STUDY

Requested by the ITRE committee

European Parliament

The design of the European electricity market

Current proposals and ways ahead

Policy Department for Economic, Scientific and Quality of Life Policies
Directorate-General for Internal Policies
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The design of the European electricity market

Current proposals and ways ahead

Abstract

The proposed reform of the electricity market design maintains crucial elements of the existing system to ensure continued efficient operation. The impact that changing the rules on longer-term contracts will have on consumer prices and investment will depend on the concrete language of proposed legislation as well as its ultimate implementation. Overall, neither the expected mode of impact of individual reform elements, let alone their interaction, is clearly spelled out by the legislators.

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LIST OF ABBREVIATIONS

ACER	Agency for the Coordination of European Regulators
CCGT	Closed-Cycle Gas Turbine
CfD	Contract for Difference
DISC	Dispatch and Contracts Model
DSO	Distribution System Operator
EEX	European Energy Exchange
EMD	Electricity Market Design
EU	European Union
FCR	Frequency Containment Reserve
ICE	Intercontinental Commodity Exchange
ITRE	Industry, Research and Energy Committee of the European Parliament
LMP	Locational Marginal Pricing
LTTR	Long-Term Transmission Right
LNG	Liquified Natural Gas
NRA	National (Energy) Regulatory Authority
OCGT	Open-Cycle Gas Turbine
PPA	Power Purchasing Agreement
PV	Solar Photovoltaics
TSO	Transmission System Operator

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EXECUTIVE SUMMARY

Background

In March 2023 the European Commission proposed a reform of the European electricity market. The proposed changes to the Electricity Regulation, the Electricity Directive, and the REMIT Regulation are being negotiated with the European Parliament and the Council at the time of writing.

The reform was initiated by Commission President von der Leyen in the midst of the European energy crisis in the second half of 2022. The main motive at that time was to mitigate the spill-over of the gas-crisis, that led wholesale natural gas prices to increase ten-fold, into electricity prices for households and industry. As demand reduction and additional supplies quickly alleviated the gas-price crisis and as it became clear that simple fixes to electricity markets have massive side-effects, the discussion moved to longer-term reforms. Most importantly, the framework for longer-term contracts between producers and consumers was adjusted with a view to allow producers to better hedge and hence more easily invest; and consumers to better protect themselves from short-term price spikes.

Aim

This study aims to assess the existing electricity market design according to how it functioned during the energy crisis. The criteria of operational efficiency, fairness, and encouraging smart investment are proposed as yardsticks for doing so. In assessing proposals for reforming individual components of the EU's electricity market the study develops a quantitative framework. This framework is used for assessing key reform questions arising from the European Commission's electricity market design reform proposal.

The study contextualises the ongoing market reform discussion as a part of the necessary multi-year reform cycle that will be needed to adapt power markets as a consequence of changes brought on by the energy transition. We offer analytical recommendations for short- and long-term priority items.

Key Findings

The energy crisis tested the **current market design** on three key elements: operation, fairness, and investment. From an operational standpoint, the electricity market continued to function well and helped Europe to navigate a historically tight position. From a fairness perspective, the size of the shock led to unexpected and substantial shifts in wealth, particularly hurting consumers who were not hedged against price fluctuations. The largest problem exposed by the crisis in terms of current design was investment incentives. The system had developed too little generation capacity, too little interconnection, too little maintenance, and too high reliance on individual fuel supplies.

In response, the **European Commission proposal** for reforming electricity market design does not propose a radical overhaul of the existing system, but rather a fine-tuning of existing market instruments on a case-by-case basis. This includes proposals concerning Contracts for Difference, hedging obligations, the design of an intervention framework for future price crises, an additional product for peak shaving (reducing consumption during existing hours of high demand), and energy sharing.

A fundamental and concerning conclusion of our paper is that Europe lacks the necessary assessment-framework for objectively analysing the impacts of proposed adjustments to such isolated market instruments. While a wealth of literature has investigated the least cost optimisation of power systems, far less attention has been devoted to the development of tools that allow **modelling the financial flows that sit behind electricity trade**. Our report proposes a highly stylised-tool the **Dispatch and**

Contracts (DISC) model. The model represents financial flows as a result of contractual arrangements between agents layered upon a physical electricity system.

We offer three specific recommendations for the ongoing electricity market design reform. First, any protection offered to customers against future price increases **should not interfere with short-term price incentives**. Incentives for demand to respond to prices were essential during the energy crisis, and their importance will likely grow as grids integrate increasing shares of weather-dependent renewable resources. Secondly, long-term contracts to encourage deployment of low-carbon generation should be designed in a way to **preserve short-term, operational efficiencies**. This particularly refers to the need for designing smart Contracts for Difference. Thirdly, excessive tinkering with incentives for flexibility should be avoided. **The existing mechanisms for balancing short-term power markets already work well**.

Moving beyond the current discussion, a more fundamental rethink of Europe's electricity market will be required as the energy transition progresses. A near-term priority should be to **increase transmission capacities** – the ability of countries to trade electricity – which will lower electricity costs across the continent. A second short-term threat to the efficient operation of grids **are political discussions to freeze prices for certain demand groups** (e.g., large industry). Any move to overrule market forces by government decree runs the risk of an inefficient subsidy race inside Europe, and inefficient investment decisions.

Managing the correct balance of an electricity system caught between a **market offering some investment signals and a constant stream of evolving government intervention** will be the key challenge moving forward. Higher-quality and more transparent planning exercises at the European level can help. Retaining sensible incentives for investment and operation will remain critical as the continent transitions toward a system of more flexible supply, and an evolving and growing demand mix.

1. INTRODUCTION

KEY FINDINGS

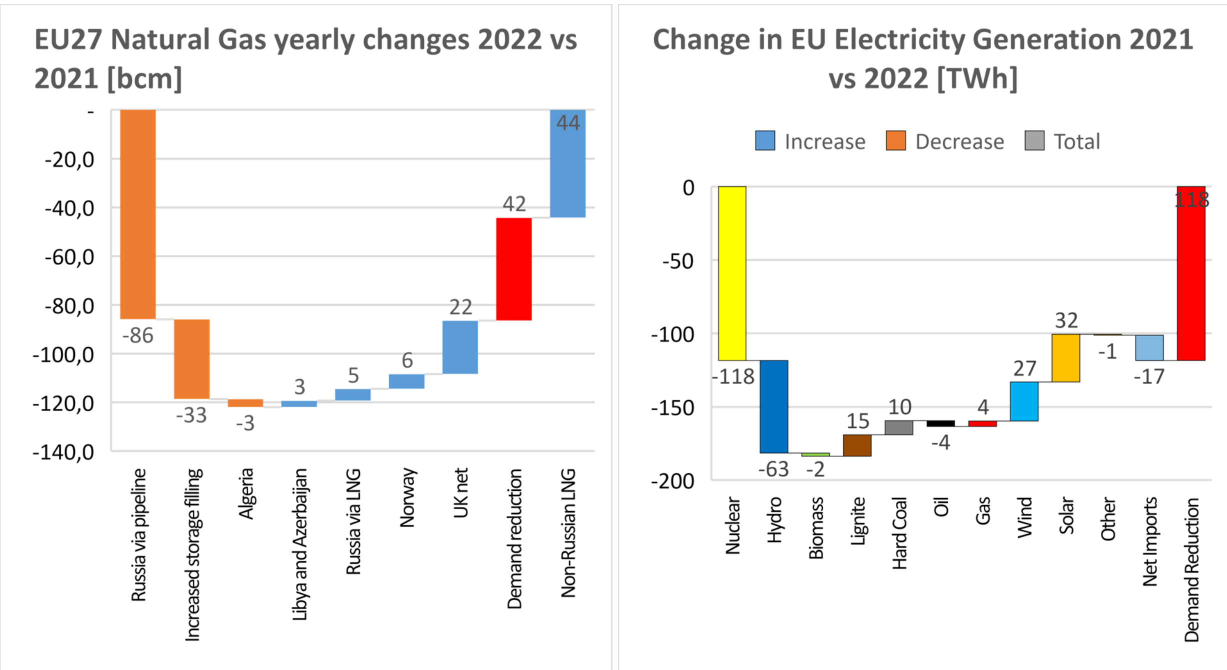
Europe's energy crisis of 2022 was driven by shortages of natural gas. The nature of electricity markets meant that higher gas prices were passed through into higher electricity prices. This experience, and the accompanying increased costs to consumers, pushed the reform of electricity markets up the political agenda. The two driving factors of a perception that a new market design is required are the need to ensure fair and efficient markets. These two elements manifested themselves in the sense that electricity prices were overly reliant on the price of natural gas, and that consumers were inefficiently protected.

Current electricity market design comprises a complex interaction between generators, traders, retail suppliers, regulatory authorities, system operators, and consumers. Any reform to the system should be designed to accommodate five core changes that are anticipated to electricity markets. These are increased demand, renewable adoption leading to declining variable costs, decentralisation, digitalisation, and a shift toward active demand that responds to prices.

1.1. Background to the study

Reform of the EU electricity market design is occurring during an unprecedented upheaval in European energy markets. 2022 saw the most severe energy crisis experienced on the continent in decades. Natural gas, a cornerstone of the energy system, became scarce and costly after Russia drastically cut pipeline supplies. Increased imports of liquified natural gas (LNG) were required to make up the deficit, purchased on international markets at a significant premium to historical prices. Drought conditions causing low hydropower output and a series of exceptional nuclear outages in France exacerbated the energy supply problem.

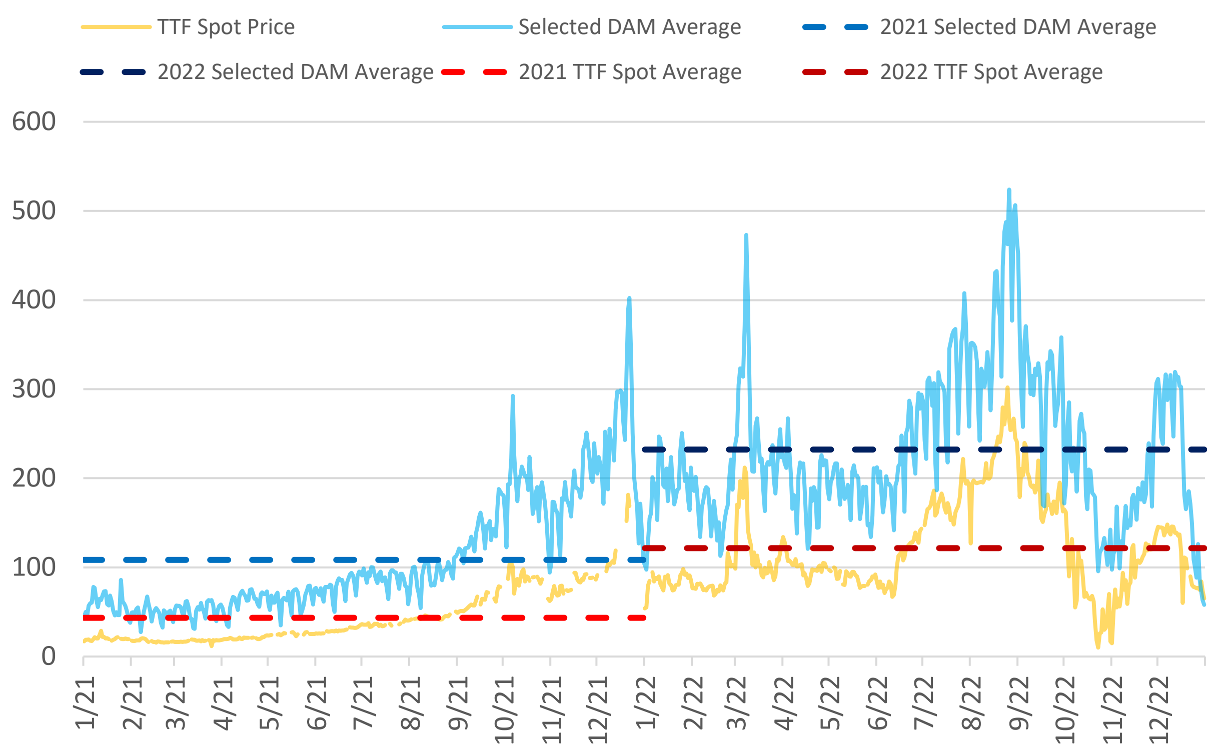
Figure 1: The 2022 energy crisis



Source: Bruegel based on Entso-G, Bloomberg and EnergyCharts.

As the electricity system is dependent on natural gas to balance supply and demand, the unavailability of sufficient cheaper production and the increase in gas costs transmitted to electricity. Consequently, prices for gas and electricity reached record levels (Figure 2). In response, hundreds of billions of public monies were spent to shield small businesses and consumers from the rising costs[1].

Figure 2: Electricity and gas prices in selected countries in 2021/2022 in EUR/MWh



Source: Bruegel based on ENSTO-E and Bloomberg.

Note: Electricity prices are the average of day-ahead market prices in Germany, France, Italy, Spain and Poland.

While Europe appears to be better positioned for winter 2023/24 in terms of gas security of supply, the energy crisis persists (McWilliams et al, 2023). Wholesale gas spot prices increased from an average of 43 €/MWh in 2021 to 122 €/MWh in 2022. In mid-September 2023, the average TTF spot price for 2023 is 35 €/MWh[2]. Electricity prices are also persistently higher in 2023 than in pre-energy crisis years (120 €/MWh on average between January 2023 and August 2023 across Germany, France, Italy, Spain and Poland[3]). Policymakers are seeking means to manage the situation, including by making changes to the European electricity market design.

The focus on electricity market reform stems from the view that there are elements of the existing design that are inefficient and unfair. Consumer electricity prices substantially increased in 2022 and 2023 compared to previous years (Figure 3). In the same period, oil and gas firms posted huge profits. European utilities also saw some revenue increases, although less significantly than the oil and gas majors. In the context of rising consumer costs combined with increasing corporate profits, a

[1] See Bruegel's tracker of fiscal responses to the energy crisis to shield consumers across Europe https://www.bruegel.org/dataset/national-policies-shield-consumers-rising-energy-prices.

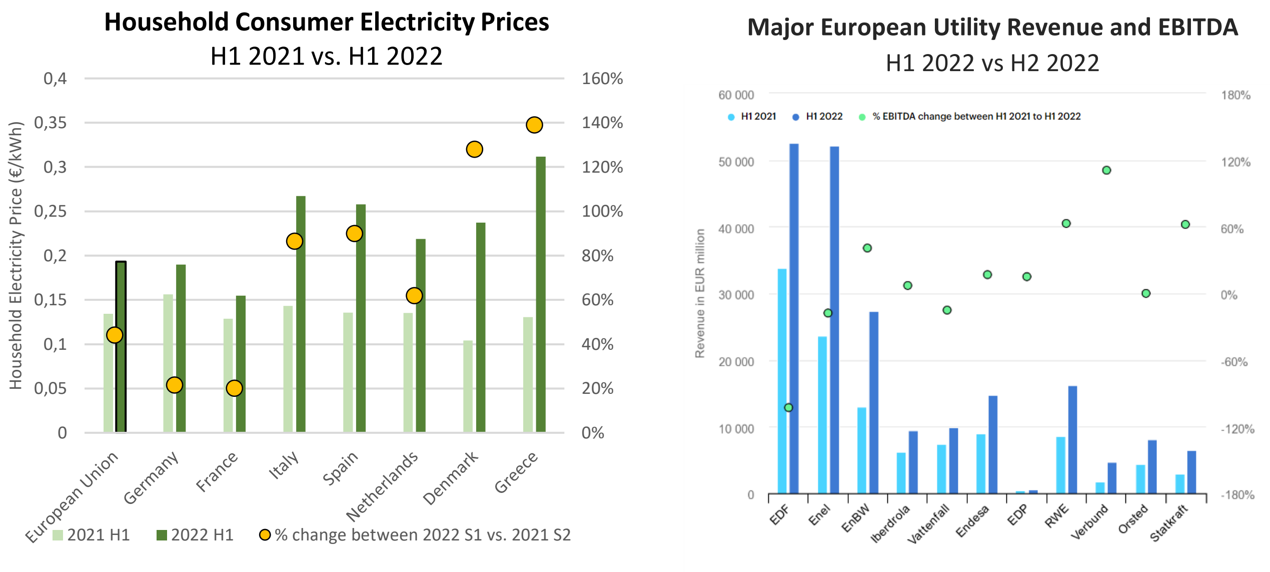
[2] Source: Bloomberg.

[3] Source: ENTSO-E.

perception understandably emerged that aspects of the policy framework around energy, and especially electricity, was flawed.

After extensive public debate, two core issues were identified. First, the electricity system was reliant on natural gas that is subject to the volatility of international commodity markets. Decoupling electricity from gas therefore became an objective of the electricity market reform. Second, consumers were insufficiently protected from severe price increases. Covering a higher share of electricity deliveries with long-term contracts between generators and consumers therefore became another goal. As a result, the initial reform proposal from the European Commission on 14 March 2023 (European Commission, 2023) set out a variety of instruments that would allow member states to attract renewable generation through long-term contracts, as well as new options for price hedging and consumer protection. By investing in renewables, the physical reliance on natural gas could be reduced, and by adjusting the rules for long-term contracts, consumers might be better protected from price volatility.

Figure 3: Consumer electricity prices and utility revenues



Source: Bruegel based on EUROSTAT and IEA.

While the need for reform emerged from the pressures of the gas crisis, electricity market design has a critical role to play in the energy transition more generally. In March 2023, as part of the REPowerEU plan, the EU finally agreed to substantially ramp up its ambitions in terms of decarbonising the energy system with a target of 42.5% renewable energy by 2030.[4] If the EU wants to meet its ambitious decarbonisation targets, a strong policy framework must be in place that can deliver appropriate investment signals for renewable energy, most importantly in the electricity sector.

In the context of electricity market design, this strong investment signal means not only incentives for wind, solar and other renewable electricity generation resources, but also for storage, demand response, clean dispatchable generation, grid expansion, and the myriad other technologies needed to deliver a reliable zero emissions electricity system. In addition to investment signals, the electricity

[4] This is, however, only the confirmation of a renewables target proposed by the European Commission already before 2022. An increase in the binding target to 45% proposed by Parliament and Commission in light of the new circumstances in 2022, did not gain the support from member states.

market should help to ensure that the costs of paying for the electricity system are fairly distributed and that a decarbonising system is efficiently operated, as discussed in section 2.

The electricity system will undergo structural changes as a direct consequence of the transition to a net zero. In Europe, these changes will be accelerated with more ambitious decarbonisation targets. It is essential that electricity market design can continue to deliver fair outcomes, efficient investment signals, and efficient system operation throughout the transition, even as the physical electricity system changes. There are five essential ways in which the electricity system will change over the next decades, as follows.

Demand increase

To meet the EU's ambitious net zero target, a substantial increase in electricity demand is foreseen (4900–6500 TWh of electricity demand in 2050 compared to 2800 TWh in 2020, according to Holz et al, 2022). Significant shares of energy demand in the heating, transport and industrial sectors must be electrified. Electricity demand will likely double in the next three decades, when it only increased by 25% in the last three decades. Therefore, investment incentives must be clear and consistent until 2050 and beyond. As renewables (and in some countries nuclear) whose investment is currently driven by idiosyncratic national polices will represent the bulk of the supply increase, designing efficient investment incentives for those will be crucial to develop a cost-effective European electricity system.

Declining variable costs

The bulk of the lifetime cost of thermal power plants is driven by variable short-run fuel costs. In the case of renewables, the asset structure is inverted. Solar and wind projects have no fuel costs. Accordingly, their lifetime cost is dominated by the initial capital expenditure involved in developing the project. Different financing requirements are needed for different asset cost structures, implying that the investment signals that worked for thermal power plants like gas and coal-fired generation may not be appropriate for renewables.

Decentralisation

The electricity system of the twentieth century was mainly centralised through a small number of large power plants generating most of the electricity. Electricity flow was unidirectional, moving from generation to consumption via the transmission and distribution grids. This configuration is challenged by renewable technology. Wind and solar plants are more geographically dispersed than thermal plants. Photovoltaics, battery systems, and electric vehicles mean that households and businesses can now play an active role in the system, even producing their own power. The flow of electricity is now bidirectional in the grid, with consumers now sending power back to the wider network. Decentralisation will continue as more modular clean-energy technologies are added to the system (Zachmann and Tagliapietra, 2016).

Digitalisation

The broader trend of digitalisation will considerably affect the power system and facilitate many opportunities for innovation. Integration and optimisation of decentralised assets like wind and solar will lead to improvements in their efficiency. More precise and granular data will provide consumers with information to manage their electricity usage and actively respond to system conditions.

Demand becoming active

Decentralisation and digitalisation will facilitate electricity consumers to become active players in the power system. Electrification of heating, transport and industry will further enhance demand-response capabilities. Consumers of electricity will be able to co-optimise their use of electricity for multiple ends (so-called 'sector coupling'). Critically, the demand-side will be responsive to system conditions, using and storing power when it is abundant and reducing demand when it is scarce. More radical possibilities are in the process of being realised in Europe, through the development of energy communities. Such organisations typically own and operate their own shared energy assets, sharing the benefits of the resource and at times selling their surplus to the grid.

Structure of the report

Electricity market design is part of complex set of levers to affect outcomes in the electricity sector, which include the fiscal system and network regulation. This study will focus on the design of the European wholesale electricity market. While retail markets are largely a national competency, the study will also discuss the consequences of policy choices in this area. Network regulation and taxation more broadly are also relevant for electricity sector outcomes and therefore the study will engage with them as they relate to electricity market design. The analysis in the study is centred on the market reform proposals put forward by the European Commission in March 2023 and the amendments agreed upon in the ITRE committee of the European Parliament in July 2023, but will also consider longer term issues for electricity market design.

The remaining parts of section 1 summarise the current European electricity market design, highlight some of its recent shortcomings, and detail the European Commission and European Parliament market reform measures. A set of criteria for assessing electricity market design are then presented (section 2), after which a detailed assessment of the possible market instruments and design details of the reform is presented (section 3). A stylised model of the European electricity market is then detailed, which is applied through a scenario analysis quantifying the effects of market instruments (section 4). An excurse on the need for an impact assessment when dealing with consequential policy areas is set out in section 5. The study concludes with a set of policy recommendations for the current reform and for the future (section 6).

1.2. The current European electricity market design

The European electricity market in 2023 is a complex system involving multiple economic agents at various levels who trade in numerous market timeframes, both short and long-term. The following description of the current electricity market is organised by first setting the legal basis for the electricity markets, outlining the different economic agents, then detailing the market timeframe, followed by a critical discussion on the role of marginal pricing. The emergency measures introduced during the energy crisis are also described.

1.2.1. Legal basis

The last electricity market reform took place as recently as 2019. The 'Clean Energy Package', was, in effect, the fourth electricity market reform, after legislative processes that happened in 1996, 2003 and 2009. The Clean Energy Package was comprised, inter alia, of Electricity Directive (EU) 2019/944, which made amendments to the previous electricity market directive (2009/72/EC), and Electricity Regulation (EU) 2019/943.

Electricity Directive (EU) 2019/944 further developed common European rules for the generation, transmission, distribution, storage, and supply of electricity, as well as consumer protection measures. The Clean Energy Package focused on increasing the integration of electricity markets, aiming to enhance cross-border-trade and better harmonise market rules. Competition between suppliers was also emphasised. Electricity Regulation (EU) 2019/943 set out the detailed rules for operating electricity markets, including price formation and balancing responsibilities. Again, cross-border capacity allocation was prominent, as well as provisions regarding network charges and design principles for capacity markets. The Agency for the Cooperation of Energy Regulators (ACER) was also established through Regulation (EU) 2019/942. Regulation (EU) No 1227/2011 (REMIT), was not revised in 2019, but is relevant for the functioning of the electricity markets as it covers market integrity and transparency through market monitoring.

1.2.2. Agents in the European electricity markets

Generators, storage units & utilities

One principal economic agent in the European electricity markets is an electricity generation unit. Some units transform other forms of costly energy entailed in uranium-rods, coal, natural gas, hydrogen etc. into electricity; while others are basically having no variable cost, but might depend on the natural forces such as solar irradiation and wind to power them. Typically, higher fuel cost correlate with a higher ability to flexibly react to demand variations (nuclear and lignite units have rather low fuel cost but are also more run to follow some seasonal trends; while hydrogen, oil and open-cycle gas plants are only ramped up when all other (cheaper) sources are insufficient. Finally, storage-units can shift electricity from hours of low demand and abundant production of cheap power production to hours of high demand. Again, some units such as big hydro-damns are used for seasonal arbitrage while pumped-hydro and batteries are used for faster cycles. This shows that power plants span a wide portfolio of capex, fuel (cost), emissions, flexibility, variability, etc.

Some generation and storage units, or a small portfolio of them, are self-standing economic entities. Then their owners sign contracts of various length and type to establish a position in electricity markets, depending on the type of unit. They sell forwards and futures to hedge their position into the future and trade in wholesale spot markets by submitting offers to sell electricity. Generators can also sign power purchase agreements (PPAs) with large consumers to guarantee the delivery of a certain volume of electricity and, if they are a renewable unit, participate in competitive government auctions for contracts-for-difference (CfDs) (or, in the past, other forms of state support).

Some generation and storage units are owned by consumers directly. But most conventional and a significant share of renewables generation units are owned by electricity utilities. Utilities mix several electricity market functions, such as a broad portfolio of generation, trading and supplying of electricity.

Traders

Traders buy and sell different electricity and related (gas, emission allowances, etc.) products typically at the wholesale level to obtain arbitrage-gains.

Suppliers

Suppliers (also referred to as retailers) connect wholesale and retail electricity markets. They offer retail contracts to various consumer types and must purchase sufficient electricity from wholesale markets to serve the demand of their consumers. Typically, the contracts offered to consumers have prices which periodically change based on the wholesale costs of a previous period, for example on a monthly basis. In some countries, such as Spain, retail contracts have prices which dynamically change on an hourly basis to reflect the price of electricity on the wholesale markets.

Industrial, business and household consumers

Electricity consumers can be categorised into industrial, business (or small-and-medium enterprise) and household. Within each consumer category, there are different consumption levels and different contractual arrangements regarding the price paid for electricity. For example, some industrial consumers may trade directly on wholesale spot markets for electricity, bypassing the intermediary of a supplier. Other industrial consumers sign long-term PPAs directly with utilities and do not trade short-term at all.

Business and household consumers purchase their electricity via a supplier, but their final bill can differ based on the terms of their retail contract, the taxation rules in their country, and other particularities.

National regulatory authorities

National regulatory authorities (NRAs) are state agencies tasked with administering the legislation in the electricity sector. Their core function is to oversee the natural monopoly part of the electricity system – i.e., the transmission and distribution networks. NRAs must implement European legislation, including changes to the electricity market design, at the national level. They also often have consumer protection responsibilities. At the European Union level the Agency for the Coordination of Electricity Regulators (ACER) is mandated with coordinating national regulatory activities and has some regulatory powers of its own.

Transmission system operators

Transmission system operators (TSOs) are responsible for transporting electricity on a regional or national level from generators to consumers, and, most importantly, ensure the secure operation of the electricity system in real-time. TSOs must ensure a second-by-second balance of electricity supply and demand. On a European level, TSOs coordinate through regional centres as well as through their Brussels association ENTSO-E, that has been mandated by the European Union with several coordination tasks.

Distribution system operators

Distribution system operators (DSOs) typically own and operate the electricity distribution system that connects most consumers and an increasing number of distributed storage and generation assets to the transmission system. They often also organise measuring. The corresponding local networks are responsible for a significant share of the overall energy supply cost that is levied to consumers through nationally regulated tariffs.

Market operators and energy exchanges

Market operators manage the business of an energy exchange. Energy exchanges bring together producers and consumers of electricity (or suppliers trading on behalf of consumers) to facilitate the trade of electricity products. Such products be physical, typically on short-term spot markets, requiring the actual production and consumption of electricity. The products can also be purely financial, such as futures over longer-term timeframes.

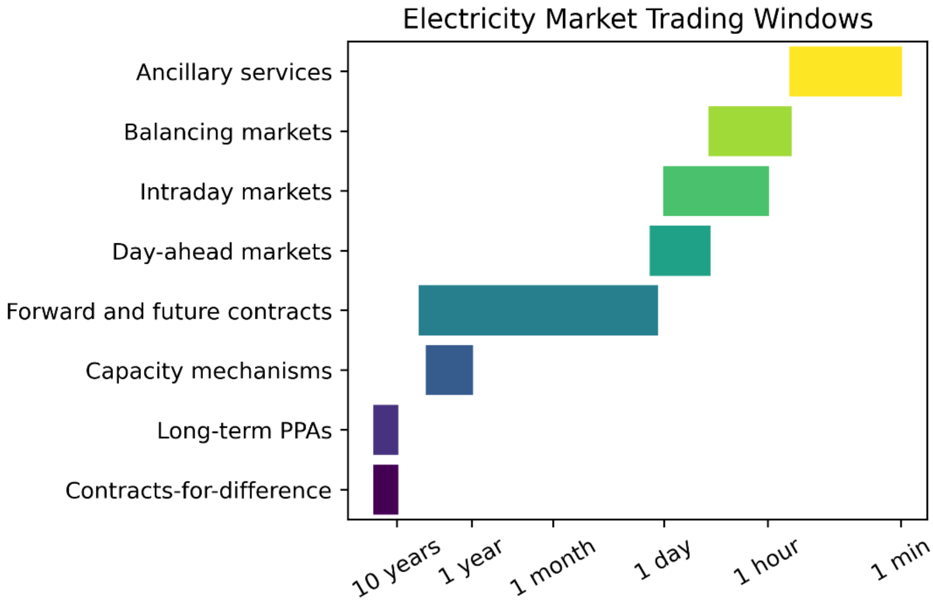
National governments

National governments are critical agents in electricity markets, affecting the distribution of costs and benefits through taxation rules, setting frameworks for network regulation, mandating levies, designing capacity mechanisms and other elements of national electricity markets and driving investment through auctions for long-term state support such as contracts-for-difference.

1.2.3. Overview of the different market timeframes

Electricity markets are characterised by different tools used to trade. These mechanisms operate over different periods of time, as shown in Figure 4. This sequencing of markets is a crucial element of electricity markets, as it allows to continuously include new information on the expected state of the world at the time of delivery. Accordingly, some market elements focus on predicting the long-term demand supply balance in order to encourage efficient investments, others are used to make longer-term decisions on procuring fuels and planning output while some then fine-tune the operational dispatch including close-to-real-time information on weather into account.

Figure 4: Electricity market trading windows



Source: Bruegel.

Subsidy schemes by governments and de-risking of investments typically provide a guaranteed price to renewable projects for a period of 15 to 20 years. These include Contracts for Difference and public power purchase agreements. Private power purchase agreements are also likely to operate over a period of 15 to 20 years, allowing for investment decisions.

Capacity mechanisms are typically centrally organised remuneration schemes intended to ensure that a certain amount of capacity (that exceeds expected peak demand) is available on a one-to-three year ahead timescale. Meanwhile, mid-term physical and financial electricity markets allow producers and consumers to hedge part of their volume and price risks. They do this by trading in forward and future contracts, which may operate less than a month-ahead to multiple years ahead.

Closer to real time, day-ahead (spot) markets are where the merit order is established for each hour of the following day and initial schedules for cross-border flows are determined. The day-ahead markets are central benchmark for the aforementioned long-term markets. Intraday markets take place between the day-ahead markets and the delivery of electricity, allowing market participants to adjust their positions as uncertainty narrows about system conditions.

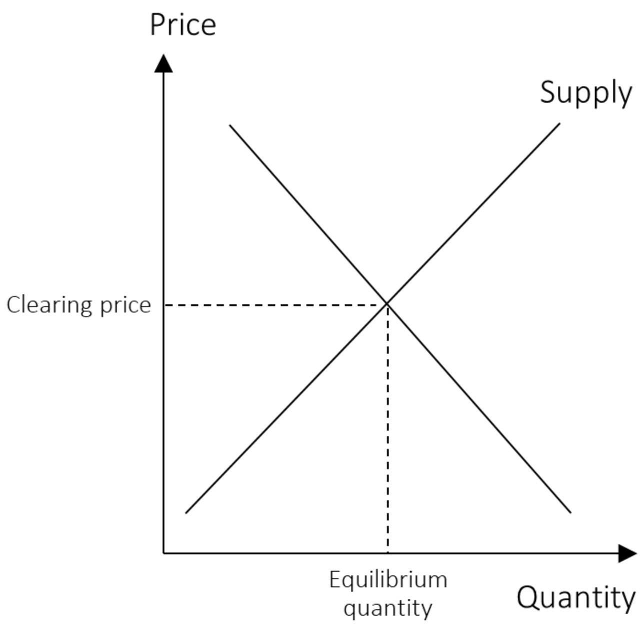
Balancing markets are operated by the transmission system operators in the respective regions to correct any imbalances between supply and demand close to real time. Finally, reserve and ancillary service markets provide remuneration for specific services that are required to ensure security and quality of supply, but for which costs cannot be recovered from other markets. These services typically occur over a period of minutes or even seconds.

1.2.4. The role of marginal pricing

Definition. Marginal pricing refers to electricity prices being shaped by the variable cost of the marginal plant, i.e., the most expensive plant that is required to serve demand, and the willingness to pay for electricity by the marginal consumer. This is how price formation on competitive commodity markets works in general. In electricity, it is the principle that describes how prices form on competitive wholesale markets. At the same time, it is also the pricing rule used on organised auctions such as the day-ahead market operated by power exchanges.

How markets work. To clear up many of the misconceptions around marginal pricing and the merit order curve, it helps to revisit the basic microeconomic model of commodity markets, which graphically can be depicted as demand and supply curves in a price-quantity diagram (Figure 5). The demand curve generally has a downward slope, representing the fact that the demand for a good decreases with increasing price. The supply curve is upward sloping, as supply increases at higher prices. The shape of the supply curve directly reflects marginal costs of firms: at any given price, only firms whose marginal costs are below the market price can operate economically. Increasing production above the quantity supplied by these firms requires other firms with higher marginal costs to join, which they will only do if prices rise accordingly. Marginal costs do not include fixed costs, such as investment costs. This makes sense because once spent, fixed costs are sunk (at least for the time scale of short-term markets), i.e., they are not recoverable. Since fixed costs occur *before* the decision of a generator whether to produce or not at any given time, they do not themselves affect this decision.

Figure 5: A simple price-quantity diagram representing supply and demand

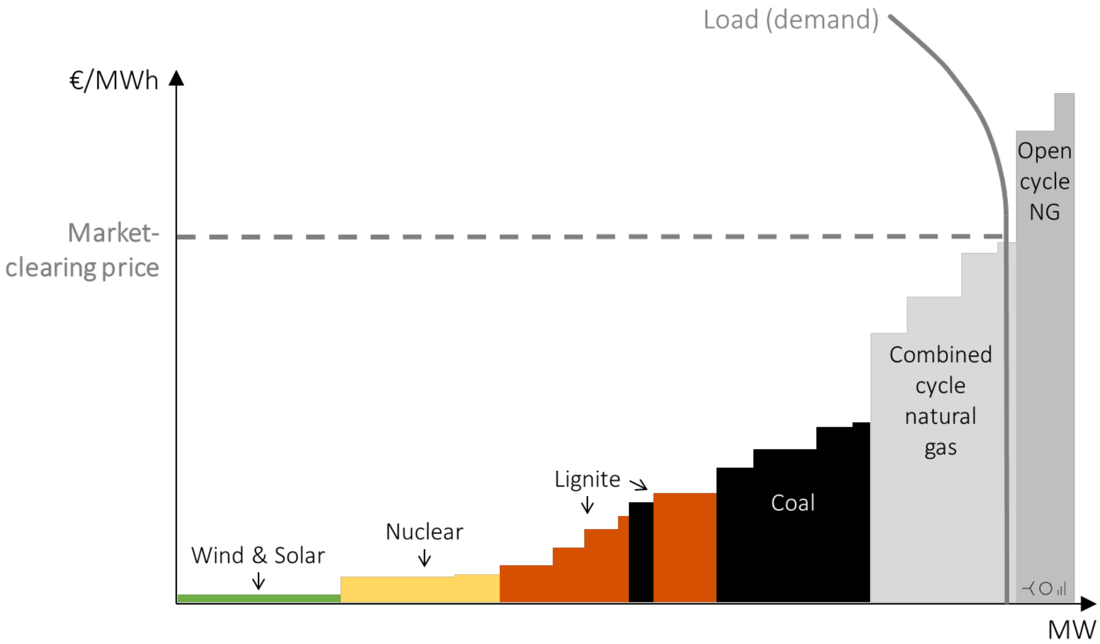


Source: Neon.

Market equilibrium. The intersection of supply and demand determines the market clearing price - the only price consistent with a market equilibrium, meaning there is no excess demand or supply. At the same time, it is the welfare optimal price and quantity, since it guarantees that demand is satisfied by those firms that can produce at the lowest costs and all consumers that are willing to pay this price are being served. In power markets, this result is called “least cost dispatch”, indicating that power plants with low operating costs are used (“dispatched”) before more expensive ones.

The merit order model. The merit order curve is just an electricity-specific term for the short-term supply curve and the merit order model is nothing else than the plain microeconomic market model applied to electricity. Figure 6 illustrates a typical merit order model. The merit order curve is derived by denoting power plant capacities of the existing power plant fleet along the x-axis, ordered by their marginal costs, which are denoted on the y-axis. Marginal costs of power plants in the EU are made up of two main components: fuel costs and emission allowances in the EU ETS, both of which are added up to calculate marginal cost per MWh produced. The demand curve in electricity markets is nearly vertical, i.e., demand is inelastic and hardly affected by prices.

Figure 6: Supply and demand in the electricity market: The merit order model



Source: Neon.

Marginal pricing. The equilibrium price in competitive electricity markets, as is the case in any competitive commodity market, is determined by the marginal costs of the marginal producer, in this example a gas-fired power plant. This means that there is just one, uniform price for the whole market. Hence, all power plants, not only the marginal one, but also the other, inframarginal ones, earn the same revenue per MWh. This allows all plants but the marginal one to make a short-term profit, also called producer rent or contribution margin. This result is a necessary consequence of the fact that they all produce the same homogeneous commodity and that gas fired power plants are needed to satisfy demand. At any price below their marginal costs, gas power plants would not produce, resulting in excess demand and no more competition among the remaining producers. Since inframarginal power plant operators know this,, they have no reason to sell at a price below that of gas-fired plants.

The role of marginal pricing for cross-border trading. Marginal pricing also plays an important role in the internal European market and its market coupling mechanisms. It provides efficient trading incentives for cross-border trading that direct the flow of electricity to where it is needed most. The market price in each bidding zone represents marginal costs - the cost of producing an addition unit of electricity in this bidding zone. If the price in country A is higher than in neighbouring country B, the market result will be that A imports from B, replacing expensive domestic with cheaper imported electricity. In the case that the national available generation capacity falls short of demand, this mechanism may even prevent load shedding that otherwise would be unavoidable to maintain system stability. During the energy crisis, this principle guaranteed that electricity was flowing to France and Italy, both of which were facing prolonged outages of substantial parts of their national generation capacity. With marginal pricing, cross-border trading may raise the price in country B, but the savings in country A will be larger. The result is the least-cost dispatch for the combined market of both countries that guarantees the least total expenditure.

Misconceptions. During the heated discussion on electricity markets during the energy crisis, we were under the impression that a number of misconceptions existed with respect to marginal pricing. These will be addressed in the following.

Misconception 1: The Merit Order Model is mandatory or prescriptive. The merit order model is not an instruction of how markets ought to function, but a description of how individual decisions lead to market outcomes. It tells you how prices emerge from decentralised decision-making. The model is descriptive, not prescriptive. As long as energy trading is free, traders would make money by buying any electricity offered somewhat below the systems marginal cost and offering it with a profit to consumers at close to the system marginal cost. As some consumers will not be able to find better offers, they will have to buy. Quickly, all prices converge to the system marginal price.

Misconception 2: Marginal pricing is an artificial and arbitrary rule. It is not a rule that some institution or person came up with. It's not an arbitrary choice among alternative "market designs" or one of a range of possible "pricing rules". It is the way prices emerge in free markets, and only these prices are equilibrium prices, meaning that the market clears and there is no over- or undersupply. Consequently, marginal pricing could only be abolished by forcing market participants to change their behaviour. They won't do this voluntarily. Generators sell electricity below the marginal price only if they are compensated by subsidies or forced to by bans.

Misconception 3: Marginal pricing is unique to electricity markets. All commodities price on the margin, and so does electricity. Commodities are homogenous, standardised, fungible goods not differentiable by brand or quality that are traded in large quantities, often on exchanges. Commodities other than electricity include bulk agricultural products such as grains, metals, or energy carriers such as, oil, gas and coal. Prices of all these goods form along the principles of marginal pricing.

Misconception 4: It is a model of the day-ahead auction. In Europe, many different wholesale electricity markets and trading platforms co-exist. Usually, the day-ahead auction is the most important short-term market, but there is no obligation for firms to trade on this auction. Marginal pricing is both an economic principle describing price formation on electricity markets per se, and the pricing rule that is used on day-ahead auctions. In other words, the pricing rule that European power exchanges apply in their auctions, sometimes called "pay-as-cleared pricing", directly implements the principle of marginal pricing. Other electricity market segments are no centralised auctions and hence do not have a pricing rule, but still prices follow the economic principle of marginal pricing. Intraday markets, for example, are organized through continuous trading where bid and ask bids are matched, therefore there is no *rule* that establishes the marginal principle there. But traders, aiming at the best possible price for their traded energy, would still ask for the best prices from their perspective, resulting in the same outcome.

Misconception 5: Pay-as-bid would yield lower prices. For organised auctions such as the day-ahead auction, a different pricing rule could be implemented. An obvious candidate would be pay-as-bid, where each generator receives the price of their bid, independent from the bids of other generators. It is sometimes believed that this would yield automatically lower prices, because each generator would earn their individual variable cost. However, this ignores that the bidding behaviour of firms would then change: They would try to anticipate the type of marginal power plant and its marginal costs (with the help of a merit order type forecasting model) and adjust their bids accordingly if they expect to be inframarginal. In the best case, all generators predict correctly, and the result will be exactly the same as with marginal pricing. In practice however, it is likely that some generators would overestimate the market clearing price, placing a bid that turns out to be too high, either becoming the marginal plant themselves or bidding themselves out of the market, in which case plants that are more costly but with less inflated bids will take their place. In both cases, the costs to consumers rise. With uniform pricing on the other hand, all generators can be sure they will receive the market clearing price, so there is no need to inflate their bids. Instead, they can reveal their true marginal costs, resulting in altogether lower prices than with pay-as-bid pricing.

Misconception 6: The power price is coupled to the gas price by law. The talk of "de-coupling" power prices from gas prices has led some people to believe there is a law or a rule that connects those prices. There is not. It is an economic mechanism, not regulation, that makes these prices move hand-in-hand. They do so only under certain market conditions, not necessarily and not always, i.e., when the marginal power plant is a gas-fired one. At times when no gas plants are needed to satisfy demand for electricity, its price will always be decoupled from the gas price. Instead, it will then be set by the marginal costs of coal power plants, or whatever happens to be the marginal power plant in that moment.

Misconception 7: Inframarginal plants are making excessive profits. Power stations with low marginal costs usually have higher investment costs. It is precisely the expectation of short-run profits (producer rents) that motivates these investments. They are necessary as contribution margins to finance these investments. Therefore, short-run profits usually do not translate into long-term profits. Long-run profits only arise if contribution margins exceed what is necessary to recover investment costs. It is true that during the energy crisis, electricity prices exceeded what could have reasonably been expected, allowing inframarginal generators to take home windfall profits (the opposite was true during the Covid crisis). However, windfall profits create an incentive to invest into new (renewable) inframarginal plants which will help bringing down electricity prices in the future. One special case where even under marginal pricing excessive profits can occur is in the presence of market power, i.e. dominant players in highly concentrated markets. However, due to the size, interconnectedness and low concentration of the European electricity market, the market power of individual generators is relatively low, which makes market power less of an issue in the energy market. For special markets, like balancing power markets, it is of greater concern (see e.g. Ehrhart et al, 2021).

Misconception 8: Spot prices determine electricity bills. All the above discusses short-term spot markets. Wholesale electricity markets are much broader and include forward contracts, power purchasing agreements and other long-term contracts. When thinking about policy interventions, we must account for long-term markets. If, say, a plant owner sold this year's production a long time ago during the Covid pandemic at rock-bottom low prices, there is no profits to be taxed away. The current crisis also underlines the need for more long-term contracting to hedge consumers against price spikes.

Misconception 9: High gas and electricity prices are a sign of market failure. The power market, the mechanism that clears demand and supply, is not dysfunctional or broken. During the energy crisis, it worked exactly as expected, given sky-high gas prices. While the outcome was certainly undesirable, it does not correspond to the economic definition of a market failure. This would have been the case if market actors had exerted monopoly power by artificially withholding supply in order to drive up prices. Such anti-competitive behaviour is typically unlawful under competition law. So far there is no clear evidence that anti-competitive behaviour played a major role in driving prices in 2022. Rather, the high electricity prices were reflecting the fact that gas, as an indispensable input to its production, had become scarce. On the gas market on the other hand, it could be argued Gazprom was exerting market power by deliberately withholding supply before fully shutting down delivery. However, this perspective is not helpful, as this was a political decision by a foreign actor, and it is unrealistic to expect appropriate compensation for the damages caused by Gazprom's behaviour through EU competition policy enforcement. Instead, gas must be seen as an increasingly scarce resource with competing uses in industry, residential heating an electricity generation. In this situation, a free market remains the most efficient allocation mechanism, directing the scarce gas to where it can generate the most value. High prices during the energy crisis fulfilled two important functions: Incentivising consumers to reduce consumption as well as motivating producers to ramp up production. In the case of the electricity market, price differences between bidding zones (which for the most part coincide with country borders) regularly direct the flow of electricity between them. During the energy crisis, high power prices in France and Italy meant they could import large amounts of electricity from their neighbours, substituting for their non-operational nuclear and hydro power plants.

1.2.5. Emergency interventions introduced as part of Council Regulation (EU) 2022/1854

In the midst of the energy crisis, the Council of the European Union used Article 122 (1) of the Treaty on the Functioning of the European Union to introduce a set of emergency interventions in energy markets (Council of the European Union, 2022). The main electricity sector provisions of this regulation were the introduction of the so-called inframarginal revenue cap, voluntary electricity demand reductions, allowing member states to temporarily set retail electricity prices. A 'temporary solidarity contribution', or a windfall tax on upstream energy companies for the fossil fuel sector, was also introduced.

The inframarginal revenue cap does not directly change the spot market price but instead limits the revenues that technologies with low variable cost can earn from the market. The demand reduction aspects of the regulation were not binding but instead attempted to encourage member states to cut peak demand (the hours in which gas is typically used) both to save gas and to reduce prices. The price setting measures allowed member states to set prices below cost to temporarily protect consumers from exceptionally high prices.

A report from the European Commission (2023a) has stated that these measures should not be prolonged, in line with feedback received in a public consultation. Regarding the demand reductions measures, the Commission argues these are no longer required as it has proposed structural demand response instruments in its market reform proposal. On the basis that the diversity of implementation of the revenue cap across Member States has caused investor uncertainty, the Commission states that the benefits of the cap no longer outweigh such negatives. Finally, on price setting measures, the Commission has included provisions to allow Member States to temporarily intervene in retail electricity markets in extraordinary circumstances.

1.3. Shortcomings of the current design

The energy crisis revealed structural shortcomings of the current European electricity market design, along several interrelated dimensions. Firstly, insufficiently strong investment signals for renewables meant that the European electricity system was vulnerable to a supply shock in a critical fuel, natural gas. Secondly, consumers were poorly protected against price spikes, with some facing huge and unaffordable increases in their final bills. Thirdly, a lack of demand response meant that scarce gas continued to be consumed, instead of a reduction in demand leading to lower prices.

If the European electricity market had attracted more investment in renewables in recent years, the impact of the gas supply shock (and nuclear outages) would have been milder. Countries with a large dependence on gas for electricity generation faced huge price increases. Higher levels of wind and solar would have reduced the need to continue burning gas for power generation, saving precious fuel for other uses, and reducing prices, ultimately benefiting consumers.

The unaffordable prices faced by some consumers due to the price increases could have been avoided with more efficient hedging and appropriation of risk by electricity retailers. However, the correct balance between long-term price hedging and short-term price exposure is not obvious. To achieve effective demand response, which is needed during supply shocks and will become more important as the electricity system decarbonises, consumers cannot be completely insulated against short-term price signals. During the energy crisis, significant interventions from the EU and national governments were required to deliver meaningful demand reductions in the electricity markets. The current electricity market design did not find the correct balance between short-term and long-term contracts, and failed to both protect consumers and encourage demand response.

1.4. Overview of the European Commission proposal and European Parliament amendments

1.4.1. The Commission proposal

The European Commission set out its proposal for reforming the electricity markets on 14 March 2023 (European Commission, 2023b). The Commission diagnosed the current market design shortcomings as an issue in which volatile fossil prices affect short-term electricity markets which then expose consumers to sharp price spikes. To address this issue, the Commission proposal broadly introduces three types of measures: improvements to short-term markets, increasing the uptake of efficient long-term contracts, and consumer empowerment & protection.

The short-term market improvements are about improving trading granularity through smaller bids and small trading periods.

Regarding long-term contracts, the measures cover forward markets, power purchase agreements (PPAs), contracts-for-difference (CfDs) and flexibility mechanisms. The proposal suggests integrating forward markets through regional trading hubs that would allow participants from neighbouring countries to trade. On PPAs, Member States can provide guarantees to reduce financial risks in these contracts, while for CfDs, they are recommended as the default state-support scheme for low-carbon, low operational cost technologies (e.g., wind & solar). The revenues earned from CfDs should be passed onto consumers. In terms of flexibility mechanisms, capacity markets are one of a number of measures that are intended to be reformed to promote technologies to complement renewables. A peak-shaving product is also suggested, which would be sold by transmission system operators to encourage demand response.

The consumer-focused measures aim to increase protection by requiring retailers to offer fixed price contracts, facilitating energy sharing, and, notably, allowing governments to set consumer prices during crisis periods. The latter measure effectively structurally maintains the emergency retail price setting intervention, albeit with specific caveats regarding the circumstances of such crisis periods. Overall, the proposal strengthens protection for consumers while formalising member states authority to direct the cash flows of domestic investors.

1.4.2. ITRE's position

The European Parliament Committee on Industry, Research and Energy (ITRE) voted on 19 July 2023 for an amended version of the Commission proposal (European Parliament, 2023). ITRE's position softened some the concrete aspects of long-term contracts set out by the Commission. Specifically, the extending the inframarginal revenue cap was ruled out by the Parliament, while other subsidy schemes for renewables besides CfDs are allowed under the ITRE position (European Parliament, 2023). Regarding PPAs, they are encouraged in the text of ITRE's position, and the Commission would be tasked with establishing a specific marketplace for their trading by the end of 2024.

The main thrust of the Parliament's amendments focused on consumer protection. Vulnerable consumers cannot be disconnected by suppliers. All consumers have a right to electricity if their supplier were to go out of business. Other consumer related measures introduced through the ITRE vote involved requiring distribution system operators to take account of energy community specificities during the grid connection procedure.

On 14 September 2023, lawmakers in the European Parliament approved the position of the ITRE committee in a vote, with the package now awaiting negotiation in the European Council. The position passed with 366 votes in favour, 186 against, and 18 abstentions.

2. MARKET DESIGN CRITERIA

KEY FINDINGS

Fairness, encouraging optimal investment, and ensuring optimal operation are considered as the set of normative criteria against which to assess proposals for electricity market reform.

Fairness is understood as the distribution of economic rents between agents involved in electricity markets. While electricity markets are balanced minute by minute, long-term investment decisions determine the generation mix of the future. It is desirable that markets send sensible signals to encourage efficient investment – this might include the need to strengthen transmission capacity between two adjacent markets or ensuring sufficient renewable deployment by 2030. Finally, a fundamental objective of the market is to match supply and demand in the short run. Through price signals, the market should incentivise running the cheapest available resource each hour to minimise final cost to the consumer.

Electricity market design is a complex policy area in which multiple aims are simultaneously sought. To frame the discussion of the specific market design instruments and the following chapter detailing the results of a quantitative scenario analysis, this chapter describes a set of *normative* criteria for electricity market design outcomes: fairness, optimal investment, and optimal operation. The criteria are normative in the sense that they describe three criteria that electricity market design should aim to achieve. It is envisioned that, when considering alternative market design choices, such criteria may be used to clarify and define the intended outcome of policy changes, thereby facilitating a common understanding of a challenging and technical topic.

2.1. Fairness

Electricity market design choices have distributional consequences. Together with other policy levers such as the fiscal system and network regulation, electricity market design choices determine how economic rents in the electricity industry are shared between the different stakeholders. These economic rents are quite substantial as consumers would be willing to still consume electricity at drastically higher electricity prices[5], while most generators would continue to offer electricity at drastically lower prices than we normally observe[6].

Fairness is not detached from optimal operation (2.3) and optimal investment (2.2) as very unfair treatment of individual stakeholders changes their (long-term) incentives – e.g., unfairly retroactively expropriating investors might cause underinvestment in the future.

In an economist's ideal world electricity market design would pay the economic value to each "service" provided and let consumers pay this economic cost for each "service" consumed. Then competition should ensure that consumers eventually get the best deal. But services such as supply security are hard to put in a market, other economic cost are very small (inertia) or highly dynamic and some services are tied to natural monopolies (networks). Hence regulators choose which services get a price and how it is determined.

More importantly, political economy considerations imply that market design choices are used to favour/disfavour individual generators and consumers. This sometimes has to do with the energy

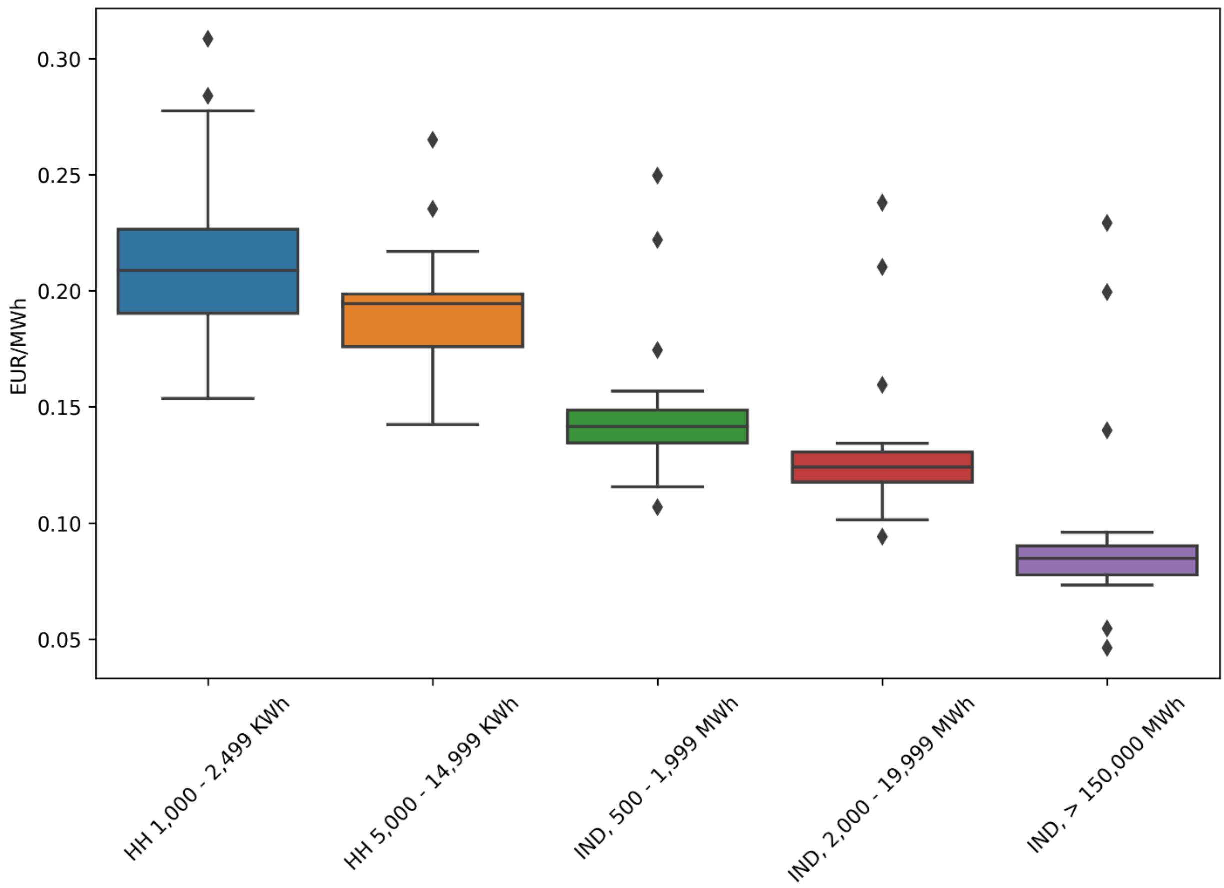
[5] For household consumers the estimates of the value of lost load are often put at around 1 € per kW – that would translate into 1000 €/MWh in specific situations – substantially more than household prices of 200-400 €/MWh.

[6] For example, a legacy hydro-power plant would produce at almost any positive electricity price.

transition that drastically changes the value of specific assets – and where then market design choices are used to avoid windfall profits or compensate losers. One example are decade old hydropower dams whose value might substantially increase with power prices in hours with little wind and sun becoming much higher, than was anticipated when those plants were built. To illustrate how market design choices impact legacy generators: in the context of the Commission proposal it has been discussed if legacy producers should get the voluntary option to sign Contracts for Differences (CfDs) – this would have meant they can possibly make more money as they can chose what is best for them, or if governments can force them into CfDs, which would likely have meant that they are worse off as governments take their freedom away to seek better prices at free markets.

The same political-economy considerations hold for the consumer side. For example, policymakers like to protect legacy consumers against changing market conditions. As a result, distributional effects are felt within countries, as various consumer and income groups might pay different prices for electricity depending on the regulation of retail markets, for example. Figure 7 shows the difference between the cost of electricity paid by large non-household consumers (e.g. industry), medium sized non-household consumers (e.g. SMEs) and by medium sized households as an average across the EU.

Figure 7: EU27 average electricity prices by consumption band



Source: Bruegel based on EUROSTAT.

Note: HH = Households. IND = Industry.

Fairness considerations not only permeate through price levels – but also through volatility that neither consumers nor producers like. Electricity prices are expected to become more volatile as renewable energy penetration levels increase (Cevik and Ninomiya, 2022). The energy crisis has also decisively demonstrated that Europe's position as a net importer of energy leaves it vulnerable to supply shocks, as was experienced with gas last year. In the context of price volatility, consumers should have equivalent options to hedge their consumption and guarantee a certain level of price stability. That is, cost of hedging should not be substantially higher for some consumers, than for others, without due economic justification[7]. Likewise, all electricity producers should be equally able to hedge against low prices, which are also expected to result from more renewables.

The distributional impacts of electricity market design also occur between countries. National and European market design choices affect prices in all connected markets. Hence some stakeholders might get better off from a certain reform while the same stakeholder group in a neighbouring country might lose. If, for example, one country organises a capacity market that provides an additional revenue stream to gas fired power plants in that county, those plants might get better off. Similarly, power plants in a neighbouring country that are not eligible might, by contrast, see day-ahead prices in the common market somewhat decline – leading to lower income for them. At the same time, consumers in the market with capacity mechanisms might end up paying more – also providing supply security for the neighbouring country.

Fairness is not an easy to operationalise criterion. But making the distributional consequences of the current system and eventual reforms transparent is crucial as distributional effects take centre-stage in the political discussions. In the end it is a political decision which distributional consequences are acceptable, which can be best dealt with through other means (especially the fiscal system) and where there are trade-offs between slightly less efficient but significantly more "fair" market design choices.

2.2. Optimal Investment

Rapidly deploying renewables is essential, both to reduce Europe's strategic dependency on fossil fuels and to decarbonise our power system. Electricity markets should send strong signals for private investment in renewables as the state cannot underwrite all capacity in the system. EU annual generation investments alone would amount to 1% of GDP for a net-zero compatible power system. Furthermore, the investment risks should be appropriately allocated between private entities, the state, and consumers. Clear market-based signals are required to attract private companies to invest.

More broadly, electricity market design should consider the whole system cost. Renewables have recently become the cheapest source of generation, but due to their characteristics they require additional investments to support them. To provide electricity when and where it is useful they need:

1) to be connected. Hence there is a trade-off between more power lines to connect the best renewable resources, or installing second-rate resources closer to consumption (example: connecting Spanish PV to Swedish consumers).
2) to store abundant generation. Hence there is, for example, a trade-off between more storage units to capture the best renewables resources, or installing renewables in a way they might on aggregate produce a bit less, but in a more even pattern (example: west-facing solar; good solar-wind mix; broad geographic distribution).
3) to be backed up when unavailable. Hence there is again a trade-off between maximising annual production and maximising the contribution to meet peak demands to reduce the cost of dedicated back-up plants (example: some overbuilding of renewable energy sources that also produce in winter can save on back-up capacities).

[7] Such as different credit risk or load profiles.

But it is not only the renewables themselves, that need to be encouraged to be developed as "system-friendly" as possible – all parts of the system need to be set up with a view to provide real value for the system. New glassworks that can stop for two weeks in winter when electricity is very scarce, hydrogen peakers that back-up the system in critical moments (there are interesting trade-offs between making those more efficient and burning hydrogen at the price of higher capital cost), batteries that reduce local network constraints are only some examples. Getting investments right into renewables, demand side, the supporting system in a coordinated way will be key to a low-cost, low-carbon system.

This not only means avoiding adding expensive capabilities that are not needed (e.g., additional solar plants that only produce when there is already more electricity than the system can absorb), but also finding combinations of assets that provide the needed capabilities at the lowest cost.

The efficient investment criterion can hence be phrased as the absence of lower cost alternatives - which in reality is not easy to operationalise, given the uncertainty of future supply technologies and demand patterns.

Security of supply

In all this, a cost-efficient development of the system needs to consider the massive cost of supply disruptions, when they happen. Under uncertainty of future electricity demand and especially supply – including technical, environmental and cybersecurity risk on all elements of the system – maintaining security of supply requires some degree of costly redundancies in the system. A mix of policies, institutions and market arrangements is likely needed to ensure that the probability and impact of failures is acceptably small.

2.3. Optimal Operation

Efficiently and reliably matching supply and demand in every instance is a fundamental objective of the electricity system. The demand for electricity constantly varies, largely following predictable periodic patterns (higher demand during daytime, work-days, winter) and some idiosyncratic fluctuations (e.g., weather related). With an increasing share of renewables there are also largely predictable periodic patterns (solar peaks during summer day-time, more wind in European winter) as well as their fluctuations (e.g., for wind and clouds) driving a constant need for rebalancing the system. Optimal operation means using the existing system in a way that minimises the operations cost.

This is complicated by the fact that some cost of running or not running plants are not very explicit. For example, switching off a nuclear plant because the wind is blowing in one minute might not be cost-optimal, because it requires time and resources to restart the nuclear plant (hence maybe better curtail the wind turbine). And using all water in a hydro-damn to produce electricity already in summer is not ideal either, as keeping some water for winter when electricity might be more valuable makes more sense. Ideally the system is optimised not only within, but also across national borders – i.e., when the wind is blowing into the Dutch wind-farms, Belgian gas fired power plants can reduce their output. The corresponding benefits can be very substantial, especially when residual demand[8] is imperfectly correlated between countries. In any case, safe operation requires that the optimal dispatch needs to observe network constraints.

Importantly, optimal operation more and more also needs to co-optimise the operation of storages and of electricity demand. Heating with electricity and charging electric vehicles might be significantly cheaper from a systems perspective, if they are done in hours where they do not necessitate natural gas or hydrogen power plants to burn expensive fuel and/or emit carbon-dioxide. In the future it might

[8] Electricity demand minus renewables generation.

carry increasing benefits to co-optimise other energy supply, storage and demand systems (such as heating networks with heat storage, or hydrogen networks with electrolysers, storage and hydrogen peakers) with the electricity system.

This shows that coordinating millions of consumers as well as thousands of generators and storage units in every instance is not a trivial exercise and getting it wrong can have substantial cost. The current system, built around marginal prices (reflecting the cost of supplying one additional unit of electricity), sends broadly efficient signals (see section 1.2.3), albeit it has been argued that more granular locational and temporal price signals as well as wider geographic optimisation carry additional efficiency potential.

Hence, the ideal efficiency criterion would be to compare an optimal dispatch for a given load situation with that incentivised by a given market design. A more qualitative approach would be to identify if a market design sets gross incentives for expensive plants to run instead of cheaper ones or reducing unnecessary demand.

3. ASSESSMENT OF MARKET INSTRUMENTS AND DESIGN DETAILS

3.1. Long-term contracts

KEY FINDINGS

The Commission proposal does not specify a completely new market design but mainly regulates specific aspects of the market design. Thereby the details of the proposed intervention are of crucial importance.

The success of the approach to make CfDs the main tool for support will strongly depend on their design and on keeping a European dimension to markets. They should be designed in a way to avoid distorting short-term power markets.

Hedging obligations can be a useful tool to prevent moral hazard, but they need to be tailored to the specific situation in electricity markets. Virtual forward hubs are a major intervention that requires further impact assessment.

An intervention framework for price crisis is an ambiguous tool. On the one hand it creates uncertainty to market actors by threatening state interventions, on the other hand it reduces said uncertainty by spelling out trigger conditions and consequences. Hence, such a tool needs to properly balance conditions and consequences in a way that reduces and not increases uncertainty for market participants.

Energy sharing can increase acceptance and deployment of renewables. But it runs a high risk of socialising cost and privatising benefits.

Additional products for peak shaving or flexibility procurement in our view only increase uncertainty and system costs. Existing short-term markets work well and are more efficient. The key barrier to flexibility provision, inflexible grid tariffs, is not addressed by the reform, which could be a focus of future reform efforts.

One of the key focus areas of the EMD proposal are long-term contracts. This includes government-backed Contracts for Differences (CfDs) and private Power Purchase Agreements (PPAs). Discussions on market design in the past decade have often focused on the efficiency of short-term markets, which are now well-working and very advanced in Europe.

The crisis showed a lack of long-term contracts. Forward markets are at the heart of the reform proposal for two main reasons. First, the crisis has laid bare a lack of long-term contracting (including the shorter 1-3 year forward market horizons), resulting in windfall profits and revenue clawbacks to contain them for suppliers at the expense of high costs for consumers. This was for example the case for renewables in countries where renewable support schemes were designed as market premia without a clawback component.

Low-carbon assets have high fixed costs. The second reason why long-term contracts are becoming increasingly important is the cost structure of low-carbon generators: They usually are high fixed-cost assets with low or zero variable costs. This amplifies the importance of capital costs as a share of overall costs, and thus makes revenue stability even more important.

Co-existence with efficient short-term markets. A desirable property of long-term contracts – if carefully crafted – is that they can co-exist with short-term electricity markets. Forward contracts can take the role of ensuring cost and revenue stability for all market parties, while short-term markets take the role of efficiently coordinating dispatch and flexibility use of all assets. However, to enable such co-existence, it is crucially important that the chosen types of forward contracting do not distort short-term markets. This is achieved if forward contracts are designed such that the payments accruing from them are independent of the dispatch of a specific asset, as we explain in the subsections below.

Interrelated instruments. Different types of long-term contracts are not independent from each other. A generator can only hedge its production once and must decide between conventional futures contracts, PPAs or CfDs. Thus, when determining the price of a PPA, the investor will consider the alternative opportunity of going for a CfD, or future product or even spot sales. Such competition of instruments can be beneficial, because it ensures that if governments set maximum strike prices for CfDs too low, low-carbon asset buildout is not stopped, because investors can contract directly with the demand side through PPAs, and such investments can help drive down costs.

This section. In the remainder of this section, we analyse the different types of long-term contracts in turn, from CfDs, to PPAs, to futures products and the proposal to increase their liquidity by setting up virtual trading hubs.

3.1.1. Contracts for differences (Regulation Art. 19b)

CfDs. Contracts for differences (CfDs)[9] are financial contracts that specify payments from a buyer to a seller if the price of an underlying is below the agreed-upon strike price. In two-sided CfDs, sellers have to give back money to buyers if prices increase above the strike price. For the electricity CfDs discussed here, the strike price is often determined competitively in an auction before the investment takes place and remains constant throughout the lifetime of the CfD, which is often in the range of 20 to 30 years. Public CfDs may be best understood as a support scheme for renewables (and sometimes nuclear) with implicit clawback mechanism. The fact that two-sided CfDs, unlike most other support schemes, generate public income in times of high electricity prices has made them attractive to policymakers particularly since the onset of the energy crisis. The UK introduced CfDs in 2014 and they are widely used in Europe today.

Reform. Already under existing State aid guidelines, the Commission's DG Competition sees two-way CfDs as a preferred (and increasingly as the only) choice for support mechanisms. The Commission proposal goes a step further by clearly specifying them as the only allowed option for direct price support, setting out rules on how government revenues from CfDs are to be used, and defining which technologies are eligible. With the inclusion of CfDs in the regulation's core text, State aid approval might also become easier for Member States wishing to implement them. The reform proposal stops short of more far-reaching proposals, such as the one brought forward by Greece in 2022, that would have made CfDs mandatory for all existing or new generators.

a. Two-way Contracts for Differences and how they impact plant design and operation

Electricity CfDs. Electricity CfDs[10] traditionally use the day-ahead spot price as an underlying. The payment is calculated for each hour as the spread between strike and spot price, multiplied with the electricity produced by a specific asset, such as a wind park. This "weighting" of price spreads with fluctuating volumes sets electricity CfDs apart from those used in security and commodity markets, but also from electricity future contracts. It also makes these contracts more complex than many realize, in terms of both incentives as well as risk allocation.

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9 Significant parts of this section are based on our paper Financial Contracts for Differences (Schlecht et al., 2023), which is joint work with Christoph Maurer.

10 Note that consistent with most of the academic literature, in this text we refer to two-way CfDs simply under the name "CfD", without repeating their *two-way* property, as that is the standard for CfDs. In other words, we only discuss two-way CfDs here.

Goals. The objective of public CfDs is to increase long-term price stability for both producers and consumers, intermediated by the state. With price risk mitigated, generation investors have lower cost of capital and hence lower levelized energy costs.

Conventional CfD. There are many ways Contracts for Differences are specified in electricity markets. We first discuss the basic specification that we use as a point of reference. This contract, which we refer to as the "conventional CfD" and which resembles the contracts introduced in the UK in 2014, it is specified as follows:

- The strike price is fixed (e.g. in an auction).
- The underlying is the hourly day-ahead spot price.
- The CfD is linked to a specific physical asset.
- Volumes are "as produced" in every hour.

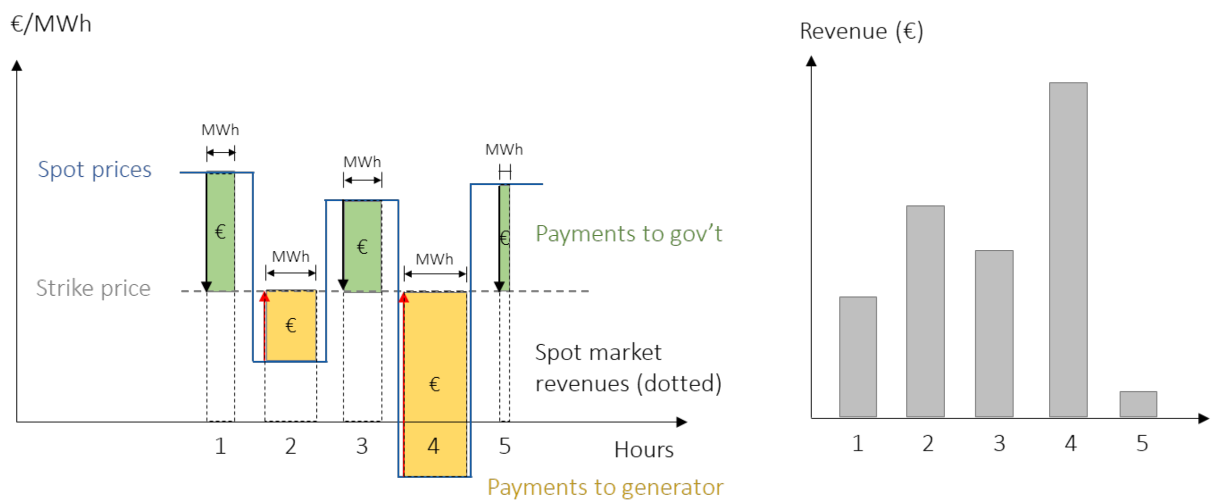
The hour-by-hour payment obligation is calculated as

$\text{Payment}_t = (\text{strike price} - \text{spot price}_t) \times \text{produced volume}_t$

If the spot price for an hour is below the strike price, governments make a payment to generators, and vice versa. The fact that it is physical production (metered output) that determines the payments is the reason these CfDs are sometimes described as called "injection-based".

Figure 8 illustrates payments for five hours. The payment in each hour is calculated as the price difference (height of the boxes) multiplied with the quantity produced (width). For the generator, this results in stable per-MWh prices. However, a generator's total revenues still depend on the production volume (i.e. how much wind blows, for a wind generator) and therefore remain volatile.

Figure 8: Payments (left) and revenues (right) under the conventional CfD



Source: Schlecht et al. (2023).

Asset-specificity. While the conventional CfD is in some ways similar to a financial derivative such as futures or a forward contract, the fact that it is linked to a specific asset makes it different. Not only does this feature make it impossible to trade CfDs on secondary markets without selling the asset too, but, more importantly, it entails that CfDs provide incentives to adjust the dispatch of the asset to manipulate payments.

Two problems. The conventional CfD comes with two problems: produce-and-forget incentives and distortion on intraday and balancing markets. We discuss them in turn.

Produce-and-forget. The conventional CfD provides a simple incentive to the generator: maximize production. In this regard, these contracts work much like traditional feed-in tariffs which isolate generator's revenues from market incentives entirely. Because the revenues per MWh always equal the strike price, there is no incentive for the generator to increase output at times of high prices (scarcity), to schedule maintenance at periods of low demand, to reduce output at times of low/negative prices (abundance), or to invest in power plants that reap above-average market prices (flexible or system-friendly plants). This has a range of adverse consequences:

- *Investment choices:* When selling to the spot market, wind and solar investors can maximize their revenues by investing into what is sometimes called "system-friendly renewables": wind turbines with higher towers and larger rotors that produce electricity more continuously; tracking solar panels with higher capacity factors; or west-facing solar that contribute more to high demand during late afternoons. The conventional CfD provides no incentives for such system-friendly plant design. For hydroelectric and thermal power plants, the incentive to simply maximize production results in plants being optimised for base load operations and a lack of flexibility including load-following capabilities, ramp rates, and part-load efficiency.
- *Retrofit and repowering choices:* Investments are not one-off decisions. Maintenance, retrofit, and repowering investments are decided on during an asset's lifetime. Conventional CfDs often distort such choices, because they mute spot price variation, the core scarcity signal of power markets. This means that under such contracts, in an energy crisis, too little would be invested into maintenance and retrofitting. In an electricity glut, too much would be invested, just to cling to an old contract. The same applies for repowering of wind turbines, i.e., replacing older, less productive wind turbines with larger, new ones. Since the conventional CfD ends with the life of the asset, an old wind turbine might not be replaced by a newer, more productive one just to keep the payments of the old contract.
- *Maintenance scheduling:* Under the conventional CfD, generators have no incentive to schedule maintenance at times of low demand. Nuclear power generators may instead schedule maintenance when engineering teams are cheapest, which is often in the winter. Intermittent renewables, regularly incur imbalance settlement costs since their actual generation may deviate from scheduled generation due to forecasting errors. Imbalance settlement prices are correlated with spot prices, which means that generators have an incentive to schedule maintenance in the hours with the highest spot prices to avoid high imbalance costs – which is the opposite of what they should do.
- *Dispatch:* Under the conventional CfD, generators have no incentive to increase production in high-price hours or to decrease it in periods where prices are below their production costs. Wind, solar and nuclear plants should curtail output whenever prices drop below their variable costs, but under the conventional CfD they keep producing – even when prices turn negative. This distortion is even more damaging for technologies with higher variable costs and/or if these costs change over time. This includes all thermal power plants (including hydrogen and nuclear power plants[11]), reservoir hydropower and storage plants, for which the conventional CfD is particularly ill-suited. These flexible generators must follow prices to be economically

[11] Under certain conditions, the variable costs of nuclear plants are rather dynamic: when refueling cycles are planned and fixed some time ahead, the short-term dispatch of the plants faces opportunity costs driven by the available fuel until the next refueling. This results in opportunity costs somewhat similar to the water value of reservoir hydro plants.

viable. Providing an incentive to continuously generate electricity would invalidate their economic value as a flexible asset. Such distortions tend to become more damaging if larger fractions of the market are covered by CfDs.

Improved CfD specifications. Some (but not all) of the "produce-and-forget" issues of the conventional CfD are fixed in more advanced CfD specifications that have been proposed or implemented in recent years, in particular monthly or yearly reference periods. The reference price is usually the monthly or yearly weighted or unweighted average spot price, e.g. the average capture price of a wider set of wind turbines. This is for example done in the German market premium (a one-sided downside-cap CfD) or in the Danish hybrid CfD. By calculating the CfD payment based on longer reference periods, intra-period price differences are no longer muted for the generator and create incentives again. Therefore, generators are incentivised to optimise dispatch and maintenance *within* these periods to capture the highest prices, and to make investment choices with a view to producing at the highest priced hours within the reference periods.

Problems of improved CfDs. While improving some of the misaligned incentives, such improved CfDs still come with three problems. First, they resolve only part of the misaligned incentives. This is because price differences across reference periods are leveled out and thus fail to create incentives. For example, while a monthly reference period creates incentives to capture high prices within the month, it does not create incentives in a seasonal perspective across months, and thereby sub-optimally suppresses incentives to focus on high winter yields. Yearly reference periods suppress output maximisation in high-price crisis years. Second, they distort bids on the day-ahead markets. Given that the CfD payments per MWh are equalised throughout the reference period (such as months or years), this payment (or the expectation thereof) is known ahead of day-ahead bidding, which provides incentives to take the payment into account at the bidding stage, distorting bids in a similar way as taxes or subsidies do. This can lead to withholding of generation at low prices during clawback times and above-optimal generation e.g., at negative prices when the CfD acts as a subsidy. Third, due to common fixes to the problem mentioned before, they reduce the revenue certainty for investors. This is because to avoid the distortive effects on day-ahead markets, improved CfDs (such as the Danish hybrid CfD) have often been extended with specific correction clauses. These suspend payments from CfDs in hours when they would distort day-ahead bids, i.e., by suspending payments during hours of negative day-ahead prices or by suspending clawbacks at low positive prices. However, by making a plant's revenues dependent on power prices, this creates new revenue risks, and thus undermines the original purpose of CfDs to provide revenue stability.

Intraday/balancing distortion. A second problem of conventional CfDs is the distortion on intraday and balancing markets. This is because the day-ahead price is used as the underlying of the contract. After that auction has cleared, the price of the hourly CfD payment is fixed and known to the generator. From this moment on, it constitutes an opportunity cost and will be priced in, just as any other variable cost component. This has implications for the subsequent market stages, the intraday and balancing markets. The effect has different signs in high-price and low-price hours:

- During high price hours, the payment obligation works like a tax. If, say, the strike price is 80 €/MWh and the day-ahead price was 200 €/MWh, generators must pay 120 €/MWh for every MWh they produce in that hour. If the intraday or imbalance price drops to 119 €/MWh, it is rational for the generator to curtail output to avoid the payment and buy the power which they sold day-ahead back on the intraday market. This example assumes operation costs of 0 €/MWh. If they were higher, the minimum price at which curtailment becomes more profitable than production would shift upwards accordingly. This implies the waste of low-cost (and low-carbon) energy and an upward pressure on intraday prices, which arbitrage trading will transmit back to day-ahead prices.

- The opposite effect occurs in low-price hours, when governments make payments to generators. Then the payment works like a subsidy. In such hours, plant owners deduct the payment from their optimal intraday bids, which means they inefficiently bid into intraday markets below their own variable costs. If, say, the strike price is 80 €/MWh and the day-ahead price was 60 €/MWh, generators receive 20 €/MWh. If their marginal costs are zero and the intraday or balancing price becomes negative, it would be economically efficient and welfare optimal if they would buy electricity on the intraday market instead of producing it themselves. However, due to the payment from the CfD, prices would have to drop further (to -20 €/MWh) for this behaviour to also become rational from their individual perspective. CfDs hence put downward pressure on prices that had been low (i.e. below the strike price) anyway.

Difficulties closer to real-time. If real-time (balancing) prices rather than day-ahead prices were used as underlying, these intraday/balancing distortions would not occur. However, this would make risk-averse generators dump all production into the system imbalance rather than revealing their available generation already at day-ahead stage, which would compromise operational system security.

Scale of the problem. If CfDs are only used for a small share of the market, the distortions mentioned above seem small enough to ignore, if they are outweighed by the upsides of CfDs such as reducing financial risks for investments. This is because the volumes that are shielded from price incentives are small. While they might render the dispatch of plants under CfDs suboptimal and to some degree inefficient, the overall market outcome is not greatly impacted. However, the larger volumes under CfDs (or similar support schemes) become, the more impact they have on overall market outcomes. In the worst case, misaligned incentives from support schemes can lead to a failure of market clearing and security of supply issues. There is also a feedback loop of simple CfDs leading to more investment in renewables not optimised for system-friendliness (i.e. with highly correlated output), which leads to price cannibalisation and thus to higher CfD payments, i.e. increased support costs. Therefore, the issues become highly significant if the predominant generation technologies such as wind, solar or, in some countries, existing nuclear plants are to be subjected to CfDs.

Negative prices as one result. Shielding generators from short-term prices, as conventional CfDs do, exacerbates price volatility in both upward and downward directions. One clearly visible example of hours in which market distortions from support scheme design affects market outcomes are hours with negative prices. They are one example where distortions from support schemes impact overall market results and sometimes even lead to difficulties with market clearing. This was the case in spring 2023 when the Dutch hourly electricity prices hit the technical lower price limit of the power exchange and a second day-ahead auction had to be called. Negative prices are predominantly an artefact of renewable support policies, not a fundamental market outcome. If all generation units were exposed to wholesale price incentives, wind and solar would economically curtail at prices of 0 €/MWh, reducing support costs and stress on the system, enabling thermal plants to continue running to avoid resource intensive shutdown and startups that cause further physical costs through wear-and-tear. If incentives from support schemes continue to be misaligned and to shield generators from market prices, more events are to be expected in which demand and supply are hard to match.

Fundamental fixes. More recent approaches aim to fix the distortions arising from CfDs and related support schemes more fundamentally. The key innovation in such approaches is to decouple the calculation of the payments from the asset's production volumes. Examples for such approaches are Capability-based CfDs (ENTSO-E, 2023), Yardstick CfDs (Newbery, 2023) or Financial CfDs (Schlecht et al., 2023). By making payments independent of actual production, and instead basing them on independent variables like weather measurements, they avoid the distortions of injection based CfD specifications. It should be noted however that these approaches have so far not been implemented and tested anywhere, so that their real-world performance cannot be evaluated yet.

b. CfDs in the reform proposal

Contentious issues. The most contentious points in the proposal are whether and to what degree investments into existing nuclear plants qualify for CfDs, how revenues are to be distributed and which requirements CfDs must fulfil so that distortions to power markets are avoided.

CfDs for existing nuclear plants. The reform proposal enables CfDs for investments into existing generators, such as existing nuclear power plants. In the initial proposal by the Commission, this could be interpreted to mean that a small investment into an existing plant would enable the whole plant's revenues to qualify for CfDs. This in turn could result in very significant capacity to be likely subject to CfDs. Given that CfDs shield generators from (some or all) price signals in power markets, to subject such large volumes to CfDs could be detrimental not only to efficiency but also to system stability. These large volumes of existing generators would then potentially no longer react to (some or all) price signals and thus reduce overall flexible capacity. Both the Council General Approach (REV4) and ITRE's positions provide safeguards to limit existing assets to qualify for CfDs, either by asking for "significant" investments (Council of the European Union, 2023) or by applying CfDs only to a share of a plant's overall output depending on the size of the new investment (European Parliament, 2023).

Contract design requirements. Good design of CfDs is essential to ensure that electricity markets continue to function efficiently, even as increasing proportions of the total generation fleet, potentially including existing nuclear plants, are subject to such contracts. CfDs should be designed in such a way that short-term electricity prices continue to provide incentives for units under CfDs, as discussed in the previous section. This can be done either by setting higher level principles or by requiring specific contract specifications. Higher level principles could be to require that CfDs provide incentives for efficient participation in electricity markets. A weaker form is to simply require some form of 'market responsiveness', e.g., by referring to Article 4(2) of the Renewable Energy Directive (Directive (EU) 2018/2001), as the Commission did in Article 2 of its proposal. However, these criteria have proved rather weak in preventing several existing support schemes for renewables from distorting short-term electricity markets. For example, existing market premium and CfD designs continue to give incentives to distort bids on intraday markets. ITRE and the Council are tending towards stronger language in their positions, requiring CfDs to maintain incentives to operate efficiently in electricity markets. An alternative is to prescribe the CfD design more specifically, such as by asking that CfD payments be decoupled from the amount of electricity generated by the plant, so that only the specific specification proposals that take such an approach (i.e. capacity, yardstick or financial CfD) would be allowed. However, given the novelty of such approaches, it might be advisable to stop short of prescribing concrete designs and go for general principles instead, making them robust enough to prevent distortive support scheme designs.

Distributing revenues. A contentious issue also was the settlement of the financial position that emerges from CfDs, i.e. the way proceeds are paid out and costs are recovered. We discuss this issue separately in section 3.2.1 in the context of protecting consumers from future energy crises.

Mandatory CfDs are off the table. Given the very high electricity prices caused by the crisis, the year 2022 triggered heated discussions on revenue recovery and options to pass on the low costs of renewable generation to consumers. Against this background, the Greek government (European Council, 2022) argued for the introduction of mandatory CfDs for generators, while prohibiting market access for new generators without CfDs. In effect, this would have been price discrimination against technologies under CfDs. It would also have discouraged investment in technologies such as wind and solar by making any investment with a cost above the government-set CfD strike price unviable, even if it was profitable at market prices. By deciding to propose CfDs that are voluntary for generators, i.e. still allowing market access without them, the Commission has chosen not to go down this route, which could have significantly damaged market confidence and reduced investment. Given the obvious downside of crowding out investment, the imposition of mandatory CfDs appears to be off the table in recent discussions.

Contentious issues. The most contentious points in the proposal are whether and to what degree investments into existing nuclear plants qualify for CfDs, how revenues are to be distributed and which requirements CfDs must fulfil so that distortions to power markets are avoided.

3.1.2. Power purchasing agreements (Regulation Art. 19a)

PPAs. Power purchasing agreements are generally understood as long-term contracts between commercial entities, usually electricity generators and consumers, but possibly also utilities as intermediaries. These contracts can stipulate electricity purchases in the sense of physical delivery or be financial in nature, similar to financial forward contracts. Usually, the purpose of PPAs is to satisfy the preference of stable power prices (price hedging) that generators share with consumers. The Commission proposes to foster such PPAs through state guarantees.

Proposal. Several years ago, the Renewable Energy Directive (Directive (EU) 2018/2001) tasked Member States to assess and remove regulatory and administrative barriers preventing the uptake of PPAs in their jurisdictions. The Commission proposal goes beyond that by obliging Member States to reduce the financial risks associated to off-taker payment default. The Commission proposal remains rather vague on how this should be achieved, but it suggests "guarantee schemes at market prices", to which ITRE added "private guarantees". In the following, we discuss if (and how much) government should charge for guarantees and how PPAs can be set apart from other contracts.

Guarantee schemes. After being signed, PPAs create an obligation for financial payments, just like forward contracts. This obligation has a positive or negative economic value (hence is an asset or a liability), depending on the evolution of power prices. If power prices decline below the price level specified in the PPA, the bankruptcy of the off-taker would require the generator to sell the electricity at a lower price. Hence the possibility of such a default constitutes a financial risk to the seller of the PPA, driving up financing cost via the associated risk premium required by creditors. Guarantee schemes essentially work like an insurance against this risk, allowing to transfer it to another party such as a private or public financial institution. Such an insurance has an economic value which in a private market would be reflected in the insurance premium. Offering such guarantee schemes free of charge would therefore constitute an economic subsidy. The reform proposal seems to rule this out by requiring guarantees to be "at market prices", suggesting that beneficiaries should pay their full price. However, it does not specify how such market prices should be determined. Crucially, market prices would have to reflect individual off-taker default risk.

Distortion of incentives. Ignoring the financial stability of a PPA off-taker would particularly benefit financially poorly positioned companies, muting the allocative effect of credit ratings and risk assessment. Risk premiums have an economic significance though: they mean that particularly risky transactions are only carried out if they are particularly promising. This corrective would be levelled out by non-discriminatory state guarantees. A concrete consequence could be a selection effect on the participating customers: If they are all charges the same, on-discriminatory "market prices", the guarantee schemes are increasingly only attractive for companies with poorer credit ratings. For customers with high credit ratings, it may be more profitable to abstain from the guarantee scheme, and to offer generators slightly higher electricity prices instead. The reform proposal tries to address this by requiring guarantees schemes only for customers that "are not in financial difficulty", however the described selection effect still applies to the remaining set of customers, i.e., by favouring customers with moderate over those with high creditworthiness.

Definition. Independent from the question of if and how much counterparties should be charged for state guarantees, PPAs must be defined. The definition of PPAs provided in Article 2(77) of the Regulation proposal states that "'PPA' means a contract under which a natural or legal person agrees to purchase electricity from an electricity producer on a market basis". This definition raises a series of questions. On the one hand is very broad, as it allows for *any* electricity market transaction to qualify as a PPA – including forward and spot market trades as well as retail contracts. This is problematic as it implies Member States must become guarantors for all these contracts. It is hard to believe that this scope is something anyone would like to demand; it seems rather more like a technical glitch in the definition, but one with potentially dramatic consequences. Therefore, more rigorous eligibility criteria should be added as discussed in the following.

Contract period. One aspect that sets PPAs apart from other electricity contracts is their duration. They are usually understood as spanning several years, longer than spot, forward or retail contracts. It seems sensible to include a minimum duration in the definition of PPAs, e.g. five years.

Linking to assets. Another property of PPAs is that they are usually linked to specific physical generation assets, such as a wind park that is mentioned by name in the contract. It seems sensible to include such a requirement in the definition. They should, however, not be tied to the physical generation in order to uphold efficient dispatch incentives.

Settlement. While in these ways, the definition of PPAs is very broad and it seems sensible to narrow it down, in a crucial aspect it seems too narrow and should be broadened up: in practice, PPAs may either require the physical delivery of electricity or, increasingly common, the financial settlement ("virtual PPAs"). In case of virtual PPAs, buyer and seller trade on the spot market independently from each other at market prices. If the spot price exceeds the PPA price, the seller pays a compensation to the buyer and vice versa. The current proposal could be interpreted as allowing only physical delivery. It seems sensible to explicitly include both physically as well as financially settled PPAs.

Objectives. The proposal mentions two distinct goals to be achieved by fostering PPAs: To accelerate the decarbonisation of the electricity system and to provide long-term price stability for consumers. While there is some overlap between these two goals, they are not identical: while the price stability objective suggests incentivising as many generators as possible to sign PPAs in order to maximise the amount of fixed-price energy available, the decarbonisation objective warrants a narrower definition in terms of eligible technologies and existing assets. The two objectives have distinct implications on eligible technologies and existing assets.

Technologies. The Commission proposal specifies that PPAs must not be applied to the purchasing of generation from fossil fuels. Beyond that, no further hard technological eligibility criteria are mentioned, although ITRE's position underlines that guarantee schemes shall exclusively support the purchase of new renewable generation "whenever conditions allow". Still, the guarantee schemes may thus also be applied to nuclear, hydrogen or other low-carbon generators.

New or existing assets. If decarbonisation is the main goal of the guarantee schemes, government support should be focused on de-risking investments and facilitating market-based capacity expansion of low-carbon technologies. Towards this end, the guarantee schemes should be limited to new renewable assets. Opening them up for existing assets would risk creating windfall profits for plants operators.

3.1.3. Virtual trading hubs (Regulation Art. 9)

Trading hubs. The proposed new Article 9 of the Electricity Regulation introduces the concept of regional virtual trading hubs for forward markets into European legislation. In the context of a zonal spot market design, virtual hubs are groups of bidding zones for which a price index is calculated to serve as an underlying for forward contracts. In practical terms, where today forward contracts use the spot prices of one bidding zone as underlying, hub forwards would use e.g. a weighted average of multiple bidding zones for settlement, where the weights are pre-defined and time-invariant. For example, the underlying could be calculated as 50% of the German, 30% of the French and 20% of the Belgium hourly spot price. In the Nordic market, the system price, a hub-like price index, is calculated not as the average of zonal prices but a hypothetical price that would emerge if cross-border capacity was unlimited. Virtual hubs are better known in the context of locational marginal pricing (LMP), where they are calculated as a weighted average of LMPs, but the same principles apply to zonal markets.

Regulation. The legislative proposal does not force market participants to use hub-based forwards, nor does it prescribe power exchanges to offer such future contracts. It does, however, regulate the supply of Long-term transmission rights (LTTRs) by TSOs, requiring that they must be defined as the price spread between bidding zones and a regional virtual hub (zone-to-hub), rather than between two bidding zones (zone-to-zone). The idea is that market parties in smaller bidding zones will hedge by using hub-based forward contract in combination with such zone-to-hub LTTRs covering the price spread between an individual bidding zone and the virtual hub. This is supposed to shift trading of forwards and futures away from zone-specific products towards regional hub products, even if not legally mandated. The trade of local, bidding-zone specific forward and futures products continues to be allowed but might fade away.

Pool liquidity. A motivation underlying the reform proposal towards virtual hubs is to pool the liquidity of multiple bidding zones to increase the availability of hedging products with little basis risk in smaller zones. Essentially, this would allow parties in small zones to be better hedged, to reduce the cost of hedging, and to increase overall market depth.

Prepare for market split. Another motivation for virtual hubs might be to lay the ground for possible splits of larger bidding zones into smaller ones, as such a move could be easier in a setting of virtual hubs than in zonal forward markets. In particular, splitting the German bidding zone, which hosts the by far largest forward market, would effectively require a solution for the forward market – for example, virtual trading hubs. Splitting large bidding zones such as the German one is sometimes discussed as a policy option because it would reduce grid congestion and the need for costly remedial actions when the grid is congested, reduce loop flows in neighbouring countries and it would improve overall market efficiency through better representation of location and grid constraints in the wholesale market.

Risk: Split liquidity. A risk in the setup of virtual hubs is that market actors in large zones with liquid forward markets continue to trade locally on their home market, while market actors from smaller zones hedge using hub forwards. That would split the liquidity of forward markets and likely diminish overall liquidity. Actors in smaller markets would no longer be able to use today's zone-to-zone LTTRs to access the liquid zonal forward market. Overall liquidity is likely to diminish, as financial actors might retreat. As a result, market actors are worse off across the bord, and the opposite of the intended increased liquidity is achieved.

Technically difficult. The proposal leaves many complex technical questions open. For example, it is unclear how a methodology could look like to determine how many LTTRs per border should be issued, given that there is no physical underpinning of the individual "borders" to the regional virtual hub and the finally available capacity depends on outcomes of the flow-based algorithm. A relevant question is also the geographical grouping of countries into regions, as ending up in a too small or illiquid hub could mean a country would be worse off in a virtual hub setting compared to the current approach of zone-to-zone LTTRs. In our view, these technical questions will determine if trading hubs succeed or fail.

Legislative positions. Contentious issues in the discussions have been the question whether there should first be an impact assessment before a decision is made on whether to pursue the approach of virtual hubs. The Commission's proposal foresees direct implementation, the Council General Approach (REV4) foresees an impact assessment with subsequent implementation while ITRE's position suggests an impact assessment with a subsequent decision. Another issue on which the text versions differ is the responsible institution. While the Commission's proposal delegates the task of setting up virtual hubs to ENTSO-E, the Council's General Approach (REV4) foresees an implementing act by the Commission.

Box 1: The importance of forward markets

Forward markets. Financial forward and futures contracts have been a core feature of electricity markets for many years. Utilities use them on large scale to hedge price risks. Financial forwards are in a sense Contracts for Differences for a specified amount of energy during a specified settlement period which are voluntarily concluded between market parties. Generators hedge their price risk by entering short positions ("selling forward") and demand entities by entering long positions ("buying forward"). In a narrow definition, the term "forwards" refers to products traded decentrally "over-the-counter", while "futures" refers to the exchange-traded equivalents, which are traded e.g. on the European Energy Exchange EEX or the Intercontinental Commodity Exchange ICE. The term "forward markets" includes both such forwards and futures.

Asset-independence. A fundamental advantage of forwards/futures compared with conventional CfDs or as-produced PPAs is that they are always asset-independent: payments are due regardless of any individual asset's production. In other words, they are financial derivatives. Asset-independence has the crucial advantage that – while fulfilling the purpose of providing long-term financial stability for both counterparties – they do not distort investment and operation decisions. Both counterparties are hedged financially while continuing to react to the power market's short-term scarcity as they remain exposed to spot price incentives. This is more important than ever in a system composed on the one hand of variable renewables which create many new short-term dynamics factoring into price patterns and on the other hand of new types of assets (from battery storages to heat pumps) which may both benefit from and mitigate such price volatility.

Products. Forwards and futures are mostly traded in baseload or futures products with delivery periods of years, quarters, months, or days. Yearly forwards and futures are the most important product for hedging 1-3 years in advance. As delivery approaches, parties often re-hedge in more granular products. Baseload is the financial equivalent to a continuous electricity delivery over the whole period while peak-load is for weekdays from 8 to 20h. Peak-load hours were historically the most expensive hours of the day, although that is changing with increasing generation shares coming from solar PV.

Liquidity and horizon. In most markets, futures/forwards are only traded for a relatively short time horizon of up to 3 years, and even these relatively short maturities are often rather illiquid in smaller

Member States, hampering reliable price discovery and efficient trade. The most liquid forward market in the EU is the German forward market. Due to its high liquidity, also market parties from smaller Member States use the German market for proxy hedging.

Proxy hedging. Firms wanting to hedge their demand or supply portfolio often hedge using products that closely resemble but are not equal to the risk they wish to hedge. For example, a Belgian demand entity might hedge using a combination of the more liquid German and French power futures, which are highly correlated to the Belgian power price. For longer time horizons, even cross-commodity proxy hedges are common. That means for years in which power prices are not available on liquid forward markets, the electricity price risk is hedged through fossil gas futures, which are more widely available for longer maturities. However, such geographical or commodity proxy hedges come with a basis risk. A Belgian demand entity that has hedged on the German and French markets faces the risk that the Belgian price could deviate significantly from the German and French prices at the time of delivery, e.g., due to domestic Belgian factors. For countries with little interconnection to bidding zones with liquid forward markets, this risk can be significant.

Status quo: LTTRs. To enable market parties to hedge such cross-border basis risk, TSOs issue long-term transmission rights (LTTRs) according to the original version of Article 9 of the Electricity Market Regulation. In a recent policy paper, ACER (2023) concluded that current LTTRs suffer from a number of flaws. One category of problems concerns implementation aspects: First, LTTRs are often only available for maturities of up to 1 year. Second, their financial nature as non-firm and of being options, rather than obligations, hampers their suitability to cover the basis risk from cross-border forward hedging. Both of these issues could be changed in a rather no-regret evolutionary fashion. A second, broader issue concerns the question of liquidity and the suboptimal availability of forwards and futures in smaller Member States. This is what the Commission aims to address by switching the overall format of LTTRs from zone-to-zone to zone-to-hub format, and thereby incentivising (but not mandating) the setup of hub futures, i.e., futures products that use a reference hub price as underlying.

3.2. Protecting consumers from future energy crises

Protecting consumers from the effects of an electricity price crisis like the 2021/22 crisis has been, of course, the trigger and main reason to conduct an electricity market reform in the first place. The proposal aims at this objective through a host of different measures and mechanisms:

- Fostering long-term contracts between producers and consumers (PPAs) that shield consumers from the consequences of spikes in spot prices (see section 3.1.2).
- Promoting long-term two-sided contracts between producers and governments (CfDs) that generate public income during price spikes that can be used to compensate power consumers.
- Obliging retail suppliers to engage in long-term power procurement.
- Entitling small-scale consumers to fixed-price retail contracts.
- Allowing Member States to cap retail prices in case a price crisis is declared.

These measures regulate different aspects of long-term contractual relationships. Figure 9 maps the different type of long-term contracts that can contribute to shielding consumers from electricity price spikes. Some of the proposals depend on each other for effectiveness, for example:

- CfDs will only help during a price crisis if the revenues are distributed properly.

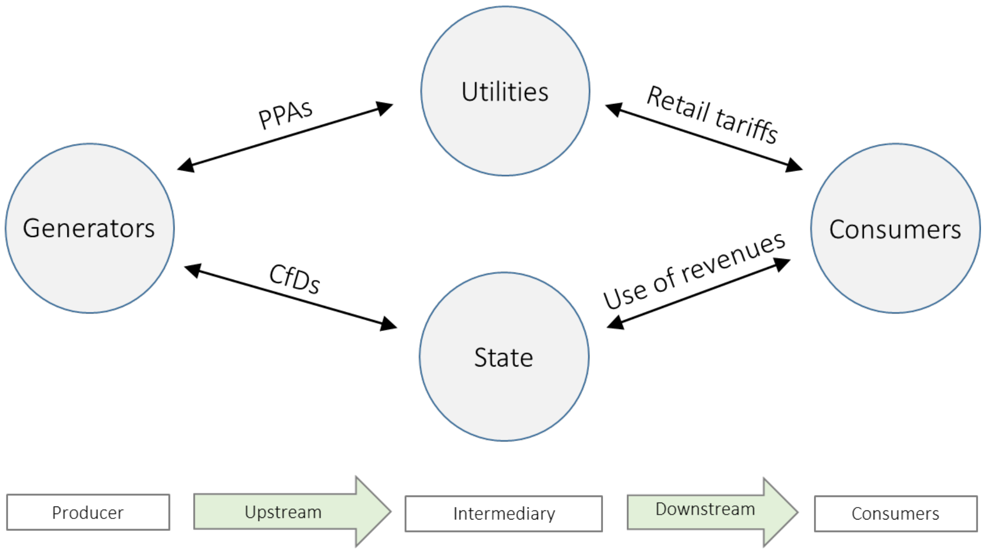
- Forcing utilities to engage in long-term procurement will only help if also retail tariffs have a longer duration.

Other proposals compete against each other, such as:

- Generators can hedge each unit of output only once, either through a PPA or a CfD, which implies that expanding on CfDs will necessarily crowd out PPAs.
- Announcing retail price caps will diminish the incentive of electricity consumers to hedge against price risk and hence reduce the demand for long-term contracts such as PPAs.

In our view, the proposal fails to develop a consistent, robust system to protect consumers against future energy crisis. It is possible for Member States to use these design elements to build a market system that protects consumers, but it is equally possible for them to implement these elements in a way that fails to protect but causes significant harm to the functioning of the power market.

Figure 9: Contractual relationships that can mitigate small-scale consumer exposure to price crisis through either utilities or the state as intermediaries between them and generators



Source: Neon.

3.2.1. Use of CfD revenues (Regulation article 19b(3))

In times of high electricity prices, CfDs generate revenue for the government due to the implicit clawback function of CfDs. What governments should be allowed to do with these revenues was a contentious issue in discussions. The Commission proposal contains a provision to distribute revenues to *all* final consumers proportionally to their consumption.

Revenues are the exception. Historically, CfD schemes more frequently generated costs rather than revenues for ratepayers. This changed during the energy crisis when power prices skyrocketed. In the next decade, given Member States' substantial renewable energy targets, most quantitative scenarios of future power prices suggest that power prices will fall below strike prices most of the time, so that often CfDs will again require, rather than provide, public revenues. It seems likely that many of the CfDs signed today will incur a net cost to the public budget over the course of the contract lifetime. Therefore, while it is important to clarify what happens to revenues, it seems equally important to clarify how costs are financed, and to be realistic about the (limited) likely volume of revenues.

Legislative positions. Provisions differ across the versions of the respective legislative text. The Commission proposal contains a provision to distribute revenues to *all* final consumers proportionally to their consumption. ITRE on the other hand opted for more specifically defined target groups from energy poor consumers to industries engaged in decarbonisation and at risk of carbon leakage. The Council General Approach (REV4) opts for allowing a departure from proportional distribution for households while keeping the proportionality requirement for undertakings. Both ITRE's position and the Council General Approach (REV4) call for the possibility to save revenues for later low-price times when CfDs require funding, which in our view is a sensible no-regret improvement of the initial text.

Distribution & efficiency. Rules on CfD revenues concern distributional as well as allocative (efficiency) questions. The distributional questions play out between ensuring a level playing field across the EU vs. supporting specific customer groups most in need of energy price support. The efficiency questions centre around incentives for flexibility, situational energy saving and hedging.

Recipient options. CfD revenues could be used in different ways: they could be distributed to all electricity consumers (i.e. reduce electricity prices across the board), used to fund grids, or be channelled to specific recipients (such as energy-poor households or electricity-intensive industry). Alternatively, they could be saved to pay for future CfD costs once power prices fall. From an economic perspective, the latter comes with the benefit of reducing distortive taxation during low-price periods and thereby increasing welfare.

Efficient price signals. Electricity prices are a signal of scarcity or abundance in electricity markets on a fine-grained time resolution. Thereby, they are necessary for consumers to make efficient choices on electricity consumption and its timing. For example, hourly electricity prices can incentivise charging an electric vehicle when renewable electricity is abundant, or they could incentivise slightly reducing the temperature within buildings during periods of exceptionally low renewable supply and high prices. If CfD revenues were to be distributed in a way that would undermine such price signals, desirable load flexibility would be inhibited. Both shifting load in time as well as saving energy during high price times could be affected. The Commission's proposal addresses the issue by asking for CfDs to keep load shifting incentives alive. However, while incentives to shift load across time can be preserved even when revenues are proportionally distributed, energy saving incentives are no longer efficient. Distributing revenues proportionally alters the *level* of prices, which results in inefficiently low incentives for energy saving during prolonged periods of high prices. This would have been undesirable for a situation such as the 2022 energy crisis.

Lump sum. To avoid deteriorating energy saving incentives during high price crises, an alternative is to distribute money as lump sums, i.e. as payments to consumers that are not dependent on their current consumption. Thereby, prices can remain high (which induces saving incentives) while consumers are directly supported financially. Lump sums can either be a fixed sum per household or customer or be calculated based on other fixed variables. Both the Council General Approach (REV4), as well as ITRE's position allow for lump sum payments, while the Commission's initial proposal excludes them due to the proportionality approach (fixed amount per MWh consumed).

3.2.2. Hedging obligation (Directive Art. 18a)

In Article 18a of the Directive, the proposal also contains provisions for supplier risk management. More concretely, the proposal demands that NRAs ensure suppliers put in place appropriate hedging strategies to limit the risk arising from wholesale price changes.

Supplier hedging. For electricity suppliers, the appropriate hedging strategy depends on the maturity of the contracts they sign with end consumers. If downstream consumer contracts are longer term (i.e. one or two years contract duration) it is often in the supplier's best interest to also sign upstream hedge contracts hedging the obligations the supplier has towards its customers. Once a supplier enters similarly sized contracts both upstream and downstream, its value at risk is low and profits become largely independent of power prices.

Over-hedging increases risks. Any further and longer hedge, above the existing downstream commitments towards customers, can increase, rather than decrease the supplier's risk. This can be shown by an example. If a supplier hedges more than what it owes its customers at a time of high prices, then if prices decrease later, it needs to cover the losses somehow, which is difficult given competitive pressures from cheaper market prices, potentially endangering the firm.

Gaming the system. However, given the relative ease of setting up electricity supply companies, absent prudential regulation there can be various profitable business models of reaping extra profits from gaming the system. One such strategy is to intentionally plan with bankruptcy: set up a retail supplier, sign longer term contracts with customers but refrain from hedging on the upstream side. Such a supplier will make significant profits if prices fall as it benefits from cheaper upstream purchases while the initial higher downstream rates remain locked-in. If prices rise, it will become bankrupt and default on its obligations. If setting up and liquidating the company is not too expensive, this could be a profitable strategy. In economics jargon, such a strategy is called "moral hazard". A different strategy could involve hedging as usual, but once prices rise the company would get rid of existing customers by pushing them out, either by cancelation of contracts or through suggestive communication strategies. Then the company could sell its hedged volumes to the spot market at high prices, avoiding supplying customers more cheaply. In both cases, bankruptcy and contract cancellation, consumers would fall back to alternative or default suppliers. If default supplier prices are regulated and do not reflect current market prices, a flood of additional customers could in turn undermine the solvency of the default supplier. These are classical issues of consumer protection that justify a need for prudential regulation to prevent them.

Goals. The goal of hedging obligations should therefore be to prevent suppliers from signing longer-term supply contracts with customers while not being adequately hedged itself. In other words, the goal is to avoid moral hazard. While fostering demand for long-term low-carbon power purchase agreements might also be seen as a goal that can be fostered by supplier obligations, there are many reasons why this is likely to be the wrong vehicle for such purposes. We explain in the following.

Pricing is based on opportunity costs. It is important to understand that retail pricing strategies depend mostly on competitive dynamics and opportunity costs, not on an individual supplier's cost structure. Therefore, even if a supplier owns upstream hedged volumes signed a long time ago when prices were cheap, it will offer the higher current, competitive price level to new consumers – with at best minimal discounts. This is because the supplier faces the opportunity cost of selling on the spot market rather than selling cheaply to customers. Therefore, customers often do not benefit when suppliers have hedged cheaply.

Specific PPA obligation. The proposed Article 18a also contains provisions to enable Member States, under certain conditions, to mandate that a certain share of retail hedging obligations must be procured from renewable PPAs. The intention seems to be to drive investment into renewables. However, absent regulation limiting this to asset-based PPAs entirely for new-built renewables, this is unlikely to have any material effect. This is because renewable PPAs could come from existing plants and be provided in any shape including those matching conventional forwards or futures by for example large incumbent utilities which also have renewables in their portfolio, so they can offer such products. Also, such obligations run the risk of forcing suppliers to over-hedge, which would increase rather than decrease their risk of defaulting.

Legislative positions. There are few differences between the institutions' drafts. While the Commission only asks the regulatory authorities to "ensure" that suppliers implement appropriate hedging strategies, ITRE's position asks for a regularly repeated stress test. Both provisions are likely to be implemented quite similarly. A fundamentally new proposal by ITRE is to require Member States to take "measures to ensure liquidity in hedging markets", including "to avoid the lack of level playing field". This could imply that governments could mandate dominant suppliers to act as market makers in otherwise illiquid forward markets, significantly broadening the scope of the proposed article.

Recommendation. We recommend strictly limiting supplier hedging obligations to match the maturities of their obligations towards customers to prevent the obligation from increasing, rather than decreasing the risk of supplier defaults. The obligation should also be targeted on preventing fraudulent practices of suppliers to make risky bets on price movements and go bankrupt or alienate customers in case the bet goes wrong. An obligation to sign long-term PPAs seems inadequate as it would increase supplier risks. If the idea is to increase renewable investments, other instruments, such as CfDs, are preferable.

3.2.3. Fixed-price vs. smart retail tariffs (Directive Art. 11)

Fixed-price tariffs. In Article 11 of the Directive, the Commission proposed requiring suppliers to offer fixed-price, fixed-term contracts. This proposal seems quite uncontroversial, with the Council and ITRE suggesting just rather technical changes.

Types of retail contracts. While there is a large variety of retail electricity contracts, two archetypes exist:

- A fixed price contract that guarantees a constant ct/kWh price for one or two years.
- A real-time pricing tariff that passes through hour-by-hour spot prices (plus grid fees and taxes).

All other contracts (shorter duration, monthly average prices, etc.) can be thought of as being somewhere in the middle between these extremes.

Pro / con. Both contracts have advantages and disadvantages. Fixed price contracts protect consumers from wholesale price spikes (for the duration of the contract), but because they mute the spot price signal, they do not provide efficient incentives for saving energy in times of crises and no incentive for demand-side flexibility e.g., load shifting by charging EVs when renewable energy is abundant and power prices are low. They can also be slightly more expensive on average as they require hedging of price risks on the utility side. Real-time pricing tariffs on the other hand provide efficient incentives for energy saving and flexibility. They can also be combined with dynamic grid fees, enabling smart heating and charging when distribution grids are uncongested. However, when wholesale prices spike, consumers remain unprotected, which was not only evident during the European energy crisis of 2021/22 but also during the Texas cold spell of early 2021[12].

Demand response. Decarbonisation requires large-scale expansion of wind and solar energy as well as the electrification of heating and transport. Both space heating and battery-electric cars have significant embedded flexibility potential, i.e., one can easily shift electricity consumption by a few hours back or forth without impacting consumers' convenience. If this demand-side flexibility potential remains unexploited, the need for large-scale batteries, electrolysers, hydrogen-fired plants, transmission and distribution networks is greatly inflated. In fact, a net-zero power system without

[12] A historical winter event in Texas that caused several coal and gas power plants to trip, leading to a severe shortage of electricity in the system with large-scale brownouts and power prices of 9000 USD/MWh for multiple days.

demand-side flexibility is hard to imagine. Granular price signals that convey abundance or scarcity of electricity generation and networks are a precondition for consumers (or aggregators and algorithms acting on their behalf) to exploit their flexibility.

Dual objective. Thus, retail tariff design must try to accommodate two objectives: providing protection against electricity cost shocks while continuing to pass on the efficient short-term price signal. Ideally, retail tariffs should be both an insurance against high prices *and* flexibility incentives. What seems to be a hard trade-off, fortunately isn't one.

Real-time-price with price insurance. There exist retail tariffs that combine flexibility incentives with price insurance (Borenstein, 2021). Such a tariff has a long duration of one or multiple years. It specifies (a) an annual volume, (b) an hour-by-hour consumption profile such as a standard load profile and (c) a price. If households consume exactly the amount along the pre-agreed pattern, they pay exactly the agreed-upon price – regardless of price movements on the wholesale market. In other words, they are insured against price spikes.

Example. If the annual consumption is 3000 kWh and the price 20 ct/kWh, households will pay EUR 600 annually, whatever wholesale price movements may occur. If households deviate from the pattern, these differences (+/-) are settled with the hour-by-hour spot prices. For example, if they avoid charging their EV during the evening peak, they get the full spot price of that hour (say, 40 ct/kWh) credited. For charging the vehicle at a windy night, they only pay the low spot price of that moment (say, 5 ct/kWh). If a Texas-type of energy crisis hits and spot prices spike at 1000 ct/kWh, even small energy savings will be financially extremely attractive. As a result, consumers can actually benefit financially from price spikes.

Interpretation. In other words, while households are insured against the effect of price spikes on their bills and know exactly what they will pay, they still have the full benefits of saving energy when it matters. Essentially, while consumers have high certainty about the size of their electricity bill, efficient price signals prevail at the margin. American energy economist Severin Borenstein (2021) put forward a similar idea after the 2021 Texas energy crisis and similar contracts are common practice for larger consumers. Effectively, a smart retail tariff would apply the logic of forward hedging to retail customers.

Conclusion. In our view, moving back to fixed-price retail tariffs represents a lost opportunity and makes the transition towards low-carbon energy systems slower and more costly. A requirement to introduce retail tariffs that combine proper incentives with price insurance would be a preferred option.

3.2.4. Electricity price crisis (Directive Art. 66a)

Background. The proposed new Article 66a of the Electricity Directive specifies under which conditions an electricity price crisis is announced and allows Member States to cap retail electricity prices during such crises. Other mechanisms, such as the introduction of a peak shaving product, might be linked to the crisis conditions (see 3.3.1). In contrast, allowing Member States to cap revenues during an electricity prices crisis, which had been proposed during the Council and Parliament negotiations, is not included in the Commission proposal, in ITRE's position, or the Council General Approach (REV4).

Trigger. An energy price crisis is triggered if three conditions are met: an increase in wholesale prices of 150% compared to the past five years, an increase in retail prices by 70%, and a negative effect on the economy. ITRE has proposed to additionally require wholesale prices to exceed 180 €/MWh (which is likely to be the case anyway under such price increases) and the Council considers excluding the year 2022 from the calculation of the five-year-average, which significantly lowers the bar for a crisis to be announced. ITRE has also suggested to lower the bar for retail prices increases from 70% to 60%.

Problems. These conditions have three independent problems:

- First, they are quite ambiguous. There is not "the" one wholesale price, but a plethora of prices that emerge from forwards, futures, day-ahead, intraday, and balancing markets. It is unclear which of them are referred to. Prices must be "expected" to remain high for some time, but it is not clear whose expectations are referred to (one option could be forward markets, but liquid forward markets do not exist in all bidding zones). Also, the five-year average could be calculated in different ways, e.g. the last five completed calendar years, or a moving average of 5x365 days – with substantially different outcomes. In the case of the retail price increase, it is not even clear what time period serves as the point of comparison. Also, retail prices differ greatly between consumers of different sizes and segments (households vs. businesses), and it is not clear which segments are referred to. All this produces significant uncertainty, potentially misaligned expectations, and leeway in announcing a crisis.
- Second, the required duration of elevated prices is very short and does not account for seasonality. The Commission suggests six months, ITRE and the Council just three. Power prices exhibit significant seasonality, such that a cold winter could already exhibit price movements as indicated. However, it seems unreasonable to trigger an energy price crisis if it is clearly temporary in nature.
- Finally, and more fundamentally, the overall market reform follows the idea of keeping short-term price signals intact while isolating consumers from the adverse consequence of price spikes through long-term contracts (PPAs, CfDs). If that is successful, spiking wholesale prices do not constitute a "crisis", because no one is hurt. In other words, the first trigger criterion is inconsistent with the principal direction of reform. An increase in retail prices, if well defined, seems to be a more appropriate trigger than wholesale prices.

Consequences. Once a crisis has been declared, Member States may cap retail prices or otherwise intervene in retail electricity markets for residential consumers and small businesses. While the intervention shall be restricted to 70% of last year's consumption to maintain energy savings incentives, there is no limit to the price cap, i.e., Member States could set prices at any level. Interventions in wholesale markets are not foreseen. Economically, retail price interventions are far less problematic than wholesale price interventions because they do not distort the decisions of generators, storage operators and cross-border trading. However, they are not without side effects. Even if designed carefully, they do mitigate the incentive to conserve energy. Applied to firms which produce tradable goods, they also distort the internal market, because businesses in some Member States benefit from capped prices while others may not. This is particularly relevant if the electricity-intensive industry is to be included, as ITRE's position suggests. Finally, the announcement of retail price interventions in case of a price increase will, of course, reduce the incentive to hedge against such prices. This, too, is particularly relevant for the energy-intensive industry. Put simply, why should these firms spend money and time to engage in long-term PPAs and forward contracts if they know that if prices go up, the government will cap their expenses? In other words, Art. 66a is likely to crowd out the very long-term contracts the overall reform is trying to promote.

Regulatory uncertainty. On the other hand, one might argue that in a sufficiently severe crisis, ad-hoc regulatory interventions will emerge anyway. It might be better to clarify conditions and nature of interventions ahead of time instead leaving it to stakeholders to speculate over which situations will result in member states or the European Commission to intervene into markets. A well-defined backstop might hence reduce uncertainty, rather than increase it.

3.3. Demand-side flexibility

A third area of proposed changes is the promotion of demand-side flexibility. This includes two specific mechanisms: the peak shaving product and flexibility support schemes.

3.3.1. Peak shaving product (Regulation Art. 7a)

Background. The proposed new Article 7a of the Electricity Regulation allows Member States to let TSOs procure a new "peak shaving product". This connects to the political discussion around peak shaving that emerged in late 2022 as a response to the electricity crisis. It also traces back to an ACER working group on demand side flexibility. It is not clear to us, however, if Member States couldn't introduce such a product already under current European legislation: for example, Austria introduced a "demand-side-response product" in late 2022 that resembles the proposal closely.

Variants. The Commission proposal, ITRE's position and the Council General Approach (REV4) differ in a number of aspects, e.g., if only transmission or also distribution system operators can procure the product, whether it can be procured always or only during an electricity price crisis according to Art. 66a, whether a prior ACER assessment is required, and whether Member States must first request such a product. While these aspects are of great practical matter, they do not affect the fundamental economic mechanisms of the proposal, which we will focus on in the following.

Mechanisms. The peak shaving product is a new service that system operators can procure from consumers. It is procured a few days before delivery and then activated before, within or after the day-ahead market (Commission, Council and ITRE disagree on this crucial point). When activated, consumers must reduce their consumption below a baseline, for which they are financially remunerated.

Goals. From a scientific perspective, regulatory proposals should have a clear objective, which allows an appropriate design. Surprisingly, this is not the case with the peak shaving product. Regarding the problem the proposal is trying to solve, Commission, ITRE and Council give starkly different answers:

- The Commission proposal suggests the product shall contribute to "an efficient integration of electricity generated from renewable energy sources in the system", as well as to "reliability" and to "grid stability". Accordingly, activation is planned after the day-ahead auction.
- The Council states the main objective is "lowering wholesale electricity prices". Accordingly, activation is foreseen to happen before or integrated into the day-ahead auction.
- ITRE's position, too, understands the instrument should "achieve a reduction of electricity demand and price", but still foresees activation after the day-ahead auction.

These two justifications – peak shaving for reliability or for lower prices – are radically different, hence we discuss them separately in turn.

Shaving for reliability. If the objective of the product is to contribute to system and grid reliability, one should note that for the many individual aspects of stability and reliability, established markets, mechanisms and system services are already in place:

- Reducing demand in times of scarcity is incentivised through the day-ahead market.
- Reducing demand on short notice during an unexpected shortage or contingency is achieved through the intraday market and / or the imbalance settlement mechanism.
- Procuring firm capacity for demand reduction on short notice can be attracted through balancing reserve auctions.

- Network congestion management is achieved through redispatch, curtailment, and markets for local flexibility.
- Voltage support is regulated in the network codes or procured via market-based mechanisms.

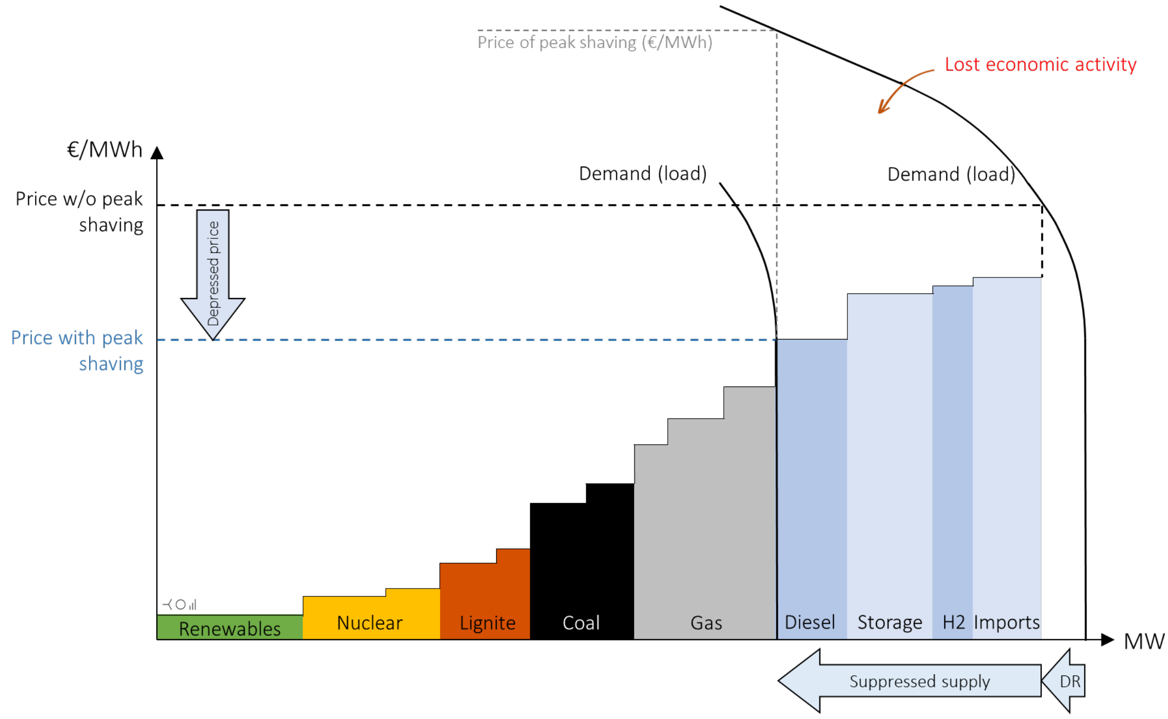
Design principles. Not only do established markets exist that allow system operators to procure the services they need, but those markets also articulate system needs much more precisely than the proposed peak shaving product – "reducing demand in peak hours" is not generally the right answer to any specific power system problem. In addition, if one were to introduce a new procurement mechanism, it should generally be technology-neutral. This is because it is not only consumers who can deliver such services, but also conventional and renewable generators as well as storage operators, often also across-borders. Hence any procurement mechanism should be open to all these potential resources in a non-discriminatory manner. In the case of a peak shaving product, it is unclear to us why consumers should be allowed to deliver such a service, but not other resources.

Shaving for lower prices. If the peak shaving product is primarily about reducing spot prices, it makes sense to activate it before or as part of the day-ahead auction. Effectively, this would mean system operators buy energy from consumers at a high price and sell it to the spot market at a lower price. In economics jargon, such activity is called "price discrimination". As a consequence, the spot price is depressed below the counterfactual case of a market clearing without prior peak shaving. However, this is problematic for four reasons: costs, static inefficiency, diminished investment incentives, and inconsistency with the overall electricity market reform approach.

1. **Costs**. When system operators buy electricity from consumers at a high price to sell it at a lower price on the day-ahead market, they incur a loss. The size of this cost depends on the volume, the price elasticity of demand, and possible imperfections such as non-competitive bidding and baseline manipulations. This loss would probably be recovered through grid fees, increasing the price of electricity for all consumers.

2. **Static inefficiency**. By lowering the spot price, the mechanism crowds out electricity suppliers that would have been willing to sell at the higher undistorted price, but not at the depressed price. Figure 10 illustrates this: At the reduced spot price, sellers with high ask prices, such as battery operators, expensive diesel plants, (future) hydrogen-fired power plants, but also imports would be suppressed. This is economically inefficient and welfare-reducing since the economy would have benefitted from the additional power supply. In addition, any market-driven demand response is crowded out, too.

Figure 10: The supply-depressing effect of peak shaving (illustration)



Source: Neon.

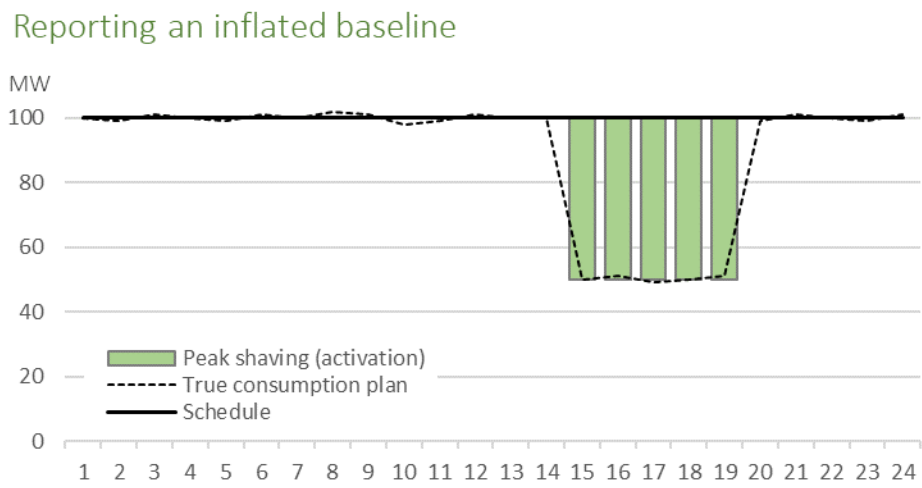
Note: Buying consumers off at a higher price, to reduce the spot price, crowds out supply as well as lower-cost demand response (DR).

3. **Investment incentives**. A third problem is the impact on investment. With the announcement of a mechanism intended to depress peak prices, it becomes less attractive to invest in said peak-load technologies. This makes future scarcity more likely and increases the pressure to implement capacity mechanisms.

4. **Inconsistency**. Finally, the idea of depressing spot prices is at odds with the overall direction of the reform proposal, which centres around the idea of leaving spot price signals intact while protecting consumers through long-term contracts and hedging arrangements such as PPAs and CfDs (see also section 3.2).

Baseline. No matter whether the objective of the peak shaving product is reliability or depressing spot prices, it requires defining a baseline ("reduction below what?"). Defining a robust baseline is a fundamental challenge of any mechanism that rewards a reduction. If the baseline is the schedule the consumer had submitted, there is an incentive to inflate the schedule to maximize the reduction reported to the system operator – without actually having to diminish the physical consumption of electricity. By doing so, peak load shaving providers might ultimately be able to consume, after the reduction ordered by the system operator, the originally wished amount, while still being paid for their demand "reduction". This way, consumers can extract windfall profits and while it looks like a demand reduction has been achieved, the physical reality of the power system is not altered by the introduction of the peak shaving product. The situation becomes even worse if consumers inflate schedules but are, contrary to their expectation, *not* activated, in which case they actually *increase* physical consumption during times of scarcity, inflating power prices and further stressing the system. Since participants of the scheme have an inherent incentive to manipulate the baseline, ideally it should be set on objective criteria by the system operator. However, it is not clear how this can be done since consumption plans are inherently private information of consumers. The legislative proposal does not provide any guidance on the baseline methodology, leaving it entirely to TSOs.

Figure 11: Manipulating the baseline to maximize payout (illustration)



Source: Neon.

Note: In the case displayed here, a consumer had planned to reduce consumption in the high-price afternoon hours. However, to benefit from the peak shaving product, they report a constant schedule. After being activated, the consumer follows exactly the planned consumption pattern – but earns a windfall from the mechanism.

Evaluation. We fear that participating consumers will often find ways to manipulate the baseline, extracting windfall from all other electricity consumers. Using the peak load shaving product to depress spot prices is, in our view, not a good idea. Protecting consumers is better archived by the various measures discussed in section 3.2. The peak shaving product can contribute to system stability and reliability, if it is designed carefully such that overlap with existing markets and system services is avoided. To add value, the peak shaving product should specifically address small-scale assets which are currently excluded from the established markets, either because they are too small, do not have smart meters, or because they do not fulfil other criteria. If it was designed as an emergency mechanism however, one could relax metering, information technology and other requirements for the peak shaving product compared to balancing responsibility and other system services.

3.3.2. Flexibility target and support scheme (Regulation Art. 19c-f)

Assessment in short. The Commission's proposal introduces assessments, targets and support mechanisms for flexibility into the EU electricity market design. It thereby creates new special markets that target storage and demand assets specifically, and thereby positively price-discriminates these assets against other types of flexibility. This deviates from the previous focus for short-term markets on non-discrimination and strong unified price signals and thereby likely to decreases overall market efficiency. In our view, a better way to address the current lack of demand-sided flexibility is by addressing the main barrier: capacity charges in grid tariffs, as we explain in Box 2. In this section, we first outline the nature of flexibility in power markets, describe how *all* power markets are implicitly flexibility markets, and then describe and asses the reform proposal in more detail.

Definition. Flexibility is an umbrella term used for a wide range of power system characteristics. The definition in the Commission proposal is very broad and defines it as "the ability of an electricity system to adjust to the variability of generation and consumption patterns and grid availability, across relevant market timeframes." This definition applies to very different capabilities of power system assets, including firm capacity, the ability to ramp fast, to operate in accordance with demand, or to be located at system-serving locations. In essence, flexibility means the consideration of the rest of the power system in the operation and investment of assets, sometimes also referred to as system-friendliness. This can be illustrated by a thought experiment: What would the components of the power system look like if they were optimised exclusively for themselves? In this scenario, thermal power plants would run at a constant base load and be located where their fuel supply is available with little transport costs, such as at coastal sites, peak load gas power plants would not exist at all. Wind and solar plants would be designed and built where their electricity generation costs are lowest. Consumers would use electricity where and when they want it; night storage heaters would never have been invented; storage and grids would not exist at all. Supply and demand would not match, neither in time nor in place (except by coincidence). All measures that bridge this gap between generation and consumption - grids, storage, but also adjustments of generation or consumption - can be understood as flexibility.

The need for flexibility. The need for flexibility has been inherent to power systems. It is not a new phenomenon, and neither is it limited to renewables. In general, every asset in the system has flexibility requirements but is also capable of providing flexibility. However, systems differ in the type, the amount, and the cost of flexibility provision. A renewable-based power system obviously needs different complementary technologies than a fossil-based one.

Every electricity market is a flexibility market. Every electricity market (spot, intraday, balancing energy, etc.) balances supply and demand and is thus a market for both energy and for flexibility. Flexibility requirements are built into the terms and conditions for participating in electricity markets. Examples are the obligation to submit quarter-hourly schedules for all balancing responsible parties and the requirements on reaction time for balancing reserves. Conversely, it is difficult to imagine an electricity market that is not simultaneously also a market for flexibility: it would consist of the pure transaction of MWh, without delivery location, product definition, or time profile. Of course, such a market does not exist.

Flexibility needs are reflected in market prices. Flexibility needs are expressed through market prices, e.g., via price differences between different hours of high and low residual load on the day-ahead market, via price movements for the same hour on the intraday market, or via the levels of the capacity payment and the energy payment on the market for balancing reserves. A flexible asset, say, a battery, may react to these prices signals by adjusting its production schedule. In doing so, it profits from these price signals while simultaneously satisfying the system's needs for flexibility. These profit opportunities provide appropriate investment incentives for flexibility, e.g., prices on the Frequency containment reserve (FCR) market motivated battery operators to enter this market at scale in recent years.

Specific needs for flexibility. The term flexibility is probably best understood as an abstract, multidimensional concept that cannot be measured in MW or MWh. Therefore, a general "merit order of flexibility" cannot be established. Individual aspects of flexibility can be defined and, if needed, traded or procured on markets. One example are the markets for balancing reserves, where the demand of the power system for short-term power increase or decrease, differentiated by lead time, is defined, dimensioned, and procured. Assessing unspecified flexibility needs and setting national flexibility objectives, on the other hand, is difficult to reconcile with the differentiated flexibility needs of the electricity system.

Flexibility is embedded in electricity products. Designing markets to account for the need for flexibility requires defining products, market segments and system services such that they reflect the physical requirements of the power grid. As the power system transforms, it may be useful to adjust market segments repeatedly to reflect changing flexibility needs or new technological opportunities. Examples of past interventions in this regard include the introduction of quarter-hourly market time units, the gradual shifting of the gate closure time closer to delivery, or the adjustment of control reserve prequalification conditions to allow for battery participation in the 2010s, the introduction of real time pricing electricity tariffs for residential customers in recent years, or possibly the procurement of instantaneous reserve sometime in the 2020s.

Flexibility is not technology specific. Most aspects of flexibility can be provided by various types of assets and technologies: Conventional and renewable generators, storage, industrial and small consumers, or through import and export. It is often the interplay of different technologies that represents the most efficient delivery of a specific flexibility need. A restriction of flexibility incentives to specific assets is usually not efficient. However, to date, a focus of flexibility provision has been on electricity generators. Thus, focusing the discussion on demand and storage seems reasonable, since there are also some specific barriers, such as power-based network charges (see Box 2).

Assessment of flexibility needs and introduction of national flexibility objectives. The Commission proposal includes an obligation for NRAs to compile bi-annual assessments of flexibility needs at the Member States level. ITRE suggests complementing these assessments with a Union-wide assessment by ACER. TSOs and DSOs, are obliged to provide the required data, coordinated by their sector associations ENTSO-E and the EU DSO entity. The national flexibility assessments are to be analysed by ACER (Commission Proposal) as well as the European Scientific Advisory Board on Climate Change (ITRE amendment). Based on these reports, Member States shall define national objectives for demand response and energy storage. These in turn are to be assessed by the Commission in a report to the Parliament and the Council, which ITRE suggests accompanying by a Union strategy on demand response and energy storage. Drafting these reports, their evaluations and the resulting strategies will introduce a substantial administrative burden and costs at these institutions.

Flexibility comes at a cost. Providing flexibility generally comes with (opportunity) costs: Batteries have high investment costs, industrial facilities engaging in demand response must interrupt their production, flexible power plants have fuel and emissions costs. For this reason, it is not efficient to satisfy every flexibility need e.g., it is currently not viable to store excess wind generation when electricity is cheap and to discharge when prices are higher. Often, it is economically efficient to curtail wind generation and to accept price differences across hours.

Flexibility support schemes. Equally, subsidising certain flexibility providers, as the reform proposes to allow Member States to do, is economically inefficient, as it reduces incentives for other market participants to operate in a system friendly manner. To the degree that the subsidy will distort the market, causing additional investments into demand response and energy storage, it will bring down price spreads on spot markets or capacity prices in balancing reserve markets that otherwise would have incentivised market-based investments. Hence, if Member States implement support schemes for demand response and energy storage, it is paramount not to introduce additional distortions, i.e., not to interfere with the market-based dispatch decisions of the subsidised assets.

Reducing barriers instead. Rather than introducing new special markets for flexibility, in our view the main barriers to demand-sided flexibility should be tackled. The elephant in the room is grid tariffs, which are likely to be the number one reason why many consumers, including industrial electricity users, shy away from making their demand more flexible. We present this argument in more detail in Box 2. Power-based network tariffs (individual peak capacity charges) are a major barrier for demand response. We recommend introducing and enhancing explicit time-variable network tariffs. If that was done, explicit markets for demand flexibility would likely not be necessary. Instead, all types of flexibility would be adequately incentivised through the existing day-ahead, intraday, and balancing markets.

Box 2: Network tariffs as a flexibility barrier

Introduction. One core aspect of the Commission's proposal for the new electricity directive is the support of demand-side flexibility. The proposal for the directive includes various support schemes for flexibility. Yet, a major barrier for untapping flexibility potentials on the demand side remains unmentioned. The elephant in the room are network tariffs. Current network tariff methodologies aim at reducing the stress on distribution and transmission networks by flattening the consumption profiles of all consumers. We argue in this info box that this strongly impedes the flexibilisation of electricity consumers and storage to serve system needs.

Background. In most Member States, the network tariffs for consumers of electricity consist of an energy-based component and a power-based component. In its report on electricity transmission and distribution tariff methodologies in Europe, ACER encourages a move towards more power-based distribution tariffs (ACER 2022). ACER argues that power-based charges best reflect the resulting cost of the network because they (somewhat) correlate with the peak network demand. The introduction of power-based network tariffs for households is also often advocated for in the context of solar self-generation and grid-friendly charging of electric vehicles.

Argument. In this info box, we discuss the economic incentives resulting from such power-based network charges. We highlight three relevant aspects of this tariff design, which we deem missing in the current debate on demand side flexibility. First, power-based tariffs are implicit time-variable network tariffs. Second, power-based tariffs imply tremendously high costs of additional consumption in particular hours and therefore restrict demand response. Third, power-based tariffs rest upon the individual consumption profile, while they should be based on the network load to provide economically reasonable incentives.

Time-variable charges. Power-based tariffs (sometimes also called peak capacity charges) imply that the cost of consuming an additional ("marginal") megawatt hour varies within the year. More precisely, there are two price tiers: If electricity is consumed below the individual peak load, only the energy-component is due. If electricity consumption is already at peak load, an increase in consumption leads to an additional payment for the power component. In other words, the marginal network tariffs are much higher in these hours. Power-based charges are thus implicit time-variable network charges.

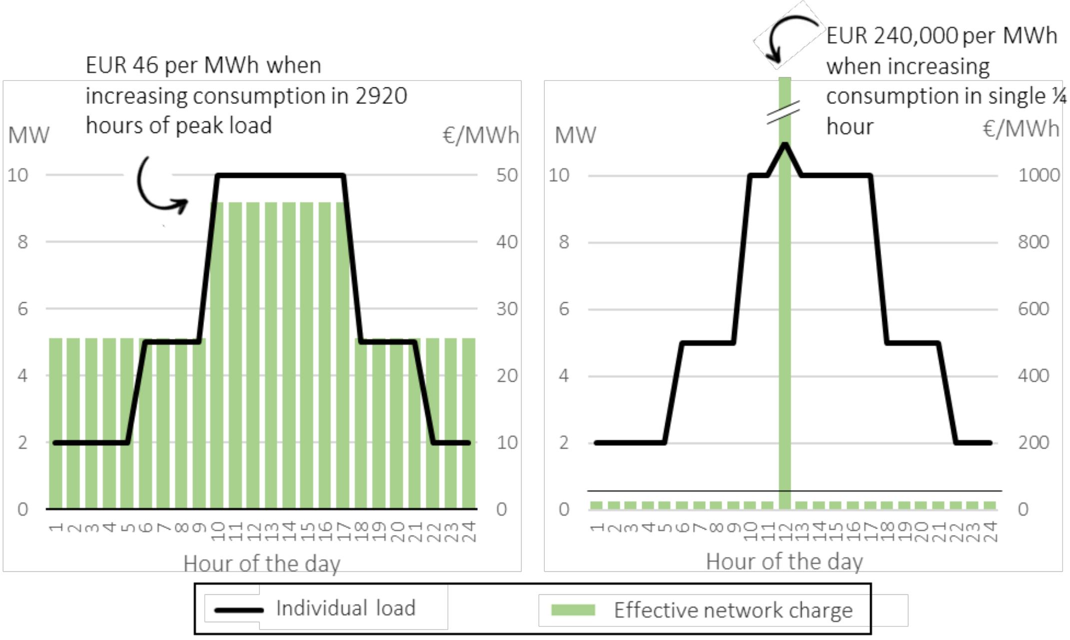
Example. The following case study illustrates this. We use the network charges at the medium voltage level in Berlin in 2022 as an example. They consisted of an energy component of 26 €/MWh and a power component of around 60,000 €/MW. Assume a consumer with a constant peak load between 9 a.m. to 5 p.m. every day of the year. If consumption increases outside these peak hours, only the energy component must be paid. However, if daily consumption increases within these hours of peak demand, a higher payment for the power component is also due. An increase in consumption by one MW in all 2,920 peak hours of the example results in an effective network charge of around EUR 46 per MWh of additional consumption.[13] Hence, a new night shift implies network charges of 26 €/MWh whereas a day shift would cost 46 €/MWh (Figure 12, left). Due to the power-component, the effective network charge fluctuates over the course of the day.

[13] The power component of EUR 60,000 per MW is spread over 8 x 365 = 2920 hours, which corresponds to around EUR 20 per MWh.

Incentives for flexibility. The differences in effective network charges become absurd if the increase in peak demand is not spread across multiple hours but occurs in a few hours only, e.g., to provide flexibility in the form of a short-term increase in consumption. If one additional MWh is consumed in just a single quarter of an hour, the peak demand would rise by four megawatts. In Berlin's medium voltage, the effective network charge would then be 240,000 €/MWh – which is almost ten thousand times more than the energy-based component of the charge (Figure 12, right). Even if the additional MWh is spread out over 100 hours at 10 kWh each, the cost per additional MWh is still EUR 600, i.e., 20 times more than the energy component. This example shows that it is practically never worthwhile for consumers with a power-based network charge to increase electricity consumption above peak consumption. The resulting increase in network charges will not be compensated for by any other financial incentives from the power market or an additional market for flexibility. Hence a power-based network charge strongly impedes the provision of flexibility.

Individual load. The problem with the power component (individual peak capacity charge) of the network charges is that it is based on individual consumption. It is the individual peak load, and not system peak load, that defines the hours when an increase in electricity consumption leads to an additional power payment and higher network charges. This implies that the highest charge may occur at different moments in time for all consumers, which is problematic for two main reasons. First, this approach does not guarantee that all consumers have an incentive to reduce consumption when the network is at full capacity because the high charge will only apply for those consumers which are at their individual demand peak. The second problem, which is even worse for the provision of flexibility, is that consumers are also disincentivised to increase their consumption when the network is not stressed. Think of a sunny Sunday in summer: even though abundant local solar generation meets little demand, consumers are strongly disincentivised to raise consumption above their individual peak load. This prevents the deployment of new electricity demand such as power-to-heat and imposes a strong barrier for the flexibilisation of existing processes.

Figure 12: Effective network charges for an increase in consumption in i) all hours of individual peak load (left) and ii) one single quarter of an hour (right)



Source: Neon.

Electricity market analogy. The approach of individual and independent peak charges diametrically contradicts the economic logic of price formation based on the overall demand in a market, such as the wholesale electricity market. On the power exchange, the equilibrium price is determined by aggregate demand, not individual demand. If the logic of network charges was applied to the power exchange, all consumers would pay an individual price. The individual electricity price would always be high when the specific consumer consumes a lot of electricity, even when a lot of wind and solar power are available. Conversely, the individual electricity price would be low when the individual consumption is low, even in a dramatic shortage situation. This shows the ridiculousness of the principle of individual prices.

Network load. According to economic logic, network charges should depend on the total network load, i.e., the joint consumption of all customers, and not the individual consumption profile of individual customers. At every moment, all consumers in one network area should pay the same charge for an increase in consumption because they all have the same effect on the network.

Summary. We showed that the power-based component in the network tariff leads to different costs for additional electricity consumption over time. However, this provides several undesirable incentives:

- It systematically promotes an inflexible design of assets and processes, i.e., a flat consumption profile.
- The resulting profile of individual network charges is not directly related to the network load. Even in an oversupplied grid, additional consumption may be massively penalised financially.
- Network charges based on individual peak load lead to bizarrely high marginal costs if power consumption is only increased in a few hours. This prevents industrial flexibility, such as using electricity in the event of negative wholesale electricity prices or grid bottlenecks.

Recommendation. Power-based network tariffs (individual peak capacity charges) are therefore a major barrier for demand response and storage. Instead of moving to more power-based tariffs, we recommend introducing and enhancing explicit time-variable network tariffs. Yet, the leeway of national governments is limited in this regard since the tariff methodology is under the NRA's jurisdiction. To incentivise demand response and storage, EU legislation should recommend or even prescribe time-variant distribution network tariffs.

3.4. Other topics

3.4.1. Energy sharing (Regulation Art. 15a)

Definition. The term "Energy Sharing" refers to self-consumption by active consumers of renewable electricity generated or stored by themselves or other active consumers either at their premises or by a facility they own, lease or rent.

Potential benefits. The arguments usually brought forward in favour of the energy sharing concept include the following:

- The opportunity to consume energy from local renewable plants would contribute to the increased acceptance of such plants in people's neighbourhoods by adding to local value creation, thereby also mobilising additional local financial capital for the energy transition.

- Participation in energy sharing communities would hedge consumers against high prices as in the 2022 energy crisis as it allows them to diversify where they buy their electricity and provides them with direct access to cheap renewable energy.
- Energy sharing would provide an incentive to synchronize local demand with local generation, i.e., to shift demand over time between hours of low and high renewable generation, thereby reducing curtailment of renewable energy as well as the need for grid expansion.

The first point is rather uncontroversial, but the other two merit some discussion. Understanding to what degree energy sharing communities can deliver on these promises, it is necessary to analyse how they may affect the temporal characteristic of electricity demand via the incentives they provide to consumers.

Incomplete substitution. Due to the limited potential of other renewable technologies, energy generated in energy sharing arrangements will mostly come from PV installations, and potentially some from wind. Both of these are intermittent in their availability. Depending on the ratio of generation capacity and participating consumers in each energy sharing community, the energy generated by the community may only sometimes or actually never suffice to satisfy the demand of the community, i.e., there will be some residual demand. Energy sharing is therefore an incomplete substitute for conventional retail supply.

Retail supplier as a fallback. To ensure customers have access to electricity whenever they need it, the proposal includes provisions to guarantees customers access to conventional retail supply and specifies that the energy procured via energy sharing be netted from their retail bill. In economic terms, the residual supply by the retail supplier can be regarded as an unlimited call option, which the customer can always fall back on in case energy sharing doesn't suffice to cover its demand fully in any given time period. Unless energy sharing communities build substantial storage facilities along with sufficient PV and wind plants, their customers will still require a conventional retail supplier in order to maintain reliable 24/7 access to electricity.

Requirements of smart metering devices. At the same time, participating consumers will require a smart metering device that registers their hourly electricity consumption in order to track how much of their consumption coincided with energy generated by their energy sharing community. The reform proposal recognizes the need for smart metering and for a residual retail supplier by stating that "active customers participating in energy sharing […] are entitled to have the shared electricity injected into the grid deducted from their total metered consumption within a time interval no longer than the imbalance settlement period."

A parallel market. Since members of energy sharing communities will simultaneously stay customers of conventional retailers, energy sharing arrangements in their economic essence constitute a parallel retail market, allowing eligible customers to choose whether to source electricity from one or the other for each moment in time. However, at times when not enough electricity is generated by the jointly operated plants (i.e., at night in case of PV installations) consumers revert to their traditional retailer. In the following, we assume that consumers aim to maximize the share of their electricity consumption that comes from energy sharing, either because of more affordable prices or because of a preference for energy sharing over their conventional retail tariff such that price differences between the two markets do not affect their behaviour, even when energy sharing is more expensive.

Load defection. Energy sharing is a form of load defection. Load defection can already be observed today for owners of rooftop PV installations (prosumers), who have an incentive to substitute away from grid-sourced electricity to the self-generated electricity in order to avoid paying grid fees, other levies and taxes that commonly take the form of a surcharge per kWh sourced via the grid. While previously owning a rooftop or other suitable site on which to install a renewable power plant was a prerequisite for engaging in load defection, energy sharing greatly increases the number of potential participants. Load defection poses a problem for grid operators and the state because it means that fewer kWh are being consumed on which taxes, fees and charges can be levied. This problem will likely not affect energy sharing, as the proposed directive text specifies that energy sharing be "without prejudice to applicable non-discriminatory taxes, levies and cost-reflective network charges". This is an important provision that greatly limits the potential for welfare-reducing and opportunistic energy sharing, because it means that energy sharing cannot be used to avoid taxes and levies.

Adverse selection. However, load defection by prosumers is problematic for a second, lesser-known reason that fully comes to bear in the case of energy sharing too: in procurement, retailers face wholesale prices which vary at least hourly, reflecting the time-varying degree of the scarcity of electricity. With increasing shares of renewable energy, wholesale prices are driven more and more by renewable availability, with the lowest prices regularly occurring at times of high renewable generation. However, many European retail customers have fixed-rate tariffs with a time-invariant rate per kWh which is adjusted only annually, reflecting the consumption-weighted average of (expected) wholesale procurement costs. Load defection by prosumers happens disproportionately often when wholesale prices are low, increasing the average price their retailers must pay for procuring the electricity. In competitive retail markets, fixed retail rates calculated for traditional consumers are therefore too low to be viable for supplying prosumers and members of energy sharing communities. To prevent losses, retailers then have to increase their rates for all customers, further strengthening the incentive for load defection in a case of adverse selection.

Time-of-use pricing as a remedy. In order to allow retailers to maintain a sustainable business model while avoiding rising prices for their traditional customers, they must be allowed to charge prosumers and members of energy sharing communities higher rates than their traditional customers. Alternatively, (dynamic) time-of-use pricing could be mandatory for these customers, allowing retailers to pass on hourly wholesale prices. Retailers should be allowed to prevent access to some fixed tariffs for customers who engage in energy sharing, because if they were not allowed to prevent them from signing such tariffs, they could not reasonably offer them at all in the presence of the load-defection incentives described above.

Energy sharing as a hedge. For the same reason that intermittent renewable generation marketed via energy sharing is an incomplete substitute for traditional retail supply, it is also an inadequate hedge against high retail prices. Since the highest power prices systematically occur in times of little or no renewable generation, energy sharing cannot shield customers from them.

Incentivising flexibility. One of the arguments put forward in favour of energy sharing is that it can help integrating high shares of renewable electricity into the system by incentivising consumers to tap into their flexibility potential and to synchronise electricity demand with (local) renewable generation, i.e., by shifting part of their consumption to hours of high local renewable availability. This is particularly relevant for consumers who own a heat pump and/or an electric vehicle. Energy sharing can indeed provide these incentives, but no more than, for example, dynamic retail electricity tariffs could, which take the whole system perspective into account. Furthermore, energy sharing can also lead to outcomes that are suboptimal or even detrimental from a system perspective, as we show in the following.

Demand flexibility is not always necessary. First of all, it has to be noted that synchronising local consumption with local production is not necessarily useful from a system perspective. At all times when the grid is not actually congested, energy sharing participants who adjust their consumption to the production profile of *local* renewables are not providing any service to the system.

Geographic delineation. Second, the usefulness of demand flexibility depends strongly on the location of the flexible consumers vis-à-vis that of renewable generators and the network topology. In times of network congestion, a necessary condition is that both consumers and generators are located on the same side of the bottleneck. The reform proposal however includes no requirements in this regard. ITRE's position is more specific, limiting energy sharing to "within the same bidding zone or a more limited geographical area determined by Member States". Bidding zones however can be very large, with grid congestion regularly appearing within them, e.g., in Germany. Consequently, this criterion can be too wide to usefully align consumption with renewable generation from a grid congestion perspective. Many position papers on energy sharing suggest an even more limited geographical scope at the municipality level, e.g., BBEn (2021). However, this increases the downside risks of inefficient dispatch from optimising locally, rather than with a system perspective. Our proposal is to delineate the geographical scope for energy sharing along regions where grid congestion frequently occurs or can be expected.

Detrimental incentives. In the worst-case scenario, their behaviour may even be detrimental to the system. For example, this could be the case if they align their consumption with the PV generation of their energy sharing community instead of the wind generation coming from local commercial wind farms, since PV and wind generation are typically negatively correlated. If customers charge their cars on a sunny afternoon, their batteries might already be fully charged during windy nights. Assuming there was no congestion in the grid during the sunny day, but there is in the windy night and the energy sharing community is located on the same side of the grid bottleneck as the wind farm, the flexibility potential of the customers is lost. If the wind farm than needs to be regulated down and to be replaced by a fossil fuel plant on the other side of the bottleneck (redispatch), energy sharing might even increase the carbon output of electricity compared to a regime where customers charge their cars randomly.

Optimising the wrong system. The fundamental problem is that energy sharing only incentivises (some) consumers to align their consumption with those (local) renewable generators that happen to supply their energy sharing community, when from a system perspective, it is the sum of local renewable generation, netted with all of local demand, that matters. While the current market setup with large bidding zones and mostly time invariant consumer prices often fails to pass on economically efficient incentives to final consumers, it is not clear whether energy sharing communities provide an improvement in this regard.

4. ASSESSING THE CURRENT MARKET DESIGN

KEY FINDINGS

While a wealth of research has focussed on the physical generation and demand of electricity, wide public understanding of the accompanying financial flows is generally poorer. The Dispatch and Contracts (DISC) model is a framework which layers contractual agreements and financial flows between agents on top of a representation of the physical electricity system. Application of the model allows for investigation of electricity market reform components.

The DISC model is applied to different contractual scenarios under both 'normal' and 'crisis' conditions in the electricity market. Contractual scenarios with differing shares of contracts for difference and power purchase agreements are investigated.

Key results show that Contracts for Difference do provide a hedge for consumers, insulating them against price spikes, and that the nature of the long-term contract has implications for the distributional outcomes, and finally, that renewables can dampen consumer costs during crisis conditions.

4.1. Model overview

4.1.1. Motivation

In recent years, a lot of modelling research has focused on the generation and supply sides of the electricity system. Researchers have considered essential questions for the future of electricity, such as whether power grids can be operated with 100% renewables, whether a rapid phase-out of fossil-fuel is possible, how grids might incorporate electric vehicles, or how the regional impacts of the energy transition might be distributed (Zappa et al, 2019; Kefford et al, 2018; Li et al, 2020; Sasse & Trutnevyte, 2020).

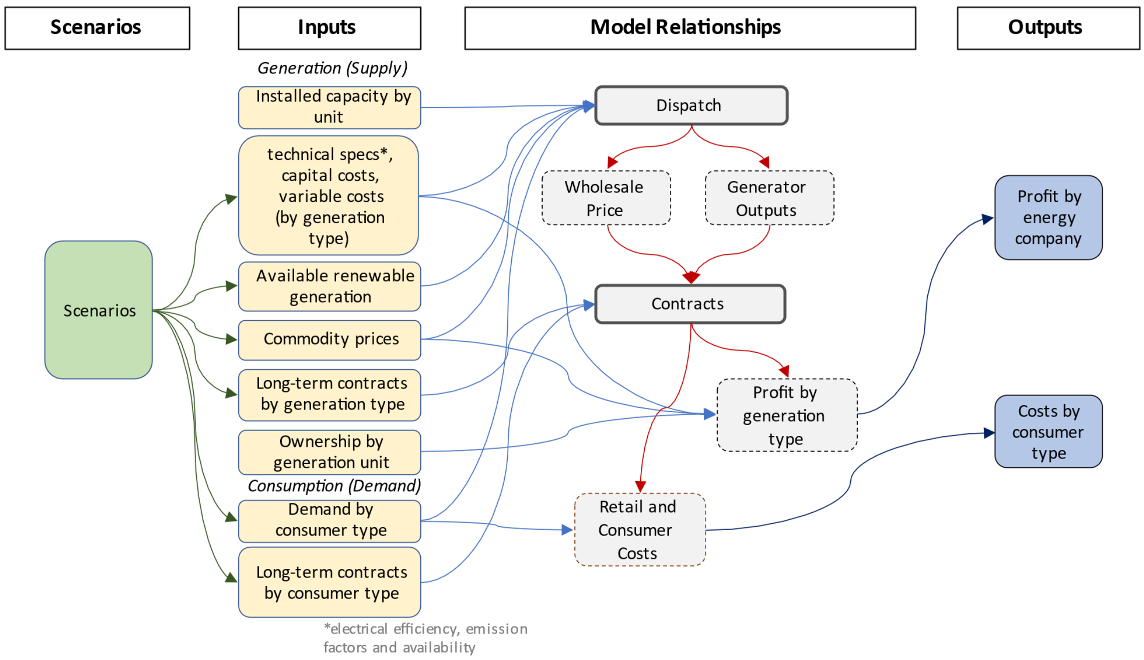
Much of this modelling work sought to represent the essential qualities of the *techno-economic* system; the flexibility and efficiency of different power plants, the transmission capacity of different configurations of power lines, the patterns of consumption and supply. However, in Europe, a complex financial system – the internal electricity market – is layered on top of the physical infrastructure of the electricity system. Understanding the dynamics of the electricity market is necessary for identifying the impacts of any market reform, as well as which agents will be impacted by a power system that is undergoing fundamental transformations. Electricity markets are characterised by an intricate arrangement of contracts between generation companies, electricity retailers, and end consumers, as well as with state institutions. These contracts can have a range of timeframes and can be settled against prices in multiple markets. The prices in those markets are themselves determined by the trading behaviour of the same agents which sign the contracts. The ultimate market outcomes are flows of money between market agents (typically from consumers to generators), mediated by the contractual arrangements and intermediate institutions such as market operators and trading houses. A common understanding of the dynamics of such contracts and their underlying markets is generally lacking, owing to the complexity of the system and the poor transparency of the contract details and market outcomes.

Improving the common understanding of the financial flows in electricity markets is essential for assessing the potential consequences of electricity market reform. To this aim, we have developed a basic model framework which represents financial flows as a result of a contractual arrangements between market agents, layered on top of a representation of the physical electricity system which dispatches generators to meet electricity demand. We have called our framework the **Dis**patch and **C**ontracts (DISC) model.

Our aspiration is that this framework will prove to be straightforward and highly intuitive, thereby improving the understanding of financial flows in electricity markets and providing useful insights for the policy debate on electricity market reform. To our knowledge, this is a novel approach that can meet the needs of this study and serve as a methodological basis for future analysis in this field. In this section, we will present core structure of the model and apply it to a set of system and market design scenarios.

4.1.2. **Dis**patch and **C**ontracts (DISC) Model

Figure 13: Contract-for-difference generator revenues between dispatch scenarios



Source: Bruegel.

DISC is based on two core aspects: the dispatch of electricity generators to meet the demand for electricity and the contracts between market agents that determine financial flows. Given that the real-world electricity market financial flows directly relate to the underlying physical system that balances the supply and demand of electricity, DISC replicates this relationship. The model consists of two modules: dispatch and contracts.

c. Dispatch

DISC applies a framework of *economic dispatch* to determine the outputs of generation types in each period. In each period of a dispatch modelling run, DISC determines the outputs of each generation type required to meet a fixed demand by minimising the cost of supplying electricity. Such a framework makes a number of assumptions:

- **Efficient operation of the electricity system**. It is assumed that the operators of the electricity system perfectly dispatch the available generation to meet demand, using the cheapest available resources. For sake of simplicity, we abstract from the fact that the design of different electricity markets and contracts itself affects the dispatch decisions of generators. Such an assumption can also be interpreted as representing the wholesale electricity market as a perfectly competitive auction in which generation types bid their marginal costs[14].

- **Renewable resources always run.** As wind, sun and perception cannot be controlled[15], DISC assumes that all available renewable output is utilised. This is largely consistent with the efficient operation assumption as renewable generators have lower costs than other generation types.

Given that renewable resources are always used, the model minimises the cost of meeting the residual demand, defined as the difference between the demand and the output of the non-dispatchable renewables (solar, wind and run-of-river hydroelectric). With this approach, the outputs of the dispatchable plants[16] are determined in each time period as well as the marginal price, defined as the marginal cost of the most expensive generation type needed to meet the demand.

Each run of the dispatch module also takes a set of input data:

- Installed capacity by generation type in each country.
- Hourly demand profile for each country.
- Hourly renewable generation profiles for each country.
- Commodity prices, including gas, coal, diesel, lignite, nuclear fuel and ETS allowance.
- Technical specifications by generation type, including electrical efficiency, emissions factors, and annual availability.

The value of these inputs can be adjusted as necessary, depending on the needs of the analysis. Naturally, the choice of this inputs affects the outputs of the dispatch module. The specific numeric values of each input used in the scenario analysis for this study are provided in annex B. In each run, the dispatch module produces a dataset with the following variables:

- Hourly marginal price.
- Hourly outputs by generation type.
- Hourly emissions.

The dispatch framework describes above is not unique to DISC and has been applied in many previous modelling studies, aiming to determine the optimal power generation mix for a given country or region under a set of assumptions and constraints, such as the introduction of a new technology type (Göransson and Johnsson, 2009; Li et al, 2019). Figure 14 is a visualisation of the dispatch optimisation carried out by DISC over a 24-hour period in Germany.

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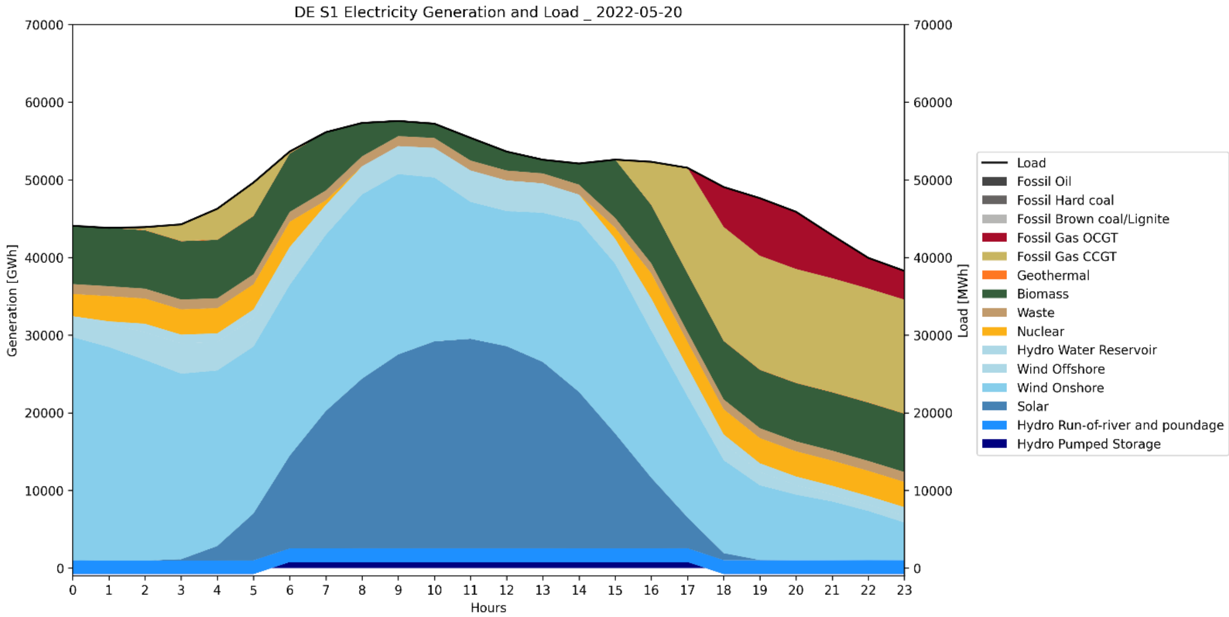
14 Thereby many real-world complications such as ramping and transmission constraints are deliberately excluded.

15 Curtailment, when a renewable generation is reduced below what it could have otherwise produced, occurs when the infeed of power from renewable generators is reduced, usually to manage stress on the grid.

16 Any type of generation that can be used to generate power on command, e.g. thermal power plants.

Figure 14: Example of DISC Dispatch



Source: Bruegel.

The dispatch can be interpreted as follows. Renewable output dominates the generation mix on this day. Pumped storage is at the bottom of the chart in dark blue and provides power during daytime hours. During nighttime hours, pumped storage is drawing energy from the grid, therefore generation from other sources starts from below zero in those hours. The intermittent renewables (run-of-river hydropower, solar, onshore wind and offshore wind) are in blue, as well as the output from reservoir-based hydropower. The baseload output of run-of-river hydropower can be seen on the bottom of the chart, with a consistent level throughout the period. Solar output is next, increasing from zero in the early morning to a maximum around midday then decreasing in the afternoon. The solar output pushes out the more expensive closed-cycle gas turbines (CCGTs) at its peak. Then, in the afternoon, as solar output drops off, CCGTs and even less efficient open-cycle gas turbines (OCGTs) come online to balance the system and meet the evening demand. These are broadly realistic results which can be expected from a standard economic dispatch framework calibrated to real-world data. DISC optimises such a dispatch for every hour of one year for Germany, France, Italy, Spain and Poland.

The DISC dispatch formulation makes a number of abstractions from the real-world electricity dispatch. For example, generator start-up and ramping costs are not included. Therefore, some generation types (such as nuclear and lignite) operate more flexibly than would be observed in reality. And hydro-dams and pumped storage follow an overly simplistic heuristic in our simplified model. Moreover, fuel and emission cost are assumed to be exogenous. Hence our dispatch model does not allow for a precise projection of outputs and prices, we believe it is sufficient for the envisaged stylised analysis.

d. Contracts

The novel aspect of DISC is the modelling of a set of financial contracts layered on top of the dispatch module. As discussed in section 2, key aims of electricity market design are to achieve a fair distribution of the costs and benefits of the electricity system while continuing to stimulate the appropriate investments in and achieve efficient operation of the same system. Contractual arrangements between market agents can determine whether these delicately balanced aims are realised or not. Contracts for Difference, Power Purchase Agreements and Futures all facilitate some form of long-term hedging between generator and consumers, thereby affecting financial flows and consequently the distributional outcomes and the investment incentives, but their design varies widely according to the agents involved, the mechanism for price setting, and the period of the contract. Such discrepancies are represented in the model.

The contract module in DISC assumes key characteristics of different contract types and uses the dispatch determined before to determine the according financial flows. The final generator profits and consumer costs therefore depend on the marginal prices and generation outputs from the dispatch module and the contract specifications provided to the contracts module.

For a given dispatch and contract scenario, DISC computes the following key variables of interest.

<u>Wholesale electricity prices</u>

The hourly marginal prices produced by the dispatch module represent the day-ahead spot market prices. They can be compared across scenario to explore how different dispatch conditions drive changes in the electricity price, and what the consequence is for generator profits and consumer costs.

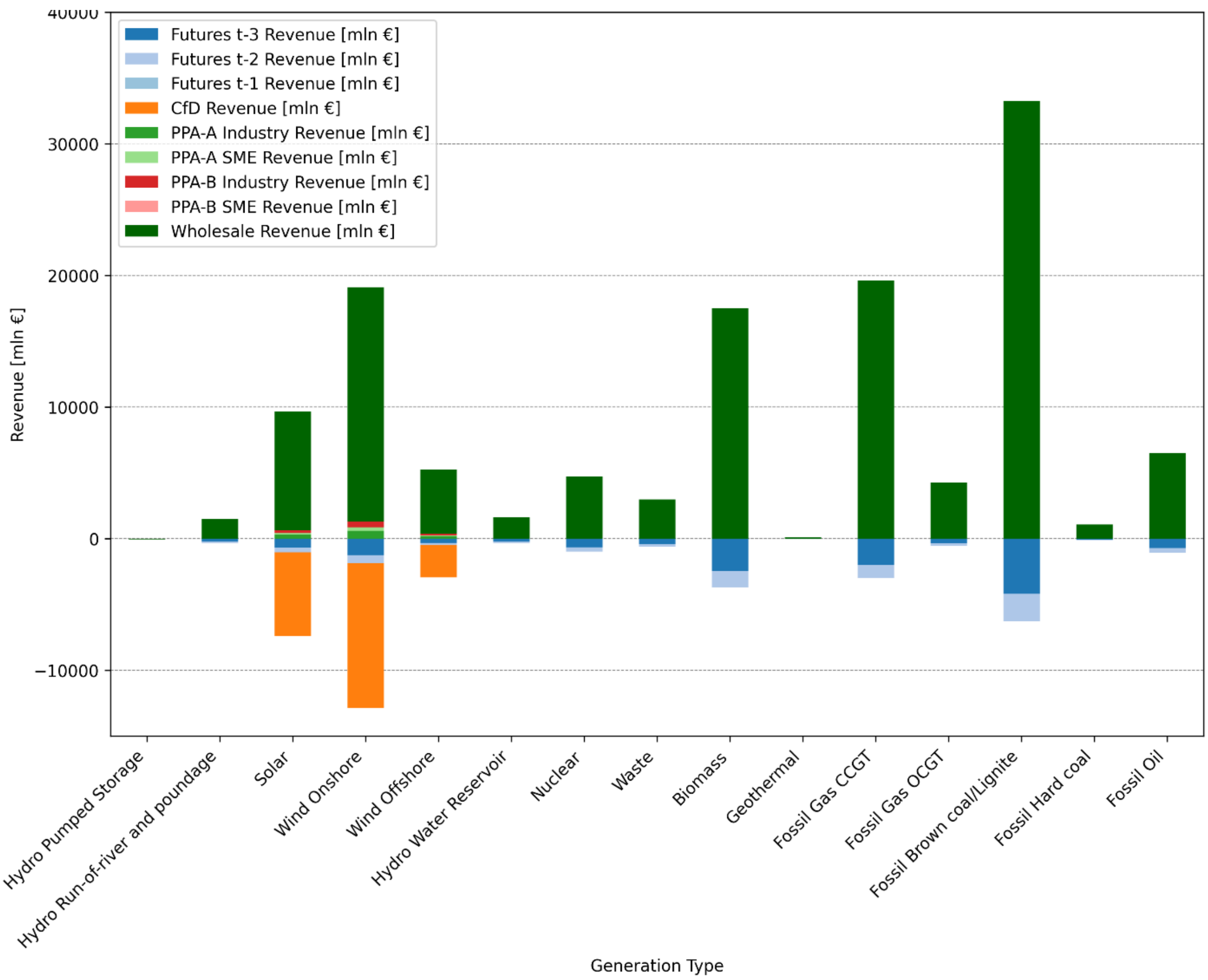
<u>Revenues and profits by generation type and utility</u>

The annual revenues and profit for each generation type are produced by the contracts module. These values depend on the volume and price of the generation type contracts as well as on their hourly outputs and the associated marginal electricity price. DISC can also map these profits onto specific electricity companies, based on a dataset developed internally at Bruegel which quantifies the share of each generation type in each country owned by major utilities.

<u>Cost by consumer type</u>

Consumers are disaggregated into industry, SMEs and households, each of which consumer a fixed share of hourly load, based on data from Eurostat. Similarly, to the revenues and profits, the costs paid by consumer types for this electricity depend on their consumption (which in turn depends on the load), the marginal electricity price, and on the volume and price of the contracts signed by the consumers.

Figure 15: Example of annual revenues by contract type for different technologies



Source: Bruegel.

Note: This is an example for a specific market situation (energy crisis) and contractual portfolio (blend) in a specific country (Germany).

Figure 15 illustrates some of the outputs that the contracts module in DISC is capable of producing. The annual revenues by generation in Germany under crisis dispatch conditions (see section 4.2) are illustrated. Each stack shows the revenue by of a specific generation type. The different bars depict the revenue earned from a specific contract source. The scenario in question combines energy crisis dispatch conditions with a blend of contractual arrangements including CfDs, PPAs and futures. Renewables have signed a significant share of their output volumes to CfDs, while all generation types have signed futures contracts. Two thirds of the futures contracts (t-3 and t-2) have been signed at prices lower than the average marginal price in the crisis year implying that producers pay to consumers. Furthermore, a small amount of renewable volumes are signed to PPAs of various design. In this scenario, lignite generation earns a large amount of revenue from the wholesale market, but its position on futures contracts meant that it also had to pay significant monies to its counterparts. Similarly, in this scenario, renewables had to pay out on their CfD contracts, although they earned significant revenue from the wholesale market as well as some small revenues from PPAs.

Further details on the structure of DISC can be found in the Technical Annex A, including the software tools utilised, the step by step logic, and the format and sources of the input data.

4.2. Scenario analysis

4.2.1. Scenario design

In the research for this study, we applied the DISC model in a number of scenarios to explore the dynamics between the underlying physical electricity system and the financial flows between market agents. Each specific scenario is determined as a combination between a *dispatch* scenario and a *contracts* scenario. The dispatch scenarios in DISC explore different conditions which are exogenous to the electricity market design in the short-run, such as commodity prices, electricity demand, and generation availability, and their effect on balancing electricity supply and demand. The contract scenarios allow DISC to represent how different market designs might affect the financial flows for a given dispatch scenario. Each 'model run' is a combination between a dispatch scenario and a contract scenario. For example, in one model run, DISC combines energy crisis dispatch conditions with a scenario in which no long-term contracts are in place. The scenarios are each calibrated to five major EU economies represented in the model: Germany, France, Italy, Spain and Poland.

a. Dispatch Scenarios

Installed capacity by generation type (e.g., solar, wind, coal, etc.) is sourced from ENTSO-E for the year 2022. The specific capacities for each of the five countries are listed in Table 7 of the Technical Annex.

Scenario D1 – 'Normal Conditions'

The first scenario aims to replicate typical dispatch conditions. The installed capacity of each generation type in the five countries is at the level of 2022. The assumed commodity prices are listed in Table 1, reflecting typical pre-crisis price levels. These prices are assumed to be the same for every country, except for Poland, whose coal price is half of that paid in the other countries. Poland has indigenous sources of coal and therefore it is assumed the commodity can be supplied to Polish coal-fired power plants at a discount compared to other European countries.

Table 1: Scenario D1 Commodity Prices

Commodity	Price	Unit
Lignite	5	[€/MWh]
Nuclear Fuel	5	[€/MWh]
Gas	15	[€/MWh]
Diesel Oil	35	[€/MWh]
Coal	40	[€/tonne]
ETS Price	80	[€/tonne]

Source: Bruegel assumptions based on European Commission electricity market reports

The hourly electricity load (or demand), and the solar, onshore wind and offshore wind generation output is based on ENTSO-E data for 2022. The availability of conventional power plants, such as nuclear, hydroelectric reservoirs, and thermal plants are assumed to be at a typical level (80% for nuclear, for example).

Scenario D2 – 'Crisis Conditions'

The second scenario aims to represent dispatch conditions similar to those which occurred during the energy crisis in 2022: increased commodity prices and low availability of some conventional power plants. The installed capacity is the same as in Scenario 1. The commodity prices for Scenario 2 are listed in Table 2, matching levels seen during the energy crisis. Notably, the gas price has increased almost ten-fold and the coal price has increased five-fold. These prices are assumed to be the same for every country, with same exception for Poland as in Scenario 1.

Table 2: Scenario D2 Commodity Prices

Commodity	Price	Unit
Lignite	5	[€/MWh]
Nuclear Fuel	5	[€/MWh]
Diesel Oil	60	[€/MWh]
ETS Price	80	[€/tonne]
Gas	150	[€/MWh]
Coal	200	[€/tonne]

Source: Bruegel assumptions based on European Commission electricity market reports.

The hourly electricity load (or demand), and the solar, onshore wind and offshore wind generation output are the same as assumed in Scenario 1. This is based on the rationale that renewable output did not change as a consequence of the energy crisis. While demand did drop in response to high prices, this was an endogenous response, and as we input demand exogenously, we prefer to leave it the same as other scenarios to aid the comparison of results.

The availability of conventional power plants is key difference in this scenario. Nuclear and hydroelectric plants are assumed to be only 50% available, reflecting the outages in France and the drought in the summer of 2022.

b. Contract Scenarios

In the contract scenarios, different assumptions are made about the volume and price of contract types. There are three contract options adjusted in each scenario, reflecting the main types of long-term contracts under consideration in the electricity market reform proposed by the European Commission and amended by the European Parliament. Futures are also included in the generators profit functions, but their volume remains constant and the price only varies between dispatch scenario.

Contracts for Difference (CfDs)

As described in section 3, CfDs are a financial contract between the state and an electricity producer, typically renewables, meaning that they do not require the physical delivery of electricity. Contract scenarios in DISC specify the volume and strike price of CfDs signed between different generation types and different consumer types. In the real world electricity markets, the counterparty for a CfD is a state agency, often the national regulatory authority. The costs of paying for these CfDs are recovered from retail electricity consumers via a renewable levy.

Within DISC, CfDs are therefore modelled as a financial contract between a renewable generation type (Solar, Onshore Wind or Offshore Wind) and both SMEs and Households, from whom the costs of paying for this contract are recovered through a levy on their final annual electricity bill. As CfDs are a financial contract, the generators that hold them sell their power on the wholesale market (or through a PPA), but the design of the contract means that for the specified volume they receive a guaranteed price.

Power Purchase Agreements (PPAs) – Fixed Volume

PPAs are a physical contract between generators and large industrial consumers which require the physical delivery of electricity. In the DISC framework, this means that any power sold through a PPA is not sold on the wholesale market. In the case that a generator produces more electricity than is specified in the volume of the PPA, the surplus power can be sold on the wholesale market at the marginal price. In the case that there is a deficit of electricity produced, the generator must make up the difference by purchasing power from the wholesale market at the marginal price. PPAs are signed between generators and Industry and SME consumers but are not signed with households. Fixed Volume PPAs specify the same volume of electricity to be delivered in every hour.

Power Purchase Agreements (PPAs) – Variable Volume

Variable Volume PPAs are similar in design to their Fixed Volume counterparts in that they require the physical delivery of electricity and any surplus traded on the wholesale market. The generators and consumers involved in the contracts are also the same. However, the volume of electricity required to be delivered in each hour is specified as a share of the output of the generator. In this way, the volume varies, and there are also never situations in which the generator must purchase power from the wholesale market to fulfil the contract terms, as it contracted volume is always a fraction of its output.

Futures

Futures contract are a financial contract similar in nature to a fixed volume PPA, although in the real world of trading futures contracts have a much shorter duration than PPAs (e.g. up to five years compared to up to 20 years). In this scenario specification, the volume of futures remains constant in each contract scenario. In terms of the price of futures contracts, 20% of these futures are modelled to represent those signed three years ahead of delivery of electricity (t-3), another 20% representing t-2, and a final 20% representing t-1. The prices of futures contracts depend on the dispatch scenario used in the modelling. In the normal dispatch scenario, futures prices are revenue neutral, exactly matching the average price for the scenario. In the crisis scenario, to reflect the price shock that hit real-world markets, futures t-3 prices are based on the mean marginal price of the normal dispatch scenario. Futures t-2 prices are the midpoint between the normal mean marginal price and the crisis marginal price, while futures t-1 prices are at the mean marginal price level seen in the crisis scenario.

<u>Scenario CA – 'Mixed Contracts'</u>

Table 3: Scenario CA – Contract Volumes

Contract	Volume
CfD	60% of total output
PPA - Fixed	5% of total output
PPA - Variable	3% of hourly output
Futures (Renewables)	20% of total output
Futures (Dispatchable)	60% of total output

Source: Bruegel assumptions.

The first contract scenario aims to represent the Mixed Contracts in long-term contracts between generators and consumers. It is important to note that data on the exact volumes of renewable electricity production signed to long-term contracts, either CfDs or PPAs, is hard to come by. Therefore, the volumes in this scenario are based on the assumptions of the authors. CfDs strike prices in the scenarios are reflective of the values published by state agencies, listed Annex B.

Intermittent renewable generators (Solar, Onshore Wind, Offshore Wind) each have 60% of their annual output covered by CfDs. 5% of output is sold on Fixed Volume PPAs, with this 5% split at a 70:30 ratio between Industry and SMEs. Finally, renewable generators also sign variable PPAs for 3% of their output, entirely with Industry. Renewable generators have 20% of their volumes signed to futures. Non-intermittent renewable generators have 60% of their output for the year covered by futures.

<u>Scenario CB – 'Wholesale Only'</u>

Table 4: Scenario CB – Contract Volumes

Contract	Volume
CfD	0%
PPA - Fixed	0%
PPA - Variable	0%
Futures (Renewables)	20% of total output
Futures (Dispatchable)	60% of total output

Source: Bruegel assumptions.

The second contract scenario models a situation in which no long-term contracts are signed and all power is traded on the wholesale market, apart from the same futures coverage as in the Mixed Contracts scenario (CA). Every generator receives the marginal price for their production and every consumer must pay the marginal price for their consumption. As with the remaining contract scenarios, this is intended to represent a 'corner' scenario, designed to exaggerate the impacts of a particular contract type.

<u>Scenario CC – 'Contracts for Difference'</u>

Table 5: Scenario CC – Contract Volumes

Contract	Volume
CfD	80%
PPA - Fixed	0%
PPA - Variable	0%
Futures (Renewables)	20% of total output
Futures (Dispatchable)	60% of total output

Source: Bruegel assumptions.

The third contract scenario explores the implications of remunerating renewable generation almost entirely through CfDs. 80% of renewable output is covered by CfDs. No PPAs are signed in this scenario. The futures specification remains the same as in other scenarios. This scenario seeks to represent in the extreme the role of CfDs in financing renewables.

Scenario CD – 'PPAs'

Table 6: Scenario CD – Contract Volumes

Contract	Volume
CfD	0%
PPA - Fixed	50% of total output
PPA - Variable	20% of hourly output
Futures (Renewables)	20% of total output
Futures (Dispatchable)	60% of total output

Source: Bruegel assumptions.

The fourth contract scenario looks at an extreme alternative approach in which there are no CfDs and renewable generators sign a significant share of output to PPAs. 50% of renewable output is sold on Fixed Volume PPAs, with the same 70:30 ratio between Industry and SMEs as in Scenario A. 15% of output is sold on Variable Volume PPAs, entirely with Industry. Again, the futures contract prices and volumes are specified consistent with other scenarios.

4.2.2. Model results

The results of the scenario analyses carried out for this study are presented in this section. The model outputs are assessed with regard to the criteria of Fairness, Optimal Investment and Optimal Operation set out in section 2. The criteria are employed in the following way when assessing the scenario results.

Fairness

In each scenario, the prices paid by consumers, the total cost of each consumer type, and the total profits of each generation type/company are compared.

Scenarios in which consumers pay a share of the cost that is proportional to their consumption are considered fair from the standpoint of the distribution of costs. Scenarios in which generators earn large profits while consumers pay large costs (relative to other scenarios) are considered unfair.

Optimal Investment

To identify whether a scenario delivers sufficient signals for optimal investment, the returns of generation companies are considered.

Optimal Operation

The DISC modelling framework assumes optimal operation from the outset. It is assumed that contract designs do not have an impact on the balancing on power system supply and demand. However, as discussed in section 3, this is not the case in the real electricity markets. Therefore, when assessing each scenario result, considerations are made regarding the issues set out in section 3 on the design of long-term contracts and other instruments.

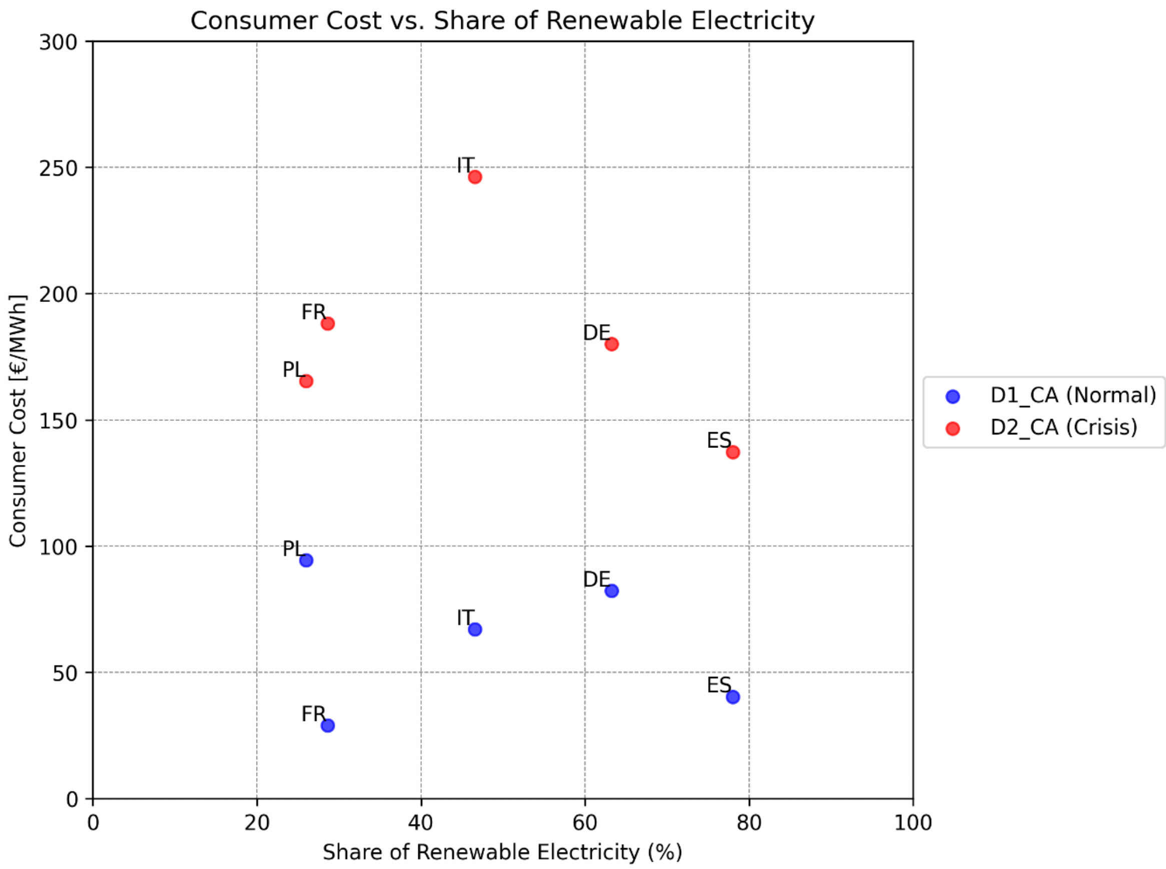
The dispatch and contracts scenarios described in the previous section are used to explore a series of policy-relevant market design hypotheses, categorised on the generator and consumer side. The aim is to quantify the effects of different market instruments under different scenarios in terms of their impact on generator revenues and profits and consumer costs. Every combination of dispatch and contracts scenarios was explored. However, in the following section, details and figures that are relevant for the market design hypothesis in question are presented. The hypotheses are divided between the generator side and consumer side. A detailed set of summary results for each dispatch and contract scenario combination is provided in Annex B.

a. Generators

Higher renewable shares reduce consumer prices

Investment in renewables and other clean electricity technologies is needed not only to decarbonise the electricity system but also to shield consumers from volatility on international commodity markets that drive the cost of thermal electricity generation. Using the DISC framework to illustrate the benefits of such investment in renewables, Figure 16 plots the share of renewable output (defined as solar, wind, hydropower, geothermal and biomass) with the average consumer cost per MWh, for both the normal dispatch scenario and the crisis dispatch scenario.

Figure 16: Consumer costs and share of renewable electricity

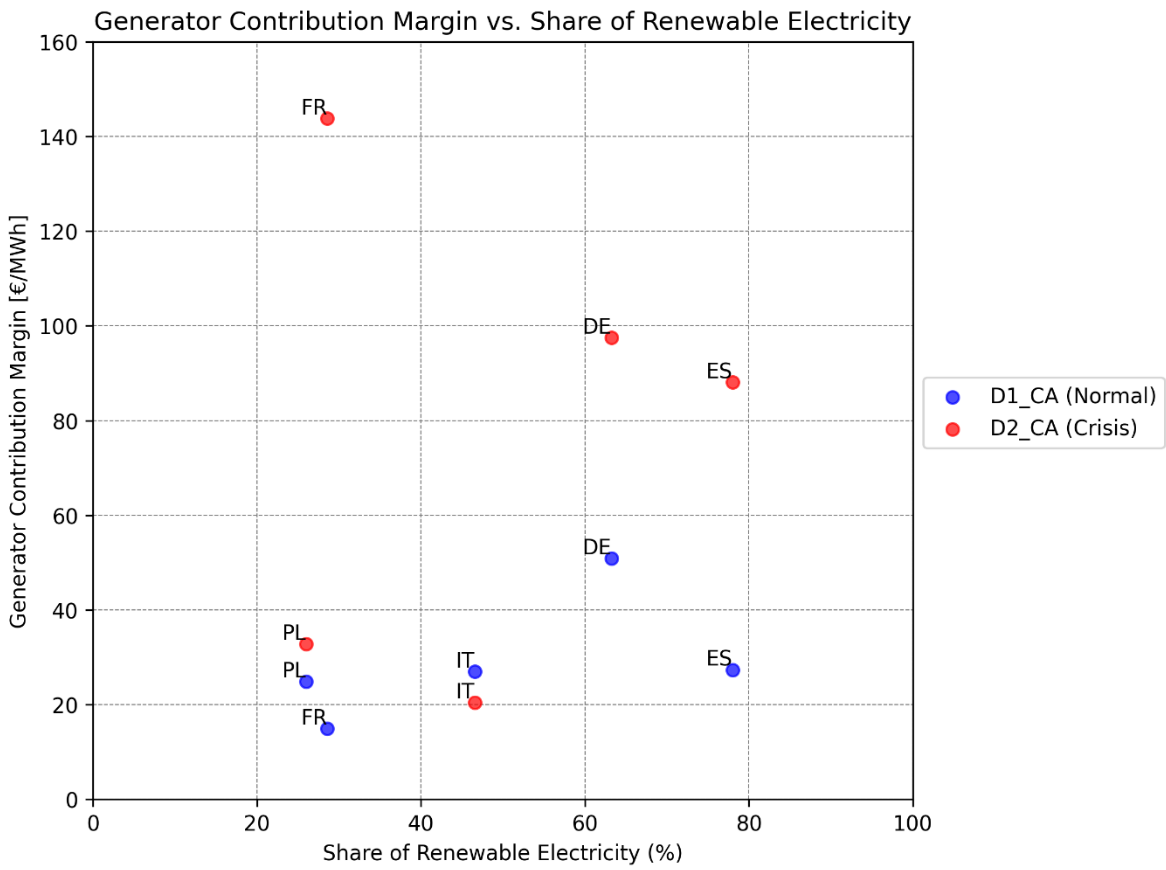


Source: Bruegel.

In the normal dispatch scenario (blue dots) a negative correlation is seen between increasing renewables and consumer prices. France is an outlier because its nuclear capacity, while not considered in the renewables share, helps to keep prices low in the normal scenario. In the crisis scenario (red dots), the same correlation between increasing renewable share and lower consumer costs maintains. Here, with the low nuclear output specified in the crisis scenario increasing consumer costs in France, we see that the costs for consumers drastically increase. For Italy, which is highly dependent on combined cycle gas turbines for electricity generation, costs also jump massively. Germany and Spain, both with high levels of renewable, are relatively protected from the massive cost increases. In the case of Poland, which is mainly reliant on coal generation, the scenario inputs keep Polish coal prices at half the level of other countries, meaning they also see less of a cost impact than in France or Italy. Nevertheless, costs are still higher than in either Germany or Spain. The policy implication is straightforward: increasing investment signals for renewables helps to protect consumers from price volatility, thereby also delivering fairer outcomes.

In terms of generator earnings, the picture is not so straightforward. Figure 17 shows the same chart as before but with generator contribution margins[17] per MWh on the y axis in place of consumer costs. No strong correlation is seen. Generator earnings depends not only on the renewable share but on the wider generation mix. For example, in the case of France, while many nuclear generators are on outage in the crisis scenario, the remaining nuclear plants earn a large windfall from the high electricity prices, as their costs do not increase. In Poland and Italy, while consumer costs do go up significantly, generator earnings do not increase at the same rate, as the costs of those generators (mainly coal and gas, respectively) have also increased in the crisis scenario.

Figure 17: Generator contribution margins and share of renewable electricity



Source: Bruegel.

Firm earnings are impacted by contract design

The earnings of electricity generation firms are dependent on long-term contract design, especially in relation to their volume and price. To illustrate this, the next section uses the scenario analysis results to explore the relationship between firm contribution margins (revenue minus variable costs) and contract scenarios.

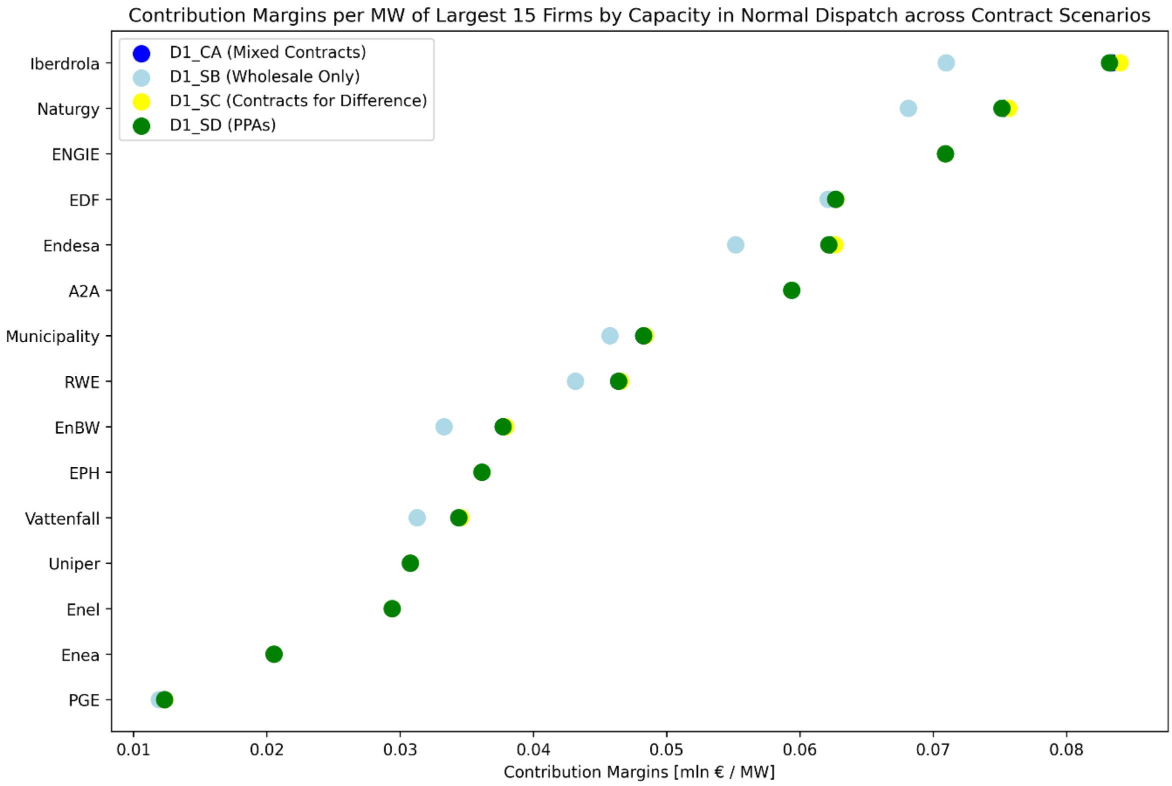
In the following analyses, a bottom-up dataset of electricity generation capacity ownership by firm in Germany, France, Italy, Spain and Poland is utilised. This dataset was gathered for this study on the

[17] Revenue minus variable costs.

basis of the publicly available data and provides a general picture of the ownership structure of European electricity generation. However, due to the fragmented nature of this data, the dataset is incomplete, and should not be taken as a final description of ownership in the sector. Power plant ownership is a complex web of partial and joint agreements, often obscured from the public. Nevertheless, the data used is broadly reflective of the shares of capacity owned by major European utilities and is indicative of financial flows to certain firms in the modelling scenarios explored herein. An overview of the dataset is presented in Technical Annex A.

Figure 18 depicts the modelling results in terms of contribution margin per MW of capacity owned for 15 major European utilities in the normal dispatch conditions and across each contract scenario.

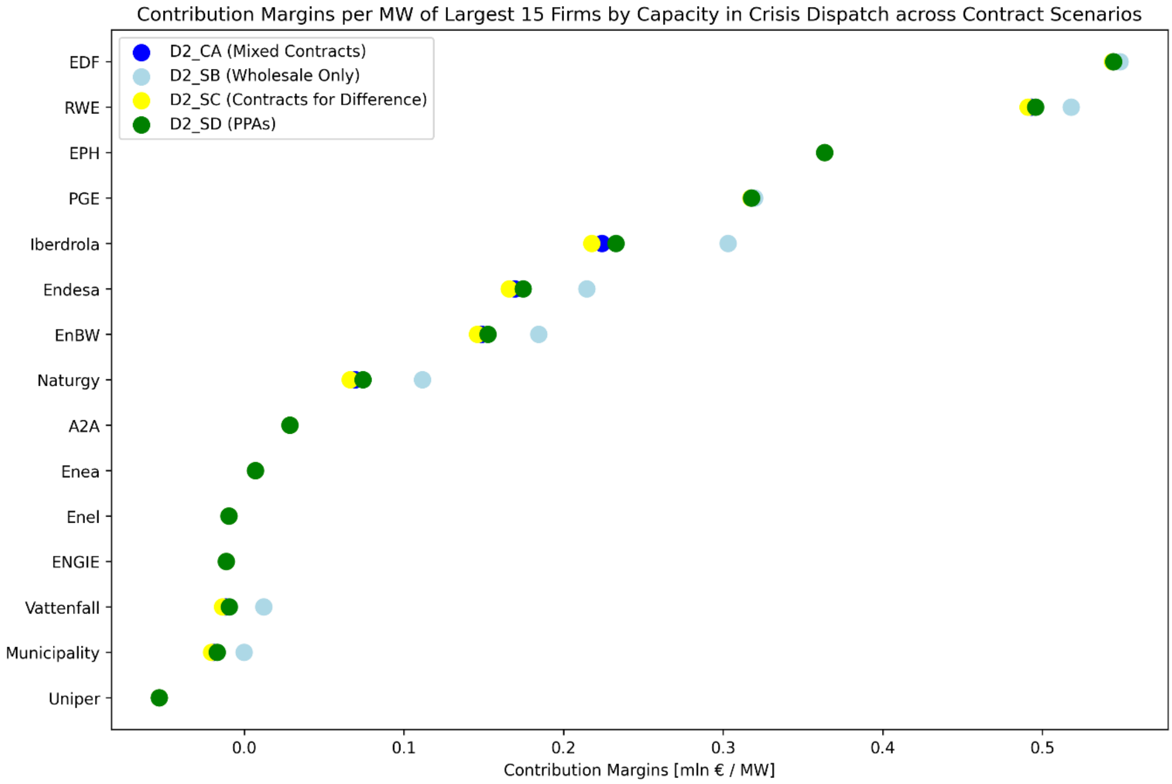
Figure 18: Firm contribution margins in normal dispatch across contract scenarios



Source: Bruegel.

Most striking in these results is that firms earn the least revenue in the 'Wholesale Only' scenario in normal dispatch conditions. As long-term contracts prices are typically higher than the average marginal price in the normal dispatch scenario, both CfDs and PPAs give an uplift to firm earnings, especially those firms with large shares of renewables (such as Iberdrola). The contribution margins earned in the mixed scenario are typically in line with the long-term contracts scenarios, and hence are mostly not visible on the chart. Firms earn slightly more in the Contracts for Difference scenario compared to PPAs scenario, as firms with high shares of renewables are guaranteed a higher price for a larger volume of electricity.

Figure 19: Firm contribution margins in crisis dispatch across contract scenarios



Source: Bruegel.

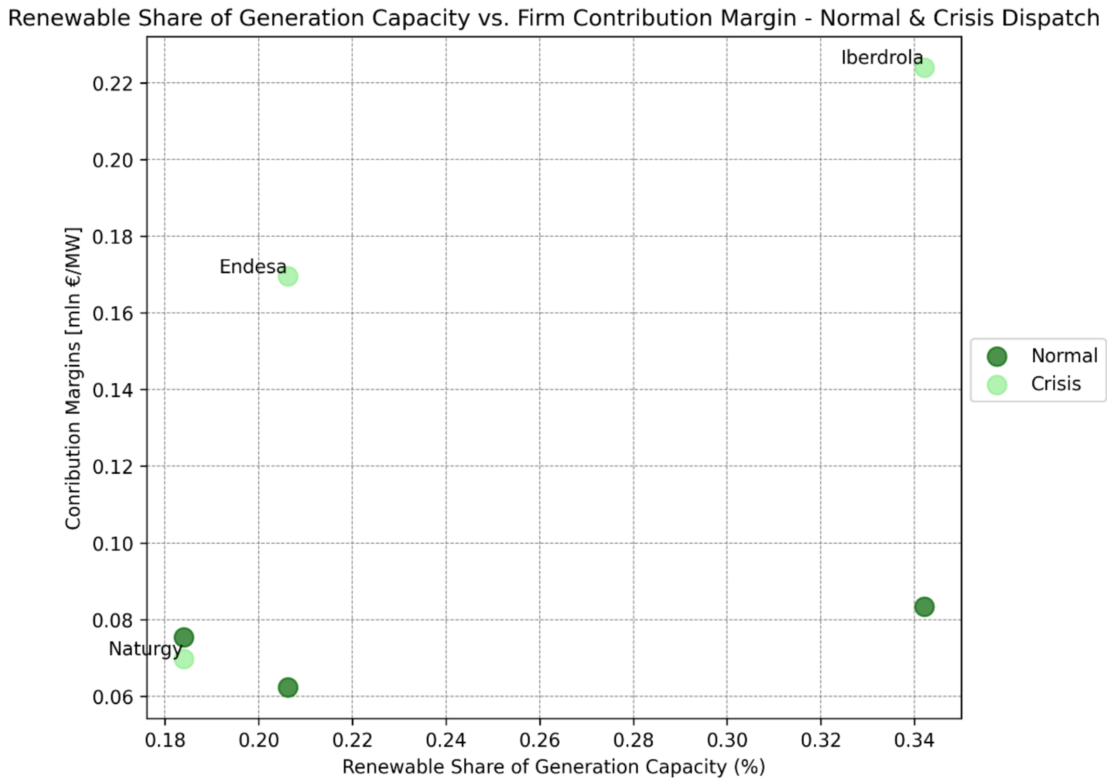
Figure 19 above shows the same chart as previous but with crisis dispatch conditions instead of the normal dispatch conditions. The reverse pattern is now seen, in which firms earn the most revenue in the 'Wholesale Only' contract scenario. This is because the price level of long-term contracts are below the level of the wholesale market price in the crisis conditions.

The main takeaway is that on the generation side there are not significant differences between the PPAs and CfDs scenarios in terms of revenues in either normal or crisis dispatch conditions. Long-term contracts hedge generators, giving them an uplift when wholesale prices are low and mitigating windfall revenues when wholesale prices are high. But, for the same price and volume, generators are relatively indifferent in terms of earnings regarding whether the contracts are physical or financial in nature.

Firm earnings are dependent on generation portfolios

In addition to the contract design, another variable that impacts firm earnings between dispatch conditions is the generation portfolio. The following section explores the contribution margins earned by firms as a function of their share of different electricity generation categories: renewable (solar, onshore wind and offshore wind), gas (CCGT and OCGT), and nuclear. The contribution margins are also compared between normal dispatch conditions and crisis dispatch conditions.

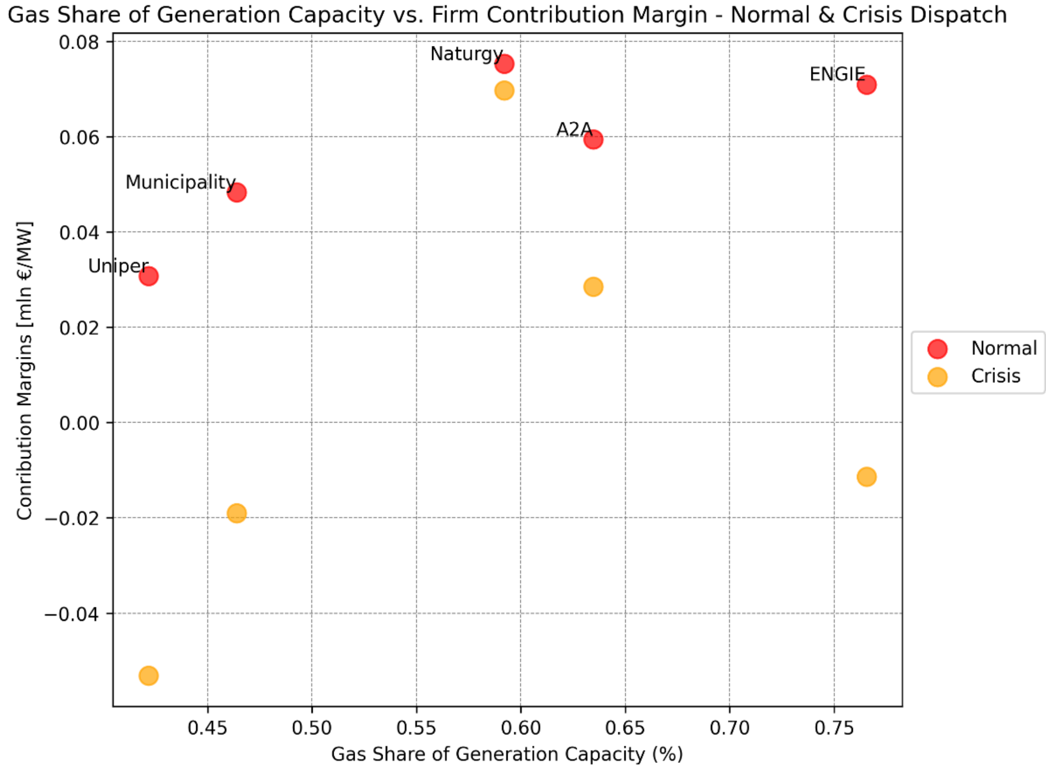
Figure 20: Firm renewable capacity share and contribution margins per megawatt



Source: Bruegel.

Figure 20 shows the share of renewable generation capacity of the firms in question on the x-axis and the contribution margins per MW in million € on the y-axis, with the top three firms in terms of renewable capacity listed. The chart presents both the normal and crisis dispatch conditions and assumes mixed contracts. Both Iberdrola and Endesa earn significantly more per MW in the crisis scenario than in the normal scenario. The reason is that even though these firms have most of their renewable generation signed to long-term, fixed price contracts and therefore the earnings from these plants do not change, there is still a small amount of merchant renewables who earn a large windfall from the high prices in the crisis scenario. Furthermore, both Iberdrola and Endesa have a large share of 'clean dispatchable' generation in our modelling specification, which typically has low variable costs and therefore also earns large revenues from the increased wholesale prices in the crisis scenario. Naturgy has a large share of renewables, but it also has mostly gas generation, leading to the slight loss between normal and crisis conditions seen in the modelling results above.

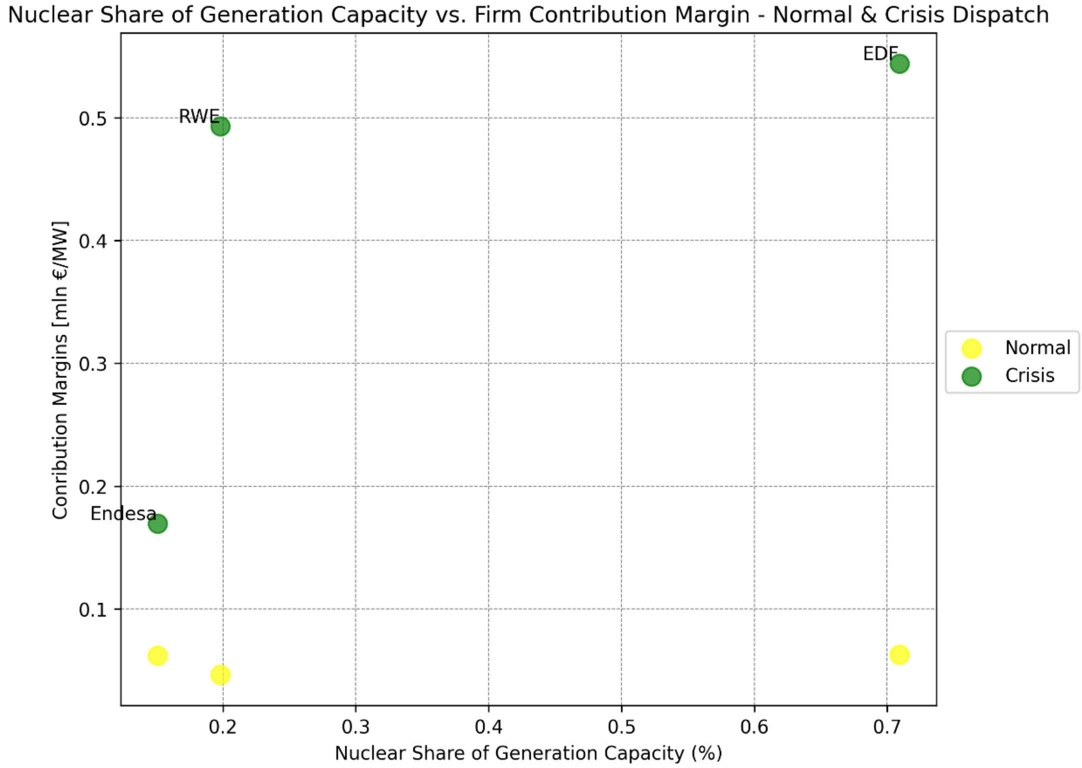
Figure 21: Firm gas capacity share and contribution margins per megawatt



Source: Bruegel.

The same chart structure is presented in Figure 21 but instead of renewable share, the five firms with the largest gas share are plotted. The 'Municipality' firm refers to mainly to publicly owned gas plants in Germany. Firstly, in the normal dispatch conditions, the contribution margins earned per MW increases with the share of gas, meaning that gas is quite lucrative in this scenario. However, in the crisis conditions, the opposite is true. At the higher three firms, having large gas share lead to less revenues, and even in the case of ENGIE, direct losses. In the case of Uniper and the municipalities, they also earn large capacities of coal, which contributed to their losses. The gas and coal driven losses are due to the fact that these firms are frequently the marginal generator in the crisis scenario, but in the scenario specification, have hedged a large fraction of their output on forward contracts that are based on normal dispatch condition prices, while their variable costs have massively increased.

Figure 22: Firm nuclear capacity share and contribution margins per megawatt



Source: Bruegel.

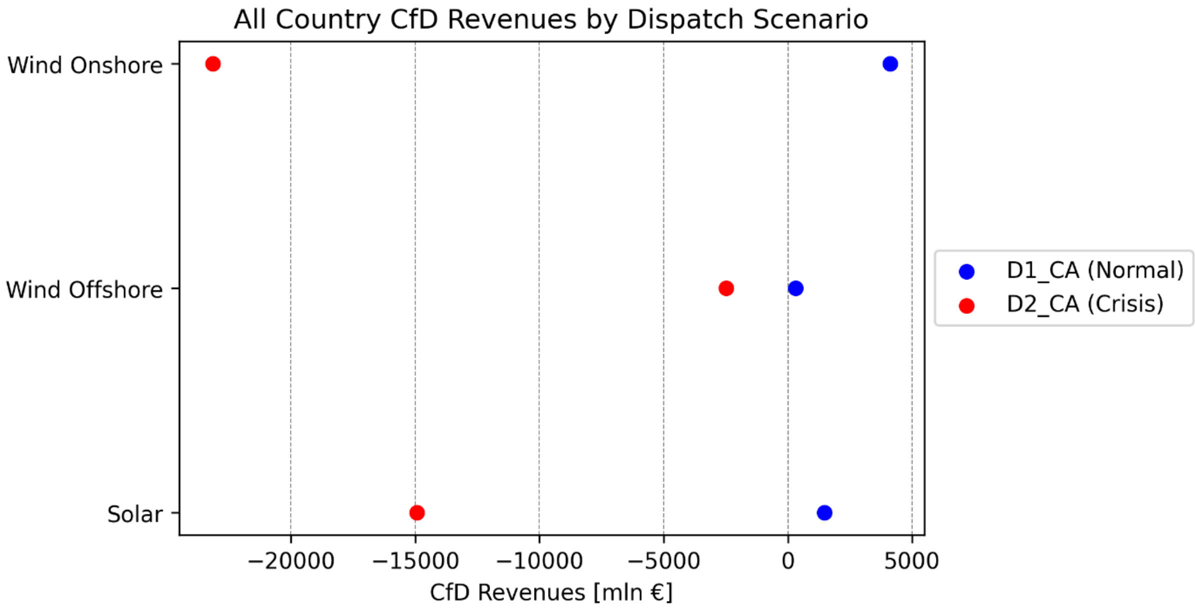
The final comparison in this section is shown on Figure 22, exploring the relationship between nuclear generation capacity share and contribution margins per MW. The three largest firms by share of nuclear capacity are presented. The pattern is clear and consistent. As nuclear is an inframarginal technology with relatively low variable costs that do not change between normal and crisis scenarios, the firms that own the nuclear power plants earn large windfalls from the high marginal prices in the crisis scenario. Furthermore, in the scenario specifications, nuclear power does not have a large amount of volumes signed to long-term contracts, meaning that it benefits hugely from the increased prices.

b. Consumers

CfDs provide a price hedge for consumers

CfDs have been promoted in the electricity market reform debate as a means not only to attract investment in renewables but also to protect consumers from price spikes. CfDs are a long-term contract between generators and states, with the costs recovered from households and businesses through renewable levies. Therefore, CfDs can be thought of as a long-term futures contract between household and business consumers and renewable generator (with states acting as a form of intermediary).

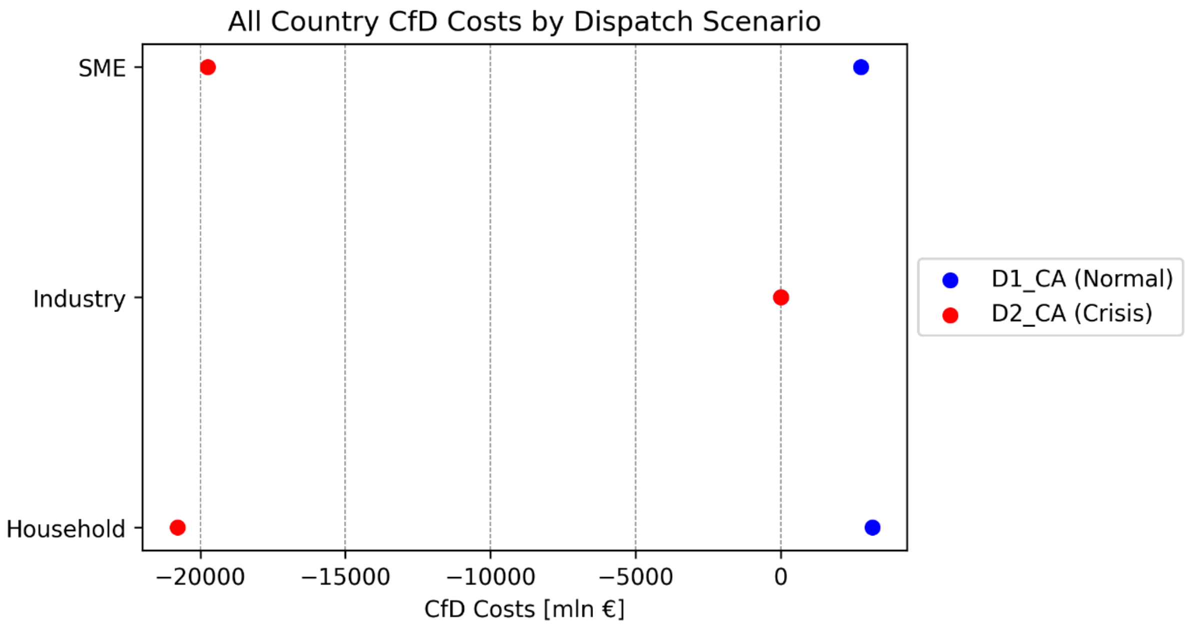
Figure 23: Contract-for-difference generator revenues between dispatch scenarios across all countries (DE, FR, IT, ES, PL)



Source: Bruegel.

Figure 23 compares the revenues earned by renewable generators in normal dispatch conditions (scenario D1) with the revenues earned in crisis dispatch conditions (scenario D2), under Mixed Contracts contract assumption (scenario CA), summed over all five countries. Under normal conditions, CfDs provide a top up to renewables, earning significant revenues throughout the year. However, during crisis conditions when the marginal price is frequently much higher, CfDs require generators to pay out, becoming a cost (see the red dots above). In these crisis conditions, consumers receive revenues from the CfDs, assuming the revenues are passed directly to end users.

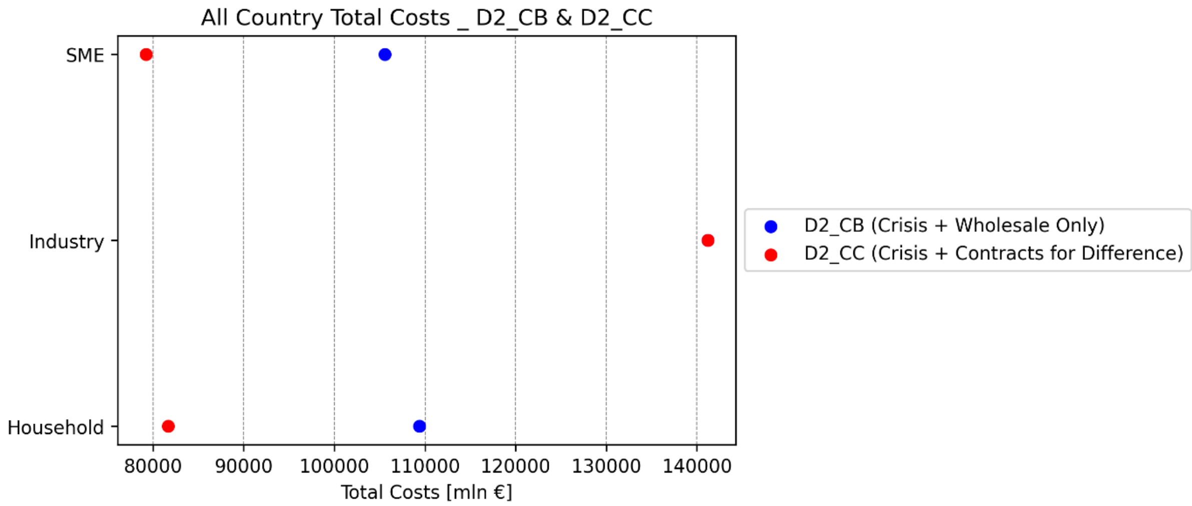
Figure 24: Contract-for-difference consumer costs between dispatch scenarios



Source: Bruegel.

Similarly, Figure 24 above shows the costs paid by consumer type between the normal dispatch scenario (blue dots) and the crisis dispatch scenario (red dots). The state does not recover costs for CfDs from industrial consumers in our model specification, so the costs remain the same for that consumer type, but households and businesses receive a large income from CfDs in the crisis scenario (negative costs are equivalent to income). The DISC framework assumes that these benefits are passed back to consumers. It is clear that, under the crisis scenario, consumers are hedged against high prices via CfDs.

Figure 25: Total consumer costs with and without contracts-for-difference



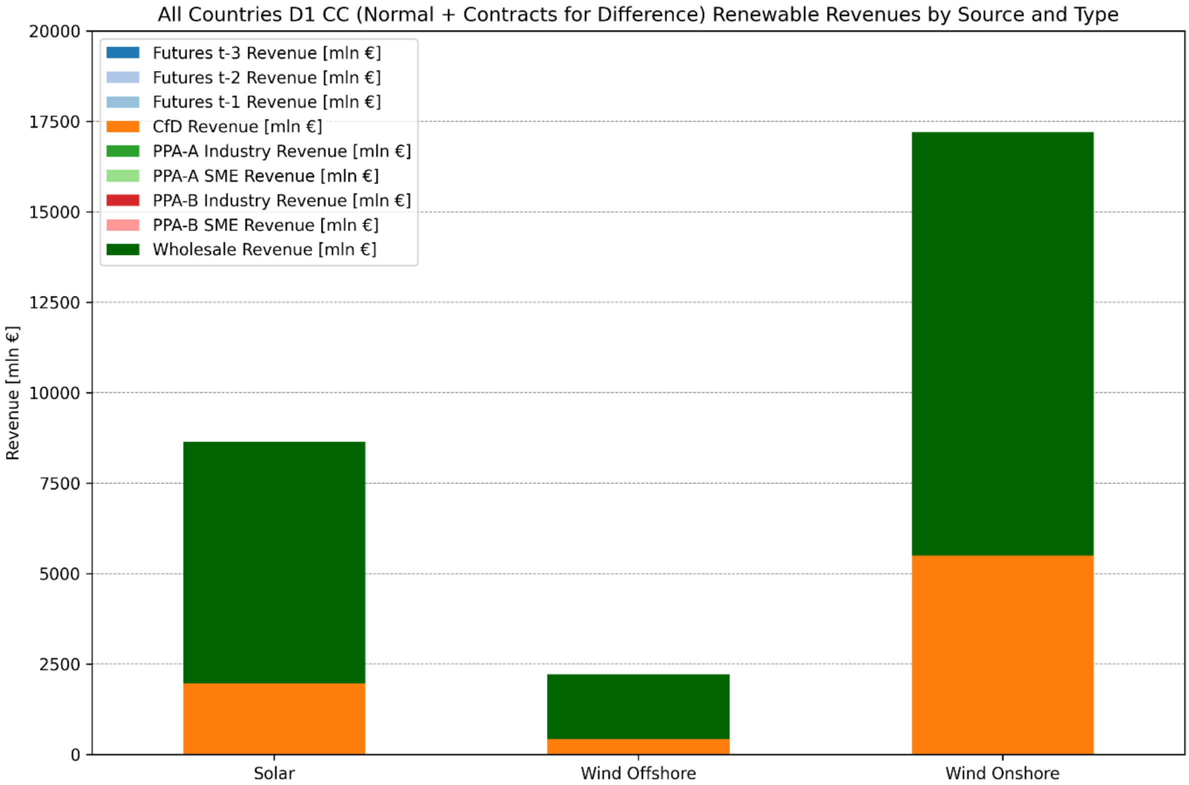
Source: Bruegel.

The effects of the price hedge provided by CfDs for consumers is most clearly illustrated in Figure 25. The scatterplot compares the total costs paid by consumers summed up across all countries in the crisis dispatch scenario, but with a difference between the amount of long-term contracts (there is no change in the costs paid by industry as they do not pay the costs of CfDs). The blue dots signify contract scenario CB – 'No long-term contracts', in which there are no long-term contracts signed between generators and consumers and the only hedging is done on the basis of futures contracts. The red dots represent contract scenario CC – 'Contracts-for-difference', in which 80% of renewable output is covered by CfDs. Households and business save €20.7bn and €20.1bn respectively from CfDs in this modelling comparison. For the criteria of fairness, lower prices for consumers during crisis situations is a better outcome.

CfDs and PPAs lead to different financial flows

CfDs and PPAs both serve a similar purpose in terms of providing a long-term contractual agreement between generators and consumers that can hedge them against short-term volatility in electricity markets. However, the nature of the contracts, especially that one is financial (CfDs) and the other physical (PPAs) as well as the counterparties involved, means that the financial outcomes are markedly different.

Figure 26: Renewable generator revenues by contract, in CfDs scenario under normal dispatch conditions



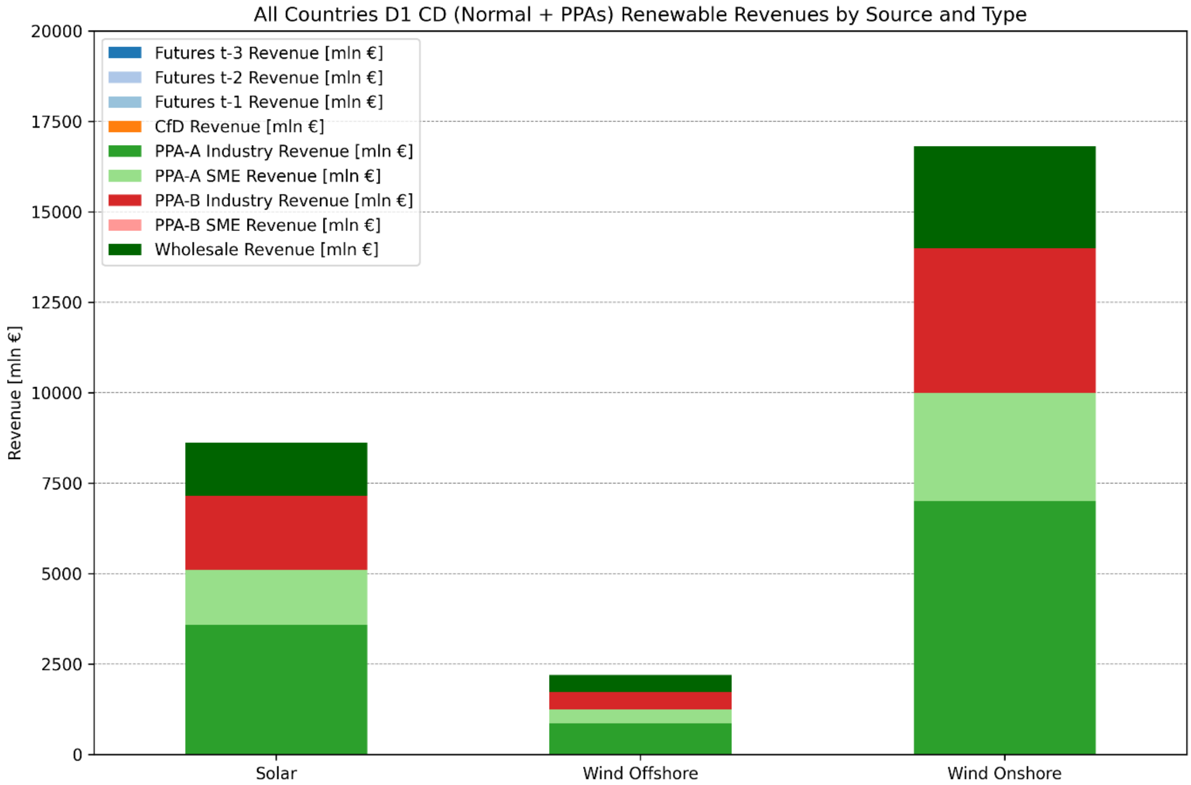
Source: Bruegel.

Note: PPA-A refers to physical contracts with a fixed price and fixed volume. PPA-B refers to physical contracts with a fixed price and a variable volume.

Figure 26 above shows the breakdown of revenues earned by renewable generators across all countries in the normal dispatch scenario, but assuming that 80% of renewable output is signed to CfDs. Even despite the significant CfD coverage, a majority of revenue for all renewables comes from the short-term markets. This is because CfDs only play a role when the spot price varies from the contract strike price (providing a top up to generators when the spot price is a lower and paying out to consumers when the spot price is higher).

In contrast, Figure 27 below shows the breakdown of renewable generator revenues under the same dispatch conditions but instead assuming that 70% of output is covered by PPAs, in a variety of designs and with different counterparties. Most of the revenue now comes from the long-term contracts because PPAs are modelled here as physical contracts with a fixed price. Assuming the electricity is delivered, the price is paid. Renewable generators then sell any surplus power (30% over the annual period in this case) at the wholesale price.

Figure 27: Renewable generator revenues by contract, in PPAs scenario under normal dispatch conditions

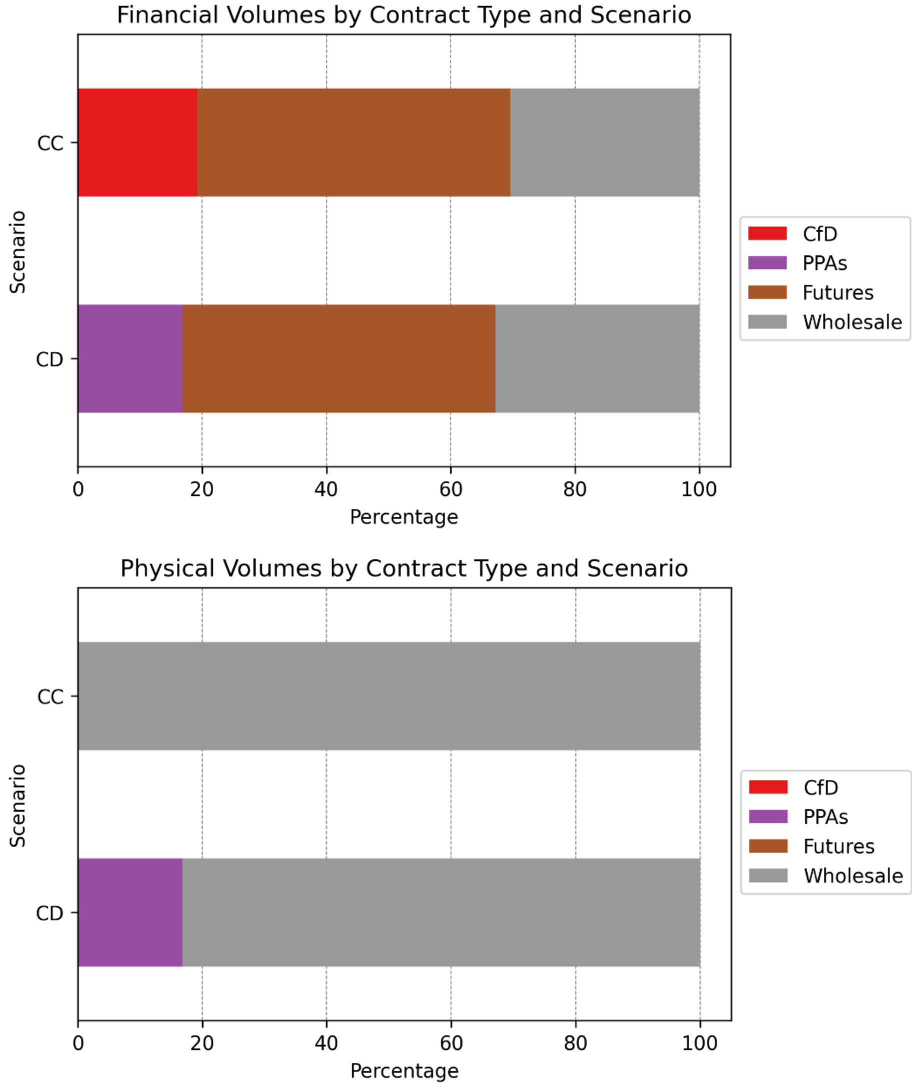


Source: Bruegel.

Note: PPA-A refers to physical contracts with a fixed price and fixed volume. PPA-B refers to physical contracts with a fixed price and a variable volume.

The physical nature of PPAs has an impact on the volumes of power traded on different markets. The first panel in the Figure 28 below compares the percentage of total volume covered by different contract types between the CfD scenario (CC) and the PPAs scenario (CD). The spread is almost even in both scenarios, reflecting the scenario design. However, the second panel shows the share of volume covered by *physical* contracts. The implication is that physical PPAs reduce the volumes of power traded on wholesale markets. At small volumes the consequences are likely negligible, but a sizeable increase in the amount of physical contracts in the European electricity sector could negatively affect efficiency in short-term markets if liquidity is impacted.

Figure 28: Share of volumes covered by all contracts between CfDs and PPAs scenarios

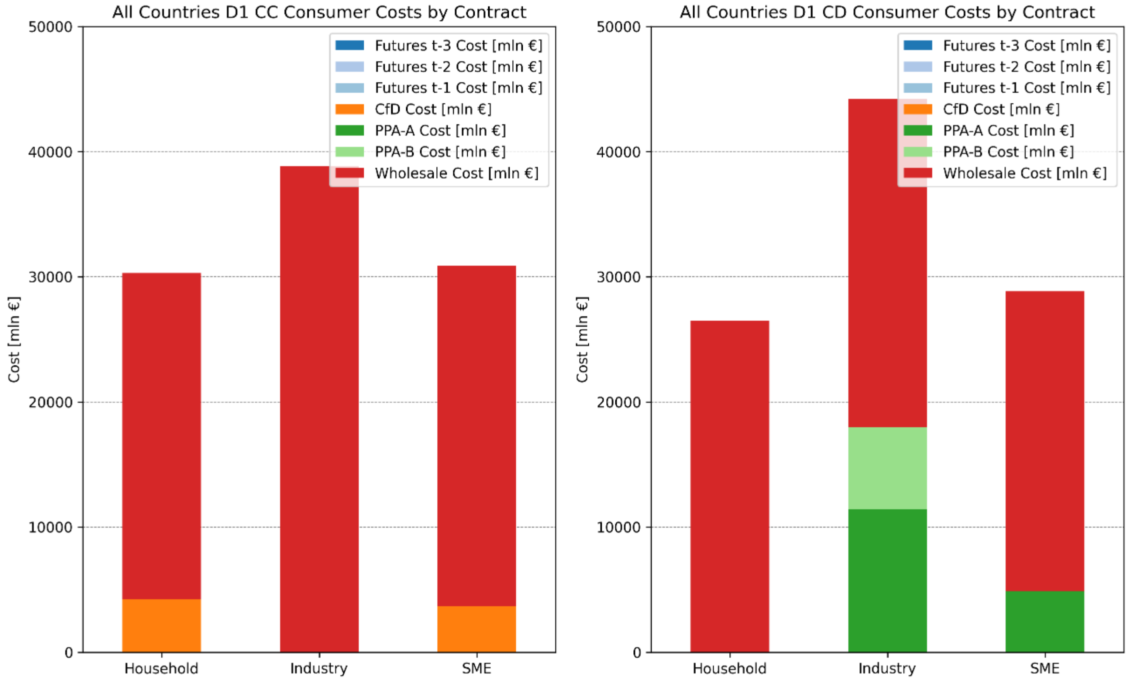


Source: Bruegel.

Note: CC: Contracts for Difference scenario. CD: PPAs scenario.

The final consideration between CfDs and PPAs is the impact on consumer costs, which differs due to the counterparties which usually enter these contracts. In our model specification, the costs of all CfDs are recovered from households and businesses while PPAs are paid directly by a specific consumer type for a certain volume. The left panel in Figure 29 shows the CfD scenario (CC), in which households and businesses must pay the costs of the CfDs as well as their short-term wholesale costs. In the right panel, the PPAs scenario shows lower costs for households in particular, as they no longer pay the cost of the CfDs. While businesses (SMEs) do pay a PPA cost in that scenario, this is not additional to their wholesale costs because the PPAs are a physical contract. Industrial consumers have to pay significantly more in this scenario, paying for PPAs as well as their share of the wholesale costs. In the CfD scenarios, industrial consumers must only pay their share of the wholesale costs.

Figure 29: Consumer costs by contract, in CfD scenario under normal dispatch conditions



Source: Bruegel.

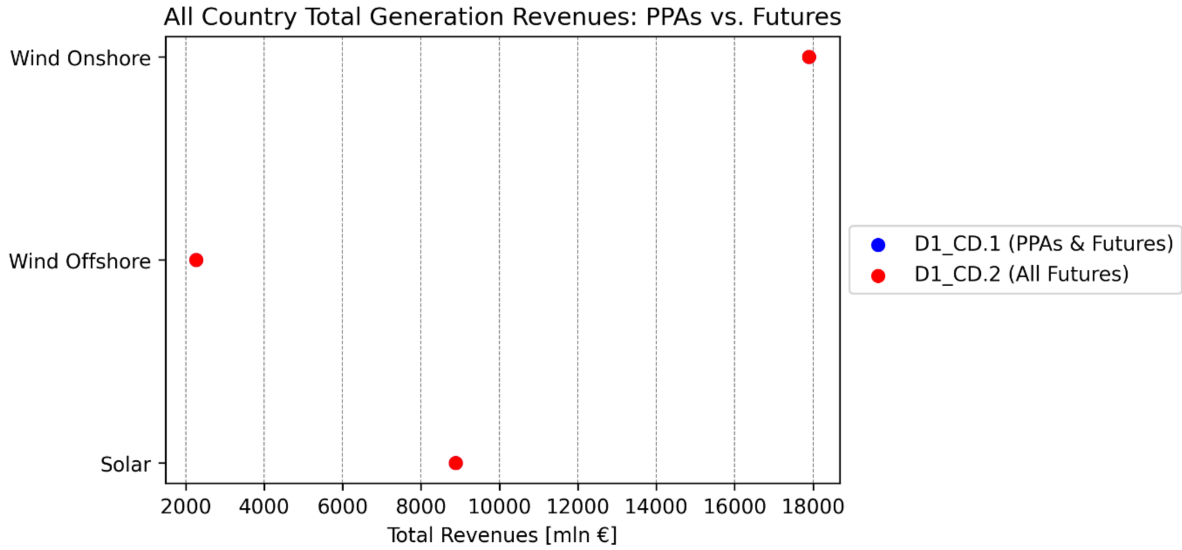
From an investment perspective, the contracts and prices in this scenario do not differ by much. Renewable generators earn similar revenues as a fixed price is guaranteed for a similar level of output. In this sense, CfDs and PPAs are substitutable for generators, as they are interested in balancing their risk-return trade-off by securing long-term contracts at a sufficient price and volume. However, from a fairness point of view, there are different considerations between CfDs and PPAs. Crucially, the costs of PPAs are paid directly by the counterparty, while the costs of CfDs are socialised through the state and recovered via taxes and levies. As illustrated in Figure 29, this implies that households and businesses could pay a disproportionate share of generation costs if CfDs were to become even more widespread as renewable penetration increases.

Futures and PPAs are not directly substitutable

To explore the extent to which futures and PPAs are substitutable, two special versions of the contracts scenarios introduced in section 4.2.1 are compared.

Scenario CD.1 takes the PPAs scenario but assumes that, for the renewable generation types, the futures prices are set at the same level as the PPA prices. Furthermore, it is assumed that only fixed volume PPA contracts are signed. All other aspects of the scenario remain the same. Scenario CD.2 assumes that all of the PPAs volumes are instead signed to futures contracts, at the same price as in CD.1. It is assumed that the contract price for each generation type is above the all-country mean marginal price for the annual period. Simply put, the differences in revenue and cost outcomes are compared between a scenario in which volumes are signed to both PPAs and futures and a scenario in which all volumes are signed to futures.

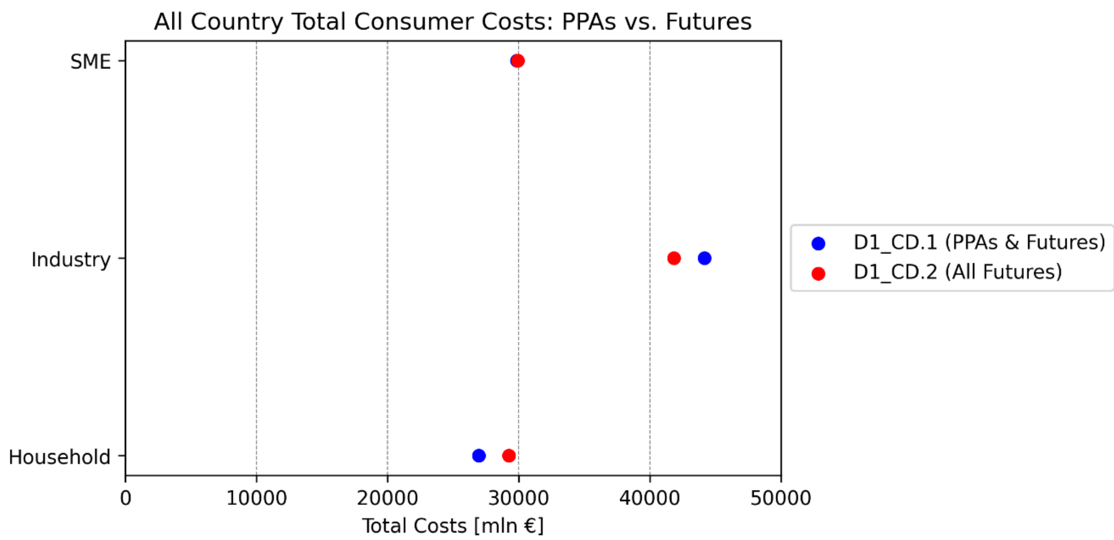
Figure 30: All country total renewable generation revenues comparing PPAs vs Futures



Source: Bruegel.

Figure 30 above shows that having the PPAs volume move to futures has no impact on generator revenues in this model specification (there is no change such that the red dots completely overlap with the blue dots underneath), assuming that the prices for both contracts are at the same level. Generators are hedged at the same price for the same volumes, therefore revenue outcomes are identical. The main difference in this comparison is the distribution of the cost of paying the contracts, seen on Figure 31 below, similar to when looking at CfDs and PPA, In the scenario which mixes the contracts (D1_CD.1), industry, the primary counterparty to PPAs in the model specification, must pay significantly more than in the alternative scenario with only futures. This is because with PPAs, industry must pay the entire cost of the specified volume directly, while under the futures specification in the model, these costs are spread amongst all consumers pro-rata on their consumption. Conversely, households (who hold no PPAs) pay more when there are only futures. There is very little impact on the costs of SMEs (the change is so small that it does not appear on the graph). SMEs had a small about of their consumption signed to PPAs and swapping this for futures has only a minor effect.

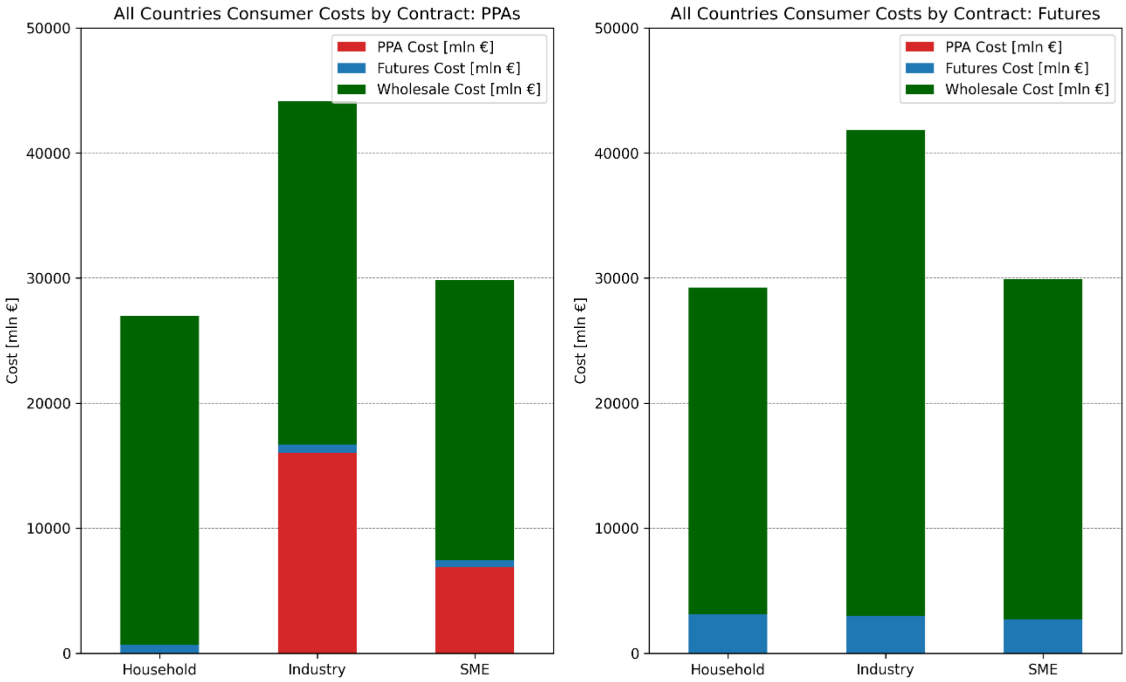
Figure 31: All country total costs comparing PPAs vs Futures



Source: Bruegel.

The change in the distribution of costs is further illustrated by Figure 32 below. The left panel shows the breakdown if the same volume of electricity is covered by a mix of PPAs and futures while the right panel shows the scenario with only futures. The difference in cost structure for consumers is stark. The physical nature of PPAs combined with the fact that the costs are paid by a single counterparty means that industry and SMEs pay a significant share of costs on their PPAs. Futures are paid by all consumes proportional to their consumption, like the wholesale costs, meaning a more even distribution in futures only scenario. It should be noted that these results are highly dependent on the price level of the relevant contracts. Should PPAs be signed at a lower price, the costs paid by industrial consumers would of course be much lower.

Figure 32: Consumer cost breakdown with PPAs vs. Futures



Source: Bruegel.

From a fairness perspective, the futures only scenario with a more even distribution of costs has its merits. However, there are other considerations when comparing PPAs and futures. Futures contracts are typically signed only up to five years before delivery, while PPAs can be up to 20 years. While industry pays more in the left panel (the scenario with a mix of contracts) they are securing a fixed price and quantity for a long period of time. On the other side of such a contract, from an investment standpoint, the renewable generators have secured low-risk revenue, reducing cost of capital. While futures appear fairer in DISC as formulated here, their prices are more unstable and reflective of short term price volatility.

4.2.3. Discussion

Higher renewable shares reduce consumer prices

The illustrations provided by DISC demonstrates that one imperative for electricity market reform should be increasing investment in renewables, as higher renewables share reduce consumer prices and ensure that the electricity system is more resilient to commodity price shocks. The earnings of electricity utilities with increasing renewables depends much more on the portfolio of the specific firm and on the specificities of contract design.

Firm earnings are impacted by contract design

Comparing the contribution margins of electricity utilities across the scenarios shows that firms benefit from long-term contracts in low marginal price scenarios but conversely do not receive large windfalls in high price scenarios. However, the type of long-term contract is relevant indifferent to the generation side.

Firm earnings are dependent on generation portfolios

The scenario analysis, using data on generation ownership, showed that firms with large gas shares do not benefit from crisis conditions. In contrast, firms with a generation portfolio that includes inframarginal technologies like renewables and nuclear actually do better in the high price conditions. This highlights the importance of the specific portfolio owned by firms in terms of assessing the beneficiaries of market design changes.

CfDs provide an effective price hedge for consumers

DISC quantifies the hypothesis that CfDs are a means to protect consumers against high and volatile prices, provided the price level of the CfDs themselves is not too high. The latter point is especially relevant. Given the volatility seen during the energy crisis of 2022, project developers and utilities might see a higher cost for hedging and bid into auctions for CfDs at higher prices than before the crisis. In a situation that governments have signed large volumes of CfDs at higher than efficient prices, while increasing deployment of renewables dampens short-term power prices, consumers that must pay the costs of those CfDs would be hedged, but at too high a level. Therefore, while the price hedging mechanism of CfDs can work and revenues to the state from such contracts should be directly returned to consumers, it is essential that state-support auctions are carried out competitively to ensure that as best possible, long-term prices efficiently distribute risk for both counterparties.

Long-term contracts are not substitutable regarding distributional effects

Through the scenario analysis using the DISC model, we have demonstrated that while some contracts might be substitutable on the generator side in the short-run, they have significantly different consequences for financial flows and the distributional impacts on consumers. What is most important for determining these outcomes is the nature of the contract (whether it is physical or financial) and whether its costs are paid directly by one consumer or socially distributed across a group of consumers (or all consumers).

Renewables dampen consumer prices – but the impact on profits is mixed

By comparing consumer costs between 'normal' and 'crisis' scenarios, we have illustrated using DISC that having more renewables in the electricity system can reduce consumer prices, especially in the context of a supply shock like that which occurred in 2022. Consumers in countries with more renewables were better insulated against price increases in our modelling results. However, the impact on generator profits in the modelling results was mixed, with the outcomes more dependent on the broader generation mix than purely on renewables. In terms of achieving the dual goals of protecting consumers and stimulating investment, increasing renewables can achieve the former, but electricity market design will need to be cleverly implemented to simultaneously achieve the latter.

Areas for future research

Any future discussion on changes to market instruments requires analysis on how electricity system cost is distributed depending on the contracts market actor engage in. Our simplified approach does abstract from several elements/interactions that characterise the electricity industry. Some elements that we believe would be worth investigating to provide more robust policy advice are:

- The impacts of fixed retail prices for different consumer types (industrial and vulnerable).
- Investigating final profits of generation types and companies including capital costs, involving to capacity payments.
- Exploring the role of demand-side response to high prices and its consequences for financial flows.
- Broader dispatch scenario assessment looking at periods with low demand to understand effects on financial flows.

5. EXCURSE: LACK OF AN IMPACT ASSESSMENT

KEY FINDINGS

The European Commission has not provided an impact assessment of the reform of the electricity market design, citing 'urgency' as a mitigating factor. There are four reasons why this is problematic. The first is a matter of principle, a substantial reform of a very complex system should not be left only to politics. The second is to provide a reference point for discussion, and facilitate easier conversation between different stakeholders with vastly different interests. The third reason is the absence fails to provide guidance to investors. Finally, the complexity of the market necessitates a systematic view which details how any decision has far-reaching implications. An impact assessment would be the tool for addressing these four factors.

The 2023 Commission proposal to reform the electricity market was not backed up by an impact assessment. It was only underpinned by a public consultation and a staff working document (European Commission, 2023c). Given the desired impact of the reform this approach carries substantial risk.

Formally, "an impact assessment is a process comprising a structured analysis of policy problems and corresponding policy responses. It develops policy objectives and alternative policy options and assesses their impacts. It also considers subsidiarity, proportionality of options and how to monitor and evaluate the policy in the future" (European Commission, 2023d). In practice the resulting impact assessment report is an often quite substantial document laying out the objectives of a reform and how the Commission proposal expects to achieve those – and arguing why alternative approaches are deemed less suitable. The 2016 impact assessment to the clean energy package electricity market reform contained almost 1,000 pages.

Since 2002 the European Commission committed itself to provide impact assessments for all initiatives with significant impacts (European Commission, 2012). The corresponding system has been refined over the years, notably with the 2015 « Better Regulation Package» under the Junker Commission that sets out a common framework for the policy cycle in which impact assessments are a key instrument. Hence, the European Commission (2023) states « An impact assessment is required when 1) a policy proposal is likely to lead to significant economic, environmental, or social impacts or entails significant spending and 2) the Commission has a choice between alternative policy options ('room for manoeuvre') » (European Commission, 2023d). Only in specific cases the Commission can deviate from this normal route. "Where an impact assessment is required in principle, but this is not possible and a derogation is granted, an analytical document in the form of a staff working document presenting the evidence behind the proposal and cost estimates should be prepared within three months of the initiative's adoption. »

The Commission is quite clear that it sees the impact assessment not only as a formality, but an important process to underpin the legitimacy of a proposal that has significant impact on its citizens (#ref). This is the case for an electricity market reform that is supposed to « significantly improve the structure and functioning of the European electricity market » (European Commission, 2023b). But with the argument of « urgency » an impact assessment has been circumvented, we see four reasons why this is problematic.

Better Regulation Principles

The first is a matter of principle. Performing a substantial reform of a very complex, hard-won system like the internal electricity market should only be left to political brinkmanship if the course and cure of the policy problem are crystal clear. Especially the EU political system put a lot of emphasis on objective analysis and clearly spelled out arguments on core principles (proportionality, subsidiarity, fairness, …) to obtain sufficient legitimacy for its regulatory activity.

A relatively short working document with no modelling of the main tools (e.g., the new rules on contracts between market participants in Art. 19) is no substitute for an impact assessment and a public consultation on such a complex matter that runs for less than a month (23 January 2023 to 13 February 2023) does not allow to really elicit the understanding needed to properly assess the implications of the reform.

Reference point for discussion

Impact assessments serve as a reference point in discussions on complex policy matters. And the electricity market is a prime example for such a complex system in which hundreds of millions of consumers, thousands of generators, hundreds of network operators and traders and dozens of national governments, regulators and transmission system operators interact based on a set of rules that have gradually developed over three decades. Each of the stakeholders sees different issues and they need to be able to talk to each other when discussing policy – and here a proper impact assessment can make a big difference as a reference point for the discussion.

This is not only important for broader stakeholders, but also for the EU's co-legislators: the European Council and the European Parliament. Their view on Commission proposals is often informed and formulated in distinguishing from the Commissions arguments. For example, the European Parliament's Directorate for Impact Assessment typically assesses the European Commission's document to inform the Parliaments view.

The current Commission proposal did show that there is not even a joint problem definition. When discussing the 2022 energy crisis, the justifications mainly focused on the lack of Russian gas – while in the same year electricity supply suffered also a massive shortfall of nuclear generation capacities and hydropower production. Including those in the analysis and discussions might have led to different policies being considered appropriate.

A well-structured discussion of trade-offs is needed to find good solutions.

Guidance for investors and national implementation

Electricity markets are no perfect clockworks that run along the mechanical rules given by the European legislator. Their working is dependent on interpretation and expectations of stakeholders. Those interpretations and expectations need to be well aligned between stakeholders, to get to a well-functioning system. And here an impact assessment that clearly lines out how rules are supposed to work can help a lot. It can give guidance to investors that certain elements in the legislation are "bugs" that might be ironed out in later reforms, while other elements are desired "features" that investors can rely on also in the future. And it might help member states to see the bigger picture when implanting the reforms domestically – better allowing to reap synergies of the internal market.

Systemic view

As we have tried to show in this report, changing individual elements in the electricity market drives complex effects along the whole system. For example, rules on capacity markets might spill over into prices in wholesale markets in neighbouring countries – affecting investment and dispatch. Reforms that pull on several levers at the same time – as the Commission proposal does – will have hard to intuitively grasp implications – that will also differ between actors.

Hence an impact assessment that provides some sensible quantification of the systemic effects would provide a lot of value for the current and future policy debates.

Allows to ex post assess regulatory success.

By lining out the expected impacts of a reform an impact assessment is crucial for assessing ex post if the underlying assumptions where correct and help to better understand where further adjustments are needed to get to desired results. As electricity markets will remain "living systems" this cycle of ex ante and ex post assessments will not only help to continuously improve the system, but also give stakeholders visibility on potential future reform steps.

Conclusion

The main argument for having a comprehensive impact assessment is providing more regulatory consistency and hence giving more credible signals for stakeholders. This will help to reduce capital cost – the main component of energy system cost.

While it is too late for a proper impact assessment on the Commission proposal, the next electricity market reform will come. And as impact assessments are not written out of nowhere, it is crucial that the tools needed to produce policy-relevant, high-quality impact assessments are set up now.

The necessary data-collection and setting up of proper market-modelling tools cannot start early enough – also allowing for some peer review and stakeholder discussions on the methodologies used. Possibly, a dedicated institution – such as a European Energy Information Administration – and the need to produce regular benchmarking reports can help to provide the analytical tools for a comprehensive electricity market reform that underpins the full decarbonisation of Europe's electricity system (one intermediate step here might be a new green paper that reassesses the options for a fundamental reconfiguration of competences in the electricity system in order to enable the necessary investments at acceptable cost).

- Risks associated with proposing a consequential reform without impact assessment.
    - Need for substantive analysis to underpin reform of electricity markets.
- Good international practice on impact assessment, including past European benchmarking reports.
- Commercial and private data to be synthesised and anonymised to allow for appropriate assessment of market performance.
- Data that should be continuously available evaluating and publicly discussing the performance of electricity markets.
    - Share of revenue coming from different markets to generator types.
    - Retail prices including final consumer bill breakdown across all EU countries.
    - Congestion revenue on publicly owned interconnectors.

6. RECOMMENDATIONS

6.1. Overview of assessments

6.1.1. Performance of the current market design against criteria

The current market design fares rather well in terms of operating the existing system efficiently. The 2022 energy crisis demonstrated that short-term price signals help to pull in all resources available to the market in one country to cover shortfalls – even if they appear in other countries. The absence of any major load-shedding event in a year that saw Germany losing most of its gas supplies and France losing half of its nuclear generation is evidence to this functionality. There, however, remains some room for improvement when it comes to the assets exposed to market prices. Countries politically phasing out major generators or consumers not being able to save and resell valuable electricity to the market are some examples.

In terms of fairness, the current market design unexpectedly led to substantial shifts in wealth between stakeholders. The picture was, however, fragmented as some consumer groups that were well hedged managed to benefit from the crisis, while others were exposed with their entire consumption to exploding prices. The same was true for generators. A little-observed winner were transmission system operators. So overall, consumers and producers were not prevented from insuring against substantial price shifts – but many stakeholders only did this to a limited degree.

The biggest problem the crisis exposed was in terms of investment. The electricity market design (and the substantial policy interventions that are happening in the sector) in the past decades did not deliver a well-diversified, secure, low-cost and low-carbon power system. There was too little generation capacity, too little interconnection, too little maintenance and a too high reliance on individual fuel supplies.

6.1.2. Assessment of market instruments and design details

The Commission proposal does not specify a completely new market design but mainly regulates into existing market instruments. Thereby the details of the proposed intervention are of crucial importance.

The success of the approach to make CfDs into the main tool for support will strongly depend on their design and on keeping a European dimension to markets.

Hedging obligations can be a useful tool to prevent moral hazard, but they need to be tailored to the specific situation in electricity markets.

An intervention framework for price crisis is an ambiguous tool. On the one hand it creates uncertainty to market actors by threatening state interventions, on the other hand it reduces said uncertainty by spelling out trigger conditions and consequences. Hence, such a tool needs to properly balance conditions and consequences in a way that reduces and not increases uncertainty for market participants.

An additional product for peak shaving in our view only increases uncertainty and is unnecessary.

Energy sharing can be a passable tool to increase acceptance and deployment of renewables up to a certain level. But it runs a high risk of socialising cost and privatising benefits.

6.1.3. Results of quantitative modelling

The main result of our quantitative modelling is that assessing market instruments is different from assessing cost-optimal power systems, and such modelling is urgently needed to properly underpin complex market design reforms. Individual instruments cannot be assessed in isolation, as the cash flows from one instrument for, both, consumers and producers, are linked to the cash-flows from all other instruments. Hence, strengthening one tool, or preventing another tool, set in motion a chain of reactions that affect prices for all other instruments and might create unexpected winners and losers.

Our stylised model provided some support for four hypothesis:

- Higher renewable shares can reduces consumer prices.
- Firm earnings are impacted by contract design.
- Firm earnings are dependent on generation portfolios.
- CfDs can provide a price hedge for consumers.
- CfDs and PPAs lead to different financial flows.
- Futures and PPAs are not directly substitutable.

A trivial but crucial message is, that revenues used to pay for operation and investments will, whatever the contractual arrangements are, ultimately need to be expenses of one consumer group, or another, unless the taxpayer jumps in.

6.2. Concluding recommendations

6.2.1. Specific recommendations

In Chapter 3, we develop several specific recommendations for the ongoing electricity market design reform. We recommend keeping the focus of reform on long-term markets, retaining the well-working European electricity short-term markets. This also means that any long-term contracts and markets should be designed so that they keep the incentives for market participants to operate efficiently in short-term markets. More concretely, this overarching recommendation manifests in three core recommendations.

First, customers should be protected from price crises using instruments that leave short-term price incentives in place. We show that for retail markets, this means future retail tariffs should not be fixed-price contracts, but instead insure the electricity bill (through what is called hedging in other market segments) while leaving short-term incentives working. Retaining flexibility incentives for the demand side is central, because in a decarbonised power system the generation side will be largely weather-dependent and integration costs can be drastically lowered by making the demand side, especially electric vehicles, and heat pumps, more flexible. Longer-term retail contracts can also remove the need for discrete price intervention mechanisms which are problematic as they destroy market confidence and should only be used as a last resort.

Second, long-term contracts for low-carbon generation should also be designed in a way to preserve short-term incentives. If Contracts for Differences are designed poorly, they remove incentives for generators to produce high-value electricity and to design plants system-friendly and efficiently. Thus, thorough design requirements for CfDs are a must. The same is true for government supported power purchase agreements. Intervening in the design of existing forward markets through the setup of virtual forward hubs should be done with care and a prior impact assessment seems warranted given the large uncertainties surrounding the potential effects of the measure.

Third, the introduction of many specific and unclearly defined submarkets for flexibility should be avoided. Regrettably, the current reform includes several such examples, from peak-shaving products to flexibility targets and procurement mechanisms. The existing multitude of well-working short-term power markets in Europe – from day-ahead to intraday to balancing markets – provide the economically right incentives not only for generation but also for demand and storage entities to use their flexibility potential efficiently. There is no clear-cut economic case for adding extra markets and subsidies.

6.2.2. Priorities for reform

The here-discussed electricity market reform of 2023 will not be the last major adjustment to European electricity market design. A first finding from our analysis is, that important data to evaluate the workings of the existing market design are not available, and that a robust model to ex ante analyse impacts of market design choices does not exist. Constantly experimenting with individual design elements to figure out a functioning market design will not convince investors to deploy hundreds of billions of Euros into power generating, storing, transporting and consuming assets. Hence, the knowledge infrastructure needed to underpin a major revision of the operation-system of Europe's electricity system should be set up quickly. Some meaningful aggregate data on contracts, prices and financial flows need to be collected to ex post evaluate the current market design. A stylised model to discuss market design choices needs to be made available as a reference for discussions on future reforms. The Commission needs to prepare a substantial stock-take of the implications of the current market design and options to reform it – maybe inspired by the UK Review of Electricity Market Arrangements (REMA) discussion.

A second near-term priority would be to maximise transmission capacities, both, physically and operationally. Making this a priority will imply significantly lower energy cost in Europe in the short, and more importantly in the longer term. Allowing a relative decline in cross-border capacities by contrast will put the internal electricity market into question and make decarbonisation national systems much more expensive. A crucial step here would be to have a more regional or Europe-wide optimisation of dispatch (and grid investments) as well as more local signals that reflect locational demand-supply imbalances.

An arising priority pertains to the demand side. Emerging discussions on price freezes for specific consumer groups (most notably the energy-intensive industry in Germany) entail a significant risk for the electricity market. If the volume, timing and location of electricity consumption is overruled by national governments there might not only be inefficient subsidy races and corresponding challenges to the cross-border flows, but also inefficient investment decisions that imply higher energy system cost in the future.

Rather than introducing additional flexibility markets, future reform should also address existing flexibility *barriers*, of which one sticks out: network tariffs. Existing network tariff schemes in many member states prevent the demand side from offering its fully flexibility potential due to inefficient capacity charges and a lack of dynamic grid tariffs, a blind spot of the 2023 reform proposal.

6.2.3. Future design considerations

The current reform will not resolve the issue of inefficient investment signals. The underlying problem runs very deep and insufficient revenues for generators in general is not the core problem. The core issue is that the electricity system is caught between a market that not always delivers the expected investments and a constant stream of government intervention that overrules market signals. Hence, we often observe that market-based investment are crowded-out by publicly-backed investments.

Resolving this state-market dichotomy in a governance system that is characterised by a dichotomy between national sovereignty on the fuel mix and the benefits of a joint European electricity system is conceptually very difficult. But indirect tools such as higher-quality and more transparent planning exercises at the national and European level that enforce real coordination can go a long way, in reducing investors uncertainties.

In physical terms demand response and flexibility will become much more important with higher shares of renewables. Getting those signals right – tapping also into other countries corresponding resources – will require market design elements that set proper incentives for investment and operation.

One area that is worthwhile exploring is experimentation on more local co-optimisation of systems – even along the value chain. With, on the one hand more local generation and storage of electricity and on the other hand more integration with heating, transport, hydrogen, data and other systems, it appears that new solutions might uncover significant efficiency potential.

A. TECHNICAL ANNEX

Set out in the following annex is a detailed description of the DISC model, including the software employed, the logical structure, the data inputs and sources, the dispatch optimisation, and the microeconomic formulation of the generator profit functions and consumer cost functions.

Software

DISC is written in Python, a widely-used general purpose programming language. Python has been used for electricity system modelling in many other instances. For example, Brown et al (2017) used Python to develop PyPSA, a power system analysis framework that has been applied in many contexts, including European and global (Horsh et al, 2018; Parzen et al, 2023). Another Python based power system modelling application is PowerGAMA (Svendsen & Spro, 2016). PowerGAMA is an open source Python package that can be used for grid and power market analyses.

Within Python, DISC makes use of the 'Pandas' package for handling data. The data preprocessing turns excel and csv files into Pandas dataframes which are then stored in the appropriate format for later input to the dispatch and contracts modules. 'Pyomo', an optimisation package in Python, is used for the dispatch module to minimise the cost of supplying electricity to meet the demand in every hour across all five countries. Pyomo is an open-source optimisation language within Python and can be used for applications ranging from power system optimisation to supply chain analysis. The plotting package 'matplotlib' is employed for producing charts, as is common in Python applications.

Logical Structure

The coding structure of DISC consists of four components. The data preprocessing component takes in the raw data from the data sources and cleans it to a format that can be input to the dispatch module. This includes installed capacities, variable costs based on fuel and carbon, availability factors, and generation ownership. The

The dispatch module uses the following inputs for each of the five countries (Germany, France, Italy, Spain and Poland):

- Hourly electricity load (MW).
- Hourly solar, onshore wind, offshore wind, hydro run-of-river and hydro pumped storage electricity generation.
- The hourly available generation of all other generation types (biomass, coal, gas, geothermal, oil, nuclear, water reservoir hydro, and waste).
- The variable costs of each generation type.

The values of the above data are different across the normal and crisis dispatch scenarios, as set out in section 4.2.1. With this data, the dispatch module minimises the cost of supplying electricity to meet the demand and produces the marginal price, in every hour of the year across each of the five countries. The hourly output of each generation type is determined in this way, as well as their hourly variable costs.

The contracts module takes in the dispatch results from each scenario (normal and crisis). With the various assumption about contract volume and price, the hourly marginal price and the hourly outputs of each generation type, as well as the share of load consumed by each consumer type, the contracts module can determine the revenues earned by each generation type and the costs paid by each consumer type. The contracts module then outputs, for each combination of dispatch scenario and contract scenario and each country, the revenues from each contract type for each generation type and the costs from each contract type for each consumer type.

The figures and analysis module uses the results from the dispatch module and the contracts module and produces the figures used in section 4.2.1

Data Inputs and Sources

The data inputs, assumptions and their sources are set out in this subsection, grouped by dispatch and contracts.

Dispatch

The hourly electricity load for each country is sourced from the ENTSO-E transparency platform. In the cases where the load was too high for the model to solve, the load was reduced (mimicking demand reduction). Furthermore, missing data points were linearly interpolated.

The hourly generation from solar, onshore wind, offshore wind, hydro run-of-river and hydro pumped storage is also sourced from the ENTSO-E transparency platform. Any missing data points are also linearly interpolated.

Installed capacity is further sourced directly from the ENTSO-E transparency platform for the year 2022.

Table 7: Installed Capacity Inputs [MW]

Generation Type	DE	FR	IT	ES	PL
Biomass	8,332	1,301	1,548	702	647
Fossil Brown coal/Lignite	18,544	0	0	0	7,560
Fossil Coal-derived gas	0	0	2041	0	284
Fossil Gas CCGT	18,322	13,074	41,961	29,862	3,807
Fossil Gas OCGT	12,231	0	0	64	0
Fossil Hard coal	18,830	1,816	6,376	4,642	19,073
Fossil Oil	3,966	2,762	1,490	669	393
Geothermal	51	2	869	0	0
Hydro Pumped Storage	9,280	5,050	7,256	0	1,591
Hydro Run-of-river and poundage	3,660	11,834	10,507	5,695	321
Hydro Water Reservoir	1,397	8,785	4,441	1,155	464
Nuclear	4,056	61,370	5,137	19,187	0
Solar	57,744	13,154	122	7,117	6,664

Generation Type	DE	FR	IT	ES	PL
Waste	1,599	947	0	14,640	0
Wind Offshore	7,787	20	10,658	565	0
Wind Onshore	55,289	19,516	1,548	0	7,950

Source: ENTSO-E Transparency Platform.

The available capacity in each hour is determined by scaling the installed capacity by an availability factor, to reflect outages and typical capacity factors of generation types. The availability factor is adjusted in the crisis scenario to reflect nuclear outages and drought conditions.

Table 8: Availability factors

Generation Type	Availability Factor in Normal Dispatch	Availability Factor in Crisis Dispatch
Biomass	0.9	0.9
Fossil Brown coal/Lignite	0.8	0.8
Fossil Coal-derived gas	0.8	0.8
Fossil Gas CCGT	0.8	0.8
Fossil Gas OCGT	0.8	0.8
Fossil Hard coal	0.8	0.8
Fossil Oil	0.8	0.8
Geothermal	0.9	0.9
Hydro Pumped Storage	0.5	0.5
Hydro Run-of-river and poundage	*N/A*	*N/A*
Hydro Water Reservoir	0.8	0.5
Nuclear	0.8	0.5
Solar	*N/A*	*N/A*
Waste	0.8	0.8
Wind Offshore	*N/A*	*N/A*
Wind Onshore	*N/A*	*N/A*

Source: Bruegel assumptions.

The variable cost assumptions of non-thermal generators determined the marginal price if they are the marginal unit and also affect the contribution margin of those generators.

Table 9: Generator Cost Assumptions

Generation Type	Variable Costs [€/MWh]
Biomass	14
Fossil Brown coal/Lignite	*Determined by fuel and carbon costs.*
Fossil Coal-derived gas	*Determined by fuel and carbon costs.*
Fossil Gas CCGT	*Determined by fuel and carbon costs.*
Fossil Gas OCGT	*Determined by fuel and carbon costs.*
Fossil Hard coal	*Determined by fuel and carbon costs.*
Fossil Oil	*Determined by fuel and carbon costs.*
Geothermal	20
Hydro Pumped Storage	0.5
Hydro Run-of-river and poundage	8
Hydro Water Reservoir	18
Nuclear	15
Solar	4
Waste	10
Wind Offshore	10
Wind Onshore	8

Source: Variable cost assumptions are based on the IEA's levelised cost of electricity calculator, the National Renewable Energy Technology Annual Technology Baseline.

The technical assumptions about generator performance determine the marginal cost of thermal generators. The electrical efficiency is the electricity produced per unit of fuel. The emissions factor is the tonnes of CO2 emitted per unit of electricity generated. The fuel cost and carbon cost per unit of electricity generated can be determined for different generator types and, combined, constitute the marginal cost.

Table 10: Generator Technical Assumptions

Generation Type	Electrical Efficiency	Source	Emissions Factor [tCO2/MWh]	Source
Biomass	0.23	IDEES Database	0.5	*Assumption*
Fossil Brown coal/Lignite	0.39	IDEES Database	1.1	EMBER
Fossil Coal-derived gas	0.38	IDEES Database	0.7	*Assumption*
Fossil Gas CCGT	0.52	IDEES Database	0.34	EPA

Generation Type	Electrical Efficiency	Source	Emissions Factor [tCO2/MWh]	Source
Fossil Gas OCGT	0.42	IDEES Database	0.52	EPA
Fossil Hard coal	0.42	EMBER	0.83	EMBER
Fossil Oil	0.38	IDEES Database	0.7	*Assumption*
Geothermal	*N/A*		0	
Hydro Pumped Storage	*N/A*		0	
Hydro Run-of-river and poundage	*N/A*		0	
Hydro Water Reservoir	*N/A*		0	
Nuclear	*N/A*		0	
Solar	*N/A*		0	
Waste	*N/A*		0.5	*Assumption*
Wind Offshore	*N/A*		0	
Wind Onshore	*N/A*		0	

Source: Bruegel assumptions or based on listed sources.

Commodity price assumptions, which determine the final variable cost of thermal generators in each dispatch scenario, are presented in section 4.2.1. The figures are repeated below.

Table 11: Normal Dispatch Scenario Commodity Prices

Commodity	Price	Unit
Lignite	5	[€/MWh]
Nuclear Fuel	5	[€/MWh]
Gas	15	[€/MWh]
Diesel Oil	35	[€/MWh]
Coal	40	[€/tonne]
ETS Price	80	[€/tonne]

Source: Bruegel assumptions based on European Commission electricity market reports.

Table 12: Crisis Dispatch Scenario Commodity Prices

Commodity	Price	Unit
Lignite	5	[€/MWh]
Nuclear Fuel	5	[€/MWh]
Diesel Oil	60	[€/MWh]
ETS Price	80	[€/tonne]
Gas	150	[€/MWh]
Coal	200	[€/tonne]

Source: Bruegel assumptions based on European Commission electricity market reports.

Contracts

The costs paid by consumers are determined by volume of long-term contracts to which they are a counterparty, the price of those contracts, the cost at the wholesale market, and the consumer category's share of the total annual load. The modelling assuming that this share of load is fixed throughout the year and does not vary by hour. The shares by consumer category for each country are set out below.

Table 13: Consumer share of load

Country	Industry Share	SMEs Share	Household Share
DE	46%	25%	29%
FR	27%	32%	41%
IT	46%	29%	24%
ES	35%	32%	34%
PL	40%	38%	22%

Source: Eurostat for 2021.

The assumptions for the contract volumes are set out in section 4.2.1. The price assumptions for each contract type is provided below (prices are constant across scenarios, with the volume determining whether the contract is active or not). The level of these contracts was selected to ensure that they would illustrate the difference financial flows from contract types between dispatch scenarios.

Table 14: Contract Price Assumptions

Contract Type	Price [€/MWh]
Solar CfD	75
Solar PPA-A	75
Solar PPA-B	75
Onshore Wind CfD	85

Contract Type	Price [€/MWh]
Onshore Wind PPA-A	85
Onshore Wind PPA-B	85
Offshore Wind CfD	100
Offshore Wind PPA-A	100
Offshore Wind PPA-B	100
Futures t-1 (Normal)	Mean Annual Wholesale Price (Normal Dispatch Scenario)
Futures t-2 (Normal)	Mean Annual Wholesale Price (Normal Dispatch Scenario)
Futures t-3 (Normal)	Mean Annual Wholesale Price (Normal Dispatch Scenario)
Futures t-1 (Crisis)	Mean Annual Wholesale Price (Crisis Dispatch Scenario)
Futures t-2 (Crisis)	Midpoint of Mean Wholesale Price (Normal Dispatch Scenario) and Mean Wholesale Price (Crisis Dispatch Scenario)
Futures t-3 (Crisis)	Mean Annual Wholesale Price (Normal Dispatch Scenario)

Source: Bruegel assumptions.

The final set of input data relates to the ownership shares of major electricity utilities. As stated in section 4.2.2, this data is based on bottom-up research by Bruegel and **does not** represent a final data product. It is better considered as a set of informed assumptions to illustrate the effects of market design and dispatch conditions on specific firm earnings. Table 15 below sets out the assumed owned capacity of the largest 15 electricity utilities by capacity across the five countries in the DISC modelling, as well as the assumed share of that installed capacity in terms of clean dispatchable (hydropower and biomass), coal, gas, nuclear, other thermal (waste and oil), and renewables (solar, onshore wind and offshore wind). The ownership of the remaining installed capacity not accounted for in these figures is either attributed to small firms or unknown, and in both cases is not used in the model results analysis.

Table 15: Firm ownership assumptions

Firm	Total Capacity [MW]	Clean Dispatchable	Coal	Gas	Nuclear	Other Thermal	Renewable
EDF	86,544	15%	2%	9%	71%	2%	1%
Iberdrola	30,126	36%	0%	19%	11%	0%	34%
Endesa	22,044	22%	18%	25%	15%	0%	21%
Enel	18,644	42%	25%	33%	0%	0%	0%
RWE	18,393	6%	52%	16%	20%	0%	6%
Municipality	15,901	3%	44%	46%	0%	1%	5%
PGE	15,726	5%	88%	5%	0%	0%	1%
Naturgy	12,500	18%	0%	59%	5%	0%	18%

Firm	Total Capacity [MW]	Clean Dispatchable	Coal	Gas	Nuclear	Other Thermal	Renewable
EPH	9,578	2%	62%	36%	0%	0%	0%
A2A	6,934	19%	5%	63%	0%	12%	0%
EnBW	6,530	17%	67%	0%	0%	5%	11%
ENGIE	6,496	23%	0%	77%	0%	0%	0%
Enea	5,903	4%	96%	0%	0%	0%	0%
Uniper	5,595	9%	49%	42%	0%	0%	0%
Vattenfall	4,776	52%	15%	28%	0%	0%	6%

Source: Bruegel internal database on electricity asset ownership.

Dispatch Optimisation

The optimisation done with Pyomo in the dispatch module is described in general terms, as follows. The objective function can be summarised as:

$$\min C(Q_g) = \sum Q_g \times c_g$$

Where,

$$Q_g = Output\ of\ each\ generator$$

$$c_g = Variable\ costs\ of\ each\ generator$$

The above minimisation is carried out subject to the constraint that generator outputs are between zero and the maximum possible output in each hour:

$$0 \leq Q_g \leq Q_{gmax}$$

The constraint that the total generation in each hour is equal to the residual load is also applied:

$$\sum Q_g = Q_{residual}$$

Where,

$$Q_{residual} = Q_{load} - Q_{hydro\ run-of-river} - Q_{hydro\ pumped\ storage} - Q_{solar} - Q_{onshore\ wind} - Q_{offshore\ wind}$$

Contracts

The hourly profit functions[18] of each generator can be formalised as follows:

$$\pi(Q) =$$
$$(Q_{fut}) \times (p_{fut} - p_m)$$
$$+(Q_{cfd}) \times (p_{cfd} - p_m)$$
$$+(Q_{ppa} \times p_{ppa}) + (Q \times S_{ppav} \times p_{ppav})$$
$$+(Q_w \times p_m)$$
$$-Q \times c_{variable}$$

Where,

$Q_{fut} = Futures\ Volume\ [MWh],\ p_{fut} = Futures\ Price\ [€/MWh]$

$Q_{cfd} = CfD\ Volume\ [MWh], p_{cfd} = CfD\ Strike\ Price\ [€/MWh]$

$Q_{ppa} = PPA\ Volume\ [MWh], p_{ppa(v)} = (variable) PPA\ Strike\ Price\ [€/MWh]$

$Q_w = Wholesale\ Volume\ [MWh],\ p_m = Marginal\ Price\ [€/MWh]$

$S_{ppav} = Share\ of\ output\ contracted\ to\ variable\ PPA$

$Q = Q_{ppa} + Q \times S_{ppav} + Q_w = Generator\ Output\ [MWh]$

$c_{variable} = c_{fuel} + c_{carbon} = Variable\ Costs\ [€/MWh]$

The hourly consumer cost functions can be formalised like so:

$$c(Q) =$$
$$(Q_{fut}) \times (p_{fut} - p_m)$$
$$+(Q_{cfd}) \times (p_{cfd} - p_m)$$
$$+(Q_{ppa} \times p_{ppa}) + (Q \times S_{ppav} \times p_{ppav})$$
$$+(Q_w \times p_m)$$

Where the quantities apply to the specific consumer type:

$Q_{fut} = Futures\ Volume\ [MWh],\ p_{fut} = Futures\ Price\ [€/MWh]$

$Q_{cfd} = CfD\ Volume\ [MWh], p_{cfd} = CfD\ Strike\ Price\ [€/MWh]$

$Q_{ppa} = PPA\ Volume\ [MWh], p_{ppa(v)} = (variable) PPA\ Strike\ Price\ [€/MWh]$

$Q_w = Wholesale\ Volume\ [MWh],\ p_m = Marginal\ Price\ [€/MWh]$

$S_{ppav} = Share\ of\ consumption\ contracted\ to\ variable\ PPA$

$Q = Q_{ppa} + Q \times S_{ppav} + Q_w = Consumer\ Load\ [MWh]$

[18] Technically, this profit function describes the contribution margin of the generation type, as capital costs and other fixed operation and maintenance costs are not accounted for.

B. COMPLETE SCENARIO RESULTS

The following is a summary of the modelling results of the eight combinations between the two dispatch scenarios and the four contract scenarios.

Dispatch Scenario 1 – 'Normal'

Table 16: Normal Dispatch Scenario Results

Country	Annual Load [TWh]	Mean Marginal Price [€/MWh]	SD Marginal Price [€/MWh]	Producer Variable Costs [mln €]	Emissions [kt]
DE	483	79	29	15,174	126
FR	445	21	19	6,239	10
IT	317	63	24	12,676	75
ES	236	23	13	3,077	6
PL	172	96	4	11,990	102
All	1,653	56	18	49,156	319

Source: DISC modelling results.

Dispatch Scenario 2 – 'Crisis'

Table 17: Crisis Dispatch Scenario Results

Country	Annual Load [TWh]	Mean Marginal Price [€/MWh]	SD Marginal Price [€/MWh]	Producer Variable Costs [mln €]	Emissions [kt]
DE	483	267	124	39,888	200
FR	428	238	181	18,941	29
IT	316	341	62	71,454	89
ES	236	207	141	11,619	16
PL	172	210	25	22,843	130
All	1,635	252	107	164,746	463

Source: DISC modelling results.

Note: The lower load in the crisis scenario is due to adjustments made to the input data to ensure that the load is low enough in all hours to be met by generation. This can be considered as demand reduction in the crisis scenario.

Dispatch 1 + Contract A: Normal Dispatch Conditions with Mixed Contracts

Table 18: Normal Dispatch Conditions with Mixed Contracts – Generation Results

Generation Type	Futures Revenue [mln €]	Futures Volume [MWh]	PPAs Revenue [mln €]	PPAs Volume [MWh]	CfD Volume [MWh]	CfD Revenue [mln €]	Total Revenue [mln €]	Total Variable Costs [mln €]	Total Contribution Margin [mln €]
Biomass	0	58,981,092	0	0	0	0	6,782	1,376	5,406
Fossil Brown coal/Lignite	0	16,581,917	0	0	0	0	3,141	2,786	354
Fossil Coal-derived gas	0	1,536,334	0	0	0	0	276	257	19
Fossil Gas CCGT	0	203,055,376	0	0	0	0	25,484	18,967	6,516
Fossil Gas OCGT	0	26,989,573	0	0	0	0	4,449	3,478	972
Fossil Hard coal	0	62,386,651	0	0	0	0	10,109	9,894	215
Fossil Oil	0	1,364,469	0	0	0	0	332	307	25
Geothermal	0	4,336,441	0	0	0	0	463	145	318
Hydro Pumped Storage	0	0	0	0	0	0	-20	0	-20
Hydro Run-of-river and poundage	0	45,427,903	0	0	0	0	3,453	606	2,847
Hydro Water Reservoir	0	77,961,561	0	0	0	0	5,573	2,339	3,234
Nuclear	0	241,577,995	0	0	0	0	10,708	6,100	4,608
Solar	0	27,253,587	1,533	20,440,190	81,760,761	1,470	8,568	545	8,023
Waste	0	13,592,684	0	0	0	0	1,168	227	941
Wind Offshore	0	4,953,402	372	3,715,052	14,860,207	311	2,194	248	1,946
Wind Onshore	0	47,037,335	2,999	35,278,001	141,112,004	4,121	16,937	1,881	15,055
Sum	**0**	**833,036,322**	**4,903**	**59,433,243**	**237,732,973**	**5,902**	**99,615**	**49,156**	**50,459**

Source: DISC modelling results.

Table 19: Normal Dispatch Conditions with Mixed Contracts – Consumer Results

Consumer Type	Futures Cost [mln €]	PPAs Cost [mln €]	CfD Cost [mln €]	Wholesale Cost [mln €]	Total Cost [mln €]
Household	0	0	3,153	26,167	29,319
Industry	0	3,923	0	36,098	40,020
SME	0	981	2,750	26,545	30,275
Sum	**0**	**4,903**	**5,902**	**88,810**	**99,615**

Source: DISC modelling results.

Table 20: Normal Dispatch Conditions with Mixed Contracts – Country Results

Country	Futures Cost [mln €]	PPAs Cost [mln €]
DE	39,716	24,542
FR	12,885	6,646
IT	21,216	8,540
ES	9,530	6,453
PL	16,269	4,279

Source: DISC modelling results.

Dispatch 1 + Contract B: Normal Conditions with Wholesale Only

Table 21: Normal Dispatch Conditions with Wholesale Only – Generation Results

Generation Type	Futures Revenue [mln €]	Futures Volume [MWh]	PPAs Revenue [mln €]	PPAs Volume [MWh]	CfD Volume [MWh]	CfD Revenue [mln €]	Total Revenue [mln €]	Total Variable Costs [mln €]	Total Contribution Margin [mln €]
Biomass	0	58,981,092	0	0	0	0	6,782	1,376	5,406
Fossil Brown coal/Lignite	0	16,581,917	0	0	0	0	3,141	2,786	354
Fossil Coal-derived gas	0	1,536,334	0	0	0	0	276	257	19
Fossil Gas CCGT	0	203,055,376	0	0	0	0	25,484	18,967	6,516
Fossil Gas OCGT	0	26,989,573	0	0	0	0	4,449	3,478	972
Fossil Hard coal	0	62,386,651	0	0	0	0	10,109	9,894	215
Fossil Oil	0	1,364,469	0	0	0	0	332	307	25
Geothermal	0	4,336,441	0	0	0	0	463	145	318
Hydro Pumped Storage	0	0	0	0	0	0	-20	0	-20
Hydro Run-of-river and poundage	0	45,427,903	0	0	0	0	3,453	606	2,847
Hydro Water Reservoir	0	77,961,561	0	0	0	0	5,573	2,339	3,234
Nuclear	0	241,577,995	0	0	0	0	10,708	6,100	4,608
Solar	0	27,253,587	0	0	0	0	6,676	545	6,131
Waste	0	13,592,684	0	0	0	0	1,168	227	941
Wind Offshore	0	4,953,402	0	0	0	0	1,797	248	1,549
Wind Onshore	0	47,037,335	0	0	0	0	11,715	1,881	9,834
Sum	**0**	**833,036,322**	**0**	**0**	**0**	**0**	**92,104**	**49,156**	**42,948**

Source: DISC modelling results.

Table 22: Normal Dispatch Conditions with Wholesale Only – Consumer Results

Consumer Type	Futures Cost [mln €]	PPAs Cost [mln €]	CfD Cost [mln €]	Wholesale Cost [mln €]	Total Cost [mln €]
Household	0	0	0	26,095	26,095
Industry	0	0	0	38,822	38,822
SME	0	0	0	27,187	27,187
Sum	**0**	**0**	**0**	**92,104**	**92,104**

Source: DISC modelling results.

Table 23: Normal Dispatch Conditions with Wholesale Only – Country Results

Country	Futures Cost [mln €]	PPAs Cost [mln €]
DE	38,940	23,766
FR	10,369	4,129
IT	20,673	7,997
ES	5,559	2,482
PL	16,564	4,574

Source: DISC modelling results.

Dispatch 1 + Contract C: Normal Conditions with Contracts for Difference

Table 24: Normal Dispatch Conditions with CfDs – Generation Results

Generation Type	Futures Revenue [mln €]	Futures Volume [MWh]	PPAs Revenue [mln €]	PPAs Volume [MWh]	CfD Volume [MWh]	CfD Revenue [mln €]	Total Revenue [mln €]	Total Variable Costs [mln €]	Total Contribution Margin [mln €]
Biomass	0	58,981,092	0	0	0	0	6,782	1,376	5,406
Fossil Brown coal/Lignite	0	16,581,917	0	0	0	0	3,141	2,786	354
Fossil Coal-derived gas	0	1,536,334	0	0	0	0	276	257	19
Fossil Gas CCGT	0	203,055,376	0	0	0	0	25,484	18,967	6,516
Fossil Gas OCGT	0	26,989,573	0	0	0	0	4,449	3,478	972
Fossil Hard coal	0	62,386,651	0	0	0	0	10,109	9,894	215
Fossil Oil	0	1,364,469	0	0	0	0	332	307	25
Geothermal	0	4,336,441	0	0	0	0	463	145	318
Hydro Pumped Storage	0	0	0	0	0	0	-20	0	-20
Hydro Run-of-river and poundage	0	45,427,903	0	0	0	0	3,453	606	2,847
Hydro Water Reservoir	0	77,961,561	0	0	0	0	5,573	2,339	3,234
Nuclear	0	241,577,995	0	0	0	0	10,708	6,100	4,608
Solar	0	27,253,587	0	0	109,014,348	1,960	8,636	545	8,091
Waste	0	13,592,684	0	0	0	0	1,168	227	941
Wind Offshore	0	4,953,402	0	0	19,813,610	415	2,212	248	1,964
Wind Onshore	0	47,037,335	0	0	188,149,339	5,494	17,210	1,881	15,328
Sum	**0**	**833,036,322**	**0**	**0**	**316,977,297**	**7,870**	**99,974**	**49,156**	**50,818**

Source: DISC modelling results.

Table 25: Normal Dispatch Conditions with CfDs – Consumer Results

Consumer Type	Futures Cost [mln €]	PPAs Cost [mln €]	CfD Cost [mln €]	Wholesale Cost [mln €]	Total Cost [mln €]
Household	0	0	4,203	26,095	30,299
Industry	0	0	0	38,822	38,822
SME	0	0	3,666	27,187	30,853
Sum	**0**	**0**	**7,870**	**92,104**	**99,974**

Source: DISC modelling results.

Table 26: Normal Dispatch Conditions with CfDs – Country Results

Country	Futures Cost [mln €]	PPAs Cost [mln €]
DE	39,653	24,479
FR	13,046	6,806
IT	21,245	8,569
ES	9,783	6,706
PL	16,248	4,258

Source: DISC modelling results.

Dispatch 1 + Contract D: Normal Conditions with PPAs

Table 27: Normal Dispatch Conditions with PPAs – Generation Results

Generation Type	Futures Revenue [mln €]	Futures Volume [MWh]	PPAs Revenue [mln €]	PPAs Volume [MWh]	CfD Volume [MWh]	CfD Revenue [mln €]	Total Revenue [mln €]	Total Variable Costs [mln €]	Total Contribution Margin [mln €]
Biomass	0	58,981,092	0	0	0	0	6,782	1,376	5,406
Fossil Brown coal/Lignite	0	16,581,917	0	0	0	0	3,141	2,786	354
Fossil Coal-derived gas	0	1,536,334	0	0	0	0	276	257	19
Fossil Gas CCGT	0	203,055,376	0	0	0	0	25,484	18,967	6,516
Fossil Gas OCGT	0	26,989,573	0	0	0	0	4,449	3,478	972
Fossil Hard coal	0	62,386,651	0	0	0	0	10,109	9,894	215
Fossil Oil	0	1,364,469	0	0	0	0	332	307	25
Geothermal	0	4,336,441	0	0	0	0	463	145	318
Hydro Pumped Storage	0	0	0	0	0	0	-20	0	-20
Hydro Run-of-river and poundage	0	45,427,903	0	0	0	0	3,453	606	2,847
Hydro Water Reservoir	0	77,961,561	0	0	0	0	5,573	2,339	3,234
Nuclear	0	241,577,995	0	0	0	0	10,708	6,100	4,608
Solar	0	27,253,587	7,154	95,387,555	0	0	8,610	545	8,065
Waste	0	13,592,684	0	0	0	0	1,168	227	941
Wind Offshore	0	4,953,402	1,734	17,336,909	0	0	2,192	248	1,945
Wind Onshore	0	47,037,335	13,994	164,630,671	0	0	16,804	1,881	14,923
Sum	**0**	**833,036,322**	**22,881**	**277,355,135**	**0**	**0**	**99,523**	**49,156**	**50,367**

Source: DISC modelling results.

Table 28: Normal Dispatch Conditions with PPAs – Consumer Results

Consumer Type	Futures Cost [mln €]	PPAs Cost [mln €]	CfD Cost [mln €]	Wholesale Cost [mln €]	Total Cost [mln €]
Household	0	0	0	26,471	26,471
Industry	0	17,978	0	26,226	44,204
SME	0	4,903	0	23,944	28,847
Sum	**0**	**22,881**	**0**	**76,641**	**99,523**

Source: DISC modelling results.

Table 29: Normal Dispatch Conditions with PPAs – Country Results

Country	Futures Cost [mln €]	PPAs Cost [mln €]
DE	39,995	24,821
FR	12,737	6,498
IT	21,200	8,524
ES	9,299	6,223
PL	16,292	4,302

Source: DISC modelling results.

Dispatch 2 + Contract A: Crisis Conditions with Mixed Contracts

Table 30: Normal Dispatch Conditions with Mixed Contracts – Generation Results

Generation Type	Futures Revenue [mln €]	Futures Volume [MWh]	PPAs Revenue [mln €]	PPAs Volume [MWh]	CfD Volume [MWh]	CfD Revenue [mln €]	Total Revenue [mln €]	Total Variable Costs [mln €]	Total Contribution Margin [mln €]
Biomass	-5,843	59,054,272	0	0	0	0	20,485	1,378	19,107
Fossil Brown coal/Lignite	-8,092	98,740,151	0	0	0	0	36,280	16,592	19,688
Fossil Coal-derived gas	-41	337,868	0	0	0	0	224	255	-31
Fossil Gas CCGT	-24,056	193,130,258	0	0	0	0	91,304	101,606	-10,302
Fossil Gas OCGT	-547	5,838,163	0	0	0	0	3,723	3,880	-156
Fossil Hard coal	-3,446	54,869,903	0	0	0	0	18,496	21,188	-2,692
Fossil Oil	-2,867	26,515,458	0	0	0	0	12,438	9,453	2,985
Geothermal	-594	4,347,315	0	0	0	0	1,854	145	1,709
Hydro Pumped Storage	0	0	0	0	0	0	-174	0	-174
Hydro Run-of-river and poundage	-2,450	21,842,221	0	0	0	0	7,593	291	7,302
Hydro Water Reservoir	-7,911	77,282,546	0	0	0	0	26,955	2,318	24,637
Nuclear	-19,924	187,659,650	0	0	0	0	55,168	4,739	50,429
Solar	-2,733	27,253,587	1,533	20,440,190	81,760,761	-14,930	7,368	545	6,823
Waste	-1,353	13,593,944	0	0	0	0	4,324	227	4,098
Wind Offshore	-465	4,953,402	372	3,715,052	14,860,207	-2,477	2,335	248	2,087
Wind Onshore	-4,544	47,037,335	2,999	35,278,001	141,112,004	-23,140	17,826	1,881	15,944
Sum	**-84,867**	**822,456,074**	**4,903**	**59,433,243**	**237,732,973**	**-40,547**	**306,198**	**164,746**	**141,452**

Source: DISC modelling results.

Table 31: Crisis Dispatch Conditions with Mixed Contracts – Consumer Results

Consumer Type	Futures Cost [mln €]	PPAs Cost [mln €]	CfD Cost [mln €]	Wholesale Cost [mln €]	Total Cost [mln €]
Household	-26,633	0	-20,792	136,440	89,014
Industry	-32,902	3,923	0	162,131	133,151
SME	-25,331	981	-19,756	128,138	84,032
Sum	**-84,867**	**4,903**	**-40,547**	**426,709**	**306,198**

Source: DISC modelling results.

Table 32: Crisis Dispatch Conditions with Mixed Contracts – Country Results

Country	Futures Cost [mln €]	PPAs Cost [mln €]
DE	86,945	47,058
FR	80,427	61,486
IT	77,916	6,462
ES	32,407	20,787
PL	28,502	5,659

Source: DISC modelling results.

Dispatch 2 + Contract B: Crisis Conditions with Wholesale Only

Table 33: Normal Dispatch Conditions with Wholesale Only – Generation Results

Generation Type	Futures Revenue [mln €]	Futures Volume [MWh]	PPAs Revenue [mln €]	PPAs Volume [MWh]	CfD Volume [MWh]	CfD Revenue [mln €]	Total Revenue [mln €]	Total Variable Costs [mln €]	Total Contribution Margin [mln €]
Biomass	-5,843	59,054,272	0	0	0	0	20,485	1,378	19,107
Fossil Brown coal/Lignite	-8,092	98,740,151	0	0	0	0	36,280	16,592	19,688
Fossil Coal-derived gas	-41	337,868	0	0	0	0	224	255	-31
Fossil Gas CCGT	-24,056	193,130,258	0	0	0	0	91,304	101,606	-10,302
Fossil Gas OCGT	-547	5,838,163	0	0	0	0	3,723	3,880	-156
Fossil Hard coal	-3,446	54,869,903	0	0	0	0	18,496	21,188	-2,692
Fossil Oil	-2,867	26,515,458	0	0	0	0	12,438	9,453	2,985
Geothermal	-594	4,347,315	0	0	0	0	1,854	145	1,709
Hydro Pumped Storage	0	0	0	0	0	0	-174	0	-174
Hydro Run-of-river and poundage	-2,450	21,842,221	0	0	0	0	7,593	291	7,302
Hydro Water Reservoir	-7,911	77,282,546	0	0	0	0	26,955	2,318	24,637
Nuclear	-19,924	187,659,650	0	0	0	0	55,168	4,739	50,429
Solar	-2,733	27,253,587	0	0	0	0	25,697	545	25,152
Waste	-1,353	13,593,944	0	0	0	0	4,324	227	4,098
Wind Offshore	-465	4,953,402	0	0	0	0	5,393	248	5,146
Wind Onshore	-4,544	47,037,335	0	0	0	0	46,369	1,881	44,488
Sum	**-84,867**	**822,456,074**	**0**	**0**	**0**	**0**	**356,129**	**164,746**	**191,383**

Source: DISC modelling results.

Table 34: Crisis Dispatch Conditions with Wholesale Only – Consumer Results

Consumer Type	Futures Cost [mln €]	PPAs Cost [mln €]	CfD Cost [mln €]	Wholesale Cost [mln €]	Total Cost [mln €]
Household	-26,633	0	0	136,014	109,380
Industry	-32,902	0	0	174,097	141,195
SME	-25,331	0	0	130,885	105,554
Sum	**-84,867**	**0**	**0**	**440,996**	**356,129**

Source: DISC modelling results.

Table 35: Crisis Dispatch Conditions with Wholesale Only – Country Results

Country	Futures Cost [mln €]	PPAs Cost [mln €]
DE	111,217	71,330
FR	86,805	67,864
IT	86,251	14,796
ES	40,663	29,043
PL	31,193	8,350

Source: DISC modelling results.

Dispatch 2 + Contract C: Crisis Conditions with Contracts for Difference

Table 36: Normal Dispatch Conditions with CfDs – Generation Results

Generation Type	Futures Revenue [mln €]	Futures Volume [MWh]	PPAs Revenue [mln €]	PPAs Volume [MWh]	CfD Volume [MWh]	CfD Revenue [mln €]	Total Revenue [mln €]	Total Variable Costs [mln €]	Total Contribution Margin [mln €]
Biomass	-5,843	59,054,272	0	0	0	0	20,485	1,378	19,107
Fossil Brown coal/Lignite	-8,092	98,740,151	0	0	0	0	36,280	16,592	19,688
Fossil Coal-derived gas	-41	337,868	0	0	0	0	224	255	-31
Fossil Gas CCGT	-24,056	193,130,258	0	0	0	0	91,304	101,606	-10,302
Fossil Gas OCGT	-547	5,838,163	0	0	0	0	3,723	3,880	-156
Fossil Hard coal	-3,446	54,869,903	0	0	0	0	18,496	21,188	-2,692
Fossil Oil	-2,867	26,515,458	0	0	0	0	12,438	9,453	2,985
Geothermal	-594	4,347,315	0	0	0	0	1,854	145	1,709
Hydro Pumped Storage	0	0	0	0	0	0	-174	0	-174
Hydro Run-of-river and poundage	-2,450	21,842,221	0	0	0	0	7,593	291	7,302
Hydro Water Reservoir	-7,911	77,282,546	0	0	0	0	26,955	2,318	24,637
Nuclear	-19,924	187,659,650	0	0	0	0	55,168	4,739	50,429
Solar	-2,733	27,253,587	0	0	109,014,348	-19,907	5,790	545	5,245
Waste	-1,353	13,593,944	0	0	0	0	4,324	227	4,098
Wind Offshore	-465	4,953,402	0	0	19,813,610	-3,302	2,091	248	1,844
Wind Onshore	-4,544	47,037,335	0	0	188,149,339	-30,854	15,515	1,881	13,634
Sum	**-84,867**	**822,456,074**	**0**	**0**	**316,977,297**	**-54,063**	**302,066**	**164,746**	**137,320**

Source: DISC modelling results.

Table 37: Crisis Dispatch Conditions with CfDs – Consumer Results

Consumer Type	Futures Cost [mln €]	PPAs Cost [mln €]	CfD Cost [mln €]	Wholesale Cost [mln €]	Total Cost [mln €]
Household	-26,633	0	-27,723	136,014	81,658
Industry	-32,902	0	0	174,097	141,195
SME	-25,331	0	-26,341	130,885	79,213
Sum	**-84,867**	**0**	**-54,063**	**440,996**	**302,066**

Source: DISC modelling results.

Table 38: Crisis Dispatch Conditions with CfDs – Country Results

Country	Futures Cost [mln €]	PPAs Cost [mln €]
DE	84,810	44,923
FR	79,942	61,001
IT	77,340	5,885
ES	31,657	20,038
PL	28,317	5,473

Source: DISC modelling results.

Dispatch 2 + Contract D: Crisis Conditions with PPAs

Table 39: Normal Dispatch Conditions with PPAs – Generation Results

Generation Type	Futures Revenue [mln €]	Futures Volume [MWh]	PPAs Revenue [mln €]	PPAs Volume [MWh]	CfD Volume [MWh]	CfD Revenue [mln €]	Total Revenue [mln €]	Total Variable Costs [mln €]	Total Contribution Margin [mln €]
Biomass	-5,843	59,054,272	0	0	0	0	20,485	1,378	19,107
Fossil Brown coal/Lignite	-8,092	98,740,151	0	0	0	0	36,280	16,592	19,688
Fossil Coal-derived gas	-41	337,868	0	0	0	0	224	255	-31
Fossil Gas CCGT	-24,056	193,130,258	0	0	0	0	91,304	101,606	-10,302
Fossil Gas OCGT	-547	5,838,163	0	0	0	0	3,723	3,880	-156
Fossil Hard coal	-3,446	54,869,903	0	0	0	0	18,496	21,188	-2,692
Fossil Oil	-2,867	26,515,458	0	0	0	0	12,438	9,453	2,985
Geothermal	-594	4,347,315	0	0	0	0	1,854	145	1,709
Hydro Pumped Storage	0	0	0	0	0	0	-174	0	-174
Hydro Run-of-river and poundage	-2,450	21,842,221	0	0	0	0	7,593	291	7,302
Hydro Water Reservoir	-7,911	77,282,546	0	0	0	0	26,955	2,318	24,637
Nuclear	-19,924	187,659,650	0	0	0	0	55,168	4,739	50,429
Solar	-2,733	27,253,587	7,154	95,387,555	0	0	9,613	545	9,068
Waste	-1,353	13,593,944	0	0	0	0	4,324	227	4,098
Wind Offshore	-465	4,953,402	1,734	17,336,909	0	0	2,653	248	2,406
Wind Onshore	-4,544	47,037,335	13,994	164,630,671	0	0	20,901	1,881	19,020
Sum	**-84,867**	**822,456,074**	**22,881**	**277,355,135**	**0**	**0**	**311,837**	**164,746**	**147,091**

Source: DISC modelling results.

Table 40: Crisis Dispatch Conditions with PPAs – Consumer Results

Consumer Type	Futures Cost [mln €]	PPAs Cost [mln €]	CfD Cost [mln €]	Wholesale Cost [mln €]	Total Cost [mln €]
Household	-26,633	0	0	138,235	111,601
Industry	-32,902	17,978	0	118,621	103,697
SME	-25,331	4,903	0	116,966	96,538
Sum	**-84,867**	**22,881**	**0**	**373,822**	**311,837**

Source: DISC modelling results.

Table 41: Crisis Dispatch Conditions with PPAs – Country Results

Country	Futures Cost [mln €]	PPAs Cost [mln €]
DE	90,050	50,162
FR	81,026	62,085
IT	78,531	7,076
ES	33,530	21,910
PL	28,700	5,857

Source: DISC modelling results.

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The proposed reform of the electricity market design maintains crucial elements of the existing system to ensure continued efficient operation. The impact that changing the rules on longer-term contracts will have on consumer prices and investment will depend on the concrete language of proposed legislation as well as its ultimate implementation. Overall, neither the expected mode of impact of individual reform elements, let alone their interaction, is clearly spelled out by the legislators.

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