MSc Program
Renewable Energy Systems

Analysis of the European Electricity Market Design reform and potential implications for market players

A Master's Thesis submitted for the degree of
"Master of Science"

supervised by
Dr. techn. Andreas Fleischhacker

Ramona Wendtner

01252641

Vienna, 22.07.2023

Affidavit

I, **RAMONA WENDTNER**, hereby declare

1. that I am the sole author of the present Master's Thesis, "ANALYSIS OF THE EUROPEAN ELECTRICITY MARKET DESIGN REFORM AND POTENTIAL IMPLICATIONS FOR MARKET PLAYERS", 65 pages, bound, and that I have not used any source or tool other than those referenced or any other illicit aid or tool, and
2. that I have not prior to this date submitted the topic of this Master's Thesis or parts of it in any form for assessment as an examination paper, either in Austria or abroad.

Vienna, 22.07.2023

Signature

Abstract

The volatile electricity during the energy crisis and the increasing share of renewable energy plants in Europe has led to increased concerns about functioning of the current electricity market design from member states and political institutions. Therefore, several member states have proposed concrete changes of the market design and increased the political pressure which subsequently led to the publication of legislative proposal on the electricity market design reform by the European Commission in March 2023. This thesis provides an overview of the member states proposals as well as the strengths and weaknesses of the mechanisms suggested in the legislative proposal. Additionally, the impact of the most relevant mechanisms on the business model of typical market players i.e., a utility company, wind generator and retail company are analyzed and compared with the likelihood of implementation. The results show that structural changes of the market design such as a deviation from the Merit Order logic and pay-as-clear pricing have a high impact on the revenue streams of market players depending on their generation portfolio. However, their implementation remains highly unlikely. On the contrary, the integration of additional mechanisms into the current market logic such as PPAs, CfDs and capacity mechanisms are highly likely to be implemented and have to some extent equally strong impacts on the business models of the market participants. Yet, the exact design of the mechanisms remains unclear since they first need to be agreed upon and implemented by member states. However, initial recommendations on the portfolio and business strategies are made for each market player. Finally, limitations of the study and shortcomings in the existing research are pointed out.

Table of Content

1 Introduction

The liberalization of the electricity market design in Europe lasted from 1996 to 2009 and has led to lower prices, improved service quality, and increased renewable energy production. However, it has also faced some challenges, such as ensuring security of supply, dealing with market power concentration, and promoting the integration of renewable energy technologies into the system.

In the context of the rising electricity prices in 2021, the Russian invasion of Ukraine in 2022 and the subsequent reductions in gas deliveries to the European Union leading to a further increase in gas and electricity prices, the European Commission called for structural reforms of the electricity market. The political pressure was primarily caused by high electricity prices for end-consumers while generators were able to generate high windfall profits from renewable generation due to the price settlement in the merit order. Additionally, the higher shares of renewable energy technologies have shown to be a challenge for the stability of the market.

In 2021 and 2022 several European member states already proposed electricity market design adaptions in the form of non-papers to address the aforementioned topics. In response to the call for action, the European Commission published a public consultation in February 2023 to allow key players to comment on the mechanism and reforms proposed by the Member States. In March 2023, the European Commission published a legislative proposal on the new Electricity Market Design.

Research has been conducted about the functioning of the current market design as well as the majority of mechanisms of the proposed market design reform. The research, however, offers limited insights on some of the mechanisms in the light of the proposed electricity market reform of the EU or on the implications for market players. This is mainly due to the actuality of the topic. The research question that is to guide the planning and conduct of this research project is:

What are the advantages and disadvantages of a proposed European Electricity Market reform as well as their implications for market players?

The current market design as well as the drivers of the call for it will be analyzed. Subsequently, insights will be given on the functioning of the mechanisms in the various market reform proposals and their impact on the electricity market as well as the consequent implications for typical market players: The advantages and disadvantages of the different mechanisms will be compared and subsequently its impact on three companies analyzed i.e., a utility company, a wind power generator, and an energy retail company. It draws conclusions based on the companies' business model and portfolio structure. The findings shall serve as a basis to further evaluate the legislative proposal on the new Electricity Market Design once implemented in the member states.

2 State of the Art

2.1 Historical Development of the European Electricity Market

European electricity markets were going through a phase of transition in the past years. The major drivers were the expansion of renewable energy systems (RES), overall changes in the technology mix and the stronger European market integration. The European Union implemented several policies and packages that were driving this transition (see Figure 1.).

The liberalization of the electricity market design in Europe started in 1996 with the adoption of the first European Energy Package with the attempt of opening the electricity market to competition, through the separation of electricity generation, transmission, and supply. This process was aimed at creating a more competitive and efficient electricity market, reducing costs, and improving service quality. In 2003, the Second Directive of European Energy Package was introducing legal unbundling. It allowed a single company to operate in only one of the activities of the electricity value chain i.e., generation, transmission, distribution, or supply. It also demanded that with the introduction of the Second Energy Package in 2007, all customers should be able choose their supplier leading to increased competition and the development of new services and products. In 2009, the EU introduced the so far last and Third Energy Package to promote the liberalization of the electricity market establishing a single market for electricity (European Commission, 2016).

The overall goal has been to generate societal benefits by allowing a market-based approach of the electricity market design and by doing so, to generate prices for consumers that reflect the economic cost of supplying electricity generation. Those benefits were meant to be realized by relying on competitive wholesale markets incentivizing efficient construction and operation of new and existing generation capacity and to shift the risks and costs to power providers and suppliers (Toskow, 2008).

The most recent reform in the form of the Third Energy Package brought about the most drastic changes in liberalizing the electricity market and establishing a single market for electricity. The wholesale market liberalization attempted to allow competition between electricity suppliers and to promote the development of new generation capacities, especially the development and deployment of RES by creating a supportive framework and implementing new incentives. To achieve this the following have been implemented (European Commission, 2016):

- Unbundling of energy suppliers from network operators
- Strengthening of the independence of regulators
- Establishment of the Agency for the Cooperation of Energy Regulators (ACER)
- Enhancement of cross-border cooperation between transmission system operators and the creation of European Networks for Transmission System Operators
- Strengthening of open and fair retail markets as well as consumer protection).

An evaluation conducted by the European Commission (2016) has shown that the Packages have led to an increase in competition and successfully removed major obstacles to cross-border competition in electricity markets. Overall, the position of end-consumers in energy markets have been strengthened. Research conducted shortly after the implementation supports this hypothesis showing that prices for end-consumers were lowered while simultaneously ensuring the security of energy supply (Ringel, 2003).

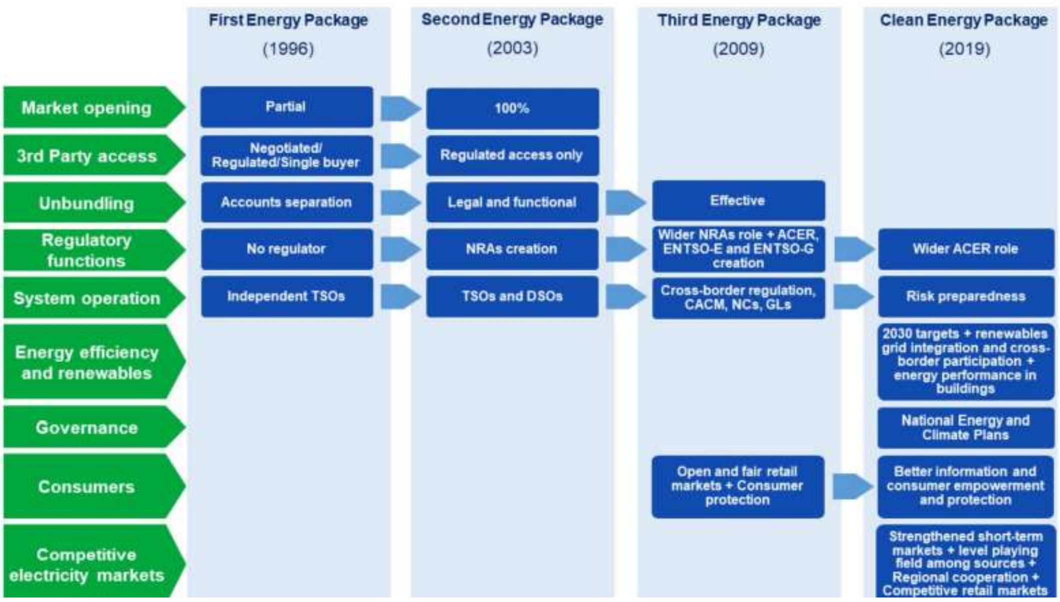

Figure 1: Overview of the EU Energy Legislation Packages and implemented measures. Source: ACER, 2022

2.2 Functioning of the European Electricity Market

The European electricity markets operate on several characteristics with the aim of ensuring an efficient electricity generation and consumption while delivering it to consumers at a reasonable price.

At the heart of the functioning of the European electricity market lies the market coupling. This mechanism connects the electricity markets of different countries allowing the efficient use of generation capacities across borders and reflecting similar prices in the various countries. It allows market participants to bid for the electricity on the various Energy Exchanges. The market coupling process is managed by independent market operators in each country, who coordinate their activities through the European Network of Transmission System Operators for Electricity (ENTSO-E) (European Energy Exchange, 2016).

The mechanism was first introduced in Central Western Europe (in Benelux, France, and Germany) at the European power exchange (EPEX) in 2010 and was extended to North-Western Europe in 2010 covering the area from Great Britain to France, Germany, and Austria as well as the Nordics and Baltics (European Energy Exchange, 2016).

Another key characteristic of the electricity system is that the energy only market (EOM) has been established. The basic principle of the EOM is that only the energy generated is remunerated i.e., generators are paid for the MWh generated, not for the capacity they secure. The price of electricity changes hourly based on factors like demand, weather, fuel, and CO2 costs. The selling and buying of electricity take place either on the wholesale market or in over the counter (OTC) trades which are bilateral commercial agreements. A central idea of the EOM is to determine consumers' actual willingness to pay for electricity instead of relying on administrative solutions.

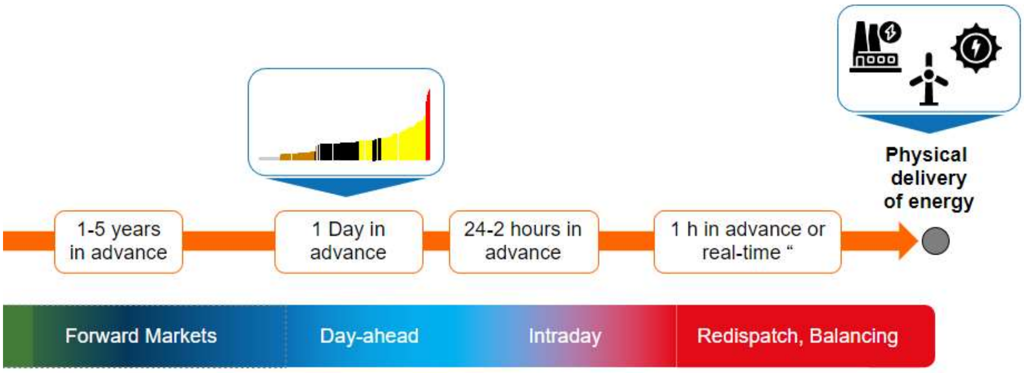

Figure 2: Overview of the EU Electricity markets and time horizon. Source: EWI, 2022

Figure 2. provides an overview of the wholesale markets' structure, including the redispatch and balancing mechanisms which are separate, out of the market mechanism to relieve possible overloads of the network. On the wholesale market one differentiates between forward markets where electricity is traded between one to four years before physical delivery, the day-ahead market where participants can buy and sell electricity in hourly blocks for the next 24 hours as well as the intra-day market which is a short-term market helping to ensure the balance between electricity supply and demand in real-time (Harris, 2013).

2.2.1 Balancing and Redispatch

Balancing and redispatch are mechanism for balancing the electricity system in real-time. If the actual electricity consumption or production deviates from the forecast, electricity producers or consumers can be asked to adjust their generation or consumption in order to rebalance the imbalances between scheduled and actual electricity deliveries. The rebalancing market is a crucial mechanism for maintaining grid stability i.e., ensuring that electricity supply matches demand. Here capacity mechanisms play a crucial role in securing the necessary capacities ensuring that there is sufficient capacity available to meet peak demand. Electricity producers are paid to ensure that they have the capacity to generate electricity when it is needed, or a strategic reserve, where electricity is held in reserve for emergency use (Harris, 2013).

2.2.2 Day-ahead and intraday markets

The Day-Ahead and Intraday Market are the two types of short-term electricity markets in Europe and are the markets with the highest liquidity. The closer the day of delivery, the more precise the required consumption and generation capacities can and must be predicted. For this reason, the short-term market consists of two markets with different lead times. The intra-day market operates on the day of delivery i.e., volumes can then be traded up to 30 minutes before delivery. On the day-ahead market participants trade electricity for the following day. The bidding takes places once per day specifying the quantity for the exact hour for the next day. The determination of the wholesale price i.e., market clearing price is based on the marginal pricing approach and is an important reference value for the electricity market (European Power Exchange, 2016).

2.2.2.1 Marginal Pricing

Marginal pricing is the pricing system on the short-term wholesale markets where the price of electricity is set by the marginal cost, i.e., the cost to produce an additional unit of electricity. The price is be determined by the cost of the marginal producer which is the cost of the last unit that is required to meet demand. This mechanism is called the Merit-Order Curve (see Figure 3.) In this process, power plant operators submit their bids on the basis of their marginal costs (equivalent to the price that generating one additional MWh costs). Starting with the power plant with the lowest marginal costs, power plants are allocated in ascending order of their marginal costs until the demand for electricity is met. Electricity from renewable energy sources such as hydro, wind and solar power have zero or low marginal costs, thus are settled first. The flow of the water in the river, the sun arrays and the blowing wind are free, thus the generation of an additional unit of electricity is equal to zero. A major part of the renewable's total costs consists in investment costs. The last power plant required to meet demand, also known as the marginal power plant, determines the wholesale electricity price and applies to all other power plants. Since demand can currently only rarely be met in full by renewable energies, thermal power plants (especially gas-fired power plants) are generally the price setters. Those conventional power plants have higher marginal costs due to the high fuel costs required to generate one additional unit of electricity e.g., coal, oil, or gas (Harris 2013, Hirth 2022).

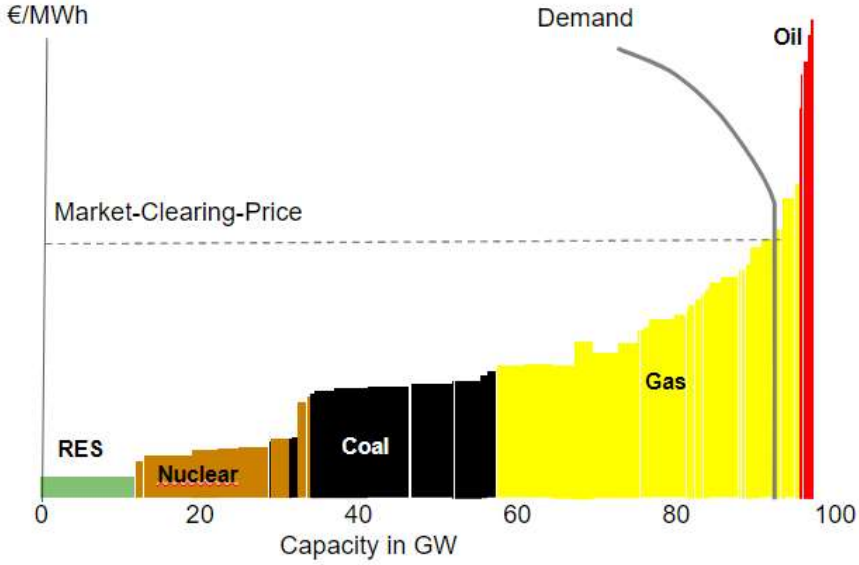

Figure 3: Marginal Cost of Electricity Generation in the Merit Order. Source: EWI Merit Order Tool

2.2.3 Forward markets

The forward markets encompass various long-term products to lock in their electricity price for a predetermined period. Those contract shield from volatile spot prices and provide more predictability in the market since trading on the forward market allows market players to anticipate more stable cash flows. Competitive and hence liquid forward electricity markets are essential allowing market participants to hedge their short-term price risks and uncertainties from the intraday market or OTC trades (Harris 2013, Hirth 2022).

2.3 Divers of a Market Design Reform

The Third Energy Package achieved their primary goals in creating a stable market-based approach. According to ACER, the current design of the wholesale electricity market effectively provides an efficient and secure electricity supply with benefits estimated to be approximately 34 billion Euros a year (ACER, 2022). However, recent developments have shown the shortcomings of the market design having a negative impact on the functioning of the markets and hindering the positive effects for market participants and end customers. Consequently, several political and non-political institutions have called for measures to improve retail competition and strengthen consumer protection (European Commission 2016).

2.3.1 High share of RES

The EU decarbonization targets for the energy industry and the subsequent commitment by market players to decarbonization has led to a significant increase in energy generated from renewable energy sources with operational implications for market and grid operators. The unique characteristics of RES i.e., their capital intensity, low to zero marginal cost, limited predictability, high volatility, and decentralized generation, make cost recovery and coordination with the grid more challenging. The current market design, however, is based on the dominant generation form of large-scale fossil fuel-based and centralized power plants. (European Commission, 2016). The rising share of RES, thus stipulate a challenge to the evolution of the market design. This encompasses the question on how to enable the recovery of fixed cost, how to develop sufficient system flexibility and how to align the time horizon of power system and market operations of RES. The overall target must be to maintain system stability as well as transmission and distribution network stability with a high RES share in the electricity mix (Roques et al., 2016).

2.3.2 Energy crisis

Energy price developments since 2021 have further illustrated the shortcomings of the current market design. The energy crisis started in 2021 and was essentially a gas price shock with drastic effects on electricity prices. The main drivers of the volatile prices have been a surge in global gas demand following the pandemic, sharply declining Russian gas supplies and related geopolitical uncertainties, Russia's invasion of Ukraine and also the design of the electricity market.

The related uncertainties such as whether gas storage facilities would be filled before winter, whether Russian gas flows would be curtailed, and whether LNG flows from overseas would be sufficient to meet demand in Europe, made it difficult for energy market participants in Europe to make informed decisions on trading gas and electricity. As a result, market participants were facing unusually high day-to-day price volatility of gas. This required market participants to pay more collateral[1] as financial institutions were concerned about their ability to manage increased price risks and fluctuations in the short term (see figure 4.).

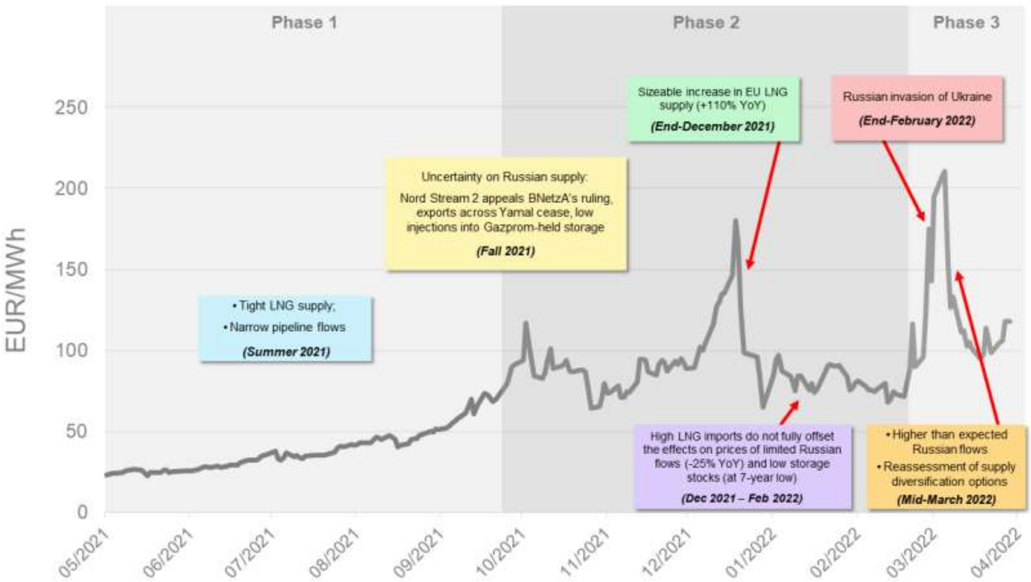

Figure 4: Overview of events and market fundamentals driving EU gas prices, TTF month-ahead contract (EUR/MWh), (May 2021 - April 2022). Source: ACER, 2022

With fossil fueled power plants as the price setting technology in the Merit Order logic, electricity prices were driven up by the increasing costs of gas-fired power generation plants (see Section 4.2.1). Other factors that contributed to the rise in electricity prices of renewable and nuclear energy included unfavorable wind conditions, maintenance on nuclear reactors, growing emission allowance prices under the ETS and a severe drought in Europe.

The high-risk environment had a negative impact on the liquidity of forward markets, with some traders facing difficulties in maintaining their financial positions. The situation worsened by Q1 2022, which made it challenging for companies to hedge their future price risks. The rising prices led to an increase in the required financial guarantees i.e., collaterals for trading, which priced out some counterparties and made

[1] Collateral refers to money set aside as a guarantee by the buyer and seller of forward products to cover the risk of counterparty failure.

others more risk averse. Some of the market participants were compelled to request support in the form of mitigation measures from public authorities. This ranged from reducing or backing up collaterals and waiving trading cancellation fees to be able to uphold energy trade and not file for bankruptcy (ACER, 2022).

Rapid action was required to ensure security of supply but also secure storage, diversification, and affordability of energy supply. Therefore, packages of emergency measures were quickly launched by the European Union in response to the high energy prices. In May 2022, REPowerEU plant was presented with the intention to reduce the EU's demand for Russian gas by two-thirds before the end of the year and make Europe significantly less dependent on fossil fuels by 2030. The plan calls for raising the renewable energy target from 40% to 45% and increasing the energy efficiency target from 9% to 13% (European Commission, 2023).

3 Methodological Approach

Given the recent developments i.e., the high volatility in energy prices and its implications for market participants and end customers, and on the basis of the RePowerEU plan, various political and non-political institutions including the EU and EU members states have called for measures to adapt the market design. In March 2023, the European Commission has proposed the legislation for a reform of the current Electricity Market reform with the overall target of reducing end-consumer prices (European Commission, 2023).

The study aims to understand the European Electricity Market Design reform by analyzing the functioning of the mechanisms in the various market reform proposals and in the final legislative proposal and to understand their impact on the electricity market as well as the consequent implications of an implementation for market players.

Therefore, the research question that is to guide the planning and conduct of this research project is:

What are the advantages and disadvantages of a proposed European Electricity Market reform as well as their implications for market players?

To answer this question several sub-questions must be considered:

What are the advantages and disadvantages of the mechanisms proposed by the Member States?

What is the likelihood of implementation and impact of the mechanism on the business model of typical market players?

The research methods for this thesis will consist in a literature review analyzing the proposed mechanisms from the Member States based on the existing literature in energy economics. Besides the energy economics literature, reports from regulators and political entities will be included. The first step is to conduct an overview of the proposed reform by members states and the EU, extract the mechanisms and analyze them accordingly.

Secondly, hypothetical implications of the proposed mechanisms for generic market players representing real world companies from the German or Austrian market will be made based on abductive reasoning. Abduction, unlike deduction or induction, does not involve verifying a theory by the formulation and testing of hypotheses. Additionally, it is not focused on building and justifying theory from analyzing empirical data through observations of singular events. Instead, abduction involves developing hypotheses by examining facts, thus generating hypotheses from inference that suggest new or existing theory development (Haig, 2005).

To this end, three for the electricity market representative market players i.e., utility company, wind power generator and energy retail company, will be chosen representing German or Austrian companies. In a next step, a contextual analysis based on the cases will be conducted i.e., the impact on their business model, position in the value chain, revenues stream and portfolio will be analyzed. Contextual analysis in case study research refers to the examination of the phenomenon being studied within its real-life context. The implicit hypothesis is that the evidence from those case studies is most likely to be valid for other companies with comparable organizational characteristics (Yin, 2017). To this end, the likelihood of implementation and monetary impact of each mechanism on the business model for the respective market players will be assessed to identify the strengths, weaknesses, opportunities, and threats and compared. By conducting this analysis, the thesis seeks to provide a comprehensive understanding of the potential impact of the mechanisms on the revenue stream of the respective market player and offer insights for how they need adapt their portfolio and business model to changing market conditions.

4 Analysis of the Electricity Market Design Reform

As a response to the high market prices and the presentation of the RePowerEU plan, several member states proposed their own market reform proposals over the course of the last year, with the aim of reducing high energy costs for household and industrial customers and increasing the resilience of the energy system. As a result of this political discussion process, the EU Commission announced to introduce an overall electricity market reform in 2023. The legislative proposal of the reform was presented by the EU Commission on March 15. The focus lies on reducing prices for end-consumers and strengthening the energy market through the targeted integration of renewable generation technologies (European Commission, 2023).

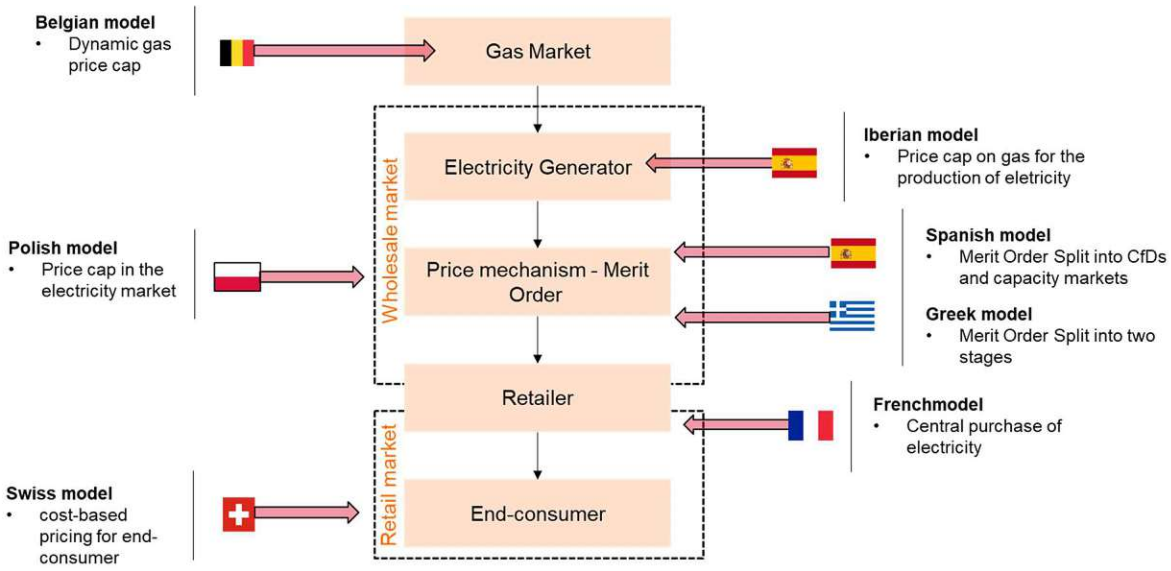

Figure 5: Overview of the proposed models and impact on the functioning of the market and market players.

4.1 Member states proposals

4.1.1 Iberian and Spanish model

In June 2022, Spain and Portugal introduced the “Iberian model” capping the gas and coal prices for electricity generation with a temporary duration of one year. The price cap started at 40 EUR/MWh for the first six months and increases by 5 EUR/MWh per month thereafter, reaching 70 EUR/MWh in the 12th month. The expected average electricity price under the price cap was 130 EUR/MWh. The estimated total cost of the price cap was 8.4 billion EUR, with Spain accounting for 6.3 billion EUR and Portugal 2.1 billion EUR. Congestion revenues and end-user charges were planned to finance the price cap.

The price cap led to lower marginal costs of peak load power plants i.e., gas and coal, and consequent reductions in wholesale electricity prices. However, the effectiveness of the price cap has been lower than anticipated. Lower electricity prices have led to increased electricity consumption, resulting in higher gas and coal consumption. This has further exacerbated the shortage of gas supply and contributed to rising gas and coal prices. Subsequently, higher subsidies were required to offset increased gas consumption and rising prices (Austrian Energy Agency, 2022).

In 2023, Spain suggested additional changes in the market design in the form of a non-paper (2022). It proposed a Merit Order split by introducing Contracts for Difference (CfDs) for inframarginal electricity generation, specifically for "uncontested" technologies such as renewable energy, nuclear, and hydropower, with fixed prices, duration, and quantity and capacity markets for the remaining technologies.

4.1.2 Greek model

The Greek government presented a model which targeted to split the Merit Order by categorizing the bids on the day-ahead markets. It differentiated between two asset categories i.e., available generation such as run of river hydro power, wind, solar PV as well as storage, nuclear and high-efficiency co-generation. These technologies are characterized with high capital expenditure (CAPEX) and low operating expenditure (OPEX) and were proposed to enter into contracts for difference and be marketed in the “first stage” of the day-ahead market. The electricity covered by these power plants would be subtracted from the load to determine the net-load, and a weighted average price would be calculated for the technologies in this first stage. The other technologies, the so called “dispatchable generation” such as fossil generation, pump/storage hydropower, demand response and storage, would bid in the second stage of the bidding process to solely serve the net-load. These power plants typically have low CAPEX and high OPEX. The end customer electricity price would be determined as the weighted average price of both stages (General Secretariat of the Council, 2022).

4.1.3 French model

The French proposal for the purchase of the entire wholesale electricity supply at the spot market through a dedicated "agency" was a comprehensive approach that encompassed both long-term capacity expansion and short-term energy procurement in the electricity market. Under this proposal, a specialized agency was to be created to oversee the entire procurement process and manage the auction-based capacity expansion for fossil-fueled power plants. The agency was meant to be responsible for conducting auctions for capacity contracts for fossil-fueled power plants and procuring the entire energy demand at the spot market. This involves purchasing electricity at the prevailing market prices to cover the energy demand. The proposal did not entail any changes in the function of the existing market model, such as the Merit-Order logic (L'organisation Des Marchés De L'électricité, 2022).

4.1.4 Polish model

Poland proposed a gas price cap on imported gas in the European Union as well as a deviation from the current pay as clear to a pay as bid model addressing the rising gas prices and their impact on the energy market. It was further proposed to introduce ex-ante bid evaluation assessing bids and ensuring that prices were justified and in line with market conditions. In addition, the proposal included an enhancement of the regulatory frameworks, thus promoting transparency in the gas market. Another important aspect of the proposal was the spot price cap. Offers that exceed the price cap but still clear the market should receive a pay-as-bid clearing price, while offers that fall below the threshold were supposed to be cleared at the price cap. Moreover, there was an ex-post redistribution of the market surplus foreseen i.e., capturing excess profits based on technology-specific reference prices. Additionally, a fund for liquidity assurance should be established to provide further support and stability to the gas market (European Parliament, 2022).

4.1.5 Belgian model

The Belgian model proposed an accelerated implementation of a European gas procurement platform as part of ongoing energy market reforms. It advocated for the immediate introduction of a dynamic gas price cap, with the maximum price calculated taking into consideration LNG prices outside of Europe. Additionally, the model aimed to develop and implement European rules by the end of 2022, allowing for the suspension of exchange trading in case of extraordinary events or irrational market behavior. Furthermore, the model proposed a reevaluation of the pay as clear price formation mechanism by winter 2023. These measures were seen as necessary steps towards ensuring a more efficient and transparent gas market in Belgium, with potential implications for the broader European energy market landscape (Non-paper: Gas Market Price Cap, 2022).

4.1.6 Swiss Model

Switzerland's electricity market and market price setting is identical to the EU's (i.e., Merit order logic and pay-as-cleared), and its active on the same markets (see section 2.2), however, its end consumer price setting is functioning differently. The Swiss have a partly liberalized electricity consumer market with the majority of end-consumers receiving a regulated price. This price is set yearly by the federal council and is an average of the generation cost i.e., CPAEX and OPEX of the electricity mix. The generator or retail company is also allowed to pass on the costs for purchasing electricity e.g., to outbalance the deficit of generation. Before the energy crisis, the general council attempted to adopt a strengthen the market liberalization. However, due to the price rally the government decided to delay but not abolish the attempted liberalization process (Axpo, 2023).

The Swiss model has been advocated for by several EU member states since the high price spikes last year. Although the impact of the energy crisis on the market prices cannot be dampened with this model. It simply reduces the prices for end-consumers and simultaneously increases the costs for the state.

4.2 Proposed mechanisms of the proposal on the European Electricity Market Reform

The European Commission's legislative proposal focuses on strengthening the energy market through the targeted integration of renewable generation technologies. This is particularly relevant since a large part of the EU emergency measures that have been adopted are gradually expiring. The basic mechanisms of the market, such as the merit order principle, will most likely continue to be upheld. Instead, the objective is to combine short-term energy markets providing signals for efficient generation with long-term contracts to attract investments (European Commission, 2023).

Before the reform proposals come into force, they must go through the ordinary legislative procedure. Provided that the European Parliament and the Council quickly agree on their respective positions, the current Swedish Council Presidency plans to conclude the interinstitutional negotiations by the end of June 2023. In this case, the revised electricity market design could be in force as early as fall or winter 2023 (European Commission, 2023). The dimensions among which changes have been debated and proposed are the following.

4.2.1 Merit Order and price setting

Uniformed auctioning in the Merit Order. The electricity price on the European wholesale markets is determined by the merit order principle (see Section 2.2.2.1). Starting with the power plant with the lowest marginal costs, power plants are allocated in ascending order of their marginal costs until the demand for electricity is met. The last power plant meeting the demand determines the wholesale electricity price for all power plants, irrespective if they are renewable or fossil based. Since demand can currently only on some occasions be fully met by renewable energies, conventional power plants such as gas and coal-fired power plants are generally the price setting technologies (ACER, 2022).

This system ensures that the market price for electricity accurately reflects the balance between supply and demand, incentivizes efficient generation and consumption, and sends price signals to generators and consumers. Uniformed auctioning is not exclusive to the electricity market but plays a role in many commodity markets (e.g., for copper, oil, natural gas, milk, solar panels, etc.). The Merit Order has been criticized in the light of the high energy crisis (see section 2.3.2) and has subsequently been evaluated: ACER (2022) suggested not to deviate from the merit order approach since it gives clear market signals to both producers and consumers, thus supports market-supporting behavior.

Splitting the Merit Order. Separating the auctioning process of the merit order has been proposed by Greece and Spain and supported by other member states such as Italy, France, and Cyprus in advance of the legislative proposal of the European Commission (see section 4.1.1 and 4.1.2). Separating the auctioning would mean to split the Merit Order into technologies with low and high marginal costs and low and high flexibility, respectively. It would mean to separate the price setting mechanism for renewable generation from conventional technologies. In the first segment of the market, generators from renewables and nuclear power can bid. This power generation is subject to high, CAPEX intensity, and low marginal prices. The second segment is open for are generation technologies whose operating costs are largely dependent on OPEX i.e., high marginal costs and high flexibilities such as goal and gas fired power plants. Another feature of a Merit Order split could be the introduction of CfDs to finance the technologies in the first segment as proposed by the Greek government (General Secretariat of the Council, 2022). The second segment would continue to operate according to the marginal cost principle of the merit order (see Figure 6.).

The impacts of such a two-stage market are manifold. A split would provide arbitrage opportunities due to the different price levels. However, it might also dilute price signals for the demand side since there are no dispatch signals for RES power plants, with and without CfDs. Maurer et a. (2022) even argue that the conventional technologies are also not receiving any dispatch signals since a divers set of technologies could be pooled together including fossil-based plants. This would no longer incentivize system-friendly behavior leading to overall higher costs and system-inefficiencies. Another challenge would be to operate market-based renewables. The RES technologies in the first segment would receive a price based on the highest awarded price from of renewable technologies only which does not remunerate the high CAPEX requirements of RES. It would make RES uncompetitive in comparison to conventional plants from the second segment. The introduction of CfDs in the first segment would have similar consequences for RES (see section 4.2.3). Concerning the impact on the demand side, end consumer prices would decrease due to taking an average of the two market clearing prices from the two segments. However, it would also diffuse the price signals for end consumers. This means that an average price will not allow consumers to see and react to the true value of a technology in a certain situation e.g., during shortages (Maurer et al., 2022).

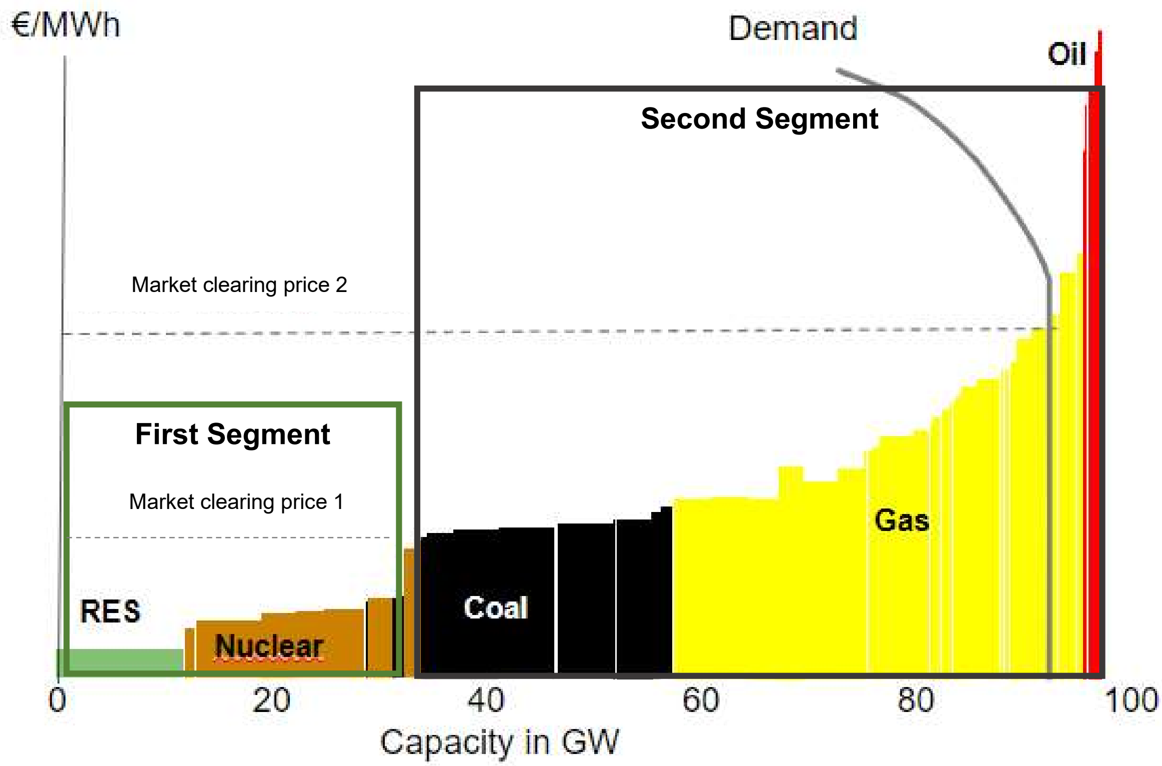

Figure 6: Functioning of a Merit Order split into two segments with two market clearing prices. Source: EWI, 2022.

Pay as cleared. The pay as cleared pricing mechanisms is the current pricing settlement approach in the merit order. The generation that is required to meet the respective demand is paid the market clearing price set by the marginal bidder, irrespective if their bidding price was lower than the clearing price. Bidders from both fossil and renewable generation are incentivized to bid their actual production costs instead of speculating on a certain strike price (ACER, 2022).

This pricing mechanism is particularly beneficial for technologies with high CAPEX and low OPEX i.e., RES, since the actual costs can be recovered with an additional margin by receiving a price that is higher than the marginal costs. By receiving a clearing price significantly above the marginal costs, the business case of RES can be made financially viable without state funding or other support instruments such as private investments. However, a further increase in RES systems in the market will drive down the clearing price, which has negative implications for RES developers i.e., the ability for RES to remain profitable on the wholesale market. On the other hand, it will drive down the costs for end-consumers.

Pay as bid. An alternative to the pay-as-clear model is the pay-as-bid or bid-price model. Here the awarded generators receive the explicitly bided prices. The final market price is obtained by averaging the price of all awarded bids. Figure 7. Illustrates the difference between the pay-as-bid and pay-as-cleared mechanism.

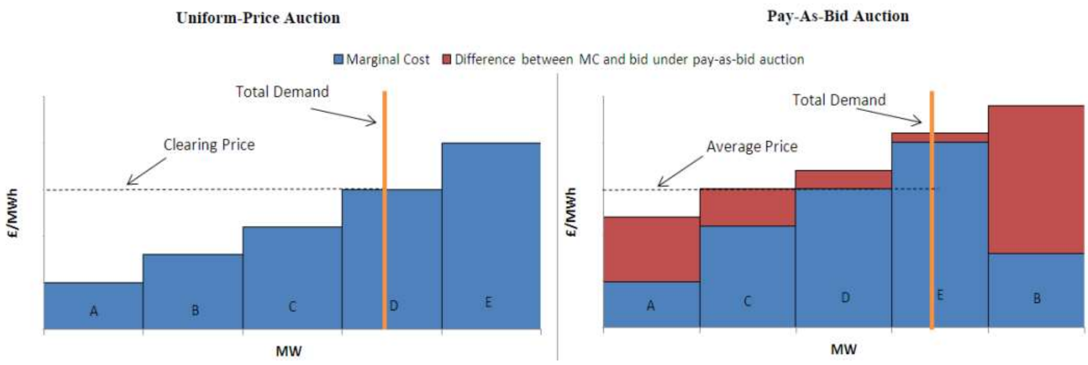

Figure 7: Comparison of pay-as-clear and pay-as-bid pricing mechanism. Source: Ofgem, 2006

ACER conducted an analysis (2022) to what extent the pay-as-big pricing mechanism could have prevented the electricity market price peaks in the last year during the energy crisis. In a pay-as-bid mechanism generators are incentivized to bid at a higher price than their marginal costs. This is because the bidders must include a contribution margin and a risk premium, into their bided price. The immediate consequence is greater market uncertainty due to the higher risks for all market participants. In the short and medium term, it is expected that retail prices would rise. In addition, RES generation does receive lower contribution margins which negatively affects the profitability of RES technologies.

However, further research has shown that a pay-as-bid auctioning has a positive impact on prices in the long term. Fabra et al. (2006) found that market prices eventually decrease due to more competitive behaviors by market participants in the pay as bid auction. The asymmetry between market participants can be reduced. The market is assumed to be more efficient since bidders reveal their valuation through their bids enabling the market to clear at the most competitive prices. This, however, is only realizing when demand is high. Concerning investment behavior, contrary to the common belief that lower prices weaken investment incentives, the study demonstrates that investment incentives may actually be stronger within a pay-as-bid auction format.

4.2.2 Price zones

Single price zone. A price or bidding zone is a geographical area in which market players can trade electricity at a uniformed price. Germany, for example, forms one price zone i.e., a market player in Bavaria can trade electricity with a wind park in Northern German. The assumption behind a single price zone is unlimited transmission capacity i.e., sufficient transmission capacity without any bottlenecks which is a prerequisite of an efficient single price zone. Only in such a perfect market environment the advantages of a single price zone can be realized. The advantages are increased liquidity, clear price signals and transparency for all market players (Hurta et al, 2022). However, single large bidding zones may have negative consequences on the market when network congestions are apparent. Congestions negatively affect redispatching costs, price signals, flexibility, the volume of cross-zonal capacities and cross-border competition.

Separation of price zones. An elevated level of congestions has been fueling the debate on splitting price zones, particularly with regard to the German zone. RES production has been growing significantly in the last years, especially in favorable locations with a lot of son hours and wind. This led to an increase in the occurrences and the magnitude of internal congestions due to limited internal transmission capacity. Consequently, RES had to be switched off (Hurta et al., 2022). For example: In Germany most of the wind capacity is located in Northern Germany while consumption is predominantly in Southern Germany and Austria. Moreover, conventional technologies such as nuclear plants are located in the Southern parts of Germany but have recently been switched off.

Overall, the bottlenecks and the localization problem could be counteracted by splitting the zone into multiple zones. By having several electricity prices, the regional investment incentives are shifted. Grimm et al. (2018) argue that the locational price signals triggered by a split further lead to a more efficient allocation of investments particularly in conventional and flexible generation. Decreased electricity transfer from e.g., North to South consequently reduces the need for network expansion, thus reduces costs and increases welfare in the long-term.

In the short-term it is expected that a price zone split leads to regional disparities i.e., price differences in the zones. For the case of Germany, it is expected that prices significantly increase in the short-term in a Southern German zone due to the decreased availability of renewable and fossil generation and lack of transmission capacities. Initially, due to the division, scarcity situations occur more frequently, where the power plants in the southern region are unable to meet the regional demand without imports. This would also lead to higher prices for end-consumers creating market entry barriers for new market players. However, this price pressure is argued to lead to a faster construction of RES as well as conventional technologies in the mid-term (Plancke et al., 2016). Conversely, in the North, prices would decrease due to regional overcapacity compared to a unified zone with RES being the price setting technology. The RES expansion in the North and suspended grid expansion to the South will most likely continue in a split leading to remaining price differences in the two zones even in the long-term. Overall, it is expected that prices in both zones remain slightly higher than in a joint zone due to the limited transfer capacities and smaller and less efficient markets (Fraunholz et al., 2021). From a political perspective, it can further be argued that splitting the price zones countervails the EU's target of an internal electricity market.

4.2.3 Incentives for investments in RES

Another focus area of the EU's proposal lies on long-term contracts such as Power Purchase Agreements and Contracts for Differences to create a dynamic market and incentivize investments into RES.

Power Purchase Agreements. The Commission envisages simplified and secured access to PPA as well as additional support by guaranteed schemes to reduce associated risks, and the possibility to combine PPAs with renewable support measures such as state subsidies (European Commission, 2023).

Power purchase agreements are bilateral electricity supply contracts between a generator and an offtaker. In this way, offtakers can purchase electricity directly or via a third-party at a pre-agreed price over pre-agreed terms for a limited amount of time. By promoting PPAs, the Commission follows a trend: In 2021, PPA contracts with a total volume of more than 17,5 GW were concluded throughout Europe to finance renewable energy plants and to hedge prices and electricity volumes (see Figure 5.) (ACER, 2022).

Even though the proposal does not foresee any specific PPAs structures, they differ in their design and pricing. In a physical PPA, the contractually fixed amount of electricity is sold and physically delivered. Differences in pricing are made between a fixed price and floating price PPA. A fixed-price PPA is a long-term contract between an electricity generator and a buyer in which the price per unit of electricity is predetermined and remains fixed throughout the duration of the agreement. This type of PPA provides price certainty and stability for both parties, shielding them from market price volatility and reducing financial risks associated with electricity price fluctuations. A variable-price PPA is a contractual arrangement in which the electricity price is linked to a specified index, such as wholesale electricity market prices, inflation rates, or a predetermined energy index. The price is adjusted periodically, allowing it to reflect market dynamics. This type of PPA exposes both the generator and the buyer to market price risks but also offers the potential for cost savings or increased revenue based on prevailing market conditions.

A sub form of a physical PPA form is the sleeved PPA which involves the participation of an intermediary, such as an energy retailer or marketer, who acts as a facilitator between the generator and the offtaker. The intermediary purchases electricity from the generator and sells it to the offtaker, providing risk management services and coordinating the transaction. As such sleeved PPAs help manage the administrative and contractual complexities of the agreement, offering additional flexibility and risk-mitigation smooth for both parties.

In comparison to a physical PPA, a financial or virtual PPA is a financial contract where the physical delivery of electricity is decoupled from the financial compensation. This means that a virtual PPA acts like a hedging product allowing the generator and the buyer to exchange the price risk associated with electricity trading. The PPA involves a financial settlement based on the difference between the agreed-upon price and the market price of electricity. The generator sells electricity to the grid at the market price, while the buyer receives the financial benefit or incurs the cost based on the price difference. Often the electricity of this PPA is traded on the market through a contract for difference. The mechanism is like a traditional CfD i.e., if the market price is above the agreed fixed price, the generator pays the difference to the company. If, on the other hand, the spot market price is below the agreed fixed price, the company pays the difference to the generator (Huneke et al., 2018).

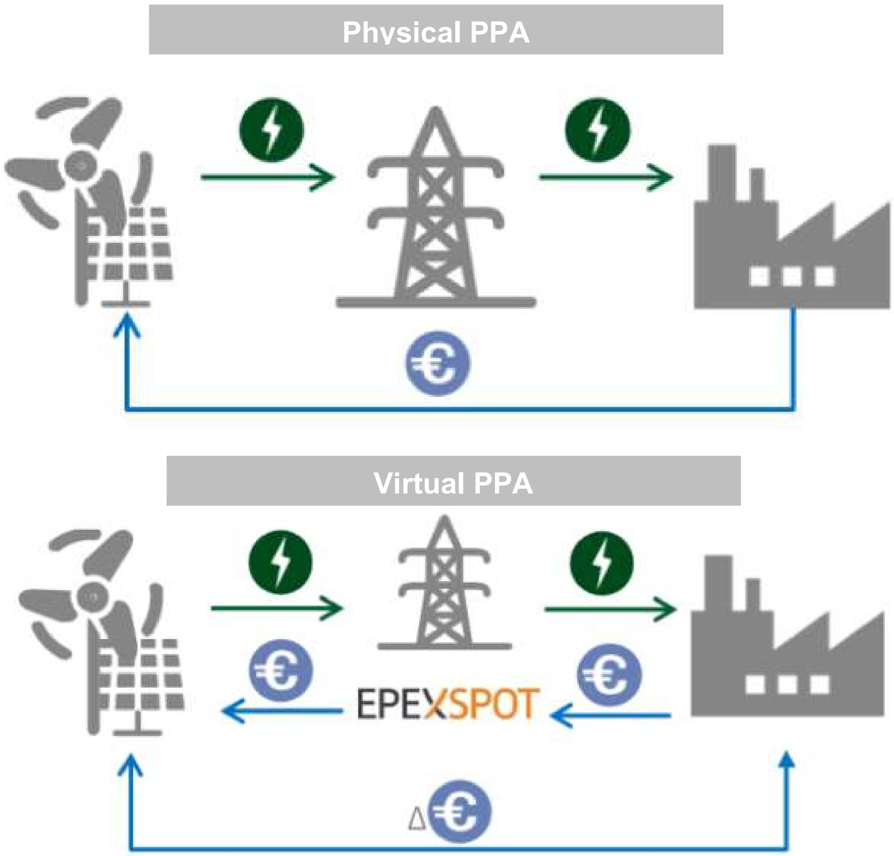

Figure 8: Functioning of a physical PPA in comparison to a virtual PPA, Source: EEX, 2016.

Concerning the volume within a PPA, one differentiates pay-as-produced and baseload PPAs. In a pay-as-produced PPA, the offtaker purchases the total amount or a fixed percentage of the electricity that is produced by the RES irrespective of its energy demand. Whereas in a baseload PPA, the off-taker purchases a predetermined amount of electricity generated from RES of generated electricity based on its electricity demand (Ghiassi-Farrokhfal et al., 2021).

PPAs as proposed by the European Commission represent a low-risk option for financing RES, thus opening secure revenue opportunities for energy producers beyond market premiums and marketing of electricity on short-term markets. The stable prices for electricity over a long-term period facilitate financing for renewable energy projects by making them more attractive to investors. The long-term price stability can reduce the risks associated with renewable energy investment, such as fluctuations in electricity market prices and provide a predictable revenue stream for investors. This can also provide certainty for electricity consumers, who can benefit from fixed electricity prices, avoiding exposure to volatile market prices. However, when introducing PPAs, it remains crucial that sufficient liquidity remains on the markets to avoid volatile market prices.

Associated risks of a PPA are the counterparty, profile, and price risk. The price risk occurs due to deviations of the market and the PPA price, e.g., when the spot price on the market is considerably lower than the PPA price for a long period of time. The profile risk is associated with the volatility of RES production i.e., when the RES system does not generate enough electricity for the offtaker. The counterparty risk is the risk of late or no-payment from the offtaker or bankruptcy and non-provision of energy from the producer (Ghiassi-Farrokhfal et al., 2021). The mitigation of the associated risk is dependent on the PPA structure. As a risk mitigation measure for the counterparty risk i.e., ensuring that the contractual obligations are met throughout the contract lifetime even in case of a counterparty default, market participants may hedge the risk through bank credits or state guarantees. Supporting state or bank guarantees can accelerate and facilitate the spread of PPAs by providing a portion of the guarantee and thus reducing the risk. Such guarantees should furthermore be non-discriminatory in nature. For example: Norway and Spain have already implemented such loan guarantee schemes (ACER, 2022).

PPAs can be complex and involve high transaction costs creating barriers to entry for small-scale renewable energy projects. This leads to PPA being typically available exclusively to large investors and within country borders. ACER (2022) already proposed to expand the PPA market to encourage investment in renewable generation and flexible resources. Small suppliers often have limited access to PPAs because they have difficulty demonstrating their economic sustainability over an extended period of time. By allowing small players to enter the market, e.g., by aggregating buyers or sellers into pools, project developers would be able to sell the energy from their projects more easily, as more potential buyers would be able to bid. On the other hand, smaller suppliers would benefit from the price predictability and hedging that PPAs offers.

Carbon Contracts for Difference. CfDs are bilateral agreements between two entities, usually between a government or governmental entity and an electricity generator, guaranteeing an energy producer a fixed amount of electricity for a fixed price independent of the wholesale market price. The Commission's proposal aims to secure support for new investments in new, repowered, expanded, or extended renewable facilities (including nuclear energy) in the form of two-sided CfDs. In a two-sided CfD both positive and negative deviations from a predetermined reference price, i.e., the strike price, are paid to the contracting party (see Figure 9.). In addition, a redistribution of excess revenues to end consumers is planned to be implemented as a substitute for the emergency measure of the revenue cap. The design of the CfD that will be implemented remains unclear i.e., particularly in terms of CfD quota requirements and the technologies covered (European Commission, 2023).

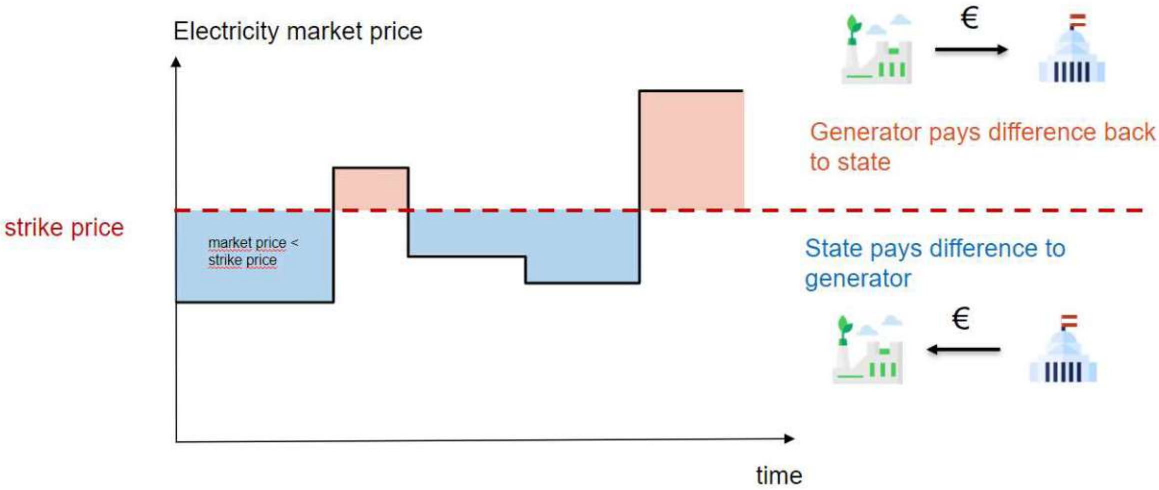

Figure 9: Overview of the functioning of a two-sided CfD with a fixed strike price.

There are different perspectives on the advantages and disadvantages of CfDs. From the perspective of consumers, CfDs can provide short-term relief during rising market prices as excess revenues shall be captured and redistributed, thus having a dampening effect on electricity prices for end consumers. From the perspective of electricity generators, CfDs can provide stable revenues as they guarantee a fixed price, which enhances planning certainty and attracts investors. De-risking the investments in RES allows a risk transfer, thus allowing smaller companies with less financial strength to participate in auctions due to the improved predictability of future revenue streams. It further reduces the prices for end consumers overall (Newbery, 2023; Hirth, 2023). In general, two-sided CfD or a market premium model are considered to be market friendly solutions since generators receive a minimum price but can also benefit from high market prices to a certain extent. For instance, the Austrian market premium model allows generators to retain a part of the surplus from high market prices that exceed the strike price.

The drawbacks of CfDs are similar as outlined for PPAs. The introduction of those mechanisms must simultaneously ensure the efficient short-term electricity markets functioning and should not negatively impact its liquidity. A major disadvantage from the system perspective side is that the decoupling of compensation from the electricity market may reduce the incentive for generators to dispatch energy during times of high demand and soaring prices. This could hinder the flexibility and resilience of the energy system, as generators may not have the incentive to adjust their generation technologies to respond to fluctuations and further drive price volatility (Newbery, 2023).

Another possibility to improve the design of CfDs are different contractual designs for each technology depending on their production profile and flexibility to short-term price signals. Technologies with high production flexibilities e.g., hydropower and storage systems should be used only when less flexible technologies such as wind and PV are not generating sufficient electricity. Fabra (2022) and Hirth (2023) argue that setting a different reference price for hydropower can ensure that the production of electricity at peak times can be penalized compared to production at off-peak times. This would indeed allow a more efficient behavior on short-term markets and, providing that sufficient players participate at the auctions, a fair rate of return. Additionally, the determination of a strike price for existing RES is highly debated. This because a low strike price might be regarded as an undervaluation of even expropriation of assets whereas a high strike price or a strike price similar to the one of new RES would impose high prices on end consumers.

4.2.4 Remuneration of flexibility options

The Commission proposes that member states assess the flexibility needs of the electricity system at regular intervals in the future and define national targets for demand side response (DSR) and storage. According to the legislative proposal, capacity mechanisms should be designed and adapted in a way that favours renewable DSR measures and storage solutions. The concrete design is left to the member states. As a result, significantly different capacity mechanisms and markets have already been established in some countries (European Commission, 2023). However, the significance and impact of the revised electricity market design on existing and new capacity mechanisms are to some extent unclear.

For the stability of the system and security of supply, not only the energy produced but also the supply of generation capacity is of vital importance in an energy system with a high renewable share. To drive the expansion of renewables and ensure their integration into the power grid, the energy system will depend on flexibility since more stability leads to stable prices and the integration of more renewables into the system. Several designs of mechanisms to support flexibilities and remunerate the installed capacity have been discussed in the academic literature and have been partly implemented in member states. The literature shows that capacity mechanisms can improve generation adequacy but also pose new challenges i.e., make markets more predictable, can ensure electricity supply at the low cost for end consumers, support security of supply, outbalance problems from market fluctuations and allow generators to reduce dependency on peaking price levels. The optimal market design, however, depends on numerous factors since they can also cause market distortions (Bublitz et al., 2019).

The European Commission distinguished between volume and price-based mechanisms. While in the former a specific capacity covering the prospected demand is set and the price is set by the market, the latter remunerates additional capacity by setting a target price.

Energy-only-market approach. Currently the additional capacity is remunerated implicitly through the EOM. In this case not the installed capacity is remunerated, instead the additional flexible generation is compensated by high market prices for peak load generation on the spot market. Hirth and Ueckerdt (2014) argue that the problem solely arises from unevenly distributed capacity and could be resolved within the EOM market by resolving grid congestions, thus attracting investments and locational price signals reflecting the regional scarcity in market prices. This is particularly prevalent in countries where RES generation is not distributed evenly, e.g., South-West Germany and Northern Bavaria the regional capacity is scarce. This is because the availability of coal and wind favour investments in generation in those areas (see section on Price zones). They argue that by solely focusing on capacity mechanisms, the locational constraints could be difficult to resolve. In a perfect market environment with rational expectation and risk-averse market players, the energy only market can secure the long-term investments into additional capacity without additional support mechanisms.

Another price-based mechanism to remunerate flexibilities is the integration of a flexibility segment in the EOM market with a market-based price setting. The price is set by the market only for eligible capacity based on estimates of the required capacity, similar to the balancing market. This mechanism provides market-based incentives for new, efficient generation plants and de-risks new investments. Moreover, certain technologies can be supported in a market-based approach, i.e., highly efficient or renewable capacity can be awarded while others e.g., inefficient fossil plants will not be awarded. However, this perfect market environment is often not prevalent. Incomplete Information and high transaction costs often dampen the willingness to pay for additional capacity (Bublitz et al, 2019).

Explicit capacity payments represent another price-based mechanism. A capacity price is a prior set price based on estimations of the required capacity to meet demand and distributed to all capacity providers in the market. Capacity payments provide a stable and secure financial incentive for power plant operators to invest in new generation. By receiving additional revenue beyond the electricity market prices, generators are encouraged to build and maintain adequate capacity to meet future electricity demand. Capacity payments might further contribute to greater price stability in the electricity market. During periods of low capacity and high demand, capacity payments help avoid extreme price spikes, which can occur when supply is scarce. However, research suggests that capacity payments for base-load power plants might not be the optimal solution since these payments can cause prices to decline and suppress competition in the short-term. This is particularly prevalent in markets with only a few participants (Bublitz, 2019). Auer and Haas (2016) go a step further and claim that the introduction of capacity payments undermines market competition. They suggest that relying solely on capacity payments hinders the development and utilization of flexibility options, leaving their deployment solely in the hands of regulatory authorities.

Strategic reserve. Capacity reserve or strategic reserve is a volume-based mechanism and defines an amount of conventional or renewable capacity that is kept available by the system operator solely for generating electricity to meet peak demand in exchange for capacity payments. Capacity is remunerated at a fixed rate independent of the energy produced. Research shows that a strategic reserve does incentivise new investments and serves as a mechanism to ensure system stability i.e., to manage capacity shortages and mitigate investment cycles in the short term. However, it also increases the potential for exercising market power as withholding capacity becomes more feasible, leading to the activation of the reserve and consequently high market prices (Bublitz, 2019).

It is recommended to use a strategic reserve as a short-term solution and replace it with other mechanisms. However, the distributional effects of a strategic reserve appear to be relatively small. Neuhoff et al. (2016) propose that a coordinated strategic reserve in Europe could be the most advantageous solution. During peak demand, capacities from neighbouring countries can be utilized, thereby increasing the system's resilience. Secondly, by jointly determining the required volume of the reserve, the required quantity can be reduced as individual demand peaks is distributed differently in the different member states. Moreover, with the potential expansion of cross-border capacity and its considerable influence on prices, a coordinated approach becomes more attractive.

Austria, for example, implemented the grid reserve. The Austrian goal of 100% renewable electricity in 2030 requires sufficient balancing and controlling capacities to balance the supply fluctuations of volatile renewables. The regulations in the grid reserve ensure that the required capacities remain available solely for peak demand that cannot be met with renewable technologies. The transmission system operator Austrian Power Grid (APG) is responsible for its implementation. On the basis of decommissioning notifications from operators, the power required for the grid reserve is calculated in a system analysis. The demand determined in this way is put out to tender, with aggregators and European operators being allowed to bid in addition to domestic power plants. However, generation plants may only be subsidized if their emissions do not exceed 550 g of CO2 per kWh of electricity and do not generate radioactive waste (Austrian Power Grid, 2023).

Concerning the integration of RES in capacity mechanisms, some countries, e.g., South American states, France, and the UK integrated RES into their capacity mechanism by introduced long-term capacity contracts for renewables. However, it can be argued that installed capacity of RES should be integrated into a capacity mechanism only to the extent to which it can contribute to system adequacy. One way to calculate the contribution is to remunerate the system based on their actual production capacity i.e., if a solar PV produces on average 15% of their capacity their remuneration should be limited to 15% (Kozlova and Overland, 2022). However, the fluctuating generation profile of RES makes predictions complex, thus more sophisticated approaches are required to truthfully predict the production profile of RES in capacity markets. Concerning the integration of demand side response and flexibility options, the introduction of capacity payments might dampen competition making flexibility solutions redundant. This would consequently require regulators to develop non-market based financial support schemes to incentivise their development (Bublitz, 2019).

In summary, market-wide capacity payments have the potential to reduce investment cycles, stabilize market prices, and ensure a reasonable reserve margin. However, the optimal design and implementation of capacity payment mechanisms depend on factors such as the type of power plants involved, market competition intensity, and the presence of market power. It is crucial to carefully consider these factors to achieve the desired outcomes in terms of market efficiency and reliability.

4.2.5 Price adaptations based on marginal costs

The Commission's proposal further encompasses the revision of the Regulation on Wholesale Energy Market Integrity and Transparency (REMIT) which is intended to prevent insider trading and price manipulation. The Commission foresees to award ACER more responsibilities and increase transparency (Europeans Commission, 2023). As part of this revision, a reform of end consumer pricing is currently discussed i.e., a shift from the current market price-based price setting to a cost-based price setting approach for end consumers similar to the Swiss market approach. The debate is further fuelled by high market revenues generated by electricity producers with a strong market position during the price spikes last year. Particularly RES generators were able to realise additional revenues since end consumer prices were adapted reflecting market prices that were by far exceeding the marginal costs of renewable electricity production.

In a market price-based approach, the end consumer pays the price per kWh electricity as reflected on the short-term markets. Consumer prices can be increased or decreased in case of changes of the market prices. In comparison, in a cost-based approach, end consumer prices reflect the actual levelized cost of electricity i.e., the cost of generating electricity from a specific technology over a given lifetime. However, the cost of generation can also encompass the market price since some energy providers are purely buying and re-selling the electricity from the market or outbalance their electricity generation with purchases from the wholesale markets. This is the case in the Swiss model (Axpo, 2023).

The introduction of a marginal-price based approach would result in lower energy prices for end-consumers given a high share of low-marginal cost technologies (i.e., RES) in the market and operated by energy providers. If not, sufficient renewable technologies are available throughout the whole day, i.e., not solely during peak production, the prices for end-consumers even in a marginal price approach would not change. This is because a marginal cost pricing approach for end-consumers does not impact the pricing mechanism on the wholesale market. This means that the Merit Order logic and pay-as-clear remain the predominant mechanisms. Hence, an introduction of a price adaptation for end-consumers does not have an impact on the market prices. In addition, the de-liberalisation, hence reregulation of the prices, the benefits of a liberalised electricity market approach such as free choice of supplier, efficiency increases, and market-based prices disappear (Momentum Institute, 2022).

From a system perspective, the cost-based approach makes a market entry less attractive since it reduces competition and potentially leads to unbundling of integrated companies, e.g., Stadtwerke. A counteracting possible positive effect on the intensity of competition could result from the increased prevalence of fixed-term contracts and early cancellations, thus households would have to deal with their supply contract on a regular basis and compare offers. Overall, transparency could be lowered since the different developments of the procurement costs of the individual market participants (differences in the generation portfolio, seasonal fluctuations in generation, different procurement strategies or purchase times) and the price changes between the market participants and the individual sub-customer groups, would highly differentiate in terms of timing and amount. In addition, if individual costs rather than objectifiable market prices are the decisive factor for price changes, the verifiability of these cost developments would be a major challenge, i.e. which costs to be used (change in variable costs, full costs, allocation of costs in portfolio procurement, etc.), for which period, which "threshold values" exist for inducing a price increase, and also how and by whom these cost developments should be verified.

4.3 Impact assessment of proposed mechanisms on market players

The impact of the proposed mechanisms on the business models of the European market players have not been thoroughly studies, thus remain unclear. This is because of the novelty of some mechanism as well as the only partial implementation. To fill this knowledge gap, the potential impact on the business model of typical market players will be analyzed i.e., a utility company, a wind power generator, and an energy retail company.

Likelihood of implementation. The legislative proposal, recent discussion in the European Commission as well as in the European Council of Ministers and further developments in Europe strongly indicate which mechanisms are most likely to be implemented and which mechanisms are still subject to further discussion.

The mechanisms that are agreed upon by the majority of member states are the uniformed Merit Order principle as well as pay-as-cleared pricing mechanism. The legislative proposal opposes an intervention in the current pricing mechanisms which is in line with the recommendations set forth by ACER (2022). This renders the introduction of a split of the Merit Order or a pay-as-bid mechanism as unlikely. In addition, stronger mechanisms to incentivize investments into RES in the form of PPAs and CfDs has been asked for by several member states and will most likely be implemented. A deviation from the implicit remuneration of flexibilities in the form of implicit capacity payments is also most likely to be implemented since the discussion on the introduction of capacity remuneration has been ongoing for several years. Various theoretical and practical approaches to integrate flexible generation capacity to balance RES have already been analyzed and implemented by some member states (Bublitz, 2019). Explicit payments in the energy only market and capacity reserves are among the most debated mechanisms, thus having the highest likelihood of implementation. The introduction of explicit capacity payments is highly unlikely, this will not be considered in the analysis. Furthermore, the high electricity prices for consumers during the energy crisis has fuelled the discussion on a deviation from the current price-setting approach of end consumer prices. The Swiss pricing approach has been highly debated to be implemented in the whole EU. Moreover, the commercial court of Vienna rendered the end consumer price adjustments to the market prices of the European Energy Exchange from the energy company Verbund GmbH as impermissible. This was because the price increase for end consumers were not in relation to the costs of electricity generation (Der Standard, 2023). The verdict is one of the first and shows the high likelihood of a deviation towards a cost-based price approach for end consumers. Concerning the implementation of new price zones or maintaining the status quo, the outlook is not as clear. This is particularly prevalent in the case of Germany and Austria. While some member states and experts argue that a price zone split would be beneficial, others argue that it countervails the EU's target of an internal electricity market.

4.3.1 Example of a utility company

The portfolio structure of a utility is renewable and fossil-based, generating electricity and heat covering the entire value chain of energy generation and supply, including production, wholesale, and retail of energy. Revenues are generated from the sale of electricity and heat both on the wholesale and end-customer markets. Their business model is based on economies of scale, diversification, and risk minimization through the development of different markets and customer segments. In the current market system, gas-fired power plants, including CHP plants, are the price-setting technology on the Austrian electricity exchange.

Additional revenues are generated from the production and supply of renewable electricity to end customers, provided that the cost of electricity is below the end customer price. As a fully integrated company, utilities are active on the wholesale market to outbalance the balance sheet. Production surpluses and deficits must be bought or sold on the wholesale markets. If the retail price is lower than the wholesale price, opportunity costs arise.

Impact on business model. Based on the analysis conducted above, given that a utility is present across the whole value chain, all the proposed mechanisms do have a monetary impact on the business model of such a company structure. It will further be assumed that the market design and all other elements of the market remain constant. Moreover, assuming that the portfolio of utilities is still dominated by conventional plans, the proposed measures that are directly or indirectly targeting the conventional technologies (e.g., CHP) as well as mechanisms that are directly affecting the functioning of the market and its prices are most likely to have the highest impact on the business model and revenue streams. These are instruments to remunerate flexibilities, changes of the pricing and bidding mechanism as well as cost-based pricing for end consumers.

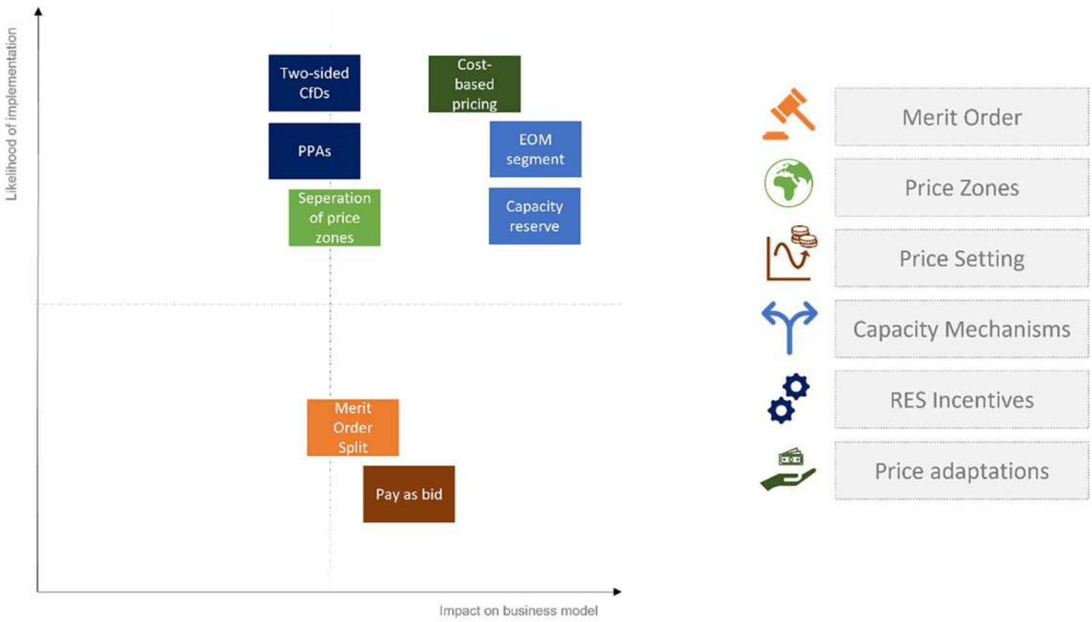

Figure 10: Matrix of likelihood of implementation and impact on the business model of a utility company for the proposed mechanisms.

In case of a deviation from the pay-as-clear to a **pay-as-bid pricing** approach, the competition in the market would increase since generators would have to bid strategically. Generators are more likely to bid prices above their marginal costs by integrating a risk margin. This would distort the market prices and lead to lower margins for conventional plants, particularly peak-load plants. The price volatility in the electricity market would further require a utility to implement effective risk management strategies to mitigate potential financial risks which consequently increases their costs.

On the other hand, revenues from renewable technologies would decrease only marginally. Since generators bid strategically, i.e., above their marginal costs, they would bid a price that is slightly below the price of the last plant that meets the demand. The margin of RES would consequently still be comparatively high.

Concerning the revenues on the end-consumer market, the greater market uncertainties due to the higher risks for all market participants is expected to lead to a rise in end-customer prices in the short and medium term. Hence, the higher risks and associated costs are offset by potentially higher revenues from end-consumers.

A utility company would be required to enhance its operational flexibility by adapting to the changing dispatch order and bid-based pricing. This could involve optimizing generation schedules and incorporating more flexible technologies into the generation mix. Moreover, strategic bidding and accurate forecasting become crucial to secure margins and maintain a strong market presence. This adaptability of operations and strategies as well as managing price volatility will impact on the utility company's financial performance.

An introduction of **marginal cost-based pricing** has a high impact on the business model of utilities. Besides allowing price adaptations based on changes of cost, retail tariffs might also be set based on electricity procurement costs. Specifically, the latter raises fundamental questions concerning utility's structure and role.

This mechanism is solely affecting the end-consumer prices while wholesale market prices remain unaffected, thus also the revenues generated on them. Assuming the merit order logic, however, the price on the wholesale market is higher than the average generation cost. If utilities and other energy companies that are providing energy to end-consumers, must set a retail price at the generation cost, their revenues will decline and potentially rendering their technologies as uneconomical. Specifically, market-based RES would be at elevated risk to become uneconomical, especially if the CAPEX cannot be considered and passed on to end-consumers. This would need to be offset by subsidies, specifically utilities with predominantly thermal generation (especially CHP plants) since they have higher procurement costs than the average.

Moreover, both generation and distribution of electricity might become a competitive disadvantage. Austrian or German utility companies have so far either sold their energy on the cross-border wholesale market or they have sold their produced electricity to a retail company within the group structure at market prices and supplied end customers directly via this retailer. if they want to supply their end customers directly with this energy. Any surplus of deficit in electricity generation required to meet end customers demand or that cannot or should not be covered by intragroup generation because in-house generation is more expensive than electricity on the market, is purchased on the wholesale market. This would no longer be possible in a marginal cost-based pricing system. Electricity generated within the group would have to be valued at the cost of electricity generation and passed on to end customers. It might result in divestment of retail since a cost-based pricing for end-consumers generates lower margin opportunities than trading on a wholesale market. However, for a utility this might not be feasible since they are majority-owned by the public sector.

The diversity of players in the energy sector is likely to be significantly reduced and competition in the end-customer market would effectively end. This would eliminate the retail business as an additional revenue source for new RES. From the point of view of the administrability and efficiency of such a system, a significant increase in the overall costs would be expected.

The deviation from implicit capacity payments is uncontroversial. The design of the future remuneration of flexibilities is, however, highly debated with explicit payments in the energy only market and capacity reserves being at the centre of discussion. Since the former is a price-based mechanism and the latter a quantity-based mechanism, the quantitative implications for the business model of a utility company differ.

The introduction of **explicit EOM segment** can have a positive impact on the revenue of a utility since a conventional plant can be marketed both on the balancing market and, if not awarded, can also offer the electricity on the spot market. Since the market are witnessing an increasing share of renewable energy sources with conventional plants potentially exiting the market, explicit capacity payments serve as a vital revenue source and financing opportunity. This allows for the development of renewable capacity or highly efficient co-generation, which can receive additional mark-up due to their high efficiencies and would be awarded as one of the first in the market. However, on the downside, the implementation of explicit capacity section in the EOM can negatively affect the business models of utilities if liquidity in the market is insufficient leading to increased volatility, thus a lack of a stable and predictable market environment. Furthermore, the absence of sufficiently high prices hinders the feasibility of investing in new capacity, hindering planning certainty. To address this issue, certain state interventions may be required to meet resource adequacy.

With a separate market for capacity, the utility would need to ensure resource adequacy by assessing the balance between supply and demand. The portfolio composition may prioritize maintaining a diverse mix of generation assets capable of meeting the capacity market obligations and customer demand. Engaging in the capacity market would require the utility to adopt robust risk management strategies. This includes ensuring that the capacity contracts align with the company's operational capabilities and financial objectives. The utility may also need to consider hedging strategies to mitigate risks associated with fluctuations in capacity prices. The capacity market may incentivize the utility to explore demand response instruments and flexible load management strategies. By actively managing demand and providing capacity when needed, the utility can optimize its revenue potential in the capacity market. This may involve collaborating with commercial and industrial customers to adjust their electricity usage during peak periods.

Concerning the implementation of a **strategic reserve**, it allows for a stable stream of revenue irrespective of the efficiency and age of the conventional plant. By guaranteeing fixed payments for new capacity, the strategic reserve provides, if sufficiently high enough, a level of certainty to investors, making investments in conventional generation potentially more attractive. Those payments received for providing backup capacity constitute an additional revenue stream. However, this is only the case if the total remuneration of the capacity is as high or higher than the electricity price on the market over the period where the plant would otherwise be marketed.

If the prices set for the strategic reserve act as a price cap, it can hinder investment in additional generation capacity. This can limit the incentives for new entrants to invest in the market and potentially impacting resource adequacy in the long run. It further lowers the revenue potentials since participants in the reserve can solely rely on revenues from the strategic reserve and cannot participate in the EOM. Furthermore, the introduction of a strategic reserve increases the complexity of market design, leading to higher transaction costs. Another drawback of the strategic reserve is the risk of incorrect price setting. Moreover, the strategic reserve does not directly address market price volatility, as it is focused on ensuring backup capacity rather than stabilizing prices.

The utility company may need to adjust its portfolio to accommodate the strategic reserve requirements. This could involve ensuring a certain portion of the portfolio consisting of suitable capacity (e.g., flexible conventional generation or energy storage assets). The company may also consider investing in renewable energy sources (RES) that can participate in the strategic reserve to diversify its portfolio which is particularly interesting with a rising share of RES. Hence, participating in the capacity market may require adjustments in operational strategies and contractual arrangements.

	Revenue from wholesale market	Revenue from retail	Associated costs	Implications for portfolio and business model
Pay-as-bid	⊖ RES Conventional	⊕ RES and conventional	⊖ risk mitigation measures	• Stronger focus on baseload plants and increased flexibility required
Marginal cost based pricing	⊖ RES and conventional	○ RES and conventional	⊖ Administrability costs	• Separation of generation and retail business
Explicit remuneration in EOM	⊕ Conventional	○ Conventional	⊖ transaction costs and risk mitigation	• Expansion of risk management • Priorisation of flexibilities and demand response
Strategic Reserve	⊖ Conventional	○ Conventional	⊖ transaction costs	• Diversification of capacity portfolio e.g. increased flexibility, storage or renewable capacity

negative impact ⊖ ⊖ ○ ⊕ ⊕ positive impact

Figure 11: Assessment of the impact of the mechanisms on the revenue streams of a utility company and associated costs and implications for the portfolio and business model

4.3.2 Example of a wind power generator

A renewable electricity generator produces electricity from various RES energy sources, in this case from on and offshore wind, and sells it on wholesale markets. Revenues result from the sale of generated electricity on the wholesale market or directly to retailers or traders i.e., over the-counter (OTC). The economic incentive of a generator is to generate a margin from the difference between its production costs and the wholesale market price level. Different technologies have different cost structures. In the case of renewable generation capacities such wind power plants, the costs are determined by investment costs.

The tasks of a generator consist in the optimization of its portfolio, project development of new plants, as well as maintenance of existing plants. Since renewable, low-emission technologies, especially in low-price phases, cannot generate their total costs of generation, but are nevertheless desired by society and politics, they are partly supported by government subsidies. In addition to the wholesale market, government subsidies thus also represent a second important source of income for producers. The investment decision to build renewable generation capacity results from the difference between the cost of generation and the expected revenue.

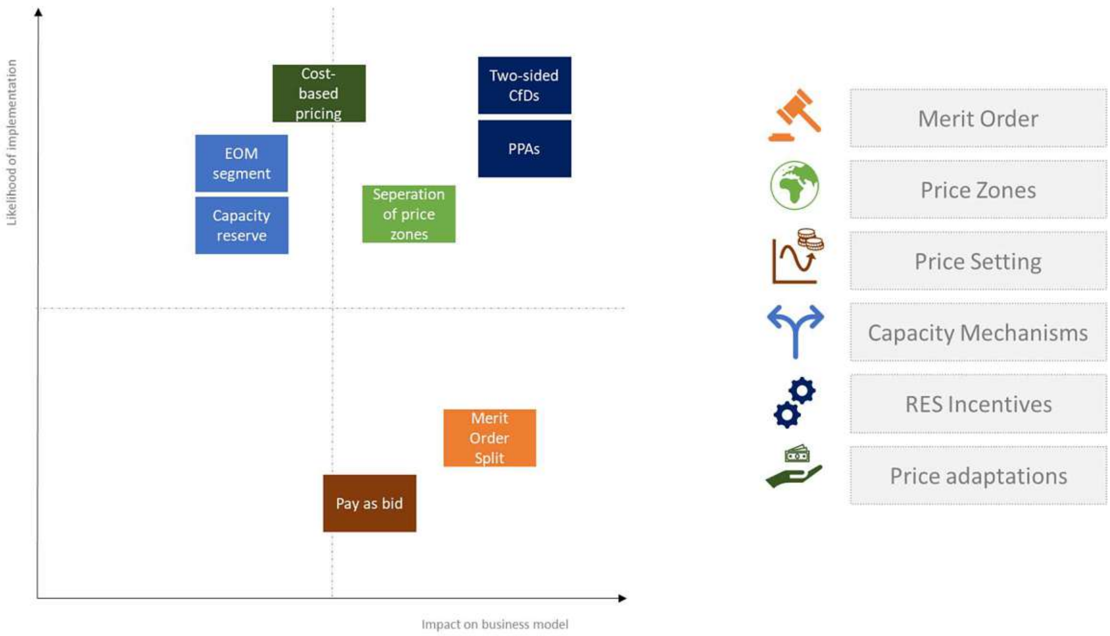

Figure 12: Matrix of likelihood of implementation and impact on the business model of a wind power generator for the proposed mechanisms.

Impact on business model. For the analysis of the implications of each mechanism on a wind energy provider, it is assumed that the market design and all other elements of the market remain constant. The proposed measures that are directly or indirectly subsidising the expansion of RES as well as mechanisms that are directly affecting the functioning of the market and its prices are most likely to have the highest impact on the business model and revenue streams i.e., PPAs and CfDs, changes of price zones and a Merit Order Split. It is assumed the revenues are solely generated by selling the generated electricity on the wholesale-market or OTC while retail activities are not considered.

In case of a **Merit Order split**, the conventional technologies i.e., technologies with low CAPEX and high OPEX such as CHP plants would bid separately from renewable technologies, i.e., technologies with high CAPEX and low OPEX. They would be dispatched to cover the net load and the price would be set according to their marginal cost (assuming a pay-as-cleared pricing). Hence, the merit order split would have negative consequences for the revenues generated by RES. With conventional technologies not setting the overall price anymore, RES will be rewarded their marginal costs which is reflecting their comparatively low OPEX. The Merit Order Split consequently does not remunerate the high CAPEX of RES, leading to reduced revenues for those technologies and prohibits market-based RES. In the case of a wind power generator, it would not even be possible to co-finance it with the revenues from conventional technologies. Alternatively, additional financing in the form of state subsidies would be required to keep RES in the market and to construct new plants.

A wind energy generator or any RES generator would be required to find alternative instruments for existing and new RES to subsidise the CAPEX and de-risks investment in new RES. This could involve state subsidies such as market premiums or CfDs or a deviation from the market towards over-the-counter trades such as PPAs. Concerning the bidding strategy on the market, wind or RES generators would be required to optimize generation schedules and incorporate more flexible technologies into the generation mix such as storage. This would allow them to leverage price volatilities, i.e., generate higher revenues during off-peak, low RES generation times.

The second instrument directly targeting the expansion of RES are PPAs. A stronger focus on **PPAs** as a vehicle to finance new RES can have a highly positive impact on the revenue generated by a wind energy generator. Standardised, risk-reduced PPAs represent an additional source of revenue for renewable electricity generators beyond the whole-sale-market or state subsidies. This mechanism can be particularly beneficial for RES generators if instruments are implemented that address and minimise the related risk of a PPA /see section 4.2.3) and if they can be combined with state subsidies such as a CfDs. PPAs are a particularly attractive revenue source given the current market situation where a high demand of renewable electricity especially from the industry, meets a low supply of stable, renewable generation, giving generators a stronger position in price negotiations.

By expanding the market and facilitating cross-border PPAs to encourage investment in renewable generation and flexible resources, all market players i.e., small, and large investors and generators, can benefit. Small generators often have limited access to PPAs because they have difficulty demonstrating their economic sustainability over an extended period. By opening PPAs to a variety of different players, project developers such as wind energy generators can sell the energy from their projects more easily, as more potential buyers would be able to bid, and on the other hand, (smaller) off-takers would benefit from the price predictability and hedging that PPAs allow.

To allow a small wind generator to fully leverage the PPA market, it would need to aggregate its production into a pool with other RES generators. In this case, the pool of buyers is collectively responsible for hedging counterparty risk, profile risk and price risk. Supporting government guarantees or an additional financing of new wind plants through e.g., CfDs could be another way to further accelerate new investments.

A downside of financing RES with PPAs is the increased associated risk leading to the need of an improved risk management and higher costs to leverage PPAs. Those risks need to be calculated, mitigation measures implemented and priced into the price of electricity within a PPA. In addition, if all generators solely focus on PPAs or mandatory quotas are introduced, this might have negative effects on the liquidity of the whole-sale-markets since liquidity is redirected out of the market making prices more volatile. This can have negative effects on the revenues of plants from the portfolio that are marketed on the wholesale markets.

Considering the implementation of **CfDs**, RES generators such as wind energy providers benefit from the introduction of CfDs since it represents an additional source of revenue besides from the wholesale market, thus reducing price risks from the markets. Additionally, with the state or state-owned entities being the counterpart of a CfD, the counterparty risk is drastically reduced, and the investment is de-risked.

The disadvantage from a system perspective results from the decoupling of remuneration from the electricity market, since generators who have entered a CfD have no incentive to feed in energy at times that serve the system. This is especially the case when demand, hence prices are high. This can further have a negative effect on the revenues in the portfolio of a wind power generator that are marketed solely on the wholesale market.

From the perspective of a wind generator's business model and portfolio, since price signals are capped by CfDs and there is no incentive to make the generation technologies more flexible or the system more resilient to fluctuations e.g., through storage batteries. To ensure that generators feed in energy in a way that is favourable to the system, CfDs must contain appropriate incentives. The suggested two-way CfD does offer them to a certain extent, since the wind generator receives a minimum price, but can also profit from market price developments if market prices are high and within a price corridor. On the one hand, this offers investment security, and on the other hand, it provides an incentive for system-favourable feed-in behaviour. However, if the cap exceeding the strike price is set to tightly i.e., only a minor amount of the revenue remains with the producer, it would further essentially complicate market-based renewable energies. To avoid the cannibalisation of revenues, the market strategy of the portfolio should be evenly distributed between CfDs, OTC and the wholesale market.

Another mechanism that has a strong influence on the prices on the wholesale-market is the **separation of price zones** between Austria and Germany with the limited capacity of the interconnecting transmission lines and security of supply being the driver of the debate.

On the one hand, generation costs of renewable electricity differ between the regions i.e., the north of Germany with a high share of wind having lower generation costs than parts of Austria, as well as the electricity prices on which investment decision are being based. Creating more accuracy by splitting the German market, allows to make thorough investment decisions by a wind power generator. Furthermore, depending on the location of the wind power generator, electricity prices increase i.e., in Southern Germany, or decrease, i.e., in Northern Germany, thus might even have a positive impact on the revenue.

However, it remains unclear if the price changes will be reflected in higher revenues. A negative consequence of a zone split is the reduction of market liquidity and an associated risk of market power abuse given a smaller amount of market players in the smaller zones. This leads to a higher volatility and is negatively impacting the revenues, particularly on forward markets. The illiquid trading and weak price signals further prohibit the use of flexibilities by market participants, even though from a market perspective, it would be logical to increase flexibilities and storage options to optimise the generation portfolio and leverage the fluctuations in prices. In addition, a wind generator would need to de-risk his portfolio by finding alternative ways to finance existing and new plants through OTC, PPAs and state subsidies such as CfDs besides marketing them solely on the wholesale market.

	Revenues	Associated costs	Implications for portfolio and business model
Merit Order Split	⊖ RES	⊖ transaction costs	• Alternative financing of RES i.e. OTC or state subsidies • Integration of flexibilities such as batteries to optimise bidding strategy
PPAs	⊕ RES	⊖ risk management	• Expanding risk management to mitigate PPA associated risks • Pooling generation with other generators
CfDs	⊕ RES	⊖ administrability	• Optimise market strategy i.e. balance between OTC, wholesale-market and CfDs
Separation of price zones	⊖ RES	⊖ transaction costs	• Optimise market strategy i.e. balance between OTC, wholesale-market and subsidies e.g. CfD

negative impact ⊖ ⊖ ○ ⊕ ⊕ positive impact

Figure 13: Assessment of the impact of the mechanisms on the revenue streams of a wind power generator and associated costs and implications for the portfolio and business model

4.3.3 Example of a retail company

A retail or supplier company has no generation assets of its own and buys electricity directly from generators or on the wholesale market to resell it to end customers. They are responsible for procurement, contract management, billing, and customer service and benefit from economies of scale and risk management strategies. The business model of a pure supplier results from the difference between wholesale prices and end-customer prices, which cover costs for administration, procurement, and service. Pure suppliers are dependent on wholesale prices and trade renewable as well as fossil-based electricity.

Impact on business model. Based on the analysis conducted above, a pure retail company is primarily affected by mechanisms that are affecting the wholesale-price of electricity and the functioning of the market as well as mechanisms that are directly targeting the end-consumer prices i.e., separation of price zones and a marginal cost-based pricing. This is irrespective of the source of electricity i.e., renewable or fossil-based generation. In addition, mechanisms that are promoting new possibilities for companies to purchase electricity or act as an intermediary, have a high impact on the business model of pure retail companies. In the case of the market reform, PPA do represent such a possibility of new revenue generation.

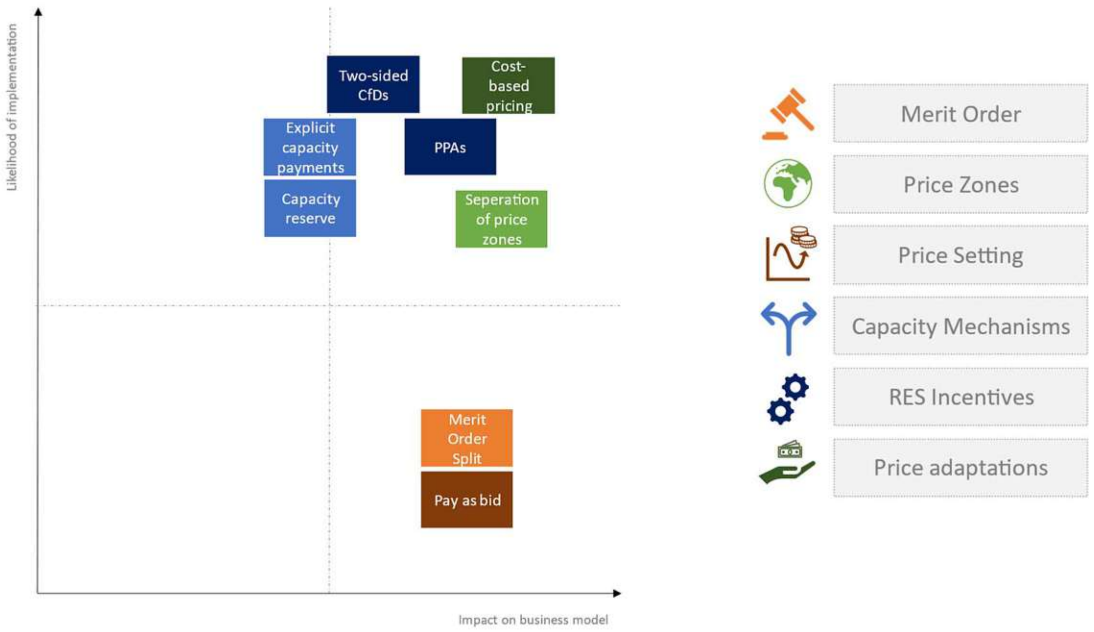

Figure 14: Matrix of likelihood of implementation and impact on the business model of a retail company for the proposed mechanisms.

The introduction of a **marginal cost-based pricing** approach allows price adaptations based on changes of generation costs as well as based on electricity procurement costs i.e., for retail tariffs, thus potentially having a high impact on the revenue stream of a retail company.

The proposed mechanism is solely affecting the end-consumer prices while wholesale market prices remain unaffected. While high wholesale prices increase the costs for pure suppliers, thus reducing their revenue and consequently profit margin, low prices allow them to pass on lower prices to their customers or increase their revenue.

Additionally, a retailer could benefit from a cost-of-supply-based system by strengthening their market position. Their procurement costs would be considered in the pricing approach for end-consumers, while other market participants could potentially leave the market voluntarily due to opportunity losses. However, a supplier must ensure that price increases are in line with cost increases i.e., an indexation of prices would need to match the procurement costs of electricity. If this should not be possible due to the complexity of the procurement strategy, this would have severe implications for the portfolio. It would be required to adapt its strategy by introducing contract limitations, early terminations, and such.

In general, the electricity procurement strategy is decisive for the resulting end-customer price for a retail company. If procurement costs are allowed to be passed on to end-consumers, the company will not experience severe changes in the revenue streams. However, it will not be incentivized to act in a forward-looking manner either. If a country-wide reference retail price were set, pure suppliers would have to be subsidized by the state to remain in the market since the procurement price is higher than the average generation costs assuming the Merit Order logic.

The **separation of price zones** can have significant impacts on the revenue streams and business model of an electricity retail company. With separate price zones, the electricity prices differ due to numerous factors such as differences in supply-demand dynamics, regulatory frameworks, and shares of RES and conventional technologies. This can create opportunities for price differentiation strategies by the retail company. They can purchase electricity at a lower price in one market and sell it at a higher price in the other, potentially increasing their revenue. They can further target customers in both zones separately, offering tailored pricing and services based on the specific market conditions. This differentiation can lead to increased revenue streams.

The price zone separation results in increased market volatility due to the reduced liquidity offered by a smaller amount of market players in each zone since market dynamics in each zone can evolve independently. A retail company needs to carefully manage and mitigate risks associated with price fluctuations to maintain stable revenue streams or leverage the opportunities that arise from a separation. If active in a zone with low generation costs, higher revenues and profit margins could be generated while in regions with high prices the margins on the end-consumer market tend to be lower.

A stronger focus on **Power Purchase Agreements** in the European market can have significant impacts on the revenues and more importantly, the business model of an electricity retail company offering alternative business cases to diversify the revenue streams from renewable electricity.

From a system perspective, a pure retail company is only marginally affected by the introduction of PPAs. There is a potential risk that liquidity is taken out from the market by generators shifting towards PPAs. This would have negative impacts on the prices and profit margins and would require improve risk management and associated mitigation strategies.

From a company perspective, the shift towards PPA can represent a business opportunity. By entering the PPA market as an intermediary between an off-taker and a generator or energy retailer purchasing electricity directly from a generator via a PPA and reselling it to a customer, the retailer can diversify its revenue streams. PPAs are long-term contracts, hence offer stable and predictable cash flows. This diversification can help mitigate risks associated with volatile wholesale electricity markets and create a more resilient business model. In addition, given the current market situation where a high demand of renewable electricity especially from the industry, meets a low supply of stable, renewable generation, entering the PPA market as an off-taker or as an intermediary allows a retail company to realise early mover advantages and creating a strong position in the PPA market. By securing long-term agreements with fixed or indexed prices early on, the retailer can minimize exposure to short-term market fluctuations and achieve more predictable revenue streams.

The associated downside is that PPAs are complex and involve high transaction costs and may require the retail company to develop or enhance its capabilities in contract negotiation, risk management, and renewable energy project evaluation. These operational considerations can impact the company's business model and may require additional expertise or partnerships.

	Revenues	Associated costs	Implications for portfolio and business model
PPAs	⊕ RES ○ Conventional	⊖ Risk management costs	• Expanding risk management to mitigate PPA associated risks • Adapt organisational structures to create new business segment
Marginal cost based pricing	⊖ RES and conventional	⊖ Administrability costs	• Adaptation of retail contract details e.g. introducing limitations and early terminations
Separation of price zones	⊕ RES and conventional	⊖ Compliance and administrability costs	• Improve of risk management • Optimise market strategy i.e. balance between zones and offer tailored contracts for different zones

negative impact ⊖ ⊖ ○ ⊕ ⊕ positive impact

Figure 15: Assessment of the impact of the mechanisms on the revenue streams of an electricity retailer and associated costs and implications for the portfolio and business model

5 Discussion & Conclusion

The European Electricity market is an overly complex construct that is historically grown with the prevalent system design having started in 1996 with the adoption of the first European Energy Package. It had been followed by additional Packages with the attempt to generate societal benefits by allowing a market-based approach of the electricity market design and by doing so, to generate prices for consumers that reflect the economic cost of supplying electricity generation. The established market design with the energy only market as its basis has provided an efficient and secure electricity supply from which market players and end-consumers were able to benefit.

However, recent developments such as the increasing share of RES and the volatile prices during the energy crisis have shown the shortcomings of the market design having an impact on the functioning of the markets. This led to several political and non-political institutions calling for measures to improve competition and strengthen consumer protection. Several member states developed their own proposals to improve the market design. Some member states such as Poland, Spain and Greece suggested a drastic system change i.e., a deviation or adaptation of the Merit Order logic by introducing a split for different technologies as well as a shift towards a pay-as-bid pricing approach. Other member states, however, suggested to maintain the design and implement more adjustive mechanisms such as price and revenue caps (e.g., Belgium) which was been in line with ACERs recommendation to not to deviate from the merit order approach since it gives clear market signals to both producers and consumers. In response to the demand for change, the EU proposed a legislative reform of the electricity marker design which has been presented in Match 2023.

This thesis provides valuable insights into the advantages and disadvantages of the proposed reform. By doing so, it contributes to the existing literature on the functioning of the mechanisms. Different to other studies, the focus of the analysis lies on the hypothetical implications for market players rather than the theoretical functioning of the mechanism. The following part presents the main points that answers the research questions:

What are the advantages and disadvantages of the mechanisms proposed by the Member States?

The proposal currently does not explicitly foresee major changes of the system design. At the heart of the proposal is the strengthening of the energy market through the targeted integration of renewable generation technologies. This is particularly important because a large part of the EU emergency measures that have been adopted will gradually expire.

The goal of the EU Commission to pass on low generation prices to households, for which long-term price signals are crucial, shall be achieved by incentivizing investment in RES through CfDs and PPAs. At the same time, capacities such as demand side response measures, storages and other capacity mechanism shall be introduced to allow security of supply and reduce volatility in the markets. Moreover, the rights of end-consumers shall be strengthened, and transparency improved i.e., by introducing a cost-based pricing approach.

The current Merit Order logic has historically shown to ensure market efficiency, incentivizes efficient generation and consumption, and clear market signals. Despite being criticised for favouring conventional power plants it has shown to be beneficial for the integration of renewable energy sources during the energy crisis. Another mechanism discussed is the introduction of price zone splits. While a single price zone offers increased liquidity, clear price signals, and transparency, congestion issues can arise, affecting redispatching costs and cross-border competition. The separation of price zones has been proposed to address those congestion problems, but it may lead to regional disparities, reduced liquidity, and increased prices for end-consumers. Concerning the incentives for investments in renewable energy sources, such as Power Purchase Agreements and Contracts for Differences. PPAs provide stable prices over a long-term period, attracting investors and reducing market price volatility. However, PPAs can be complex and have high transaction costs, limiting access for small-scale projects. In comparison, CfDs guarantee a fixed price for electricity independent of the wholesale market price, offering planning certainty and attracting investment. However, decoupling compensation from the market development may reduce the incentive for generators to integrate the required flexibilities. Lastly, the thesis examines the remuneration of capacities within and outside of the EOM market. Capacity mechanisms can enhance the reliability and security of the electricity system by ensuring the availability of sufficient generation capacity to meet demand in peak hours. If designed appropriately, capacity mechanisms can support the integration of renewable energy sources by providing a stable revenue stream for high-efficient and renewable plants. However, accurately determining the appropriate level of capacity needed in a rapidly evolving energy landscape and potential market distortions remain a challenge.

What is the likelihood of implementation and impact of the mechanism on the business model of typical market players?

The mechanisms that are long-term contracts and solutions to attract investments in RES and renewable capacities are highly likely to be implemented, however, the details being subject to negotiation and implementation in the member states. Another highly likely but structurally more severe mechanism to be implemented is a split of certain price zones e.g., between Austria and Germany. While a shift towards a pay-as-bid pricing approach or the split of the Merit Order as proposed by member states remains highly improbable.

The degree of impact on the business model of the market players depends on the exact design of the mechanism as well as the specificities of the business model and portfolio of the company itself. However, by analyzing the impact on each mechanism independently from other mechanisms and assuming the current state of the market, a general assumption can be made for each market player.

The business model of utility would most negatively be influenced by a marginal cost-based pricing approach since current high revenues would experience a sharp cut. It might further force a utility to separate its generation from its retail business segment. On the other hand, remuneration for flexibilities in a separate EOM market represents an opportunity to finance existing and newly constructed high-efficient or renewable flexibilities. Concerning the impact on a typical wind generator, a merit order split would have the most negative consequences since currently high revenues from RES would experience a sharp decline. This would render market-based RES impossible and would require alternative ways to finance existing and new RES e.g., through subsidies. The biggest opportunity to increase revenues represents the shift towards PPAs particularly if the wind generator enters the market early on i.e., in the current situation of high renewable energy demand from industries and low supply. For a retail company, the marginal cost-based pricing represents the biggest threat and might require it to adapt contract specificities and diversify its portfolio. Hereby, PPA represent an opportunity of revenue diversification and additionally opens up new business segment opportunities e.g., acting as an intermediary between a generator and off-taker.

To summarize, it can be said that the current legislative proposal is the biggest reform in recent years and brings about big challenges but also opportunities for the market players. How far-reaching and severe the mechanisms will be for the market players and to what extent the goals of the European Commission will be realized will depend on the outcome of the negotiations on the proposal on the European level and the consequent implementation in the member states.

6 Limitations & Outlook

The thesis represents a qualitative analysis of the proposed mechanisms in the legislative proposal on the market design reform of the European Commission. The market design is still an ongoing discussion in politics as well as academia and has not yet been agreed upon by the European Commission nor been implemented by member states. Therefore, the thesis derives hypothetical assumptions not considering externalities or the complexities of the interactions of several mechanisms being implemented together. It serves as a basis for further in-depth analysis.

Some mechanisms such as capacity mechanisms and structural changes of the market i.e., price zone splits, alternatives to the Merit Order and pay-as-clear pricing approach, have already been implemented in Europe or overseas and are therefore thoroughly studied in the literature. Other mechanisms such as the introduction of PPAs and CfDs as well as marginal price-based pricing are comparatively new instruments, thus the literature offers limited insights into the consequences of those mechanism on the market and its players.

In addition, given the ambiguity concerning the accurate design of the mechanisms and its exact implementation in the member states, an in depth-analysis with a quantitative approach shall be conducted once the reform has been implemented. Before the reform proposals can come into force, it must go through the ordinary legislative procedure. Given that the European Parliament and the Council and the Council agree on their respective positions the current Swedish Council Presidency plans to start the interinstitutional negotiations by the end of June 2023. In this case, the revised electricity market design could be implemented in the fall or winter of 2023.

7 Bibliography

Auer, H., Haas, R. (2016). On integrating large shares of variable renewables into the electricity system. Energy Vol. 115 (3), pp. 1592–1601.

Austrian Energy Agency (2022). Empirical Analysis of the Iberian Electricity Price Cap. Retrieved from: https://www.energyagency.at/fileadmin/1_energyagency/publikationen/empirical_analysis_of_the_iberian_electricity_price_cap_final_version.pdf

Austrian Power Grid (2023). Netzreserve. Retrieved from: https://markt.apg.at/netz/netzreserve/

Axpo (2023). Electricity market facts and figures. Retrieved from: https://www.axpo.com/ch/en/about-us/media-and-politics/power-market-switzerland.html

Bublitz, A., Keles, D., Zimmermann, F., Fraunholz, C., Fichtner, W. (2019). A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms. Energy Economics, Vol. 80, pp. 1059-1078

Der Standard (2023). Geld zurück? Gerichtsurteil lässt Verbund-Kunden hoffen. Retrieved from: https://www.derstandard.at/story/2000143843124/warum-der-verbund-moeglicherweise-geld-zurueckzahlen-muss

European Energy Exchange (2016) Retrieved from: https://www.eex.com/de/

European Commission (2023). Commission proposal for an Electricity Market Design reform. Retrieved from: https://energy.ec.europa.eu/publications/electricity-market-reform-consumers-and-annex_en

European Union Agency for the Cooperation of Energy Regulators (ACER) (2022). ACER's Final Assessment of the EU Wholesale Electricity Market Design. Retrieved from: https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER's%2520Final%2520Assessment%2520of%2520the%2520EU%2520Wholesale%2520Electricity%2520Market%2520Design.pdf

European Parliament (2022). Emergency intervention to address high energy prices in the EU. Retrieved from: https://www.europarl.europa.eu/RegData/etudes/BRIE/2022/733687/EPRS_BRI(2022)733687_EN.pdf

Evaluation Report: Part 1/2 (2016) European Commission. Retrieved from: https://energy.ec.europa.eu/system/files/2016-11/2_en_autre_document_travail_service_part1_v2_1_0.pdf

Evaluation Report: Part 2/2 (2016) European Commission. Retrieved from: https://energy.ec.europa.eu/system/files/2016-12/2_en_autre_document_travail_service_part2_v2_412_0.pdf

Energiewirtschaftliches Institut an der Universität zu Köln (EWI). (2022) Merit Order Tool. Retrieved from: https://www.ewi.uni-koeln.de/en/tools/ewi-merit-order-tool/

Fabra, N., von der Fehr, N.-H., and Harbord, D. (2006). Designing electricity auctions. The RAND Journal of Economics, 37(1):23–46.

Fabra, N. (2022). Electricity markets in transition: A proposal for reforming European electricity markets. VoxEU. Retrieved from: https://cepr.org/voxeu/columns/electricity-markets-transition-proposal-reforming-european-electricity-markets

Federal Ministry for Economic Affairs and Energy (BMWi) (2015). An electricity market for Germany's energy transition. Retrieved from: https://www.bmwk.de/Redaktion/EN/Publikationen/whitepaper-electricity-market.pdf?__blob=publicationFile&v=7

Fraunholz, C., Hladik, D., Keles, D., Möst, D. and Fichtner, W. (2021). On the long-term efficiency of market splitting in Germany. Energy Policy. Vol. 149, 111833.

General Secretariat of the Council (2022). Proposal for a power market design in order to decouple electricity prices from soaring gas prices - Information from the Greek delegation. Retrieved from: https://data.consilium.europa.eu/doc/document/ST-11398-2022-INIT/en/pdf

Ghiassi-Farrokhfal, Y., Ketter, W., Collins, J. (2021) Making green power purchase agreements more predictable and reliable for companies. Decision Support Systems, Vol. 144.

Grimm, V., Rückel, B., Solch, C., Zottl, G., 2018. The Impact of Market Design on Transmission and Generation Investment in Electricity Markets. Retrieved from: https://doi.org/10.2139/ssrn.3235262

Haig, B. D. (2005). An Abductive Theory of Scientific Method. Psychological Methods, 10(4), pp. 371–388.

Hancher, L., De Hauteclocque, A., Sadowska, M. (2015). Capacity mechanisms in the EU energy market: law, policy, and economics. Oxford: Oxford University Press.

Harris, Chris (2013). Electricity Markets: Pricing, Structures and Economics. Wiley Finance.

Hirth, L. (2022). The Merit Order Model and Marginal Pricing in Electricity Markets. Explainer. Retrieved from: https://neon.energy/marginal-pricing

Hirth, L. and Ueckerdt, F (2014). Ten propositions on electricity market design: Energy-only vs. capacity markets. Presented at: Sustainable Energy Policy and Strategies for Europe, Rome, Italy - October 28-31, 2014.

Huneke F., Göss S., Österreicher J., Dahroug O. (2018). Power Purchase Agreements: Financial Model for Renewable Energies: Tech. Rep. Energy Brainpool, Berlin.

Hurta, A., Žilka, M., Freiberg, F. (2022). Impact of the splitting of the German–Austrian electricity bidding zone on investment in a grid-scale battery energy storage system deployed for price arbitrage with gray and green power in Austrian and German day-ahead power markets. Energy Reports, Vol. 8, pp. 12045-12062.

Kozlova, M, Overland I. (2022). Combining capacity mechanisms and renewable energy support: A review of the international experience. Renewable and Sustainable Energy Reviews, Vol. 155. pp. 111878.

L'organisation Des Marchés De L'électricité (2022). Cour des comptes. Retrieved from: https://www.ccomptes.fr/system/files/2022-07/20220705-rapport-organisation-marches-electricite_0.pdf

Maurer, C., Schlecht, I. and Hirth, L. (2022). Retrieved from: The Greek market design proposal would be the end of electricity markets as we know them. https://www.euractiv.com/section/electricity/opinion/the-greek-market-design-proposal-would-be-the-end-ofelectricity-markets-as-we-know-them/

Momentum Institut (2022). Deckel drauf? Ein Preisdeckel gegen weiter steigende Gas und Stromrechnungen. Policy Brief. Retrieved from: https://www.momentum-institut.at/system/files/2022-03/Vergleich_Varianten_Energiekostenausgleich_1.pdf

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

Ofgem (2006). Pay-as-bid or pay-as-clear pricing for energy balancing services in the Balancing Mechanism Retrieved from: https://www.ofgem.gov.uk/sites/default/files/docs/2012/10/pay-as-bid-or-pay-as-clear-presentation.pdf

Plancke, G., de Jonghe, C., Belmans, R., (2016) The implications of two German price zones in a european-wide context. In: 2016 13th International Conference on the European Energy Market (EEM). IEEE, Piscataway, NJ.

Pollitt, Tooraj Jamasb and Cleveland (2005) Electricity Market Reform in the European Union: Review of Progress toward Liberalization & Integration. The Energy journal (Cambridge, Mass.), 2005, Vol.26 (1), pp.11-41.

Ringel, M (2003) Liberalising European electricity markets: opportunities and risks for a sustainable power sector. Renewable and Sustainable Energy Reviews. Vol. 7 (6), pp. 485-499.

Roques, Fabian, Perekhodtsev, Dmitri Electricity and Hirth Lion (2016). Market Design and RE Deployment. IEA Renewable Energy Technology Deployment Technology Collaboration Programme (IEA RETD TCP): Utrecht.

Schlecht, I., Maurer, C and Hirth, L. (2023) Financial Contracts for Differences. Econstor Preprints. Retrieved from: https://econpapers.repec.org/paper/zbwesprep/268370.htm

Spanish non-paper on electricity market reform (2023). Retrieved from: https://table.media/europe/wp-content/uploads/sites/9/2023/01/230110_Strommarktreform_Non-Paper_ES.pdf

Neuhoff, K., Diekmann, J., Kunz, F., Rüster, S., Schill, W.-P., Schwenen, S. (2016). A coordinated strategic reserve to safeguard the European energy transition. Utilities Policy, Vol. 41, pp. 252–263.

Non-paper: Gas Market Price Cap (2022). Position paper for Belgium in the EU discussions for Emergency Electricity Market Interventions. Retrieved from:

https://www.euractiv.com/wp-content/uploads/sites/2/2022/09/Non-paper-emergency-electricity-interventions.pdf

Toskow, Paul (2008) Lessons Learned from Electricity Market Liberalization. The Energy Journal, Vol. 29 (2), pp. 9-42.

Yin, R. K. (2017). Case study research and applications: Design and methods. Sage Publications.

8 List of Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
APG	Austrian Power Grid
CAPEX	Capital Expenditures
CfD	Contract for Difference
DSR	Demand Side Response
ENTSO-E	European Network of Transmission System Operators for Electricity (EN-TSO-E)
EPEX	European Power exchange
EU	European Union
OPEX	Operational Expenditures
OTC	Over the counter
PPA	Power Purchase Agreement
REMIT	Regulation on Wholesale Energy Mar-ket Integrity and Transparency
RES	Renewable Energy Systems

9 List of Figures

Figure 15: Assessment of the impact of the mechanisms on the revenue streams of an electricity retailer and associated costs and implications for the portfolio and business model