# Future-proof electricity prices for consumers



*European electricity systems are undergoing unprecedented changes in response to the profound transformation of our modes of production from fossil fuels to decarbonised energy, to our shift to electricity for heating and transport, the emergence of decentralised energy sources (e.g. solar PV on the rooftop), and to the gas crisis we face. In response, the price formation and signals sent by both the electricity markets and the networks are changing, too. This article summarizes how the energy transition and the latest developments in the energy market affect prices and what policies and regulations can be introduced to keep energy consumption affordable.*

## 1. Introduction

For a long time, experts have alerted about the limits of the price signals sent by wholesale electricity markets to drive the transition to clean energy technologies. Others have warned about the risk of the explosion of electricity bills for the fair transition. More recently, in the midst of a major geopolitical crisis with our first natural gas supplier, Ursula von der Leyen, President of the European Commission, pointed to the limits of the electricity market as responsible for the surge in electricity prices and announced "a structural reform".

Rising electricity prices, as we could observe in Denmark and the whole of Europe, are first and foremost the result of a mismatch between short-term operations and long-term financial risk of investments in a rapidly changing energy landscape. At the end of the chain, the increasing cost of the transition effectively borne by society further complicates the equation for successfully moving away from carbon-based energies, without leaving anyone behind.

It is becoming urgent to untangle the causes and modalities of the market and regulation pitfalls that are causing the surge in electricity prices in Europe. In the following, we analyze the principal price components driving electricity system costs up focusing on wholesale electricity market rules and distribution grids transformation to portray the main trends, challenges, emerging solutions, and risks facing European consumers. Ultimately, we suggest possible solutions for redesign, in line with the fair and decarbonized transition we ambition.

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## 2. State of play

Consumer electricity prices are composed of market-based, unregulated prices such as the wholesale price part, and regulated elements, such as the network tariffs. In the following, we will shed light on what is the status quo of the regulation of these different elements.

### 2.1. Unregulated market prices, but designed markets

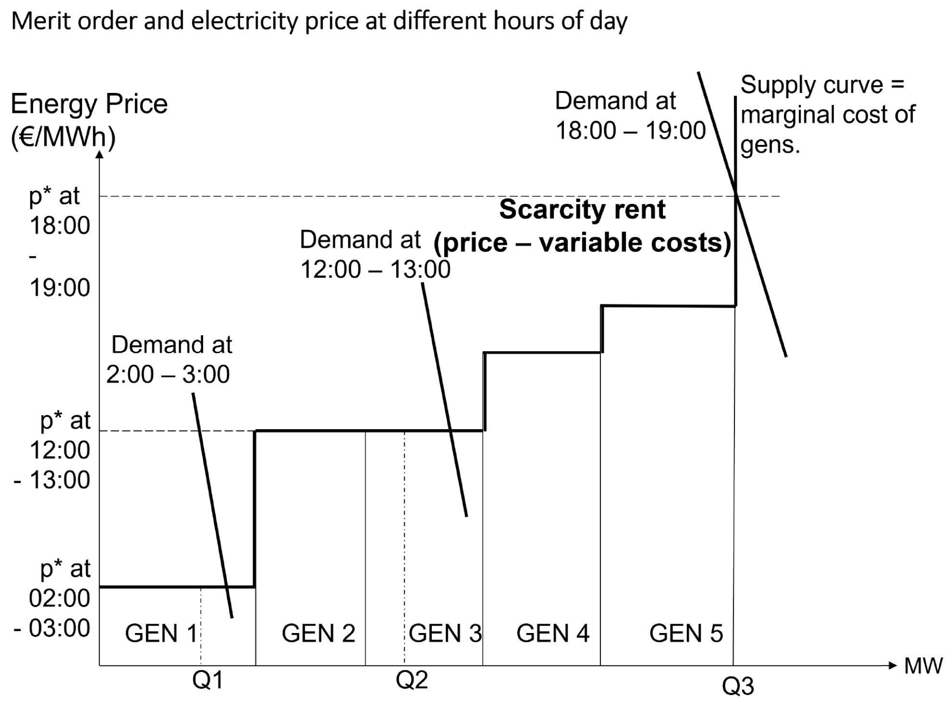
***Merit-order curve and price settlement***

Electricity prices are mainly set by price bids on liberalised wholesale markets equal to the short-run marginal costs (SRMCs) of the production technologies in the system. Thereby, all electricity production units, in the following named ”generators (GEN)” are sorted by their SRMCs forming the so-called merit order curve, which is equal to the supply curve of the electricity market. Prices are then set at the intersection between a given demand curve and the merit order curve. As the demand for electricity varies throughout the day, there is another demand curve available for each traded hour. For instance, demand is low in night hours and in the sketch in Figure 1, GEN1 sets the demand, while in peak demand times the more expensive generators at the end of the merit order curve set the price equal to their SRMCs. While the SRMCs of renewable power plants are close to zero, the SRMCs of thermal generators are mainly driven by fuel prices and prices for $CO_2$ emission allowances. This is why high prices for fuels, such as natural gas, lead to high marginal costs and therefore to peaking electricity prices up to extreme shocks, as we can currently observe in European electricity markets.

In hours when demand is higher than all the capacities in the system can supply, the demand curve will have its intersection with the supply curve at a higher point than the SRMC of the most-expensive generator (see demand curve at the right upper corner, 18:00-19:00, in Figure 1). In this case, the generators at the end of the merit order curve can earn so-called scarcity rents, which are needed to cover their fixed costs and capital expenses.

As the demand for electricity is quite inelastic and the demand curve is almost vertical, these scarcity situations can produce extreme price peaks (i.e. when the above-described intersection of both curves happens at a very high price level), European market regulators have introduced technical price caps (i.e. 3000 €/MWh in the day-ahead market) to protect consumers from being completely exposed to extreme shocks.

*Figure 1: Price formation (stylized) at different hours depending on the specific demand. The sketch includes 5 generators, producing the equilibrium quantity "Q" for three exemplary hours. p* denotes the equilibrium price*




***Electricity market design***

European electricity markets are divided into two parts: short-term spot markets and long-term forward contract markets. Long-term forward markets enable electricity trading months or even years in advance, allowing available power plant capacity to be supplied to energy retailers or major consumers via long-term contracts and their use to be planned months or even years in advance. Forward markets can provide guaranteed long-term earnings, allowing investment in new generation capacity to be refinanced. (Lawrence, Ausubel, Cramton, 2010).

Spot markets, on the other hand, are important for short-term decisions on power plant dispatch. The primary and most liquid spot market in European electricity systems is the so-called day-ahead market, which trades energy for hours or blocks of hours the next day via single-price auctions. The prices settled on day-ahead market are crucial for the decisions about the operation of power plants. These decisions can be updated via trading on the further short-term market, the intraday market. Intraday trading ceases 30 minutes before delivery for inter-zonal transactions in the coupled European market (EPEX SPOT 2018). If there are imbalances between supply and demand that occur within the last 30 minutes and during the real-time operation, the network operators, also called transmission system operators TSOs, handle these imbalances by utilizing capacity reserved on the so-called ancillary services or reserve power market. Auctions for reserve power are held the day before delivery, and some of the market's production capacities or demand response capacity are contracted as reserve power if they meet certain conditions. These reserve capacities are then activated if there is an imbalance during real-time operation, and the costs for their reservation are covered through the regulated grid tariff.

### 2.2. Regulated price components: the electricity grid tariff

Electricity grids physically connect generators to consumers. We commonly distinguish transmission from distribution grids due to their different voltage levels and architecture. High-voltage lines connect large power plants and transport bulk power over long distances. Distribution grids connect individual consumers to the transmission network and operate at lower voltage levels.

Since the E.U. liberalisation reforms in the mid-'90s', the network activities are legally separated from the generation activities, and retail activities are separated from the transmission and distribution network activities. The result of this separation is that the recovery of production costs and the recovery of network costs are separated. In other words, consumers receive two bills: one for the energy they consume and one for accessing the grid.

Network industries are considered common goods, essential for the functioning of society, and are natural monopolies that, by definition, meet conditions of increasing returns to scale and are regulated. Grid tariffs have historically focused on distributing the total network costs according to the size of the consumers (e.g. household vs. industry). The network costs depend on three factors: capacity, energy, and consumer-related cost. The capacity factor implies that certain physical assets in the grid are sized to meet peak demand. Letting the load approach the maximum available capacity results in a situation of peak (or congestion). The energy cost factor reflects the cost incurred to the network that is a direct function of the energy that flows through such as the energy losses and ancillary services. Customer-related costs are specific to individuals (households, industries etc.), meaning that they can be directly tracked, e.g. meter or billing costs.

The ideas of tracking and of congestion are fundamental to rate-making. First, the physical characteristics of electricity make it impossible to know exactly who generated the electron that will light our light bulb, nor which lines it would have followed in a meshed grid. Second, physical congestions translate in economic terms into higher incremental costs signalling that capacity reinforcement investment is needed. In a competitive market, the price of a good is set according to the marginal utility it provides. In a natural monopoly, this marginalist approach is impossible to apply in normal circumstances because of the cost structure of the infrastructure.

However, it becomes increasingly possible to link network costs to those who cause it in times of congestion and therefore to design a cost-reflective tariff signal mitigating peaky effects in demand.

## 3. Ongoing transformations impacting energy bills

This section details how the ongoing energy systems transformation effects, such as the merit-order effect (3.1.) and gas shortage (3.2.) as well as grid pricing (3.3.), the different price components of the final electricity bill, especially wholesale electricity price and network tariff part.

### 3.1. Energy transition and merit-order effect

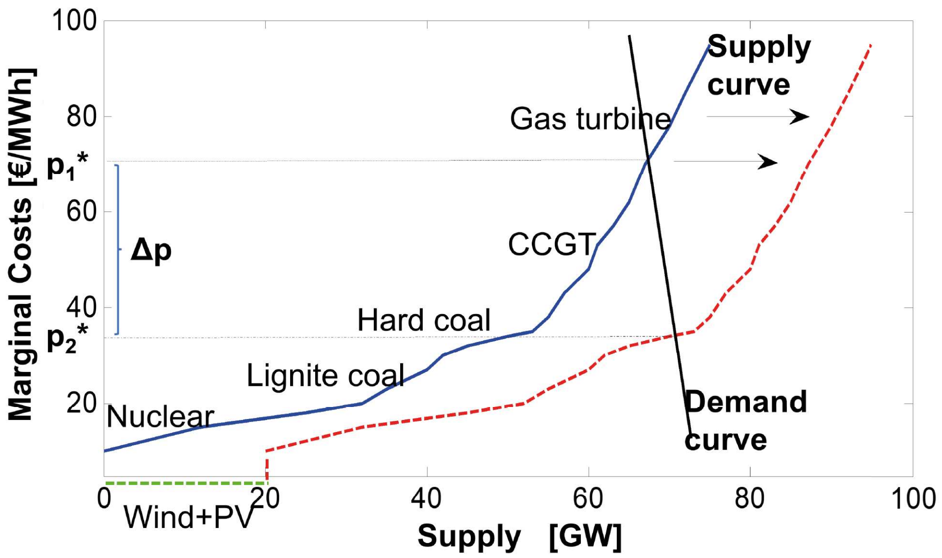
The major transition in the energy market, which we have been especially in the last ten years, is the transition from thermal power plants to renewable energies (RES). During the early 2000s, some scarcity conditions occurred at some hours of the year, when there was little renewable capacity on the European electricity market, resulting in high peak prices. During the remaining hours, electricity wholesale prices were primarily determined by fossil-fuelled power prices, with marginal costs averaging around 50 €/MWh (see section 2.1.). This has changed dramatically with the growth of renewable energies such as wind and solar power. When inflexible production capacities (e.g. nuclear and coal power plants) cannot be shut off during surplus electricity circumstances and so-called must-run capacities must remain online to fulfil other services, prices began to fall to around 0 €/MWh, if not negative values (Nicolosi, 2010).

These situations are most common when there is a low demand in the system and a high availability of wind and solar power. The price drop caused by renewable energies is known as the merit order effect, and it is caused by a shift in the supply curve to the right (i.e. the merit order curve, see Figure 2) when wind and solar power feed low marginal cost electricity into the system and related low price bids are sent to the market clearing. Wind and solar power technologies are at the very beginning of the supply curve due to their low marginal costs. The magnitude of the right shift they induce is determined by the amount of renewables available in a given area.

Although we observe for almost 10 years a decline in wholesale electricity prices in many European countries including Denmark due to rapidly expanding renewable energy shares, the energy crisis we are facing since 2021 shows that we are still very vulnerable to peaking fuel prices. This is mainly due to the intermittent nature of solar and wind power as their production can drop to almost zero in times without wind and solar energy. In these times, expensive gas power plants need to be turned on and the price shock in gas markets is fully translated into electricity prices.

Overall, the increased price volatility (low price when renewables are sufficiently producing and high price when gas turbines need to be turned on) has significantly increased price risk on the market, so that investments in new generation became rare in the European markets, fuelling the discussion (see section 4) on how to change the market design.

*Figure 2: Merit-order effect of RES in an exemplary electricity market with thermal power plants. The figure illustrates the right shift of the traditional supply curve (blue) without renewables in case renewables become available (red curve). The main outcome of this shift is that the equilibrium price falls from p1* to p2* because of the new intersection between the demand curve and the red curve. This price drop is called merit-order effect.*




### 3.2. Impact of gas shortage/supply crisis on electricity prices

Gas prices only began to rise extremely from the summer of 2021. Although their growth accelerated after the war in Ukraine, the price of gas on the relevant European gas trading hubs had already tripled by October 2021. The main reason for this was the recovery of the world economy post-COVID-19, which boosted global gas demand, while on the other hand investment in upstream gas production had remained constant. The onset of the war exacerbated shortages in global gas markets, as supplies from Russia to its main importing region, Central Western Europe (CWE), initially fell to a small percentage of pre-war levels and then ceased completely after the attack on the Nord Stream pipelines. This sudden drop in supplies led to historic shortages in gas markets and a jump in prices to above 300 €/MWh (15 times pre-crisis levels) that ultimately affected European electricity prices.

This, combined with power plant shutdown for maintenance (almost half of France's nuclear capacity was out of service due to long maintenance delays) capacity in the CWE electricity market led to price spikes of several hundred Euros/MWh occurred in Europe. The huge increase in prices on wholesale markets resulted in skyrocketing energy bills of consumers leading to the severe political discussion on how to protect citizens in the EU from these turbulences. The EU Commission as well as different Member States proposed or introduced gas price caps at different levels to combat high energy bills. On the one side, the EU Commission proposed a "dynamic price limit" on the central wholesale market hub for gas, the TTF energy exchange in the

Netherlands. On the other side, different Member States have proposals for gas price caps on retail prices (e.g. Germany introduced a cap for consumer gas prices at 12 €-ct/kWh applying under specific conditions). The goal is to support suffering businesses and households with energy bills. However, whether these measures are effective and reasonable and what else can be done to avoid future scarcity will be discussed in section 4.

### 3.3. Energy transition impact on electricity grids and pricing effects

Besides the transformation on the supply side, we are also currently undergoing two major upheavals in the history of electricity networks, and in particular on distribution networks. Up until recently, distribution grids were considered passive since their function was simply to transport electricity from the higher voltage networks, down to the final consumer. Consumers' demand was historically well forecasted and its variations between peak and baseload periods were known with a high degree of confidence.

The first of these upheavals is the development of new electricity uses with the growth of electrification combined with decentralized electricity resources (DER). In fact, they open a new era for the power system, bringing many challenges to the planning, investment and operation of distribution grids. DER is a generic term that combines all decentralized energy resources capable of generating and storing electricity (e.g. solar PV panel with storage) and of providing flexibility. Electrification refers to the shift to electricity for transportation and heating, which in turn expands the potential for flexibility.

Recent projections indicate that 45 million electric heat pumps and 50 to 70 million electric vehicles will be connected to European grids by 2030 (Eurelectric, 2021). Now, end consumers have the possibility to become prosumers (producer-consumers), and flexibility service providers. While these two new attributes are beneficial in terms of low carbon energy and lower electricity cost, they also entail significant network costs. Projected investments in the European networks are estimated to total up to €575 billion in less than a decade (European Commission, 2017). In Denmark, the estimated cost on distribution grid may be 20% higher than in the previous decade (Hansen, Larsen, Larsen, 2021).

When consumers become prosumers, they can produce and self-consume all or part of their energy, which means less withdrawal from the grid resulting in higher risk for cost recovery for the grid operator. On the other hand, the electrification of transportation and heating increases the bulk demand for electricity and exacerbates peak effects, raising system costs for grid dimensioning. Put trivially, these new uses and decentralised production modes offer unprecedented opportunities to accelerate the shift towards decarbonised energies while benefiting prosumers who will lower their electricity bill by being flexible and less dependent. However, this may take place at the expense of unprecedented network costs borne by the whole society. Some of the decentralised production units will require the construction of new lines.

In some places, the injections of electricity into the grid caused by these new units may require to resize the local grid. Finally, the consumption of heat pumps in winter will almost permanently increase the volumes of electricity on the lines, and the charging of electric vehicles, if not done in a smart (flexible) way, may also lead to considerable peak effects. All that calls for a rapid revision of grid pricing.

The second upheaval is the deployment of smart metering and communication systems. With the deployment of mart meters, it has become possible to know how much electricity each consumer uses at hourly intervals. Here comes the possibility to obtain finer information on individual loads and the missing piece to connect loads to system cost. Since system costs (of electricity production and networks) are also dynamic, it becomes possible to tailor price signals capable of capturing these cost effects and allocating them more efficiently to those who cause them.

## 4. Discussion (of measures and policies)

### *Price caps in European gas and electricity markets*

To combat the high energy bills of European energy consumers, the EU wants to jointly purchase gas and LNG from producing countries, strengthening the buyer's position in the negotiations by aggregating and increasing the purchased volume. Some Member States directly support low and middle-income households with paychecks (e.g. Denmark). Beyond these measures, both at EU level (Guidelines, such as the RepowerEU plan) and at Member State level (Directives or Laws), different price caps have been introduced to limit costs for consumers, especially in natural gas markets also affecting electricity prices.

However, implementing price caps in the wholesale market does not come without downsides:

1. If you cap prices at a too low level, and if gas consumers ask for more gas at this price than importers can supply, we have a situation of excess demand. How should the market operator allocate the resource efficiently?
2. Gas power plants lower their offers/bids to the electricity market because of lower gas prices, but others probably do not (such as coal power plants). The electricity prices remain high, as other technologies might become price-setting at some point. Besides, with a gas price cap or subsidy, we will continue or even extend gas consumption in the electricity sector, which we highly need in other sectors.
3. If the EU caps gas prices in Europe, there is the danger that LNG gas producers sell their gas to other parts of the world, such as Asia, leading to a further shortage of gas in Europe.
4. Finally, the lower gas prices should also reflect in final users' bills which may reduce our incentive to save scarce gas.

Beyond this, also price caps for electricity trading were discussed and led to the EU Commission's recommendation to tax infra-marginal profits of low-carbon technologies which do not rely on high-priced fossil fuels (e.g. when wholesale prices on the spot market exceed 180€/MWh). Although this measure sounds reasonable, its implementation is difficult from a legal, but also technical position. For instance, the question remains how to assess if a low-carbon power plant is making infra-marginal or regular profits, which are needed to cover the capital expenses. Hence, the real-world test of price caps will remain an object of monitoring and reassessment.

To avoid supply-side scarcity in the gas and electricity market in the long term, the only effective measure is to increase investments in clean energy technologies and in flexibility of consumption combined with increased energy efficiency and savings.

### *Capacity markets/auctions*

At the national and European levels, there is intense debate on which market architecture can effectively and cost-effectively ensure long-term supply security. Discussions about the ability of the current design (energy-only market, EOM) to provide sufficient investment incentives for new generation capacities originally steamed from the missing money problem: Because very high peak prices on the energy market are repressed by politically imposed price caps, peak load power plants with high marginal costs do not always cover their fixed costs, creating a disincentive for future investments.

Capacity remuneration mechanisms (CRMs) are seen as an effective way of ensuring generation adequacy by providing sufficient revenues for existing capacities and incentives for new investments. This is mainly due to the reason that electricity wholesale markets remunerate only produced energy units, while CRMs reward the provision of and keeping secured power generation capacities in the market, even if they are less used for electricity generation. The compensation offered to capacity suppliers is in addition to the returns from the market sale of electrical energy (Hawker, Bell, Gill, 2017).

There are various approaches to market design and CRM and their optimal arrangement remains a theoretical debate (Bublitz, Keles, Fichtner, 2017). The key issue is to minimize misconfiguration, which can lead to overcapacities and these in turn lead to higher costs for consumers, who will ultimately pay for capacity provision through compensation payments. This, as well as current arguments regarding design choices (for example, in the case of the French capacity market), underline the need for additional research into supply security and market design.

### *Grid tariffs for flexibility*

Over the past decade or so, there has been a growing debate in Europe and elsewhere on the issue of new tariff designs which support the green transition. This debate was facilitated by the new granularity potential brought by smart metering that makes it possible to charge different grid fees to better reflect grid conditions. In practice, a majority of grid operators have introduced time-differentiated rates that penalize grid use during peak periods. In that sense, utilities keep on applying a monthly subscription charge like before and simply apply different kWh fees depending on the time-of-use (ToU) of the system. Denmark implemented such a design involving a high, medium and low fee per kWh. Most European countries use similar tariffs, each with its specific attributes in terms of price level and period duration. Other jurisdictions like Norway or Finland for some DSOs have also implemented forward-looking tariff signals for households. In general, this signal comes in addition to ToU pricing and applies a capacity-based charge reflecting the long-term incremental cost of network usage that penalizes consumption when the system is congested.

Locational pricing is widely used as a tool to incentivise the location of energy-intensive actors such as large industries where the transmission grid is most able to integrate them at lower cost. Geographical differentiation at low voltage network level is rarer. Implicitly it implies a lower tariff for consumption close to local production and for use where the network is not congested, and vice versa. Currently, only Austria implemented spatial pricing for households. Denmark published a roadmap to implement it by 2035. In some cases, this differentiation collides with other overarching principles and legal frameworks. In France for example, the law provides that the cost of providing public services is shared equitably among users, regardless of their location.

*Grid tariffs, energy justice and other trade-offs*

So far, we have taken a technical-economic approach to discuss the main trends in network pricing. It is important to add at this stage two final considerations. First, another debate is emerging on the energy justice implications of cost-reflective tariffs between active-passive and between wealthy and less well-off households. In some frontrunner regions with DER, we see a knock-on effect where the loss of grid revenue generated by the lower withdrawal of self-sufficient sites is passed on to other grid users, creating an additional incentive for them to also invest in their own generation-storage facilities and to pass on more of the grid costs to those without access to such equipment, including because they simply cannot afford it. Therefore, a growing concern of social equity with grid cost recovery is emerging, calling for anticipated action from policymakers. Second, many studies have shown that a lack of transparency and simplicity in tariff design affects their acceptance, especially by households. Therefore, future tariffs for the green transition will have to balance cost recovery, efficient price signal, fairness, and acceptance.

## 5. Conclusions

The envisaged transition of the energy system is associated with major impacts on wholesale electricity prices and grid costs. Although the declining cost of wind and solar energy and the merit-order effect of renewables lead to falling electricity prices, the continued strong demand for fossil fuels leads to price shocks worldwide. This reflects in electricity prices when natural gas plants set the price. The burden of high energy prices on energy consumers leads to a discussion on the distributional effects of costs and effective policies to improve energy affordability in times of energy scarcity.

In the short term, price caps are a preferred and politically chosen method and can provide some relief to consumers. In the long term, however, investments in clean renewables and flexible capacity, such as energy storage, are the only way to avoid interruptions, reduce scarcity on the supply side and thus limit energy prices. In this context, capacity auctions or markets, as proposed by some economists and implemented in some countries, seem to be an effective way to finance and trigger new investments.

The shift to volatile renewables associated with electrification also requires investments in grid infrastructure. Smart grid tariff structures are needed to first minimize expansion and reinforcement and second to organize the distribution of grid costs among the different users. A cost-based tariff is essential for the energy transition as it will drive more efficient behaviours and support decarbonised energy investments where they are most needed. A smart grid tariff must strike an appropriate balance between addressing distribution grid cost drivers and ensuring that grid users equipped with smart technologies can respond to price signals that lead to energy savings.

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