Electricity Market Design for Climate Neutrality: Fundamentals

Guidehouse Germany GmbH
Dr. Christian Nabe, Dr. Konstantin Staschus
Albrechtstr. 10c
10117 Berlin
Germany
guidehouse.com

30 January 2023

Table of Contents

1. Introduction

Russian deliveries of natural gas to Europe began to decline as early as autumn 2021, creating a tight supply situation that became dramatically worse with the Russian invasion of Ukraine in February 2022. The ensuing record-high gas prices have had the knock-on effect of record-high wholesale electricity prices, because gas-fired plants are often last in the merit order and thus set the wholesale price. In 2021, Dutch TTF wholesale natural gas futures were already some 3 times higher than the average that prevailed in 2018–20, and in 2022 they were 3 times higher than the 2021 average (and thus 9 times higher than 2018–20). Gas prices fluctuated wildly over 2022, especially from the middle of the year onward, as different market assessments evolved with regard to gas storage levels, expectable winter temperatures, and the ability of consumers to reduce consumption. Similarly, wholesale electricity prices increased 4.5-fold from 2018–21 to the average that prevailed between October 2021 and September 2022.[1]

Electricity customers have seen dramatic jumps in their power bills, with those industrial customers facing particularly steep increases, who rely on spot market purchases. As fixed price guarantees and hedging contracts expire in coming weeks and months, the prices borne by end consumers will climb even higher. While households worry about fuel poverty and businesses are concerned about the threat of bankruptcy, exporters of natural gas and generators have been reaping record windfall profits.

These developments have provoked discussion concerning fundamental aspects of European electricity markets, not least due to the profound burdens the crisis is placing on energy consumers. Accordingly, the EU has adopted a set of emergency measures to soften some of the impacts of high energy prices. However, the increased attention being devoted to the design of the electricity market has also brought numerous fundamental market design questions to the fore.

This policy paper looks beyond current crisis response measures to examine deeper structural issues. As electricity market design is a highly complex topic, we restrict our main analysis to the core of the current debate. Specifically, we examine the role of price formation mechanisms for (1) the allocation of rents between consumers and producers; (2) investment signals; and (3) the secure operation of the increasingly renewables-dominated power system.

We first explore how the current market evolved, the goals the market should fulfil, and the suitability of the current design for attaining these goals (Section 2). Our main contribution in Section 3 lies in evaluating market design features and options most relevant to the current crisis while giving due attention to the three main goals of energy equity, security of supply, and environmental sustainability. This discussion emphasises the conditions under which different market design options can fulfil stated goals, given considerable decentralised generation, the adoption of new digital technologies, or high gas prices over the long term. Our analysis culminates in a comparison of three alternative approaches. In the appendix, we undertake quantitative analyses to show that investment incentives, especially for non-gas-fired generation, were borderline sufficient in past years. This analysis also spotlights how very high wholesale market prices are and will affect investment incentives, and the associated role played by siting, permitting, supply chains, and renewables auctions. Section 4 summarises our conclusions.

[1] Such as the EPEX spot volume-weighted average day-ahead prices for DE-LU.

2. Electricity market fundamentals and design options

The following subsections provide an overview of electricity markets, including associated design features and options. They also address the historical development of EU electricity markets, highlighting aspects particularly relevant to the current crisis.

2.1 Special features of the electricity market

Electricity is a commodity, which means its individual “units” are essentially interchangeable (i.e. fully fungible), and they are treated by the market as such, regardless of who produced them or how. Electricity shares this characteristic with many other resources and raw materials (and certain manufactured goods). Like most commodities, electricity is traded both in organised spot and derivative exchange markets, and “over-the-counter”, i.e. directly between two parties under more flexible contract conditions.

Interchangeable commodities usually trade at the same price in a well interconnected market. The scope of such a market may be continental or global (as in the case of oil) or, alternatively, national or regional (as in the case of electricity). The “market-clearing price” is usually equivalent to the price demanded by the most expensive producer whose output is still needed to meet demand. This feature of commodity pricing has led to marginal pricing in power exchange markets, and to hedging and bilateral contracts being anchored at the marginal prices of the power exchanges and their forecasts.

However, ensuring optimal market design is more pressing for electricity than for most commodities, because of three special features:

- Electricity can only be transported via **grids**, and these grids and other parts of the value chain have cost characteristics that make them **natural monopolies**. The introduction of competition into parts of the electricity value chain without natural monopoly characteristics (i.e. generation) must be performed carefully, to ensure that customers can benefit from competition while remaining protected from monopolistic abuses.
- A **balance between production and consumption** must be ensured at all times to avoid blackouts: Sizeable imbalances can lead to blackouts within seconds, and there are few proven and easy options for long-term storage to help maintain this balance. No other product or service has such profound reliance on the proper balance between momentary supply and demand.
- For many uses of electricity, there are **no alternative services or products**. This leads to a customer willingness-to-pay that hugely exceeds normal production and distribution costs, at least over the short term. Appendix 1 illustrates the inelastic nature of electricity prices by comparing the 2021 EU average household electricity price of 22 ct/kWh to a 100 times higher potential willingness-to-pay (“Value of Lost Load” for short-term interruptions; see details in Appendix 1). In economics, the difference between willingness-to-pay and market prices is called the “consumer surplus”, while the “producer surplus” is the difference between market prices and production costs, including acceptable rates of return. If the consumer surplus is large and there are few alternatives, sustained high prices cause steep decreases in consumer welfare. Appendix 1 discusses the significance of a very high consumer surplus, and highlights the importance of the producer surpluses for regulation, investment incentives, and government crisis intervention.

The special features outlined in the foregoing are highly relevant to the current crisis. Specifically, the scarcity of natural gas threatens to restrict the generation of electricity, which could affect operating reserves and endanger the balance between production and consumption. Accordingly, some voices have raised the spectre of blackouts, not least given growing concern regarding cyberattacks and infrastructure sabotage. The current scarcity of natural gas has led to high wholesale power prices when gas-fired power plants are toward the end of the merit order. In April and July 2022, for example, exchange prices in parts of Central and Western Europe were 3 to 8 times above trend. Such wholesale price spikes can lead monthly customer bills to jump 50 to 150%, assuming cost pass through by providers (after a given time lag).[2] These figures illustrate the substantial cost burden that is resulting for households and businesses, including attendant bankruptcy risks.

2.2 Historical development of the electricity value chain

The structure of the electricity supply system has evolved over time, moving from decentralised "islands" serving local customers to ever larger and better integrated distribution and transmission grids. Transport networks evolved in the 1920's, to enhance security of supply and make use of the combination of storage hydro plants in combination with coal-fired power plants to balance supply and demand effectively in different seasons with different availability of hydro power.

The power sector quickly became concentrated in the hands of a small number of actors, not least due to the need for real-time balancing of supply and demand and the sector's strategic importance for the entire economy. Hence governments took shares or full responsibility for electricity supply. The sector quickly concentrated to integrated companies who took responsibility for all of generation, dispatch, transmission, distribution and retail in growing geographic areas.

The degree to which this integration took place varied from country to country, but it was accepted by legislative bodies that the electricity sector deserved exceptions from legislation that prevents the evolution of monopolistic structures as electricity grids represent a natural monopoly. For obvious reasons, establishing multiple grids in parallel to enable direct competition would be wholly impractical. At the same time, legislators recognised the need for regulation that would limit price-gouging and monopoly profits.[3]

In the 1980s, technological changes led to new regulatory approaches. The construction of ever-larger generation plants to harness economics of scale had come to end as nuclear power plants reached capacities that made it difficult to manage even temporary outages. In addition, new combined cycle gas turbine (CCGT) technology dramatically improved the efficiency of fossil-based generation, and new players were keen to enter the shielded generation market. While it was recognised that grid operation was still a natural monopoly, generation and retail were opened up to market competition, in the hope of creating new efficiencies. With the advent of high numbers of small generation capacities on distribution level and consumers taking up the role of producers (now named prosumers) the value chain with clear power flows from top-to-bottom value chain is structured differently. The remainder of this Chapter discusses this development and how European legislation reacted to this.

[2] "In Europe, the electricity component represents 31% of the electricity bill, while network tariffs account for 28% and taxes and levies reach 41%.", see Eurelectric 2022.

[3] Key reasons for the large economies of scale in electricity transmission are the voltage levels, where at the moderate cost of transformers and a bit higher towers, the transmitted power can be increased so substantially that costs fall steeply if more power is transmitted at higher voltage. E.g., the University of Texas showed that transmission costs per km and kW decreased from \$4.82 at 69 kV and \$2.23 at 137 kV to \$0.46 at 345 kV – see Table 3 on p. 14 in Baldick and Andrade 2016. If there was competition for transmission in the same corridor, the lower power transmitted per competitor would often preclude them from using the cost advantages of higher voltage levels. At the distribution level, a key reason is the large cost component of earthworks for undergrounding distribution cables, which makes one higher capacity cable much cheaper per km and kW than two or three smaller cables managed by different competitors.

2.3 Main targets which electricity markets must achieve

Energy policy generally seeks to reconcile three conflicting priorities.[4] The World Energy Council refers to these priorities as the "energy trilemma" (World Energy Council 2022):

1. Energy security: Maintaining system security and resource adequacy, i.e. having enough generation, storage and network resources, and operating them so securely, that customers are without electricity very rarely: Aspects are security of supply as emphasized by the EU Electricity Directive (EU) 2019/944, but also operational security, investment incentives, especially for renewable energy sources and for flexible, dispatchable assets, and a good alignment between physical network needs and market structures.
2. Energy equity: This refers to energy prices and costs for consumers, as emphasised in the EU Electricity Directive, but also to the balance between the consumer vs. producer surplus, and how consumer costs relate to system costs.
3. Environmental sustainability: This refers to the need to ensure the power system is compatible with the goal of environmental sustainability, including in particular the goal of reducing greenhouse gases, but it also encompasses considerations related to air pollution, land use, etc.

Precise formulations of the three goals have evolved strongly over time and still vary between countries and regions:

Security of electricity supply was and still is formulated as fixed planning criteria for system security (e.g. the (n-1) criterion that the system must not fail if a single element like a power line or plant fails) and resource adequacy (e.g. that the expected value of hours per year when any part of the demand cannot be supplied be less than 1 hour (Sweden), 2-3 hours (e.g. France, Germany, Italy) or 15 hours (Czech Republic)).[5]

Given the high value of electricity to its users and the dependence of our societies′ functioning on electricity, a very high security standard makes sense and cannot easily be traded off against economics or the environment.

The second criterion refers to economic aspects of electricity provision. It has several sub-aspects. First, the EU legislation recognises that adequate heating, cooling and lighting, and energy to power appliances, are essential services, and the European Pillar of Social Rights includes energy among the essential services which everyone is entitled to access. Second, affordable electricity rates are not only essential from a social point of view, but also important for commercial and industrial activities. This criterion also includes the balance of consumer and producer surplus highlighted above.

Finally, the third criterion has become much more important over the years. It means not only numerous government restrictions on air pollution, cooling water use from fossil fuel power plants or river flow restrictions on hydro plants, but also government interventions in the electricity market such as CO_2 pricing and support of renewables.

Translating these targets into market design requirements, the first and the last criteria can be interpreted as boundary conditions or constraints that market design has to deal with. From an operational point of view, market design must allow the cost-effective integration of variable

[4] For example, the EU Electricity Directive (EU) 2019/944 of June 2019 aims to ensure affordable, transparent energy prices and costs for consumers, a high degree of security of supply and a smooth transition towards a sustainable low-carbon energy system (Art. 1 Subject Matter). See also the German Energy Market Law EnWG §1.1, the stated purpose of which is to ensure a secure, inexpensive, consumer-friendly, efficient, environmentally sustainable and greenhouse gas-neutral supply of energy; Department for Business, Energy & Industrial Strategy, UK Government 2022 list as objectives for market design decarbonisation, security of supply and cost-effectiveness.

[5] See Figure I in ACER 2022.

renewables with highly stochastic behaviour without compromising the balance between supply and demand. From an investment point of view, market design needs to support appropriate investment and disinvestment in generation capacities that complement the properties of renewables and ensure security of supply by providing the necessary capacities for efficient and safe operation.

The government-driven switch from fossil energy carriers in heating, transport and industry to renewables-based electricity and hydrogen necessitates further government adjustments to market design. However, it also opens opportunities for beneficial integration between sectors.

One can argue that the described market design requirements are not substantially different for any power system, independent of geography, the generation mix, or environmental targets. Indeed, the economic efficiency of operational and investment decisions has always been important. Ensuring security of supply remains the overarching concern. And government intervention is nearly inevitable given the importance of the power system to society. Dealing with variability and stochasticity in power system load is a perennial issue. Given this fact, it is perhaps surprising that after 140 years of evolving power systems, no best-practice solution has been found, and market design regimes continue to diverge internationally. One reason for this is that functioning competition between generators is easier to ensure in systems large enough for multiple competitors who rely on a mix of generation technologies. In addition, small differences in basic regulatory conditions matter, many trade-offs exist, and one solution cannot optimally serve all market design priorities. The following sections thus discuss the primary building blocks of market design, which choices need to be made, and how these choices have evolved over time.

2.4 Regulated monopolies vs. competitive markets

Section 2.2 mentioned the changes in generation structure that emerged in the 1980s, indicating possible efficiency gains. During this decade, academics developed theories on the spot market pricing of electricity (e.g. Schweppe et al. 1988), and the United Kingdom and Chile were the first to liberalise their electricity markets.

Previously, almost all countries regulated the value chain by providing guaranteed rates of return. Economists and policy makers hoped that introducing competition between generation would lead to lower costs for consumers by discouraging over-investment and other inefficiencies. One main cause of inefficiency in a regulated monopoly is the Averch–Johnson effect (Averch and Johnson 1962). This effect describes the tendency of regulated companies to engage in excessive capital investment in order to increase their profits, which are often set by the government in relation to invested capital. It was also hoped that the introduction of competition would encourage greater innovation in generation technologies and system operations. With the rise of distributed generation and the active participation of consumers in electricity markets, the argument for introducing competition in the generation and retail segments gained additional traction. Closely connected with this dynamic was the concern that regulated generation monopolies would oppose distributed renewables as unwelcome competition, rather than embracing them as an essential component of a decarbonised energy future.

On the downside, electricity markets are much more complex to manage, coordinate, and regulate than integrated monopolies. When competitive markets replace the internal short- and long-term planning processes of an integrated monopoly company, and formerly integrated monopolies are unbundled, new interfaces emerge. Hence there is a need to coordinate generation investment and operations with grid management and investment decisions.

A further set of challenges lies in ensuring proper coordination between generators, both with regard to future capacity planning and day-to-day operations. This includes ensuring adequate back-up and storage capacities to cope with fluctuating feed-in from variable renewables. In a regulated monopoly, integrated resource planning processes and central dispatch solve this problem. However, in a competitive market, investment incentives and short-term market rules need to be precisely tailored to avoid excessive costs.

In competitive markets, this includes the operational challenge of establishing an optimal generation unit commitment and dispatch that leads to cost-minimising and secure operations every day, hour, and minute. This involves coordinating an ever-larger number of market participants in generation, storage, and demand, including tens of millions rooftop PV systems, household batteries, EV charging and heat pump demand response. As the number of market participants continues to rise, such coordination will only be possible by enhancing grid operations and other aspects of the power market with new IT technologies.

In the beginning: Basic models for the electricity market

Prior to the adoption of the first European Directive on Common Rules for the Internal Market in Electricity of 1997, several models were discussed to solve aforementioned challenges. As no agreement on a common model could be found, several alternatives entered the Directive.

The single buyer model was one of them. This was inspired by the partial deregulation of several electricity markets in the US, as initiated by the Public Utility Regulatory Policies Act (PURPA) of 1978. In this model, vertically integrated structures in the electricity sector were preserved, but transmission and distribution companies were obliged to purchase electricity from new entrants via long-term contracts. The contractual conditions for the power purchase agreements could either be determined by the regulator or in a competitive auction process. As part of this process, the regulator could explore competitive generation, which helped to regulate the incumbent company. This model is similar to competitive auctions for renewable generation capacities that have been established in the recent years in Europe. The crucial difference is that in most electricity markets in Europe today, no single buyer exists who ultimately decides on the dispatch of these resources; rather, the new capacities are self-dispatched. Generation investment decisions are made by profit-oriented companies competing with each other in auctions designed usually by system operators and approved by regulators.

A second and very important model in which monopoly structures are abandoned and generators compete directly with each other is third-party access (TPA). In some countries, this model was first adopted as negotiated TPA, and later as regulated TPA. This model requires the unbundling of generation from transmission to ensure non-discriminatory generator access to grids. Bilateral – and voluntary exchange-based - trading of electricity takes place, but the short-term balancing of supply and demand remains the purview of the unbundled and regulated transmission system operator (TSO). The current European electricity market (with the exception of Ireland) is based on this model. Generation investment decisions are made by profit-oriented companies competing with each other based on each company’s own estimate of the future profitability of investing in specific technologies.

The pool model is based on a centralised power market with central dispatch. This variant of the TPA was used previously in the United Kingdom, and was discussed in the run up to the first EU Directive. It is currently used in North America’s liberalised electricity markets and in Ireland today. All generators are required to offer their generation capabilities to a central pool. The model is mostly known by its Independent System Operator (ISO) implementation in the US (e.g. PJM market). As the central dispatch can be very well integrated in transmission network management, nodal prices can be calculated; accordingly, the model has re-appeared in European discussions on nodal pricing.

From 1997 to the present day, the design of the European market has been further developed with several Directives and Regulations.[6] These changes were motivated by two main pressures on the system: First, the introduction of competition beginning in the 1990s led to a reduction in generation capacities. At the time, this was a desired effect, as it indicated the system was becoming more efficient, by reducing overcapacity. However, as capacity reserves dwindled while increasing feed-in from renewable energy made such reserves all the more important, around 2008 a discussion began concerning whether the energy-only market could ensure sufficient reserve capacity. The Clean Energy Package's Electricity Regulation (EU) 2019/943 fine-tuned conditions for the national implementation of capacity mechanisms to ensure sufficient investment under certain conditions; the choice as to whether a capacity mechanism is implemented, and of what kind, varies by country.

A second pressure on the system motivating changes to the market design was the closer integration of European power markets in combination with higher shares of variable renewables. Long-distance power flows as well as the increased need for short-term balancing forced increased cooperation for short-term balancing and the coordination of redispatch to manage grid congestion. An established process for the review of bidding zones is designed to adjust the uniform price zones, if redispatch actions become increasingly inefficient. Balancing markets have also been designed to operate in a cross-border fashion, in order to decrease the cost of ancillary services to keep the system reliable and balanced.

Both developments show that the market and regulatory arrangements used to implement liberalised generation have successfully adjusted to the evolving needs of the European power system as it moves towards decarbonisation.

2.5 Current challenges to market design

2.5.1 Difficult consumer and producer reactions to high prices

As mentioned in Sections 1 and 2.1, high natural gas prices challenge the system, exerting strong effects on the balance between the consumer and producer surplus. However, high gas prices translating into high electricity spot prices correctly signal resource scarcity. From a purely economic perspective, the market is operating as it should. High prices are designed to reduce demand and thus reduce the stress on the system. However, there are two difficult problems: First, on the consumer side, electricity is a basic need, meaning there is a very high willingness-to-pay. Accordingly, consumers and policymakers might not take solace in the proper function of market economics, insofar as they entail real reductions in well-being. In this connection, demand response by consumers is partially impaired by pricing and metering arrangements which do not support demand response to high prices.. Second, on the producer side, the market is not producing investment with sufficient speed, leading to the risk of social unrest.[7] The first problem is described in more detail in Appendix 1. The second problem is described generally here below, and in more detail in Appendix 2.

High marginal electricity prices are in theory an excellent investment incentive, both for ensuring sufficient reserve capacity and for ensuring the best type of resource. The very high

[6] These include especially the 1st Energy Package 1996 which introduced competition, the second Package 2003 for refined open access conditions and regulation, the 3rd Package EP3 2009 for EU-wide planning and codes, the 2019 Clean Energy Package for flexible retail markets, and the Green Deal for sector coupling and decarbonising the entire economy.

[7] A related challenge is providing market incentives for investments in resources which protect rather than endanger the climate.

prices seen in recent months mean that all resources not relying on natural gas accumulate very high inframarginal rents, i.e. revenues exceeding their operating costs. This signals to investors that large profits can be made on generation technologies that do not require natural gas, including those with high capital costs and lower (variable) fuel cost such as renewables, nuclear, coal generation, and energy storage. These market price signals can be seen not only in the day-ahead spot prices but also in forward markets and in various hedging contracts.

However, the lumpiness of investment, the risk of sunk investments, long time lags in investment due to planning, permitting and construction, other practical and political restrictions, and, last but not least, supply chain disruptions mean in practice that this link between spot markets and investment is not sufficiently direct or rapid in the current unstable situation. Hedging and forward contracts concluded when prices were lower also mean that the current high prices are not yet fully reflected in customer rates.

This reaction speed problem on the producer side is made worse by pre-existing technology choice uncertainties, which have been further exacerbated by the gas crisis. Climate policy imperatives mean that natural gas, oil, and coal have no long-term business case; additional wind and solar capacity is necessary, but such renewables cannot carry Europe through windless winter weeks. Investment incentives should encourage clean but flexible resources with strong future potential, including green hydrogen and energy storage, vehicle-to-grid, demand response solutions. However, these technologies are still evolving, and many have not yet reached market maturity. Thus, even if the current electricity market price signals are strong enough to incentivise green and flexible resources, many solutions are not yet ready for mass market deployment.

In this way, we find that an appropriate market reaction to current price signals is prevented by various factors.

2.5.2 The scale of generation windfall profits compared to investment incentives

There is ample economic literature on investment incentives in electricity markets under entirely free marginal pricing in point of comparison to situations in which market prices are capped administratively, algorithmically, or politically, or where they have little effect because of ineffective demand response.[8] The main finding of this literature is that there should be sufficient investment incentives for all needed types of resources with entirely free marginal pricing, but that there can be “missing money”, i.e. a gap in expected revenue that leads to worse business cases and insufficient investment, if pricing is not entirely free.

The literature often cites two main ways in which pricing may not be free. First, in the absence of smart meters and dynamic pricing for all customers (including households), large demand shares will not react to high prices when generation resources are scarce. Because no appropriate market clearing price can be found, the TSO may need to institute rotating outages at price levels lower than a true market price would be, thus reducing the revenues of available generators. Second, economists worry that exceptionally high prices during scarcities will lead to consumer outcry such that politicians cap prices or otherwise limit the (after-tax) revenue of generators. In fact, the current discussion would appear to confirm this worry.

However, as we argue quantitatively in Appendix 2, only recently have EU policymakers begun to enact revenue limitation measures. Accordingly, in past months, investment incentives attributable to scarcity prices have accumulated, reaching levels sufficient for the

[8] E.g. Hogan 2017; Newbery 2015; European Parliament 2017; Cramton et al. 2013

entire economic lifetimes of at least some generation technologies. By waiting so long to enact revenue limitation measures, policymakers have shown they will not destroy investment incentives by limiting prices at the first sign of crisis. If changes to market design are discussed and even implemented now, a rational investor could still retain confidence that a sufficiently large share of scarcity revenues will be theirs to keep, thus ensuring sufficient investment profitability. Thus, while the investor confidence argument is important, it need not prevent a discussion on measures to protect the consumer surplus, if the timing of changes takes a reasonable accumulation of scarcity revenues into account. Of course, any changes must keep the three main goals of energy markets in mind, while also accommodating potentially unforeseen market developments in coming years.

2.5.3 Decarbonisation and market design

The EU's energy transition and associated decarbonisation targets have had a strong influence on EU market design discussions and choices in recent years. Renewables integration has been discussed since the early 2000s, and the 2009 Third Energy Package introduced EU-wide network codes and ten-year network development plans as tools to enable the integration of ever-higher renewable shares.

With the decarbonisation of the power system coming many years before the complete decarbonisation of the economy as a whole, society requires a plan for the replacement of all fossil-fuel-based electricity production within less than two decades, i.e. within the lifespan of investments made today. Flexibility, demand response, energy storage and hydrogen investments (including for power generation) need appropriate investment signals now and in the coming years. Accordingly, the range of resources that need incentives is much larger than in the past. Even more so than in the recent years, there will likely be many hours where zero marginal cost renewables dominate the generation mix, leading to marginal prices above zero only if prices are pushed up by the value of energy in storage or the Europe-wide exchange of regional generation surpluses and deficits. Thus the inter-dependence of prices in different hours as a function of storage values will increase, and so will the importance of investment signals that correctly reflect regional renewable surpluses and deficits.

During hours with little wind or sunshine and especially in the winter when millions of new heat pumps will have replaced fossil fuel heating, thus adding to electricity demand, prices will be based on the marginal cost of demand response, energy in storage, and the cost of green hydrogen-based power generation. All of these resources may be very expensive, possibly above €100/MWh. The spreads and volatilities will routinely be much larger than what our market design had to handle in the past. Furthermore, the market design challenges posed as the system moves closer to decarbonisation bear resemblance to the current gas crisis, thus making the consideration of targeted adjustments to market design appropriate, as discussed in Section 3.

2.5.4 Approaches to market design changes

Reacting to the current situation, the EU and national governments have developed short-term measures to capture the surplus revenues of inframarginal generators (see Box 1). This idea of capturing excessive inframarginal rents is perceived as the best way forward in the short term. However, the practical implementation of a mechanism to capture the rents that exceed reasonable investment incentives appears to be very complicated, even if perfection may not be needed or possible. On the one hand, the design of such a mechanism is complicated by the fact that not all electricity is traded in the short-term wholesale market. Rather, different generation technologies are aggregated in bids, and traded several times and on different timescales in forward, future, and day-ahead markets and over-the-counter. Hence, the implementation of measures to capture excess rents requires significant data collection and analysis. Additionally, the price cap implemented over the short term is far from accurate but chosen to be on "the safe side" to avoid negative impacts on generator investment and profitability. While inaccurate and high-effort measures may be acceptable as a crisis response, there is a clear need for more robust solutions that address the fundamental problems at hand.

The following fundamental questions are thus posed when considering potential reforms to the market design:

1) Is the **market design fix compatible** with current market design or not? "Compatible" in this content means that the market design fix has acceptable levels of efficiency and acceptable implementation costs ("side effects").

2) If it is not compatible, can the current market design be **easily** modified to:

    a) be compatible with the market design fix, while avoiding side effects, or

    b) can a light-touch modification of the market design help to alleviate inappropriate inframarginal rents, without triggering severe side effects?

3) Or are **fundamental** market design changes required in order to allow the implementation of a solution that is robust to crisis situations, but that also remains efficient in the long run if the crisis is over?

As a reaction to the gas crisis, European countries decided on Council Regulation (EU) 2022/1854 of 6 October 2022 as a framework for national short-term measures. One important element is the introduction of a cap on market revenues at €180/MWh. This price cap was well above the initial expectations of investors. It does not force revision of their investment profitability assessments and allows them to cover their investment and operating costs.

The price cap applies to generation technologies with low marginal cost such as solar, wind, run-of-river hydropower, lignite, and nuclear energy.

The regulation calls for the establishment of mechanisms to distribute the surplus revenues resulting from the application of the cap to final electricity customers. This can be implemented by direct payments, by reduced taxation, or by exemptions on grid fees or other levies.

Box 1: Short term measures in reaction to the gas crisis[9]

2.6 Overview of market design options

Since 1996 various aspects of market design have been intensely discussed as part of the liberalisation and regulation of power markets, with these discussions finding concrete expression in the EU's First, Second, and Third Internal Electricity Market (IEM) legislation, the Clean Energy Package, and the Green Deal. Figure 1 from a recent UK government (BEIS) report provides an overview. It shows the scope of the UK Review of Electricity Market Arrangements (REMA).

[9] Council regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices.

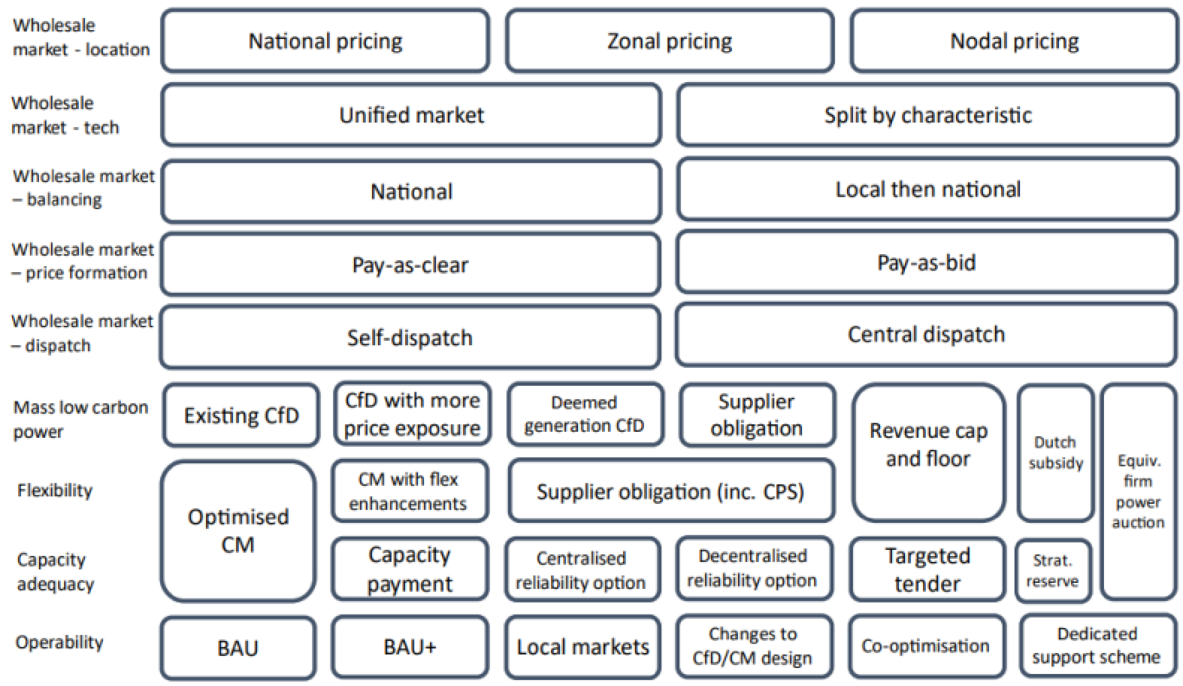

Figure 1: Electricity market design options[10]

Not all of these elements are relevant to the current crisis, as this crisis primarily calls into question the balance between the consumer and producer surplus resulting from high natural gas prices. Design options regarding balancing or locational pricing have little effect on the overall balance between the consumer and producer surplus. But wholesale price formation is obviously relevant. Also, the options for mass low-carbon power, flexibility, and capacity adequacy are relevant because one main risk of changing price formation mechanisms is a possible reduction in investment incentives, such that options for supporting investments outside the day-ahead and intraday markets become important. Furthermore, the option for self- versus central dispatch affects the options one has for price formation and regulation.

However, the analysis in the following section will focus on options with low implementation hurdles, options that will be further described in Section 3.4.

[10] Department for Business, Energy & Industrial Strategy, UK Government 2022, Figure 7

3. Evaluation of Market Design Options

3.1 Overview of methodology

In this section we analyse market design aspects and options that are relevant to the current crisis with respect to their performance in fulfilling the main goals of energy markets. We pay special attention to investment incentives, to the balance between the consumer and producer surplus, and to specific consumer groups – issues that most policy makers believe are in urgent need of correction.

We also show that not all market design options are appropriate in all circumstances, and their performance towards the targets can vary. Our analysis of options builds on the basic conditions described below.

3.2 Basic conditions for market design choices

No natural monopoly in generation and supply

Before the 1980s, natural monopoly conditions held for electricity generation. Over years and decades, generation plants kept increasing their output, with the newest nuclear units reaching capacities of 1600 MW. These units were so large that few generators were needed to cover all demand in the relevant market areas of the time, which were at the size of countries of less because of limited interconnection capacity between them. This meant that a single utility could take best advantage of increasing economies of scale and provide power to customers at a lower cost than several competing companies could. These natural monopolies were subject to regulation. But since the 1980s, due to new CCGT generation technology, which are efficiently sized starting at already around 300 MW, and due to more interconnections, which led to larger market areas, the previous logic for monopoly generation has no longer held. In the new era, competition has benefitted customers. With the advent of mass-produced, modular generation and storage units, such as wind turbines, PV, biogas, batteries, and even EVs with vehicle-to-grid capability, it has become increasingly evident that electricity generation will go on for decades without a natural monopoly.

EU market integration

So many reasons speak for the integration of the European electricity system into a single internal market that we take it as a given for the period of our analysis. An integrated European electricity system supports all energy market targets. For example, it improves security of supply (through cross-border support during emergencies or shortages), lowers investment costs (the weather diversity across Europe reduces the need to back up fluctuating renewables with reserve capacity), and makes dispatch more efficient, especially when the share of renewables is high. Thus, European integration allows more renewables to be introduced to the system and contributes to the achievement of environmental targets.

Decentralised generation investment and governance through digitalisation

The reasons for Europe-wide market integration suggest that a return to regulated generation and supply would be conceptually very difficult. A single, EU-wide monopoly controlling all electricity generation operation and investment, and all supply to customers, seems unrealistic. But even if there were only national generation and supply monopolies, the trading between them to balance regional surpluses and deficits in renewables would be a strongly competitive element, requiring EU trading rules similar to today's network codes.

To avoid cross-subsidies between captive national customers, policymakers would have to admit competition in each country.

Another reason for decentralised resource investment decisions lies in the economies of scale of mass-produced wind turbines, PV panels, and batteries. As the mass production economies become stronger, they will enable small-scale, modular generation investment. Demand-side flexibilities are also an important resource for balancing renewables and managing scarcity situations. They are inherently decentralised insofar as they depend on decisions by millions of consumers with very different characteristics based on whether demand is in heating, EV charging, or industry.

Digitalisation is a prerequisite for a competitive retail electricity market, for unlocking demand-side response (DSR) potential, and for coordinating operations of millions of renewable energy installations and small-scale storage resources. The more potential is available and unlocked, the more effectively price signals can make use of them. If price signals are distorted or weakened, increased regulatory effort will be required for efficient investment and operation.

Availability of equipment and human resources compared with the speed and volume of investment

Investment decisions are increasingly influenced by restricting factors. Supply chain problems since COVID and made worse by the Russian invasion of Ukraine have increased lead times for investments in generation, storage, heat pumps, and energy efficiency. For instance, transformers have become a scarce resource worldwide. And shortages of skilled labour are a factor in many countries and industries due to a combination of demography, long COVID, and a mismatch between prior and current labour needs. Market forces cannot stimulate investments against such obstacles – at least, they cannot do so as fast as required. Over the next years, labour shortages and other restricting factors will be significant, though their exact effects remain uncertain.

Fuel scarcities and fuel-price shocks

The relevance of fuel scarcities and price shocks for market design is illustrated by the gas crisis. In theory, decentralised investment decisions and strong price signals should be able to handle shocks and scarcities better than monopolies or the state. But the effectiveness of price signals decreases if the system cannot react fast enough because of permitting delays, supply-chain problems, or labour scarcities. Moreover, fuel-price shocks can lead to imbalances in consumer and producer surpluses that last longer than is sustainable for industrial, commercial, and household customers. Though the months-long record natural gas prices began to decrease in the fall of 2022, natural gas prices in the future – e.g. in 2025 – are highly uncertain. They may be high, moderate, or even low. The accommodation of different possible outcomes in terms of fuel scarcities and price shocks is an important factor when considering the best market design options.

3.3 Evaluation criteria

The criteria we use for evaluating the key market design questions must relate to the three main targets for energy markets described in Section 2.3:

1. **Energy security**

Could an alternative system provide mechanisms to maintain sufficient generation and resource investments (including sufficient flex investments in storage or demand response)? Specifically, to what extent does each option support:

a. operational security, including system controllability and the alignment between physical requirements and market structures; and
b. investment incentives, investor confidence, and bankability for renewable energy sources and for flexible, dispatchable assets (e.g. storage and demand response)?

2. **Energy equity: access, affordability, and social welfare**

Could an alternative system maintain the efficiency level currently achieved in dispatch and system balancing, given the enormity of the European system and the increasing number of decentralised generators that do not participate directly in the wholesale market? Specifically, to what extent does each option support:

a. the maximisation of social welfare, i.e. the sum of producer and consumer surplus, which implies overall economic efficiency and the least-cost provision of energy in the highly interconnected European energy system;

b. incentives for innovation and dynamic adaptation to new conditions; and

c. an appropriate balance of producer and consumer surplus, including an absence of monopoly rents?

All three criteria contribute to affordable consumer prices.

3. **Environmental sustainability**

To what extent does each option support:

a. climate targets and decreased levels of air pollution, land use, and water use through, for example, price signals for externalities such as greenhouse gases and through the efficient retirement of carbon-intensive assets; and

b. energy efficiency and DSR incentives?

4. **Implementation efforts and adaptability**

In addition to the above criteria, which relate to the main targets for energy markets, market design options:

a. need to be realistic and fast enough to implement in the EU policy environment and be a good fit with the unchanging basic conditions described above;

b. need to perform well under fuel scarcities or price shocks.

Figure 2 summarises the evaluation criteria.

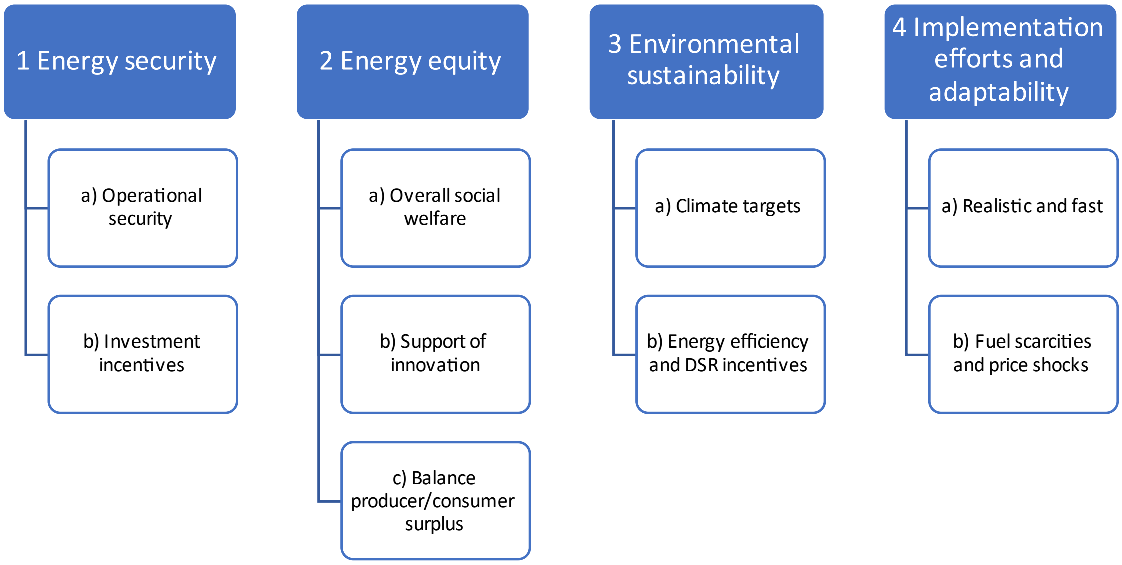

Figure 2: Evaluation criteria

3.4 Market design questions and options

The natural gas crisis has placed unprecedented stress on the energy system. This again raises the question whether alternative basic models, or price formation mechanisms and investment incentive options could fulfil the three main goals of energy policy better than the current market design.

The following market design questions are especially relevant to the current crisis. Could a centralised dispatch system instead of decentralised dispatch provide a better basis for measures that cap prices to avoid windfall profits and lead to a more balanced consumer and producer surplus? If so, it would represent a substantial “fix” to current prevailing market design in Continental Europe, though it would be similar to US, and Irish markets, and would thus preserve competition in generation and supply.

The second question is: which price formation options can be used to cap prices for adjusting the balance between the consumer and producer surplus during times of energy scarcity without diluting the investment incentives necessary for decarbonisation?[11] The key aspects of this question include how investments are incentivised, whether retail pricing

[11] The current discussion focuses on marginal cost pricing. Marginal cost pricing means that the price for all traded electricity is set at the level of the short-term operating cost of the most expensive (marginal) generator. The most expensive units are usually open-cycle gas turbines (OCGT), while the merit order between hard coal-fired units vs. combined-cycle gas turbines (CCGT) depends on the relative coal price vs. natural gas price. High natural gas prices lead to very high marginal prices and high (inframarginal) rents for all generators regardless whether OCGT or CCGT is on the margin. Immediate market reactions such as investments in renewables or more flexibility could balance out the price effects. However, these investments cannot be realised quickly. Therefore, temporary measures are needed to bridge this period for investment or until the gas price has decreased again.

details can serve to protect consumer surplus, and whether different price formation mechanisms such as pay-as-bid or average pricing automatically lead to a centralised dispatch and/or more regulatory decision power.

Finally, what other complementary measures can be introduced should the price formation remain the same? What is the least radical “fix” to the current market design that could still improve the balance of consumer and producer surplus in the event that natural gas prices stay high in the longer run?

In this paper we do not consider extreme options, such as re-introducing the full regulation of the value chain, eliminating competition, and introducing a single-buyer system. As we have argued, a decarbonised and decentralised electricity system cannot rely entirely on centralised regulatory measures.

At first glance, changing the price formation mechanism from marginal cost pricing to a pay-as-bid approach seems like an ideal way to avoid inframarginal rents. In theory as well as in practice, however, this approach requires heavy regulatory interventions. Market actors would estimate the marginal price and increase their bids to this level. Bids would need to be so strongly regulated that the approach would almost amount to regulated cost-based bidding, which has less innovation and flexibility. Due to the substantial regulatory intervention, implementation effort, and time required, especially in power exchanges, we do not consider this option any further.[12]

In central dispatch systems, all generation units would be dispatched by a single system operator. This would be akin to a mandatory power exchange or to the ISOs of North America. In centralised dispatch markets, generators are dispatched on a unit basis. All units must be transparent about their individual marginal costs and flexibility. To the system operator they must submit multipart bids, including marginal costs, start-up costs, and no-load costs. The ISO considers all elements of the bids to define the optimal dispatch, so their accuracy is crucial. Hence, regulators need to implement extensive measures to verify accuracy and avoid gaming. Central dispatch can work with a pay-as-clear approach, or the tight control of the system operator can be leveraged to change the price formation rule to a pay-as-bid mechanism. Enforcing the pay-as-bid method and passing on average prices to customers would lead to a decoupling of gas and electricity prices. If a successful pay-as-bid pricing scheme could be implemented, short-term measures to decouple natural gas and electricity prices would be unnecessary.

[12] A pay-as-bid approach could avoid the drawback of heavy regulation by not restricting the bids to costs and by appealing to bidders’ public welfare conscience in combination with imaginative state nudging. But this option would still involve power exchanges to switch to pay-as-bid pricing, and the resulting implementation effort is why we do not pursue it here. The hourly price applicable to all demand would be the volume-weighted average of all bids on the supply side up to the market-clearing bid. But without any voluntary bid adjustments, this would lead to prices that were the same or similar to those in the pay-as-clear method, as all bidders would bid their guess of the market-clearing price. There would be few efficiency disadvantages except when bidders misestimate the clearing price and a slightly suboptimal set of resources gets dispatched.

However, during long periods of scarcity or in the event of political price distortions, the regulator could ask bidders to voluntarily bid prices closer to their full costs. Generators that have entered into forward, future, or hedging contracts that depend on market-clearing prices need follow the request only to the extent that it does not endanger their contract structure and financial viability. Generators that have benefited from support schemes such as RES feed-in tariffs or premiums or coal or nuclear phase-out aid could easily follow this request as the supports they received assure their financial viability. If they do not follow the request, a negative evaluation marker for future RES auctions might be able to nudge them. The more generation units bid near their costs during extended periods of scarcity, the more a pay-as-bid price formation would resemble average cost pricing than marginal cost pricing, the less producer surplus and windfall profits would result, and the less pain consumers would feel. During normal times, there would be no nudging and no requests and the market results would not be substantially different from those yielded in a pay-as-clear system.

Changing the price formation mechanism is difficult in a decentralised system. We understand that no practical examples of central dispatch combined with pay-as-bid pricing exist today – the North American ISOs have good data on actual costs but use a pay-as-clear approach, which has pragmatic advantages over a pay-as-bid system. But tight regulatory oversight would come close to the cost-based pricing implemented in some central dispatch markets in Latin America.[13]

Although we recognise that the introduction of central dispatch could support more regulated price formation thanks to the possibility of cost-based bids, we will not examine the option any further in this paper. Central dispatch systems could be easily combined with nodal pricing, but the complexity of their implementation and the time required would be substantial. What is more, examining the benefits of nodal pricing lies outside the scope of this paper.

Another option under discussion is separating the wholesale market for low-carbon technologies from the remaining market ("market split"). Essentially, each of these markets would find a separate equilibrium at the marginal cost, and overall wholesale prices would be calculated based on the average prices from these two markets. This proposal is known as the "Greek proposal", and it was developed to deal with the natural-gas price crisis. We do not follow up on this proposal here because numerous problems with the approach have emerged during the past months.[14]

In this paper we focus on options with significantly less implementation time and effort, i.e. the support of merchant Power Purchase Agreements (PPAs) and voluntary and mandatory Contracts for Difference (CfDs). The three options are based on established support schemes for renewables applied to varying degrees in Europe. Currently, they are being discussed in the context of Europe's energy crisis. These measures have already reduced the immediate impact of high natural gas prices on consumers.[15] It is possible to evaluate them based on the criteria we have set.

[13] See Wolak 2003, section 4.4

[14] See Council of the European Union 2022 for more information on the proposal itself, see also Maurer et al. 2022. The authors emphasise the lack of dispatch incentives for pool resources, the end of market incentives for innovative investment in renewables and demand response, and the existence of severe implementation and legal hurdles. Ockenfels 2022 points out the market incentive-related problems of the Greek proposal and suggests a tax-based alternative.

[15] Amid the multitude of market design options in Figure 1, we concentrate on changes that could be implemented and have effects on consumer surplus soon. Accordingly:

- We do not consider a change from zonal to nodal or national pricing because policy discussions and IT implementation would take too long. Depending on the outcome of the current bidding zone review, this may need to be discussed in a future round of more fundamental market design adjustments.
- We do not consider dividing up the market by characteristic, as this would decrease investment and dispatch efficiency and also cause implementation and legal issues.
- We do not consider a change in wholesale market balancing, as the costs involved are not large enough to significantly affect the current consumer surplus crisis, while the EU's current move towards international balancing platforms is proving efficient, is fully in line with the needs of a renewables-dominated system, and still allows for local congestion management by DSOs.
- We do not consider a change in EU rules on pay-as-clear vs. pay-as-bid approaches, as we perceive this measure as not being effective.
- We do not consider a change in EU rules on central vs. self-dispatch approaches, as the policy discussions and IT implementation would take too long. These changes may need to be discussed in a future round of more fundamental market design adjustments.
- We do not consider operability options, as they are not closely related to the current consumer surplus crisis.
- We do consider a subset of the many options for managing mass low-carbon power, flexibility, and capacity adequacy, but rule out from consideration any options that are not closely related to the consumer surplus crisis because they are primarily focused on adequacy regarding, say, supplier obligations, capacity mechanisms, and reliability options.

Option 1: Support for long-term Power Purchase Agreements (PPAs)

Power Purchase Agreements (PPAs) are long-term contracts between renewable energy producers and certain customers for the delivery of electricity. Such contracts currently exist between large industrial consumers and (renewable) power producers. Contract durations exceed typical futures contracts and can reach the lifetime of an asset.

PPAs are essentially long-term forward contracts where counterparties arrive at long-term agreement on purchasing prices and quantities. If the PPA price is not attached to market prices, the contracting parties ignore price developments and agree on a common price expectation. For both parties, this arrangement guarantees revenue and cost stability. Hence, PPA contracts are regarded as a countermeasure against future fuel price shocks. They are also seen as an important instrument to create space for private initiatives in the field of low-carbon energy financing, to foster the innovation and market integration of renewables, and to end or reduce the need for government-driven renewable energy support schemes.

From the producer's point of view, PPAs are alternative or complementary to renewable energy support schemes. PPA markets play a larger role in jurisdictions where support schemes have less favourable conditions (as in the US). In Germany, PPAs and support schemes are mutually exclusive if the PPA contractor wants to claim a Guarantee of Origin (GOO). From the consumer's point of view, a PPA with renewable energy producers provides long-term hedging possibilities as well as a contribution to the consumer's sustainability targets (by purchasing the GOO).[16]

The specific option we analyse is a measure to improve the balance of consumer and producer surplus during crises. It describes possible government interventions in the PPA market in order to lower some existing barriers for bigger market shares of PPA. These barriers include missing contract standardisation, a lack of price transparency, and a higher level of risk for producers relative to governmental support schemes (counterparty risk, mismatch of investment depreciation time, and contract duration). Another problem of PPA contracts is that realistically they are only open to large electricity consumers active on the power market. For smaller customers, aggregators would have to take a role in the PPA.

Hence, multiple policy interventions are possible to support the application of PPAs. Current EU discussions focus on options that propose using public support to manage counterparty risks and to bundle PPAs to provide market access. Some additional proposals in discussion are the provision of standard contracts or the support of a PPA platform to facilitate price definition. Another proposal for government intervention lies at the juncture between PPAs and CfDs. In this case, instead of closing a PPA contract on their own, energy-intensive industries forward their desired volumes to a centralised CfD pool administered by the state.[17]

In Section 3.5, we will discuss the possible impacts of such measures.

This leaves us to consider variations of CfDs. There are two main policy options: making CfDs mandatory for certain kinds of resources and encouraging them strongly but keeping them voluntary. Both can be easily combined with caps and floors for more price exposure but this detail does not significantly affect their performance for consumer surplus and is hence not analysed in detail below. By contrast, encouraging PPAs is not a market design option per se as it is already possible in the current market design. In our study, we analyse PPAs as the private market equivalent to the regulatory and government-steered procurement process for CfDs.

[16] In Germany this is known as the *Doppelvermarktungsverbot*.

[17] See Neuhoff et al. 2022.

Option 2: Voluntary Contracts for Difference (CfDs) strongly encouraged for all new generators with low marginal costs

In this option we assume the introduction and systematic encouragement of two-sided Contracts for Difference for low-carbon technologies. Such contracts are currently used in the UK. An offshore windfarm in the UK wins an offshore wind auction with a set price per MWh strike price, the government promises additional revenue during times of lower power exchange prices to make up the difference between strike price and a defined market reference price, and the government receives the difference from the generator during times of higher market prices. This makes the windfarm bankable because sufficient revenues are guaranteed over the economic lifetime of the installation. Because it does not lead to reduced power exchange prices during scarcity, it maintains strong incentives for other investments or for demand response.

CfDs could be offered to generators with low marginal costs so that they all could switch to this scheme. This could apply to new generators and possibly existing ones as well. The expectation here is that the long-term financial viability ensured by the CfD would be a sufficient incentive for so many generation investors to pursue CfDs, that the combined effect would bring substantial improvements to the balance of consumer and producer surplus during fuel-price crises.

However, the detailed design of CfDs can be challenging since they can easily remove incentives for generators to optimise their output based on market signals of intraday and balancing market. To address this problem, several solutions are in discussion.[18]

CfDs are comparable to a power purchase agreement (PPA) at a fixed price or bandwidth, administered by a state institution on behalf of all customers.

Option 3: Mandatory CfDs for all new generators with low marginal costs

In the case of mandatory CfDs, the core change would be that for all new generation technologies with low operational and high capital costs entering the market, CfDs would be obligatory. This would essentially push all generation technologies that are not fired by natural gas or hydrogen and its derivatives into CfDs, and would thus create a way for the government to limit windfall profits when natural gas prices are high. It would also leave other high marginal-cost options out, such as demand response, batteries, and hydrogen-based generation. But merchant projects may no longer be permissible for renewable, nuclear, and coal generation. This would require extremely difficult discussions and choices with regard to, say, exceptions or penalties.[19] In order to show the impact of a mandatory introduction, we assume in our evaluation that no exceptions are made.

3.5 Evaluation results

In this section we provide a detailed evaluation of the options presented in the previous section according to the criteria defined in Section 3.3. We compare the three options with the status quo. After that we summarise the results of the evaluation.

[18] See Newbery 2023 and Schlecht et al. 2022

[19] A stronger variant would be to make the CfD mechanism voluntary for existing technologies or to force existing technologies to use this option.

Energy security – operations (criterion 1a):

Both CfD options can support operational security by steering investment decisions to appropriate resource flexibility. These options can perform better than the current system if investments are incentivised and auctioned in a way to target operational flexibility and system adequacy. The higher volume of mandatory CfDs could make this advantage stronger than for voluntary CfDs, but it is offset by the better flexibility and innovation of energy generation units that choose not to participate in CfDs.

The CfD arrangements are relevant for operational security. For instance, the calculation of the reference price determines whether generators have an incentive to produce during periods of oversupply and negative prices.

The measures discussed to support PPAs have no significant impact on operational security, assuming that producers have no feed-in incentives during oversupply periods.

Energy security – investment incentives (criterion 1b):

Most new generation, storage, and DSR investments have required support payments in the past. The gas crisis removed the need for support, but its duration is unclear. Hence, it makes sense to guarantee stable payments with a mechanism that can be used to limit windfall profits and to improve consumer surplus during times of scarcity, but that also provides long-term revenue stability. CfDs achieve revenue stability more efficiently than, say, feed-in premiums, in which recipients benefit from power exchange prices above the tariffs. Regarding investor confidence, we see advantages in all options that include CfDs to support investment decisions, especially in the case of renewables. This also counts for voluntary CfD schemes if investors have the option of switching voluntarily to a CfD system.

Mandatory CfDs would constitute a barrier for investment in smaller technologies (like PV) that capture their revenue from an increase in self-consumption.

PPAs can per se create fewer investment incentives than CfDs since counterparty risks need to be carried by market participants, and PPAs are less bankable than CfDs. If a PPA support mechanism helps to cover counterparty risks, the disadvantage decreases. However, no regulatory mechanism can entirely replace investment security incentives by a state body. Additionally, the current price insecurity leads to low liquidity in all forward markets. This affects long-term PPA to a corresponding degree. In the current crisis, measures to support PPA would have a limited impact.

Energy equity - social welfare: least cost dispatch (criterion 2a):

All options under consideration leave the wholesale market mechanism untouched. As described above, details of the CfD scheme design could lead to electricity generation at negative prices. This would negatively affect the efficiency of dispatch and, ultimately, total welfare. We score the mandatory CfD schemes worse than the other two options as we believe that such design mistakes are more likely to occur if future low-carbon generation is subject to a mandatory CfD.

Energy equity - consumer/producer surplus (criterion 2b):

Mandatory CfDs are best suited to capture producer surplus. The other two options are voluntary schemes where producers would have the option to avoid the capture of their inframarginal rents. In case of voluntary CfDs, they could try to secure financing via PPAs. But typically, PPAs cannot guarantee the same level of revenue stability and risk protection as CfDs.

As mentioned before, long-term PPAs are difficult to close but the situation is likely to change as markets find new equilibria. We score PPA support lowest in terms of this criterion because we believe that producers have few incentives to forgo high market revenues.

Energy equity - Innovation (criterion 2c):

While de-risking investment costs is crucial to lowering capital costs for renewables, the energy transition also requires incentives to implement new, innovative approaches to deal with variability and limited predictability of renewables. The more the requirements and technical details of investments are determined by centralised regulatory bodies, the less room remains for innovative approaches. Mandatory CfDs limit the ability to develop and test new technologies and ways of dealing with the properties of renewables – such as storage systems, new market products, etc. Hence, we rate mandatory CfDs (option 3) lowest in terms of this criterion, while we see advantages in supporting innovative PPA schemes against the status quo.

Environmental sustainability – climate targets, externalities (criterion 3a):

Under CfDs, investments especially appropriate for climate targets could be supported through the targeted design of CfD auctions, leading to a possible improvement of the current system.

PPA support has little impact on investments in low-carbon technologies only when not combined with another support scheme.

Environmental sustainability – incentives DSR, efficiency (criterion 3b):

Under CfDs, investment signals for decentral, non-auction climate-friendly investment decisions in DSR, hydrogen, batteries, and efficiency would depend on appropriate scarcity prices and on good administrative choices about the amount of low-carbon generation to be auctioned. The danger of poor administrative choices having a strong impact is higher with mandatory CfDs, thus offsetting their aforementioned advantages.

Realistic/fast implementation (criterion 4a):

No major adjustments to the market design are needed for the implementation of CfDs. They are already allowed under current European legislation for electricity markets. We regard the mandatory CfD to be more difficult in implementation than the voluntary system, as the magnitude of increase in administrative processes is higher for mandatory CfDs than for voluntary CfDs. By contrast, PPA support schemes do not face principal barriers and could be implemented quickly.

Reaction to fuel-price shocks (criterion 4b):

PPAs and both CfD approaches perform better than the current market design with regard to consumer surplus but are slow to achieve substantial effects because the investments they incentivise take years to go online. And in contrast to the current system, they lock in high prices for the lifetime of generation procured during high prices in times of scarcities, i.e. investors will partially base the prices they offer on today’s high price levels. Nevertheless, the long-term stability of costs or revenues can be seen as an improvement compared with the current situation. The level of improvement is smallest for the PPA options.

Both the advantages but also the substantial disadvantages or risks are stronger with mandatory than with voluntary CfDs or PPAs. The possible lock-in of current high prices would happen more in mandatory CfD systems, leading to an overall neutral rating for mandatory CfDs.

Summary of evaluation results

The following table provides a summary of our qualitative evaluation.

*

Options	1a Opera-tional security	1b Invest-ment incentives	2a Max social welfare, efficiency, least cost	2b Balance consumer - producer surplus	2c Support of inno-vation	3a Climate targets, externalities	3b Incentives DSR, energy efficiency	4a Realistic, fast to implement (fit w/ stable cond's)	4b Fit w/ fuel price shocks
1 PPA support	⚪	⚪	⚪	⚪	🟢	⚪	⚪	🟢	⚪
2 Voluntary CfD	🟢	🟢	⚪	🟢	⚪	🟢	⚪	🟢	🟢
3 Mandatory CfD	🟢	⚪	🔴	🟢	🔴	🟢	🔴	🔴	⚪

Table 1: Evaluation of relevant market design options

Table 1 reveals diverse pros and cons but also significant drawbacks. There are more cons than pros for option 3, and a predominance of advantages in option 2. The seeming advantage of option 3's mandatory CfDs with regard to consumer vs. producer surplus – a topic that deserves special focus in the current crisis – is more than offset by its disadvantages in terms of innovation, DSR incentives, and the ability to cope with unforeseen fuel-price shocks.

Interestingly, PPAs offer advantages on two important criteria when the overall best option (voluntary CfDs) is neutral relative to the status quo, i.e. the support of innovation and the speed of implementation. Since PPAs and voluntary CfDs do not mutually exclude each other, pursuing both could lead to an even better improvement than option 2 alone.

Voluntary two-sided CfDs, either alone or in combination with PPAs, offer a promising way to improve the balance of consumer vs. producer surplus in the long run with little implementation effort and limited risks.

4. Summary

This section summarises the conclusions that can be drawn from our evaluation of market design options in response to current scarcities and to possible market evolution scenarios through 2030.

We looked at the history and particularities of EU electricity markets, main targets they must achieve, and current challenges. Of many detailed market design options, we concentrated our analysis on those with low implementation barriers. Some harder-to-implement options may become part of later, 5th Energy Package discussions, especially if they support high RES shares, complete decarbonisation, and flexibilities.

Overall, the least disruptive approach for electricity markets given their complexity – which means that any “fixes” are likely to create negative unintended consequences – involves making no significant adjustments to the current market design. For a scenario in which natural gas prices and power exchange prices fall and approach 2018–2021 levels, this course of non-action would sufficiently support the main goals of energy markets.

However, in the event of sustained elevated natural gas prices and for any other shocks that upset the balance of consumer and producer surplus, non-action would poorly support the targets. Eventually, the natural gas and electricity markets will find new equilibria as Europe becomes more independent from Russian natural gas and as renewables and hydrogen-based storage and generation technologies take a large share in the electricity system but waiting for that uncertain outcome will not serve customers well.

The most important conclusion is that there are attractive options that carry advantages over the current market design for a range of targets. A more systematic use of voluntary CfDs to steer investments and windfall profits has several advantages and relatively few disadvantages. By contrast, mandatory CfDs have important power system risks, including lower market efficiency, reduced support for innovation, increased implementation effort and time, and a less nimble response to equipment and labour scarcitiesor to unforeseen fuel-price shocks.

PPA support has a few advantages compared with the current system. They are not particularly pronounced and are by themselves not substantial enough to address the skewed distribution of producer and consumer rents today.

The most promising approach is the immediate introduction of voluntary CfDs for all new low-carbon generation, potentially complemented by several measures to support PPA with their innovation and implementation speed advantages. CfDs would do better than the status quo for consumer surplus and fairness during fuel scarcities and price shocks, without changing the basic design of the complex European power market. Voluntary CfDs preserve market signals for investment better than other options, can improve operational and investment efficiency and climate targets, and have very few drawbacks or risks. However, it is clear that the analysed measures cannot entirely decouple natural gas from electricity prices. The consumer protection effects grow over the years with new investments; short-term relief depends on uptake by existing resources. What they can do is gradually improve the long-term stability of consumer and producer rents. To decouple natural gas from electricity prices, fundamental market design changes would be required, bringing with them long implementation times, a significant increase in regulatory interventions, and large associated risks.

5. Appendices

5.1 Appendix 1: The importance of consumer surplus in electricity for robust future market design – a numeric example

As mentioned in Section 2.1, the lack of alternative services or products for many uses of electricity leads to values or willingness-to-pay on the side of consumers that hugely exceed normal production and distribution costs. In Europe, household customers in late 2021 paid between 10 and 34.5 ct/kWh (Hungary and Denmark made up the extremes).[20] The value of the lost load – i.e. the value consumers lose if a kWh is not delivered in, say, a blackout – ranged between €4 (Czech Republic) and €69 per kWh (Netherlands).[21] To compare apples with apples, the EU average price was 21.7 ct/kWh and the average value of the lost load (over 11 countries) was 22 €/kWh, i.e. a factor 101 times higher than the price. Included in the 21.7 ct/kWh are not only the costs but also the producer surpluses – the difference between production costs including acceptable rates of return and market prices – for power plants and renewable energy, for transmission and distribution grids and their second-by-second management, for the supply and customer services, and for taxes and levies (36% of the price). For decades, those prices proved sufficient to cover costs and provide utilities with sufficient funds and incentives to invest.

For the late 2021 EU-average ct/kWhwithout taxes and levies – 15.15 ct/kWh – the producer surplus was roughly 1 to 3 ct/kWh. By comparison, the consumer surplus amounted to 2178 ct/kWh, which is the difference between willingness-to-pay (2200 ct/kWh) and market prices (22 ct/kWh).

This combination of a huge consumer surplus and moderate production costs and producer surpluses illustrates how inelastic electricity demand is compared with other markets. If electricity becomes more expensive, consumers do not reduce demand much because the value is still high to them. Instead, they suffer financially and reduce their demand for other goods and services. Inflexible power markets and grid fees, and the absence of smart meters, add to this low price elasticity, but even if such conditions improve, price elasticity would still remain low. This suggests that policies and regulations should carefully monitor the balance of consumer and producer surpluses and aim to avoid undue exploitation of consumers' vulnerable position in the electricity market.

The balance of consumer and producer surplus has indeed been upset during the current natural gas scarcity crisis. Power exchange prices have risen substantially, particularly because of the price-setting role of gas-fired units. This has caused monthly average power exchange prices in Central and Western Europe to rise from between 16 and 23 ct/kWh in April 2022 to between 31 and 40 ct/kWh in July 2022 (base day-ahead prices). This means that the producer surplus for all power plants whose costs are not substantially affected by natural gas prices rose by roughly 10 to 35 ct/kWh, or by a factor of roughly 6 to 18. Accordingly, the consumer surplus decreased by 10 to 35 ct/kWh. This decrease may seem small compared with the huge consumer surplus of almost 2200 ct/kWh. But depending on the retail contract, the decrease can roughly double the price per kWh paid by households, forcing them either to forgo consumption of between €50 to several hundred euros per month, or to save so much electricity that their comfort is severely impacted. The relationship between prices, producer surplus, and consumer surplus is similar or worse for commercial and industrial electricity consumers for which electricity is a major cost factor, endangering their competitiveness and even their survival.

[20] See Eurostat 2022
[21] See ACER 2022

The quantitative examples from the past months' power markets show why the European Commission and many policymakers intend to adjust the market design to protect consumers from welfare losses and, ideally, to decrease windfall profits for generators. Appendix 2 examines to what degree the increased producer surpluses over the months of 2022 may go beyond what is needed to maintain investment incentives.

5.2 Appendix 2: The scale of generation windfall profits versus investment incentives – a numeric example

We compare the levelised costs of new generation from onshore wind, PV, offshore wind, bioenergy, and nuclear energy with scarcity prices since October 2021 that are in excess of the prior power exchange prices on which investors may have based their business cases. Table 2 provides the data for this analysis.

Table 2: Investment incentives in crises and prior power exchange prices

Avg DA price EPEX spot for DE-LU, €/MWh[22]		Levelised cost of electricity generation (LCOE) €/MWh[23]				
2018 through 2021	Oct-21 through Sep-22	Onshore wind	PV	Offshore wind	Bioenergy	Nuclear
51	227	42	60	65	88	71
Say investor confidence depends on a generation station's 25-year lifetime difference between 2018–2021 spot prices and its LCOE after one year of scarcity prices: Would the Oct-21–Sep-22 surplus rents be sufficient to overcome 25 lifetime years of each generation station type falling short of normal (2018–2021) PX revenues?						
Scarcity surplus rent €/MWh		€/MWh captured above (+) or below (-) sufficient incentive				
176		400	-50	-175	-565	-1033
The calculation would remain the same if Oct-21–Sep-22 scarcity prices prevailed for a 2nd year						
		576	126	1	-389	-857

This table shows that onshore wind generators have already earned substantially more surplus profits between October 2021 and September 2022 than needed for an investment business case. This assumes that they relied on spot prices and were not hedged by a two-sided CfD and that future revenues for 25 years would only be 51 €/MWh, the average of the 2018–2021 period. There is one exception, however: there is a single 12-month period of scarcity prices during the gas crisis, during which they receive as much revenue as in the past 12 crisis months even without any support schemes. For PV, offshore wind, bioenergy, and nuclear, 12 crisis months would not suffice, but for PV and offshore wind, 24 crisis months would.

In interpreting these results, several important issues must be kept in mind. First, all generation types in Table 2 are low carbon and thus represent investments that EU

[22] Volume-weighted day-ahead prices, with an average of 37 €/MWh for the 2018–2020 period. See Fraunhofer ISE https://www.energy-charts.info/charts/price_average/chart.htm?l=en&c=DE&chartColumnSorting=default&interval=month&month=-1)

[23] See IRENA 2022 and IEA 2020.

countries will need. They stand in contrast to investments in coal- and oil-based generation, which might help in the current crisis but are so CO_2-intensive that we have designed phase-out plans for them. In most cases in Europe today, these generation types receive out-of-market support such as contracts for difference or feed-in premiums. In view of the cannibalisation effect that occurs when solar and wind units reach increasing penetration rates in the power system, most experts expect that support schemes will continue to be needed. But this means that the generation units analysed in Table 2 actually need fewer surplus profits than estimated in the table, which strengthens our argument that policy makers have waited long enough and will not endanger investor confidence.

Second, LCOE and past years′ average day-ahead prices are only rough indicators for actual business case calculations. Investors must also consider the forecasts of power prices in different countries for several scenarios, the peak or off-peak times of generation, the controllability of generation, different weather years, and, most importantly, revenues from different power markets, which includes not only day-ahead and intraday markets but also forward markets, bilateral contracts, power purchase agreements, other hedging instruments, and various balancing and ancillary services markets.

6. Publication bibliography

ACER (2022): Security of EU electricity supply in 2021. Available online at https://acer.europa.eu/sites/default/files/documents/Publications/ACER_Security_of_EU_Electricity_Supply_2021.pdf.

Averch, Harvey; Johnson, Leland L. (1962): Behavior of the Firm Under Reglatory Constraint. In *American Economic Review* 52 (5), pp. 1052–1069.

Baldick, R.; Andrade, J. (2016): Estimation of Transmission Costs for New Generation. White Paper UTEI/2016-09-1. Available online at https://energy.utexas.edu/sites/default/files/UTAustin_FCe_TransmissionCosts_2017.pdf.

Council of the European Union (2022): Proposal for a power market design in order to decouple electricity prices from soaring gas prices - Information from the Greek delegation (11398/22).

Cramton, Peter; Ockenfels, Axel; Stoft, Steven (2013): Capacity Market Fundamentals. In *Economics of Energy & Environmental Policy* 2 (2). Available online at https://EconPapers.repec.org/RePEc:aen:eeepjl:2_2_a02.

Department for Business, Energy & Industrial Strategy, UK Government (2022): Review of Electricity Market Arrangements. Consultation Document. Available online at https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements.

Eurelectric (2022): How are EU electricity prices formed and why have they soared? Available online at https://www.eurelectric.org/in-detail/electricity_prices_explained/.

European Parliament (2017): Capacity mechanisms for electricity. Briefing. Available online at https://www.europarl.europa.eu/RegData/etudes/BRIE/2017/603949/EPRS_BRI(2017)603949_EN.pdf.

Eurostat (2022): Electricity Prices for Household Customers. Available online at https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Electricity_price_statistics.

Hogan, Michael (2017): Follow the missing money: Ensuring reliability at least cost to consumers in the transition to a low-carbon power system. In *The Electricity Journal* 30 (1).

IEA (2020): Projected Costs of Generating Electricity 2020. Paris. Available online at https://www.iea.org/reports/projected-costs-of-generating-electricity-2020.

IRENA (2022): Renewable Power Generation Costs in 2021.

Maurer, Christoph; Hirth, Lion; Schlecht, Ingmar (2022): The Greek market design proposal would be the end of electricity markets as we know them (Euractiv). Available online at https://www.euractiv.com/section/electricity/opinion/the-greek-market-design-proposal-would-be-the-end-of-electricity-markets-as-we-know-them/.

Neuhoff, Karsten; Kröger, Mats; Richstein, Jörn (2022): Erneuerbaren-CfD-Pool für Industriestrom. Edited by ZBW - Leibniz Information Centre for Economics (EconStor Research Reports, 262287).

Newbery, David (2015): Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors (Cambridge Working Paper in Economics, 1513).

Newbery, David (2023): Efficient Renewable Electricity Support: Designing an Incentive-compatible Support Scheme. In *The Energy Journal* 44 (3).

Ockenfels, Axel (2022): A simple proposal to skim electricity firm's windfall profits (Euraktiv). Available online at https://www.euractiv.com/section/energy/opinion/a-simple-proposal-to-skim-electricity-firms-windfall-profits/.

Schlecht, Ingmar; Maurer, Christoph; Hirth, Lion (2022): Financial Wind CfDs. Edited by ZBW – Leibniz Information Centre for Economics. Kiel, Hamburg.

Schweppe, Fred C.; Caramanis, Michael C.; Tabors, Richard D.; Bohn, Roger E. (1988): Spot Pricing of Electricity. Boston, MA: Springer US (The Kluwer International Series in Engineering and Computer Science, Power Electronics & Power Systems).

Wolak, Frank A. (2003): Designing Competitive Wholesale Electricity Markets for Latin American Countries. Prepared for the First Meeting of the Latin American Competition Forum. Paris. Available online at https://www.oecd.org/daf/competition/prosecutionandlawenforcement/2490209.pdf.

World Energy Council (2022): World Energy Trilemma Index 2022. Available online at https://www.worldenergy.org/transition-toolkit/world-energy-trilemma-index.