid infrastructure since building two parallel grids to serve customers in one region is (almost) always more expensive than establishing just a single

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infrastructure.[①] And investments are obviously irreversible, as grids involve not only components like overhead lines, poles and transformers which could be reused in other circumstances but also a lot of construction work which implies "sunk" costs that are not recoverable, even if the aluminum of the power lines and the steel of the poles could be reused.

Contrarily to the grid business, the electricity generation business as well as the retail business is considered as apt to competition. In electricity generation, sub-additive costs exist due to the economies of scale inherent to large modern power plants. Yet, these economies are limited by the size of the single units, i.e., roughly around 1 GW for thermal power plants. This is much smaller than the size of typical national electricity markets so that competition among several generation companies (GenCos) is feasible in principle.[②] And in the retail business, irreversible investments are rather limited, enabling market entry of new players – even if incumbents may have some cost advantages related to the size of their customer portfolio and to their possibilities of limiting risk exposure through internal hedges with affiliated GenCos.

Correspondingly, the deregulation of European electricity and gas markets has focused on competition both on retail and on wholesale markets from the outset. On retail markets, retail companies – sometimes also called suppliers – propose contracts to final customers, both households and firms. This market segment thus enables customer choice and consumer sovereignty, reflecting also Adam Smith's saying "consumption is the sole end and purpose of all production" [13]. On wholesale markets, GenCos sell their produced electricity to intermediaries like the aforementioned suppliers or to (pure) trading companies. Subsequently, we focus on these wholesale markets, notably since the retail markets for electricity and gas are quite similar to retail markets for other goods such as mobile phone services or internet connections.

B. *Market Segments*

The relevant market segments within the wholesale market are summarized in Fig. 1 [4]. As with other commodities such as oil or coffee or orange juice, one may distinguish two major market segments within the wholesale market: the spot markets, where electricity and gas are traded for immediate delivery, and the derivative markets where so-called "derivatives" are traded. These notably include contracts for deliveries in some future period.

The term of "derivative" emphasizes that these are products which are derived from some basic product called "underlying". These underlyings are traded on the spot markets – a term designating in finance any market for immediate delivery. When competition was introduced in Europe, the trading was done one day ahead of delivery in order to enable the coordination of the trading activities with the actual grid operation. This coordination is done via schedules submitted by all market participants to their grid operators.

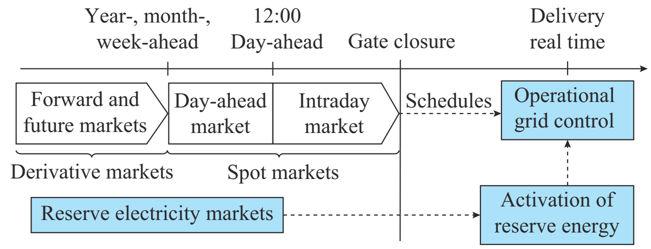

Fig. 1. Sequence of markets for a specific delivery time segment.

Still today, the so-called day-ahead market is the most important segment of the spot market. It is based on a single two-sided multi-unit auction typically held on noon of the previous day. Generators, retail companies and other market participants thereby submit bid curves as a series of quantity-price pairs, indicating at which price they are willing to sell or buy a certain quantity. The market operator collects all bid curves and uses them to determine the market clearing price at which supply matches demand. Under effective and well-functioning competition, the optimal bidding strategy for generation companies is thereby to submit bids based on marginal generation costs, cf. [4], [14].

Besides the day-ahead market, a second spot market segment has gained importance over the last decade, namely the intraday market for deliveries within the same day. This market notably allows to cope with changed forecasts for renewable infeed, but also with power plant outages or updated demand forecasts. This market operates like typical financial stock markets with an open order book where market participants can continuously place buy and sell orders which are immediately executed if there is a matching bid on the opposite market side.

As electricity is hardly storable, deliveries for different time periods have to be treated as different products to reflect changing demand and supply patterns over time. For example, electricity demand is typically higher during daytime than during the night and this will induce higher prices other things being equal. Also, fluctuations in renewable infeed, changes in fuel prices and power plant outages induce considerable price fluctuations. This implies considerable risks for both sellers and buyers on the wholesale markets.

To mitigate these risks, forward and future markets have emerged soon after the introduction of competition in the electricity markets. Still today, these are the most important derivative markets in the electricity and gas sectors. Their primary function is to enable market participants to hedge, i.e., limit, their risk exposure by concluding purchase and sale contracts at fixed prices months or years ahead of delivery. While so-called futures are traded anonymously at power or energy exchanges with central market clearing and strict regulatory oversight, forwards are traded bilaterally on trading platforms in so-called over-the-counter trading.

① Note that the sub-additivity of costs has sometimes been contested for parts of the large-scale transport or transmission infrastructure. Notably, a second gas transport network had been built up in Germany by a competitor before the deregulation of European gas markets. Also, several competitive interconnection projects have been proposed in the last years, e.g., to connect continental Europe and Scandinavia.

② In order to achieve effective competition, a sufficient number of competitors have to be established in the process of deregulation. These may arise from a disintegration of former national monopolies as in the British case, or from a sufficient number of former regional monopolists and municipal utilities as in Norway and Germany. New market entrants and cross-border trading are other drivers of competition albeit in many circumstances their effect may remain limited. In Europe, France may be cited as an example of limited competition, at least in the first decade after deregulation.

Thereby, the market participants bear the counterparty risk, i.e., the risk that their contractual partner is not capable of fulfilling the contractual obligations at the moment of delivery, e.g., due to bankruptcy. For the buyer of a forward, the risk is that his counterpart does not deliver the electricity; and for a seller of forward, the risk is that the buyer does not pay the traded quantities.

In terms of their financial volume, the futures and forward markets are much more important than the spot markets, in well-developed markets the trading volume on the derivative markets exceeds the volume on the spot market by a factor of five or more. For example, the leading European power exchange (EEX) reports a trading volume on European spot markets for electricity of 629 TWh in 2021, whereas the trades in derivatives (mostly future) reached 4568 TWh [15]. At the same time, the temporal granularity of products on the forward and future markets is much lower. Whether it is for monthly or yearly delivery periods, mostly products with constant deliveries over the entire period, so-called base contracts, are traded – at best, peak contracts covering deliveries during daytime from Monday to Friday may be available for trade. Correspondingly, the forward and future markets do not enable a perfect hedging of price risks for the individual spot market hours and a fortiori renewable power plants with fluctuating infeed will not be able to fully hedge their price and quantity risk adequately on the derivative markets.

The non-storability of electricity implies that the balance of demand and supply has to be kept not only at the (mostly hourly) timescale of the traded products, but also at much smaller time intervals of minutes, seconds and even milliseconds. This is part of the operational grid control performed by the grid operators also in deregulated electricity systems. Similar to integrated systems, they make use of so-called reserve power to ensure the balance of supply and demand in real time. In contrast to the "old" integrated world, the grid operators yet do not have direct control over the generation units. Therefore, reserve power markets have been established to enable the grid operators to contract in advance reserve power which may then be used in real time to cope with any imbalance caused by unforeseen events. The design of these markets has continuously evolved over the last two decades as it has to reflect both the needs of the grid operators as well as the technical constraints of the power plants.③ Correspondingly, regions with lots of flexible power plants, e.g., Scandinavia with its high share of hydropower, have had less elaborate reserve power markets than small market areas like Ireland with predominantly thermal generation of limited flexibility.

A further market segment that has been put into place in many deregulated electricity markets is so-called capacity market. According to standard economic theory, the combination of spot and derivative markets should provide appropriate signals not only for efficient operation but also for investments. Yet several arguments have been put forward why this is unlikely to happen [16], [17]. Among the arguments are the lack of demand elasticity and the limited possibilities to control the real-time deliveries to customers in electricity markets. But also the existence of price caps in many real-world markets and the important stochasticity of demand (and nowadays also supply) imply that many regulators in Europe and other parts of the world have introduced capacity mechanisms to ensure supply adequacy. In their simplest form, these are yearly auctions where bidders can offer firm capacity and receive a capacity payment as compensation. This will generally solve the so-called "missing-money problem" yet induce other problems: ① the sizing of demand in the capacity auction (taking also into account the possibilities for cross-border trading); ② the availability of capacities when they are actually needed; ③ the inclusion of demand-side flexibilities and storages – to name just a few. Therefore, the design of capacity market mechanisms has evolved over the years and further modifications are to be expected.

C. International Harmonization

The introduction of competitive electricity markets in Europe has not been a one-time system change. Rather, the initial introduction of competition at the end of the 1990's has been complemented by a series of later regulatory reforms which have aimed at strengthening competition within the member states as well as the European-wide integration of electricity and gas markets.

One recurring element of the regulatory reforms has been more precise and tightened unbundling requirements. Nowadays, five dimensions of unbundling are distinguished: accounting, operational, management, legal and ownership unbundling [4]. All, except the last one, are mandatory for grid operators, meaning that they are set up as separate legal entities with own management staff, independent operational processes, and separate accounts.④ Only a full ownership unbundling ensures that both transmission and distribution grid operators do not have any incentive to discriminate among different grid users – notably between affiliated and non-affiliated companies. Yet a forced dismantling of formerly integrated private (or municipal) companies implies a strong interference in private property rights – which has not been considered as opportune.

Another key element of the ongoing reforms in the European electricity markets has been the enabling of efficient cross-border trading. Since the grid interconnection capacities between different European countries (and partly also within single countries) are limited, the optimal use of these scarce resources has been in the focus. This notably requires a coordination between grid operators and spot market operators. From modest beginnings such as the tri-lateral market coupling of the day-ahead markets of France, Belgium and Netherlands, the system has gradually evolved and extended to today's single day-ahead coupling (SDAC) and single intraday coupling (SIDC) [18], [19]. Both now cover the entire EU (plus Norway) except the islands of Cyprus and Mal-

③ Note that the technical constraints to the flexible operation of power plants also have implications for bidding strategies on the spot markets and even the design of spot markets, cf. the debate on complex vs. simple bids ([4], pp. 347-349 and the literature cited therein).

④ Some exceptions may exist for small grid operators at the distribution grid level, e.g., so-called "deminimis" clauses in Germany.

ta. After the completion of the market coupling for the spot markets, the grid operators in the EU are now in the process of harmonizing their procurement and activation of reserve power. The corresponding platforms PICASSO for automatic frequency restoration reserve (aFRR) and MARI for manual frequency restoration reserve (mFRR) have gone live in 2022, and successively all member states are expected to connect to these platforms until 2024 [20].

As with previous steps of market coupling, the objective is to make efficient use of available resources and to lower thus the costs for satisfying the customer and system demand.

III. Striving for Sustainability – Decarbonization and Renewables

In parallel with the development of the internal market for electricity, the EU has also developed policies to achieve a more sustainable energy system, aiming notably to reduce substantially the emission of greenhouse gases (GHGs) which contribute to global warming. Thereby the EU and its member states have followed two parallel and partly overlapping routes, namely the introduction of the EU ETS, and various, mostly national renewable support mechanisms. Both also have strong repercussions on electricity markets.

A. EU ETS

According to economic theory, the establishment of tradeable emission certificates is one of two first-best instruments to cope with an environmental externality like climate change. The other first-best alternative would be a so-called Pigouvian tax, i.e., a tax on GHG emission corresponding to the (expected) marginal damage costs. Yet in the presence of uncertainties, following an argument first made by Weitzman [21], the use of tradeable certificates is preferable.

The EU has been a front-runner in the establishment of such a system since the EU ETS has started its operation in 2005. Over the years, prices have been rather volatile, and the system has undergone several reforms. Notably after an extended period of low prices, the EU has set more stringent emission targets in 2018 and again in 2021 and has moreover established the so-called market stabilization reserve (MSR) which effectively eliminates some of the excess certificates that remained in the system after the financial and economic crisis of 2008/2009.

This has led to a substantial increase in the CO_2 certificate prices (cf. Fig. 2) from below 10 €/t to around 80 €/t which has put gas-fired power plants before coal-fired power plants in the merit order (cf. [14]) before the recent gas crisis.

The EU ETS is to date by far the largest ETS worldwide in terms of trading volume, yet it is still incomplete in terms of sectoral coverage. Emission certificates are so far only mandatory for power plants and a few other carbon-intensive processes (e.g., in the iron and steel and the cement industry). Only after 2025, a broader ETS will be put into place that also covers emissions in the building and transport sector. Also in terms of geographical coverage, the EU ETS is incomplete – given that climate change is a global environmental problem, a true first-best instrument should have a global coverage.

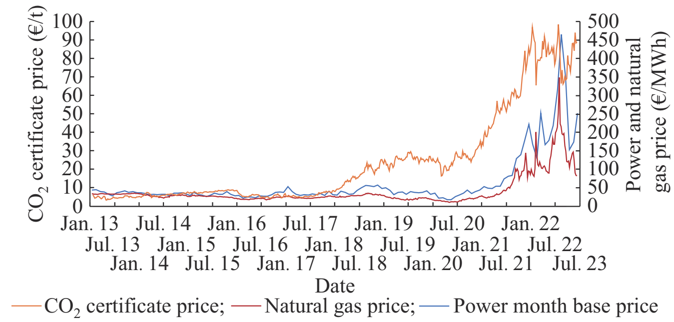

Fig. 2. Prices for EU ETS CO_2 certificates, natural gas (Dutch Title Transfer Facility (TTF) trading hub) and electricity (German market area) for 2012 to 2022.

Nonetheless, the EU ETS is expected to play a key role in the European strategy towards climate neutrality.

B. Renewable Support

Even before the EU ETS has been put in place, many EU countries started to promote renewable energies. In contrast to internal market issues, energy policy is not an exclusive domain of EU legislation, rather the EU member states retain the right to determine their energy mix – in line with the general principle of subsidiarity applied in the EU, which stipulates that decisions should be taken at the level closest to the citizens as far as possible. Consequently, the EU has not established any common support mechanisms for renewables so far. Rather, the individual EU countries, depending on their priorities in energy and climate policy as well as on budgetary considerations, have put into place a broad variety of support mechanisms for renewable energy. These included fixed feed-in tariffs, feed-in premia, renewable quota obligations, subsidies for installations as well as tendering auctions. Whereas fixed feed-in tariffs were the prevailing instrument at least until 2010, the focus has shifted towards tendering mechanisms during the last years [22] – except for small-scale installations like rooftop solar. Installed capacities have increased from 12 GW of wind and 0.2 GW of solar in 2000 to 187 GW of wind and 160 GW of solar by the end of 2021, respectively [23].

C. Impact of Environmental Policies on Electricity Markets

Over the first two decades of the 21st century, renewable capacity additions induced by support mechanisms have had a larger impact on the transformation of the European energy markets than the rather low carbon prices resulting from the EU ETS.

In principle, the CO_2 prices should penalize carbon intensive electricity production notably from coal. By imposing additional variable costs on the power plant operation, the coal-fired units should move to the right of the merit order, implying that less carbon-intensive generation units like gas-fired plants operate more frequently.

As the production from wind and solar power plants is not controllable, their impacts on the market equilibrium may be investigated based on the net load (also called residual load), which corresponds to the difference between load and the infeed from uncontrollable renewables (mainly solar and wind energy).

In the short run, when conventional generation capacities remain unchanged, the reduction in net load implies that prices in the electricity market decrease. This is the so-called merit-order effect of (uncontrollable) renewables.

Yet based on the equilibrium model introduced by [14] (cf. also [4], Chapter 7), it can be shown that the merit-order effect disappears in the longer run (cf. also [24]). When considering the ordered net load (duration curve, cf. [14]) in Fig. 3, the following impacts of increased renewable infeed can be identified: ① (small) reduction of the maximum net load; ② occurrence of hours with negative net load; ③ reduction of base load capacities (eventually to zero); ④ increase in peak load capacities (and hours with unserved load); ⑤ no changes in prices except for hours with negative residual load.

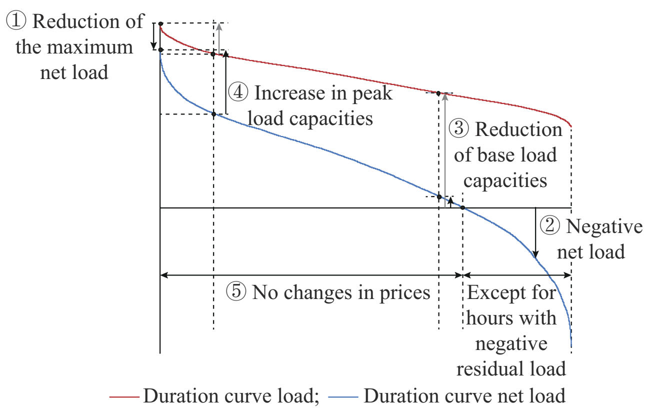

Fig. 3. Impact of renewables on duration curve of net load.

Note that in the long-term equilibrium, no negative prices occur in contrast to the actual prices on European spot markets for electricity. Two effects account for these observed negative prices: first, inflexibilities of conventional power plants which prevent them from immediately stopping operation when prices drop below variable costs. Second, the presence of feed-in premia for renewable infeed, which provides incentives for their continued operation even in the presence of negative prices.

D. Storage as Complement?

With increasing frequency of negative net loads, i.e., renewable surpluses, storage of electricity appears as an attractive complement. In order to be economically attractive in the spot market, storage has to recover its investment cost through price arbitrage, i.e., charging at low prices and discharging at high prices. Both higher CO_2 prices, which induce higher variable cost of fossil generation, and negative prices in case of renewable surplus increase the economic attractivity of storage solutions. Yet still the economics of storage in competitive electricity markets are challenging, notably since storage need repeated charging and discharging cycles to become economically profitable. Moreover, for wind energy, the fluctuations are rather irregular. Therefore, utility-scale storage investments are so far mostly driven by revenues from reserve power markets and sometimes capacity markets.

IV. COORDINATION

Both the quest for efficient conventional electricity systems and the quest for sustainable electricity systems require a good coordination of activities by different agents. Subsequently, I discuss the strengths and weaknesses of the current EU energy markets and related policies under that angle. Thereby, the focus is first on operational coordination and then on investment incentives. A particular emphasis is put on locational incentives as well as on the resilience of the markets to external shocks.

A. Operational Coordination

In a welfare-maximizing perspective, the objective of operational coordination should be to make optimal use of the existing scarce resources to satisfy demand. A central planner may in principle achieve such an optimal plan yet only under the condition that he has all relevant information available. At the same time, in such a system, there are no (direct monetary) incentives in place to incite decentral agents both to provide accurate information and to proactively search for possibilities for improvement of the current system. In market-based system with decentral operation management, the market participants obviously have an incentive to react to price incentives provided by the market. For such a decentral system to reach welfare-optimal outcomes, the following two conditions have to be fulfilled: ① no market participant has the potential to influence the prices substantially (absence of market power); ② the market price signals truly reflect the scarcities in the system. In order to mitigate potential abuse of market power, typically market monitoring units at the electricity regulator or the competition authorities are put in place. To avoid misleading price signals, it is necessary that markets reflect actual physical system operation constraints. This is notably not the case if market prices do not adequately reflect grid constraints.

B. Investment Incentives

Spot market prices (should) reflect actual scarcities. And current prices on the forward and future markets are reflective of anticipated scarcities in future periods. According to the principle of informational efficiency, the prices observed on the future markets today should reflect all information available today on future evolutions, e.g., future scarcities of generation capacities or emission certificates. But the past years have provided ample evidence that prices both on spot and on future markets are subject to strong fluctuations.

Consequently, it is fair to say that the electricity markets by themselves are well suited to provide appropriate investment signals. Yet undertaking irreversible investments into physical assets is a risky decision under these conditions and investors may either ask for some guarantees to limit market risks or they will search for high returns in compensation for the risks they take.

In such a setting, governments or supranational bodies such as the EU may take two directions to improve the incentivizing effects of market signals: ① take time-consistent decisions; ② implement mechanisms to de-risk investments in clean energy technologies. Taking time-consistent decisions notably requires that the CO_2 pricing mechanism as well as other market design features in the energy markets is not subject to sudden changes. Rather, they should be designed from the outset in a way that is consistent with long term objectives. The time consistency of decisions concerning climate change mitigation may notably be improved by putting into place an independent public institution with a clear mandate to limit carbon emissions – analogously to the central banks in Europe or the US, which in principle act independently from policy makers with the objective to ensure price stability. Such an institution has been given various names, e.g. carbon central bank or independent carbon board [25], [26]. This is one way to establish a mechanism providing forward guidance on carbon prices – which in turn is an important step forward to de-risking low carbon investments.

Still, electricity price risks are likely to persist even if carbon prices are stabilized. Therefore, further mechanisms may be envisaged to secure investments in renewable and storage similar to the tenders for renewable capacities put into place today. Yet these instruments interfere much more with the electricity market operation and they are sensitive with respect to misspecifications, e. g., of the auction quantities or the contracting rules. Notably, incentives to continue production at negative prices should be avoided – one straight-forward way could be to provide support payments for a pre-specified number of operation hours instead of fixing a maximum of years for the support payments.

C. Locational Incentives

A challenge so far only partly addressed in European electricity systems is the provision of locational signals. Yet with increasing shares of distributed renewable energy sources, the location of these sources and their system-adequate operation are getting increasingly important. Notably, constraints in the power grid may prevent the full use of renewable feed-ins at remote locations. These are not reflected in zonal market designs as commonly in place in Europe.

This has two major implications: ① system operation necessitates an additional redispatch step to be carried out after the market clearing to ensure that the physical grid constraints are met; ② for investment decisions, the spatially uniform prices incentivize locational choices that maximize the energy yield instead of contributing to a long-term system cost minimum.

The alternative would be so-called locational marginal pricing as it has been in place in North American deregulated markets for years. This provides clearer locational incentives for both operation and investments. On the other hand, it yet induces additional locational price risks and reduces the liquidity of derivative markets, respectively, i.e., their aptitude to hedge revenue fluctuations. Moreover, private investors in a system with locational marginal prices are subject to some additional political risks as grid development is a regulated business (cf. Section II).

D. Shocks and Resilience

The past years have seen various shocks of diverse origins that strongly affected the European electricity and gas markets. These shocks notably include the tightening of the emission budgets within the EU ETS, which led to an increase in CO_2 prices from about 5 €/t in 2017 to around 80 €/t in 2022. On the other side, the Corona pandemics has led to a decline in electricity demand by up to 10% in 2020 and the beginning of 2021. And last but not least, Russia's conflict with Ukraine has catapulted wholesale market prices for gas to more than 10 times their pre-crisis levels and also wholesale electricity market prices peaked at more than 400 €/MWh for monthly average spot prices, compared to about 50 €/MWh before the outbreak of the crisis (cf. Fig. 3).

These shocks have put the markets under strong pressure and price reactions were enormous. But at the same time, there have been no interruptions of deliveries so far and the markets have been able to adjust supplies (and partly also demands) to match with the new situation.

Certainly, the established market models tend to induce high extra profits ("wind-fall profits") for producers in periods of scarcity. At the same time, the high prices provide incentives for market entry and also incentivize consumers to reduce their consumption. It is an ethical and political judgement whether governments should intervene to relieve the burden of those strongly affected by increasing bills and whether they put some taxation on the excess profits to finance the compensation measures. Yet a change in the market design to dampen price shocks is considered as problematic by most economists, as it comes along with distortions in operational and investment incentives.

So in their current form, the market mechanisms in place have proven to be resilient to a wide range of shocks – but obviously, additional efforts are needed to maintain this resiliency in the future. At the same time, the challenges raised by the necessity to limit global warming have not yet been fully resolved. The mix of different policy instruments and market mechanisms has enabled substantial progress on the path towards decarbonization, yet it has certainly not been welfare-optimal in a social planner perspective. Given the necessity to coordinate actions also across a broad range of political preferences between and within member states, the mix of instruments and approaches has yet proven to be quite resilient against extreme political shifts.

V. Conclusion

The paper at hand has discussed the evolution of European energy markets over the last decades with a focus on electricity. Thereby, the interplay of the double ambition of achieving efficient markets and simultaneously moving towards climate neutrality has been highlighted. These combined challenges along with the supranational approach to cope with them have led to an evolutionary process. Without doubt, the European markets for electricity have been implemented successfully and their cross-border integration is also widely completed. They have also resisted successfully to a number of shocks over the past years.

At the same time, policy instruments for decarbonization have been implemented and gradually tightened. Still, the future progress towards a fully decarbonized electricity system will require further steps. Notably, striking the balance between the provision of sound investment incentives and the avoidance of excessive market risk is a key challenge for both market design and political guidance. Thereby, the coordination of investments and operations at a spatially disaggregated level will require particular attention, especially since this also includes an interplay between regulated grid operators and other, rather market-driven agents.

Obviously, an increase in inflexible renewable generation will come along with a stronger volatility in spot market prices. But at the same time, these prices provide signals for investments and operations of storages. And in turn, storages will contribute to dampen the volatility of prices as can be already observed today in the Scandinavian markets. The large capacities of hydro reservoirs in these countries lead to a much lower short-term spot price volatility. Consequently, it is certainly too early to state that the current electricity market design is inapt to address the challenges of a future sustainable electricity system – although further evolutionary steps are certainly to be taken.

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