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EWL Working Paper No. [18/13]

Price Determinants in the German Intraday Market for Electricity: An Empirical Analysis

by

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Abstract

This paper presents a first investigation of hourly price determinants in the German intraday market for electricity. The influence of power plant outages, forecast errors of wind and solar power production, load forecast errors and foreign demand and supply on intraday prices are explained from a theoretical perspective. Furthermore the influences of the non-linear merit-order shape, ramping costs and strategic market behavior are discussed. The empirical results from different regression analysis with data from 2010 and 2011 show that most price determinants increase and decrease intraday prices as expected. Nevertheless, only a minor share of power plant outages and solar power forecast errors are traded on the electronic intraday trading platform, thus influencing prices not as strongly as expected. Furthermore the price determinants influence intraday prices differently over the course of the day which may be explained by an alternating liquidity provision.

Keywords: Intraday market for electricity, price modeling, price determinants.

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Executive Summary

While day-ahead prices for electricity are being extensively studied, the literature so far has neglected the analysis of intraday market prices. Intraday markets are becoming increasingly important in the presence of high shares of electricity production from intermittent renewable energy sources. Trading the deviations of the actually realized production profile from the day-ahead planned one in the intraday market may enhance system security and increase social welfare. This paper contributes to the electricity market pricing literature by exploring the influence of theoretical price determinants on intraday prices, presumably for the first time.

The influence of power plant outages, forecast errors of wind and solar power production, load forecast errors and foreign demand and supply on German intraday prices are explained from a theoretical perspective. Furthermore the influences of the non-linear merit-order shape, ramping costs and strategic market behavior are discussed. The empirical results from regression analysis for different time periods of the day in 2010 and 2011 show that most analyzed price determinants significantly increase and decrease intraday prices. The algebraic signs of the regression coefficients of outages (+0.73 €/ GWh), wind power forecast errors (sell -2.61 €/ GWh, buy +3.14 €/ GWh) and solar power forecast errors (sell -1.42 €/ GWh, buy 0.43 €/ GWh) in the regression for the base period are as expected. An intraday surplus of wind and solar power production significantly decreases intraday prices while unplanned power plant outages or a lacking wind power production lead to purchases and significantly increase intraday prices. Foreign demand and supply (here considered as French trades) did not have a significant influence on German intraday prices in the base period in 2010 – 2011. Further partly surprising results are revealed by the analysis of the regression coefficients at different time periods of the day and the non linear merit-order shape.

The empirical analysis confirms that wind forecast errors, solar forecast errors and outages have significant influences on intraday prices. Nevertheless, only a minor share of power

plant outages and solar power forecast errors are traded on the electronic intraday trading platform, thus influencing prices not as strongly as expected. Furthermore the price determinants influence intraday prices differently over the course of the day, e. g. wind forecast errors have a stronger price impact during the time from midnight to eight am than during the rest of the day. This may be explained by an alternating liquidity provision.

Practitioners may benefit from this study because the understanding of intraday price developments is a prerequisite for the assessment of the market value of (1) flexible power plants like gas turbines or pump storage plants and (2) intraday portfolio positions. Researchers might be interested in the results of this study as it lays a foundation for further more theoretically orientated research projects about intraday markets.

1 INTRODUCTION

Electricity is different from other commodities notably due to its non-storability in economic quantities and limited international transmission capacities. Furthermore, the demand side tends to be price-inelastic in the short run. Due to these special characteristics, a constant balance between demand and supply is required for a safe system operation. In Germany, the intraday market is the last trading market before physical delivery where market participants may self-balance their portfolios in order to avoid the involuntary purchase of costly balancing services from the transmission system operators (TSO). Yet so far, researchers like Huisman and Kilic (2013), Keles et al. (2012), Kristiansen (2012) or Bobinaite et al. (2013) have focused on explaining and forecasting prices in day-ahead markets.[1] This is a difficult task because Huisman and Mahieu (2003) or Seifert (2008) mention that day-ahead prices show a high volatility, seasonality, mean reversion, non-constant mean and variance in the short run, a high percentage of unusual price movements like extreme jumps that die out rapidly, positive skewness, leptokurtosis and negative prices. The literature so far has neglected the analysis of intraday market prices, even though the intraday market is becoming increasingly important in the presence of high shares of electricity production from intermittent renewable energy sources. The significant deviations of the actually realized production profile from the day-ahead planned one may threaten system security if they are not being traded in the intraday market.

The objective of this paper is to explain the hourly price differences between the German intraday market for electricity (GIME) and the day-ahead market under

[1] For an overview and classification of day-ahead modeling approaches consider Aggarwal et al. (2009); Weber (2005), pp. 31-32; Weron/ Misiorek (2008), pp. 745-746.

consideration of market specific price determinants and the fundamental merit-order model.[2] This paper provides several contributions to the existing literature. First of all it contributes to the electricity market pricing literature by exploring the influence of theoretical price determinants on intraday prices, presumably for the first time. Secondly, this paper may enrich the understanding of the so far neglected intraday market where continuous trading takes place. The understanding of intraday price developments is a prerequisite for the assessment of the market value of (1) flexible power plants like gas turbines or pump storage plants and (2) intraday portfolio positions. Thirdly, this explorative study may lay a foundation for further more theoretically orientated research projects.

The structure is as follows. In section two, the need for intraday trading, different options of market participants to balance their intraday positions and the theoretical determination of hourly intraday prices are discussed. Section three investigates the intraday price determinants and their theoretical influence on hourly intraday prices in detail. In section four, the empirical approach and the data used are described before the empirical results are being presented and discussed. Section five concludes and gives an outlook on further research opportunities.

2 THE NEED FOR INTRADAY TRADING AND INTRADAY PRICE DETERMINATION

German electricity market participants with intraday imbalances in their portfolios may self-balance the deviations both internally within their own portfolio and externally through intraday trading either over the counter (OTC) or via the electron-

[2] For a detailed explanation of the fundamental merit-order model see e. g. Weight/ Hirschhausen (2008), p. 4229 or Misiorek et al. (2006), pp. 1-2.

ic intraday trading platform of the power exchange EPEX SPOT.[3] Nicolosi (2010) and Zachmann (2008) note that the prices of OTC trades cannot deviate systematically from the exchange prices because traders may otherwise arbitrage between the two markets. Thus the price on EPEX SPOT can be considered as a reference market price and is taken as basis in this paper. But what are the drivers of prices in the GIME? This question will be analyzed theoretically and tested empirically in the remaining of this paper.

The GIME is an order driven and continuous market where demand and supply is being matched automatically according to the price and time priority principle. Market participants with open intraday positions may enter limit buy/ sell orders or market buy/ sell orders. While market orders are executed immediately at the best price available, limit orders are being stored in the limit order book (Jiang et al. 2011). Within the limit order book, intraday demand is being queued on the bid side and intraday supply on the ask side. As done by Weber (2005), Weight and Hirschhausen (2008) or Lang and Schwartz (2006) for the day-ahead market, it can be assumed that the price formation in the intraday market may be explained (at least to some extent) through the so-called merit-order model. Weber and Woll (2007) explain that the merit-order model assumes that power plant owners will offer electricity only if they can recover at least their short term variable costs. In a competitive market, this strategy ensures profit maximization. The merit-order is created by arranging the available power plant capacities according to their increasing short term variable costs.

[3] Another way to balance intraday positions externally is to do nothing and let the TSO balance the deviation from the day-ahead planning in real time. The latter is usually the most costly option and may push the TSO to abrogate the balance-group contract if such imbalances occur too often. Therefore, market participants have an incentive to self-balance open positions.

Shortly after the gate closure for the daily day-ahead auction, the hourly intraday market prices will gather around the hourly day-ahead market prices. The price-demand function for one delivery hour at the opening of the intraday market is illustrated in figure I. The demand function reflects the flexible downward ramping capacities at prices below the day-ahead price. Conversely, intraday supply initially reflects the upward ramping capacity at prices above the day-ahead price (right side of figure I). The price difference between the cheapest offer (ask-side) and most expensive bid (bid-side) is called the bid ask-spread (BAS). The initial intraday market equilibrium equals the day-ahead market equilibrium with the price P^* and the quantity MWh^*. Changes in intraday demand and supply lead to new equilibrium prices and market clearing quantities. As time after the day-ahead gate closure passes by, the need for intraday optimizations may increase successively as intraday deviations of demand and supply occur for some market participants. According to Borggrefe and Neuhoff (2011) and Hagemann and Weber (2013) exemplary deviations are intraday updates of the production forecasts of intermittent renewable energy sources or unplanned power plant outages.

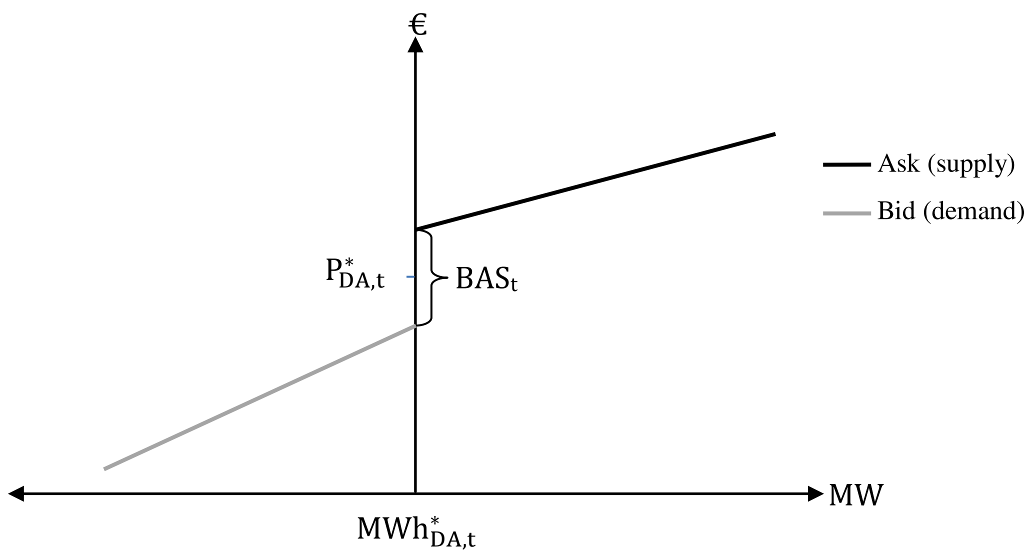

Figure I: Simplified price-demand and price-supply curves in the intraday market.

The hourly volume weighted average intraday prices reflect the scarcity of the good electricity in the intraday market and result from the matching of demand and supply in the limit order book. The initial supply and demand curves are determined by the available up- and down ramping capacities of flexible power plants. As new information about deviations from the day-ahead planning enter the market, they are being traded against the available power plant flexibilities or other contrary deviations from the day-ahead planning. Thus, deviations of intraday prices from day-ahead prices may be explained by changes of demand and supply after the day-ahead gate closure and the fundamental characteristics of the merit-order.[4] These intraday price determinants will be presented in the next chapter.

3 PRICE DETERMINANTS IN THE GIME

Unplanned power plant outages

If power plant owners experience unplanned outages, they still have to deliver the electricity production that they previously sold on the long-term or day-ahead market. From approximately one hour after the outage on, the power plant owners may compensate the outage via purchases on the intraday market. This is advantageous, if the marginal costs of free generation units in the producer's portfolio are higher than the benchmark prices on the EPEX platform for intraday trading. In the very short run, they may use highly flexible generation units like pump storages or running steam reserves to compensate the outage within their own portfolio. Not all unplanned outages are relevant for intraday trading. If a power

[4] The information diffusion and the reaction of market participants to new information may also determine intraday prices. E.g. technical restrictions and missing office occupation may hinder market participants to benefit fully from available information.

plant defaults before the day-ahead gate closure at 12 am, its delivery for the next day (*d+1*) will be substituted by purchases in the day-ahead market (cf. Figure II). Thus, only power until the end of the day *d* will be purchased on the intraday market. If a power plant defaults after the day-ahead gate closure at 12 am on day *d*, the electricity production for the current and the next day has to be replaced by purchases on the intraday market. Only from the day after tomorrow onwards (*d+2*), the power plant can be substituted by purchases on the day-ahead market auction on *d+1*. Power plant outages are expected to lead to purchases in the GIME and thus reduce the quantity of electricity offered and increase intraday prices. The following hypothesis can be formulated.

Hypothesis I: Power plant outages increase intraday prices.

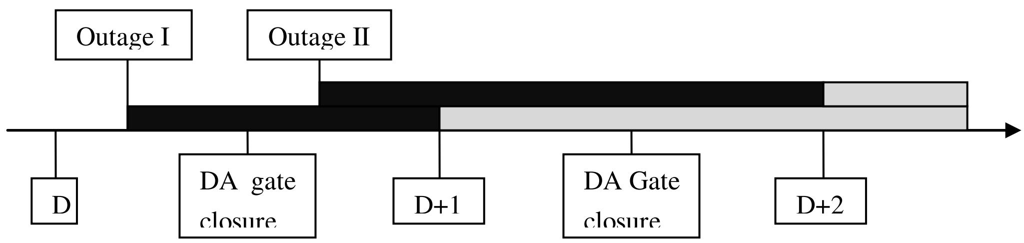

Figure II: Compensation of power plant outages in the Intraday and Day-Ahead market. Black: Purchase in the GIME. Gray: Purchase in the day-ahead market

Differences between day-ahead and intraday forecasts of intermittent renewable energy sources

In 2011 (2010), the intermittent renewable energy sources wind and solar power already contributed 11% (8%) to the gross domestic electricity production in Germany (BDEW 2012). From January 2010 until December 2011, the four TSOs were responsible for the marketing of the expected renewable electricity (RES) production under the feed-in tariff support scheme as described in EEX (2009). The expected wind and solar power production for the next day was estimated with forecast models and sold limitless on the day-ahead market. As the hour of delivery approached, intraday forecasts with lower forecast error rates became available. The forecast error is generally defined as the quantity difference between the previously sold day-ahead profile of RES and the more precise intraday forecast. Weber (2010) concludes that the forecast errors are traded in the GIME to minimize the use of balancing services. Hagemann and Weber (2013) find out that RES forecast errors are one of the main sources of intraday liquidity and thus are expected to influence prices as well. For a positive (negative) forecast error, the TSOs held a long (short) position and acted as a seller (buyer) of electricity on the intraday market. In the data sample of this study, the capacity-weighted root mean square error for wind and solar power amounted to 3.59 % and 2.11 % in 2010 and to 3.60 % and 3.02 % in 2011.

Hypothesis II a: A positive quantity difference between the intraday and day-ahead forecast of RES will lead to sales on the GIME and decrease intraday prices.

Hypothesis II b: A negative quantity difference between the intraday and day-ahead forecast of RES will lead to purchases on the GIME and increase intraday prices.

Roon and Wagner (2009) analyze, if the difference between day-ahead and intraday prices at the EEX is influenced by the wind forecast error and find a weak correlation between the forecast error and the price difference. Nevertheless, a positive wind forecast error of 1000 MW (more wind than expected previously at the day-ahead gate closure) decreases intraday prices significantly by one Euro according to their analysis.

Load forecast error

Haubrich (2008) defines the load forecast error as the deviation of the realized per-quarter-hour mean load value from the forecasted load value. The daily system load is influenced by the time of the day, day of the week and random effects and strongly affects prices in deregulated electricity markets (Aggarwal et al. 2011). In the intraday market, the TSOs are responsible for managing the load forecast errors, presumably via price influencing sales and purchases in the GIME. Unfortunately there are no aggregated grid-wide load forecasts available for Germany.[5] For an empirical analysis of the influence of the load forecast error on hourly intraday prices data about the size of the hourly forecast error is needed which is not available for the time period 2010 to 2011.

Net foreign imports and exports

The ENTSOE (2011) calculates net transfer capacities (NTC) of 16585 MW for imports into Germany 15280 MW for exports respectively. NTCs which have not been used in day-ahead or long term auctions are freely available for intraday cross border trading (ETSO, 2007) and can be nominated explicitly or implicitly by market participants. Foreign market participants may close their open intraday positions on the German intraday market and vice versa. Lehmann et al. (2012) report significant increases of RES in bordering countries like Demark, the Neth-

[5] Estimated distributions for the absolute deviation between the day-ahead and intraday load forecast reach from an average of 225 MW and a standard deviation of 1154 MW (Haubrich 2008) to a density function with a mean value of 53.56 MW and a standard deviation of 644.67 MW (DENA 2010).

erlands, France and the Czech Republic over the last years. Along with this development, the importance of intraday cross border trades is raising, as e. g. Jorgensen and Ropenus (2008) note. Since EPEX Spot (2010) coupled only the German and French intraday markets in 2011, the French trades on the GIME will be considered as price determinants in this paper.[6]

Hypothesis III: French exports into the GIME are expected to decrease German intraday prices whereas imports to France are expected to increase German intraday prices.

Explaining price peaks in the GIME

During peak hours when demand meets supply in the steep end of the merit order, intraday prices might react asymmetrically to the same volume of net intraday demand and supply. Prices might rise higher and fall not so deep. The tendency of intraday prices to exhibit peaks strongly above day-ahead prices during peak hours can be explained by the non-linear shape of the merit-order curve, ramping costs and strategic behavior of market participants.

A surplus of intraday demand can only be satisfied by flexible conventional power plants which have not been marketed previously on long-term, day-ahead or balancing markets. For a merit order with a convex and steeply increasing right end, the aggregated capacity of power plants with up-ramping potential decreases as the price level increases and the marginal costs of each next unused power plant increase overproportionately. Consequently, intraday prices may increase as demand rises due to higher costs of the next marginal power plant which has to be activated to satisfy the net surplus of intraday demand. Figure III shows an exem-

[6] The Austrian intraday market has been coupled to Germany on the October 16th 2012 and the Swiss intraday market was coupled to Germany in 2013.

plary German merit-order curve for the delivery period from five to six pm on the January 24th, 2013. The equilibrium can be found at a day-ahead price of 77.14 € and a trading quantity of 23872.1 MW. For a hypothetical intraday excess demand of 1000 MW in this delivery hour, the intraday price level may rise from the day-ahead equilibrium of 77.14 € to 190.20 €, whereas the price decrease due to an excess intraday supply of 1000 MW is from 77.14 € to 59 €.

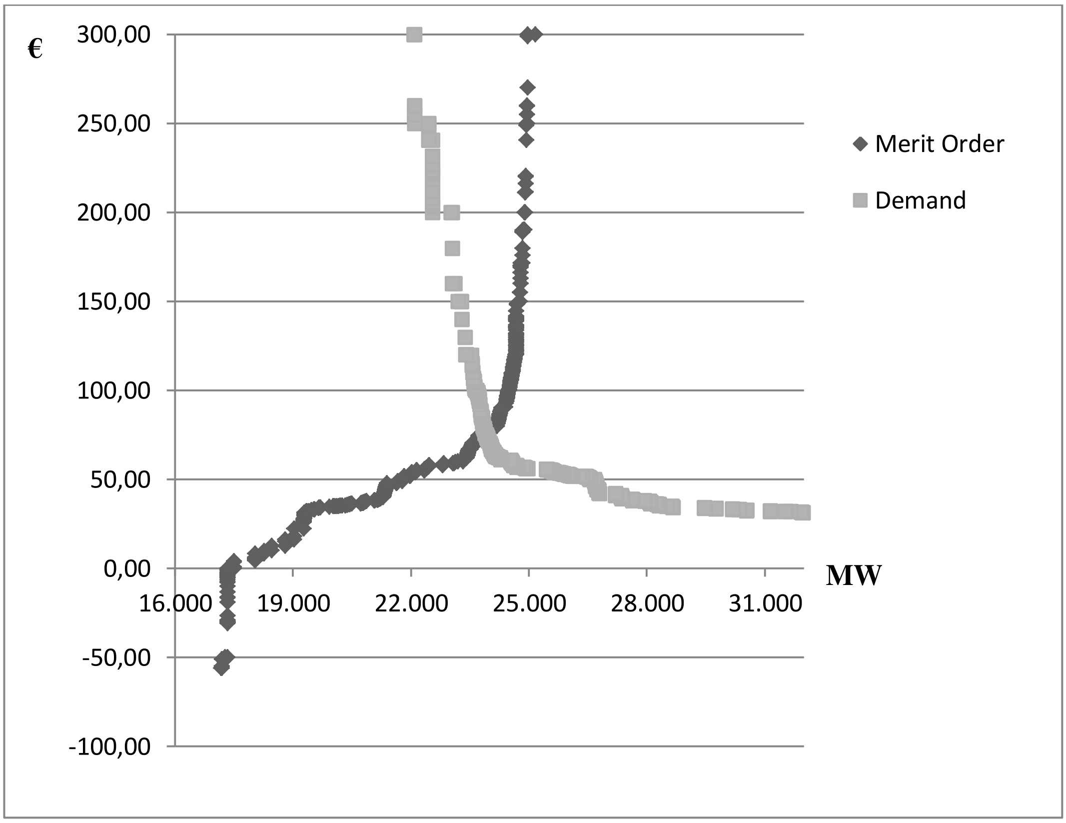

Figure III: German day-ahead demand and supply (merit-order) curves for the delivery hour from five to six pm of the august 7th 2012. *Source:* Author, based on data from the EEX.

A further reason for intraday price peaks may be ramping costs. Profit maximizing power plant owners will only activate unused flexible power plants at a price that ensures the recovery of all marginal and ramping costs. Ramping costs like startup depreciation due to increased forced outage rates, additional maintenance and loss of life expectancy increase the costs of a spontaneous short term dispatch significantly. Furthermore the balancing and fuel costs during the up and down ramping period when the power plant has not yet reached its scheduled output increase the total ramping costs. Traber and Kemfert (2011) estimate that the ramping depreciation of natural gas power plants amounts to 10 €/ MW for each up-ramping procedure. Under the assumption that at the steep end of the merit-order only natural gas plants are available as upward capacities, one would expect an intraday price jump of at least 10 € in addition to the merit-order effect during the first production hour if gas-fired power plants are being ramped up to satisfy an intraday demand surplus.

In addition to the fundamental explanation of extreme intraday prices, strategic behavior may also contribute to explain intraday price peaks. In such tight hours the number of market participants with the ability to deliver upward or downward capacities is already low (Bowden and Payne, 2008). Market participants with flexible power plants may then exploit their temporal monopolistic or oligopolistic market power and charge prices which do not reflect marginal generation or ramping costs but the willingness to pay of market participants in need of upward ramping flexibility.[7] Thus, in addition to ramping costs and the merit-order effect, the market participants' strategic behavior may contribute to the emergence of price peaks.

Hypothesis IV: During delivery hours with day-ahead prices above 55 Euro, intraday prices are on average higher than day-ahead prices.

[7] In 2010 and 2011, the willingness to pay in the GIME was capped by the expected prices for negative and positive balancing services. From winter 2012 on, balancing services will be priced with regard to intraday prices and will always exceed the average hourly intraday price. Hence, intraday prices are not capped anymore, market participants will always try to close open positions on the intraday market.

Explaining price sinks in the GIME

When the electricity demand is low and meets supply at the non-linear concave beginning of the merit-order, intraday prices might react asymmetrically to a net intraday demand and supply surplus in the way that intraday prices rather tend to fall below than to rise above day-ahead prices. Furthermore, price sinks may also be explained by ramping costs and strategic behavior of market participants.

A supply surplus in the intraday market can be absorbed by operating power plants with downwards flexibilities and marginal costs below day-ahead prices. For a merit-order beginning with a concave slope (figure III), the aggregated capacity of power plants with down-ramping potential decreases as the price level decreases and the marginal costs of each next operating power plant also decrease overproportionately. Consequently, intraday prices may fall sharply as supply increases because the marginal costs of the next power plant which has to be deactivated to compensate the net surplus of intraday supply are disproportionately lower.

At the beginning of the merit-order, must-run capacities and base load plants satisfy the electricity demand. To ramp base load plants down below their minimum load threshold or up from a downtime is costly. Troy et al. (2010) argue that such a schedule reduces the lifetime of parts that are exposed to high pressure and heat and pushes up inspections and repairs. Nicolosi (2010) explains that opportunity costs occur if the prices of hours after shutting down rise above the plant's marginal costs and the plant cannot be started up fast enough to deliver in those hours. The number of thermal power plants which can operate at their minimum load level or can even be shut off completely is being further reduced by must-run capacities which stand ready to provide negative balancing services or heat. Profit maximizing power plant operators require the optimization profit to be strictly positive before they shut down an operating base-load plant. Therefore, the intraday price has to be low enough to compensate the ramping and opportunity costs plus a profit margin before a power plant operator buys electricity on the intraday market to ramp or shut a power plant down.

Finally strategic behavior of market participants during tight market situations may also contribute to the explanation of intraday price sinks. Day-ahead price sinks usually occur at times when the electricity demand is low. This is typically the case during off-peak hours from eight pm to eight am or during weekends.[8] The number of actively trading intraday market participants is low at those times because small energy companies with small intraday positions will rather prefer to pay imbalance costs than employ a costly shift team for the off-office hours. The remaining owners of down ramping flexibilities may temporally charge monopolistic or oligopolistic prices which do not reflect marginal generation, ramping or opportunity costs but the willingness to pay of market participants in need of downward ramping flexibility. The concave part of the merit-order begins at a negative price level and ends at roughly 35 Euros. Thus, hypothesis V will be formulated as:

Hypothesis V: During delivery periods with day-ahead prices below 35 Euro, intraday prices are on average lower than day-ahead prices.

[8] Since 2012 the installed capacity of solar and wind power plants increased significantly. This development may increase the probability of comparably low day-ahead prices even during noon on working days when an average wind power production coincides with a high power production from solar power plants.

Other determinants

The intraday optimization of the electricity production from combined heat and power (CHP) plants is certainly an important determinant of intraday prices. According to the UBA (2013), a capacity of around 20 GW_e of CHP plants is installed in Germany.[9] The CHP power plant fleet is fired by diverse fuels like by biomass, lignite, gas, hard coal and oil. The intraday market optimization of a CHP plant depends on the hourly intraday prices, plant specific marginal costs of electricity production, the amount of previously sold electricity and the intraday changes in heat demand. The latter three factors are only known to the individual power plant operator. Hence it is too complex for the scope of this paper to model the intraday activities of CHP plant operators.

Another determinant of intraday prices may be intraday trading positions. Until the end of 2011 market participants could transfer long or short positions from the day-ahead into the intraday market as noted by the ETSO (2007). Market participants could then profit from expected price differences between both markets. Those trading positions both increased intraday demand or supply and thus may have influenced intraday prices. Trading positions have been created by market participants according to their individual market expectations and are not observable.

[9] GW_e stands for electrical output in Gigawatt. Considered are only power plants with an electrical capacity above 100 MW.

4 EMPIRICAL ANALYSIS

4.1 Research method and data

A multiple regression is run on a time series of the difference between the hourly day-ahead and quantity weighted average intraday prices. The measureable price determinants described in chapter three are used as independent variables. As for other time series, regression variables and residuals are expected to show positive autocorrelation which leads to biased standard errors if the model is estimated using the ordinary least squares method (Petersen, 2008). Wooldridge (2011) recommends to use the Newey-West procedure to calculate heteroskedasticity and autocorrelation (HAC) consistent standard errors.

The data used covers the period from January 1st 2010 to December 31st 2011 and stems from different sources. The day-ahead prices, intraday prices, transaction lists, trading volumes and unplanned outages of power plants with a capacity larger than 100 MW are provided by the EPEX Spot and EEX. A yearly profile of the total unplanned hourly outage capacity with relevance for intraday trading is calculated from the unplanned outages data provided by the EEX.

Wind and solar day-ahead forecasts and the actually realized infeed have been collected from the websites of the four TSOs and their common online platform www.eeg-kwk.net. The wind and solar power values are provided as quarter of an hour data and were averaged to hourly values before the analysis. Concerning the solar day-ahead forecast and infeed, data is missing completely or partly in 2010, because the publication of such data is only obligatory, if the installed solar capacity exceeds a certain threshold.

Before the regression is performed, outliers of the dependent variable that may bias the regression results are identified and replaced. In this paper an observation is defined as an outlier if it deviates more than six times the standard deviation from the mean.[10] Positive outliers are replaced by the mean value plus six times the standard deviation (50.47) while negative outliers are replaced by the mean value minus six times the standard deviation (-49.25). In total, 28 observations or 0.07 % of all observations are replaced through this procedure.

4.2 Empirical results

Table I: Descriptive statistics of the volume-weighted average hourly intraday prices and the difference between the volume-weighted average hourly intraday and the day-ahead price for different blocks of the day from 2010 to 2011. The descriptive statistics were calculated after treating the outliers, thus the minimum and maximum prices for different blocks of the day are equal. All mean values are different from zero with a significance level below 0.01 as indicated by ***.

	Intraday price	**Intraday price – day ahead price**			
	Base	**Base**	**Off-peak I**	**Peak**	**Off-peak II**
N (missing)	17512 (9)	17512 (9)	5836	8756	2920
Mean €	48.41***	0.61***	0.80***	0.43***	0.78***
Standard deviation €	16.25	8.06	8.61	7.99	7.04
Minimum €	-139.07	-49.25	-49.25	-49.25	-49.25
Maximum €	180.07	50.47	43.62	50.47	50.47
Skewness	-0.48	-0.12	-0.79	0.45	-0.155
Excess kurtosis	5.35	7.29	8.50	6.25	6.39

[10] Previous research defined an observation as an outlier it fit deviates more than three times the standard deviation from the mean (Cf. Ketterer, 2012 or Mugele et al., 2005). In the present study, eliminating outliers that deviate more than three times the standard deviation from the mean does not change the overall model fit or the size of the regression coefficients significantly but more observations are treated before the analysis.

The descriptive statistics in table I reveal several peculiarities of the German intraday prices. Despite the high price volatility indicated by a standard deviation of 16.25 and the repeated occurrence of extreme intraday prices (minimum and maximum values beyond -49.25 € and 50.47 €), the average deviation between the volume weighted hourly intraday price and the hourly day-ahead price is quite small with a value of 0.61 € in the base case.

Table II: Overall regression model results for different block periods of a trading day with the difference between the average hourly intraday and hourly day-ahead prices as the dependent variable.

	Base	**Off-peak 1**	**Peak**	**Off-peak 2**
R square	0.1861	0.2000	0.2108	0.2193
Adjusted R square	0.1854	0.1981	0.2095	0.2155
Standard error of regression	7.27	7.71	7.11	6.24
F value of regression	285.67	103.94	166.77	58.28
Model significance	0.00	0.00	0.00	0.00
Durbin-Watson statistic	0.43	0.67	0.48	0.79
Observations	17512	5836	8756	2920
Prewhitening lags	12	9	10	7

Linear regressions are performed for different block periods of the trading day. The base captures the whole day while the peak is defined as the time from eight am to eight pm. The off-peak one is defined as the time from zero to eight am and the off-peak two as the time from eight pm to midnight. The overall model results in table II show adjusted R square values between 0.1854 and 0.2155.[11] These model fits are too low to make predictions about future price differences between the hourly average intraday price and the day-ahead price but the overall model

[11] The histogram of the residuals reveals that they show heavy tails (skewness of -0.17, kurtosis of 8.36 and a mean of 5.48^{-16}).

significance of < 0.01 implies that determinants that are significantly different from zero are identified.[12] Following the recommendation of Wooldridge (2011), the prewhitening lag length in the Newey-West regression is set to $n^{1/4}$ where n is the sample size.

Table III: Regression coefficients for different blocks of the day with the dependent variable being the difference between the hourly average intraday price and the hourly day-ahead price. Significance at the 0.01 level are indicated with three stars behind the coefficient (***), while significances at the 0.05 level are indicated with two stars (**) and on the 0.1 level with one star (*). Variance inflation factors (VIF) for the base-period regression are also reported.

	Hypothesis	**Base**	**Off-peak 1**	**Peak**	**Off-peak 2**	**VIF**
Intercept		-0.56989	-0.28586	-0.97269*	-0.40114	
Outages	H I +	0.00073***	-0.00012	0.00109***	0.00113***	1.20
Wind sell total	H II a -	-0.00261***	-0.00346***	-0.00246***	-0.00239***	1.11
Wind buy total	H II b +	0.00314***	0.00472***	0.00286***	0.00225***	1.07
Solar sell total	H II a -	-0.00142**	0.00077	-0.00204***	-0.01781	1.30
Solar buy total	H II b +	0.00043	-0.00188	0.00082**	-0.00175	1.24
Volume sell France	H III -	0.00027	0.00673**	-0.00073	-0.00001	1.20
Volume buy France	H III +	0.00117	0.00769***	0.00003	0.00283**	1.25
DAP < 15 €	H V -	2.55869*	2.01278	2.56959	31.1555***	1.35
15 € <= DAP < 25 €	H V -	1.19893*	0.66223	2.29292	8.27549**	1.55
25 € <= DAP < 35 €	H V -	0.20221	0.38033	-0.52303	1.46391	1.67
35 € <= DAP < 45 €		0.00807	-0.10186	-0.68693*	0.3727	1.56
55 € <= DAP < 65 €	H IV +	-0.57306**	-0.35359	-0.32933	-0.78613**	1.51
65 € <= DAP < 75 €	H IV +	-1.02071**	-1.20716	-0.66805	-1.4199*	1.49
DAP >= 75 €	H IV +	-0.41682	-4.30533	0.13972	-3.42257	1.24

[12] One may argue that the difference between the last intraday trade price per delivery hour and the hourly day-ahead price may be used as the dependent variable in the regressions because the last trade is being executed after all available information for the delivery hour has been incorporated into the market. In this paper, the difference between the volume weighted average intraday price and the day-ahead price is used, because the volume weighted average intraday price mirrors all information available until the end of the trading period and thus not only the final market equilibrium but also all previous equilibriums. However the model is robust to a change of the dependent variable. A regression analysis with the difference between the hourly last intraday trade price and the day-ahead price yields similar results as the regression analysis presented here in detail (table VI and table VII in the appendices).

The unstandardized regression coefficients and significances are presented in table III. Asymmetric effects of intraday demand and supply on intraday prices due to the merit-order shape, ramping costs and strategic behavior are tested with dummy variables. Seven dummies for price regions in the merit-order are defined (< 15 €, 15-25 €, 25-35 €, 35-45 €, 55-65 €, 65-75 €, > 75 €). If asymmetric effects exist, one would expect the dummies representing the beginning of the merit-order (up to 35 €) to have negative regression coefficients and the dummies representing the end of the merit-order (> 55 €) to have positive ones in comparison to the reference case of the price region 45-55 €.[13] Except the dummies for the day-ahead prices between 25 and 35 € and above 75 €, all regression coefficients have a significant influence in at least one regression model. The variance inflation factors (VIF) in table IV are reported for the base-period. The VIF for all other regressions are all below three except one VIF which has a value of 3.19. Because all VIFs are below critical thresholds, multicollinearity should not bias the regression slope estimators.

4.3 Discussion

In the first part of the discussion, the regression coefficients for the sample of all observations (base period) will be analyzed. In the second part, the regression coefficients for the off-peak one, peak and off-peak two period and their significances will be compared and differences will be discussed.

[13] As two alternative measures for the influence of extreme day-ahead prices on the intraday price formation, the difference and the squared difference between the hourly day-ahead price and the two years average day-ahead price of 47.81 Euro is calculated. Afterwards, each time series is included separately as an independent variable in the regression model but the regression coefficient is insignificant in both cases.

The algebraic signs of the regression coefficients of outages (+0.73 €/ GWh), wind power forecast errors (sell -2.61 €/ GWh, buy +3.14 €/ GWh) and solar power forecast errors (sell -1.42 €/ GWh, buy 0.43 €/ GWh) in the regression for the base period are as expected. An intraday surplus of wind and solar power production significantly decreases intraday prices while unplanned power plant outages or a lacking wind power production lead to purchases and significantly increase intraday prices. An intraday shortage in solar power production also seems to lead to purchases because intraday prices are increasing with this explanatory factor, but the regression coefficient is insignificant in the base-period. Thus, hypotheses I and II are not falsified. French trades did not have a significant influence in the base period in 2010 – 2011, hence hypothesis III is rejected. This may be due to two reasons. First of all, French counterparts were only able to trade via the electronic intraday platform since December 2010. Thus, French trades are considered only for one year. Secondly, the electricity company EDF has basically a monopoly on the electricity production in France and thus may compensate most deviations from the day-ahead planning within its own portfolio and is not forced to trade externally in the intraday market at all. Thus, the trading activity of French counterparts is typically low.

Surprising are the differences in the absolute values of the regression coefficients. Considering the fact that electricity is a homogenous good, a one MW trade in the GIME due to a change of any driver can be expected to have a similar effect on the price. One reason which may explain the differences may be that forecast errors and outages are being traded only partly and by different portfolio owners via the electronic trading platform.[14] The total amount of forecast errors and outages

[14] To explore how much of the total outage and forecast error volumes are actually traded by market participants in the GIME, a regression of the price determinants on the total hourly trading

may not equal the traded quantity in the GIME because market participants match opposing positions within their portfolio first before they trade the net imbalance in the intraday market. The regression of the price determinants on the hourly trading volume (tables V and VI) reveals that about one third of the solar forecast errors and 54 % of the wind forecast errors were traded in the GIME. The TSOs who were responsible for the marketing of the RES in 2010 and 2011 may have matched complementary positions from wind, solar and load forecast errors within their portfolio first before they traded the net deviation in the GIME. The small amount of solar forecast errors having been traded in the GIME may indicate that the TSOs did not trade this forecast errors as actively as wind forecast errors. Furthermore, the TSOs may have balanced the forecast errors at least partly through the activation of balancing services. Of the outages, only 19 %were traded in the GIME from 2010 to 2011 which may also explain the smaller impact of outages on intraday prices. In Germany, the major share of production capacity is owned by four electricity companies.[15] Therefore, it seems plausible that these companies can often compensate power plant outages by ramping up their own unused power plants or buy electricity from one of the other three large producers bilaterally instead of trading anonymously in the GIME.

Hypothesis IV can be rejected. During delivery periods with day-ahead prices above 55 Euro, intraday prices tend to be lower than day-ahead prices. An explanation for this observation may be that day-ahead prices above 55 Euro often oc-

volume is performed (table VI and table VII in the appendices). Again, the Durbin-Watson statistic of 0.32 indicates positive autocorrelation in the residuals wherefore the standard errors are estimated using the Newey-West algorithm. The adjusted R square of 0.4111 indicates a moderate model fit and all independent variables have a highly significant and positive influence on trading volume.

[15] According to the BNA (2012) and BNA (2013), E.ON, RWE, Vattenfall and EnBW owned 77 % of the conventional production capacities in Germany in 2010 and 72 % in 2011.

cur because the expected production of wind and solar power is low.[16] In this case, the probability of a significant intraday increase of the production of intermittent renewable energy sources is larger than the probability of an intraday decrease. An increase of positive forecast errors leads to sales in the intraday market and thus significantly decreases intraday prices and may explain the significantly negative coefficients of the dummy variables for the day-ahead prices between 55 and 75 Euro.

The dummy variables for delivery periods with day-ahead prices below 35 Euro are either insignificant or significantly positive. These empirical results lead to the rejection of hypothesis V and indicate that the operating base load plants have enough downward ramping potential and may compensate excess supply in the intraday market. Furthermore the tendency of intraday prices to rise above day-ahead prices during hours with day-ahead prices below 35 Euro indicates that the short term supply- or merit order curve is steep during the hours with low day-ahead prices, thus leading to larger price impacts of purchases. The steep slope of the intraday merit-order curve during hours with day-ahead prices below 35 Euros can be explained from a fundamental perspective. Intraday demand cannot be compensated in the short run by hard coal fired power plants (which would be the next unused power plant technology in the day-ahead merit-order) because these power plants require lead times of several hours to start production. Thus, in the short run intraday demand may only be compensated by flexible generation units like gas-turbines with high marginal costs. Furthermore highly flexible water pump storage power plants may supply power in the very short run. The opportunity costs to use this power plant technology during hours with prices below 35

[16] For the price decreasing effect of intermittent renewable energy sources on German day-ahead prices consider Ketterer (2012); Sensfuß (2011); Scharff/ Amelin (2011).

Euros equal the peak prices because the unplanned usage and reduction of the water storages during hours with low prices reduces the sale potential during hours with high prices.[17] Thus profit maximizing owners of hydro pumped storages require at least peak prices to improve their profits ceteris paribus.

In addition to regressions for the entire sample, separate regressions for the off-peak one, peak and off-peak two periods have been computed (tables II and III). The coefficients in the three regressions are partly different in size and also show alternating significances.

The influence of unplanned outages on the difference between intraday and day-ahead prices during the off-peak one period is negative and insignificant. One may rather expect a large positive and significant coefficient because the liquidity in terms of trading volume, the bid ask-spread and price volatility in the GIME is low during the off-peak one as shown by Hagemann and Weber (2013). During hours with low liquidity, the price impact of additional intraday demand can be expected to be large and increase intraday prices. There are basically two considerations explaining the missing influence of power plant outages on intraday prices during the off-peak one. Firstly, the concentration of production capacity in the German electricity market may enable power plant owners to compensate outages within their own portfolios or via purchases from one of the other three large producers via unobservable OTC trades. The second explanation is that a share of the defaulting power plants has marginal costs above the day-ahead prices of the off-peak one and is not operating at night anyway. Hence, these outages do not lead to purchases during the off-peak one.

[17] Water pump storages power plants usually consume (pump water up) power when the prices are low and produce (turbine) power when prices are high, thus profiting from the price spread between the peak and off-peak periods.

The price impact of wind forecast errors on intraday prices during the off-peak one period is highly significant and between 41 and 110 percent higher than during the rest of the day. This observation may indicate that the short term supply and demand curves are steeper at night, leading to larger price impacts when the TSOs trade wind forecast errors during the off-peak one. The demand and supply curves may be steeper during the off-peak one because the number of active market participants is lower during the night which reduces competition and liquidity. Furthermore the impact of purchases during the off-peak one (4.72 Euro/ GWh) is larger than the impact of sales due to wind forecast errors (3.46 Euro/ GWh).[18] This indicates that the supply curve is even steeper than the demand curve during the off-peak one which underlines the previous conclusion that the intraday supply-curve is steep because the supply-side is inflexible and thus unable to supply liquidity at day-ahead prices in the short run.

Solar forecast errors only have a significant influence on intraday prices during the peak period, because solar predominantly only produces during this period.[19] The influence of an unexpected intraday excess supply of solar power on intraday prices is more than twice as strong and has a higher significance as the influence of a lack of solar power. This observation is difficult to explain, it may be because solar forecast errors were only partly handled through intraday trades by the TSOs in 2010.

French purchases have a significant influence on intraday prices during the off-peak periods. Nevertheless, it contradicts hypothesis III that French sales increase

[18] A Wald-test is used to calculate the statistical significance of the difference of the wind purchase and wind sale coefficients. The test results show a 0.0 probability for the hypothesis that both coefficients are equal.

[19] The average forecast error of the solar power production during the off-peak on is 15.39 MWh, during the peak 292.20 MWh and during the off-peak two 3.46 MWh.

intraday prices significantly during the off-peak one period by 6.73 Euro.[20] The meaning of the French sales coefficient within the model cannot be explained plausibly and should not be considered as a systematic influence on intraday prices.

5 CONCLUSION AND OUTLOOK

This paper presented an analysis of the price formation process and price determinants in the German intraday market for electricity. Significant determinants of the price difference between the German day-ahead and intraday markets are identified. The empirical analysis confirms that wind forecast errors, solar forecast errors and outages have significant influences on intraday prices. French trades affect intraday prices only during the off-peak periods significantly. Asymmetric price effects are identified which may be attributed to the shape of the merit-order, ramping costs or strategic market behavior, yet they do not affect intraday prices as expected initially. Intraday prices tend to be higher (lower), when the day-ahead prices are below 35 Euro (above 55 Euro). Ex-post explanations for those empirical observations are delivered. The regressions for different blocks of the day reveal a stronger price impact of the wind forecast errors during the time from midnight to eight am which indicates that the intraday demand- and supply-curves are steeper at night. A temporal market concentration due to a smaller number of active market participants during the night and inflexibility of base-load plants to satisfy intraday demand in the short run may explain the larger price impact of wind forecast errors during this off-peak I period. The comparably high share of

[20] Because the French intraday market was coupled to the German intraday market in December 2010, the regression model for the off-peak one was also calculated with a subsample containing only data from December 2010 to December 2011. In this regression the influence of French sales on German intraday prices remained positive (4.61 €) but insignificant.

unexplained variance in the regression model may be due to unobservable determinants like the intraday optimization of CHP plants, intraday trading positions, load forecast errors and foreign demand and supply from other countries than France.

Further research might focus on the analysis of so far unobserved determinants, as further data about the intraday use of net transfer capacities and the hourly load forecast error becomes available. Since 2012, the direct marketing of the electricity production from wind turbines by different electricity companies may have changed the price impact of the wind forecast error on intraday prices. The TSOs are forced by regulation to invest their profits into the expansion of (cross boarder) transmission capacities or to lower the grid tariffs and thus are not really profit maximizing companies. The profit maximizing direct marketers may trade more cautiously than the TSOs in the intraday market in order to increase their profits, which may lead to a different price impact of wind forecast errors. Interesting from a theoretical point of view may be the empirical analysis, if a fundamental merit-order model can explain the intraday price formation. The influence of redispatch on the liquidity provision and price formation in the intraday market may also be a further research topic.

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7 APPENDICES

Table IV: Overall regression results with the difference between the hourly last intraday trade price and the day-ahead price as the dependent variable.

	Intraday Price – Day Ahead Price
R square	0.127730
Adjusted R square	0.127032
Standard error of regression	15.08132
F value of regression	182.9805
Model significance	0.000000
Durbin-Watson statistic	1.256404
Observations	17509

Table V: Regression coefficients, standard errors, t-statistics, significances and variance inflation factors with the dependent variable being the difference between the hourly last intraday trade price and the day-ahead price.

	Hypothesis	Coefficient	Standard error	t-statistic	Probability	VIF
Intercept	-	-1.217522	0.568994	-2.139781	0.0324	
Volume Buy France	+	0.001142	0.001545	0.739586	0.4596	1.37
Volume Sell France	-	-0.002014	0.001305	-1.543285	0.1228	1.17
SOLAR Buy Total	+	0.001217	0.000437	2.784150	0.0054	1.21
SOLAR Sell Total	-	-0.002761	0.001350	-2.044110	0.0410	1.55
Wind Buy Total	+	0.004892	0.000381	12.84699	0.0000	1.19
Wind Sell Total	-	-0.004540	0.000558	-8.140203	0.0000	1.35
Outages	+	0.001301	0.000326	3.991423	0.0001	1.29
DAP < 15 €	-	2.700721	2.233719	1.209069	0.2267	1.25
15 € <= DAP < 25 €	-	1.176185	1.157400	1.016231	0.3095	1.50
25 € <= DAP < 35 €	-	-0.225218	0.501954	-0.448683	0.6537	1.39
35 € <= DAP < 45 €		-0.540980	0.337792	-1.601519	0.1093	1.48
55 € <= DAP < 65 €	+	-0.437892	0.387048	-1.131363	0.2579	1.36
65 € <= DAP < 75 €	+	-0.074216	0.791863	-0.093723	0.9253	1.31
DAP >= 75 €	+	1.374847	2.081950	0.660365	0.5090	1.14

Table VI: Overall regression results with the hourly trading volume (MWh) in 2010 and 2011 as the dependent variable.

	Volume
R square	0.4113
Adjusted R square	0.4111
Standard error of regression	859.28
F value of regression	3056.75
Model significance	< 0.01
Durbin-Watson statistic	0.32
Observations	17508
Prewhitening lags	12

Table VII: Exogenous variables explaining the hourly trading volume.

	Coefficient	**Standard error**	**t-Statistic**	**Probability**	**VIF**
Intercept	464.12	36.76	12.62	0.00	
Volume French trades	2.061439	0.095666	21.55	0.00	1.21
Solar volume	0.303780	0.063225	4.80	0.00	1.19
Wind volume	0.537602	0.024798	21.68	0.00	1.02
Outages	0.185097	0.025824	7.17	0.00	1.02