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The relevance of wholesale electricity market places: the Nordic case

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Keywords: electricity market, Nordic, wind forecast, demand forecast.

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THE RELEVANCE OF WHOLESALE ELECTRICITY MARKET PLACES: THE NORDIC CASE

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Abstract

Electricity wholesale markets are undergoing rapid transformation due to the increasing share of distributed and variable renewable energy sources (vRES) penetrating the market. 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 from the traditionally dominant day-ahead market into the intra-day and regulating power markets. This is because predicting vRES power generation closer to the actual delivery is more reliable and because power generators are motivated to avoid high imbalance costs. We study price spreads between day-ahead, intra-day and regulating power markets in three Nordic countries (Denmark, Sweden and Finland) during 2013-2017. We estimate vector autoregressive (VAR) models to study the interrelationships between the price spreads and the effects of wind forecast and demand forecast errors, and other exogenous variables, such as transmission congestions, and hydrological conditions, on price spreads in different Nord Pool bidding areas. We use the variation in the shares of wind power between bidding areas to analyse the impacts of increased shares of wind power on different market places. We find that wind forecast errors do affect price spreads in areas with large shares of wind power generation. Moreover, demand forecast errors have an impact on almost all price spreads, except in areas with relatively low consumption. Our results indicate that increasing shares of wind power are, indeed, changing the relevance of different market places. Markets closer to real time are playing more important role than in the past.

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I. Introduction

Electricity wholesale markets are undergoing rapid transformation due to the increasing share of distributed and variable renewable energy sources (vRES) penetrating the market traditionally dominated by centralized and dispatchable generation. After electricity market liberalization and ownership unbundling in Europe, the most relevant market place with respect to volume, liquidity

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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. Thus, it is reasonable to assume that trading activity is shifting more into the intra-day and balancing markets, because it is more reliable to predict the actual power generation of vRES closer to power delivery and thus avoiding high imbalance costs.

Ongoing institutional changes are also promoting the usage of closer-to-delivery markets, such as shorter gate-closer time, higher resolution for imbalance settlement (from 60 minutes to 15 minutes), and more granular tradable products (15 and 30 minutes). Unique to the Nordic electricity market is the design of the regulating power market (and its imbalance settlement mechanism), which is a market that allows power generators and demand side to offer flexibility to the transmission system operators (TSOs) close to the actual delivery. Compared to the most of Continental Europe, the Nordic electricity market follows dual imbalance pricing, where consumption and production imbalances are treated differently, depending on the deviation direction of the control area. Because of this particular design as well as relatively low imbalance prices due to the innate flexibility of the Nordic hydro-dominated power system, the incentives to use intraday or regulating power market are different than in the more studied regions, such as Germany.

From the brief discussion above a question arises, how relevant each electricity market place is with the increasing share of vRES? Is the dominating position of day-ahead market diminishing and the markets closer to real time start dominating the trading activity and price discovery? Reliable understanding of the market dynamics is critical because investments into new power generation, real-time pricing, and price-risk hedging strategies are often based on the day-ahead market. In this study we therefore investigate the trading behaviour and price discovery of the Nordic day-ahead, intra-day and regulating power markets during 2013-2017. We further narrow down the geographical scope of our study to three countries with the greatest increase in wind power, which are Denmark, Sweden, and Finland.

The current energy transition towards emission-free energy system has initiated deep changes in the Nordic countries' generation mix with implications for flexibility. Three trends contribute to less flexibility in the Nordic power generation: growth in intermittent generation, less flexible thermal generation, and surplus generation in the years with normal precipitation (Norden, 2014). In this study we particularly focus on the impacts of intermittent wind power generation, which has been rapidly penetrating the Nordic markets and which has direct implications for the costs of power system balancing, among others. The deployment of vRES in the Nordic countries also differs. In 2017, Denmark produced over 40 percent of total power production by wind, whereas Sweden and Finland produced 12 and 5 percent, respectively. In this study we find that in areas with more wind power generation, wind forecast errors cause prices to differ between market places.

Specifically, we utilize price spreads between day-ahead, intra-day and regulating power market prices and run vector autoregressive (VAR) models to study the interrelationships between these price spreads. Nordic electricity market is divided in number of different bidding areas[2], each having a different amount of wind power capacity installed. We use this variation when analysing

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

impacts of increased wind power. We further control for fundamental variables, such as demand forecast errors, transmission congestions, and hydrological conditions.

Using the pairwise spreads between market places enables us to clearly disentangle the price dynamics between all wholesale electricity market places. This is in contrast to previous studies that either use only a single spread and assume the dynamics of the rest, such as (Karanfil and Li 2017), or studies that calculate a combined spread out of multiple market prices and price components, which impedes clear understanding of its fundamental drivers, such as (Batalla-Bejerano & Baute-Trojillo, 2016) In addition, VAR models are well suited for forecasting, therefore our method can bring highly valuable information for market participants, who want to estimate the underlying risk between market places.

The paper is structured as follows. In section II we lay down the foundations of the Nordic electricity wholesale markets, explain the unique Nordic imbalance settlement mechanism, and outline details of the Nordic power generation mix. In section III we review relevant literature, which is followed by data description in section IV. We discuss the main findings based on Granger-causality tests and impulse response functions in section VI, and conclude the work in section VII.

II. Market places – institutional setup

In this section we first lay down the foundations of the individual market places in the Nordic electricity wholesale markets (subsection A), followed by a subsection B on explaining the imbalance settlement, which is influential in determining the trading strategies in the day-ahead, intraday and also regulating power markets. The section ends by an overview of the Nordic electricity mix in subsection C.

A. Nordic electricity wholesale markets

The Nordic electricity wholesale market is a liberalised and unbundled market that can be divided into *financial* and *physical* markets[3]. In this paper we focus on the physical market, which comprises of day-ahead, intra-day, and regulating markets. In general, the main reason for the existence of different electricity wholesale markets is to efficiently and effectively *balance* the electrical power system both in the short-run (least cost economic dispatch) and long-run (investments). According to the European electricity target model, market participants (generators, consumers, retailers, and traders) in the physical markets are responsible in their balance between electricity procurement/use or production/sales. However, as small actors are not capable to handle real-time balance by themselves, they can "outsource" this responsibility to server providers (e.g. electricity retailers) by open supply contracts. Market parties, of which open supplier is TSO, are called balance responsible parties (BRP). BRPs in the Nordic market currently submit their generation and/or consumption schedules to transmission system operators (TSOs) in time steps (trading period) of 60 minutes. However, according to the guideline on electricity balancing (EBGL) established by the EU Commission regulation (2017/2195), the time steps of schedules, called imbalance settlement period (ISP), are to be harmonized into 15 minutes. This is planned to

[3] 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 work.

be implemented first for the intraday and balancing markets, followed by the day-ahead. The difference between schedules and final positions is called *imbalance*, and in order to avoid the associated imbalance costs (more details below on balancing market), BRPs typically aim for a balanced portfolio via physical dispatch and trade (via exchange, broker or bilateral trade). See Figure 1 for overview of the Nordic electricity wholesale markets.

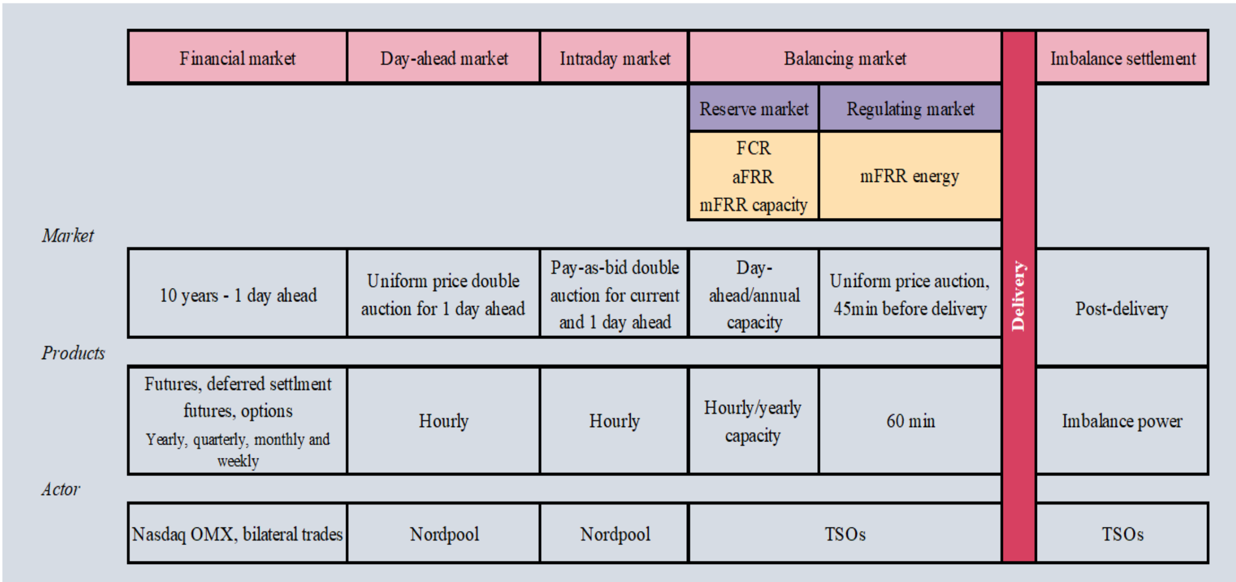


Figure 1 Overview of the Nordic electricity wholesale markets

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[4] by 12:00 CET 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 hours 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 hours ahead of the first delivery hour (00:00-00:59 day-ahead) up to 36 hours before the last delivery hour (23:00-23:59 day ahead). The intersection of the aggregated supply and demand curves provides the equilibrium hourly price for the entire Nordic electricity market, also known as the *system price*. The system price works as a price reference for congestion-free grid on an hour-by-hour basis.

In addition to electricity, also 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)

[4] The type of bids are single hourly blocks, block orders, minimum acceptance ratio, linking, flexi orders and exclusive orders, see https://www.nordpoolgroup.com/trading/Day-ahead-trading/Order-types/

when the cross-border transmission, allocated by TSOs on a daily basis, reaches its limits. Even though the policy goal is to have an integrated electricity price across the region, area prices exist to reflect transmission scarcity *between bidding areas*, and to alleviate long-term transmission bottlenecks. To deal with short-term bottlenecks *within the bidding areas*, TSOs can, at their request and expense, order redispatch of the regional distribution of power plant production that resulted from the day-ahead market auction. Redispatching, also called countertrading, is priced according to pay-as-bid principle, in contrast to the uniform price in the day-ahead market. For discussion about possible inefficiencies between different auction designs and congestion management techniques, see (Holmberg & Lazarcyk, 2015).

Intraday market

Once the day-ahead market is closed, *intraday market Elbas* continues trading up to 1 hour prior to delivery hour to allow market participants address errors in their demand and supply forecasts. Elbas is a joint intraday market of the Nordic (Norway, Sweden, Finland, Denmark), Baltic (Estonia, Lithuania, Latvia), and Continental (the Netherlands, Belgium, and an alternative to EPEX Intraday in Germany) markets. Market participants can begin trading on Elbas from 14:00 CET the day before delivery. Elbas market follows continuous pay-as-bid double auction[5], where limit orders form an order book of bids and asks sorted by price and time of offer, similarly as in equity markets. Capacity allocation and energy matching processes are done simultaneously, which means that the local order book views take into account capacities that are allocated by different TSOs on each border. The initial Elbas transmission capacity for the next day is given after the Elspot auction is settled, normally around 14:00 CET. The initial Elbas transmission capacities may change during the day of operation, but trades already agreed are guaranteed (Energinet, 2011). Therefore, market participants possess the initial information about the *planned* transmission capacities available for Elbas trade across bidding areas 10 hours ahead of the first delivery hour (00:00-00:59 day-ahead) and up to 34 hours ahead of the last delivery hour (23:00-23:59 day-ahead). Cross-border trades will only be possible if there is enough allocated capacity between the areas. Figure 12 in the Appendix shows the Elbas volume trades among bidding areas during 2012-2017. The figure highlights, among others, the effect of congestion, as shown by the example of Finland, which buys most of its intraday volume from its own area.

Currently, Elbas offers trading of 15 minutes, 30 minutes, hourly and block products. The sub-hourly products have been introduced only recently in the Nordic market and are out of 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 (Henriot, 2012; Neuhoff, Ritter, Salah-Abou-El-Enien, & Vassilopoulos, 2016). Because of high variability and lower predictability of wind speed resources, particularly wind generation benefits from shorter, sub-hourly contracts.

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

Regulating power market

Each balance responsible party (BRP) must maintain a continuous power balance between its electricity production/procurement and consumption/sales. TSOs are obliged to keep power balance during every second, which is manifested by a stable network frequency of 50 Hz. Because production/consumption plans often deviate from their actual values, and bottlenecks, incidents and disturbances do occur during the operation hour, TSOs are procuring *balancing* products, which ensure power system balance.

Balancing market can be generally divided into *reserve market* and *regulating market*. Reserve market is divided into three categories 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 (mFRR).

TSOs maintain Manual Frequency Restoration Reserves to cover the dimensioning fault[6] 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 *regulating power market*.

Regulating power market follows a uniform price auction jointly operated by all the Nordic TSOs with a common merit order exchanged via a common platform called Nordic Operational Information System (NOIS). Market participants can submit their bids for up- or/and down-regulation to the local TSO from afternoon the day-before until 45 minutes 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.

Each delivery hour is declared as up-, down-, or no-regulation, depending on the sum of activated bids on the NOIS. In the up-regulation state the TSO is buying power from the bidders and in the down-regulation state the TSO is selling power to the bidders, so depending on the need, either the least expensive up-regulating bid or the best paying down-regulating bid sets the regulating power price that each activated bid receives. There is a link between the day-ahead price and the regulating power price in such a way that the day-ahead price sets the floor for the up-regulation price and the cap for the down-regulation price, and consequently for the imbalance prices. Each up-regulation bid has to contain information about the maximum up-regulation capacity (MW) and minimal price (€/MWh), and equally each down-regulation bid has to include maximum down-regulation capacity (MW) and maximum price (€/MWh). Balancing energy bids may be given for all resources that can carry out a 10 MW change of power in 15 minutes (5 MW if using electronic activation), and the bids can be aggregated from multiple sources.

The regulating price is identical in all electricity bidding areas provided that no bottlenecks exist during the delivery hour. Hence, it is not the local demand that determines the direction of the

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

regulation, but the aggregated net regulation carried out in the Nordic area. If bottlenecks between bidding areas in the delivery hour exist, the direction of the regulation may not be the same in all the areas (Energinet, 2017). The hourly sum of the regulation offers given by local market parties to the regulating power market is published hourly with one hour delay, e.g. information from hour 09-10 is published at 11 o'clock. Note that national TSOs are the single buyers of regulating power in the Nordic market.

B. Imbalance settlement

The regulating energy prices also serve as the basis for pricing *imbalance power*, which arises due to the difference between physical positions and final schedules (including regulating bids) all reported at the latest 45 minutes before the beginning of the specific hour. After the delivery hour, deviations between the activated load and production balance responsible bids, and the actual amount of electricity provided/utilised, are determined. Local TSOs serve as open suppliers for the BRPs that are obliged to buy or sell these imbalances from/to the TSO. The institution responsible for imbalance settlement in Norway, Finland and Sweden is called eSett, and Denmark's system operator Energinet settles the imbalances by itself. The final settlement of imbalances is made day after the delivery.

In general, market players have two choices to close open positions close to the real time, either through the intraday market or by adjusting generation or loads. They typically strive for a balanced portfolio and thus actively trade before the delivery hour to avoid the cost of imbalances (Pogosjan & Winberg, 2013). It is worth pointing out two important features of the Nordic balancing market that influence the decision about which market to use for balancing. First, a so-called *proactive balancing philosophy* is practiced in the Nordic electricity market (Energinet, 2018). 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, applied for instance in 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 market place usage between the German[7] and the Nordic markets, because the Nordic regulating market plays a much more important role in the proactive balancing approach. This is why the intraday market has historically played 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 (Energinet, 2018). 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 the usage of the intraday market.

The second distinct feature of the Nordic balancing market is the design of the imbalance settlement mechanism, which applies two different pricing systems for *production* (two-price system) and *consumption* (one-price system) *imbalances*. Production imbalance simply means the difference between the observed production and the latest submitted bidding production plan. The production plans are submitted to the TSOs in the afternoon the day before the delivery hour and

[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 a pay-as-bid bases. Market clearing pricing and free bids are planned to be introduced in late 2019 (Koch & Hirth, 2018). Also, the imbalance settlement period in Germany is 15 minutes, whereas in the Nordics it is still one hour.

updates can be sent up to 45 minutes before the delivery after which they become binding. Consumption imbalance means the difference between the binding production plan and trades, which include purchases and sales from Elspot, Elbas and bilateral trades. Figure 2 summarizes the differences between one- and two-price systems.

The two-price system, applied to production imbalances, penalises the market participants for exacerbating the system imbalance, if it is in the need for up- or down-regulating volumes. At the same time, market participants do not gain extra benefit, in comparison to trading the corresponding production imbalance volume in Elspot, if their production imbalances contributed to system imbalance mitigation. For instance, when the system is in the state of needing up-regulation, and the participant has an excess production imbalance, the price received is equal to the Elspot price for the hour in question, instead of the higher up-regulation price (the positive imbalance in panel c, Figure 2).

In contrast, under the one-price system applied to consumption imbalances market participants benefit from consumption imbalances, if they positively contributed to reducing the system imbalances. For instance, if a market participant had a deficit in the consumption imbalance and the system was in the down-regulation state, he or she would have to pay the lower down-regulation price for the imbalance, instead of the higher (or equal) Elspot price for that hour (the negative imbalance in panel b, Figure 2).

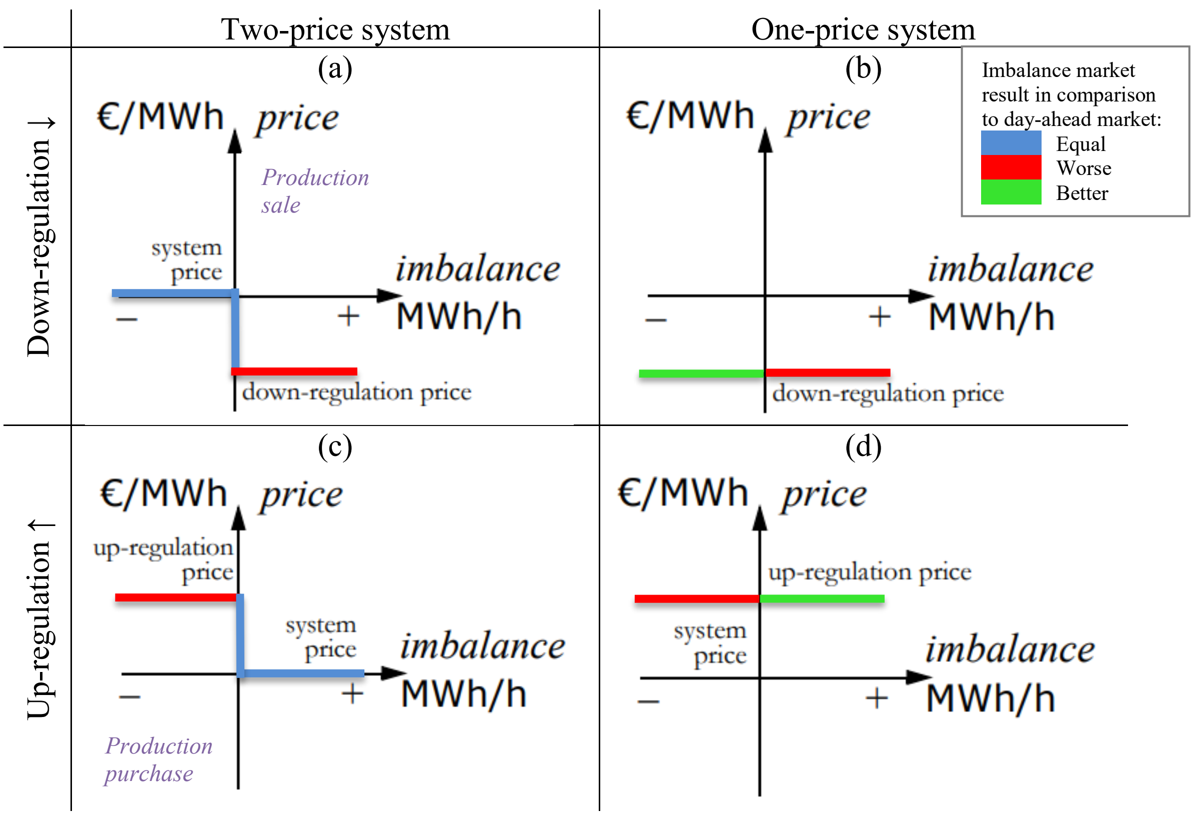


Figure 2 Imbalance pricing under one- and two-price systems

The main difference between the production and consumption imbalances is that the production imbalance considers only the physical difference between the observed production and binding production plan during the delivery hour. However, because most of the market players *trade* electricity on Elspot's day-ahead market, unless they balance out their position on Elbas, or the regulating power market, their imbalances get settled according to the consumption imbalance pricing. It must be noted that a great uncertainty exists in predicting the balancing direction and prices, which reduces the incentive to strategically carrying out imbalances. Also as mentioned above, market players receive information about balancing prices with one hour delay, which makes the market less informed and transparent. Additionally, when BRPs sign agreements with TSOs, they agree not to use open deliveries for systematic power purchases or deliveries (Fingrid, 2018).

Both the proactive balancing philosophy and the difference in pricing imbalances affect market participants' willingness to participate in the intraday versus regulating market or to settle their imbalances in the phase of imbalance settlement. Price spread between the day-ahead and intraday prices can be explained by updates in production plans and demand from forecasted values after the closure of the day-ahead market. 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 exist an ask in 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 can offer its extra production in the regulating power market for balancing purposes even closer to delivery. The revenue and need for production is however uncertain at the time bidding in the regulating power market auction. Hence, flexible producers get either a certain price during continuous intraday auction, conditional there is a counterpart in the intraday market, or uncertain price if waiting to the regulating power market. Wind producers, for instance, face similar kind of uncertainty. They can settle their imbalances caused by forecast errors by trading in intraday markets or wait until imbalance settlement.

C. Electricity mix in the Nordics

The Nordic electricity production has traditionally been dominated by hydro, nuclear, and thermal plants. The main market place for trading has been the day-ahead market, because it allows sufficient time for the dispatchable production units to ramp up and down (Norden, 2014). 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 baseload produced by nuclear and hydro power. Norway's electricity production originates almost entirely from hydro power and Denmark's electricity mix is dominated by wind and thermal plants.

The Nordic countries also differ in the rate of vRES deployment and the type of support. Denmark was a forerunner in supporting wind power via feed-in premium tariffs, while Sweden has opted for the green certificate system since 2003, joined by Norway in 2012. Finland has since 2011 supported wind power production via feed-in tariffs, but the support was capped by 2500 MVA capacity which was quickly reached. Finland has recently turned to an auction-based support mechanism and the speed of wind power deployment is slowly catching-up with the other Nordic states. The share of solar (photovoltaics) is still minor in the Nordic electricity supply. See Figure 3 to observe the growth of wind power capacity and generation during 2000-2017.

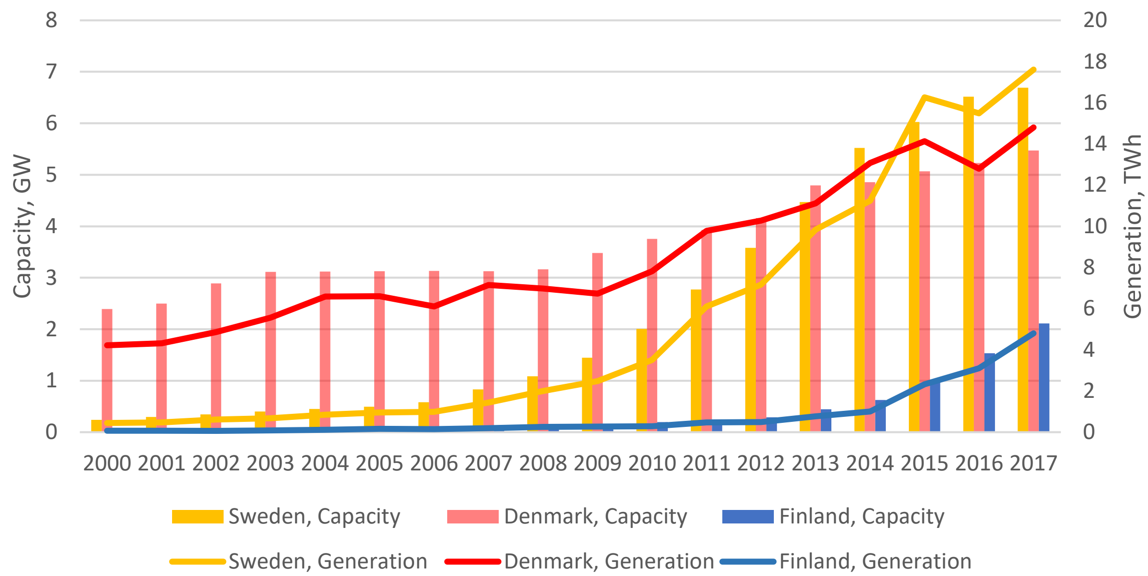


Figure 3 Wind power capacity and generation in Sweden, Denmark and Finland
Source: (VTT, 2019; Swedish Energy Authority, 2019; Danish Energy Authority, 2019)

In this paper we particularly focus on three Nordic countries, namely Finland, Denmark, and Sweden, for the following reasons. Denmark is a pioneer and well researched country which 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 overtook Denmark in installed capacity. Sweden is also in the process of decommissioning older nuclear plants and is planning to renounce nuclear power (Swedish Ministry of Energy, 2016), 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 with the nearly completed Olkiluoto-3 and a new investment into Hanhikivi-1, adding a total new capacity of 2800 MW. 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.

In addition, the shares of wind power differ between Nord Pool bidding areas. This is described in Table 1 for years 2015-2017. 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 western part of Denmark (DK1): almost 57 percent of power generation was produced by wind power in 2017. In eastern part of Denmark (DK2) the share of wind power was 34 percent, respectively. In Sweden, the shares of wind power are the highest in 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 is higher in the middle parts of Sweden (SE3 and SE2), the shares of total production are much lower than in south: 7 percent in SE3 and 12 percent in SE2 in 2017. In northern Sweden (SE4) and Finland (FI), the shares of wind power are still modest. In both of these regions approximately 6 percent of electricity generation was produced by wind power in 2017.

Table 1 Wind power generation (TWh) and the shares of wind power in total electricity production (%) in Nord Pool bidding areas in Sweden (SE), Denmark (DK), and Finland (FI)

		2015	2016	2017
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	TWh	2.1	2.8	4.1
	%	3.2 %	4.4 %	6.5 %
SE-DK-FI	TWh	31.1	30.1	34.9
Total	%	13.0 %	12.4 %	14.0 %

Note: Data for Finnish wind power generation are from 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 are not considered for this period when calculating the shares of Swedish wind power in 2015.

III. Relevant literature

There is a vast academic literature that studies the effects of fundamentals, trading strategies, and market efficiency on individual electricity wholesale markets or their pairs. However, work that studies the trading behaviour and prices in all three electricity market places jointly is much scarcer. Literature that focuses on the *day-ahead* market typically observes the merit-order effect of vRES (Cludius, Hermann, Matthes, & Graichen, 2014), the associated decline in average (Gil;Gomez-Quiles;& Riquelme, 2012) or peak (Winkler, Gaio, Pfluger, & Ragwitz, 2016) electricity prices, increase in electricity price volatility (Ketterer, 2014) and the effects of CO_2 price (Hirth, 2018).

Intraday markets are studied by Scharff and Amelin (2016) (Nordic region), Gianfreda et al. (2016) (Italy), Frade et al. (2018) (the Iberian Peninsula), and Märkle-Huß et al. (2018) and Kiesel and Praschiv (2017) (Germany). Most of the intraday studies assess the impacts of various fundamental variables, such as vRES and forecast errors, others focus on market design and liquidity (Furió & Lucia, 2009; Weber, 2010) or trading strategies for balancing wind power forecast errors (Henriot, 2012). *Balancing market* studies often focus on bidding strategies and the effects of imbalance settlement rules on profits (Holttinen & Koreneff, 2012; Ravnaas, Farahmand, & Doorman, 2010). Another research strand is a direct simulation of real-time balancing prices which are then used in bidding strategies in balancing markets (Olsson & Söder, 2008; Olsson, 2005).

There are few studies that focus on price differences between different electricity market places. For instance, Karanfil and Li (2017) study 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 study 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 others that wind forecast errors Granger cause the price difference in Denmark. Using VAR and impulse response functions, they claim intraday market to be effective because causality between the intraday price signals and market fundamentals was found. Pape et al. (2016) develop a fundamental model for German day-ahead and intraday markets and study the explanatory power of fundamentals on price variations, such as must-run operations of CHP and shortened intraday supply stack, on their price variations. Hagemann (2015) uses multiple linear regression to model the price difference between the German intraday and day-ahead prices by market fundamentals, such as load, wind and solar forecast errors, power plant outages, and cross border flows. He finds that intraday supply side shocks may have different price effects. Furió and Lucia (2009) study the price convergence between the Spanish day-ahead and intraday markets and find significant price differences between the two.

Studied from another methodological angle (mixed integer program) and not directly working with price differences, Faria and Fleten (2011) find that for a price-taker medium-sized producer, considering Elbas when bidding on the day-ahead market does not impact significantly its profit. Knaut and Obermueller (2016) consider trading of renewable and conventional power generators in the German day-ahead and intraday markets and find that it is optimal for renewable producers to sell less than the expected production in the day-ahead market.

Table 2 Literature on the impacts of vRES and other fundamentals on single and multiple electricity wholesale markets

	Day-ahead	Intraday	Balancing
Day-ahead	(Cludius, Hermann, Matthes, & Graichen, 2014; Gil, Gomez-Quiles, & Riquelme, 2012; Ketterer, 2014; Hirth, 2018; Winkler, Gaio, Pfluger, & Ragwitz, 2016)	x	x
Intraday	(Karanfil & Li, 2017) (Pape;Hagemann;& Weber, 2016); (Faria & Fleten, 2011); (Knaut & Obermueller, 2016); (Hagemann, 2015); (Furió & Lucia, 2009) (Ito & Reguant, 2016)	(Scharff & Amelin, 2016); (Gianfreda, Parisio, & Pelagatti, 2016); (Frade, Vieira-Costa, Osório, Santana, & Catalão, 2018); (Märkle-Huß, Feuerriegel, & Neumann, 2018); (Mauritzen, 2015); (Chavez-Ávila & Fernandes, 2015) (Weber, 2010); (Kiesel & Paraschiv, 2017); (Henriot, 2012)	x
Balancing	(Boomsma, Juul, & Fleten, 2014); (Vilim & Botterud, 2014) (Holmberg & Lazarcyk, 2015); (Hesamzadeh, Holmberg, & Sarfati, 2018)	(Koch & Hirth, 2018); (Batalla-Bejerano & Baute-Trojillo, 2016)	(Brouwer, van den Broek, Seebregts, & Faaij, 2014); (Holttinen, et al., 2011) (De Vos, Morbee, Driesen, & Belmans, 2013); (Hirth & Ziegenhagen, 2015); (Holttinen & Koreneff, 2012); (Ravnaas, Farahmand, & Doorman, 2010); (Olsson & Söder, 2008); (Olsson, 2005)

Note: A study that refers to two same market places indicates that the study focused only on the one market place in question.

Koch and Hirth (2018) study the German intraday and balancing markets in the context of vRES. Among others, the authors study ex-post the difference between imbalance and intraday prices, which they dub the "imbalance price spread". They interpret the spread as the opportunity cost/economic incentive for balance 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 volume-weighted average intraday price of trades between three hours and 30 minutes 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 (Hirth & Ziegenhagen, Balancing power and variable renewables: Three links, 2015) call "German balancing paradox", i.e. the growth of vRES reduces the need for balancing services. Demonstrated on the German market, the authors call it a paradox because other studies typically found a positive effect of vRES on balancing reserves (Batalla-Bejerano & Baute-Trojillo, 2016; Brouwer, van den Broek, Seebregts, & Faaij, 2014; Holttinen, et al., 2011; De Vos, Morbee, Driesen, & Belmans, 2013). In another study (Batalla-Bejerano & Baute-Trojillo, 2016), the authors investigate the impacts of vRES on the balancing market requirements and costs measured by adjustment service cost (ASC). They calculate the ASC a price spread between what they called electricity final price, day-ahead price, intraday price, and capacity payments, which they attempt to econometrically model by different attributes of intermittent generation.

Literature that jointly studies the day-ahead and balancing markets mostly focuses on coordinated bidding strategies of power generators in sequential electricity markets. For instance, Boomsma et al. (2014) quantify the gain from coordinated bidding in day-ahead and balancing markets, finding that there is no gain under a one-price balancing mechanism, but a significant gain under a two-price balancing mechanism. Similarly, Vilim and Botterud (2014) optimal day-ahead bidding strategies under the two balancing mechanisms showing that wind power has a substantial influence on the day-ahead prices, imbalance pricing, and regulation volume. Another research strand argues that the reduced price difference between day-ahead and balancing (real time) markets reduces the arbitrage opportunity to oversell in export constrained nodes and buy-back cheap in real time markets which mitigates the so-called increase-decrease game (Holmberg & Lazarcyk, 2015; Hesamzadeh, Holmberg, & Sarfati, 2018).

IV. Data

Our analysis focuses on three countries of the Nordic region that have experienced a rapid growth in wind power generation, but which differ in their market fundamentals. These differences bring interesting insights into the analysis and allow comparison of the same effects in different setting. The countries we study are Finland (FI), Sweden (SE1-SE4) and Denmark (DK1-DK2), totalling 7 separate bidding areas. Time resolution of the data is one hour, and the time period studied are the years 2013-2017. Some of the summary statistics may include older data, which is clearly marked. The main sources of price and market fundamentals data are ENTSO-E's Transparency Platform and Nord Pool's FTP server, to which we were granted access. In subsection A we present information about prices from the three market places as well as their pairwise differences, which will represent the first endogenous variable in our three-variable VAR model, defined is section V. Additional two endogenous variables are specified in subsection B with further exogenous variables underlying the power market fundamentals.

A. Market prices and spreads

Our dataset comprises of 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, all measured in EUR/MWh. In section II we have specified each market price and its formation in detail, but their spreads require further interpretation. 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 are made 24 hours before the actual delivery or consumption, which are then updated by trades in the intraday market in order to balance out the errors. 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 one-price system of the imbalance settlement, where 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 one hour delay. This spread is therefore calculated ex-post and the delayed price disclosure, and the underlying uncertainty should be kept in mind when interpreting the hypothetical gains from gaming the one-price system of the imbalance settlement.

Finally, the spread between 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 the imbalance settlement based on the regulating power prices. Alternatively, ID-RP spread can be interpreted as an opportunity for additional revenues for qualified[8] 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 down-regulation state, or down in up-regulation state). The interpretation of the price spreads is summarized in Figure 4.

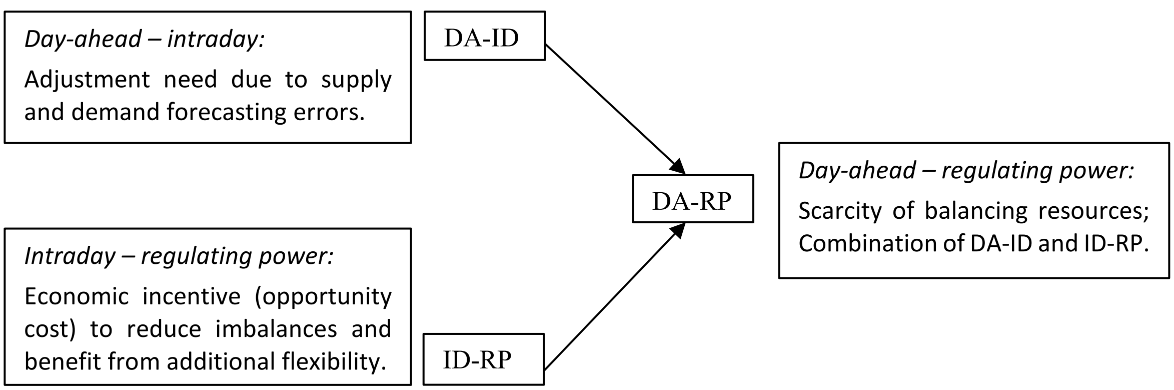


Figure 4 Summary of price spreads

As described in section II, 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 hour in the same area. To calculate a representative intraday price, we calculate a volume-weighted average price[9] for each hour and area. This approach places a greater emphasis on trades carried out closer to

[8] Resources that can carry out a 10 MW change of power in 15 minutes (5 MW if using electronic activation), see section II.

[9] For a comparison we have also calculated the so-called ID3 price as in the German Epex intraday market. However, this lead to a loss of large number of observations due to no trade activity three hours before delivery. For this reason we preferred the weighted average to derive a representative intraday price.

delivery, when most of the intraday volume is traded. Detailed summary statistics of the intraday market based on over 1.8 million trades among 22 bidding zones between 2012-2017 are presented in the Appendix, Table 7. Note that occasionally no Elbas trades occur for a given hour which implies no need for trade adjustment. In our price spreads' calculations, we replace these missing points with the day-ahead price, which best reflects the market's need in a given hour. The regulating power price is simply based on the direction of the regulation market (up, down, none) with their respective prices, see section II for details.

The summary of price levels and spreads is presented in Table 3 and Table 4, respectively. From Table 3 it can be seen that the mean and median prices in all three market places are the highest in Finland and lowest in DK1. The high skewness and kurtosis in DK1 in panel (a) is due to price spike on June 7, 2013 when the price cap of 2000 EUR/MWh was approached between hours 7-11. Price caps and floors were also hit in the regulating power market, panel (c), in Finland and Sweden, and overall, the regulating market is the most volatile among the three. The intraday market, panel (c), has much fewer price spikes and is less volatile compared to the other two.

Table 3 Summary of price levels, 2013-2017

(a) Day-ahead price								
Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	43824	34.494	32.98	12.78958	0.32	214.25	2.285	22.038
SE1	43824	30.313	29.98	10.30147	0.32	214.25	1.667	21.748
SE2	43824	30.315	29.98	10.30255	0.32	214.25	1.666	21.738
SE3	43824	30.708	30.11	10.86307	0.32	214.25	1.874	21.206
SE4	43824	31.290	30.39	11.31979	0.32	214.25	1.752	18.409
DK1	43824	29.859	29.67	23.62825	-62.03	2000	60.506	4900.812
DK2	43824	31.522	30.7	12.50806	-62.03	214.25	1.168	14.362
(b) Intraday price								
Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	42853	33.688	32.243	12.779	-8.798	194.683	1.699	13.444
SE1	26028	29.569	29.054	10.011	-12.000	213.890	1.816	24.666
SE2	38326	29.454	29.000	10.272	-5.817	188.000	1.198	13.455
SE3	40332	29.934	29.258	11.037	-7.769	209.432	1.639	16.816
SE4	19676	32.117	31.000	11.739	-10.000	275.000	2.485	31.738
DK1	27165	30.506	30.000	11.963	-36.000	124.892	0.570	5.575
DK2	28538	31.526	30.409	13.129	-54.001	197.000	1.153	11.032
(c) Regulating power price								
Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	43824	34.747	30.82	35.4273	-1000	3000	26.512	1895.125
SE1	43824	29.251	28.455	17.21342	-66.89	1999	38.228	3984.663
SE2	43824	29.264	28.47	17.23127	-66.89	1999	38.120	3968.152
SE3	43824	30.068	28.73	19.45091	-66.89	1999	29.486	2511.380
SE4	43824	30.908	28.93	21.32594	-66.89	1999	23.537	1746.313
DK1	43824	29.352	28.23	17.36887	-159.8	335.01	3.408	38.663
DK2	43824	31.694	29.2	23.25354	-112.5	1999	18.773	1239.024

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.

From Table 4 it can be seen that in DK1 and DK2, the median spreads are zero across the three market places, implying the highest integration among the market places. This is interesting given the dominance of variable wind power generation in Denmark's generation mix, see section B below. The mean spreads between day-ahead and intraday (DA-ID) markets are mostly positive (highest in FI, and SE1-SE3), suggesting there is 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) are zero in all bidding areas which points to non-systematic scarcity for up- or down-regulation and that strategic imbalances are not riskless. Up- and down-regulation events happen with approximately the same frequency - in reality this is roughly 40% up-regulation, 30% down-regulation, 30% no regulation. The median spreads between the regulating power and intraday price (ID-RP) are non-zero and even more negatively skewed than the DA-RP spread. The negative skewness points out to infrequent but high up-regulation prices that drive the mean ID-RP spread to the negative territory and increasing the motivation for a balanced portfolio to avoid high imbalance costs. From the perspective that ID-RP spread indicates the opportunity for additional revenues, FI and SE4 are bidding areas where this spread/opportunity is the highest. In the Appendix, Figure 13 and Figure 14 explores the mean market price levels and spreads by hour of the day, respectively.

To get a better understanding of the actual costs and benefits associated with price spreads, we consider the *absolute* price spreads which take into account the both-sidedness of the underlying price risk. The absolute mean price spreads are displayed in Figure 5 - Figure 7.

Table 4 Summary of price spreads, 2013-2017

(a) Day-ahead — intraday price (DA-ID)								
Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	43824	0.858	0.576	6.256	-112.462	131.622	0.099	58.020
SE1	43824	0.533	0.000	3.482	-134.580	105.080	-7.010	372.034
SE2	43824	0.933	0.586	3.474	-62.640	79.818	0.780	52.608
SE3	43824	0.860	0.543	3.873	-109.502	83.382	-1.511	80.489
SE4	43824	0.029	0.000	3.711	-177.410	133.520	-5.676	423.914
DK1	43824	0.446	0.000	20.440	-78.710	1930.832	87.732	8048.318
DK2	43824	0.468	0.000	4.577	-87.252	92.558	0.265	45.204
(b) Day-ahead — regulating power price (DA-RP)								
Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	43824	-0.253	0.000	33.072	-2957.250	1026.480	-31.037	2416.097
SE1	43824	1.061	0.000	14.323	-1972.580	185.250	-64.923	8360.224
SE2	43824	1.052	0.000	14.342	-1972.580	185.250	-64.684	8316.274
SE3	43824	0.641	0.000	16.060	-1909.240	185.250	-45.480	4734.638
SE4	43824	0.381	0.000	17.856	-1909.240	185.250	-34.642	3114.149
DK1	43824	0.507	0.000	24.104	-284.190	1965.840	55.603	4474.728
DK2	43824	-0.173	0.000	19.559	-1909.240	185.250	-27.165	2168.287
(c) Intraday — regulating power price (ID-RP)								
Area	Obs	Mean	Median	Std. Dev.	Min	Max	Skew	Kurt
FI	43824	-1.111	0.299	32.146	-2941.424	1024.804	-33.318	2669.203
SE1	43824	0.529	0.040	14.235	-1972.580	185.250	-65.868	8555.293

SE2	43824	0.119	0.073	13.976	-1972.484	159.125	-69.504	9190.135
SE3	43824	-0.219	0.063	15.587	-1921.632	169.333	-50.452	5469.146
SE4	43824	0.353	0.200	17.607	-1909.240	185.250	-36.030	3293.848
DK1	43824	0.062	0.000	12.492	-284.190	187.680	-5.054	73.017
DK2	43824	-0.641	0.000	19.140	-1927.294	156.846	-29.286	2442.005

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

Figure 5 - Figure 7 display the average absolute price spreads per year between the pairs of market places, assuming 1MWh trades per hour in each market. In addition to magnitudes we were interested in whether any trend across years exists. The figures reveal a contrast between mostly increasing spread in the day-ahead and intraday markets, and mostly declining spread in the other two markets. This finding implies that the market's need for adjusting positions in the intraday market is growing, but the scarcity of the balancing resources is not worsening. Nonetheless, taking into account the absolute spreads' magnitudes of around 2-4 EUR/MWh in relation to the day-ahead price of around 30EUR.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 RP-ID absolute spread represents a sizable risk from keeping imbalances or the opportunity for additional revenues from offering flexibility in the regulating power market.

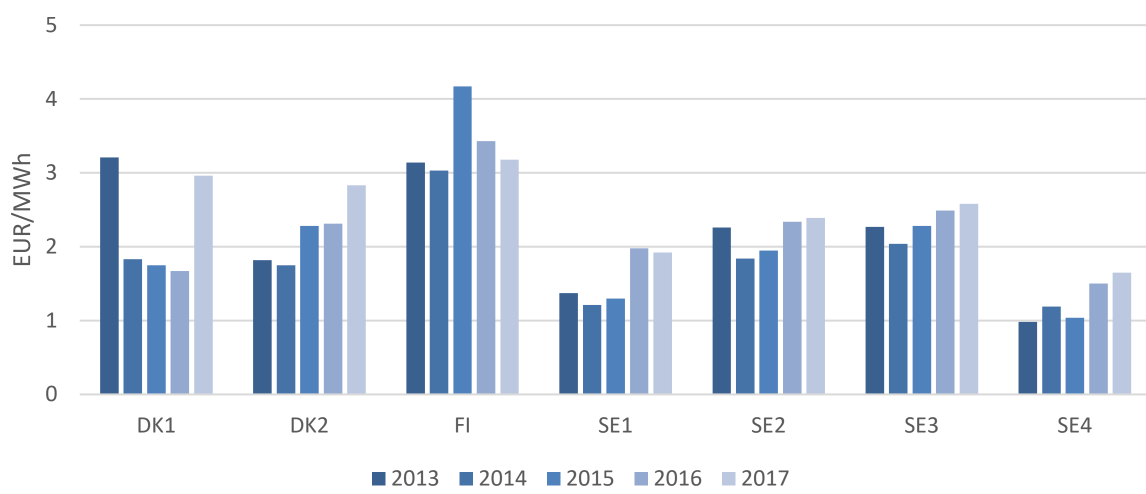


Figure 5 Average absolute price spreads between day-ahead and intraday prices for 1MWh

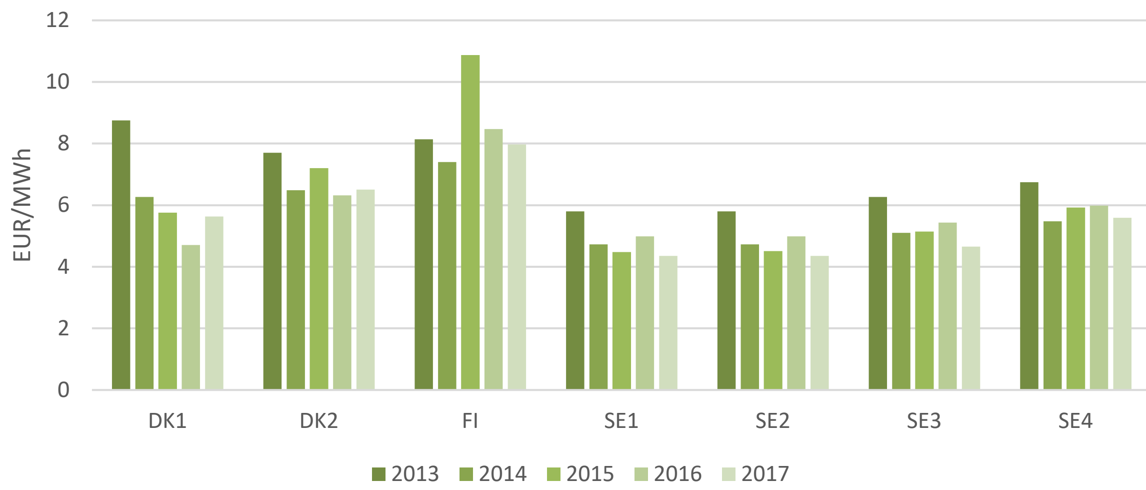


Figure 6 Average absolute price spreads between day-ahead and regulating power prices for 1MWh

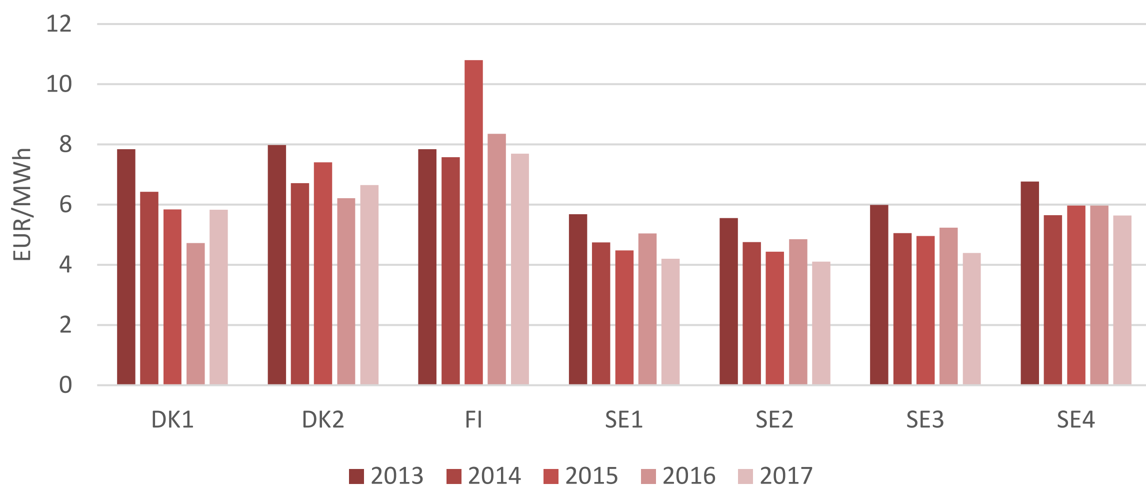


Figure 7 Average absolute price spreads between regulating power and intraday prices for 1MWh

B. Power market fundamentals

This work is primarily interested in the impacts of intermittent wind power production on the relevance of different electricity wholesale markets, we therefore focus on the uncertainty around wind power production. This uncertainty is often measured by *wind forecast errors* (MWh) which we calculate as the difference between wind power production forecast 1 day before delivery minus the realized wind power production. Positive values indicate over-forecasted production whereas negative values represent under-forecast.

We possess wind power production data for the entire studied horizon, but we were unable to obtain reliable wind power forecasts data from Sweden and Finland from earlier than approximately the second half of 2014. For this reason, a shorter time horizon is used in distribution summary of forecast wind errors in Figure 8, as well as in the final VAR models of the Swedish and Finnish markets. Nevertheless, over three years of hourly data is a sufficient sample size for a reliable time series analysis. In Figure 8 the red vertical line shows the mean wind forecast errors, the teal line represents 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 is close to zero in DK2 and SWE, slightly positive (overforecast) in DK1 and quite negative (underforecast) in FI where a left tail is also apparent.

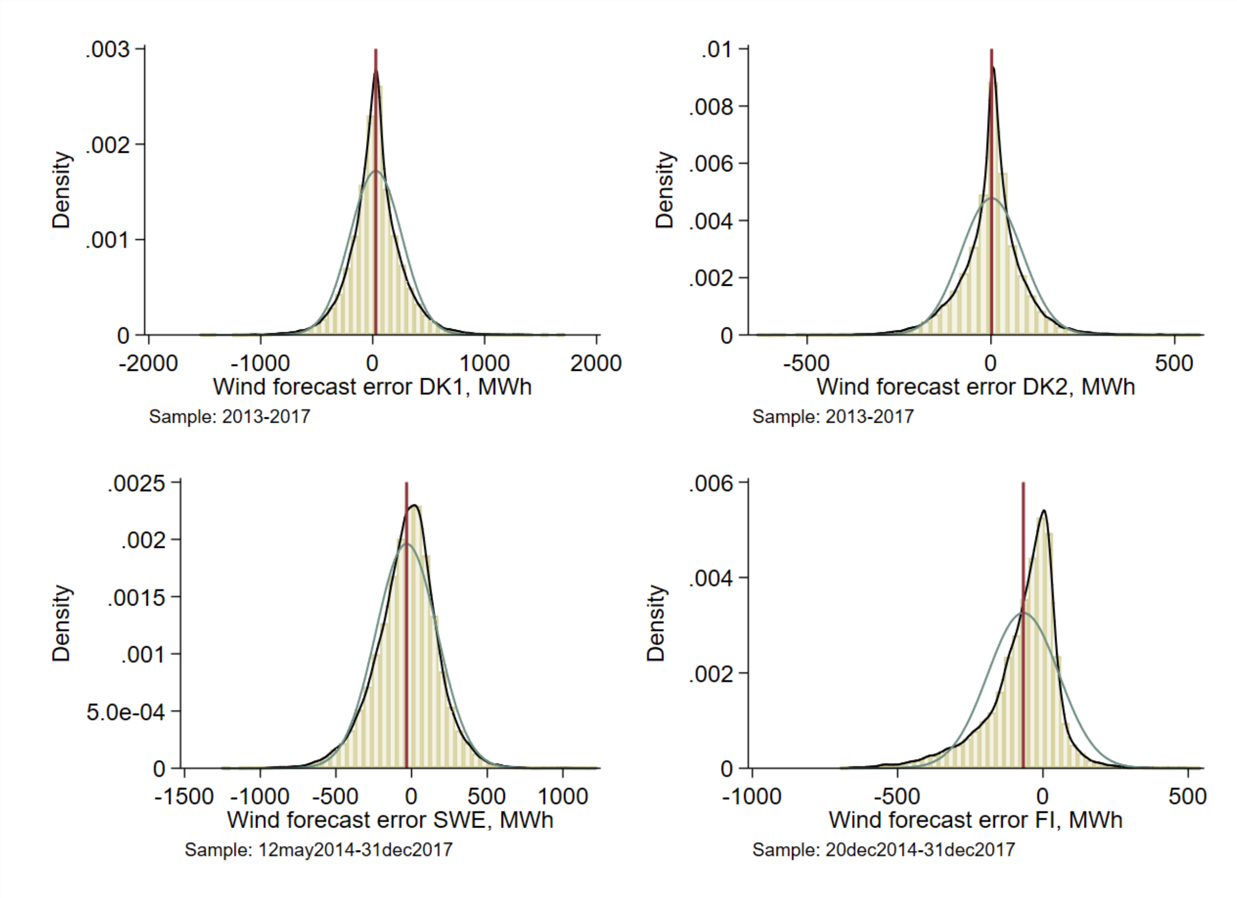


Figure 8 Distribution of wind forecast errors for Denmark (DK1-DK2), Finland (FI), and Sweden (SWE)

In addition to the supply risk, we model the uncertainty about the demand-side, namely *demand forecast error*, defined as the difference between hourly electricity demand forecasted 1 day before and the realized demand. The mean demand in DK1 and DK2 has been around 2.3 GWh/h and 1.5 GWh/h, respectively, with a standard deviation of approximately 400 MWh/h. The very high kurtosis (peakedness) of the Danish demand forecast errors in Figure 9 is due to a couple of rare events, such as under-forecast of almost 2 GWh/h in DK1 on October 23, 2013 or overforecast of 1.5 GWh/h in DK2 on December 15, 2016. The demand forecast errors are mostly normally distributed in Finland and Sweden, where the mean demand over 2013-2017 has 9.4 GWh/h and 15.6 GWh/h, respectively.

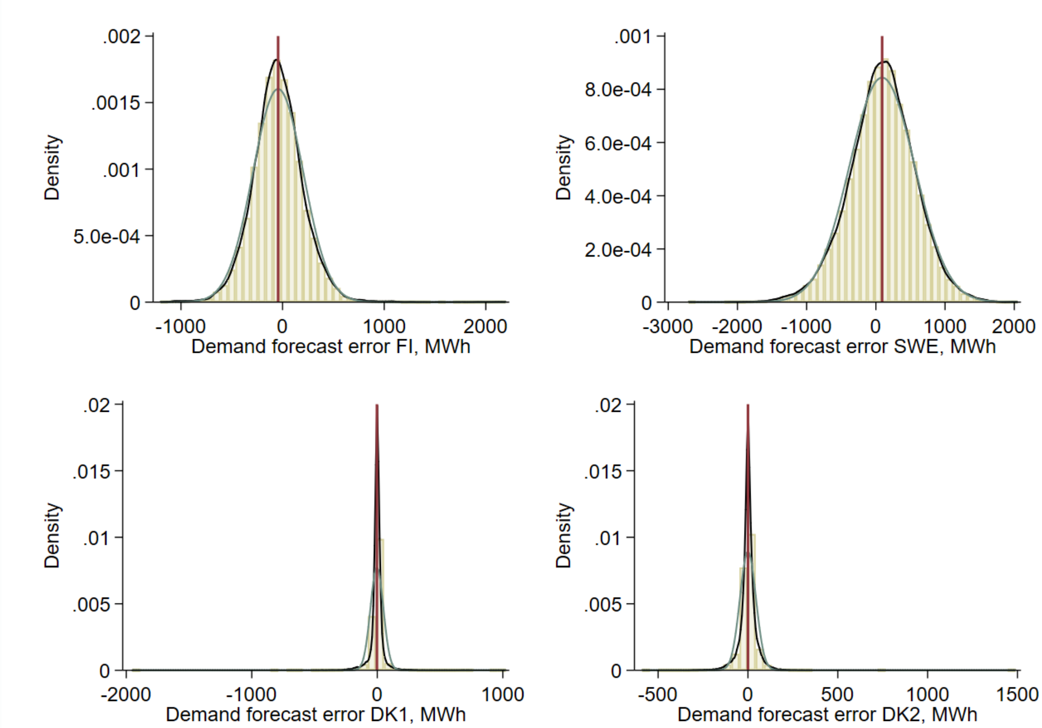


Figure 9 Demand forecast errors for Finland (FI), Sweden (SWE) and Denmark (DK1-DK2), 2013-2017

Next, we define several exogenous fundamental variables and controls. Power system can be impacted not only by the error about wind power production, but also by the sudden change in the output of intermittent power generation. This is because sudden hourly variations in wind productions need to be accommodated by sufficient flexible resources, see for instance (Batalla-Bejerano & Baute-Trojillo, 2016). We therefore control for the *wind power ramping* (MWh/h), defined as hourly change in realized wind power production. Positive values imply ramping-up wind generation and negative ramping-down.

The role of cross-border transmission network and the impact of congestion on prices has been discussed in section II. We include a variable that controls for *transmission bottlenecks* by indicating whether a bidding area's day-ahead hourly price differed from the reference system price. The transmission bottlenecks and flows are especially relevant for the day-ahead price formation, whereas the intraday cross-border flows follow physical limitations instead of commercial activity (Pape, Hagemann, & Weber, 2016). 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. We control for hydrological conditions in Norway, Sweden and Finland by calculating a difference between the running historical median of hydro reservoir fillings since 1995 and the current hydro reservoir filling, both measured in percentages. Figure 10 presents weekly *deviations of hydro reservoir fillings* showing, 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 control the diurnal and seasonal patterns by including week of sample fixed effects and hour fixed effects.

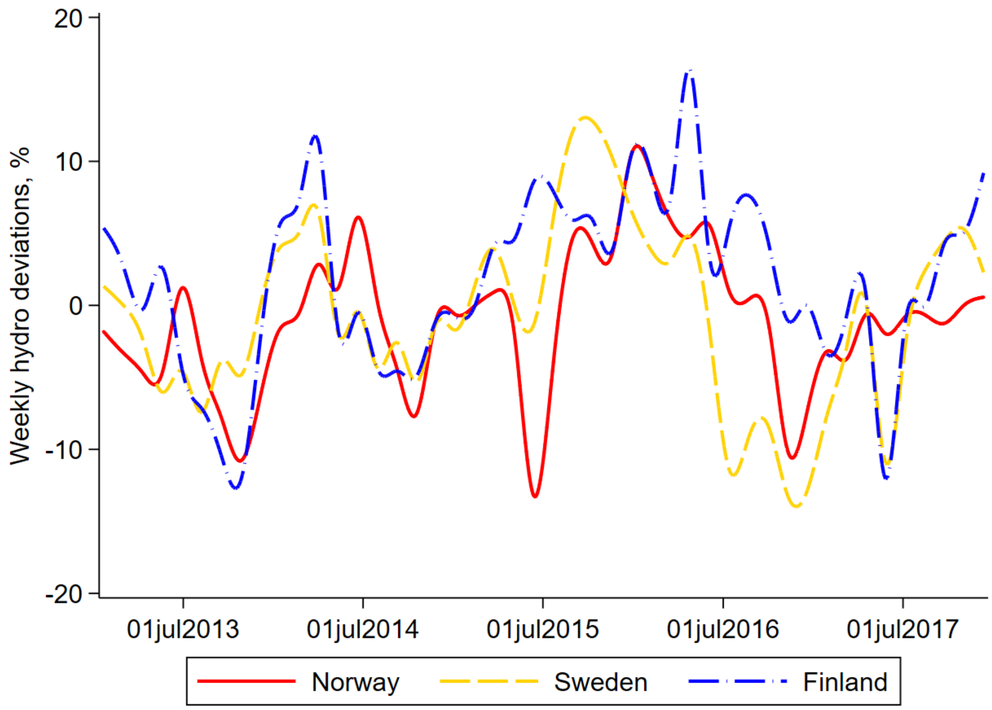


Figure 10 Deviations of weekly hydro reservoir fillings (%), 2013-2017
Note: Deviations are measured as the difference between the current percentage level of hydro-reservoir filling and the respective historical median measured since 1995. Negative values represent drier than usual week and positive values represent higher reservoir values than in a typical week, measured in percentages.

V. Methods

We study the dynamics of three electricity market prices in a vector autoregression (VAR) setup, specified as linear functions of their own lags, the lags of every other variable in the vector, and exogenous variables. By this dynamic modelling approach, we are able to perform causal inference and provide policy advice (Luetkepohl, 2011). This is because compared to, for instance, OLS which provides a static picture of temporally interrelated variables, VAR model can capture this temporality and follow the trajectories of price signals and their responses to imbalances.

We focus on three endogenous(response) variables, namely price spreads (DA-ID, DA-RP, ID-RP), wind forecast errors, and load forecast errors in 7 bidding areas (3 countries), which gives us 63 response variables studied over the years 2013-2017. The VAR model is specified in equation [1]:

$$y_t = a_0 + A_1 y_{t-1} + \cdots + A_p y_{t-p} + Bx_t + \epsilon_t \qquad (1)$$

Where y_t is a 3x1 vector of endogenous variables ($PriceSpread_t$, $WindError_t$, $LoadError_t$)', $x_t = (x_{1t}, x_{2t}, \dots x_{dt})'$ is a dx1 vector of exogenous variables, A_i are 3x3 matrices of lag coefficients to be estimated, B is a 3x1 matrix of exogenous variable coefficients to be estimated, a_0 is a 3x1 vector of constant terms; and ϵ_t is a 3x1 vector of 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 VAR model it is assumed that all of the endogenous variables are stationary. We test this assumption by Augmented Dickey-Fuller (ADF) test as well as alternative unit-root tests, all confirming the stationarity of our time series variables. For the sake of brevity, the tests statistics are not reported here but are available upon request from the corresponding author.

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

Because correlation does not necessarily imply causation and because we are primarily interested in the latter, we focus on testing the causality among our endogenous variables. Granger (1969) defined a testable definition of causality which tests whether *x* causes *y* by testing whether the lagged values of *x* improve the explanation of *y,* in comparison to using the lags of *y* process alone. This causality in the Granger-sense tests the significance of the information content of *x* for explaining *y*. We test a bidirectional Granger causality between each pair of the endogenous variables and report the χ^2 statistics of the Wald test for the joint hypothesis of $\beta_1=\beta_2=...=\beta_l=0$, for each equation in [2]. The null hypothesis is that *x* in the first regression and *y* in the second regression does not Granger-cause *y* and *x,* respectively.

$$
\begin{aligned}
y_t &= \alpha_0 + \alpha_1 y_{t-1} + \cdots + \alpha_l y_{t-l} + \beta_1 x_{t-1} + \cdots + \beta_l x_{t-l} + \epsilon_t \\
x_t &= \alpha_0 + \alpha_1 x_{t-1} + \cdots + \alpha_l x_{t-l} + \beta_1 y_{t-1} + \cdots + \beta_l y_{t-l} + u_t
\end{aligned}
\tag{2}
$$

Finally, after specifying a stable VAR model (all eigenvalues of the dynamic matrix lie within the unit circle) and exploring the pairwise causality, we trace 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 orthogonized impulse response functions (IRF), which use the estimated results from [2] to quantify the impact of one standard deviation shock at time *t* on the expected values of *y* at time *t+n*. To further gain insight into how important each shock is to the expected *y*, we measure the fraction of the forecast error variance of an endogenous variable that can be contributed to orthogonalized shocks to another endogenous variable. The next section provides the results and discusses the main findings.

VI. Results and discussion

In this section we present the main results and discuss the causal links (subsection A) and dynamic relationships (subsection B) between spreads and forecasting errors. These results are based on the postestimation statistics (Granger causality and impulse response functions, respectively) of the VAR system. In subsection C we explore the effects of exogenous variables on spreads. We report only the coefficients of exogenous variables and model fit statistics of the estimated VAR models in Appendix, Table 8.

A. Granger-causality tests

In this subsection we present the supply and demand factors causing the spreads in the Granger-sense. 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 consumption 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 5 shows the chi-square test statistics testing the null hypothesis that wind or consumption forecasting errors do not Granger-cause the spreads. The main finding from the table is that wind forecast errors do not cause the spreads in bidding areas with lower shares of wind power generation (FI, SE1, SE2). Vice versa, spreads in areas with large shares of wind power are significantly driven by wind forecast errors, especially in DK2 and SE4, but also in SE3 and DK1 (except DA-ID). This implies that there may be a threshold effect when spreads start to be driven by wind power forecast when the share of wind power reaches a certain threshold.

The spreads are the most clearly demand-driven in Finland, as indicated by the significance of consumption forecast errors across all market places. In fact, consumption forecast errors Granger cause most of the spreads except in DK2 and SE1, which was also the finding of (Karanfil & Li, 2017) with respect to DK2. The threshold or size effect may be in play here again where the consumption error is not significant in areas with relatively low consumption.

Our findings underline the utmost relevance of the demand-side measures for spreads. It is 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 possibility to counterbalance the negative effects of wind power forecasts in DK1, SE3 and SE4 where they both exert influence on the spreads.

Table 5 Granger causality between wind and demand forecast errors and spreads

Area	Market	Wind forecast error	Consumption forecast error
FI	DA-ID	24.09	79.22***
	DA-RP	30.31	115.05***
	ID-RP	28.37	104.38***
DK1	DA-ID	11.44	69.51***
	DA-RP	123.92***	78.18***
	ID-RP	334.73***	97.18***
DK2	DA-ID	75.83***	32.3
	DA-RP	181.61***	32.58
	ID-RP	158.93***	25.74
SE1	DA-ID	25.16	25.81
	DA-RP	25.74	25.3
	ID-RP	21.28	27.94
SE2	DA-ID	19.92	32.61
	DA-RP	20.03	94.91***
	ID-RP	21	94.72***
SE3	DA-ID	24.46	95.27***
	DA-RP	39.26**	121.93***
	ID-RP	35.58*	111.19***
SE4	DA-ID	48.02***	36.09*
	DA-RP	65.03***	42.32**
	ID-RP	57.48***	47.29***

Note: The table shows the results of Granger causality which tests whether wind or consumption forecast errors Granger cause the spreads, i.e. divergence between wholesale electricity market places. The table shows χ^2 statistic with significance levels, where *** p<0.01, ** p<0.05, * p<0.1.

B. Impulse response functions

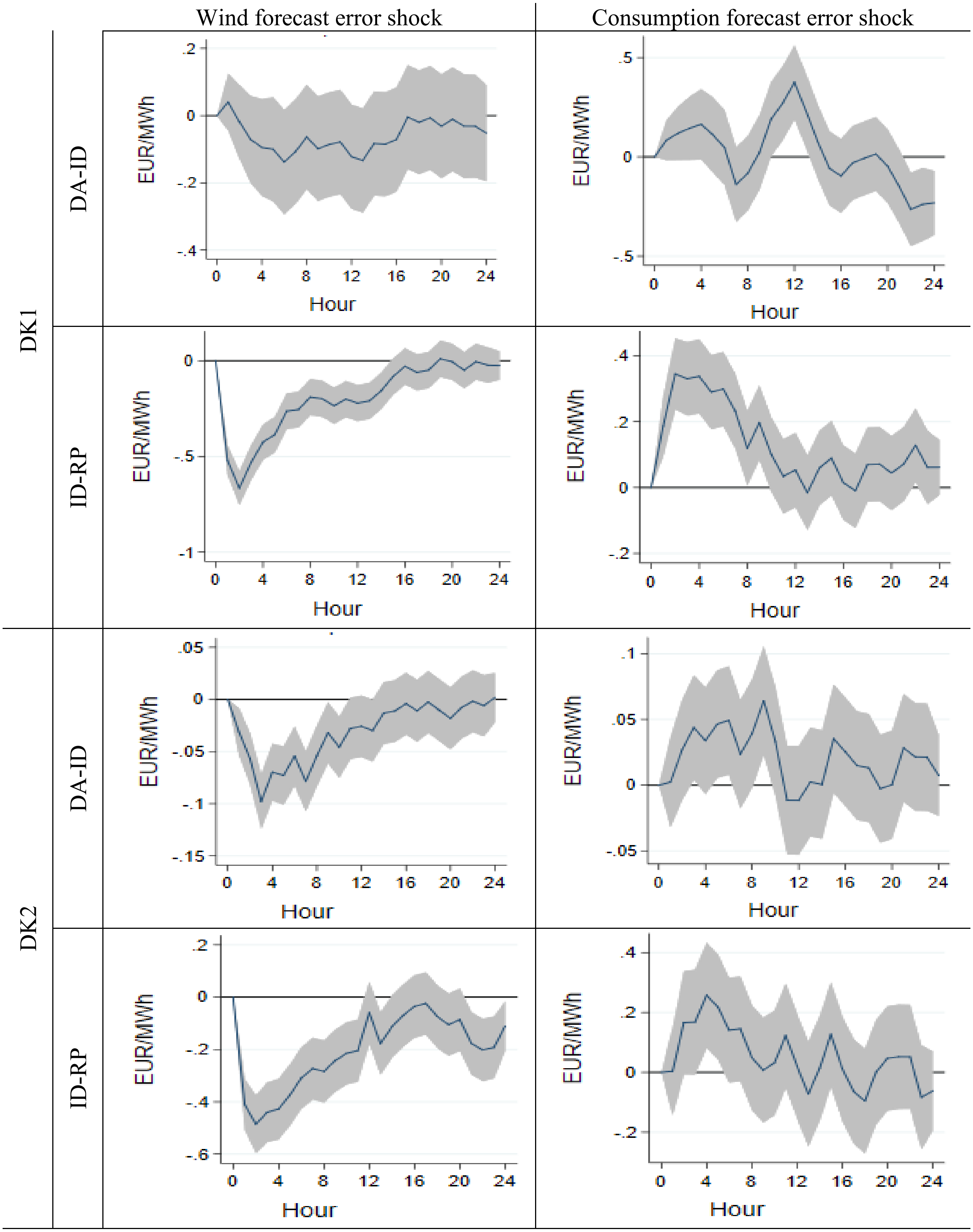
The results from the Granger-causality tests provided useful information about the relevance and significance of supply and demand factors for price spreads. However, we do not know much about the magnitudes and direction of these effects. In this part we focus on the trajectories of price spreads and their responses to supply and demand shocks. Figure 11 presents the impulse response functions (IRFs) which show a one standard deviation shock 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 show IRFs only for four selected bidding areas (DK1, DK2, FI and SE3) and two spreads (DA-ID and ID-RP). In fact, the IRFs for DA-RP spread not shown here are very similar to the ID-RP so responses can be quickly deduced from these.

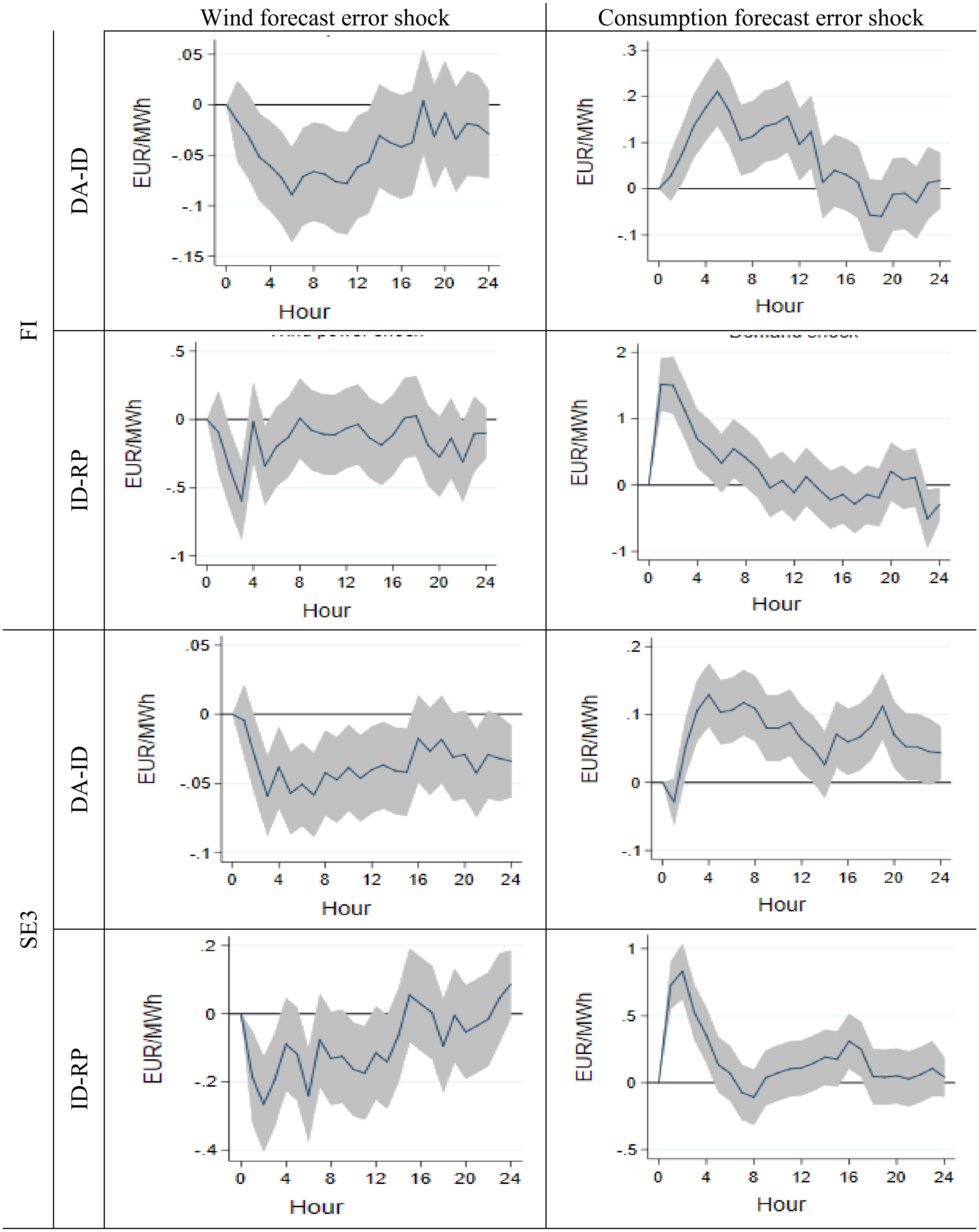
We first focus on the effects of wind forecast errors on the price spreads, shown in the left column of Figure 11. It is perhaps the most surprising finding that wind forecast errors do not significantly affect the DA-ID spread in DK1, where the highest absolute and relative wind power generation is located. There are several possible reasons for this finding which is in contrast to previous work conducted on much shorter and older sample (Karanfil & Li, 2017). First, bidding area DK1 belongs to the synchronous zone of Continental Europe, whereas DK2 is part of the Nordic synchronous zone to which the rest of our sample belongs. In conditions with sufficient available transmission capacities asynchronous areas can pool generation and consumption resources as well as share balancing reserves.

However, DK1 experiences an overflow of wind power that is not always possible to internally utilize or export due to the limited cross-border capacity. Konti-Skan interconnector from DK1 to SE3 has a capacity of approximately 700 MW but is often congested, as is the AC line between DK1 and Germany, which is often blocked for exports due to internal congestion in the German grid. There are grid investment plans to allow transporting the excess wind production to the Continental Europe, such as the new 700 MW interconnector COBRAcable between DK1 and the Netherlands, or reinforcement of the DK1-SE3 link. Nonetheless, excess wind power and limited export capacity seem to explain the finding that wind power forecast errors are not digested in the intraday market, as indicated by the insignificant effect on DA-ID. Instead, the correction is done via the shorter-term markets 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. This implies that the realized wind power generation is less than forecasted which, ceteris paribus, creates greater pressure on up-regulation price than on the intraday price, and thus increases the absolute value of the negative ID-RP spread. This effect holds true for ID-RP spreads in DK2 (similar magnitude) and weakly in SE3 (drop of 20 cents/MWh after two hours). We do not find significant effects of wind forecast errors on spreads in Finland, in line with the Granger-causality results above.

In contrast to DK1, wind forecast errors do significantly impact the DA-ID spread in DK2, underlying the difference between the Danish asynchronous bidding areas and the greater interconnection of DK2 to both the Nordic region and Continental Europe. The significant impact of a wind power forecast shock on DA-ID in DK2, SE3 and FI is between 5-10 euro cents/MWh within the first four hours after the shock. The interpretation is the same as above.

Figure 11 Impulse response functions showing responses of price spreads to shocks in wind and demand forecast errors during the next 24 hours





Note: The figure shows responses of price spreads (DA-ID and ID-RP) to one standard deviation in wind or consumption forecast error during the following 24 hours. The grey area represents 95 percent confidence intervals.

Next, we turn to observe the responses of price spreads to the shocks in consumption forecast errors as shown in the right column of Figure 11. We can deepen the previous finding that most of the price spreads are demand-driven, as shown by the Granger-causality results. The first and the most important finding is that the consumption forecast errors have a significantly positive impact on most of the price spreads. More explicitly, positive (overforecasted demand) shock shifts 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 decline, which implies increased DA-ID and ID-RP spreads. We can interpret this as such, that the excess demand is sold back at discount in the intraday market (DA-ID) or that the non-realized consumption/excess supply leads to down-regulation (ID-RP). Similarly, negative consumption shock (underforecasted consumption) shifts the demand curve outwards to the right, increasing the prices in the intraday market (DA-ID) or regulating power market (ID-RP) markets and the price adjustment to the unexpected excess demand occurs in the real-time.

The most pronounced effects of consumption forecast errors on price spreads are in FI and SE3, where a positive shock leads to an increase of 10-20 euro cents/MWh in DA-ID and 80 euro cents to 1.5 euro/MWh in ID-RP during the first four hours after the event. As previously argued, the insignificance of consumption forecast errors on the spreads in DK2 can be due to the relatively low consumption as compared to DK1, where a positive shock significantly increases especially the ID-RP spread by 40 euro cents/MWh within the first four hours.

Two points can be raised from observing the IRFs. First, all significant supply and demand shocks dissipate within a half a day or shorter time period, which points out to active market participants efficiently adjusting to market conditions in the short-run. Second, the impacts of shocks are much greater in the short-term markets (ID-RP) which reflects the higher costs of balancing reserves as well as the uncertainty and thus risk premia in the regulating power prices.

C. Impacts of exogenous variables

Finally, we explore the effects of exogenous variables on the price spreads. Hydro deviations do significantly and negatively impact most of the spreads, especially the Swedish hydro in SE3 and the Swedish hydro in DK2. The effect is stronger in the DA-RP and ID-RP spreads than in the DA-ID spread. The negative sign can be interpreted as such that 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 remains less affected by the deviations. This is an interesting finding, implying that despite the changes in hydro reservoirs the cost of balancing remains stable relative to the day-ahead (in DA-RP spread) and intraday markets (in ID-RP spread). Exception is DK2, whose DA-ID and DA-RP spreads seem to be significantly and positively impacted by the deviations in the Finnish hydro implying an impact on the cost of balancing. Interestingly, the deviations in the Norwegian hydro do not seem to significantly affect spreads, except negatively the Finnish DA-ID spread.

The ramping of wind power has a significantly positive impact on DA-RP and ID-RP spreads in DK1, DK2, and SE4, whereas negative impact on DA-ID spreads in Finland. This means that in areas with large share of wind power generation (DK1, DK2, and SE4), the wind power ramping is associated with direct impact on balancing costs. The sudden ramp-ups (ramp-downs) in wind power seem to reduce (increase) the regulating power price, leading to increasing (decreasing) spreads between DA-RP and ID-RP. In Finland, wind power ramping appears to exert a greater pressure on the intraday market, in comparison to the day-ahead price, where ramp-ups (ramp-downs) in wind power decrease (increase) the intraday price.

Finally, the day-ahead congestion indicator appears to be mostly insignificant for the spreads, except having a significantly positive impact on DA-ID in SE4 and significantly negative impact on DA-RP and ID-RP in DK2, and on ID-RP in DK1. The negative impact on DK spreads means that during congestion, the cost of balancing increases by approximately 50 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.

VII. Conclusions

Increased shares of wind power are affecting wholesale electricity markets in many ways. First, overall price levels are decreasing, when production capacity with low marginal costs is entering into the markets. This affects, for instance, the profitability of conventional condensing power plants. Second, 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. This is expected to increase the needs for balancing services, and thereby the costs of keeping the power system in balance.

The growing share of renewable energy production also changes the relationship and importance of different marketplaces in the electricity market. The closer-to-delivery markets, e.g. 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 and hedging strategies, among other things. This work fills the gap in the current literature and studies all three main electricity wholesale market places in a single study.

We have particularly studied the price spreads between the day-ahead, intraday and regulating power markets in Denmark, Sweden, and Finland in 2013 – 2017. We have exploited the variation in the share of wind power in different Nord Pool bidding areas in these three Nordic countries. We have 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 congestions and hydrological conditions, on price spreads in different bidding areas. The novelty of our study is that we are able to disentangle the effects on intraday and regulating power markets by analysing the price spreads between different market places (day-ahead, intraday and regulating power markets) jointly.

We have found that wind forecast errors do affect the price spreads in areas with large shares of wind power generation, such as in Denmark and in southern Sweden. In southern Sweden (SE4) and in eastern part of Denmark (DK2), where the wind power is in a dominant position in the market, wind forecast errors affect (i.e. Granger-cause) all price spreads. Western Denmark (DK1), where the highest absolute and relative wind power generation is located, makes an exception. There wind forecast errors have no statistically significant impact on the spread between day-ahead and intraday prices. This can be explained, for instance, by excess wind power and limited export capacity, and by the fact that the bidding area DK1 belongs to the synchronous zone of Continental Europe, unlike other studied bidding areas. Positive forecast errors, i.e. forecasted wind power production is higher than the realized production, tend to decrease the price spreads. In DK1, and also in the middle part of Sweden (SE3) where the shares of wind power are lower but still meaningful, wind forecast errors affect only the price spreads between intraday (or day-ahead) and regulating power markets. Finally, in those bidding areas where the shares of wind power are still modest, such as in northern Sweden (SE1) and Finland (FI), wind forecast errors have no statistically significant effect on the price spreads. Hence, we have found a threshold effect, meaning the 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.

Moreover, we have found that demand forecast errors do 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 have also found that hydro deviations do significantly and negatively impact most of the spreads, having larger impact on the day-ahead and intraday price levels than on the regulating power market. The ramping of wind power has a significantly positive impact on DA-RP and ID-RP spreads in areas with large share of wind power generation (DK1, DK2, and SE4), and is thus associated with a direct impact on balancing costs. Finally, the day-ahead congestion indicator appears to be mostly insignificant for the spreads, with some exceptions in areas with large share of wind power generation.

In this paper, we have quantitatively shown that increasing shares of wind power are changing the relevance of different market places. This has implications for future market design, where markets closer to real time play more important role than in the past. For the next steps, it would be useful to expand our method and find the economic value of flexibility and demand response. Also, finding a quantitative threshold for the wind and consumption forecasts could be interesting, even though these will often be market/area specific. We were mainly interested in the effects of wind power on the relevance of market places, however, the effects of solar PV as another major source of vRES should be explored. Finally, exploring the Explore microstructure of the intraday market in more detail, such as liquidity and transactions costs, which could explain why, for instance, wind forecasts errors do not impact DA-ID spreads in DK1.

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IX. Appendix

Table 6 Mean price levels by year, 2013-2017

	FI	SE1	SE2	SE3	SE4	DK1	DK2
(a) Day-ahead price							
2013	41.156	39.190	39.190	39.448	39.929	38.981	39.608
2014	36.023	31.422	31.422	31.621	31.915	30.671	32.153
2015	29.658	21.164	21.176	22.004	22.901	22.894	24.486
2016	32.445	28.951	28.951	29.234	29.529	26.668	29.396
2017	33.192	30.842	30.842	31.239	32.181	30.090	31.971
Total	34.494	30.313	30.315	30.708	31.290	29.859	31.522
(b) Intraday price							
	FI	SE1	SE2	SE3	SE4	DK1	DK2
2013	40.439	37.871	37.656	38.441	40.910	39.765	42.311
2014	35.042	30.866	30.541	31.051	31.947	31.561	32.862
2015	28.375	21.446	20.938	21.719	24.738	23.872	24.840
2016	31.934	28.930	28.348	28.748	30.587	27.216	30.163
2017	32.798	30.182	29.674	30.105	33.583	30.076	31.860
Total	33.688	29.569	29.454	29.934	32.117	30.506	31.526
(c) Imbalance consumption price							
	FI	SE1	SE2	SE3	SE4	DK1	DK2
2013	41.294	37.935	37.935	38.643	39.310	37.570	39.359
2014	35.995	30.850	30.850	31.316	31.882	31.096	32.911
2015	30.496	20.381	20.442	21.819	22.883	22.972	25.204
2016	32.691	27.695	27.695	28.445	29.049	25.667	29.061
2017	33.262	29.400	29.400	30.121	31.423	29.465	31.944
Total	34.747	29.251	29.264	30.068	30.908	29.352	31.694

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.

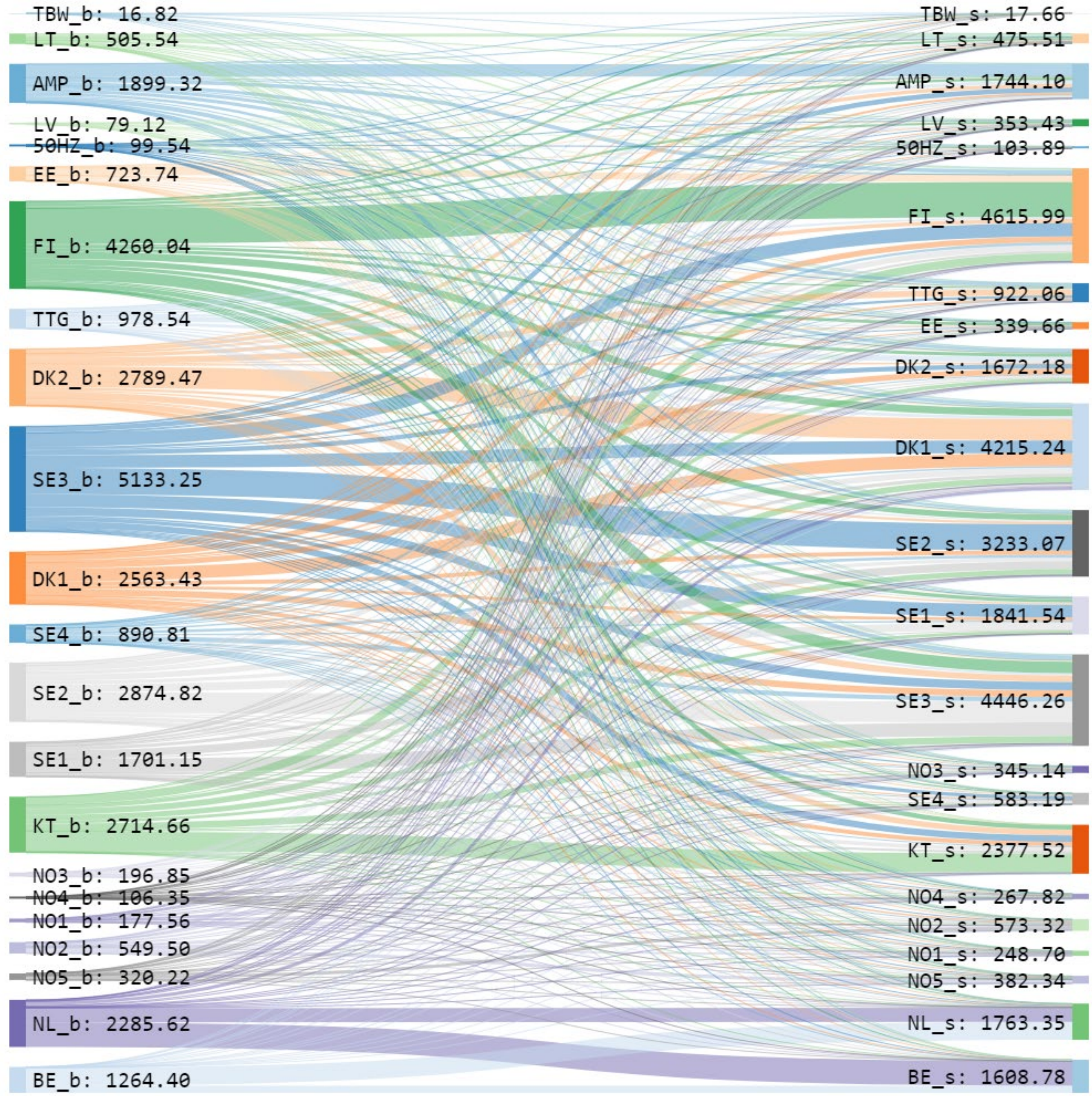

Figure 12 Total traded volumes on Elbas in GWh during 2012-2017

Note: The bidding areas on the left edge with index _b indicate buying volumes, whereas the bidding areas on the right with index _s indicate selling volumes; Total of 32151.93 GWh traded. From 26 November 2014 in addition to the code KT used for trades in the German area 4 new German TSO areas (50HZ, TTG, AMP, TBW) have been added.

Table 7 Intraday (Elbas) market summary by area over 2012-2017

	VWAP_b	VWAP_s	Tot Volume_b	Tot Volume_s	Net Volume	Turnover_b	Turnover_s	TTD_b	TTD_s	Trades_b	Trades_s
	EUR/MWh	EUR/MWh	GWh	GWh	GWh	Mil. EUR	Mil. EUR	hh:mm:ss	hh:mm:ss	#	#
50HZ	34.38	34.80	120748	125113	-4365	4.21	4.28	05:05:48	05:00:47	10619	10616
AMP	32.11	31.78	1899349	1744098	155251	60.41	55.02	05:27:03	05:08:19	110295	100693
BE	46.80	45.61	1264393	1608779	-344386	62.77	78.71	05:59:16	06:24:29	40709	57473
DK1	31.82	28.87	2563435	4215221	-1651786	82.12	123.75	05:28:44	06:35:58	126326	176458
DK2	33.59	33.07	2789468	1672167	1117301	91.32	54.72	06:35:20	05:46:41	109928	80604
EE	38.97	36.28	723744	339660	384084	28.59	12.78	05:52:51	05:05:39	55983	34500
FI	33.70	34.79	4260039	4615976	-355937	143.33	160.12	05:05:34	04:41:40	435067	446539
KT	36.43	34.57	2714654	2377515	337139	98.50	84.71	04:34:50	04:08:32	117253	100101
LT	44.96	45.43	505530	475487	30043	21.16	22.52	10:01:08	10:59:58	37125	43809
LV	40.46	36.66	79111	353441	-274330	3.23	14.17	06:36:30	06:19:19	13630	32482
NL	43.34	43.63	2285611	1763362	522249	103.09	81.49	05:52:19	05:11:32	84784	64503
NO1	26.02	29.32	177565	248727	-71162	4.25	7.19	10:52:47	10:24:03	10764	13535
NO2	24.99	28.54	549507	573333	-23826	13.62	15.00	08:32:50	09:20:29	22970	26488
NO3	29.05	30.04	196861	345113	-148252	5.69	10.01	08:18:13	07:21:25	13202	30887
NO4	30.29	30.86	106337	267804	-161467	3.11	8.21	09:19:16	08:09:29	6020	15179
NO5	24.73	26.91	320203	382362	-62159	7.63	9.94	10:32:00	10:25:33	10582	14214
SE1	28.18	29.03	1701169	1841511	-140342	48.22	52.44	07:02:59	07:21:18	68266	75495
SE2	27.68	29.22	2874786	3233059	-358273	78.96	94.37	06:18:58	06:32:17	173863	182255
SE3	29.60	30.86	5133280	4446274	687006	151.65	136.23	06:23:44	06:27:34	271213	240506
SE4	31.91	29.86	890788	583210	307579	29.58	17.61	06:09:48	05:33:47	62579	42669
TBW	35.10	34.28	16803	17663	-860	0.56	0.61	03:38:09	03:30:03	744	730
TTG	30.84	29.86	978554	922059	56495	29.15	27.28	05:34:10	05:21:33	63597	55783
Total	33.03	33.07	32151933	32151933	0	1071.15	1071.15	06:47:23	06:37:45	1845519	1845519

Note: _b and _s indices refer to buying and selling zone perspective, respectively. VWAP refers to volume weighted average price of Elbas trades; Tot Volume is the sum of volume traded on Elbas, and Net Volume is the difference between buying and selling volume per area, negative (-) implying net export and positive (+) net import; Turnover is the sum of quantity*price of Elbas trades; TTD refers to the average time-to-maturity of a contract from its purchase to delivery time; Trades refers to the total number of trades.

Table 8 Results of the vector autoregression models

Variables	Panel (a)											
	SE1			SE2			SE3			SE4		
	DA-ID	*DA-RP*	*ID-RP*	*DA-ID*	*DA-RP*	*ID-RP*	*DA-ID*	*DA-RP*	*ID-RP*	*DA-ID*	*DA-RP*	*ID-RP*
Congestion	-0.086	-0.201	-0.136	-0.085	-0.220	-0.122	-0.042	-0.221	-0.232	0.147*	-0.041	-0.216
	-0.069	-0.350	-0.354	-0.067	-0.350	-0.350	-0.069	-0.354	-0.356	-0.083	-0.389	-0.391
Weekend	-0.024	-0.258	-0.240	0.018	-0.150	-0.201	0.026	-0.032	-0.092	-0.032	0.168	0.224
	-0.040	-0.201	-0.204	-0.039	-0.202	-0.202	-0.040	-0.204	-0.205	-0.047	-0.223	-0.224
Wind ramp	0.001	0.004	0.003	0.000	0.002	0.001	0.000	0.001	0.001	0.000	0.006***	0.006***
	-0.001	-0.004	-0.005	0.000	-0.002	-0.002	0.000	-0.002	-0.002	0.000	-0.002	-0.002
Hydro dev. NO	0.005	0.015	0.007	0.006	-0.001	-0.013	0.005	0.012	-0.001	0.003	-0.008	-0.015
	-0.004	-0.021	-0.021	-0.004	-0.022	-0.022	-0.004	-0.021	-0.022	-0.005	-0.023	-0.024
Hydro dev. SWE	-0.007**	-0.015	-0.004	-0.003	-0.003	0.002	-0.006*	-0.036**	-0.031*	-0.003	-0.026	-0.027
	-0.003	-0.016	-0.016	-0.003	-0.018	-0.018	-0.003	-0.017	-0.017	-0.004	-0.018	-0.018
Hydro dev. FI	-0.008*	-0.015	-0.003	-0.007*	-0.016	-0.004	-0.005	-0.011	-0.002	0.000	0.004	0.005
	-0.004	-0.020	-0.020	-0.004	-0.020	-0.020	-0.004	-0.020	-0.020	-0.005	-0.022	-0.023
Hour 0-22, ref. 24	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Week 2-52, ref. 1	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
DA-ID, L.1-24,48	Y	N	N	Y	N	N	Y	N	N	Y	N	N
DA-RP, L.1-24,48	N	Y	N	N	Y	N	N	Y	N	N	Y	N
ID-RP, L.1-24,48	N	N	Y	N	N	Y	N	N	Y	N	N	Y
Wind error, L.1-24,48	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Demand error, L.1-24,48	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
LL	-64166	-106585	-106894	-63508	-106572	-106605	-64147	-106905	-107058	-68848	-109237	-109391
RMSE	2.835	14.39	14.57	2.764	14.39	14.41	2.833	14.57	14.66	3.392	15.93	16.03
R-sq	0.505	0.211	0.184	0.454	0.215	0.175	0.557	0.330	0.288	0.352	0.350	0.324
Parameters	156	156	156	156	156	156	156	156	156	156	156	156
Observations	26,106	26,107	26,108	26,106	26,106	26,106	26,106	26,106	26,106	26,106	26,106	26,106

Panel (b)

	FI			DK1			DK2		
	DA-ID	*DA-RP*	*ID-RP*	*DA-ID*	*DA-RP*	*ID-RP*	*DA-ID*	*DA-RP*	*ID-RP*
Congestion	0.012	-0.040	-0.144	-0.049	-0.384	-0.518***	-0.040	-0.549*	-0.566**
	-0.108	-0.811	-0.804	-0.196	-0.272	-0.181	-0.067	-0.282	-0.286
Weekend	-0.028	0.647	0.803*	-0.108	-0.009	0.138	0.004	0.278*	0.310*
	-0.061	-0.462	-0.458	-0.115	-0.159	-0.106	-0.040	-0.167	-0.169
Wind ramp	-0.002**	-0.002	0.000	0.000	0.002***	0.002***	0.000	0.010***	0.009***
	-0.001	-0.005	-0.005	0.000	-0.001	0.000	0.000	-0.002	-0.002
Hydro dev. NO	-0.015**	-0.028	0.012	0.016	0.027	0.013	0.004	-0.003	-0.010
	-0.007	-0.050	-0.049	-0.013	-0.018	-0.012	-0.004	-0.019	-0.019
Hydro dev. SWE	0.006	-0.051	-0.078**	0.000	-0.017	-0.021**	-0.008**	-0.040**	-0.036**
	-0.005	-0.038	-0.038	-0.011	-0.016	-0.010	-0.004	-0.016	-0.017
Hydro dev. FI	0.005	-0.060	-0.088*	-0.007	0.002	0.012	0.008**	0.0271*	0.021
	-0.006	-0.046	-0.045	-0.011	-0.015	-0.010	-0.004	-0.016	-0.016
Hour 0-22, ref. 24	Y	Y	Y	Y	Y	Y	Y	Y	Y
Week 2-52, ref. 1	Y	Y	Y	Y	Y	Y	Y	Y	Y
DA-ID, L.1-24,48	Y	N	N	Y	N	N	Y	N	N
DA-RP, L.1-24,48	N	Y	N	N	Y	N	N	Y	N
ID-RP, L.1-24,48	N	N	Y	N	N	Y	N	N	Y
Wind error, L.1-24,48	Y	Y	Y	Y	Y	Y	Y	Y	Y
Demand error, L.1-24,48	Y	Y	Y	Y	Y	Y	Y	Y	Y
LL	-76726	-130151	-129928	-164958	-179181	-161362	-118668	-181425	-182000
RMSE	4.406	33.16	32.89	10.66	14.78	9.819	3.676	15.48	15.69
R-sq	0.567	0.236	0.206	0.730	0.627	0.385	0.359	0.378	0.333
Parameters	156	156	156	156	156	156	156	156	156
Observations	26,467	26,468	26,469	43,594	43,594	43,594	43,646	43,647	43,648

Note: The table shows coefficients, t-statistics, and model summary statistics based on the vector autoregression model specified in section V. Significance levels are displayed as *** p<0.01, ** p<0.05, * p<0.1.

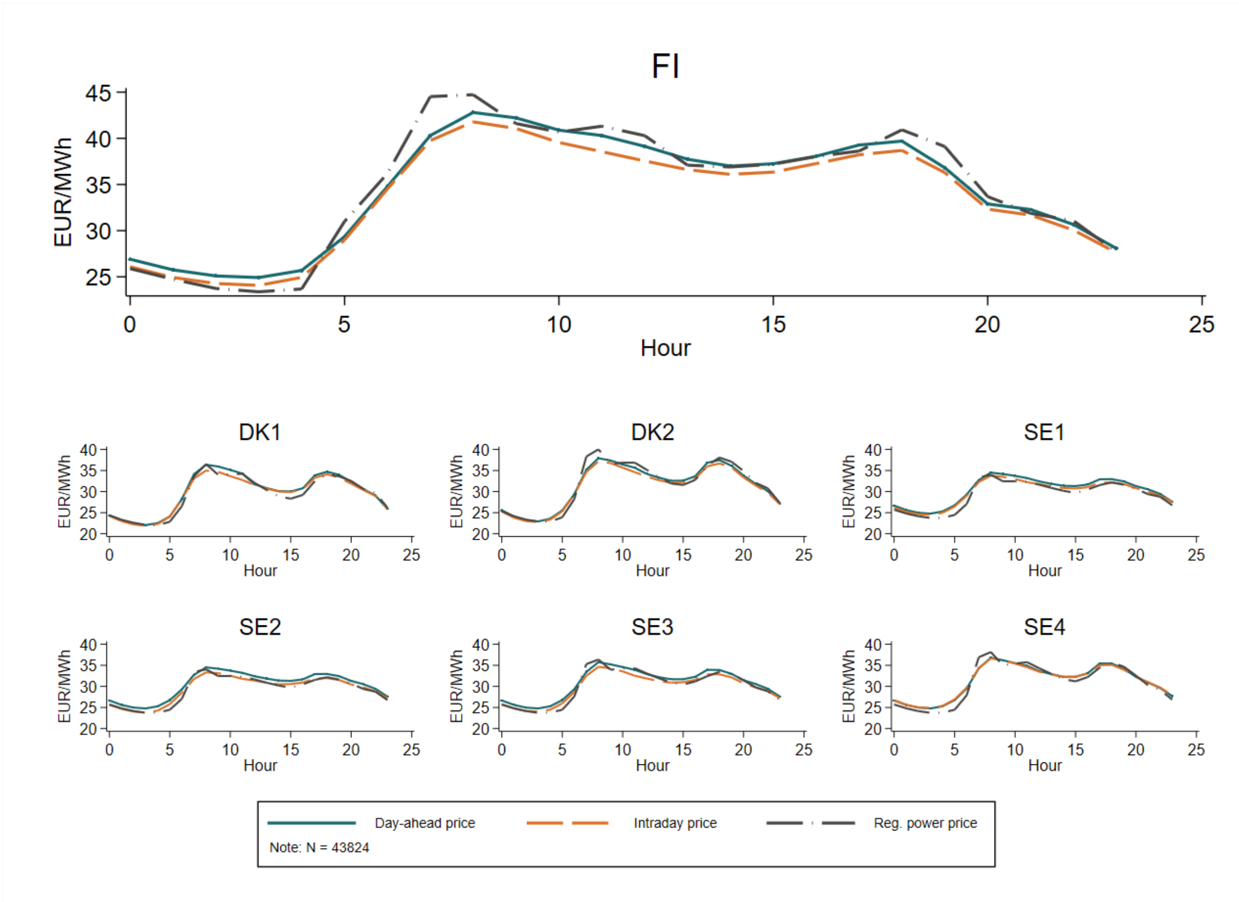

Figure 13 Summary of price levels by delivery hour, 2013-2017

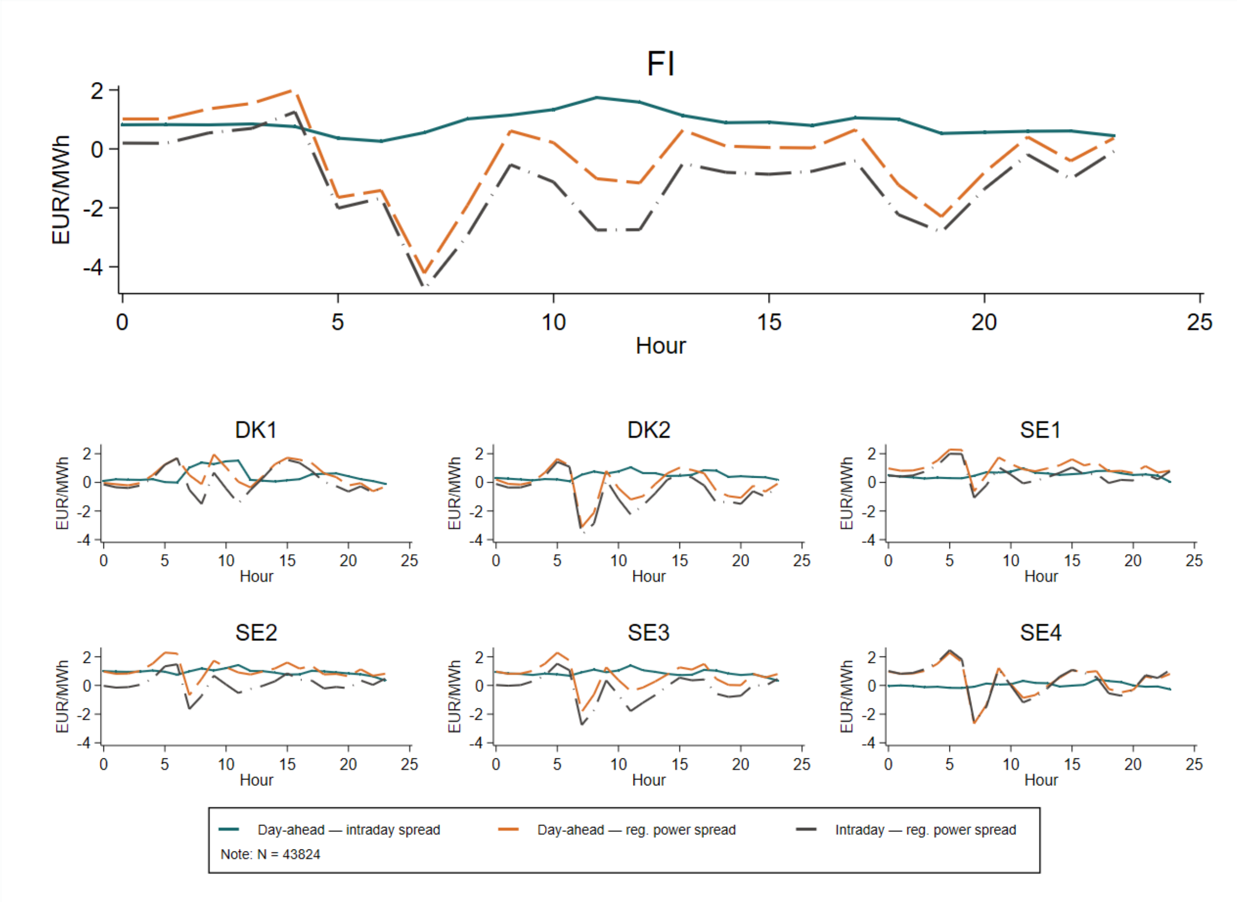

Figure 14 Summary of price spreads by delivery hour, 2013-2017