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TRADING VOLUMES IN INTRADAY MARKETS - THEORETICAL REFERENCE MODEL AND EMPIRICAL OBSERVATIONS IN SELECTED EUROPEAN MARKETS

by

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and

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Abstract

This paper presents an analytical benchmark model for national intraday adjustment needs under consideration of fundamental drivers, market concentration and portfolio internal netting. The benchmark model is used to calculate the intraday market outcomes if (i) large and small players as well as transmissions operators trade and (ii) only large players and transmission system operators trade. Transaction costs may prevent the competitive fringe from intraday market participation. The theoretical national intraday trading volumes are calculated with market data from three European countries with auction-based intraday markets (Italy, Portugal, Spain) and four countries with continuous intraday markets (Denmark, France, Germany, United Kingdom). The model results allow two main conclusions: The competitive fringe is not trading on exchanges in Denmark and France but in Germany. The second conclusion is that the high observed volumes in auction-based intraday markets cannot be explained by fundamentals or the auction-based design but are mainly caused by market peculiarities. The same result applies to the UK.

Keywords: Renewables market integration, Liquidity modeling, continuous and auction-based intraday markets.

JEL-Classification : L94, Q41

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1 Introduction

To meet the EU 2020 targets on renewable energy, the electricity production from renewables has to grow from a European average of 19 % in 2010 to 34 % in 2020 (European Commission, 2011). Becker et al. (2014) as well as others note that this target will be reached by an increase in the electricity production from variable renewable energy sources (VRES) such as wind and solar photovoltaic power. Hiroux and Saguan (2010) and Scharff et al. (2013) conclude that an effective short-term electricity market design is a prerequisite for the cost-minimal market integration of VRES. With a rapid increase in the electricity production from VRES, intraday markets also gain importance (Henriot and Glachant, 2013 or Weber, 2010).[1]

This article focuses on the analysis of trading volumes in European intraday markets for electricity. Trading volumes are an important indicator for liquidity (cf. Hagemann and Weber 2013) and are therefore indicators of information and allocation efficiency in any market (Sarr and Lybek, 2002). In Europe, the intraday markets are part of a sequence of separated but interrelated electricity markets (Grimm et al, 2008). Intraday markets enable generators to adjust their production schedules after the day-ahead gate closure. VRES owners forecast the electricity production for the next day and sell the expected production in the day-ahead market. Trading commences in intraday markets after the gate closure of the day-ahead market and continues until shortly before physical delivery. The forecast quality of wind (Roon and Wagner, 2009) and solar power (Schierenbeck et al., 2010) production improves significantly from the day-ahead to real time and makes short-term adjustments necessary to keep supply and demand in balance. With intraday gate closures close to real time, market participants may efficiently self-balance their VRES intraday deviations. This may significantly reduce the reserve power capacity requirements and costs in the balancing market so that fewer power plants have to operate in an inefficient partial load mode in order to deliver balancing services (Müsgens, 2006).

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[1] The integration of VRES into electricity markets has many other consequences. In Germany, short run production overcapacities due to the large increase in installed VRES power plants has led to falling wholesale electricity prices, which in turn has reduced investment incentives for new conventional power plants or has led to yield reductions of existing power plants (European Association of the Electricity Industry, 2010 or Traber and Kemfert, 2011). Furthermore, the probability of grid congestions (Winkler and Altmann, 2012) and requirements for balancing reserves may increase (Vandezande et al., 2010).

Shortly before physical delivery, the transmission system operators take over responsibility for all remaining system imbalances and ensure system security through the activation of control energy (Haucap et al. 2014). In Scandinavian countries, the Nord Pool Spot operates a regulating market where the TSO may buy or sell fast reserves up to 10 minutes before delivery (Matevosyan and Söder, 2006).[2]

The target of this paper is to develop a reference model for the trading volumes to be expected in different European intraday markets. This allows assessing whether the market designs applied in intraday markets across Europe are effectively inducing the trading volume needed to balance short variations, e.g., from VRES. The benchmark is derived using an analytical model that includes the major fundamental drivers of intraday trading, such as VRES forecast errors and power plant outages (Borggrefe and Neuhoff, 2011; Hagemann and Weber, 2013).

The empirical analysis is based on publicly observable intraday volumes that are traded on Danish, French, German, Italian, Portuguese, Spanish and British power exchanges. The model is tested on a data set from 2012 that includes countries with continuous and auction-based intraday markets. While the model performs well in predicting the trading volumes in Denmark, France and Germany, it greatly underestimates the trading volumes in Italy, Portugal, Spain and the UK. The empirical results are discussed with respect to further influences on intraday liquidity that are not considered in the model.

This paper contributes to the present literature in several ways. In a theoretical perspective, the analytical model captures the impact of fundamental factors such as VRES on intraday trading, also taking into consideration market concentration, portfolio internal balancing options and the national RES support scheme currently in place. These interdependencies have not been analyzed yet, but the present work extends the analyses from at least three earlier papers. Weber (2010) develops a simple analytical model for calculating the theoretical intraday trading volume under consideration of fundamental factors but does not consider market concentration or portfolio internal balancing options. Borggrefe and Neuhoff (2011) present the intraday market as an alternative to balancing markets in order to cope with an increasing demand for reserves and responses due to the increased production from VRES. Henriot (2014) presents an analytical approach focusing on two other influences on intraday trading and related costs, namely, forecasting accuracy and system flexibility. Among other insights, he reveals that trade-offs between continuous and auction-based intraday market designs exist, and he

[2] A more detailed description of the German electricity market design can be found in Pape et al. (2015).

concludes that discrete auctions may lead to inefficiencies due to lost trading opportunities. Empirically, the paper provides insights regarding to what extent existing intraday markets across Europe attain the theoretical benchmark. The developed approach could be used further to analyze the impact of future changes in VRES penetration, market design or market concentration on intraday trading activity.

The paper is organized as follows. In the next section, the main alternatives for intraday market design, namely, continuous vs. auction-based trading, are briefly reviewed, and key characteristics of existing European intraday markets are summarized. Section 3 develops an analytical model of intraday trading starting with a description of key drivers of intraday trading. Then, a formal derivation of the model is given followed by a discussion of further influences on intraday trading that are not considered in the model. Section 4 is devoted to the empirical analysis, including an overview of the data sources, empirical results and a discussion of the results. Section 5 concludes, elaborates on the limitations of the present paper and provides indications for further research.

2 Intraday market designs in Europe

The intraday market allows market participants to eliminate any imbalance in their portfolio (balance group) after the day-ahead gate closure and before physical delivery. While European day-ahead markets are widely harmonized,[3] two different exchange-based organizations can be distinguished for intraday markets: the auction-based and continuous intraday market designs.[4] Continuous intraday markets consist of a limit order book that stores incoming buy orders on the bid side and sell orders on the offer or ask side. Trades are executed as soon as the bid price meets or exceeds the ask price. During the trading period for a certain delivery period, the market equilibrium may change quite rapidly, depending on the arrival of information about intraday deviations from the day-ahead planning. This stretching of liquidity over the whole trading period can make the intraday market price volatile and nontransparent.[5] Continuous markets allow 24/7 trading and thus offer immediacy in the sense that market participants may

[3] The day-ahead market is organized as an auction-based market where market participants may trade electricity that goes into delivery on the next day. The day-ahead gate closures in European day-ahead markets are between 9.15 and 12:00 am on the day before delivery. In the UK, the APX UK exchange complemented the existing continuous day-ahead market by a day-ahead auction in 2011.

[4] In addition to anonymous exchange-based trading, market participants may also trade directly with each other.

[5] Hagemann and Weber (2013) compute an average of 24.65 EUR/MWh for the difference between the highest and lowest trade price for one delivery hour in the German intraday market in 2010 and 2011.

trade imbalances as soon as they appear. Hence, new information can be used continuously, which is especially important for the efficient integration of VRES. In European continuous intraday markets, the gate closures of electronic exchanges are 45 to 60 minutes before physical delivery (Table 1).

In auction-based intraday markets, market participants may bid into the next auction for several hours before the gate closure. After a gate closure, aggregated demand and supply curves are matched once. Therefore, auction-based intraday markets do not allow immediate self-balancing. A market participant who wants to trade has to wait until the next auction is carried out. In contrast to continuous intraday markets, the auction-based intraday market is cleared once and shows one equilibrium price and the quantity for each delivery period. This increases price transparency and decreases direct liquidity costs such as bid-ask spread costs, price impact costs or search and delay costs (Amihud and Mendelson, 1991). The gate closures in auction-based intraday markets are between 135 and 690 minutes before delivery, as indicated in Table 1.[6] Intraday imbalances in a specific delivery period that occur after the gate closure for that specific delivery period cannot be traded in the intraday market which may lead to inefficiencies, e.g. portfolio internal balancing with inefficient resources or usage of balancing energy.

[6] Because the electricity markets are constantly developing, market rules may change from time to time. The figures in Table 1 were gathered in December 2013.

Table 1: Intraday markets in selected European countries, including national consumption and intraday trading data from 2012

Country	Grid operator	Intraday exchange	Intraday gate closure ahead of delivery (min)	Intraday market design	National consumption (TWh)	Intraday trading Volume (TWh)	Share of national consumption (%)
Denmark	Energinet.dk	Elbas	60	Continuous	31.4	0.45	3.4
France	Réseau de Transport d'Electricité	Epex Spot	45	Continuous	434.1	2.2	0.5
Germany	50Hertz, Amprion, Tennet, TransnetBW	Epex Spot	45	Continuous	525.8	15.8	3.0
UK	National Grid	APX Power UK	60	Continuous	317.6	10.4	3.3
Italy	Terna	Gestore dei Mercati Energetici	255 – 690	Auction	296.7	25.1	8.5
Portugal	Redes Energéticas Nacionais	OMEL	135	Auction	46.2	5.2	11.3
Spain	Red Eléctrica de España	OMEL	135	Auction	240.2	46.8	19.5

Sources: Eurostat (2013), Websites of the grid operators and intraday exchanges.

3 Methodology

3.1 General considerations

Fundamental influences

As indicated by Borggrefe and Neuhoff (2011), Hagemann and Weber (2013) and Weber (2010), trading in the intraday market is driven by random information updates and a fundamental supply-stack or merit-order model.

Random information updates about intraday deviations from the day-ahead planning induce a need for an adjustment of schedules. In an efficient decentralized market design, market participants will always try to self balance unforeseen deviations from the day-ahead planning in order to avoid the costly usage of flexible resources in real-time balancing. According to Hagemann (2015), important stochastic factors impacting intraday trading are unplanned power plant outages and forecast errors of wind power, solar power and load. Correspondingly, Table 2 gives an overview of the installed conventional, wind and solar power capacities and peak load in the countries considered.

The adjustment of intraday schedules induces a demand for flexibility. This flexibility can be provided by controllable generating units. Upward flexibility for intraday adjustments is provided by power plants that may increase their scheduled output and have marginal costs above the day-ahead price. Henriot (2014) states that the fundamental intraday supply curve has a steeper slope than the day-ahead supply curve due to limited short term flexibility of base and mid load power plants. Supply of downward flexibility stems from operating power plants with downward ramping capacities. At intraday prices below the day-ahead price, power plant operators may buy electricity in the intraday market and correspondingly reduce the scheduled power output of a flexible power plant. This way, operators will realize a profit margin that equals the difference between the marginal costs of the flexible power plant and the intraday purchase price of the electricity.

Table 2: Overview of fundamental market data and drivers for intraday trading in 2012

Country	Installed conventional capacity MW	Installed wind capacity MW	Installed solar capacity MW	Maximum Load MW
Denmark	7984	4162	394	6051
France	96430	7564	4003	102098
Germany	99745	31308	32411	74475
UK	78298	8445	1829	55614
Italy	80775	8144	16361	54098
Portugal	10082	4525	244	8554
Spain	61421	22796	5166	42813

Sources: ENTSO-E (2013), European Photovoltaic Industry Association (2013), The European Wind Energy Association (2013), U.S. Energy Information Administration (2015).

Portfolio effects in generation portfolios

When generating companies need to make intraday adjustments due to unplanned power plant outages or forecast errors of directly marketed wind or solar power production, they have two options for self-balancing. Notably, they may use controllable generating units within their portfolios or trade externally in the intraday market.[7] In a system perspective, it is cost minimizing if an intraday buying need is satisfied by the next unused power plant in the supply-stack. Correspondingly, a selling need should be matched by the most expensive power plant that is able to reduce its scheduled output. The probability that the marginal power plant that

[7] A presumption for internal balancing is that the affected power plants are within the same grid zone or that no grid congestions between different zones limit physical power exchanges. This assumption is justifiable for France, Germany, the UK, Portugal and Spain and is strongly justified for the zonal systems of Denmark and Italy.

ensures cost optimal self-balancing is portfolio internal is dependent on the player’s market share. Furthermore, the probability that stochastic intraday imbalances within the portfolio of a market participant compensate each other also increases with the player´s market size. In other words, the more wind and solar power plants and controllable generation units are concentrated within one portfolio, the lower the probability that occurring deviations are traded externally in the intraday market. Hagemann and Weber (2013) and Hagemann (2015) find empirical evidence for the German intraday market that power plant owners trade only a small fraction of their outages in the intraday market (approximately 13 %).

To measure market concentration, the Herfindahl-Hirschman index (HHI, Hirschman, 1945 and Herfindahl, 1950) is widely used. The HHI equals the sum of the squared market share of each firm in a market. Table 3 indicates the market share of the largest company and the HHI for the selected markets. The market share is thereby defined as each player´s capacity of conventional, wind and solar power plants in relation to the total installed capacity of those power plants in each country in 2012.[8] The European Commission and the U.S. Department of Justice assess markets with HHI values below 1000 as competitive. Markets with HHI-values between 1000 and 1800 are moderately concentrated and HHI values above 1800 indicate a high market concentration. According to these benchmark values, the UK is a competitive market, while Denmark, Germany, Italy and Spain are moderately concentrated. Portugal has a high and France a very high market concentration (Table 3).

Table 3: Overview of indicators for market concentration and the national RES support instruments in 2012.

Country	Main generating companies	Market share largest generator	HHI	RES support schemes
Denmark	2	37	1492	FIP
France	1	86	6154	FIT, TEN
Germany	4	28	1376	FIT, FIP
UK	7	52[a]	954	FIT, TGC
Italy	3	26	1079	FIT, FIP, TEN, TGC
Portugal	4	37	1899	FIT
Spain	4	24	1244	FIT, FIP

[8] This approach abstracts from the fact that the power plant technologies have different full load hours throughout the year. Theoretically, another approach is to calculate the HHI values based on the annual power production of each portfolio in relation to the total power production in one year.

Sources: Eurostat (2014), German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (2014), Herfindahl-Hirschman Index: Own calculation with data from various sources. (a) According to the business report of EDF for 2012 (EDF, 2013), the company owned 14283 MW capacity in the UK in 2012, which equals a market share of 18 %. This figure will be used for further calculation within this paper.

VRES balancing responsibility according to installed support instruments

Although Kitzing et al. (2012) conclude that European renewables support schemes are at least partly converging, different support instruments are currently implemented (Table 3). Following the classification of the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (2014), four major support instruments may be distinguished: feed-in tariffs (FIT), feed-in premia (FIP), tenders (TND) and quota obligations with tradable green certificates (TGC).[9] These renewable support instruments imply a different assignment of the balancing responsibility for VRES. Consequently, the owners of the VRES are also exposed to a different level of market risk. FIT (and TND combined with FIT) can be classified among the low-risk support schemes because the marketing and balancing responsibility is taken over by a distribution grid or transmission grid operator (Battle et al., 2012). The grid operators are obliged to pay a guaranteed price to the owner of wind or solar power plants (Mitchell et al., 2006). Furthermore, grid operators do not control conventional power plants (except during real-time balancing); hence, portfolio internal balancing is not possible. If wind, solar and load forecast errors are not offsetting each other, the TSOs are obliged to trade externally in the intraday market in order to balance their intraday deviations. Thus, in countries with low-risk support schemes, intraday trading volumes can be raised by the trading of the TSOs.

In contrast to low-risk support schemes, high-risk support schemes, such as the FIP (as well as target-price FIT, TND combined with FIP and quota obligations with TGC), attribute the marketing and balancing risks to the owners/operators of wind and solar power plants (Klessmann et al., 2008).

The dominant market participants may use controllable generation units within their portfolios to balance intraday forecast errors of wind and solar power and trade less forecast errors externally in the intraday market. Forecast errors of VRES power plants that are marketed by small market participants may not be traded in the intraday market at all but may be left to being

[9] Furthermore, supplementary support instruments such as investment grants, fiscal measures or financing support are granted in many European countries but are not relevant for the further analysis. For a detailed description of each support instrument, consider Kitzing et al. (2012).

balanced by TSOs. This is because the costs of setting up and operating the infrastructure for the intraday management of a small VRES portfolio may outweigh the benefits from reduced balancing costs. In conclusion, a lower share of VRES forecast errors may be traded in countries with high-risk support schemes because the RES-owners either have the option to use controllable generation for internal self-balancing or are small and do not manage forecast errors actively in the intraday market.

3.2 Model specification

Adjustment demand for a single stochastic source of deviations

Consider a source *i* of deviations between day-ahead schedules and intraday realizations (e.g., solar forecast errors, wind forecast errors). We write ΔX_i as the aggregate deviation stemming from source *i*. We start from the following assumptions:

1. There are *j* (physical) players in an electricity market.
2. Each player *j* has a market share $m_{i,j}$ in activity *i*.
3. His contribution to the deviations is proportional to his share in the market (i.e., no systematic differences in forecast performance among players).
4. There are two types of forecast errors: one is systematic, η_i, and is perfectly correlated for all players; and one is unsystematic, ε_i, and is fully uncorrelated among players. Going one step further, we assume that $\varepsilon_{i,j}$ for each player is the result of a large number of identically, independently distributed forecast errors (e.g., load deviations for individual loads), with the number of these atomistic forecast errors being proportional to the market share $m_{i,j}$ (note that, obviously, $\sum_j m_{i,j} = 1$).
5. For the sake of simplicity, we assume both types of forecast errors to be normally distributed, i.e., for the aggregate errors: $\Delta\eta_i \sim N(0, \varphi_i)$, $\Delta\varepsilon_i \sim N(0, \sigma_i)$

Then, the following relationships hold:

$$\Delta X_i = \Delta\eta_i + \Delta\varepsilon_i \tag{1}$$

$$\Delta\eta_{i,j} = m_{i,j}\Delta\eta_i \tag{2}$$

$$\Delta\eta_{i,j} \sim N\left(0, m_{i,j}\varphi_i\right) \tag{3}$$

$$\Delta\varepsilon_{i,j} \sim N\left(0, \sqrt{m_{i,j}}\sigma_i\right) \tag{4}$$

The last proposition holds because the variances add up for independent stochastic variables.[10]

$$E[(\Delta\varepsilon_i)^2] = E\left[\sum_j \left(\Delta\varepsilon_{i,j}\right)^2\right] = \sum_j \left(\sqrt{m_{i,j}}\sigma_i\right)^2 = \sigma_i^2 \tag{5}$$

Source *i* of intraday trading now causes two types of intraday trades:

1. Those that have to be balanced by another source, notably controllable generation.
2. Those that can be balanced among the market participants just because the imbalances are partly of opposite sign.

The first type of imbalance corresponds to $\Delta X_i = \Delta\eta_i + \Delta\varepsilon_i$. Notably, the entire systematic error $\Delta\eta_i$, as far as it is not counterbalanced by the aggregate unsystematic error $\Delta\varepsilon_i$, has to be compensated from other sources.

For trades caused by the unsystematic error, we may add up all positive imbalances of market participants:

$$\Delta\varepsilon_i^+ = \sum_j \Delta\varepsilon_{i,j}^+ \qquad \text{with} \qquad \Delta\varepsilon_{i,j}^+ = max\{0, \Delta\varepsilon_{i,j}\} \tag{6}$$

Similarly, the negative imbalances add up:

$$\Delta\varepsilon_i^- = \sum_j \Delta\varepsilon_{i,j}^- \qquad \text{with} \qquad \Delta\varepsilon_{i,j}^- = min\{0, \Delta\varepsilon_{i,j}\} \tag{7}$$

$\Delta\varepsilon_{i,j}^+$ and $\Delta\varepsilon_{i,j}^-$ are censored normal distributions with expected values of $+\sigma_{i,j}$ or $-\sigma_{i,j}$, respectively.

The expected volume of intraday trading caused by unsystematic errors in source *i* is then without portfolio internal netting:

$$\bar{T}_i = \sum_j E\left(\Delta\varepsilon_{i,j}^+\right) + \sum_j E\left(\Delta\varepsilon_{i,j}^-\right) = 2 \cdot \sum_j \sqrt{m_{i,j}}\sigma_i \leq 2 \cdot \sqrt{J}\sigma_i \tag{8}$$

The last inequality thereby holds because the square root is a concave function. Any distribution deviating from the equal distribution among the J market participants will, hence, lower the volume of intraday trading.

Adjustment demand for multiple stochastic sources of deviations and for power outages

The above approach may be generalized to multiple sources of deviations in a straightforward way. However, unplanned power plant outages are a particular source of intraday deviations. They differ in two respects from wind, solar and load errors. Ex ante, when the full power is

[10] The German wind and solar power forecast errors in 2012 and 2013 were perfectly uncorrelated within the portfolios of three German TSOs. Only within the TSO 50 Hertz portfolio was the correlation between wind and solar power forecast errors significant, but it was very close to zero (0.0274).

scheduled, outages always reduce the ex-ante value. Hence, the expected outage volume is negative and not zero. Furthermore, outages are binary events, the sum of outages over a power plant fleet thus follows a binomial distribution. However, for a sufficiently large power plant fleet (more than 30 units), the binomial distribution may be approximated with sufficient accuracy by a normal distribution. We use then the following assumptions:

1. The typical unit size is *r*.
2. The individual outage probability per unit is ψ.
3. The market share of controllable resources of each player *j* is $m_{k,j}$.
4. The residual demand to be covered by controllable units is *D*.

Then, the number of operating units g is $g = \frac{D}{r}$, and the distribution for the overall adjustment demand resulting from outages is given by:

$$\Delta X_{out} = N\left(-\psi g r, \sqrt{\psi g r^2(1-\psi)}\right) \quad (9)$$

Similarly, for any individual operator of conventional power plants, one may write:

$$\Delta X_{out,j} = N\left(-\psi g_j r, \sqrt{\psi g_j r^2(1-\psi)}\right) \text{ with } g_j = m_{k,j} * g \quad (10)$$

Then, $\Delta X_{out,j}$ is comparable to other sources of uncertainty, except that there is no systematic source of uncertainty if we assume individual plant failures to be uncorrelated.

Adjustment supply by controllable plants

Extending the work of Weber (2010), the portfolio internal optimization of intraday positions is taken into consideration. The total net imbalance ΔX (aggregated possibly over several sources: $\Delta X = \sum_i \Delta X_i$) has in any case to be cleared from controllable resources. We further assume:

1. The controllable resources are chosen according to a merit-order approach.
2. Market participants do not exercise market power, and there are no transaction costs that would favor or grid congestions that would prevent internal netting.

Under these assumptions, market participants will use the most efficient resource for netting their imbalances and only proceed for internal netting of their open positions if it is economically advantageous.

For a total net imbalance ΔX (aggregated possibly over several sources: $\Delta X = \sum_i \Delta X_i$), the following number of controllable resources has to be activated:[11]

$$k = \frac{|\Delta X|}{r} \tag{11}$$

According to our assumptions, *k* is a normally distributed random variable.

We assume that the share of *k* belonging to market player *j* is a non-random variable

$$k_j = m_{k,j} k \tag{12}$$

$$\Delta Z_j = m_{k,j} \Delta X \tag{13}$$

Covariance of deviations with overall deviations

For a substantial share in total intraday deviations, the net market position of a player is not independent of the aggregate net imbalance. The covariance Ω_j of the total amount of intraday deviations with the individual deviations of each player *j* corresponds to:

$$\Omega_j = \mathrm{Cov}(\Delta X, \Delta X_j) \tag{14}$$

with

$$\Delta X_j = \sum_i (\Delta \eta_{i,j} + \Delta \varepsilon_{i,j}) \tag{15}$$

$$\Delta X = \sum_i (\Delta \eta_i + \Delta \varepsilon_i) \tag{16}$$

This yields

$$\begin{aligned} \Omega_j &= \sum_i Cov(\Delta \eta_{i,j}, \Delta \eta_i) + \sum_i Cov(\Delta \varepsilon_i, \Delta \varepsilon_{i,j}) \\ &= \sum_i Cov(m_{i,j} \Delta \eta_i, \Delta \eta_i) + \sum_i Cov(\Delta \varepsilon_i, \Delta \varepsilon_{i,j}) \\ &= \sum_i (m_{i,j} \varphi_i^2) + \sum_i (m_{i,j} \sigma_i^2) \\ &= \sum_i m_{i,j} (\varphi_i^2 + \sigma_i^2) \end{aligned} \tag{17}$$

Net market position of a player

Under the previously specified assumptions, the net market position of player *j* is then a normally distributed variable given by:

[11] One may note that after the activation of *k* controllable resources, these resources also have a probability to fail and may increase ΔX again. However, this second-order error is probably of minor importance for the calculation of intraday deviations.

$$\Delta Y_j = \sum_i \Delta X_{i,j} - m_{k,j}\Delta X = \sum_i\left(\Delta\eta_{i,j} + \Delta\varepsilon_{i,j}\right) - m_{k,j}\sum_i(\Delta\eta_i + \Delta\varepsilon_i) \tag{18}$$

Then, $\Delta Y_j \sim N\left(-\psi gr, \varsigma_j\right)$ with

$$\varsigma_j = \sqrt{\sum_i Var\left(\Delta\eta_{i,j}\right) + \sum_i Var\left(\Delta\varepsilon_{i,j}\right) + Var\left(\Delta X_{out,j}\right) + Var\left(\Delta Z_j\right) - 2\,\Omega_j} \tag{19}$$

Inserting the above relationships, one obtains

$$\varsigma_j = \sqrt{\begin{gathered}\sum_i m_{i,j}^2\varphi_i^2 + \sum_i m_{i,j}\sigma_i^2 + m_{k,j}gr^2\psi(1-\psi) + {m_{k,j}}^2\left[\sum_i(\varphi_i^2+\sigma_i^2) + gr^2\psi(1-\psi)\right] \\ -2m_{k,j}\left(\sum_i m_{i,j}\,(\varphi_i^2+\sigma_i^2) + m_{k,j}gr^2\psi(1-\psi)\right)\end{gathered}} \tag{20}$$

ς_j may be rewritten such that the separate covariance term Ω_j vanishes. Instead, the remaining terms are corrected by portfolio internal netting:

$$\varsigma_j = \sqrt{\begin{gathered}\sum_i\left(m_{i,j} - m_{k,j}\right)^2\varphi_i^2 + \sum_i\left(m_{i,j} - 2m_{i,j}m_{k,j} + m_{k,j}^2\right)\sigma_i^2 \\ +\left(1-m_{k,j}\right)m_{k,j}gr^2\psi(1-\psi)\end{gathered}} \tag{21}$$

The first term under the square root then captures the net position due to systematic errors. The second term defines the intraday deviations of other market participants that are compensated by the player *j* according to his market share $m_{k,j}$. The third term defines the sum of power plant outages that are not netted internally. The interpretation in variance components becomes more obvious when using the following reformulations for the second and third terms:

$$\sum_i\left(m_{i,j} - 2m_{i,j}m_{k,j} + m_{k,j}^2\right)\sigma_i^2 = \sum_i\left(m_{i,j}\left(1-m_{k,j}\right)^2 + \left(1-m_{i,j}\right)m_{k,j}^2\right)\sigma_i^2 \tag{22}$$

$$\begin{aligned}&\left(1-m_{k,j}\right)m_{k,j}gr^2\psi(1-\psi) \\ &= m_{k,j}\left(1-m_{k,j}\right)^2 gr^2\psi(1-\psi) + \left(1-m_{k,j}\right)m_{k,j}^2 gr^2\psi(1-\psi)\end{aligned} \tag{23}$$

Thus, each variance component corresponds to a weighted sum of variances. The weights are the shares of the players *j* in the stochastic source *i* and the outage-induced variance. The quadratic terms describe the fraction of the stochastic term that is compensated externally/internally. This share is squared because the resulting stochastic variable scales linearly with the fraction.

For illustrative purposes, the formula for ς_j is evaluated for particular players such as pure renewable or pure conventional players (cf. Appendix).

Because ΔY_j is normally distributed, we may determine the expected intraday volume using an approach similar to equation (8):

$$\bar{T}_{tot} = \sum_j E(\Delta Y_j^+) + \sum_j E(\Delta Y_j^-) = 2 \cdot \sum_j \varsigma_j \quad (24)$$

with $Y_j^+ = max\{0, \Delta Y_j\}$ and $\Delta Y_j^- = min\{0, \Delta Y_j\}$

Given the complicated expression for ς_j, no easy conclusions may be derived on the impact of the number and size of market participants on the (theoretical) intraday trading volume. However, for some limiting cases, analytical insights may still be gathered.

3.3 Benchmark trading volumes

Using the definition of ς_j, two benchmarks for the calculation of the theoretically expected intraday trading volumes can be derived. In the first model, it is assumed that all groups of market participants, namely, large players, the competitive fringe and the TSOs, manage their intraday imbalances actively in the market. The first model is expected to be applicable to markets with an HHI below 1000 and low transaction costs for trading. In that case, the generation is not concentrated and the market offers competitive trading opportunities. The expected trading volume in this "competitive benchmark model" may then be written

$$T_{BM1} = 2 \cdot \sum_j \varsigma_j \quad (25)$$

In the second model, it is assumed that an intraday market participation results in transaction costs for forecasting, trading, scheduling, labor, or exchange fees. For small companies, these transaction costs may exceed the benefits from intraday trading, especially if the balancing power prices are, on average, close to the day-ahead prices. This may lead to a situation where the competitive fringe leaves all imbalances to be corrected by control energy and does not trade actively in the intraday market. The second model is likely to be applicable to markets with an HHI above 1000 and substantial transaction costs. This corresponds to a moderate or high market concentration and the presence of one or several dominant players. The resulting trading volume in this "oligopolistic model" may then be written

$$T_{BM2} = 2 \cdot j; m_{k,j} > 0.05 \; or \; TSO \varsigma_j$$

$$T_{BM2} = 2 \cdot \sum_{j; m_{k,j} > 0.05 \; or \; TSO} \varsigma_j \quad (26)$$

The trading volume T_{BM2}, then, is obviously lower than the volume T_{BM1}, and it provides a benchmark for minimum efficiency to be reached by intraday markets.

3.4 Further influences

Intraday market peculiarities

The intraday markets are not perfectly harmonized across Europe. Some of the seven intraday markets on which the empirical analysis focuses have unique characteristics that may influence the observed intraday trading to deviate from the levels predicted by the benchmarks.

In Denmark, market participants may leave imbalances for the regulating power market that operates after the gate closure of the intraday market. Here, the TSO may buy or sell fast reserves up to 10 minutes before delivery (Matevosyan and Söder, 2006). While the market participant causing the imbalance has to pay imbalance fees, other market participants helping compensate the imbalance are rewarded by the TSO (Skytte, 1999). Especially if the imbalances penalties are low, market participants may have an incentive to do nothing and leave imbalances for the regulating power market, thus withdrawing trading volumes from the intraday market. The separation of Denmark into different grid zones prevents the cross-zonal netting of contrary intraday positions, which may further increase the total intraday trading volume.

In the UK, the APX UK exchange complemented the existing half-hourly continuous market by a day-ahead auction in 2011. The day-ahead auction aligns the British electricity market design with the market designs in other European countries such as France and Germany. Nevertheless, one difference persists that may influence intraday trading. Market participants are not forced to hedge their complete production and consumption in the day-ahead auction but are allowed to transfer positions into the continuous intraday market. If they do so at least partially, the observed intraday trading will exceed the theoretically anticipated volumes.

The Italian intraday market has several peculiarities that influence trading volume. Notably, large single generating units are represented by separate balancing areas (cf. Lanfranconi 2014). This leads to intraday trading activities between two generating units if the owner wishes to optimize the production output between those power plants. Second, the Italian power exchange does not allow block bids in the day-ahead market. For inflexible base load plants with cycling restrictions (consider, e.g., Nicolosi, 2010 or Troy et al., 2010) this might lead to infeasible production schedules from the day-ahead marketing. The correction of unfeasible schedules in the intraday market may further increase intraday trading volumes. Third, the Italian electricity market is a zonal system, where it is necessary for the management of inter-zonal congestions that all intraday trades be delivered through the power exchange. Thus, bilateral trading is theoretically possible but only executable via the exchange. As in the case of Denmark, the zonal system in Italy may prevent the cross-zonal netting of contrary intraday positions, which may further increase the total intraday trading volume.

In Spain and Portugal, portfolio internal optimizations are only allowed via the intraday market (Furió et al., 2009 or Henriot, 2014). Thus, intraday dispatch decisions between different power plants within one portfolio are executed via the intraday exchange. Similarly to the Italian case, this could increase measured intraday trading volumes compared to the theoretical benchmarks.

Continuous and auction-based intraday market design

The intraday market design may determine the ability of market participants to adjust their intraday schedules. While continuous intraday markets enable market participants to trade immediately and shortly before delivery, auction-based intraday markets restrict trading to a set of predefined moments in time. As Henriot (2014) derives analytically, discrete auctions may lead to lost trading opportunities. If gate closures in auction-based intraday markets are set at times that do not suit the market participants' trading needs, market participants will not trade. If intraday trading needs become apparent after the intraday gate closure (in Italy, the shortest gate closures are 4.15 hours before delivery), relevant information cannot be incorporated into the intraday market. Therefore, the early gate closures in auction-based intraday markets may constitute an obstacle to an efficient intraday market operation and may lead to lower trading volumes.

Bilateral over-the-counter trading

In all countries except Italy, market participants may trade directly with each other and are not forced to use the exchange to self balance their portfolios. These so-called over-the-counter (OTC) trades remain unobserved by the electricity exchange and only need to be announced to the TSO via electricity schedules. Therefore, OTC trades increase the true trading volume even though they are not considered in the observable exchange-based trading volumes.

Cross-border trading

The European intraday markets are partly connected via implicit or explicit coupling agreements. Foreign trading demands may be satisfied in one of the analyzed countries through cross-border trading and thus raise the observed volumes above the levels that are predicted by a model that considers only national trading needs. In contrast, national trading needs may be satisfied abroad and may thus reduce the national trading volumes below levels predicted by a pure national model. Consequently, the influence of cross-border trading on national trading volumes is ambiguous.

4 Empirical analysis

4.1 Data

Data from 2012 and 2013 are collected from different sources. Organizational details about intraday markets and the intraday trading volumes stem from the web sites of the European TSOs and power exchanges (Table 1). Information about the national renewable support schemes is obtained from the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (2014). To calculate the theoretical intraday trading volumes per country, data about each major player´s capacities for wind, solar and conventional (including hydro) power were collected from their web sites. The total installed capacity of conventional generation per country in 2012 is taken from the U.S. Energy Information Administration (2015); for wind power, it is taken from the European Wind Energy Association (2013); and for solar power, it is taken from the European Photovoltaic Industry Association (2013). The statistics about market concentration, each player´s power plants and the total installed capacity are used to calculate each player´s market share of conventional, wind and solar power. To calculate the theoretical VRES forecast errors, root mean squared errors of 3.6 % for wind power and 3 % for solar power are taken from Hagemann (2015) and multiplied by the installed VRES capacity in 2012. The capacity of unplanned power plant outages with relevance for intraday trading is calculated for Germany and France with data from the transparency platforms of the European Energy Exchange (2014) and Réseau de Transport d´Électricité (2014). The computations indicate how much outage capacity (measured in Megawatts) with relevance for intraday trading occurred in 2012 on average per unit (Megawatt) installed capacity of a power plant technology in Germany and France. The results are presented in Table 4. Those average values are then used to estimate the outage capacities with relevance for intraday trading in the remaining countries.

Table 4: Outages with relevance for intraday trading per installed MW of each production technology. Source: Own calculation (Appendix).

Source	Outage per installed capacity (MW)
Uranium	0.00182739
Fossil	0.00745487
Hydro	0.00473291

Several assumptions are applied in order to overcome data lacunas. The market shares of the competitive fringe are not determined individually but are assumed to be distributed equally, with each small player owning a market share of 3 %. All countries are assumed to have one TSO (or, equivalently, no trading activities between TSOs). Wind power capacity that cannot be assigned to one of the major wind power marketers is assumed to be managed by the national TSOs. An exception to this rule is Denmark, where wind power is subsidized by an FIP support scheme and is thus not marketed by the TSO. Here, the remaining wind power capacities are assigned to the competitive fringe. For solar power, it is assumed that the owner structure is truly atomistic and that forecast errors are managed only by the national TSOs. Danish solar power is assumed to be marketed only by the competitive fringe because the two large players do not own solar power plants. The root mean square errors for forecasts are assumed to be equal in the analyzed countries. The systematic forecast error is estimated to correspond to 80 % and the unsystematic error to 20 % of the total. Finally, the load forecast errors are assumed to be corrected through balancing services instead of being traded in the intraday markets. This is justified by the fact that intraday forecasts about the total consumption within balance groups are generally not available.

4.2 Empirical results

The results on observed intraday trading volumes and the theoretical benchmarks are shown in Table 5. For Denmark, the observed trading volume is reported with the inclusion of the regulating power market (252 MW) and without (103 MW). The trading volumes calculated according to the second benchmark (oligopolistic market) are 30 % to 70 % lower than the benchmark values for the competitive market. The French and Danish markets are best described according to the oligopolistic model. For Germany, the observed volume falls between the oligopolistic and competitive benchmarks. For the UK, Italy, Portugal and Spain, even the competitive market model significantly underestimates the observed trading volumes. The deviations between the theoretically calculated and actually observed intraday trading volumes are discussed in the following section.

Table 5: Model results

Country	Competitive Market Benchmark [MW]	Oligopolistic Market Benchmark [MW]	Observed volume Buy / Sell [MW]	Impact of IDM peculiarities
Denmark	437	112	103(252)	(-)
France	742	503	495	(o)
Germany	4570	2679	3598	(o)
UK	1533	888	2372	(+)

Italy	2150	1282	5731	(+)
Portugal	518	364	1196	(+)
Spain	1777	1141	10688	(+)

4.3 Discussion

The analytical model of section three abstracts from the impacts of market peculiarities, market design and unobserved OTC trades. Thus, the empirical results also have to be discussed with respect to those influences.

The competitive market benchmark strongly overestimates the Danish trading activities. This computation assumes that the whole competitive fringe trades actively, which is apparently not the case in reality. The theoretical trading needs of the competitive fringe equal the difference between the two benchmarks (325 MW). However, the oligopolistic model almost exactly predicts the Danish intraday trading volumes in 2012.

The HHI for Denmark shows a moderate concentration in generation. Only two Danish electricity companies produced more than 5 % of the electricity output in 2012 (Eurostat, 2014), and both players together owned roughly two-thirds of the total conventional generation. The oligopolistic market benchmark indeed shows a good fit. Moreover, the empirical results indicate that many Danish imbalances are corrected in the regulating power market. The usage of the regulating power market is not strongly penalized, and in 2012, even more quantities were traded in the Danish regulating power market (661 GWh) compared to the intraday market (460 GWh).[12] Those imbalances may be caused by the competitive fringe. A large share of wind power plants (roughly 68 % in 2012) was owned by the competitive fringe, which in turn may not have the infrastructure to manage and trade wind forecast errors in the intraday market.

The FIP support scheme in Denmark is considered in the theoretical model by distributing all wind and solar power capacities to either the two dominant players or the competitive fringe. Thus the high potential for internal balancing of wind and solar power forecast errors under a FIP scheme is already adequately considered in the analytical models.

The continuous intraday market design does not seem to influence intraday trading above the levels predicted by the theoretical benchmarks in Denmark. Unobserved OTC trades may increase the intraday trading volume slightly above 103 MW. However, the power exchange Nord Pool Spot has a monopoly on the cross-border capacities between Danish grid zones DK1

[12] In 2012, the prices of the regulating power market were relatively close to the day-ahead prices. The upwards regulating prices were, on average, 5.20 euros higher in DK1 and 6.66 euros higher in DK2. The downward-regulating prices were, on average, 4.71 euros lower than the day-ahead prices in the DK1 area and 5.14 Euros lower in the DK2 area. Source: Own calculation with historical market data from the Nord Pool Spot (2014).

and DK2. This circumstance forces market participants to execute cross-border trades via the exchange and reduces the share of unobserved OTC trades. This leads to the conclusion that the competitive market benchmark still overestimates trading strongly and that the oligopolistic benchmark may only slightly underestimate the Danish trading volumes.

For the case of France, the competitive benchmark model strongly overestimates trading volume by 50 %. The oligopolistic benchmark actually corresponds to a duopoly model that calculates the trading volumes of EDF and the TSO (as a marketer for renewables). The largest market participant, EDF, was responsible for balancing 86.5 GW of conventional generation and 768 MW of wind power in 2012. EDF´s intraday trading potential, according to the atomistic or oligopolistic model, equals 249 MW. EDF is approximately three times larger than the largest German player, RWE (26 GW conventional and 471 MW wind power), but RWE is expected to have an intraday trading potential that is nearly twice as high as EDF´s trading volume (417 MW). These results indicate that the model captures the market participants´ potential for internal self-balancing adequately. The oligopolistic benchmark additionally includes trading volumes from the TSO, and the competitive benchmark also includes trading volumes from the competitive fringe. The low resulting values (compared to Germany, which is not much larger) are plausible because in an isolated monopolistic market, the monopolist will always balance any system imbalance internally.[13] Similarly to Denmark, the competitive fringe seems not to be trading on the intraday exchange in France.

In 2012, both an FIT and a tender support scheme were established in France, which makes it impossible to isolate the effect of a support scheme on intraday trading. Furthermore, no market peculiarities are known to the authors that may influence intraday trading. Similarly to the case of Denmark, the continuous intraday market design does not seem to induce additional intraday trading in France beyond the levels predicted by the theoretical models. OTC trading may increase the true French trading above the level of 495 MW. This implies that the oligopolistic benchmark may underestimate the actual trading volume, but the competitive benchmark probably still greatly exceeds actual trading.

For the German market, the observed trading volume of 3598 MW is almost halfway between the results of the competitive (4570 MW) and the oligopolistic (2679 MW) benchmarks. The HHI value of 1376 indicates a moderate concentration of the electricity market in 2012.

[13] The trading model results for a monopoly ($m_k = 1$) equal zero, as shown in the exemplary cases in the appendix. EDF´s trading volume is greater than zero because EDF is not a pure monopolist.

Nevertheless, the observed trading volume exceeds the oligopolistic benchmark by 34 %, thus indicating that the competitive fringe is trading quite actively on the exchange.

The influences of VRES support schemes on intraday trading are adequately considered in the data of the theoretical models. In 2012, the feed in premium system was introduced in Germany, and wind producers in particular quickly rushed into the new direct marketing support scheme (Rostankowski, 2013). In the model, 70 % of wind power is assumed to be marketed directly through an FIP support scheme. The remaining wind and all solar power plants are assumed to be managed by a single TSO. At the same time, the German Federal Network Agency reminded all balancing responsible parties to adhere to their responsibility for self-balancing in the intraday market.[14] This may have led to increased trading by smaller market participants.

For the case of Germany, no market peculiarities are known to the authors that may influence intraday trading above the levels predicted by the models. Also, the continuous intraday market design does not seem to influence trading. Unobserved OTC trading increases the true trading volumes in Germany and leads to the conclusion that the competitive benchmark is closer to reality. It overestimates the observed volume by 972 MW, or 27 %, but this difference can probably be attributed completely to unobserved OTC trades. Viehmann (2011) estimates that the exchange-based and bilateral trading volumes in the German day-ahead market are approximately of the same magnitude. This estimation may also apply to the intraday market.

The British electricity market has an HHI of 954, which indicates that the market structure is competitive. Correspondingly, the competitive benchmark is expected to describe the intraday trading volumes, but even this approach greatly underestimates the observed trading by 55 %. Due to the FIT and tender support schemes in the UK, the TSO and generators are responsible for balancing wind and solar power forecast errors. The higher-than-expected trading volumes in the UK may be attributed to market peculiarities. Notably, market participants are still allowed to use the continuous market for day-ahead hedging, which could increase the observed values above the level predicted by the competitive benchmark, which only accounts for intraday imbalances. A further explanation for the high trading volume in the UK might be a higher-than-assumed wind forecast error. Unobserved OTC trades may further increase the spread between the true trading volume and the model results.

The developed approach based on fundamental factors, market concentration and portfolio internal netting options fails to approximate the observed intraday trading volumes in Italy,

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[14] Unpublished letter from the German Federal Network Agency to all balance-responsible parties in Germany.

Portugal and Spain. The HHI values indicate a moderate concentration in Italy (1079) and Spain (1244) and a strong concentration in Portugal (1899). However, in contrast to the relatively good explanatory power of the fundamental modeling approach including portfolio internal netting for Denmark, France and Germany, the observed intraday trading deviates strongly from the expectations derived from the fundamental model in the case of the Southern European countries. Even the competitive benchmark underestimates the observed trading volumes in Italy and Portugal by more than a factor of two and in Spain by a factor of six. This has to be attributed to market peculiarities in Italy, Portugal and Spain.

At first sight, the hypothesis formulated by Henriot (2014) that the auction-based market design leads to lost trading opportunities is firmly rejected because the observed volumes greatly exceed the model results. However, this observation cannot be attributed to the market design alone but is rather a consequence of market peculiarities. The most important peculiarity in all three markets is that the rescheduling of generation output between power plants within one generation portfolio is only possible via trades in the intraday market. Unobserved OTC trades may further increase the true trading volumes in Portugal and Spain. In Italy, OTC trades are only executable via the exchange and are thus included in the observed volumes. Overall, the fundamental model of intraday trading volumes is not invalidated by the observations obtained from the Southern European markets. However, in order to be applicable, further extensions to the model would be needed to address the peculiarities in these markets.

5 Final remarks

This paper presents an analytical method to derive a liquidity benchmark in national intraday markets. Trading volume is frequently taken as a key indicator for market liquidity, and market liquidity in intraday markets is a prerequisite for an efficient integration of wind and solar power plants into electricity systems. Therefore, a benchmark model for trading volumes in intraday markets is instrumental to assess the efficiency of the market arrangements and the current practices. The developed analytical method considers wind and solar power forecast errors, power plant outages with relevance for intraday trading, market concentration and portfolio internal netting options as the main drivers of trading volume. A key assumption is that the probability that the next-best alternative for intraday balancing is portfolio-internal is proportional to each player´s portfolio size. Under this assumption, it is economically beneficial in most cases for small players to balance their intraday deviations in the market, whereas for larger players, internal netting is frequently more advantageous.

Two benchmarks for the national trading volumes are derived from the analytical method. The first model assumes that dominant companies, the competitive fringe and TSOs (as marketers of renewables) trade actively in the intraday market. The second model assumes that transaction costs prevent the competitive fringe from intraday market participation. The models are tested empirically with market data from four European countries with continuous intraday markets (Denmark, France, Germany, United Kingdom) and three countries with auction-based intraday markets (Italy, Portugal, Spain) in 2012.

Although the computations are based on a number of simplifying assumptions, the trading volumes observed in the continuous intraday markets of Denmark, France and Germany are rather in line with the benchmarks. The comparison of the observed trading volumes with the oligopolistic benchmark reveals that in France and Denmark, only the dominant companies and the TSOs seem to be trading actively. The competitive fringe seems to leave intraday imbalances for the regulating power market in Denmark. In France, small players leave imbalances to be corrected by controlling energy or by direct trading with other counterparts. The latter behavior remains unobserved. For Germany, the competitive benchmark model predicts the trading volume quite well, which leads to the conclusion that the competitive fringe participates at least partly in exchange-based intraday trading. In the other analyzed markets, the observed trading volumes exceed the competitive benchmark considerably. However, this can be explained by market peculiarities. At first sight, fundamentals, market concentration and portfolio internal balancing options fail to explain the intraday liquidity provision in all analyzed auction-based markets. However, all auction-based markets exclude or strongly limit the possibilities of portfolio internal netting. This precludes an efficient (non)trading strategy from the outset. With the present data, it is not possible to empirically infer the effects of the market design on the market efficiency. Auction-based intraday markets show generally higher trading volumes than expected, but this does not necessarily indicate a higher degree of economic efficiency, given that with the longer time lag between gate closure and actual delivery the informational efficiency in these markets tends to be lower (cf. Bellenbaum et al. 2014).

Appendix

Appendix A: Model predictions for simple analytical cases

Table 6: Examples of model results for simple analytical cases.

Portfolio structure of player *j*	Value ς_j	Interpretation

Monopoly $m_{i,j} = m_{k,j} = 1$	0	All intraday deviations are netted within the portfolio.
No controllable resources $m_{i,j} =$?, $m_{k,j} = 0$	$\sqrt{\sum_i m_{i,j}^2 \varphi_i^2 + \sum_i m_{i,j} \sigma_i^2}$	The variances of the forecast errors of renewables determine the player's trading volume completely.
No renewables, variable share of controllable generation $m_{i,j} = 0, m_{k,j} =?$	$\sqrt{m_{k,j}^2 \sum_i (\varphi_i^2 + \sigma_i^2) + m_{k,j}(1 - m_{k,j}) g r^2 \psi (1 - \psi)}$	The player´s trading activity is determined by the outages of his controllable generation, the renewables forecast errors and the outages of other players. For $m_{k,j} = \frac{1}{2}$, the player's trading volume due to his own outages reaches its maximum.
Duopoly: $m_{i,j} = m_{k,j} = \frac{1}{2}$	$\sqrt{\sum_i \frac{1}{4} \sigma_i^2 + \frac{1}{4} g r^2 \psi (1 - \psi)}$	Total variance is the sum of unsystematic forecast errors and outages. All systematic forecast errors are netted within each player's portfolios because their market shares for renewables and conventional are equal.

Appendix B: Approximation of outage probabilities

While the outages per installed megawatt of uranium and hydro power plants are relatively similar in Germany and France, fossil-fired power plants tripped more often in Germany. This may be explained by differences in the national power plant fleets. Germany has numerous lignite and hard-coal-fired power plants that have higher outage rates, whereas France has no lignite power plants at all and only 6395 MW of hard coal power plants (Réseau de transport d´Électricité, 2014). Finally, an average of the German and French outages per installed megawatt of each fuel type is calculated to make the results more generalizable to other countries (Table 7).

Table 7: Overview of unplanned outage data of generating units with an installed capacity above 100 MW. Sources: Own calculations with outage data from the transparency platforms of the European Energy Exchange (2014) and Réseau de transport d´Électricité (2014). The installed capacities of nuclear, fossil and hydro power plants for 2011 are from the U.S. Energy Information Administration (2015).

		AVG intraday outage duration h	AVG outage size MW	Number of outages 2012	AVG Outage capacity MW 2012	Installed capacity	Outage per installed MW
Germany	Uranium	10.51	580	27	19	12068	0.00155688
	Coal	12.72	303	962	423	74595	0.01151587
	Lignite	10.72	305	592	221	NA	
	Gas	13.4	302	465	215	NA	
	Hydro	8.17	181	210	35	6777	0.00523092
France	Uranium	8.83	1123	117	132	63130	0.00209791
	Coal	6.27	373	235	63	30461	0.00339387
	Oil	4	401	99	18	NA	
	Gas	5.73	447	77	23	NA	
	Hydro	3	183	472	30	6985	0.00423491

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