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The effects of wind power on electricity markets: A case study of the Swedish intraday market

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A B S T R A C T

We investigate the process of electricity price formation in the Swedish intraday market, given a large share of wind power in the Swedish electricity system. According to Karanfil and Li's (2017) approach, if the intraday market is efficient, with large shares of intermittent electricity in the entire electricity system, intraday prices should send signals based on scarcity pricing for balancing power. Based on this theory, we analyze Swedish electricity market data for the period 2015–2018 and find that the Swedish intraday market, despite its small trading volumes, is functioning properly. In particular, our results show that intraday price premia mostly respond to wind power forecast errors and other imbalances resulting from either supply or demand sides of the electricity market, as they should if the intraday market is efficient. The results of wind power forecast errors hold for central and southern Sweden, but not for northern Sweden where the share of wind power production is still very small. However, we find no effect of unplanned nuclear power plant outages on intraday price premia.

1. Introduction

European electricity systems are currently undergoing a rapid transformation as more and more electricity is produced from intermittent renewable energy sources, such as wind and solar power. The same trend applies to the Swedish electricity system. According to the Swedish Transmission System Operator — Svenska Kraftnät (2017), electricity produced from wind power in Sweden increased from 6.2 TWh in 2011 to about 17 TWh by the end of 2017. Renewable electricity generation in Sweden has been promoted through a mix of policies for almost three decades. Some of these policies are national, some are regional, while others are established at the EU level. But only recently did the Swedish Parliament decide that by 2040, at the latest, Sweden will have a 100% renewable electricity production system. This means that renewable electricity generation in the form of bioenergy and intermittent power, primarily wind and solar power, has to be significantly expanded to replace non-intermittent energy sources such as nuclear power. The share of wind in the Swedish generation mix is expected to be more than 20% by the end of 2020 and will increase to 40% in 2050. In other words, wind power will fully replace nuclear power in a 30-year time horizon (Jaraitė et al. 2019).

Not surprisingly, these changes pose challenges for the entire Swedish electricity system: to accommodate supply variability caused by the intermittent nature of electricity generated from wind and solar, an electricity system with highly flexible generation capacity, or highly price-driven flexible demand, or both are needed (Joskow 2019). Specifically, to solve these challenges in a cost-effective way, Sweden needs to have decentralized, competitive, and well-functioning sequential electricity markets, such as day-ahead and intraday electricity markets.

In this study, we focus on the Swedish sequential electricity markets and provide some evidence for the argument that appropriately designed markets provide the incentives to cost-effectively integrate intermittent power generation. As markets provide a natural place for

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flexible resources to trade in, well-functioning markets, in principle, should offer incentives for balancing power supply and demand both in the short run and in the long run. In particular, there is a common understanding that the role of intraday markets is likely to expand with the incremental shares of intermittent renewable power generation. Well-functioning intraday markets may well lower societal costs of intermittent power integration and may directly benefit, for example, wind power producers who otherwise have to use other balancing strategies or to trade their generation imbalances at a higher cost in balancing markets. The theoretically implied positive premia (Soysal et al. 2017) in the intraday market should also adequately reward flexible generators for their timely contribution to power system security, thus making it profitable for them to stay in this market. More specifically, as the time approaches the delivery hourly, the market price of electricity should include a premium because of the loss of flexibility. As electricity generated by wind power increases in the system, there is an increasing demand for ramping capacity at congested hours, which will be reflected by a positive price premium in the intraday market. Therefore, the differences between electricity prices in the intraday and day-ahead markets can be considered to be an intraday price premium.

Yet, there is a lot of evidence showing that many European intraday markets, including the Swedish intraday market, are illiquid and hence might be inefficient and result in higher costs of imbalances (Weber 2010). Historically, the volume of trade on the Swedish intraday market has been relatively low, especially compared to that in the day-ahead market. The low liquidity in the Swedish intraday market has led to concerns that many potential market participants may have been discouraged from participating in this market. According to the Swedish Energy Markets Inspectorate (2017), currently, the intraday market is used primarily by balance responsible parties, which are mainly big power producing companies, although there is no requirement for the intraday market participant to be a balance responsible party.

This paper aims to further investigate the performance and functioning of the Swedish intraday market and to understand whether this market expectedly rewards its participants. To understand this, we will look at price formation in the intraday market and its relation to price formation in the day-ahead market, and we will analyze whether intraday price premia – calculated as differences between intraday electricity prices and day-ahead electricity prices – are responding to market fundamentals, namely imbalances caused by wind power and other power-generating technologies, as well as the interconnection system. Following Karanfil and Li's (2017) approach, if causality between intraday price premia and market fundamentals can be established, it is reasonable to conclude that the intraday market is effective and, hence, capable of integrating increasing imbalances caused by intermittent electricity generation. In other words, a well-functioning intraday market should reward flexibility in the expected way by sending correct price signals to flexibility providers.

To date, besides us, only the concurrent paper by Spodniak et al. (2020) have applied Karanfil and Li's novel approach to investigate the functioning of modern intraday markets. Our paper provides important new policy insights compared to the other two papers. First, the recent rapid growth in wind power generation makes the Swedish intraday market, which functions alongside quite diverse power generation mixes, an interesting case to study as it has not been profoundly explored. Unlike Karanfil and Li (2017), we investigate four Swedish electricity price zones with different energy generation mix, while they focus on the Danish market with two electricity price zones with similar energy mix.

Second, the rise of wind power (as a share of total generation) from low levels is more recent in Sweden than in Denmark (Karanfil and Li (2017). The share of wind power has increased from 4.6% to 10.4% in Sweden from 2011 to 2017, while it is more stable around and above 30% since 2011 in Denmark. Our study is of great interest for countries with low wind power shares transitioning or considering to transition to a system with significant shares of wind power.

Third, our paper is important for understanding the interaction between wind power and nuclear power as nuclear power is common in many countries, although not in Denmark. Among other things, we study unplanned nuclear power outages, which could create significant imbalances to consider when adopting more wind power. To the best of our knowledge, this has not been done before. This analysis, therefore, may provide some early insights to policy makers, scholars, and practitioners on how gradual nuclear power phase-outs together with increasing intermittent power generation — a situation that is and will be relevant to some European countries — may affect electricity markets.

Finally, compared to the study by Spodniak et al. (2020) on the Nordic electricity markets (including the Swedish one), our paper considers additional important major market fundamentals needed for better understanding the functioning of electricity markets. They do not address fundamentals such as cross-region flows and imbalances related to nuclear power.

Our key findings can be summarized as follows. Wind power forecast errors are estimated to have the negative effect on intraday price premia in central and southern Sweden, but no effect in the north of the country potentially due to smaller wind penetration in this region than in the remaining regions. However, we find no evidence of unplanned nuclear plant outages having effects on intraday price premia in central Sweden — SE3 electricity price area. These outages, however, are estimated to be positively associated with cross-region flows in SE3 area. Electricity price area SE3 has the least transmission constraints compared with the other electricity price areas in Sweden. Hence, we suspect that when there are forced outages in nuclear power plants, producers or consumers are likely to absorb these shocks by buying electricity from the five adjacent electricity price areas instead.[1] Therefore, intraday price premia can be unaffected by these imbalances.

The paper proceeds as follows. Section 2 provides a brief literature review. Section 3 gives a short overview of the structure of the Swedish electricity markets and discusses data used in this study. Section 4 describes the model specifications and estimation methods. Section 5 reports the results from both baseline and robustness empirical models. Section 6 concludes.

2. Literature review

According to Joskow (2019), next to various flexible demand-inducing strategies, decentralized and competitive sequential electricity markets are commonly used to reduce the market inefficiency caused by intermittent renewable energy. Our paper relates to studies in energy economics assessing the importance of intraday markets in accommodating growing shares of intermittent renewable energy in electricity systems.

As shares of intermittent renewable electricity have become substantial, more market players are expected to participate in the intraday market. Scharff and Amelin (2016) point out that there are several reasons why this market is attractive for market participants. First, it offers a possibility to reduce the imbalance costs to which electricity consumers/producers are exposed to when supplying/consuming more or less electricity than they planned. Based on simulation studies, Mauritzen (2015) provides some evidence showing that the option of trading in the intraday market can reduce balancing costs related to a large share of wind power in the system. This will directly benefit wind power producers who otherwise have to use other balancing strategies or trade their generation imbalances at a higher cost in balancing markets (Borggrefe and Neuhoff 2011). Second, the intraday

[1] Stockholm (SE3) is connected with Sundsvall (SE2), Malmö (SE4), Norway East (NO1), Denmark West (DK1) and Finland (FI).

Table 1
Summary statistics from January 2015 to June 2018.

	Mean	S·D	Median	Max	Min	Skewness	Kurtosis	Units
SE1								
Intraday price premia	−0.460	4.111	0	134.6	−105.1	5.651	307.4	EUR/MWh
Wind forecast errors	−0.890	36.49	−2	299	−236	−0.202	7.881	MWh
Non-wind forecast errors	−18.45	139.5	0	1540	−902	−0.735	7.735	MWh
Load forecast errors	−4.361	84.09	−5	1604	−476	0.286	9.013	MWh
Intraday flows	0.344	97.86	0	980	−913.1	0.0547	19.82	MWh
Congestion	6150	971.6	6223	8175	0	−0.422	3.559	MW
SE2								
Intraday price premia	−0.938	4.109	−0.560	62.64	−130.0	−4.120	128.3	EUR/MWh
Wind forecast errors	1.217	110.1	−3	681	−817	−0.478	7.522	MWh
Non-wind forecast errors	−10.18	198.6	1	1358	−1105	−0.286	4.690	MWh
Load forecast errors	−49.20	154.1	−45	1508	−1010	0.201	5.369	MWh
Intraday flows	−1.945	101.8	0	718.7	−1153	−0.233	12.08	MWh
Congestion	14,115	1485	14,361	17,070	0	−2.214	17.51	MW
SE3								
Intraday price premia	−0.954	4.587	−0.660	167.3	−137.6	2.113	165.4	EUR/MWh
Wind forecast errors	−6.411	120.1	−8	541	−1067	−1.039	10.02	MWh
Non-wind forecast errors	51.48	169.2	32	1121	−728	0.564	4.535	MWh
Load forecast errors	−25.70	317.3	−31	1725	−1840	0.116	3.603	MWh
Intraday flows	5.592	168.5	0.3	1349	−1431	1.246	16.21	MWh
Congestion	11,464	1799	11,550	16,920	0	−0.479	4.287	MW
Forced outages	1.749	12.44	0	737.3	0	26.58	1011	MWh
SE4								
Intraday price premia	−0.147	4.350	0	177.4	−133.5	3.783	375.3	EUR/MWh
Wind forecast errors	11.18	77.91	6	530	−571	0.0943	5.194	MWh
Non-wind forecast errors	8.434	92.07	9	1929	−485	2.175	43.81	MWh
Load forecast errors	−17.17	144.2	−14	924	−1007	−0.475	6.211	MWh
Intraday flows	5.109	77.80	0	1104	−1430	−0.0803	37.80	MWh
Congestion	3523	1125	3545	6787	0	−0.341	2.986	MW

Notes: Forced outages of nuclear power plants measure the unavailable capacity of the nuclear plants per hour, which is only available in SE3. The reason is that all Swedish nuclear power plants are located in SE3.

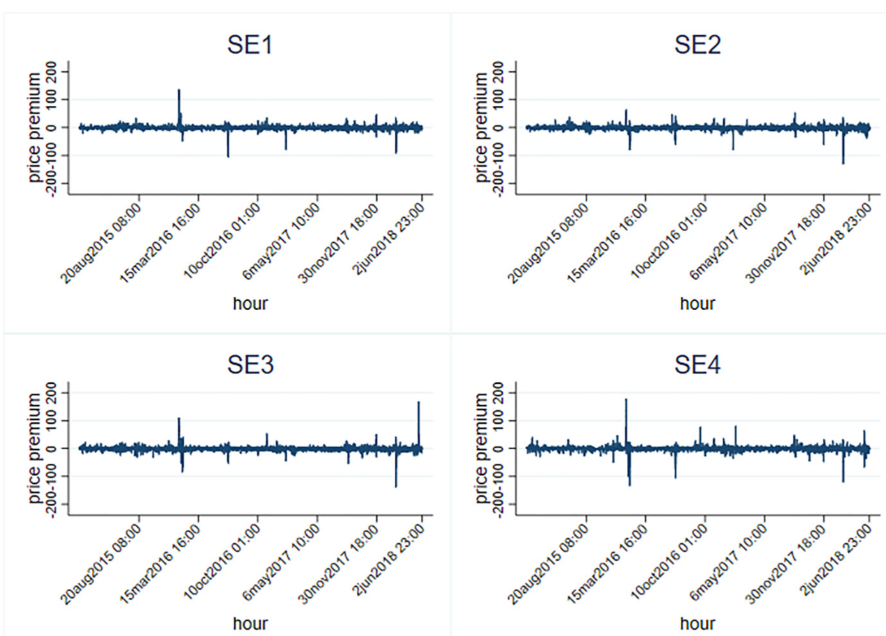

Fig. 1. The hourly intraday price premia for each bidding area from 2015 to 2018 in Sweden. *Notes:* Intraday price premia are measured in EUR/MWh. They are adjusted to zero at the hours when there are no trades performed in the intraday market because price premia can no longer send price signals about the scarcity of electricity when there is no trade taking place in the intraday market.

market provides a possibility for participants to optimize own production/consumption schedules, for example, by buying electricity to reduce generation in their own power plant that would be costlier to run. Last but not the least, intraday trading can also be used as a venue to sell flexibility of own production/consumption to other market participants who need this flexibility and are willing to pay for it.

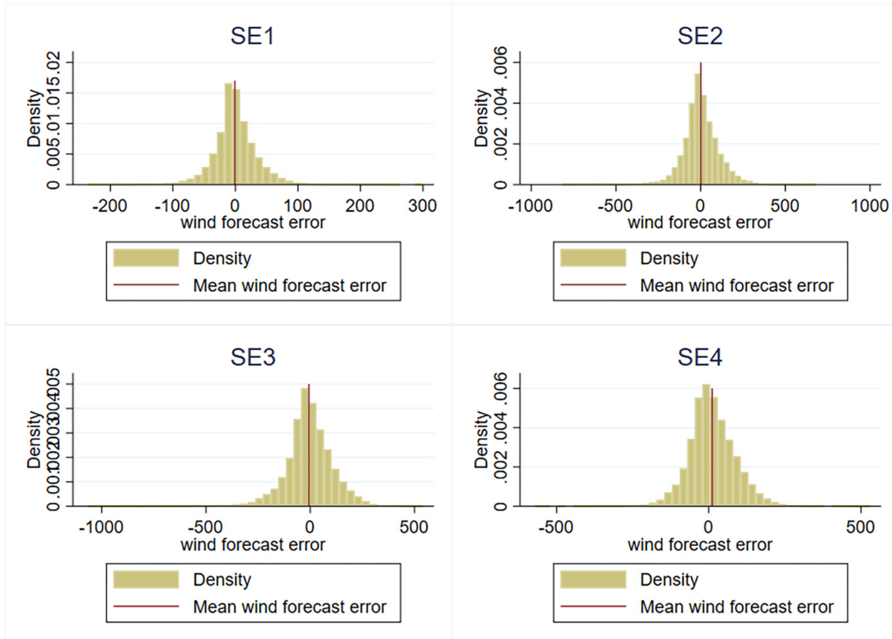

Fig. 2. Histograms of wind power forecast errors (in MWh) for each electricity price area in Sweden from 2015 to 2018.

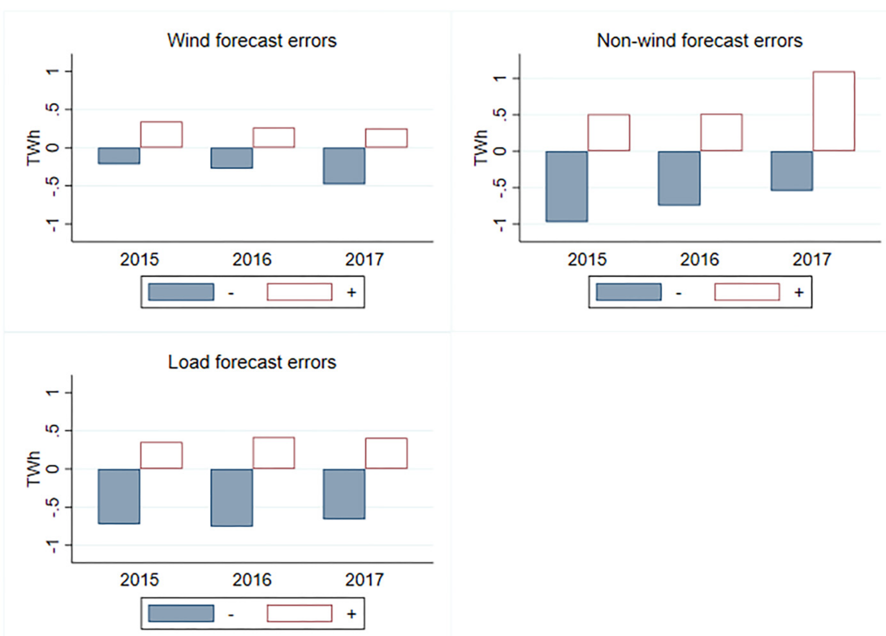

Fig. 3. The positive and negative wind forecast errors, non-wind forecast errors, and load forecast errors in Sweden from 2015 to 2017. *Notes:* "-" indicates the negative errors and "+" indicates the positive errors. The year 2018 is not included since data for this year is only available until June 2018.

According to Jaraitė et al. (2019), without intraday trading, this flexibility might not be utilized because flexibility on intraday and balancing markets can have different characteristics.[2] Additionally, Borggrefe and Neuhoff (2011) conclude that a well-functioning intraday market will prevent the abuse of market power and lower overall societal costs of wind power.

Despite these economic incentives to participate in intraday trading, given the increasing generation from variable renewable energy, there is a lot of evidence showing that many European intraday markets have small trading volumes that result in higher costs of imbalances and low market liquidity and efficiency (Henriot 2014; Mauritzen 2015; Scharff and Amelin 2016). For instance, Weber (2010) argues that, historically, the potential trading volume on the German intraday market, defined as the required short-term adjustments, should have been at least

[2] Balancing markets usually have higher requirements on balancing bids in terms of minimum bid size, activation times and purely physical fulfilment. This means that not all flexibility identified by market participants during the intraday trading period can be offered on the balancing market. In consequence, intraday markets provide a venue to access this flexibility and, hence, they should be regarded as complements rather than substitutes to balancing markets.

Table 2
Results of Granger causality tests.

Dependent variables	(1) Intraday price premia	(2) Wind power f.e.	(3) Non-wind power f.e.	(4) Load f.e.	(5) Cross-region flows	(6) Forced outages
SE1						
Intraday price premia	n/a	28.89	183.4***	19.88	27.38	n/a
Wind power f.e.	25.61	n/a	29.87	60.47***	22.59	n/a
Non-wind power f.e.	81.75***	323.8***	n/a	53.61***	35.44**	n/a
Load f.e.	24.84	646.7***	33.86*	n/a	24.58	n/a
Cross-region flows	34.37*	47.44***	34.74*	33.00*	n/a	n/a
SE2						
Intraday price premia	n/a	61.75***	245.8***	34.10*	38.18**	n/a
Wind power f.e.	17.24	n/a	26.80	78.76***	20.45	n/a
Non-wind power f.e.	61.18***	253.0***	n/a	278.5***	40.71**	n/a
Load f.e.	33.50*	1003***	145.0***	n/a	25.34	n/a
Cross-region flows	37.46**	99.60***	102.5***	55.32***	n/a	n/a
SE3						
Intraday price premia	n/a	142.9***	228.0***	73.06***	54.64***	22.77
Wind power f.e.	15.60	n/a	38.99**	88.30***	23.70	20.37
Non-wind power f.e.	60.01***	1891***	n/a	108.4***	53.89***	22.04
Load f.e.	48.59***	202.2***	58.49***	n/a	38.80**	33.35*
Cross-region flows	84.51***	193.9***	314.0***	125.5***	n/a	83.97***
Forced outages	22.25	33.73*	13.61	21.53	84.49***	n/a
SE4						
Intraday price premia	n/a	45.74***	39.13**	35.42**	22.63	n/a
Wind power f.e.	21.21	n/a	32.18*	44.64***	23.18	n/a
Non-wind power f.e.	22.93	1058***	n/a	37.09**	30.11	n/a
Load f.e.	32.31*	284.0***	21.37	n/a	28.44	n/a
Cross-region flows	40.39**	30.25	25.91	30.59	n/a	n/a

Notes: *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$. The results are Wald statistics and follow χ^2 distribution.
Wind power f.e. refers to wind power forecast errors. Non-wind power f.e. refers to non-wind power forecast errors, which is the total production error excluding wind power production errors. Load f.e. refers to load forecast errors.

two times larger than the actual trading volume. Besides, the liquidity on the intraday market might be asymmetric, such as in Denmark where wind shortfalls increase the probability of intraday trading, while wind surpluses make intraday trading less likely (Mauritzen 2015). According to Henriot (2014), the low liquidity of the intraday market is caused by the variable nature of wind forecasts, which discourages the players from trading in intraday markets, given available cheaper options in balancing markets.

One exception is the Spanish intraday market, which historically has had high trading volumes compared with other European markets. A possible explanation is that the intraday market design and electricity regulations are different in Spain (Chaves-Avila and Fernandes 2015). Chaves-Avila et al. (2013) argue that although wind farm owners prefer to participate in intraday markets to adjust production, the majority of electricity is still produced by the conventional generators who usually commit their production long ahead of time because of start-up costs and generation planning.

While a high level of liquidity has been viewed as a standard criterion for an effective intraday market, some scholars argue that an optimal intraday market should not target a large trading volume per se because economic agents behave according to the incentives that they receive from price signals (Henriot 2014; Karanfil and Li 2017). Karanfil and Li (2017) suggest that instead of focusing on the level of liquidity or intraday trade volumes, it is better to consider causality between price signals and market fundamentals. They use causality tests to access the functionality of the Danish intraday market and conclude that it is operating as intended, since wind and conventional generation forecast errors are the two fundamental factors that drive intraday prices, aside from day-ahead prices. There is a growing literature studying the efficiency in electricity markets, focusing on the price difference between the intraday and day-ahead markets (e.g., Ito and Reguant 2016; Woo et al. 2016; Karanfil and Li 2017; Tangerås and Mauritzen 2018). Our paper contributes to this emerging literature in energy economics by rigorously studying the price divergence between the electricity sequential markets and overall intraday market functionality in the case of Sweden. One novelty of our analysis is that it considers imbalances caused by unplanned nuclear power outages, which, to the best of our knowledge, has not been done before.

3. Swedish electricity markets and data

3.1. Swedish electricity markets

Swedish electricity markets consist of three sequential electricity markets: the day-ahead market, intraday market, and balancing market. The day-ahead and intraday markets are parts of the integrated Nordic-Baltic market Nord Pool.[3] In the day-ahead market, market actors submit their supply and demand bids for the next day no later than 12 noon. The market price is settled as a marginal price through a uniform auction at each hour. After the day-ahead price calculations, precise figures for unused cross-border transmission capacities are provided to the Nord Pool intraday market, where market actors can continue to trade and to balance their portfolios, if load or production forecasts turn out to be inaccurate. The intraday market opens for trading at 14:00 CET the day before and closes one hour before delivery. The market price is settled by continuous actions.

The day-ahead market is the primary electricity trading market and most Swedish electricity production is first allocated here. It plans for nearly 90% of the electricity consumed in Sweden (Swedish Energy Markets Inspectorate 2019). The intraday market is an adjustment market to the day-ahead market and its function is to keep the balance

[3] Nord Pool is a multinational power exchange market originally consisting of Sweden, Norway, Finland, Denmark, Latvia, Lithuania, and Estonia. Since June 12, 2018, the Nord Pool intraday market has been integrated with the European Cross-Border Intraday Market (XBID), through which all users can trade in 13 intraday markets, including Nordic and Baltic countries, Germany, Luxembourg, France, the Netherlands, Belgium, and Austria.

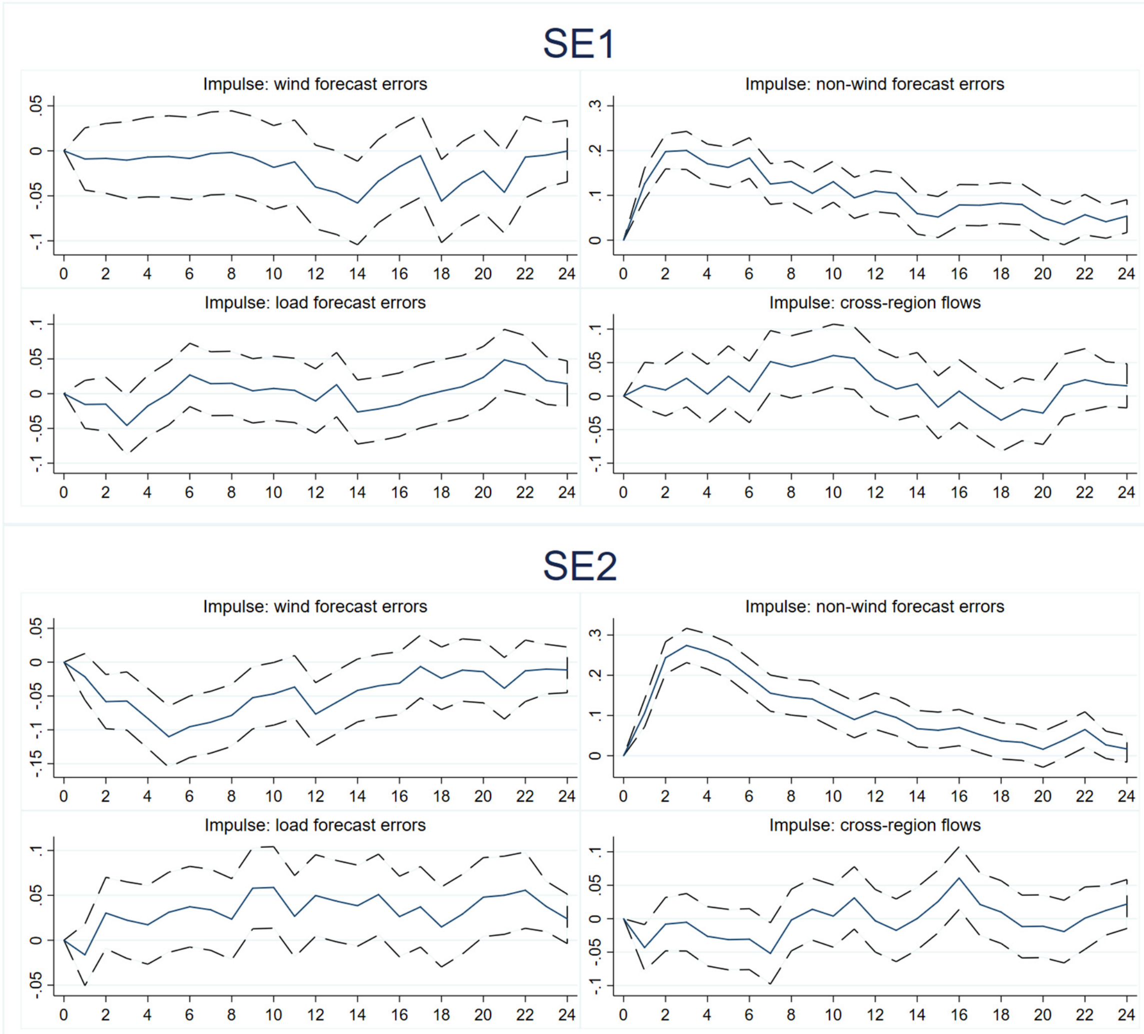

Fig. 4. Generalized impulse response functions of price premia in SE1 and SE2. Notes: Responses of price premia given one standard deviation shock to wind power forecast errors, non-wind forecast errors, load forecast errors, and cross-region flows, respectively, for an interval of 24 h after the shock. The solid line represents the point estimates, and the dashed dotted line represents the 95% confidence interval. The vertical axis represents the deviations of intraday price premia from their steady state measured in EUR/MWh.

between scheduled demand and supply. Compared to the day-ahead market, its trading volume is rather small. In 2018, the Swedish trading volume in the intraday market was only about 4% of the total electricity consumption in Sweden (Swedish Energy Markets Inspectorate 2019).

Because of the geographic transmission constraints, Sweden is divided into four electricity price areas: Luleå (SE1), Sundsvall (SE2), Stockholm (SE3), and Malmö (SE4). Within each area, the electricity price is determined by the demand and supply of electricity and the available transmission capacity. In each of these pricing zones, electricity generation mix is quite different. For example, in the middle part of Sweden (SE3), nuclear power dominates local generation capacity, while in the northern part of Sweden (SE1 and SE2), hydropower is dominating. Most of the electricity production is located in the north of Sweden, while most of the consumption is in the south of the country (Swedish Energy Markets Inspectorate 2014).

3.2. Data and descriptive analysis

We use time series data from the Nord Pool FTP server and the ENTSO-E Transparency Platform for the period 2015–2018.[4] In total, our dataset consists of 23,820 h-day observations. One of our key variables is the intraday price premium, which is defined as the difference between the intraday electricity price and the day-ahead electricity price, measured in euros per megawatt hour (EUR/MWh). The rest of the variables consist of the fundamental drivers of the intraday price premium, which include wind power forecast error, non-wind power forecast error, load (consumption) forecast error, cross-border electricity flow, transmission congestion, and forced outage of nuclear power plants. The majority of these drivers are measured in megawatt hours (MWh), except for transmission congestion, which is measured in megawatts (MW). All variables are available on an hourly basis for each electricity price area, excluding forced outage of nuclear power plants, which is only available for electricity price area SE3 because all Swedish nuclear power plants are located there.

Wind power forecast error is defined as the difference between the actual wind power production and the day-ahead wind power forecast. Similarly, non-wind power forecast error is the difference between the total actual and forecasted power production, excluding production from wind power. Nuclear plants forced outage is defined as the unavailable capacity of nuclear plants caused by an unplanned shutdown. In this paper, we will only consider forced outages since they drive most of the uncertainty in total outages. Using the sum of forced outages and planned outages can bias the estimated effects, since market players can adjust their production plans following public announcements of planned outages far ahead of the intraday market. We aggregate plant-level forced outages into total forced outages for each hour in

[4] We include data from January 24, 2015 to June 2, 2018.

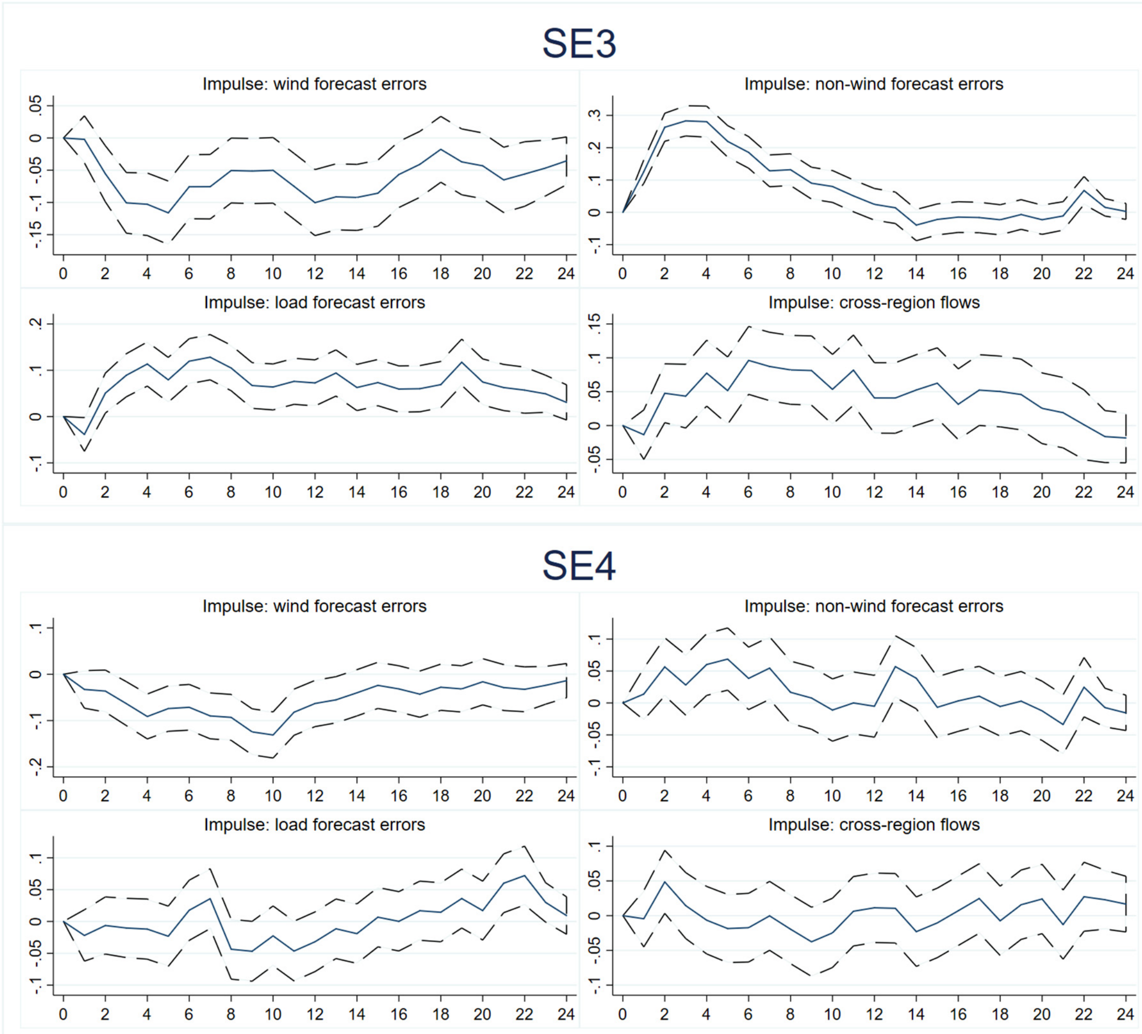

Fig. 5. Generalized impulse response functions of price premia in SE3 and SE4. Notes: Responses of price premia given one standard deviation shock to wind power forecast errors, non-wind forecast errors, load forecast errors, and cross-region flows, respectively, for an interval of 24 h after the shock. The solid line represents the point estimates, and the dashed dotted line represents the 95% confidence interval. The vertical axis represents the deviations of intraday price premia from their steady state measured in EUR/MWh.

electricity price area SE3. For modeling the imbalances caused by market fundamentals from the demand side, we include consumption (load) forecast error, which is measured as the difference between the actual and forecasted (day-ahead scheduled) consumption of electricity. Cross-region intraday flow measures the scheduled intraday electricity net import (import minus export) between a particular price area and its trading areas in the Nordic and Baltic countries.[5] To partly capture the potential congestion of transmission networks, we use the hourly initial capacity available in the intraday market. Data used to aggregate forced outages are obtained from the ENTSO-E Transparency Platform, while the rest of data are obtained from the Nord Pool FTP server.

Table 1 presents summary statistics of our variables for each Swedish electricity price area. A comparison of intraday price premia across all price areas shows that the mean of the hourly price premium is slightly below zero and it ranges from −0.147 to −0.460 EUR/MWh. However, the standard deviation of the price premium is rather large compared to the mean and we can easily reject the hypothesis that the mean value of the price premium is not zero for each Swedish electricity price area. Fig. 1 shows that hourly intraday premia are concentrated around zero in all price areas. According to the sequential electricity market design and current power generation mix in Sweden, intraday price premia could be positive as well as negative, depending on the excess of wind power supply and total demand in the system. A positive price premium indicates that the intraday electricity price is higher than the day-ahead electricity price, and vice versa. The direction of price change between the intraday and day-ahead markets depends on many things. For example, if there is a scarcity of balancing power, positive intraday price premia should appear more often and be larger than negative intraday price premia. However, this is not what we find in our data. Fig. 1 shows that extreme negative intraday price premia seem to happen at least as often as extreme positive intraday price premia, and this is true for almost all price areas. This could imply that there is no scarcity of balancing services in the Swedish electricity system.

Fig. 2 illustrates the distribution of wind power forecast errors. Positive values of wind power forecast errors indicate under-forecast. Conversely, negative values represent over-forecast. Fig. 2 shows that wind power forecast errors are symmetrically distributed around zero, except for a few negative extreme values in SE3, based on which, we draw the conclusion that over-forecast cases and under-forecast cases are balanced in all price areas.

Fig. 3 illustrates the annual total positive and negative wind forecast errors, non-wind forecast errors, and load forecast errors (TWh) in Sweden from 2015 to 2017. Wind power forecast errors and load forecast

[5] There are in total fifteen price areas in the Nordic and Baltic countries, among which there are five regions in Norway (NO1, NO2, NO2, NO4, NO5), four in Sweden (SE1, SE2, SE3, SE4), two in Denmark (DK1,DK2), and the single bidding region countries, Finland (FI), Estonia (EE), Latvia (LV), and Lithuania (LT).

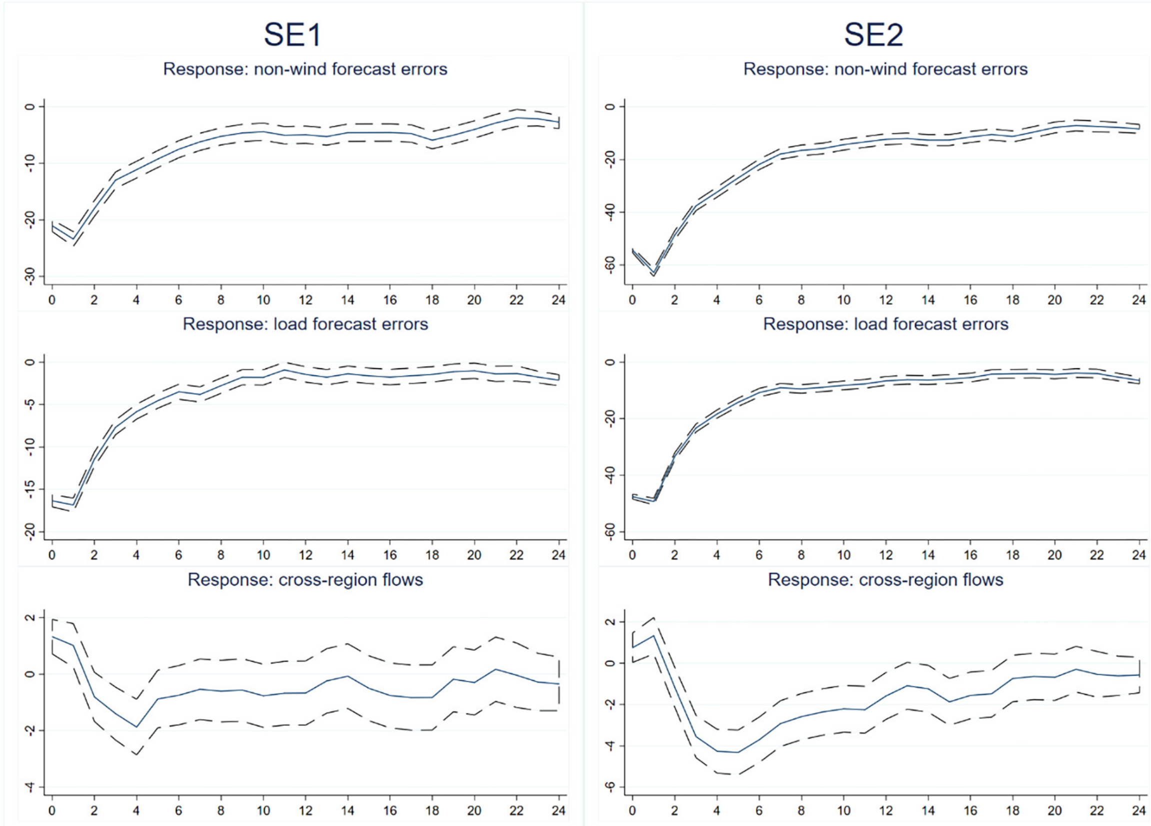

Fig. 6. Responses of market price drivers to wind power forecast errors in SE1 and SE2. *Notes:* Responses of market fundamentals (non-wind power forecast errors, load forecast errors, and cross-region flows), given one standard deviation shock to wind power forecast errors for an interval of 24 h after the shock. The solid line represents the point estimates, and the dashed dotted line represents the 95% confidence interval. The vertical axis represents the deviation of a corresponding response variable from its steady state measured in MWh.

errors are the major sources of the uncertainty that can cause deviations between day-ahead plans and actual power delivery. According to Fig. 3, load forecast errors don't vary much between years, but this is not true for wind forecast errors. There is a significant increase in total negative wind forecast errors (overestimation) over time. In 2017, the total negative wind power forecast error is almost twice the size of the one in 2015. This shows the increasing difficulty to forecast wind power production and potentially the increasing demand for balancing services.

4. Methods

To estimate the interactions of the intraday price premium with its market fundamentals in a dynamic setting, we use the vector autoregressive (VAR) framework. A VAR model is a multivariate and dynamic econometric model based on time series data. It requires that the time series are stationary or transformed into their stationary values. Assuming that the intraday price premium is the equilibrium outcome of the supply and demand for electricity in the intraday market, the major drivers from the supply side are wind power forecast error, non-wind power forecast error, and forced outage. Load forecast error represents the demand side price driver. In addition, intraday cross-region flow is another factor that could drive the price divergence between the intraday and day-ahead markets.

We estimate the following n-lag VAR model:

$$\boldsymbol{y}_{tr} = \boldsymbol{\mu} + \boldsymbol{\Pi}_1 \boldsymbol{y}_{t-1,r} + \boldsymbol{\Pi}_2 \boldsymbol{y}_{t-2,r} + \ldots + \boldsymbol{\Pi}_n \boldsymbol{y}_{t-n,r} + \epsilon_{tr}, \quad (1)$$

where $t = 1, \ldots T, \ r = 1, 2, 3, 4$

$$\boldsymbol{y}_{tr} = (p_{tr}, w_{tr}, nw_{tr}, l_{tr}, f_{tr})\prime \quad (2)$$

$\boldsymbol{y}_{tr}$ is the (5×1) vector of endogenous variables at hour t in electricity price area r. $\boldsymbol{y}_{tr}$ consists of the intraday price premium (p_{tr}), wind power forecast error (w_{tr}), non-wind power forecast error (nw_{tr}), load forecast error (l_{tr}) and cross-region flow (f_{tr}).

We estimate the VAR(n) model separately for each electricity price area r, where n represents the number of lags. In addition to the variables in Eq. (2), forced outage of nuclear plants is added in the analysis of price area SE3. Therefore, for price areas SE1, SE2, and SE4, we estimate the VAR model Eq. (1) with the endogenous variables as described in Eq. (2). For SE3, we estimate the VAR model Eq. (1) with the following endogenous variables:

$$\boldsymbol{y}_{t3} = (p_{t3}, w_{t3}, nw_{t3}, l_{t3}, f_{t3}, o_{t3})' \quad (3)$$

where o_{t3} represents unplanned outage of nuclear power plants. Additionally, the congestion of transmission networks, c_{tr}, is introduced as an additional variable for robustness purposes in all measured VAR models.

The VAR model specified here is based on the assumption of stationarity, which requires the first and second moments of the time series matrix $\boldsymbol{y}_t$ ($E[\boldsymbol{y}_t]$ and $E[\boldsymbol{y}_t \boldsymbol{y}_{t-j}']$) to be independent of t. These conditions imply that each element of $\boldsymbol{y}_t$ is stationary. Consequently, we start by carrying out the stationary tests for each of the variables. Three types of stationary tests are applied here: modified augmented Dickey-Fuller (DF-GLS) test, Phillips and Perron's (PP) test, and Augmented Dickey-Fuller (ADF) test.[6] The null hypothesis for the tests is that a

[6] We apply augmented Dickey-Fuller (ADF) test (without drift and with trend), which is used to obtain the test statistics. Unlike other tests, the number of lagged difference terms needs to be specified in this test. To verify the conclusion drawn from ADF test and check the robustness of test results, we include two improved versions of stationary tests: Phillips and Perron's (PP) and modified augmented Dickey-Fuller (DF-GLS) tests. The PP test is robust to serial correlation by using the Newey and West (1987) heteroscedasticity- and autocorrelation-consistent covariance matrix estimator. The DF-GLS test gives more robust test results compared to ADF and PP tests, since it controls for a linear time trend.

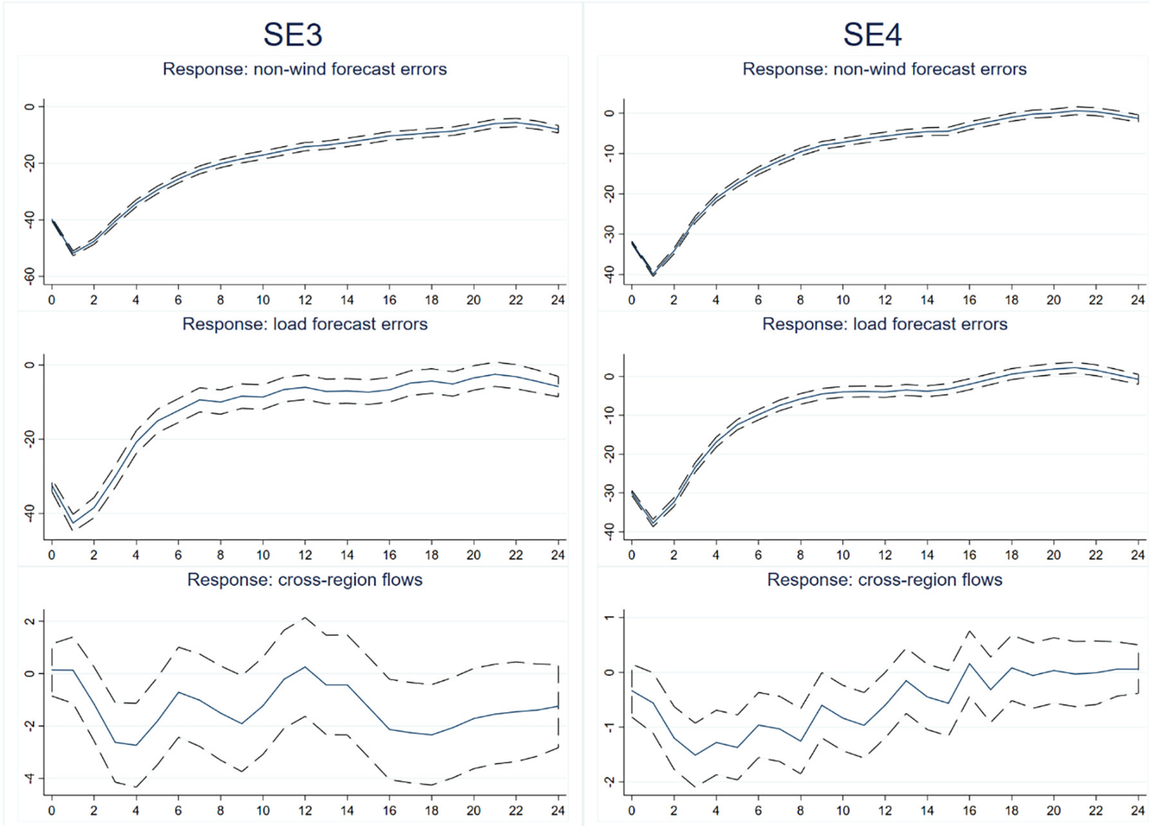

Fig. 7. Responses of market price drivers to wind power forecast errors in SE3 and SE4. Notes: Responses of market fundamentals (non-wind power forecast errors, load forecast errors, and cross-region flows), given one standard deviation shock to wind power forecast errors for an interval of 24 h after the shock. The solid line represents the point estimates, and the dashed dotted line represents the 95% confidence interval. The vertical axis represents the deviation of a corresponding response variable from its steady state measured in MWh.

variable has a unit root, while the alternative hypothesis is that the variable is stationary.

The lag length (n) for the VAR model is determined by using Akaike Information Criterion (AIC) before analyzing the VAR model (Akaike 1973). Granger causality tests and generalized impulse responses are used to summarize the dynamics of VAR estimation results. Intuitively, Granger causality tests are based on the idea that a cause cannot come after the effect (Granger 1969). Granger causality does not imply true causality but the forecasting ability. In our VAR model, if one variable, e.g., wind power forecast error (w_t), fails to Granger cause another variable, e.g., the intraday price premium (p_t), then we cannot reject that all of the coefficients on the lagged values of w_t are zero in the equation for p_t. These linear restrictions can be tested by constructing Wald statistics. The Wald statistics testing the Granger causation of one variable on every other variable are used to summarize interactions between variables.

In addition to Granger causality tests, we apply generalized impulse responses (GIR)[7] to measure directions and magnitudes of the interactions between intraday price premia and market fundamentals. In general, impulse responses show how the response variable changes due to one standard deviation change in the impulse variable. Our primary interest is to investigate the effect of wind power forecast errors on intraday price premia.

5. Results and discussion

5.1. The results of unit root and Granger causality tests

Table A1 in the appendix presents the results of unit root tests. Columns (1,2) show the results of modified augmented Dickey-Fuller (DF-GLS) and Augmented Dickey-Fuller (ADF) tests, respectively. Columns (3, 4) show two test statistics for Phillips and Perron's (PP) tests. Each variable in every price area is treated as one time series. Together, these results indicate that all time series are stationary and integrated of order zero. Table A2 in the Appendix presents the choice of the lag length using Akaike's Information Criterion. The results suggest the choice of 23 lags (i.e., 23 h) is appropriate for each electricity price area.

Table 2 presents the results of Granger causality tests. Panels SE1, SE2, and SE4 are based on the endogenous variables in Eq. 2, and Panel SE3 is based on the endogenous variables in Eq. 3. Column (2) shows the test statistics for Granger causality of the wind power forecast error on all other variables, among which intraday price premium is our primary interest. We conclude that wind power forecast errors Granger cause intraday price premia in all electricity price areas except in SE1, where the absence of any effect in SE1 is likely to be explained by low wind power penetration in the north of Sweden. We also find that non-wind power forecast errors Granger cause intraday price premia in all price areas (see Column (3)). Column (6) presents the test results of another supply-side factor—forced outages of nuclear power plants, which are relevant only for electricity price area SE3. We show that these outages do not Granger cause intraday price premia, instead, they Grager cause cross-region flows. This finding might suggest that electricity shortages caused by an unplanned nuclear plant shutdown are likely to be mitigated by cross-region imports of electricity. This argument is further supported by our results from GIR function analysis (see discussion of Fig. 8 below).

Column (4) of Table 2 focuses on the effects on price premia from the demand side. It shows that load forecast errors Granger cause intraday prices to diverge from day-ahead prices in price areas SE2, SE3, and SE4. The non-significant effect in SE1 is associated with its small electricity demand relative to other price areas in Sweden. Column (5) shows that

[7] GIR was developed by Pesaran and Shin (1998). It is invariant to the ordering of the variables in the VAR model.

Fig. 8. Responses of cross-region flows to nuclear power forced outages in SE3. *Notes:* The solid line represents the point estimates, and the dashed dotted line represents the 95% confidence interval. The vertical axis represents the deviations of cross-region flows from their steady state measured in MWh.

cross-region flows Granger cause the price deviation between the intraday market and the day-ahead market in price areas SE2 and SE3.

Similar to Karanfil and Li's (2017) results, we find that in addition to intraday price premia, wind forecast errors are estimated to Granger cause non-wind forecast errors, load forecast errors and cross-region flows in nearly all electricity price areas (see column (2) in Table 2). We view these results as indicating that uncertainty in wind power production does not only cause the intraday price to diverge from the day-ahead price but also that it is associated with uncertainty in electricity production by other technologies, electricity consumption, and regional electricity trades. In this respect, electricity production and consumption forecast errors can be considered as measures of uncertainty. Uncertainty in wind power production causes generators of other electricity generation technologies to correct their production plans in the intraday market. Similarly, the consumption of electricity also responds to uncertainty in wind power production by adjusting away from the planned consumption levels.

5.2. Impulse responses

Additionally, we apply GIR function analysis[8] to assess the direction of the significant effects which we found by using Granger causality tests. First, we analyze the responses of intraday price premia after one standard deviation shock from each of the market fundamentals. After that, we look at the responses of the market fundamentals after one standard deviation shock from wind power forecast errors.

We begin by showing the responses of intraday price premia for each electricity price area in Figs. 4 and 5. It is evident that one standard deviation shock in wind power forecast errors has a negative effect on intraday price premia during the 24 h after the shock in electricity price areas SE2, SE3, and SE4.[9] These results are consistent with the findings from other studies (see, e.g., Karanfil and Li 2017; Spodniak, 2020) and provide some suggestive evidence on how the intraday market responds to imbalances caused by intermittent wind power. For example, when there is a positive shock in wind power forecast errors, i.e., more wind power is produced than forecasted, owners of wind power plants are willing to sell more electricity in the market, which will push down the electricity price in the intraday market. On the contrary, when the shock is negative, i.e., less wind power is produced than forecasted, owners of wind power plants need to buy electricity to meet their original production plans, which drives up the price in the intraday market.

Furthermore, this negative relationship between wind power forecast errors and intraday price premia might provide some insights on how balancing costs related to intraday trading could depend on the sign of wind power forecast error. When this error is positive (overproduction), intraday premia decrease, which presumably suggests that the correction of this error does not lead to higher balancing costs than in the case of the negative wind power forecast error (underproduction), which is associated with increasing intraday premia. However, from these results we cannot conclude about the actual size of balancing costs related to correction of wind power forecast errors in the intraday market, and whether these errors are fully absorbed in the intraday market.

The effect of non-wind power forecast errors on intraday price premia is found to be positive during the first 24 h in price areas SE1, SE2, and SE3. This result is in line with Karanfil and Li's (2017) study, which finds that forecast errors from combined heat and power (CHP) generation have positive effects on Danish intraday price premia. Generally, CHP generation has higher marginal costs compared to other generation technologies. An unexpected increase in CHP supply, for example, due to ramping-up for the imbalance caused by a sudden drop in wind power supply, will increase the electricity price in the intraday market relative to the electricity price in the day-ahead market. In our paper, non-wind power forecast errors send out the same signals as CHP forecast errors in the case of Denmark. Non-wind power in Sweden consists of nuclear power, hydropower, and other conventional power generation. Given stable (and low) marginal production costs for nuclear and hydropower generation, the variation in marginal production costs for non-wind power is mainly associated with other conventional power technologies, such as CHP. When there is a need for ramping-up, actual non-wind power production will increase, and because of its higher marginal production costs, electricity prices in the intraday market will increase. Therefore, a positive shock in non-wind power production with respect to its forecast increases the divergence between the intraday and day-ahead electricity prices.

The effect of load (consumption) forecast errors on intraday price premia is positive for electricity price area SE3 and slightly positive but very close to zero for other price areas. This positive relationship between consumption forecast errors and intraday price premia is in line with the fundamental electricity price setting model, which implies that when there is a sudden increase in the demand for electricity, the electricity price will increase to reflect the scarcity. Our results suggest that this scarcity is well absorbed in the Swedish intraday market.

Fig. 6 and Fig. 7 illustrate the effects of wind power forecast errors on the other market fundamentals, such as non-wind power forecast errors, load forecast errors, and intraday flows. It is evident that the responses of the same market fundamentals follow the same patterns across all electricity price areas. For instance, one standard deviation shock in wind power forecast errors has a significant and negative impact on non-wind forecast errors across all price areas. Intuitively, when there is more electricity supply from wind power relative to its forecast, the generation of electricity by using other power technologies will be reduced. Consequently, this will lead to lower non-wind forecast errors.

Furthermore, we find that a shock from wind power forecast errors has a negative and significant effect on cross-region flows for all price areas. Intuitively, if wind power production increases more than forecasted in one price area, there will be a lower net import of electricity from other price areas. This is in line with the findings of Karanfil and Li (2017).

Since the relationship between unplanned outages of nuclear power plants and cross-region flows might provide some explanations of why these outages have no effect on intraday price premia (see the results of the Granger causality test in Table 2, column 6), we additionally look at how cross-region flows respond to one standard deviation shock in forced nuclear power outages using GIR function analysis (see Fig. 8).

[8] The interpretations of impulse response are informative only when the impulse variable can Granger cause the response variable (Becketti 2013). For instance, recall that all variables except for forced outages of nuclear power plants Granger cause intraday price premia in SE3, which provides the foundation necessary for further analysis using impulse responses.

[9] For SE1, GIR results are not very informative, since wind power forecast errors do not Granger cause price premia (recall Table 2, Panel SE1).

Table 3
Results of Granger causality tests for robustness check.

Dependent variables	(1) Intraday price premia	(2) Wind power f.e.	(3) Non-wind power f.e.	(4) Load f.e.	(5) Cross-region flows	(6) Congestions	(7) Forced outages
SE1							
Intraday price premia	n/a	27.93	183.4***	14.63	28.75	60.70***	n/a
Wind power f.e.	26.88	n/a	26.54	60.42***	22.68	77.33***	n/a
Non-wind power f.e.	77.17***	339.7***	n/a	46.30***	38.89**	214.9***	n/a
Load f.e.	22.00	654.60***	29.11	n/a	20.87	239.9***	n/a
Cross-region flows	34.31*	47.62***	31.98	35.72**	n/a	34.18*	n/a
Congestions	31.83	92.08***	702.2***	550.5***	107.5***	n/a	n/a
SE2							
Intraday price premia	n/a	64.12***	245.2***	28.47	35.63**	35.47**	n/a
Wind power f.e.	17.38	n/a	20.04	78.36***	22.57	55.91***	n/a
Non-wind power f.e.	61.88***	240.7***	n/a	275.7***	37.35**	125.2***	n/a
Load f.e.	31.06	1013***	140.4***	n/a	29.22	183.4***	n/a
Cross-region flows	36.64**	96.07***	104.3***	55.67***	n/a	91.85***	n/a
Congestions	28.29	121.9***	210.3***	274.1***	105.6***	n/a	n/a
SE3							
Intraday price premia	n/a	134.9***	218.2***	71.53***	54.53***	49.82***	23.13
Wind power f.e.	14.93	n/a	37.46**	61.18***	28.14	120.1***	20.70
Non-wind power f.e.	59.61***	1845***	n/a	112.4***	60.64***	102.3***	21.93
Load f.e.	49.51***	197.7***	45.75***	n/a	33.19*	411.8***	32.68*
Cross-region flows	84.62***	185.6***	301.1***	129.6***	n/a	55.15***	85.10***
Congestions	33.79*	132.8***	145.1***	306.1***	156.9***	n/a	16.44
Forced outage	22.12	33.09*	13.32	20.20	86.08***	15.30	n/a
SE4							
Intraday price premia	n/a	47.52***	39.44**	35.02*	22.64	28.35	n/a
Wind power f.e.	20.57	n/a	25.27	23.83	17.29	163.2***	n/a
Non-wind power f.e.	23.05	1071***	n/a	23.66	27.11	127.1***	n/a
Load f.e.	31.77	307.8***	23.94	n/a	23.72	532.5***	n/a
Cross-region flows	39.87**	33.14*	20.15	27.91	n/a	103.0***	n/a
Congestion	23.79	31.06	24.83	248.5***	133.7***	n/a	n/a

Notes: *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$. The results are Wald statistics and follow χ^2 distribution.
Wind power f.e. refers to wind power forecast errors.
Non-wind power f.e. refers to non-wind power forecast error, which is the total production error excluding wind power production error. Load f.e. refers to load forecast errors.

It shows that the sudden change in these outages is positively correlated with cross-region flows. This result might suggest that when nuclear power plants suddenly cut down production because of unplanned outages, one way to balance the electricity market in SE3 is to increase the import of electricity from other regions.

5.3. Robustness test

In the baseline estimation, we estimate the effects of wind power forecast errors on intraday price premia based on the VAR models using non-wind power forecast errors, load forecast errors, forced outages of nuclear power plants, and cross-region flows (net import). We perform a robustness check where we include a proxy for network congestion as an additional variable. The results of unit root tests are presented in Table 1, which show that the congestion variable is stationary in all price areas. Besides, the choice of the lag length is 23 h based on the results of Akaike's Information Criterion as reported in Table A3 in the Appendix.

Table 3 presents the results of the Granger causality tests. Overall, the test statistics of robustness exercise are consistent with the ones from the baseline estimation (see Table 2). Price divergence between the intraday and day-ahead markets can more or less be explained by wind and non-wind power forecast errors, load forecast errors, forced outages, cross-region flows and congestions in each price area. As before, wind power forecast errors Granger cause intraday price premia in electricity price areas SE2, SE3, and SE4. Non-wind power forecast errors are estimated to have impacts on intraday price premia in all price areas. Load forecast errors and cross-region flows also show evidence of having impacts on intraday price premia in the SE3 price area. Again, unplanned nuclear power plant outages have no impact on intraday price premia, but the effect is significant on cross-region flows. Based on the results as reported in column (6) of Table 3, we can conclude that congestion affects intraday price premia in all price areas except SE4, and it Granger causes all other intraday market determinants across all price areas.

The GIR analysis, which is based on the extended model, provides additional evidence on the robustness of the effects of the major price drivers on intraday price premia. Figs. B1–B4 in the Appendix present the effects of the main price drivers on intraday price premia in price areas SE1–SE4 by using GIR analysis. We can conclude that the effects of the main price drivers on the divergence between the electricity price in the intraday market and the electricity price in the day-ahead market have the same sign in the robustness exercise as in the baseline model in each price area. For instance, wind forecast errors have significant and negative impacts on intraday price premia, and non-wind forecast errors have significant and positive instantaneous effects on intraday price premia in most price areas except for SE4.

In addition, we illustrate the effect of congestion on intraday price premia. We find that a positive shock from congestion, which is equivalent to an increase in the hourly initial capacity available on the intraday market, will reduce intraday price premia for the first six hours in price areas SE1 and SE2, while it will increase intraday price premia instantaneously in price area SE3 and will have no effect in SE4.[10] The results on congestion indicate that the initial capacity available in the intraday market can partly explain the price divergence between intraday and day-ahead markets. This result, along with results from other price drivers, suggests that the Swedish intraday market is sending price signals to incentivize electricity producers and consumers to participate in this market to reduce imbalances.

[10] Column (6) in Table 3 shows that congestion does not affect price premia in price area SE4. Thus, the GIR result for congestion in Figure B4 of the Appendix is not informative.

6. Conclusions

This paper uses detailed Swedish data to provide a case study of the functioning of intraday markets. As shares of intermittent renewable energy are getting substantial in Sweden, the intraday market becomes more essential in providing balancing services and flexibility in the system. We use the approach suggested by Karanfil and Li (2017) to assess the importance of the Swedish intraday market by studying the causality between price signals and market fundamentals. By doing so, we are able to investigate whether the intraday market rewards its participants, as it should if it is efficient. To understand this, we have looked at price formation in the intraday market and its relation to the price formation in the day-ahead market. We have analyzed, imbalances caused by wind power and other power-generating technologies, and the interconnection system.

Similar to Karanfil and Li's findings, our results suggest that several market fundamentals— wind power forecast errors, non-wind power forecast errors, load forecast errors, and cross-region flows—could explain the divergence between electricity prices in the Swedish intraday and day-ahead markets. Seemingly, wind forecast errors are "corrected" by joint responses from cross-region intraday power flows and adjustments of non-wind power generation and electricity consumption. These results are robust to adding the congestion as an additional price driver in our empirical models.

One of our key findings is that the relationships between wind power forecast errors and intraday price premia are found to be negative in three out of four Swedish electricity price areas (SE2, SE3, and SE4). This estimated negative relationship has two implications. First, it indicates that when the actual wind power production diverges from its forecast, the price of electricity in the intraday market is going to incorporate this information and be differentiated from the day-ahead market price. In particular, when the actual wind power production is larger than its forecast, market participants are willing to pay a lower electricity price on the intraday market compared to the price of electricity on the day-ahead market and vice versa. Second, it provides some insights on how the costs of balancing in the intraday market could depend on the sign of wind power forecast errors. Intraday price premia can be considered as balancing costs for electricity producers and consumers who participate in the intraday market. Our results suggest that a positive wind power forecast error, which occurs when there is an overproduction of wind power, may lead to lower intraday price premia. Conversely, a shortfall of wind power (negative wind forecast error) is expected to increase intraday price premia. Thus, we can imply that the costs of balancing related to trading in the intraday market might be smaller when the value of wind power forecast error is positive instead of being negative. However, from these results we cannot conclude about the actual size of balancing costs related to correction of wind power forecast errors in the intraday market, and whether these errors are fully absorbed in the intraday market. Furthermore, we have found that unplanned (forced) outages of the Swedish nuclear power plants, which occur only in price area SE3, have no effect on intraday price premia. The possible explanation of this result is that imbalances caused by these outages are mediated by electricity flows from other price areas to price area SE3, which is the best-connected price area in Sweden. Consequently, this type of outage is less likely to influence electricity prices in the Swedish intraday market.

Together, our results shed light on the Swedish intraday market's role in accommodating intermittent renewable energy. Price signals from the intraday market adequately incentivize trading decisions to reduce imbalances in scheduled production or consumption. That is to say, deviations from intermittent power generation are absorbed by other market fundamentals, and intraday price premia respond to these deviations and send out correct price signals based on scarcity pricing. Suppose a rapid growth of wind power in Sweden will continue, as well as a likely increasing number of participants on the demand side, intraday markets will play more important roles than in the past. Hence, we see a need for future research that tries to better understand the functioning of intraday markets by analyzing their microstructure in more detail, which could explain how we can increase their popularity among smaller market participants on the demand and supply sides.

Credit author statement

All authors participated equally in every part of the research process.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.eneco.2021.105159.

Appendix

Table A1
Results of unit root tests.

	(1) DF-GLS	(2) ADF	(3) PP Z_τ	(4) PP Z_ρ
Price premium				
SE1	−53.58***	−52.09***	−84.23***	−12,197***
SE2	−61.66***	−53.49***	−79.86***	−11,018***
SE3	−59.08***	−51.05***	−73.80***	−9552***
SE4	−69.42***	−57.19***	−95.08***	−14,962***
Wind power forecast error				
SE1	−52.82***	−47.32***	−46.00***	−3915***
SE2	−50.65***	−43.67***	−42.00***	−3297***
SE3	−38.23***	−30.35***	−30.33***	−1783***
SE4	−55.05***	−39.76***	−38.93***	−2870***

Table A1 (*continued*)

	(1) DF-GLS	(2) ADF	(3) PP Z_τ	(4) PP Z_ρ
Non-wind power forecast error				
SE1	−49.75***	−65.74***	−68.10***	−8186***
SE2	−47.05***	−47.40***	−44.28***	−3646***
SE3	−38.65***	−34.77***	−28.78***	−1593***
SE4	−49.19***	−38.51***	−36.89***	−2589***
Load forecast error				
SE1	−57.12***	−82.68***	−95.79***	−15,912***
SE2	−41.55***	−52.94***	−53.57***	−5259***
SE3	−39.20***	−43.27***	−42.55***	−3391***
SE4	−41.41***	−39.37***	−37.85***	−2708***
Flow				
SE1	−42.24***	−46.61***	−47.05***	−4124***
SE2	−49.42***	−59.52***	−61.68***	−6842***
SE3	−40.59***	−45.96***	−46.62***	−4059***
SE4	−72.44***	−86.43***	−91.75***	−13,895***
Congestion				
SE1	−37.64***	−28.14***	−31.37***	−1921***
SE2	−31.02***	−22.77***	−26.89***	−1427***
SE3	−31.53***	−19.60***	−23.94***	−1138***
SE4	−34.79***	−26.58***	−27.15***	−1444***
Outage				
Forced outage SE3	−56.04***	−60.58***	−60.67***	−6532***

Notes: *** represents 1% significance level. DF-GLS: Dickey-Fuller test modified by Elliot, Rothenberg, and Stock (1996). ADF: augmented Dickey-Fuller test with the trend and no lags. PP: Phillips-Perron tests with two statistics. ADF tests yield the same results when we include the different numbers of lags up to 10. DF_GLS already include lags. PP has no lags.

Table A2
Lag length selection for the baseline models.

lag	SE1	SE2	SE3	SE4
0	51.972	55.375	65.997	51.385
1	47.565	49.906	57.312	45.007
2	47.434	49.794	57.164	44.860
3	47.392	49.749	57.109	44.843
4	47.383	49.743	57.063	44.840
5	47.377	49.737	57.041	44.839
6	47.374	49.730	57.027	44.838
7	47.372	49.724	57.014	44.798
8	47.369	49.721	57.010	44.797
9	47.366	49.719	57.004	44.797
10	47.362	49.718	57.000	44.788
11	47.361	49.717	56.999	44.787
12	47.361	49.716	56.995	44.786
13	47.36	49.714	56.990	44.779
14	47.359	49.711	56.989	44.777
15	47.359	49.711	56.987	44.775
16	47.358	49.710	56.985	44.769
17	47.358	49.708	56.982	44.766
18	47.358	49.706	56.979	44.762
19	47.357	49.703	56.977	44.755
20	47.355	49.700	56.970	44.749
21	47.353	49.696	56.961	44.740
22	47.348	49.687	56.951	44.729
23	47.344*	49.679*	56.939*	44.718*

Notes: * indicates the optimal lag. The selection is based on Akaike Information Criterion (AIC) and conducted separately for each electricity price area. Endogenous variables in eq. (2) are used for the bidding areas SE1, SE2, and SE4. Endogenous variables in eq. (3) are used for the bidding area SE3.

Table A3
Lag length selection for models in robustness exercise.

lag	SE1	SE2	SE3	SE4
0	68.533	72.775	83.805	68.214
1	61.81	64.638	72.141	59.402
2	61.341	64.298	71.618	59.114
3	61.296	64.235	71.561	59.092
4	61.285	64.226	71.515	59.088
5	61.278	64.217	71.49	59.086
6	61.268	64.203	71.471	59.084
7	61.243	64.183	71.444	59.029

(continued on next page)

Table A3 (*continued*)

lag	SE1	SE2	SE3	SE4
8	61.236	64.175	71.436	59.023
9	61.233	64.173	71.429	59.022
10	61.229	64.171	71.424	59.014
11	61.227	64.168	71.422	59.012
12	61.225	64.165	71.418	59.011
13	61.224	64.163	71.409	59.001
14	61.218	64.157	71.401	58.996
15	61.207	64.149	71.386	58.99
16	61.187	64.136	71.361	58.966
17	61.157	64.117	71.332	58.946
18	61.112	64.095	71.303	58.918
19	61.078	64.082	71.292	58.895
20	61.071	64.077	71.281	58.887
21	61.059	64.073	71.268	58.873
22	61.044	64.065	71.258	58.859
23	61.038*	64.051*	71.239*	58.846*

Notes: * indicates the optimal lag. The selection is based on Akaike Information Criterion (AIC) and conducted separately for each electricity price area. Endogenous variables in eq. (2) and the additional variable Congestions are used for the bidding areas SE1, SE2, and SE4. Endogenous variables in eq. (3) and the additional variable Congestions are used for the bidding area SE3.

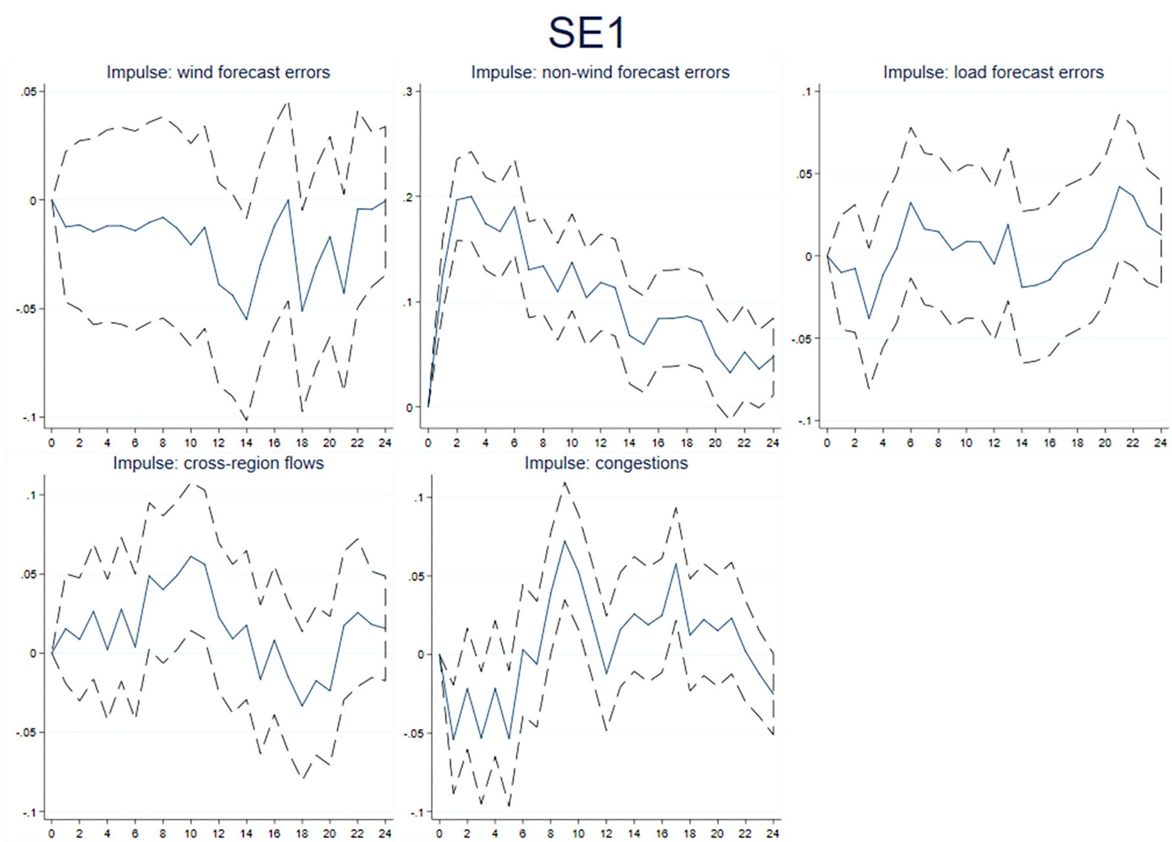

Fig. B1. Robustness check—Generalized Impulse Response of price premia in SE1. *Notes:* Responses of price premia, given one standard deviation shock to wind power forecast errors, non-wind forecast errors, load forecast errors, cross-region flows, and congestions, respectively, for an interval of 24 h after the shock. The solid line represents the point estimates, and the dashed dotted line represents the 95% confidence interval. The vertical axis represents the deviations of intraday price premia from their steady state measured in EUR/MWh.

Fig. B2. Robustness check—Generalized Impulse Response of price premium in SE2. *Notes:* Responses of price premia, given one standard deviation shock to wind power forecast errors, non-wind forecast errors, load forecast errors, cross-region flows, and congestions, respectively, for an interval of 24 h after the shock. The solid line represents the point estimates, and the dashed dotted line represents the 95% confidence interval. The vertical axis represents the deviations of intraday price premia from their steady state measured in EUR/MWh.

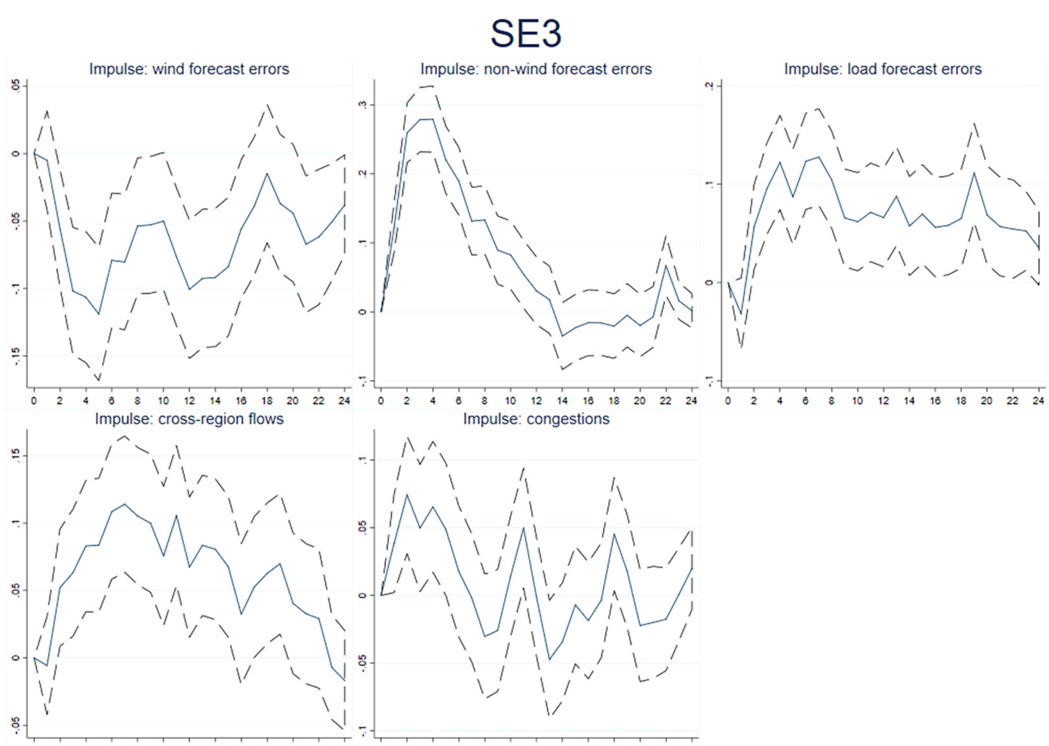

Fig. B3. Robustness check—Generalized Impulse Response of price premium in SE3. *Notes:* Responses of price premia, given one standard deviation shock to wind power forecast errors, non-wind forecast errors, load forecast errors, cross-region flows, and congestions, respectively, for an interval of 24 h after the shock. The solid line represents the point estimates, and the dashed dotted line represents the 95% confidence interval. The vertical axis represents the deviations of intraday price premia from their steady state measured in EUR/MWh.

Fig. B4. Robustness check—Generalized Impulse Response of price premium in SE4. *Notes: Responses of price premia, given one standard deviation shock to wind power forecast errors, non-wind forecast errors, load forecast errors, cross-region flows, and congestions, respectively, for an interval of 24 h after the shock. The solid line represents the point estimates, and the dashed dotted line represents the 95% confidence interval. The vertical axis represents the deviations of intraday price premia from their steady state measured in EUR/MWh.*

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