

Eicke, Anselm; Ruhnau, Oliver; Hirth, Lion

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Electricity balancing as a market equilibrium

Estimating supply and demand of imbalance energy

Anselm Eicke^{a*}, Oliver Ruhnau^a, Lion Hirth^{a,b}

Anselm Eicke and Oliver Ruhnau shared their contribution to this paper

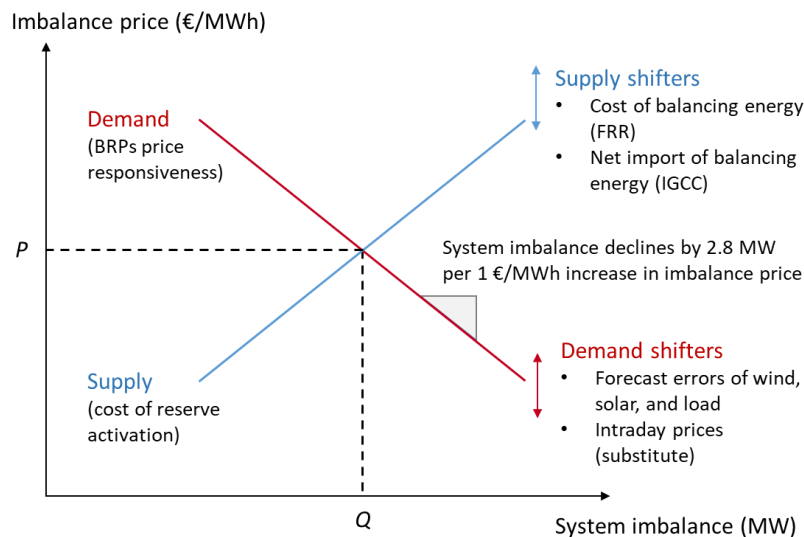
^a Hertie School, Berlin, Germany

^b Neon Neue Energieökonomik GmbH

*Corresponding author: Anselm Eicke, eicke@hertie-school.org, Hertie School, Friedrichstraße 180, 10117 Berlin

Abstract. Stable power systems require equalizing demand and supply of electricity at short time scales. Such electricity balancing is often understood as a sequential process: exogenous shocks, such as weather events or technical outages, cause system imbalances that system operators close by activating balancing reserves. By contrast, we study electricity balancing as a market where the equilibrium price (imbalance charge) and quantity (system imbalance) are determined endogenously by supply and demand. System operators supply imbalance energy by activating reserves. Market parties that, deliberately or not, deviate from schedules create demand for imbalance energy. When deliberately taking open positions, firms respond to price signals from electricity markets and imbalance charges. Based on this market framework, we estimate the demand curve of imbalance energy, and hence the price responsiveness of market parties to deviate from schedules. To overcome the classical endogeneity problem of price and quantity in the market equilibrium, we deploy instruments that we derive from a novel theoretical framework. Using data from Germany, we find that firms reduce the physical system imbalance by about 2.8 MW for each increase in the imbalance charge by EUR 1 per MWh. This price response is remarkable because such behavior is prohibited. It is, however, beneficial: on average, such strategic deviations reduced the German system imbalance by 20%.

Keywords: Electricity balancing, Intraday electricity market, Imbalance energy, Arbitrage trading



The equilibrium in the market for imbalance energy is determined by the intersection of supply and demand. In this paper, we estimate the supply and demand curves empirically, using supply and demand shifters as instruments to overcome the endogeneity problem of price and quantity.

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1 Introduction

Imbalances in power systems. In electric power systems, the consumption and production of electricity need to be balanced at every point in time. In European power systems, market parties such as generators and retail suppliers, referred to as balancing responsible parties (BRPs), must trade excess generation and consumption with other BRPs ahead of time and submit the resulting schedules to transmission system operators (TSOs). Firms that are out of balance, i.e. where physical quantities deviate from schedules, receive imbalance energy from TSOs. The aggregate of all individual deviations of firms within one balancing area is called the “system imbalance”.

Addressing and pricing imbalances. TSOs physically redress the system imbalance by activating different types of balancing reserves, thereby procuring balancing energy from balancing service providers. This results in costs which TSOs pass on to BRPs, whose imbalances are cleared at an imbalance (settlement) price, or imbalance charge. Two ways to set the imbalance price exist: some countries, including Germany, apply the same imbalance price for negative and positive deviations across all firms; others use dual price systems and/or discriminate between generators and loads (ENTSO-E, 2019). The temporal granularity of imbalance settlement varies between 15 mins (as in Germany) and 60 mins but is set to be harmonized at 15 mins (ENTSO-E, 2019). Firms can trade on short-term intraday wholesale electricity markets to avoid (or provoke) imbalances, i.e. to close or open positions. Many European intraday markets are organized as continuous trading, in contrast to day-ahead markets, in which only one auction is conducted per day (Ocker and Jaenisch, 2020). German intraday markets allow trading until between 30 and five minutes before delivery.

Linear perspective. Regulators, policy makers and system operators often understand electricity balancing as a linear process. Exogenous stochastic shocks (e.g. weather events that impact wind and solar generation or technical outages that affect power plants) cause deviations in the demand or supply of electricity. The aggregate of such individual deviations, the system imbalance, is resolved physically through the activation of balancing reserves by TSOs and settled financially at the imbalance price. From this viewpoint, there is no feedback from imbalance prices to market party behavior. This is in line with the legal situations in many European countries. In Germany, for example, connection contracts explicitly require market parties to minimize imbalances (Bundesnetzagentur (2020), Bilanzkreisvertrag, §5.2), regardless of imbalance prices. With this perspective in mind, long-term trends in the system imbalance must be caused by structural changes such as a shift in the generation mix, improved equipment reliability or enhanced weather forecasting (Joos and Staffell, 2018; Ocker and Ehrhart, 2017; Hirth and Ziegenhagen, 2015).

Feedback perspective. By contrast, the economic academic literature has long acknowledged the existence of a feedback from the imbalance price on the behavior of market parties (Figure 1). Several papers have shown theoretically that firms can increase profits by intentionally deviating from their schedules, depending on the imbalance price (Lisi and Edoli, 2018; Just and Weber, 2015; Chaves-Ávila et al., 2014; Möller et al., 2011). Such behavior exploits arbitrage opportunities between the electricity price on short-term intraday markets and the imbalance price. The economic implications of such strategic deviations are reflected in the imbalance price spread (Koch and Hirth, 2019):

$$\text{imbalance price spread}_t = \text{imbalance price}_t - \text{intraday price}_t \quad (1)$$

If the imbalance price spread is positive, it is beneficial for market parties to take a long position, i.e. to buy energy on the intraday market with the intention to “sell” it through the imbalance system. This can be done by actively buying on the intraday market (opening a long position) or by not selling excess energy (not closing a long position). Alternatively, firms can make a profit by going short if the imbalance price spread is negative. This is essentially arbitrage trading between two stages of the electricity market. Note that such arbitrage might violate legal obligations. For example, it is a breach of the balancing contract between BRPs and TSOs in Germany.

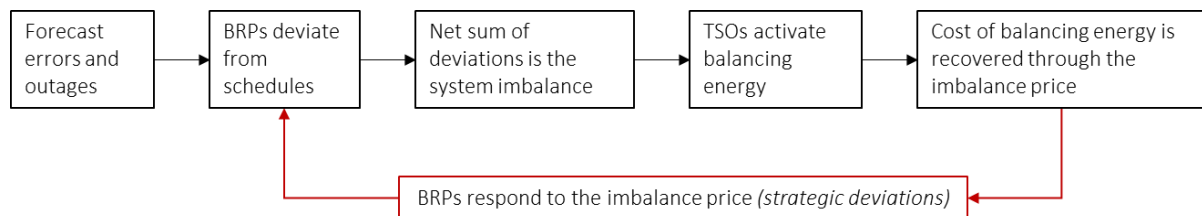


Figure 1: Feedback perspective on the balancing system: BRPs respond to the imbalance price

Strategies. To benefit from the imbalance price spread, BRPs need to compare the imbalance price and intraday price. While the intraday price can be directly observed from open bids in order books, imbalance prices are published only after the intraday gate closure. In some countries (e.g. NL and BE), this is done within minutes; in others, such as Germany, only about a month later (Datencenter der deutschen Übertragungsnetzbetreiber, 2020). In any case, the imbalance price is uncertain at the time of decision-taking on strategic deviations and BRPs would therefore need to predict the imbalance price (Koch, 2019; Just and Weber, 2015). An alternative strategy is to predict the system imbalance, given that usually system-stabilizing behavior is rewarded financially. Lisi and Edoli (2018) show that forecasting the sign of the system imbalance is possible in Italy and strategic deviations on this basis are economically viable.

Empirical evidence. Earlier studies have found empirical evidence for strategic deviations. Geographically, this literature is biased towards Germany, Benelux, and Italy. In the German market, Moeller et al. (2011) find systematic patterns in the system imbalance in the period 2003-09, which provided arbitrage opportunities. Just and Weber (2015) suggest that a simple strategy of going short at high spot prices and going long at low spot prices yielded, on average, profits during 2009-10. They report a correlation between spot prices and the system imbalance, which they interpret as evidence for strategic deviations. Such systematic arbitrage opportunities gradually disappear in the German market after 2011 (Hirth and Ziegenhagen, 2015), which Koch and Hirth (2019) interpret as the result of an efficient market fulfilling the non-arbitrage condition. Koch and Maskos (2019) demonstrate empirically a significant relationship between intraday trades and the most recent information about the system during 2016-18, which they attribute to firms’ strategic deviations. Table 1 summarizes the relevant publications to date that either discuss the theoretical possibility of engaging in arbitrage trading, propose trading strategies, and/or provide evidence that position taking occurs.

Table 1: Literature on strategic deviations

Theoretical potential	Strategies	Evidence
<ul style="list-style-type: none"> • Lisi and Edoli (2018): ITA • Just and Weber (2015): GER • Chaves-Ávila et al. (2014): GER, NLD, BEL, DNK • Moeller et al. (2011): GER 	<ul style="list-style-type: none"> • Koch (2019): GER • Koch and Maskos (2019): GER • Lisi and Edoli (2018): ITA • Just and Weber (2015): GER • Chaves-Ávila et al. (2013): NLD 	<ul style="list-style-type: none"> • Koch and Hirth (2019): GER • Koch and Maskos (2019): GER • Röben and de Haan (2019): GER, NLD, BEL • Just and Weber (2015): GER

Terminology. Deliberately taking an open position in the balancing system to exploit the imbalance price spread has earlier been referred to as *passive balancing* (Koch and Maskos, 2019; Hirth and Ziegenhagen, 2015; Chaves-Ávila et al., 2014). In this paper, we depart from this terminology, for two reasons. First, *balancing* suggests that these actions always reduce the system imbalance, which may not be the case. Koch and Maskos (2019) find that in 90-95% of the time, stabilizing behavior is rewarded, but in 5-10% of the time, incentives turn out to be perverse and firms that stress the system are rewarded. Second, the attribute “passive” depends on the perspective. If market parties respond to price incentives, TSOs can remain passive – they do not need to activate balancing reserves. The market parties engaging in speculation, however, are not passive at all. They need to actively conduct analysis, assess risk, take decisions, and trade. In the following, we will use the term *taking a position* for the deliberate decision of firms to open a gap between commercial schedules and metered quantities and *strategic deviations* for the resulting differences.

Our contribution. We study the balancing system as a market where the equilibrium price (imbalance charge) and quantity (system imbalance) are determined by supply and demand. TSOs supply imbalance energy by activating reserves they had procured in auctions; market parties demand imbalance energy by, deliberately or not, deviating from schedules. The net sum of these deviations determines the demand for imbalance energy. The contribution of this paper is three-fold: First, we develop a comprehensive and consistent framework to study electricity balancing as a market, in which the imbalance price and the system imbalance in every quarter-hour result from the intersection of supply and demand. We assume rational, profit-maximizing firms that respond to incentives while taking price and legal risk into account. Second, we estimate the demand curve empirically, i.e. the price elasticity of demand. To overcome the classical identification problem in market equilibriums, we use instrumental variables. To the best of our knowledge, we are the first to do so when it comes to electricity balancing. Third, we quantify the aggregate impact of strategic deviations on the system balance, carefully distinguishing ex-ante incentives from the ex-post financial settlement.

Findings. Using data from Germany during 2018-19, we focus on situations in which the absolute system imbalance exceeded 500 MW. On average, we find that firms respond to an increase in the imbalance price by EUR 1 per MWh with a reduction of the physical system imbalance by about 2.8 MW. This is supportive evidence for the notion of firms responding to economic incentives and supports our theoretical approach. It is also surprising given the fact that such behavior is prohibited. Analyzing the price responsiveness, we find that a EUR 1 per MWh change in the intraday price has a nearly three times larger impact on the system imbalance as compared to the imbalance price. This makes sense because intraday prices are known while imbalance prices are uncertain at the time of

trading. We calculate that such speculations reduced, on average, the German system imbalance by about 200 MW, or 20%.

2 Analytical framework

Market equilibrium. While many observers seem to understand the system imbalance as the result of exogenous stochastic processes, such as forecast errors and outages, we interpret the balancing system as a market for “imbalance energy”. As in any other market, the equilibrium quantity (system imbalance) and price (imbalance price) of imbalance energy emerge from the intersection of demand and supply curves (Figure 2).

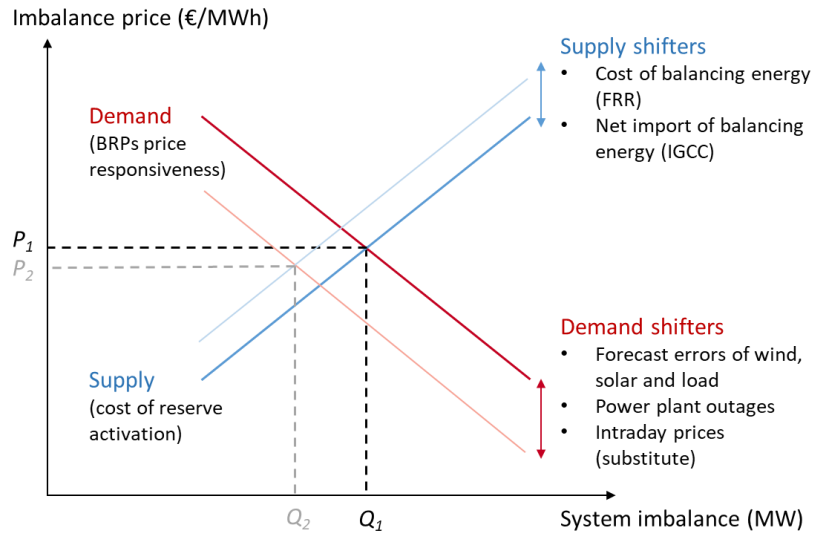


Figure 2: Schematic interpretation of the system imbalance and the imbalance price equilibria of the demand and supply of imbalance energy for two exemplary quarter hours t_1 and t_2

Short and long systems. Within our market framework, we distinguish positive and negative system imbalances. We use the following sign convention in this paper: a positive system imbalance means a net undersupply in the system (the system is short), and a negative sign implies a net oversupply in the system (the system is long). For simplicity, we focus on short systems first and subsequently extend the framework to long systems.

Imbalance energy vs. balancing energy. For clarity, we distinguish imbalance energy and balancing energy. *Imbalance* energy, for which we consider the supply and demand curves in our model, is the energy by which BRPs deviate from the schedule and for which they pay or receive the imbalance price. By contrast, *balancing* energy is provided by balancing service providers (i.e. reserve plants) previously contracted by TSOs. The system imbalance, which is the net sum of the imbalance energy, is mainly compensated through the activation of balancing energy. In addition, TSOs apply other balancing measures including international grid control cooperation (IGCC), and emergency measures (in the case of high imbalances).

Supply. Abstracting from the details of imbalance pricing, the supply curve of imbalance energy and thereby the imbalance price depends on the cost of activating balancing reserves. Because TSOs

activate balancing reserves in increasing order of energy prices, the supply curve has a positive slope¹: at higher system imbalances, more balancing reserves are activated, hence more expensive suppliers are needed, leading to higher prices. Note, however, that the energy price that balancing reserves receive upon activation may differ from the imbalance price (e.g. in Germany, balancing reserves are compensated based on their individual bids).

Demand. The demand for imbalance energy results from the net sum of the individual imbalances of all market parties in a balancing area. Hence both positive and negative deviations are included in the demand for imbalance energy. The slope of the demand curve reflects the responsiveness of BRPs to the imbalance price, i.e. the price elasticity of demand. If imbalances were the result of exogenous, stochastic processes and hence independent from economic incentives, or if BRPs respected the legal balancing obligation to ignore incentives, this curve would be vertical. Economically speaking, the demand for imbalance energy would be perfectly price-inelastic. Otherwise, if BRPs respond to changes in the imbalance price, the curve will be downward sloped: the higher the imbalance price, the lower the remaining system imbalance after strategic deviations.

Supply and demand shifters. Besides their interdependency, the system imbalance and the imbalance price are affected by exogenous shocks. These shocks can be differentiated into supply and demand shifters: supply shifters affect the position of the supply curve, whereas demand shifters relocate the demand curve.

Supply shifters. On the supply side, TSOs balance the system imbalance through the activation of balancing energy, IGCC, and emergency measures. The activation costs of balancing reserves result from the process of balancing procurement for specific delivery periods. In Germany, for instance, balancing energy is procured in daily auctions for four-hourly periods on the day ahead since July 2018. The energy bids submitted by the reserve providers vary over time because of changes in the opportunity costs of power plants, fuel and CO₂ costs, water value for pumped hydro storages, operational cycling constraints, and collusive behavior. The varying costs of balancing energy activation constitute a supply shifter: the higher this cost, the higher the imbalance price for the same system imbalance. In addition, IGCC can be interpreted as a supply shifter; the more balancing energy is substituted by IGCC, the lower the imbalance price for the same system imbalance.²

Demand shifters: forecast errors. In the short term, the demand curve is shifted by forecast errors of wind and solar energy and load as well as power plant outages: *ceteris paribus*, larger (net) forecast errors lead to a higher system imbalance for any given imbalance price. For example, surprisingly cloudy skies will decrease solar electricity generation, shifting the demand curve upwards, increasing the system imbalance. In the long term, it is plausible to believe that forecast accuracy is also, to some extent, endogenous to the price: the higher the imbalance price, the stronger the incentive to invest in better forecasting models.

Demand shifters: spot prices. If BRPs respond to economic incentives, the intraday price can be considered an additional demand shifter. At higher intraday prices, the economic incentive to sell (or

¹ Intuitively, one would expect a comparatively flat supply curve because agents can maximize profits by submitting bids close to the clearing price in repeated pay-as-bid auctions (Kahn et al., 2001). In balancing service auctions, however, prices for balancing energy activation are heterogeneous because the position in the merit order curve has a strong impact on the activation probability (utilization) (Ocker et al., 2018; Müsgens et al., 2014).

² We do not include IGCC in the econometric analysis in Section 3, because IGCC is only activated at high imbalance prices and hence the exclusion restriction does not hold, as we show in the following.

avoid buying) electricity at the intraday market is stronger, which increases the net sum of the deviations of the BRPs (all else being equal). In economic terms, buying energy at the intraday market (paying the intraday price) is a substitute for buying at the “imbalance market” (paying the imbalance price).

Long systems. Above, we have outlined our analytical framework for short systems. It can be symmetrically applied to oversupplied (long) systems (Figure 3). In this case, the negative system imbalance can be interpreted as a demand for negative imbalance energy. In other words, one can think of two different markets for two different products: positive and negative imbalance energy. This aligns with the procurement of balancing reserves, which is often organized in separate auctions for upward (positive) and downward (negative) reserves. These different types of reserves have diverging opportunity costs, for instance negative reserves sometimes have a negative energy price, i.e. a payment from balancing service providers to TSOs (Hirth and Ziegenhagen, 2015). As a result, the supply curve for positive imbalance energy is shifted by the activation price of upward reserves, while the supply curve for negative imbalance energy is shifted by the activation price of downward reserves. All other shifters apply equally for short and long systems.

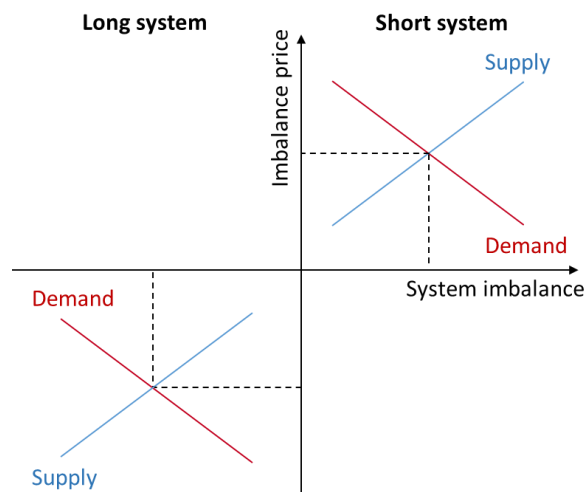


Figure 3: The market equilibrium is established where demand for and supply of imbalance energy intersect. It is helpful to think of two distinct markets for positive and negative imbalance energy.

Interpretation. This economic framework of an “imbalance market” helps clarify, and test, the implications of balancing incentives. Of course, the imbalance pricing mechanism is not designed as a marketplace where BRPs and TSOs explicitly agree on prices and quantities in bilateral trades or negotiations. Instead, BRPs deviate from their schedules and TSOs have no choice but to balance the net sum of these deviations. However, TSOs charge a quantity-dependent price, the imbalance price, and BRPs may choose their deviations based on their expectations of this price. This holds true even in countries where responding to balancing incentives is prohibited, such as in Germany, as we show in the following.

Balancing incentives. In the framework, economic incentives arise from the imbalance price and the intraday price. A downward-sloped demand curve, which is shifted by the intraday price, can be interpreted as BRPs responding to these incentives. We do not explicitly focus on the imbalance price spread but on its two determinants: imbalance and intraday prices. This allows distinguishing their individual characteristics, e.g. the uncertainty involved with the imbalance price.

3 Empirical methodology

We test our framework and examine strategic deviations in the German electricity market.³ We are particularly interested in the demand for imbalance energy and how this demand responds to the imbalance and intraday prices. In our framework, this price responsiveness appears as the slope and as a shifter of the demand curve, respectively. While the intersection of the demand and supply curves can directly be observed as the equilibrium price (the imbalance price) and quantity (the system imbalance), the curves themselves, including their slope and shifters, cannot. This is a classic econometric identification problem, which we address by using instrumental variables and by estimating both curves simultaneously (MacKay and Miller, 2018). Model and data are presented in the following.

3.1 Econometric model and identification strategy

Equations for supply and demand. As in other markets, price and quantity of imbalance energy mutually depend on each other. We therefore estimate the equations for supply (Equation 2) and demand (Equation 3) simultaneously. In this system of equations, the imbalance price and the system imbalance are both dependent and independent variables. For simplification, we assume linear demand and supply curves. Additional explanatory variables, or covariates, are the supply and demand shifters (MacKay and Miller, 2018). As discussed in Section 2, they are exogenous shocks, which affect the position of the curves. Based on Brijs et al. (2017) we use forecast errors as covariates for the demand curve and extend the model by adding the intraday price as additional covariate. The supply curve is different for short and long systems (Section 2), for which we account for with a dummy variable. As covariate for the supply curve, we employ a weighted average of the energy prices of positive and negative frequency restoration reserves (FRR), respectively. We assume a linear relationship for all covariates. Data sources and descriptive statistics are described in Section 3.3.

$$\text{Supply: } P_t = \alpha_1 \cdot Q_t + \alpha_2 \cdot \text{IGCC}_t + S_t \cdot (\alpha_{3S} \cdot \text{FRR}_t^+ + \alpha_{0S}) + L_t \cdot (\alpha_{3L} \cdot \text{FRR}_t^- + \alpha_{0L}) + \varepsilon_t \quad (2)$$

$$\text{Demand: } Q_t = \beta_1 \cdot P_t + \beta_2 \cdot \text{ID1}_t + \beta_3 \cdot \text{err}_{load,t} + \beta_4 \cdot \text{err}_{solar,t} + \beta_5 \cdot \text{err}_{wind,t} + S_t \cdot \beta_{0S} + L_t \cdot \beta_{0L} + \mu_t \quad (3)$$

where,

Q	= System imbalance (MW)
P	= Imbalance price (€/MWh)
ID1	= ID1 Intraday price (€/MWh)
err _{load}	= Load forecast errors (MW)
err _{solar}	= Solar generation forecast errors (MW)
err _{wind}	= Wind generation forecast errors (MW)
IGCC	= International grid control cooperation (MW)
FRR _t ^{+/-}	= Weighted frequency restoration reserve price (upward: + / downward: -) (€/MWh)
S, L	= Dummy variables for short (S) and long (L) systems
β _{1,2}	= Price responsiveness of the demand for imbalance energy (MW per €/MWh)
β _{3...5}	= Effect of forecast errors on system imbalance (MW / MW)
α ₁	= Effect of the system imbalance on the imbalance price (€/MWh per MW)
α ₂	= Effect of IGCC on the imbalance price (€/MWh per MW)

³ Python code is made available on Github and can be accessed at: https://github.com/anselm-eicke/electricity_balancing

α_3	= Effect of the FRR price on the imbalance price (€/MWh per €/MWh)
α_0, β_0	= Constants (€/MWh and MW)
ε_t, μ_t	= Error terms (€/MWh and MW)

Effect of balancing incentives. At the core of our analysis is the effect of economic incentives on the system imbalance. These are included in Equation (3) as the responsiveness of the demand for imbalance energy to the imbalance price β_1 and to the intraday price β_2 . Estimates of these coefficients differing significantly from zero indicate price sensitivity and hence strategic deviations of BRPs.

Endogeneity. A causality problem arises from the endogeneity of price and quantity when estimating the price responsiveness of demand. If the demand for imbalance energy increases because of an exogenous demand shifter, imbalance prices will rise due to the upward sloping supply curve. This supply-driven rise implies a positive relationship between quantity and prices, counteracting the expected negative price-quantity relationship arising from the price responsiveness of demand. A simple regression on Equation (3) cannot isolate the price responsiveness of demand and yields a positive value for β_1 (Table 7).⁴

Instrumental variables. To overcome this classical endogeneity problem, we use instrumental variables. This is a common approach when estimating demand response in wholesale electricity markets (Bönte et al., 2015; Lijesen, 2007). As instruments for the system imbalance in the supply function (Equation 2), we use the forecast errors as presented above and the difference between the intraday and day-ahead price (Equation 4).⁵ In the demand function (Equation 3), the FRR prices serve as instruments for the imbalance price (Equation 5). The relevance and exclusion restrictions of the instruments are discussed below.

$$Q_t = \gamma_1 \cdot \text{err}_{load,t} + \gamma_2 \cdot \text{err}_{solar,t} + \gamma_3 \cdot \text{err}_{wind,t} + \gamma_4 \cdot (ID1_t - DA_t) + \gamma_0 + \sigma_t \quad (4)$$

$$P_t = S_t \cdot (\delta_{1S} \cdot FRR_t^+ + \delta_{0S}) + L \cdot (\delta_{1L} \cdot FRR_t^- + \delta_{0L}) + \tau_t \quad (5)$$

Estimator. We simultaneously estimate the system of equations, using the Generalized Method of Moments System Estimator (GMM) estimator (Kevin Sheppard, 2020; Arellano and Bover, 1995). As compared to the statistically more efficient three-stage least squares approach, the GMM estimator allows for a non-normal distribution and heteroscedasticity in the input data.

3.2 Relevance and exclusion restrictions of instruments

Relevance and exclusion restriction. To be valid instruments, the explanatory variables in Equations (4) and (5) must fulfill the relevance and exclusion restrictions. The relevance of instruments, i.e. their strong first stage, is theoretically explained in Section 2: the instruments used are also supply and demand shifters.⁶ Empirically, ordinary least squares regressions confirm the relevance of all instruments (Annex Table 6). To satisfy the exclusion restriction, instruments must not explain variations of the dependent variable except through the replaced endogenous variable, which we discuss in the following.

⁴ Technically, the error terms of the equations (2) and (3) correlate with the endogenous explanatory variables, violating the strict exogeneity condition.

⁵ We use this price spread instead of the ID1 price to satisfy the exclusion restriction, as we will justify in the following.

⁶ We replace one instrument for the system imbalance to satisfy the exclusion restriction. Instead of the ID1, we employ the difference between ID1 and DA, i.e. the price spread between day-ahead market and last hour of intraday electricity trading.

Wind, solar and load forecasts. Wind and solar forecasts are based on meteorological models that are used for general weather forecasting and the imbalance price does not impact the outcome of these models in the short term. Load forecasts stem from standardized load profiles based on historical data for small electricity consumers and account for production decisions of large consumers. We cannot think of any way these forecast errors could impact the imbalance price in the short term other than through the demand for imbalance energy. Only in the long run, high imbalance prices could theoretically incentivize improvements in the quality of forecasts. Given that weather forecasts are used for multiple purposes, it seems unlikely that imbalance prices have any impact.

Intraday prices. Arguing for the exclusion restriction for the intraday electricity price is challenging, for two reasons. First, the imbalance price is directly linked to the intraday price under certain conditions. If the system is short of energy, the volume-weighted average hourly intraday price serves as a lower bound to the quarter-hourly imbalance price; if the system is long, the hourly intraday price serves as an upper bound. This explicit linkage violates the exclusion restriction in times when the floor or cap is binding. We therefore drop all possibly affected observations from the sample.⁷ A second causal link between the imbalance price and the intraday price stems from the time-varying opportunity costs of balancing services providers. As an alternative to provide balancing reserves, balancing service providers could sell electricity on the wholesale market. Wholesale electricity prices thus affect the opportunity costs of balancing service providers and their bids. To satisfy the exclusion restriction, we use the price difference between the day-ahead market and the prices in the last hour of intraday trading (ID1). We thereby exploit the sequencing of these market segments: the procurement auctions of balancing reserves are conducted before the day-ahead wholesale market auction is held, and intraday trading starts only afterwards⁸. While the opportunity costs of balancing service providers are reflected in day-ahead prices, the spread between day-ahead and intraday prices is uncorrelated with these opportunity costs (Narajewski and Ziel, 2019).

FRR prices. The applied FRR prices are a proxy for the activation cost of balancing reserves, i.e. the energy price suppliers of balancing reserves receive. We calculate this proxy as the average of all winning bids of the automatic and manual FRR auctions, weighted with the dispatch probability depending on their position in the merit order of balancing reserves. We argue that this indicator does not affect the system imbalance other than through the imbalance price. Because the dispatch probability is calculated over the timespan of 14 months, this proxy for FRR prices is unaffected by system imbalances in specific quarter hours. We find no evidence for other chains of interaction between FRR prices and the system imbalance.

3.3 Data

Time covered. We calibrate the model with German data between July 12, 2018 and September 29, 2019. The start date was set to the day when automatic FFR auctions first took place on a daily basis for four-hour periods. The end date was set to the latest day for which we could obtain publicly

⁷ We do not know in which hours price coupling actually occurred and therefore exclude all observations in which it might have occurred (loss of around 14% of observations), i.e. quarter hours in which the average hourly intraday price equals the imbalance price or is up to EUR 3 per MWh higher. This markup is the highest possible mark-up on the imbalance price resulting from additional corrections after price coupling.

⁸ In Germany, automatic and manual FRR are procured at 8 and 10 a.m., respectively, the day-ahead auction is held at 12 p.m., and intraday trading starts at 3 p.m., one day ahead of delivery.

available price data from the EPEX website. The dataset covers 41 553 quarter hours. Within the period of investigation, there were two major regulatory changes: first the introduction and later the abolishment of a new winner selection rule in the auctions for balancing reserves.⁹ These regulatory changes mainly affected FRR prices and are hence captured in our model through this supply shifter.

Imbalance price and system imbalance. Data on the imbalance price and the system imbalance are taken from the German TSO TenneT, covering all of Germany. These two variables are depicted in Figure 4; the color indicates the density of observations.

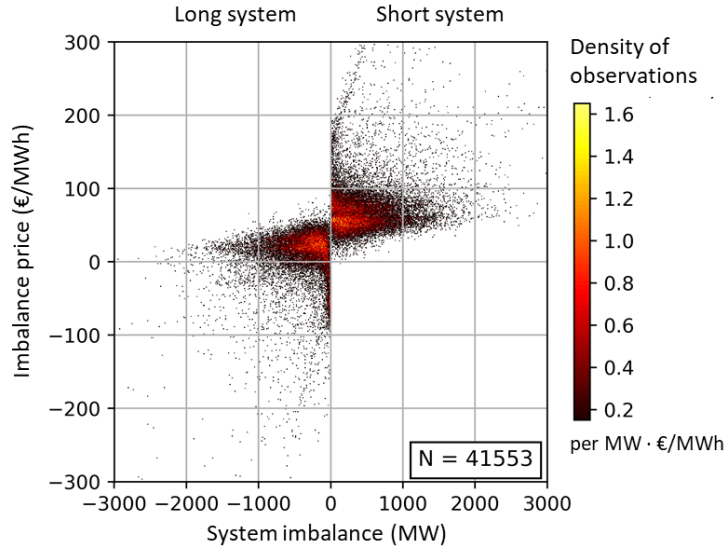


Figure 4: Historical observations of quarter hourly imbalance price and system imbalance from July 2018 to September 2019.

Data selection. Based on the system imbalance, we group the dataset into short and long systems (Section 2). From the resulting two subsets of data, we make the following exclusions.

Significant system imbalances. First, we limit our analysis to system imbalances above 500 MW and below -500 MW. For smaller imbalances, the assumption of a linear supply curve is questionable, due to the imbalance pricing mechanism: abstracting from technical details, the imbalance price in each quarter hour is the ratio between the reserve activation costs and the average system imbalance. For quarter-hours with small average system imbalances, the activation costs may be substantial when positive and negative reserves are activated.¹⁰ These costs divided by a small quarter-hourly average system imbalance lead to extraordinary high prices, with a discontinuity between high positive prices for slightly positive and high negative prices for slightly negative system imbalances (see Figure 4). To avoid unreasonably high prices for small system imbalances, the German regulator introduced a linear cap on the imbalance price (based on the intraday price) for absolute imbalances below 500 MW (also visible in Figure 4). To sum up, the supply curve for small system imbalances has a hyperbolic instead of a linear form, is discontinuous and capped by regulation. This limits the explanatory power of the model to significantly imbalanced systems, but these are of most interest to system stability. Dropping

⁹ This different procurement system with the German name “Mischpreisverfahren” was in place from October 16, 2018 to July 31, 2019 (Ehrhart and Ocker, 2020).

¹⁰ The continuous imbalance may vary between positive and negative values within the quarter-hourly settlement period.

these cases reduces the number of observations to 13 450 (32% of the initial dataset). A sensitivity analysis for the threshold of which observations are included in the analysis shows that smaller thresholds of 300 MW and 400 MW lead to similar results (Annex, Table 9).

ID price coupling. Second, we exclude all quarter hours in which the imbalance price was potentially coupled to the intraday price because such linkage violates the exclusion restriction of the imbalance price as an instrument for the intraday price (Section 3.2), reducing the dataset to 11 817 quarter hours (28% of the initial dataset).

Intraday prices. Intraday prices, which serve as demand shifters, are taken from EPEX Spot, the largest power exchange in Germany. The intraday market is characterized by varying prices because bids and offers are continuously settled throughout the trading period. If BRPs strategically deviate, the relevant intraday price will be the one shortly before gate closure, when most information about the (uncertain) system imbalance and imbalance price is available. We therefore use the ID1 price, which is the volume-weighted average price of all trades during the last hour before delivery. The ID1 indicator reflects about 30% of intraday trades (EPEX SPOT, 2020a).

Forecast errors. We define forecast errors as the difference between forecasted and actual values. We employ forecast errors for solar and load based on day-ahead forecasts, which is publicly available. For wind, we use non-public intraday forecasts errors, which are available to traders shortly before intraday gate closure. We expect these intraday forecasts to better explain the system imbalance as compared to day-ahead forecasts. A comparison with day-ahead wind generation forecasts confirms this expectation but shows that the effect on the overall results is small (Annex, Table 8).

Supply shifter. As supply shifter, we use the average of the energy prices of accepted automatic and manual FRR bids, weighted with the activation probability depending on their position in the merit order of balancing reserves. We derive the activation probability of the different FRR types during the entire investigation period from quarter-hourly activation time series, conditional on a system imbalance above 500 MW for positive reserves and below -500 MW for negative reserves.¹¹ Table 2 provides an overview of all parameters, their sources, and their mean value for the two subsets.

¹¹ Technically, we calculate the complementary cumulative distribution function of reserve activation, i.e. the probability of FRR activation exceeding a certain threshold. The underlying time series are retrieved from Regelleistung.net (2020).

Table 2: Parameter description, mean values, and sources

Parameter	Description	Mean (system short)	Mean (system long)	Source
System imbalance	Net imbalance in the Germany electricity system (net sum of all four TSOs)	903 MW	-839 MW	TenneT TSO (2020)
Imbalance price (German: <i>reBAP</i>)	Charge (or compensation) that BRP pay (or receive) for deviations of physical positions from schedules.	83 €/MWh	3 €/MWh	TenneT TSO (2020)
Intraday price (ID1)	Weighted average price of all trades executed in the last hour before delivery	55 €/MWh	31 €/MWh	EPEX Spot (2020b)
Load forecast error	Difference between forecasted and realized volume (forecast minus realized).	-2029 MW	-756 MW	ENTSO-E (2020)
Wind forecast error	We employ (public) day-ahead forecasts for load and solar, and (non-public) ID forecasts for wind.	322 MW	-335 MW	ENTSO-E (2020) (for DA data)
Solar forecast error		-181 MW	-214 MW	ENTSO-E (2020)
FRR ⁺ price (upward)	FRR energy prices reflecting the activation cost of balancing reserves; average of accepted automatic and manual FRR bids, weighted with their probability of activation.	127 €/MWh	-	Regelleistung.net (2020)
FRR ⁻ price (downward)		-	160 €/MWh	Regelleistung.net (2020)
IGCC	Net import of balancing energy through IGCC; a positive IGCC value reduces the German system imbalance	195	-159	Regelleistung.net (2020)

3.4 Model limitations

Limitations of the model. Using the GMM model, we apply the presented analytical framework to the German imbalance system. This yields quantitative insights on the behavior of balancing responsible parties. However, a few shortcomings are worth noting. First, we assume linear supply and demand curves. While this is certainly a strong simplification, we deem it acceptable for the comparatively high imbalances we analyze. Second, the econometric model aims at analyzing overarching trends, and performs relatively poor when forecasting imbalances in specific hours. This is due to changes in the levels of explanatory variables throughout the analyzed period. A trade-off is that longer periods of investigation increase the validity of the model due to the higher number of observations while shorter time periods imply smaller changes in the level of parameters. Third, to satisfy the exclusion restriction, we exclude a significant amount of observations, mainly with small system imbalances. Technically, our results thus only hold for quarter hours in which the system is significantly short or significantly long, but we argue that these are the most relevant ones for system stability.

4 Results and discussion

This section presents and discusses the results of the econometric model. We find a significant price response of BRPs to balancing incentives, which we interpret and quantify. In a last step, we discuss under which circumstances strategic deviations are problematic.

4.1 Strategic deviations are happening

Results overview. Table 3 shows the model results for a combined estimation of short and long systems (1) and for separate estimates for situations when the system was short (2) and long (3) of energy. As expected, all coefficients except the constant are similar in all three models. The constant is different across the models because of the exclusion of observations with absolute imbalances smaller than 500 MW. Nearly all results are significant at a p-level of 0.1% and all coefficients have the expected sign.

Effect of balancing incentives. According to the estimates, an increase in the imbalance price by EUR 1 per MWh causes a decrease in the absolute system imbalance of about 2.8 MW.¹² This indicates that the demand for imbalance energy is price-elastic. An increase by EUR 1 per MWh in the ID1 price leads to an increase in the system imbalance of about 7.3 MW. This suggests that BRPs respond to both imbalance and intraday prices, in the way we would expect in case of strategic deviations: high imbalance prices incentivize BRPs to reduce individual shortages or to deliberately take long positions. High intraday prices have the opposite effect because the intraday price reflects the costs of reducing shortages and of buying long.

Strategic deviations are happening. By itself, the fact that the coefficients of the imbalance price and the intraday price are statistically significantly different from zero is an important piece of evidence: it suggests that BRPs respond to these prices with strategic deviations. This is remarkable because BRPs in Germany are legally obliged to minimize their imbalance regardless of the price. We will discuss the magnitude and consequences of these strategic deviations in more detail in the following subsections.

¹² An increase in the imbalance prices reduces a positive system imbalance and increases a negative system imbalance.

Table 3: GMM estimation of coefficients for the combined model and for the separate models of short and long systems

	(1) Combined model	(2) System short	(3) System long
Demand curve			
Dependent variable: System imbalance (MW)			
Instruments:	FRR ⁺ and FRR ⁻ prices	Instrument: FRR ⁺ price	Instrument: FRR ⁻ price
Imbalance price (€/MWh)	-2.81**	-3.18**	-1.49*
Intraday price (MW)	7.26**	8.58**	5.76**
Load forecast error (MW)	-0.02**	-0.03**	-0.01
Wind forecast error (MW)	0.10**	0.12**	0.07**
Solar forecast error (MW)	0.05*	0.08*	0.01
Constant (MW)	656** -1 030**	580**	-1 013**
Supply curve			
Dependent variable: Imbalance price (€/MWh)			
Instruments: imbalance price; ID1-DA; load, wind, and solar forecast error)			
System imbalance (MW)	0.08**	0.07**	0.10**
IGCC (MW)	-0.05**	-0.07**	-0.06**
FRR ⁺ price (€/MWh)	0.37**	0.35**	-
FRR ⁻ price (€/MWh)	-0.03*	-	-0.12**
Constant (€/MW)	-25* 65**	-13	95**

** significant at $p < 0.001$, * significant at $p < 0.05$

Plausible other coefficients. The other coefficients have the expected sign and are of plausible size. Load forecast errors have a negative impact, while generation forecast errors have a positive impact on the system imbalance. This is as expected: the system becomes longer through positive load forecast errors (i.e. load is lower than expected) and shorter at positive generation forecast errors (i.e. generation is lower than expected). Wind forecast errors have a significantly higher impact on the system imbalance than the other forecast errors. This can be explained by the use of intraday forecasts errors for wind and day-ahead data for load and solar. Most of the day-ahead forecast errors are compensated by BRPs through intraday trading (all forecast error coefficients have similar magnitudes when using day-ahead forecast errors also for wind, Annex Table 8). The effect of the FRR price is also as expected: positive FRR reserves are activated in short systems. Higher prices for these reserves cause higher costs for reserve activation, increasing the imbalance price. In long systems, the activation of more costly negative reserves (further) reduces the (often negative) imbalance price. The net import of IGCC substitutes the activation of positive reserves or requires the activation of negative reserves and hence has a negative impact on the imbalance price.

Robustness. The model results are robust against changes in the data set. Reducing the threshold value for the data exclusion to ± 400 MW and ± 300 MW and using day-ahead wind forecast errors instead of intraday data does not change the model outcome significantly (Annex, Table 8 and Table 9). Controlling for season (summer, winter and mid-season), business days, position of quarter hour in a full hour, and hour of the day barely affect results (Annex, Table 10).

Problem of endogeneity. Table 7 in the Annex compares our estimates to a regression on the demand curve without instrumental variables (Equation 3). It shows that ignoring the endogeneity induced through the simultaneity of price and quantity biases the estimated impact of the imbalance price on

the system imbalance: the results without instruments show a smaller magnitude and an opposing sign of the coefficient. Hence, estimating the price elasticity in imbalance markets without instruments can be highly misleading.

4.2 Interpreting the magnitude of strategic deviations

Response to imbalance prices. Figure 5 shows the observed market equilibria for each moment in time (dots) and the estimated demand and supply curves for one hypothetical moment in which all shifters are at average values. Independent of the position, the estimated responsiveness of BRPs to the imbalance price is reflected in the slope of the demand curve, which is linear by assumptions.

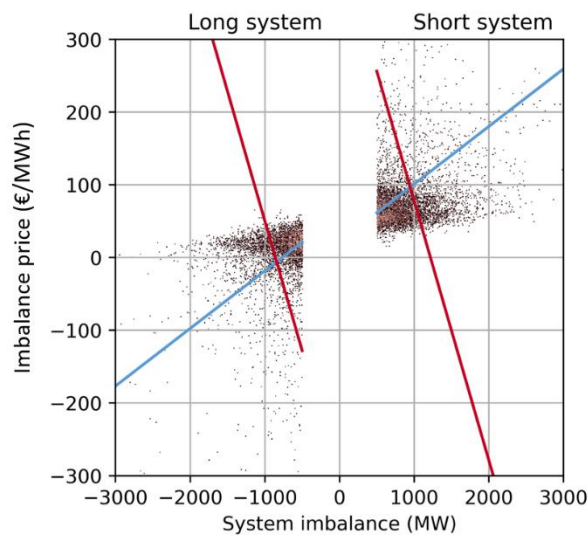


Figure 5: Supply and demand curves for imbalance energy based on the model results of Section 3.4 (exemplary curves for average values of supply and demand shifters)

Response to intraday prices. What cannot be seen in Figure 5: BRPs also respond to changes in the intraday price, which shifts the demand curve. The results show that this responsiveness to the intraday price is nearly three times stronger than the responsiveness to the imbalance price. This is plausible because intraday prices are known at the time of trading while imbalance prices are not.

Response to a typical price change. To illustrate the magnitude of the price-responsiveness, consider the effect of an exemplary ceteris paribus change of EUR 20 per MWh in the imbalance price and in the intraday price, respectively. Although imbalance and intraday prices are correlated, a ceteris paribus change in this order of magnitude is conceivable. To estimate the impact on the system imbalance, we multiply this price delta with the estimated price-responsiveness from the combined model. According to our estimates, an increase in the imbalance price by EUR 20 per MWh leads to a decline of the system imbalance by 56 MW, and an increase of the intraday price by EUR 20 per MWh causes an increase in the system imbalance by 145 MW, and vice versa. Compared to an average absolute system imbalance of about 900 MW (Table 2), this corresponds to a quite significant change of 6-16% in the system imbalance.

Response equivalent to contracted reserves. Another way to interpret the coefficients is to compare them to the approximately 3 000 MW of balancing reserves currently contracted in Germany. According to the model results, a ceteris paribus change in the imbalance price by about EUR 1 000

per MWh would be sufficient to retrieve (or relieve) all contracted reserves. Similarly, a *ceteris paribus* shock on the intraday price by about EUR 400 per MWh would also deplete (or relieve) all balancing reserves. However, such large price responses to a shock in one of these prices would also affect the other price, which would have a counterbalancing effect on the system imbalance.

Comparison to previous literature. These findings support the finding of (Koch and Maskos, 2019), who reveal the occurrence of strategic deviations in the current German market. Moreover, our findings highlight a shortcoming of the imbalance price spread (Equation 1), which has been assumed to provide the economic incentive for position taking in the previous literature (Koch and Hirth, 2019; Hirth and Ziegenhagen, 2015). By definition, the spread is calculated *ex post*. At the time of trading and dispatch decisions, the imbalance price is unknown to firms, while intraday prices can be observed. While the imbalance price spread does not reflect this difference in uncertainty, our empirical model does. Results indicate that market parties respond about three times stronger to intraday price changes than to imbalance price changes, suggesting that it is important to take price risk into account when assessing responses of firms to incentives.

4.3 Quantifying the impact of strategic deviations

Impact of strategic deviations. After having demonstrated the statistical significance of strategic deviations, the question remains whether they relieve or stress the system imbalance. This question can be decomposed into two parts:

1. In which quarter-hours do BRPs relieve/stress the system imbalance?
2. By how much do BRPs relieve/stress the system imbalance?

Ex-post perspective. A straight-forward approach to address the first sub-question is the evaluation of what would have been beneficial from an *ex-post* perspective, based on the imbalance price spread. This assumes that BRPs have perfect foresight on the imbalance price when deciding to strategically deviate from schedules and neglects that intraday prices vary around the ID1 average, both of which is not the case. From this perspective, it would have been beneficial for BRPs to relieve the system imbalance in about 90% of the time (Table 4).

Table 4: *Balancing incentives between 07.2018 and 09.2019 in the German system*

	System short	System long
Imbalance price > ID1 price	90.5%	9.3%
ID1 price > Imbalance price	9.5%	90.7%

Ex-ante perspective. In reality, BRPs respond to the observed, and continuously varying, intraday price and to the expected, and hence uncertain, imbalance price. We do not know these *ex-ante* incentives – they are private information to the BRPs. Instead, our estimates are based on *ex-post* information, but the estimated response of BRPs to this information considers variability of intraday prices and the uncertainty associated with predicting the imbalance price when taking positions.

Strategic deviations with equal effects. In our linear model, an increase in the imbalance price always has a depressing effect on the system imbalance in short systems, while an increase in the intraday price persistently causes an increase in the system imbalance. The estimated coefficients reveal that,

to compensate an increase in the intraday price by EUR 1 per MWh, the imbalance price must increase by EUR 2.58 per MWh¹³. This is visualized by the orange line in Figure 6, which highlights price combinations with the same effect on the system imbalance; its slope is 2.58. However, the model does not provide information on the combination of imbalance and intraday prices for which the net strategic deviations of all BRPs are zero, i.e. the y-intercept of a line through all price combinations where no strategic deviations occur.

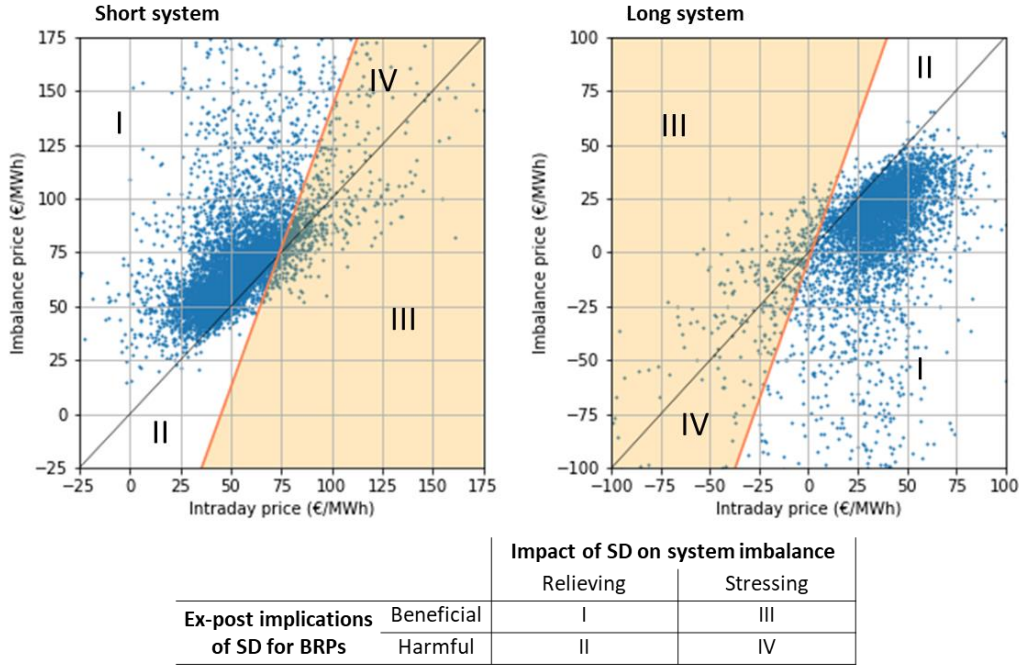


Figure 6: Distinction between strategic deviations relieving the system imbalance (white area) and those stressing the system imbalance (orange area)

Methodology. Some price combinations cause strategic deviations to relieve the system imbalance while others stress it. To distinguish them, we assume that BRPs deteriorate the system imbalance as often as there is an ex-post benefit to do so (see Table 4). If this were not the case, BRPs would structurally under- or overestimate the likelihood of such events. This assumption allows to distinguish quarter hours in which strategic deviations relieve the system imbalance (white area in Figure 6) and those in which strategic deviations aggravate it (orange area in Figure 6). This behavior does not always correspond to situations in which stressing the system imbalance was actually beneficial for BRPs (above the black line in short systems and below the black line in long systems). We explain this discrepancy by the uncertainty of the imbalance price predictions and the risk aversion of BRPs. Based on this assumption and on the estimated responsiveness to intraday and imbalance prices, we estimate the effect of strategic deviations in every quarter-hour.

Average impact of strategic deviations. As argued before, strategic deviations mostly relieve and only sometimes stress the system imbalance. We find that the average effect of strategic deviations is stronger when they have a positive effect (Table 5). Overall, strategic deviations relieve the system imbalance on average by 194 MW in short and by 204 MW in long systems (Table 5). Compared to an

¹³ Ration of price effect on system imbalance: $(7.26 \text{ MW}/(\text{€/MWh})) / (2.81 \text{ MW}/(\text{€/MWh})) = 2.58$

average imbalance of about 900 MW in the reviewed systems with significant system imbalances (Table 2), strategic deviations relieve the system imbalance on average by about 20% .

Table 5: Estimated effect of strategic deviations on the system imbalance

(MW)	Short system	Long system
Strategic deviations <i>relieve</i> system imbalance (I + II)	-194	204
Strategic deviations <i>stress</i> system imbalance (III+ IV)	136	-134
Average effect (time weighted)	-162	172
Highest observed system imbalance with strategic deviations	8 068	-3 417
Highest estimated system imbalance without strategic deviations	10 362	-7 403

Impact of strategic deviations on peak demand. Not only do strategic deviations reduce the average system imbalance, they also lower the peak demand for imbalance energy. According to our model, the peak demand in the investigated period declines significantly in long and short systems (Table 5). Note that the highest observed and the highest estimated system imbalances occur at different moments in time. For example, the highest observed system imbalance occurred on June 12, 2019 when our results indicate that strategic deviations stressed the system by approximately 5.3 GW¹⁴. Yet, we estimate that without strategic deviations the system imbalance would have been significantly higher on August 10, 2019, when we estimate strategic deviations responded to the extraordinarily high imbalance price of EUR 2 800 per MWh and relieving the system imbalance by approximately 9 GW.

Comparison to literature. Koch and Maskos (2019) estimate that strategic deviations reduce the German system imbalance on average by 6 to 48 MW.¹⁵ While we also find that strategic deviations are on average beneficial for the system imbalance, the magnitude of our estimate is substantially larger. We explain this divergence by the fact that Koch and Maskos (2019) base their analysis on effected ID trades, while our definition of strategic deviations also includes not closing open positions at the ID market (which does not result in a trade). Another difference is that Koch and Maskos (2019) base their estimates on all observed quarter-hours, while we only consider significantly imbalanced systems.

¹⁴ On this day, the ID1 was EUR 456 per MWh, while the imbalance price was only EUR 377 per MWh. The large system imbalance almost led to a blackout (see also Ehrhart and Ocker, 2020).

¹⁵ Koch and Maskos (2019) estimate that strategic deviations relieve the absolute system imbalance by 57 to 422 GWh/a, which equals on average 6 to 48 MW. According to the authors, strategic deviations relieve the 95% quantile absolute system imbalance by 16 to 129 MW. They do not estimate the peak demand for imbalance energy.

4.4 Are strategic deviations a problem?

Cost perspective. We find that strategic deviations, on average, lower the demand for positive and negative imbalance energy. This reduces the activation of balancing reserves and thereby saves activation costs. In addition, our results indicate that the cost of reserving balancing capacity, which depend on the maximum system imbalance, also declines due to strategic deviations.

Cost-efficiency: marginal cost. Reducing the activation of balancing reserves and the related costs may appear promising, but is not an end in itself. It will only be cost-efficient if electricity can be contracted from less expensive generators on the intraday market. By contrast, when intraday prices are very high, it may be cost-efficient to employ balancing reserves instead. BRPs would solve this trade-off cost-efficiently through strategic deviations when intraday and imbalance prices reflected the marginal cost of electricity generation. RPs would then have the incentive to open and/or close individual positions until the marginal cost for doing so equals the marginal cost of reserve activation. This is not the case in Germany, where the imbalance settlement price reflects average, not marginal, activation cost of balancing reserves. Hence, the (absolute) imbalance price is always below the marginal cost of reserve activation.

Cost-efficiency: predictability and permission. Under this condition, improving the predictability of the imbalance price and permitting BRPs to respond to balancing incentives can be expected to help cost-efficiency. Imbalance prices that reflect marginal cost will always be unknown at the time of trading. Yet, in Germany, the imbalance price is published only 20 working days after delivery and the activation of reserves about 10 minutes after delivery. Such late publications deteriorate the predictability of the imbalance price. Also, BRPs are not allowed to respond to balancing incentives in Germany. Even though we find that BRPs still respond to these incentives, their response is presumably less efficient because of this restriction and the incurred legal risk.

Security of supply. Of course, the purpose of balancing energy regulation goes beyond cost-efficient dispatch: it should also ensure security of supply and avoid costs of supply interruptions. Our results indicate that strategic deviations reduce the peak demand for balancing energy, which is beneficial for the security of supply. On the other hand, in some situations, strategic deviations also aggravate extreme system imbalances, such as on June 12, 2019. We trace this back to perverse incentives that reward stressing the system imbalance. Whether strategic deviations are beneficial for the security of supply hence depends on the respective economic incentives.

5 Conclusion

Empirical findings. In this paper, we propose a framework to interpret the balancing system as a fictive imbalance market. We apply this framework to empirical data of the German balancing system and find evidence that BRPs respond to balancing incentives. The proposed approach allows to disentangle the response to balancing incentives into two components: the response to the imbalance price and the response to the intraday price. According to our model, the system imbalance declines by 2.8 MW for each increase in the imbalance price by EUR 1 per MWh and rises by 7.3 MW for a EUR 1 per MWh increase in the intraday price. Such strategic deviations are, although prohibited, not necessarily problematic. In quarter hours in which the system was significantly imbalanced, such strategic

deviations reduced the system imbalance by about 200 MW, corresponding to 20% of the average imbalance.

Policy recommendation. Because strategic deviations happen despite their prohibition, regulators should ensure the underlying incentives encourage a behavior that enhances system stability and reduces system costs. We see two different strategies to enhance the incentive design. One approach is to reduce imbalance price spreads that reward BRPs for stressing the system imbalance. This seems to be the approach of the German regulator who recently revised the price coupling mechanism to ensure that the imbalance price is always higher (lower) than the intraday price for short (long) systems (BNetzA, 2020). Alternatively, regulation can aim for more cost-reflective balancing incentives, which would imply that the profit-maximizing behavior of market participants reduces the overall system costs. Important steps for this second approach are imbalance prices reflecting the marginal costs of balancing reserves, higher transparency on the imbalance price, and the legalization of strategic deviations. While this is currently not the strategy of the German regulator, these steps are already undertaken in other countries such as the Netherlands.

Methodology evaluation. Interpreting the balancing system as a fictive marketplace for imbalance energy offers new insights on balancing incentives. This perspective can improve understanding the short-term response of BRPs to these incentives and can thus help to design incentives adequately. The empirical evidence for a price responsiveness of the system imbalance supports the theoretical foundation of the proposed framework. Methodology-wise, we apply instruments to address the endogeneity of imbalance price and system imbalance. The importance of instrumentation is confirmed by the empirical results: estimates without instrumental variables even lead to opposite signs. Future research could enhance the presented econometric model, e.g. by a nonlinear estimation of the supply and demand curves. In addition, the framework could be used to study the effect of different market designs by comparing the price responsiveness across countries.

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7 Annex

Table 6: Relevance of instruments (OLS regressions)

Dependent variable: System imbalance (MW)	R-squared: 0.436
ID-DA price (€/MWh)	16.51**
Load forecast error (MW)	-0.10**
Wind forecast error (MW)	0.38**
Solar forecast error (MW)	0.17**
Constant (MW)	-41.69**
Dependent variable: Imbalance price (€ / MW)	R-squared: 0.282
FRR+ price (€/MWh)	0.33**
FRR- price (€/MWh)	-0.02**
Constant (positive)	40.52**
Constant (negative)	6.44**

** significant at $p < 0.001$

Table 7: Estimation results without instruments

	(1) Combined model	(4) Demand without instruments	(5) Supply without instruments
Demand curve (Instruments: positive and negative FRR price)			
Dependent variable: System imbalance (MW)			
Imbalance price (€/MWh)	-2.81**	0.29*	
Intraday price (MW)	7.26**	5.05**	
Load forecast error (MW)	-0.02**	-0.01**	
Wind forecast error (MW)	0.10**	0.08**	
Solar forecast error (MW)	0.05*	0.05**	
Constant (MW)	656** -1 030**	539** -972**	
Supply curve (Instruments: imbalance price; ID1-DA; load, wind, and solar forecast error)			
Dependent variable: Imbalance price (€/MWh)			
System imbalance (MW)	0.08**		0.04**
IGCC (MW)	-0.05**		-0.05**
FRR+ price (€/MWh)	0.37**		0.35**
FRR- price (€/MWh)	-0.03*		-0.02**
Constant (€/MW)	-25* 65**		10 34**

** significant at $p < 0.001$, * significant at $p < 0.05$

Table 8: Sensitivity analysis: Day-ahead vs. intraday forecast errors

	(1) Combined model Intraday wind forecast error	(6) Combined model Day-ahead wind forecast error
Demand curve (Instruments: positive and negative FRR price)		
Dependent variable: System imbalance (MW)		
Imbalance price (€/MWh)	-2.81**	-2.55**
Intraday price (MW)	7.26**	5.55**
Load forecast error (MW)	-0.02**	-0.02**
Wind forecast error (MW)	0.10**	0.04**
Solar forecast error (MW)	0.05*	0.05*
Constant (MW)	656** -1 030**	735** -973**
Supply curve (Instruments: imbalance price; ID1-DA; load, wind, and solar forecast error)		
Dependent variable: Imbalance price (€/MWh)		
System imbalance (MW)	0.08**	0.04**
IGCC (MW)	-0.05**	-0.05**
FRR ⁺ price (€/MWh)	0.37**	0.34**
FRR ⁻ price (€/MWh)	-0.03*	-0.05*
Constant (€/MW)	-25* 65**	-9.5 39**

** significant at p<0.001, * significant at p<0.05

Table 9: Sensitivity analysis: Varying the thresholds of data selection (combined model)

	(1)	(7)	(8)	(9)
Data selection	SB > 500 MW or SB < -500 MW	SB > 400 MW or SB < -400 MW	SB > 300 MW or SB < -300 MW	SB > 200 MW or SB < -200 MW
Number of observations	11817	15112	19 147	23 976
Demand curve (Instruments: positive and negative FRR price)				
Dependent variable: System imbalance (MW)				
Imbalance price (€/MWh)	-2.81**	-3.48**	-4.72**	-6.25**
Intraday price (MW)	7.26**	7.5**	8.39**	9.69**
Load forecast error (MW)	-0.02**	-0.02**	-0.02**	-0.03**
Wind forecast error (MW)	0.10**	0.10**	0.11**	0.12**
Solar forecast error (MW)	0.05*	0.05**	0.04*	0.03*
Constant (MW)	656** -1 030**	610** -948**	568** -887**	534** -837**
Supply curve (Instruments: imbalance price; ID1-DA; load, wind, and solar forecast error)				
Dependent variable: Imbalance price (€/MWh)				
System imbalance (MW)	0.08**	0.08**	0.05**	0.06**
IGCC (MW)	-0.05**	-0.06**	-0.06**	-0.07**
FRR ⁺ price (€/MWh)	0.37**	0.28**	0.60**	-0.63**
FRR ⁻ price (€/MWh)	-0.03*	-0.02*	-0.02*	0.01*
Constant (€/MW)	-25* 65**	-7 56**	-34 39**	-39 36**

** significant at p<0.001, * significant at p<0.05

Table 10: Controlling for season (summer, winter and mid-season), business days (business day and weekend), position of quarter hour in a full hour (:15, :30, and :45), and hour of the day (1:00 – 23:00)

	(1) Combined model uncontrolled	(6) Combined model controlled
Demand curve (Instruments: positive and negative FRR price)		
Dependent variable: System imbalance (MW)		
Imbalance price (€/MWh)	-2.81**	-2.95**
Intraday price (MW)	7.26**	7.46**
Load forecast error (MW)	-0.02**	-0.02**
Wind forecast error (MW)	0.10**	0.10**
Solar forecast error (MW)	0.05*	0.05*
Constant (MW)	656** -1 030**	664** -1 022**
Supply curve (Instruments: imbalance price; ID1-DA; load, wind, and solar forecast error)		
Dependent variable: Imbalance price (€/MWh)		
System imbalance (MW)	0.08**	0.07**
IGCC (MW)	-0.05**	-0.05**
FRR ⁺ price (€/MWh)	0.37**	0.37**
FRR ⁻ price (€/MWh)	-0.03*	-0.02*
Constant (€/MW)	-25* 65**	-25* 65**

** significant at p<0.001, * significant at p<0.05

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