Energy Policy 167 (2022) 113025

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Decision strategies in sequential power markets with renewable energy

Derck Koolen [a,b,*], Ronald Huisman [c,d], Wolfgang Ketter [b,e]

[a] European Commission, JRC Directorate for Energy, Transport and Climate, the Netherlands
[b] Rotterdam School of Management, Erasmus University Rotterdam, the Netherlands
[c] Erasmus School of Economics, Erasmus University Rotterdam, the Netherlands
[d] Kyiv-Mohyla Business School, National University of Kyiv Mohyla Academy, Ukraine
[e] Faculty of Management, Economics, and Social Sciences, University of Cologne, Germany

ARTICLE INFO

Keywords:
Electricity markets
Renewable energy
Decision strategies
Intermittent production

ABSTRACT

With direct electrification at the core of global decarbonization efforts, it is key for policy makers to adequately evaluate market dynamics in renewable power systems. The ongoing integration of renewable energy sources fundamentally changes these dynamics, with variable production profiles, lower marginal production costs and increased price volatility. This motivates us to study how an increasing supply from renewable energy sources impacts decision making of intermittent and non-intermittent producers in sequential forward and spot markets. We do this by examining prices and volumes observed in an experimental trading environment that allows us to vary the market share of intermittent renewable energy production with a high degree of control. The results show that non-intermittent power producers, who can flexibly adjust volumes in the short-term, can retain their profits by moving focus from forward to spot markets. We find empirical support for our experimental results by validating data from German short-term power markets in 2021 and create awareness on the convenience yield for flexibility in power systems with a high market share of intermittent renewable energy sources. The study thereby guides policy makers to align supporting the uptake of intermittent renewable energy production with taking away hurdles faced by low-carbon flex technologies.

1. Introduction

There is broad scientific consensus on the necessity to reduce greenhouse gas emissions as one of the key factors to mitigate climate change (Intergovernmental Panel on Climate Change, 2022). In recent years, numerous governments and policy makers around the world have accordingly announced ambitious climate strategies to reduce emissions. A cornerstone pillar in achieving such challenging targets is the transition of the power sector, as decarbonising current electricity systems accounts for roughly one third of the way to net-zero emissions. The share of electricity in final energy consumption is moreover expected to jump to 50% towards 2050, as other sectors like transport, buildings and industry rely heavily on deep electrification powered by renewable energy sources (International Energy Agency, 2021). With the demand for sustainable, affordable and reliable energy on the rise, global power systems and markets are going through a series of swift and radical transformations.

A growing stream of related energy policy literature hence addresses the feasibility and viability of achieving 100% renewable power systems (Brown et al., 2018; Diesendorf and Elliston, 2018). Feasibility studies of fully renewable power systems address the reliability and security of such systems, and mainly assess issues with respect to prominent technologies (Jacobson and Delucchi, 2011) and flexibility needs (Narayanan et al., 2019; Papaefthymiou and Dragoon, 2016). Economic viability studies address the affordability of renewable power systems at acceptable socio-economic costs (Delucchi and Jacobson, 2011; Riesz et al., 2016), and typically do so by modelling total system costs, taking into account the levelised costs and cost efficiencies of renewable technologies. While such studies provide relevant insights on the economic feasibility of renewable power systems (Brown et al., 2018), they generally do not focus on the effects of the transition towards renewable power systems on decision strategies in wholesale power markets (Levin et al., 2019). By providing these insights, our study paves the way for policy makers to understand implications on existing market structures and their participants' strategic space, considering alternative market designs both from a market and individual perspective.

In this study, we research how intermittent renewable producers and non-intermittent flexible producers position themselves in sequential

* Corresponding author. European Commission, Westerduinweg 3, 1755LE, Petten, the Netherlands.
E-mail address: derck.koolen@ec.europa.eu (D. Koolen).

https://doi.org/10.1016/j.enpol.2022.113025
Received 23 October 2021; Received in revised form 24 April 2022; Accepted 3 May 2022
Available online 19 May 2022
0301-4215/

forward and spot power markets, and affect power price dynamics as a consequence, when confronted with an increasing market supply of variable renewable energy sources. Decisions in power markets are, among other factors, affected by uncertainty and risk, due to price fluctuations and spikes, intermittent production from renewable energy sources and uncertain demand profiles. Managing this risk creates a demand for forward contracts, committing a producer (the seller of the contract) to deliver an agreed amount of power for a fixed price during a specified period in the future. Forward markets provide information about future prices and, given that power market agents can often only make accurate predictions for a limited time horizon (Borenstein et al., 2002), allow for contract adjustments and risk sharing over spot uncertainty. As such, decisions in forward and spot markets allow efficient allocation of resources for commodities that face uncertainty in price or quantity for a future time of delivery (Ito and Reguant, 2016).

The literature on the economic effects of intermittent renewable energy resources on price formation in forward and spot power markets is gaining attraction. Peura and Bunn (2021) model hedging and strategic rationales for trading forward contracts in oligopolistic power markets with conventional, inflexible and intermittent producers. They find that, with increasing supply uncertainty, spot risk may induce an increase of prices when trading incentives favor suppliers. Where in markets with moderate intermittent capacity the merit-order effect may prevail, flexible non-intermittent producers may favor spot market conditions through their strategic commitment. Koolen et al. (2021) find opposing hedging needs of producers and retailers to affect forward and spot price formation by modelling sequential power markets with an increasing market share of intermittent renewable energy at both sides of the supply chain.

We contribute to this line of work by empirically investigating rationales for forward trading in wholesale power markets with an increasing share of intermittent renewable energy. We do so via a developed experimental market environment. Given that previous empirical studies addressing the role of technology on sequential market dynamics have presented mixed results with no clear economic interpretations (Bunn and Chen, 2013), the experimental design allows us to implement variations in the market share of intermittent production with a high degree of control and explore under ceteris paribus conditions forward and spot market decision behaviour. As such, we are able to focus exclusively on individual decision making, strategies of intermittent and non-intermittent producers and price formation in sequential power markets with an increasing share of intermittent renewable energy sources.

Our work guides policy makers and regulators to adequately evaluate the role of renewable market dynamics and increased price volatility on flexibility in wholesale power markets. When confronted with an increasing supply from intermittent renewable energy sources, we find that non-intermittent power producers can retain their profits by shifting focus from forward to spot markets. They do so by strategically adjusting volumes on forward and spot markets, thereby exploiting a convenience yield for flexibility. We validate our insights with data from German short-term power markets in 2021, a year in which European power prices surged and markets experienced increased price volatility. The empirical results confirm our view on the role of intermittent renewable energy sources on forward price dynamics. As policy makers are gradually adopting a more market-driven approach to the further integration of renewable energy sources, this study engages them to adequately understand decision strategies and accommodate an efficient integration of low-carbon flexibility in wholesale power markets.

The remainder of this paper is organized as follows. We first establish the research question in light of related work. We then discuss the experimental framework and design from an agent and market perspective. We next analyze the results from the experimental sessions, and relate implications to notions on forward trading in power markets with an increasing market share of intermittent producers. We conclude by validating our findings empirically in German power markets and discuss how the results help regulators and government policies to understand market price implications.

2. Decision making in forward and spot power markets

The ongoing integration of intermittent renewable energy sources in liberalized wholesale power markets has a clear economic impact on, and policy implications for, market pricing and decision making (Kyritsis et al., 2017). Markets wherein supply predominantly came from fossil fuel based power plants now face a growing market share of renewable energy producers. Bearing no fuel or emission costs, renewable suppliers face lower marginal production costs than (traditional) fuel burning suppliers do. In competitive markets renewable producers as such undercut prices of fuel based producers and thereby drive them out of the (forward) market. Most electricity produced by renewable energy sources is however inherently variable and difficult to predict by nature, which in combination with factors like limited storage capacity and price inelastic demand puts power systems operations under pressure and cause (spot) prices to fluctuate heavily. Increased competition, new production technologies, lower prices and increasing price volatility have completely changed operations in power markets (Scholten et al., 2020).

Decision making and price formation in wholesale power markets are thus affected by uncertainty and risk. Volatile supply and demand profiles may result in price fluctuations and spikes, motivating risk-averse market agents to mitigate risks by engaging in forward contracts. Borenstein et al. (2008), among others, show that the price of forward contracts equals the expected price in spot markets plus a forward (risk) premium, as market participants agree upon a price which takes into account expected variations in demand and supply. Forward trading decisions and forward prices reflect as such the net cost of hedging against short-term risks and may fluctuate depending on the needs for risk mitigation from producers and retailers (Bessembinder and Lemmon, 2002; Koolen et al., 2017). In oligopolistic markets, producers may furthermore take strategic positions in forward contracts (Allaz and Vila, 1993), allowing them to gain market share in the spot market. No conclusive view on modeling forward and spot market behaviour has however been put forward yet and both theories have presented shortcomings with respect to empirical validations,[1] motivating the choice for an experimental market environment in this study.

Summarizing, decision making in forward and spot markets as well as the sign and size of the premium priced in forward contracts depend on hedging and strategic rationales for forward trading, influenced by operational market characteristics, underlying production technologies, and demand, supply and price uncertainty. In this paper, we examine the research question how an increased market integration of intermittent renewable energy sources affects sequential market decisions in relation to the above rationales for forward trading. We thereby focus on whether volume adjustment flexibility leads to an advantage in spot markets, and whether non-intermittent producers can thereby retain their profits by shifting focus from forward to spot markets.

3. The framework of the experiment

We examine the research question in an experimental framework, as this enables us to allow for more variation than a theoretical framework

[1] Mixed empirical results have been presented for sequential power markets operating under different operational constraints and underlying production technologies (Bunn and Chen, 2013). For example, Redl and Bunn (2013) show that underlying fuel fundamentals impact the forward price in Germany. Huisman and Kilic (2012) find evidence that premiums priced in forward contracts in the Nordic Nord pool market, a market with abundant flexible hydro power, differ from the premiums in the Dutch APX market, primarily operating with coal and gas-fired power plants.

and rule out other empirical effects than a change in renewable energy supply. Experiments have been applied to analyze individual trading behaviour in financial markets (Brown and Kim, 2013) and market competition in forward trading (Le Coq and Orzen, 2006). In the context of power markets, experiments have been used to examine changes in market design (Ketter et al., 2016; Bower and Bunn, 2000), system behaviour (Koritarov, 2004) and the introduction of trading forward in addition to spot contracts (Brandts et al., 2008). Ketter et al. (2013) demonstrate that experiments and simulation studies are not only an effective way to spur innovation, but also provide a flexible way to analyze decision making and price formation under various real-world conditions to test the efficacy of both analytic and strategic research ideas.

The seminal work of Bessembinder and Lemmon (2002) inspires the theoretical framework for our experimental market design. They examine the pricing of forward contracts in a power market where power producers compete to supply the price inelastic and uncertain demand from (price-taking) retailers. Their findings indicate that forward prices are biased predictors of spot prices, respectively correlating negatively to the variance and positively to the skewness of spot prices. Some empirical studies find support for these results (Douglas and Popova, 2008), but other empirical studies only do so partially (Botterud et al., 2010; Redl et al., 2009). In a similar experimental market setting to ours, Huisman et al. (2021) however confirm the findings of Bessembinder and Lemmon (2002) and find evidence in markets with an increasing share of renewable energy sources for respectively reinforcing the effect of spot price volatility and weakening the effect of spot price skewness on the forward premium. Where Bessembinder and Lemmon (2002) assume that all producers have the same supply technology, we relax this assumption by allowing for two types of producers, namely i) non-intermittent producers with positive marginal costs (fuel costs and emission rights) and ii) intermittent (variable) renewable energy sources. Similar to Bessembinder and Lemmon (2002), these two types of producers, intermittent and non-intermittent, buy and sell electricity contracts during two periods, the forward and spot market. In period 1, they trade a forward contract that delivers power in period 2. In period 2, they trade in the spot market after which delivery takes place.

3.1. The agents

The first type of agent (labeled **consumer**) is an automated power consumer that demands a volume of power for delivery in period 2. Although modelled as a single entity, this agent represents a group of power retail companies that deliver power to households and enterprises. Typically, their demand is price inelastic in the short run, meaning that the consumer agent purchases the demand in the market whatever the price is (price-taker). Short run inelastic demand is a typical assumption for stylized short run electricity market models. Indeed, studies examining short run markets find no significant demand elasticity (Cramton et al., 2013; Lijesen, 2007) or only little during specific hours (Knaut and Paulus, 2017). This behaviour occurs due to energy retail companies hedging their margins with forward contracts as they typically sell power to their clients against fixed prices. We assume that consumer demand is uncertain, but that the normally distributed probability function of demand is publicly known with mean μ_D and variance σ_D^2.

The second agent (labeled **intermittent producer** or **ip**) supplies power from intermittent power sources such as wind mills or solar panels during period 2. His supply is uncertain, depending on for instance wind speed or solar radiation. Following the work of Ito and Reguant (2016), renewable energy producers have zero marginal costs but are uncertain about their production realization. We assume that the supply of the intermittent production is normally distributed with mean $\mu_{P_{ip}}$ and variance $\sigma_{P_{ip}}^2$. All intermittent producers have the same production technology, with the same probability structure, and their supply is mutually independent in order to simulate an entire market rather than a specific region. We further assume that this agent is not incentivized to curtail power supply when prices remain above a negative threshold, as many countries have policies and regulation to subsidize this type of production.[2] We define n_{ip}, a treatment variable in the experiment, as the number of intermittent producers in the market.

The third agent (labeled **non-intermittent producer** or **nip**) supplies (non-intermittent) power with a maximal production capacity during delivery of P_{nip}. It converts a storable commodity in the form of chemical energy into electrical energy and can determine the amount of delivered power flexibly. We assume that non-intermittent suppliers can do so with unlimited flexibility or ramping, i.e. production volumes can be varied freely between 0 and P_{nip}. Fuel and emissions right costs are given by a variable cost efficiency parameter η_{nip}, implying that total production costs increase with output. We assume no other variable costs. Fixed costs are assumed zero, representing a sunk cost not affecting the decision-making process (Pindyck, 1993). For simplicity, we assume all non-intermittent producers to have the same production cost function, where we disregard supply issues like faults or maintenance. We define n_{nip}, a treatment variable in the experiment, as the number of non-intermittent producers present in the market.

The fourth agent (labeled **operator**) is an automated market and system operator. The market operator collects all bids and offers and calculates the market clearing price. As soon as the actual demand and supply from the intermittent agents is revealed in period 2, this agent determines the additional amount of electricity to be purchased or sold in the spot market to balance demand and supply. As such, the market operator is a price-taker.

In all sessions, we keep the total number of producers as well as total generation capacity fixed, but vary the number of intermittent and non-intermittent producers. Market information like the number of intermittent and non-intermittent agents, cost structures and operating constraints of individual power producers are transparent to all market participants.

3.2. The power market and time periods

Trading electricity in wholesale power markets takes place in multiple sequential markets. Where forward contracts commit a seller to deliver and a buyer to receive power for a price that is agreed upon before delivery, spot markets serve to deal with any remaining imbalances of market agents at real time, as a perfect match between supply and demand is required to ensure grid stability.

With respect to the terminology, classic financial decision literature defines a spot market as the market when the transaction is carried out in the same period at which the decision is made (Mulvey and Vladimirou, 1992). In this study, we consider the spot market to be such a

[2] This applies to supply from subsidized renewable energy that has mainly been integrated over the past decennia, guaranteeing renewable producers a fixed price per unit of electricity produced. The most commonly used mechanism to establish this is via feed-in tariffs, which may lead to market inefficient investment in the technology mix (Couture and Gagnon, 2010). Moreover, the loss of curtailing this type of generation is generally perceived as an unacceptable solution in the view of both the renewable energy owner (Ghiassi-Farrokhfal et al., 2021) and publicly (Jacobsen and Schröder, 2012). Note that where sharply falling costs and favorable market conditions may lead to a surge of merchant renewable investments (Simshauser, 2020), and subsequently raise the curtailment threshold, operational and contractual constraints will typically enforce such projects to curtail below marginal costs.

financial market.[3] We define the forward market as the place where agents trade contracts for delivery of power during future periods of time ranging from one day to several years ahead.[4] Power is thus traded during two periods in respectively the forward and the spot market, for physical delivery immediately after clearance of the second market.

During period 1, a forward contract is traded. Forward contracts guarantee the supply of 1 entity of power in the unit MWh, in period 2 at a fixed price. All types of producers, both intermittent and non-intermittent, can submit a limit offer price and volume; i.e. they submit the minimum price against which they are willing to sell the submitted number of forward contracts. We limit intermittent producers forward trading to 115% of their nominal capacity, in line with existing policies preventing speculative behaviour of inflexible power plants (Morales et al., 2010). Moreover, since electricity is mainly traded with physically binding contracts rather than financial arbitrage in energy markets (Knaut and Paschmann, 2017), we prevent all producers from purchasing forward contracts.

The automated consumer agent is price-taking when purchasing the expected demand for period 2 in the forward market. As we only consider short-term sequential markets in this study, the market clearing volume equals the expected demand μ_D from the consumer agent. After receiving the limit offers from producers, the market clearing forward price is set at the price where total supply of forwards equals expected consumer demand. After market clearing, the forward market price is transparent to all producers.

During period 2, a spot contract is traded. Non-intermittent producers can submit both limit bid and offer prices; i.e. a maximum price against which they are willing to purchase power and a minimum price against which they are willing to sell power. Intermittent producers act as price-takers, as they do not engage in strategic trading since we assume as previously discussed that production in incentivized through subsidies. Once all bids and offers are submitted in period 2, the automated operator determines the volume needed to balance demand and supply. The system operator purchases and sells power respectively in the case of power shortage or oversupply, and thus at most 1 out of the 2 limit orders is cleared in the spot market. Once the market is cleared, realized consumer demand, realized intermittent production and the spot market price become transparent to all producers.

3.3. *Experimental framework limitations*

Weron (2014) discusses in his review on electricity price forecasting models a set of limitations related to the experimental framework of developed trading platforms. The exploitative power of such models may reduce the ecological validity, as a number of exogenous variables need to be defined. We note that the experimental framework serves to study strategies that energy agents adopt under increasing market uncertainty, not to build an experiment that mimics the economics of renewable energy as much as possible. Although we control for ecological validity and approximate exogenous variables with real-world values, some design choices, similar to limiting assumptions in the discussed analytical work on which we base our experimental framework, are difficult to overcome in an experimental setting.

First, we note that with an increasing supply intermittent renewable production, network operator costs may increase as reactive power management for voltage stability becomes more complex (Notton et al., 2018; Soares et al., 2020). Second, a growing renewable market share may cause network instabilities. For instance, Bigerna et al. (2016) show that frictions from grid instabilities grew in the Italian power market with an increasing power supply of renewable energy sources. Third, the sharp increase of renewable energy sources may cause the electrical grid to become congested, for example when grid capacity cannot accommodate the influx of renewable power. With the increase of renewable energy sources, these frictions have become more pronounced in a number of European power systems (Ciferri et al., 2020), urging the need for technological and infrastructural developments. In our experimental framework, we assume that the energy market is flexible in accommodating supply from renewable energy sources. As such, the experimental framework omits frictions like grid instabilities or congestion problems.

In the scope of this study, we believe that the experimental results are robust to leaving out of account the indicated frictions. Our research question is about how agents change decision strategies on forward and spot markets when the market share of renewable energy sources increases. The forward market decision is thereby made ex-ante, by agents facing uncertainty over consumer demand and intermittent renewable energy supply. Where differences with actual market uncertainties may persist, the above frictions could theoretically be reflected in this ex-ante uncertainty. We furthermore believe that the qualitative findings are robust to such frictions as strategic rationales for forward and spot trading remain the same with zero marginal cost producers driving positive marginal cost producers out of the forward market.

4. The experimental design

The goal of the study is to examine via a clean experimental market set-up the effects of an increasing share of intermittent renewable power production. We distinguish between three market structures:

1. The **no intermittent** production (NI) market is a market with only non-intermittent agents. We use this treatment as a base scenario, representing a traditional market without any market capacity of intermittent renewable energy supply.
2. The **low share intermittent production** market (LI) is a market with both intermittent and non-intermittent producers. The market share of intermittent capacity is one third of the total installed market capacity, the rest are non-intermittent producers. This represents a market in which renewable supply capacity is lower than conventional power supply capacity.
3. The **high share intermittent production** market (HI) is a market with both intermittent and non-intermittent producers. The share of intermittent and non-intermittent producers is inverted compared with the LI market, representing a market that is dominated by renewable supply capacity. The share of intermittent capacity is thus two thirds of the total market capacity, with the remaining production capacity supplied by non-intermittent producers in the market.

[3] Care needs to be taken with respect to the terminology in published literature. A number of studies in the energy economics literature refer to the day-ahead market as the spot market, as it has typically been the most liquid market to close positions. This is in principle inaccurate, as several markets offer the opportunity to trade away portfolio imbalances after closure of the day-ahead market. Indeed, in the context of electricity markets with increasing uncertainty driven by a growing share of intermittent renewable energy production, risk-sharing close to delivery becomes more important and short-term financial instruments, like intraday and continuous trading, gain liquidity (Knaut and Paschmann, 2017). It is furthermore expected that in power markets with high shares of intermittent renewable energy sources, rather than the day-ahead or intraday market, the real-time balancing market will become the reference market in the future, as it corresponds to the true electricity spot market (Kuepper, 2020). In this paper, we therefore consider the latter as the actual spot market.

[4] For the purpose of this paper, there is no need to focus on the differences between futures and forward contracts. Therefore we actually refer to both forward and futures contracts when we mention a forward contract.

In order to control for ecological validity, exogenous variables defined above are set to approximate real world values.[5] The number of all (intermittent and non-intermittent) power producers is set to $n = n_{ip} + n_{nip} = 15$, as power markets typically include a few dominant firms representing most of the market share (Ito and Reguant, 2016). The consumer agent's demand follows a normalized distribution with $D \approx N$ (11500, 1150), which is in the same order of magnitude to that of a small country like the Netherlands or large metropolitan area like New York. We set the maximum capacity of non-intermittent producers to $P_{nip} =$ 900 MW, nominal capacity of intermittent producers to $\mu_{P_{ip}} = 900$ MW with a deviation $\sigma_{P_{ip}} = 50$ MW. Variable costs of non-intermittent producers are set to $\eta_{nip} = 50$ euro/MWh. We allow minimum bidding prices of −300 euro/MWh and maximum bidding prices of 3000 euro/MWh.[6]

We conducted a total of five laboratory experiments, with a different set of subjects selected for every experiment. A single experiment included three sessions for each market structure, with a session being a continuous period of time where a fixed group is exposed to a single experimental treatment. Each session consisted of 30 rounds, where in every round participants could trade their production in a forward and spot market. Before the start of an experimental session, participants were randomly assigned a producer role, being either an intermittent or non-intermittent producer. For the LI and HI treatment, this procedure was repeated two more times during the respective session in order to ensure that every subject participated an equal amount of rounds as every producer type. The three market structures or treatments were presented in a counterbalanced order over the set of five experiments. A computerized program, written in JAVA and openly accessible via the web,[7] was used to implement the experimental environment.

Subjects were recruited among graduate students that specialize in energy finance and receive extensive training on energy trading, power market design and financial decision making as part of the curriculum. Once selected for the experiment, subjects were further instructed on submitting bid and offer prices, understand the probability structure of demand and intermittent supply, different types of production technologies, and keep track of financial results. They were provided the specific experimental instructions, available in appendix, via e-mail before the experiment and these instructions were read aloud before the experiment. No communication between subjects was allowed and each experiment lasted about 1 h.

Incentives were created and communicated to solely depend on financial performance. Participants were paid proportionally with total generated profit, in order to keep a diverse set of strategies open and allow for a realistic representation of market participants with different degrees of risk aversion or strategic incentives. Besides the goal of profit maximization, no further incentives were given in order to avoid any hedging or strategic biases. Cash was the only incentive offered and paid proportionally to the experimental subject group with a total of 375 euro per experiment, averaging to 25 euro per participant.

In order to control for learning in the initial rounds, the analysis is performed only on data from the rounds where market clearing prices converged and remained within a margin of 25 percent of the average over the previous five rounds. For all five experiments, convergence was achieved within five learning-rounds, resulting in data of 25 rounds for every market structure in every experiment. Fig. 1, providing information on summary statistics of forward bidding volumes of non-intermittent producers over all five experiments, further provides insights on whether subjects acted rationally across treatments and experiments. First, forward bidding volumes approximate P_{nip} with relatively little variation for NI. As the market share of intermittent renewable energy sources increases towards HI, forward bidding volumes of non-intermittent producers drop and become more variable. This is line with Peura and Bunn (2021), who indicate that with higher renewable output variability, hedging is reduced and non-intermittent producers may engage strategically in forward trading to gain spot market share. Second, non-intermittent bidding volumes remain between 0 and P_{nip} across all experiments. Where the intuition behind the figure is discussed further in the next section, the above points illustrate that ex-ante decisions of individual subjects on forward positions are rational and in line with the expectation from literature. It further confirms the view that outlier strategies in the experimental design remain within boundary conditions.

5. Experimental results

We first analyze the outcomes of the experiments by analyzing market performance in terms of allocated forward and spot volumes for both types of producers. Next, we elaborate on individual decision making, evaluating how non-intermittent producers place market bids in order to retain profits in power systems with a high market share of intermittent renewable energy sources.

5.1. Allocated volumes

Table 1 shows the allocated volumes of intermittent producers in the forward and spot market for the two treatment set-ups where intermittent producers are active. In the first experiment of the LI market, intermittent producers sell on average 892 MWh forward (median 900 MWh). They sell 5 MWh on average on the spot market (median 4 MWh), or alternatively on average 55 MWh in terms of absolute values. This shows the balancing nature of the spot market where imbalances from both shortage and oversupply are settled in order to ensure market and grid stability. Over all the experiments of the LI market, intermittent producers sell almost all of their expected output (900 MWh) on the forward market. We observe the same behaviour in the HI market, as intermittent producers with low marginal costs enter the merit order and sell almost all of their expected production volume on the forward market. The similar outcome of intermittent producers in LI and HI markets is consistent with Knaut and Paschmann (2017), who argue that restricted participation in real-time markets prevents intermittent producers from engaging in strategic behaviour.

Although the average and median allocated volumes do not differ between the LI and HI market, we do observe differences between the LI and HI standard errors in the forward market. In all experiments, the standard error of the allocated volumes is higher in the HI market than in the LI market. We attribute the higher dispersion of allocated volumes in the HI market to the increased market share of intermittent producers. Indeed, with increasing intermittent capacity, minimum values in the HI market indicate that some intermittent producers deviate from the nominal bidding procedure. This is mainly due to high bidding prices, which result in the risk of not being cleared in the market.

Table 2 shows the allocated volumes of non-intermittent producers. In the first experiment, producers sell 750 MWh on average (median 890 MWh) in the forward market. They purchase on average 20 MWh (median 0 MWh) in the spot market, or on average 56 MWh in terms of absolute values. Moving from NI to LI and HI, we observe a decreasing pattern in allocated conventional volumes in the forward market. With an increasing market share of intermittent producers, the volumes

[5] We note that the absolute numbers in the experiment are of little importance, arbitrarily depending on the number of market participants, market technologies and production costs. The results of the experiment are rather illustrative for relative performance of market prices in relation to the decision making behaviour of intermittent and non-intermittent producers.

[6] To the best of our knowledge, all power markets apply minimum and maximum prices. The limits that we apply are in accordance with Dutch power markets.

[7] While the online experimental market environment was originally designed for this study, it has been further developed and used by other research groups. The documentation, JAVA code and original instructions are openly accessible via github.com/eur-rsm/hedging_game. The instructions can also be found in Appendix A.

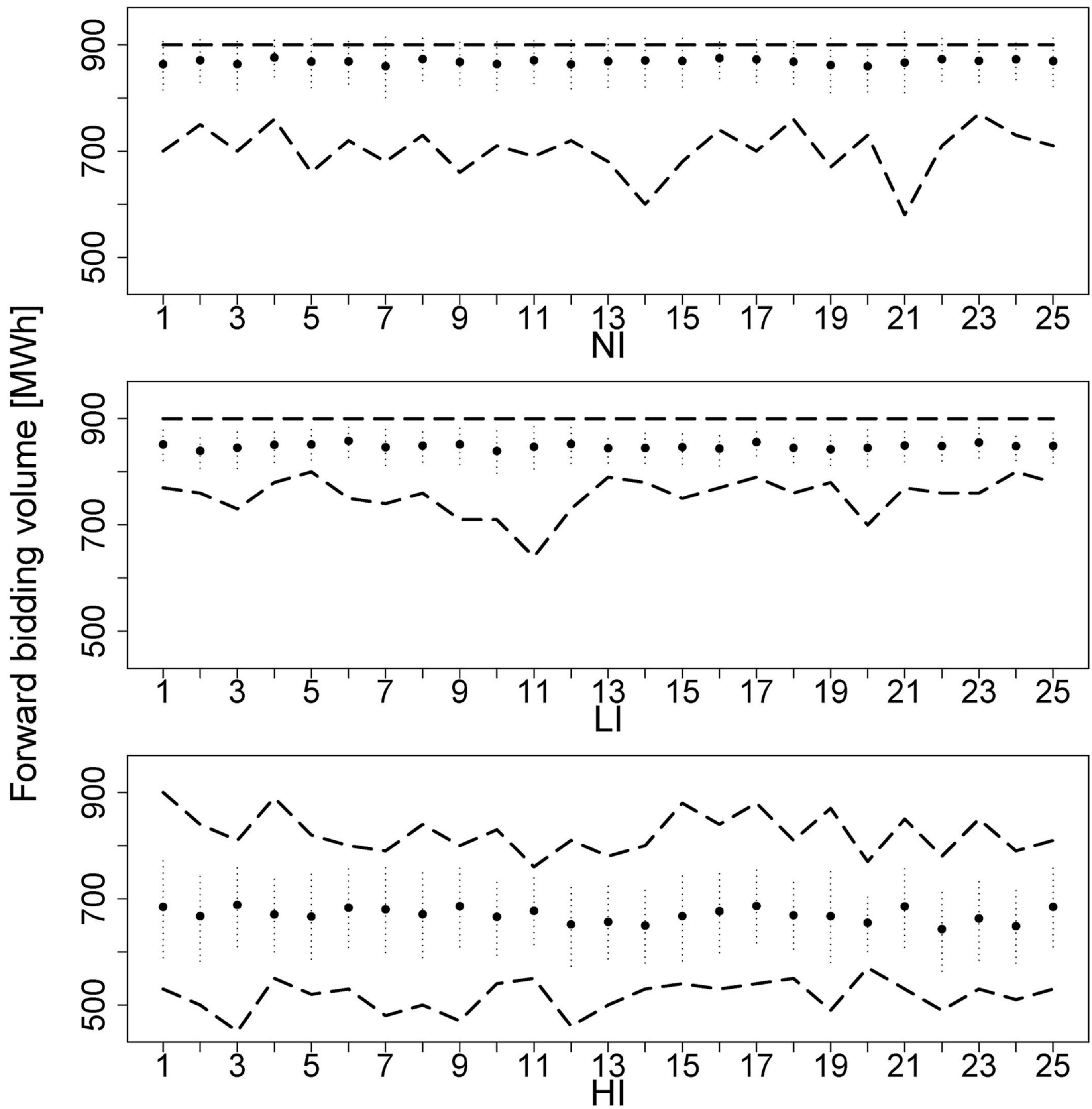

Fig. 1. Average forward bidding volumes of non-intermittent producers per round and treatment, incl. max-min range (dashed) and standard deviation error bars (dotted).

allocated to non-intermittent producers decreases. This is in line with the well-known decreasing merit-order effect of intermittent renewable energy supply on electricity prices in short-term forward markets, as low marginal cost producers replace conventional production capacity (Sensfuβ et al., 2008). Interestingly, the opposite pattern is apparent in the spot market. Minimum allocated volumes in the forward market and median allocated volumes in the spot market furthermore indicate that not all bids of non-intermittent producers are successful when the market has cleared.

We observe that standard errors for allocated volumes of non-intermittent producers are higher than those of intermittent producers. Moreover, we notice larger standard errors with an increasing intermittent market share, both for the forward and the spot market. This indicates a larger discrepancy in forward and spot decision making between individual non-intermittent producers.

5.2. Forward decision making of non-intermittent producers

The above results indicate that non-intermittent producers move from the forward market to the spot market when the share of intermittent producers increases. In other words, flexible power producers trade less on the forward market and more on the spot market when the market capacity of renewable energy sources increases. This results in more uncertainty in profits and losses of non-intermittent power plants,

Table 1
Allocated market volumes intermittent producers.

experiment	Forward				spot				
	mean(se)	median	min	max	mean(se)	|mean|(se)	median	min	max
	Market: LI								
1	892(1)	900	890	920	5(7)	55(5)	4	−142	610
2	906(1)	900	890	930	−2(5)	41(3)	−2	−118	107
3	889(1)	890	870	910	3(4)	39(2)	12	−114	80
4	896(1)	900	840	930	14(5)	40(3)	11	−89	131
5	891(2)	890	840	940	24(5)	47(3)	25	−90	125
	Market: HI								
1	893(4)	900	269	930	−6(6)	56(4)	−29	−164	634
2	894(5)	900	152	940	−23(7)	62(6)	−38	−176	777
3	878(2)	880	342	910	27(5)	55(3)	18	−105	575
4	884(3)	890	307	930	0(4)	36(3)	−3	−118	604
5	891(3)	900	210	950	−4(4)	40(3)	3	−120	642

Table 2
Allocated market volumes non-intermittent producers.

experiment	Forward				Spot				
	mean(se)	median	min	max	mean(se)	|mean|(se)	median	min	max
	Market: NI								
1	750(15)	890	0	900	−20(10)	56(9)	0	−900	900
2	750(14)	880	0	900	−25(10)	58(9)	0	−900	765
3	758(15)	880	0	900	8(10)	58(10)	0	−900	900
4	751(14)	890	0	900	−8(9)	48(8)	0	−900	900
5	753(15)	880	0	900	−17(11)	74(10)	0	−900	900
	Market: LI								
1	687(19)	830	0	900	4(14)	88(13)	0	−870	900
2	683(21)	845	0	900	−43(17)	110(16)	0	−900	900
3	706(19)	840	0	900	−34(15)	90(14)	0	−900	900
4	692(19)	830	0	900	−25(15)	86(14)	0	−871	900
5	691(20)	840	0	900	−32 (16)	104(15)	0	−880	900
	Market: HI								
1	489(25)	620	0	880	−3(34)	237(26)	0	−840	900
2	476(24)	610	0	870	40(34)	251(25)	0	−810	900
3	533(24)	640	0	840	−84(30)	216(24)	0	−810	773
4	523(23)	610	0	840	−39(28)	194(23)	0	−800	900
5	485(23)	580	0	890	24(28)	181(22)	0	−850	900

but not necessarily in reduced profits. Since non-intermittent producers set prices in the spot market where intermittent producers act as price-takers, obliged to trade away any remaining imbalances resulting from variation in realized production volumes, they may use their convenience yield for flexibility to retain profits.

Table 3 presents the average profits of non-intermittent producers for all experiments. In the first experiment, average profits of non-intermittent producers were 16758 euro in the forward market (median 18900 euro), 1949 euro in the spot market (median 0 euro) and 18707 euro in total (median 19800 euro). We find evidence for the merit-order effect in the forward market, resulting in lower profits and a subsequent market push-out of conventional power plants. Non-intermittent producers do however increase trading profits in the spot market, with higher profits in markets with an increased share of intermittent renewable energy sources. This indicates a demand for flexible spot production, i.e. a convenience yield for flexibility in the producer's portfolio. Moreover, lower median values in the NI and LI spot market indicate that non-intermittent producers mostly earn money in the HI spot market.

In order to verify whether non-intermittent producers are able to retain their profits when the market share of intermittent producers increases, we run a multilevel mixed-model extension of the Mann-Whitney test, allowing to test for differences between the three market set-ups while taking into account the nested group structure. Z-scores are reported in Table 3, calculated by comparing ranks between treatment levels, while p-values are obtained by comparing the Z-score against a distribution of Z-scores calculated by bootstrapping ranks with no treatment interference. We find that with an increasing intermittent market share, forward profits decrease and spot profits increase significantly, resulting in total profits to significantly decrease from NI to LI and significantly increase from LI to HI. No significant differences are found in total profits between the NI and HI market for non-intermittent producers, indicating that non-intermittent producers can indeed retain profits.[8]

Risk-adjusted profits, defined here as average profits divided by the standard deviation, drop sharply in the forward market but increase in the spot market with an increasing share of intermittent producers. This indicates that hedging pressure may decrease as the market share of intermittent producers increases, and non-intermittent producers move to spot markets to exploit favorable market conditions. Note that total risk-adjusted profits however decline, indicating that despite larger expected profits, non-intermittent producers are exposed to more risk in order to retain profits.

We verify whether the shift in decision making of non-intermittent producers also appears in forward bidding volumes and prices in Table 4. In the first experiment, non-intermittent producers offer to sell on average 870 MWh (median 900 MWh) against an average price of 66 euro per MWh (median 67 euro per MWh). We find that the standard error of the bidding volumes increases from NI to HI, indicating that not all producers follow the same strategy. We define this form of disagreement as the mean of the individual producers' variances, resembling on average the difference of individual non-intermittent producer strategies. Highest levels of disagreement are found for the HI market, with some producers clearly bidding forward volumes around half of their capacity (450 MWh), while others remain more risk-averse. Fig. 1 confirms this view, as the range of forward bidding volumes of non-intermittent producers increases with a growing market share of intermittent producers.

We further find that with an increasing market share of renewable energy sources, non-intermittent producers sell against lower prices on average in the forward market, approaching the marginal production cost of 50 euro per MWh in the HI market. Minimum prices may actually fall below marginal production costs for some producers. This motivates us to study whether individual non-intermittent producers act as price-takers or price-setters.[9] Fig. 2 shows the capacity-weighted shares of price-taking and price-setting non-intermittent producers. We find that for the NI market, over half of the non-intermittent producers are price-taking. For the LI market, just a few non-intermittent producers are price-taking, whereas in the HI market all are price-setting. This shows that as the market share of intermittent production increases, non-intermittent producers are willing to take more risk in order to retain their revenues. In line with the findings of Peura and Bunn (2021), the results thus show evidence that an increasing market share of intermittent renewable energy impacts strategic and risk-related rationales

[8] We note that this result is distinctly different from established findings indicating that flexible strategic producers may withhold capacity in order to profit from created price differences. For example, Morales et al. (2014); Rintamäki et al. (2020) build on the notion of correctly predicting a deficit or surplus in power spot markets. In case deviations do not occur as expected, losses occur as the created portfolio imbalances do not counterbalance the existing system imbalance. Instead, our result shows that irrespective of the realized system imbalance, flexible non-intermittent producers decide to adjust their forward price and volume decisions in order to retain profits in spot markets.

[9] In the set-up of our methodological framework, profit maximizing price-takers minimize costs. They bid their marginal production cost in the forward market and the realized forward price in the spot market. We allow a price deviation of 5% to be assigned as a price-taking producer. Note that as the only objective given during the experiments was to maximize profits, the share of price-takers relates to the degree of risk-aversity. The ex-post analysis therefore only focuses on relative differences between market treatments.

Table 3
Market profits non-intermittent producers.

exp	Forward			Spot			total		
	mean(se)	median	risk-adjusted	mean(se)	median	risk-adjusted	mean(se)	median	risk-adjusted
	Market: NI								
1	16758(342)	18900	2.53	1949(420)	0	0.24	18707(457)	19800	2.12
2	24667(499)	27390	2.55	2045(329)	0	0.32	26712(552)	28500	2.5
3	23656(488)	26400	2.5	3290(611)	0	0.28	26946(608)	27000	2.29
4	16975(335)	18630	2.62	1979(412)	0	0.25	18954(456)	18920	2.15
5	23256(538)	25800	2.23	2943(516)	0	0.29	26199(607)	28560	2.23
	Market: LI								
1	10937(323)	12390	2.14	4683(801)	0	0.37	15620(757)	14280	1.31
2	13394(450)	15160	1.88	4901(889)	0	0.35	18295(903)	16332	1.28
3	13973(446)	14400	1.98	4091(683)	0	0.38	18064(742)	16175	1.54
4	14456(436)	16600	2.1	4060(697)	0	0.37	18516(738)	17920	1.59
5	12331(389)	13920	2	4751(746)	0	0.4	17082(745)	15132	1.45
	Market: HI								
1	6147(366)	6300	1.5	19398(2545)	5382	0.68	25545(2534)	12920	0.9
2	4747(263)	4960	1.61	17465(1875)	10179	0.83	22212(1837)	14793	1.08
3	4791(284)	4970	1.51	16041(1830)	5977	0.78	20832(1879)	10349	0.99
4	7216(367)	7300	1.76	13590(1832)	465	0.66	20806(1815)	12640	1.03
5	6537(368)	6480	1.59	16190(2148)	2178	0.67	22727(2147)	12150	0.95
	Nested multilevel Z-scores								
NI-LI	0.412***			0.598***			0.213**		
LI-HI	0.589***			0.843***			0.145**		
NI–HI	0.735***			0.975***			0.032		

***$p < 0.001$, **$p < 0.01$, *$p < 0.05$.

Table 4
Forward bid volumes and prices of non-intermittent producers.

exp	Volumes					Prices			
	mean(se)	disagreement	median	min	max	mean(se)	median	min	max
	Market: NI								
1	870(2)	51	900	710	900	66(0)	67	52	81
2	864(3)	71	900	600	900	68(1)	68	51	97
3	875(2)	42	900	760	900	71(0)	71	50	95
4	857(3)	79	900	580	900	64(0)	63	51	88
5	877(2)	33	900	760	900	70(0)	69	51	94
	Market: LI								
1	840(2)	31	840	760	900	60(0)	60	51	77
2	857(2)	45	860	760	900	61(0)	60	49	82
3	850(2)	35	850	770	900	60(1)	56	51	95
4	842(3)	52	845	640	900	64(0)	64	45	85
5	851(1)	26	850	790	900	61(0)	60	50	84
	Market: HI								
1	671(6)	74	670	480	880	59(1)	57	48	74
2	653(7)	85	640	450	870	57(0)	57	51	69
3	692(6)	72	690	530	880	56(1)	55	33	74
4	672(7)	83	670	490	840	59(1)	59	49	74
5	660(8)	96	650	460	900	59(1)	58	50	75

for forward trading.

5.3. *Forward and spot price dynamics under supply uncertainty*

Non-intermittent producers shifting focus from forward to spot markets affect price dynamics in such sequential markets. Table 5 provides summary statistics of market clearing prices in the forward and spot market. We observe two well-documented effects of variable renewable energy sources on power prices. First, mean forward and spot power prices decrease from NI to HI, in line with the merit-order effect (Sensfuβ et al., 2008). Second, spot prices become more volatile as the share of variable renewable energy sources increases, in line with the findings of Huisman et al. (2021). Moreover, minimum and maximum spot clearing prices indicate that the increasing market share of variable renewable energy sources also affects the tails of the spot price distribution. These results are largely in line with Huisman et al. (2022), who provide proof that variable renewable energy sources may affect the fatness of the left and right tails of spot price distribution asymmetrically. Indeed, where minimum prices indicate that the increasing share of renewable energy sources fattens the left tail of the spot price distribution, the effect is less clear on the right side of the distribution, as maximum prices first decrease from NI to LI and sharply increase again from LI to HI.

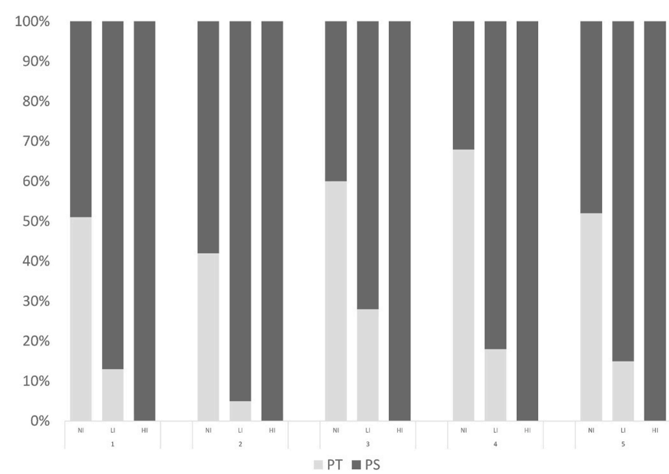

Fig. 2. Capacity-weighted share of non-intermittent producers engaging in price-taking (PT) and price-setting (PS) market decision behaviour, per market treatment and experiment.

Fig. 3 visualizes bidding price density distributions of non-intermittent producers in forward and spot markets for all market treatments. The figure shows that across all experiments, forward bidding prices decrease in markets with an increasing share of intermittent renewable energy sources. Note that in line with Figs. 1 and 3 indicates that ex-ante decisions of individual subjects are rational and remain within boundary conditions. Signalling a more competitive market setting, forward bidding prices are closest to the marginal producing costs of non-intermittent producers in the HI market. Spot bidding price density functions present a bimodal distribution (confirmed for all market structures by a Hartigans dip test index < 0.05), as producers

Table 5
Forward and spot clearing prices.

exp	Forward						Spot					
	mean	sd	median	min	max	skew	mean	sd	median	min	max	skew
	Market: NI											
1	72	2	72	69	77	0.2	83	44	88	34	163	0.45
2	83	4	83	75	91	0.22	64	42	43	16	133	0.41
3	81	4	80	74	92	0.81	75	51	84	15	163	0.88
4	73	3	73	67	81	0.5	76	45	94	29	151	0.24
5	81	6	82	69	90	−0.1	80	48	44	35	154	0.35
	Market: LI											
1	66	2	66	62	71	0.2	86	47	102	22	154	−0.13
2	70	4	69	63	78	0.22	60	47	40	12	157	0.82
3	70	5	69	63	86	1.4	77	52	99	6	148	−0.1
4	71	4	71	64	78	0.01	74	52	34	11	153	0.48
5	68	4	67	62	74	0.11	70	50	32	11	171	0.53
	Market: HI											
1	63	4	62	57	70	0.42	70	78	21	−20	202	0.47
2	60	2	60	56	64	0	73	65	101	−27	158	0.1
3	59	4	59	54	68	0.44	49	78	7	−45	200	−0.63
4	64	4	63	59	74	0.97	65	70	17	−10	194	0.46
5	63	5	63	57	74	0.46	83	79	113	−49	189	−0.3

need to place two limit orders in the spot market, one for selling power and one for buying back power[10]. This is in line with published empirical research of German power markets, showing that higher quantile prices are more heavily affected by variations in supply from renewables (Huisman and Stet, 2022). We further observe spot bidding prices to become more volatile with an increasing market share of intermittent production, creating more favorable spot market conditions for flexible non-intermittent producers in markets with a high share of renewable energy sources. This means that with an increasing market share of intermittent renewable energy sources, (1) the spread between the two modes increases, meaning that the absolute value of the forward premium increases, and (2) the volatility increases related to the wider distribution of both modes.

Summarizing, we find that a deep decarbonization of the power sector, driven by an increasing market share of intermittent renewable energy sources, may cause non-intermittent producers to retain profits by moving focus from the forward to the spot market. An increasing market share of intermittent production increases the expected volatility of spot demand and thereby reduces the relative risk-related hedging pressure in the forward market of non-intermittent producers, as they engage in strategic forward decisions motivated by favorable spot market conditions. The indicated forward-spot decision strategies of non-intermittent producers result in a larger bidding spread between the two limit orders in the spot market for buying back power and selling extra power, as non-intermittent producers utilise a convenience yield for flexibility in order to retain their profits. As most non-intermittent flexible producers in current power markets burn polluting fossil fuels to produce power,[11] a further integration of renewable energy sources may as such induce adverse market effects and indirectly hamper emission reduction targets. The results therefore urge policy makers and regulators to adequately evaluate sequential price dynamics and the role of low-carbon flex technologies.

6. Empirical validation

In this section, we validate whether we can find empirical evidence for the experimental results. Where the findings confirm the well-documented view that the intermittent nature of renewable energy sources may cause spot prices to fluctuate heavily and exhibit price spikes, our experimental results show that this effect may be strengthened by the strategic decision behaviour of non-intermittent producers. Irrespective of actual spot demand, predictions on high market shares of variable renewable energy sources may thus lead to a wider spot bidding spread. We examine whether we can find empirical evidence for this by estimating the effect of forward (day-ahead) wind prediction levels on the forward premium. We propose the following model:

$$p_f^{t,T} - p_s^T = \alpha_v + \beta_1 \mathrm{Vol}_T + \beta_2 \mathrm{Wind}_{t,T} + \beta_3 \mathrm{Gas}_t + \beta_4 \mathrm{Margin}_t + \varepsilon_T \tag{1}$$

where the term on the left-hand side resembles the realized forward premium,[12] $p_f^{t,T}$ is the forward price at time t for delivery in T and p_s^T is the spot price at delivery. All predictive variables are day-ahead predictions, with the obvious exception of actual realized imbalance volumes. This resembles our experimental design, controlling for information gains between forward market closing and spot market decision making. The main variables of interest are the predicted volume of wind production Wind_t,T at t for delivery in T, and the spot demand for power Vol_T at T.[13]

For illustration purposes, we consider a power market where wind generation is responsible for a substantial part of the supply curve. Day-ahead predictions for day A indicate that wind mills will produce at maximum capacity, whereas it is predicted to be windstill on day B: $\mathrm{Wind}_{A-1,A} > \mathrm{Wind}_{B-1,B}$. Considering on the day itself an equal spot demand $\mathrm{Vol}_A = \mathrm{Vol}_B$, our experimental findings suggest the absolute value of the forward premium to be higher in case of the windier day: $\left|p_f^A - p_s^A\right| > \left|p_f^B - p_s^B\right|$.

[10] We note that further follow-up work could consider the implementation of multi-unit bidding, as risk and strategic preferences vary across quantities and prices.

[11] Studying the impact of renewables in the Californian power market, Bushnell and Novan (2018) show that an additional GWh of solar generation may increase the average level of gross generation of the most polluting gas turbines, in contrast to decreasing the usage of more clean alternatives like CCGT and steam turbines.

[12] While forward price models focus on ex-ante expectations of spot price and premium realizations, empirical analyses focus on an ex-post analyses of realized premiums. This may be addressed by controlling for shocks to spot price expectations as well as for the endogeneity of the premium with realized spot prices (Bunn and Chen, 2013).

[13] While we expect both these independent variables to correlate, estimating the model with subsets of our data presented further do not raise major concerns of multicollinearity.

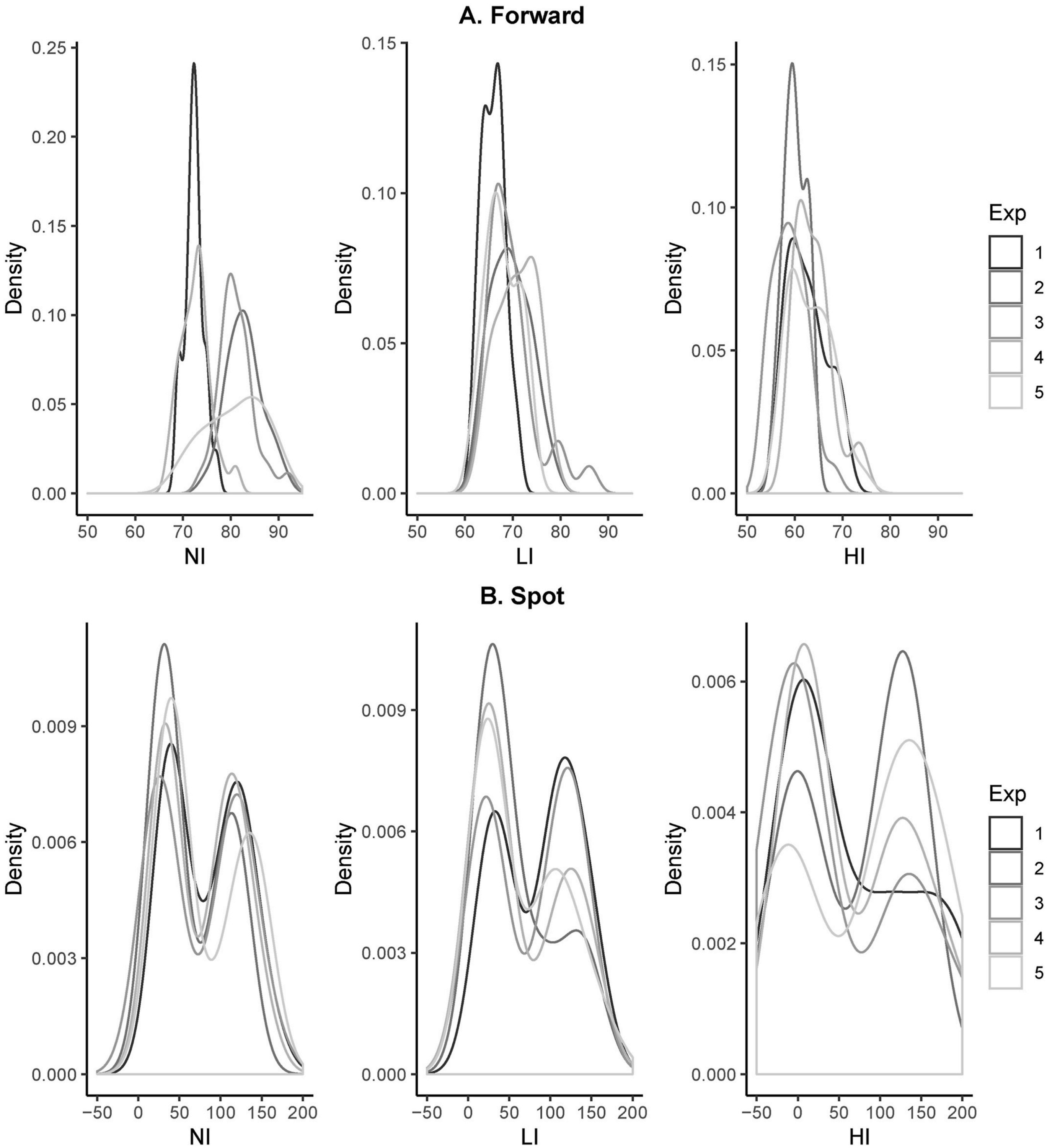

Fig. 3. Bidding prices of non-intermittent producers in the no intermittent production (NI), low share intermittent production (LI) and high share intermittent production (HI) market structures for the (A) forward market and (B) spot market.

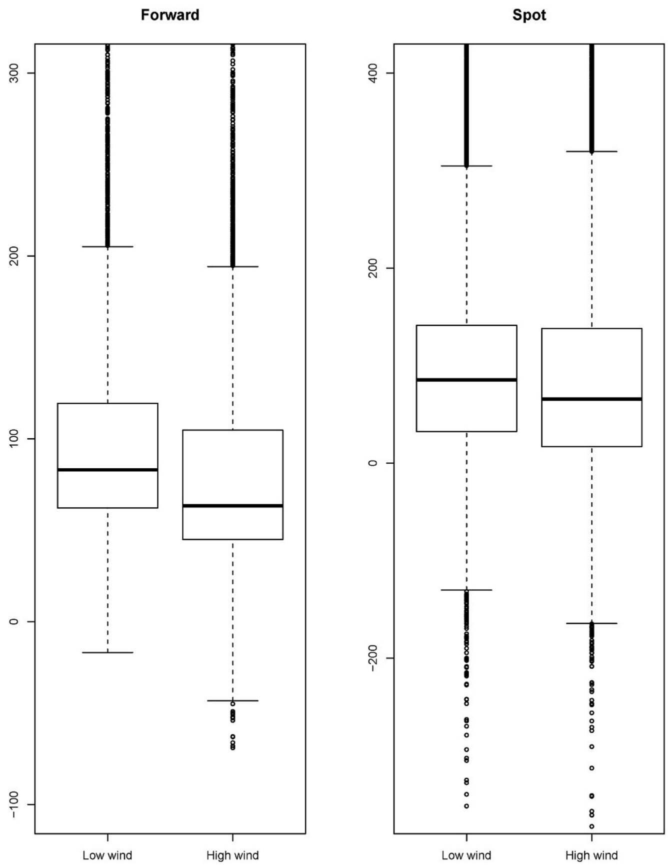

Fig. 4. Boxplots of German forward (day-ahead) and spot (imbalance) prices [EUR/MWh] for respectively the 50% least (Low wind) and the 50% most windy days (High wind) in 2021, forecasted day-ahead. Data from ENTSO-E (2022).

6.1. Data

We validate the above argumentation using data from short-term forward and spot power markets in Germany in 2021.[14] With the outspoken objective to achieve a share of renewable energy in power production of 80% by 2050, Germany's renewable energy share has boosted through massive subsidies. At the same time, several subsidy free renewable projects have been announced in recent years, leaving developers exposed to merchant risks and decision strategies in open markets. These rapid expansions in wind and solar power and a more market-driven approach by regulators motivate us to empirically evaluate our findings in the German power market, as the main reference for power systems with a pronounced increase in renewable market capacity in Europe.

We note that German electricity markets, similar to most European markets, observed an electricity price surge in the second half of 2021. The increasing prices have been attributed to a combination of supply and demand factors. In particular an increased global demand for energy, linked to the economic recovery of the Covid-19 pandemic, in combination with price hikes for all energy commodities, but in particular natural gas, have been put forward as the main drivers (Kanellopoulos et al., 2022). This unprecedented market situation has also been linked to additional market volatility in electricity spot markets, which could sustain itself in the years ahead (International Energy Agency, 2022). It is therefore of interest to study to which extent the studied decision making and a convenience yield for flexibility could prevail in such market conditions.

We collect German power market data over the year 2021 from the ENTSO-E Transparency platform (ENTSO-E, 2022). Wind [MWh] day-ahead predictions are provided by the Transmission System Operator (TSO) with a quarter-hourly frequency. Note that reported data by the system operator is not based on exact metering for each utility but rather based on a combination of computation, measurements and extrapolations from specific metered utilities in combination with weather data. Forward (day-ahead) [euro/MWh] and spot (balancing[15]) [euro/MWh] market price data is reported with a respective hourly and quarter-hourly granularity by the TSO.[16] We further collect hourly day-ahead gas spot prices from TTF [euro/MWh] ,[17] the main reference hub for gas prices in Northwestern Europe (Broadstock et al., 2020), to serve as a proxy for fuel costs of the marginal producer. Lastly, we collect data on day-ahead predictions of total generation [MWh] and total load [MWh] in the German control area to define the reserve margin as the ratio between both (Redl and Bunn, 2013). We interpolate the daily (day-ahead gas price) and hourly (day-ahead power price) data to a quarter-hourly time granularity.

[14] We note that validating experimental findings with empirical data is subject to a number of design constraints, as the exploitative power of an experiment reduces the ecological validity. Indeed, Redl and Bunn (2013) study how sequential price formation in wholesale power markets depends on the interaction between multiple drivers, related to fundamental, behavioural, market or external drivers. As such, any empirical validation of an experimental market design may thus fail to meet the exact ceteris paribus conditions of the experiment. Rather than over a prolonged period of time, we therefore choose to empirically validate the experimental findings over one year of data, as it allows to keep variation in exogenous price drivers to a minimum. Note that variations in intermittent production capacity therefore also occur in similar market settings, while the experimental design considers the transition towards a market with a high penetration of low marginal cost producers replacing conventional production capacity. With long run marginal costs for non-intermittent generation units typically above their short run marginal costs (Blazquez et al., 2020), we believe the qualitative experimental finding of non-intermittent producers moving focus from forward to spot markets would be robust to such extensions.

[15] With the increase of intermittent renewable energy sources it is expected that the balancing market will become the main reference spot market (Kuepper, 2020). The balancing market price corresponds to the true spot price, as system operators match supply and demand subject to real-time system constraints. We thus represent the spot price by the reBAP price, a uniform imbalance price across all control areas in Germany. The price is regarded as a price for balancing the system, rather than penalizing imbalances (balancing can lead to costs, but also generate revenues) and incorporates the price for activating both secondary and tertiary imbalance reserves close to real-time. Some further interesting characteristics motivate the reBAP price as a good representation for the spot price; (1) the reBAP price is symmetric per time interval, i.e. the same price is applied for both positive and negative imbalances. This is similar to our experiment, where irrespective of the individual imbalance, the cleared spot price is the same for all market participants; and (2) European balancing markets are in general regulated markets, where the auction design differs slightly per region and country. Although it is becoming more common, in line with the further integration and harmonisation of European balancing markets, the reBAP price was one of the first European imbalance prices based on (energy) bids that are made day-ahead. As we make use of day-ahead prediction levels for wind generation, this feature is particularly interesting with regards to our experimental set-up as no additional information on generation levels is available to market participants on the spot market. As a consequence, prediction accuracy between the forward and spot market does not change and hence does not affect the results.

[16] Note that spot prices in general tend to be higher(lower) than forward prices for positive(negative) imbalances, resulting in a negative(positive) forward premium in order to compensate for ramping-up(ramping-down) capacity. In order to accommodate the model, we remove about 15% of the data where this was not the case.

[17] We take into account the price for a gas-fired power generation adding 2 euro/MWh as balancing and transmission tariff costs and considering the Lower Heating Value.

Fig. 4 illustrates the intuition behind the effects of intermittent production on German forward and spot trading. The figure depicts forward (day-ahead) and spot (balancing) prices for the 50% least and the 50% most windy forecast days in 2021. Note the different scale for both markets, indicating generally higher price volatility in spot markets. The merit-order effect is observed in the forward market, as prices drop on more windy days. There is a less clear decreasing pattern in the spot market, as prices are more volatile and scattered in both the positive and negative direction. In line with our experiment, the simple illustration demonstrates the impact of intermittent renewable energy sources on price formation in short-term electricity forward and spot markets.

6.2. Results

With power prices typically non-normally distributed and the impact of the explanatory variables on prices likely to be non-linear (Mulder and Scholtens, 2013), we first apply the Box-Cox transformation ($\lambda = 0.22$). As the dependent forward premium needs to be strictly positive, we estimate equation (1) on the absolute value of the premium.[18] Accommodating the Box-Cox transformation in line with our experimental results, we also take the absolute value of the spot volume explanatory variable $|\mathrm{Vol}_T|$. We then apply the Davidson-Mackinnon test (PE test) to compare the linear and log-linear specifications in both non-nested models. As adding the auxiliary regressor with the difference of the log-fitted values from both models is non-significant, we report the results over the linear specification. Results given in Table 6 largely follow our expectation, with the adjusted R^2 statistics suggesting an adequate fit in terms of a model estimating the short-term forward premium in power markets (Douglas and Popova, 2008; Koolen et al., 2021).

Focusing on the role of intermittent wind production, we find evidence for a positive effect of day-ahead wind predictions on the absolute premium, while controlling for actual imbalances. This result indicates that when high shares of intermittent production are predicted day-ahead, non-intermittent producers are likely to increase the absolute forward premium by bidding lower(higher) spot prices to balance negative(positive) real-time demand. In other words, irrespective of the actual spot demand in real-time on the day itself, high day-ahead predictions on wind generation result in more extreme spot prices. This is in line with the experimental results indicating favorable spot conditions for non-intermittent producers with an increasing market share of renewables.

These results imply that as regulators and policy makers gradually adopt a more market-driven approach to the integration of renewable energy sources, it is important to adequately evaluate the role of flexibility in wholesale power markets as strategic decisions of financial stakeholders may create market instabilities. Our findings show that the option-like characteristics of assets offering short-term flexibility, such as having the option to store power or having the option to increase or decrease consumption volumes, profit from the increased volatility in short-term power markets. As this increased volatility offers a financial stimulation for investments in flexibility assets, policy makers should focus on taking away hurdles faced by low-carbon flex technologies. In order to allow for a more efficient market integration of such flexible assets, regulators and policy makers could for example address an efficient uptake of low-carbon dispatchable production and storage technologies. Furthermore, stimulating the uptake of demand-side flexibility to increase demand elasticity may facilitate the transition to a low-carbon power system (Hirth et al., 2022). Next to financial and technological hurdles, lowering grid tariffs while reinforcing power grids, increasing the access to short-term balancing markets, reducing minimum trade sizes and increasing the allowed price ranges could for example address market design, infrastructure and regulation uncertainties hampering the efficient uptake of low-carbon flex.

In terms of other specifications, we find the expected result that larger realized imbalance volumes increase the demand for spot balancing in real-time. Gas prices further present a positive effect on the absolute premium in time, in line with the expectation that day-ahead prices may strongly correlate with gas prices (Kanellopoulos et al., 2022). In case of positive (deficit) demand, costs are associated to ramping costs of gas-fired power plants, whereas gas prices negatively influence the magnitude of the premium when negative (surplus) demand occurs, associated with ramping down costs being offset by avoided fuel and carbon costs.

Table 6
Regression estimates for equation (1), Germany 2021. Robust standard errors in parentheses.

	Dependent variable: $\left\|p_f^{t,T} - p_s^T\right\|$
	(2021)
$\|\mathrm{Vol}_T\|.10^{-3}$	3.48***
	(0.15)
$\mathrm{Wind}_t.10^{-6}$	3.79**
	(1.45)
Gas_t	0.03***
	(0.00)
Margin_t	0.15
	(0.09)
Constant	4.58***
	(0.09)
Adjusted R^2	0.22

Note: *p<0.05; **p<0.01; ***p<0.001.

7. Conclusion and policy implications

With public concerns about the adverse effects on the environment of using fossil fuels to generate electricity leading to an, often politically motivated, increase of renewable energy sources in global power systems, power markets are increasingly in a state of uncertainty and flux. Renewable energy producers bear no marginal costs from fuels and emission rights and are therefore placed before fuel based power plants in the merit-order of the supply curve. Where the increased volume supplied by renewable energy sources lowers market prices, it may also increase spot price volatility as variation from intermittent renewable supply cannot (yet) be off-set flexibly due to limited storage capacity and price inelastic demand. Lower market prices threaten the profitability of traditional non-intermittent fuel based power plants. Increased price volatility is however an opportunity for such non-intermittent producers as they have the option to adjust production volumes and can therefore counterbalance the variation in supply from renewable energy sources. As policy makers and regulators gradually adopt a more market-driven approach to a further integration of intermittent renewable energy sources, market design must be inherently robust and adequately

[18] Note that by taking the absolute value of the forward premium, we leave out of account market differences related to positive (deficit) and negative (surplus) imbalance volumes. For example, where spot price distributions of the German power market exhibit predominantly positive skewness, Gianfreda and Bunn (2018) observe that negative skewness occurs more frequently with the increase of intermittent renewable energy sources. Huisman et al. (2021) allocate this to distinct effects of variable renewable energy sources on markets with positive or negative imbalance demand and validate the equilibrium model results of Bessembinder and Lemmon (2002) by showing that an increasing market share of intermittent renewable energy sources negatively affects the forward price premium. Taking the absolute value allows us to disregard this and focus exclusively on the strategic (absolute) convenience yield for flexibility. Second, where renewable energy producers are typically price-takers in the case of positive (deficit) spot markets, renewable strike prices may play a significant role in setting the price in negative (surplus) spot markets. Where the effect in practice may thus differ between both sides of the market, we focus on the overall effect in the entire market.

evaluate low-carbon flexibility.

In this paper, we study how the increase of supply from intermittent renewable energy sources in power markets affects decision making and price formation in forward and spot power markets via an experimental approach. The results indicate that while an increasing market share of intermittent renewable energy production may lower prices and increase short-term price volatility, non-intermittent producers, who can flexibly adjust spot volumes, can retain their profits by shifting focus from forward to spot markets. The present study is a first step in using experiments to investigate operations, decision making and pricing in power markets with an increasing share of renewable energy sources. The developed trading environment allows us to vary the market share of renewable energy sources with a high degree of control via three market structures ranging from a non-intermittent market with no intermittent renewable energy sources, to a market with a low share of intermittent renewable energy sources and a market with a high share of intermittent renewable energy sources. We find the increase of intermittent renewable energy sources in short-term power markets to affect hedging and strategic rationales for forward trading. With more intermittent renewable market capacity, non-intermittent producers may engage in strategic forward positions as relative hedging pressure decreases, motivated by favorable spot market conditions and a convenience yield for flexibility.

Our study provides important insights for policy makers to adequately evaluate renewable market dynamics in wholesale power markets. As regulators turn away from complex feed-in tariffs and support mechanisms by gradually adopting a more market-driven approach, it is key for policy makers to ensure that markets provide adequate price signals for assets and investments, ensuring security of supply in an efficient and sustainable way. We show that an increasing market share of intermittent renewable energy sources increases the volatility in markets for short-term delivery of power. This provides financial opportunities for investments in assets that provide short-term flexibility such as batteries and demand response systems, but currently also fuel based supply may offer volume adjustment flexibility that renewable supply does not have. As a further integration of renewable energy sources may as such induce adverse market effects and indirectly hamper emission reduction targets, the study engages regulators and policy makers to address the role of increased price volatility and flexibility in wholesale power markets to achieve a robust decarbonization of the power sector. Our findings thereby urge policy makers to focus on taking away financial, economic and regulatory hurdles which may hamper an efficient uptake of low-carbon flexibility.

CRediT authorship contribution statement

Derck Koolen: Conceptualization, Methodology, Software, Data curation, Formal analysis, Visualization, Investigation, Validation, Writing – original draft, Writing – review & editing. **Ronald Huisman:** Conceptualization, Methodology, Investigation, Validation, Writing – original draft, Writing – review & editing, Supervision. **Wolfgang Ketter:** Conceptualization, Methodology, Investigation, Validation, Writing – review & editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enpol.2022.113025.

References

Allaz, B., Vila, J.-L., 1993. Cournot competition, forward markets and efficiency. J. Econ. Theor. 59 (1), 1–16.

Bessembinder, H., Lemmon, M.L., 2002. Equilibrium pricing and optimal hedging in electricity forward markets. J. Finance 57 (3), 1347–1382.

Bigerna, S., Bollino, C.A., Polinori, P., 2016. Renewable energy and market power in the Italian electricity market. Energy J. 37.

Blazquez, J., Fuentes, R., Manzano, B., 2020. On some economic principles of the energy transition. Energy Pol. 147, 111807.

Borenstein, S., Bushnell, J., Knittel, C.R., Wolfram, C., 2008. Inefficiencies and market power in financial arbitrage: a study of California's electricity markets. J. Ind. Econ. 56 (2), 347–378.

Borenstein, S., Bushnell, J.B., Wolak, F.A., 2002. Measuring market inefficiencies in California's restructured wholesale electricity market. Am. Econ. Rev. 92 (5), 1376–1405.

Botterud, A., Kristiansen, T., Ilic, M.D., 2010. The relationship between spot and futures prices in the nord pool electricity market. Energy Econ. 32 (5), 967–978.

Bower, J., Bunn, D.W., 2000. Model-based comparisons of pool and bilateral markets for electricity. Energy J. 21 (3), 1–29.

Brandts, J., Pezanis-Christou, P., Schram, A., 2008. Competition with forward contracts: a laboratory analysis motivated by electricity market design. Econ. J. 118 (525), 192–214.

Broadstock, D.C., Li, R., Wang, L., 2020. Integration reforms in the European natural gas market: a rolling-window spillover analysis. Energy Econ. 92, 104939.

Brown, A.L., Kim, H., 2013. Do individuals have preferences used in macro-finance models? An experimental investigation. Manag. Sci. 60 (4), 939–958.

Brown, T.W., Bischof-Niemz, T., Blok, K., Breyer, C., Lund, H., Mathiesen, B.V., 2018. Response to burden of proof: a comprehensive review of the feasibility of 100% renewable-electricity systems. Renew. Sustain. Energy Rev. 92, 834–847.

Bunn, D.W., Chen, D., 2013. The forward premium in electricity futures. J. Empir. Finance 23, 173–186.

Bushnell, J., Novan, K., 2018. Setting with the Sun: the Impacts of Renewable Energy on Wholesale Power Markets. Energy Institute at Haas, p. WP292. Technical report.

Ciferri, D., D'Errico, M.C., Polinori, P., 2020. Integration and convergence in European electricity markets. Econ. Politic. 37 (2), 463–492.

Couture, T., Gagnon, Y., 2010. An analysis of feed-in tariff remuneration models: implications for renewable energy investment. Energy Pol. 38 (2), 955–965.

Cramton, P., Ockenfels, A., Stoft, S., 2013. Capacity market fundamentals. Econ. Energy & Environ. Pol. 2 (2), 27–46.

Delucchi, M.A., Jacobson, M.Z., 2011. Providing all global energy with wind, water, and solar power, part ii: reliability, system and transmission costs, and policies. Energy Pol. 39 (3), 1170–1190.

Diesendorf, M., Elliston, B., 2018. The feasibility of 100% renewable electricity systems: a response to critics. Renew. Sustain. Energy Rev. 93, 318–330.

Douglas, S., Popova, J., 2008. Storage and the electricity forward premium. Energy Econ. 30 (4), 1712–1727.

Entso-E, 2022. Entso-e Transparency Platform. Retrieved from transparency.entsoe.eu [Online; last access 5-February-2022].

Ghiassi-Farrokhfal, Y., Ketter, W., Collins, J., 2021. Making green power purchase agreements more predictable and reliable for companies. Decis. Support Syst. 144, 113514.

Gianfreda, A., Bunn, D., 2018. A stochastic latent moment model for electricity price formation. Oper. Res. 66 (5), 1189–1203.

Hirth, L., Khanna, T., Ruhnau, O., 2022. The (Very) Short-Term Price Elasticity of German Electricity Demand. ZBW-Leibniz Information Centre for Economics. Technical report.

Huisman, R., Kilic, M., 2012. Electricity futures prices: indirect storability, expectations, and risk premiums. Energy Econ. 34 (4), 892–898.

Huisman, R., Koolen, D., Stet, C., 2021. Pricing forward contracts in power markets with variable renewable energy sources. Renew. Energy 180, 1260–1265.

Huisman, R., Kyritsis, E., Stet, C., 2022. Fat tails due to variable renewables and insufficient flexibility: evidence from Germany. Energy J. 43 (5).

Huisman, R., Stet, C., 2022. The dependence of quantile power prices on supply from renewables. Energy Econ. 105, 105685.

Intergovernmental Panel on Climate Change, 2022. AR6 climate change 2022: mitigation of climate change. In: Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press.

International Energy Agency, 2021. Net Zero by 2050: A Roadmap for the Global Energy Sector. Flagship Report.

International Energy Agency, 2022. Electricity Market Report - January 2022.

Ito, K., Reguant, M., 2016. Sequential markets, market power, and arbitrage. Am. Econ. Rev. 106 (7), 1921–1957.

Jacobsen, H.K., Schröder, S.T., 2012. Curtailment of renewable generation: economic optimality and incentives. Energy Pol. 49, 663–675.

Jacobson, M.Z., Delucchi, M.A., 2011. Providing all global energy with wind, water, and solar power, part i: technologies, energy resources, quantities and areas of infrastructure, and materials. Energy Pol. 39 (3), 1154–1169.

Kanellopoulos, K., De Felice, M., Busch, S., Koolen, D., 2022. Simulating the Electricity Price Hike in 2021. Publications Office of the European Union, p. JRC127862.

Ketter, W., Collins, J., Reddy, P., 2013. Power TAC: a competitive economic simulation of the smart grid. Energy Econ. 39, 262–270.

Ketter, W., Peters, M., Collins, J., Gupta, A., 2016. A multiagent competitive gaming platform to address societal challenges. MIS Q. 40 (2), 447–460.

Knaut, A., Paschmann, M.H., 2017. Decoding restricted participation in sequential electricity markets. In: Technical Report, EWI Working Paper.
Knaut, A., Paulus, S., 2017. When are consumers responding to electricity prices? An hourly pattern of demand elasticity. In: Technical Report, EWI Working Paper.
Koolen, D., Bunn, D., Ketter, W., 2021. Renewable energy technologies and electricity forward market risks. Energy J. 42 (4).
Koolen, D., Ketter, W., Qiu, L., Gupta, A., 2017. The sustainability tipping point in electricity markets. In: Proceedings of 2017 International Conference on Information Systems.
Koritarov, V.S., 2004. Real-world market representation with agents. IEEE Power Energy Mag. 2 (4), 39–46.
Kuepper, G., 2020. Power market design choices with high shares of intermittent renewables. In: Proceedings of the 2020 CIRED Berlin Workshop.
Kyritsis, E., Andersson, J., Serletos, A., 2017. Electricity prices, large-scale renewable integration, and policy implications. Energy Pol. 101, 550–560.
Le Coq, C., Orzen, H., 2006. Do forward markets enhance competition?: experimental evidence. J. Econ. Behav. Organ. 61 (3), 415–431.
Levin, T., Kwon, J., Botterud, A., 2019. The long-term impacts of carbon and variable renewable energy policies on electricity markets. Energy Pol. 131, 53–71.
Lijesen, M.G., 2007. The real-time price elasticity of electricity. Energy Econ. 29 (2), 249–258.
Morales, J.M., Conejo, A.J., Pérez-Ruiz, J., 2010. Short-term trading for a wind power producer. IEEE Trans. Power Syst. 25 (1), 554–564.
Morales, J.M., Zugno, M., Pineda, S., Pinson, P., 2014. Electricity market clearing with improved scheduling of stochastic production. Eur. J. Oper. Res. 235 (3), 765–774.
Mulder, M., Scholtens, B., 2013. The impact of renewable energy on electricity prices in The Netherlands. Renew. Energy 57, 94–100.
Mulvey, J.M., Vladimirou, H., 1992. Stochastic network programming for financial planning problems. Manag. Sci. 38 (11), 1642–1664.
Narayanan, A., Mets, K., Strobbe, M., Develder, C., 2019. Feasibility of 100% renewable energy-based electricity production for cities with storage and flexibility. Renew. Energy 134, 698–709.
Notton, G., Nivet, M.-L., Voyant, C., Paoli, C., Darras, C., Motte, F., Fouilloy, A., 2018. Intermittent and stochastic character of renewable energy sources: consequences, cost of intermittence and benefit of forecasting. Renew. Sustain. Energy Rev. 87, 96–105.
Papaefthymiou, G., Dragoon, K., 2016. Towards 100% renewable energy systems: uncapping power system flexibility. Energy Pol. 92, 69–82.
Peura, H., Bunn, D.W., 2021. Renewable power and electricity prices: the impact of forward markets. Manag. Sci. 67 (8), 4772–4788.
Pindyck, R.S., 1993. Investments of uncertain cost. J. Financ. Econ. 34 (1), 53–76.
Redl, C., Bunn, D.W., 2013. Determinants of the premium in forward contracts. J. Regul. Econ. 43 (1), 90–111.
Redl, C., Haas, R., Huber, C., Böhm, B., 2009. Price formation in electricity forward markets and the relevance of systematic forecast errors. Energy Econ. 31 (3), 356–364.
Riesz, J., Gilmore, J., MacGill, I., 2016. Assessing the viability of energy-only markets with 100% renewables: an Australian National Electricity Market case study. Econ. Energy & Environ. Pol. 5 (1), 105–130.
Rintamäki, T., Siddiqui, A.S., Salo, A., 2020. Strategic offering of a flexible producer in day-ahead and intraday power markets. Eur. J. Oper. Res. 284 (3), 1136–1153.
Scholten, D., Bazilian, M., Overland, I., Westphal, K., 2020. The geopolitics of renewables: new board, new game. Energy Pol. 138, 111059.
Sensfuß, F., Ragwitz, M., Genoese, M., 2008. The merit-order effect: a detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany. Energy Pol. 36 (8), 3086–3094.
Simshauser, P., 2020. Merchant renewables and the valuation of peaking plant in energy-only markets. Energy Econ. 91.
Soares, T., Carvalho, L., Morais, H., Bessa, R.J., Abreu, T., Lambert, E., 2020. Reactive power provision by the dso to the tso considering renewable energy sources uncertainty. Sustain. Energy Grids Netw. 22, 100333.
Weron, R., 2014. Electricity price forecasting: a review of the state-of-the-art with a look into the future. Int. J. Forecast. 30 (4), 1030–1081.