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The impact of wind power and electricity demand on the relevance of different short-term electricity markets: The Nordic case

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HIGHLIGHTS

- Day-ahead, intraday and regulating power markets in three Nordic countries are studied.
- Focus on price spreads which reveal preferences to use one market over another.
- The effects of wind and demand forecast errors on price spreads are quantified.
- Increasing shares of wind power are changing the relevance of different marketplaces.
- Markets closer to real time becoming more important in operations and market design.

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ABSTRACT

Electricity wholesale markets are undergoing rapid transformation due to the increasing shares of variable renewable energy sources. We therefore asked whether trading activity is shifting from the traditionally dominant day-ahead market into the markets closer to real time. We studied the relevance of different electricity markets indirectly by analysing the price spreads between day-ahead, intraday and regulating power markets. We estimated vector autoregressive models for Denmark, Sweden and Finland for the period from 2015 to 2017 and studied the interrelationships between the price spreads and the effects of wind forecast and demand forecast errors, and other exogenous variables. We found that wind forecast errors do affect price spreads in areas with large shares of wind power generation. Demand forecast errors have an impact on almost all price spreads, except in areas with relatively low consumption. Interestingly, while the impact of demand forecasts was relatively stable over the studied years, the effects of wind forecasts became more important each year. As a conclusion, markets closer to real time are becoming more important due to the increasing shares of wind power, and their role as reference prices relevant for price risk hedging, capacity markets, and other decision making will probably increase in the future.

1. Introduction

Electricity wholesale markets are undergoing rapid transformation due to the increasing share of distributed and variable renewable energy sources (vRES) penetrating the market, which has traditionally been dominated by centralized and dispatchable generation. After electricity market liberalization and ownership unbundling in Europe, the most relevant marketplace with respect to volume, liquidity and efficiency has been the day-ahead market. However, the increasing shares of stochastic wind generation bring along greater deviations between the real-time power generation and the day-ahead forecasts of power supply. It is therefore reasonable to assume that trading activity is shifting more into the intraday and balancing markets because it is more reliable to predict the actual power generation of vRES closer to power delivery and thus avoid high imbalance costs.

There are various risks related to operating in the electricity markets. The most relevant are price and volume risks. Price risk originates from the uncertainty about the selling or buying price of electricity in the

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future. Volume risk is related to the uncertainty about the amount of produced or consumed energy in the future. The increasing amount of vRES impacts both risks because by its nature the weather-dependent and intermittent generation includes uncertainty about the generation volume which impacts price volatility and therefore the price risk.

Ongoing institutional changes in Europe are also promoting the usage of closer-to-delivery markets, such as shorter gate-closer time, higher resolution for imbalance settlement (from 60 min to 15 min), and more granular tradable products (15 and 30 min). The design of the regulating power market, especially its imbalance settlement mechanism, also plays an important role because it affects how power generators and the demand side are rewarded to offer flexibility to the transmission system operators (TSOs) close to the actual delivery.

Many studies have found that increased shares of variable RES have also increased the need for balancing reserves, (e.g., [1]). However, in Germany, the growth of variable RES has actually reduced the need for balancing services [2]. This controversial outcome, also called "the German balancing paradox[1]", is thought to be the result mainly of changes in institutional factors, such as using quarter-hour contracts.

We therefore asked the following research questions: How relevant is each electricity marketplace in power systems with increasing shares of vRES in Nordic countries? Is the dominant position of the day-ahead market diminishing and are the markets closer to real time becoming more important in terms of trading activity and price discovery? A reliable understanding of market dynamics is critical because investments in new power generation, real-time pricing, reference prices in capacity markets, and price-risk hedging strategies are often based on the day-ahead market. However, we do not argue that day-ahead markets become useless. They will be in important part of the functioning of the electricity markets in the future as well. Instead, we argue that intraday and regulating power markets may play a more relevant role as weather dependent production becomes more dominant in the production mix.

We studied the increased importance of markets closer to delivery and the impacts of the increasing shares of vRES on different marketplaces by analysing the pairwise price differences between the day-ahead, intraday and regulating power markets[2]. Without any changes in demand or supply conditions, these price spreads would be close to zero. However, even though we talk about the delivery of power for the same moment in the future, market participants in each marketplace have different information available at the time of bidding. The motivation of participants for trading may also differ depending on the marketplace in which they are participating. The increased share of wind power can affect both market uncertainty and trading strategies and thus the price differences between wholesale power markets. The price differences then indicate the increased relevance of different market places, at least in the short run. In the longer term, markets may adjust to price differences, for instance, through new investments in balancing power or demand response methods.

We provide a detailed explanation of price spreads in Section 4.1, but our brief interpretation is as follows: the price spread between day-ahead and intraday markets (DA-ID) indicates the adjustment needs due to forecast errors of power supply and demand factors; the price spread between intraday and regulating power markets (ID-RP) indicates the economic incentive to reduce imbalances and benefit from additional flexibility; and the price spread between day-ahead and regulating power markets (DA-RP) indicates the scarcity of balancing resources.

In this study, we focused on the Nordic electricity market because it currently has one of the most ambitious decarbonisation targets in Europe[3], which introduces deep changes to the Nordic power system. In particular, the traditional Nordic power market flexibility, which is driven by hydro-resources, may be challenged by the following factors: (1) growth in intermittent generation, (2) less flexible thermal generation, and (3) surplus generation in years with normal precipitation (see, for example, [3]).

We particularly focused on the impacts of intermittent wind power generation, which has been rapidly penetrating the Nordic markets and has direct implications for the costs of power system balancing, among others. We further narrowed down the geographical scope of our study to the three countries with the greatest increase in wind power during the studied interval: Denmark, Sweden, and Finland. The deployment rate of wind power and the share of wind in national energy mixes differed. In 2017, Denmark produced over 40 percent of total power production by wind, whereas Sweden and Finland produced 12 and 5 percent, respectively. The Nordic electricity market is divided into a number of different bidding areas[4] with different amounts of installed wind power capacity, which is mainly driven by the availability of wind resources.

Methodologically, we estimated a vector autoregressive (VAR) model of three endogenous variables – price spreads, wind forecast error, and demand forecast error, which are explained by their lags and other exogenous variables, namely, transmission congestion, hydro-deviations, and wind power ramping. We used three years of hourly data from Finland, Sweden and Denmark during the time period from 2015 to 2017. With correctly specified VAR models, we then explored the causal relationships among the endogenous variables with the Granger causality test. Furthermore, we quantified the size and duration of the shocks in wind forecast and demand forecast errors on the price spreads with impulse response functions.

We found that in the areas with large shares of wind power, the price spreads are causally driven by wind forecast errors, especially in both the bidding areas of Denmark (DK1, DK2) and those in southern Sweden (SE4). We did not find such a clear causal effect in the bidding areas with lower shares of wind power generation, namely, in Finland and northern Sweden (SE1, SE2), at least in the beginning of the study period. Moreover, we found that in 2017 (the most recent studied year), the impact of a shock in wind forecast error of one standard deviation on the spread between day-ahead and intraday prices (DA-ID spread) was between 10 and 20 euro cents/MWh within the first four hours after the shock in Denmark, Finland and southern Sweden. If we took the absolute average price spread[5] between DA-ID across bidding areas and the studied period as 2.2 EUR/MWh, this effect translated into a 5–9 percent price risk between the day-ahead and intraday markets due to a wind power shock.

The effect of a wind error shock of one standard deviation on the spread between intraday and regulating power prices (ID-RP spread) was from 20 to 50 euro cents/MWh in the first two hours after the shock. Similarly, if we took the absolute average price spread between ID-RP across bidding areas and the studied period as 6 EUR/MWh, this translated into a 3–8 percent price risk between the intraday and regulating power markets caused by a wind power shock. The impacts of the shocks are greater in the short-term markets (ID-RP), but the shocks appear to create effects on the DA-ID spreads that last longer than the effects on the ID-RP spreads.

[1] "The German balancing paradox" refers to the generally counter-intuitive finding that the growth of vRES, especially wind and solar PV, was initially associated with a lower demand for balancing services in Germany, see [2].

[2] Regulating power market in the Nordics refers to the more commonly used name mFRR energy market, and its up- and down-regulation prices are used in addition to the regulating power market also as reference prices for imbalance settlement, and energy remuneration in aFRR and FCR-Normal markets (see section 3.13 for details).

[3] See the National Energy and Climate Plans (NECP) – for example Finland aims for carbon neutrality by 2035.

[4] Denmark is divided in two bidding areas and Sweden in four areas. Finland is one sole bidding area.

[5] See Fig. 4 for a detailed presentation of absolute price spreads by year, bidding area and market pair.

Demand forecast errors, on the other hand, seem to have impacts on the spreads linked to the regulating power markets in all bidding areas, and the effects remain similar across all studied years. The spreads were the most clearly demand-driven in Finland and southern Sweden (SE3), where demand forecast errors also affected the spreads between day-ahead and intraday prices (DA-ID spread). Again, if we took the absolute average price spread between DA-ID and ID-RP across bidding areas and the studied period being 2.2 EUR/MWh and 6 EUR/MWh, respectively, we found that a demand forecast shock of one standard deviation caused 5–9 percent (10–20 euro cents/MWh in DA-ID) and 13–69 percent (80 euro cents-1.5 euro/MWh in ID-RP) price risk between the market pairs.

The novelty of our study relates to three distinct points. First, we were able to disentangle the effects of different marketplaces (day-ahead, intraday and regulating power markets) by analysing the price spreads between these markets jointly. Second, in addition to analysing multiple markets, we also cover three different Nordic countries and seven different bidding areas in a single study. Third, we compared our results by individual years, which shows the effects of growing share of wind power production on electricity markets in different areas. In our view, these aspects have not been thoroughly studied in the current literature.

The finding that price spreads start to be driven by wind power forecasts when the share of wind power reaches a certain threshold implies that there is a threshold effect. We confirmed this view by studying the results for individual years and found that the effects of wind forecasts became more important each year in areas with relatively low initial shares of wind power. In contrast to the existing studies, we compared our results by individual years as well as over the entire period, which provided a much greater depth of understanding of the studied drivers as well as a robustness check on the found relationships. Our dynamic approach therefore provides an important outlook for areas with currently low wind power capacity but plans for rapid expansion. Another major contribution of our study is that it had a cross-market and cross-country nature and investigated this topic over a multi-year sample in a single econometric study. This enables the readers to obtain a full and comparative understanding of the main fundamental drivers behind the relevance of different Nordic electricity marketplaces with relevant lessons for other electricity markets.

The paper is structured as follows. In Section 2, we review the relevant literature. In Section 3, we lay down the foundations of the Nordic electricity wholesale markets and outline the details of the Nordic power generation mix. This is followed by a description of the data and methods in Section 4. We discuss the main findings based on Granger causality tests and impulse response functions in Section 5 and conclude the work in Section 6.

2. Review of literature

In the current academic literature on wholesale electricity markets, a large share of studies focuses on the impacts of fundamentals, such as solar [4], wind [5], electricity demand [6] or support schemes [7], and different trading strategies, such as trading effects of imbalance settlement rules [8] or CO_2 prices [9], on the market outcomes in individual electricity markets, especially day-ahead markets. Nonetheless, since market participants take into consideration the outcomes of all relevant sequential markets, it is essential not to consider individual markets in isolation.

We distinguish two main research strands in the economic literature on sequential electricity markets. The first strand focuses on trading and usage of different marketplaces. In one of earlier studies, Furió and Lucia [10] argued that the day-ahead market lost ground to the intraday market for consumption units in Spain because of the extra costs from the resolution of transmission constraints in the day-ahead market. The authors also presented the argument that strategic generators face economic incentives to bid higher prices in the day-ahead market to be later dispatched in the intraday market to solve congestion. Knaut and Obermueller [11] explored the trading of renewable and conventional power generators in the German day-ahead and intraday markets and found that it is optimal for renewable producers to sell less than the expected production in the day-ahead market. However, Faria and Fleten [12] explicitly studied the economic benefits of coordinated bidding between day-ahead and intraday (Elbas) electricity markets in the Nordic market and did not find any significant impact on the profits of a price-taking medium-sized producer. Similarly, Boomsma et al. [13] quantified the gain from coordinated bidding in day-ahead and balancing markets in the Nordic markets and found no extra gain under a one-price balancing mechanism but a significant gain under a two-price balancing mechanism.

Vilim and Botterud [14] studied optimal day-ahead bidding strategies under two balancing mechanisms, showing that wind power has a substantial influence on day-ahead prices, imbalance pricing, and regulation volume. Other authors in this strand focus more directly on market efficiency and competition questions. For example [15] studied arbitrage opportunities and mitigation of the so-called increase–decrease game, in which generators oversell in export constrained nodes and buy back at cheap rates in real-time markets. The authors argued that the smaller differences between day-ahead and balancing (real time) markets limit this arbitrage opportunity. Similarly, [16] focused on strategic behaviour in two sequential electricity markets (day-ahead and intraday) under imperfect competition and restricted entry and showed on the example of Iberian electricity market that these explain the present systematic price differences. Others [17] studied the Swedish day-ahead and intra-day markets and found a theoretical and empirical evidence of imperfect competition and a presence of some local market power.

The second strand focuses on understanding more directly the fundamental drivers behind market prices in sequential markets and their spreads. Pape et al. [18] focused on the growing importance of the German intraday market by developing a fundamental model for the day-ahead and intraday markets. They studied the explanatory power of some fundamentals, such as must-run operations of CHP and shorter lead times of power plants, on price variations but find that the fundamental model cannot capture avoided startup costs, different market states and trading behaviour. Olsson [19] used statistical methods to directly simulate real-time balancing prices and discussed the impacts of forecast errors on real-time balancing. Batalla-Bejerano et al. [1] investigated the impacts of vRES on the balancing market requirements and costs measured by adjustment service cost (ASC) in Spain. They calculated the ASC as a price spread between what they called electricity final price, day-ahead price, intraday price, and capacity payments, which they attempted to econometrically model with different attributes of intermittent generation. They find that vRES uncertainty and variability exerted positive and significant effects on adjustment costs and highlighted the importance of forecast errors when explaining integration costs.

Koch and Hirth [20] studied the German intraday and balancing markets in the context of vRES. Among other things, the authors studied the ex-post the difference between imbalances and intraday prices, which they dubbed the “imbalance price spread”. They interpreted the spread as the opportunity cost/economic incentive for balance the responsible parties (BRPs) to reduce imbalances. Their definition of imbalance price spread is the difference between imbalance price and the so-called ID3 price, which is the volume-weighted average intraday price of trades between three hours and 30 min before the real time. The authors, however, mainly focus on the institutional effects of improved short-term wholesale electricity trading (quarter-hourly contracts, 24/7 trading), which led to what [2] call the “German balancing paradox”, i.e., the growth in vRES reduces the need for balancing services. Demonstrated on the German market, the authors called it a paradox because other studies typically found a positive effect of vRES on balancing reserves, for example [21].

Hagemann [22] used multiple linear regression to model the price difference between the German intraday and day-ahead prices with market fundamentals, such as load, wind and solar forecast errors, power plant outages, and cross-border flows. He found that intraday supply side shocks may have different price effects. Karanfil and Li [23] studied the functionality of the Nordic intraday market by investigating the main drivers of the price difference between the Nordic day-ahead and intraday markets. The authors studied the causality between market fundamentals (wind forecast errors, conventional generation forecast errors, demand forecast errors and intraday cross-border electricity flow) and the price differential, finding among other things that the wind forecast errors Granger-caused the price difference in Denmark. Using VAR and impulse response functions, they claimed the intraday market to be effective because causality between the intraday price signals and market fundamentals was found.

From our review of the most relevant and recent literature, we identified that most of the current research focuses on a single-country analysis over a limited time period, and none of the reviewed papers studied all three main sequential markets in a single work. We filled this gap by studying the drivers of price spreads in day-ahead, intraday and balancing markets in seven different bidding areas over three years.

3. Market places – Institutional setup

In this section, we first lay down the foundations of the individual marketplaces in the Nordic electricity wholesale markets (Section 3.1). In Section 3.2, we provide an overview of the Nordic electricity mix. More detailed description of the Nordic electricity wholesale market design is provided in the working paper of Spodniak et al. [24].

3.1. Nordic electricity wholesale markets

The Nordic electricity wholesale market is a liberalised and unbundled market that can be divided into *financial* and *physical* markets[6]. In this paper, we focus on the physical market, which comprises day-ahead, intraday, and regulating power markets.

In general, the main reason for the existence of different electricity wholesale markets is to efficiently and effectively *balance* electrical power system in both the short run (least cost economic dispatch) and long run (investments). In the short run, market players typically strive for a balanced portfolio and thus actively trade before the delivery hour to avoid the cost of imbalances [25]. It is worth pointing out that a so-called *proactive balancing philosophy* is practised in the Nordic electricity market [26]. This means that during the delivery hour, TSOs foresee the imbalances and procure and activate the necessary regulating power reserves. This is in contrast to a reactive balancing philosophy, which is applied in countries such as Germany, where each market player balances its position close to real time and the TSO's automatic and fast reserves play a more important role. This is why we may expect differences in marketplace usage between the German[7] and the Nordic markets. The regulating power market has historically played a much more important role and the intraday market a less important role in the Nordic countries because the (flexible) market participants can sell their imbalances as up- or down-regulation on the regulating power market close to operation [26]. Furthermore, because of the abundance of flexible hydro production in the Nordic region, the risks of facing large imbalance costs have been relatively low, which disincentivises usage of the intraday market.

3.1.1. Day-ahead market

The first and historically most important (volume and liquidity) wholesale electricity market is the *day-ahead market (Elspot)* operated by Nord Pool in Nordic countries. Elspot follows a uniform price periodic double auction in which buyers and sellers submit their bids[8] by 12:00 CET the day before delivery for each hour of the following day. Market participants receive information about the binding trading transmission capacities available for the day-ahead auction at 10:00 CET from Nord Pool, i.e., 2 h before the gate closure. The day-ahead prices are published shortly after the auction closes, which gives market participants information about the next day's hourly prices 12 h ahead of the first delivery hour (00:00–00:59 day ahead) up to 36 h before the last delivery hour (23:00–23:59 day ahead). The intersection of the aggregated supply and demand curves provides the equilibrium hourly marginal price for the entire Nordic electricity market, also known as the *system price*. The system price works as a price reference for a congestion-free grid on an hour-by-hour basis.

In addition to electricity, cross-border transmission capacity is implicitly auctioned in the day-ahead market. This is part of a congestion management technique called zonal pricing. Instead of pricing the day-ahead transmission capacity explicitly, the market is split into predefined geographical regions that decouple from the reference system price into area prices (currently 16) when the cross-border transmission, allocated by TSOs on a daily basis, reaches its limits.

3.1.2. Intraday market

Once the day-ahead market is closed, the intraday market Elbas continues trading up to 1 h prior to the delivery hour to allow market participants to address errors in their demand and supply forecasts. Market participants can begin trading on Elbas from 14:00 CET the day before delivery. The Elbas market follows a continuous pay-as-bid double auction[9], where limit orders form an order book of bids and asks are sorted by price and time of offer in a manner similar to that of equity markets. Capacity allocation and energy matching processes are performed simultaneously, which means that the local order book views take into account capacities that are allocated by different TSOs on each border.

Currently, Elbas offers trading of 15 min, 30 min, hourly and block products. The sub-hourly products have been introduced only recently in the Nordic market and are outside the scope of our time horizon (2013–2017). Nonetheless, it has been shown that the introduction of 15-minute intraday contracts in Germany has increased the limited liquidity typically associated with intraday markets [27]. Because of the high variability and lower predictability of wind speed resources, wind generation benefits from shorter, sub-hourly contracts.

3.1.3. Regulating power market

Power system reserves are divided into three categories that are mostly determined by their activation time: primary, secondary, and tertiary, which are in the current terminology called frequency containment reserve (FCR), automatic frequency restoration reserve (aFRR), and manual frequency restoration reserve (mFRR), respectively. In this paper, we focus on the manual frequency restoration reserve, which is also known as the regulating power market.

TSOs maintain manual frequency restoration reserves to cover the

[6] Financial markets utilize derivative contracts for risk management and market power mitigation purposes. Nasdaq OMX operates the main Nordic power derivatives exchange, where market participants can settle and clear their exchange-traded or over-the-counter (OTC) contracts. Purchasing power agreements (PPA) and other long-term contracts could be considered as part of the financial market, however, none of these are addressed in this study.

[7] There are other differences between the Nordic and German balancing markets. For instance, market participants in the German balancing market are remunerated for their capacity and energy on pay-as-bid bases. Market clearing pricing and free bids were planned to be introduced in late 2019 [19]. Additionally, the imbalance settlement period in Germany is 15 min, whereas in the Nordic markets it is still one hour.

[8] The type of bids are single hourly blocks, block orders, minimum acceptance ratio, linking, flexi orders and exclusive orders, see [38].

[9] In other European markets, the gate closure can be shorter than 1 h, for instance 30 min before delivery (in Germany and in Finland). Additionally, even though Elbas is organized as continuous market, other markets can have intraday auctions, or the combination of continuous trading and auctions.

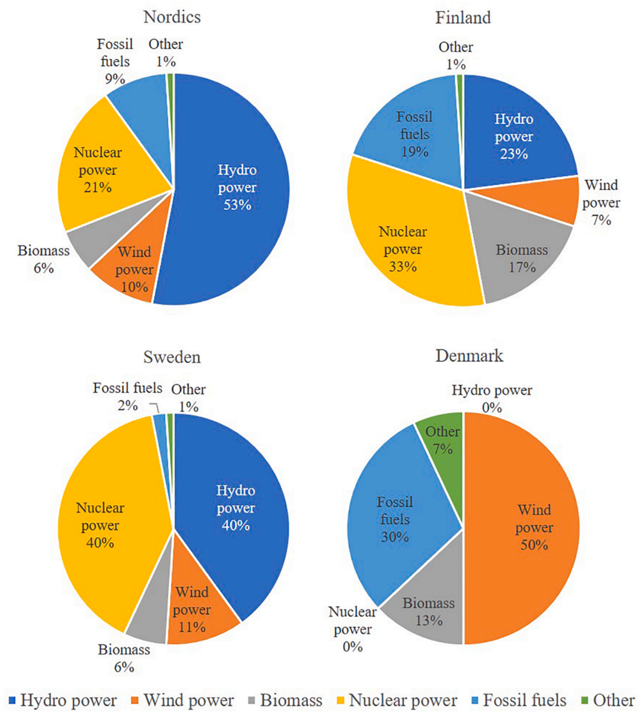

Fig. 1. Generation mix in the whole Nordic market area, and in Finland, Sweden, and Denmark in 2017. Source: [30]

dimensioning fault[10] in their own area. The Nordic TSOs own or lease back-up generating plants as part of mFRR capacity; however, the main source of balancing mFRR energy comes from the joined Nordic balancing energy market. This market is also called the regulating power market. It is important to note that the regulating power market prices for up- and down-regulation also serve as a reference for energy compensation in other Nordic reserve markets, namely FCR-Normal and aFRR.

The regulating power market follows a uniform price auction jointly operated by all Nordic TSOs with a common merit order exchanged via a common platform called the Nordic Operational Information System (NOIS). The clearing methodology is marginal pricing based on the most expensive up-regulation bid or the lowest down-regulation bid activated during the operation hour. Market participants can submit their bids for up- or/and down-regulation to the local TSO from afternoon the day before until 45 min before the delivery hour. TSOs order up- or down-regulation from the regulating energy market according to the power system requirements, where up-regulation means increasing production or reducing consumption, and down-regulation means reducing production or increasing consumption.

Finally, the regulating energy prices also serve as the basis for pricing imbalance power in the imbalance settlement process, which arises due to the difference between physical positions and final schedules (including regulating bids). After the delivery hour, deviations between the activated load and production balance responsible bids and the actual amount of electricity provided/utilized are determined. Local TSOs serve as open suppliers for the balance responsible parties (BRPs) that are obliged to buy or sell these imbalances from/to the TSO. The balancing settlement is currently based on 1-hour periods which will be shortened to 15 min in the second half of 2023 [28]. This new market design rule will push BRPs, including wind power generators, to improve the reliability of their generation/consumption forecasts due to shorter time interval to handle imbalances and the motivation to minimize imbalance price risk.

3.2. Electricity mix in the Nordic markets

Nordic electricity production has traditionally been dominated by hydro, nuclear, and thermal plants. The main marketplace for trading has been the day-ahead market because it allows sufficient time for the dispatchable production units to ramp up and down [3]. The trading patterns between bidding areas and other European electricity markets are often driven by differences in generation type and capacity, hydrological conditions, and the transmission network. Denmark and Finland in particular rely on electricity imports, whereas Sweden and Norway are net exporters. Both Sweden and Finland have large baseloads produced by nuclear and hydropower. Norway's electricity production originates almost entirely from hydropower, and Denmark's electricity mix is dominated by wind and thermal plants.

In this paper, we particularly focused on three Nordic countries, namely, Finland, Denmark, and Sweden, for the following reasons. Denmark is a pioneering and well-researched country that was able to integrate a large share of wind power into a system traditionally dominated by thermal plants. Sweden has rapidly increased its installed wind power capacity and despite its slower start overtaking Denmark in installed capacity. Sweden is also in the process of decommissioning older nuclear plants and is planning to renounce nuclear power [29], which has implications for generation adequacy. Finally, Finland has had a more moderate approach towards wind power deployment and relies on a diversified production mix. In contrast to Sweden, Finland is increasing nuclear power capacity by 1600 MW with the nearly completed Olkiluoto-3, and a new investment of 1200 MW is also in the process of preparation (Hanhikivi-1). All three countries follow different approaches towards energy system decarbonisation, and we expect these differences to play a role in explaining the usage and relevance of different electricity market places. Generation mix in the whole Nordic market area (including Finland, Sweden, Norway, Denmark, and Estonia) and in the studied Nordic countries (Finland, Sweden, and Denmark) in year 2017 is illustrated in Fig. 1. In addition, the growth of

[10] Dimensioning fault refers to the power system's ability to continuously withstand the single largest fault of an individual major component, e.g., production unit, line, transformer, bus bar, or consumption.

wind power capacity and generation from 2000 to 2018 in Denmark, Sweden and Finland is presented in Fig. 2. The biggest change in the generation mix is that condensing power is being replaced by increasing amount of wind power.

In addition, the shares of wind power differ between Nord Pool bidding areas. This was described in Table 1 for the years from 2015 to 2017. The spatial variation in wind power shares provides us with an interesting comparison between Nord Pool bidding areas. The share of wind power is the highest in the western part of Denmark (DK1), where almost 57 percent of power generation was produced by wind power in 2017. In the eastern part of Denmark (DK2), the share of wind power was 34 percent. In Sweden, the shares of wind power were the highest in the southern part of the country (SE4), where 54 percent of power production was produced by wind in 2017. Even though the total electricity generation by wind was higher in the middle parts of Sweden (SE3 and SE2), the shares of total production were much lower than in the south: 7 percent in SE3 and 12 percent in SE2 in 2017. In northern Sweden (SE1) and Finland (FI), the shares of wind power were still modest. In both of these regions, approximately 6 percent of electricity generation was produced by wind power in 2017.

4. Research methods and data

Our analysis focused on three countries of the Nordic region that have experienced rapid growth in wind power generation but that differ in their market fundamentals. These differences bring interesting insights into the analysis and allow comparison of the same effects in different settings. The time resolution of the data is one hour, and the time period studied is from 2015 to 2017. The main sources of price and market fundamentals data are the transparency platform of the European Network of Transmission System Operators for Electricity (ENTSO-E) and Nord Pool's FTP server, to which we were granted access. In Section 4.1, we present information about prices from the three marketplaces as well as their pairwise differences, which will represent the first endogenous variable in our three-variable vector autoregressive (VAR) model, which is defined in Section 4.3. Two additional endogenous variables are specified in Section 4.2, with further exogenous variables underlying the power market fundamentals.

Table 1
Wind power generation (TWh) and the shares of wind power in total electricity production (%) in Nord Pool bidding areas in Finland (FI), Sweden (SE1-SE4), and Denmark (DK1-DK2).

		2015	2016	2017
FI	TWh	2.1	2.8	4.1
	%	3.2%	4.4%	6.5%
SE1	TWh	1.4	1.3	1.4
	%	6.6%	5.6%	6.4%
SE2	TWh	4.7	4.9	5.4
	%	10.4%	12.9%	12.4%
SE3	TWh	5.5	5.5	5.8
	%	7.5%	6.6%	6.8%
SE4	TWh	3.8	3.8	4.3
	%	51.6%	50.2%	54.1%
DK1	TWh	10.8	9.4	10.9
	%	56.1%	48.7%	56.9%
DK2	TWh	2.9	2.4	3.0
	%	36.7%	29.6%	34.0%
FI-SE-DK	TWh	31.1	30.1	34.9
Total	%	13.0%	12.4%	14.0%

Note: Data for Finnish wind power generation are from the Fingrid database. All other data are from Nord Pool. Figures of wind power production in Sweden are missing for January 1– January 23, 2015. Total production amounts were not considered for this period when calculating the shares of Swedish wind power in 2015.

4.1. Market prices and spreads

Our dataset comprised hourly prices from three Nordic wholesale electricity markets, namely, day-ahead (DA), intraday and (ID), and regulating power (RP), as well as their pairwise differences, here called spreads, which were all measured in EUR/MWh. In Section 3, we have specified each market price and its formation in detail, but their spreads require further interpretation.

Market design affects market participants' willingness to participate in the intraday versus regulating market or to settle their imbalances through the process of imbalance settlement. The spread between day-ahead and intraday (DA-ID) markets measures the adjustment need due to supply and demand forecasting errors. This is because most of the trades in the day-ahead market are made 24 h before the actual delivery or consumption, which are then updated by trades in the intraday

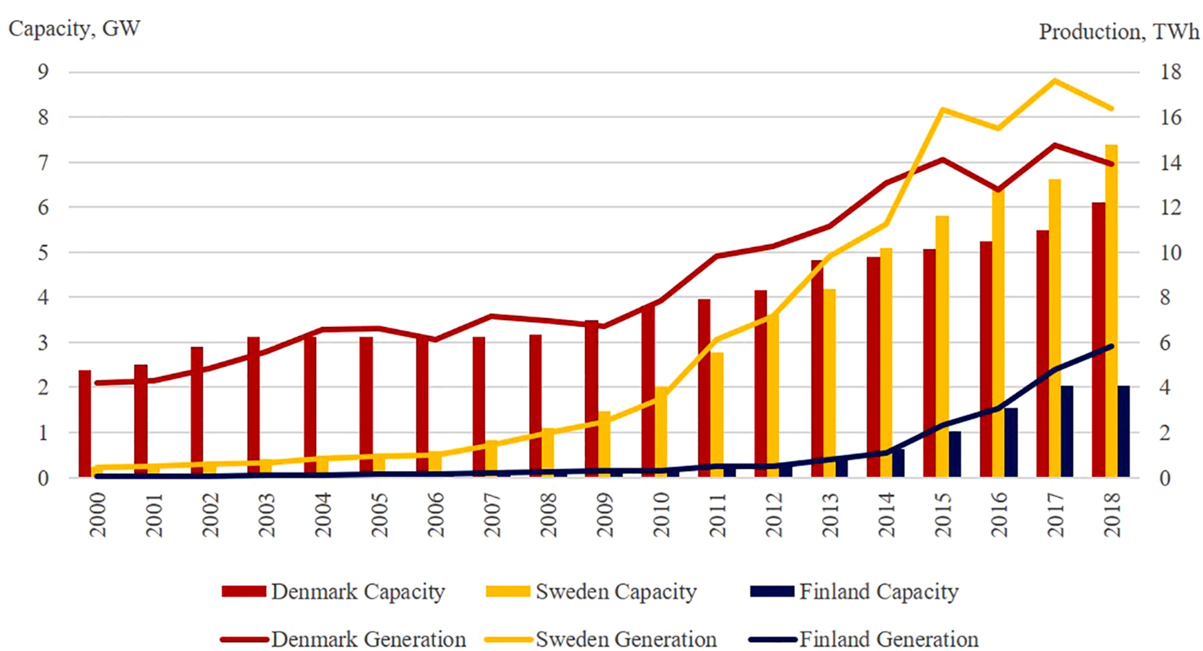

Fig. 2. Wind power capacity and generation in Sweden, Denmark and Finland. Source: [31–35].

market to balance out the errors. Thus, wind and demand forecast errors, among other things, are expected to be important factors explaining the spread.

The links between intraday and regulating power market prices are more complex. First, the price spread between these two prices indicates the short-term balancing needs and, thus, costs of balancing. Second, there is also a link through trading strategies. Consider, for instance, a power producer that can ramp up its production flexibly. If there exists an ask in the intraday market with a price higher than the day-ahead price, the flexible producer could sell extra production in intraday markets. Alternatively, the flexible producer could offer its extra production in the regulating power market for balancing purposes even closer to delivery. The revenue and the need for production is, however, uncertain at the time bidding in the regulating power market auction. Hence, flexible producers obtain either a certain price during continuous intraday auction, which is conditional on the presence of a counterpart in the intraday market, or uncertain price if waiting for the regulating power market. Wind producers, for instance, face similar kinds of uncertainty. They can settle their imbalances caused by forecast errors by trading in intraday markets or wait until imbalance settlement.

The price spread between day-ahead and regulating power (DA-RP) markets measures the scarcity of balancing resources, which we interpret as an additional cost for delivering one MWh of electricity on top of the day-ahead and intraday price. The interpretation of the additional cost may be turned into a hypothetical benefit under the imbalance settlement, where the strategic imbalances that aid the power system are rewarded on top of the day-ahead price. However, at the gate closure of the regulating power market, most of the participants (who do not/cannot participate) do not know precisely the imbalance settlement price, which is disclosed only with a one-hour delay. This spread is therefore calculated ex post, and the underlying price uncertainty ex ante should be kept in mind when interpreting the hypothetical gains from the imbalance settlement.

Finally, the spread between the regulating power and intraday (ID-RP) markets reflects the economic incentive (opportunity cost) to reduce imbalances. This is because the intraday market is the last opportunity to reduce trade imbalances before facing imbalance settlement based on regulating power prices. Alternatively, ID-RP spread can be interpreted as an opportunity for additional revenues for qualified[11] market participants, offering flexibility to the TSOs. It must be remembered that trading in the regulating power market carries additional risks of not being dispatched because the need for regulating power does not arise or the offered flexibility is in the opposite direction (up in a down-regulation state, or down in an up-regulation state). The interpretation of the price spreads is summarized in Fig. 3.

As described in Section 3, the intraday market is a continuous market following a pay-as-bid double auction, which means there can be dozens of different prices for the same delivery hour in the same area. To calculate a representative intraday price, we calculated a volume-weighted average price[12] for each delivery hour and area. This approach placed a greater emphasis on trades carried out closer to delivery, when most of the intraday volume is traded. Note that occasionally no Elbas trades occur for a given hour, which implies no need for trade adjustment. In our price spread calculations, we replace these missing points with the day-ahead price, which best reflected the market's need in a given hour.

The summary of price levels and spreads is presented in Tables 2 and 3, respectively. From Table 2, it can be seen that the mean and median prices in all three marketplaces were the highest in Finland and lowest in DK1. Price caps and floors were hit in the regulating power market, panel (c). Overall, the regulating market was the most volatile among the three.

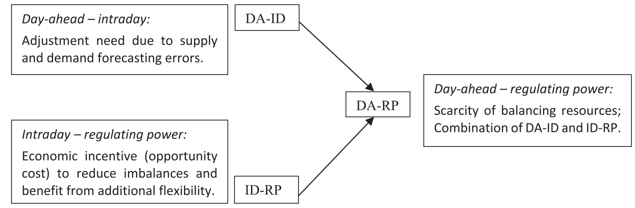

Fig. 3. Summary of price spreads.

From Table 3, it can be seen that in DK1 and DK2, the median spreads were zero across the three market places, indicating the highest integration among the marketplaces together with SE4.[13] This was interesting given the dominance of variable wind power generation in Denmark's generation mix. The mean spreads between day-ahead and intraday (DA-ID) markets were mostly positive (highest in FI, and SE2-SE3), suggesting sufficient capacity in the intraday market, which is discounted in comparison to the day-ahead market. The median spreads between day-ahead and regulating power (DA-RP) were zero in all bidding areas, which pointed to non-systematic scarcity for up- or down-regulation and suggested that strategic imbalances are not without risk. Up- and down-regulation events occurred with approximately the same frequency; in reality, this is approximately 40 percent up-regulation, 30 percent down-regulation, and 30 percent no regulation. From the perspective that the ID-RP spread indicates the opportunity for additional revenues, FI and DK2 seem to be bidding areas where this spread/opportunity is the highest.

The median spreads between the regulating power and intraday price (ID-RP) were non-zero and even more negatively skewed than the DA-RP spread. The negative skewness suggests infrequent but high up-regulation prices, driving the mean ID-RP spread to the negative territory and increasing the motivation for a balanced portfolio to avoid high imbalance costs. In Table 4, we present the number of hours when the regulating power price was lower than −150 euro/MWh or higher than 400 euro/MWh in different bidding areas. In Finland, there were altogether six hours with very low down-regulating prices and 23 h with very high up-regulating prices. In other bidding areas, price outliers of the regulating power markets were rarer. Moreover, up- and down-regulating prices have often been at their limits in Finland: there were hours when the down-regulating price was −1000 euro/MWh (in 2017) and the up-regulation price was 3000 euro/MWh (in 2016). At the same time as these extreme price events, the wind power forecast errors were negative in both 2016 and 2017, and it is thus reasonable to assume that the wind power shocks do not cause these price outliers.

In our estimations, we thus omitted the price outliers of the regulating power (RP) markets, i.e., when the regulating power market price is lower than −150 euro/MWh or higher than 400 euro/MWh. Omitting the outliers was justified, as these extreme prices are typically caused by a significant system fault, for instance, tripping of a large generation unit or transmission line, and hence, they are unrelated to wind power. Indeed, the combined effect of very low down-regulation prices or very high up-regulation prices together with negative wind forecast errors would cause abnormal impacts on our results.

To obtain a better understanding of the actual costs and benefits associated with price spreads, we considered the *absolute* price spreads,

[11] Resources that can carry out a 10 MW change in power in 15 min (5 MW if using electronic activation); see section 3.

[12] To provide a comparison, we have also calculated the so-called ID3 price as in the German Epex intraday market. However, this led to a loss of large number of observations due to the lack of trade activity three hours before delivery. For this reason, we preferred the weighted average to derive a representative intraday price.

[13] This can also be seen from the distribution plots of price spreads, which were, however, omitted from the paper but can be provided upon request from the authors.

Table 2
Summary of price levels from 2015 to 2017.

(a) Day-ahead price

Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	26,304	31.77	30.20	12.66	0.32	214.25	2.24	20.39
SE1	26,304	26.99	26.82	10.15	0.32	214.25	2.85	38.15
SE2	26,304	26.99	26.82	10.15	0.32	214.25	2.84	38.10
SE3	26,304	27.49	26.97	10.92	0.32	214.25	2.96	34.34
SE4	26,304	28.20	27.31	11.48	0.32	214.25	2.61	28.09
DK1	26,304	26.55	26.55	10.93	−53.62	120.01	0.32	7.07
DK2	26,304	28.62	27.96	12.35	−53.62	214.25	1.90	22.08

(b) Intraday price

Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	25,880	31.05	29.61	12.92	−8.80	194.68	1.96	15.50
SE1	17,442	27.28	27.00	9.93	−12.00	213.89	2.70	37.88
SE2	23,078	26.44	26.10	10.16	−5.82	188.00	1.95	21.93
SE3	24,525	26.92	26.40	11.13	−7.77	209.43	2.51	26.18
SE4	12,592	30.20	29.00	12.31	−10.00	275.00	3.16	40.64
DK1	16,738	27.44	27.19	10.96	−28.98	124.89	0.64	6.87
DK2	19,583	29.21	28.21	12.74	−46.34	197.00	1.63	15.44

(c) Regulating power price

Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	26,304	32.15	27.90	39.75	−1000.00	3000.00	25.88	1764.91
SE1	26,304	25.83	25.50	18.22	−25.55	1999.00	52.20	5314.17
SE2	26,304	25.85	25.50	18.25	−25.55	1999.00	51.94	5276.99
SE3	26,304	26.80	25.82	20.62	−25.55	1999.00	39.42	3319.62
SE4	26,304	27.79	26.00	22.77	−25.55	1999.00	30.46	2239.62
DK1	26,304	26.03	25.60	15.17	−112.50	335.01	3.30	42.02
DK2	26,304	28.74	26.35	24.57	−112.50	1999.00	24.89	1655.01

Note: The intraday Elbas market does not always provide a price for each hour due to the lack of trade; therefore, the original sample size of this market is smaller than that of the day-ahead and regulating markets.

Table 3
Summary of price spreads from 2015 to 2017.

(a) Day-ahead — intraday price (DA-ID)

Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	26,304	0.84	0.55	6.62	−112.46	95.50	−1.15	39.46
SE1	26,304	0.41	0.00	4.01	−134.58	105.08	−7.80	348.26
SE2	26,304	0.82	0.47	3.73	−62.64	79.82	0.90	56.57
SE3	26,304	0.87	0.58	4.23	−109.50	83.38	−1.86	90.49
SE4	26,304	0.11	0.00	4.19	−177.41	133.52	−6.21	428.61
DK1	26,304	0.44	0.00	4.15	−78.71	68.14	−0.10	27.81
DK2	26,304	0.72	0.00	4.83	−87.25	92.56	0.72	49.34

(b) Day-ahead — regulating power price (DA-RP)

Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	26,304	−0.38	0.00	37.69	−2957.25	1026.48	−28.97	2114.76
SE1	26,304	1.16	0.00	16.10	−1972.58	185.25	−74.25	8702.53
SE2	26,304	1.14	0.00	16.13	−1972.58	185.25	−73.88	8641.75
SE3	26,304	0.70	0.00	17.68	−1909.24	185.25	−54.46	5345.15
SE4	26,304	0.42	0.00	19.63	−1909.24	185.25	−41.22	3532.26
DK1	26,304	0.52	0.00	11.15	−284.19	86.12	−5.61	93.14
DK2	26,304	−0.12	0.00	21.29	−1909.24	185.25	−33.14	2557.54

(c) Intraday — regulating power price (ID-RP)

Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	26,304	−1.22	0.35	36.68	−2941.42	1024.80	−30.93	2319.26
SE1	26,304	0.75	0.37	16.02	−1972.58	185.25	−75.12	8860.99
SE2	26,304	0.32	0.21	15.76	−1972.48	159.13	−78.89	9443.11
SE3	26,304	−0.18	0.10	17.26	−1921.63	169.33	−59.76	6047.11
SE4	26,304	0.31	0.18	19.36	−1909.24	185.25	−42.93	3730.95
DK1	26,304	0.08	0.00	10.74	−284.19	69.32	−5.23	85.64
DK2	26,304	−0.84	0.00	20.77	−1927.29	156.85	−36.22	2916.51

Note: When the intraday Elbas price was missing, this was substituted by the day-ahead price for the respective hour and bidding area.

which take into account the both-sidedness of the underlying price risk. Fig. 4 displays the average absolute price spreads per year between the pairs of marketplaces from 2013 to 2017, assuming 1 MW trades per hour in each market. In addition to magnitudes, we were interested in whether any trend existed across years. The figure revealed a contrast between mostly increasing spread in the day-ahead and intraday markets and mostly declining spread in the other two markets. This implied that the market's need to adjust positions in the intraday market seemed

Table 4
Number of hours with the price outliers of the regulating power (RP) markets, i.e., when p < -150 euro/MWh or p > 400 euro/MWh

	2015		2016		2017	
	p < -150	p > 400	p < -150	p > 400	p < -150	p > 400
FI	–	11	–	8	6	4
SE1	–	2	–	2	–	–
SE2	–	2	–	2	–	–
SE3	–	3	–	4	–	–
SE4	–	3	–	4	–	–
DK1	–	–	–	–	–	–
DK2	–	3	–	4	–	–

(overforecast) in Denmark (DK1-DK2) and negative (underforecast) in Sweden (SE1-SE4).

Unfortunately, not all wind power production is accounted for in the Finnish wind power production forecasts made by ENTSO-E, from which we extracted the forecast data for Finland.[14] Using the ENTSO-E wind power production forecasts resulted in a distribution of wind forecast error with a significant negative mean and a thick left tail. Therefore, we calculated the modified wind forecasts by estimating a rolling window regression using the realized wind power production and the ENTSO-E wind production forecasts with 30-day rolling windows and thus 720-hour rolling windows. First, our simple estimation for wind power production forecasts for each hour separately was as follows:

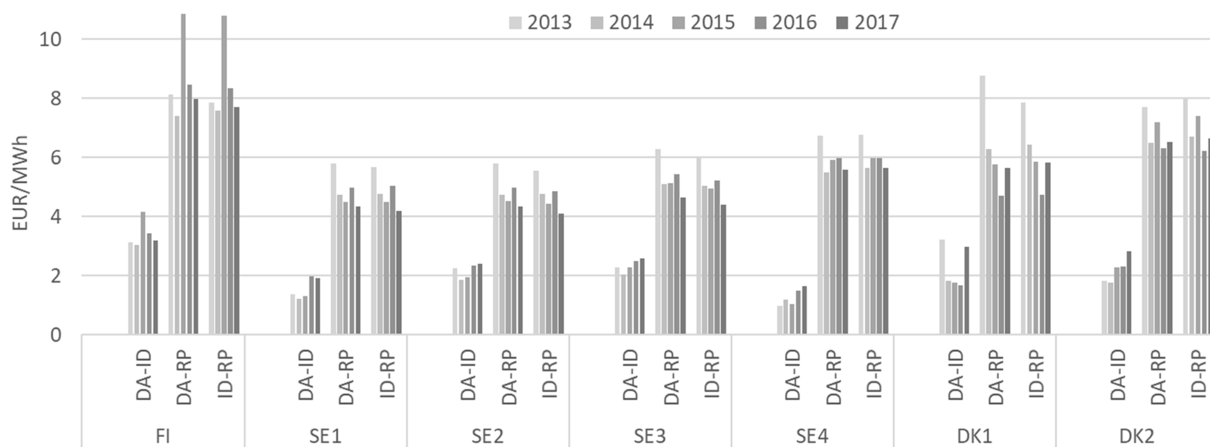

Fig. 4. Means of absolute values of price spreads, 2013–2017.

to be growing, but the scarcity of balancing resources was not worsening. Nonetheless, taking into account the magnitudes of absolute spreads of approximately 2–4 EUR/MWh in relation to the day-ahead price of approximately 30 EUR/MWh, this is a very sizable risk to the market participants. In contrast, we could look at the absolute DA-RP spread as a hypothetical benefit to be gained from strategic imbalances using the one-price system, i.e., having imbalances that helped to limit power shortage (having excess) or oversupply (having deficit). By the same token, the ID-RP absolute spread represented a sizable risk of keeping imbalances or the opportunity for additional revenues by offering flexibility in the regulating power market.

4.2. Power market fundamentals

We used two endogenous variables in addition to price spreads in our VAR models: wind forecast errors and demand forecast errors. We also used a number of other exogenous variables as controls: transmission network congestion indicator, wind power ramping, historical hydro reservoir filling deviations in Norway, Sweden, and Finland, as well as weekend, week of year, and hour of day controls. Next, we explained these variables. Their summary tables are presented in Tables 5 and 6.

This study is primarily interested in the impacts of intermittent wind power production on the relevance of different electricity wholesale markets, and we therefore focused on the uncertainty around wind power production. This uncertainty is often measured by wind forecast errors (MWh), which we calculated as the difference between wind power production forecasts one day before delivery minus the realized wind power production. Positive values indicate overforecasted production, whereas negative values represent underforecasted production. InFig. 5, the red vertical line shows the mean wind forecast errors, the teal line represents the standard normal distribution function, and the black line stands for the kernel density estimation based on the actual observations. The mean of the forecast errors was slightly positive

$$y_t = \alpha^t + \beta_1^t x_t + \beta_2^t x_t^2 + \epsilon_t \tag{1}$$

where y_t is the realized wind power production for delivery hour t and x_t is the ENTSO-E wind power production forecast for the same hour. In each estimation, we used observations for hours $[t-720, t]$. The predicted wind power production forecast $\widehat{x}_t$ for delivery hour t is then given as follows:

$$\widehat{x}_t = \widehat{\alpha}^{t-1} + \widehat{\beta}_1^{t-1} x_t + \widehat{\beta}_2^{t-1} x_t^2 \tag{2}$$

where $\widehat{\alpha}^{t-1}$, $\widehat{\beta}_1^{t-1}$, and $\widehat{\beta}_2^{t-1}$ are coefficient estimates from the rolling window regression of the previous delivery hour $(t-1)$. Finally, we calculated the wind forecast errors for Finland by $y_t - \widehat{x}_t$, which have, by assumption, close to zero mean value (see Fig. 5), but which used the information content of the original wind power forecasts by the ENTSO-E.

In addition to the supply risk, we modelled the uncertainty in the demand side, namely, the demand forecast error, which was defined as the difference between the hourly electricity demand forecasted one day before and the realized demand (see Table 5 and Fig. 6). The mean demands in DK1 and DK2 were approximately 2.2 GWh/h and 1.5 GWh/h, respectively, with standard deviations of approximately 450 MWh/h and 300 MWh/h. The very high kurtosis (peakedness) of the Danish demand forecast errors in Fig. 6 was due to a couple of rare events, such as overforecasting of 1.5 GWh/h in DK2 on December 15, 2016. The demand forecast errors were almost normally distributed in Finland and Sweden, where the mean demand from 2015 to 2017 was 9.4 GWh/h in Finland and 1.1 GWh/h, 1.9 GWh/h, 9.9 GWh/h, and 2.8 GWh/h in SE1-

[14] Finnish TSO, Fingrid, also provides wind power forecasts, but they were only from the end of 2016.

Table 5
Summary of endogenous variables: (a) wind forecast errors and (b) demand forecast errors from 2015 to 2017

(a) Wind forecast errors

Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	25,581	0.76	3.08	105.80	−568.43	624.86	−0.05	5.53
SE1	26,301	−2.05	0.86	33.79	−299.39	182.01	−0.55	6.50
SE2	26,301	−9.50	1.66	99.11	−681.18	433.47	−0.46	4.44
SE3	26,301	−9.13	−0.68	106.02	−536.53	761.84	−0.11	5.13
SE4	26,301	−11.14	−4.97	78.89	−530.14	540.26	−0.19	4.85
DK1	26,301	56.58	47.00	238.67	−1539.00	1714.00	0.25	5.50
DK2	26,301	14.76	12.00	82.00	−636.00	561.00	0.01	6.30

(b) Demand forecast errors

Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	26,301	−82.17	−90.00	241.48	−1148	2197	0.86	9.72
SE1	26,277	−0.34	1.00	83.11	−1604	476	−0.37	9.50
SE2	26,277	40.20	36.00	151.61	−1508	1010	−0.17	5.17
SE3	26,277	21.41	28.00	319.17	−1725	1840	−0.13	3.65
SE4	26,277	18.84	14.00	144.44	−924	1007	0.62	6.20
DK1	26,301	0.98	0.00	29.84	−596	1024	4.28	183.35
DK2	26,301	2.56	1.00	34.55	−590	1490	3.44	153.98

Note: The wind power forecast data for Finland are missing the first 30 days of observation due to the predicted values from ENTSO-E data.

Table 6
Summary of exogenous variables: (a) congestion indicator, (b) wind power ramping, and (c) deviations of weekly hydro reservoir fillings from 2015 to 2017.

(a) Congestion indicator

Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	26,304	0.92	1	0.27	0	1	−3.07	10.45
SE1	26,304	0.92	1	0.28	0	1	−3.03	10.17
SE2	26,304	0.92	1	0.28	0	1	−3.03	10.17
SE3	26,304	0.92	1	0.28	0	1	−3.03	10.16
SE4	26,304	0.92	1	0.27	0	1	−3.04	10.24
DK1	26,304	0.92	1	0.27	0	1	−3.13	10.80
DK2	26,304	0.92	1	0.27	0	1	−3.11	10.65

(b) Wind power ramping

Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	26,298	0.03	−0.17	44.69	−430.94	383.75	0.07	8.49
SE1	26,298	−0.01	−0.11	20.84	−131.85	178.89	0.18	5.71
SE2	26,298	−0.01	−0.47	63.75	−378.01	388.39	0.17	5.50
SE3	26,298	−0.03	−0.59	59.06	−331.02	511.04	0.13	4.85
SE4	26,298	−0.01	−0.34	48.28	−312.79	309.80	0.06	5.19
DK1	26,298	0.01	−1.00	120.33	−866.00	946.00	0.07	5.84
DK2	26,298	0.00	0.00	45.83	−505.00	655.00	0.20	10.13

(c) Deviations of weekly hydro reservoir fillings

Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
Norway	26,304	−0.09	0.00	5.39	−16.59	12.63	−0.37	3.50
Sweden	26,304	−0.24	0.28	7.38	−15.26	14.15	−0.22	2.23
Finland	26,304	3.84	4.65	5.42	−19.50	19.62	−0.59	5.35

SE4, respectively.

Next, we define several exogenous fundamental variables and controls. Power systems can be impacted not only by errors in wind power production but also by sudden changes in the output of intermittent power generation. This is because sudden hourly variations in wind production need to be accommodated by sufficient flexible resources; see, for instance, [1]. We therefore controlled for wind power ramping (MWh/h), which was defined as the hourly change in realized wind power production. Positive values imply ramping up wind generation and negative values suggest ramping down.

The role of the cross-border transmission network and the impact of congestion on prices has been discussed in Section 3. We included a variable that controls for transmission bottlenecks by indicating whether a bidding area's day-ahead hourly price differed from the reference system price. Transmission bottlenecks and flows are especially relevant for day-ahead price formation, whereas intraday cross-border flows follow physical limitations rather than commercial activity [18].

Hydro power is a dominant source of power generation in the Nordic region, where price levels and their dynamics are impacted by seasonal hydrological conditions. Hydro power producer's marginal cost is based on the future opportunity cost therefore their bidding is strongly dependent on the forecasts of market prices and hydro inflow. For example, in an unusually wet time period when water inflows are much higher than usual the day-ahead prices may plunge due to excess hydro generation. If such unusually wet period would coincide with high wind power generation or higher number of forced outage rates, prices in the intraday and regulating power markets could be more attractive for hydro power producers. We therefore controlled for hydrological conditions in Norway, Sweden and Finland by calculating the difference between the running historical median of hydro reservoir fillings since 1995 and the current hydro reservoir filling, which were both measured in percentages. Fig. 7 presents the weekly deviations in hydro reservoir

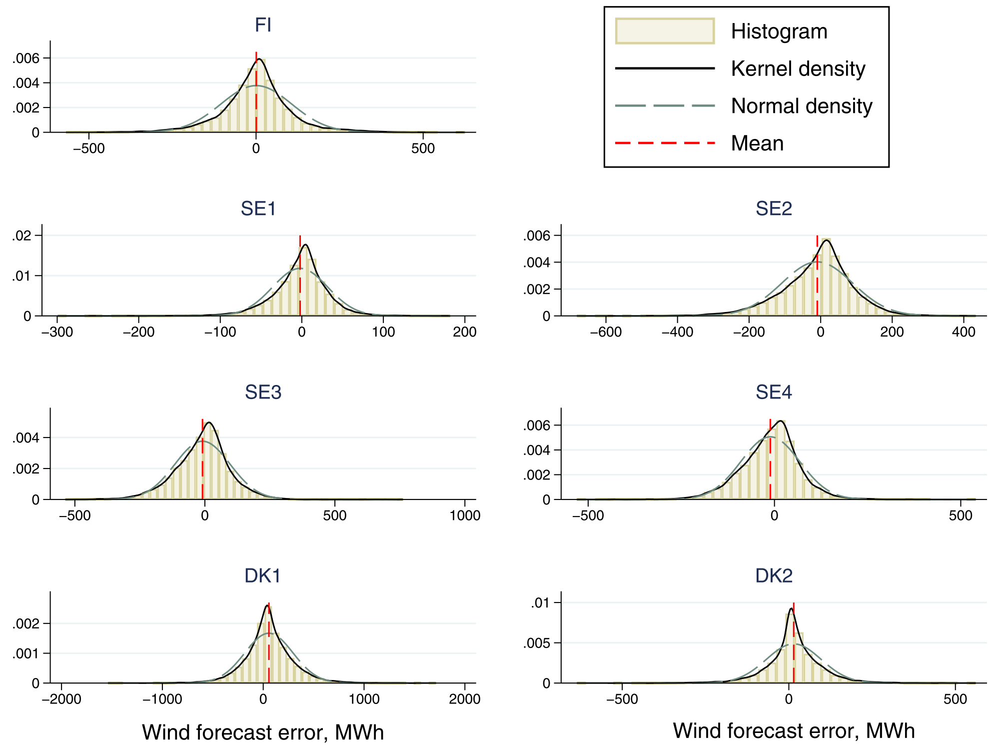

Fig. 5. Distribution of wind forecast errors for Finland (FI), Sweden (SE1-SE4), and Denmark (DK1-DK2) from 2015 to 2017.

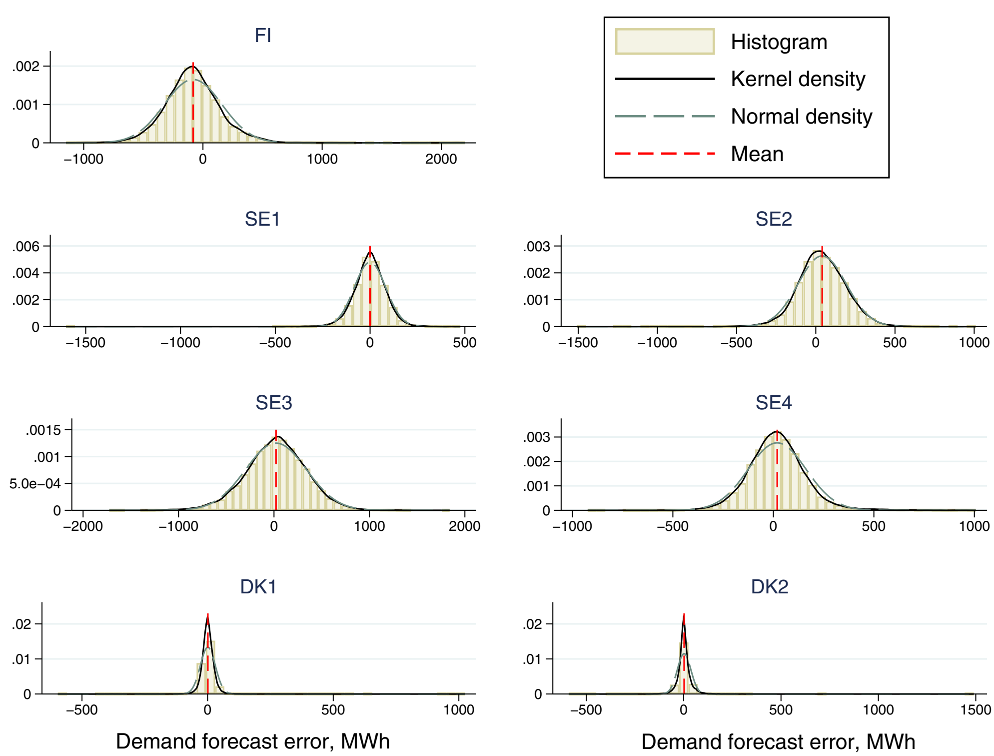

Fig. 6. Demand forecast errors for Finland (FI), Sweden (SE1-SE4), and Denmark (DK1-DK2). 2015–2017.

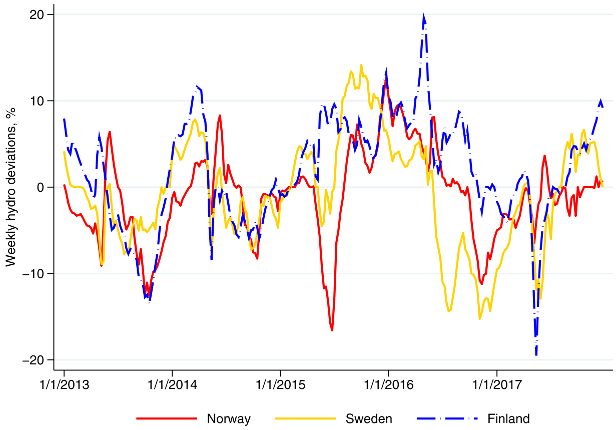

Fig. 7. Deviations in weekly hydro reservoir fillings (%) from 2013 to 2017. Note: Deviations are measured as the difference between the current percentage level of hydro reservoir filling and the respective historical median measured since 1995. Negative values represent drier than usual weeks, and positive values represent higher reservoir values than those in a typical week; both were measured in percentages.

fillings and shows, for example, that Norway experienced a drier period in July 2015 or that Finland had better than usual hydro conditions in May 2016. Finally, we controlled the diurnal and seasonal patterns by including the week-of-year, weekend, and hour-of-day fixed effects.

4.3. Methods

We studied the dynamics of three electricity market prices in a vector autoregression (VAR) setup, specified as the linear functions of their own lags, the lags of every other variable in the vector, and exogenous variables. By this dynamic modelling approach, we were able to perform causal inference and provide policy advice [36]. This is because compared to, for instance, OLS, which provides a static picture of temporally interrelated variables, the VAR model can capture this temporality and follow the trajectories of price signals and their responses to the imbalances.

We focused on three endogenous (response) variables, namely, price spreads (DA-ID, DA-RP, ID-RP), wind forecast errors, and demand forecast errors in 7 bidding areas (3 countries), which gave us 63 response variables that were studied for the years from 2015 to 2017[15]. The VAR model is specified in Eq. (3) as follows:

$$y_t = \alpha_0 + A_1 y_{t-1} + \cdots + A_p y_{t-p} + Bx_t + \epsilon_t \tag{3}$$

where y_t is a 3x1 vector of endogenous variables ($PriceSpread_t$, $WindError_t$, $DemandError_t$)', $x_t = (x_{1t}, x_{2t}, \cdots x_{dt})$' is a dx1 vector of exogenous variables, A_i are 3x3 matrices of the lag coefficients to be estimated, B is a 3xd matrix of the exogenous variable coefficients to be estimated, α_0 is a 3x1 vector of the constant terms, and ϵ_t is a 3x1 vector of the white noise innovation process, with $E(\epsilon_t) = 0$, $E(\epsilon_t, \epsilon_t{}') = \Sigma_\epsilon$, and $E(\epsilon_t, \epsilon_s{}') = 0$ for $t \neq s$.

In the VAR model, it was assumed that all of the endogenous variables were stationary. We test this assumption by the augmented Dickey-Fuller (DF-GLS) test and Phillips-Perron unit-root test, both confirming the stationarity of our time series variables. A table of the unit root test results is presented in the Appendix in Table 9.

Another important step in VAR modelling is the selection of the appropriate lag-order structure of the endogenous variables, which we based on theory (minimizing Akaike and Bayesian information criteria, AIC and BIC, respectively) and practice (capturing the diurnal pattern). Our lag structure included each hour of the previous day (1–24) and the same hour from two days before (48). To capture the seasonal structure, we additionally included the week, weekend and hour fixed effects in the form of dummy variables.

Because correlation does not necessarily imply causation and because we were primarily interested in the latter, we focused on testing the causality among our endogenous variables. Granger [37] defined a testable definition of causality that tests whether, for instance, y_2 causes y_1 by testing whether the lagged values of y_2 improve the explanation of y_1 in comparison to using the lags of the y_1 process alone. This causality in the Granger sense tests the significance of the information content of y_2 for explaining y_1. We tested a bidirectional Granger causality between each pair of endogenous variables, and we report the χ^2 statistics of the Wald test for the joint hypothesis of $\gamma_{i1} = \gamma_{i2} = \ldots = \gamma_{il} = 0$ for each equation in (4). Hence, the null hypothesis was that y_2 in the first regression and y_1 in the second regression did not Granger cause y_1 and y_2.

$$\begin{aligned} y_{1t} &= \alpha_{10} + \alpha_{11} y_{1t-1} + \cdots + \alpha_{1l} y_{1t-l} + \gamma_{21} y_{2t-1} + \cdots + \gamma_{2l} y_{2t-l} + B_1 x_t + \epsilon_{1t} \\ y_{2t} &= \alpha_{20} + \alpha_{21} y_{2t-1} + \cdots + \alpha_{2l} y_{2t-l} + \gamma_{11} y_{1t-1} + \cdots + \gamma_{1l} y_{1t-l} + B_2 x_t + \epsilon_{2t} \end{aligned} \tag{4}$$

Finally, after specifying a stable VAR model (all eigenvalues of the dynamic matrix lie within the unit circle) and exploring the pairwise causality, we traced the marginal effects of a shock (impulse) to one endogenous variable on another endogenous variable (response). The magnitude, duration, and direction of the responses can be studied by orthogonalized impulse response functions (IRFs), which used the estimated results from Eq. (4) to quantify the impact of one standard deviation shock at time t on the expected values of y_i at time $t + n$.

5. Results and discussion

In this section, we present the main results and discuss the causal links (Section 5.1) and dynamic relationships (Section 5.2) between the spreads and forecasting errors. These results were based on the post-estimation statistics (Granger causality and impulse response functions, respectively) of the VAR system. In Section 5.3, we explore the effects of exogenous variables on the spreads.

5.1. Causal effects of wind power and demand forecast errors

Table 7 shows the chi-square test statistics (p values) testing the null hypothesis that wind or demand forecasting errors did not Granger cause the spreads.[16] We ran Granger causality tests for the whole study period from 2015 to 2017 and for each year separately to see if there was a change over time in the results.

5.1.1. Wind power forecast errors

The main finding from the table was that spreads in the areas with large shares of wind power were significantly driven by wind forecast errors, especially in DK1, DK2 and SE4. Moreover, when looking at the test statistics for the whole period, it seemed that the wind forecast errors did not cause spreads in bidding areas with lower shares of wind power generation (FI, SE1, SE2), at least in the case of DA-ID spreads.

[15] The sample period, which includes approximately 26 thousand observations, is represented by a strong presence and growth of wind power in the studied countries (see Figs. 1 and 2) allowing us to meaningfully capture the interdependencies between price spreads, wind and demand forecast errors. Unavailability of official wind forecasts in all the studied countries also limited the study period to begin only in 2015.

[16] As a reminder, the Granger-causality is a probabilistic account of causality where we are observing whether past values of other endogenous variables, in our case wind and demand forecast errors, help to forecast the future spreads. Hence, Granger-causality is rather an anticipatory effect than the cause-and-effect relationship as understood by microeconomics.

Table 7
Granger causality between wind and demand forecast errors and price spreads

Wind forecast error					Demand forecast error				
DA-ID					DA-ID				
	2015	2016	2017	2015–2017		2015	2016	2017	2015–2017
FI	0.433	0.438	0.015**	0.152	FI	0.003***	0.013**	0.000***	0.000***
SE1	0.687	0.599	0.542	0.454	SE1	0.921	0.495	0.145	0.418
SE2	0.602	0.158	0.008***	0.751	SE2	0.000***	0.684	0.002***	0.141
SE3	0.669	0.386	0.048**	0.493	SE3	0.000***	0.173	0.013**	0.000***
SE4	0.056*	0.031**	0.008***	0.004***	SE4	0.016**	0.242	0.000***	0.070*
DK1	0.000***	0.000***	0.012**	0.000***	DK1	0.900	0.008***	0.769	0.513
DK2	0.002***	0.281	0.000***	0.000***	DK2	0.010**	0.146	0.770	0.193
DA-RP					DA-RP				
	2015	2016	2017	2015–2017		2015	2016	2017	2015–2017
FI	0.458	0.038**	0.000***	0.000***	FI	0.000***	0.000***	0.000***	0.000***
SE1	0.029**	0.188	0.021**	0.000***	SE1	0.000***	0.000***	0.648	0.003***
SE2	0.203	0.435	0.115	0.006***	SE2	0.000***	0.000***	0.000***	0.000***
SE3	0.939	0.633	0.000***	0.034**	SE3	0.000***	0.000***	0.000***	0.000***
SE4	0.116	0.015**	0.065*	0.001***	SE4	0.000***	0.000***	0.000***	0.000***
DK1	0.000***	0.000***	0.000***	0.000***	DK1	0.025**	0.001***	0.057*	0.000***
DK2	0.000***	0.040**	0.000***	0.000***	DK2	0.002***	0.004***	0.538	0.003***
ID-RP					ID-RP				
	2015	2016	2017	2015–2017		2015	2016	2017	2015–2017
FI	0.533	0.037**	0.000***	0.000***	FI	0.000***	0.000***	0.000***	0.000***
SE1	0.118	0.230	0.037**	0.003***	SE1	0.007***	0.000***	0.721	0.003***
SE2	0.184	0.060*	0.038**	0.001***	SE2	0.000***	0.000***	0.000***	0.000***
SE3	0.872	0.703	0.000***	0.041**	SE3	0.000***	0.000***	0.000***	0.000***
SE4	0.180	0.051*	0.152	0.009***	SE4	0.000***	0.000***	0.000***	0.000***
DK1	0.000***	0.000***	0.000***	0.000***	DK1	0.030**	0.000***	0.032**	0.000***
DK2	0.000***	0.038**	0.000***	0.000***	DK2	0.002***	0.010***	0.565	0.001***

Note: The table shows the results of Granger causality test, which tests whether wind or demand forecast errors Granger cause the price spreads, i.e., divergence between the prices of wholesale electricity marketplaces. The table shows the p values of the χ^2 statistics with significance levels, where *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$. Test statistics are based on the model ignoring the price outliers of the regulating power (RP) markets, i.e., when $p <$ -150 euro/MWh or $p >$ 400 euro/MWh.

This implies that there may be a threshold effect such that spreads start to be driven by wind power forecasts when the share of wind power reaches a certain threshold. This view is strengthened when the test statistics are looked at for different years. The effect of wind forecasts seemed to become more important in each year in areas with a relatively low initial shares of wind power. The p values of the chi-square test statistics decreased year by year in every bidding area, and the test statistics were statistically significant for all spreads in almost all bidding areas for 2017. Only in northern Sweden (SE1) for DA-ID spread was the p value relatively high in 2017, whereas for 2015, the p values were low only in areas with high shares of wind: SE4, DK1 and DK2.

5.1.2. Demand forecast errors

The spreads were the most clearly demand-driven in Finland and SE3, as indicated by the significance of the demand forecast errors across all marketplaces. In fact, the demand forecast errors seemed to Granger cause most of the spreads except DA-ID spread in SE1-SE2 and Denmark, which was also the finding of [23] with respect to Denmark. The threshold or size effect may have been in play here again where the demand forecast error was not significant in areas with relatively low consumption. In contrast to the wind forecast errors, the chi-square test statistics were relatively stable during different years.

Our findings underlined the utmost relevance of the demand-side measures for spreads. It was evident that through adequate demand-side measures, balancing risks and costs can be controlled and lowered by bringing the market prices closer to each other. Demand-side management has the potential to counterbalance the negative effects of wind power forecasts in DK1, SE3 and SE4, where they both exert influence on the spreads.

5.2. Dynamic effects of wind power and demand shocks

The results from the Granger causality tests provided useful information about the relevance and significance of the supply and demand factors for price spreads. However, we did not know much about the magnitudes and direction of these effects. In this part, we focus on the trajectories of the price spreads and on their responses to supply and demand shocks.

The following figures presented the impulse response functions (IRFs), which showed a shock of one standard deviation to either wind forecast error or demand forecast error and the response of a price spread during the following 24-hour period. For the sake of brevity, we showed IRFs only for two spreads (DA-ID and ID-RP). In fact, the IRFs for DA-RP spread not shown here were very similar to the ID-RP spread, so the responses could be quickly deduced from these.

5.2.1. Wind power shock

We first focused on the effects of wind forecast errors on the price spreads. In Fig. 10, we show the IRFs for all bidding areas for the whole study period from 2015 to 2017. In Fig. 8(DA-ID) and Fig. 9 (ID-RP), on the other hand, we showed the IRFs related to wind power shocks only for FI, SE3 and DK1. These IRFs were presented separately for each year and for the whole three-year period.

It is perhaps the most surprising finding that wind forecast errors do not meaningfully affect the DA-ID spread in DK1 until 2017 (Fig. 8). However, DK1 is the bidding area where the highest absolute and relative wind power generation is located. This also holds true in Finland and SE3, where the shock in wind forecast error of one standard deviation had no statistically significant effect on DA-ID spread until 2017. However, in 2017, the significant impact of a wind power forecast shock

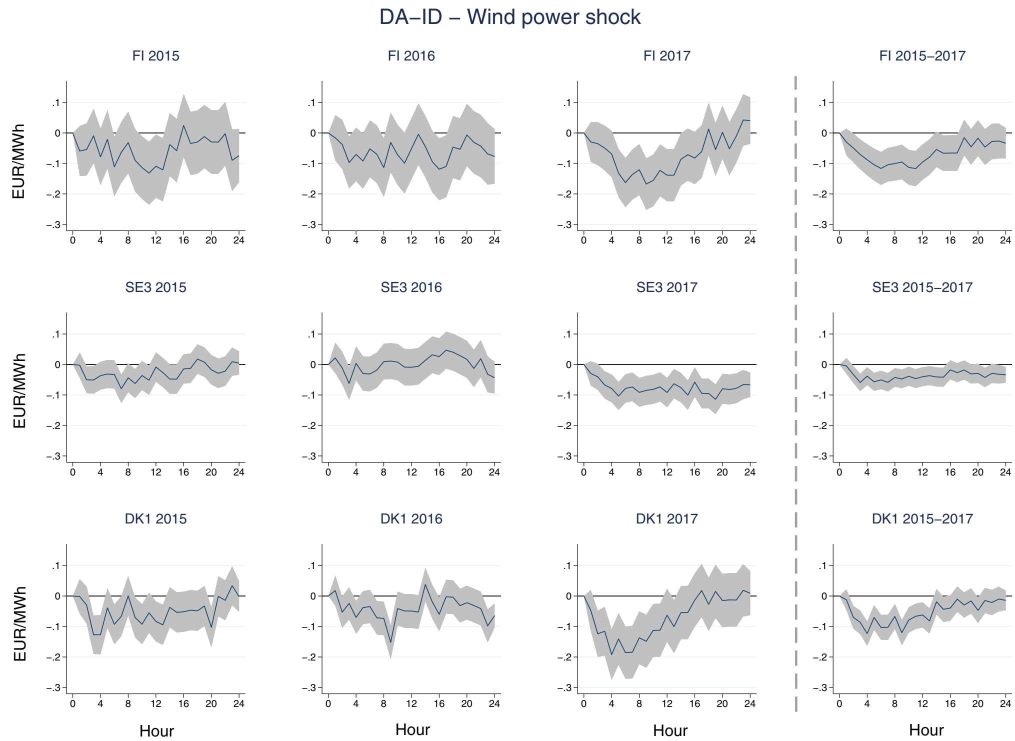

Fig. 8. Impulse response functions showing responses of price spreads DA-ID to shocks in wind forecast errors during the next 24 h in bidding areas FI, SE3 and DK1 for the whole study period from 2015 to 2017 (right column) and for each year separately. Note: The figure shows the responses of price spreads to one standard deviation in wind or demand forecast error during the following 24 h. The grey area represents the 95 percent confidence intervals.

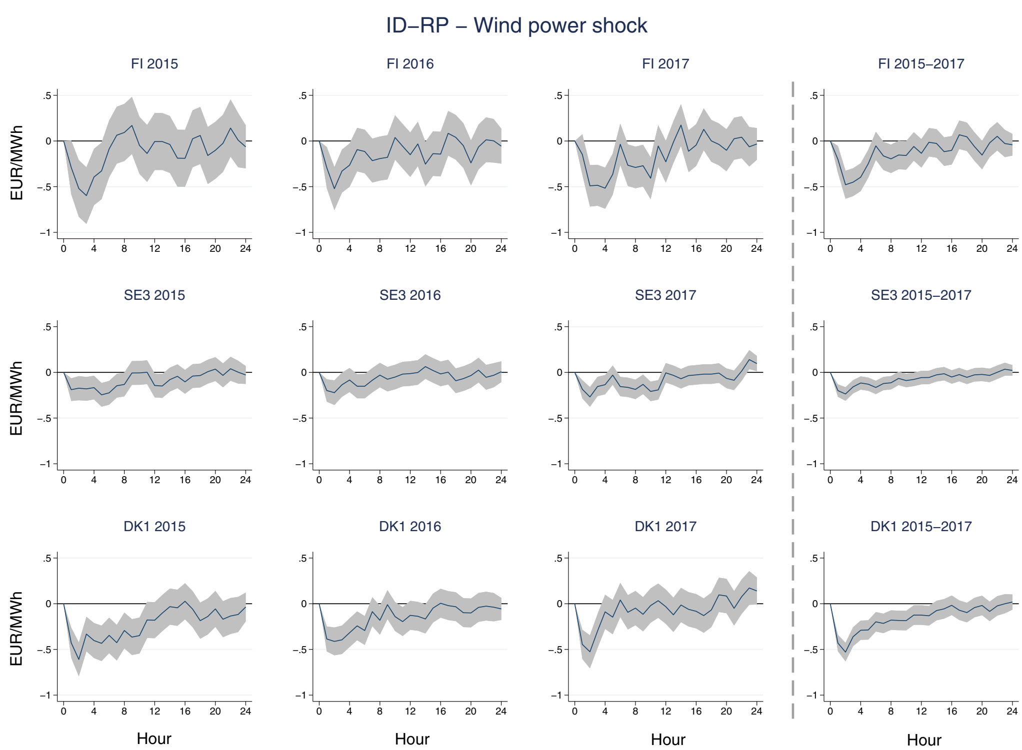

Fig. 9. Impulse response functions showing responses of the price spreads ID-RP to shocks in wind forecast errors during the next 24 h in bidding areas FI, SE3 and DK1 for the whole study period from 2015 to 2017 (right column) and for each year separately. Note: The figure shows the responses of price spreads to one standard deviation in wind or demand forecast error during the following 24 h. The grey area represents the 95 percent confidence intervals. The IRFs are based on the model ignoring the price outliers of the regulating power (RP) markets, i.e., when p < -150 euro/MWh or p > 400 euro/MWh.

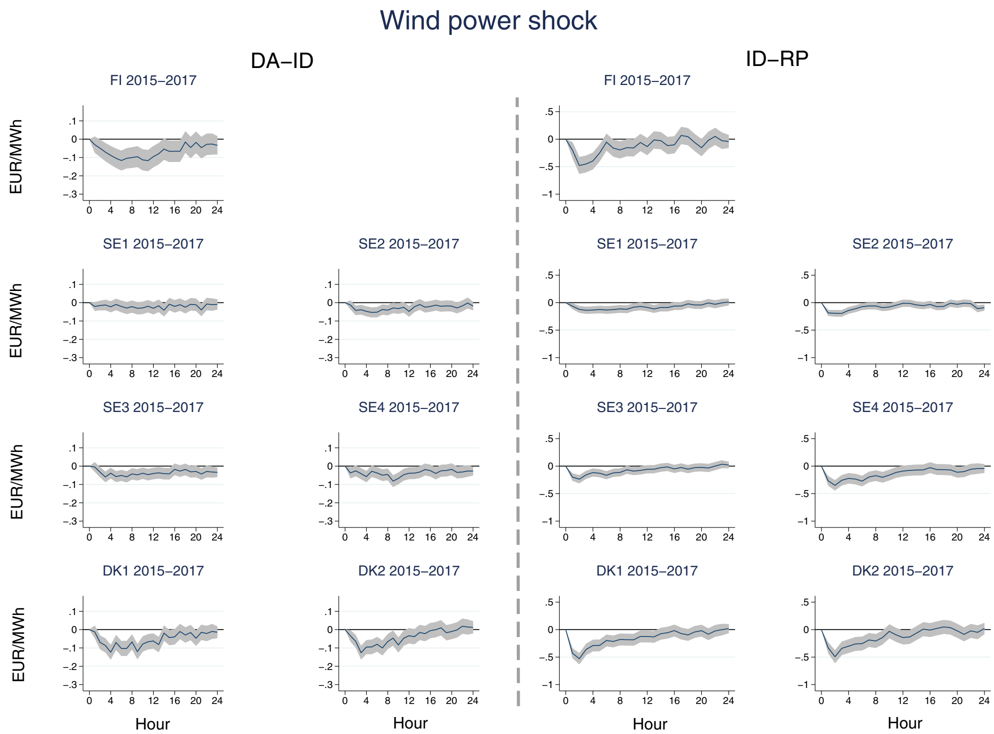

Fig. 10. Impulse response functions showing responses of price spreads (DA-ID and ID-RP) to shocks in wind forecast errors during the next 24 h in Finland (FI), Sweden (SE1-SE4), and Denmark (DK1-DK2) for the whole study period from 2015 to 2017. Note: The figure shows responses of price spreads to one standard deviation in wind forecast error during the following 24 h. The grey area represents 95 percent confidence intervals. IRFs are based on the model ignoring the price outliers of the regulating power (RP) markets, i.e., when p < -150 euro/MWh or p > 400 euro/MWh.

on DA-ID in FI, SE3 and DK1 was between 10 and 20 euro cents/MWh within the first four hours after the shock. If we took the absolute average price spread between DA-ID across the bidding areas and the studied period as 2.2 EUR/MWh (see Fig. 4 for details), the effect of the wind power shock translated into a 5–9 percent price risk between the day-ahead and intraday markets. The effect of the wind error shock on DA-ID spreads seemed to last at least 12 to 16 h in FI and DK1 (in 2017) and even longer in SE3.

Hence, when the wind power production is higher (lower) than forecasted and the wind error shock is negative (positive), then the price in the intraday market tends to fall under (rise over) the price of the day-ahead market, and the spread between the DA-ID market becomes positive (negative). However, the correction is not fully covered by intraday markets.

Instead, corrections are mostly implemented via the shorter-term markets in DK1, where a positive (overforecast) shock to wind forecast error leads to a drop of ID-RP spread by over 50 euro cents/MWh in the first two hours (Fig. 9). If we took the absolute average price spread between ID-RP across the bidding areas and the studied period as 6 EUR/MWh, this translated into a 3–8 percent price risk between the intraday and regulating power markets caused by a wind power shock. The effect was fairly similar in all years from 2015 to 2017. This implies that when the realized wind power generation was less than forecasted, ceteris paribus, a greater pressure was created on the up-regulation price than on the intraday price and thus this increased the absolute value of the negative ID-RP spread.

If we omitted the extreme up- and down-regulating prices from the model, the impulse response functions of ID-RP spreads looked fairly similar for all years in Finland and in SE3. The positive shock to wind forecast error led to a drop in the ID-RP spread by approximately 50 euro cents/MWh in Finland and 20–30 euro cents/MWh in SE3 during the first four hours after the shock.

In other bidding areas, the IRFs related to wind power shocks were comparable to the IRFs of FI, SE3, and DK1 (see Fig. 10). In DK2, the dynamics of the wind power shock were relatively similar to those in DK1. In Sweden, the responses of DA-ID and ID-RP spreads to the wind power shock were highest in SE4, where the share of wind power was also highest, and the responses were the lowest or non-existent in SE1, where the share of wind power was lowest.

5.2.2. *Demand shock*

Next, we turned to observe the responses of price spreads to the shocks in the demand forecast errors, as shown in Fig. 11. We can deepen the previous finding that most of the price spreads are demand-driven, as shown by the Granger causality results. Moreover, the effects are relatively stable over the years 2015–2017, and we thus do not present here the yearly IRFs.

The first and most important finding was that the demand forecast errors had a significantly positive impact on most of the price spreads. More explicitly, positive (overforecasted demand) shock shifted the demand curve to the left from the forecasted consumption in the day-ahead market. With lower than expected consumption in the real-time markets, the prices in the intraday and regulating power markets declined, which implied increased DA-ID and ID-RP spreads. We can interpret this as that the excess demand was sold back at discount in the intraday market (DA-ID) or that the non-realized consumption/excess

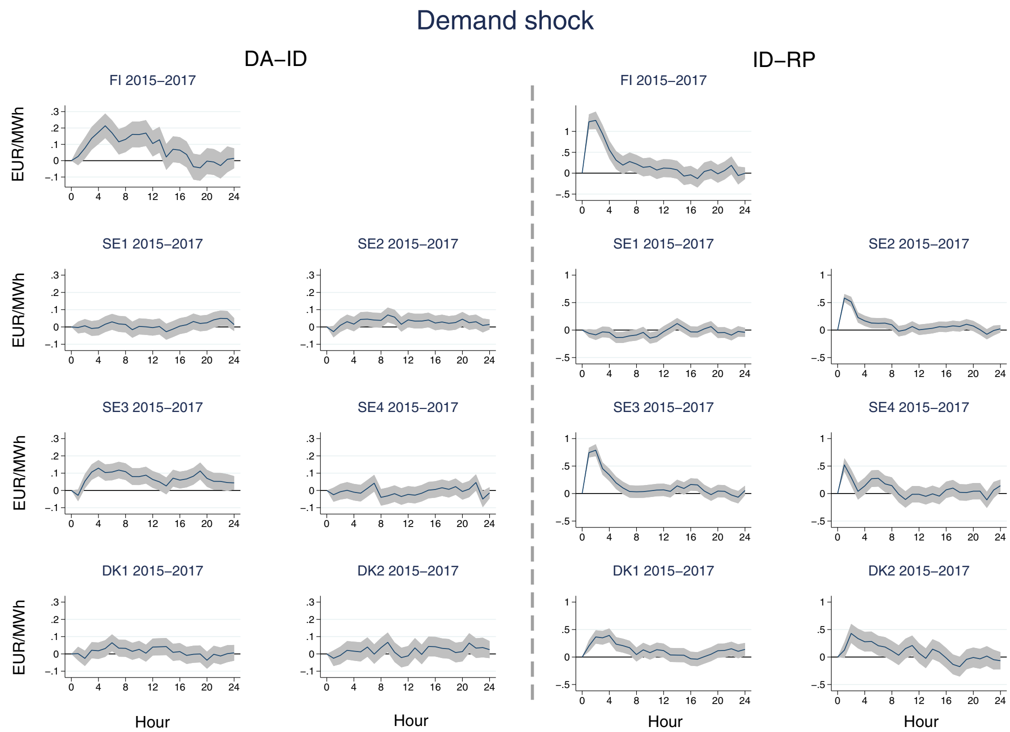

Fig. 11. Impulse response functions showing responses of the price spreads DA-ID and ID-RP to shocks in the demand forecast errors during the next 24 h in Finland (FI), Sweden (SE1-SE4), and Denmark (DK1-DK2) for the whole study period from 2015 to 2017. Note: The figure shows responses of price spreads to one standard deviation in wind or demand forecast error during the following 24 h. The grey area represents 95 percent confidence intervals. IRFs are based on the model ignoring the price outliers of the regulating power (RP) markets, i.e., when p < -150 euro/MWh or p > 400 euro/MWh.

Table 8
Results of the vector autoregression models – Exogenous variables

(a) Dependent variable: Price spread DA-ID

	FI	SE1	SE2	SE3	SE4	DK1	DK2
Congestion	−0.008	−0.086	−0.085	−0.042	0.147*	−0.116	−0.003
Wind ramp	−0.002**	0.001	0.000	0.000	0.000	0.0003*	0.000
Hydro dev. NO	−0.016**	0.005	0.006	0.005	0.003	−0.004	0.000
Hydro dev. SE	0.005	−0.007**	−0.003	−0.006*	−0.003	0.002	−0.004
Hydro dev. FI	0.005	−0.008*	−0.007*	−0.005	0.000	−0.003	0.000

(b) Dependent variable: Price spread DA-RP

	FI	SE1	SE2	SE3	SE4	DK1	DK2
Congestion	−0.186	−0.033	−0.045	−0.080	0.046	−0.417**	−0.248
Wind ramp	0.000	0.005***	0.001**	0.002**	0.005***	0.002***	0.006***
Hydro dev. NO	0.013	0.013	0.007	0.019*	0.007	0.019	0.028
Hydro dev. SE	−0.030*	−0.003	0.001	−0.017**	−0.013	−0.006	−0.030**
Hydro dev. FI	−0.006	−0.006	−0.006	−0.004	0.006	0.004	0.012

(c) Dependent variable: Price spread ID-RP

	FI	SE1	SE2	SE3	SE4	DK1	DK2
Congestion	−0.291	0.015	−0.003	−0.078	−0.087	−0.352	−0.311
Wind ramp	0.001	0.004*	0.001*	0.002**	0.005***	0.002***	0.006***
Hydro dev. NO	0.049**	0.012	0.002	0.015	0.003	0.028**	0.032*
Hydro dev. SE	−0.054***	0.003	0.005	−0.015*	−0.014	−0.010	−0.031**
Hydro dev. FI	−0.020	−0.001	−0.001	0.002	0.006	0.009	0.014

Note: The table shows coefficient estimates based on the vector autoregression model specified in Section 4.3. Significance levels are displayed as *** p < 0.01, ** p < 0.05, * p < 0.1. The results are based on the model ignoring the price outliers of the regulating power (RP) markets, i.e., when p < -150 euro/MWh or p > 400 euro/MWh.

supply led to down-regulation (ID-RP). Similarly, the negative demand shock (underforecasted demand) shifted the demand curve outwards to the right, increasing the prices in the intraday market (DA-ID) or regulating power market (ID-RP) markets, and price adjustment to unexpected excess demand occurred in real time.

The most pronounced effects of demand forecast errors on price spreads were in FI and SE3, where a positive shock led to an increase of 10–20 euro cents/MWh in the DA-ID spread and from 80 euro cents to 1.5 euro/MWh in the ID-RP spread during the first four hours after the event. Again, if we took the absolute average price spread between the DA-ID and ID-RP spreads across bidding areas and the studied period as 2.2 EUR/MWh and 6 EUR/MWh, respectively, this translated into a 5–9 percent (DA-ID) and 13–69 percent (ID-RP) price risk due to the demand forecast shock. In Denmark, a positive shock significantly increased the ID-RP spread in particular by 40 euro cents/MWh within the first four hours. As previously argued, the lower impact in Denmark and insignificance of demand forecast errors on the spreads in other areas can be due to the relatively low consumption compared to FI and SE3.

Finally, two points can be raised from observing the IRFs. First, the impacts of the shocks were much greater in the short-term markets (ID-RP), which reflected the higher costs of balancing reserves as well as the uncertainty and thus risk premia in the regulating power prices. Second, all significant supply and demand shocks dissipated within a half day or in a shorter time period, which shows that active market participants efficiently adjust to market conditions in the short run. However, shocks, especially those in wind forecasts, appeared to create effects on the DA-ID spreads that lasted much longer than the effects on the ID-RP spreads. For instance, the effect of wind error shock on the DA-ID spreads was significant for at least 12 h in 2017, and in SE3, the effect seemed to last the full day. However, the effects of wind and demand forecast errors on the ID-RP spreads seemed to more or less die out in four to six hours in all bidding areas. One explanation for this could be the continuous trading of the intraday market. The ID price was the volume weighted price of all trades during the time when the intraday market was open. Hence, the intraday price reacted more slowly to the shock, and the reaction to the shock was not fully covered by the intraday market.

5.3. Impacts of exogenous variables

Finally, we explored the effects of exogenous variables on the price spreads (see Table 8; a full table of the estimation results is presented in the Appendix in Table 10). Hydro-deviations did significantly and negatively impact most of the spreads, especially the Swedish hydro power in SE1, SE3, FI, and DK2 and the Norwegian hydro power in FI and DK1. The effect was stronger in the DA-RP and ID-RP spreads than in the DA-ID spread. The negative sign can be interpreted as better (worse) than usual hydro-conditions decrease (increase) the spreads, which implies a stronger effect directly on the levels of the day-ahead and intraday markets, while the regulating power market remained less affected by the deviations. This was an interesting finding, implying that despite the changes in hydro reservoirs, the cost of balancing remained stable relative to the day-ahead (in DA-RP spread) and intraday markets (in ID-RP spread). The exception was DK1, which had an ID-RP spread that seemed to be significantly and positively impacted by the deviations in the Norwegian hydro power, implying an impact on the cost of balancing.

The ramping of wind power had a significantly positive impact on the DA-RP and ID-RP spreads in Denmark and Sweden, and the impact was slightly stronger in SE4 and DK2 than in the other areas, whereas the wind power ramping had a negative impact on the DA-ID spread in Finland. This meant that in areas with a large share of wind power generation (DK1, DK2, and SE4), wind power ramping was associated with a direct impact on balancing costs. The sudden ramp-ups (ramp-downs) in wind power seemed to reduce (increase) the regulating power price, leading to increasing (decreasing) spreads between DA-RP and ID-RP. In Finland, wind power ramping appeared to exert a greater pressure on the day-ahead market in comparison to the intraday price, where ramp-ups (ramp-downs) in wind power decreased (increased) the day-ahead price.

Finally, the day-ahead congestion indicator appeared to be mostly insignificant for the spreads, except having a significantly positive impact (at the 10 percent significance level) on the DA-ID in SE4 and a significantly negative impact on DA-RP in DK1. The negative impact on the DK1 spread meant that during congestion, the cost of balancing increased by approximately 40 euro cents/MWh. The positive impact on the DA-ID spread in SE4 during congested hours can mean that the average day-ahead price is higher during these events due to limited import capacity or that the intraday price is lower due to the higher local intraday supply.

6. Conclusions

Increased shares of wind power affect wholesale electricity markets in many ways. First, the overall price levels were decreasing when production capacity with low marginal costs was entering the markets. This affected, for instance, the profitability of the conventional thermal power plants. Second, the increasing shares of stochastic wind generation brought along greater deviations between the real-time power generation and the day-ahead forecasts of power supply. This was expected to increase the needs for balancing services and thereby the costs of keeping the power system in balance.

The growing share of weather-dependent renewable energy production has also changed the relationship and importance of the different marketplaces in the electricity market. The closer-to-delivery markets – intraday and regulating markets – are expected to become more important in terms of trading activity and price discovery. It is important to understand these dynamics because to date, the day-ahead market has been dominant and has served as a basis for new electricity generation investments, real-time pricing, hedging strategies, and as reference prices in capacity markets, among other things. This study fills a gap in the current literature and investigated all three main electricity wholesale marketplaces in a single study.

We particularly studied the price spreads between the day-ahead, intraday and regulating power markets in seven biding areas in Denmark (DK1, DK2), Sweden (SE1, SE2, SE3, SE4), and Finland (FI) from 2015 to 2017 by exploring the actual electricity market prices in these bidding areas. We exploited the variation in the share of wind power in different Nord Pool bidding areas in these three Nordic countries. We used vector autoregression (VAR) models to explain the interrelationships between the price spreads and the effects of wind forecast and demand forecast errors and other exogenous variables, such as transmission congestion and hydrological conditions, on the price spreads in different bidding areas.

The novelty of our study is that we were able to disentangle the effects on intraday and regulating power markets by analysing the price spreads between different marketplaces (day-ahead, intraday and regulating power markets) jointly. The cross-market and cross-country nature of our study, which was conducted with a multi-year sample in a single econometric study, is unique in the current body of literature. This enables the reader to obtain a full and comparative understanding of the main fundamental drivers behind the relevance of different Nordic electricity marketplaces, with important lessons for other international electricity markets. In contrast to the existing studies, we also compared our results by individual years as well as over the entire period, which provided a better understanding of the studied drivers as well as a robustness check on the found relationships.

Importantly, our findings about the regulating power market are not only directly relevant to the market participants in this market but also to other Nordic balancing markets, namely aFRR and FCR-Normal because their energy remuneration price is set by the regulating power market. In fact, our findings about the regulating power market is relevant to all balance responsible parties because the regulating power market prices set the imbalance prices.

We found that wind forecast errors did affect the price spreads in areas with large shares of wind power generation, such as in Denmark and in southern Sweden. In southern Sweden (bidding area SE4) and in Denmark, wind forecast errors Granger caused all price spreads. In the middle part of Sweden (bidding area SE3), where the shares of wind power were lower but were still very meaningful, the wind forecast errors affected only the price spreads between intraday (ID) (or day-ahead (DA)) and regulating power (RP) markets. In those bidding areas where the shares of wind power were still modest, such as in northern Sweden (SE1) and Finland (FI), wind forecast errors had no statistically significant effect on the price spreads, especially when looking at 2015. However, in 2017, the wind forecast errors had a statistically significant impact on all price spreads in almost all bidding areas. Hence, we found a threshold effect, meaning that causality in the Granger sense is relevant for spreads only after a certain threshold of the share of wind power in the electricity market. However, we did not explicitly search this threshold in this paper. We also quantified the dynamic impact of a one standard deviation shock of wind forecast error on the price spreads and found a significant effect ranging between 5 and 9 percent (10–20 euro cents/MWh) on the DA-ID and 3–8 percent (20–50 euro cents/MWh) on the ID-RP absolute price spreads.

Moreover, we have found that the demand forecast errors did have an impact on almost all price spreads, except in areas with relatively low consumption. This may again be an indication of the threshold or size effect. We quantified the dynamic impact of one standard deviation of demand forecast error on price spreads and found that a demand forecast shock caused a 5–9 percent (10–20 euro cents/MWh) impact on the DA-ID and 13–69 percent (80 euro cents-1.5 euro/MWh) impact on the ID-RP absolute price spreads. We also found that hydro-deviations did significantly and negatively impact most of the spreads and had larger impacts on the day-ahead and intraday price levels than on the regulating power market. The ramping of wind power had a significantly positive impact on the DA-RP and ID-RP spreads in the areas with large shares of wind power generation (DK1, DK2, and SE4, that is Denmark and southern Sweden) and was thus associated with a direct impact on balancing costs. Finally, the day-ahead congestion indicator appeared to be the most insignificant for the spreads, with some exceptions in areas with a large share of wind power generation.

In this paper, we have quantitatively shown that increasing the shares of wind power, after reaching a certain threshold, begins to change the relevance of different electricity marketplaces. This finding is relevant not only for the Nordic electricity markets but also for other liberalized electricity markets transitioning into variable renewable energy sources (vRES)-dominated systems. This has implications for future market design, where markets closer to real time will play a more important role than in the past. Near real-time markets should start to be used as a more relevant price reference for hedging, capacity markets, investments and other decision-making purposes if the rapid growth of vRES and especially wind power continues. Our results can be used as a starting point for the analyses of bidding and risk mitigation strategies of power market participants active in markets with increasing intermittent generation. Additionally, the changing value of flexibility, an important business indicator for aggregators, can be analysed by further applying our methodology and results.

Our chosen methodological approach based on the econometric analysis of historical data allowed us to investigate the changing relevance of different short-term electricity markets, but at the same time it did not enable us to simulate the underlying behaviour of market participants directly. We acknowledge this as a limitation of our work which could be addressed by future research directly studying the impacts of different bidding behaviour and risk preferences on the usage of different electricity marketplaces. Another limitation of our work is the conscious decision to focus on studying the short-term impacts for 24 h ahead while capturing the underlying seasonal components in the model. Nonetheless, we acknowledge that in power systems with substantial energy storage capacity represented by hydro reservoirs, pumped storages or any future technologies, the question of longer-term and seasonal effects on the market price dynamics becomes interesting. This is certainly an interesting topic for future research. Finally, finding a quantitative threshold for the wind and demand forecasts could be an interesting avenue for further research, even though these will often be market/area specific.

CRediT authorship contribution statement

Petr Spodniak: Conceptualization, Methodology, Formal analysis, Software, Writing - original draft, Writing - review & editing. **Kimmo Ollikka:** Conceptualization, Investigation, Formal analysis, Software, Visualization, Writing - original draft, Writing - review & editing. **Samuli Honkapuro:** Conceptualization, Supervision, Writing - review & editing.

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.

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Appendix

Table 9
Unit root tests of endogenous variables: (a-c) price spreads and (d-e) forecast errors

(a) Day-ahead — intraday price (DA-ID)

	DF-GLS		Phillips-Perron	
Area	No Trend	Trend	No Trend	Trend
FI	−9.22	−16.20	−65.02	−7.75
SE1	−11.76	−18.51	−75.63	−11.57
SE2	−21.91	−21.53	−78.68	−12.20
SE3	−13.91	−18.74	−65.63	−7.21
SE4	−39.50	−38.83	−91.87	−13.14
DK1	−55.24	−12.87	−88.52	−13.79
DK2	−46.84	−47.36	−86.30	−12.44

(b) Day-ahead — regulating power price (DA-RP)

	DF-GLS		Phillips-Perron	
Area	No Trend	Trend	No Trend	Trend
FI	−48.68	−57.53	−101.32	−10.20
SE1	−19.35	–22.72	−106.99	−11.19
SE2	−19.32	–22.69	−106.91	−11.19
SE3	−21.62	−47.49	−88.60	−11.23
SE4	–22.56	−47.93	−85.38	−10.91
DK1	−19.16	−25.39	−76.95	−11.96
DK2	–22.56	−48.08	−85.79	−11.05

(c) Intraday — regulating power price (ID-RP)

	DF-GLS		Phillips-Perron	
Area	No Trend	Trend	No Trend	Trend
FI	−60.83	−67.65	−103.31	−11.98
SE1	−57.87	−64.25	−107.81	−12.38
SE2	−21.10	−58.48	−109.48	−12.55
SE3	−73.57	−74.55	−91.57	−13.53
SE4	−20.87	−49.89	−87.02	−11.37
DK1	−17.34	−38.68	−86.05	−12.85
DK2	−19.67	−49.74	−89.37	−11.78

(d) Wind forecast errors

	DF-GLS		Phillips-Perron	
Area	No Trend	Trend	No Trend	Trend
FI	−19.35	−20.08	–32.02	−6.20
SE1	−19.47	−37.87	–47.62	−5.72
SE2	−14.13	−16.51	−45.15	−5.55
SE3	−24.18	–23.44	−34.12	−4.97
SE4	−3.35	−6.14	−37.27	−5.75
DK1	−38.18	−39.63	−34.03	−6.33
DK2	−5.94	−11.05	−41.72	−6.69
Critical values:				
1%	−2.58	−3.48	−3.43	−3.96
5%	−1.95	−2.84	−2.86	−3.41
10%	−1.62	−2.55	−2.57	−3.12

(e) Demand forecast errors

	DF-GLS		Phillips-Perron	
Area	No Trend	Trend	No Trend	Trend
FI	−18.73	−18.41	−25.74	−3.94
SE1	−10.54	−14.88	−90.27	−13.55
SE2	−7.31	−13.35	−49.83	−6.88
SE3	−3.92	−7.32	−41.13	−5.85
SE4	−3.27	−6.46	−36.79	−5.44
DK1	−12.10	−25.42	−96.44	−12.42
DK2	−4.71	−8.95	−70.79	−9.09
Critical values:				
1%	−2.58	−3.48	−3.43	−3.96
5%	−1.95	−2.84	−2.86	−3.41
10%	−1.62	−2.55	−2.57	−3.12

Note: The table shows test statistics of the Dickey–Fuller test with a generalized least squares regression (DF-GLS) and the Phillips–Perron (PP) test with options of no trend and trend. Critical values are presented in Tables (d-e), but they are similar with Tables (a-c). In DF-GLS test the lag length is selected based on the minimum Schwarz information criterion. However, the results are independent of the chosen criterion. The null hypothesis of the DF-GLS and PP test is unit root. Based on the test statistics, we can reject the null hypothesis in all cases.

Table 10
Results of the vector autoregression models

(a) Dependent variable: Price spread DA-ID

	FI	SE1	SE2	SE3	SE4	DK1	DK2
Constant	−0.699**	−0.466***	0.195	−0.057	−0.969***	0.166	−0.515**
	(0.297)	(0.171)	(0.168)	(0.171)	(0.206)	(0.199)	(0.228)
Congestion	−0.008	−0.086	−0.085	−0.042	0.147*	−0.116	−0.003
	(0.109)	(0.069)	(0.067)	(0.069)	(0.083)	(0.082)	(0.093)
Wind ramp	−0.002**	0.001	0.000	0.000	0.000	0.0003*	0.000
	(0.001)	(0.001)	(0.000)	(0.000)	(0.000)	(0.000)	(0.001)
Hydro dev. NO	−0.016**	0.005	0.006	0.005	0.003	−0.004	0.000
	(0.007)	(0.004)	(0.004)	(0.004)	(0.005)	(0.005)	(0.005)
Hydro dev. SE	0.005	−0.007**	−0.003	−0.006*	−0.003	0.002	−0.004
	(0.005)	(0.003)	(0.003)	(0.003)	(0.004)	(0.004)	(0.004)
Hydro dev. FI	0.005	−0.008*	−0.007*	−0.005	0.000	−0.003	0.000
	(0.006)	(0.004)	(0.004)	(0.004)	(0.005)	(0.005)	(0.005)
Weekend	−0.017	−0.024	0.018	0.026	−0.032	−0.137***	−0.001
	(0.063)	(0.040)	(0.039)	(0.040)	(0.047)	(0.046)	(0.053)
Observations	25,458	26,106	26,106	26,106	26,106	26,178	26,178
RMSE	4.403	2.835	2.764	2.833	3.392	3.293	3.755
R-sq	0.568	0.505	0.454	0.557	0.352	0.378	0.398
LL	−73780	−64166	−63508	−64147	−68848	−68265	−71704

(b) Dependent variable: Price spread DA-RP

	FI	SE1	SE2	SE3	SE4	DK1	DK2
Constant	−2.396**	−1.070***	−0.868**	−1.518***	−1.516**	0.445	−1.590**
	(1.018)	(0.346)	(0.349)	(0.444)	(0.595)	(0.505)	(0.736)
Congestion	−0.186	−0.033	−0.045	−0.080	0.046	−0.417**	−0.248
	(0.367)	(0.137)	(0.137)	(0.175)	(0.235)	(0.207)	(0.294)
Wind ramp	0.000	0.005***	0.001**	0.002**	0.005***	0.002***	0.006***
	(0.002)	(0.002)	(0.001)	(0.001)	(0.001)	(0.000)	(0.002)
Hydro dev. NO	0.013	0.013	0.007	0.019*	0.007	0.019	0.028
	(0.022)	(0.008)	(0.009)	(0.011)	(0.014)	(0.012)	(0.018)
Hydro dev. SE	−0.030*	−0.003	0.001	−0.017**	−0.013	−0.006	−0.030**
	(0.017)	(0.006)	(0.007)	(0.008)	(0.011)	(0.010)	(0.013)
Hydro dev. FI	−0.006	−0.006	−0.006	−0.004	0.006	0.004	0.012
	(0.021)	(0.008)	(0.008)	(0.010)	(0.014)	(0.012)	(0.017)
Weekend	−0.028	−0.179**	−0.122	−0.101	0.024	−0.184	0.029
	(0.209)	(0.079)	(0.079)	(0.101)	(0.135)	(0.117)	(0.167)
Observations	25,087	26,050	26,050	26,020	26,020	26,178	26,092
RMSE	14.620	5.626	5.641	7.202	9.628	8.346	11.900
R-sq	0.421	0.596	0.598	0.536	0.501	0.445	0.443
LL	−102819	−81883	−81952	−88216	−95768	−92610	−101564

(c) Dependent variable: Price spread ID-RP

	FI	SE1	SE2	SE3	SE4	DK1	DK2
Constant	−1.748*	−0.909**	−1.471***	−1.774***	−1.283**	0.304	−1.475**
	(1.007)	(0.385)	(0.374)	(0.453)	(0.618)	(0.524)	(0.746)
Congestion	−0.291	0.015	−0.003	−0.078	−0.087	−0.352	−0.311
	(0.363)	(0.152)	(0.147)	(0.179)	(0.244)	(0.215)	(0.298)
Wind ramp	0.001	0.004*	0.001*	0.002**	0.005***	0.002***	0.006***
	(0.002)	(0.002)	(0.001)	(0.001)	(0.001)	(0.000)	(0.002)
Hydro dev. NO	0.049**	0.012	0.002	0.015	0.003	0.028**	0.032*
	(0.022)	(0.009)	(0.009)	(0.011)	(0.015)	(0.013)	(0.018)
Hydro dev. SE	−0.054***	0.003	0.005	−0.015*	−0.014	−0.010	−0.031**
	(0.017)	(0.007)	(0.007)	(0.008)	(0.011)	(0.010)	(0.014)
Hydro dev. FI	−0.020	−0.001	−0.001	0.002	0.006	0.009	0.014
	(0.021)	(0.009)	(0.008)	(0.010)	(0.014)	(0.012)	(0.017)
Weekend	0.011	−0.209**	−0.178**	−0.171*	0.071	−0.062	0.023
	(0.207)	(0.088)	(0.085)	(0.103)	(0.140)	(0.121)	(0.169)
Observations	25,087	26,050	26,050	26,020	26,020	26,178	26,092
RMSE	14.480	6.258	6.037	7.338	10.010	8.665	12.060
R-sq	0.334	0.484	0.473	0.424	0.420	0.355	0.371
LL	−102571	−84656	−83722	−88702	−96777	−93593	−101909

Note: The table shows the coefficient estimates (standard errors are given in parentheses) and model summary statistics based on the vector autoregression model specified in Section 4.3.
Significance levels are displayed as *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$.
In addition to the reported variables, each model includes the following variables: Spread (DA-ID, DA-RP or ID-RP) with lags 1–24 and 48; Wind forecast errors with lags 1–24 and 48; Demand forecast errors with lags 1–24 and 48; Hour-of-day dummy for hours 2–24; Week-of-year dummy for weeks 2–52.
The results are based on the model ignoring the price outliers of the regulating power (RP) markets, i.e., when $p <$ -150 euro/MWh or $p >$ 400 euro/MWh.

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